VIRGINIA ELECTRIC & POWER CO
Form 10-Q
July 31, 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 June 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 001-02255

VIRGINIA ELECTRIC AND POWER COMPANY

(Exact name of registrant as specified in its charter)

VIRGINIA	**54-0418825**
(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 ¨ 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	¨	Accelerated filer	¨
Non-accelerated filer	x (Do not check if a smaller reporting company)	Smaller reporting company	¨

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

At June 30, 2009, the latest practicable date for determination, 209,833 shares of common stock, without par value, of the registrant were outstanding.

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VIRGINIA ELECTRIC AND POWER COMPANY

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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
affiliates	Other Dominion subsidiaries
AOCI	Accumulated other comprehensive income (loss)
AROs	Asset retirement obligations
CEO	Chief Executive Officer
CFO	Chief Financial Officer
DOE	Department of Energy
Dominion	Dominion Resources, Inc.
DRS	Dominion Resources Services, Inc., a subsidiary of Dominion
DVP	Dominion Virginia Power operating segment
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN	FASB Interpretation No.
FSP	FASB Staff Position
FTRs	Financial transmission rights
GAAP	U.S. generally accepted accounting principles
kWh	Kilowatt-hour
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
PJM	PJM Interconnection, LLC
ROE	Return on equity
RTO	Regional transmission organization
SEC	Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards
Standard & Poor s	Standard & Poor s Ratings Services, a division of the McGraw-Hill Companies, Inc.
U.S.	United States of America
VIEs	Variable interest entities
Virginia Commission	Virginia State Corporation Commission

VIRGINIA ELECTRIC AND POWER COMPANY

PART I. FINANCIAL INFORMATION

ITEM 1. CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED STATEMENTS OF INCOME

(Unaudited)

(millions)	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Operating Revenue	**$ 1,675**	$ 1,546	**$ 3,534**	$ 3,070
Operating Expenses				
Electric fuel and other energy-related purchases	**685**	500	**1,479**	997
Purchased electric capacity	**104**	97	**212**	203
Other operations and maintenance:				
Affiliated suppliers	**100**	90	**201**	176
Other	**281**	274	**527**	493
Depreciation and amortization	**160**	150	**317**	299
Other taxes	**46**	45	**97**	94
Total operating expenses	**1,376**	1,156	**2,833**	2,262
Income from operations	**299**	390	**701**	808
Other income	**23**	9	**32**	18
Interest and related charges[(1)]	**87**	78	**174**	157
Income before income tax expense	**235**	321	**559**	669
Income tax expense	**86**	121	**206**	247
Net Income	**149**	200	**353**	422
Preferred dividends	**4**	4	**8**	8
Balance available for common stock	**$ 145**	$ 196	**$ 345**	$ 414

(1) Includes $4 million and $12 million incurred with an affiliated trust for the three and six months ended June 30, 2008, respectively.

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

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VIRGINIA ELECTRIC AND POWER COMPANY

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(millions)	June 30, 2009	December 31, 2008[1]
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 29**	$ 27
Customer accounts receivable (less allowance for doubtful accounts of $11 and $8)	**954**	940
Other receivables (less allowance for doubtful accounts of $6 and $7)	**43**	82
Inventories (average cost method)	**591**	547
Prepayments	**89**	28
Regulatory assets	**525**	212
Other	**62**	75
Total current assets	**2,293**	1,911
Investments		
Nuclear decommissioning trust funds	**1,074**	1,053
Other	**3**	3
Total investments	**1,077**	1,056
Property, Plant and Equipment		
Property, plant and equipment	**24,457**	23,476
Accumulated depreciation and amortization	**(9,153)**	(8,915)
Total property, plant and equipment, net	**15,304**	14,561
Deferred Charges and Other Assets		
Regulatory assets	**258**	921
Other	**348**	353
Total deferred charges and other assets	**606**	1,274
Total assets	**$ 19,280**	$ 18,802

(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 the Consolidated Financial Statements.

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VIRGINIA ELECTRIC AND POWER COMPANY

CONSOLIDATED BALANCE SHEETS (Continued)

(Unaudited)

(millions)	June 30, 2009	December 31, 2008[(1)]
LIABILITIES AND SHAREHOLDER S EQUITY		
Current Liabilities		
Securities due within one year	**$ 15**	$ 125
Short-term debt	**379**	297
Accounts payable	**390**	436
Payables to affiliates	**54**	132
Affiliated current borrowings	**522**	417
Accrued interest, payroll and taxes	**219**	236
Other	**450**	386
Total current liabilities	**2,029**	2,029
Long-Term Debt	**6,450**	6,000
Deferred Credits and Other Liabilities		
Deferred income taxes and investment tax credits	**2,244**	2,485
Asset retirement obligations	**614**	715
Regulatory liabilities	**867**	760
Other	**361**	282
Total deferred credits and other liabilities	**4,086**	4,242
Total liabilities	**12,565**	12,271
Commitments and Contingencies (see Note 12)		
Preferred Stock Not Subject to Mandatory Redemption	**257**	257
Common Shareholder s Equity		
Common stock no par, 300,000 shares authorized; 209,833 shares outstanding	**3,738**	3,738
Other paid-in capital	**1,110**	1,110
Retained earnings	**1,592**	1,421
Accumulated other comprehensive income	**18**	5
Total common shareholder s equity	**6,458**	6,274
Total liabilities and shareholder s equity	**$ 19,280**	$ 18,802

(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 the Consolidated Financial Statements.

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VIRGINIA ELECTRIC AND POWER COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Six Months Ended June 30,	
(millions)	2009	2008
Operating Activities		
Net income	$ 353	$ 422
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	367	346
Deferred income taxes and investment tax credits	(103)	223
Other adjustments	(14)	(35)
Changes in:		
Accounts receivable	18	(7)
Affiliated accounts receivable and payable	(24)	91
Inventories	(44)	8
Deferred fuel expenses	331	(382)
Accounts payable	(27)	(24)
Accrued interest, payroll and taxes	(18)	(10)
Prepayments	(61)	10
Other operating assets and liabilities	133	(55)
Net cash provided by operating activities	911	587
Investing Activities		
Plant construction and other property additions	(1,125)	(848)
Purchases of nuclear fuel	(69)	(66)
Purchases of securities	(346)	(243)
Proceeds from sales of securities	330	209
Other	(47)	67
Net cash used in investing activities	(1,257)	(881)
Financing Activities		
Issuance of short-term debt, net	83	433
Issuance (repayment) of affiliated current borrowings, net	105	(114)
Repayment of affiliated notes payable		(412)
Issuance of long-term debt	460	630
Repayment of long-term debt	(119)	(39)
Common dividend payments	(176)	(198)
Preferred dividend payments	(8)	(8)
Other	3	3
Net cash provided by financing activities	348	295
Increase in cash and cash equivalents	2	1
Cash and cash equivalents at beginning of period	27	49
Cash and cash equivalents at end of period	$ 29	$ 50

Supplemental Cash Flow Information		
Significant noncash investing activities:		
Accrued capital expenditures	**$ 103**	$ 10

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

VIRGINIA ELECTRIC AND POWER COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

Note 1. Nature of Operations

Virginia Electric and Power Company (Virginia Power) is a regulated public utility that generates, transmits and distributes electricity for sale in Virginia and northeastern North Carolina. We are a member of PJM, a regional transmission organization (RTO), and our electric transmission facilities are integrated into the PJM wholesale electricity markets. All of our common stock is owned by our parent company, Dominion Resources, Inc. (Dominion).

We manage our daily operations through two primary operating segments: Dominion Virginia Power (DVP) and Generation. In addition, we also report a Corporate and Other segment that primarily includes specific items attributable to our operating segments that are not included in profit measures evaluated by executive management in assessing the segments performance or allocating resources among the segments. See Note 15 for further discussion of our operating segments.

The terms 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, Virginia Power, one or more of its consolidated subsidiaries or operating segments or the entirety of Virginia Power, including our Virginia and North Carolina operations and our 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 Report on Form 10-Q for the quarter ended March 31, 2009.

In our opinion, the accompanying unaudited Consolidated Financial Statements contain all adjustments necessary to present fairly our financial position as of June 30, 2009 and our results of operations for the three and six months ended June 30, 2009 and 2008, and our cash flows for the six months ended June 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 revenue 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 5 for further information on fair value measurements in accordance with SFAS No. 157, *Fair Value Measurements*.

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

We have evaluated subsequent events through July 31, 2009, the date our Consolidated Financial Statements were issued.

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Note 3. Newly Adopted Accounting Standards

FSP FAS 115-2 and FAS 124-2

We adopted the provisions of FSP FAS 115-2 and FAS 124-2, *Recognition and Presentation of Other-Than-Temporary Impairments* (FSP FAS 115-2) effective April 1, 2009. This FSP amends the guidance for the recognition and presentation of other-than-temporary impairments and requires additional disclosures. The recognition provisions of FSP FAS 115-2 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 FSP FAS 115-2, 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 hold the investments through the anticipated recovery period.

Effective with the adoption of FSP FAS 115-2, 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. Additionally, 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 certain jurisdictions subject to cost-based regulation, 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.

Upon the adoption of FSP FAS 115-2 for debt investments held at April 1, 2009, we recorded a $3 million ($2 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. Comprehensive Income

The following table presents total comprehensive income:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	**2008**	**2009**	**2008**
(millions)				
Net income	**$ 149**	$ 200	**$ 353**	$ 422
Other comprehensive income (loss):				
Net other comprehensive income associated with effective portion of changes in fair value of derivatives designated as cash flow hedges, net of taxes and amounts reclassified to earnings	**8**		**8**	1
Other, net of tax	**4**	(3)	**7**	(8)
Other comprehensive income (loss)	**12**	(3)	**15**	(7)
Total comprehensive income	**$ 161**	$ 197	**$ 368**	$ 415

Other comprehensive income for the three and six months ended June 30, 2009 excludes a $3 million ($2 million after-tax) adjustment representing the cumulative effect of the change in accounting principle related to the adoption of FSP FAS 115-2.

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Note 5. Fair Value Measurements

Our fair value measurements are made in accordance with the policies discussed in Note 6 to our Annual Report on Form 10-K for the year ended December 31, 2008. In addition, see Note 6 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 June 30, 2009				
Assets				
Derivatives	**$**	**$ 109**	**$ 8**	**$ 117**
Investments	**295**	**679**		**974**
Total assets	**$ 295**	**$ 788**	**$ 8**	**$ 1,091**
Liabilities				
Derivatives	**$**	**$ 9**	**$ 16**	**$ 25**
As of December 31, 2008				
Assets				
Derivatives	$	$ 60	$ 7	$ 67
Investments	225	714		939
Total assets	$ 225	$ 774	$ 7	$ 1,006
Liabilities				
Derivatives	$	$ 23	$ 76	$ 99

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions)	2009	2008	2009	2008
Beginning balance	**$ (41)**	$ 35	**$ (69)**	$ (4)
Total realized and unrealized gains or (losses):				
Included in earnings	**(87)**	70	**(138)**	89
Included in other comprehensive income (loss)		(3)		
Included in regulatory assets/liabilities	**32**	167	**55**	200
Purchases, issuances and settlements	**88**	(59)	**142**	(75)
Transfers out of Level 3			**2**	
Ending balance	**$ (8)**	$ 210	**$ (8)**	$ 210
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	**$**	$ 15	**$**	$ 15

The gains and losses included in earnings in the Level 3 fair value category, including those attributable to the change in unrealized gains and losses relating to assets still held at the reporting date, were classified in electric fuel and other energy-related purchases expense in our Consolidated Statements of Income for the three and six months ended June 30, 2009 and 2008.

As of June 30, 2009, our net balance of commodity derivatives categorized as Level 3 fair value measurements was a net liability of $8 million. A hypothetical 10% increase in commodity prices would increase the net liability by $2 million, while a hypothetical 10% decrease in commodity prices would decrease the net liability by $2 million.

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

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Fair Value of Financial Instruments

Substantially all of our financial instruments are recorded at fair value, with the exception of the instruments described below that are reported at historical cost. Estimated fair values have been determined using available market information and valuation methodologies considered appropriate by management. At June 30, 2009 and December 31, 2008, 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:

	June 30, 2009		December 31, 2008	
(millions)	Carrying Amount	Estimated Fair Value(1)	Carrying Amount	Estimated Fair Value(1)
Long-term debt(2)	**$ 6,465**	**$ 6,885**	$ 6,125	$ 6,231
Preferred stock(3)	**257**	**231**	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) Includes securities due within one year and amounts which represent the unamortized discount and premium. Also includes the valuation of certain fair value hedges associated with our fixed rate debt of $1 million at June 30, 2009 and December 31, 2008.
(3) Includes issuance expenses of $2 million at June 30, 2009 and December 31, 2008.

Note 6. Derivatives and Hedge Accounting Activities

Our accounting policies and objectives and strategies for using derivative instruments are discussed in Note 2 to the Consolidated Financial Statements in 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 June 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	15.2	
Basis	7.6	
Electricity (MWh):		
Fixed price(1)	241,491	
FTRs	97,202,239	
Capacity (MW)	492,270	585,000
Interest rate	$ 370,000,000	$ 625,000,000
Foreign currency (euros)	9,847,638	4,000,000

(1) Includes options.

For the three and six months ended June 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 six months ended June 30, 2009 and 2008.

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

(millions)	AOCI After-Tax	Portion Expected to be Reclassified to Earnings During the Next 12 Months After-Tax	Maximum Term
Interest rate	$ 8	$	374 months
Other	4	2	65 months
Total	$ 12	$ 2	

The amounts that will be reclassified from AOCI to earnings will generally be offset by the recognition of the hedged transactions (e.g., anticipated purchases) 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.

Fair Value and Gains and Losses on Derivative Instruments

The following table presents the fair values of our derivatives as of June 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	$ 16	$ 8	$ 24
Interest rate	23		23
Foreign currency	1		1
Total current derivative assets(1)	40	8	48
Noncurrent Assets			
Commodity	19		19
Interest rate	49		49
Foreign currency	1		1
Total noncurrent derivative assets(2)	69		69
Total derivative assets	$ 109	$ 8	$ 117
LIABILITIES			
Current Liabilities			
Commodity	$ 7	$ 16	$ 23

Total current derivative liabilities[3]	7	16	23
Noncurrent Liabilities			
Commodity	2		2
Total noncurrent derivative liabilities[4]	2		2
Total derivative liabilities	$ 9	$ 16	$ 25

(1) Current derivative assets are recorded in other current assets on our Consolidated Balance Sheet.
(2) Noncurrent derivative assets are recorded in other deferred charges and other assets on our Consolidated Balance Sheet.
(3) Current derivative liabilities are recorded in other current liabilities on our Consolidated Balance Sheet.
(4) Noncurrent derivative liabilities are recorded in other deferred credits and other liabilities on our Consolidated Balance Sheet.

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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 Consolidated Statements of Income:

Derivatives in SFAS No. 133 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 June 30, 2009			
Derivative Type and Location of Gains (Losses)			
Commodity:			
Electric fuel and other energy-related purchases		$ (1)	
Purchased electric capacity		2	
Total commodity	$ (1)	1	$ (4)
Interest rate[3]	14		86
Foreign currency[4]	1		2
Total	$ 14	$ 1	$ 84
Six months ended June 30, 2009			
Derivative Type and Location of Gains (Losses)			
Commodity:			
Electric fuel and other energy-related purchases		$ (6)	
Purchased electric capacity		3	
Total commodity	$ (2)	(3)	$ 1
Interest rate[3]	13		73
Foreign currency[4]		1	
Total	$ 11	$ (2)	$ 74

(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 expense.
(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 under SFAS No. 133	**Amount of Gain (Loss) Recognized in Income on Derivatives[1]**	
	Three Months Ended June 30,	**Six Months Ended June 30,**

(millions)	2009	2009
Derivative Type and Location of Gains (Losses)		
Commodity[2]	$ (87)	$ (138)
Total	$ (87)	$ (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.

(2) Amounts are recorded in electric fuel and other energy-related purchases in our Consolidated Statements of Income.

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

See Note 5 for further information about fair value measurements and associated valuation methods for derivatives under SFAS No. 157.

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Note 7. Decommissioning Trust Investments

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
June 30, 2009				
Marketable equity securities	**$ 466**	**$ 70**	**$**	**$ 536**
Marketable debt securities:				
Corporate bonds	**149**	**5**	**(4)**	**150**
U.S. Treasury securities and agency debentures	**98**	**3**		**101**
State and municipal	**172**	**6**	**(3)**	**175**
Cost method investments	**96**			**96**
Cash equivalents and other(2)	**16**			**16**
Total	**$ 997**	**$ 84**	**$ (7)(3)**	$ 1,074
December 31, 2008				
Marketable equity securities	$ 459	$ 9	$	$ 468
Marketable debt securities:				
Corporate bonds	144	7		151
U.S. Treasury securities and agency debentures	122	4		126
State and municipal	177	6		183
Cost method investments	108			108
Cash equivalents and other (2)	17			17
Total	$ 1,027	$ 26	$	$ 1,053

(1) Included in AOCI and the decommissioning trust regulatory liability.
(2) Includes net assets related to pending sales and purchases of securities of $5 million and $6 million at June 30, 2009 and December 31, 2008, respectively.
(3) The fair value of securities in an unrealized loss position was $118 million at June 30, 2009.

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

(millions)	Amount
Due in one year or less	**$ 20**
Due after one year through five years	**97**
Due after five years through ten years	**155**
Due after ten years	**154**
Total	**$ 426**

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions)	2009	2008	2009	2008
Proceeds from sales[1]	**$ 193**	$ 89	**$ 330**	$ 209
Realized gains[2]	**15**	8	**23**	17
Realized losses[2]	**6**	23	**70**	50

(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 June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Total other-than-temporary impairment losses[1]	**$ 8**	$ 20	**$ 82**	$ 40
Losses recorded to decommissioning trust regulatory liability	**(7)**	(17)	**(70)**	(34)
Net impairment losses recognized in earnings	**$ 1**	$ 3	**$ 12**	$ 6

(1) Amount includes other-than-temporary impairment losses for debt securities of $1 million and $4 million for the three months ended June 30, 2009 and 2008, respectively, and $5 million and $8 million for the six months ended June 30, 2009 and 2008, respectively.

Note 8. Regulatory Assets and Liabilities

Our regulatory assets and liabilities include the following:

(millions)	June 30, 2009	December 31, 2008
Regulatory assets		
Deferred cost of fuel used in electric generation[1]	**$ 463**	$ 133
Other	**62**	79
Regulatory assets current	**525**	212
RTO start-up costs and administration fees[2]	**118**	122
Deferred cost of fuel used in electric generation[1]	**15**	676
Other	**125**	123
Regulatory assets non-current	**258**	921
Total regulatory assets	**$ 783**	$ 1,133
Regulatory liabilities		
Provision for future cost of removal[3]	**$ 533**	$ 506
Decommissioning trust[4]	**221**	213
Other[5]	**128**	61
Total regulatory liabilities	**$ 882**	$ 780

(1) As discussed under Virginia Fuel Expenses in Note 12, in March 2009 we filed our Virginia fuel factor application with the Virginia Commission which requested an annual decrease in fuel expense recovery of approximately $236 million for the period July 1, 2009 through June 30, 2010. 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 to be held on July 16, 2009. In a subsequent order, the Virginia Commission postponed the July 16th hearing until September 1, 2009.

(2) The FERC has approved our recovery of start-up costs incurred in connection with joining an RTO and on-going administrative charges paid to PJM through a Deferred Recovery Charge (DRC). As discussed in Note 12, in June 2009, the Virginia Commission approved full recovery of the DRC from retail customers. In July 2009, FERC issued an order denying requests for rehearing of its December 2008 order. The time to appeal FERC s orders has not yet expired. Recovery of the DRC, over a ten year period, will begin September 1, 2009. Approximately $19 million of these costs are included in other current regulatory assets.

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

(4) Primarily reflects a regulatory liability established in 2007 representing amounts previously collected from Virginia jurisdictional customers and placed in external trusts (including income, losses and changes in fair value thereon) for the future decommissioning of our utility nuclear generation stations, in excess of amounts recorded pursuant to SFAS No. 143, *Accounting for Asset Retirement Obligations.*

(5) Includes $15 million and $20 million reported in other current liabilities at June 30, 2009 and December 31, 2008, respectively.

At June 30, 2009, approximately $560 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 two years.

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Note 9. Asset Retirement Obligations

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

(millions)	Amount
AROs at December 31, 2008[1]	$ 717
Revisions in estimated cash flows[2]	**(118)**
Accretion	**18**
AROs at June 30, 2009[1]	**$ 617**

(1) Includes $2 million and $3 million reported in other current liabilities at December 31, 2008 and June 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.

Note 10. Variable Interest Entities

As discussed in Note 13 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 in accordance with FIN 46R, *Consolidation of Variable Interest Entities*.

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 variable interest entities (VIEs). However, the information they provided, as well as our knowledge of generation facilities in Virginia, enabled us to conclude that, if they were VIEs, we would not be the primary beneficiary. This conclusion was based primarily on a qualitative assessment of our variable interests as compared to the operations, commodity price and other risks retained by the equity and debt holders during the remaining terms of our contracts and for the years the entities are expected to operate after our contractual relationships expire. The contracts expire at various dates ranging from 2015 to 2021. We are not subject to any risk of loss from these potential VIEs other than our remaining purchase commitments which totaled $1.9 billion as of June 30, 2009. We paid $51 million and $50 million for electric capacity and $25 million and $46 million for electric energy to these entities for the three months ended June 30, 2009 and 2008, respectively. We paid $104 million and $102 million for electric capacity and $66 million and $92 million for electric energy to these entities for the six months ended June 30, 2009 and 2008, respectively.

We purchased shared services from Dominion Resources Services, Inc. (DRS), an affiliated VIE, of $99 million and $90 million for the three months ended June 30, 2009 and 2008, respectively, and $199 million and $176 million for the six months ended June 30, 2009 and 2008, respectively. We determined that we are not the most closely associated entity with DRS and therefore not the primary beneficiary. DRS provides accounting, legal, finance and certain administrative and technical services to all Dominion subsidiaries, including us. We have no obligation to absorb more than our allocated share of DRS costs.

Note 11. Significant Financing Transactions

Joint Credit Facilities and Short-Term Debt

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

Our credit facility commitments are with a large consortium of banks, which included Lehman Brothers Holdings, Inc. (Lehman). In March 2009, we executed a consent agreement with the bank syndicates to reduce Lehman s remaining commitment to zero in each of our credit facilities in which it had participated.

Our short-term financing is supported by a $2.9 billion five-year joint revolving credit facility with Dominion dated February 2006, which is scheduled to terminate in February 2011. This credit facility is being used for working capital, as support for the combined commercial paper programs of Dominion and us and for other general corporate purposes. This credit facility can also be used to support up to $1.5 billion of letters of credit.

At June 30, 2009, total outstanding commercial paper supported by the joint credit facility was $379 million, all of which were our borrowings, and the total outstanding letters of credit supported by the joint credit facility were $291 million, of which $226 million were issued on our behalf.

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At June 30, 2009, capacity available under the joint credit facility was $2.2 billion.

In addition to the credit facility commitments of $2.9 billion disclosed above, we also have a five-year credit facility that supports certain of our tax-exempt financings. In June 2009, the committed amount was reduced from $182 million to $120 million. The reduced amount reflects the size necessary to cover outstanding variable rate tax-exempt financing.

Long-Term Debt

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, we 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.

We repaid $119 million of long-term debt during the six months ended June 30, 2009.

Note 12. Commitments and Contingencies

Other than the following matters, there have been no significant developments regarding the commitments and contingencies disclosed in Note 20 to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2008, or Note 8 to the Consolidated Financial Statements in our Quarterly Report on Form 10-Q for the quarter ended March 31, 2009, nor have any significant new matters arisen during the three months ended June 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).

In March 2009, we submitted our base rate filing and accompanying schedules to the Virginia Commission. Our filing proposed to increase our Virginia jurisdictional base rates by approximately $298 million annually. We also 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 April 2009, we submitted a revised filing that corrected certain plant balances. The corrected plant balances and related adjustments reduced the increase in our annual requirement by approximately $9 million, to $289 million. We proposed that the base rate increase become effective on an interim basis on September 1, 2009, subject to refund and adjustment by the Virginia Commission. 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 that further reduced the increase in our annual revenue requirement approximately $39 million, to $250 million. The proposed rate increase would increase a typical 1,000 kWh Virginia jurisdictional residential customer s bill by approximately $5.22 per month. The amended filing reflects an upward adjustment of 50 basis points in the proposed ROE. An evidentiary hearing on our base rate filing will be held in January 2010.

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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. Once implemented, Rider T is expected to increase 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 supply-side resources, to meet our projected load growth over the next 15 years. The DSM programs will also help to achieve 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. Our application requests approval of the DSM programs by February 1, 2010 and two associated rate adjustment clauses for cost recovery to be effective April 1, 2010, although the Regulation Act gives the Virginia Commission until the end of March 2010 to act on our application. In the filing, we requested approval of the two rate adjustment clauses to recover from Virginia jurisdictional customers an annual net increase 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.

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 to be held on July 16, 2009. In a subsequent order, the Virginia Commission postponed the July 16th hearing until September 1, 2009.

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 has been scheduled before a hearing examiner in August 2009.

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, and would increase a typical 1,000 kWh Virginia jurisdictional residential customer s bill by approximately $1.40 per month. An evidentiary hearing has been scheduled before a hearing examiner in August 2009.

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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 program, 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 allows recovery of approximately $153 million of RTO costs ($140 million of our costs and $13 million of Dominion s costs) that are being 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 will begin September 1, 2009. In July 2009, FERC issued an order denying requests for rehearing of its December 2008 order. The time to appeal FERC s orders has not yet expired. We cannot predict the status or outcome of a potential appeal, if any, of FERC s orders.

Guarantees and Surety Bonds

As of June 30, 2009, we had issued $16 million of guarantees primarily to support tax-exempt debt. We had also purchased $88 million of surety bonds for various purposes, including providing workers compensation coverage. Under the terms of surety bonds, we are obligated to indemnify the respective surety bond company for any amounts paid.

Note 13. Credit Risk

We maintain a provision for credit losses based on factors surrounding the credit risk of our customers, historical trends and other information. We believe, based on our credit policies and our June 30, 2009 provision for credit losses, 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.

We sell electricity and provide distribution and transmission services to customers in Virginia and northeastern North Carolina. Management believes that this geographic concentration risk is mitigated by the diversity of our customer base, which includes residential, commercial and industrial customers, as well as rural electric cooperatives and municipalities. Credit risk associated with trade accounts receivable from energy consumers is limited due to the large number of customers.

Our exposure to potential concentrations of credit risk results primarily from sales to wholesale customers. Our gross credit exposure for each counterparty is calculated as outstanding receivables plus any unrealized on or off-balance sheet exposure, taking into account contractual netting rights. Gross credit exposure is calculated prior to the application of collateral. At June 30, 2009, our gross credit exposure totaled $40 million. After the application of collateral, our credit exposure is reduced to $27 million. Of this amount, investment grade counterparties, including those internally rated, represented 67%, and no single counterparty exceeded 34%.

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 June 30, 2009, we would be required to post an additional $2 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 June 30, 2009 we have not posted any collateral related to derivatives with credit-related contingent provisions that are in a liability position and not fully collateralized with cash. 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 June 30, 2009 is $1 million and does not include the impact of any offsetting asset positions. See Note 6 for further information about our derivative instruments.

Note 14. Related Party Transactions

We engage in related-party transactions primarily with other Dominion subsidiaries (affiliates). Our receivable and payable balances with affiliates are settled based on contractual terms or on a monthly basis, depending on the nature of the underlying transactions. We are included in Dominion s consolidated federal income tax return and participate in certain Dominion benefit plans. A discussion of significant related party transactions follows.

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Transactions with Affiliates

We transact with affiliates for certain quantities of natural gas and other commodities in the ordinary course of business. We also enter into certain commodity derivative contracts with affiliates. We use these contracts, which are principally comprised of commodity swaps and options, to manage commodity price risks associated with purchases of natural gas. We designate the majority of these contracts as cash flow hedges for accounting purposes.

We receive a variety of services from DRS and other affiliates, primarily for accounting, legal, finance and certain administrative and technical services. In addition, we provide certain services to affiliates, including charges for facilities and equipment usage.

Presented below are significant transactions with DRS and other affiliates:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
(millions)				
Commodity purchases from affiliates	**$ 55**	$ 121	**$ 154**	$ 186
Services provided by affiliates	**100**	90	**201**	176

The following table presents our borrowings from Dominion under short-term arrangements:

	June 30, 2009	December 31, 2008
(millions)		
Outstanding borrowings, net of repayments, under the Dominion money pool for our nonregulated subsidiaries	**$ 142**	$ 198
Short-term demand note borrowings from Dominion	**380**	219

Interest charges related to our borrowings from Dominion were not material for the three or six months ended June 30, 2009 and 2008.

Note 15. Operating Segments

We are organized primarily on the basis of the products and services we sell. The majority of our revenue is provided through tariff rates. Generally, such revenue is allocated for management reporting based on an unbundled rate methodology among our DVP and Generation segments. We manage our daily operations through the following segments:

DVP includes our transmission, distribution and customer service operations.

Generation includes our generation and energy supply operations.

Corporate and Other primarily includes specific items attributable to our operating segments. The contribution to net income by our primary operating segments is determined based on a measure of profit that 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, either in assessing the segment s performance or in allocating resources among the segments and are instead reported in the Corporate and Other segment.

In the six months ended June 30, 2009, our Corporate and Other segment included $9 million ($6 million after-tax) of expenses attributable to the Generation segment, reflecting net losses on investments in our nuclear decommissioning trusts. There were no specific items attributable to our operating segments included in the Corporate and Other segment in the six months ended June 30, 2008.

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The following table presents segment information pertaining to our operations:

(millions)	DVP	Generation	Corporate and Other	Consolidated Total
Three Months Ended June 30, 2009				
Operating revenue	**$ 353**	**$ 1,322**	**$**	**$ 1,675**
Net income	**76**	**72**	**1**	**149**
Three Months Ended June 30, 2008				
Operating revenue	$ 357	$ 1,186	$ 3	$ 1,546
Net income (loss)	64	139	(3)	200
Six Months Ended June 30, 2009				
Operating revenue	**$ 733**	**$ 2,801**	**$**	**$ 3,534**
Net income (loss)	**166**	**193**	**(6)**	**353**
Six Months Ended June 30, 2008				
Operating revenue	$ 718	$ 2,346	$ 6	$ 3,070
Net income (loss)	143	282	(3)	422

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VIRGINIA ELECTRIC AND POWER COMPANY

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 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, Virginia Electric and Power Company, one or more of its consolidated subsidiaries or operating segments, or the entirety of Virginia Electric and Power Company and its consolidated subsidiaries. All of our common stock is owned by our parent company, Dominion.

Contents of MD&A

Our MD&A consists of the following information:

Forward-Looking Statements

This report contains statements concerning 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, shoul 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;

State and federal legislative and regulatory developments and changes to environmental and other laws and regulations, including those related to climate change, greenhouse gas emissions and other emissions to which we are subject;

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

Risks associated with the operation of nuclear facilities;

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

Capital market conditions, including the availability of credit and our ability to obtain financing on reasonable terms;

Risks associated with our 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 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;

Changes to regulated electric rates collected by the Company, 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;

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

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

Adverse outcomes in litigation matters.

Additionally, other factors 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 June 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 9 to our Consolidated Financial Statements. The policies disclosed included the accounting for derivative contracts and other instruments at fair value, regulated operations, AROs, unbilled revenue and income taxes.

Results of Operations

Presented below is a summary of our consolidated results:

	Second Quarter			**Year-To-Date**		
	2009	**2008**	**$ Change**	**2009**	**2008**	**$ Change**
(millions)						
Net income	**$ 149**	$ 200	$ (51)	**$ 353**	$ 422	$ (69)

Overview

Second Quarter and Year-To-Date 2009 vs. 2008

Our net income for the three and six months ended June 30, 2009 was lower than the comparable prior year periods, primarily reflecting a reduced benefit from financial transmission rights (FTRs) reflecting lower fuel prices, an increase in outage costs related to scheduled outages at certain of our generating facilities, and lower gains from sales of emissions allowances.

Analysis of Consolidated Operations

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

	Second Quarter			**Year-To-Date**		
	2009	**2008**	**$ Change**	**2009**	**2008**	**$ Change**
(millions)						
Operating Revenue	**$ 1,675**	$ 1,546	$ 129	**$ 3,534**	$ 3,070	$ 464
Operating Expenses						
Electric fuel and other energy-related purchases	**685**	500	185	**1,479**	997	482
Purchased electric capacity	**104**	97	7	**212**	203	9
Other operations and maintenance	**381**	364	17	**728**	669	59
Depreciation and amortization	**160**	150	10	**317**	299	18
Other taxes	**46**	45	1	**97**	94	3

Other income	**23**	9	14	**32**	18	14
Interest and related charges	**87**	78	9	**174**	157	17
Income tax expense	**86**	121	(35)	**206**	247	(41)

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An analysis of our results of operations follows:

Second Quarter 2009 vs. 2008

Operating Revenue increased 8%, primarily reflecting the combined effects of:

- A $198 million increase in fuel revenue primarily due to the impact of a comparatively higher fuel rate in certain customer jurisdictions, including the recovery of previously deferred fuel costs; and
- A $21 million increase due to the impact of a rate adjustment clause associated with the recovery of financing costs for the Virginia City Hybrid Energy Center; partially offset by
- A $54 million decrease in sales to wholesale customers due to decreased volumes ($29 million) and lower prices ($25 million);
- A $17 million decrease in base revenues from sales to retail customers due to an 8% decrease in cooling degree days, partially offset by a 12% increase in heating degree days; and
- A $9 million decrease reflecting the impact of unfavorable economic conditions on customer usage in base revenues and other factors.

Operating Expenses and Other Items

Electric fuel and other energy-related purchases expense increased 37%, primarily reflecting an increase due to a comparatively higher fuel rate in certain customer jurisdictions, including recovery of previously deferred fuel costs ($188 million) and a reduced benefit from FTRs ($38 million), partially offset by a decrease in fuel expenses associated with wholesale customers ($41 million).

Other operations and maintenance expense increased 5%, primarily reflecting:

- A $23 million increase in outage costs related to scheduled outages at certain fossil generating facilities; and
- A $16 million decrease in gains from the sale of emissions allowances; partially offset by
- A $13 million decrease reflecting lower storm damage and service restoration costs associated with our distribution operations; and
- A $12 million decrease due to the deferral of transmission-related expenditures collectible under certain rate adjustment clauses.

Other income increased 156%, primarily due to an increase in net realized gains on investments held in our nuclear decommissioning trusts for jurisdictions that are not subject to cost-based regulation ($4 million), greater charitable contributions in the comparable prior year period ($4 million) and an increase in amounts collectible from customers for taxes in connection with contributions in aid of construction (CIAC) ($3 million).

Interest and related charges increased 12%, largely due to the impact of additional borrowings.

Income tax expense decreased 29%, reflecting lower pre-tax income in 2009.

Year-To-Date 2009 vs. 2008

Operating Revenue increased 15%, primarily reflecting the combined effects of:

- A $500 million increase in fuel revenue primarily due to the impact of a comparatively higher fuel rate in certain customer jurisdictions, including the recovery of previously deferred fuel costs;

- A $53 million increase in base revenues from sales to retail customers due to a 19% increase in heating degree days, partially offset by an 8% decrease in cooling degree days; and

- A $43 million increase due to the impact of a rate adjustment clause associated with the recovery of financing costs for the Virginia City Hybrid Energy Center; partially offset by

- An $84 million decrease in sales to wholesale customers due to lower prices ($48 million) and decreased volumes ($36 million); and

- A $48 million decrease reflecting the impact of unfavorable economic conditions on customer usage in base revenues and other factors.

Operating Expenses and Other Items

Electric fuel and other energy-related purchases expense increased 48%, primarily reflecting an increase due to a comparatively higher fuel rate in certain customer jurisdictions, including recovery of previously deferred fuel costs ($490 million) and a reduced benefit from FTRs ($43 million), partially offset by a decrease in fuel expenses associated with wholesale customers ($51 million).

Other operations and maintenance expense increased 9%, primarily reflecting:

A $44 million increase in outage costs related to scheduled outages at nuclear and fossil generating facilities; and

A $27 million decrease in gains from the sale of emissions allowances; partially offset by

A $17 million decrease due to the deferral of transmission-related expenditures collectible under certain rate adjustment clauses.

Other income increased 78%, primarily due to an increase in the equity component of AFUDC as a result of construction and expansion projects ($8 million) and an increase in amounts collectible from customers for taxes in connection with CIAC ($5 million).

Interest and related charges increased 11%, largely due to the impact of additional borrowings.

Income tax expense decreased 17%, reflecting lower pre-tax income in 2009.

Segment Results of Operations

Presented below is a summary of contributions by our operating segments to net income:

	Second Quarter			Year-To-Date		
	2009	**2008**	**$ Change**	**2009**	**2008**	**$ Change**
(millions)						
DVP	**$ 76**	$ 64	$ 12	**$ 166**	$ 143	$ 23
Generation	**72**	139	(67)	**193**	282	(89)
Primary operating segments	**148**	203	(55)	**359**	425	(66)
Corporate and Other	**1**	(3)	4	**(6)**	(3)	(3)
Consolidated	**$ 149**	$ 200	$ (51)	**$ 353**	$ 422	$ (69)

DVP

Presented below are operating statistics related to our DVP operations:

	Second Quarter			Year-To-Date		
	2009	**2008**	**% Change**	**2009**	**2008**	**% Change**
Electricity delivered (million MWh)	**19.0**	20.0	(5)%	**40.3**	40.8	(1)%
Degree days:						
Cooling(1)	**459**	501	(8)	**463**	504	(8)
Heating(2)	**294**	263	12	**2,457**	2,072	19
Average retail customer accounts (thousands)(3)	**2,401**	2,382	1	**2,400**	2,381	1

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

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

(3) Period average.

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

(millions)	Second Quarter 2009 vs. 2008 Increase (Decrease)	Year-To-Date 2009 vs. 2008 Increase (Decrease)
Storm damage and service restoration distribution operations	$ 8	$ 8
Regulated electric sales:		
Weather	(3)	13
Customer growth	1	3
Other[1]	(2)	(9)
Other[2]	8	8
Change in net income contribution	$ 12	$ 23

(1) Decrease primarily reflects the impact of unfavorable economic conditions on customer usage and other factors.
(2) Primarily reflects the deferral of transmission-related expenditures collectible under certain rate adjustment clauses.

Generation

Presented below are operating statistics related to our Generation operations:

	Second Quarter			Year-To-Date		
	2009	2008	% Change	2009	2008	% Change
Electricity supplied (million MWh)	**19.0**	20.0	(5)%	**40.3**	40.8	(1)%
Degree days:						
Cooling	**459**	501	(8)	**463**	504	(8)
Heating	**294**	263	12	**2,457**	2,072	19

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

(millions)	Second Quarter 2009 vs. 2008 Increase (Decrease)	Year-To-Date 2009 vs. 2008 Increase (Decrease)
Energy supply margin[1]	$ (17)	$ (20)
Outage costs	(14)	(27)
Sales of emissions allowances	(10)	(16)
Ancillary service revenue	(9)	(13)
Regulated electric sales:		
Weather	(8)	20
Rate adjustment clause[2]	13	27
Customer growth	3	6
Other[3]	(13)	(40)
Depreciation and amortization expense[4]	(4)	(8)
Other	(8)	(18)

Change in net income contribution	$ (67)	$ (89)

(1) Reflects lower settlement gains on FTRs.
(2) Reflects the impact of a new rate adjustment clause associated with the recovery of financing costs for the Virginia City Hybrid Energy Center.
(3) Decrease reflects the impact of unfavorable economic conditions on customer usage and other factors, as well as lower sales to wholesale customers.
(4) Primarily due to incremental expense resulting from property additions.

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Liquidity and Capital Resources

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

At June 30, 2009, we had $2.2 billion of unused capacity under our joint credit facility.

A summary of our cash flows is presented below:

(millions)	2009	2008
Cash and cash equivalents at January 1,	**$ 27**	$ 49
Cash flows provided by (used in)		
Operating activities	**911**	587
Investing activities	**(1,257)**	(881)
Financing activities	**348**	295
Net increase in cash and cash equivalents	**2**	1
Cash and cash equivalents at June 30,	**$ 29**	$ 50

Operating Cash Flows

For the six months ended June 30, 2009, net cash provided by operating activities increased by $324 million as compared to the six months ended June 30, 2008. The increase is primarily due to a positive impact from deferred fuel cost recoveries in our Virginia jurisdiction due to increased fuel revenue and lower fuel costs, partially offset by higher income tax payments. We believe that our operations provide a stable source of cash flow to contribute to planned levels of capital expenditures and provide dividends to Dominion. However, 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 13 to our Consolidated Financial Statements, our exposure to potential concentrations of credit risk results primarily from sales to wholesale customers. Presented below is a summary of our gross credit exposure as of June 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]	$ 29	$ 13	$ 16
Non-investment grade[2]	9		9
No external ratings:			
Internally rated investment grade[3]	2		2
Internally rated non-investment grade			
Total	$ 40	$ 13	$ 27

(1) Designations as investment grade are based on minimum credit ratings assigned by Moody s and Standard & Poor s. The five largest counterparty exposures, combined, for this category represented approximately 60% of the total net credit exposure.
(2) The only counterparty exposure for this category represented approximately 32% of the total net credit exposure.
(3) The two largest counterparty exposures, combined, for this category represented approximately 8% of the total net credit exposure.

Investing Cash Flows

For the six months ended June 30, 2009, net cash used in investing activities increased by $376 million as compared to the six months ended June 30, 2008, primarily reflecting an increase in capital expenditures for generation and transmission construction projects, including our Virginia City Hybrid Energy Center.

Financing Cash Flows and Liquidity

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

For the six months ended June 30, 2009, net cash provided by financing activities increased by $53 million as compared to the six months ended June 30, 2008, primarily due to higher net debt issuances and a reduction in common dividend payments.

See Note 11 to our Consolidated Financial Statements for further information regarding our credit facilities, liquidity and significant financing transactions. Also, see Note 14 to our Consolidated Financial Statements for further information regarding our borrowings from Dominion.

Credit Ratings and Debt Covenants

Credit ratings are intended to provide banks and capital market participants with a framework for comparing the credit quality of securities and are not a recommendation to buy, sell or hold securities. In the *Credit Ratings* and *Debt Covenants* sections of MD&A in our Annual Report on Form 10-K for the year ended December 31, 2008, we discussed the use of capital markets and the impact of credit ratings on the accessibility and costs of using these markets, as well as various covenants present in the enabling agreements underlying our debt. As of June 30, 2009, there have been no changes in our credit ratings, nor have there been any changes to or events of default under our debt covenants. In April 2009, Moody s revised its credit ratings outlook for the Company to positive from stable.

Future Cash Payments for Contractual Obligations and Planned Capital Expenditures

As of June 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.

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 Report on Form 10-Q for the quarter ended March 31, 2009. In addition, see Note 12 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.

North Anna Power Station

In January 2008, the Nuclear Regulatory Commission (NRC) accepted and deemed complete our application for a Combined Construction Permit and Operating License (COL) that references a specific reactor design and which would allow us to build and operate a new nuclear unit at North Anna. In December 2008, we terminated a long-lead agreement with our vendor with respect to the reactor design identified in our COL application and certain related equipment. In March 2009, we commenced a competitive process to determine if vendors can provide an advanced technology reactor that could be licensed and built under terms acceptable to us. If, as a result of this process, we choose a different reactor design, we will amend our COL application, as necessary. We have not yet committed to building a new nuclear unit.

In May 2009, the Department of Energy (DOE) announced the names of four energy companies that have been selected to begin negotiations for federal loan guarantees for proposed new nuclear units in the U.S. Although, in a two-part process, we submitted an application for a federal loan guarantee for the proposed North Anna unit, the Company was not among those selected. While we can provide no assurance, because of the dynamic nature of the market for new nuclear units, there may be other opportunities to secure a loan guarantee with the DOE.

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. We intend to appeal the court s decision and ask for a stay of the court s order. A final order is expected to be issued by the end of August 2009. It is expected that the order will allow North Anna to continue to operate pursuant to the currently issued VPDES permit. 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 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 is currently being considered in the U.S. Senate. 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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VIRGINIA ELECTRIC AND POWER COMPANY

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 and Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2008 for discussion of various risks and uncertainties that may impact the Company.

Market Risk Sensitive Instruments and Risk Management

Our financial instruments, commodity contracts and related financial derivative instruments are exposed to potential losses due to adverse changes in commodity prices, interest rates and equity security prices as described below. Commodity price risk is due to our exposure to market shifts for prices paid for commodities. 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 debt and equity securities.

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

Commodity Price Risk

To manage price risk, we hold commodity-based financial derivative instruments for non-trading purposes associated with purchases of electricity, natural gas and other energy-related products. 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 commodity prices would have resulted in a decrease of approximately $2 million and $23 million in the fair value of our non-trading commodity-based financial derivatives as of June 30, 2009 and December 31, 2008, respectively. The decline in sensitivity is largely due to a decrease in commodity prices.

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. For example, our expenses for power purchases, when combined with the settlement of commodity derivative instruments used for hedging purposes, will generally result in a range of prices for those purchases contemplated by the risk management strategy.

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 June 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 $1 million and $2 million, respectively.

Additionally, we may use forward-starting interest-rate swaps and treasury rate locks as anticipatory hedges of future financings. At June 30, 2009, we had $850 million 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 $30 million in the fair value of these interest-rate derivatives at June 30, 2009. We did not have a significant amount of these interest-rate derivatives outstanding at December 31, 2008.

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 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.

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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 losses (net of investment income) on nuclear decommissioning trust investments of $53 million, $9 million and $57 million for the six months ended June 30, 2009 and 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 six months ended June 30, 2009, we recorded, in AOCI and regulatory liabilities, a net increase in unrealized gains on these investments of $72 million. For the six months ended June 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 $91 million and $233 million, respectively.

Dominion sponsors 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 that we will provide to Dominion for our share of employee benefit plan contributions.

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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VIRGINIA ELECTRIC AND POWER COMPANY

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

From time to time, we are alleged to be in violation or in default under orders, statutes, rules or regulations relating to the environment, compliance plans imposed upon or agreed to by us, or permits issued by various local, state and federal agencies for the construction or operation of facilities. Administrative proceedings may also be pending on these matters. In addition, in the ordinary course of business, we are involved in various legal proceedings. We believe that the ultimate resolution of these proceedings will not have a material adverse effect on our financial position, liquidity or results of operations. See *Future Issues and Other Matters* in MD&A and Note 12 to our Consolidated Financial Statements for discussions on various environmental, rate matters and other regulatory proceedings to which we are a party.

ITEM 1A. RISK FACTORS

Our business is influenced by many factors that are difficult to predict, involve uncertainties that may materially affect actual results and are often beyond our control. We have identified a number of these risk factors in our Annual Report on Form 10-K for the year ended December 31, 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.

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

On April 24, 2009, by consent in lieu of the annual meeting, Dominion Resources, Inc., the sole holder of all the voting common stock of the Company, unanimously elected the following persons to serve as Directors: Thomas F. Farrell, II, Chairman of the Board, Thomas N. Chewning and Steven A. Rogers. On June 1, 2009, by consent in lieu of a special meeting, Dominion Resources, Inc., the sole holder of all the voting common stock of the Company, unanimously elected Mark F. McGettrick to serve as a Director, due to the retirement of Thomas N. Chewning. The names of the other Directors whose term of office continued after the meeting are: Thomas F. Farrell, II, Chairman of the Board and Steven A. Rogers.

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ITEM 6. EXHIBITS

(a) Exhibits:

3.1	Restated Articles of Incorporation, as in effect on October 28, 2003 (Exhibit 3.1, Form 10-Q for the quarter ended September 30, 2003, File No. 1-2255, incorporated by reference).
3.2	Bylaws, as amended and restated on June 1, 2009 (Exhibit 3.1, Form 8-K filed June 3, 2009, File No. 1-2255, incorporated by reference).
4.1	Form of Senior Indenture, dated as of June 1, 1998, between Virginia Electric and Power Company and The Bank of New York (as successor trustee to JP Morgan Chase Bank (formerly The Chase Manhattan Bank)) as supplemented by the First Supplemental Indenture (Exhibit 4.2, Form 8-K filed June 12, 1998, File No. 1-2255, incorporated by reference); Second Supplemental Indenture (Exhibit 4.2, Form 8-K filed June 4, 1999, File No. 1-2255, incorporated by reference); Third Supplemental Indenture (Exhibit 4.2, Form 8-K filed October 27, 1999, File No. 1-2255, incorporated by reference); Form of Fourth Supplemental Indenture (Exhibit 4.2, Form 8-K filed March 26, 2001, File No. 1-2255, incorporated by reference); Form of Fifth Supplemental Indenture (Exhibit 4.3, Form 8-K filed March 26, 2001, File No. 1-2255, incorporated by reference); Form of Sixth Supplemental Indenture (Exhibit 4.2, Form 8-K filed January 29, 2002, File No. 1-2255, incorporated by reference); Seventh Supplemental Indenture (Exhibit 4.4, Form 8-K filed September 11, 2002, File No. 1-2255, incorporated by reference); Form of Eighth Supplemental Indenture (Exhibit 4.2, Form 8-K filed February 27, 2003, File No. 1-2255, incorporated by reference); Form of Ninth Supplemental Indenture (Exhibit 4.2, Form 8-K filed December 4, 2003, File No. 1-2255, incorporated by reference); Form of Tenth Supplemental Indenture (Exhibit 4.3, Form 8-K filed December 4, 2003, File No. 1-2255, incorporated by reference); Form of Eleventh Supplemental Indenture (Exhibit 4.2, Form 8-K filed December 11, 2003, File No. 1-2255, incorporated by reference); Form of Twelfth Supplemental Indenture (Exhibit 4.2, Form 8-K filed January 12, 2006, File No. 1-2255, incorporated by reference); Form of Thirteenth Supplemental Indenture (Exhibit 4.3, Form 8-K filed January 12, 2006, File No. 1-2255, incorporated by reference); Form of Fourteenth Supplemental Indenture (Exhibit 4.2, Form 8-K filed May 16, 2007, File No. 1-2255, incorporated by reference); Form of Fifteenth Supplemental Indenture (Exhibit 4.2, Form 8-K filed September 10, 2007, File No. 1-2255, incorporated by reference); Form of Sixteenth Supplemental Indenture (Exhibit 4.2, Form 8-K filed November 30, 2007, File No. 1-2255, incorporated by reference); Form of Seventeenth Supplemental Indenture (Exhibit 4.3, Form 8-K filed November 30, 2007, File No. 1-2255, incorporated by reference); Form of Eighteenth Supplemental Indenture (Exhibit 4.2, Form 8-K filed April 15, 2008, File No. 1-2255, incorporated by reference); Nineteenth Supplemental Indenture (Exhibit 4.2, Form 8-K filed November 5, 2008, File No. 1-2255, incorporated by reference); Form of Twentieth Supplemental Indenture (Exhibit 4.3, Form 8-K filed June 24, 2009, File No. 1-2255, incorporated by reference).
10.1*	Dominion Resources, Inc. 2005 Incentive Compensation Plan, Originally Effective May 1, 2005, as Amended and Restated Effective May 5, 2009 (Exhibit 10, Form 8-K filed by Dominion Resources, Inc. on May 11, 2009, File No. 1-8489, incorporated by reference).
12.1	Ratio of earnings to fixed charges (filed herewith).
12.2	Ratio of earnings to fixed charges and preferred dividends (filed herewith).
31.1	Certification by Registrant s CEO pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).
31.2	Certification by Registrant s CFO pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).
32	Certification to the SEC by Registrant s CEO and CFO, as required by Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith).
99	Condensed consolidated earnings statements (unaudited) (filed herewith).

* Indicates management contract or compensatory plan or agreement.

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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.

VIRGINIA ELECTRIC AND POWER COMPANY
Registrant

July 31, 2009

/s/ Ashwini Sawhney

Ashwini Sawhney
Vice President and Controller

(Chief Accounting Officer)

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