DOMINION RESOURCES INC /VA/
Form 10-Q
November 02, 2009

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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 September 30, 2009

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	**(I.R.S. Employer**
incorporation or organization)	**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 has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). 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 September 30, 2009, the latest practicable date for determination, 597,240,826 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)
AROs	Asset retirement obligations
bcf	Billion cubic feet
bcfe	Billion cubic feet equivalent
CEO	Chief Executive Officer
CFO	Chief Financial Officer
DCI	Dominion Capital, Inc.
DD&A	Depreciation, depletion and amortization expense
Dominion	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, depending on the context of its use
DEI	Dominion Energy, Inc.
Dominion Direct®	A dividend reinvestment and open enrollment direct stock purchase plan
Dominion East Ohio	The East Ohio Gas Company
DVP	Dominion Virginia Power operating segment
E&P	Exploration and production
EPA	Environmental Protection Agency
EPS	Earnings per share
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FTRs	Financial transmission rights
GAAP	U.S. generally accepted accounting principles
Hope	Hope Gas, Inc.
kWh	Kilowatt-hour
LNG	Liquefied natural gas
mcf	Thousand cubic feet
mcfe	Thousand cubic feet equivalent
MD&A	Management s Discussion and Analysis of Financial Condition and Results of Operations
Moody s	Moody s Investors Service
MW	Megawatt
MWh	Megawatt-hour
North Anna	North Anna power station
NRC	Nuclear Regulatory Commission
Pennsylvania Commission	Pennsylvania Public Utility Commission
Peoples	The Peoples Natural Gas Company
PJM	PJM Interconnection, LLC
ROE	Return on equity
RTO	Regional transmission organization
SEC	Securities and Exchange Commission
Standard & Poor s	Standard & Poor s Ratings Services, a division of the McGraw-Hill Companies, Inc.
U.S.	United States of America
VIEs	Variable interest entities
Virginia City Hybrid Energy Center	A 585 Mw (nominal) carbon capture-compatible, clean-coal powered electric generation facility currently under construction in Wise County, Virginia
Virginia Commission	Virginia State Corporation Commission
Virginia Power	Virginia Electric and Power Company
West Virginia Commission	Public Service Commission of West Virginia

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DOMINION RESOURCES, INC.

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

CONSOLIDATED STATEMENTS OF INCOME

(Unaudited)

(millions, except per share amounts)	**Three Months Ended September 30, 2009**	**Three Months Ended September 30, 2008[1]**	**Nine Months Ended September 30, 2009**	**Nine Months Ended September 30, 2008[1]**
Operating Revenue	**$ 3,648**	$ 4,365	**$ 11,876**	$ 12,117
Operating Expenses				
Electric fuel and other energy-related purchases	**1,072**	1,383	**3,211**	2,950
Purchased electric capacity	**96**	102	**309**	306
Purchased gas	**279**	692	**1,785**	2,482
Other operations and maintenance	**748**	762	**2,695**	2,409
Depreciation, depletion and amortization	**274**	259	**824**	770
Other taxes	**107**	112	**373**	375
Total operating expenses	**2,576**	3,310	**9,197**	9,292
Income from operations	**1,072**	1,055	**2,679**	2,825
Other income	**123**	14	**127**	10
Interest and related charges[2]	**217**	213	**658**	634
Income from continuing operations including noncontrolling interests before income tax expense	**978**	856	**2,148**	2,201
Income tax expense	**380**	344	**840**	701
Income from continuing operations including noncontrolling interests	**598**	512	**1,308**	1,500
Loss from discontinued operations[3]				(2)
Net Income Including Noncontrolling Interests	**598**	512	**1,308**	1,498
Noncontrolling Interests	**4**	4	**12**	12
Net Income Attributable to Dominion	**$ 594**	$ 508	**$ 1,296**	$ 1,486
Amounts Attributable to Dominion:				
Income from continuing operations, net of tax	**$ 594**	$ 508	**$ 1,296**	$ 1,488
Loss from discontinued operations, net of tax				(2)
Net income attributable to Dominion	**$ 594**	$ 508	**$ 1,296**	$ 1,486
Earnings Per Common Share Basic[4]				
Net income attributable to Dominion	**$ 1.00**	$ 0.88	**$ 2.19**	$ 2.58
Earnings Per Common Share Diluted[4]				
Net income attributable to Dominion	**$ 1.00**	$ 0.87	**$ 2.19**	$ 2.56

Dividends paid per common share	**$ 0.4375**	$ 0.395	**$ 1.3125**	$ 1.185

(1) Our Consolidated Statements of Income for the three and nine months ended September 30, 2008 have been recast due to the application of new accounting guidance for noncontrolling interests, as discussed in Note 3.

(2) Includes affiliated interest expense of $5 million for the three months ended September 30, 2009 and 2008 and $16 million and $28 million for the nine months ended September 30, 2009 and 2008, respectively.

(3) Net of income tax benefit of $3 million for the nine months ended September 30, 2008.

(4) For the nine months ended September 30, 2008, loss from discontinued operations had no impact on basic or diluted earnings per share.

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

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DOMINION RESOURCES, INC.

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(millions)	September 30, 2009	December 31, 2008(1)
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 50**	$ 66
Customer receivables (less allowance for doubtful accounts of $30 and $32)	**1,760**	2,354
Other receivables (less allowance for doubtful accounts of $13 and $7)	**105**	205
Inventories	**1,178**	1,166
Derivative assets	**1,498**	1,497
Assets held for sale	**1,360**	1,416
Regulatory assets	**475**	340
Prepayments	**115**	163
Other	**310**	454
Total current assets	**6,851**	7,661
Investments		
Nuclear decommissioning trust funds	**2,554**	2,246
Investment in equity method affiliates	**600**	726
Other	**271**	285
Total investments	**3,425**	3,257
Property, Plant and Equipment		
Property, plant and equipment	**37,913**	35,448
Accumulated depreciation, depletion and amortization	**(13,230)**	(12,174)
Total property, plant and equipment, net	**24,683**	23,274
Deferred Charges and Other Assets		
Goodwill	**3,503**	3,503
Regulatory assets	**1,583**	2,226
Other	**2,042**	2,132
Total deferred charges and other assets	**7,128**	7,861
Total assets	**$ 42,087**	$ 42,053

(1) Our Consolidated Balance Sheet at December 31, 2008 has been derived from the audited Consolidated Financial Statements at that date.
The accompanying notes are an integral part of our Consolidated Financial Statements.

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DOMINION RESOURCES, INC.

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(millions)	September 30, 2009	December 31, 2008[1]
LIABILITIES AND SHAREHOLDERS EQUITY		
Current Liabilities		
Securities due within one year	**$ 709**	$ 444
Short-term debt	**649**	2,030
Accounts payable	**1,046**	1,499
Accrued interest, payroll and taxes	**742**	754
Derivative liabilities	**1,016**	1,100
Liabilities held for sale	**540**	570
Accrued dividends		260
Other	**746**	1,137
Total current liabilities	**5,448**	7,794
Long-Term Debt		
Long-term debt	**14,472**	13,890
Junior subordinated notes payable:		
Affiliates	**268**	268
Other	**1,483**	798
Total long-term debt	**16,223**	14,956
Deferred Credits and Other Liabilities		
Deferred income taxes and investment tax credits	**4,088**	4,137
Asset retirement obligations	**1,563**	1,802
Pension and other postretirement benefit liabilities	**1,592**	1,525
Regulatory liabilities	**1,126**	944
Other	**463**	561
Total deferred credits and other liabilities	**8,832**	8,969
Total liabilities	**30,503**	31,719
Commitments and Contingencies (see Note 18)		
Subsidiary Preferred Stock Not Subject to Mandatory Redemption	**257**	257
Common Shareholders Equity		
Common stock no par[2]	**6,443**	5,994
Other paid-in capital	**182**	182
Retained earnings	**4,956**	4,170
Accumulated other comprehensive loss	**(254)**	(269)
Total common shareholders equity	**11,327**	10,077
Total liabilities and shareholders equity	**$ 42,087**	$ 42,053

(1) Our Consolidated Balance Sheet at December 31, 2008 has been derived from the audited Consolidated Financial Statements at that date.

(2) 1 billion shares authorized; 597 million shares outstanding at September 30, 2009 and 583 million shares outstanding at December 31, 2008.

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)

Nine Months Ended September 30, (millions)	2009	2008
Operating Activities		
Net income including noncontrolling interests	**$ 1,308**	$ 1,498(1)
Adjustments to reconcile net income including noncontrolling interests to net cash from operating activities:		
Dominion Capital, Inc. impairment loss		62
Impairment of gas and oil properties	**455**	
Net change in realized and unrealized derivative (gains) losses	**(46)**	177
Depreciation, depletion and amortization	**960**	888
Deferred income taxes and investment tax credits	**(342)**	351
Other adjustments	**(49)**	48
Changes in:		
Accounts receivable	**804**	187
Inventories	**(41)**	(244)
Deferred fuel and purchased gas costs	**678**	(636)
Accounts payable	**(475)**	(289)
Accrued interest, payroll and taxes	**(4)**	(232)
Margin deposit assets and liabilities	**(194)**	(249)
Other operating assets and liabilities	**(72)**	(134)
Net cash provided by operating activities	**2,982**	1,427
Investing Activities		
Plant construction and other property additions	**(2,753)**	(2,307)
Additions to gas and oil properties	**(131)**	(166)
Proceeds from assignment of natural gas drilling rights		343
Proceeds from sale of securities and loan receivable collections and payoffs	**1,258**	1,058
Purchases of securities and loan receivable originations	**(1,294)**	(1,035)
Investment in affiliates and partnerships	**(40)**	(337)
Distributions from affiliates and partnerships	**174**	41
Other	**42**	82
Net cash used in investing activities	**(2,744)**	(2,321)
Financing Activities		
Issuance (repayment) of short-term debt, net	**(1,381)**	695
Issuance of long-term debt	**1,695**	1,830
Repayment of long-term debt	**(134)**	(889)
Repayment of affiliated notes payable		(412)
Issuance of common stock	**381**	178
Common dividend payments	**(777)**	(686)
Subsidiary preferred dividend payments	**(12)**	(12)(1)
Other	**(28)**	(7)
Net cash provided by (used in) financing activities	(256)	697
Decrease in cash and cash equivalents	(18)	(197)

Cash and cash equivalents at beginning of period(2)		71		287
Cash and cash equivalents at end of period(3)	$	53	$	90
Significant Noncash Investing and Financing Activities				
Accrued capital expenditures	**$**	**184**	$	60
Debt for equity exchange	**$**	**56**	$	

(1) Our Consolidated Statement of Cash Flow for the nine months ended September 30, 2008 has been recast due to the application of new accounting guidance for noncontrolling interests, as discussed in Note 3.

(2) 2009 and 2008 amounts include $5 million and $4 million, respectively, of cash classified as held for sale in our Consolidated Balance Sheets.

(3) 2009 and 2008 amounts include $3 million and $2 million, respectively, of cash classified as held for sale in our 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 operations are conducted through various subsidiaries, including Virginia Electric and Power Company (Virginia Power), our regulated public utility that generates, transmits and distributes electricity for sale in Virginia and northeastern North Carolina. In addition, our operations also include a regulated interstate natural gas transmission pipeline and underground storage system in the Northeast, mid-Atlantic and Midwest states, a liquefied natural gas (LNG) import and storage facility in Maryland and regulated gas transportation and distribution operations in Ohio, Pennsylvania and West Virginia. We have entered into an agreement to sell our Pennsylvania and West Virginia gas distribution operations as discussed in Note 4. Our nonregulated operations include merchant generation, energy marketing and price risk management activities, retail energy marketing operations and natural gas exploration and production in the Appalachian basin 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 corporate, service company and other functions and the net impact of certain operations disposed of or to be disposed of, which are discussed in Note 4. Corporate and Other also includes specific items attributable to Dominion s operating segments that are not included in profit measures evaluated by executive management in assessing the segments performance or in allocating resources among the segments. See Note 21 for further discussion of our operating segments.

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

Note 2. Significant Accounting Policies

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 the Consolidated Financial Statements and Notes in our Annual Report on Form 10-K for the year ended December 31, 2008 and our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2009 and June 30, 2009.

In our opinion, the accompanying unaudited Consolidated Financial Statements contain all adjustments necessary to present fairly our financial position as of September 30, 2009, our results of operations for the three and nine months ended September 30, 2009 and 2008 and our cash flows for the nine months ended September 30, 2009 and 2008. Such adjustments are normal and recurring in nature unless otherwise noted.

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. See Note 9 for further information on 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 other energy-related purchases, purchased gas expenses and other factors.

DOMINION RESOURCES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Certain amounts in our 2008 Consolidated Financial Statements and Notes have been recast to conform to the 2009 presentation.

We have evaluated subsequent events through November 2, 2009, the date our Consolidated Financial Statements were issued.

Note 3. Newly Adopted Accounting Standards

Noncontrolling Interests in Consolidated Financial Statements

Effective January 1, 2009, we adopted new accounting guidance for noncontrolling interests that requires retrospective application of presentation and disclosure changes including that noncontrolling interests be reported as a component of equity and that net income attributable to the parent and noncontrolling interests be separately identified in the income statement.

Our subsidiary preferred dividends were previously included in interest and related charges in our Consolidated Statements of Income and in operating activities in our Consolidated Statements of Cash Flows. Due to the application of new accounting guidance for noncontrolling interests, we now reflect our subsidiary preferred dividends as an adjustment (noncontrolling interests) to arrive at net income attributable to Dominion in our Consolidated Statements of Income and in financing activities in our Consolidated Statements of Cash Flows. Since our subsidiary preferred stock does not qualify as permanent equity, we continue to report these amounts as mezzanine equity in our Consolidated Balance Sheets.

Recognition and Presentation of Other-Than-Temporary Impairments

The FASB amended its guidance for the recognition and presentation of other-than-temporary impairments, which we adopted effective April 1, 2009. The recognition provisions of this guidance apply only to debt securities classified as available for sale or held to maturity, while the presentation and disclosure requirements apply to both debt and equity securities. Prior to the adoption of this guidance, as described in Note 2 in our Annual Report on Form 10-K for the year ended December 31, 2008, we considered all debt securities held by our nuclear decommissioning trusts with market values below their cost bases to be other-than-temporarily impaired as we did not have the ability to ensure the investments were held through the anticipated recovery period.

Effective with the adoption of this guidance, using information obtained from our nuclear decommissioning trust fixed-income investment managers, we record in earnings any unrealized loss for a debt security when the manager intends to sell the debt security or it is more likely than not that the manager will have to sell the debt security before recovery of its fair value up to its cost basis. For any debt security that is deemed to have experienced a credit loss, we record the credit loss in earnings and any remaining portion of the unrealized loss in other comprehensive income. We evaluate credit losses primarily by considering the credit ratings of the issuer, prior instances of non-performance by the issuer and other factors. For investments in our utility nuclear decommissioning trusts, all net realized and unrealized gains and losses on debt securities (including any other-than-temporary impairments) continue to be recorded to a regulatory liability for certain jurisdictions subject to cost-based regulation.

Upon the adoption of this guidance for debt investments held at April 1, 2009, we recorded a $20 million ($12 million after-tax) cumulative effect of a change in accounting principle to reclassify the non-credit related portion of previously recognized other-than-temporary impairments from retained earnings to AOCI, reflecting the fixed-income investment managers intent and ability to hold the debt securities until the amortized cost bases are recovered.

Note 4. Dispositions

Sale of Certain DCI Operations

Previously, Dominion Capital, Inc. (DCI) held an investment in the subordinated notes of a third-party collateralized debt obligation (CDO) entity determined to be a variable interest entity (VIE), which we consolidated. In March 2008, we reached an agreement to sell our remaining interest in the subordinated notes, effectively eliminating the variability of our interest, and therefore deconsolidated the CDO entity as of March 31, 2008 and recognized impairment losses of $62 million ($38 million after-tax) in other operations and maintenance expense. In connection with the sale of the subordinated notes, in April 2008, we received proceeds of $54 million, including accrued interest.

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DOMINION RESOURCES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Planned Sale of Regulated Gas Distribution Subsidiaries

In July 2008, we entered into an agreement with Peoples Hope Gas Companies LLC, a subsidiary of Babcock & Brown Infrastructure Fund North America LP (the Fund), to sell Peoples and Hope for approximately $910 million, subject to adjustments to reflect levels of capital expenditures and changes in working capital. In May 2009, the Fund s management team established a new entity, SteelRiver Infrastructure Partners LP (SteelRiver), to acquire the general partner of the Fund from Babcock & Brown. John Hancock Life Insurance Company (John Hancock) acquired Babcock & Brown s limited partner interests in the Fund. Management rights over the Fund were acquired by an entity jointly owned by SteelRiver and John Hancock and will be managed under contract with SteelRiver. The transactions described in the three preceding sentences are referred to as the SteelRiver Transaction. Following the SteelRiver Transaction, the Fund was renamed SteelRiver Infrastructure Fund North America LP. The sale of Peoples and Hope is expected to close in 2009, subject to state regulatory approvals in Pennsylvania and West Virginia.

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)	September 30, 2009	December 31, 2008
ASSETS		
Current Assets		
Customer receivables	**$ 61**	$ 172
Other	**225**	142
Total current assets	**286**	314
Property, Plant and Equipment		
Property, plant and equipment	**1,234**	1,204
Accumulated depreciation, depletion and amortization	**(352)**	(358)
Total property, plant and equipment, net	**882**	846
Deferred Charges and Other Assets		
Regulatory assets	**139**	156
Other	**53**	100
Total deferred charges and other assets	**192**	256
Assets held for sale	**$ 1,360**	$ 1,416
LIABILITIES		
Current Liabilities	**$ 167**	$ 192
Deferred Credits and Other Liabilities		
Deferred income taxes and investment tax credits	**284**	289
Other	**89**	89

Total deferred credits and other liabilities		**373**		378
Liabilities held for sale	**$**	**540**	$	570

The following table presents selected information regarding the results of operations of Peoples and Hope, which are included in income from continuing operations including noncontrolling interests:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	**2008**	**2009**	**2008**
(millions)				
Operating revenue	**$ 51**	$ 74	**$ 452**	$ 480
Income (loss) before income taxes	**(24)**[(1)]		**32**[(1)]	100[(1)]

(1) For the nine months ended September 30, 2008, reflects a $47 million benefit related to the re-establishment of a regulatory asset in connection with the planned sale of Peoples and Hope. The three and nine months ended September 30, 2009, include the impact of a $22 million charge due to a reduction of the previously established regulatory asset.

DOMINION RESOURCES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Note 5. Operating Revenue

Our operating revenue consists of the following:

(millions)	Three Months Ended September 30, 2009	2008	Nine Months Ended September 30, 2009	2008
Operating Revenue				
Electric sales:				
Regulated	**$ 1,905**	$ 2,143	**$ 5,377**	$ 5,153
Nonregulated	**999**	1,005	**2,917**	2,669
Gas sales:				
Regulated	**50**	107	**658**	898
Nonregulated	**338**	816	**1,629**	2,239
Gas transportation and storage	**249**	189	**968**	799
Other	**107**	105	**327**	359
Total operating revenue	**$ 3,648**	$ 4,365	**$ 11,876**	$ 12,117

Note 6. Income Taxes

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

	Nine Months Ended September 30, 2009	2008
U.S. statutory rate	**35.0%**	35.0%
Increases (reductions) resulting from:		
State taxes, net of federal benefit	**4.4**	3.9
Reversal of deferred taxes stock of subsidiaries held for sale		(6.2)
Other, net	**(0.3)**	(0.8)
Effective tax rate	**39.1%**	31.9%

In 2008, our effective tax rate reflected the reversal of $136 million of deferred tax liabilities, recognized in 2006, associated with the excess of our financial reporting basis over the tax basis in the stock of Peoples and Hope. In 2006, based on the intended form of the sale of Peoples and Hope to Equitable Resources, Inc. (Equitable), we recognized these deferred tax liabilities since the difference between the financial reporting basis and our tax basis in the stock of the subsidiaries was expected to reverse upon closing of the sale. In January 2008, Dominion and Equitable agreed to terminate the agreement for the sale of Peoples and Hope. At that time, based on our expectation that the form of any future disposal of these subsidiaries would be structured so that the taxable gain would instead be determined by reference to the basis in the subsidiaries underlying assets, we reversed the related deferred tax liabilities recognized in 2006. As discussed in Note 4, we have executed a new agreement to sell Peoples and Hope, whereby we will determine our taxable gain by reference to the basis in the subsidiaries underlying assets.

In the second quarter of 2009, the U.S. Congressional Joint Committee on Taxation completed its review of our settlement with the Appellate Division of the Internal Revenue Service (IRS Appeals) for tax years 1999 through 2001. We were entitled to a $60 million refund, of which $20 million was applied as an estimated payment for 2009 taxes and $40 million was paid to us in October 2009. Settlement negotiations with IRS Appeals regarding our protest of adjustments proposed for tax years 2002 and 2003 are ongoing. In addition, the Internal Revenue Service (IRS) has completed its audit and has proposed adjustments for tax years 2004 and 2005. We filed protests for certain of those adjustments in July 2009.

At September 30, 2009, unrecognized tax benefits related to current year tax positions were $39 million. During the nine months ended September 30, 2009, unrecognized tax benefits related to prior year uncertain tax positions increased on a gross basis by $44 million and decreased on a gross basis by $86 million. In addition, unrecognized tax benefits for prior years decreased by $11 million for settlements with tax authorities, $28 million for amounts that otherwise become deductible in 2009 and $5 million for expiration of statutes of limitations.

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DOMINION RESOURCES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

See Note 7 to our Annual Report on Form 10-K for the year ended December 31, 2008, for a discussion of reasonably possible changes that could occur in our unrecognized tax benefits during the next twelve months, including our efforts to eliminate or reduce uncertainty regarding the calculation of our qualified production activities deduction under the IRS Pre-filing Program. It is reasonably possible that we could reach an agreement with the IRS about our calculation in the fourth quarter of 2009, and unrecognized tax benefits for 2009 and prior years would decrease by $25 million to $35 million, which would be reflected in our earnings. In addition, with the completion of the audit of tax years 2004 and 2005, it is reasonably possible that unrecognized tax benefits could decrease up to $45 million over the next twelve months, resulting from successful settlement negotiations or payments to tax authorities, with no material impact on our results of operations.

Note 7. Earnings Per Share

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	**2008**	**2009**	**2008**
(millions, except EPS)				
Net income attributable to Dominion	**$ 594**	$ 508	**$ 1,296**	$ 1,486
Average shares of common stock outstanding Basic	**595.9**	578.6	**591.7**	577.0
Net effect of potentially dilutive securities(1)	**0.4**	3.4	**0.3**	3.3
Average shares of common stock outstanding Diluted	**596.3**	582.0	**592.0**	580.3
Earnings Per Common Share Basic	**$ 1.00**	$ 0.88	**$ 2.19**	$ 2.58
Earnings Per Common Share Diluted	**$ 1.00**	$ 0.87	**$ 2.19**	$ 2.56

(1) Potentially dilutive securities consist of options, goal-based stock and contingently convertible senior notes.

Potentially dilutive securities with the right to acquire approximately 0.5 million and 1.6 million common shares for the three and nine months ended September 30, 2009, respectively, were not included in the respective period s calculation of diluted EPS because the exercise or purchase prices of those instruments were greater than the average market price of our common shares. There were no potentially dilutive securities excluded from the calculation of diluted EPS during the three and nine months ended September 30, 2008.

Note 8. Comprehensive Income

The following table presents total comprehensive income:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	**2008**	**2009**	**2008**
(millions)				
Net income including noncontrolling interests	**$ 598**	$ 512	**$ 1,308**	$ 1,498

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	**(156)**	1,263[1]	**(117)**	140[1]
Other, net of tax[2]	**67**	(19)	**144**	(79)
Other comprehensive income (loss)	**(89)**	1,244	**27**	61
Comprehensive income including noncontrolling interests	**509**	1,756	**1,335**	1,559
Noncontrolling interests	**4**	4	**12**	12
Total comprehensive income attributable to Dominion	**$ 505**	$ 1,752	**$ 1,323**	$ 1,547

(1) For the quarter, increase principally due to the impact of a decrease in commodity prices. For the year-to-date period, reflects a decrease in commodity prices in the third quarter, partially offset by an increase in commodity prices through the first six months of the year.

(2) Principally represents a net increase in unrealized gains on investments held in merchant nuclear decommissioning trusts in 2009 as compared to a decrease in 2008.

Other comprehensive income (loss) for the nine months ended September 30, 2009 excludes a $20 million ($12 million after-tax) adjustment to AOCI representing the cumulative effect of the change in accounting principle related to the recognition and presentation of other-than-temporary impairments.

DOMINION RESOURCES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Note 9. Fair Value Measurements

Our fair value measurements are made in accordance with the policies discussed in Note 8 to our Annual Report on Form 10-K for the year ended December 31, 2008. In addition, see Note 10 in this report for further information about our derivatives and hedge accounting activities.

The following table presents our assets and liabilities that are measured at fair value on a recurring basis for each hierarchy level, including both current and noncurrent portions:

(millions)	Level 1	Level 2	Level 3	Total
As of September 30, 2009				
Assets				
Derivatives	**$ 94**	**$ 1,662**	**$ 132**	**$ 1,888**
Investments:				
Marketable equity securities	**1,507**			**1,507**
Marketable debt securities:				
Corporate bonds		**247**		**247**
U.S. Treasury securities and agency debentures	**219**	**95**		**314**
State and municipal		**433**		**433**
Other		**2**		**2**
Cash equivalents and other		**39**		**39**
Total assets	**$ 1,820**	**$ 2,478**	**$ 132**	**$ 4,430**
Liabilities				
Derivatives	**$ 30**	**$ 1,031**	**$ 143**	**$ 1,204**
As of December 31, 2008				
Assets				
Derivatives	$ 125	$ 1,672	$ 243	$ 2,040
Investments:				
Marketable equity securities	514	573		1,087
Marketable debt securities:				
Corporate bonds		249		249
U.S. Treasury securities and agency debentures	209	179		388
State and municipal		455		455
Other		6		6
Cash equivalents and other	2	39		41
Total assets	$ 850	$ 3,173	$ 243	$ 4,266
Liabilities				
Derivatives	$ 7	$ 1,146	$ 144	$ 1,297

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DOMINION RESOURCES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

The following table presents the net change in the assets and liabilities measured at fair value on a recurring basis and included in the Level 3 fair value category:

(millions)	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Beginning balance	**$ 31**	$ (191)	**$ 99**	$ (61)
Total realized and unrealized gains or (losses):				
Included in earnings	**3**	(9)	**(128)**	53
Included in other comprehensive income (loss)	**(7)**	357	**(95)**	(19)
Included in regulatory assets/liabilities	**(45)**	(249)	**10**	(49)
Purchases, issuances and settlements	**5**	(15)	**118**	(27)
Transfers out of Level 3	**2**	5	**(15)**	1
Ending balance	**$ (11)**	$ (102)	**$ (11)**	$ (102)
The amount of 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	**$ 7**	$ (35)	**$ 2**	$ (3)

The following table presents gains and losses included in earnings in the Level 3 fair value category:

(millions)	Operating revenue	Electric fuel and other energy-related purchases	Purchased gas	Total
Three Months Ended September 30, 2009				
Total gains or (losses) included in earnings	**$ 17**	**$ (14)**	**$**	**$ 3**
The amount of total gains (losses) for the period included in earnings attributable to the change in unrealized gains/losses relating to assets/liabilities still held at the reporting date	**6**		**1**	**7**
Three Months Ended September 30, 2008				
Total gains or (losses) included in earnings	$ 2	$ 17	$ (28)	$ (9)
The amount of total gains (losses) for the period included in earnings attributable to the change in unrealized gains/losses relating to assets/liabilities still held at the reporting date	9	(19)	(25)	(35)
Nine Months Ended September 30, 2009				
Total gains or (losses) included in earnings	**$ 31**	**$ (152)**	**$ (7)**	**$ (128)**
The amount of total gains (losses) for the period included in earnings attributable to the change in unrealized gains/losses relating to assets/liabilities still held at the reporting date	**5**		**(3)**	**2**

Nine Months Ended September 30, 2008				
Total gains or (losses) included in earnings	$ (50)	$ 107	$ (4)	$ 53
The amount of total gains (losses) for the period included in earnings attributable to the change in unrealized gains/losses relating to assets/liabilities still held at the reporting date	8	(4)	(7)	(3)

As of September 30, 2009, our net balance of commodity derivatives categorized as Level 3 fair value measurements was a net liability of $11 million. A hypothetical 10% increase in commodity prices would increase the net liability by $30 million, while a hypothetical 10% decrease in commodity prices would decrease the net liability by $30 million.

Additionally, during the first quarter of 2009, we evaluated an equity method investment for impairment and

DOMINION RESOURCES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

recorded a $23 million impairment in other income in our Consolidated Statement of Income. The resulting fair value of $10 million was estimated using an expected present value cash flow model and is considered a Level 3 fair value measurement due to the use of significant unobservable inputs related to the timing and amount of future equity distributions based on the investee s future financing structure, contractual and market based revenues and operating costs.

There were no significant non-financial assets or liabilities that were measured at fair value on a nonrecurring basis during the nine months ended September 30, 2009.

Fair Value of Financial Instruments

Substantially all of our financial instruments are recorded at fair value, with the exception of the instruments described below that are reported at historical cost. Estimated fair values have been determined using available market information and valuation methodologies considered appropriate by management. The carrying amount of our cash and cash equivalents, customer and other receivables, short-term debt and accounts payable are representative of fair value due to the short-term nature of these instruments. The financial instruments carrying amounts and fair values are as follows:

	September 30, 2009		December 31, 2008	
(millions)	Carrying Amount	Estimated Fair Value(1)	Carrying Amount	Estimated Fair Value(1)
Long-term debt, including securities due within one year(2)	**$ 15,181**	**$ 16,702**	$ 14,334	$ 14,260
Junior subordinated notes payable to:				
Affiliates	**268**	**257**	268	234
Other(3)	**1,483**	**849**	798	409
Subsidiary preferred stock(4)	**257**	**240**	257	231

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

(2) The estimated fair value compared to the carrying amount increased during the current period due to the recovery in corporate credit spreads since December 31, 2008. Includes net unamortized discount of $31 million and $35 million at September 30, 2009 and December 31, 2008, respectively, and the valuation of certain fair value hedges associated with our fixed rate debt of $29 million and $15 million at September 30, 2009 and December 31, 2008, respectively.

(3) Includes net unamortized discount of $2 million at September 30, 2009 and December 31, 2008.

(4) Includes issuance expenses of $2 million at September 30, 2009 and December 31, 2008.

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DOMINION RESOURCES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Note 10. Derivatives and Hedge Accounting Activities

Our accounting policies and objectives and strategies for using derivative instruments are discussed in Note 2 to our Annual Report on Form 10-K for the year ended December 31, 2008.

The following table presents the volume of our derivative activity as of September 30, 2009. These volumes are based on open derivative positions and represent the combined absolute value of our long and short positions, except in the case of offsetting deals, for which we present the absolute value of the net volume of our long and short positions.

	Current	Noncurrent
Natural Gas (bcf):		
Fixed price(1)	751.5	235.0
Basis	1,165.3	514.5
Electricity (MWh):		
Fixed price	18,203,303	10,960,574
FTRs	71,487,157	
Capacity (MW)	976,216	5,587,400
Liquids (gallons)(1)	164,124,327	173,040,000
Interest rate	$ 1,450,000,000	$ 1,625,000,000
Foreign currency (euros)	13,847,638	

(1) Includes natural gas liquids and oil.

For the three and nine months ended September 30, 2009 and 2008, gains or losses on hedging instruments determined to be ineffective were not material. Amounts excluded from the assessment of effectiveness include gains or losses attributable to changes in the time value of options and changes in the differences between spot prices and forward prices and were not material for the three and nine months ended September 30, 2009 and 2008.

The following table presents selected information related to gains (losses) on cash flow hedges included in AOCI in our Consolidated Balance Sheet at September 30, 2009:

(millions)	AOCI After-Tax	Amounts Expected to be Reclassified to Earnings during the next 12 Months After-Tax	Maximum Term
Commodities:			
Gas	$ (27)	$ (29)	45 months
Electricity	302	228	27 months
Natural gas liquids	39	22	27 months
Other	5		68 months
Interest rate	71	(4)	375 months
Foreign currency	1	1	62 months

Total	$ 391	$ 218

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.

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DOMINION RESOURCES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Fair Value and Gains and Losses on Derivative Instruments

The following table presents the fair values of our derivatives as of September 30, 2009 and where they are presented on our Consolidated Balance Sheet:

(millions)	Fair Value Derivatives under Hedge Accounting	Fair Value Derivatives not under Hedge Accounting	Total Fair Value
ASSETS			
Current Assets			
Commodity	$ 674	$ 720	$ 1,394
Interest rate	102		102
Foreign currency	2		2
Total current derivative assets	778	720	1,498
Noncurrent Assets			
Commodity	230	115	345
Interest rate	45		45
Total noncurrent derivative assets(1)	275	115	390
Total derivative assets	$ 1,053	$ 835	$ 1,888
LIABILITIES			
Current Liabilities			
Commodity	$ 202	$ 807	$ 1,009
Interest rate	7		7
Total current derivative liabilities	209	807	1,016
Noncurrent Liabilities			
Commodity	61	126	187
Interest rate	1		1
Total noncurrent derivative liabilities(2)	62	126	188
Total derivative liabilities	$ 271	$ 933	$ 1,204

(1) Noncurrent derivative assets are presented in other deferred charges and other assets on our Consolidated Balance Sheet.

(2) Noncurrent derivative liabilities are presented in other deferred credits and other liabilities on our Consolidated Balance Sheet.

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DOMINION RESOURCES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

The following tables present the gains and losses on our derivatives, as well as where the associated activity is presented on our Consolidated Balance Sheet and Statement of Income:

Derivatives in cash flow hedging relationships (millions)	**Amount of Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion)(1)**	**Amount of Gain (Loss) Reclassified from AOCI to Income**	**Increase (Decrease) in Derivatives Subject to Regulatory Treatment(2)**
Three Months Ended September 30, 2009			
Derivative Type and Location of Gains (Losses)			
Commodity			
Operating revenue		$ 307	
Purchased gas		(16)	
Electric fuel and other energy-related purchases		(2)	
Purchased electric capacity		1	
Total commodity	$ 50	290	$ 4
Interest rate(3)	(15)	(1)	(18)
Foreign currency(4)		1	(2)
Total	$ 35	$ 290	$ (16)
Nine Months Ended September 30, 2009			
Derivative Type and Location of Gains (Losses)			
Commodity			
Operating revenue		$ 829	
Purchased gas		(99)	
Electric fuel and other energy-related purchases		(9)	
Purchased electric capacity		4	
Total commodity	$ 424	725	$ 9
Interest rate(3)	109	(3)	57
Foreign currency(4)	1	2	(2)
Total	$ 534	$ 724	$ 64

(1) Amounts deferred into AOCI have no associated effect in our Consolidated Statements of Income.
(2) Represents net derivative activity deferred into and amortized out of regulatory assets/liabilities. Amounts deferred into regulatory assets/liabilities have no associated effect in our Consolidated Statements of Income.

(3) Amounts recorded in our Consolidated Statements of Income are classified in interest and related charges.
(4) Amounts recorded in our Consolidated Statements of Income are classified in electric fuel and other energy-related purchases.

Derivatives not designated as hedging instruments (millions)	Amount of Gain (Loss) Recognized in Income on Derivatives[1] Three Months Ended September 30, 2009	Nine Months Ended September 30, 2009
Derivative Type and Location of Gains (Losses)		
Commodity		
Operating revenue	$ 28	$ 74
Purchased gas	(15)	(61)
Electric fuel and other energy-related purchases	(14)	(151)
Total	$ (1)	$ (138)

(1) Includes derivative activity amortized out of regulatory assets/liabilities. Amounts deferred into regulatory assets/liabilities have no associated effect on our Consolidated Statements of Income.

For the three and nine months ended September 30, 2009, there were no significant gains or losses recorded related to fair value hedging relationships.

DOMINION RESOURCES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

See Note 9 for further information about fair value measurements and associated valuation methods for derivatives.

Note 11. Investments

Rabbi Trust Securities

Marketable equity and debt securities and cash equivalents held in our rabbi trusts and classified as trading totaled \$93 million and \$95 million at September 30, 2009 and December 31, 2008, respectively. Cost-method investments held in our rabbi trusts totaled \$17 million and \$21 million at September 30, 2009 and December 31, 2008, respectively.

Decommissioning Trust Securities

We hold marketable equity and debt securities and cash equivalents (classified as available-for-sale) and cost method investments in nuclear decommissioning trust funds to fund future decommissioning costs for our nuclear plants. Our decommissioning trust funds are summarized below.

(millions)	Amortized Cost	Total Unrealized Gains[1]	Total Unrealized Losses[1]	Fair Value
September 30, 2009				
Marketable equity securities	**$ 1,189**	**$ 273**	**$**	**$ 1,462**
Marketable debt securities:				
Corporate bonds	**234**	**14**	**(1)**	**247**
U.S. Treasury securities and agency debentures	**298**	**15**		**313**
State and municipal	**362**	**29**	**(1)**	**390**
Other	**2**			**2**
Cost method investments	**95**			**95**
Cash equivalents and other[2]	**45**			**45**
Total	**$ 2,225**	**$ 331**	**$ (2)[3]**	**$ 2,554**
December 31, 2008				
Marketable equity securities	$ 1,022	$ 26	$	$ 1,048
Marketable debt securities:				
Corporate bonds	238	11		249
U.S. Treasury securities and agency debentures	371	16		387
State and municipal	386	14		400
Other	6	1		7
Cost method investments	108			108
Cash equivalents and other[2]	47			47
Total	$ 2,178	$ 68	$	$ 2,246

(1) Included in AOCI and the decommissioning trust regulatory liability.
(2) Includes net assets related to pending sales and purchases of securities of $7 million and $8 million at September 30, 2009 and December 31, 2008, respectively.
(3) The fair value of securities in an unrealized loss position was $66 million at September 30, 2009.

The fair value of our marketable debt securities at September 30, 2009, by contractual maturity is as follows:

(millions)	**Amount**
Due in one year or less	**$ 85**
Due after one year through five years	**232**
Due after five years through ten years	**295**
Due after ten years	**340**
Total	**$ 952**

DOMINION RESOURCES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Presented below is selected information regarding our marketable equity and debt securities.

(millions)	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Trading securities:				
Net unrealized gain (loss)	**$ 8**	$ (6)	**$ 10**	$ (17)
Available-for-sale securities:				
Proceeds from sales[1]	**531**	178	**1,258**	580
Realized gains[2]	**113**	18	**174**	57
Realized losses[2]	**25**	91	**184**	213

(1) The increase in proceeds primarily reflects changes in asset allocation and liquidation of positions in connection with changes in fund managers.
(2) Includes realized gains and losses recorded to the decommissioning trust regulatory liability.

We recorded other-than-temporary impairment losses on investments as follows:

(millions)	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Total other-than-temporary impairment losses[1]	**$ 10**	$ 66	**$ 166**	$ 166
Losses recorded to decommissioning trust regulatory liability	**(6)**	(22)	**(76)**	(56)
Losses recognized in other comprehensive income (before taxes)			**(1)**	
Net impairment losses recognized in earnings	**$ 4**	$ 44	**$ 89**	$ 110

(1) Amount includes other-than-temporary impairment losses for debt securities of $1 million and $24 million for the three months ended September 30, 2009 and 2008, respectively, and $9 million and $36 million for the nine months ended September 30, 2009 and 2008, respectively.

DOMINION RESOURCES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Note 12. Regulatory Assets and Liabilities

Our regulatory assets and liabilities include the following:

(millions)	September 30, 2009	December 31, 2008
Regulatory assets		
Deferred cost of fuel used in electric generation[1]	**$ 295**	$ 133
Unrecovered gas costs[2]	**63**	107
Other	**117**	100
Regulatory assets current	**475**	340
Unrecognized pension and other postretirement benefit costs[3]	**1,072**	1,090
PIPP[4]	**156**	131
RTO start-up costs and administration fees[5]	**133**	135
Deferred cost of fuel used in electric generation[1]		676
Other	**222**	194
Regulatory assets non-current	**1,583**	2,226
Total regulatory assets	**$ 2,058**	$ 2,566
Regulatory liabilities		
Provision for future cost of removal and AROs[6]	**$ 737**	$ 688
Decommissioning trust[7]	**299**	213
Other[8]	**115**	63
Total regulatory liabilities	**$ 1,151**	$ 964

(1) Primarily reflects deferred fuel expenses for the Virginia jurisdiction of our utility generation operations. See Note 18 for more information.

(2) Primarily reflects prior period unrecovered gas costs at Dominion East Ohio, which are recovered through quarterly filings with the Public Utilities Commission of Ohio.

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

(4) Under the Ohio Percentage of Income Payment Plan (PIPP), eligible customers can receive energy assistance based on their ability to pay. The difference between the customer s total bill and the PIPP plan amount is deferred and collected under the PIPP rider according to Dominion East Ohio tariff provisions. Although the current rider rate was designed to recover deferred costs over a three year period, unrecovered costs have increased. Accordingly, Dominion East Ohio plans to file for approval to amend the recovery rate in the fourth quarter of 2009.

(5)

See Note 18 regarding FERC approval of our recovery of start-up costs incurred in connection with joining an RTO and ongoing administrative charges paid to PJM through a Deferral Recovery Charge (DRC). At September 30, 2009, approximately $20 million of these costs were included in other current regulatory assets.

(6) In some circumstances, rates charged to customers by our regulated businesses include a provision for the cost of future activities to remove assets that are expected to be incurred at the time of retirement.

(7) Primarily reflects a regulatory liability representing amounts collected from Virginia jurisdictional customers and placed in external trusts (including income, losses and changes in fair value thereon) for the future decommissioning of our utility nuclear generation stations, in excess of the related ARO.

(8) Includes $25 million and $20 million reported in other current liabilities at September 30, 2009 and December 31, 2008, respectively.

At September 30, 2009, approximately $507 million of our regulatory assets represented past expenditures on which we do not earn a return. These expenditures consist primarily of deferred fuel costs that are expected to be recovered within the next twelve months.

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Note 13. Asset Retirement Obligations

The following table describes the changes in our AROs during 2009:

(millions)	Amount
AROs at December 31, 2008(1)	$ 1,822
Obligations incurred during the period	**3**
Obligations settled during the period	**(7)**
Revisions in estimated cash flows(2)	**(304)**
Accretion	**66**
AROs at September 30, 2009(1)	**$ 1,580**

(1) Includes $20 million and $17 million reported in other current liabilities at December 31, 2008 and September 30, 2009, respectively.
(2) Primarily reflects updated decommissioning cost studies and applicable escalation rates received for each of our nuclear facilities during the second quarter of 2009.

In June 2009, we recorded a $103 million ($62 million after-tax) reduction in other operations and maintenance expense due to a downward revision in the nuclear decommissioning ARO for a power station unit that is no longer in service.

Note 14. 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%, assuming period-end hedge-adjusted prices. If net capitalized costs exceed the ceiling at the end of any quarterly period, then a permanent write-down of the assets must be recognized in that period; however, subsequent commodity price increases may be utilized to reduce or eliminate any impairment in accordance with SEC guidelines.

We used prices in effect subsequent to September 30, 2009 to calculate the ceiling test limitation. Using hedge-adjusted prices subsequent to period-end there was no ceiling test impairment. Approximately 3% of our anticipated production is hedged by qualifying cash flow hedges, for which hedge-adjusted prices were used to calculate estimated future net revenue. Excluding the effects of hedge-adjusted prices in calculating the ceiling test limitation would have resulted in a $12 million ($7 million after-tax) ceiling test impairment. Using prices in effect on September 30, 2009 would have resulted in a ceiling test impairment charge of $107 million ($66 million after-tax). Excluding the effects of period-end hedge-adjusted prices in calculating the ceiling test limitation, the impairment would have been $247 million ($148 million after-tax).

At March 31, 2009, we recorded a ceiling test impairment charge of $455 million ($281 million after-tax, including a subsequent $9 million increase for estimated state taxes recorded in the second quarter of 2009) in other operations and maintenance expense in our Consolidated Statement of Income. Excluding the effects of hedge-adjusted prices in calculating the ceiling limitation, the impairment would have been $631 million ($387 million after-tax, including a subsequent update for estimated state taxes recorded in the second quarter of 2009). Following adoption of the SEC s Final Rule, *Modernization of Oil and Gas Reporting* effective December 31, 2009, we will be required to use trailing twelve month average natural gas and oil prices when performing the full cost ceiling test calculation.

Note 15. Variable Interest Entities

As discussed in Note 16 to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2008, certain variable pricing terms in some of our long-term power and capacity contracts cause them to be considered variable interests in the counterparties.

We have long-term power and capacity contracts with four non-utility generators with an aggregate generation capacity of approximately 940 MW. These contracts contain certain variable pricing mechanisms in the form of partial fuel reimbursement that we consider to be variable interests. After an evaluation of the information provided to us by these entities, we were unable to determine whether they were VIEs. However, the information they provided, as well as our knowledge of generation facilities in Virginia, enabled us to conclude that, if they were VIEs, we would not be the primary beneficiary. This conclusion was based primarily on a qualitative assessment of our variable interests as compared to the operations, commodity price and other risks retained by the entities equity and debt holders during the remaining terms of our contracts and for the years the entities are expected to operate after our contractual relationships expire. The contracts expire at various dates ranging from 2015 to 2021. We are not subject to any risk of loss from these potential VIEs other than our remaining purchase commitments which totaled $1.8 billion as of September 30, 2009. We paid $52 million and $50 million for electric capacity and $24 million and $60 million for electric energy to these entities for the three months ended September 30, 2009 and 2008, respectively. We paid $156 million and $152 million for electric capacity and $90 million and $153 million for electric energy to these entities for the nine months ended September 30, 2009 and 2008, respectively.

Note 16. 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 interim 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 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 September 30, 2009, we had the following amounts outstanding and capacity available under our 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)	$ 2,872	$	$	$ 252	$ 2,620
Five-year Dominion credit facility(2)	1,700	49	600	16	1,035
Five-year Dominion bilateral facility(3)	200			52	148
Totals	$ 4,772	$ 49	$ 600	$ 320	$ 3,803

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

(2) This credit facility was entered into in August 2005 and terminates in August 2010. This credit facility can be used to support bank borrowings, commercial paper and letter of credit issuances.

(3) This facility was entered into in December 2005 and terminates in December 2010. This facility can be used to support bank borrowings, commercial paper and letter of credit issuances.

In addition to the credit facility commitments disclosed above, we also have a five-year $120 million syndicated credit facility that can be used to support certain Virginia Power tax-exempt financings.

Long-Term Debt

In May 2009, Brayton Point power station (Brayton Point) borrowed $50 million in connection with the Massachusetts Development Finance Agency Solid Waste Disposal Revenue Refunding Bonds Series 2009, which mature in 2042 and bear a coupon rate of 5.75% for the first ten years, after which they will bear interest at a market rate to be determined at that time, using a remarketing process. The proceeds were used to finance certain improvements at Brayton Point.

In May 2009, Virginia Power borrowed $40 million in connection with the Economic Development Authority of the County of Chesterfield Pollution Control Refunding Revenue Bonds, Series 2009 A, which mature in 2023 and bear a coupon rate of 5.0%. The proceeds were used to refund the principal amount of the Industrial Development Authority of the County of Chesterfield Money Market Municipals™ Pollution Control Revenue Bonds, Series 1985 that would otherwise have matured in October 2009.

In May 2009, Virginia Power borrowed $70 million in connection with the Economic Development Authority of York County, Virginia Pollution Control Refunding Revenue Bonds, Series 2009 A, which mature in 2033 and bear an initial coupon rate of 4.05% for the first five years, after which they will bear interest at a market rate to be determined at that time, using a remarketing process. The proceeds were used to refund the principal amount of the Industrial Development Authority of York County, Virginia Money Market Municipals™ Pollution Control Revenue Bonds, Series 1985 that would otherwise have matured in July 2009.

In June 2009, Virginia Power issued $350 million of 5.0% senior notes that mature in 2019. The proceeds were used for general corporate purposes and the repayment of short-term debt, including commercial paper.

In June 2009, Dominion issued $685 million (including $60 million related to the underwriter s option to purchase additional notes to cover over-allotments) of its 8.375% Series A Enhanced Junior Subordinated Notes (hybrids) that will mature in 2064, subject to extensions to no later than 2079. The proceeds were used for general corporate purposes. The hybrids are listed on the New York Stock Exchange under the symbol DRU.

In August 2009, Dominion issued $500 million of 5.20% senior notes that mature in 2019. The proceeds were used for general corporate purposes.

In September 2009, Virginia Power borrowed $60 million in connection with the $160 million Industrial Development Authority of Wise County Solid Waste and Sewage Disposal Revenue Bonds, Series 2009 A, which mature in 2040 and bear interest during the initial period at a variable rate. Due to unfavorable market conditions, Virginia Power acquired the $60 million in bonds upon issuance in September 2009 with the intention of remarketing them to a third party at a later time. Proceeds will be used to finance facilities at the Virginia City Hybrid Energy Center. As of September 30, 2009, these bonds have not been remarketed and thus are eliminated in consolidation, along with the investment.

We repaid $134 million of long-term debt during the nine months ended September 30, 2009.

Convertible Securities

We have $202 million of outstanding contingent convertible senior notes that are convertible by holders into a combination of cash and shares of our common stock under certain circumstances. The conversion feature requires that the principal amount of each note be repaid in cash, while 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 September 30, 2009, the conversion rate has been adjusted, primarily due to individual dividend payments above the level paid at issuance, to 28.0338 shares of common stock per $1,000 principal amount of senior notes, which represents a conversion price of $35.67.

The senior notes have not been eligible for conversion during 2009, and as of September 30, 2009, the closing price of our common stock was not higher than $42.81 per share for at least 20 out of the last 30 consecutive trading days; therefore, the senior notes are also not eligible for conversion during the fourth quarter of 2009.

Issuance of Common Stock

During the nine months ended September 30, 2009, we issued 12 million shares of common stock and received cash proceeds of $381 million. We issued 6.2 million shares through at-the-market issuances under our sales agency agreements and received cash proceeds of $191 million, net of fees and commissions paid of $2 million. The remainder of the shares issued and cash proceeds received during the nine months ended September 30, 2009 were through Dominion Direct®, employee savings plans and the exercise of employee stock options.

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

Following these issuances, we have the ability to issue up to $207 million of stock under sales agency agreements; however, we expect remaining 2009 equity needs to be met by proceeds from Dominion Direct®, employee savings plans and the exercise of employee stock options.

Note 17. Stock-Based Awards

Our results for the three months ended September 30, 2009 and 2008 include $9 million and $10 million, respectively, of compensation costs and $3 million and $4 million, respectively, of income tax benefits related to our stock-based compensation arrangements. Our results for the nine months ended September 30, 2009 and 2008 include $32 million and $29 million, respectively, of compensation costs and $12 million and $11 million, respectively, of income tax benefits related to our stock-based compensation arrangements. Stock-based compensation cost is reported in other operations and maintenance expense in our Consolidated Statements of Income. Benefits from tax deductions in excess of the compensation cost recognized for stock-based compensation (excess tax benefits) are classified as a financing cash flow. Approximately $3 million and $9 million of excess tax benefits were realized for the nine months ended September 30, 2009 and 2008, respectively.

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Stock Options

The following table provides a summary of changes in amounts of stock options outstanding during 2009:

	Shares (thousands)	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life (years)	Aggregated Intrinsic Value(1) (millions)
Outstanding and exercisable at January 1, 2009	5,558	$ 30.53		
Exercised	**(863)**	**28.39**		**$ 4**
Forfeited/expired	**(30)**	**28.89**		
Outstanding and exercisable at September 30, 2009	**4,665**	**$ 30.93**	**1.66**	**$ 17**

(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 $27 million and $30 million in the nine months ended September 30, 2009 and 2008, 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. New shares are issued for these awards. Restricted stock generally vests over a three year service period. The following table provides a summary of restricted stock activity during 2009:

	Shares (thousands)	Weighted-Average Grant Date Fair Value
Nonvested at January 1, 2009	1,756	$ 38.55
Granted	**530**	**33.84**
Vested	**(887)**	**34.63**
Cancelled and forfeited	**(70)**	**38.36**
Converted from goal-based stock to restricted stock	**185**	**44.18**
Nonvested at September 30, 2009	**1,514**	**$ 39.90**

As of September 30, 2009, unrecognized compensation cost related to nonvested restricted stock awards totaled approximately $27 million and is expected to be recognized over a weighted-average period of 1.5 years.

Goal-Based Stock

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

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. Goal-based stock awards granted to key non-officer employees convert to restricted stock at the end of the two-year performance period and generally vest three years from the original grant date. Awards to officers vest at the end of the two-year performance period. All goal-based stock awards are settled by issuing new shares. Current outstanding goal-based shares include awards granted in April 2008, February 2009 and April 2009.

After the performance period for the April 2007 grants ended on December 31, 2008, the Compensation, Governance and Nominating Committee determined the actual performance against metrics established for those awards. For awards to key non-officer employees, 127 thousand shares of the outstanding goal-based stock awards granted in April 2007 were converted to 185 thousand shares of restricted stock for the remaining term of the vesting period ending in April 2010. For awards to officers, 27 thousand shares of the outstanding goal-based stock awards were converted to 38 thousand non-restricted shares and issued to the officers.

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For remaining goal-based stock awards, at September 30, 2009, the targeted number of shares to be issued is 324 thousand. The following table provides a summary of goal-based stock activity during 2009:

	Targeted Number of Shares (thousands)	Weighted-Average Grant Date Fair Value
Nonvested at January 1, 2009	315	$ 42.56
Granted	**165**	**31.43**
Vested	**(28)**	**44.33**
Cancelled and forfeited	**(1)**	**38.33**
Converted from goal-based stock to restricted stock	**(127)**	**44.18**
Nonvested at September 30, 2009	**324**	**$ 36.12**

At September 30, 2009, unrecognized compensation cost related to nonvested goal-based stock awards totaled approximately $7 million and is expected to be recognized over a weighted-average period of 1.6 years.

Cash-Based Performance Grant

The actual payout of our cash-based performance grants will vary between zero and 200% of the targeted amount based on the level of performance metrics achieved.

The targeted amount of the cash-based performance grant made to officers in April 2007 was $11 million, but the actual payout of the award in February 2009 determined by the Compensation, Governance and Nominating Committee was $16 million, based on the level of performance metrics achieved. At December 31, 2008, a liability of $16 million had been accrued for this award.

In April 2008, a cash-based performance grant was made to officers. Payout of the performance grant will occur by March 15, 2010 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 September 30, 2009, the targeted amount of the grant was $12 million and a liability of $10 million had been accrued for this award.

In February 2009, a cash-based performance grant was made to officers. Payout of the performance grant will occur by March 15, 2011 and is based on the achievement of three performance metrics during 2009 and 2010: return on invested capital, book value per share and total shareholder return relative to that of a peer group of companies. At September 30, 2009, the targeted amount of the grant was $11 million and a liability of $4 million had been accrued for this award.

Note 18. Commitments and Contingencies

Other than the following matters, there have been no significant developments regarding the commitments and contingencies disclosed in Note 23 to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2008, or Note 15 and Note 18 to the Consolidated Financial Statements in our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2009 and June 30, 2009, respectively, nor have any significant new matters arisen during the three months ended September 30, 2009.

Electric Regulation in Virginia

2007 Virginia Regulation Act

Pursuant to the Virginia Electric Utility Regulation Act (the Regulation Act), the Virginia Commission entered an order in January 2009 initiating reviews of the base rates and terms and conditions of all investor-owned electric utilities in Virginia. Possible outcomes of the 2009 rate review, according to the Regulation Act, include a rate increase, a rate decrease, or a partial refund of 2008 earnings more than 50 basis points above the authorized return on equity (ROE).

During 2009, we submitted base rate filings and accompanying schedules to the Virginia Commission, which, as amended, propose to increase our Virginia jurisdictional base rates by approximately $250 million annually. Our initial March 2009 filing proposed a 12.5% ROE, plus an additional 100 basis point performance incentive pursuant to the Regulation Act based on our generating plant performance, customer service, and operating efficiency, resulting in a total ROE request of 13.5%. In July 2009, in response to rulings by the Virginia Commission relating to the appropriate rate year and capital structure to be used in the Company s base rate review, we submitted a revised filing reflecting a number of adjustments, including an upward adjustment of 50 basis points in the proposed ROE. The base rate increase became effective on an interim basis on September 1, 2009, subject to refund and adjustment by the Virginia Commission and increases a typical 1,000 kWh Virginia jurisdictional residential customer s bill by approximately $5.22 per month. An evidentiary hearing on our base rate filing is scheduled to be held in January 2010.

In March 2009, we filed with the Virginia Commission, pursuant to the Regulation Act, a petition to recover from Virginia jurisdictional customers an annual net increase of approximately $78 million in costs related to FERC-approved transmission charges and PJM demand response programs. This amount also included a portion of costs discussed further in the *RTO Start-up Costs and Administrative Fees* section. In a final order in June 2009, the Virginia Commission approved a new rate adjustment clause (Rider T) to recover approximately $218 million over the 12-month period beginning September 1, 2009, subject to an annual review and re-set in 2010, if necessary. The approved amount to be recovered through Rider T includes approximately $150 million of transmission-related costs that were traditionally incorporated in base rates, plus an incremental increase of approximately $68 million. The Virginia Commission also ruled that approximately $10 million that the Company had proposed to collect in Rider T would be more appropriately recovered through base rates, and those costs have been incorporated into the Company s revised base rate filing that was submitted in July 2009. Rider T became effective on September 1, 2009, and increases a typical 1,000 kWh Virginia jurisdictional residential customer s bill by approximately $1.11 per month.

In July 2009, we filed with the Virginia Commission an application for approval and cost recovery of twelve demand-side management (DSM) programs, including one peak-shaving program and eleven energy efficiency programs. We plan to use DSM, along with our traditional and renewable supply-side resources, to meet our projected load growth over the next 15 years. The DSM programs provide the first steps toward achieving Virginia s goal of reducing, by 2022, the electric energy consumption of the Company s retail customers by ten percent of what was consumed in 2006. The Virginia Commission has set an evidentiary hearing for February 16, 2010, to consider the DSM programs and the related recovery. The Company has requested approval of two rate adjustment clauses for the associated cost recovery to be effective April 1, 2010. Specifically, the two rate adjustment clauses for recovery from Virginia jurisdictional customers represent an annual net increase in costs of approximately $51 million for the period April 1, 2010 to March 31, 2011. If approved by the Virginia Commission, the rate adjustment clauses will be expected, on a combined basis, to increase a typical 1,000 kWh residential bill by approximately $0.95 per month. The Regulation Act gives the Virginia Commission until the end of March 2010 to act on our application.

Virginia Fuel Expenses

In March 2009, we filed our Virginia fuel factor application with the Virginia Commission. The application requested an annual decrease in fuel expense recovery of approximately $236 million for the period July 1, 2009 through June 30, 2010, a decrease from 3.893 cents per kWh to 3.529 cents per kWh, or approximately $3.64 per month for the typical 1,000 kWh Virginia jurisdictional residential customer s average bill. The proposed fuel factor went into effect on July 1, 2009 on an interim basis and an evidentiary hearing on the Company s application was held on September 1, 2009. Consistent with a proposal made by the Company at the hearing in September 2009, the Virginia Commission issued an interim fuel order, effective October 1, 2009, further reducing the fuel factor by approximately $103 million for the period July 1, 2009 through June 30, 2010. The cumulative decrease in the fuel factor for the period July 1, 2009 through June 30, 2010 reflects lower projected fuel expenses and a prospective credit against fuel expenses of certain financial transmission rights (FTRs) allocated to the Company. The Virginia Commission has not yet issued a final order.

Utility Generation Expansion

In March 2009, we filed with the Virginia Commission our first annual update to the rate adjustment clause for the Virginia City Hybrid Energy Center requesting an increase of approximately $99 million for financing costs to be recovered through rates in 2010. As part of this filing we requested that the 13.5% ROE proposed in our March 31, 2009 base rate filing be applied to the Virginia City Hybrid Energy Center rate adjustment clause (Rider S), plus the 100 basis point enhancement for construction of a new coal-fired generation facility as previously authorized by the Virginia Commission pursuant to the Regulation Act, for a requested total ROE of 14.5%. If approved by the Virginia Commission, the revised Rider S could become effective as early as January 1, 2010 as requested by the Company and would increase a typical 1,000 kWh Virginia jurisdictional residential customer s bill by approximately $1.78 per month. An evidentiary hearing was held before a hearing examiner in August 2009, at which we presented a proposed stipulation and recommendation that, among other things, would reduce the revenue requirement by approximately $8 million to $91 million, the result of which would increase a typical 1,000 kWh Virginia jurisdictional residential customer s bill by approximately $1.63 per month. No report has yet been issued by the hearing examiner.

In June 2008, the Virginia State Air Pollution Control Board approved and issued an air permit to construct and operate the Virginia City Hybrid Energy Center and also approved and issued another air permit for hazardous emissions. Construction of the Virginia City Hybrid Energy Center commenced and the facility is expected to be in operation by 2012. In August 2008, the Southern Environmental Law Center (SELC), on behalf of four environmental groups, filed Petitions for Appeal in Richmond Circuit Court challenging the approval of both of the air permits. The Richmond Circuit Court issued an Order in September 2009 upholding the initial air permit and upholding the second air permit for hazardous emissions except for one condition related to the permit limit for mercury emissions. The hazardous emissions air permit was amended by the Virginia Department of Environmental Quality in September 2009 to comply with the Richmond Circuit Court Order. The permit amendment does not impact the project. In October 2009, a Notice of Appeal of the court s Order regarding the initial air permit was filed with the Richmond Circuit Court by several environmental groups, initiating the appeals process to the Court of Appeals.

In March 2009, the Virginia Commission authorized construction and operation of our proposed Bear Garden facility, a 580 MW (nominal) natural gas- and oil-fired combined-cycle electric generating facility and associated transmission interconnection facilities in Buckingham County, Virginia, estimated to cost $619 million, excluding financing costs. In March 2009, we also filed a petition with the Virginia Commission for the initiation of a rate adjustment clause for recovery of approximately $77 million in financing costs related to the construction of the Bear Garden facility to be recovered through rates in 2010. As part of this filing we requested that the 13.5% ROE proposed in our March 31, 2009 base rate filing be applied to the Bear Garden facility rate adjustment clause, with a 100 basis point enhancement for construction of a combined-cycle facility, as authorized by the Regulation Act, for a requested total ROE of 14.5%. If approved by the Virginia Commission, the rate adjustment clause could become effective as early as January 1, 2010 as requested by the Company. An evidentiary hearing was held before a hearing examiner in August 2009. In the Company s post-hearing brief, it unilaterally agreed to reduce the revenue requirement by $4 million to $73 million, the result of which would increase a typical 1,000 kWh Virginia jurisdictional residential customer s bill by approximately $1.33 per month. No report has yet been issued by the hearing examiner.

We are unable to predict the outcome of the Virginia Commission s future rate actions, including actions relating to our 2009 base rate review, our DSM programs, our recovery of Virginia fuel expenses, and our additional rate adjustment clause filings; however, unfavorable future decisions by the Virginia Commission could adversely affect our results of operations, financial condition and cash flows.

RTO Start-up Costs and Administrative Fees

In December 2008, FERC approved our DRC request to become effective January 1, 2009, which would allow recovery of approximately $153 million of RTO costs that were deferred due to a statutory base rate cap established under Virginia law. In June 2009, the Virginia Commission approved full recovery of the DRC from retail customers through Rider T. Recovery of the DRC began September 1, 2009. In July 2009, FERC issued an order denying the Virginia Attorney General s office and the Virginia Commission s requests for rehearing of its December 2008 order. Notices of appeal were filed in September 2009 at the U.S. Court of Appeals for the Fourth Circuit and the appeal is currently pending. We cannot predict the outcome of the appeal.

Fowler Ridge Wind Farm Project

In January 2008, we acquired a 50% interest in a joint venture with a subsidiary of BP Alternative Energy (BP) to develop a wind-turbine facility in Benton County, Indiana (Fowler Ridge). The first phase consisting of 300 MW achieved full commercial operations in March 2009. We have a long-term agreement with Fowler Ridge to purchase 200 MW of energy, capacity and environmental attributes from this first phase. In June 2009, we reached an agreement with BP to split the development assets of the final 350 MW phase. We will own 150 MW of development assets and BP will retain the remaining development assets. Pending regulatory and other approvals, the transaction is expected to close in the fourth quarter of 2009. BP has developed an additional 100 MW facility in which Dominion does not have an ownership interest. In September 2009, we received a $123 million distribution from Fowler Ridge based on proceeds received in connection with non-recourse permanent financing for the first phase of the project.

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Guarantees

At September 30, 2009, we had issued $261 million of guarantees to support third parties and equity method investees (issued guarantees). This includes $182 million of guarantees to support our investment in a joint venture with Shell WindEnergy Inc. (Shell), which owns a wind-turbine facility in Grant County, West Virginia (NedPower). These NedPower guarantees are primarily comprised of a limited-scope guarantee and indemnification for one-half of the project-level financing for phases one and two of the NedPower wind farm, which would require us to pay one-half of NedPower s debt, only if it is unable to do so, as a direct result of an unfavorable ruling associated with current litigation seeking to halt the project. This litigation-related guarantee will terminate upon receipt of a final non-appealable ruling in favor of the project. We do not expect an unfavorable ruling and no significant amounts have been recorded. Our exposure under this litigation-related guarantee totaled $156 million as of September 30, 2009. Shell has provided an identical guarantee for the other one-half of NedPower s borrowings.

Issued guarantees also include $21 million of guarantees to support our investment in Fowler Ridge wind farm. The guarantees primarily relate to certain reserve requirements associated with Fowler Ridge s non-recourse financing. Our exposure under these guarantees was $21 million as of September 30, 2009.

In addition to the above guarantees, we, and our partners Shell and BP, may be required to make additional periodic equity contributions to NedPower and Fowler Ridge in connection with certain funding requirements associated with their respective non-recourse financings. As of September 30, 2009, our maximum remaining cumulative exposure under these equity funding agreements is $153 million through 2019 and our maximum annual future contributions could range from approximately $14 million to $19 million. We expect the operating cash flows for these projects to be sufficient to meet their financing requirements.

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 September 30, 2009, we had issued the following subsidiary guarantees:

(millions)	Stated Limit	Value[(1)]
Subsidiary debt[(2)]	$ 126	$ 126
Commodity transactions[(3)]	2,668	199
Lease obligation for power generation facility[(4)]	837	837
Nuclear obligations[(5)]	564	401
Other	483	130
Total	$ 4,678	$ 1,693

(1) Represents the estimated portion of the guarantee s stated limit that is utilized as of September 30, 2009 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 Dominion Energy, Inc. (DEI) subsidiaries. In the event of default by the subsidiaries, we would be obligated to repay such amounts.

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

(4) Guarantee of a DEI subsidiary s leasing obligation for Fairless 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 commitments to buy nuclear fuel. Excludes our agreement to provide up to $150 million and $60 million to two DEI subsidiaries to pay the operating expenses of Millstone power station

and Kewaunee power station, 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.

Surety Bonds and Letters of Credit

As of September 30, 2009, we had purchased $151 million of surety bonds and authorized the issuance of standby letters of credit by financial institutions of $320 million to facilitate commercial transactions by our subsidiaries with third parties.

Litigation

We are co-owners with Old Dominion Electric Cooperative of the Clover power station. We have been in litigation with Norfolk Southern Railway Company (Norfolk Southern) regarding a long term coal transportation agreement for the delivery of coal to the facility. The trial court agreed with Norfolk Southern s interpretation that the agreement specifies the use of an index (NS Index) which Norfolk Southern claims should have been applied to adjust the base rate and which should be applied going forward. The trial court assessed damages of approximately $78 million for the contract period from December 1, 2003 through November 30, 2007 and imposed prejudgment interest of approximately $9 million. Our share would have been one-half of the total judgment, or approximately $44 million. On appeal, the Supreme Court of Virginia in September 2009 affirmed the decisions of the trial court on all issues except for the calculation of damages. The Supreme Court of Virginia remanded the case to the trial court to recalculate damages in accordance with its opinion. We expect that the recalculation will reduce damages, with interest, to approximately $10 million as of September 30, 2009. We have recorded a liability in our Consolidated Financial Statements for our one-half share of the expected judgment. We do not believe that final resolution of this matter will materially impact our results of operations or financial condition.

Note 19. 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 believe, based on our credit policies, that it is unlikely a material adverse effect on our financial position, results of operations or cash flows would occur as a result of counterparty nonperformance.

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

Our exposure to credit risk is concentrated primarily within our energy marketing and price risk management activities, as we transact with a smaller, less diverse group of counterparties and transactions may involve large notional volumes and potentially volatile commodity prices. Energy marketing and price risk management activities include trading of energy-related commodities, marketing of merchant generation output, structured transactions and the use of financial contracts for enterprise-wide hedging purposes. Gross credit exposure for each counterparty is calculated as outstanding receivables plus any unrealized on- or off-balance sheet exposure, taking into account contractual netting rights. Gross credit exposure is calculated prior to the application of collateral. At September 30, 2009, our gross credit exposure totaled approximately $1 billion. After the application of collateral, our credit exposure was reduced to $710 million. Of this amount, investment grade counterparties, including those internally rated, represented 96%. Two counterparty exposures are greater than 10% of our total exposure, one representing 25% and the other 13%, both of which are large financial institutions rated investment grade.

The majority of our derivative instruments contain credit-related contingent provisions. These provisions require us to provide collateral upon the occurrence of specific events, primarily a credit downgrade. If the credit-related contingent features underlying these instruments that are in a liability position and not fully collateralized with cash were fully triggered as of September 30, 2009, we would be required to post an additional $13 million of collateral to our counterparties. The collateral that would be required to be posted includes the impacts of any offsetting asset positions and any amounts already posted for derivatives, non-derivative contracts and derivatives elected under the normal purchases and normal sales exception, per contractual terms. As of September 30, 2009, we have posted $99 million in collateral, including $85 million of letters of credit, related to derivatives with credit-related contingent provisions that are in a liability position and not fully collateralized with cash. The collateral posted includes any amounts paid related to non-derivative contracts and derivatives elected under the normal purchases and normal sales exception, per contractual terms. The aggregate fair value of all derivative instruments with credit-related contingent provisions that are in a liability position and not fully collateralized with cash as of September 30, 2009 is $156 million and does not include the impact of any offsetting asset positions. See Note 10 for further information about our derivative instruments.

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Note 20. Employee Benefit Plans

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

	Pension Benefits		Other Postretirement Benefits	
(millions)	2009	2008	2009	2008
Three Months Ended September 30,				
Service cost	**$ 26**	$ 25	**$ 15**	$ 13
Interest cost	**63**	57	**24**	19
Expected return on plan assets	**(101)**	(99)	**(14)**	(14)
Amortization of prior service cost (credit)	**1**	1	**(1)**	(1)
Amortization of net loss	**9**	1	**7**	1
Net periodic benefit cost (credit)	**$ (2)**	$ (15)	**$ 31**	$ 18
Nine Months Ended September 30,				
Service cost	**$ 79**	$ 77	**$ 45**	$ 43
Interest cost	**188**	178	**74**	66
Expected return on plan assets	**(304)**	(310)	**(42)**	(52)
Amortization of prior service cost (credit)	**3**	3	**(5)**	(4)
Amortization of net loss	**28**	5	**22**	5
Benefit enhancement	**2**			
Curtailments	**2**			
Net periodic benefit cost (credit)	**$ (2)**	$ (47)	**$ 94**	$ 58

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, if any, is determined at that time. We made no contributions to our defined benefit pension plans or other postretirement benefit plans during the nine months ended September 30, 2009. No contributions to our pension plans are currently expected in 2009, but we do expect to contribute approximately $61 million to our other postretirement benefit plans through Voluntary Employees Beneficiary Associations during the remainder of 2009.

Note 21. 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, natural gas gathering and by-products extraction activities, regulated LNG operations and our Appalachian E&P operations. Dominion Energy also includes producer services, which aggregates natural gas supply, engages in natural gas trading and marketing activities and natural gas supply management and provides price risk management services to Dominion affiliates.

Dominion Generation includes the 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). This segment also includes our regulated gas distribution subsidiaries that are held for sale. In addition, the contribution to net income by our primary operating segments is determined based on a measure of profit that executive management believes represents the segments core earnings. As a result, certain specific items attributable to those segments are not included in profit measures evaluated by executive management in assessing the segments performance or allocating resources among the segments and are instead reported in the Corporate and Other segment. In the nine months ended September 30, 2009 and 2008, our Corporate and Other segment included $242 million and $54 million, respectively, of after-tax expenses attributable to our operating segments.

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The expenses in 2009 primarily reflect:

A $455 million ($281 million after-tax) ceiling test impairment charge related to the carrying value of our E&P properties, attributable to Dominion Energy; partially offset by

A $103 million ($62 million after-tax) reduction in other operations and maintenance expense due to a downward revision in the nuclear decommissioning ARO for a power station unit that is no longer in service, attributable to Dominion Generation.

The expenses in 2008 primarily reflect $83 million ($50 million after-tax) of impairment charges resulting from other-than-temporary declines in the fair value of securities held in nuclear decommissioning trust funds, attributable to Dominion Generation.

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

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 September 30, 2009						
Total revenue from external customers	**$ 666**	**$ 393**	**$ 2,261**	**$ 36**	**$ 292**	**$ 3,648**
Intersegment revenue	**20**	**312**	**115**	**180**	**(627)**	
Total operating revenue	**686**	**705**	**2,376**	**216**	**(335)**	**3,648**
Net income (loss) attributable to Dominion	**95**	**95**	**459**	**(55)**		**594**
2008						
Total revenue from external customers	$ 615	$ 447	$ 2,679	$ 62	$ 562	$ 4,365
Intersegment revenue	18	624	20	198	(860)	
Total operating revenue	633	1,071	2,699	260	(298)	4,365
Net income (loss) attributable to Dominion	84	81	449	(106)		508
Nine Months Ended September 30, 2009						
Total revenue from external customers	**$ 2,315**	**$ 1,775**	**$ 6,542**	**$ 406**	**$ 838**	**$ 11,876**
Intersegment revenue	**103**	**964**	**276**	**527**	**(1,870)**	
Total operating revenue	**2,418**	**2,739**	**6,818**	**933**	**(1,032)**	**11,876**
Net income (loss) attributable to Dominion	**292**	**371**	**1,098**	**(465)**		**1,296**
2008						
Total revenue from external customers	$ 2,179	$ 1,669	$ 6,508	$ 466	$ 1,295	$ 12,117
Intersegment revenue	109	1,497	67	509	(2,182)	
Total operating revenue	2,288	3,166	6,575	975	(887)	12,117
Loss from discontinued operations, net of tax				(2)		(2)

Net income (loss) attributable to Dominion	278	333	991	(116)	1,486

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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

Our MD&A consists of the following information:

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, shoulc 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, high winds and severe storms, that can cause outages and property damage to our facilities;

Federal, state and local legislative and regulatory developments;

Changes to federal, state and local environmental laws and regulations, including those related to climate change, the tightening of emission or discharge limits for greenhouse gases and other emissions, more extensive permitting requirements and the regulation of additional substances;

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 the availability of credit and our ability to obtain financing on reasonable terms;

Risks associated with our regulated electric utility s membership and participation in PJM related to obligations created by the default of other participants;

Price risk due to marketable securities held as investments in nuclear decommissioning and benefit plan trusts;

Fluctuations in interest rates;

Changes in federal and state tax laws and regulations;

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

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

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

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

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

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

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

Changes to rates for our regulated electric utility operations, including the outcome of our 2009 rate filings;

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;

Completing the divestiture of Peoples and Hope; and

Adverse outcomes in litigation matters.

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

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 September 30, 2009, 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, 2008, other than the impact of updated nuclear decommissioning cost studies on our AROs as discussed in Note 13 to our Consolidated Financial Statements. The policies disclosed included the accounting for derivative contracts and other instruments 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 Note 3 to our Consolidated Financial Statements for a discussion of newly adopted accounting standards. See Note 9 to our Consolidated Financial Statements for information on our fair value measurements.

Results of Operations

Presented below is a summary of our consolidated results:

(millions, except EPS)	2009	2008	$ Change
Third Quarter			
Net income attributable to Dominion	**$ 594**	$ 508	$ 86
Diluted EPS	**1.00**	0.87	0.13
Year-to-Date			
Net income attributable to Dominion	**$ 1,296**	$ 1,486	$ (190)
Diluted EPS	**2.19**	2.56	(0.37)

Overview

Third Quarter 2009 vs. 2008

Net income attributable to Dominion increased by 17%. Favorable drivers include a higher contribution from our gas transmission operations due to the completion of the Cove Point expansion project, the impact of net realized gains (including investment income) for our merchant nuclear decommissioning trust funds in 2009 as compared to net realized losses (net of investment income) in 2008, the absence of post-closing adjustments to the gain on the sale of the U.S. E&P business recorded in 2008 and a higher contribution from our retail energy marketing operations. Unfavorable drivers include a lower contribution from our producer services business and lower margins in our merchant generation operations.

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Year-to-Date 2009 vs. 2008

Net income attributable to Dominion decreased by 13%. Unfavorable drivers include an impairment charge related to the carrying value of our E&P properties due to declines in gas and oil prices, the absence of benefits recognized in 2008 from the reversal of deferred tax liabilities and re-establishment of a regulatory asset associated with the planned sale of Peoples and Hope and a decrease in sales of gas and oil production from our E&P operations primarily reflecting the expiration of fixed-term overriding royalty interests associated with our former volumetric production payment agreements (VPP royalty interests). Favorable drivers include higher margins in our merchant generation operations, a higher contribution from our gas transmission operations due to the completion of the Cove Point expansion project, a benefit from a downward revision in the nuclear decommissioning ARO for a power station unit that is no longer in service, fewer scheduled outages at certain nuclear and fossil generating facilities and the impact of net realized gains (including investment income) for our merchant nuclear decommissioning trust funds in 2009 as compared to net realized losses (net of investment income) in 2008.

Analysis of Consolidated Operations

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

	Third Quarter			**Year-to-Date**		
	2009	**2008**	**$ Change**	**2009**	**2008**	**$ Change**
(millions)						
Operating Revenue	**$ 3,648**	$ 4,365	$ (717)	**$ 11,876**	$ 12,117	$ (241)
Operating Expenses						
Electric fuel and other energy-related purchases	**1,072**	1,383	(311)	**3,211**	2,950	261
Purchased electric capacity	**96**	102	(6)	**309**	306	3
Purchased gas	**279**	692	(413)	**1,785**	2,482	(697)
Other operations and maintenance	**748**	762	(14)	**2,695**	2,409	286
Depreciation, depletion and amortization	**274**	259	15	**824**	770	54
Other taxes	**107**	112	(5)	**373**	375	(2)
Other income	**123**	14	109	**127**	10	117
Interest and related charges	**217**	213	4	**658**	634	24
Income tax expense	**380**	344	36	**840**	701	139

An analysis of our results of operations follows:

Third Quarter 2009 vs. 2008

Operating Revenue decreased 16%, primarily reflecting:

- A $285 million decrease in our producer services business primarily due to the net impact of unfavorable price changes on economic hedging transactions ($158 million) and a decrease in prices on physical gas sales ($152 million), partially offset by an increase in volumes on physical gas sales ($25 million), all associated with natural gas aggregation, marketing and trading activities;

- A $238 million decrease in revenue from our electric utility operations resulting primarily from:

  - A $141 million decrease in fuel revenue largely due to the impact of a comparatively lower fuel rate in certain customer jurisdictions implemented in July 2009, including the recovery of previously deferred fuel expenses; and

  - A $97 million decrease in sales to wholesale customers due to decreased volumes ($67 million) and lower prices ($30 million);

An $87 million decrease for our merchant generation operations, primarily reflecting lower realized prices at certain fossil generating facilities;

A $77 million decrease in nonregulated gas sales by our gas distribution operations primarily due to lower storage sales associated with Dominion East Ohio s planned exit from the gas merchant function;

A $56 million decrease in regulated gas sales by our gas distribution operations reflecting:

- A $28 million decrease in volumes resulting largely from the migration of customers to energy choice programs primarily due to Dominion East Ohio s planned exit from the gas merchant function; and

- A $28 million decrease reflecting lower gas prices;

A $54 million decrease in gas sales by our retail energy marketing operations primarily due to lower prices; and

A $29 million decrease in sales of gas production from our E&P operations primarily reflecting the expiration of VPP royalty interests.

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These decreases were partially offset by:

An $80 million increase in electric sales by our retail energy marketing operations primarily due to the acquisition of a retail energy marketing business in September 2008 ($76 million) and higher sales volumes ($38 million), partially offset by lower sales prices ($34 million);

A $32 million increase related to our gas transmission operations largely due to the completion of the Cove Point expansion project; and

A $28 million increase in gas transportation and storage revenue resulting principally from higher customer charges at our gas distribution operations due to the implementation of a Straight Fixed Variable rate design, whereby Dominion East Ohio recovers a larger portion of its fixed operating costs through a flat monthly charge accompanied by a reduced volumetric base delivery rate, and customer migration due to Dominion East Ohio s planned exit from the gas merchant function.

Operating Expenses and Other Items

Electric fuel and other energy-related purchases expense decreased 22%, primarily reflecting the combined effects of:

A $229 million decrease for our utility generation operations primarily reflecting a comparatively lower fuel rate in certain customer jurisdictions, including recovery of previously deferred fuel expenses ($144 million) and a decrease in fuel expenses associated with wholesale customers ($85 million); and

A $73 million decrease for our merchant generation operations primarily reflecting lower commodity prices; partially offset by

A $49 million increase from our retail energy marketing operations primarily due to increased energy purchases resulting from the acquisition of a retail energy marketing business in September 2008 ($69 million) and an increase in volumes ($28 million), partially offset by lower prices ($48 million).

Purchased gas expense decreased 60%, principally resulting from the following factors:

A $214 million decrease in our producer services business primarily due to the net impact of a decrease in prices on physical gas purchases ($180 million) and favorable price changes on economic hedging transactions ($69 million), partially offset by an increase in volumes on physical gas purchases ($35 million), all associated with natural gas aggregation and marketing activities;

A $109 million decrease in the cost of gas sold by our gas distribution operations resulting primarily from a decrease in volumes reflecting the impact of lower nonregulated gas sales and the migration of customers to energy choice programs primarily due to Dominion East Ohio s planned exit from the gas merchant function ($82 million) and lower gas costs ($27 million);

A $59 million decrease from our retail energy marketing operations primarily due to lower prices; and

A $32 million decrease in our gas transmission operations due to lower prices.

Other operations and maintenance expense decreased 2%, primarily reflecting the combined effects of the following:

The absence of a $42 million post-closing adjustment to the gain on the sale of the U.S. E&P operations recorded in 2008; partially offset by

A $31 million increase in salaries, wages and benefits largely due to higher pension and other postretirement benefit costs.

DD&A increased 6%, principally due to higher depreciation from property additions ($32 million), partially offset by decreased DD&A associated with our E&P operations primarily reflecting lower rates ($14 million).

Other income increased $109 million primarily due to the impact of net realized gains (including investment income) on our merchant nuclear decommissioning trust funds in 2009 as compared to net realized losses (net of investment income) in 2008.

Income tax expense increased 10%, reflecting higher pretax income.

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Year-to-Date 2009 vs. 2008

Operating Revenue decreased 2%, primarily reflecting:

- A $382 million decrease in our producer services business primarily due to the net impact of a decrease in prices on physical gas sales ($412 million), partially offset by an increase in volumes on physical gas sales ($30 million), both associated with natural gas aggregation, marketing and trading activities;
- A $239 million decrease in regulated gas sales by our gas distribution operations reflecting the combined effects of:
  - A $171 million decrease resulting largely from customer migration at Dominion East Ohio; and
  - An $86 million decrease reflecting lower gas prices; partially offset by
  - An $18 million increase in volumes due to the net impact of colder weather during the first quarter of 2009, changes in customer usage patterns and other factors;
- A $99 million decrease in gas sales by our retail energy marketing operations primarily due to lower gas prices;
- A $59 million decrease in sales of gas production from our E&P operations primarily reflecting the expiration of VPP royalty interests;
- A $44 million decrease primarily due to lower prices for certain requirements-based power sales contracts;
- A $44 million decrease in nonregulated gas sales by our gas distribution operations largely reflecting lower volumes; and
- A $22 million decrease in sales of gas production from our gas transmission operations due to lower prices.

These decreases were partially offset by:

- A $224 million increase in revenue from our electric utility operations resulting largely from:
  - A $358 million increase in fuel revenue largely due to the impact of a comparatively higher fuel rate in certain customer jurisdictions, including the recovery of previously deferred fuel expenses; and
  - A $66 million increase due to the impact of a rate adjustment clause associated with the recovery of construction-related financing costs for the Virginia City Hybrid Energy Center; partially offset by

- A $181 million decrease in sales to wholesale customers due to decreased volumes ($102 million) and lower prices ($79 million); and

- A $35 million decrease in base revenues reflecting the impact of unfavorable economic conditions on customer usage and other factors;

A $218 million increase in electric sales by our retail energy marketing operations primarily due to the acquisition of a retail energy marketing business in September 2008 ($207 million) and higher sales volumes ($70 million), partially offset by lower sales prices ($59 million);

An $87 million increase related to our gas transmission operations largely due to the completion of the Cove Point expansion project;

An $82 million increase in gas transportation and storage revenue resulting principally from customer migration and the implementation of a Straight Fixed Variable rate design at Dominion East Ohio; and

A $78 million increase for merchant generation operations largely due to the net impact of higher volumes resulting primarily from fewer scheduled nuclear refueling outages and higher demand for natural gas generation ($169 million), partially offset by lower realized prices ($91 million).

Operating Expenses and Other Items

Electric fuel and other energy-related purchases expense increased 9%, primarily reflecting the combined effects of:

A $248 million increase for our utility generation operations primarily reflecting a comparatively higher fuel rate in certain customer jurisdictions, including recovery of previously deferred fuel expenses ($339 million) and a reduced benefit from FTRs ($44 million), partially offset by a decrease in fuel expenses associated with wholesale customers ($135 million); and

A $165 million increase from our retail energy marketing operations primarily due to increased energy purchases resulting from the acquisition of a retail energy marketing business in September 2008 ($183 million) and an increase in volumes ($52 million), partially offset by lower prices ($70 million); these increases were partially offset by

A $79 million decrease for our merchant generation operations reflecting lower commodity prices ($153 million), partially offset by increased consumption ($74 million) at certain fossil generating facilities; and

A $52 million decrease primarily due to lower prices for power purchased to serve certain requirements-based power sales contracts.

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Purchased gas expense decreased 28%, principally resulting from the following factors:

- A $360 million decrease in our producer services business primarily due to the net impact of a decrease in prices on physical gas purchases ($462 million), partially offset by an increase in volumes on physical gas purchases ($72 million) and unfavorable price changes on economic hedging transactions ($30 million), all associated with natural gas aggregation and marketing activities;
- A $188 million decrease in the cost of gas sold by our gas distribution operations resulting primarily from lower gas costs ($95 million) and a decrease in volumes reflecting the impact of lower nonregulated sales and customer migration at Dominion East Ohio ($93 million);
- A $78 million decrease from our retail energy marketing operations primarily due to lower prices; and
- A $64 million decrease in our gas transmission operations primarily due to lower prices.

Other operations and maintenance expense increased 12%, primarily reflecting the combined effects of:

- A $455 million ceiling test impairment charge related to the carrying value of our E&P properties due to declines in natural gas and oil prices;
- A $96 million increase in salaries, wages and benefits largely due to higher pension and other postretirement benefit costs; and
- A $69 million increase primarily reflecting the combined effects of the absence of the net benefit recorded in 2008 related to the re-establishment of a regulatory asset in connection with the planned sale of Peoples and Hope ($47 million) and a 2009 charge due to a reduction in this regulatory asset ($22 million); partially offset by
- A $103 million downward revision in the nuclear decommissioning ARO for a power station unit that is no longer in service;
- Fewer scheduled outages at certain nuclear and fossil generating facilities ($91 million);
- The absence of a $59 million charge related to the impairment of a DCI investment sold in 2008; and
- The absence of a $42 million post-closing adjustment to the gain on the sale of the U.S. E&P operations recorded in 2008.

DD&A increased 7%, principally due to higher depreciation from property additions ($88 million), partially offset by a decrease in DD&A associated with our E&P operations reflecting lower rates ($20 million) and decreased gas and oil production ($16 million).

Other income increased $117 million primarily due to the impact of net realized gains (including investment income) on our merchant nuclear decommissioning trust funds in 2009 as compared to net realized losses (net of investment income) in 2008.

Interest and related charges increased 4%, primarily due to an increase in outstanding long-term debt ($102 million), partially offset by a decrease in commercial paper borrowings ($55 million) and interest accrued for issues recently resolved with taxing authorities ($25 million).

Income tax expense increased by 20% largely due to the absence of the benefit from the reversal of deferred tax liabilities in the first quarter of 2008, associated with a change in the expected tax treatment of the planned sale of Peoples and Hope.

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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 attributable to Dominion:

Third Quarter	Net Income attributable to Dominion 2009	2008	$ Change	Diluted EPS 2009	2008	$ Change
(millions, except EPS)						
DVP	**$ 95**	$ 84	$ 11	**$ 0.16**	$ 0.15	$ 0.01
Dominion Energy	**95**	81	14	**0.16**	0.14	0.02
Dominion Generation	**459**	449	10	**0.77**	0.77	
Primary operating segments	**649**	614	35	**1.09**	1.06	0.03
Corporate and Other	**(55)**	(106)	51	**(0.09)**	(0.19)	0.10
Consolidated	**$ 594**	$ 508	$ 86	**$ 1.00**	$ 0.87	$ 0.13
Year-to-Date						
DVP	**$ 292**	$ 278	$ 14	**$ 0.49**	$ 0.48	$ 0.01
Dominion Energy	**371**	333	38	**0.63**	0.57	0.06
Dominion Generation	**1,098**	991	107	**1.86**	1.71	0.15
Primary operating segments	**1,761**	1,602	159	**2.98**	2.76	0.22
Corporate and Other	**(465)**	(116)	(349)	**(0.79)**	(0.20)	(0.59)
Consolidated	**$ 1,296**	$ 1,486	$ (190)	**$ 2.19**	$ 2.56	$ (0.37)

DVP

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

	Third Quarter 2009	2008	% Change	Year-to-Date 2009	2008	% Change
Electricity delivered (million MWh)	**21.8**	23.4	(7)%	**62.1**	64.2	(3)%
Degree days (electric distribution service area):						
Cooling[(1)]	**988**	1,083	(9)	**1,451**	1,587	(9)
Heating[(2)]	**5**	2	150	**2,462**	2,074	19
Average electric distribution customer accounts (thousands)[(3)]	**2,403**	2,387	1	**2,401**	2,383	1
Average retail energy marketing customer accounts (thousands)[(3)]	**1,747**	1,617	8	**1,699**	1,601	6

(1) Cooling degree days are units measuring the extent to which the average daily temperature is greater than 65 degrees Fahrenheit, and are calculated as the difference between 65 degrees and the average temperature for that day.
(2) Heating degree days are units measuring the extent to which the average daily temperature is less than 65 degrees Fahrenheit, and are calculated as the difference between 65 degrees and the average temperature for that day.
(3) Period average.

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

	Third Quarter 2009 vs. 2008 Increase (Decrease)		Year-to-Date 2009 vs. 2008 Increase (Decrease)	
(millions, except EPS)	Amount	EPS	Amount	EPS
Retail energy marketing operations	$ 10	$ 0.02	$ (12)	$ (0.02)
Storm damage and restoration services[1]	3		12	0.02
Regulated electric sales:				
Weather	(7)	(0.01)	6	0.01
Customer growth	1		4	
Rate adjustment clause[2]	3		3	
Other[3]	2		(8)	(0.01)
Other[4]	(1)		9	0.01
Share dilution				
Change in net income contribution	$ 11	$ 0.01	$ 14	$ 0.01

(1) Reflects lower storm damage and service restoration costs associated with our electric distribution operations.
(2) Reflects the impact of a new rate adjustment clause associated with the recovery of transmission-related expenditures.
(3) Year-to-date decrease primarily reflects the impact of unfavorable economic conditions on customer usage and other factors.
(4) Year-to-date increase primarily reflects the deferral of transmission-related expenditures collectible under a rate adjustment clause.

Dominion Energy

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

	Third Quarter			Year-to-Date		
	2009	2008	% Change	2009	2008	% Change
Gas distribution throughput (bcf):						
Sales	**1**	3	(67)%	**25**	35	(29)%
Transportation	**22**	28	(21)	**137**	156	(12)
Heating degree days (gas distribution service area)	**82**	54	52	**3,900**	3,929	(1)
Average gas distribution customer accounts (thousands)[1]:						
Sales	**144**	384	(63)	**223**	396	(44)
Transportation	**1,036**	802	29	**972**	807	20
Production[2] (bcfe):	**12.5**	15.2	(18)	**38.9**	49.2	(21)
Average realized prices without hedging results (per mcfe)	**$ 3.42**	$ 9.94	(66)	**$ 4.07**	$ 9.39	(57)
Average realized prices with hedging results (per mcfe)	**6.88**	8.54	(19)	**7.34**	8.61	(15)
DD&A (unit of production rate per mcfe)	**1.37**	2.06	(33)	**1.57**	1.98	(21)
Average production (lifting) cost[3] (per mcfe)	**1.10**	1.51	(27)	**1.20**	1.35	(11)

(1) Period average.
(2) Includes natural gas, natural gas liquids and oil. Production includes 2.3 bcfe for the year-to-date period ended September 30, 2009, and 3.5 bcfe and 14.4 bcfe for the quarter and year-to-date period ended September 30, 2008, respectively, associated with the VPP royalty interests. There was no production related to VPPs for the quarter ended September 30, 2009 due to the expiration of these interests in February 2009.
(3) The inclusion of volumes associated with the VPPs would have resulted in lifting costs of $1.15 for the year-to-date period ended September 30, 2009, and $1.26 and $1.07 for the quarter and year-to-date period ended September 30, 2008, respectively. There were no

volumes related to VPPs for the quarter ended September 30, 2009 due to the expiration of these interests in February 2009.

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

(millions, except EPS)	Third Quarter 2009 vs. 2008 Increase (Decrease) Amount	EPS	Year-to-Date 2009 vs. 2008 Increase (Decrease) Amount	EPS
Cove Point expansion revenue	$ 28	$ 0.05	$ 63	$ 0.11
DD&A gas and oil	9	0.01	22	0.04
Producer services[1]	(17)	(0.03)	13	0.02
Gas and oil production[2]	(14)	(0.02)	(52)	(0.09)
Change in state tax legislation[3]			(16)	(0.02)
Other	8	0.01	8	0.01
Share dilution				(0.01)
Change in net income contribution	$ 14	$ 0.02	$ 38	$ 0.06

(1) Quarter-to-date decrease is largely due to unfavorable price changes related to economic hedging transactions, partially offset by higher physical margins associated with natural gas aggregation, marketing and trading activities. Year-to-date increase is largely due to colder than normal weather throughout the mid-Atlantic and Northeast market areas and higher physical margins, partially offset by unfavorable price changes related to economic hedging transactions all associated with natural gas aggregation, marketing and trading activities.

(2) Principally due to the expiration of VPP royalty interests.

(3) Reflects the absence of a 2008 benefit resulting from the reduction of deferred tax liabilities related to the enactment of West Virginia income tax rate reductions.

Included below are the volumes and weighted-average prices associated with hedges in place for our E&P operations as of September 30, 2009, by applicable time period:

Year	Natural Gas Hedged Production (bcf)	Average Hedge Price (per mcf)
2009	7.3	$ 9.13
2010	22.1	7.94
2011	6.6	6.82

Dominion Generation

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

	Third Quarter 2009	2008	% Change	Year-to-Date 2009	2008	% Change
Electricity supplied (million MWh):						
Utility	**21.8**	23.4	(7)%	**62.1**	64.2	(3)%
Merchant	**12.4**	12.4		**37.1**	33.4	11
Degree days (electric utility service area):						
Cooling	**988**	1,083	(9)	**1,451**	1,587	(9)
Heating	**5**	2	150	**2,462**	2,074	19

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

	Third Quarter 2009 vs. 2008 Increase (Decrease)		Year-to-Date 2009 vs. 2008 Increase (Decrease)	
(millions, except EPS)	Amount	EPS	Amount	EPS
Outage costs	$ 7	$ 0.01	$ 58	$ 0.10
Merchant generation margin[1]	(15)	(0.02)	91	0.17
Depreciation and amortization	(6)	(0.01)	(28)	(0.05)
Regulated electric sales:				
Weather	(14)	(0.02)	6	0.01
Customer growth	3		8	0.01
Rate adjustment clause[2]	14	0.02	40	0.07
Other[3]	(5)		(45)	(0.08)
Sales of emissions allowances			(17)	(0.03)
Other	26	0.04	(6)	(0.01)
Share dilution		(0.02)		(0.04)
Change in net income contribution	$ 10	$	$ 107	$ 0.15

(1) Quarter-to-date decrease primarily attributable to lower realized prices. Year-to-date increase primarily attributable to higher volumes at certain nuclear and fossil generating facilities, partially offset by lower realized prices.
(2) Reflects the impact of a new rate adjustment clause associated with the recovery of construction-related financing costs for the Virginia City Hybrid Energy Center.
(3) Year-to-date decrease primarily reflects lower sales to wholesale customers, as well as the impact of unfavorable economic conditions on customer usage and other factors.

Corporate and Other

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

	Third Quarter			Year-to-Date		
(millions, except EPS)	2009	2008	$ Change	2009	2008	$ Change
Specific items attributable to operating segments	**$ 30**	$ (27)	$ 57	**$ (242)**	$ (54)	$ (188)
Sale of U.S. E&P business		(26)	26		(26)	26
Peoples and Hope	**(11)**	2	(13)	**23**	63	(40)
Other corporate operations	**(74)**	(55)	(19)	**(246)**	(99)	(147)
Total net benefit (expense)	**$ (55)**	$ (106)	$ 51	**$ (465)**	$ (116)	$ (349)
EPS impact	**$ (0.09)**	$ (0.19)	$ 0.10	**$ (0.79)**	$ (0.20)	$ (0.59)

Specific Items Attributable to Operating Segments

Corporate and Other 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 21 to our Consolidated Financial Statements for discussion of significant items.

Sale of U.S. E&P business

The 2008 quarter and year-to-date amounts reflect post-closing adjustments to the gain on the sale.

Peoples and Hope

Third Quarter 2009 vs. 2008

The decrease primarily reflects an adjustment to a regulatory asset established in 2008 in connection with the planned sale of these subsidiaries.

Year-to-date 2009 vs. 2008

The decrease primarily reflects the combined effects of the absence of the net benefit recorded in 2008 related to the re-establishment of a regulatory asset in connection with the planned sale of these subsidiaries and a 2009 charge due to a reduction in this regulatory asset.

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Other Corporate Operations

Third Quarter 2009 vs. 2008

Net expenses increased $19 million primarily due to higher net interest expense.

Year-to-date 2009 vs. 2008

Net expenses increased $147 million, primarily due to the absence of the following 2008 items:

The reversal of $136 million of deferred tax liabilities associated with Peoples and Hope; partially offset by

A $38 million after-tax impairment charge recorded related to a DCI investment that was sold in April 2008.

In addition, net expenses increased due to higher net interest expense and an increase in our interim income tax provision attributable to the impact of the planned sale of Peoples and Hope on our 2009 estimated annual effective tax rate, partially offset by a reduction in interest accrued for issues recently resolved with tax authorities.

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, 2008 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 follows:

(millions)	Amount
Net unrealized gain at December 31, 2008	**$ 43**
Contracts realized or otherwise settled during the period	**(42)**
Net unrealized gain at inception of contracts initiated during the period	
Change in unrealized gains and losses	**31**
Changes in unrealized gains and losses attributable to changes in valuation techniques	
Net unrealized gain at September 30, 2009	**$ 32**

The balance of net unrealized gains and losses recognized for our energy-related derivative instruments held for trading purposes at September 30, 2009, 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)]	$ 23	$ (2)	$	$	$	$ 21
Other external sources Level 2[(2)]	(7)	3	(2)			(6)

Models and other valuation methods	Level 3[3]	5	5	7	1	(1)	17
Total		$ 21	$ 6	$ 5	$ 1	$ (1)	$ 32

(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 September 30, 2009, we had $3.8 billion of unused capacity under our credit facilities.

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A summary of our cash flows for the nine months ended September 30, 2009 and 2008 is presented below:

(millions)	2009	2008
Cash and cash equivalents at January 1,[(1)]	**$ 71**	$ 287
Cash flows provided by (used in):		
Operating activities	**2,982**	1,427
Investing activities	**(2,744)**	(2,321)
Financing activities	**(256)**	697
Net decrease in cash and cash equivalents	**(18)**	(197)
Cash and cash equivalents at September 30,[(2)]	**$ 53**	$ 90

(1) 2009 and 2008 amounts include $5 million and $4 million, respectively, of cash classified as held for sale in our Consolidated Balance Sheets.

(2) 2009 and 2008 amounts include $3 million and $2 million, respectively, of cash classified as held for sale in our Consolidated Balance Sheets.

Operating Cash Flows

Net cash provided by operating activities increased by approximately $1.6 billion, primarily due to higher deferred fuel and gas cost recoveries, higher cash contributions from our merchant generation operations, lower outage costs and a decrease in customer receivables, partially offset by 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 our Annual Report on Form 10-K for the year-ended December 31, 2008.

Credit Risk

As discussed in Note 19 to our Consolidated Financial Statements, 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 September 30, 2009, 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)]	$ 862	$ 279	$ 583
Non-investment grade[(2)]	7	1	6
No external ratings:			
Internally rated investment grade[(3)]	99		99
Internally rated non-investment grade[(4)]	22		22
Total	$ 990	$ 280	$ 710

(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 54% 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 9% of the total net credit exposure.
(4) The five largest counterparty exposures, combined, for this category represented approximately 1% of the total net credit exposure.

Investing Cash Flows

Net cash used in investing activities increased by $423 million, primarily due to an increase in capital expenditures related to our electric utility operations and the absence of proceeds received in 2008 from the assignment of drilling rights in the Marcellus Shale formation, partially offset by reduced investments in and a distribution from our Fowler Ridge wind farm investment in connection with non-recourse project financing proceeds received in September 2009.

Financing Cash Flows and Liquidity

We rely on banks and capital markets as significant sources of funding for capital requirements not satisfied by cash provided by our operations. As discussed further in the *Credit Ratings and Debt Covenants* section, our ability to

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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 impacted by credit market conditions and subject to meeting certain regulatory requirements, including registration with the SEC and in the case of Virginia Power, approval by the Virginia Commission.

Net cash used in financing activities was $256 million as compared to net cash provided by financing activities of $697 million in 2008. This change is primarily due to higher dividend payments, and lower net debt issuances as a result of higher cash inflows from our operating activities, partially offset by increased proceeds from common stock issuances.

See Note 16 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* section of MD&A in our Annual Report on Form 10-K for the year ended December 31, 2008, 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. As of September 30, 2009, there have been no changes in our credit ratings. In April 2009, Moody s revised its credit ratings outlook for Virginia Power to positive from stable.

In addition, in the *Debt Covenant* section of MD&A in our Annual Report on Form 10-K for the year ended December 31, 2008, we discussed various covenants present in the enabling agreements underlying Dominion and Virginia Power s debt. As of September 30, 2009, there have been no events of default under our debt covenants. As of September 30, 2009, there have been no changes to our debt covenants other than the execution of a replacement capital covenant discussed in MD&A in our Quarterly Report on Form 10-Q for the quarter ended June 30, 2009.

Future Cash Payments for Contractual Obligations and Planned Capital Expenditures

As of September 30, 2009, 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, 2008.

Use of Off-Balance Sheet Arrangements

As of September 30, 2009, 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, 2008.

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 Item 1. Business and Future Issues and Other Matters in MD&A in our Annual Report on Form 10-K for the year ended December 31, 2008 and Future Issues and Other Matters in our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2009 and June 30, 2009. In addition, see Note 18 to our Consolidated Financial Statements and Part II, Item 1. Legal Proceedings for additional information on various environmental, regulatory, legal and other matters that may impact our future results of operations and/or financial condition, including a discussion of electric regulation in Virginia.

Regulatory Approval of Sale of Peoples and Hope

In September 2008, Dominion and the Fund each filed a Premerger Notification and Report Form with the U.S. Department of Justice (DOJ) and the Federal Trade Commission (FTC) under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 (HSR Act). In October 2008, the mandatory waiting period under the HSR Act related to the proposed sale of Peoples and Hope to PH Gas expired. In September 2009, Dominion and the Fund each filed a renewed Premerger Notification and Report Form with the DOJ and FTC. In October 2009, Dominion and the Fund were granted early termination of the mandatory waiting period under the HSR Act.

In September 2008, Peoples, Dominion and Peoples Hope Gas Companies LLC (PH Gas) filed a joint petition with the Pennsylvania Commission seeking approval of the purchase by PH Gas of all of the stock of Peoples. In August 2009, evidentiary hearings for the sale of

Peoples were held before the Pennsylvania Commission. In September 2009, Peoples, Dominion, PH Gas and two of the active interveners in the Peoples sale proceeding reached a settlement on issues involved in the Peoples sale. In October 2009, the administrative law judge (ALJ) in the Peoples sale proceeding issued an interim order denying the settlement. The ALJ did not reject the sale and did not rule on the merits of the sale petition. In October 2009, Dominion filed a petition with the Pennsylvania Commission requesting that it approve the settlement, and therefore the sale application, at a public meeting of the Pennsylvania Commission on November 19, 2009, consistent with the regulatory deadline for Commission action on such petitions.

In October 2008, Hope, Dominion and PH Gas filed a joint petition seeking West Virginia Commission approval of the purchase by PH Gas of all of the stock of Hope. In August 2009, evidentiary hearings for the sale of Hope and the associated rate case were held before the West Virginia Commission. The sale of Hope is pending before the West Virginia Commission.

The sale of Peoples and Hope is expected to close in 2009, subject to state regulatory approvals in Pennsylvania and West Virginia.

Federal Regulation

Federal Energy Regulatory Commission

In January 2008, FERC affirmed an earlier decision that the PJM transmission rate design for existing facilities had not become unjust and unreasonable. For recovery of costs of investments of new PJM-planned transmission facilities that operate at or above 500 kilovolt (kV), FERC established a regional rate design where all customers pay a uniform rate based on the costs of such investment. For recovery of costs of investment in new PJM-planned transmission facilities that operate below 500 kV, FERC affirmed its earlier decision to allocate costs on a beneficiary pays approach. A notice of appeal of this decision was filed in February 2008 at the U.S. Court of Appeals for the Seventh Circuit. In August 2009, the court denied the petition for review concerning the rate design for existing facilities, but granted the petition concerning the rate design for new facilities that operate at or above 500 kV, and remanded that issue back to FERC for further proceedings. We cannot predict the outcome of the FERC proceedings on remand.

In May 2008, the Maryland Public Service Commission, Delaware Public Service Commission, Pennsylvania Commission, New Jersey Board of Public Utilities, the American Forest & Paper Association, the Portland Cement Association and several other organizations representing consumers in the PJM region (the RPM Buyers) filed a complaint at FERC claiming that PJM s Reliability Pricing Model s transitional auctions have produced unjust and unreasonable capacity prices. The RPM Buyers requested that a refund effective date of June 1, 2008 be established and that FERC provide appropriate relief from unjust and unreasonable capacity charges within 15 months. In September 2008, FERC dismissed the complaint. The RPM Buyers requested rehearing of the FERC order in October 2008 and rehearing was denied in June 2009. A notice of appeal was filed in August 2009 by the Maryland Public Service Commission and the New Jersey Board of Public Utilities at the U.S. Court of Appeals for the Fourth Circuit. We cannot predict the outcome of the appeal.

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.

Clean Water Act Compliance

In October 2007, the Virginia State Water Control Board (Water Board) issued a renewed water discharge (VPDES) permit for North Anna. The Blue Ridge Environmental Defense League, and other persons, appealed the Water Board s decision to the Richmond Circuit Court, challenging several permit provisions related to North Anna s discharge of cooling water. In February 2009, the court ruled that the Water Board was required to regulate the thermal discharge from North Anna into the waste heat treatment facility. We filed a motion for reconsideration with the court in February 2009, which was denied. The final order was issued by the court in September 2009. The court s order allows North Anna to continue to operate pursuant to the currently issued VPDES permit. In October 2009, we filed a Notice of Appeal of the court s Order with the Richmond Circuit Court, initiating the appeals process to the Court of Appeals. Until the final permit is reissued, it is not possible to predict any financial impact that may result.

Global Climate Change

In June 2009, the U.S. House of Representatives passed comprehensive legislation titled the American Clean

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Energy and Security Act of 2009 to encourage the development of clean energy sources and reduce greenhouse gas (GHG) emissions. The legislation contains provisions establishing federal renewable energy standards for electric suppliers. The legislation also includes cap-and-trade provisions for the reduction of GHG emissions. Similar legislation has been introduced in the U.S. Senate. In addition, the EPA has proposed two rules that, if finalized, will hold that GHGs are air pollutants subject to the provisions of the Clean Air Act. These are the EPA *Proposed Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act* (proposed April 2009) and the *Proposed Rulemaking To Establish Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards* (proposed September 2009). The cost of compliance with future GHG emission reduction programs could be significant. Given the highly uncertain outcome and timing of future action by the U.S. federal government and states on this issue, we cannot predict the financial impact of future GHG emission reduction programs on our operations, shareholders or customers at this time.

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

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

Commodity Price Risk

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

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

A hypothetical 10% unfavorable change in market prices of our non-trading commodity-based financial derivative instruments would have resulted in a decrease in fair value of approximately $166 million and $236 million as of September 30, 2009 and December 31, 2008, respectively. The decline in sensitivity is largely due to settlements of commodity derivative positions existing as of the beginning of the period. A hypothetical 10% unfavorable change in commodity prices would have resulted in a decrease of approximately $11 million and $5 million in the fair value of our commodity-based financial derivative instruments held for trading purposes as of September 30, 2009 and December 31, 2008, respectively. The increase in sensitivity is largely due to a decrease in commodity prices as well as increased commodity derivative activity.

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

Interest Rate Risk

We manage our interest rate risk exposure predominantly by maintaining a balance of fixed and variable rate debt. We may also enter into interest-rate swaps when deemed appropriate to adjust our exposure based upon market conditions. At September 30, 2009 and December 31, 2008, a hypothetical 10% increase in market interest rates would have resulted in a decrease in annual earnings of approximately $2 million and $4 million, respectively.

Additionally, we may use forward-starting interest-rate swaps and treasury rate locks as anticipatory hedges. At September 30, 2009, we had $2 billion in aggregate notional amounts of these interest-rate derivatives outstanding. A hypothetical 10% decrease in market interest rates would have resulted in a decrease of approximately $76 million in the fair value of these interest-rate derivatives at September 30, 2009. We did not have a significant amount of these interest-rate derivatives outstanding at December 31, 2008.

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The impact of a change in market interest rates on these anticipatory hedges at a point in time is not necessarily representative of the results that will be realized when such contracts are settled. Net gains and/or losses from interest-rate derivatives used for anticipatory hedging purposes, to the extent realized, will generally be amortized over the life of the respective debt issuance being hedged.

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.

We recognized net realized gains (including investment income) on nuclear decommissioning trust investments of $10 million for the nine months ended September 30, 2009. We recognized net realized losses (net of investment income) on nuclear decommissioning trust investments of $91 million and $192 million for the nine months ended September 30, 2008 and for the year ended December 31, 2008, respectively. Net realized losses include gains and losses from the sale of investments as well as other-than-temporary impairments recognized in earnings. For the nine months ended September 30, 2009, we recorded, in AOCI and regulatory liabilities, a net increase in unrealized gains on these investments of $298 million. For the nine months ended September 30, 2008 and for the year ended December 31, 2008, we recorded, in AOCI and regulatory liabilities, a reduction in unrealized gains on these investments of $259 million and $451 million, respectively.

We sponsor employee pension and other postretirement benefit plans, in which our employees participate, that hold investments in trusts to fund benefit payments. Investment-related declines in these trusts will result in future increases in the periodic cost recognized for such employee benefit plans and will be included in the determination of the amount of cash to be contributed to the employee benefit plans.

ITEM 4. CONTROLS AND PROCEDURES

Senior management, including our 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 Note 18 to our Consolidated Financial Statements and Future Issues and Other Matters in MD&A for discussions on various environmental and other regulatory proceedings to which we are a party.

In December 2006 and January 2007, we submitted self-disclosure notifications to EPA Region 8 regarding three E&P facilities in Utah that potentially violated Clean Air Act (CAA) permitting requirements. In July 2007, a third party purchased Dominion s E&P assets in Utah, including these facilities. In September 2008, we received a draft Consent Decree related to the potential CAA infractions, which imposed obligations on our subsidiary, Dominion Exploration and Production, Inc. and the purchaser, including payment of a civil penalty to the U.S. Department of Justice (DOJ) in the amount of $250,000. In September 2009, upon expiration of the thirty day public comment period, the DOJ requested the U.S. District Court, District of Utah, Northern Division to enter the final Consent Decree. Per our asset purchase agreement, the party purchaser assumed responsibility for the resolution of any enforcement action or Consent Decree, including penalties.

In February 2008, we received a request for information pursuant to Section 114 of the Clean Air Act from the EPA. The request concerns historical operating changes and capital improvements undertaken at our State Line and Kincaid power stations. In April 2009, we received a second request for information. We have provided information in response to both requests. Also in April, we received a Notice and Finding of Violations from the EPA claiming new source review violations, new source performance standards violations, and Title V permit program violations pursuant to the Clean Air Act and the respective State Implementation Plans. We have met with the EPA regarding the alleged violations, and have provided additional information to the EPA. We are evaluating the impact of the Notice. While we cannot predict the outcome of 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.

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, 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, 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.

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

There were no unregistered sales of equity securities during the third quarter of 2009.

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(2)
7/1/09-7/31/09	2,037	$ 33.27	N/A	53,971,148 shares/ $ 2.68 billion
8/1/09-8/31/09			N/A	53,971,148 shares/ $ 2.68 billion
9/1/09-9/30/09	4,809	33.08	N/A	53,971,148 shares/ $ 2.68 billion
Total	6,846	$ 33.14	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 and goal-based stock.

(2) The remaining repurchase authorization is pursuant to repurchase authority granted by our Board of Directors in February 2005, as modified June 2007.

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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 and as further amended November 9, 2007 (filed herewith).

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).

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* Indicates management contract or compensatory plan or arrangement.

^ This exhibit will not be deemed filed for purposes of Section 18 of the Securities Exchange Act of 1934 (15 U.S.C. 78r), or otherwise subject to the liability of that section. Such exhibit will not be deemed to be incorporated by reference into any filing under the Securities Act or Securities Exchange Act, except to the extent that the Company specifically incorporates it by reference.

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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

November 2, 2009

/s/ Ashwini Sawhney
Ashwini Sawhney

Vice President and Controller

(Chief Accounting Officer)

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