DOMINION RESOURCES INC /VA/
Form 10-Q
May 03, 2007

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 March 31, 2007

or

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

Commission File Number 001-08489

DOMINION RESOURCES, INC.

(Exact name of registrant as specified in its charter)

VIRGINIA	**54-1229715**
(State or other jurisdiction of	*(I.R.S. Employer*
incorporation or organization)	*Identification No.)*
120 TREDEGAR STREET	**23219**

RICHMOND, VIRGINIA
(Address of principal executive offices) ***(Zip Code)***

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

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

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

Large accelerated filer x Accelerated filer ¨ Non-accelerated filer ¨

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 March 31, 2007, the latest practicable date for determination, 350,317,451 shares of common stock, without par value, of the registrant were outstanding.

DOMINION RESOURCES, INC.

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DOMINION RESOURCES, INC.

PART I. FINANCIAL INFORMATION

ITEM 1. CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED STATEMENTS OF INCOME

(Unaudited)

	Three Months Ended March 31, 2007	Three Months Ended March 31, 2006
(millions, except per share amounts)		
Operating Revenue	**$ 4,712**	$ 4,951
Operating Expenses		
Electric fuel and energy purchases	**918**	765
Purchased electric capacity	**119**	123
Purchased gas	**1,148**	1,378
Other energy-related commodity purchases	**56**	400
Other operations and maintenance	**857**	767
Depreciation, depletion and amortization	**422**	377
Other taxes	**184**	180
Total operating expenses	**3,704**	3,990
Income from operations	**1,008**	961
Other income	**50**	42
Interest and related charges:		
Interest expense	**220**	226
Interest expense junior subordinated notes payable[1]	**35**	27
Subsidiary preferred dividends	**4**	4
Total interest and related charges	**259**	257
Income before income tax expense and minority interest	**799**	746
Income tax expense	**313**	207
Minority interest	**5**	
Income from continuing operations	**481**	539
Loss from discontinued operations[2]	**(28)**	(5)
Net Income	**$ 453**	$ 534
Earnings Per Common Share - Basic		
Income from continuing operations	**$ 1.38**	$ 1.56
Loss from discontinued operations	**(0.08)**	(0.02)
Net income	**$ 1.30**	$ 1.54
Earnings Per Common Share - Diluted		
Income from continuing operations	**$ 1.37**	$ 1.55

Loss from discontinued operations	**(0.08)**	(0.02)
Net income	**$ 1.29**	$ 1.53
Dividends paid per common share	**$ 0.71**	$ 0.69

(1) Includes $22 million and $27 million of affiliated interest expense for the three months ended March 31, 2007 and 2006, respectively.
(2) Net of income tax benefit of $3 million for the three months ended March 31, 2007 and 2006.
The accompanying notes are an integral part of the Consolidated Financial Statements.

DOMINION RESOURCES, INC.

CONSOLIDATED BALANCE SHEETS

(Unaudited)

	March 31, 2007	December 31, 2006[1]
(millions)		
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 103**	$ 138
Customer receivables (less allowance for doubtful accounts of $28 and $26)	**2,569**	2,395
Other receivables (less allowance for doubtful accounts of $11 and $13)	**296**	358
Inventories	**749**	1,101
Derivative assets	**1,221**	1,593
Assets held for sale	**1,122**	1,391
Other	**1,204**	1,122
Total current assets	**7,264**	8,098
Investments		
Nuclear decommissioning trust funds	**2,817**	2,791
Other	**1,036**	1,034
Total investments	**3,853**	3,825
Property, Plant and Equipment		
Property, plant and equipment	**44,404**	43,575
Accumulated depreciation, depletion and amortization	**(14,570)**	(14,193)
Total property, plant and equipment, net	**29,834**	29,382
Deferred Charges and Other Assets		
Goodwill	**4,274**	4,298
Pension and other postretirement benefit assets	**1,266**	1,246
Other	**2,084**	2,420
Total deferred charges and other assets	**7,624**	7,964
Total assets	**$ 48,575**	$ 49,269

(1) The Consolidated Balance Sheet at December 31, 2006 has been derived from the audited Consolidated Financial Statements at that date.

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

DOMINION RESOURCES, INC.

CONSOLIDATED BALANCE SHEETS

(Unaudited)

	March 31, 2007	December 31, 2006[1]
(millions)		
LIABILITIES AND SHAREHOLDERS EQUITY		
Current Liabilities		
Securities due within one year	**$ 2,254**	$ 2,478
Short-term debt	**2,750**	2,332
Accounts payable	**2,003**	2,142
Derivative liabilities	**2,192**	2,276
Liabilities held for sale	**462**	497
Other	**1,299**	1,504
Total current liabilities	**10,960**	11,229
Long-Term Debt		
Long-term debt	**12,371**	12,842
Junior subordinated notes payable:		
Affiliates	**1,152**	1,151
Other	**798**	798
Total long-term debt	**14,321**	14,791
Deferred Credits and Other Liabilities		
Deferred income taxes and investment tax credits	**5,944**	5,858
Asset retirement obligations	**1,943**	1,930
Other	**2,160**	2,268
Total deferred credits and other liabilities	**10,047**	10,056
Total liabilities	**35,328**	36,076
Commitments and Contingencies (see Note 15)		
Minority Interest	**27**	23
Subsidiary Preferred Stock Not Subject to Mandatory Redemption	**257**	257
Common Shareholders Equity		
Common stock no par[2]	**11,344**	11,250
Other paid-in capital	**141**	128
Retained earnings	**2,107**	1,960
Accumulated other comprehensive loss	**(629)**	(425)
Total common shareholders equity	**12,963**	12,913
Total liabilities and shareholders equity	**$ 48,575**	$ 49,269

(1) The Consolidated Balance Sheet at December 31, 2006 has been derived from the audited Consolidated Financial Statements at that date.
(2) 500 million shares authorized; 350 million shares outstanding at March 31, 2007 and 349 million shares outstanding at December 31, 2006.

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

DOMINION RESOURCES, INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

Three Months Ended March 31,	**2007**	**2006**
(millions)		
Operating Activities		
Net income	**$ 453**	$ 534
Adjustments to reconcile net income to net cash provided by operating activities:		
Net realized and unrealized derivative (gains)/losses	**47**	(241)
Depreciation, depletion and amortization	**458**	414
Deferred income taxes and investment tax credits, net	**205**	187
Charges related to pending sale of gas distribution subsidiaries		172
Other adjustments to net income	**7**	7
Changes in:		
Accounts receivable	**(169)**	412
Inventories	**391**	262
Deferred fuel and purchased gas costs, net	**2**	125
Accounts payable	**(131)**	(659)
Accrued interest, payroll and taxes	**(142)**	(22)
Deferred revenues	**(47)**	(79)
Margin deposit assets and liabilities	**(68)**	(206)
Other operating assets and liabilities	**204**	78
Net cash provided by operating activities	**1,210**	984
Investing Activities		
Plant construction and other property additions	**(471)**	(439)
Additions to gas and oil properties, including acquisitions	**(576)**	(484)
Net proceeds from sale of merchant generation peaking facilities	**257**	
Acquisition of businesses, net of cash acquired		(91)
Proceeds from sale of securities and loan receivable collections and payoffs	**287**	273
Purchases of securities and loan receivable originations	**(304)**	(281)
Other	**11**	36
Net cash used in investing activities	**(796)**	(986)
Financing Activities		
Issuance (repayment) of short-term debt, net	**418**	(215)
Issuance of long-term debt		1,000
Repayment of long-term debt	**(720)**	(609)
Issuance of common stock	**86**	3
Common dividend payments	**(249)**	(240)
Other	**17**	(10)
Net cash used in financing activities	**(448)**	(71)
Decrease in cash and cash equivalents	**(34)**	(73)
Cash and cash equivalents at beginning of period(1)	**142**	146
Cash and cash equivalents at end of period (2)	**$ 108**	$ 73

Noncash Investing and Financing Activities

Accrued capital expenditures	**$ 205**	$ 162
Exchange of debt securities		330
Issuance of long-term debt and establishment of trust		47

(1) 2007 amount includes $4 million of cash classified as held for sale on the Consolidated Balance Sheet.

(2) 2007 and 2006 amounts include $5 million and $4 million, respectively, of cash classified as held for sale on the Consolidated Balance Sheets.

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

DOMINION RESOURCES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

Note 1. Nature of Operations

Dominion Resources, Inc. (Dominion) is a fully integrated gas and electric holding company headquartered in Richmond, Virginia. Our principal subsidiaries are Virginia Electric and Power Company (Virginia Power), Consolidated Natural Gas Company (CNG), Dominion Energy, Inc. (DEI) and Virginia Power Energy Marketing, Inc. (VPEM).

Virginia Power is a regulated public utility that generates, transmits and distributes electricity for sale in Virginia and northeastern North Carolina. As of March 31, 2007, Virginia Power served approximately 2.4 million retail customer accounts, including governmental agencies and wholesale customers such as rural electric cooperatives and municipalities. Virginia Power is a member of PJM Interconnection, LLC (PJM), a regional transmission organization (RTO), and its electric transmission facilities are integrated into the PJM wholesale electricity markets.

CNG operates in all phases of the natural gas business, explores for and produces gas and oil and provides a variety of energy marketing services. As of March 31, 2007, its regulated gas distribution subsidiaries served approximately 1.7 million residential, commercial and industrial gas sales and transportation customer accounts in Ohio, Pennsylvania and West Virginia and its nonregulated retail energy marketing businesses served approximately 1.5 million residential and commercial customer accounts in the Northeast, Mid-Atlantic and Midwest regions of the United States (U.S.). CNG also operates an interstate gas transmission pipeline system, underground natural gas storage system and gathering and extraction facilities in the Northeast, Mid-Atlantic and Midwest states and a liquefied natural gas (LNG) import and storage facility in Maryland. Its producer services operations involve the aggregation of natural gas supply and related wholesale activities. CNG s exploration and production (E&P) operations are located in several major gas and oil producing basins in the U.S., both onshore and offshore.

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

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

We have substantially exited the core operating businesses of Dominion Capital, Inc. (DCI) whose primary business was financial services, including loan administration, commercial lending and residential mortgage lending. Refer to Note 12 for information on a third-party collateralized debt obligation (CDO) entity that we consolidate in accordance with Financial Accounting Standards Board (FASB) Interpretation No. 46 (revised December 2003), *Consolidation of Variable Interest Entities* (FIN 46R).

We manage our daily operations through four primary operating segments: Dominion Delivery, Dominion Energy, Dominion Generation and Dominion E&P. In addition, we report a Corporate segment that includes our corporate, service company and other functions. Our assets remain wholly owned by us and our legal subsidiaries.

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

Note 2. Significant Accounting Policies

As permitted by the rules and regulations of the Securities and Exchange Commission (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 accounting principles generally accepted in the United States of America (GAAP). These unaudited Consolidated Financial Statements should be read in conjunction with our Consolidated Financial Statements and Notes in our Annual Report on Form 10-K for the year ended December 31, 2006.

In our opinion, the accompanying unaudited Consolidated Financial Statements contain all adjustments, including normal recurring accruals, necessary to present fairly our financial position as of March 31, 2007, and our results of operations and cash flows for the three months ended March 31, 2007 and 2006.

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

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

In accordance with GAAP, we report certain contracts and instruments at fair value. Market pricing and indicative price information from external sources are used to measure fair value when available. In the absence of this information, we estimate fair value based on near-term and historical price information and statistical methods. For individual contracts, the use of differing assumptions could have a material effect on the contract s estimated fair value. See Note 2 to our Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2006, for a more detailed discussion of our estimation techniques.

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

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

Note 3. Newly Adopted Accounting Standards

FIN 48

We adopted the provisions of FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* (FIN 48), on January 1, 2007. As a result of the implementation of FIN 48, we recorded a $58 million charge to beginning retained earnings, representing the cumulative effect of the change in accounting principle.

Unrecognized tax benefits represent those tax benefits related to tax positions that have been taken or are expected to be taken in tax returns, including refund claims, that are not recognized in the financial statements because, in accordance with FIN 48, management has either measured the tax benefit at an amount less than the benefit claimed, or expected to be claimed, or concluded that it is not more-likely-than-not that the tax position will be ultimately sustained. Unrecognized tax benefits may result in an increase in income taxes payable, a reduction of an income tax refund receivable, an increase in deferred tax liabilities, or a decrease in deferred tax assets. Noncurrent income taxes payable related to unrecognized tax benefits are classified in other deferred credits and other liabilities; current payables are included in other current liabilities, except when such amounts are presented net with amounts receivable from or amounts prepaid to taxing authorities in other current assets. As of January 1, 2007, unrecognized tax benefits totaled $642 million. For the majority of these tax positions, the ultimate deductibility is highly certain, but there is uncertainty about the timing of such deductibility. Unrecognized tax benefits as of January 1, 2007, included $76 million that, if recognized, would lower the effective tax rate. Through March 31, 2007, there have been no significant changes in our unrecognized tax benefits.

Consistent with our existing policies, we continue to recognize estimated interest payable on underpayments of income taxes in interest expense and estimated penalties that may result from the settlement of some uncertain tax positions in other income. As of January 1, 2007, we had accrued approximately $9 million for interest and penalties.

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

For Dominion and its subsidiaries, the U.S. federal statute of limitations has expired for tax years prior to 1993. However, for CNG and its subsidiaries, tax years prior to Dominion s acquisition of CNG in January 2000 are no longer subject to examination, except for tax year 1998, for which the statute of limitations is scheduled to expire in September 2007, and tax years 1996 and 1997, for which we have reserved the right to file a claim for refund for certain tax credits.

We have recently reached a settlement for tax years 1993 1998 with the Appellate Division of the Internal Revenue Service (IRS), which is subject to a mandatory review by the U.S. Congressional Joint Committee on Taxation. We expect the settlement to be finalized later this year, resulting in a refund of approximately $42 million. We are also currently engaged in settlement negotiations with the Appellate Division of the IRS regarding certain adjustments proposed during the examination of tax years 1999-2001. With settlement negotiations possibly concluding later this year, unrecognized tax benefits could be reduced by approximately $24 million by applying amounts previously deposited with the IRS. In addition, the examination of our 2002 and 2003 returns by the IRS is expected to be completed by July 2007. Based on our concurrence with certain proposed adjustments and payments expected to be made later this year, unrecognized tax benefits could be reduced by approximately $24 million. Our receipt or payment of the amounts discussed above would not impact our results of operations. At this time, we cannot estimate the impact on unrecognized tax benefits that could result in the next twelve months from additional payments that may be made for adjustments remaining in dispute or any newly proposed adjustments.

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

State	**Earliest Open Tax Year**
Pennsylvania	2000
Connecticut	2001
Virginia	2003
Massachusetts	2003

We are also obligated to report adjustments resulting from IRS settlements to state taxing authorities. In addition, if we utilize state net operating losses or credits generated in years for which the statute of limitations has expired, the determination of such amounts is subject to examination.

EITF 04-13

We enter into buy/sell and related agreements primarily as a means to reposition our offshore Gulf of Mexico crude oil production to more liquid marketing locations onshore and to facilitate gas transportation. In September 2005, the FASB ratified the Emerging Issues Task Force s (EITF) consensus on Issue No. 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty* (EITF 04-13), that requires buy/sell and related agreements to be presented on a net basis in the Consolidated Statements of Income if they are entered into in contemplation of one another. We adopted the provisions of EITF 04-13 on April 1, 2006, for new arrangements entered into, and modifications or renewals of existing arrangements after that date. As a result, a significant portion of our activity related to buy/sell arrangements is presented on a net basis in our Consolidated Statement of Income for the three months ended March 31, 2007; however, there was no impact on our results of operations or cash flows. Pursuant to the transition provisions of EITF 04-13, activity related to buy/sell arrangements that were entered into prior to April 1, 2006, and have not been modified or renewed after that date continue to be reported on a gross basis and are summarized below:

	Three Months Ended March 31,	
	2007	2006
(millions)		
Sale activity included in operating revenue	**$ 34**	$ 279
Purchase activity included in operating expenses[1]	**36**	280

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

EITF 06-3

Effective January 1, 2007, EITF Issue No. 06-3, *How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That Is, Gross versus Net Presentation)*, requires certain disclosures if an entity collects any tax assessed by a governmental authority that is both imposed on and concurrent with a specific revenue-producing transaction between the entity, as a seller, and its customers. We collect sales, consumption and consumer utility taxes but exclude such amounts from revenue.

Note 4. Recently Issued Accounting Standards

SFAS No. 157

In September 2006, the FASB issued Statement of Financial Accounting Standards (SFAS) No. 157, *Fair Value Measurements* (SFAS No. 157), which defines fair value, establishes a framework for measuring fair value and expands disclosures related to fair value measurements. SFAS No. 157 clarifies that fair value should be based on assumptions that market participants would use when pricing an asset or liability and establishes a fair value hierarchy of three levels that prioritizes the information used to develop those assumptions. The fair value hierarchy gives the highest priority to quoted prices in active markets and the lowest priority to unobservable data. SFAS No. 157 requires fair value measurements to be separately disclosed by level within the fair value hierarchy. The provisions of SFAS No. 157 will become effective for us beginning January 1, 2008. Generally, the provisions of this statement are to be applied prospectively. Certain situations, however, require retrospective application as of the beginning of the year of adoption through the recognition of a cumulative effect of accounting change. Such retrospective application is required for financial instruments, including derivatives and certain hybrid instruments with limitations on initial gains or losses under EITF Issue No. 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities*, and SFAS No. 155, *Accounting for Certain Hybrid Financial Instruments.* We are currently evaluating the impact that SFAS No. 157 will have on our results of operations and financial condition.

SFAS No. 159

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities* (SFAS No. 159). SFAS No. 159 provides an entity with the option, at specified election dates, to measure certain financial assets and liabilities and other items at fair value, with changes in fair value recognized in earnings as those changes occur. SFAS No. 159 also establishes presentation and disclosure requirements that include displaying the fair value of those assets and liabilities for which the entity elected the fair value option on the face of the balance sheet and providing management s reasons for electing the fair value option for each eligible item. The provisions of SFAS No. 159 will become effective for us beginning January 1, 2008. We are currently evaluating the impact that SFAS No. 159 may have on our results of operations and financial condition.

EITF 06-4

In September 2006, the FASB ratified the consensus reached by the EITF on Issue No. 06-4, *Accounting for Deferred Compensation and Postretirement Benefit Aspects of Endorsement Split-Dollar Life Insurance Arrangements* (EITF 06-4). EITF 06-4 specifies that if an employer provides a benefit to an employee under an endorsement split-dollar life insurance arrangement that extends to postretirement periods, it should recognize a liability for future benefits in accordance with SFAS No. 106, *Employers Accounting for Postretirement Benefits Other Than Pensions* (if, in substance, a postretirement benefit plan exists) or Accounting Principles Board Opinion No. 12, Deferred Compensation Contracts (if the arrangement is, in substance, an individual deferred compensation contract) based on the substantive agreement with the employee. We have certain insurance policies subject to the provisions of EITF 06-4 and are currently evaluating the impact that EITF 06-4 may have on our results of operations and financial condition. The provisions of EITF 06-4 will become effective for us beginning January 1, 2008.

Note 5. Operating Revenue

Our operating revenue consists of the following:

	Three Months Ended March 31, 2007	2006
(millions)		
Operating Revenue		
Electric sales:		
Regulated	**$ 1,411**	$ 1,298
Nonregulated	**736**	594
Gas sales:		
Regulated	**559**	800
Nonregulated	**879**	882
Other energy-related commodity sales	**146**	493
Gas transportation and storage	**349**	285
Gas and oil production	**559**	532
Other	**73**	67
Total operating revenue	**$ 4,712**	$ 4,951

Note 6. Income Taxes

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

	Three Months Ended March 31, 2007	2006
(millions)		
U.S. statutory rate	**35.0%**	35.0%
Increases (reductions) resulting from		
Amortization of investment tax credits	**(0.4)**	(0.4)
Employee pension and other benefits	**(0.3)**	(0.4)
Employee stock ownership plan and restricted stock dividends	**(0.4)**	(0.4)
State taxes, net of federal benefit	**4.6**	5.0
Other, net	**(0.6)**	(1.2)
Subtotal	**37.9**	37.6
Changes in valuation allowances	**1.0**	(28.8)
Recognition of deferred taxes stock of subsidiaries held for sale	**0.3**	18.9
Effective tax rate	**39.2%**	27.7%

The change in our effective tax rate is primarily attributable to the absence of a tax benefit from the partial reversal of previously recorded valuation allowances on certain federal and state tax loss carryforwards ($222 million), since these carryforwards are expected to be utilized to offset capital gain income that is expected to be generated from the pending sale of The Peoples Natural Gas Company (Peoples) and Hope Gas, Inc. (Hope). This benefit was partially offset by the establishment of $141 million of deferred tax liabilities, in 2006, associated with the excess of our financial reporting basis over the tax basis in the stock of Peoples and Hope, in accordance with EITF Issue No. 93-17, *Recognition of Deferred Tax Assets for a Parent Company s Excess Tax Basis in the Stock of a Subsidiary that is Accounted for as a Discontinued Operation*

(EITF 93-17). Although these subsidiaries are not classified as discontinued operations, EITF 93-17 requires that the deferred tax impact of the excess of the financial reporting basis over the tax basis of a parent s investment in a subsidiary be recognized when it is apparent that this difference will reverse in the foreseeable future. We recorded a charge, since the financial reporting basis of our investment in Peoples and Hope exceeded our tax basis. This difference and related deferred taxes will reverse and will partially offset current tax expense that will be recognized upon closing of the sale.

Note 7. Earnings Per Share

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

	Three Months Ended March 31, 2007	Three Months Ended March 31, 2006
(millions, except EPS)		
Income from continuing operations	**$ 481**	$ 539
Loss from discontinued operations	**(28)**	(5)
Net income	**$ 453**	$ 534
Basic EPS		
Average shares of common stock outstanding basic	**348.4**	346.5
Income from continuing operations	**$ 1.38**	$ 1.56
Loss from discontinued operations	**(0.08)**	(0.02)
Net income	**$ 1.30**	$ 1.54
Diluted EPS		
Average shares of common stock outstanding	**348.4**	346.5
Net effect of potentially dilutive securities[1]	**2.4**	1.6
Average shares of common stock outstanding diluted	**350.8**	348.1
Income from continuing operations	**$ 1.37**	$ 1.55
Loss from discontinued operations	**(0.08)**	(0.02)
Net income	**$ 1.29**	$ 1.53

(1) Potentially dilutive securities consist of options, restricted stock, equity-linked securities and contingently convertible senior notes. Potentially dilutive securities with the right to acquire approximately 1.4 million common shares for the three months ended March 31, 2006, were not included in the period s calculation of diluted EPS because the exercise or purchase prices of those instruments were greater than the average market price of our common shares. There were no such anti-dilutive securities outstanding during the three months ended March 31, 2007.

Note 8. Dispositions

Sale of Merchant Generation Facilities

In March 2007, we sold three of our natural gas-fired merchant generation peaking facilities (Peaker facilities) for net cash proceeds of $257 million. The sale resulted in a $24 million after-tax loss ($0.07 per share). The Peaker facilities are:

Armstrong, a 625-megawatt (Mw) station in Shelocta, Pennsylvania;

Troy, a 600 Mw station in Luckey, Ohio; and

Pleasants, a 313 Mw station in St. Mary s, West Virginia.

The carrying amounts of the major classes of assets and liabilities classified as held for sale in our Consolidated Balance Sheet at December 31, 2006 were comprised of property, plant and equipment, net ($245 million), inventory ($13 million) and accounts payable ($3 million).

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

	Three Months Ended March 31,	
	2007	**2006**
(millions)		
Operating revenue	**$ 5**	$ 6
Loss before income taxes[1]	**(31)**	(8)

(1) The 2007 amount includes a $25 million pre-tax loss on the sale of the Peaker facilities, resulting largely from the allocation of $24 million of Generation reporting unit goodwill to the bases of the investments being sold.

Sale of Regulated Gas Distribution Subsidiaries

On March 1, 2006, we entered into an agreement with Equitable Resources, Inc., to sell two of our wholly-owned regulated gas distribution subsidiaries, Peoples and Hope, for approximately $970 million plus adjustments to reflect capital expenditures and changes in working capital. Peoples and Hope serve approximately 500,000 customer accounts in Pennsylvania and West Virginia. The transaction is expected to close by the end of the second quarter of 2007, subject to regulatory approval, as discussed in *Future Issues and Other Matters* in Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations. The carrying amounts of the major classes of assets and liabilities classified as held for sale in our Consolidated Balance Sheets are as follows:

	March 31, 2007	December 31, 2006
(millions)		
ASSETS		
Current Assets		
Cash	**$ 5**	$ 4
Customer receivables	**179**	144
Unrecovered gas costs	**28**	31
Other	**38**	90
Total current assets	**250**	269
Investments	**2**	2
Property, Plant and Equipment		
Property, plant and equipment	**1,135**	1,129
Accumulated depreciation, depletion and amortization	**(373)**	(375)
Total property, plant and equipment, net	**762**	754
Deferred Charges and Other Assets		
Regulatory assets	**105**	106
Other	**3**	2
Total deferred charges and other assets	**108**	108
Assets held for sale	**$ 1,122**	$ 1,133
LIABILITIES		
Current Liabilities		
Accounts payable	**$ 61**	$ 90
Payables to affiliates	**27**	40
Accrued taxes	**22**	23
Deferred income taxes	**2**	9
Other	**93**	74
Total current liabilities	**205**	236
Deferred Credits and Other Liabilities		
Asset retirement obligations	**38**	38
Deferred income taxes and investment tax credits	**187**	187
Regulatory liabilities	**26**	26
Other	**6**	7
Total deferred credits and other liabilities	**257**	258

Liabilities held for sale	**$ 462**	$ 494

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

	Three Months Ended March 31,	
	2007	**2006**
(millions)		
Operating revenue	**$ 309**	$ 357
Income (loss) before income taxes	**54**	(128)

In March 2006, we recognized a $159 million ($94 million after-tax) charge, recorded in other operations and maintenance expense in our Consolidated Statement of Income, resulting from the write-off of certain regulatory assets related to the pending sale of Peoples and Hope, since the recovery of those assets is no longer probable. At March 31, 2007, our Consolidated Balance Sheet reflects $147 million of deferred tax liabilities, which were recorded in accordance with EITF 93-17.

Note 9. Comprehensive Income

The following table presents total comprehensive income (loss):

	Three Months Ended March 31,	
	2007	**2006**
(millions)		
Net income	**$ 453**	$ 534
Other comprehensive income (loss):		
Net other comprehensive income (loss) associated with effective portion of changes in fair value of derivatives designated as cash flow hedges, net of taxes and amounts reclassified to earnings	**(215)**	719(1)
Other	**11**	20
Other comprehensive income (loss)	**(204)**	739
Total comprehensive income	**$ 249**	$ 1,273

(1) Largely due to the settlement of certain commodity derivative contracts and favorable changes in fair value, primarily resulting from a decrease in electricity and gas prices.

Note 10. Hedge Accounting Activities

We are exposed to the impact of market fluctuations in the price of natural gas, oil, electricity and other energy-related products marketed and purchased, as well as currency exchange and interest rate risks of our business operations. We use derivative instruments to manage our exposure to these risks and designate certain derivative instruments as fair value or cash flow hedges for accounting purposes as allowed by SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*. Selected information about our hedge accounting activities follows:

	Three Months Ended March 31,	
	2007	**2006**
(millions)		
Portion of gains (losses) on hedging instruments determined to be ineffective and included in net income:		
Fair value hedges	**$ 4**	$ (7)
Cash flow hedges	**15**	19
Net ineffectiveness	**$ 19**	$ 12

Gains and losses on hedging instruments that were excluded from the measurement of effectiveness and included in net income for the three months ended March 31, 2007 and 2006 were not material.

The following table presents selected information related to cash flow hedges included in accumulated other comprehensive income (AOCI) in our Consolidated Balance Sheet at March 31, 2007:

	AOCI After-Tax	Portion Expected to be Reclassified to Earnings during the next 12 Months After-Tax	Maximum Term

(millions)			
Commodities:			
Gas	$ (261)	$ (242)	48 months
Oil	(229)	(181)	33 months
Electricity	(131)	(138)	33 months
Other	(7)	(7)	38 months
Interest rate	(25)		231 months
Foreign currency	16	8	6 months
Total	$ (637)	$ (560)	

The amounts that will be reclassified from AOCI to earnings will generally be offset by the recognition of the hedged transactions (e.g., anticipated sales) in earnings, thereby achieving the realization of prices contemplated by the underlying risk management strategies and will vary from the expected amounts presented above as a result of changes in market prices, interest rates and foreign exchange rates.

Note 11. Ceiling Test

We follow the full cost method of accounting for gas and oil E&P activities prescribed by the SEC. Under the full cost method, capitalized costs are subject to a quarterly ceiling test. Under the ceiling test, amounts capitalized are limited to the present value of estimated future net revenues to be derived from the anticipated production of proved gas and oil reserves, assuming period-end hedge-adjusted prices. The ceiling test is prepared on a separate country basis for our U.S. and Canadian cost centers.

Approximately 7% of our U.S. and Canadian anticipated production is hedged by qualifying cash flow hedges, for which hedge-adjusted prices were used to calculate estimated future net revenue. Whether period-end market prices or hedge-adjusted prices were used for the portion of production that is hedged, there was no ceiling test impairment for our U.S. or Canadian cost centers as of March 31, 2007.

Note 12. Variable Interest Entities

Certain variable pricing terms in some of our long-term power and capacity contracts cause them to be considered potential variable interests in the counterparties. As discussed in Note 16 to our Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2006, two potential VIEs, with which we have existing power purchase agreements (signed prior to December 31, 2003), had not provided sufficient information for us to perform our evaluation under FIN 46R.

As of March 31, 2007, no further information has been received from the two remaining potential VIEs. We will continue our efforts to obtain information and will complete an evaluation of our relationship with each of these potential VIEs if sufficient information is ultimately obtained. We have remaining purchase commitments with these two potential VIE supplier entities of $1.3 billion at March 31, 2007. We are not subject to any risk of loss from these potential VIE s, other than the remaining purchase commitments. We paid $26 million and $25 million for electric generation capacity and $27 million and $18 million for electric energy from these entities in the three months ended March 31, 2007 and 2006, respectively.

In 2006, we restructured three long-term power purchase contracts with two VIEs, of which we are not the primary beneficiary. The restructured contracts expire between 2015 and 2017. We have remaining purchase commitments with these two VIE supplier entities of $1 billion at March 31, 2007. We are not subject to any risk of loss from these VIEs, other than the remaining purchase commitments. We paid $30 million and $29 million for electric generation capacity and $14 million and $15 million for electric energy from these entities in the three months ended March 31, 2007 and 2006, respectively.

During 2005, we entered into four long-term contracts with unrelated limited liability companies (LLCs) to purchase synthetic fuel produced from coal. Certain variable pricing terms in the contracts protect the equity holders from variability in the cost of their coal purchases, and therefore, the LLCs were determined to be VIEs. After completing our FIN 46R analysis, we concluded that although our interests in the contracts, as a result of their pricing terms, represent variable interests in the LLCs, we are not the primary beneficiary. We paid $99 million and $111 million to the LLCs for coal and synthetic fuel produced from coal in the three months ended March 31, 2007 and 2006, respectively. We are not subject to any risk of loss from the contractual arrangements, as our only obligation to the VIEs is to purchase the synthetic fuel that the VIEs produce according to the terms of the applicable purchase contracts.

In 2006, we, along with three other gas and oil exploration companies, entered into a long-term contract with an unrelated LLC whose only current activities are to design, construct, install and own the Thunder Hawk facility, a semi-submersible production facility, to be located in the deep water Gulf of Mexico. Certain variable pricing terms and guarantees in the contract protect the equity holder from variability, and therefore, the LLC was determined to be a VIE. After completing our FIN 46R analysis, we concluded that although our 25% interest in the contract, as a result of its pricing terms and guarantee, represents a variable interest in the LLC, we are not the primary beneficiary. Our maximum exposure to loss from the contractual arrangement is approximately $63 million. As of March 31, 2007, we have not made any payments to the LLC.

Our Consolidated Balance Sheets as of March 31, 2007 and December 31, 2006, reflect net property, plant and equipment of $335 million and $337 million, respectively and $370 million of debt, related to the consolidation, in accordance with FIN 46R, of a variable interest lessor entity through which we have financed and leased a power generation plant for our utility operations. The debt is non-recourse to us and is secured by the entity s property, plant and equipment. The lease under which we operate the power generation facility terminates in August 2007. We intend to take legal title to the facility through repayment of the lessor s related debt at the end of the lease term.

As discussed in Note 27 to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2006, DCI held an investment in the subordinated notes of a third-party CDO entity. The CDO entity s primary focus is the purchase and origination of middle market senior secured first and second lien commercial and industrial loans in both the primary and secondary loan markets. We concluded that the CDO entity is a VIE and that DCI is the primary beneficiary of the CDO entity, which we have consolidated in accordance with FIN 46R. At March 31, 2007, the CDO entity had $385 million of notes payable that mature in January 2017 and are nonrecourse to us. The CDO entity held the following assets that serve as collateral for its obligations at March 31, 2007:

	Amount
(millions)	
Other current assets	$ 190
Loans receivable, net	363
Other investments	35
Total assets	$ 588

Note 13. Significant Financing Transactions

Credit Facilities and Short-Term Debt

We use short-term debt, primarily commercial paper, to fund working capital requirements, as a bridge to long-term debt financing and as bridge financing for acquisitions, if applicable. The levels of borrowing may vary significantly during the course of the year, depending upon the timing and amount of cash requirements not satisfied by cash from operations. In addition, we utilize cash and letters of credit to fund collateral requirements under our commodities hedging program. Collateral requirements are impacted by commodity prices, hedging levels and the credit quality of our companies and their counterparties. At March 31, 2007, we had committed lines of credit totaling $4.7 billion. These lines of credit support commercial paper borrowings and letter of credit issuances. At March 31, 2007, we had the following commercial paper and letters of credit outstanding and capacity available under credit facilities:

	Facility Limit	Outstanding Commercial Paper	Outstanding Letters of Credit	Bank Borrowing	Facility Capacity Available
(millions)					
Five-year revolving credit facility[(1)]	$ 3,000	$ 1,978	$ 299	$	$ 723
Five-year CNG credit facility[(2)]	1,700	211	307	500	682
Totals	$ 4,700	$ 2,189	$ 606	$ 500	$ 1,405

(1) The $3.0 billion five-year credit facility was entered into in February 2006 and terminates in February 2011. This credit facility can also be used to support up to $1.5 billion of letters of credit.

(2) The $1.7 billion five-year credit facility is used to support the issuance of letters of credit and commercial paper by CNG to fund collateral requirements under its gas and oil hedging program. The facility was entered into in February 2006 and terminates in August 2010.

We have also entered into several bilateral credit facilities in addition to the facilities above in order to provide collateral required on derivative contracts used in risk management strategies for our gas and oil production operations. At March 31, 2007, we had the following letter of credit facilities:

Company	Facility Limit	Outstanding Letters of Credit	Facility Capacity Available	Facility Inception Date	Facility Maturity Date
(millions)					
CNG[1]	$ 100	$	$ 100	June 2004	June 2007
CNG	100	100		August 2004	August 2009
CNG[2]	200		200	December 2005	December 2010
Totals	$ 400	$ 100	$ 300		

(1) We do not intend to renew this facility prior to its maturity.
(2) This facility can also be used to support commercial paper borrowings.

Long-Term Debt

In June 2006, DCI began consolidating a CDO entity, in accordance with FIN 46R. At March 31, 2007, this CDO entity had $385 million of notes payable that mature in January 2017 and are nonrecourse to us.

We repaid $720 million of long-term debt during the three months ended March 31, 2007.

Convertible Securities

In December 2003, we issued $220 million of contingent convertible senior notes that are convertible by holders into a combination of cash and shares of our common stock under certain circumstances. At March 31, 2007, since none of these conditions had been met, these senior notes are not yet subject to conversion. In 2004 and 2005, we entered into exchange transactions with respect to these contingent convertible senior notes in contemplation of EITF Issue No. 04-8, *The Effect of Contingently Convertible Instruments on Diluted Earnings per Share*. We exchanged the outstanding notes for new notes with a conversion feature that requires that the principal amount of each note be repaid in cash. The notes are valued at a conversion rate of 13.5865 shares of common stock per $1,000 principal amount of senior notes, which represents a conversion price of $73.60. Amounts payable in excess of the principal amount will be paid in common stock. The conversion rate is subject to adjustment upon certain events such as subdivisions, splits, combinations of common stock or the issuance to all common stock holders of certain common stock rights, warrants or options and certain dividend increases.

The new notes have been included in the diluted EPS calculation using the method described in EITF 04-8 when appropriate. Under this method, the number of shares included in the denominator of the diluted EPS calculation is calculated as the net shares issuable for the reporting period based upon the average market price for the period. This results in an increase in the average shares outstanding used in the calculation of our diluted EPS when the conversion price of $73.60 is lower than the average market price of our common stock over the period, and no adjustment when the conversion price exceeds the average market price.

Issuance of Common Stock

During the three months ended March 31, 2007, we issued 1.5 million shares and received net cash proceeds of $86 million, primarily in connection with the exercise of employee stock options.

Note 14. Stock-Based Awards

In April 2005, our shareholders approved the 2005 Incentive Compensation Plan (2005 Incentive Plan) for employees and the Non-Employee Directors Compensation Plan (Non-Employee Directors Plan). Both plans permit stock-based awards that include restricted stock, performance grants, goal-based stock and stock options under the 2005 Incentive Plan and restricted stock and stock options under the Non-Employee Directors Plan. Under provisions of both plans, employees and non-employee directors may be granted options to purchase common stock at a price not less than its fair market value at the date of grant with a maximum term of eight years. Option terms are set at the discretion of either the Compensation, Governance and Nominating Committee of the Board of Directors or the Board of Directors itself, as provided under each individual plan. Prior to April 2005, we had an incentive compensation plan that provided stock options and restricted stock awards to directors, executives and other key employees with vesting periods from one to five years. Stock options generally had contractual terms from six and one half to ten years in length.

Our results for the three months ended March 31, 2007 and 2006, include $9 million and $4 million, respectively, of compensation costs and $3 million and $2 million, respectively, of income tax benefits related to our stock-based compensation arrangements. Stock-based compensation cost is reported in other operations and maintenance expense in our Consolidated Statements of Income.

Stock Options

The following table provides a summary of changes in amounts of stock options outstanding as of and for the three months ended March 31, 2007.

	Shares (thousands)	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life (years)	Aggregated Intrinsic Value[1] (millions)
Outstanding and exercisable at January 1, 2007	7,246	$ 60.51		
Exercised	**(1,427)**	**60.41**		$ 37
Forfeited/expired				
Outstanding and exercisable at March 31, 2007	**5,819**	**$ 60.54**	**3.12**	**$ 164**

(1) Intrinsic value represents the difference between the exercise price of the option and the market value of our stock.

We issue new shares to satisfy stock option exercises. We received cash proceeds from the exercise of stock options of approximately $88 million and $3 million in the three months ended March 31, 2007 and 2006, respectively. SFAS No. 123R, *Share-Based Payment*, requires the benefits of tax deductions in excess of the compensation cost recognized for stock-based compensation (excess tax benefits) to be classified as a financing cash flow. Approximately $14 million and $1 million of excess tax benefits were realized for the three months ended March 31, 2007 and March 31, 2006, respectively.

Restricted Stock

As of March 31, 2007, unrecognized compensation cost related to nonvested restricted stock awards totaled $27 million and is expected to be recognized over a weighted-average period of 1.4 years. Restricted stock awards granted prior to January 1, 2006 contain terms that accelerate vesting upon retirement. We continue to recognize compensation cost over the stated vesting term for existing restricted stock awards, but are now required to recognize compensation cost over the shorter of the stated vesting term or period from the date of grant to the date of retirement eligibility for newly issued or modified restricted stock awards with similar terms. In each of the three months ended March 31, 2007 and March 31, 2006, we recognized approximately $1 million of compensation cost related to awards previously granted to retirement eligible employees. At March 31, 2007, unrecognized compensation cost for restricted stock awards held by retirement eligible employees totaled approximately $4 million.

Goal-Based Stock

As of March 31, 2007, unrecognized compensation cost related to nonvested goal-based stock awards totaled $4 million and is expected to be recognized over a weighted-average period of 1.5 years.

Cash-Based Performance Grant

At March 31, 2007, the targeted amount of the cash-based performance grant made to officers in April 2006, is $14 million, but actual payout will vary between zero and 200% of the targeted amount depending on the level of performance metrics achieved described in Note 20 to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2006. At March 31, 2007, a liability of $8 million has been accrued for this award.

Note 15. Commitments and Contingencies

Other than the matters discussed below, there have been no significant developments regarding the commitments and contingencies disclosed in Note 23 to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2006, nor have any significant new matters arisen during the three months ended March 31, 2007.

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Litigation

In 2006, Gary P. Jones and others filed suit against Dominion Transmission, Inc. (DTI), Dominion Exploration and Production, Inc. (DEPI) and Dominion Resources Services, Inc. (DRS). The plaintiffs are royalty owners, seeking to recover damages as a result of the Dominion defendants allegedly underpaying royalties by improperly deducting post-production costs and not paying fair market value for the gas produced from their leases. The plaintiffs seek class action status on behalf of all West Virginia residents and others who are parties to or beneficiaries of oil and gas leases with the Dominion defendants. DRS is erroneously named as a defendant as the parent company of DTI and DEPI. In the first quarter of 2007, we established a litigation reserve representing our best estimate of the probable loss related to this matter. We do not believe that the final resolution of this matter will have a material adverse effect on our results of operations or financial condition.

Guarantees

At March 31, 2007, we had issued $27 million of guarantees to support third parties, equity method investees and employees affected by Hurricane Katrina. We also enter into guarantee arrangements on behalf of our consolidated subsidiaries primarily to facilitate their commercial transactions with third parties. To the extent that a liability subject to a guarantee has been incurred by one of our consolidated subsidiaries, that liability is included in our Consolidated Financial Statements. We are not required to recognize liabilities for guarantees issued on behalf of our subsidiaries unless it becomes probable that we will have to perform under the guarantees. No such liabilities have been recognized as of March 31, 2007. We believe it is unlikely that we would be required to perform or otherwise incur any losses associated with guarantees of our subsidiaries obligations. At March 31, 2007, we had issued the following subsidiary guarantees:

	Stated Limit	Value(1)
(millions)		
Subsidiary debt(2)	$ 627	$ 627
Commodity transactions(3)	3,631	805
Lease obligation for power generation facility(4)	898	898
Nuclear obligations(5)	383	302
Offshore drilling commitments(6)		493
Other	692	489
Total	$ 6,231	$ 3,614

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

(2) Guarantees of debt of certain DEI and CNG subsidiaries. In the event of default by the subsidiaries, we would be obligated to repay such amounts.

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

(4) Guarantee of a DEI subsidiary s leasing obligation for the Fairless Energy power station.

(5) Guarantees related to certain DEI subsidiaries potential retrospective premiums that could be assessed if there is a nuclear incident under our nuclear insurance programs and guarantees for a DEI subsidiary s and Virginia Power s commitment to buy nuclear fuel. In addition to the guarantees listed above, we have also agreed to provide up to $150 million and $60 million to two DEI subsidiaries, to pay operating expenses of Millstone and Kewaunee power stations, respectively, in the event of a prolonged outage as part of satisfying certain Nuclear Regulatory Commission requirements concerned with ensuring adequate funding for the operations of nuclear power stations.

(6) Performance and payment guarantees related to an offshore day work drilling contract, rig share agreements and related services for certain subsidiaries of CNG. There are no stated limits for these guarantees.

Surety Bonds and Letters of Credit

As of March 31, 2007, we had purchased $129 million of surety bonds and authorized the issuance of standby letters of credit by financial institutions of $728 million. We enter into these arrangements to facilitate commercial transactions by our subsidiaries with third parties.

Status of Electric Regulation in Virginia

2007 Virginia Restructuring Act and Fuel Factor Amendments

In April 2007, the Virginia General Assembly passed legislation that significantly changes electricity restructuring in Virginia. The legislation ends capped rates two years early, on December 31, 2008. After capped rates end, retail choice will be eliminated for all but individual retail customers with a demand of more than 5 Mw and non-residential retail customers who obtain Virginia State Corporation Commission (Virginia Commission) approval to aggregate their load to reach the 5 Mw threshold; individual retail customers will be permitted to purchase renewable energy from competitive suppliers if the incumbent electric utility does not offer a renewable energy tariff. Also after the end of capped rates, the Virginia Commission will set our base rates under a modified cost-of-service model. Among other features, the new model provides for the Virginia Commission to:

- Initiate a base rate case during the first six months of 2009, reviewing the 2008 test year, as a result of which the Virginia Commission:
  - shall establish a return on equity (ROE) no lower than that reported by a group of utilities within the southeastern U.S., with certain limitations, as described in the legislation;
  - may increase or decrease the ROE by up to 100 basis points based on generating plant performance, customer service and operating efficiency, if appropriate;
  - shall increase base rates, if needed, to allow the Company the opportunity to recover its costs and earn a fair rate of return, if we are found to have earnings more than 50 basis points below the established ROE; and
  - may reduce rates or, alternatively, order a credit to customers if we are found to have earnings more than 50 basis points above the established ROE.
- After the initial rate case, review base rates biennially, as a result of which the Virginia Commission:
  - shall establish an ROE no lower than that reported by a group of utilities within the southeastern U.S., with certain limitations, as described in the legislation;
  - may increase or decrease the ROE by up to 100 basis points based on generating plant performance, customer service and operating efficiency, if appropriate;
  - shall increase base rates, if needed, to allow the Company the opportunity to recover its costs and earn a fair rate of return if we are found to have earned, during the test period, more than 50 basis points below the then currently established ROE; and
  - may order a credit to customers if we are found to have earned, during the test period, more than 50 basis points above the then currently established ROE, and reduce rates if we are found to have such excess earnings during two consecutive biennial review periods.
- Authorize stand-alone rate adjustments for recovery of certain costs, including new generation projects, major generating unit modifications, environmental compliance projects, Federal Energy Regulatory Commission (FERC)-approved costs for transmission

service, energy efficiency and conservation programs, and renewable energy programs;

Authorize an enhanced ROE on new capital expenditures as a financial incentive for construction of major generation projects; and

After 2010, authorize an enhanced ROE on overall rate base as a financial incentive for renewable energy portfolio standard programs. The legislation also continues statutory provisions directing us to file annual fuel cost recovery cases with the Virginia Commission beginning in 2007 and continuing thereafter. However, our fuel factor increase as of July 1, 2007 will be limited to an amount that results in the residential customer class not receiving an increase of more than 4% of total rates as of that date, and the remainder will be deferred and collected over three years, as provided in the legislation.

We are currently evaluating the timing and the impact of reapplying SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*, to our electric utility generation operations.

Virginia Fuel Expenses

Under amendments to the Virginia fuel cost recovery statute passed in 2004, our fuel factor provisions were frozen until July 1, 2007. Fuel prices have increased considerably since 2004, which has resulted in our fuel expenses being significantly in excess of our fuel cost recovery. Pursuant to the 2007 amendments to the fuel cost recovery statute, annual fuel rate adjustments, with deferred fuel accounting for over- or under-recoveries of fuel costs, will be instituted beginning July 1, 2007. We expect that fuel expenses will continue to exceed fuel cost recovery until our fuel factor is adjusted in July 2007. While the 2007 amendments do not allow us to collect any unrecovered fuel expenses that were incurred prior to July 1, 2007, once our fuel factor is adjusted, the risk of under-recovery of prudently incurred fuel costs is greatly diminished.

In April 2007, we filed a Virginia fuel factor application with the Virginia Commission. The application shows a need for an annual increase in fuel expense recovery for the period July 1, 2007 through June 30, 2008 of approximately $662 million; however, the requested increase is limited to $219 million under the 2007 amendments to the fuel cost recovery statute. Under these amendments, our fuel factor increase as of July 1, 2007 is limited to an amount that results in the residential customer class not receiving an increase of more than 4% of total rates in effect as of June 30, 2007. The percentage increase for individual residential customers, and for other customer classes, will depend on their current rates and respective usage. The 4% limitation to the residential class would limit the fuel factor increase for Virginia jurisdictional customers to approximately $219 million, effective July 1, 2007, with the balance of approximately $443 million deferred and subsequently recovered, without interest, during the period commencing July 1, 2008 and ending June 30, 2011.

Note 16. Credit Risk

Credit risk is our risk of financial loss if counterparties fail to perform their contractual obligations. In order to minimize overall credit risk, we maintain credit policies, including the evaluation of counterparty financial condition, collateral requirements and the use of standardized agreements that facilitate the netting of cash flows associated with a single counterparty. In addition, counterparties may make available collateral, including letters of credit or cash held as margin deposits, as a result of exceeding agreed-upon credit limits, or may be required to prepay the transaction.

We maintain a provision for credit losses based on factors surrounding the credit risk of our customers, historical trends and other information. We believe, based on our credit policies and our March 31, 2007 provision for credit losses, that it is unlikely that a material adverse effect on our financial position, results of operations or cash flows would occur as a result of counterparty nonperformance.

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

Our exposure to credit risk is concentrated primarily within our sales of gas and oil production and energy marketing and price risk management activities, as we transact with a smaller, less diverse group of counterparties and transactions may involve large notional volumes and potentially volatile commodity prices. Energy marketing and risk management activities include trading of energy-related commodities, marketing of merchant generation output, structured transactions and the use of financial contracts for enterprise-wide hedging purposes. 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 March 31, 2007, our gross credit exposure totaled $1.14 billion. After the application of collateral, our credit exposure is reduced to $1.13 billion. Of this amount, investment grade counterparties represented 81% and no single counterparty exceeded 7%.

Note 17. Employee Benefit Plans

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

Three Months Ended March 31,	Pension Benefits 2007	Pension Benefits 2006	Other Postretirement Benefits 2007	Other Postretirement Benefits 2006
(millions)				
Service cost	**$ 11**	$ 35	**$ 14**	$ 21
Interest cost	**22**	58	**19**	23
Expected return on plan assets	**(38)**	(99)	**(18)**	(17)
Amortization of prior service cost (credit)		1	**(1)**	(1)
Amortization of transition obligation			**1**	1
Amortization of net loss	**4**	25	**1**	8
Settlements and curtailments[(1)]		6		
Net periodic benefit cost (credit) [(2)]	**$ (1)**	$ 26	**$ 16**	$ 35

(1) Relates to the pending sale of Peoples and Hope.

(2) Reduction in pension and other postretirement benefit costs, primarily reflecting an increase in the associated discount rate.

Employer Contributions

We made no contributions to our defined benefit pension plans or other postretirement benefit plans during the three months ended March 31, 2007. We expect to contribute approximately $23 million to our other postretirement benefit plans during the remainder of 2007. Under our funding policies, we evaluate pension and other postretirement benefit plan funding requirements annually, usually in the second half of the year after receiving updated plan information from our actuary. Based on the funded status of each plan and other factors, the amount of additional contributions to be made in 2007 will be determined at that time.

Note 18. Operating Segments

Our Company is organized primarily on the basis of products and services sold in the U.S. We manage our operations through the following segments:

Dominion Delivery includes our regulated electric and gas distribution and customer service business, as well as nonregulated retail energy marketing operations.

Dominion Energy includes our regulated electric transmission, natural gas transmission pipeline and underground natural gas storage businesses and the Cove Point LNG facility. It also includes gathering and extraction activities, certain Appalachian natural gas production and producer services, which consist of aggregation of gas supply, market-based services related to gas transportation and storage and associated gas trading.

Dominion Generation includes the generation operations of our electric utility and merchant fleet, as well as energy marketing and price risk management activities associated with our generation assets.

Dominion E&P includes our gas and oil exploration, development and production operations. These operations are located in several major producing basins in the lower 48 states, including the outer continental shelf and deepwater areas of the Gulf of Mexico, West Texas, Mid-Continent, the Rockies and Appalachia, as well as the Western Canadian Sedimentary Basin.

Corporate includes our corporate, service company and other functions (including unallocated debt), corporate-wide enterprise commodity risk management, the remaining assets of DCI and the net impact of the discontinued operations of the Peaker facilities. In addition, the contribution to net income by our primary operating segments is determined based on a measure of profit that executive management believes represents the segments core earnings. As a result, certain specific items attributable to those segments are not included in profit measures evaluated by executive management in assessing the segment s performance or allocating resources among the segments and are instead reported in the Corporate segment. In the three months ended March 31, 2007 and 2006, we reported net expenses of $36 million and $94 million, respectively, in the Corporate segment attributable to our operating segments.

The net expenses in 2007 largely resulted from:

- A $26 million ($16 million after-tax) charge resulting from the accrual of litigation reserves, attributable to Dominion E&P ($10 million after-tax) and Dominion Energy ($6 million after-tax); and

- $14 million ($9 million after-tax) of incremental expenses, primarily related to retention agreements and legal costs associated with the potential disposition of substantially all of our E&P assets, attributable to Dominion E&P.

The net expenses in 2006 primarily related to the impact of a $159 million ($94 million after-tax) charge resulting from the write-off of certain regulatory assets related to the pending sale of Peoples and Hope, attributable to Dominion Delivery.

Intersegment sales and transfers are based on underlying contractual arrangements and may result in intersegment profit or loss.

The following table presents segment information pertaining to our operations:

	Dominion Delivery	Dominion Energy	Dominion Generation	Dominion E&P	Corporate	Adjustments/ Eliminations	Consolidated Total
(millions)							
Three Months Ended March 31,							
2007							
Total revenue from external customers	**$ 1,614**	**$ 389**	**$ 1,779**	**$ 656**	**$ 19**	**$ 255**	**$ 4,712**
Intersegment revenue	**13**	**292**	**28**	**53**	**161**	**(547)**	
Total operating revenue	**1,627**	**681**	**1,807**	**709**	**180**	**(292)**	**4,712**
Loss from discontinued operations, net of tax					**(28)**		**(28)**
Net income (loss)	**199**	**102**	**139**	**138**	**(125)**		**453**
2006							
Total revenue from external customers	$ 1,672	$ 598	$ 1,653	$ 872	$ (37)	$ 193	$ 4,951
Intersegment revenue	3	276	42	68	195	(584)	
Total operating revenue	1,675	874	1,695	940	158	(391)	4,951
Loss from discontinued operations, net of tax					(5)		(5)
Net income (loss)	156	107	138	230	(97)		534

Note 19. Subsequent Event

In April 2007, we entered into an agreement with Eni Petroleum Co. Inc. (Eni Petroleum) to sell substantially all of our offshore E&P operations for approximately $4.76 billion. The transaction is expected to close by early July 2007, subject to customary closing conditions and adjustments. Our offshore operations include approximately 967 billion cubic feet equivalent (bcfe) of proved natural gas and oil reserves in the outer continental shelf and deepwater areas of the Gulf of Mexico at December 31, 2006. Of this total, approximately 961 bcfe are being sold to Eni Petroleum. The effective date for the sale is June 30, 2007. Eni Petroleum s obligations under the agreement are guaranteed by its parent company, Eni S.p.A. Remaining offshore E&P operations are expected to be disposed of in a separate transaction by early July 2007.

We continue to pursue the potential disposition of our Canadian and U.S. onshore E&P operations, excluding those in the Appalachian Basin. Net cash proceeds from this disposition and any future dispositions will be used to reduce debt, including debt at our CNG subsidiary. We would also expect to repurchase shares of our common stock and/or acquire select assets to complement our remaining businesses.

The offshore disposition will result in an initial pre-tax charge of approximately $370 million, which will be reported in second quarter 2007 earnings. This reflects the discontinuance of hedge accounting for certain cash flow hedges related to our offshore E&P operations since it became probable that the forecasted sales of gas and oil will not occur. In connection with the discontinuance of hedge accounting for these contracts, we will reclassify approximately $370 million of pre-tax losses from AOCI to earnings. We have entered into offsetting positions for these gas and oil derivatives that will minimize the volatility that would have resulted from these contracts being marked to market through earnings. We expect that this charge will be more than offset by the gain we ultimately expect to recognize on the disposition.

In addition to this initial charge, we anticipate recording additional charges related to the disposition plan that are not currently estimable. These charges will include cash expenditures for transaction costs, including employee-related, legal and other costs.

DOMINION RESOURCES, INC.

ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS

OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Management s Discussion and Analysis of Financial Condition and Results of Operations (MD&A) discusses the results of operations and general financial condition of Dominion. MD&A should be read in conjunction with our Consolidated Financial Statements. The terms Dominion, Company, we, our and us are used throughout MD&A and, depending on the context of its use, may represent any of the followi the legal entity, Dominion Resources, Inc., one of Dominion Resources, Inc. s consolidated subsidiaries or operating segments, or the entirety of Dominion Resources, Inc. and its consolidated subsidiaries.

Contents of MD&A

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

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

Forward-Looking Statements

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

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

- Unusual weather conditions and their effect on energy sales to customers and energy commodity prices;

Extreme weather events, including hurricanes and winter storms, that can cause outages, production delays and property damage to our facilities;

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

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

Risks associated with the operation of nuclear facilities;

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

Counterparty credit risk;

Capital market conditions, including price risk due to marketable securities held as investments in nuclear decommissioning and benefit plan trusts;

Fluctuations in interest rates;

Changes in 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 in our ability to recover investments made under traditional regulation through rates;

Receipt of approvals for and timing of closing dates for acquisitions and divestitures, including our divestiture of Peoples and Hope, the divestiture of our offshore E&P operations and any divestiture of our other E&P operations;

Risks associated with any realignment of our operating assets, including the potential dilutive effect on earnings in the near term, costs associated with the disposition of our offshore E&P operations and any disposition of our other E&P operations, as well as the costs and reinvestment risks related to deployment of proceeds from any disposition;

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

Completing the divestiture of investments held by our financial services subsidiary, DCI;

Additional risk exposure associated with the termination of business interruption and offshore property damage insurance related to our E&P operations and our inability to replace such insurance on commercially reasonable terms; and

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

Additionally, other risks that could cause actual results to differ from predicted results are set forth in Item 1A. Risk Factors in this report and in our Annual Report on Form 10-K for the year ended December 31, 2006.

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 March 31, 2007, 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, 2006. The policies disclosed included the accounting for derivative contracts at fair value, goodwill and long-lived asset impairment testing, asset retirement obligations, employee benefit plans, regulated operations, gas and oil operations, and income taxes.

Other

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

Results of Operations

Presented below is a summary of our consolidated results for the quarters ended March 31, 2007 and 2006:

	2007	2006	$ Change
(millions, except EPS)			
First Quarter			
Net income	**$ 453**	$ 534	$ (81)
Diluted EPS	**1.29**	1.53	(0.24)

Overview

Net income decreased 15% to $453 million. Unfavorable drivers include higher fossil fuel and purchased power costs incurred by our utility generation operations, the absence of a 2006 net income tax benefit recorded in connection with our planned sale of Peoples and Hope, as well as the absence of a 2006 benefit from favorable price changes on derivatives that were de-designated as hedges following Hurricanes Katrina and Rita in 2005 (2005 hurricanes). Favorable drivers include the impact of colder weather on our regulated gas and electric sales, as well as a higher contribution from our gas transmission and merchant generation operations.

Analysis of Consolidated Operations

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

	First Quarter		
	2007	**2006**	**$ Change**
(millions)			
Operating Revenue	**$ 4,712**	$ 4,951	$ (239)
Operating Expenses			
Electric fuel and energy purchases	**918**	765	153
Purchased electric capacity	**119**	123	(4)
Purchased gas	**1,148**	1,378	(230)
Other energy-related commodity purchases	**56**	400	(344)
Other operations and maintenance	**857**	767	90
Depreciation, depletion and amortization	**422**	377	45
Other taxes	**184**	180	4
Other income	**50**	42	8
Interest and related charges	**259**	257	2
Income tax expense	**313**	207	106
Loss from discontinued operations, net of tax	**(28)**	(5)	(23)

An analysis of our results of operations for the first quarter of 2007 compared to the first quarter of 2006 follows:

Operating Revenue decreased 5% to $4.7 billion, primarily reflecting:

- A $241 million decrease in gas sales by our gas distribution operations reflecting a $188 million decrease resulting from the migration of customers to energy choice programs and a $181 million decrease reflecting lower gas prices, partially offset by a $128 million increase due to colder weather, changes in customer usage patterns and other factors. This decrease was largely offset by a corresponding decrease in *Purchased gas expense;*

- A $232 million decrease in revenue from sales of oil purchased by E&P operations, primarily due to the impact of netting sales and purchases of oil under buy/sell arrangements associated with the implementation of EITF 04-13 in 2006. This decrease was largely offset by a corresponding decrease in *Other energy-related commodity purchases expense;*

- A $113 million decrease in our producer services business as a result of a decrease in prices associated with gas aggregation activities and lower margins related to price risk management due to reduced market volatility. The effect of this decrease was partially offset by a corresponding decrease in *Purchased gas expense*;

- An $81 million decline in nonutility coal sales, primarily resulting from lower sales volumes related to exiting certain sales activities. This decrease was largely offset by a corresponding decrease in *Other energy-related commodity purchases expense*; and

- A $45 million decrease in sales of emissions allowances held for resale, primarily reflecting lower overall sales volume. This decrease was largely offset by a corresponding decrease in *Other energy-related commodity purchases expense.*

These decreases were partially offset by:

- A $113 million increase in revenue from our electric utility operations, largely resulting from:

A $52 million increase associated with comparably colder weather during the current year. As compared to the prior year, we experienced an 11% increase in heating degree days;

A $26 million increase attributable to variations in rates resulting from changes in customer usage patterns and sales mix, as well as other factors;

A $17 million increase due to new customer connections primarily in our residential and commercial customer classes; and

A $15 million increase resulting primarily from higher ancillary service revenue reflecting higher regulation and operating reserves revenue received from PJM;

A $108 million increase in gas sales by our retail energy marketing operations, primarily due to increased customer accounts ($196 million), partially offset by lower contracted sales prices ($88 million). The effect of this increase is partially offset by a corresponding increase in *Purchased gas expense*;

A $98 million increase associated with hedging activities for our merchant generation assets. The effect of this increase was largely offset by a corresponding increase in *Other operations and maintenance expense*;

A $65 million increase from merchant generation operations, primarily reflecting higher overall realized prices; and

A $64 million increase in gas transportation and storage revenue from our gas distribution operations due to increased volumes ($40 million) and higher prices ($24 million).

Operating Expenses and Other Items

Electric fuel and energy purchases expense increased 20% to $918 million, primarily reflecting the combined effects of:

- A $119 million increase related to our utility generation operations, primarily due to increased consumption of fossil fuel and purchased power, as a result of comparably colder weather during the current year; and
- A $24 million increase for our merchant generation operations primarily due to increased fuel consumption and purchases of replacement power during plant outages.

Purchased gas expense decreased 17% to $1.1 billion, principally resulting from the following factors, all of which are discussed in *Operating Revenue*:

- A $200 million decrease attributable to gas distribution operations, due primarily to lower average gas prices; and
- An $82 million decrease associated with our producer services business, primarily due to lower prices; partially offset by
- A $93 million increase associated with retail energy marketing operations, primarily due to higher volumes ($200 million), partially offset by decreased prices ($107 million).

Other energy-related commodity purchases expense decreased 86% to $56 million, primarily resulting from the following factors, all of which are discussed in *Operating Revenue*:

- A $224 million decrease as a result of the impact of netting sales and purchases of oil under buy/sell arrangements associated with the implementation of EITF 04-13;
- A $77 million decrease in the cost of nonutility coal sales; and
- A $43 million decrease in the cost of sales of emissions allowances held for resale.

Other operations and maintenance expense increased 12% to $857 million, primarily reflecting the combined effects of:

- A $97 million increase primarily related to hedging activities associated with our merchant generation assets. The effect of this increase is offset by a corresponding increase in *Operating Revenue*;
- A $39 million increase in salaries, wages and other benefits expense;
- A $26 million charge resulting from the accrual of litigation reserves;
- A $24 million increase in bad debt expense, primarily reflecting expenses for gas distribution operations related to low income energy assistance programs. These expenditures are recovered through rates;

- $14 million of incremental expenses, primarily related to retention agreements and legal costs associated with the potential disposition of substantially all of our E&P assets; and

- A $10 million increase in outage costs, primarily due to an increase in the number of scheduled outage days at certain of our utility generation facilities.

These charges were partially offset by:

- A $40 million reduction in pension and other postretirement benefits expenses, primarily resulting from an increase in the associated discount rate;

- A $15 million decrease in insurance costs for E&P operations resulting from 2006 premium adjustments and the decision not to renew certain insurance coverages due to cost increases caused by hurricanes in 2005 and 2004;

- A $12 million decrease due to an increased benefit from financial transmission rights granted by PJM to our utility generation operations used to offset congestion costs associated with PJM spot market activity, which are included in *Electric Fuel and Energy Purchases Expense*; and

- A net benefit resulting from the absence of the following items recognized in 2006:

  - A $159 million charge from the write off of certain regulatory assets related to the pending sale of Peoples and Hope; partially offset by

  - A $118 million benefit resulting from favorable changes in the fair value of certain gas and oil derivatives that were de-designated as hedges following the 2005 hurricanes.

Depreciation, depletion and amortization expense (DD&A) increased 12% to $422 million, primarily due to the impact of higher E&P finding and development costs and increased gas production.

Interest and related charges increased 1% to $259 million, reflecting a $23 million increase primarily due to additional borrowings and higher interest rates on variable rate debt, largely offset by a $21 million decrease attributable to a revised estimate of interest on income taxes payable.

Income tax expense reflects an increase in our effective tax rate to 39.2%, resulting primarily from the absence of a 2006 net income tax benefit recorded in connection with our planned sale of Peoples and Hope.

Loss from discontinued operations increased to $28 million, primarily reflecting a $25 million loss on the sale of the Peaker facilities in March 2007.

Segment Results of Operations

Segment results include the impact of intersegment revenues and expenses, which may result in intersegment profit and loss. Presented below is a summary of contributions by operating segments to net income for the quarters ended March 31, 2007 and 2006:

	Net Income			Diluted EPS		
First Quarter	**2007**	**2006**	**$ Change**	**2007**	**2006**	**$ Change**
(millions, except EPS)						
Dominion Delivery	**$ 199**	$ 156	$ 43	**$ 0.57**	$ 0.45	$ 0.12
Dominion Energy	**102**	107	(5)	**0.29**	0.31	(0.02)
Dominion Generation	**139**	138	1	**0.40**	0.39	0.01
Dominion E&P	**138**	230	(92)	**0.39**	0.66	(0.27)
Primary operating segments	**578**	631	(53)	**1.65**	1.81	(0.16)
Corporate	**(125)**	(97)	(28)	**(0.36)**	(0.28)	(0.08)
Consolidated	**$ 453**	$ 534	$ (81)	**$ 1.29**	$ 1.53	$ (0.24)

Dominion Delivery

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

	First Quarter		
	2007	**2006**	**% Change**
Electricity delivered (million mwhrs) [(1)]	**21.0**	19.5	8 %
Degree days (electric service area):			
Cooling[(2)]	**12**	13	(8)
Heating[(3)]	**1,993**	1,796	11
Average electric delivery customer accounts[(4)]	**2,351**	2,314	2
Gas throughput (bcf):			
Gas sales	**46**	50	(8)
Gas transportation	**107**	87	23
Heating degree days (gas service area)[(3)]	**3,015**	2,580	17
Average gas delivery customer accounts[(4)]:			
Gas sales	**784**	1,004	(22)
Gas transportation	**914**	697	31
Average retail energy marketing customer accounts[(4)]	**1,490**	1,179	26

mwhrs = megawatt hours

bcf = billion cubic feet

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(1) Includes electricity delivered through the retail choice program for our Virginia jurisdictional electric customers.
(2) Cooling degree days (CDDs) are units measuring the extent to which the average daily temperature is greater than 65 degrees. CDDs are calculated as the difference between the average temperature for each day and 65 degrees.
(3)

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

(4) Period average, in thousands.

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

	First Quarter 2007 vs. 2006 Increase (Decrease)	
	Amount	EPS
(millions, except EPS)		
Regulated gas sales weather	$ 12	$ 0.03
Retail energy marketing operations[1]	10	0.03
Regulated electric sales:		
Weather	7	0.02
Customer growth	2	0.01
Interest expense	5	0.01
Other	7	0.02
Change in net income contribution	$ 43	$ 0.12

(1) Higher margins largely attributable to an increase in the number of gas customers.

Dominion Energy

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

	First Quarter		
	2007	2006	% Change
Gas transportation throughput (bcf)	**278**	234	19%

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

	First Quarter 2007 vs. 2006 Increase (Decrease)	
	Amount	EPS
(millions, except EPS)		
Producer services[1]	$ (22)	$ (0.07)
Gas transmission margins[2]	18	0.05
Electric transmission operations	4	0.01
Other	(5)	(0.01)
Change in net income contribution	$ (5)	$ (0.02)

(1) Decreased margins related to price risk management activities and certain transportation contracts, as a result of reduced market volatility, as compared to the post-2005 hurricane market conditions in 2006.

(2) Primarily due to lower fuel costs resulting from reduced gas usage and lower gas prices, and higher margins from extracted products, largely resulting from lower gas prices associated with gas replacement costs.

Dominion Generation

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

	First Quarter		
	2007	**2006**	**% Change**
Electricity supplied (million mwhrs)			
Utility	**21.0**	19.5	8%
Merchant[1]	**11.2**	11.0	2
Degree days (electric utility service area):			
Cooling	**12**	13	(8)
Heating	**1,993**	1,796	11

(1) Includes electricity supplied by the Peaker facilities prior to their sale in March 2007. The operating results of the Peaker facilities are reflected as discontinued operations.

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

	First Quarter 2007 vs. 2006 Increase (Decrease)	
	Amount	**EPS**
(millions, except EPS)		
Regulated electric sales:		
Weather	$ 15	$ 0.04
Customer growth	5	0.01
Other	3	0.01
Merchant generation margin[1]	13	0.04
Ancillary service revenue	9	0.03
Interest expense	4	0.01
Unrecovered Virginia fuel expenses[2]	(48)	(0.13)
Outage costs[3]	(6)	(0.02)
Other	6	0.02
Change in net income contribution	$ 1	$ 0.01

(1) Primarily reflects higher volumes and realized prices, partially offset by higher replacement power costs during unplanned plant outages.

(2) Increased consumption of fossil fuel and higher purchased power costs due to colder weather, as well as an increase in scheduled outage days.

(3) Higher costs due to an increase in the number of scheduled outage days, primarily for our utility generation facilities.

Dominion E&P

Presented below are operating statistics related to our E&P operations:

	First Quarter 2007	2006	% Change
Gas production (bcf)	**76.3**	72.0	6 %
Oil production (million bbls)	**5.6**	6.1	(8)
Average realized prices without hedging results:			
Gas (per mcf) [1]	**$ 6.57**	$ 7.99	(18)
Oil (per bbl)	**46.69**	53.35	(12)
Average realized prices with hedging results:			
Gas (per mcf) [1]	**5.80**	4.99	16
Oil (per bbl)	**35.47**	38.82	(9)
DD&A (unit of production rate per mcfe)	**1.92**	1.66	16

bbl(s) = barrel(s)

mcf = thousand cubic feet

mcfe = thousand cubic feet equivalent

(1) Excludes $47 million and $79 million for the three months ended March 31, 2007 and 2006, respectively, of revenue recognized under the volumetric production payment (VPP) agreements described in Note 12 to our Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2006.

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

	First Quarter 2007 vs. 2006 Increase (Decrease) Amount	EPS
(millions, except EPS)		
Operations and maintenance[1]	$ (78)	$ (0.22)
DD&A[2]	(20)	(0.06)
Gas and oil production[3]	(16)	(0.05)
Interest expense	(10)	(0.03)
Gas and oil prices	20	0.06
Other	12	0.03
Change in net income contribution	$ (92)	$ (0.27)

(1) Higher operations and maintenance expenses, primarily reflecting the absence of a 2006 benefit from favorable changes in the fair value of certain gas and oil hedges that were de-designated following the 2005 hurricanes.

(2) Higher DD&A, primarily reflecting higher industry finding and development costs, as well as increased gas production.

(3) Represents a decrease in oil production, primarily attributable to deepwater Gulf of Mexico Green Canyon, Triton and Goldfinger projects, as well as reduced natural gas deliveries and associated revenues recognized under the VPP agreements. These decreases were partially offset by increased gas production from deepwater and Permian basin locations.

Included below are the volumes and weighted average prices associated with hedges in place as of March 31, 2007 by applicable time period:

	Natural Gas		Oil	
	Hedged Production	Average Hedge Price	Hedged Production	Average Hedge Price
Year	(bcf)	(per mcf)	(million bbls)	(per bbl)
2007	178.4	$ 5.95	7.5	$ 33.41
2008	174.9	8.23	5.0	49.36
2009	36.6	7.97	0.3	75.36

Corporate

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

	First Quarter		
	2007	**2006**	**$ Change**
(millions, except EPS)			
Specific items attributable to operating segments	**$ (36)**	$ (94)	$ 58
Peaker discontinued operations	**(28)**	(5)	(23)
Other corporate operations	**(61)**	2	(63)
Total net expense	**$ (125)**	$ (97)	$ (28)
Earnings per share impact	**$ (0.36)**	$ (0.28)	$ (0.08)

Specific Items Attributable to Operating Segments

Corporate includes specific items attributable to our operating segments that have been excluded in profit measures evaluated by management, either in assessing segment performance or in allocating resources among the segments. See Note 18 to our Consolidated Financial Statements for discussion of these items.

Peaker Discontinued Operations

The increase in the loss from the discontinued operations of the Peaker facilities primarily reflecting a $25 million loss on the sale of the Peaker facilities in March 2007, resulting largely from the allocation of $24 million of Generation reporting unit goodwill to the bases of the investments being sold.

Other Corporate Operations

We reported net expenses of $61 million in 2007 associated with other corporate operations, as compared to a net benefit of $2 million in 2006, primarily reflecting the absence of a net tax benefit recorded in 2006 as a result of the pending sale of Peoples and Hope. In 2006, we recognized a $201 million tax benefit from the partial reversal of previously recorded valuation allowances on deferred tax assets, representing certain federal and state tax loss carryforwards, since these carryforwards are expected to be utilized to offset capital gain income that is expected to be generated from the sale. This benefit was partially offset, in 2006, by the establishment of $141 million of deferred tax liabilities in accordance with EITF 93-17.

Selected Information Energy Trading Activities

See *Selected Information-Energy Trading Activities* in MD&A included in our Annual Report on Form 10-K for the year ended December 31, 2006 for a discussion of our energy trading, hedging and marketing activities, and related accounting policies. For additional discussion of trading activities, see *Market Risk Sensitive Instruments and Risk Management* in Item 3.

A summary of the changes in the unrealized gains and losses recognized for our energy-related derivative instruments held for trading purposes during the three months ended March 31, 2007 follows:

	Amount
(millions)	
Net unrealized gain at December 31, 2006	$ 42
Contracts realized or otherwise settled during the period	**(57)**
Net unrealized gain at inception of contracts initiated during the period	
Changes in unrealized gains and losses	**(8)**
Changes in valuation techniques	

Net unrealized loss at March 31, 2007	**$ (23)**

The balance of net unrealized gains and losses recognized for our energy-related derivative instruments held for trading purposes at March 31, 2007, is summarized in the following table based on the approach used to determine fair value and contract settlement or delivery dates:

Source of Fair Value	Maturity Based on Contract Settlement or Delivery Date(s) Less than 1 year	1-2 years	2-3 years	3-5 years	In excess of 5 years	Total
(millions)						
Actively quoted[1]	$ (31)	$ 8	$ 2	$ 3	$ 1	$ (17)
Other external sources[2]		(5)	(1)			(6)
Total	$ (31)	$ 3	$ 1	$ 3	$ 1	$ (23)

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

Liquidity and Capital Resources

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

At March 31, 2007, we had $1.7 billion of unused capacity under our credit facilities, comprised of approximately $1.4 billion under our core credit facilities and $300 million available under bilateral credit facilities.

A summary of our cash flows for the three months ended March 31, 2007 and 2006 is presented below:

	2007	2006
(millions)		
Cash and cash equivalents at January 1,[1]	**$ 142**	$ 146
Cash flows provided by (used in):		
Operating activities	**1,210**	984
Investing activities	**(796)**	(986)
Financing activities	**(448)**	(71)
Net decrease in cash and cash equivalents	**(34)**	(73)
Cash and cash equivalents at March 31,[2]	**$ 108**	$ 73

(1) 2007 amount includes $4 million of cash classified as held for sale in our Consolidated Balance Sheet.
(2) 2007 and 2006 amounts include $5 million and $4 million, respectively, of cash classified as held for sale in our Consolidated Balance Sheets.

Operating Cash Flows

For the three months ended March 31, 2007, net cash provided by operating activities increased by $226 million as compared to the three months ended March 31, 2006. The increase was partly due to higher regulated electric and gas sales as a result of colder weather and improved margins from our merchant generation, retail energy marketing and transmission businesses, partially offset by higher unrecovered fuel costs. Operating cash flow also increased due to lower collateral requirements related to our commodity hedging transactions. Our operations are subject to risks and uncertainties that may negatively impact the timing or amounts of operating cash flows which are discussed in Item 1A. Risk Factors in this report and in our Annual Report on Form 10-K for the year-ended December 31, 2006.

Credit Risk

Our exposure to potential concentrations of credit risk results primarily from our energy marketing and price risk management activities and sales of gas and oil production. Presented below is a summary of our gross credit exposure as of March 31, 2007, for these activities. Our gross credit exposure for each counterparty is calculated as outstanding receivables plus any unrealized on or off-balance sheet exposure, taking into account contractual netting rights. Gross credit exposure is calculated prior to the application of collateral.

	Gross Credit Exposure	Credit Collateral	Net Credit Exposure
(millions)			
Investment grade[(1)]	$ 725	$ 1	$ 724
Non-investment grade[(2)]	39	1	38
No external ratings:			
Internally rated investment grade[(3)]	195	5	190
Internally rated non-investment grade[(4)]	182		182
Total	$ 1,141	$ 7	$ 1,134

(1) Designations as investment grade are based upon minimum credit ratings assigned by Moody s Investors Service and Standard & Poor s Ratings Services. The five largest counterparty exposures, combined, for this category represented approximately 18% of the total net credit exposure.
(2) The five largest counterparty exposures, combined, for this category represented approximately 2% of the total net credit exposure.
(3) The five largest counterparty exposures, combined, for this category represented approximately 11% of the total net credit exposure.
(4) The five largest counterparty exposures, combined, for this category represented approximately 4% of the total net credit exposure.

Investing Cash Flows

Significant cash flows used in investing activities for the three months ended March 31, 2007, included:

- $576 million of capital expenditures for the purchase and development of gas and oil producing properties, drilling and equipment costs and undeveloped lease acquisitions;
- $471 million of capital expenditures, including environmental upgrades, routine capital improvements, purchase of nuclear fuel, and construction and improvements of gas and electric transmission and distribution assets; and
- $264 million for purchases of securities held as investments in our nuclear decommissioning trusts.

Cash flows used in investing activities for the three months ended March 31, 2007, were partially offset by:

- $257 million of net proceeds from the sale of the Peaker facilities; and
- $225 million of proceeds from sales of securities held as investments in our nuclear decommissioning trusts.

Financing Cash Flows and Liquidity

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

Significant financing activities for the three months ended March 31, 2007 included:

- $720 million for the repayment of long-term debt; and
- $249 million of common dividend payments; partially offset by
- $418 million from the issuance of short-term debt; and
- $86 million from the issuance of common stock.

See Note 13 to our Consolidated Financial Statements for further information regarding our credit facilities, liquidity and significant financing transactions.

Credit Ratings and Debt Covenants

Credit ratings are intended to provide banks and capital market participants with a framework for comparing the credit quality of securities and are not a recommendation to buy, sell or hold securities. In the *Credit Ratings* and *Debt Covenants* sections of MD&A in our Annual Report on Form 10-K for the year ended December 31, 2006, we discussed the use of capital markets by Virginia Power, CNG and us (the Dominion Companies), as well as the impact of credit ratings on the accessibility and costs of using these markets. In addition, these sections of MD&A discussed various covenants present in the enabling agreements underlying the Dominion Companies debt. As of March 31, 2007, there have been no changes in the Dominion Companies credit ratings, nor changes to or events of default under our debt covenants.

Future Cash Payments for Contractual Obligations

As of March 31, 2007, there have been no material changes outside the ordinary course of business to the contractual obligations disclosed in MD&A in our Annual Report on Form 10-K for the year ended December 31, 2006.

Use of Off-Balance Sheet Arrangements

As of March 31, 2007, there have been no material changes in the off-balance sheet arrangements disclosed in MD&A in our Annual Report on Form 10-K for the year ended December 31, 2006.

Future Issues and Other Matters

The following discussion of future issues and other information includes current developments of previously disclosed matters and new issues arising during the period covered by and subsequent to our Consolidated Financial Statements. This section should be read in conjunction with *Future Issues and Other Matters* in our Annual Report on Form 10-K for the year ended December 31, 2006.

Regulatory Approval of Sale of Peoples and Hope

In March 2006, Peoples and Equitable Resources, Inc. (Equitable) filed a joint petition with the Pennsylvania Public Utility Commission (Pennsylvania Commission) seeking approval of the purchase by Equitable of all of the stock of Peoples and Hope. In April 2006, Hope and Equitable filed a joint petition seeking West Virginia Public Service Commission (West Virginia Commission) approval of the purchase by Equitable of all of the stock of Hope. In April 2007, the Pennsylvania Commission approved a joint settlement approving the sale in Pennsylvania. Following the approval of the sale of Peoples by the Pennsylvania Commission, the Federal Trade Commission (FTC) filed an action in federal court seeking to block the transaction. A hearing on the FTC s request for an injunction is scheduled for early June. Dominion and Equitable have asked the court to dismiss the FTC s complaint and a ruling on this motion to dismiss is expected in early May 2007. The West Virginia Commission has scheduled hearings in May 2007 related to the sale of Hope to Equitable.

Possible Disposition of E&P Business

In November 2006, we announced our decision to pursue the disposition of all of our oil and natural gas E&P operations and assets, with the exception of those located in the Appalachian Basin. At December 31, 2006, our natural gas and oil assets excluding the Appalachian Basin included about 5.5 trillion cubic feet of proved reserves. The Appalachian assets that we would retain constituted approximately 15% of our total reserves at December 31, 2006.

In April 2007, we entered into an agreement with Eni Petroleum to sell substantially all of our offshore E&P operations for approximately $4.76 billion. The transaction is expected to close by early July 2007, subject to customary closing conditions and adjustments. Our offshore operations include approximately 967 bcfe of proved natural gas and oil reserves in the outer continental shelf and deepwater areas of the Gulf of Mexico at December 31, 2006. Of this total, approximately 961 bcfe are being sold to Eni Petroleum. The effective date for the sale is June 30, 2007. Eni Petroleum s obligations under the agreement are guaranteed by its parent company, Eni S.p.A. Remaining offshore E&P operations are expected to be disposed of in a separate transaction by early July 2007.

We continue to pursue the potential disposition of our Canadian and U.S. onshore E&P operations, excluding those in the Appalachian Basin. Net cash proceeds from this disposition and any future dispositions will be used to reduce debt, including debt at our CNG subsidiary. We would also expect to repurchase shares of our common stock and/or acquire select assets to complement our remaining businesses.

The offshore disposition will result in an initial pre-tax charge of approximately $370 million, which will be reported in second quarter 2007 earnings. This reflects the discontinuance of hedge accounting for certain cash flow hedges related to our offshore E&P operations since it became probable that the forecasted sales of gas and oil will not occur. In connection with the discontinuance of hedge accounting for these contracts, we will reclassify approximately $370 million of pre-tax losses from AOCI to earnings. We have entered into offsetting positions for these gas and oil derivatives that will minimize the volatility that would have resulted from these contracts being marked to market through earnings. We expect that this charge will be more than offset by the gain we ultimately expect to recognize on the disposition.

In addition to this initial charge, we anticipate recording additional charges related to the disposition plan that are not currently estimable. These charges will include cash expenditures for transaction costs, including employee-related, legal and other costs.

Status of Electric Regulation in Virginia

2007 Virginia Restructuring Act and Fuel Factor Amendments

In April 2007, the Virginia General Assembly passed legislation that significantly changes electricity restructuring in Virginia. The legislation ends capped rates two years early, on December 31, 2008. After capped rates end, retail choice will be eliminated for all but individual retail customers with a demand of more than 5 Mw and non-residential retail customers who obtain Virginia Commission approval to aggregate their load to reach the 5 Mw threshold; individual retail customers will be permitted to purchase renewable energy from competitive suppliers if the incumbent electric utility does not offer a renewable energy tariff. Also after the end of capped rates, the Virginia Commission will set our base rates under a modified cost-of-service model. Among other features, the new model provides for the Virginia Commission to:

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

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

Authorize stand-alone rate adjustments for recovery of certain costs, including new generation projects, major generating unit modifications, environmental compliance projects, FERC-approved costs for transmission service, energy efficiency and conservation programs, and renewable energy programs;

Authorize an enhanced ROE on new capital expenditures as a financial incentive for construction of major generation projects; and

After 2010, authorize an enhanced ROE on overall rate base as a financial incentive for renewable energy portfolio standard programs.

The legislation also continues statutory provisions directing us to file annual fuel cost recovery cases with the Virginia Commission beginning in 2007 and continuing thereafter. However, our fuel factor increase as of July 1, 2007 will be limited to an amount that results in the residential customer class not receiving an increase of more than 4% of total rates as of that date, and the remainder will be deferred and collected over three years, as provided in the legislation.

We are currently evaluating the timing and the impact of reapplying SFAS No. 71 to our electric utility generation operations.

Virginia Fuel Expenses

Under amendments to the Virginia fuel cost recovery statute passed in 2004, our fuel factor provisions were frozen until July 1, 2007. Fuel prices have increased considerably since 2004, which has resulted in our fuel expenses being significantly in excess of our fuel cost recovery. Pursuant to the 2007 amendments to the fuel cost recovery statute, annual fuel rate adjustments, with deferred fuel accounting for over- or under-recoveries of fuel costs, will be instituted beginning July 1, 2007. We expect that fuel expenses will continue to exceed fuel cost recovery until our fuel factor is adjusted in July 2007. While the 2007 amendments do not allow us to collect any unrecovered fuel expenses that were incurred prior to July 1, 2007, once our fuel factor is adjusted, the risk of under-recovery of prudently incurred fuel costs is greatly diminished.

In April 2007, we filed a Virginia fuel factor application with the Virginia Commission. The application shows a need for an annual increase in fuel expense recovery for the period July 1, 2007 through June 30, 2008 of approximately $662 million; however, the requested increase is limited to $219 million under the 2007 amendments to the fuel cost recovery statute. Under these amendments, our fuel factor increase as of July 1, 2007 is limited to an amount that results in the residential customer class not receiving an increase of more than 4% of total rates in effect as of June 30, 2007. The percentage increase for individual residential customers, and for other customer classes, will depend on their current rates and respective usage. The 4% limitation to the residential class would limit the fuel factor increase for Virginia jurisdictional customers to approximately $219 million, effective July 1, 2007, with the balance of approximately $443 million deferred and subsequently recovered, without interest, during the period commencing July 1, 2008 and ending June 30, 2011.

Transmission Expansion Plan

Each year, as part of PJM s Regional Transmission Expansion Plan (RTEP) process, reliability projects will be authorized. In June 2006, PJM, through the RTEP process, authorized construction of numerous electric transmission upgrades through 2011. We are involved in two of the major construction projects. The first project is an approximately 270-mile 500-kilovolt (kV) transmission line from southwestern Pennsylvania to Virginia, of which we will construct approximately 65 miles in Virginia and a subsidiary of Allegheny Energy, Inc. will construct the remainder. The second project is an approximately 56-mile 500 kV transmission line that we will construct in southeastern Virginia. These transmission upgrades are designed to improve the reliability of service to our customers and the region. The siting and construction of these transmission lines will be subject to applicable state and federal permits and approvals. In April 2007, we filed an application with the Virginia Commission requesting approval of the proposed construction of the 65-mile transmission line in Virginia.

Generation Expansion

Based on available generation capacity and current estimates of growth in customer demand in our utility service territory, we will need additional generation in the future. As a result, in April 2007, we filed an application with the Virginia Commission requesting approval to add two 150 Mw natural gas-fired electric generating units to our Ladysmith Power Station to supply electricity during periods of peak demand. Pending regulatory approval and necessary permits, the facility is expected to be in operation by August 2008 at an estimated cost of $135 million. We will continue to evaluate the development of a southwest Virginia coal plant and other new plants to meet customer demand for additional generation in the future.

Cove Point Expansion

In June 2006, FERC approved our plans to expand our Cove Point LNG terminal including the installation of two LNG storage tanks, each capable of storing 160 thousand cubic meters of LNG, and expand the send-out capacity of our Cove Point pipeline to approximately 1.8 million dekatherms per day. FERC also approved our plans to expand our DTI facilities by building 81 miles of pipeline and two compressor stations in central Pennsylvania. Statoil ASA has committed to all of the incremental terminal, transportation and storage capacity of the expansion for a term of 20 years. Expansion construction started in August 2006 and is expected to be completed in the fourth quarter of 2008.

PJM Rate Design

In May 2005, FERC issued an order finding that PJM s existing transmission service rate design may not be just and reasonable, and ordered an investigation and hearings into the matter. Hearings were held in April 2006, and in July 2006, the Presiding Administrative Law Judge issued an initial decision (Initial Decision). The Initial Decision concluded that the existing PJM transmission service rate design has been shown to be unjust and unreasonable, and should be replaced with a new rate design that would allocate substantial transmission costs to the Dominion zone, effective April 2006. Our position was that the existing rate design remained just and reasonable, as supported by a broad coalition of PJM stakeholders. In April 2007, FERC overruled the Initial Decision by reaffirming PJM s existing transmission service rate design. FERC also determined that the costs of new, PJM-planned transmission facilities that operate at or above 500 kV will be allocated on a PJM region-wide basis, while the costs of new, PJM-planned facilities that operate below 500 kV will be assigned to zones within the PJM region based on a new model to be developed in further proceedings. We cannot predict how the cost of the facilities below 500 kV will be allocated, or whether the FERC decision will be modified upon rehearing or appeal.

Collective Bargaining Agreement

Virginia Power and the International Brotherhood of Electrical Workers, Local 50 (Local 50), have reached a tentative agreement for a six-year collective bargaining agreement to replace the current agreement that was scheduled to expire on March 31, 2007. The new agreement is subject to a ratification vote by the members of Local 50, which represents approximately 3,200 Virginia Power employees in Virginia, North Carolina and the Mount Storm Power Station in West Virginia. The current agreement remains in effect until the new agreement is ratified or, if it is not ratified, so long as the parties continue to negotiate.

Environmental Matters

In April 2007, the U. S. Supreme Court ruled that the Environmental Protection Agency (EPA) has the authority to regulate greenhouse gas emissions under the Clean Air Act which could result in future EPA action. Although we expect federal legislative or regulatory action on the regulation of greenhouse gas emissions in the future, the outcome in terms of specific requirements and timing is uncertain, and we cannot predict the financial impact on our operations at this time.

In addition to possible federal action, some of the states in which we operate have already or may adopt carbon reduction programs. For example, Massachusetts has implemented state-specific regulations requiring reductions in carbon dioxide (CO_2) emissions from power plants. We operate two coal/oil-fired generating power stations in Massachusetts that are already subject to the implementation of CO_2 emission regulations issued by the Massachusetts Department of Environmental Protection. Massachusetts, Rhode Island and Connecticut have joined the Regional Greenhouse Gas Initiative (RGGI), a multi-state effort to reduce CO_2 emissions in the Northeast to be implemented through state-specific regulations which are currently in development in these states. We own and operate a gas/oil-fired electric generating facility in Rhode Island that would be subject to RGGI in addition to the two coal/oil stations in Massachusetts. Implementing regulations for RGGI in Massachusetts and Rhode Island have yet to be developed. It is not currently possible to predict the financial impact that may result.

Clean Air Act Compliance

Illinois has finalized regulations to implement the Clean Air Mercury Rule (CAMR) with requirements more strict than the federal rule, and has proposed, but not yet finalized, regulations to implement the Clean Air Interstate Rule (CAIR) that are also more strict than the federal requirements. Indiana has adopted CAIR and is considering, but has not yet officially proposed regulations adopting the federal CAMR rule. Projected capital expenditures at our affected facilities remain consistent with the estimates provided in our Annual Report on Form 10-K for the year ended December 31, 2006.

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, Management s Discussion and Analysis of Financial Condition and Results of Operations of this Form 10-Q. The reader s attention is directed to those paragraphs for discussion of various risks and uncertainties that may affect our future.

Market Risk Sensitive Instruments and Risk Management

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

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

Commodity Price Risk

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

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

A hypothetical 10% increase in market prices for our non-trading commodity-based financial derivative instruments would have resulted in a decrease in fair value of approximately $613 million and $597 million as of March 31, 2007 and December 31, 2006, respectively. A hypothetical 10% increase in commodity prices would have resulted in a decrease of approximately $8 million in fair value of our commodity-based financial derivative instruments held for trading purposes as of March 31, 2007. A hypothetical 10% decrease in commodity prices would have resulted in a decrease of approximately $3 million in the fair value of our commodity-based financial derivative instruments held for trading purposes as of December 31, 2006.

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

Foreign Currency Exchange Risk

Our Canadian natural gas and oil E&P activities are relatively self-contained within Canada. As a result, our exposure to foreign currency exchange risk for these activities is limited primarily to the effects of translation adjustments that arise from including that operation in our Consolidated Financial Statements. We monitor this exposure and believe it is not material. In addition, we manage our foreign exchange risk exposure associated with anticipated future purchases of nuclear fuel processing services denominated in foreign currencies by utilizing currency forward contracts. As a result of holding these contracts as hedges, our exposure to foreign currency risk is minimal. A hypothetical 10% decrease in relevant foreign exchange rates would have resulted in a decrease of approximately $1 million and $3 million in the fair value of currency forward contracts held by us at March 31, 2007 and December 31, 2006, respectively.

Interest Rate Risk

We manage our interest rate risk exposure predominantly by maintaining a balance of fixed and variable rate debt. We also enter into interest rate sensitive derivatives, including interest rate swaps and interest rate lock agreements. For financial instruments outstanding at March 31, 2007, a hypothetical 10% increase in market interest rates would have resulted in a decrease in annual earnings of approximately $27 million. A hypothetical 10% increase in market interest rates, as determined at December 31, 2006, would have resulted in a decrease in annual earnings of approximately $25 million.

In addition, we retain ownership of mortgage investments, including subordinated bonds and interest-only residual assets retained from securitizations of mortgage loans originated and purchased in prior years. Note 27 to our Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2006 discusses the impact of changes in value of these investments.

Investment Price Risk

We are subject to investment price risk due to marketable securities held as investments in decommissioning trust funds. These marketable securities are managed by third-party investment managers and are reported in our Consolidated Balance Sheets at fair value. We recognized net realized gains (including investment income) on nuclear decommissioning trust investments of $27 million and $25 million for the three months ended March 31, 2007 and 2006, respectively, and $63 million for the year ended December 31, 2006. We recorded, in AOCI, a $2 million reduction in gross unrealized gains on these investments for the three months ended March 31, 2007, and net unrealized gains on these investments of $38 million for the three months ended March 31, 2006. For the year ended December 31, 2006, we recorded, in AOCI, gross unrealized gains on these investments of $194 million.

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

ITEM 4. CONTROLS AND PROCEDURES

Senior management, including the Chief Executive Officer and Chief Financial Officer, 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 Chief Executive Officer and Chief Financial Officer have concluded that Dominion s disclosure controls and procedures are effective. There were no changes in Dominion s internal control over financial reporting that occurred during the last fiscal quarter that have materially affected, or are reasonably likely to materially affect, Dominion s internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

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

In March 2006, Peoples and Equitable filed a joint petition with the Pennsylvania Commission seeking approval of the purchase by Equitable of all of the stock of Peoples and Hope. In April 2006, Hope and Equitable filed a joint petition seeking West Virginia Commission approval of the purchase by Equitable of all of the stock of Hope. In April 2007, the Pennsylvania Commission approved a joint settlement approving the sale in Pennsylvania. Following the approval of the sale of Peoples by the Pennsylvania Commission, the FTC filed an action in federal court seeking to block the transaction. A hearing on the FTC s request for an injunction is scheduled for early June. Dominion and Equitable have asked the court to dismiss the FTC s complaint and a ruling on this motion to dismiss is expected in early May. The West Virginia Commission has scheduled hearings in May related to the sale of Hope to Equitable.

In July 1997, Jack Grynberg brought suit against CNG Producing Company, predecessor to DEPI, and several of its affiliates (there are 73 defendants in this case). The suit seeks damages for alleged fraudulent mis-measurement of gas volumes and underreporting of gas royalties from gas production taken from federal leases. The suit was consolidated with approximately 360 other cases in the U.S. District Court for the District of Wyoming. Parts of Mr. Grynberg s claims were dismissed on the basis that they overlapped with Mr. Wright s claims, which are noted below. Mr. Grynberg has filed an appeal. In October 2006, Judge Downes issued an order dismissing all claims against DEPI and its affiliates on the jurisdictional grounds that Mr. Grynberg has failed to meet his burden to prove he is the original source of the claims being asserted under the False Claims Act. Mr. Grynberg has appealed this order.

In April 1998, Harrold E. (Gene) Wright filed suit against DEPI (formerly known as CNG Producing Company), a subsidiary of CNG, and numerous other companies under the False Claims Act. Mr. Wright alleged various fraudulent valuation practices in the payment of royalties due under federal oil and gas leases. Shortly after filing, this case was consolidated under the Federal Multidistrict Litigation rules with the Grynberg case noted above. A substantial portion of the claim against us was resolved by settlement in late 2002. The case was remanded back to the U.S. District Court for the Eastern District of Texas, which denied our motion to dismiss on jurisdictional grounds in January 2005. Discovery in this matter is currently underway. In February 2007, the Judge issued an order providing that trials will occur in phases on 25% of each defendant s leases to be selected by the opposing party by July 1, 2007. The Phase I trial (currently involving another defendant) will commence in August 2008. A Phase II trial will occur in February 2009 against two defendants selected by the opposing party by September 14, 2007, with subsequent phases of trials occurring against other defendants in the future with up to two defendants at each future trial.

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, 2006, which should be taken into consideration when reviewing the information contained in this report. With the exception of the risk factor below, there have been no material changes with regard to the risk factors previously disclosed in our most recent Form 10-K. 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.

We are exposed to cost-recovery shortfalls because of capped base rates and amendments to the fuel cost recovery statute in effect in Virginia. Under the 1999 Virginia Electric Utility Restructuring Act (Restructuring Act) as amended in 2007, our base rates remain capped through December 31, 2008 unless sooner modified or terminated. Although the Restructuring Act allows for the recovery of certain generation-related costs during the capped rates period, we remain exposed to numerous risks of cost-recovery shortfalls. These risks include exposure to stranded costs, future environmental compliance requirements, certain tax law changes, costs related to hurricanes or other weather events, inflation, the cost of obtaining replacement power during unplanned plant outages and increased capital costs.

In addition, our current Virginia fuel factor provisions are locked-in until July 1, 2007, with no deferred fuel accounting. As a result, until July 1, 2007 we are exposed to fuel price and other risks. These risks include exposure to increased costs of fuel, including purchased power costs, differences between our projected and actual power generation mix and generating unit performance (which affects the types and amounts of fuel we use) and differences between fuel price assumptions and actual fuel prices. Annual fuel rate adjustments, with deferred fuel accounting for over- or under-recoveries of fuel costs, will be instituted beginning July 1, 2007. Beginning July 1, 2007, our risk of under-recovering prudently incurred fuel and purchased power expenses is greatly diminished.

The 2007 amendments to the fuel cost recovery statute call for annual fuel cost recovery proceedings beginning July 1, 2007 and continuing thereafter. The first annual increase as of July 1, 2007 will be limited to an amount that results in the residential customer class not receiving an increase of more than 4% of total rates as of that date, and the remainder will be deferred, without interest, and collected in the period commencing July 1, 2008 and ending June 30, 2011. The amendments to the Restructuring Act and the fuel cost recovery statute will become effective July 1, 2007.

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

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

ISSUER PURCHASES OF EQUITY SECURITIES

Period	(a) Total Number of Shares (or Units) Purchased[1]	(b) Average Price Paid per Share (or Unit)	(c) Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased under the Plans or Programs
1/1/07-1/31/07	1,976	$82.33	N/A	15,738,572 shares/ $1.23 billion
2/1/07-2/28/07	19,446	86.55	N/A	15,738,572 shares/ $1.23 billion
3/1/07-3/31/07			N/A	15,738,572 shares/ $1.23 billion
Total	21,422	$86.16	N/A	15,738,572 shares/ $1.23 billion

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

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

Our Annual Shareholders Meeting was held on April 27, 2007. Results of items presented for voting are listed below.

Election of Directors

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

Nominee	Votes For	Votes Withheld
Peter W. Brown	294,112,081	4,833,721
George A. Davidson, Jr.	293,735,150	5,210,652
Thomas F. Farrell, II	294,132,024	4,813,778
John W. Harris	293,689,396	5,256,406
Robert S. Jepson, Jr.	293,722,488	5,223,314
Mark J. Kington	293,719,056	5,226,746
Benjamin J. Lambert, III	293,786,886	5,158,916
Margaret A. McKenna	294,083,863	4,861,939
Frank S. Royal	292,274,888	6,670,914
David A. Wollard	293,605,025	5,340,777

Appointment Of Auditors

The appointment of Deloitte & Touche LLP as our independent auditors for 2007 was ratified by shareholders as follows:

Votes For	**Votes Against**	**Votes Abstained**
295,047,020	1,581,023	2,317,750

Shareholder Proposals

Shareholders did not approve a proposal requesting a report to shareholders on how we are responding to regulatory and public pressure to reduce carbon dioxide and other emissions from the Company s power plant operations. The vote was as follows:

Votes For	Votes Against	Votes Abstained
46,755,754	168,734,156	37,269,361

Shareholders did not approve a proposal requesting a report evaluating how the environmental, health and cultural impacts created by utilizing a National Interest Electric Transmission Corridor would differ if that process was not used to site a new transmission line in Northern Virginia. The vote was as follows:

Votes For	Votes Against	Votes Abstained
13,668,685	201,516,904	37,510,787

ITEM 5. OTHER INFORMATION

The following items are reported below in lieu of on a Form 8-K. Each of these events has occurred within four business days preceding the date of this report.

Entry into a Material Definitive Agreement (Form 8-K Item 1.01)

In April 2007, we entered into an agreement with Eni Petroleum to sell substantially all of our offshore E&P operations for approximately $4.76 billion. The transaction is expected to close by early July 2007, subject to customary closing conditions and adjustments. Our offshore operations include approximately 967 bcfe of proved natural gas and oil reserves in the outer continental shelf and deepwater areas of the Gulf of Mexico at December 31, 2006. Of this total, approximately 961 bcfe are being sold to Eni Petroleum. The effective date for the sale is June 30, 2007. Eni Petroleum s obligations under the agreement are guaranteed by its parent company, Eni S.p.A. A copy of the Agreement is filed herewith as Exhibit 10.5. Remaining offshore E&P operations are expected to be disposed of in a separate transaction by early July 2007.

We continue to pursue the potential disposition of our Canadian and U.S. onshore E&P operations, excluding those in the Appalachian Basin. Net cash proceeds from this disposition and any future dispositions will be used to reduce debt, including debt at our CNG subsidiary. We would also expect to repurchase shares of our common stock and/or acquire select assets to complement our remaining businesses.

Costs Associated with Exit or Disposal Activities (Form 8-K Item 2.05)

The offshore disposition will result in an initial pre-tax charge of approximately $370 million, which will be reported in second quarter 2007 earnings. This reflects the discontinuance of hedge accounting for certain cash flow hedges related to our offshore E&P operations since it became probable that the forecasted sales of gas and oil will not occur. In connection with the discontinuance of hedge accounting for these contracts, we will reclassify approximately $370 million of pre-tax losses from AOCI to earnings. We have entered into offsetting positions for these gas and oil derivatives that will minimize the volatility that would have resulted from these contracts being marked to market through earnings. We expect that this charge will be more than offset by the gain we ultimately expect to recognize on the disposition.

In addition to this initial charge, we anticipate recording additional charges related to the disposition plan that are not currently estimable. These charges will include cash expenditures for transaction costs, including employee-related, legal and other costs.

ITEM 6. EXHIBITS

(a) Exhibits:

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

3.2 Bylaws as in effect on February 28, 2007 (Exhibit 3.1, Form 8-K filed March 2, 2007, File No. 1-8489, incorporated by reference).

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

4.2 Form of Senior Indenture, dated June 1, 2000, between Dominion Resources, Inc. and The Bank of New York (as successor trustee to JP Morgan Chase Bank (formerly The Chase Manhattan Bank)), as Trustee (Exhibit 4 (iii), Form S-3, Registration Statement, File No. 333-93187, incorporated by reference); First Supplemental Indenture, dated June 1, 2000 (Exhibit 4.2, Form 8-K, dated June 21, 2000, File No. 1-8489, incorporated by reference); Second Supplemental Indenture, dated July 1, 2000 (Exhibit 4.2, Form 8-K, dated July 11, 2000, File No. 1-8489, incorporated by reference); Third Supplemental Indenture, dated July 1, 2000 (Exhibit 4.3, Form 8-K dated July 11, 2000, incorporated by reference); Fourth Supplemental Indenture and Fifth Supplemental Indenture dated September 1, 2000 (Exhibit 4.2, Form 8-K, dated September 8, 2000, incorporated by reference); Sixth Supplemental Indenture, dated September 1, 2000 (Exhibit 4.3, Form 8-K, dated September 8, 2000, incorporated by reference); Seventh Supplemental Indenture, dated October 1, 2000 (Exhibit 4.2, Form 8-K, dated October 11, 2000, incorporated by reference); Eighth Supplemental Indenture, dated January 1, 2001 (Exhibit 4.2, Form 8-K, dated January 23, 2001, incorporated by reference); Ninth Supplemental Indenture, dated May 1, 2001 (Exhibit 4.4, Form 8-K, dated May 25, 2001, incorporated by reference); Form of Tenth Supplemental Indenture (Exhibit 4.2, Form 8-K filed March 18, 2002, File No. 1-8489, incorporated by reference); Form of Eleventh Supplemental Indenture (Exhibit 4.2, Form 8-K filed June 25, 2002, File No. 1-8489, incorporated by reference.); Form of Twelfth Supplemental Indenture (Exhibit 4.2, Form 8-K filed September 11, 2002, File No. 1-8489, incorporated by reference); Thirteenth Supplemental Indenture dated September 16, 2002 (Exhibit 4.1, Form 8-K filed September 17, 2002, File No. 1-8489, incorporated by reference); Fourteenth Supplemental Indenture, dated August 20, 2003 (Exhibit 4.4, Form 8-K filed August 20, 2003, File No. 1-8489, incorporated by reference); Forms of Fifteenth and Sixteenth Supplemental Indentures (Exhibits 4.2 and 4.3 to Form 8-K filed December 12, 2002, File No. 1-8489, incorporated by reference); Forms of Seventeenth and Eighteenth Supplemental Indentures (Exhibits 4.2. and 4.3 to Form 8-K filed February 11, 2003, File No. 1-8489, incorporated by reference); Forms of Twentieth and Twenty-First Supplemental Indentures (Exhibits 4.2 and 4.3 to Form 8-K filed March 4, 2003, File No. 1-8489, incorporated by reference); Form of Twenty-Second Supplemental Indenture (Exhibit 4.2 to Form 8-K filed July 22, 2003, File No. 1-8489 incorporated by reference); Form of Twenty-Third Supplemental Indenture (Exhibit 4.2, Form 8-K filed December 9, 2003, File No. 1-8489, incorporated by reference); Form of Twenty-Fifth Supplemental Indenture (Exhibit 4.2, Form 8-K filed January 14, 2004, File No. 1-8489, incorporated by reference); Form of Twenty-Sixth Supplemental Indenture (Exhibit 4.3, Form 8-K filed January 14, 2004, File No. 1-8489, incorporated by reference); Form of Twenty-Seventh Supplemental Indenture (Exhibit 4.2, Form S-4 Registration Statement, File No. 333-120339, incorporated by reference); Form of Twenty-Eighth and Twenty-Ninth Supplemental Indenture (Exhibits 4.2 and 4.3, Form 8-K filed June 17, 2005, File No. 1-8489, incorporated by reference); Form of Thirtieth Supplemental Indenture (Exhibit 4.2, Form 8-K, filed July 12, 2005, File No. 1-8489, incorporated by reference); Form of Thirty-First Supplemental Indenture (Exhibit 4.2, Form 8-K, filed September 26, 2005, File No. 1-8489, incorporated by reference); Forms of Thirty-Second and Thirty-Third Supplemental Indentures (Exhibits 4.2 and 4.3 to Form 8-K filed November 13, 2006, File No. 1-8489, incorporated by reference).

10.1 2007 Long-Term Compensation Program Form of Restricted Stock Grant (Exhibit 10.1, Form 8-K filed April 5, 2007, File No. 1-8489, incorporated by reference).

10.2 2007 Long-Term Compensation Program Form of Performance Grant (Exhibit 10.2, Form 8-K filed April 5, 2007, File No. 1-8489, incorporated by reference).

10.3 2007 Long-Term Compensation Program (E&P) Form of Restricted Stock Grant (Exhibit 10.3, Form 8-K filed April 5, 2007, File No. 1-8489, incorporated by reference).

10.4 2007 Long-Term Compensation Program (E&P) Form of Performance Grant (Exhibit 10.4, Form 8-K filed April 5, 2007, File No. 1-8489, incorporated by reference).

10.5 Offshore Package Purchase Agreement Between Dominion Exploration & Production, Inc. as Seller and ENI Petroleum Co., Inc. as Purchaser dated as of April 27, 2007 (filed herewith).

10.6 Non-Employee Directors Annual Compensation effective April 27, 2007 (filed herewith).

12 Ratio of earnings to fixed charges (filed herewith).

31.1 Certification by Registrant s Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).

31.2 Certification by Registrant s Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).

32 Certification to the Securities and Exchange Commission by Registrant s Chief Executive Officer and Chief Financial Officer, as required by Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith).

99 Condensed consolidated earnings statements (unaudited) (filed herewith).

SIGNATURE

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

DOMINION RESOURCES, INC.

Registrant

May 2, 2007

/s/ Steven A. Rogers
Steven A. Rogers

Senior Vice President and

Chief Accounting Officer