DOMINION RESOURCES INC /VA/
Form 10-Q
July 31, 2008
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark one)

x **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the quarterly period ended June 30, 2008

or

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

Commission File Number 001-08489

DOMINION RESOURCES, INC.

(Exact name of registrant as specified in its charter)

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

(804) 819-2000

(Registrant s telephone number)

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, 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	x	Accelerated filer	¨
Non-accelerated filer	¨ (Do not check if a smaller reporting company)	Smaller reporting company	¨

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

At June 30, 2008, the latest practicable date for determination, 579,937,884 shares of common stock, without par value, of the registrant were outstanding.

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GLOSSARY OF TERMS

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

Abbreviation or Acronym	Definition
AOCI	Accumulated other comprehensive income (loss)
BBIFNA	A subsidiary of Babcock & Brown Infrastructure Fund North America
bcf	Billion cubic feet
bcfe	Billion cubic feet equivalent
Bremo	Bremo power station
CDO	Collateralized debt obligation
CEO	Chief Executive Officer
CFO	Chief Financial Officer
Dallastown	Dallastown Realty
DCI	Dominion Capital, Inc.
DD&A	Depreciation, depletion and amortization expense
DEI	Dominion Energy, Inc.
DEPI	Dominion Exploration & Production, Inc.
DOE	Department of Energy
Dominion Direct®	A dividend reinvestment and open enrollment direct stock purchase plan
Dominion East Ohio	The East Ohio Gas Company
Dresden	Partially-completed generation facility sold in 2007
DTI	Dominion Transmission, Inc.
DVP	Dominion Virginia Power operating segment
E&P	Exploration & production
EITF	Emerging Issues Task Force
EPA	Environmental Protection Agency
EPS	Earnings per share
Equitable	Equitable Resources, Inc.
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN	FASB Interpretation No.
FSP	FASB Staff Position
FTRs	Financial transmission rights
GAAP	U.S. generally accepted accounting principles
Gichner	Gichner LLC
Hope	Hope Gas, Inc.
kWh	Kilowatt-hour
Ladysmith	Ladysmith power station
LNG	Liquefied natural gas
Local 69-I	The Utility Workers Union of America, United Gas Workers Local 69-I, AFL-CIO
Local 69-II	The Utility Workers Union of America, United Gas Workers Local 69-II, AFL-CIO
mcf	Thousand cubic feet
mcfe	Thousand cubic feet equivalent
MD&A	Management s Discussion and Analysis of Financial Condition and Results of Operations
Moody s	Moody s Investors Services
Mw	Megawatt
mwhrs	Megawatt hours
North Anna	North Anna power station
North Carolina Commission	North Carolina Utilities Commission
NRC	Nuclear Regulatory Commission
ODEC	Old Dominion Electric Cooperative
Peaker facilities	Collectively, the three natural gas-fired merchant generation peaking facilities sold in March 2007
Peoples	The Peoples Natural Gas Company
PJM	PJM Interconnection, LLC

RTO	Regional transmission organization

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Abbreviation or Acronym	Definition
SEC	Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards
State Line	State Line power station
U.S.	United States of America
VIEs	Variable interest entities
Virginia City Hybrid Energy Center	A 585 Mw (nominal) coal-fired electric generation facility to be located in Wise County, Virginia
Virginia Commission	Virginia State Corporation Commission
Virginia Power	Virginia Electric and Power Company
VPEM	Virginia Power Energy Marketing, Inc.
VPP	Volumetric production payment
West Virginia Commission	The Public Services Commission of West Virginia

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DOMINION RESOURCES, INC.

PART I. FINANCIAL INFORMATION

ITEM 1. CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED STATEMENTS OF INCOME

(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions, except per share amounts)	**2008**	**2007**	**2008**	**2007**
Operating Revenue	**$ 3,452**	$ 3,730	**$ 7,841**	$ 8,391
Operating Expenses				
Electric fuel and energy purchases	**830**	910	**1,636**	1,828
Purchased electric capacity	**97**	109	**204**	228
Purchased gas	**689**	530	**1,876**	1,678
Other energy-related commodity purchases	**21**	64	**34**	120
Other operations and maintenance	**738**	1,934	**1,547**	2,762
Depreciation, depletion and amortization	**257**	423	**511**	832
Other taxes	**109**	140	**263**	323
Total operating expenses	**2,741**	4,110	**6,071**	7,771
Income (loss) from operations	**711**	(380)	**1,770**	620
Other income (loss)	**(1)**	43	**(4)**	92
Interest and related charges:				
Interest expense	**183**	239	**371**	459
Interest expense junior subordinated notes payable[1]	**23**	35	**50**	70
Subsidiary preferred dividends	**4**	4	**8**	8
Total interest and related charges	**210**	278	**429**	537
Income (loss) from continuing operations before income taxes, minority interest and extraordinary item	**500**	(615)	**1,337**	175
Income tax expense (benefit)	**200**	(232)	**357**	78
Minority interest		9		14
Income (loss) from continuing operations before extraordinary item	**300**	(392)	**980**	83
Extraordinary item[2]		(158)		(158)
Income (loss) from discontinued operations[3]	**(2)**	20	**(2)**	(2)
Net Income (Loss)	**$ 298**	$ (530)	**$ 978**	$ (77)
Earnings Per Common Share - Basic				
Income (loss) from continuing operations before extraordinary item	**$ 0.52**	$ (0.56)	**$ 1.70**	$ 0.12
Extraordinary item		(0.23)		(0.23)
Income from discontinued operations		0.03		

Net income (loss)	**$ 0.52**	$ (0.76)	**$ 1.70**	$ (0.11)
Earnings Per Common Share - Diluted				
Income (loss) from continuing operations before extraordinary item	**$ 0.51**	$ (0.56)	**$ 1.69**	$ 0.12
Extraordinary item		(0.23)		(0.23)
Income from discontinued operations		0.03		
Net income (loss)	**$ 0.51**	$ (0.76)	**$ 1.69**	$ (0.11)
Dividends paid per common share	**$ 0.395**	$ 0.355	**$ 0.79**	$ 0.71

(1) Includes affiliated interest expense of $9 million and $22 million for the three months ended June 30, 2008 and 2007, respectively, and $23 million and $44 million for the six months ended June 30, 2008 and 2007, respectively.

(2) Reflects a $259 million ($158 million after-tax) extraordinary charge in connection with the reapplication of SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*, to the Virginia jurisdiction of our generation operations.

(3) Net of income tax benefit of $3 million for the three and six months ended June 30, 2008. Net of income tax expense of $114 million and $113 million for the three and six months ended June 30, 2007, respectively. For the three and six months ended June 30, 2007, the expense includes $76 million and $56 million for U.S. federal and Canadian taxes, respectively, related to the gain on the sale of our Canadian E&P operations.

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

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DOMINION RESOURCES, INC.

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(millions)	June 30, 2008	December 31, 2007[1]
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 88**	$ 283
Customer receivables (less allowance for doubtful accounts of $30 and $37)	**2,044**	2,130
Other receivables (less allowance for doubtful accounts of $7 and $10)	**146**	226
Inventories	**1,038**	1,045
Derivative assets	**1,834**	775
Assets held for sale	**1,287**	1,160
Margin deposit assets	**610**	54
Prepayments	**588**	387
Deferred income taxes	**356**	
Other	**504**	610
Total current assets	**8,495**	6,670
Investments		
Nuclear decommissioning trust funds	**2,674**	2,888
Other	**837**	992
Total investments	**3,511**	3,880
Property, Plant and Equipment		
Property, plant and equipment	**34,694**	33,331
Accumulated depreciation, depletion and amortization	**(12,377)**	(11,979)
Total property, plant and equipment, net	**22,317**	21,352
Deferred Charges and Other Assets		
Goodwill	**3,496**	3,496
Pension and other postretirement benefit assets	**1,494**	1,565
Regulatory assets	**1,353**	957
Other	**1,375**	1,219
Total deferred charges and other assets	**7,718**	7,237
Total assets	**$ 42,041**	$ 39,139

(1) Our Consolidated Balance Sheet at December 31, 2007 has been derived from the audited Consolidated Financial Statements at that date and includes the impact of adopting FSP No. FIN 39-1, *Amendment of FASB Interpretation No. 39, Offsetting of Amounts Related to Certain Contracts*, as discussed in Note 3.

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

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DOMINION RESOURCES, INC.

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(millions)	June 30, 2008	December 31, 2007[1]
LIABILITIES AND SHAREHOLDERS EQUITY		
Current Liabilities		
Securities due within one year	**$ 715**	$ 1,477
Short-term debt	**2,478**	1,757
Accounts payable	**1,726**	1,734
Accrued interest, payroll and taxes	**567**	934
Derivative liabilities	**2,722**	694
Liabilities held for sale	**556**	492
Other	**592**	672
Total current liabilities	**9,356**	7,760
Long-Term Debt		
Long-term debt	**13,138**	11,759
Junior subordinated notes payable:		
Affiliates	**268**	678
Other	**798**	798
Total long-term debt	**14,204**	13,235
Deferred Credits and Other Liabilities		
Deferred income taxes and investment tax credits	**4,228**	4,253
Asset retirement obligations	**1,762**	1,722
Derivative liabilities	**1,008**	183
Other	**2,351**	2,295
Total deferred credits and other liabilities	**9,349**	8,453
Total liabilities	**32,909**	29,448
Commitments and Contingencies (see Note 16)		
Minority Interest		28
Subsidiary Preferred Stock Not Subject to Mandatory Redemption	**257**	257
Common Shareholders Equity		
Common stock no par[2]	**5,857**	5,733
Other paid-in capital	**184**	175
Retained earnings	**4,029**	3,510
Accumulated other comprehensive loss	**(1,195)**	(12)
Total common shareholders equity	**8,875**	9,406
Total liabilities and shareholders equity	**$ 42,041**	$ 39,139

(1) Our Consolidated Balance Sheet at December 31, 2007 has been derived from the audited Consolidated Financial Statements at that date and includes the impact of adopting FSP No. FIN 39-1, as discussed in Note 3.

(2) 1 billion shares authorized; 580 million shares outstanding at June 30, 2008 and 577 million shares outstanding at December 31, 2007.

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

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DOMINION RESOURCES, INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

Six Months Ended June 30, (millions)	2008	2007
Operating Activities		
Net income (loss)	$ 978	$ (77)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Dominion Capital, Inc. (DCI) impairment losses	62	8
Dresden impairment loss		387
Gain on sale of Canadian E&P operations		(194)
Extraordinary item, net of income taxes		158
Charges related to termination of volumetric production payment agreements		139
Net realized and unrealized derivative losses	66	517
Depreciation, depletion and amortization	576	922
Deferred income taxes and investment tax credits, net	322	(108)
Changes in:		
Accounts receivable	152	118
Inventories	24	191
Prepayments	(216)	(7)
Deferred fuel and purchased gas costs, net	(423)	59
Accounts payable	(28)	(116)
Accrued interest, payroll and taxes	(366)	(27)
Margin deposit assets and liabilities	(590)	(46)
Other operating assets and liabilities	(29)	49
Net cash provided by operating activities	528	1,973
Investing Activities		
Plant construction and other property additions	(1,509)	(947)
Additions to gas and oil properties, including acquisitions	(107)	(1,409)
Proceeds from sale of merchant generation peaking facilities		254
Proceeds from sale of Canadian E&P operations		448
Proceeds from sales of securities and loan receivable collections and payoffs	880	610
Purchases of securities and loan receivable originations	(825)	(657)
Other	(110)	27
Net cash used in investing activities	(1,671)	(1,674)
Financing Activities		
Issuance of short-term debt, net	721	413
Issuance of long-term debt	1,830	600
Repayment of long-term debt	(853)	(935)
Repayment of affiliated notes payable	(412)	
Issuance of common stock	120	116
Repurchase of common stock		(117)
Common dividend payments	(457)	(497)
Other	(2)	22
Net cash provided by (used in) financing activities	947	(398)

Decrease in cash and cash equivalents	**(196)**	(99)
Cash and cash equivalents at beginning of period[1]	**287**	142
Cash and cash equivalents at end of period[2]	**$ 91**	$ 43
Noncash Investing and Financing Activities:		
Accrued capital expenditures	**$ 67**	$ 165
Proceeds held in escrow from sale of Canadian E&P operations		156

(1) 2008 and 2007 amounts include $4 million of cash classified as held for sale in the Consolidated Balance Sheets.
(2) 2008 and 2007 amounts include $3 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.

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DOMINION RESOURCES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

Note 1. Nature of Operations

Dominion Resources, Inc., headquartered in Richmond, Virginia, is one of the nation s largest producers and transporters of energy. Our principal subsidiaries are Virginia Power, Dominion Energy, Inc. (DEI), Dominion Transmission, Inc. (DTI), Virginia Power Energy Marketing, Inc. (VPEM), Dominion Exploration & Production, Inc. (DEPI) and 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 June 30, 2008, Virginia Power served approximately 2.4 million retail customer accounts, including governmental agencies, as well as wholesale customers such as rural electric cooperatives and municipalities. Virginia Power is a member of PJM, a regional transmission organization (RTO), and its electric transmission facilities are integrated into the PJM wholesale electricity markets.

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

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

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

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

As of June 30, 2008, our regulated gas distribution subsidiaries, Dominion East Ohio, Peoples and Hope, served approximately 1.7 million residential, commercial and industrial gas sales and transportation customer accounts in Ohio, Pennsylvania and West Virginia. Approximately 500,000 of these customers are served by Peoples and Hope, which are held for sale, as discussed in Note 5.

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 June 30, 2008, our retail energy marketing operations served approximately 1.6 million residential and small commercial customer accounts in the Northeast, mid-Atlantic and Midwest regions of the U.S.

We manage our daily operations through three primary operating segments: Dominion Virginia Power (DVP), Dominion Energy and Dominion Generation. In addition, we also report a Corporate and Other segment that includes our service company functions, as well as the net impact of certain operations disposed of or to be disposed of, as discussed in Note 5. 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 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

As permitted by the rules and regulations of the SEC, our accompanying unaudited Consolidated Financial Statements contain certain condensed financial information and exclude certain footnote disclosures normally included in annual audited consolidated financial statements prepared in accordance with GAAP. These unaudited Consolidated Financial Statements should be read in conjunction with our Consolidated Financial Statements and Notes in our Annual Report on Form 10-K for the year ended December 31, 2007 and our Quarterly Report on Form 10-Q for the quarter ended March 31, 2008.

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In our opinion, the accompanying unaudited Consolidated Financial Statements contain all adjustments, including normal recurring accruals, necessary to present fairly our financial position as of June 30, 2008, our results of operations for the three and six months ended June 30, 2008 and 2007 and our cash flows for the six months ended June 30, 2008 and 2007.

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

Our accompanying unaudited Consolidated Financial Statements include, after eliminating intercompany transactions and balances, our accounts and those of our majority-owned subsidiaries.

In accordance with GAAP, we report certain contracts and instruments at fair value. Observable market prices are used to measure fair value when available. In the absence of this information, we estimate fair value based on near-term and historical price information and statistical methods. For individual contracts, the use of differing assumptions could have a material effect on the contract s estimated fair value. See Note 10 for further information on fair value measurements in accordance with SFAS No. 157, *Fair Value Measurements*.

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

Certain amounts in our 2007 Consolidated Financial Statements and Notes have been recast to conform to the 2008 presentation. See Note 3 for discussion of 2007 amounts that have been recast due to the adoption of FSP No. FIN 39-1, *Amendment of FASB Interpretation No. 39, Offsetting of Amounts Related to Certain Contracts*.

Note 3. Newly Adopted Accounting Standards

SFAS No. 157

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

Generally, the provisions of this statement are applied prospectively. Certain situations, however, require retrospective application as of the beginning of the year of adoption through the recognition of a cumulative effect of accounting change. Such retrospective application 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, *Accounting for Certain Hybrid Financial Instruments*. Retrospective application resulted in an immaterial amount recognized through a cumulative effect of accounting change adjustment to retained earnings as of January 1, 2008.

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

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

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 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.

See Note 10 for further information on fair value measurements in accordance with SFAS No. 157.

SFAS No. 159

The provisions of SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities*, became effective for us beginning January 1, 2008. SFAS No. 159 provides an entity with the option, at specified election dates, to measure certain financial assets and liabilities and other items at fair value, with changes in fair value recognized in earnings as those changes occur. SFAS No. 159 also establishes presentation and disclosure requirements that include displaying the fair value of those assets and liabilities for which the entity elected the fair value option on the face of the balance sheet and providing management s reasons for electing the fair value option for each eligible item. As of June 30, 2008, we had not elected the fair value option for any eligible items. Therefore, the provisions of SFAS No. 159 have not impacted our results of operations or financial condition.

FSP FIN 39-1

The provisions of FSP FIN 39-1 became effective for us beginning January 1, 2008. FSP FIN 39-1 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. Upon our adoption of FSP FIN 39-1, we revised our accounting policy to no longer offset fair value amounts recognized for certain derivative instruments and recast our prior year Consolidated Balance Sheet in order to retrospectively apply the standard. The adoption of FSP FIN 39-1 resulted in an increase in Derivative assets of $14 million, Other deferred charges and other assets of $2 million, Derivative liabilities-current of $14 million and Derivative liabilities-noncurrent of $2 million as of December 31, 2007. The adoption of FSP FIN 39-1 had no impact on our results of operations or cash flows.

EITF 06-4

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

EITF 06-11

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

Note 4. Recently Issued Accounting Standards

SFAS No. 141R

In December 2007, the FASB issued SFAS No. 141 (revised 2007), *Business Combinations*. SFAS No. 141R requires an acquirer to recognize the assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at their acquisition-date fair values. SFAS No. 141R also requires disclosure of 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. The provisions of SFAS No. 141R will become effective for acquisitions completed on or after January 1, 2009; however, the income tax provisions of SFAS No. 141R will become effective as of that date for all acquisitions, regardless of the acquisition date. SFAS No. 141R amends SFAS No. 109, *Accounting for Income Taxes*, to require the acquirer to recognize changes in the amount of its

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deferred tax benefits recognizable due to a business combination either in income from continuing operations in the period of the combination or directly in contributed capital, depending on the circumstances. SFAS No. 141R further amends SFAS No. 109 and FIN 48, *Accounting for Uncertainty in Income Taxes*, to require, subsequent to a prescribed measurement period, changes to acquisition-date income tax uncertainties and acquiree deferred tax benefits to be reported in income from continuing operations or directly in contributed capital, depending on the circumstances. For acquisitions completed before June 30, 2008, we do not expect these SFAS No. 141R provisions to have a material impact on our future results of operations or financial condition.

SFAS No. 160

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements.* SFAS No. 160 requires that noncontrolling (minority) interests be reported as a component of equity, net income attributable to the parent and to the 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 noncontrolling 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 do not expect the provisions of SFAS No. 160 to have an impact on our results of operations or financial condition.

SFAS No. 161

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities*. SFAS No. 161 requires enhancements to disclosures regarding derivative instruments and hedging activities accounted for under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*. The enhancements include additional disclosures regarding the reasons derivative instruments are used, how they are used, how these instruments and their related hedged items are accounted for under SFAS No. 133, as well the impact of these derivative instruments on an entity s results of operations, financial condition and cash flows. SFAS No. 161 requires the disclosure of the fair values of derivative instruments and associated gains and losses in a tabular format and derivative features that are credit-risk related. The provisions of SFAS No. 161 will become effective for us beginning January 1, 2009 and will have no impact on our results of operations or financial condition.

FSP EITF 03-6-1

In June 2008, the FASB issued FSP EITF 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities*. This FSP addresses whether instruments granted in share-based payment transactions are participating securities prior to vesting and, therefore, need to be included in the earnings allocation in computing earnings per share under the two-class method as described in SFAS No. 128, *Earnings per Share*. Under the guidance in FSP EITF 03-6-1, unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and shall be included in the computation of earnings per share pursuant to the two-class method. The provisions of FSP EITF 03-6-1 will become effective for us beginning January 1, 2009 and will be applied retrospectively. We do not expect FSP EITF 03-6-1 will have a material impact on our earnings per share.

FSP APB 14-1

In May 2008, the FASB issued FSP APB 14-1, *Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion (Including Partial Cash Settlement).* FSP APB 14-1 clarifies that convertible debt instruments that may be settled in cash upon conversion (including partial cash settlement) are not addressed by paragraph 12 of Accounting Principles Board Opinion No. 14, *Accounting for Convertible Debt and Debt Issued with Stock Purchase Warrants.* The FSP specifies that issuers of convertible debt instruments should separately account for the liability and equity components in a manner that will reflect the entity s nonconvertible debt borrowing rate when interest cost is recognized in subsequent periods. The provisions of FSP APB 14-1 will become effective for us beginning January 1, 2009 and will be applied retrospectively. We are currently evaluating the impact that FSP APB 14-1 will have on our results of operations and financial condition.

EITF 07-5

In June 2008, the FASB ratified the consensus on EITF 07-5, *Determining Whether an Instrument (or an Embedded Feature) Is Indexed to an Entity s Own Stock*. This issue addresses whether an instrument (or an embedded feature) is indexed to an entity s own stock, which is the first part of the scope exception in paragraph 11(a) of SFAS No. 133, for purposes of determining whether the instrument should be classified as an equity instrument or accounted for as a derivative instrument. The provisions of EITF 07-5 will become effective for us beginning January 1, 2009 and will be applied retrospectively through a cumulative effect adjustment to retained earnings for outstanding instruments as of that date. We do not expect EITF 07-5 to have a material impact on our results of operations or financial condition.

Note 5. Dispositions

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

In 2007, we completed the sale of our non-Appalachian natural gas and oil E&P operations and assets for approximately $13.9 billion. The results of operations for our U.S. non-Appalachian E&P operations 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. Due to the sale of our entire Canadian cost pool, the results of operations for our Canadian E&P operations are reported as discontinued operations in our 2007 Consolidated Statement of Income. For the three and six months ended June 30, 2007, our Canadian E&P operations reported $41 million and $82 million of operating revenue and $141 million and $149 million of income before income taxes, respectively. Income before income taxes, for the three and six months ended June 30, 2007, included a pre-tax gain of $194 million recognized on the sale.

Sale of Merchant Generation Facilities

In March 2007, we sold the Peaker facilities for net cash proceeds of $254 million. The results of operations of the Peaker facilities are reported as discontinued operations in our 2007 Consolidated Statement of Income. For the six months ended June 30, 2007, the Peaker facilities recorded $5 million of operating revenue and a $31 million loss before income taxes. The loss before income taxes included a pre-tax loss of $25 million recognized on the sale, resulting largely from the allocation of $24 million of Generation reporting unit goodwill to the bases of the investments sold.

Sale of Certain DCI Operations

In August 2007, we completed the sale of Gichner, LLC (Gichner), all of the issued and outstanding shares of the capital stock of Gichner, Inc. (an affiliate of Gichner) and Dallastown Realty (Dallastown) for approximately $30 million. The results of operations of Gichner and Dallastown are reported as discontinued operations in our Consolidated Statements of Income. For the three and six months ended June 30, 2007, Gichner and Dallastown recorded $12 million and $22 million of operating revenue and $7 million and $6 million of losses before income taxes, respectively. The losses before income taxes included an $8 million impairment charge recorded in June 2007 in other operations and maintenance expense in our Consolidated Statements of Income in connection with the sale.

In April 2008, we sold our remaining interest in the subordinated notes of a third-party collateralized debt obligation (CDO) entity held as an investment by DCI and received proceeds of $54 million, including accrued interest. In connection with the sale of the subordinated notes, we recognized impairment losses of $62 million ($38 million after tax) for the six months ended June 30, 2008.

Planned Sale of Regulated Gas Distribution Subsidiaries

In January 2008, Dominion and Equitable announced the termination of the agreement for the sale of Peoples and Hope, primarily due to the continued delays in achieving final regulatory approvals. We continued to seek other offers for the purchase of these utilities.

In July 2008, we announced that we entered into an agreement with a subsidiary of Babcock & Brown Infrastructure Fund North America (BBIFNA) to sell Peoples and Hope for approximately $910 million, subject to adjustments to reflect levels of capital expenditures and changes in working capital. The transaction is expected to close in 2009, subject to regulatory approvals in Pennsylvania and West Virginia as well as clearance under the Hart-Scott-Rodino Act and under the Exon-Florio provision of the Omnibus Trade and Competitiveness Act.

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The carrying amounts of the major classes of assets and liabilities associated with the planned sale of Peoples and Hope and classified as held for sale in our Consolidated Balance Sheets are as follows:

(millions)	June 30, 2008	December 31, 2007
ASSETS		
Current Assets		
Customer receivables	**$ 105**	$ 147
Other	**113**	109
Total current assets	**218**	256
Property, Plant and Equipment		
Property, plant and equipment	**1,176**	1,160
Accumulated depreciation, depletion and amortization	**(362)**	(367)
Total property, plant and equipment, net	**814**	793
Deferred Charges and Other Assets		
Regulatory assets	**155**	109
Other	**100**	2
Total deferred charges and other assets	**255**	111
Assets held for sale	**$ 1,287**	$ 1,160
LIABILITIES		
Current Liabilities	**$ 188**	$ 210
Deferred Credits and Other Liabilities		
Deferred income taxes(1)	**273**	203
Other	**95**	79
Total deferred credits and other liabilities	**368**	282
Liabilities held for sale	**$ 556**	$ 492

(1) Represents net deferred tax liabilities that relate to, and are being reported with, the subsidiaries assets and liabilities held for sale and that, based on the form of the dispositions, will reverse upon closing.

The following table presents selected information regarding the results of operations of Peoples and Hope:

(millions)	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
Operating revenue	**$ 101**	$ 108	**$ 406**	$ 417
Income before income taxes(1)	**50**	1	**100**	55

(1)

Income before income taxes for the three and six months ended June 30, 2008 includes a $47 million benefit related to the re-establishment of a regulatory asset in connection with the pending sale of Peoples and Hope to BBIFNA.

Note 6. Operating Revenue

Our operating revenue consists of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions)	**2008**	**2007**	**2008**	**2007**
Operating Revenue				
Electric sales:				
Regulated	**$ 1,514**	$ 1,386	**$ 3,010**	$ 2,797
Nonregulated	**765**	724	**1,647**	1,460
Gas sales:				
Regulated	**189**	184	**791**	743
Nonregulated	**640**	850	**1,531**	2,113
Other energy-related commodity sales	**77**	300	**155**	580
Gas transportation and storage	**221**	212	**610**	561
Other	**46**	74	**97**	137
Total operating revenue	**$ 3,452**	$ 3,730	**$ 7,841**	$ 8,391

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Note 7. Income Taxes

A reconciliation of income taxes at the U.S. statutory federal rate as compared to the income tax expense recorded for continuing operations in our Consolidated Statements of Income is presented below:

	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
U.S. statutory rate	**35.0%**	35.0%
Increases (reductions) resulting from:		
State taxes, net of federal benefit	**2.8**	4.7
Reversal of deferred taxes stock of subsidiaries held for sale	**(10.2)**	(0.1)
Changes in valuation allowances	**1.2**	1.9
Legislative changes	**(1.0)**	
Other, net	**(1.1)**	2.8
Effective tax rate	**26.7%**	44.3%

The change in our effective tax rate for the six months ended June 30, 2008, is primarily attributable to the reversal of deferred tax liabilities, recognized in 2006, associated with the excess of our financial reporting basis over the tax basis in the stock of Peoples and Hope, in accordance with EITF Issue No. 93-17, *Recognition of Deferred Tax Assets for a Parent Company s Excess Tax Basis in the Stock of a Subsidiary that is Accounted for as a Discontinued Operation.* Although these subsidiaries are not classified as discontinued operations, EITF 93-17 requires that the deferred tax impact of the excess of the financial reporting basis over the tax basis of a parent s investment in a subsidiary be recognized when it is apparent that this difference will reverse in the foreseeable future. Based on the intended form of the sale to Equitable, we recognized these deferred tax liabilities in 2006, and such difference was expected to reverse upon closing of the sale.

In January 2008, Dominion and Equitable agreed to terminate the agreement for the sale of Peoples and Hope. In January 2008, based on our expectation that the form of the ultimate disposal of these subsidiaries could be structured so that the taxable gain would instead be determined by reference to the basis in the subsidiaries underlying assets, we reversed those deferred tax liabilities recognized in 2006. As discussed in Note 5, we have executed a new agreement to sell Peoples and Hope. We will determine our taxable gain by reference to the basis in the subsidiaries underlying assets.

In addition, as the result of West Virginia income tax rate reductions enacted in March 2008, to be phased in during the period 2009 through 2014, we reduced our net deferred tax liabilities by $13 million.

Our 2007 annual effective tax rate reflects the effects of the sale of the majority of our U.S. E&P operations. The effects included the impact of goodwill, not recognized for tax purposes, that was deducted in the determination of book gain on the sale and the recognition of additional deferred tax expense to reflect changes in our state income tax profile. Those effects were partially offset by tax benefits related to the elimination of valuation allowances on federal loss carryforwards that would be utilized to offset gains generated from the sales.

At June 30, 2008, unrecognized tax benefits related to current year tax positions are $23 million. During the six months ended June 30, 2008, unrecognized tax benefits related to prior year uncertain tax positions increased by $8 million and decreased by $59 million, reflecting reductions to uncertain tax positions for amounts that would otherwise be deductible in 2008, settlement negotiations and payments to tax authorities.

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Note 8. Earnings Per Share

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions, except EPS)	**2008**	**2007**	**2008**	**2007**
Income (loss) from continuing operations before extraordinary item	**$ 300**	$ (392)	**$ 980**	$ 83
Extraordinary item, net of tax		(158)		(158)
Income (loss) from discontinued operations, net of tax	**(2)**	20	**(2)**	(2)
Net income (loss)	**$ 298**	$ (530)	**$ 978**	$ (77)
Basic EPS				
Average shares of common stock outstanding basic	**577.1**	698.2	**576.2**	697.6
Income (loss) from continuing operations before extraordinary item	**$ 0.52**	$ (0.56)	**$ 1.70**	$ 0.12
Extraordinary item		(0.23)		(0.23)
Income from discontinued operations		0.03		
Net income (loss)	**$ 0.52**	$ (0.76)	**$ 1.70**	$ (0.11)
Diluted EPS				
Average shares of common stock outstanding	**577.1**	698.2	**576.2**	697.6
Net effect of potentially dilutive securities(1)(2)	**3.6**		**3.3**	4.7
Average shares of common stock outstanding diluted	**580.7**	698.2	**579.5**	702.3
Income (loss) from continuing operations before extraordinary item	**$ 0.51**	$ (0.56)	**$ 1.69**	$ 0.12
Extraordinary item		(0.23)		(0.23)
Income from discontinued operations		0.03		
Net income (loss)	**$ 0.51**	$ (0.76)	**$ 1.69**	$ (0.11)

(1) Potentially dilutive securities consist of options, restricted stock and contingently convertible senior notes.
(2) As a result of the net loss from continuing operations for the three months ended June 30, 2007, the issuance of approximately 4.6 million common shares under potentially-dilutive securities was considered anti-dilutive and therefore was not included in the calculation of the diluted loss per share for the period.

There were no anti-dilutive securities outstanding during the three and six months ended June 30, 2008 or during the six months ended June 30, 2007.

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Note 9. Comprehensive Income

The following table presents total comprehensive income:

(millions)	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
Net income (loss)	**$ 298**	$ (530)	**$ 978**	$ (77)
Other comprehensive income (loss):				
Net other comprehensive income (loss) associated with effective portion of changes in fair value of derivatives designated as cash flow hedges, net of taxes and amounts reclassified to earnings	**(787)**[1]	539[2]	**(1,123)**[1]	324[2]
Other, net of tax	**(4)**	(81)[3]	**(60)**[4]	(70)[3]
Other comprehensive income (loss)	**(791)**	458	**(1,183)**	254
Total comprehensive income (loss)	**$ (493)**	$ (72)	**$ (205)**	$ 177

(1) Principally due to the impact of an increase in commodity prices.
(2) Principally due to the de-designation of certain E&P cash flow hedges in connection with the sale of our non-Appalachian E&P operations.
(3) Primarily reflects the impact of foreign currency translation adjustments due to the sale of our Canadian E&P operations and the reclassification of pension-related amounts and gross unrealized gains on investments held in nuclear decommissioning trusts, both associated with the Virginia jurisdiction of our utility generation operations. As a result of the reapplication of SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*, to those operations, those amounts previously recorded in AOCI are now recorded in regulatory assets and regulatory liabilities.
(4) Primarily represents a reduction in unrealized gains on investments held in merchant nuclear decommissioning trusts.

Note 10. Fair Value Measurements

As described in Note 3, we adopted SFAS No. 157 effective January 1, 2008. SFAS No. 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability (exit price) in an orderly transaction between market participants at the measurement date. However, SFAS No. 157 permits the use of a mid-market pricing convention (the mid-point between bid and ask prices). SFAS No. 157 clarifies that fair value should be based on assumptions that market participants would use when pricing an asset or liability, including assumptions about risk and the risks inherent in valuation techniques and the inputs to valuations. This includes not only the credit standing of counterparties involved and the impact of credit enhancements but also the impact of our own nonperformance risk on our liabilities. SFAS No. 157 also requires fair value measurements to assume that the transaction occurs in the principal market for the asset or liability (the market with the most volume and activity for the asset or liability from the perspective of the reporting entity), or in the absence of a principal market, the most advantageous market for the asset or liability (the market in which the reporting entity would be able to maximize the amount received or minimize the amount paid). We apply fair value measurements to certain assets and liabilities including commodity and interest rate derivative instruments, and nuclear decommissioning trust and other investments in accordance with the requirements described above.

In accordance with SFAS No. 157, we maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. Fair value is based on actively-quoted market prices, if available. In the absence of actively-quoted market prices, we seek price information from external sources, including broker quotes and industry publications. If pricing information from external sources is not available, we must estimate prices based on available historical and near-term future price information and certain statistical methods, including regression analysis, that reflect our market assumptions.

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For options and contracts with option-like characteristics where observable pricing information is not available from external sources, we generally use a modified Black-Scholes Model that considers time value, the volatility of the underlying commodities and other relevant assumptions when estimating fair value. We use other option models under special circumstances, including a Spread Approximation Model, when contracts include different commodities or commodity locations and a Swing Option Model, when contracts allow either the buyer or seller the ability to exercise within a range of quantities. For contracts with unique characteristics, we 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.

Also, we utilize the following fair value hierarchy, which prioritizes the inputs to valuation techniques used to measure fair value, into three broad levels:

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

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

Level 3 Unobservable inputs for the asset or liability, including situations where there is little, if any, market activity for the asset or liability. Instruments categorized in Level 3 include long-dated and modeled commodity derivatives and financial transmission rights (FTRs).

The fair value hierarchy gives the highest priority to quoted prices in active markets (Level 1) and the lowest priority to unobservable data (Level 3). In some cases, the inputs used to measure fair value might fall in different levels of the fair value hierarchy. The lowest level input that is significant to a fair value measurement in its entirety determines the applicable level in the fair value hierarchy. Assessing the significance of a particular input to the fair value measurement in its entirety requires judgment, considering factors specific to the asset or liability.

SFAS No. 157 requires fair value measurements to be separately disclosed by level within the fair value hierarchy and requires a separate reconciliation of fair value measurements categorized as Level 3. The following table presents for each hierarchy level our assets and liabilities, including both current and noncurrent portions, measured at fair value on a recurring basis, as of June 30, 2008:

(millions)	Level 1	Level 2	Level 3	Total
Assets:				
Derivatives	$ 31	$ 1,783	$ 303	$ 2,117
Investments	960	1,708		2,668
Total	991	3,491	303	4,785
Liabilities:				
Derivatives	$ 231	$ 3,005	$ 494	$ 3,730

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The following table presents the changes in the assets and liabilities measured at fair value on a recurring basis and included in the Level 3 fair value category for the six months ended June 30, 2008:

(millions)	Derivatives[1]
Balance at January 1, 2008	$ (61)
Total realized and unrealized gains or (losses):	
Included in earnings	63
Included in other comprehensive income (loss)	(377)
Included in regulatory and other assets/liabilities	200
Purchases, issuances and settlements	(12)
Transfers out of Level 3	(4)
Balance at June 30, 2008	$ (191)
The amount of total gains (losses) for the period included in earnings attributable to the change in unrealized gains/losses relating to assets still held at the reporting date	$ 21

(1) Derivative assets and liabilities are presented on a net basis.

The following table presents gains and losses included in earnings in the Level 3 fair value category for the three and six months ended June 30, 2008:

(millions)	Operating Revenue	Electric Fuel and Energy Purchases	Other Operations and Maintenance	Total
Three Months Ended June 30, 2008				
Total gains or (losses) included in earnings	$ (28)	$ 34	$ 48	$ 54
The amount of total gains (losses) for the period included in earnings attributable to the change in unrealized gains/losses relating to assets still held at the reporting date	(5)		25	20
Six Months Ended June 30, 2008				
Total gains or (losses) included in earnings	$ (39)	$ 42	$ 60	$ 63
The amount of total gains (losses) for the period included in earnings attributable to the change in unrealized gains/losses relating to assets still held at the reporting date	16		5	21

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Note 11. 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 to our Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2007, for certain 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:

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions)	**2008**	2007	**2008**	2007
Portion of gains (losses) on hedging instruments determined to be ineffective and included in net income:				
Fair value hedges	**$**	$ (2)	**$ 5**	$ 2
Cash flow hedges	**3**	28		43
Net ineffectiveness	**$ 3**	$ 26	**$ 5**	$ 45

For the three and six months ended June 30, 2008 and 2007, amounts excluded from the measurement of effectiveness did not have a significant impact on net income.

The sale of the majority of our U.S. E&P operations resulted in the discontinuance of hedge accounting for certain cash flow hedges since it became probable that the forecasted sales of gas and oil would not occur. In connection with the discontinuance of hedge accounting for these contracts, we recognized a $536 million ($341 million after-tax) charge, recorded in other operations and maintenance expense in our Consolidated Statement of Income, reflecting the reclassification of losses from AOCI to earnings and subsequent changes in fair value of these contracts in the three months ended June 30, 2007.

During the three months ended June 30, 2007, we also recorded a charge of approximately $171 million ($108 million after-tax) for the recognition of certain forward gas contracts that previously qualified for the normal purchase and sales exemption under SFAS No. 133. The $171 million charge included $139 million associated with volumetric production payment (VPP) agreements to which we were a party. We paid $250 million to terminate the VPP agreements and retained the repurchased fixed-term overriding royalty interests formerly associated with these agreements.

The following table presents selected information related to cash flow hedges included in AOCI in our Consolidated Balance Sheet at June 30, 2008:

(millions)	AOCI After-Tax	Amounts Expected to be Reclassified to Earnings during the next 12 Months After-Tax	Maximum Term
Commodities:			
Gas	$ (98)	$ (72)	33 months
Electricity	(912)	(563)	42 months
Natural gas liquids	(165)	(52)	42 months
Other	9	5	83 months
Interest rate	(1)	(3)	361 months
Foreign currency	2	2	35 months
Total	$ (1,165)	$ (683)	

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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 12. Ceiling Test

We follow the full cost method of accounting for gas and oil E&P activities prescribed by the SEC. Under the full cost method, capitalized costs are subject to a quarterly ceiling test. Under the ceiling test, amounts capitalized are limited to the present value of estimated future net revenues to be derived from the anticipated production of proved gas and oil reserves, discounted at 10 percent, assuming period-end hedge-adjusted prices.

Approximately 6% of our anticipated production, from our remaining E&P operations and fixed-term overriding royalty interests formerly associated with VPP agreements terminated in conjunction with the 2007 sale of the majority of our U.S. E&P operations, 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 June 30, 2008.

Note 13. Variable Interest Entities

As discussed in Note 17 to our Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2007, certain variable pricing terms in some of our long-term power and capacity contracts cause them to be considered variable interests in the counterparties in accordance with FIN 46 (revised December 2003), *Consolidation of Variable Interest Entities*.

We have long-term power and capacity contracts with four variable interest entities (VIEs), which contain certain variable pricing mechanisms to the counterparty in the form of partial fuel reimbursement. We have concluded that we are not the primary beneficiary of any of these VIEs. The contracts expire at various dates ranging from 2015 to 2021. We are not subject to any risk of loss from these VIEs other than our remaining purchase commitments which totaled $2 billion as of June 30, 2008. We paid $50 million and $54 million for electric capacity and $45 million and $36 million for electric energy to these entities for the three months ended June 30, 2008 and 2007, respectively. We paid $102 million and $109 million for electric capacity and $92 million and $77 million for electric energy to these entities for the six months ended June 30, 2008 and 2007, respectively.

As discussed in Note 28 to our Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2007, DCI held an investment in the subordinated notes of a third-party CDO entity. The CDO entity s primary focus is the purchase and origination of middle market senior secured first and second lien commercial and industrial loans in both the primary and secondary loan markets. We concluded previously that the CDO entity was a VIE and that DCI was the primary beneficiary of the CDO entity and therefore we consolidated the CDO entity in accordance with FIN 46R at December 31, 2007. Due to the consolidation of the CDO entity at December 31, 2007, our consolidated balance sheet included $460 million of notes payable, which were nonrecourse to us, and the following assets that served as collateral for its obligations:

(millions)	**Amount**
Other current assets[1]	$ 257
Loans held for sale	323
Other investments	32
Total assets	$ 612

(1) Includes $30 million of loans held for resale.

In March 2008, we entered into an agreement to sell our remaining interest in the subordinated notes effectively eliminating the variability of our interest, and therefore deconsolidated the CDO entity as of March 31, 2008.

Note 14. Significant Financing Transactions

Credit Facilities and Short-Term Debt

We use short-term debt, primarily commercial paper, to fund working capital requirements, as a bridge to long-term debt financing and as bridge financing for acquisitions, if applicable. The levels of our borrowings may vary significantly during the course of the year, depending upon the timing and amount of cash requirements not satisfied by cash from

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operations. In addition, we utilize cash and letters of credit to fund collateral requirements under our commodities hedging program. Collateral requirements are impacted by commodity prices, hedging levels and our credit quality and the credit quality of our counterparties. At June 30, 2008, we had committed lines of credit totaling $4.9 billion. These lines of credit support commercial paper borrowings and letter of credit issuances. At June 30, 2008, we had the following commercial paper, bank loans and letters of credit outstanding and capacity available under our core credit facilities:

(millions)	Facility Limit	Outstanding Commercial Paper	Outstanding Bank Borrowings	Outstanding Letters of Credit	Facility Capacity Available
Five-year joint revolving credit facility(1)	$ 3,000	$ 1,131	$	$ 733	$ 1,136
Five-year Dominion credit facility(2)	1,700	747	600	353	
Five-year Dominion bilateral facility(3)	200			200	
Totals	$ 4,900	$ 1,878	$ 600	$ 1,286	$ 1,136

(1) The $3.0 billion five-year credit facility was entered into in February 2006 and terminates in February 2011. The credit facility can be used to support bank borrowings and the issuance of commercial paper, as well as to support up to $1.5 billion of letters of credit.

(2) The amended and restated $1.7 billion five-year credit facility is dated February 2006 and terminates in August 2010. This facility can be used to support bank borrowings, the issuance of letters of credit and commercial paper.

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

In addition to the facilities above, we also entered into a $100 million bilateral credit facility in August 2004 that terminates in August 2009. We elected to terminate this credit facility effective May 15, 2008.

On July 30, 2008, we closed on a $500 million 364-day syndicated credit facility that will expire on July 29, 2009. This facility will be used to support the issuance of commercial paper and bank borrowings, and is incremental to the facilities and bilateral agreements in place at June 30, 2008.

Long-Term Debt

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 5.6%. 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. We have withdrawn $6 million from the trust as of June 30, 2008.

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 an initial coupon rate of 3.6% for the first five years, after which they will bear interest at a market rate to be determined at that time. The proceeds were used to refund the principal amount of the Industrial Development Authority of the City of Chesapeake Money Market Municipals Pollution Control Revenue Bonds, Series 1985 that would otherwise have matured in February 2008.

In April 2008, Virginia Power issued $600 million of 5.4% senior notes that mature in 2018. The proceeds were used for general corporate purposes, including the repayment of short-term debt and the redemption of all 16 million units of the $400 million 7.375% Virginia Power Capital Trust II preferred securities (including the related $412 million 7.375% unsecured Junior Subordinated Notes) due July 30, 2042. These securities were called for redemption in April 2008 and redeemed in May 2008 at a price of $25 per preferred security plus accrued and unpaid distributions.

In June 2008, Dominion issued $500 million of 6.4% senior notes that mature in 2018, $400 million of 7.0% senior notes that mature in 2038 and $300 million of floating rate senior notes that mature in 2010 and bear interest at the three-month London Interbank Offered Rate (LIBOR) plus 1.05%, reset quarterly. We used the proceeds for general corporate purposes, including the repayment of short-term debt.

Including the amounts discussed above, we repaid $1.3 billion of long-term debt and notes payable during the six months ended June 30, 2008.

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Convertible Securities

In December 2003, we issued $220 million of contingent convertible senior notes that are convertible by holders into a combination of cash and shares of our common stock under certain circumstances. In 2004 and 2005, we entered into exchange transactions with respect to these contingent convertible senior notes in contemplation of EITF Issue No. 04-8, *The Effect of Contingently Convertible Instruments on Diluted Earnings per Share*. We exchanged the outstanding notes for new notes with a conversion feature that requires that the principal amount of each note be repaid in cash. At issuance, the notes were valued at a conversion rate of 27.173 shares of common stock per $1,000 principal amount of senior notes, which represents 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 June 30, 2008, the conversion rate has been adjusted to 27.6228 primarily due to individual dividend payments above the level paid at issuance.

The new notes have been included in the diluted EPS calculation using the method described in EITF 04-8 when appropriate. Under this method, the number of shares included in the denominator of the diluted EPS calculation is calculated as the net shares issuable for the reporting period based upon the average market price for the period. This results in an increase in the average shares outstanding used in the calculation of our diluted EPS when the conversion price of $36.80 is lower than the average market price of our common stock over the period, and no adjustment when the conversion price exceeds the average market price.

As of December 31, 2007, the closing price of our common stock was equal to $44.16 per share (the applicable contingent conversion price) or higher for at least 20 out of the last 30 consecutive trading days. Therefore, the senior notes were eligible for conversion during the first quarter of 2008. During the first quarter, less than $1 million of the contingent convertible senior notes were converted by shareholders. At March 31, 2008, the applicable contingent conversion price of the notes was $43.51 per share and none of the conditions for conversion had been met, therefore the senior notes were not eligible for conversion during the second quarter of 2008. As of June 30, 2008, the closing price of our common stock was equal to $43.44 (the applicable contingent conversion price) 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 third quarter of 2008.

Issuance of Common Stock

During the six months ended June 30, 2008, we issued 2.9 million shares and received cash proceeds of $120 million, through Dominion Direct®, employee savings plans and the exercise of employee stock options.

Note 15. Stock-Based Awards

Our results for the three months ended June 30, 2008 and 2007 include $12 million and $15 million, respectively, of compensation costs and $5 million and $6 million, respectively, of income tax benefits related to our stock-based compensation arrangements. Our results for the six months ended June 30, 2008 and 2007 include $19 million and $24 million, respectively, of compensation costs and $7 million and $9 million, respectively, of income tax benefits related to our stock-based compensation arrangements. Stock-based compensation cost is reported in other operations and maintenance expense in our Consolidated Statements of Income. SFAS No. 123R, *Share-Based Payment*, requires the benefits of tax deductions in excess of the compensation cost recognized for stock-based compensation (excess tax benefits) to be classified as a financing cash flow. Approximately $7 million and $23 million of excess tax benefits were realized for the six months ended June 30, 2008 and 2007, respectively.

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Stock Options

The following table provides a summary of changes in amounts of stock options outstanding as of and for the six months ended June 30, 2008:

	Shares (thousands)	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life (years)	Aggregated Intrinsic Value[(1)] (millions)
Outstanding and exercisable at January 1, 2008	7,021	$ 30.46		
Exercised	**(658)**	**29.98**		**$ 10**
Forfeited/expired	**(2)**	**31.29**		
Outstanding and exercisable at June 30, 2008	**6,361**	**$ 30.51**	**2.63**	**$ 108**

(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 $20 million and $123 million in the six months ended June 30, 2008 and 2007, 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 six months ended June 30, 2008:

	Shares (thousands)	Weighted-Average Grant Date Fair Value
Nonvested at January 1, 2008	2,014	$ 35.31
Granted	**532**	**40.93**
Vested	**(860)**	**31.48**
Cancelled and forfeited	**(39)**	**39.18**
Transferred from goal-based stock to restricted stock	**200**	**34.77**
Nonvested at June 30, 2008	**1,847**	**$ 38.57**

As of June 30, 2008, unrecognized compensation cost related to nonvested restricted stock awards totaled approximately $38 million and is expected to be recognized over a weighted-average period of 1.6 years.

Goal-Based Stock

Goal-based stock awards are generally granted to key non-officer employees on an annual basis. The issuance of awards is based on the achievement of multiple performance metrics during a two-year period, including return on invested capital, book value per share and total shareholder return relative to that of a peer group of companies. Goal-based stock awards are also granted in lieu of cash-based performance grants to certain officers who had not achieved a certain level of share ownership. Current outstanding goal-based shares include awards granted in April 2007 and April 2008.

After the performance period for the April 2006 grants ended on December 31, 2007, the Compensation, Governance and Nominating Committee determined the actual performance against metrics established for those awards, and 130 thousand shares of the outstanding goal-based stock awards granted in April 2006 were converted to 200 thousand shares and transferred to restricted stock for the remaining term of the vesting period.

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For remaining goal-based stock awards, at June 30, 2008, the targeted number of shares to be issued is 317 thousand, but the actual number of shares issued will vary between zero and 200% of targeted shares depending on the level of performance metrics achieved. The fair value of goal-based stock is equal to the market price of our stock on the date of grant. These awards generally vest over a three-year service period and are settled by issuing new shares. The following table provides a summary of goal-based stock activity:

	Targeted Number of Shares (thousands)	Weighted-Average Grant Date Fair Value
Nonvested at January 1, 2008	289	$ 39.16
Granted	**161**	**40.87**
Cancelled and forfeited	**(3)**	**43.39**
Converted from goal-based stock to restricted stock	**(130)**	**34.77**
Nonvested at June 30, 2008	**317**	**$ 42.54**

At June 30, 2008, unrecognized compensation cost related to nonvested goal-based stock awards totaled $10 million and is expected to be recognized over a weighted-average period of 1.7 years.

Cash-Based Performance Grant

The targeted amount of the cash-based performance grant made to officers in April 2006 was $13 million, but the actual payout of the award in February 2008 determined by the Compensation, Governance and Nominating Committee was $18 million, based on the level of performance metrics achieved.

In April 2007, a cash-based performance grant was made to officers. Payout of the performance grant 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 June 30, 2008, 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.

In April 2008, a cash-based performance grant was made to officers. Payout of the performance grant will occur by March 15, 2010 and is based on the achievement of three performance metrics during 2008 and 2009: return on invested capital, book value per share and total shareholder return relative to that of a peer group of companies. At June 30, 2008, the targeted amount of the grant is $13 million, but actual payout will vary between zero and 200% of the targeted amount depending on the level of performance metrics achieved.

At June 30, 2008, a liability of $10 million has been accrued for these awards.

Note 16. Commitments and Contingencies

Other than the following matters, there have been no significant developments regarding the commitments and contingencies disclosed in Note 24 to our Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2007, or Note 16 to our Consolidated Financial Statements in our Quarterly Report on Form 10-Q for the quarter ended March 31, 2008, nor have any significant new matters arisen during the three months ended June 30, 2008.

Guarantees

At June 30, 2008, we had issued $335 million of guarantees to support third parties and equity method investees. This includes $132 million of guarantees to support our investment in a joint venture with Shell WindEnergy Inc. (Shell) to develop a wind-turbine facility in Grant County, West Virginia (NedPower). This amount is primarily comprised of a limited-scope guarantee and indemnification for one-half of the project-level financing for phase one of the NedPower wind farm. 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 $96 million as of June 30, 2008 and will increase to $103 million during the remainder of 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.

This also includes $158 million of guarantees to support our investment in a joint venture with BP Alternative Energy Inc. to develop a wind-turbine facility in Benton County, Indiana, referred to as the Fowler Ridge wind farm. The guarantees primarily relate to payments for wind turbines and construction costs. Our exposure under these guarantees was $80 million as of June 30, 2008 and will largely decline during the remainder of 2008, as the joint venture makes the underlying payments covered by these guarantees. BP has provided identical guarantees for the other one-half of these joint venture commitments.

We also enter into guarantee arrangements on behalf of our consolidated subsidiaries primarily to facilitate their commercial transactions with third parties. To the extent that a liability subject to a guarantee has been incurred by one of our consolidated subsidiaries, that liability is included in our Consolidated Financial Statements. We are not required to recognize liabilities for guarantees issued on behalf of our subsidiaries unless it becomes probable that we will have to perform under the guarantees. We believe it is unlikely that we would be required to perform or otherwise incur any losses associated with guarantees of our subsidiaries obligations. At June 30, 2008, we had issued the following subsidiary guarantees:

(millions)	Stated Limit	Value[(1)]
Subsidiary debt[(2)]	$ 75	$ 75
Commodity transactions[(3)]	3,033	1,154
Lease obligation for power generation facility[(4)]	891	891
Nuclear obligations[(5)]	383	302
Other[(6)]	881	726
Total	$ 5,263	$ 3,148

(1) Represents the estimated portion of the guarantee s stated limit that is utilized as of June 30, 2008, based upon prevailing economic conditions and fact patterns specific to each guarantee arrangement. For those guarantees related to obligations that are recorded as liabilities by our subsidiaries, the value includes the recorded amount.
(2) Guarantees of debt of certain DEI subsidiaries. In the event of default by the subsidiaries, we would be obligated to repay such amount.
(3) Guarantees related to energy trading and marketing activities and other commodity commitments of certain subsidiaries, including subsidiaries of Virginia Power and DEI. These guarantees were provided to counterparties in order to facilitate physical and financial transactions in gas, oil, electricity, pipeline capacity, transportation and related commodities and services. If these subsidiaries fail to perform or pay under the contracts and the counterparties seek performance or payment, we would be obligated to satisfy such obligation. We and our subsidiaries receive similar guarantees as collateral for credit extended to others. The value provided includes certain guarantees that do not have stated limits.
(4) Guarantee of a DEI subsidiary s leasing obligation for the Fairless Energy power station.
(5) Guarantees related to certain DEI subsidiaries potential retrospective premiums that could be assessed if there is a nuclear incident under our nuclear insurance programs and guarantees for a DEI subsidiary s and Virginia Power s commitment to buy nuclear fuel. In addition to the guarantees listed above, we have also agreed to provide up to $150 million and $60 million to two DEI subsidiaries, to pay the operating expenses of the Millstone and Kewaunee power stations, respectively, in the event of a prolonged outage, as part of satisfying certain Nuclear Regulatory Commission (NRC) requirements concerned with ensuring adequate funding for the operations of nuclear power stations.
(6) Includes a $550 million payment and performance guarantee related to the expansion of our Cove Point LNG facility.

Surety Bonds and Letters of Credit

As of June 30, 2008, we had purchased $162 million of surety bonds and authorized the issuance of standby letters of credit by financial institutions of $1.3 billion to facilitate commercial transactions by our subsidiaries with third parties.

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. By order dated July 16, 2008, the Court preliminarily approved settlement of the class action and conditionally certified a temporary settlement class. The Court also dismissed DRS and added Dominion Appalachian Development LLC as a defendant for the sole purpose of settling the class claims. 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.

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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. A trial occurred in May 2008 and post-trial briefing and argument concluded in July 2008. A decision is expected in 2008. We will continue to manage our spent fuel until it is accepted by the DOE.

Note 17. Credit Risk

Credit risk is our risk of financial loss if counterparties fail to perform their contractual obligations. In order to minimize overall credit risk, we maintain credit policies, including the evaluation of counterparty financial condition, collateral requirements and the use of standardized agreements that facilitate the netting of cash flows associated with a single counterparty. We maintain a provision for credit losses based on factors surrounding the credit risk of our customers, historical trends and other information. We believe, based on our credit policies and our June 30, 2008 provision for credit losses, that it is unlikely that a material adverse effect on our financial position, results of operations or cash flows would occur as a result of counterparty nonperformance.

As a diversified energy company, we transact primarily with major companies in the energy industry and with commercial and residential energy consumers. These transactions principally occur in the Northeast, mid-Atlantic and Midwest regions of the U.S. 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 June 30, 2008, our gross credit exposure totaled $1.1 billion. After the application of collateral, our credit exposure remained approximately $1.1 billion. Of this amount, investment grade counterparties, including those internally rated, represented 75% and no single counterparty exceeded 14%.

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Note 18. Employee Benefit Plans

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

	Pension Benefits		Other Postretirement Benefits	
(millions)	**2008**	**2007**	**2008**	**2007**
Three Months Ended June 30,				
Service cost	**$ 25**	$ 30	**$ 17**	$ 13
Interest cost	**57**	59	**27**	19
Expected return on plan assets	**(100)**	(105)	**(22)**	(18)
Amortization of prior service cost (credit)	**1**	1	**(2)**	(1)
Amortization of transition obligation				1
Amortization of net loss	**2**	10	**3**	2
Benefit enhancement[(1)]		3		9
Settlements and curtailments[(2)]		7		
Net periodic benefit cost (credit)	**$ (15)**	$ 5	**$ 23**	$ 25
Six Months Ended June 30,				
Service cost	**$ 52**	$ 53	**$ 30**	$ 28
Interest cost	**121**	102	**47**	38
Expected return on plan assets	**(211)**	(181)	**(38)**	(36)
Amortization of prior service cost (credit)	**2**	2	**(3)**	(3)
Amortization of transition obligation				2
Amortization of net loss	**4**	18	**4**	3
Benefit enhancement[(1)]		3		9
Settlements and curtailments[(2)]		7		
Net periodic benefit cost (credit)	**$ (32)**	$ 4	**$ 40**	$ 41

(1) Reflects a one-time benefit enhancement for certain employees in connection with the disposition of our non-Appalachian E&P operations.
(2) Relates to the then-pending sale of Peoples and Hope and sales of our non-Appalachian E&P operations.

Employer Contributions

Under our funding policies, we evaluate pension and other postretirement benefit plan funding requirements annually, usually in the second half of the year after receiving updated plan information from our actuary. Based on the funded status of each plan and other factors, the amount of additional contributions to be made each year is determined at that time. We made no contributions to our defined benefit pension plans or other postretirement benefit plans during the six months ended June 30, 2008. We do not expect to make any contributions to our pension plans in 2008, but we do expect to contribute approximately $35 million to our other postretirement benefit plans during the remainder of 2008.

Note 19. Operating Segments

We are organized primarily on the basis of the products and services we sell. We manage our daily operations through the following segments.

DVP includes our regulated electric transmission, distribution and customer service operations, as well as our nonregulated retail energy marketing operations.

Dominion Energy includes our Ohio regulated natural gas distribution company, regulated gas transmission pipeline and storage operations, including gathering and extraction activities, regulated LNG operations and our remaining E&P operations. Dominion Energy also includes producer services, which aggregates gas supply, provides market-based services related to gas transportation and storage and engages in associated gas trading and marketing.

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Dominion Generation includes the electric generation operations of our 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 and other functions (including unallocated debt), the remaining assets and operations of DCI, the net impact of discontinued operations, our divested U.S. E&P operations and our regulated gas distribution subsidiaries in West Virginia and Pennsylvania 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 segment s performance or allocating resources among the segments and are instead reported in the Corporate and Other segment. In the six months ended June 30, 2008 and 2007, our Corporate and Other segment included $27 million and $437 million, respectively, of after-tax expenses attributable to our operating segments:

The expenses in 2008 primarily reflect $51 million ($31 million after-tax) of impairment charges resulting from other-than-temporary declines in the fair value of securities held in merchant nuclear decommissioning trust funds, attributable to Dominion Generation.

The expenses in 2007 largely resulted from:

A $387 million ($252 million after-tax) charge related to the impairment of Dresden, attributable to Dominion Generation;

A $259 million ($158 million after-tax) extraordinary charge in connection with the reapplication of SFAS No. 71 to the Virginia jurisdiction of our utility generation operations, attributable to Dominion Generation; and

A $26 million ($16 million after-tax) charge resulting from the accrual of litigation reserves, attributable to Dominion Energy.

Intersegment sales and transfers are based on contractual arrangements and may result in intersegment profit or loss that is eliminated in consolidation.

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The following table presents segment information pertaining to our operations:

(millions)	DVP	Dominion Energy	Dominion Generation	Corporate and Other	Adjustments/ Eliminations	Consolidated Total
Three Months Ended June 30,						
2008						
Total revenue from external customers	**$ 615**	**$ 373**	**$ 1,887**	**$ 105**	**$ 472**	**$ 3,452**
Intersegment revenue	**21**	**521**	**28**	**153**	**(723)**	
Total operating revenue	**636**	**894**	**1,915**	**258**	**(251)**	**3,452**
Loss from discontinued operations, net of tax				**(2)**		**(2)**
Net income (loss)	**76**	**70**	**206**	**(54)**		**298**
2007						
Total revenue from external customers	$ 597	$ 324	$ 1,737	$ 748	$ 324	$ 3,730
Intersegment revenue	21	416	39	132	(608)	
Total operating revenue	618	740	1,776	880	(284)	3,730
Extraordinary item, net of tax				(158)		(158)
Income from discontinued operations, net of tax				20		20
Net income (loss)	98	66	81	(775)		(530)
Six Months Ended June 30,						
2008						
Total revenue from external customers	**$ 1,534**	**$ 1,305**	**$ 3,817**	**$ 424**	**$ 761**	**$ 7,841**
Intersegment revenue	**91**	**873**	**43**	**311**	**(1,318)**	
Total operating revenue	**1,625**	**2,178**	**3,860**	**735**	**(557)**	**7,841**
Loss from discontinued operations, net of tax				**(2)**		**(2)**
Net income (loss)	**194**	**252**	**542**	**(10)**		**978**
2007						
Total revenue from external customers	$ 1,478	$ 1,132	$ 3,516	$ 1,685	$ 580	$ 8,391
Intersegment revenue	72	715	67	269	(1,123)	
Total operating revenue	1,550	1,847	3,583	1,954	(543)	8,391
Extraordinary item, net of tax				(158)		(158)
Loss from discontinued operations, net of tax				(2)		(2)
Net income (loss)	230	208	220	(735)		(77)

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DOMINION RESOURCES, INC.

ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS

OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

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

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

- Forward-Looking Statements
- Accounting Matters
- Results of Operations
- Segment Results of Operations
- Selected Information Energy Trading Activities
- Liquidity and Capital Resources
- Future Issues and Other Matters

Forward-Looking Statements

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

Cost of environmental compliance, including those costs related to climate change;

Risks associated with the operation of nuclear facilities;

Fluctuations in energy-related commodity prices and the effect these could have on our earnings, liquidity position and the underlying value of our assets;

Counterparty credit risk;

Capital market conditions, including price risk due to 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 to benefit plan assumptions such as discount rates and the expected rate of return on plan assets;

Changes in rating agency requirements or credit ratings and their effect on availability and cost of capital;

Changes in financial or regulatory accounting principles or policies imposed by governing bodies;

Employee workforce factors including collective bargaining agreements and labor negotiations with union employees;

The risks of operating businesses in regulated industries that are subject to changing regulatory structures;

Changes to regulated gas and electric rates collected by Dominion and the timing of such collection as it relates to fuel costs;

Receipt of approvals for and timing of closing dates for acquisitions and divestitures;

Changes in rules for RTOs in which we participate, including changes in rate designs and capacity models;

Adverse outcomes in litigation matters;

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Political and economic conditions, including the threat of domestic terrorism, inflation and deflation;

Timing and receipt of regulatory approvals necessary for planned construction or expansion projects;

The inability to complete planned construction or expansion projects within the terms and time frames initially anticipated; and

Completing the divestiture of Peoples and Hope.

Additionally, other risks that could cause actual results to differ from predicted results are set forth in Item 1A. Risk Factors in this report, in our Quarterly Report on Form 10-Q for the quarter ended March 31, 2008, and in our Annual Report on Form 10-K for the year ended December 31, 2007.

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

Accounting Matters

Critical Accounting Policies and Estimates

As of June 30, 2008, there have been no significant changes with regard to the critical accounting policies and estimates disclosed in MD&A in our Annual Report on Form 10-K for the year ended December 31, 2007. The policies disclosed included the accounting for derivative contracts at fair value, goodwill and long-lived asset impairment testing, regulated operations, asset retirement obligations, employee benefit plans, gas and oil operations, and income taxes.

Other

See Notes 3 and 4 to our Consolidated Financial Statements for a discussion of newly adopted and recently issued accounting standards.

Results of Operations

Presented below is a summary of our consolidated results for the quarter and year-to-date periods ended June 30, 2008 and 2007:

(millions, except EPS)	2008	2007	$ Change
Second Quarter			
Net income (loss)	**$ 298**	$ (530)	$ 828
Diluted EPS	**0.51**	(0.76)	1.27
Year-To-Date			
Net income (loss)	**$ 978**	$ (77)	$ 1,055
Diluted EPS	**1.69**	(0.11)	1.80

Overview

Second Quarter 2008 vs. 2007

Net income was $298 million in 2008, as compared to a net loss of $530 million in 2007. Diluted EPS increased to $0.51 and includes $0.08 of share accretion resulting primarily from the repurchase of shares in 2007 with proceeds received from the sale of the majority of our E&P operations. Favorable drivers include the absence of the following 2007 items:

Charges related to the sale of the majority of our E&P operations;

An impairment charge related to the sale of Dresden;

An extraordinary charge in connection with the reapplication of SFAS No. 71 to the Virginia jurisdiction of our utility generation operations. Additional favorable drivers include the reinstatement of annual fuel rate adjustments for the Virginia jurisdiction of our utility generation operations effective July 1, 2007, with deferred fuel accounting for over- or under-recoveries of fuel costs and a higher contribution from our merchant generation operations. Unfavorable drivers include a decrease in earnings due to the sale of the majority of our E&P operations and an increase in outage costs at certain electric generating facilities.

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Year-to-Date 2008 vs. 2007

Net income was $978 million in 2008, as compared to a net loss of $77 million in 2007. Diluted EPS increased to $1.69 and includes $0.26 of share accretion resulting primarily from the repurchase of shares in 2007 with proceeds received from the sale of the majority of our E&P operations. Favorable drivers include the absence of the following 2007 items:

Charges related to the sale of the majority of our E&P operations;

An impairment charge related to the sale of Dresden;

An extraordinary charge in connection with the reapplication of SFAS No. 71 to the Virginia jurisdiction of our utility generation operations. Additional favorable drivers include the reversal of deferred tax liabilities associated with the planned sale of Peoples and Hope, the reinstatement of annual fuel rate adjustments for the Virginia jurisdiction of our utility generation operations effective July 1, 2007, with deferred fuel accounting for over- or under-recoveries of fuel costs, a higher contribution from our merchant generation operations and higher volumes and realized prices for our remaining E&P operations. Unfavorable drivers include a decrease in earnings due to the sale of the majority of our E&P operations and an increase in outage costs at certain electric generating facilities.

Analysis of Consolidated Operations

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

	Second Quarter			Year-To-Date		
	2008	**2007**	**$ Change**	**2008**	**2007**	**$ Change**
(millions)						
Operating Revenue	**$ 3,452**	$ 3,730	$ (278)	**$ 7,841**	$ 8,391	$ (550)
Operating Expenses						
Electric fuel and energy purchases	**830**	910	(80)	**1,636**	1,828	(192)
Purchased electric capacity	**97**	109	(12)	**204**	228	(24)
Purchased gas	**689**	530	159	**1,876**	1,678	198
Other energy-related commodity purchases	**21**	64	(43)	**34**	120	(86)
Other operations and maintenance	**738**	1,934	(1,196)	**1,547**	2,762	(1,215)
Depreciation, depletion and amortization	**257**	423	(166)	**511**	832	(321)
Other taxes	**109**	140	(31)	**263**	323	(60)
Other income (loss)	**(1)**	43	(44)	**(4)**	92	(96)
Interest and related charges	**210**	278	(68)	**429**	537	(108)
Income tax expense (benefit)	**200**	(232)	432	**357**	78	279
Extraordinary item, net of tax		(158)	158		(158)	158

An analysis of our results of operations for the second quarter and year-to-date periods of 2008 compared to the second quarter and year-to-date periods of 2007 follows:

Second Quarter 2008 vs. 2007

Operating Revenue decreased 7% to $3.5 billion, primarily reflecting:

A $619 million decrease due to the sale of the majority of our U.S. E&P operations; and

A $44 million decrease in nonutility coal sales, resulting principally from lower sales volumes related to exiting these activities.

These decreases were partially offset by:

- A $128 million increase in revenue from our electric utility operations resulting primarily from:
  - An $83 million increase in fuel revenue largely due to the impact of a comparatively higher fuel rate in certain customer jurisdictions;
  - A $19 million increase associated with sales to wholesale customers; and
  - A $14 million increase due to new customer connections primarily in our residential and commercial customer classes.
- A $111 million increase in our producer services business as a result of an increase in prices and volumes associated with gas aggregation and marketing activities;
- A $71 million increase for merchant generation operations reflecting higher realized prices for nuclear and fossil operations ($123 million) partially offset by lower overall volumes ($52 million) primarily due to outages at certain generating facilities;

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A $52 million increase in sales of gas production from our remaining E&P operations as a result of an increase in volumes largely associated with reacquired overriding royalty interests arising from the VPPs terminated in 2007; and

A $24 million increase in gas sales by our retail energy marketing operations primarily due to higher prices.

Operating Expenses and Other Items

Electric fuel and energy purchases expense decreased 9% to $830 million, primarily reflecting the combined effects of:

A $104 million decrease for our utility generation operations due to the deferral of fuel expenses ($277 million). The underlying fuel costs, including those subject to deferral accounting, increased $173 million as a result of higher commodity prices, including purchased power.

This decrease was partially offset by:

A $33 million increase for our merchant generation operations primarily reflecting the net impact of higher commodity prices partially offset by lower volumes due to outages at certain generation facilities.

Purchased gas expense increased 30% to $689 million, principally resulting from the following factors:

A $126 million increase associated with our producer services business as a result of an increase in prices and volumes associated with gas aggregation and marketing activities; and

A $26 million increase associated with retail energy marketing operations primarily due to higher prices; partially offset by

A $24 million decrease due to the sale of the majority of our U.S. E&P operations.

Other energy-related commodity purchases expense decreased 67% to $21 million, primarily due to a $44 million decrease in the cost of nonutility coal sales resulting principally from lower sales volumes related to exiting these activities.

Other operations and maintenance expense decreased 62% to $738 million, primarily reflecting the combined effects of:

An $858 million decrease reflecting the sale of the majority of our U.S. E&P operations, including the absence of charges incurred in 2007 in connection with the sale;

The absence of a $387 million impairment charge in 2007 related to the sale of Dresden; and

A $47 million benefit related to the re-establishment of a regulatory asset in connection with the pending sale of Peoples and Hope to BBIFNA.

These decreases were partially offset by:

A $68 million increase in outage costs primarily reflecting an increase in scheduled merchant nuclear and fossil outages; and

The absence of a $29 million mark-to-market gain on interest rate swap derivatives used to economically hedge the repurchase of debt securities in connection with our 2007 debt tender offer.

DD&A decreased 39% to $257 million, principally due to decreased gas and oil production resulting from the sale of the majority of our U.S. E&P operations, partially offset by an increase in production from our remaining E&P operations, property additions and an increase in depreciation rates for our utility generation assets.

Other taxes decreased 22% to $109 million primarily due to lower severance and property taxes resulting from the sale of the majority of our U.S. E&P operations.

Other income (loss) decreased by $44 million to a loss of $1 million, primarily due to higher other-than-temporary impairments for merchant decommissioning trust investments.

Interest and related charges decreased 24% to $210 million primarily due to a reduction in outstanding debt.

Income tax expense (benefit) increased by $432 million to $200 million, reflecting higher pre-tax income in 2008.

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

Year-To-Date 2008 vs. 2007

Operating Revenue decreased 7% to $7.8 billion, primarily reflecting:

- A $1.2 billion decrease due to the sale of the majority of our U.S. E&P operations.

This decrease was partially offset by:

- A $213 million increase in revenue from our electric utility operations resulting primarily from:
  - A $157 million increase in fuel revenue largely due to the impact of a comparatively higher fuel rate in certain customer jurisdictions;
  - A $58 million increase in sales to retail customers attributable to variations in rates resulting from changes in sales mix and other factors ($29 million) and new customer connections ($29 million) primarily in our residential and commercial customer classes; and
  - A $33 million increase associated with sales to wholesale customers; partially offset by
  - A $48 million decrease in sales to retail customers due to fewer heating degree days (HDDs), primarily in the first quarter of 2008.
- A $203 million increase for merchant generation operations, primarily reflecting higher realized prices for nuclear and fossil operations ($268 million), including the impact of terminating the long-term power sales agreement for State Line power station in 2007, partially offset by lower overall volumes due to outages at certain generating facilities ($65 million);
- A $123 million increase in sales of gas production from our remaining E&P operations, primarily associated with reacquired overriding royalty interests arising from the VPPs terminated in 2007;
- A $75 million increase in our producer services business primarily reflecting the net impact of an increase in prices partially offset by a decrease in volumes associated with gas aggregation and marketing activities;
- A $55 million increase in gas sales by our retail energy marketing operations due to higher prices ($69 million), partially offset by lower volumes ($14 million);
- A $48 million increase in sales attributable to regulated gas distribution operations primarily resulting from the net impact of higher prices ($69 million) partially offset by lower volumes ($21 million); and
- A $38 million increase in sales of extracted products from our gas transmission operations as a result of higher realized prices.

Operating Expenses and Other Items

Electric fuel and energy purchases expense decreased 11% to $1.6 billion, primarily reflecting the combined effects of:

- A $256 million decrease for our utility generation operations due to the deferral of fuel expenses ($447 million). The underlying fuel costs, including those subject to deferral accounting, increased $191 million as a result of higher commodity prices, including purchased power, partially offset by lower volumes due to fewer HDDs.

This decrease was partially offset by:

- A $48 million increase for our merchant generation operations primarily reflecting the impact of higher commodity prices and an increase in fuel costs for State Line power station. In 2007, State Line s fuel was supplied by a customer under a long-term power sales agreement that was terminated in the fourth quarter; and
- A $20 million increase related to our retail energy marketing operations resulting from higher prices ($15 million) and increased volumes ($5 million).

Purchased gas expense increased 12% to $1.9 billion, primarily due to the following factors:

- A $115 million increase associated with our producer services business primarily reflecting the net impact of an increase in prices partially offset by a decrease in volumes associated with gas aggregation and marketing activities;
- A $52 million increase in costs attributable to regulated gas distribution operations primarily resulting from the net impact of higher prices ($104 million) partially offset by lower volumes ($52 million); and
- A $44 million increase in gas sales associated with retail energy marketing activities due to higher prices ($57 million), partially offset by lower volumes ($13 million).

These increases were partially offset by:

- A $56 million decrease due to the sale of the majority of our U.S. E&P operations.

Other energy-related commodity purchases expense decreased 72% to $34 million, primarily due to an $88 million decrease in the cost of nonutility coal sales resulting principally from lower sales volumes related to exiting these activities.

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Other operations and maintenance expense decreased 44% to $1.5 billion, primarily reflecting the combined effects of:

- A $985 million decrease reflecting the sale of the majority of our U.S. E&P operations, including the absence of charges incurred in 2007 in connection with the sale;
- The absence of a $387 million impairment charge in 2007 related to the sale of Dresden; and
- A $47 million benefit related to the re-establishment of a regulatory asset in connection with the pending sale of Peoples and Hope to BBIFNA.

These decreases were partially offset by:

- A $68 million increase in outage costs primarily reflecting an increase in scheduled merchant nuclear and fossil outages partially offset by fewer scheduled utility generation outages;
- A $59 million charge related to the impairment of certain DCI investments; and
- A $38 million increase in salaries, wages and benefits expenses.

DD&A decreased 39% to $511 million, principally due to decreased gas and oil production resulting from the sale of the majority of our U.S. E&P operations, partially offset by an increase in production from our remaining E&P operations, an increase in property additions and an increase in depreciation rates for our utility generation assets.

Other taxes decreased 19% to $263 million primarily due to lower severance and property taxes resulting from the sale of the majority of our U.S. E&P operations.

Other income (loss) decreased by $96 million to a loss of $4 million, primarily due to higher other-than-temporary impairments for merchant decommissioning trust investments.

Interest and related charges decreased 20% to $429 million, primarily due to a reduction in outstanding debt.

Income tax expense (benefit) increased by $279 million to $357 million, reflecting higher pre-tax income in 2008 partially offset by the reversal of deferred tax liabilities associated with a change in the expected tax treatment of the planned sale of Peoples and Hope.

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

Segment Results of Operations

Segment results include the impact of intersegment revenues and expenses, which may result in intersegment profit and loss. Presented below is a summary of contributions by our operating segments to net income (loss) for the quarter and year-to-date periods ended June 30, 2008 and 2007:

	Net Income (Loss)			Diluted EPS		
Second Quarter	**2008**	**2007**	**$ Change**	**2008**	**2007**	**$ Change**

(millions, except EPS)						
DVP	$ 76	$ 98	$ (22)	$ 0.13	$ 0.14	$ (0.01)
Dominion Energy	70	66	4	0.12	0.09	0.03
Dominion Generation	206	81	125	0.36	0.12	0.24
Primary operating segments	352	245	107	0.61	0.35	0.26
Corporate and Other	(54)	(775)	721	(0.10)	(1.11)	1.01
Consolidated	$ 298	$ (530)	$ 828	$ 0.51	$ (0.76)	$ 1.27
Year-To-Date						
(millions, except EPS)						
DVP	$ 194	$ 230	$ (36)	$ 0.34	$ 0.33	$ 0.01
Dominion Energy	252	208	44	0.43	0.30	0.13
Dominion Generation	542	220	322	0.94	0.31	0.63
Primary operating segments	988	658	330	1.71	0.94	0.77
Corporate and Other	(10)	(735)	725	(0.02)	(1.05)	1.03
Consolidated	$ 978	$ (77)	$ 1,055	$ 1.69	$ (0.11)	$ 1.80

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DVP

Presented below are operating statistics related to DVP s operations:

	Second Quarter			Year-To-Date		
	2008	**2007**	**% Change**	**2008**	**2007**	**% Change**
Electricity delivered (million mwhrs)[1]	**20.0**	20.0	%	**40.8**	41.0	%
Degree days (electric distribution service area):						
Cooling[2]	**501**	481	4	**504**	493	2
Heating[3]	**263**	367	(28)	**2,072**	2,360	(12)
Average electric distribution customer accounts[4]	**2,382**	2,356	1	**2,381**	2,354	1
Average retail energy marketing customer accounts[4]	**1,597**	1,540	4	**1,592**	1,513	5

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) HDDs are units measuring the extent to which the average daily temperature is less than 65 degrees. HDDs are calculated as the difference between the average temperature for each day and 65 degrees.
(4) Period average, in thousands.

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

	Second Quarter 2008 vs. 2007 Increase (Decrease)		Year-To-Date 2008 vs. 2007 Increase (Decrease)	
(millions, except EPS)	**Amount**	**EPS**	**Amount**	**EPS**
Operations and maintenance[1]	$ (8)	$ (0.01)	$ (17)	$ (0.02)
Storm damage and service restoration distribution operations	(7)	(0.01)	(11)	(0.01)
Regulated electric sales:				
Weather	1		(8)	(0.01)
Customer growth	2		5	
Other	(3)		2	
Interest expense	(3)		(9)	(0.01)
Retail energy marketing operations	5		10	0.01
Other	(9)	(0.01)	(8)	(0.01)
Share accretion		0.02		0.06
Change in net income contribution	$ (22)	$ (0.01)	$ (36)	$ 0.01

(1) Primarily due to increases in salaries, wages and benefits, outside contractor services and general administrative costs.

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Dominion Energy

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

	Second Quarter			Year-To-Date		
	2008	**2007**	**% Change**	**2008**	**2007**	**% Change**
Gas distribution throughput (bcf):						
Sales	**6**	7	(14)%	**32**	33	(3)%
Transportation	**37**	37		**128**	126	2
HDDs (gas distribution service area)	**703**	775	(9)	**3,875**	3,892	
Average gas distribution customer accounts[(1)]						
Sales	**396**	422	(6)	**401**	417	(4)
Transportation	**810**	793	2	**810**	801	1
Production[(2)] (bcfe)	**16.0**	12.4	29	**33.9**	22.4	51
Average realized prices without hedging results (per mcfe)	**$ 10.53**	$ 7.29	44	**$ 9.14**	$ 6.99	31
Average realized prices with hedging results (per mcfe)	**8.48**	6.13	38	**8.65**	6.19	40
DD&A (unit of production rate per mcfe)	**1.97**	1.57	25	**1.94**	1.53	27
Average production (lifting) cost[(3)] (per mcfe)	**1.35**	1.33	2	**1.27**	1.28	(1)

bcf = billion cubic feet

bcfe = billion cubic feet equivalent

mcfe = thousand cubic feet equivalent

(1) Period average, in thousands.

(2) Includes natural gas, natural gas liquids and oil. Production includes 4.5 bcfe and 10.8 bcfe for the quarter and year-to-date periods ended June 30, 2008, respectively, and 2.3 bcfe for the quarter and year-to-date periods ended June 30, 2007, associated with reacquired overriding royalty interests arising from the VPPs terminated in 2007.

(3) The inclusion of volumes associated with reacquired overriding royalty interests arising from the VPPs terminated in 2007 would have resulted in lifting costs of $1.09 and $0.99 for the quarter and year-to-date periods ended June 30, 2008, respectively, and $1.09 and $1.16 for the quarter and year-to-date periods ended June 30, 2007, respectively.

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

	Second Quarter 2008 vs. 2007 Increase (Decrease)		Year-To-Date 2008 vs. 2007 Increase (Decrease)	
(millions, except EPS)	**Amount**	**EPS**	**Amount**	**EPS**
Gas and oil prices	$ 17	$ 0.02	$ 34	$ 0.04
Gas and oil production[(1)]	14	0.02	49	0.07
Producer services[(2)]	(14)	(0.02)	(22)	(0.03)
DD&A gas and oil	(7)	(0.01)	(19)	(0.03)
Other	(6)		2	
Share accretion		0.02		0.08
Change in net income contribution	$ 4	$ 0.03	$ 44	$ 0.13

(1) Increase is primarily due to volumes associated with reacquired overriding royalty interests arising from the VPPs terminated in 2007.

(2) Decrease primarily due to lower margins related to transportation, storage and trading contracts, along with unfavorable price changes associated with affiliated price risk management services.

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Included below are the volumes and weighted-average prices associated with hedges in place for our E&P operations and fixed-term overriding royalty interests formerly associated with VPP agreements as of June 30, 2008, by applicable time period:

	Natural Gas	
Year	Hedged Production (bcf)	Average Hedge Price (per mcf)
2008	27.1	$ 8.67
2009	30.9	9.07
2010	9.8	8.44

mcf = thousand cubic feet.

Dominion Generation

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

	Second Quarter			Year-To-Date		
	2008	2007	% Change	2008	2007	% Change
Electricity supplied (million mwhrs)						
Utility	**20.0**	20.0	%	**40.8**	41.0	%
Merchant	**9.7**	10.2	(5)	**21.0**	21.4	(2)
Degree days (electric utility service area):						
Cooling	**501**	481	4	**504**	493	2
Heating	**263**	367	(28)	**2,072**	2,360	(12)

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

	Second Quarter 2008 vs. 2007 Increase (Decrease)		Year-To-Date 2008 vs. 2007 Increase (Decrease)	
(millions, except EPS)	Amount	EPS	Amount	EPS
Virginia fuel expenses[(1)]	$ 118	$ 0.18	$ 243	$ 0.36
Merchant generation margin[(2)]	26	0.04	88	0.13
Sales of emissions allowances	9	0.01	18	0.03
Regulated electric sales:				
Customer growth	4		8	0.01
Weather	3		(13)	(0.02)
Other	9	0.01	30	0.04
Outage costs	(45)	(0.06)	(48)	(0.07)
Depreciation and amortization	(8)	(0.01)	(20)	(0.03)
Other	9	0.01	16	0.02
Share accretion		0.06		0.16
Change in net income contribution	$ 125	$ 0.24	$ 322	$ 0.63

(1) Primarily reflects the reapplication of deferred fuel accounting effective July 1, 2007 for the Virginia jurisdiction of our utility generation operations.

(2) Primarily reflects higher realized prices partially offset by lower volumes due to outages at certain generating facilities.

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Corporate and Other

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

	Second Quarter			Year-To-Date		
(millions, except EPS)	2008	2007	$ Change	2008	2007	$ Change
Specific items attributable to operating segments	**$ (11)**	$ (413)	$ 402	**$ (27)**	$ (437)	$ 410
Discontinued operations	**(2)**	20	(22)	**(2)**	(2)	
Divested U.S. E&P operations		(408)	408		(293)	293
Peoples and Hope	**30**	1	29	**61**	32	29
Other corporate operations	**(71)**	25	(96)	**(42)**	(35)	(7)
Total net expense	**$ (54)**	$ (775)	$ 721	**$ (10)**	$ (735)	$ 725
EPS impact	**$ (0.10)**	$ (1.11)	$ 1.01	**$ (0.02)**	$ (1.05)	$ 1.03

Specific Items Attributable to Operating Segments

Corporate includes specific items attributable to our operating segments that have been excluded from profit measures evaluated by management, either in assessing segment performance or in allocating resources among the segments. See Note 19 to our Consolidated Financial Statements for discussion of these items.

Discontinued Operations

Second Quarter 2008 vs. 2007

The decrease in discontinued operations is primarily due to the sale of our Canadian E&P operations in June 2007.

Peoples and Hope

The net benefit related to Peoples and Hope increased for the second quarter and year-to-date periods primarily due to the re-establishment of a regulatory asset in connection with the agreement to sell these subsidiaries to BBIFNA.

Other Corporate Operations

Second Quarter 2008 vs. 2007

We reported net expenses of $71 million in 2008 associated with other corporate operations, as compared to a net benefit of $25 million in 2007, primarily reflecting higher tax benefits in 2007 related to a reduction of previously recorded valuation allowances on deferred tax assets.

Selected Information Energy Trading Activities

See *Selected Information-Energy Trading Activities* in MD&A included in our Annual Report on Form 10-K for the year ended December 31, 2007 for a discussion of our energy trading, hedging and marketing activities and related accounting policies. For additional discussion of trading activities, see *Market Risk Sensitive Instruments and Risk Management* in Item 3.

A summary of the changes in unrealized gains and losses recognized for our energy-related derivative instruments held for trading purposes during the six months ended June 30, 2008 follows:

	Amount

(millions)		
Net unrealized gain at December 31, 2007	$	52
Contracts realized or otherwise settled during the period		**(31)**
Net unrealized gain at inception of contracts initiated during the period		
Changes in valuation techniques		
Other changes in fair value		**(12)**
Net unrealized gain at June 30, 2008	**$**	**9**

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Effective January 1, 2008, we adopted SFAS No. 157. The fair values summarized below were determined in accordance with the requirements of SFAS No. 157. In addition, we aligned the categories below with the Level 1, 2, and 3 fair value measurements as defined by SFAS No. 157. The balance of net unrealized gains and losses recognized for our energy-related derivative instruments held for trading purposes at June 30, 2008, is summarized in the following table based on the inputs used to determine fair value:

	Maturity Based on Contract Settlement or Delivery Date(s)					
Source of Fair Value (millions)	Less than 1 year	1-2 years	2-3 years	3-5 years	In excess of 5 years	Total
Actively quoted Level 1[1]	$ (1)	$	$	$	$	$ (1)
Other external sources Level 2[2]	(2)	7	1			6
Models and other valuation methods Level 3[3]	(3)	1	3	2	1	4
Total	$ (6)	$ 8	$ 4	$ 2	$ 1	$ 9

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

Liquidity and Capital Resources

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

At June 30, 2008, we had $1.1 billion of unused capacity under our credit facilities.

A summary of our cash flows for the six months ended June 30, 2008 and 2007 is presented below:

(millions)	2008	2007
Cash and cash equivalents at January 1,[1]	**$ 287**	$ 142
Cash flows provided by (used in):		
Operating activities	**528**	1,973
Investing activities	**(1,671)**	(1,674)
Financing activities	**947**	(398)
Net decrease in cash and cash equivalents	**(196)**	(99)
Cash and cash equivalents at June 30,[2]	**$ 91**	$ 43

(1) 2008 and 2007 amounts include $4 million of cash classified as held for sale on the Consolidated Balance Sheets.
(2) 2008 and 2007 amounts include $3 million of cash classified as held for sale on the Consolidated Balance Sheets.

Operating Cash Flows

For the six months ended June 30, 2008, net cash provided by operating activities decreased by $1.4 billion as compared to the six months ended June 30, 2007. The decrease was primarily due to a reduction in cash flow resulting from the disposition of the majority of our E&P operations in the third quarter of 2007, higher collateral requirements related to our commodity hedging transactions as a result of higher commodity prices and higher income tax payments. Our operations are subject to risks and uncertainties that may negatively impact the timing or amounts of operating cash flows which are discussed in Item 1A. Risk Factors in this report, our Quarterly Report on Form 10-Q for the quarter ended March 31, 2008 and in our Annual Report on Form 10-K for the year-ended December 31, 2007.

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Credit Risk

Our exposure to potential concentrations of credit risk results primarily from our energy marketing and price risk management activities. Presented below is a summary of our gross credit exposure as of June 30, 2008, for these activities. Our gross credit exposure for each counterparty is calculated as outstanding receivables plus any unrealized on or off-balance sheet exposure, taking into account contractual netting rights.

(millions)	Gross Credit Exposure	Credit Collateral	Net Credit Exposure
Investment grade[1]	$ 431	$ 34	$ 397
Non-investment grade[2]	2		2
No external ratings:			
Internally rated investment grade[3]	408	1	407
Internally rated non-investment grade[4]	280	12	268
Total	$ 1,121	$ 47	$ 1,074

(1) Designations as investment grade are based upon minimum credit ratings assigned by Moody s and Standard & Poor s. The five largest counterparty exposures, combined, for this category represented approximately 16% of the total net credit exposure.
(2) The five largest counterparty exposures, combined, for this category represented less than 1% of the total net credit exposure.
(3) The five largest counterparty exposures, combined, for this category represented approximately 31% of the total net credit exposure.
(4) The five largest counterparty exposures, combined, for this category represented approximately 10% of the total net credit exposure.

Investing Cash Flows

For the six months ended June 30, 2008, net cash used in investing activities decreased by $3 million as compared to the six months ended June 30, 2007. The decrease was primarily due to a reduction in capital expenditures as a result of the disposition of the majority of our E&P operations in 2007, partially offset by the absence of the proceeds received in 2007 from the sales of the Peaker facilities and Canadian E&P operations and an increase in capital expenditures for our other business units.

Financing Cash Flows and Liquidity

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

For the six months ended June 30, 2008, net cash provided by financing activities was $947 million as compared to net cash used in financing activities of $398 million for the six months ended June 30, 2007. This change was primarily due to higher issuances of long-term and short-term debt, partially offset by higher debt repayments.

See Note 14 to our Consolidated Financial Statements for further information regarding our credit facilities, liquidity and significant financing transactions.

Credit Ratings and Debt Covenants

Credit ratings are intended to provide banks and capital market participants with a framework for comparing the credit quality of securities and are not a recommendation to buy, sell or hold securities. In the *Credit Ratings* and *Debt Covenants* sections of MD&A in our Annual Report on Form 10-K for the year ended December 31, 2007, we discussed the use of capital markets by Dominion and Virginia Power, as well as the impact of credit ratings on the accessibility and costs of using these markets. In addition, these sections of MD&A discussed various covenants present in the enabling agreements underlying Dominion and Virginia Power s debt. As of June 30, 2008, there have been no changes in our credit ratings, other than the matters discussed in MD&A in our Quarterly Report on Form 10-Q for the quarter ended March 31, 2008, nor have there been any changes to or events of default under our debt covenants.

Future Cash Payments for Contractual Obligations and Planned Capital Expenditures

As of June 30, 2008, there have been no material changes outside the ordinary course of business to our contractual obligations nor any material changes to our planned capital expenditures disclosed in MD&A in our Annual Report on Form 10-K for the year ended December 31, 2007.

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Use of Off-Balance Sheet Arrangements

As of June 30, 2008, there have been no material changes in the off-balance sheet arrangements disclosed in MD&A in our Annual Report on Form 10-K for the year ended December 31, 2007.

Future Issues and Other Matters

The following discussion of future issues and other information includes current developments of previously disclosed matters and new issues arising during the period covered by and subsequent to our Consolidated Financial Statements. This section should be read in conjunction with *Future Issues and Other Matters* in our Annual Report on Form 10-K for the year ended December 31, 2007 and our Quarterly Report on Form 10-Q for the quarter ended March 31, 2008.

Sale of Peoples and Hope

In July 2008, we announced that we entered into an agreement with BBIFNA to sell two of our wholly-owned regulated gas distribution subsidiaries, Peoples and Hope, for approximately $910 million, subject to adjustments to reflect levels of capital expenditures and changes in working capital. Peoples and Hope serve approximately 500,000 customer accounts in Pennsylvania and West Virginia. The transaction is expected to close in 2009, subject to state regulatory approvals in Pennsylvania and West Virginia as well as clearance under the Hart-Scott-Rodino Act and under the Exon-Florio provision of the Omnibus Trade and Competitiveness Act.

Marcellus Shale

In June 2008, we entered into an agreement with Antero Resources (Antero) to assign our natural gas drilling rights in the Marcellus Shale formation on about 205,000 net acres in the Appalachian Basin for approximately $552 million, which will result in after-tax proceeds of approximately $325 million. Under the agreement, we will receive a 7.5 percent royalty interest on future natural gas production from the assigned acreage. We will retain the drilling rights in traditional formations both above and below the Marcellus Shale interval and will continue our conventional drilling program on the acreage. We expect to recognize a pre-tax gain of between $250 million and $300 million upon closing of the transaction in late September 2008, with the remainder of the proceeds credited to our full-cost pool.

The acreage for which we will assign drilling rights to Antero is principally in western Pennsylvania and West Virginia and is about one-third to one-quarter of the 600,000 to 800,000 acres where we control drilling rights in the Marcellus Shale formation. We continue to receive indications of interest in our Marcellus Shale acreage and expect to pursue similar transactions.

In addition, we have announced the proposed development of Dominion Keystone, a pipeline project that would transport new natural gas supplies from the Appalachian Basin to markets throughout the eastern U.S. As part of the drilling rights agreement, Antero will join DEPI as anchor tenants on Dominion Keystone. Dominion is holding an open season for Dominion Keystone which commenced July 7, 2008 and ends August 12, 2008 for other customers interested in the new capacity. A formal application for approval of the project is expected to be submitted to FERC in 2009. The project is expected to be placed into service in 2012.

Cove Point Expansion

In 2006, FERC approved the proposed expansion of our Cove Point terminal and DTI pipeline and the commencement of construction of such project. Such expansion included the installation of two new LNG storage tanks at our Cove Point terminal, each capable of storing 160,000 cubic meters of LNG and expansion of our Cove Point pipeline to approximately 1,800,000 dekatherms per day. In addition, our DTI gas pipeline and storage system would be expanded by building 81 miles of pipeline, two compressor stations in Pennsylvania and other upgrades. We have commenced construction and anticipate that these projects will be placed into service in 2008.

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

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We anticipate that FERC will act promptly to resolve the one issue that it has been directed to consider. In July 2008, Dominion filed a motion with FERC to ensure that project construction will continue and that related facilities will go into service on schedule. We expect FERC to grant these requests and to also issue orders confirming that the WGL system will not experience unsafe leakage as the result of additional LNG imports at Cove Point. FERC s action, if undertaken as expected by Dominion, should enable the Cove Point expansion project to be implemented as previously planned.

Appalachian Gateway Project

Dominion has announced the proposed development of the Appalachian Gateway Project which is designed to transport gas on a firm basis out of the Appalachian Basin in West Virginia and southwestern Pennsylvania to Dominion s interconnect with Texas Eastern Transmission Corporation at Oakford, Pennsylvania. A significant expansion of gathering and processing facilities is also likely to occur as a result of increased production in the region. An open season for the project was held in April and producers are in the process of finalizing the volumes they want Dominion to transport. A formal application for approval of the project is expected to be submitted to FERC in 2009. The project is expected to be placed into service during the fourth quarter of 2011.

Wind Power Projects

In April 2008, we announced plans to develop a 300 Mw wind farm in central Illinois, referred to as the Prairie Fork wind farm. The project is in the development stages and is subject to receipt of all necessary permits and approvals.

In December 2006 we acquired a 50% interest in a joint venture with Shell WindEnergy, Inc. 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) began commercial operations in July 2008.

Collective Bargaining Agreements

Members of Local 69-II recently ratified a new two-year labor contract with Dominion. The agreement began April 1, 2008 and runs through April 1, 2010. Local 69-II represents about 840 employees of our DTI subsidiary and about 160 employees of our Hope subsidiary.

Members of Local 69-I recently ratified a two-year extension to its labor contract with Dominion. The extension will commence May 1, 2009 and runs through May 1, 2011. Local 69-I represents about 350 employees of our Peoples subsidiary.

Virginia Fuel Expenses

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

Upon approval of a Stipulation and Recommendation proposed by us and other parties, the Virginia Commission ordered an increase of our fuel factor effective July 1, 2008 as follows:

i) we will place into effect a fuel tariff of 3.893 cents per kWh for the collection of the current period and partial recovery of the prior year under-recovered fuel balance;

ii) we will recover $231 million of the approximately $697 million prior year under-recovered fuel balance, with the balance to be recovered in subsequent fuel periods as provided by Virginia law;

iii) the fuel tariff of 3.893 cents per kWh is estimated to result in an under- recovery of $231 million of projected fuel expenses during the current period; and

iv) we will not propose to recover a return or interest or any other form of carrying costs on the balance of uncollected fuel expenses described in subsection (ii) above, including the estimated $231 million under-recovery of current period expenses described in subsection (iii), provided that the total amount on which we will not propose to recover interest or any other form of carrying costs is limited to $697 million.

The resulting increase in the typical 1,000 kWh Virginia jurisdictional residential customer s monthly bill is approximately 18.3 percent for the 2008 through 2009 fuel period.

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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, multi-technology generation capacity to meet the growing demand in our core market in Virginia. Our Annual Report on Form 10-K for the year ended December 31, 2007 and our Quarterly Report on Form 10-Q for the quarter ended March 31, 2008 provide a description of these projects, which are in various stages of development. The following is a discussion of certain significant developments related to such projects.

In June 2008, two 150 Mw natural gas-fired electric generating units (Units 3 and 4), previously approved by the Virginia Commission, commenced commercial operations at Ladysmith. In March 2008, the Virginia Commission approved our application to construct a fifth combustion turbine (Unit 5) at Ladysmith, at an estimated cost of $79 million, and granted a certificate to construct and operate the proposed generating unit. In July 2008, the air emissions permit allowing construction of Unit 5 was issued by the Virginia Department of Environmental Quality (VDEQ). Construction has since commenced.

After an evidentiary hearing in February 2008, the Virginia Commission issued a final order in March 2008 (Final Order), approving a certificate to construct and operate the proposed Virginia City Hybrid Energy Center and approving a rate adjustment clause as specified in the Final Order. In its Final Order, the Virginia Commission approved an initial return on common equity for the facility of 12.12%, consisting of a base return of 11.12% plus a 100 basis point premium that Virginia law provides for new conventional coal generation facilities. The Virginia Commission also authorized us to apply for an additional 100 basis point premium upon a demonstration that the plant is carbon-capture compatible. The enhanced return will apply to the Virginia City Hybrid Energy Center during construction and through the first twelve years of the facility s service life. In July 2008, the Southern Environmental Law Center (SELC), on behalf of four environmental groups, filed a Petition for Appeal of the Final Order with the Supreme Court of Virginia.

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

We are considering the construction of a third nuclear unit at a site located at North Anna which we own along with Old Dominion Electric Cooperative (ODEC). In November 2007, the NRC issued an Early Site Permit (ESP) to our subsidiary, Dominion Nuclear North Anna, LLC (DNNA), for a site located at North Anna. Also in November 2007, Virginia Power, 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. In April 2008, we filed applications at the Virginia Commission and the North Carolina Utilities Commission (North Carolina Commission) requesting authority to merge DNNA into Virginia Power. The Virginia Commission approved such merger in July 2008. Our request for approval of the merger is pending before the North Carolina Commission. In April 2008, we also filed an application with the NRC requesting authority to transfer the ESP to Virginia Power and ODEC. We have not yet committed to building a new nuclear unit.

In June 2008, the DOE issued a solicitation announcement inviting the submission of applications for loan guarantees from the DOE under its Loan Guarantee Program in support of debt financing for nuclear power facility projects in the U.S. (the Solicitation). The Solicitation is specifically designed to provide loan guarantees to support those projects that employ new or significantly improved nuclear power facility technologies. Any loan guarantee which may be issued by the DOE pursuant to the Solicitation would be backed by the full faith and credit of the U.S. federal government, and would provide credit enhancement for all or a portion of the debt financing an applicant would incur with respect to such

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a project. We intend to submit to the DOE, during the third quarter of 2008, Part I of the application, which would include a high-level description of the proposed nuclear unit, project eligibility, financing strategy and progress to date related to critical path schedules.

Conservation Plan

In June 2008, we announced an energy conservation plan that, if implemented, is expected to produce long-term environmental benefits while providing our electric utility customers with cost savings. The conservation plan is part of our *Powering Virginia* strategy to meet the future needs of customers. We hope to begin implementing the plan in 2009, subject to approval by the Virginia Commission and the North Carolina Commission, as applicable.

A key component of the plan is the installation of smart grid technologies that are designed to enhance our electric distribution system by allowing energy to be delivered more efficiently. We expect to invest about $600 million and replace all of our existing meters with Advanced Metering Infrastructure (AMI). The technology is expected to lead to improvements in service reliability and the ability of customers to monitor and control their energy use. Along with installing the AMI technology, programs in the conservation plan include:

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

Application for Enhanced ROE for Electric Transmission Projects

In July 2008, we filed an application with FERC requesting a revision to our cost of service to reflect an additional return on equity (ROE) for eleven electric transmission enhancement projects. Under the proposal our cost of transmission service would increase to include an ROE incentive adder for each of the eleven projects, beginning the date each project enters commercial operation (but not before January 1, 2009). We proposed an incentive of 150 basis points or 1.5% for four of the projects and an incentive of 125 basis points or 1.25% for the other seven projects. We expect that FERC will issue an order in early September 2008 either accepting our proposal or setting the matter for hearing. Several parties have intervened in the case. We cannot predict the outcome of these proceedings, but do not expect a material impact on our results of operations.

PJM Capacity Auction Complaint

In May 2008, the Maryland Public Service Commission, Delaware Public Service Commission, Pennsylvania Public Utility Commission, New Jersey Board of Public Utilities, the American Forest & Paper Association, the Portland Cement Association and several other organizations representing consumers in the PJM region (the RPM Buyers) filed a complaint at FERC claiming that PJM s Reliability Pricing Model s transitional auctions have produced unjust and unreasonable capacity prices. The RPM Buyers request that a refund effective date of June 1, 2008 be established and that FERC provide appropriate relief from unjust and unreasonable capacity charges within 15 months. We cannot predict the outcome of this complaint at FERC, but do not expect a material adverse effect on our financial position, liquidity or results of operations.

Environmental Matters

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

To the extent that environmental costs are incurred in connection with operations regulated by the Virginia Commission during the period ending December 31, 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.

Clean Air Act Compliance

In February 2008, the U.S. Court of Appeals for the District of Columbia issued a ruling that vacates the Clean Air Mercury Rule (CAMR) as promulgated by the EPA. In May 2008, the EPA s appeal of this decision with the U.S. Court of Appeals for the District of Columbia was denied. At this time we cannot determine if this ruling will be subject to further appeals. We also cannot predict how the EPA and the states that adopted CAMR-based mercury emissions reduction rules may alter their approach to reducing mercury emissions. Given this regulatory uncertainty, we cannot estimate at this time the impact of the ruling on our future capital and operational expenditures. It should be noted that we continue to be governed by individual state mercury emission reduction regulations in Massachusetts and Illinois that were largely unaffected by the CAMR ruling.

In July 2008, the U.S. Court of Appeals for the District of Columbia issued a ruling that vacates the Clean Air Interstate Rule (CAIR) as promulgated by the EPA. The ruling will be deferred during the 45-day period allowed for the filing of any petitions for rehearing. At this time we cannot determine if this ruling will be appealed. The primary effects of the Court s decision are the elimination of the CAIR requirement to surrender sulfur dioxide (SO_2) allowances under the Acid Rain Program at a 2:1 ratio starting in 2010 and a 2.86:1 ratio starting in 2015, and the emission reduction targets and timetables for nitrogen oxides (NO_X) that were beyond those reductions already required under the Clean Air Act s Acid Rain Program. The CAIR annual NO_X emissions allowance cap and trade program is also eliminated. Remaining in effect is the EPA NO_X State Implementation Plan Call regulation applicable to summertime NO_X emissions under a cap and trade program and the Acid Rain Program for SO_2 reductions.

At this time we cannot predict how the EPA and the states may alter their approach to reducing SO_2 and NO_X emissions in the absence of CAIR. We are currently evaluating the ruling to determine what impacts it may have on our compliance planning in regards to future SO_2 and NO_X emission reduction requirements; however because of this regulatory uncertainty we cannot estimate at this time the impact on our future capital and operational expenditures. It is anticipated that, in the short-term, the CAIR invalidation will not have a material adverse impact on expenditures related to compliance with state and federal rules regulating SO_2 and NO_X emissions. Expenditures could potentially increase in the long-term in the event that a new federal program is reinstituted and does not provide for the use of emissions allowances to satisfy emission reduction requirements. Despite the CAIR ruling, we are still subject to SO_2 and NO_X emission restrictions under federal and state rules unaffected by the ruling and under our 2003 agreement with the EPA and five other states in which we committed to a 12 year program to significantly reduce air emissions across our coal-fired utility generating fleet in Virginia and West Virginia.

We do not expect to recognize any loss in connection with the elimination of the annual NO_X program as all of our annual NO_X allowances were allocated to us and were not assigned a cost value. The Court s decision has resulted in a decline in the market value of SO_2 allowances which may impact our ability to monetize the value of these allowances in the future. We are currently evaluating whether an impairment adjustment is required for SO_2 allowances currently held by us, or a portion thereof, as a result of this decline in market value; however such impairment, if any, is not expected to have a material impact on our results of operations, cash flows or financial position.

Regulation of Greenhouse Gas Emissions

In April 2007, the U.S. Supreme Court ruled that the EPA has the authority to regulate greenhouse gas emissions. In July 2008, the EPA released an Advanced Notice of Proposed Rulemaking to solicit comment on potential issues related to the regulation of greenhouse gases under the Clean Air Act, which could result in further EPA 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 presented several compliance options. However, in January 2007, the U.S. Court of Appeals for the Second Circuit issued a decision on an appeal of the regulations, remanding the rule to the EPA. In July 2007, the EPA suspended the regulations pending further rulemaking, consistent with the decision issued by the U.S. Court of Appeals for the Second Circuit. In November 2007, a number of industries appealed the lower court decision to the U.S. Supreme Court. In April 2008, the U.S. Supreme Court granted the industry request to review the question of whether Section 316b of the Clean Water Act authorizes EPA to compare costs with benefits in determining the best technology available for minimizing adverse environmental impact at cooling water intake structures. 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.

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ITEM 3. QUANTITATIVE AND QUALITATIVE

DISCLOSURES ABOUT MARKET RISK

The matters discussed in this Item may contain forward-looking statements as described in the introductory paragraphs under Part I, Item 2. MD&A of this Form 10-Q. The reader s attention is directed to those paragraphs for discussion of various risks and uncertainties that may affect our future.

Market Risk Sensitive Instruments and Risk Management

Our financial instruments, commodity contracts and related financial derivative instruments are exposed to potential losses due to adverse changes in commodity prices, interest rates and equity security prices. 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 primarily hold commodity-based financial derivative instruments for non-trading purposes associated with purchases and sales of electricity, natural gas and other energy-related products. As part of our strategy to market energy and to manage related risks, we also hold commodity-based financial derivative instruments for trading purposes.

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

A hypothetical 10% unfavorable change in market prices of our non-trading commodity-based financial derivative instruments would have resulted in a decrease in fair value of approximately $633 million and $338 million as of June 30, 2008 and December 31, 2007, respectively. The change is largely due to increases in gas and electricity prices as well as increased gas and electric derivative activity. A hypothetical 10% unfavorable change in commodity prices would have resulted in a decrease of approximately $18 million and $8 million in the fair value of our commodity-based financial derivative instruments held for trading purposes as of June 30, 2008 and December 31, 2007, respectively. The change is primarily due to gas price increases.

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 June 30, 2008, a hypothetical 10% increase in market interest rates would have resulted in a decrease in annual earnings of approximately $7 million. A hypothetical 10% increase in market interest rates, as determined at December 31, 2007, would have resulted in a decrease in annual earnings of approximately $11 million.

Investment Price Risk

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

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

We recognized net realized losses (net of investment income) on nuclear decommissioning trust investments of $38 million for the six months ended June 30, 2008 and net realized gains (including investment income) of $55 million and $43 million for the six months ended June 30, 2007 and for the year ended December 31, 2007, respectively. For the six months ended June 30, 2008, we recorded, in AOCI and regulatory liabilities, a reduction in unrealized gains on these investments of $176 million. For the six months ended June 30, 2007, we recorded, in AOCI and regulatory liabilities, unrealized gains on these investments of $66 million. For the year ended December 31, 2007, we recorded, in AOCI and regulatory liabilities, unrealized gains on these investments of $52 million.

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

ITEM 4. CONTROLS AND PROCEDURES

Senior management, including the CEO and CFO, evaluated the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on this evaluation process, the CEO and CFO have concluded that our disclosure controls and procedures are effective.

There were no changes in our internal control over financial reporting that occurred during the last fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

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

ITEM 1A. RISK FACTORS

Our business is influenced by many factors that are difficult to predict, involve uncertainties that may materially affect actual results and are often beyond our control. We have identified a number of these risk factors in our Annual Report on Form 10-K for the year ended December 31, 2007 and our Quarterly Report on Form 10-Q for the quarter ended March 31, 2008, which should be taken into consideration when reviewing the information contained in this report. There have been no material changes with regard to the risk factors previously disclosed in our Annual Report on Form 10-K for the year ended December 31, 2007 or our Quarterly Report on Form 10-Q for the quarter ended March 31, 2008. 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.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

The table below provides certain information with respect to our purchases of our common stock:

ISSUER PURCHASES OF EQUITY SECURITIES

Period	(a) Total Number of Shares (or Units) Purchased[(1)]	(b) Average Price Paid per Share (or Unit)	(c) Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased under the Plans or Programs
4/1/08-4/30/08	59,611	$ 43.32	N/A	53,971,148 shares/ $2.68 billion
5/1/08-5/31/08	5,928	43.68	N/A	53,971,148 shares/ $2.68 billion
6/1/08-6/30/08	9,914	46.30	N/A	53,971,148 shares/ $2.68 billion
Total	75,453	$ 43.74	N/A	53,971,148 shares/ $2.68 billion

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

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

A summary of matters voted upon at our Annual Shareholders Meeting that was held on May 9, 2008 are listed below:

Election of Directors

Directors were elected to the Board of Directors for a one-year term or until next year s annual meeting.

Nominee	Votes For	Votes Against	Votes Abstained
Peter W. Brown	476,462,977	4,634,767	5,643,375
George A. Davidson, Jr.	475,901,888	5,214,098	5,625,133
Thomas F. Farrell, II	474,987,890	6,171,110	5,582,119
John W. Harris	476,061,075	4,997,200	5,682,844
Robert S. Jepson, Jr.	476,142,148	4,917,949	5,681,022
Mark J. Kington	476,435,995	4,611,343	5,693,781
Benjamin J. Lambert, III	475,023,133	5,985,564	5,732,422
Margaret A. McKenna	476,114,812	5,035,483	5,590,824
Frank S. Royal	470,487,658	10,433,042	5,820,419
David A. Wollard	475,566,725	5,447,612	5,726,782

Appointment of Independent Auditors

The appointment of Deloitte & Touche LLP as our independent auditors for 2008 was ratified by shareholders as follows:

Votes For	Votes Against	Votes Abstained
476,615,314	4,728,910	5,396,895

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Item 6. EXHIBITS

(a) Exhibits:

3.1 Articles of Incorporation as in effect August 9, 1999, as amended March 12, 2001 (Exhibit 3.1, Form 10-K for the year ended December 31, 2002, File No. 1-8489, incorporated by reference), as amended November 9, 2007 (Exhibit 3, Form 8-K, filed November 9, 2007, File No. 1-8489, incorporated by reference).

3.2 Amended and Restated Bylaws effective on June 20, 2007 (Exhibit 3.1, Form 8-K filed June 22, 2007, File No. 1-8489, incorporated by reference).

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

4.2 Form of Senior Indenture, dated June 1, 2000, between Dominion Resources, Inc. and The Bank of New York (as successor trustee to JP Morgan Chase Bank (formerly The Chase Manhattan Bank)), as Trustee (Exhibit 4 (iii), Form S-3, Registration Statement, File No. 333-93187, incorporated by reference); First Supplemental Indenture, dated June 1, 2000 (Exhibit 4.2, Form 8-K, dated June 21, 2000, File No. 1-8489, incorporated by reference); Second Supplemental Indenture, dated July 1, 2000 (Exhibit 4.2, Form 8-K, dated July 11, 2000, File No. 1-8489, incorporated by reference); Third Supplemental Indenture, dated July 1, 2000 (Exhibit 4.3, Form 8-K dated July 11, 2000, incorporated by reference); Fourth Supplemental Indenture and Fifth Supplemental Indenture dated September 1, 2000 (Exhibit 4.2, Form 8-K, dated September 8, 2000, incorporated by reference); Sixth Supplemental Indenture, dated September 1, 2000 (Exhibit 4.3, Form 8-K, dated September 8, 2000, incorporated by reference); Seventh Supplemental Indenture, dated October 1, 2000 (Exhibit 4.2, Form 8-K, dated October 11, 2000, incorporated by reference); Eighth Supplemental Indenture, dated January 1, 2001 (Exhibit 4.2, Form 8-K, dated January 23, 2001, incorporated by reference); Ninth Supplemental Indenture, dated May 1, 2001 (Exhibit 4.4, Form 8-K, dated May 25, 2001, incorporated by reference); Form of Tenth Supplemental Indenture (Exhibit 4.2, Form 8-K filed March 18, 2002, File No. 1-8489, incorporated by reference); Form of Eleventh Supplemental Indenture (Exhibit 4.2, Form 8-K filed June 25, 2002, File No. 1-8489, incorporated by reference.); Form of Twelfth Supplemental Indenture (Exhibit 4.2, Form 8-K filed September 11, 2002, File No. 1-8489, incorporated by reference); Thirteenth Supplemental Indenture dated September 16, 2002 (Exhibit 4.1, Form 8-K filed September 17, 2002, File No. 1-8489, incorporated by reference); Fourteenth Supplemental Indenture, dated August 20, 2003 (Exhibit 4.4, Form 8-K filed August 20, 2003, File No. 1-8489, incorporated by reference); Forms of Fifteenth and Sixteenth Supplemental Indentures (Exhibits 4.2 and 4.3 to Form 8-K filed December 12, 2002, File No. 1-8489, incorporated by reference); Forms of Seventeenth and Eighteenth Supplemental Indentures (Exhibits 4.2. and 4.3 to Form 8-K filed February 11, 2003, File No. 1-8489, incorporated by reference); Forms of Twentieth and Twenty-First Supplemental Indentures (Exhibits 4.2 and 4.3 to Form 8-K filed March 4, 2003, File No. 1-8489, incorporated by reference); Form of Twenty-Second Supplemental Indenture (Exhibit 4.2 to Form 8-K filed July 22, 2003, File No. 1-8489 incorporated by reference); Form of Twenty-Third Supplemental Indenture (Exhibit 4.2, Form 8-K filed December 9, 2003, File No. 1-8489, incorporated by reference); Form of Twenty-Fifth Supplemental Indenture (Exhibit 4.2, Form 8-K filed January 14, 2004, File No. 1-8489, incorporated by reference); Form of Twenty-Sixth Supplemental Indenture (Exhibit 4.3, Form 8-K filed January 14, 2004, File No. 1-8489, incorporated by reference); Form of Twenty-Seventh Supplemental Indenture (Exhibit 4.2, Form S-4 Registration Statement, File No. 333-120339, incorporated by reference); Form of Twenty-Eighth and Twenty-Ninth Supplemental Indenture (Exhibits 4.2 and 4.3, Form 8-K filed June 17, 2005, File No. 1-8489, incorporated by reference); Form of Thirtieth Supplemental Indenture (Exhibit 4.2, Form 8-K, filed July 12, 2005, File No. 1-8489, incorporated by reference); Form of Thirty-First Supplemental Indenture (Exhibit 4.2, Form 8-K, filed September 26, 2005, File No. 1-8489, incorporated by reference); Form of Thirty-Second Supplemental Indenture (Exhibit 4.2, Form 8-K, filed November 13, 2007, File No. 1-8489, incorporated by reference); Form of Thirty-Third Supplemental Indenture (Exhibit 4.3, Form 8-K, filed November 13, 2007, File No. 1-8489, incorporated by reference) ; Form of Thirty-Fourth Supplemental Indenture (Exhibit 4.2, Form 8-K, filed November 29, 2007, File No. 1-8489, incorporated by reference); Form of Thirty-Fifth Supplemental Indenture (Exhibit 4.2, Form 8-K, filed June 16, 2008, File No. 1-8489, incorporated by reference);. Form of Thirty-Sixth Supplemental Indenture (Exhibit 4.3, Form 8-K, filed June 16, 2008, File No. 1-8489, incorporated by reference); and Form of Thirty-Seventh Supplemental Indenture (Exhibit 4.4, Form 8-K, filed June 16, 2008, File No. 1-8489, incorporated by reference).

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12	Ratio of earnings to fixed charges (filed herewith).
31.1	Certification by Registrant s CEO pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).
31.2	Certification by Registrant s CFO pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).
32	Certification to the SEC by Registrant s CEO and CFO, as required by Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith).
99	Condensed consolidated earnings statements (unaudited) (filed herewith).

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

DOMINION RESOURCES, INC.

Registrant

July 31, 2008

/s/ Thomas P. Wohlfarth
Thomas P. Wohlfarth
Senior Vice President and Chief Accounting Officer

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