DOMINION RESOURCES INC /VA/
Form 10-Q
August 03, 2006

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark one)

__X__ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2006

or

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

Commission File Number 001-08489

DOMINION RESOURCES, INC.
(Exact name of registrant as specified in its charter)

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, 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 June 30, 2006, the latest practicable date for determination, 352,848,326 shares of common stock, without par value, of the registrant were outstanding.

DOMINION RESOURCES, INC.

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PART I. Financial Information

DOMINION RESOURCES, INC.
PART I. FINANCIAL INFORMATION
ITEM 1. CONSOLIDATED FINANCIAL STATEMENTS
CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	**2006**	2005
(millions, except per share amounts)				
Operating Revenue	**$ 3,556**	$ 3,646	**$ 8,513**	$ 8,382
Operating Expenses				
Electric fuel and energy purchases	**760**	943	**1,526**	1,784
Purchased electric capacity	**116**	122	**239**	256
Purchased gas	**432**	553	**1,810**	1,775
Other energy-related commodity purchases	**318**	318	**718**	642
Other operations and maintenance	**906**	522	**1,674**	1,353
Depreciation, depletion and amortization	**410**	349	**791**	695
Other taxes	**131**	134	**312**	299
Total operating expenses	**3,073**	2,941	**7,070**	6,804
Income from operations	**483**	705	**1,443**	1,578
Other income	**49**	32	**92**	83
Interest and related charges:				
Interest expense	**224**	199	**458**	416
Interest expense - junior subordinated notes payable	**33**	26	**60**	52
Subsidiary preferred dividends	**4**	4	**8**	8
Total interest and related charges	**261**	229	**526**	476
Income before income tax expense	**271**	508	**1,009**	1,185
Income tax expense	**110**	176	**314**	424
Net income	**$ 161**	$ 332	**$ 695**	$ 761
Earnings Per Common Share - Basic	**$ 0.46**	$ 0.98	**$ 2.00**	$ 2.24
Earnings Per Common Share - Diluted	**$ 0.46**	$ 0.97	**$ 1.99**	$ 2.23
Dividends paid per common share	**$ 0.69**	$ 0.67	**$ 1.38**	$ 1.34

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

DOMINION RESOURCES, INC.
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(millions)	June 30, 2006	December 31, 2005[1]
ASSETS		
Current Assets		
Cash and cash equivalents	$ 81	$ 146
Customer accounts receivable (less allowance for doubtful accounts of $24 and $38)	2,220	3,335
Other receivables (less allowance for doubtful accounts of $9 at both dates)	241	226
Inventories	1,034	1,167
Derivative assets	2,554	3,429
Deferred income taxes	642	928
Assets held for sale	1,059	4
Prepayments	103	161
Other	590	733
Total current assets	8,524	10,129
Investments		
Nuclear decommissioning trust funds	2,557	2,534
Available for sale securities	39	287
Loans receivable, net	397	31
Other	652	649
Total investments	3,645	3,501
Property, Plant and Equipment		
Property, plant and equipment	42,937	42,063
Accumulated depreciation, depletion and amortization	(13,418)	(13,123)
Total property, plant and equipment, net	29,519	28,940
Deferred Charges and Other Assets		
Goodwill	4,298	4,298
Prepaid pension cost	1,882	1,915
Derivative assets	1,082	1,915
Regulatory assets	435	758
Other	1,283	1,204
Total deferred charges and other assets	8,980	10,090
Total assets	$ 50,668	$ 52,660

(1) The Consolidated Balance Sheet at December 31, 2005 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)

(millions)	June 30, 2006	December 31, 2005[1]
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Securities due within one year	**$ 2,279**	$ 2,330
Short-term debt	**1,065**	1,618
Accounts payable	**1,773**	2,756
Accrued interest, payroll and taxes	**681**	694
Derivative liabilities	**4,212**	6,087
Liabilities held for sale	**404**	--
Other	**662**	995
Total current liabilities	**11,076**	14,480
Long-Term Debt		
Long-term debt	**13,964**	13,237
Junior subordinated notes payable:		
Affiliates	**1,440**	1,416
Other	**299**	--
Total long-term debt	**15,703**	14,653
Deferred Credits and Other Liabilities		
Deferred income taxes and investment tax credits	**5,384**	4,984
Asset retirement obligations	**2,335**	2,249
Derivative liabilities	**2,174**	3,971
Regulatory liabilities	**590**	607
Other	**1,023**	1,062
Total deferred credits and other liabilities	**11,506**	12,873
Total liabilities	**38,285**	42,006
Commitments and Contingencies (see Note 15)		
Minority Interest	**17**	--
Subsidiary Preferred Stock Not Subject to Mandatory Redemption	**257**	257
Common Shareholders' Equity		
Common stock - no par[2]	**11,672**	11,286
Other paid-in capital	**127**	125
Retained earnings	**1,762**	1,550
Accumulated other comprehensive loss	**(1,452)**	(2,564)
Total common shareholders' equity	**12,109**	10,397
Total liabilities and shareholders' equity	**$ 50,668**	$ 52,660

(1) The Consolidated Balance Sheet at December 31, 2005 has been derived from the audited Consolidated Financial Statements at that date.

(2) 500 million shares authorized; 353 million shares outstanding at June 30, 2006 and 347 million shares outstanding at December 31, 2005.

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

DOMINION RESOURCES, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

Six Months Ended June 30,	2006	2005
(millions)		
Operating Activities		
Net income	$ 695	$ 761
Adjustments to reconcile net income to net cash provided by operating activities:		
DCI impairment losses	89	15
Charges related to pending sale of gas distribution subsidiaries	178	--
Net realized and unrealized derivative (gains) losses	(234)	50
Depreciation, depletion and amortization	862	751
Deferred income taxes and investment tax credits, net	242	115
Other adjustments to income, net	(176)	(135)
Changes in:		
Accounts receivable	964	171
Inventories	93	69
Deferred fuel and purchased gas costs, net	202	114
Prepaid pension cost	28	15
Accounts payable	(884)	(164)
Accrued interest, payroll and taxes	33	33
Deferred revenues	(143)	(163)
Margin deposit assets and liabilities	(142)	(323)
Other operating assets and liabilities	182	61
Net cash provided by operating activities	1,989	1,370
Investing Activities		
Plant construction and other property additions	(913)	(774)
Additions to gas and oil properties, including acquisitions	(1,018)	(812)
Proceeds from sale of gas and oil properties	20	580
Acquisition of businesses	(91)	(642)
Proceeds from sale of securities	493	422
Purchases of securities	(530)	(451)
Other	87	122
Net cash used in investing activities	(1,952)	(1,555)
Financing Activities		
Issuance (repayment) of short-term debt, net	(553)	709
Issuance of long-term debt	1,300	600
Repayment of long-term debt	(723)	(915)
Issuance of common stock	372	245
Repurchase of common stock	--	(276)
Common dividend payments	(483)	(458)
Other	(13)	(37)
Net cash used in financing activities	(100)	(132)
Decrease in cash and cash equivalents	(63)	(317)
Cash and cash equivalents at beginning of period	146	361
Cash and cash equivalents at end of period[(1)]	$ 83	$ 44
Noncash Financing Activities:		
Issuance of long-term debt and establishment of trust	$ 47	--

Assumption of debt related to acquisition of non-utility generating facility	--	$	62

(1) 2006 amount includes $2 million of cash classified as held for sale on the Consolidated Balance Sheet.

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 within an area of approximately 30,000 square miles in Virginia and northeastern North Carolina. Virginia Power serves approximately 2.3 million retail customer accounts, including governmental agencies and wholesale customers such as rural electric cooperatives and municipalities. On May 1, 2005, Virginia Power became a member of PJM Interconnection, LLC (PJM), a regional transmission organization (RTO). As a result, Virginia Power integrated its control area 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. Its regulated gas distribution subsidiaries serve 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 serve approximately 1.4 million residential and commercial customer accounts in the Northeast, Mid-Atlantic and Midwest regions of the United States. 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 operations are located in several major gas and oil producing basins in the United States, 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.

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.

We manage our daily operations through four primary operating segments: Dominion Delivery, Dominion Energy, Dominion Generation and Dominion Exploration & Production (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 the use, may represent any of 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, 2005 and our Quarterly Report on Form 10-Q for the quarter ended March 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 June 30, 2006, our results of operations for the three and six months ended June 30, 2006 and 2005, and our cash flows for the six months ended June 30, 2006 and 2005.

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.

We report certain contracts and instruments at fair value in accordance with GAAP. 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, 2005 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 2005 Consolidated Financial Statements and Notes have been reclassified to conform to the 2006 presentation.

Note 3. Newly Adopted Accounting Standards

SFAS No. 123R

Effective January 1, 2006, we adopted Statement of Financial Accounting Standards (SFAS) No. 123 (revised 2004), *Share-Based Payment* (SFAS No. 123R), which requires that compensation expense relating to share-based payment transactions be recognized in the financial statements based on the fair value of the equity or liability instruments issued. SFAS No. 123R covers a wide range of share plans, performance-based awards, share appreciation rights and employee share purchase plans. We adopted SFAS No. 123R using the modified prospective application transition method. Under this transition method, compensation cost is recognized (a) based on the requirements of SFAS No. 123R for all share-based awards granted subsequent to January 1, 2006 and (b) based on the original provisions of SFAS No. 123, *Accounting for Stock-Based Compensation*, for all awards granted prior to January 1, 2006, but not vested as of that date. Results for prior periods were not restated.

Prior to January 1, 2006, we accounted for our stock-based compensation plans under the measurement and recognition provisions of Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees,* and related interpretations. Under this method, stock option awards generally did not result in compensation expense since their exercise price was typically equal to the market price of our common stock on the date of grant. Accordingly, stock-based compensation expense was included as a pro forma disclosure in the footnotes to our financial statements.

The following table illustrates the pro forma effect on net income and earnings per share (EPS) for the three and six months ended June 30, 2005, if we had applied the fair value recognition provisions of SFAS No. 123 to stock-based employee compensation:

	Three Months Ended June 30, 2005	Six Months Ended June 30, 2005
(millions, except EPS)		
Net income, as reported	$ 332	$ 761
Add: actual stock-based compensation expense, net of tax	3	6
Deduct: pro forma stock-based compensation expense, net of tax	(4)	(7)
Net income, pro forma	$ 331	$ 760
Basic EPS - as reported	$ 0.98	$ 2.24
Basic EPS - pro forma	$ 0.98	$ 2.24
Diluted EPS - as reported	$ 0.97	$ 2.23
Diluted EPS - pro forma	$ 0.97	$ 2.22

Prior to the adoption of SFAS No. 123R, we presented the benefits of tax deductions resulting from the exercise of stock-based compensation as an operating cash flow in our Consolidated Statements of Cash Flows. SFAS No. 123R requires the benefits of tax deductions in excess of the compensation cost recognized for stock-based compensation (excess tax benefits) to be classified as a financing cash flow. Approximately $1 million of excess tax benefits were realized for the six months ended June 30, 2006.

Restricted stock awards granted prior to January 1, 2006 contain terms that accelerate vesting upon retirement. Our previous practice was to recognize compensation cost for these awards over the stated vesting term unless vesting was actually accelerated by retirement. Following our adoption of SFAS No. 123R, we continue to recognize compensation cost over the stated vesting term for existing restricted stock awards, but 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 the three months and six months ended June 30, 2006, we recognized approximately $1 million and $3 million, respectively, of compensation cost related to awards previously granted to retirement eligible employees. At June 30, 2006 unrecognized compensation cost for restricted stock awards held by retirement eligible employees totaled approximately $7 million.

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. We typically enter into either a single or a series of buy/sell transactions in which we sell our crude oil production at the offshore field delivery point and buy similar quantities at Cushing, Oklahoma for sale to third parties. We are able to enhance profitability by selling to a wide array of refiners and/or trading companies at Cushing, one of the largest crude oil markets in the world, versus restricting sales to a limited number of refinery purchasers in the Gulf of Mexico.

In September 2005, the Financial Accounting Standards Board (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*, 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 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 June 30, 2006; however, there was no impact on our results of operations or cash flows. Pursuant to the transition provisions of EITF 04-13, activity related to buy/sell arrangements that were entered into prior to April 1, 2006 and have not been modified or renewed after that date continue to be reported on a gross basis and are summarized below:

	Three Months Ended June 30,		**Six Months Ended June 30,**	
	2006	2005	**2006**	2005
(millions)				
Sale activity included in operating revenue	**$191**	$83	**$422**	$176
Purchase activity included in operating expenses(1)	**185**	79	**409**	168

(1) Included in other energy-related commodity purchases expense

Note 4. Recently Issued Accounting Standards

SFAS No. 155

In February 2006, the FASB issued SFAS No. 155, *Accounting for Certain Hybrid Financial Instruments.* SFAS No. 155 permits fair value remeasurement for any hybrid financial instrument that contains an embedded derivative that would otherwise require bifurcation. We will adopt the provisions of this standard prospectively beginning January 1, 2007 and do not expect the adoption to have a material impact on our results of operations and financial condition.

FIN 48

In July 2006, the FASB issued FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* (FIN 48). FIN 48 establishes standards for measurement and recognition in financial statements of positions taken by an entity in its income tax returns. In addition, FIN 48 requires new disclosures about positions taken by an entity in its tax returns that are not recognized in its financial statements, information about potential significant changes in estimates related to tax positions and descriptions of open tax years by major jurisdiction. The provisions of FIN 48 will become effective for us beginning January 1, 2007, with the cumulative effect of the change in accounting principle recorded as an adjustment to retained earnings. We are currently evaluating the impact that FIN 48 will have on our results of operations and financial condition.

Note 5. 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, The Peoples Natural Gas Company (Peoples) and Hope Gas, Inc. (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 first quarter of 2007, subject to state regulatory approvals in Pennsylvania and West Virginia, as well as approval under the federal Hart-Scott-Rodino Act. The carrying amounts of the major classes of assets and liabilities classified as held for sale in our Consolidated Balance Sheet are as follows:

		June 30, 2006
(millions)		
ASSETS		
Current Assets		
Cash	$	2
Customer accounts receivable		127
Unrecovered gas costs		30
Other		66
Total current assets		225
Investments		2
Property, Plant and Equipment		
Property, plant and equipment		1,110
Accumulated depreciation, depletion and amortization		(382)
Total property, plant and equipment, net		728
Deferred Charges and Other Assets		
Regulatory assets		101
Other		2
Total deferred charges and other assets		103
Assets held for sale	$	1,058
LIABILITIES		
Current Liabilities		
Accounts payable, trade	$	46
Payables to affiliates		20
Deferred income taxes		14
Other		92
Total current liabilities		172
Deferred Credits and Other Liabilities		
Asset retirement obligations		33
Deferred income taxes		164
Regulatory liabilities		26
Other		9
Total deferred credits and other liabilities		232
Liabilities held for sale	$	404

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	**2006**	2005
(millions)				

Operating Revenue	**$ 92**	$ 96	**$ 449**	$ 412
Income (loss) before income taxes	**--**	1	**(128)**	46

In the six months ended June 30, 2006, we recognized a $162 million ($98 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. We also established $135 million of deferred tax liabilities on our Consolidated Balance Sheet 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 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 an adjustment since the financial reporting basis of our investment in Peoples and Hope exceeds our tax basis. This difference and related deferred taxes will reverse and will partially offset current tax expense recognized upon closing of the sale.

EITF Issue No. 03-13, *Applying the Conditions of Paragraph 42 of FASB Statement No. 144 in Determining Whether to Report Discontinued Operations*, provides that the results of operations of a component of an entity that has been disposed of or is classified as held for sale shall be reported in discontinued operations if both of the following conditions are met: (a) the operations and cash flows of the component have been (or will be) eliminated from the ongoing operations of the entity as a result of the disposal transaction and (b) the entity will not have any significant continuing involvement in the operations of the component after the disposal transaction. While we do not expect to have significant continuing involvement with Peoples or Hope after their disposal, we do expect to have continuing cash flows related primarily to our sale to them of natural gas production from our E&P operations, as well as natural gas transportation and storage services provided to them by our transmission operations. Due to these expected significant continuing cash flows, the results of Peoples and Hope have not been reported as discontinued operations in our Consolidated Statements of Income. We will continue to assess the level of our involvement and continuing cash flows with Peoples and Hope for one year after the date of sale in accordance with EITF 03-13, and if circumstances change, we may be required to reclassify the results of Peoples and Hope as discontinued operations in our Consolidated Statements of Income.

Note 6. Operating Revenue

Our operating revenue consists of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	**2006**	2005
(millions)				
Operating Revenue				
Electric sales:				
Regulated	**$ 1,283**	$ 1,245	**$ 2,581**	$ 2,567
Nonregulated	**551**	541	**1,151**	1,255
Gas sales:				
Regulated	**175**	217	**975**	995
Nonregulated	**377**	475	**1,259**	1,220
Other energy-related commodity sales	**415**	389	**908**	785
Gas transportation and storage	**202**	181	**487**	456
Gas and oil production	**489**	407	**1,021**	818
Other	**64**	191	**131**	286
Total operating revenue	**$ 3,556**	$ 3,646	**$ 8,513**	$ 8,382

Note 7. Income Taxes

The statutory U.S. federal income tax rate reconciles to our effective income tax rate as follows:

	Six Months Ended June 30,	
	2006	2005
U.S. statutory rate	**35.0%**	35.0%
Increases (decreases) resulting from:		
Amortization of investment tax credits	**(0.5)**	(0.5)
Employee pension and other benefits	**(0.4)**	(0.4)
Employee stock ownership plan and restricted stock dividends	**(0.5)**	(0.4)
Other benefits and taxes - foreign operations	**(0.5)**	(0.9)
State taxes, net of federal benefit	**6.3**	2.8
Changes in valuation allowances	**(20.1)**	0.1
Recognition of deferred taxes - stock of subsidiaries held for sale	**13.4**	--
Other, net	**(1.6)**	0.1
Effective tax rate	**31.1%**	35.8%

Our 2006 effective tax rate reflects a $222 million tax benefit from the reduction of previously recorded valuation allowances on deferred tax assets that arose from federal and state tax loss carryforwards, since a portion of these carryforwards are expected to be utilized to offset capital gain income generated from the pending sale of Peoples and Hope. The effect of that decrease to valuation allowances was partially offset by the establishment of $135 million of deferred tax liabilities associated with the excess of our financial reporting basis over the tax basis in the stock of Peoples and Hope, in accordance with EITF 93-17, as discussed in Note 5. Also during the three-months ended June 30, 2006, we increased valuation allowances by $41 million primarily associated with the deferred tax asset recognized as a result of the impairment of a DCI investment, as discussed in Note 18.

Note 8. Earnings Per Share

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	**2006**	2005
(millions, except EPS)				
Net income	**$ 161**	$ 332	**$ 695**	$ 761
Basic EPS				
Average shares of common stock outstanding - basic	**349.0**	339.7	**347.8**	340.0
Net income	**$ 0.46**	$ 0.98	**$ 2.00**	$ 2.24
Diluted EPS				
Average shares of common stock outstanding	**349.0**	339.7	**347.8**	340.0
Net effect of potentially dilutive securities[1]	**1.5**	2.3	**1.5**	2.1
Average shares of common stock outstanding - diluted	**350.5**	342.0	**349.3**	342.1
Net income	**$ 0.46**	$ 0.97	**$ 1.99**	$ 2.23

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

Potentially dilutive securities with the right to acquire approximately 1.5 million and 3.0 million common shares for the three months ended June 30, 2006 and 2005, respectively, and 1.5 million and 2.2 million common shares for the six months ended June 30, 2006 and 2005, respectively, were not included in the respective period's calculation of diluted EPS because the exercise or purchase prices of those instruments were greater than the average market price of our common shares.

Note 9. Comprehensive Income

The following table presents total comprehensive income (loss):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	**2006**	2005
(millions)				
Net income	**$161**	$332	**$ 695**	$ 761
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	**404**(1)	(27)	**1,123**(1)	(915)(2)
Other(3)	**(31)**	18	**(11)**	(19)
Other comprehensive income (loss)	**373**	(9)	**1,112**	(934)
Total comprehensive income (loss)	**$534**	$323	**$1,807**	$(173)

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

(2) Principally due to unfavorable changes in the fair value of certain commodity derivatives resulting from an increase in commodity prices.

(3) Primarily reflects the impact of both unrealized gains and losses on investments held in decommissioning trusts and foreign currency translation adjustments.

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 mitigate 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 June 30,		Six Months Ended June 30,	
	2006	2005	**2006**	2005
(millions)				
Portion of gains (losses) on hedging instruments determined to be ineffective and included in net income:				
Fair value hedges	**$(1)**	$ 1	**$ (8)**	$ 5
Cash flow hedges (1)	**5**	(15)	**24**	(21)
Net ineffectiveness	**$ 4**	$(14)	**$16**	$(16)

(1) Represents hedge ineffectiveness, primarily due to changes in the fair value differential between the delivery location and commodity specifications of derivatives held by our E&P operations and the delivery location and commodity specifications of our forecasted gas and oil sales.

Gains and losses on hedging instruments that were excluded from the measurement of effectiveness and included in net income for the three and six months ended June 30, 2006 and 2005 were not material.

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

The following table presents selected information related to cash flow hedges included in AOCI in our Consolidated Balance Sheet at June 30, 2006:

(millions)	AOCI After-Tax	Portion Expected to be Reclassified to Earnings during the next 12 Months After-Tax	Maximum Term
Commodities:			
Gas	$ (743)	$ (486)	57 months
Oil	(550)	(343)	30 months
Electricity	(367)	(246)	42 months
Other	(2)	(2)	4 months
Interest rate	(14)	8	240 months
Foreign currency	22	12	17 months
Total	$ (1,654)	$ (1,057)	

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. Approximately 10% of our anticipated production is hedged by qualifying cash flow hedges, for which hedge-adjusted prices were used to calculate estimated future net revenue. Whether period-end market prices or hedge-adjusted prices were used for the portion of production that is hedged, there was no ceiling test impairment as of June 30, 2006.

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, 2005, three potential VIEs, with which we have existing power purchase agreements (signed prior to December 31, 2003), have not provided sufficient information for us to perform our evaluation under FASB Interpretation No. 46 (revised December 2003), *Consolidation of Variable Interest Entities,* (FIN 46R).

As of June 30, 2006, the requested information has not been received from the three 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 three potential VIE supplier entities of $2.0 billion at June 30, 2006. We paid $44 million and $48 million for electric generation capacity and $41 million and $34 million for electric energy to these entities in the three months ended June 30, 2006 and 2005, respectively. We paid $94 million and $101 million for electric generation capacity and $77 million and $80 million for electric energy to these entities in the six months ended June 30, 2006 and 2005, respectively.

During 2005, we entered into four long-term contracts with unrelated limited liability corporations (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 $104 million and $43 million to the LLCs for coal and synthetic fuel produced from coal during the three months ended June 30, 2006 and 2005, respectively, and $215 million and $63 million to the LLCs for coal and synthetic fuel produced from coal in the six months ended June 30, 2006 and 2005, 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 coal and synthetic fuel that the VIEs provide according to the terms of the applicable purchase contracts.

In June 2006, we entered into a six-month weather derivative contract with a special purpose entity (SPE) that will provide us cash payments based on the occurrence of specific hurricane-related weather events in the Gulf of Mexico. This weather derivative was executed as an alternative to traditional business interruption insurance. Concurrent with the execution of the weather derivative contract, the SPE issued $50 million of catastrophe bonds. If specific weather events occur, we will be entitled to proceeds from the SPE of up to $50 million. If no specific weather events occur during the term of the contract, then we will not receive payment from the SPE. Under the weather derivative contract, we will make fixed payments to the SPE totaling approximately $5 million, which will be used by the SPE to pay a portion of the bond investors' interest payments. We will also reimburse the SPE for certain operating costs, including bond issuance costs and other ongoing fees which should total less than $2 million. Our FIN 46R analysis determined that the SPE does not have sufficient equity investment at risk, and therefore is a VIE. Furthermore, we concluded that although our interest in the contract represents a variable interest in the SPE, we are not the primary beneficiary. We are not subject to any risk of loss from the contractual arrangement, as our only obligation is to make fixed payments to the SPE and pay certain operating costs of the SPE.

As discussed in Note 18, DCI holds an investment in the subordinated notes of a third-party collateralized debt obligation (CDO) entity. In June 2006, the CDO entity's equity investor withdrew its capital, which required a redetermination of whether the CDO entity is a VIE under FIN 46R. We concluded that the CDO entity is a VIE and that DCI is the primary beneficiary of the CDO entity, which we have consolidated in accordance with FIN 46R.

In accordance with FIN 46R, we consolidate certain variable interest lessor entities through which we have financed and leased several power generation projects, as well as our corporate headquarters and aircraft. Our Consolidated Balance Sheets as of June 30, 2006 and December 31, 2005 reflect net property, plant and equipment of $928 million and $943 million, respectively and $1.1 billion of debt related to these entities. The debt is non-recourse to us and is secured by the entities' property, plant and equipment. Of the $1.1 billion of debt, $580 million relates to leases under which we operate three of the power generation facilities that terminate in November 2006. We intend to purchase the facilities under the terms of the lease agreements on or before the end of the lease term from the lessor entities who will use the proceeds to repay the related debt.

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 June 30, 2006, we had committed lines of credit totaling $5.75 billion. These lines of credit support commercial paper borrowings and letter of credit issuances. At June 30, 2006, we had the following commercial paper and letters of credit outstanding and capacity available under credit facilities:

(millions)	Facility Limit	Outstanding Commercial Paper	Outstanding Letters of Credit	Facility Capacity Available
Five-year revolving credit facility[1]	$ 3,000	$ 998	$ 653	$ 1,349
Five-year CNG credit facility[2]	1,700	--	1,039	661
364-day CNG credit facility[3]	1,050	--	--	1,050
Totals	$ 5,750	$ 998	$ 1,692	$ 3,060

(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.

(3) The $1.05 billion 364-day 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 February 2007.

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 our price risk management strategies for gas and oil production operations. At June 30, 2006, we had the following letter of credit facilities:

Company (millions)	Facility Limit	Outstanding Letters of Credit	Facility Capacity Remaining	Facility Inception Date	Facility Maturity Date
CNG	$ 100	$ 100	$ --	June 2004	June 2007
CNG	100	5	95	August 2004	August 2009
CNG[1]	200	--	200	December 2005	December 2010
Totals	$ 400	$ 105	$ 295		

(1) This facility can also be used to support commercial paper borrowings.

Long-Term Debt

In January 2006, Virginia Power issued $450 million of 5.4% senior notes that mature in 2016 and $550 million of 6.0% senior notes that mature in 2036. We used the proceeds from this issuance to repay short-term debt incurred to redeem Virginia Power's $512 million callable mortgage bonds, and a portion of Virginia Power's maturing long-term debt.

In February 2006, Dominion Energy Brayton Point, LLC borrowed $47 million in connection with the Massachusetts Development Finance Agency's issuance of its Solid Waste Disposal Revenue Bonds (Dominion Energy Brayton Point Issue) Series 2006, which mature in 2036 and bear a coupon rate of 5.0%. The bonds were issued pursuant to a trust agreement whereby funds are withdrawn from the trust as improvements are made at our Brayton Point Station located in Somerset, Massachusetts. We have withdrawn $33 million from the trust as of June 30, 2006.

In February 2006, we remarketed $330 million of 5.75% Series A senior notes related to our equity-linked debt securities. The senior notes, which will mature in 2008, now carry an annual interest rate of 5.687%.

In June 2006, we issued $300 million of 2006 Series A Enhanced Junior Subordinated Notes (hybrids) that mature in 2066. The hybrids will bear interest at 7.5% per year until June 30, 2016. Beginning June 30, 2016, the hybrids will bear interest at the three-month London Interbank Offered Rate (LIBOR) plus 2.825%, reset quarterly. We used the proceeds from this issuance for general corporate purposes including the repayment of short-term debt.

As discussed in Note 18, in June 2006, DCI began consolidating a CDO entity in accordance with FIN 46R. At June 30, 2006, this CDO entity had $385 million of notes payable that mature in January 2017 and are nonrecourse to us.

We repaid $723 million of long-term debt during the six months ended June 30, 2006.

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 June 30, 2006, 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
We maintain Dominion Direct® (a dividend reinvestment and open enrollment direct stock purchase plan) and a number of employee savings plans through which employer and employee contributions may be invested in Dominion common stock. These shares may either be newly issued or purchased on the open market with proceeds contributed to these plans by plan participants and us.

From February 2005 until May 2006, Dominion Direct® and the employee savings plans purchased Dominion common stock on the open market with the proceeds received through these programs, rather than having additional new common shares issued. In May 2006, we began issuing new common shares in consideration of proceeds received through these programs.

During the six months ended June 30, 2006, we issued 5.1 million shares of common stock and received proceeds of $372 million. Of this amount, 4.5 million shares and proceeds of $330 million resulted from the settlement of stock purchase contracts associated with our 2002 issuance of equity-linked debt securities. Net proceeds were used for general corporate purposes, principally repayment of debt. The remainder of the shares issued and proceeds received were through Dominion Direct®, employee savings plans and 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 Organization, Compensation and Nominating Committee of the Board of Directors or the Board of Directors itself, as provided under each individual plan. At June 30, 2006, approximately 15 million shares were available for future grants under these plans. Prior to April 2005, we had an incentive compensation plan that provided stock options and restricted stock awards to directors, executives and other key employees with vesting periods from one to five years. Stock options generally had contractual terms from six and one half to ten years in length.

Our results for the three months ended June 30, 2006 and 2005 include $11 million and $6 million, respectively, of compensation costs and $4 million and $2 million, respectively, of income tax benefits related to our stock-based compensation arrangements. Our results for the six months ended June 30, 2006 and 2005 include $15 million and $10 million, respectively, of compensation costs and $5 million and $4 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 stock options outstanding for the six months ended June 30, 2006:

	Shares (thousands)	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life (years)	Aggregate intrinsic value[(1)] (millions)
Outstanding and exercisable at January 1, 2006	8,214	$ 60.43		
Granted	--	--		
Exercised	(89)	57.50		$ 1
Forfeited/expired	(10)	61.85		
Outstanding and exercisable at June 30, 2006	8,115	$ 60.46	3.7	$ 114

(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 $5 million and $236 million in the six months ended June 30, 2006 and 2005, respectively.

Restricted Stock

The fair value of our restricted stock awards is equal to the market price of our stock on the date of grant. These awards generally vest over a three-year service period and are settled by issuing new shares. The following table provides a summary of restricted stock activity for the six months ended June 30, 2006:

	Shares (thousands)	Weighted-Average Grant Date Fair Value

Nonvested at January 1, 2006	1,131	$63.28
Granted	313	70.20
Vested	(164)	60.42
Cancelled and forfeited	(8)	67.69
Nonvested at June 30, 2006	1,272	$65.32

As of June 30, 2006, unrecognized compensation cost related to nonvested restricted stock awards totaled $44 million and is expected to be recognized over a weighted-average period of 1.6 years. In the six months ended June 30, 2006, the fair value of restricted stock awards that vested totaled $13 million.

Goal-Based Stock

In April 2006, goal-based stock awards were granted to key non-officer employees. The issuance of awards is based on the achievement of multiple performance metrics during 2006 and 2007, including business unit goals, return on invested capital and total shareholder return relative to that of a peer group of companies. At June 30, 2006, the targeted number of shares to be issued is 99,525, but the actual number of shares issued will vary between zero and 200% of targeted shares depending on the level of performance metrics achieved. The fair value of goal-based stock is equal to the market price of our stock on the date of grant. Awards will vest in April 2009 and be settled by issuing new shares. The following table provides a summary of goal-based stock activity:

	Targeted Number of Shares (thousands)	Weighted-Average Grant Date Fair Value
Nonvested at January 1, 2006	--	$ --
Granted	100.0	69.53
Vested	--	--
Cancelled and forfeited	(0.5)	69.53
Nonvested at June 30, 2006	99.5	$69.53

As of June 30, 2006, unrecognized compensation cost related to nonvested goal-based stock awards totaled $6 million and is expected to be recognized over a weighted-average period of 1.9 years.

Cash-Based Performance Grant

In April 2006, a cash-based performance grant was made to officers. Payout of the performance grant will occur by March 15, 2008 and is based on the achievement of two performance metrics, return on invested capital and total shareholder return relative to that of a peer group of companies. These metrics will be measured during 2006 and 2007. At June 30, 2006, the targeted amount of the grant is $15 million, but actual payout will vary between zero and 200% of the targeted amount depending on the level of performance metrics achieved. At June 30, 2006, a liability of $2 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, 2005, or Note 16 to the Consolidated Financial Statements in our Quarterly Report on Form 10-Q
for the quarter ended March 31, 2006, nor have any significant new matters arisen during the three months ended June 30, 2006.

Income Taxes

As a matter of course, we are regularly audited by federal and state tax authorities. We establish liabilities for probable tax-related contingencies in accordance with SFAS No. 5, *Accounting for Contingencies,* and review them in light of changing facts and circumstances. Although the results of these audits are uncertain, we believe that the ultimate outcome will not have a material adverse effect on our financial position. At June 30, 2006 and December 31, 2005, our Consolidated Balance Sheets reflect $148 million and $144 million, respectively, of income tax-related contingent liabilities, including accrued interest.

Environmental Matters

In 1987, we and a number of other entities were identified by the Environmental Protection Agency (EPA) as potentially responsible parties (PRPs) at two Superfund sites located in Kentucky and Pennsylvania. In 2003, the EPA issued its Certificate of Completion of remediation for the Kentucky site. Future costs for the Kentucky site will be limited to minor operations and maintenance expenditures. Regarding the Pennsylvania site, in March 2006, a federal district court approved three consent decrees between the United States and the PRPs, under which we and certain other PRPs, all of which are utilities, will perform the site remediation. The remediation costs are expected to be in the range of $11 million to $18 million, the majority of which are to be paid by the non-utility site owners. After evaluating the impact of these actions, we have reduced our current reserve from $2 million to less than $1 million to meet our potential obligations at these two sites. We generally seek to recover our costs associated with environmental remediation from third party insurers. At June 30, 2006, no pending or possible insurance claims were recognized as an asset or offset against obligations.

Insurance for E&P Operations

In the past, we have maintained business interruption, property damage and other insurance for our E&P operations. However, the recent increased level of hurricane activity in the Gulf of Mexico has led our insurers to terminate certain coverages for our E&P operations; specifically, our Operator’s Extra Expense (OEE), offshore property damage and offshore business interruption coverage has been terminated. All onshore property coverage (with the exception of OEE) and liability coverage commensurate with past coverage remain in place for our E&P operations under our current policy. Efforts to replace the terminated insurance for our E&P operations with similar traditional insurance on commercially reasonable terms have been unsuccessful. We have recently entered into a six-month weather derivative contract with an SPE, as further described in Note 12. This arrangement provides limited alternative risk mitigation; however, it offers substantially less protection than our previous E&P insurance policies. This lack of insurance could adversely affect our results of operations.

In 2005, Hurricanes Katrina and Rita struck the Gulf of Mexico, causing interruptions to expected gas and oil production and damage to certain facilities in and along the Gulf of Mexico. We have reached an agreement in principle on our insurance claims for Katrina and Rita and expect to receive proceeds in excess of $300 million in the third quarter of 2006.

Guarantees

At June 30, 2006, we had issued $27 million of guarantees to support third parties, equity method investees and employees affected by Hurricane Katrina. In addition, in 2005, we, along with two other gas and oil E&P companies, entered into a four-year drilling contract related to a new, ultra-deepwater drilling rig that is expected to be delivered in mid-2008. The contract has a four-year primary term, plus four one-year extension options. Our minimum commitment under the agreement is for approximately $99 million over the four-year term; however, we are also jointly and severally liable for up to $394 million to the contractor if the other parties fail to pay the contractor for their obligations under the primary term of the agreement, which we view as highly unlikely. We have not recognized any significant liabilities related to any of these guarantee arrangements.

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 June 30, 2006. We believe it is unlikely that we would be required to perform or otherwise incur any losses associated with guarantees of our subsidiaries' obligations. At June 30, 2006, we had issued the following subsidiary guarantees:

		Stated Limit		**Value**[1]
(millions)				
Subsidiary debt[2]	$	1,318	$	1,318
Commodity transactions[3]		3,678		1,183
Lease obligation for power generation facility[4]		898		898
Nuclear obligations[5]		375		302
Offshore drilling commitments[6]		--		493
Other		599		424
Total	$	6,868	$	4,618

(1) Represents the estimated portion of the guarantee's stated limit that is utilized as of June 30, 2006 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 Dominion Resources Services, Inc. (DRS), and 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 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 Virginia Power's and certain DEI subsidiaries' potential retrospective premiums that could be assessed if there is a nuclear incident under our nuclear insurance programs and guarantees for 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, if requested by such subsidiaries, to pay the operating expenses in the event of a prolonged outage of the Millstone and Kewaunee power stations, respectively, as part of satisfying certain NRC 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 June 30, 2006, we had also purchased $71 million of surety bonds and authorized the issuance of standby letters of credit by financial institutions of $1.8 billion. We enter into these arrangements to facilitate commercial transactions by our subsidiaries with third parties.

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. We maintain a provision for credit losses based on factors surrounding the credit risk of our customers, historical trends and other information. We believe, based on our credit policies and our June 30, 2006 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 gas and oil E&P business activities, these transactions principally occur in the Northeast, Mid-Atlantic and Midwest regions of the United States. 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 price risk management activities include trading of energy-related commodities, marketing of merchant generation output, structured transactions and the use of financial contracts for enterprise-wide hedging purposes. Our gross credit exposure for each counterparty is calculated as outstanding receivables plus any unrealized on or off-balance sheet exposure, taking into account contractual netting rights. Gross credit exposure is calculated prior to the application of collateral. At June 30, 2006, our gross credit exposure totaled $1.20 billion. After the application of collateral, our credit exposure is reduced to $1.18 billion. Of this amount, investment grade counterparties represent 82% and no single counterparty exceeded 10%.

Note 17. Employee Benefit Plans

The following table illustrates the components of the provision for net periodic benefit cost for our pension and other postretirement benefit plans:

	Pension Benefits		Other Postretirement Benefits	
	2006	2005	**2006**	2005
(millions)				
Three Months Ended June 30,				
Service cost	**$ 30**	$ 27	**$ 19**	$ 16
Interest cost	**50**	51	**21**	21
Expected return on plan assets	**(86)**	(86)	**(15)**	(13)
Amortization of prior service cost (credit)	**1**	1	**(1)**	(1)
Amortization of transition obligation	**--**	--	**1**	1
Amortization of net loss	**22**	19	**7**	5
Net periodic benefit cost	**$ 17**	$ 12	**$ 32**	$ 29
Six Months Ended June 30,				
Service cost	**$ 65**	$ 56	**$ 40**	$ 32
Interest cost	**108**	105	**44**	41
Expected return on plan assets	**(185)**	(179)	**(32)**	(26)
Curtailment loss(1)	**6**	--	--	--
Amortization of prior service cost (credit)	**2**	2	**(2)**	(1)
Amortization of transition obligation	**--**	--	**2**	2
Amortization of net loss	**47**	40	**15**	10
Net periodic benefit cost	**$ 43**	$ 24	**$ 67**	$ 58

(1) Relates to the pending sale of Peoples and Hope, as discussed in Note 5.

Employer Contributions

We made no contributions to our defined benefit pension plans or other postretirement benefit plans during the six months ended June 30, 2006. We expect to contribute at least $35 million to our other postretirement benefit plans during the remainder of 2006. 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 2006 will be determined at that time.

Note 18. Dominion Capital, Inc.

As discussed in Note 27 to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2005, 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. This investment consisted of $100 million of Class B-1 Notes, 7.5% current pay interest and $148 million of Class B-2 Notes, 3% paid-in-kind interest. Prior to June 2006, our intent was to seek a rating for and market the B-1 Notes and hold the B-2 Notes to maturity. DCI also had a commitment to fund up to $15 million of liquidity to the CDO entity, but this commitment has expired. The equity interests in the CDO entity are held by another entity that is not affiliated with us.

DCI's investments in the CDO entity were previously included in available for sale securities on our Consolidated Balance Sheets. We have decided to pursue the sale of the B-2 Notes. In June 2006 we recorded an $85 million charge in other operations and maintenance expense reflecting an other-than-temporary decline in the fair value of the B-2 Notes. An impairment charge was required because of a further increase in interest rates, an increase in our credit risk associated with the equity reduction discussed below and because we no longer expect the fair value of the B-2 Notes to recover prior to a sale.

In June 2006, the equity investor withdrew its capital from the CDO entity, which required a redetermination of whether the CDO entity is a VIE under FIN 46R. We concluded that the CDO entity is a VIE and that DCI is the primary beneficiary of the CDO entity, which we have consolidated in accordance with FIN 46R. Due to its consolidation, we now reflect the assets and liabilities of the CDO entity on our Consolidated Balance Sheet. At June 30, 2006, 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 June 30, 2006:

(millions)		**Amount**
Other current assets	$	155
Loans receivable, net		365
Other investments		64
Total assets	$	584

Note 19. Operating Segments

Our Company is organized primarily on the basis of products and services sold in the United States. 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 tariff-based electric transmission, natural gas transmission pipeline and underground natural gas storage businesses and an LNG facility. It also includes gathering and extraction activities, certain 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, utility energy supply activities and energy marketing and price risk management activities associated with the optimization of generation assets.

Dominion E&P includes our gas and oil exploration, development and production operations. 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, and Western Canada.

Corporate includes our corporate, service company and other functions (including unallocated debt), corporate-wide enterprise commodity price risk management and optimization services and the remaining assets of DCI. 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 six months ended June 30, 2006 and 2005, we reported net expenses of $102 million and $56 million, respectively, in the

Corporate segment attributable to our operating segments.

The net expenses in 2006 primarily related to the impact of a $162 million ($98 million after-tax) charge resulting from the write-off of certain regulatory assets related to the pending sale of Peoples and Hope, attributable to the Dominion Delivery segment.

The net expenses in 2005 largely resulted from:

- A $77 million ($47 million after-tax) charge resulting from the termination of a long-term power purchase agreement, attributable to Dominion Generation; and
- A $13 million ($8 million after-tax) charge related to our interest in a long-term power tolling contract that was divested in 2005, attributable to Dominion Generation.

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

The following table presents segment information pertaining to our operations:

(millions)	**Dominion Delivery**	**Dominion Energy**	**Dominion Generation**	**Dominion E&P**	**Corporate**	**Adjustments/ Eliminations**	**Consolidated Total**
Three Months Ended June 30**,**							
2006							
Operating Revenue:							
External customers	**$737**	**$248**	**$1,575**	**$780**	**$ (19)**	**$ 235**	**$3,556**
Intersegment	**3**	**287**	**38**	**50**	**187**	**(565)**	**--**
Total operating revenue	**740**	**535**	**1,613**	**830**	**168**	**(330)**	**3,556**
Net income (loss)	**80**	**68**	**60**	**114**	**(161)**	**--**	**161**
2005							
Operating Revenue:							
External customers	$707	$271	$1,670	$715	$ 10	$ 273	$3,646
Intersegment	10	277	35	46	142	(510)	--
Total operating revenue	717	548	1,705	761	152	(237)	3,646
Net income (loss)	73	64	54	189	(48)	--	332
Six Months Ended June 30**,**							
2006							
Operating Revenue:							
External customers	**$2,409**	**$ 845**	**$3,233**	**$1,653**	**$ (56)**	**$ 429**	**$8,513**
Intersegment	**6**	**563**	**81**	**118**	**381**	**(1,149)**	**--**
Total operating revenue	**2,415**	**1,408**	**3,314**	**1,771**	**325**	**(720)**	**8,513**
Net income (loss)	**236**	**175**	**192**	**344**	**(252)**	**--**	**695**
2005							
Operating Revenue:							
External customers	$2,238	$ 755	$3,536	$1,350	$ 8	$ 495	$8,382
Intersegment	28	504	91	89	291	(1,003)	--
Total operating revenue	2,266	1,259	3,627	1,439	299	(508)	8,382
Net income (loss)	257	163	199	301	(159)	--	761

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 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.

Contents of MD&A

Our MD&A consists of the following information:

Forward-Looking Statements

This report contains statements concerning our expectations, plans, objectives, future financial performance and other statements that are not historical facts. These statements are "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. In most cases, the reader can identify these forward-looking statements by such words as "anticipate," "estimate," "forecast," "expect," "believe," "should," "could," "plan," "may" or other 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, including deregulation and changes in environmental and other laws and regulations to which we are subject;
- Cost of environmental compliance;
- 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 the 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;
- Realization of expected business interruption insurance proceeds;
- 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; and

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

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, 2005 and our Quarterly Report on Form 10-Q for the quarter ended March 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 June 30, 2006, 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, 2005. 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

FIN 48

In July 2006, the FASB issued FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes*. FIN 48 establishes standards for measurement and recognition in financial statements of positions taken by an entity in its income tax returns. In addition, FIN 48 requires new disclosures about positions taken by an entity in its tax returns that are not recognized in its financial statements, information about potential significant changes in estimates related to tax positions and descriptions of open tax years by major jurisdiction. The provisions of FIN 48 will become effective for us beginning January 1, 2007, with the cumulative effect of the change in accounting principle recorded as an adjustment to retained earnings. We are currently evaluating the impact that FIN 48 will have on our results of operations and financial condition.

Accounting for Pensions and Other Postretirement Benefits

In late 2005, the FASB added a two-phase comprehensive project to its technical agenda to reconsider the accounting for pensions and other postretirement benefits. In March 2006, the FASB issued an Exposure Draft, *Employer's Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)*, representing the first phase of the project. In this phase, the FASB is proposing to require that entities recognize the current economic over-funded or under-funded status of their defined benefit postretirement plans in their balance sheets effective December 31, 2006. The FASB's goal is to issue a final Statement by September 2006. We are currently following the FASB's deliberations and are assessing the impact that this new guidance will have on our results of operations and financial condition.

Results of Operations

Presented below is a summary of our consolidated results for the second quarter and year-to-date periods ended June 30, 2006 and 2005:

	2006	2005	$ Change

(millions, except EPS)			
Second Quarter			
Net income	**$ 161**	$ 332	$(171)
Diluted EPS	**0.46**	0.97	(0.51)
Year-To-Date			
Net income	**$ 695**	$ 761	$ (66)
Diluted EPS	**1.99**	2.23	(0.24)

Overview

Second Quarter 2006 vs. 2005

Net income decreased 52% to $161 million, primarily resulting from the absence of business interruption insurance proceeds received in 2005 as a result of Hurricane Ivan, and the impairment of a DCI investment. These decreases were partially offset by a higher contribution from our merchant generation business.

Year-To-Date 2006 vs. 2005

Net income decreased 9% to $695 million. Unfavorable drivers include the absence of business interruption insurance proceeds received in 2005 as a result of Hurricane Ivan, charges associated with the pending sale of Peoples and Hope, higher fuel expenses incurred by our utility generation operations and the impairment of a DCI investment. Favorable drivers include increased gas and oil production, higher realized prices for gas and oil, and a higher contribution from our merchant generation business.

Analysis of Consolidated Operations

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

	Second Quarter			**Year-To-Date**		
	2006	2005	$ Change	**2006**	2005	$ Change
(millions)						
Operating Revenue	**$3,556**	$3,646	$ (90)	**$8,513**	$8,382	$ 131
Operating Expenses						
Electric fuel and energy purchases	**760**	943	(183)	**1,526**	1,784	(258)
Purchased electric capacity	**116**	122	(6)	**239**	256	(17)
Purchased gas	**432**	553	(121)	**1,810**	1,775	35
Other energy-related commodity purchases	**318**	318	--	**718**	642	76
Other operations and maintenance	**906**	522	384	**1,674**	1,353	321
Depreciation, depletion and amortization	**410**	349	61	**791**	695	96
Other taxes	**131**	134	(3)	**312**	299	13
Other income	**49**	32	17	**92**	83	9
Interest and related charges	**261**	229	32	**526**	476	50
Income tax expense	**110**	176	(66)	**314**	424	(110)

An analysis of our results of operations for the second quarter and year-to-date periods of 2006 compared to the second quarter and year-to-date periods of 2005 follows:

Second Quarter 2006 vs. 2005

Operating Revenue decreased 2% to $3.6 billion, primarily reflecting:

- The absence of $135 million of business interruption insurance proceeds received in 2005 associated with Hurricane Ivan;
- A $95 million decrease in non-utility coal sales revenue primarily resulting from decreased sales volumes ($74 million) and lower prices ($21 million);
- An $81 million decrease from gas trading and marketing activities primarily reflecting decreased volumes and lower prices;
- A $42 million decrease from regulated gas distribution operations, primarily reflecting a $35 million decrease resulting from the loss of customers to Energy Choice programs and a $27 million decrease associated with milder weather, changes in customer usage and other factors, partially offset by a $20 million increase related to the

recovery of higher gas prices. The effect of this net decrease was largely offset by a corresponding decrease in *Purchased gas expense*;

- A $30 million decrease in sales of emissions allowances held for resale, primarily as a result of decreased sales volume; and
- A $20 million decrease in revenue from sales of gas purchased by E&P operations to facilitate gas transportation and other contracts.

These decreases to operating revenue were partially offset by the following:

- A $108 million increase in sales of purchased oil under buy/sell arrangements by E&P operations, resulting from higher prices ($47 million) and increased sales volume ($61 million);

- An $82 million increase in sales of gas and oil production, primarily due to higher volumes ($93 million), partially offset by decreased prices ($11 million);
- A $47 million increase from the Kewaunee power station (Kewaunee) acquired in July 2005;
- A $44 million increase in gas sales by nonregulated retail energy marketing activities primarily reflecting higher volumes;
- A $43 million increase in sales of extracted products, primarily due to increased prices and a contractual change for a portion of our gas production processed by third parties. We now take title to and market the extracted products from this gas; and
- A $41 million decrease in revenues associated with price risk management activities for our merchant generation operations, including lower sales volume for requirements-based sales contracts.

Operating Expenses and Other Items

Electric fuel and energy purchases expense decreased 19% to $760 million, primarily reflecting the combined effects of:

- A $254 million decrease in purchases primarily due to lower volumes associated with price risk management activities for our merchant generation operations and purchases for requirements-based sales contracts; partially offset by
- A $50 million increase related to our utility generation operations, primarily due to higher commodity prices, including purchased power; and
- An $18 million increase resulting from the addition of Kewaunee.

Purchased gas expense decreased 22% to $432 million, principally resulting from:

- A $57 million decrease related to gas aggregation activities;
- A $24 million decrease related to E&P operations;
- A $22 million decrease from nonregulated retail energy marketing activities; and
- A $28 million decrease in costs attributable to regulated gas distribution operations, reflecting lower prices ($12 million) and lower volumes ($16 million).

Other operations and maintenance expense increased 74% to $906 million, primarily reflecting the combined effects of:

- An $89 million increase primarily resulting from price risk management activities associated with our merchant generation assets;
- An $85 million charge resulting from the impairment of a DCI investment;
- A $60 million increase due to an adjustment eliminating the application of hedge accounting for certain interest rate swaps associated with our junior subordinated notes payable to affiliated trusts that sold trust preferred securities. Prior to June 30, 2006, we applied the shortcut method of fair value hedge accounting under SFAS No. 133 to these swaps, allowing us to assume no hedge ineffectiveness for these derivatives. We have since determined that these swaps did not qualify for the shortcut method because of an interest deferral mechanism within the junior subordinated notes and they cannot qualify for hedge accounting retrospectively because the hedge documentation required for the long-haul method was not in place at the inception of the hedge. These instruments have been and, we believe, will continue to be highly effective economic hedges. We have since re-designated the interest rate swaps associated with these transactions as fair value hedges under the long-haul accounting method in order to qualify them going forward for fair value hedge accounting under SFAS No. 133;
- $42 million of additional incentive-based compensation, salaries, wages and benefits expenses;
- A $40 million decrease in gains from the sales of emission allowances held for consumption;
- A $34 million increase due to the addition of Kewaunee;
- A $33 million increase due to higher production and transportation costs for E&P operations; and
-

An $11 million increase in insurance costs for E&P operations, primarily due to higher insurance premiums following the 2005 hurricanes; partially offset by

- A $20 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 17% to $410 million, largely due to the impact of higher E&P finding and development costs, as well as increased gas and oil production.

Interest and related charges increased 14% to $261 million resulting principally from higher interest rates on variable rate debt, as well as increased commercial paper borrowings.

Year-to Date 2006 vs. 2005

Operating Revenue increased 2% to $8.5 billion, primarily reflecting:

- A $246 million increase in sales of purchased oil under buy/sell arrangements by E&P operations resulting from higher prices ($95 million) and increased sales volumes ($151 million);
- A $203 million increase in sales of gas and oil production, primarily due to increased production ($156 million) and higher average realized prices ($47 million);
- A $146 million increase in gas sales by nonregulated retail energy marketing activities primarily reflecting higher volumes ($66 million) and increased prices ($80 million);
- A $95 million increase from the addition of Kewaunee; and
- A $79 million increase in sales of extracted products, primarily due to increased prices and a contractual change for a portion of our gas production processed by third parties. We now take title to and market the extracted products from this gas.

These benefits were partially offset by:

- A $217 million decrease in revenues associated with price risk management activities for our merchant generation operations, including lower sales volume for requirements-based sales contracts;
- A $165 million decline in nonutility coal sales resulting primarily from lower sales volumes ($147 million) and decreased prices ($18 million);
- A $179 million decrease due to the absence of business interruption insurance proceeds recognized in 2005 associated with Hurricane Ivan;
- A $30 million decrease in sales of emissions allowances held for resale, resulting from lower overall sales volumes for the current year-to-date period ($46 million), partially offset by higher prices realized on sales during the first quarter of 2006 ($16 million). The effect of this decrease was largely offset by a corresponding decrease in *Other energy-related commodity purchases expense*; and
- A $22 million decrease in revenue from sales of gas purchased by E&P operations to facilitate gas transportation and other contracts.

Operating Expenses and Other Items

Electric fuel and energy purchases expense decreased 14% to $1.5 billion, primarily reflecting the combined effects of:

- A $424 million decrease primarily due to lower volumes associated with price risk management activities for our merchant generation operations and purchases for requirements-based sales contracts; partially offset by
- A $137 million increase related to our utility generation operations, primarily due to higher commodity prices, including purchased power and congestion costs associated with PJM; and
- A $22 million increase resulting from the addition of Kewaunee.

Purchased electric capacity expense decreased 7% to $239 million, as a result of scheduled capacity reductions for certain long-term power purchase contracts, as well as the termination of a long-term power purchase agreement in connection with the acquisition of the related generating facility in February 2005.

Other energy-related commodity purchases expense increased 12% to $718 million due predominantly to a $241 million increase in purchases of oil under buy/sell arrangements by our E&P operations, partially offset by a $138 million decrease in nonutility coal purchased for resale and a $28 million decrease in purchases of emissions allowances held for resale.

Other operations and maintenance expense increased 24% to $1.7 billion, resulting from:

- A $162 million charge from the write-off of certain regulatory assets related to the pending sale of Peoples and Hope;
- $89 million of impairment charges related to DCI investments;
- $76 million of additional salaries, wages, incentive-based compensation and benefits expenses;

- A $61 million increase due to the addition of Kewaunee;
- $61 million of additional production and transportation costs for E&P operations;
- A $60 million increase due to an adjustment eliminating the application of hedge accounting for certain interest rate swaps associated with our junior subordinated notes payable to affiliated trusts;
- A $33 million decrease in gains from the sale of emission allowances held for consumption;

- A $33 million increase in expenses for regulated gas operations related to low income home energy assistance programs. These expenditures for regulated gas operations are recovered through rates and do not impact our net income; and
- A $26 million increase in insurance costs for E&P operations primarily due to higher insurance premiums following the 2005 hurricanes.

These charges were partially offset by:

- A $138 million benefit resulting from favorable changes in the fair value of certain gas and oil derivatives that were de-designated as hedges following the 2005 hurricanes;
- A $33 million benefit primarily from price risk management activities associated with our merchant generation assets as discussed in Operating Revenue;
- A $31 million benefit related to financial transmission rights (FTRs) granted by PJM to our utility generation operations to offset congestion costs associated with PJM spot market activity; and
- A benefit resulting from the net impact of the following items recognized in 2005:
  - A $77 million charge resulting from the termination of a long-term power purchase agreement; and
  - A $47 million loss related to the discontinuance of hedge accounting for certain oil derivatives primarily resulting from a delay in reaching anticipated production levels in the Gulf of Mexico, and subsequent changes in the fair value of those derivatives; partially offset by
  - A $24 million net benefit recognized by regulated utility operations resulting from the establishment of certain regulatory assets and liabilities in connection with settlement of a North Carolina rate case.

Depreciation, depletion and amortization expense increased 14% to $791 million, largely due to the impact of higher E&P finding and development costs, as well as increased gas and oil production.

Interest and related charges increased 11% to $526 million resulting principally from higher interest rates on variable rate debt.

Income tax expense reflects lower pretax book income and a decrease in our effective tax rate to 31.1% primarily resulting from a net tax benefit recorded in connection with our pending sale of Peoples and Hope, as discussed in Notes 5 and 7 to our Consolidated Financial Statements. This reduction was partially offset by an increase in valuation allowances on deferred tax assets in the second quarter primarily associated with the impairment of a DCI investment.

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 quarter and year-to-date periods ended June 30, 2006 and 2005:

	Net Income			**Diluted EPS**		
Second Quarter	**2006**	2005	$ Change	**2006**	2005	$ Change
(millions, except EPS)						
Dominion Delivery	**$ 80**	$ 73	$ 7	**$ 0.23**	$ 0.21	$ 0.02
Dominion Energy	**68**	64	4	**0.20**	0.19	0.01
Dominion Generation	**60**	54	6	**0.17**	0.16	0.01
Dominion E&P	**114**	189	(75)	**0.32**	0.55	(0.23)
Primary operating segments	**322**	380	(58)	**0.92**	1.11	(0.19)
Corporate	**(161)**	(48)	(113)	**(0.46)**	(0.14)	(0.32)
Consolidated	**$ 161**	$332	$(171)	**$ 0.46**	$ 0.97	$(0.51)
Year-To-Date						
(millions, except EPS)						

Dominion Delivery	**$ 236**	$ 257	$ (21)	**$ 0.68**	$ 0.75	$(0.07)
Dominion Energy	**175**	163	12	**0.50**	0.48	0.02
Dominion Generation	**192**	199	(7)	**0.55**	0.58	(0.03)
Dominion E&P	**344**	301	43	**0.98**	0.88	0.10
Primary operating segments	**947**	920	27	**2.71**	2.69	0.02
Corporate	**(252)**	(159)	(93)	**(0.72)**	(0.46)	(0.26)
Consolidated	**$ 695**	$ 761	$ (66)	**$ 1.99**	$ 2.23	$(0.24)

Dominion Delivery

Dominion Delivery includes our regulated electric and gas distribution and customer service business, as well as nonregulated retail energy marketing operations. Presented below are operating statistics related to our Dominion Delivery operations:

	Second Quarter			Year-To-Date		
	2006	2005	% Change	**2006**	2005	% Change
Electricity delivered (million mwhrs)	**18.7**	18.6	1%	**38.2**	38.5	(1)%
Degree days (electric service area):						
Cooling[1]	**396**	370	7	**409**	370	11
Heating[2]	**245**	355	(31)	**2,041**	2,466	(17)
Electric delivery customer accounts[3]	**2,325**	2,283	2	**2,325**	2,283	2
Gas throughput (bcf):						
Gas sales	**12**	20	(40)	**62**	83	(25)
Gas transportation	**43**	44	(2)	**130**	136	(4)
Heating degree days (gas service area)[2]	**656**	748	(12)	**3,236**	3,770	(14)
Gas delivery customer accounts[3]:						
Gas sales	**789**	1,002	(21)	**789**	1,002	(21)
Gas transportation	**892**	677	32	**892**	677	32
Nonregulated retail energy marketing customer accounts[3]	**1,392**	1,149	21	**1,392**	1,149	21

mwhrs = megawatt hours
bcf = billion cubic feet

(1) Cooling degree days are the differences between the average temperature for each day and 65 degrees, assuming the average temperature is greater than 65 degrees.
(2) Heating degree days are the differences between the average temperature for each day and 65 degrees, assuming the average temperature is less than 65 degrees.
(3) In thousands, at period end.

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

	Second Quarter 2006 vs. 2005 Increase (Decrease)		**Year-To-Date 2006 vs. 2005 Increase (Decrease)**	
	Amount	**EPS**	**Amount**	**EPS**
(millions, except EPS)				
Nonregulated retail energy marketing operations[1]	$ 6	$ 0.02	$ 16	$ 0.04
Regulated electric sales:				
Customer growth	3	0.01	6	0.02
Weather	(2)	(0.01)	(11)	(0.03)
Interest expense[2]	(4)	(0.01)	(11)	(0.03)
Regulated gas sales - weather	(2)	(0.01)	(15)	(0.04)
2005 North Carolina rate case settlement[3]	--	--	(6)	(0.02)

Other	6	0.02	--	--
Share dilution	--	--	--	(0.01)
Change in net income contribution	$7	$ 0.02	$(21)	$(0.07)

(1) Largely reflects higher electric and gas margins.
(2) Primarily reflects additional intercompany borrowings and higher interest rates on those borrowings.
(3) A benefit recognized in 2005 by electric utility operations resulting from the establishment of certain regulatory assets in connection with settlement of a North Carolina rate case.

Dominion Energy

Dominion Energy includes our tariff-based electric transmission, natural gas transmission pipeline and storage businesses and an LNG facility. It also includes certain 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. Presented below are operating statistics related to our Dominion Energy operations.

	Second Quarter			Year-To-Date		
	2006	2005	% Change	**2006**	2005	% Change
Gas transmission throughput (bcf)	**122**	133	(8)%	**356**	434	(18)%

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

	Second Quarter 2006 vs. 2005 Increase (Decrease)		Year-To-Date 2006 vs. 2005 Increase (Decrease)	
	Amount	**EPS**	**Amount**	**EPS**
(millions, except EPS)				
Gas transmission:				
Rate settlement(1)	$(5)	$(0.01)	$(13)	$(0.04)
Other margins(2)	15	0.04	17	0.04
Producer services(3)(4)	(5)	(0.01)	9	0.03
Salaries, wages, and benefits expense	(2)	(0.01)	(4)	(0.01)
Other	1	--	3	0.01
Share dilution	--	--	--	(0.01)
Change in net income contribution	$ 4	$0.01	$ 12	$0.02

(1) Represents lower natural gas transportation and storage revenues as a result of a rate settlement effective July 2005.
(2) Higher margins primarily from extracted products, natural gas production and short-term service opportunities.
(3) Lower gains in the quarter-to-date period, resulting from the impact of unfavorable price changes on gas marketing activities associated with certain contractual assets.
(4) Higher gains in the year-to-date period, resulting from the impact of favorable price changes on gas marketing activities and higher margins on the aggregation of gas supply.

Dominion Generation

Dominion Generation includes the generation operations of our electric utility and merchant fleet, utility energy supply activities and energy marketing and price risk management activities associated with the optimization of generation assets. Presented below are operating statistics related to our Dominion Generation operations.

	Second Quarter			Year-To-Date		
	2006	2005	% Change	**2006**	2005	% Change
Electricity supplied (million mwhrs)						
Utility	**18.7**	18.6	1	**38.2**	38.5	(1)
Merchant	**9.9**	8.6	15	**20.9**	18.6	12

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

	Second Quarter 2006 vs. 2005 Increase (Decrease)		Year-To-Date 2006 vs. 2005 Increase (Decrease)	
	Amount	**EPS**	**Amount**	**EPS**
(millions, except EPS)				
Merchant generation margin(1)	$65	$ 0.19	$141	$ 0.41
Outage costs	2	0.01	(11)	(0.03)
Regulated electric sales:				
Customer growth	5	0.01	11	0.03
Weather	(5)	(0.01)	(24)	(0.07)
Sale of emissions allowances	(25)	(0.07)	(21)	(0.06)
Fuel expenses in excess of rate recovery	(18)	(0.05)	(50)	(0.14)
Salaries, wages, and benefits expense	(9)	(0.03)	(13)	(0.04)
Interest expense	(3)	(0.01)	(12)	(0.04)
Energy supply margin(2)	(7)	(0.02)	(2)	(0.01)
2005 North Carolina rate case settlement	--	--	(10)	(0.03)
Other	1	--	(16)	(0.04)
Share dilution	--	(0.01)	--	(0.01)
Change in net income contribution	$ 6	$ 0.01	$ (7)	$ (0.03)

(1) Primarily due to an increased contribution from Millstone, reflecting a significant decrease in planned outage days over the prior year.
(2) Primarily reflects a reduced benefit from FTRs in excess of congestion costs.

Dominion E&P
Dominion E&P manages our gas and oil exploration, development and production business. 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 and Western Canada. Presented below are operating statistics related to our E&P operations:

	Second Quarter			Year-To-Date		
	2006	2005	% Change	**2006**	2005	% Change
Gas production (bcf)	**79**	70	13%	**151**	144	5%
Oil production (million bbls)	**6.3**	4.2	50	**12.4**	8.0	55
Average realized prices without hedging results:						
Gas (per mcf) (1)	**$ 6.35**	$ 6.79	(6)	**$ 7.13**	$ 6.48	10
Oil (per bbl)	**58.92**	46.28	27	**56.19**	45.55	23
Average realized prices with hedging results:						
Gas (per mcf) (1)	**4.10**	4.17	(2)	**4.52**	4.18	8
Oil (per bbl)	**35.43**	26.66	33	**37.09**	27.71	34
DD&A (unit of production rate per mcfe)	**$1.67**	$1.42	17	**$1.66**	$1.42	17

bbl(s) = barrel(s)
mcf = thousand cubic feet

mcfe = thousand cubic feet equivalent

(1) Excludes $63 million and $86 million for the three months ended June 30, 2006 and 2005, respectively, and $143 million and $163 million for the six months ended June 30, 2006 and 2005, 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, 2005.

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

	Second Quarter 2006 vs. 2005 Increase (Decrease)		**Year-To-Date 2006 vs. 2005 Increase (Decrease)**	
	Amount	**EPS**	**Amount**	**EPS**
(millions, except EPS)				
Business interruption insurance	$(86)	$(0.25)	$(116)	$(0.34)
DD&A(1)	(41)	(0.12)	(71)	(0.21)
Operations and maintenance(2)	(28)	(0.08)	50	0.15
Interest expense	(7)	(0.02)	(11)	(0.03)
Gas and oil ¾ prices	(6)	(0.02)	56	0.16
Gas and oil ¾ production(3)	86	0.25	134	0.39
Other	7	0.02	1	--
Share dilution	--	(0.01)	--	(0.02)
Change in net income contribution	$(75)	$(0.23)	$ 43	$ 0.10

(1) Higher DD&A, primarily reflecting higher industry finding and development costs. For the year-to-date period, the increase also reflects increased acquisition costs.
(2) Higher operations and maintenance expenses for the quarter, primarily resulting from increased production costs and salaries, wages and benefits expenses, partially offset by favorable changes in the fair value of certain gas and oil hedges that were de-designated following the 2005 hurricanes. Lower operations and maintenance expenses for the year-to-date period are largely attributable to favorable changes in the fair value of the de-designated hedges mentioned above.
(3) Represents an increase in oil production primarily resulting from deepwater oil production at the Gulf of Mexico Devils Tower, Triton and Goldfinger projects, as well as an increase in gas production primarily resulting from deepwater and Rocky Mountain production.

Included below are the volumes and weighted average prices associated with hedges in place as of June 30, 2006 by applicable time period. Prior cash flow hedges for which hedge accounting was discontinued due to production interruptions caused by Hurricanes Katrina and Rita, and for which amounts were reclassified from AOCI to earnings upon the discontinuance of hedge accounting, are excluded from the following table:

	Natural Gas		**Oil**	
Year	**Hedged Production (bcf)**	**Average Hedge Price (per mcf)**	**Hedged Production (million bbls)**	**Average Hedge Price (per bbl)**
2006	112.1	$4.63	7.1	$25.02
2007	218.1	5.89	10.0	33.41
2008	164.1	8.27	5.0	49.36

Corporate

Corporate includes our corporate, service company and other functions (including unallocated debt), corporate-wide enterprise commodity risk management and optimization services and the remaining assets of DCI. Presented below are the Corporate segment's after-tax results:

Second Quarter			**Year-To-Date**	
2006	2005	$ Change	**2006**	2005

(millions, except EPS)						$ Change
Specific items attributable to operating segments	**$ (9)**	$ (2)	$ (7)	**$ (102)**	$ (56)	$ (46)
DCI operations	**(83)**	--	(83)	**(84)**	(3)	(81)
Other corporate operations	**(69)**	(46)	(23)	**(66)**	(100)	34
Total net expense	**$ (161)**	$ (48)	$ (113)	**$ (252)**	$ (159)	$ (93)
Earnings per share impact	**$(0.46)**	$(0.14)	$(0.32)	**$(0.72)**	$(0.46)	$(0.26)

Specific Items Attributable to Operating Segments

Year-To-Date 2006 vs. 2005

We reported expenses of $102 million and $56 million in 2006 and 2005, respectively, in the Corporate segment that are attributable to our operating segments. The net expenses in 2006 primarily reflect a $162 million ($98 million after-tax) charge resulting from the write-off of certain regulatory assets related to the pending sale of Peoples and Hope, attributable to the Dominion Delivery segment. In addition, we recognized a $21 million tax benefit from the partial reduction of previously recorded valuation allowances on certain federal and state tax loss carryforwards (attributable to Dominion Generation), since these carryforwards are expected to be utilized to offset capital gain income generated from the sale of Peoples and Hope.

The net expenses in 2005 largely resulted from:

- A $77 million ($47 million after-tax) charge resulting from the termination of a long-term power purchase agreement, attributable to Dominion Generation; and
- A $13 million ($8 million after-tax) charge related to our interest in a long-term power tolling contract that was divested in 2005, attributable to Dominion Generation.

DCI Operations

DCI's net loss for the second quarter and year-to-date period increased $83 million and $81 million, respectively, primarily due to an $85 million impairment of a DCI investment.

Other Corporate Operations

Second Quarter 2006 vs. 2005

The net expenses associated with other corporate operations for 2006 increased $23 million, primarily reflecting an adjustment eliminating the application of hedge accounting for certain interest rate swaps associated with our junior subordinated notes to affiliated trusts, partially offset by a lower effective tax rate.

Year-To-Date 2006 vs. 2005

We reported net expenses of $66 million in 2006 associated with other corporate operations, as compared to net expenses of $100 million in 2005, primarily reflecting a net tax benefit recorded in 2006 as a result of the pending sale of Peoples and Hope. We recognized a $194 million tax benefit from the partial reduction 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 generated from the sale. This benefit was partially offset by the establishment of $135 million of deferred tax liabilities in accordance with EITF 93-17, as discussed in Note 5 to our Consolidated Financial Statements and an adjustment eliminating the application of hedge accounting for certain interest rate swaps associated with our junior subordinated notes to affiliated trusts.

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, 2005 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 six months ended June 30, 2006 follows:

	Amount
(millions)	
Net unrealized loss at December 31, 2005	$ (7)

Contracts realized or otherwise settled during the period	**24**
Net unrealized gain at inception of contracts initiated during the period	**--**
Changes in valuation techniques	**--**
Other changes in fair value	**(25)**
Net unrealized loss at June 30, 2006	**$ (8)**

The balance of net unrealized gains and losses recognized for our energy-related derivative instruments held for trading purposes at June 30, 2006, is summarized in the following table based on the approach used to determine fair value and contract settlement or delivery dates:

	Maturity Based on Contract Settlement or Delivery Date(s)					
Source of Fair Value	Less than 1 year	1-2 years	2-3 years	3-5 years	In Excess of 5 years	Total
(millions)						
Actively quoted[1]	$ 17	$ (13)	$ 1	$ 1	$ --	$ 6
Other external sources[2]	(6)	(6)	(1)	--	(1)	(14)
Total	$ 11	$ (19)	$ --	$ 1	$ (1)	$ (8)

(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.

Sources and Uses of Cash
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 the 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 June 30, 2006, we had cash and cash equivalents of $83 million (including $2 million classified as held for sale on our Consolidated Balance Sheet) and $3.4 billion of unused capacity under our credit facilities. The $3.4 billion of unused capacity is comprised of approximately $3.1 billion under our core credit facilities and $295 million available under bilateral credit facilities.

Operating Cash Flows
As presented on our Consolidated Statements of Cash Flows, net cash flows provided by operating activities were $2.0 billion and $1.4 billion for the six months ended June 30, 2006 and 2005, respectively. Management believes that our operations provide a stable source of cash flow sufficient to contribute to planned levels of capital expenditures and maintain or grow the dividend on common shares.

Our operations are subject to risks and uncertainties that may negatively impact the timing or amounts of operating cash flow. See the discussion of such factors in *Operating Cash Flows* in the MD&A of our Annual Report on Form 10-K for the year ended December 31, 2005.

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 June 30, 2006 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 (millions)
Investment grade[1]	$ 636
Non-investment grade[2]	34
No external ratings:	
Internally rated - investment grade[3]	346
Internally rated - non-investment grade[4]	185
Total	$1,201

(1) Designations as investment grade are based on minimum credit ratings assigned by Moody's Investor Services (Moody's) and Standard & Poor's Rating Services (Standard & Poor's). The five largest counterparty exposures, combined, for this category represented approximately 18% of the total gross credit exposure.
(2) The five largest counterparty exposures, combined, for this category represented approximately 2% of the total gross credit exposure.
(3) The five largest counterparty exposures, combined, for this category represented approximately 20% of the total gross credit exposure.
(4) The five largest counterparty exposures, combined, for this category represented approximately 3% of the total gross credit exposure.

Investing Cash Flows

For the six months ended June 30, 2006 and 2005, investing activities resulted in net cash outflows of $2.0 billion and $1.6 billion, respectively. Significant investing activities in the six months ended June 30, 2006 included:

- $1.0 billion of capital expenditures for the purchase and development of gas and oil producing properties, drilling and equipment costs and undeveloped lease acquisitions;
- $913 million of capital expenditures for the construction and expansion of generation facilities, environmental upgrades, purchase of nuclear fuel, and construction and improvements of gas and electric transmission and distribution assets;
- $530 million for the purchases of securities held as investments in our nuclear decommissioning trusts; and
- $91 million related to the acquisition of Pablo Energy LLC, which holds producing and other properties in the Texas Panhandle area, net of cash acquired; partially offset by
- $493 million of proceeds from the sales of securities held as investments in our nuclear decommissioning trusts; and
- $20 million of proceeds received from prior year sales of gas and oil mineral rights and properties.

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 our operations. As discussed further in the *Credit Ratings and Debt Covenants* section below, 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 and, in the case of Virginia Power, obtaining regulatory approval from the Virginia State Corporation Commission (Virginia Commission).

As presented on our Consolidated Statements of Cash Flows, net cash used in financing activities was $100 million and $132 million for the six months ended June 30, 2006 and 2005, respectively.

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

Credit Ratings

Credit ratings are intended to provide banks and capital market participants with a framework for comparing the credit quality of securities and are not a recommendation to buy, sell or hold securities. In the *Credit Ratings* section of MD&A in our Annual Report on Form 10-K for the year ended December 31, 2005, 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. As of June 30, 2006, there have been no changes in the Dominion Companies' credit ratings, other than the matters discussed in MD&A in our Quarterly Report on Form 10-Q for the quarter ended March 31, 2006.

Debt Covenants

In June 2006, we executed a Replacement Capital Covenant (RCC) in connection with the offering of our $300 million 2006 Series A Enhanced Junior Subordinated Notes due 2066 (hybrids). We have initially designated the $250 million 8.4% Capital Securities of Dominion Resources Capital Trust III that were issued in January 2001 as covered debt under the RCC. In the future, we are allowed to change the series of our debt designated as covered debt under the RCC. Under the terms of the RCC, we agree not to redeem or repurchase all or part of the hybrids prior to June 30, 2036, unless we issue qualifying securities to non-affiliates in a replacement offering in the 180 days prior to the redemption or repurchase date. The proceeds we receive from the replacement offering, adjusted by a predetermined factor, must exceed the redemption or repurchase price. Qualifying securities include common stock, preferred stock and other securities that generally rank equal to or junior to the hybrids and include distribution deferral and long-dated maturity features similar to the hybrids. For purposes of the RCC, non-affiliates include individuals enrolled in our dividend reinvestment plan, direct stock purchase plan and employee benefit plans. For a complete copy of the RCC, refer to our Current Report on Form 8-K filed on June 22, 2006. Other than the RCC discussed above, as of June 30, 2006, there have been no changes to or events of default under our debt covenants.

Future Cash Payments for Contractual Obligations

As of June 30, 2006, 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, 2005.

Use of Off-Balance Sheet Arrangements

In June 2006, we entered into a six-month weather derivative contract with an SPE that will provide us cash payments based on the occurrence of specific hurricane-related weather events in the Gulf of Mexico. This weather derivative was executed as an alternative to traditional business interruption insurance. Concurrent with the execution of the weather derivative contract, the SPE issued $50 million of catastrophe bonds. If specific weather events occur, we will be entitled to proceeds from the SPE of up to $50 million. If no specific weather events occur during the term of the contract, then we will not receive payment from the SPE. Under the weather derivative contract, we will make fixed payments to the SPE totaling approximately $5 million, which will be used by the SPE to pay a portion of the bond investors' interest payments. We will also reimburse the SPE for certain operating costs, including bond issuance costs and other ongoing fees which should total less than $2 million. Our FIN 46R analysis determined that the SPE does not have sufficient equity investment at risk, and therefore is a VIE. Furthermore, we concluded that although our interest in the contract represents a variable interest in the SPE, we are not the primary beneficiary. We are not subject to any risk of loss from the contractual arrangement, as our only obligation is to make fixed payments to the SPE and pay certain operating costs of the SPE.

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, 2005 and our Quarterly Report on Form 10-Q for the quarter ended March 31, 2006.

Virginia Fuel Factor

In May 2006, the Governor of Virginia signed into law Senate Bill 262, a substitute energy bill with a provision that changes the way our Virginia jurisdictional fuel factor is set during the three and one-half year period beginning July 1, 2007. The bill became law effective July 1, 2006.

The fuel factor amendment:

- Allows annual fuel rate adjustments for three twelve-month periods beginning July 1, 2007 and one six-month period beginning July 1, 2010 (unless capped rates are terminated earlier under the Virginia Restructuring Act);
- Allows an adjustment at the end of each of the twelve-month periods to account for differences between projections and actual recovery of fuel costs during the prior twelve months; and
- Authorizes the Virginia Commission to defer up to 40% of any fuel factor increase approved for the first twelve-month period, with recovery of the deferred amount over the two and one-half year period beginning July 1, 2008 (under prior law, such a deferral was not possible).

The amendment does not allow us to collect any unrecovered fuel expenses incurred prior to July 1, 2007.

Forward Capacity Market Settlement

Our New England generation plants participate in a market administered by the New England Independent System Operator (ISO-NE). In March 2006, ISO-NE and a broad cross-section of critical stakeholders from around the region filed a comprehensive settlement agreement at the Federal Regulatory Commission (FERC) implementing a Forward Capacity Market in place of Locational Installed Capacity. FERC approved the settlement in June 2006, however such settlement is currently under appeal.

Ohio Energy Choice Pilot Program

In May 2006, the Public Utilities Commission of Ohio (the Ohio Commission) approved our proposal for a two-year pilot program to improve and expand our Energy Choice Program. Under the current structure, non-Energy Choice customers purchase gas directly from us at a monthly gas cost recovery, or GCR, rate that includes true-up adjustments that can change significantly from one quarter to the next. Our approved proposal replaces the GCR with a monthly market price that eliminates those adjustments, making it easier for customers to compare and switch to competitive suppliers. By the end of the transition period, and subject to Ohio Commission approval, we plan to exit the gas merchant function in Ohio entirely and have all customers select an alternate gas supplier. We will continue to remain the provider of last resort in the event of default by a supplier.

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 the expansion of our Cove Point pipeline to approximately 1.8 million dekatherms per day. FERC also approved our plans to expand our Dominion Transmission, Inc. 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. We will begin expansion construction upon receipt of certain state and local permits, which is expected in the third quarter of 2006.

Potential Future Divestitures

We continually review our portfolio of assets to determine if they fit strategically and support our objectives to improve Dominion's return on invested capital and shareholder value. If we identify assets that do not support our objectives going forward and believe they may be of greater value to another owner, we may consider them for divestiture. In connection with this effort, we are evaluating the possible sale of four of our merchant generation facilities. The facilities include:

- State Line, a 515-megawatt coal-fired station in Hammond, Indiana;
- Armstrong, a 625-megawatt natural gas-fired station in Shelocta, Pennsylvania;
- Troy, a 600-megawatt natural gas-fired station in Luckey, Ohio, and
- Pleasants, a 313-megawatt natural gas-fired station in St. Mary’s, West Virginia.

We currently operate the gas-fired units under leasing arrangements that terminate in November 2006. We intend to purchase the units under the terms of the lease agreements on or before the end of the lease term.

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. 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, effective April 2006. To avoid sudden rate increases, under the Initial Decision, the new rate design would be phased-in so that no customer receives greater than a 10% annual rate increase. The Initial Decision also concluded that other rate designs proposed in the hearing could be considered by FERC as alternatives to the rate design recommended in the Initial Decision. Our position is that the existing rate design remains just and reasonable, as supported by a broad coalition of PJM stakeholders. After submission of briefs by the parties, FERC will review the Initial Decision and make a determination whether to agree with it or to overrule the decision and issue a different ruling. At this time, we are unable to predict the ruling by FERC; however, we continue to monitor this matter.

Transmission Expansion Plan

In June 2006, PJM, as part of its latest Regional Transmission Expansion Plan, 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 240-mile 500-kilovolt transmission line from southwestern Pennsylvania to Virginia, of which we will construct approximately 30 miles in Virginia and a subsidiary of Allegheny Energy, Inc. (Allegheny) will construct the remainder. The second project is an approximately 56-mile 500-kilovolt transmission line that we will construct in southeastern Virginia. These transmission upgrades are designed to improve the reliability of the PJM transmission system, including service to our customers. Construction of these transmission lines will be subject to applicable state and federal permits and approvals.

DOMINION RESOURCES, INC.
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, interest rates, foreign currency exchange 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. Interest rate risk is generally related to our outstanding debt. We are exposed to foreign currency exchange rate risks related to our purchases of fuel and fuel services denominated in foreign currencies. 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, interest rates and foreign currency exchange 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% unfavorable change in market prices of our non-trading commodity-based financial derivative instruments would have resulted in a decrease in fair value of approximately $671 million and $691 million as of June 30, 2006 and December 31, 2005, respectively. A hypothetical 10% unfavorable change in commodity prices would have resulted in a decrease of approximately $21 million and $3 million in the fair value of our commodity-based financial derivative instruments held for trading purposes as of June 30, 2006 and December 31, 2005, respectively.

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

Interest Rate Risk
We manage our interest rate risk exposure predominantly by maintaining a balance of fixed and variable rate debt. We also enter into interest rate sensitive derivatives, including interest rate swaps and interest rate lock agreements. For

financial instruments outstanding at June 30, 2006 and December 31, 2005, a hypothetical 10% increase in market interest rates would decrease annual earnings by approximately $21 million and $20 million, respectively.

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, 2005 discusses the impact of changes in value of these investments.

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 have foreign exchange risk exposure associated with anticipated future purchases of nuclear fuel and nuclear fuel processing services denominated in foreign currencies. We manage certain of these risks 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% unfavorable change in relevant foreign exchange rates would have resulted in a decrease of approximately $5 million and $8 million in the fair value of currency forward contracts held by us at June 30, 2006 and December 31, 2005, respectively.

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 reported on our Consolidated Balance Sheets at fair value. We recognized net realized gains (including investment income) on nuclear decommissioning trust investments of $41 million and $22 million for the six months ended June 30, 2006 and 2005, respectively and $67 million for the year ended December 31, 2005. We recorded, in AOCI, net unrealized losses on decommissioning trust investments of $18 million and $21 million for the six months ended June 30, 2006 and 2005, respectively and net unrealized gains on decommissioning trust investments of $27 million for the year ended December 31, 2005.

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.

In accordance with FIN 46R, we have included in our Consolidated Financial Statements certain VIEs through which we have financed and leased several power generation projects as well as our corporate headquarters and aircraft. Our Consolidated Balance Sheet as of June 30, 2006 reflects $586 million of property, plant and equipment and deferred charges and $688 million of related debt attributable to the VIEs. As these VIEs are owned by unrelated parties, we do not have the authority to dictate or modify, and therefore cannot assess, the disclosure controls and procedures or internal control over financial reporting in place at these entities.

DOMINION RESOURCES, INC.
PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

From time to time, we are alleged to be in violation or in default under orders, statutes, rules or regulations relating to the environment, compliance plans imposed upon or agreed to by us, or permits issued by various local, state and federal agencies for the construction or operation of facilities. Administrative proceedings may also be pending on these matters. In addition, in the ordinary course of business, we are involved in various legal proceedings. We believe that the ultimate resolution of these proceedings will not have a material adverse effect on our financial position, liquidity or results of operations. See *Future Issues and Other Matters* in MD&A and *Environmental Matters* in Note 15 to our Consolidated Financial Statements for discussions on various environmental and other regulatory proceedings to which we are a party.

Before being acquired by us, Louis Dreyfus Natural Gas Corp. (Louis Dreyfus) was one of numerous defendants in a lawsuit consolidated and pending in the 93rd Judicial Court in Hidalgo County, Texas. The lawsuit alleged that gas wells and related pipeline facilities operated by Louis Dreyfus and other facilities operated by other defendants caused an underground hydrocarbon plume in McAllen, Texas. In April 2006, we entered into a settlement agreement with the plaintiffs resolving all of their claims against us. In May 2006, the plaintiffs non-suited Dominion with prejudice. We remain subject, however, to a cross-claim and an indemnity claim with certain of the other defendants that were not a party to our settlement with the plaintiffs. Neither claim is material and we do not expect the resolution of these remaining claims or the settlement to have a material adverse effect on the results of operations or financial condition.

ITEM 1A. RISK FACTORS

Our business is influenced by many factors that are difficult to predict, involve uncertainties that may materially affect actual results and are often beyond our control. We have identified a number of these risk factors in our Annual Report on Form 10-K for the year ended December 31, 2005 and our Quarterly Report on Form 10-Q for the quarter ended March 31, 2006, which should be taken into consideration when reviewing the information contained in this report. With respect to our previous disclosure regarding our exposure to cost-recovery shortfalls because of capped rates and amendments to the fuel factor statute in effect in Virginia, we note that in May 2006, the Governor of Virginia signed into law Senate Bill 262, which became effective July 1, 2006. With the exception of the risk factor below, which has been modified to take into account recent developments relating to insurance for our E&P operations, there have been no other material changes with regard to the risk factors previously disclosed in our most recent Forms 10-K and 10-Q. For other factors that may cause actual results to differ materially from those indicated in any forward-looking statement or projection contained in this report, see *Forward-Looking Statements* in MD&A.

Our exploration and production business is dependent on factors that cannot be predicted or controlled and that could damage facilities, disrupt production or reduce the book value of our assets. Factors that may affect our financial results include damage to or suspension of operations caused by weather, fire, explosion or other events to our or third-party gas and oil facilities, fluctuations in natural gas and crude oil prices, results of future drilling and well completion activities and our ability to acquire additional land positions in competitive lease areas, as well as inherent operational risks that could disrupt production.

Short-term market declines in the prices of natural gas and oil could adversely affect our financial results by causing a permanent write-down of our natural gas and oil properties as required by the full cost method of accounting. Under the full cost method, all direct costs of property acquisition, exploration and development activities are capitalized. If net capitalized costs exceed the present value of estimated future net revenues based on hedge-adjusted period-end prices from the production of proved gas and oil reserves (the ceiling test) at the end of any quarterly period, then a permanent write-down of the assets must be recognized in that period.

In the past, we have maintained business interruption, property damage and other insurance for our E&P operations. However, the recent increased level of hurricane activity in the Gulf of Mexico has led our insurers to terminate certain coverages for our E&P operations; specifically, our Operator’s Extra Expense (OEE), offshore property damage and offshore business interruption coverage has been terminated. All onshore property coverage (with the exception of OEE) and liability coverage commensurate with past coverage remain in place for our E&P operations under our current policy. Efforts to replace the terminated insurance for our E&P operations with similar insurance on commercially reasonable terms have been unsuccessful. We have recently entered into a six-month weather derivative contract with an SPE, as further described in Note 12 to our Consolidated Financial Statements. This arrangement provides limited alternative risk mitigation; however, it offers substantially less protection than our previous E&P insurance policies. This lack of insurance could adversely affect our results of operations.

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 Program
4/1/06-4/30/06	101	$74.55	N/A	21,275,000 shares/ $1.72 billion
5/1/06-5/31/06	--	--	N/A	21,275,000 shares/ $1.72 billion
6/1/06-6/30/06	835	$72.20	N/A	21,275,000 shares/ $1.72 billion
Total	936	$72.45	N/A	21,275,000 shares/ $1.72 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

A summary of matters voted upon at our Annual Shareholders Meeting that was held on April 28, 2006 are listed below:

- Directors were elected to the Board of Directors for a one-year term or until next year’s annual meeting;
- Deloitte & Touche LLP was ratified as our independent auditor for 2006;
- Shareholders did not approve the following:
  - A proposal requesting that our articles of incorporation be amended to require director nominees be elected by majority vote of shareholders;
  - A proposal requesting a report to shareholders on how we are responding to regulatory and public pressure to reduce carbon dioxide and other emissions; and
  - A proposal requesting that shareholders approve any future extraordinary retirement benefits for senior executives.

See our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2006 for detailed voting results.

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 October 20, 2000 (Exhibit 3, Form 10-Q for the quarter ended September 30, 2000, File No. 1-8489, incorporated by reference).
4	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.
4.1	Junior Subordinated Indenture II, dated June 1, 2006, between Dominion Resources, Inc. and JPMorgan Chase Bank, N.A., as Trustee (filed herewith).
4.2	First Supplemental Indenture to the Junior Subordinated Indenture II dated as of June 1, 2006 pursuant to which the 2006 Series A Enhanced Junior Subordinated Notes Due 2066 will be issued (filed herewith). The form of the 2006 Series A Enhanced Junior Subordinated Notes Due 2066 is included as Exhibit A to the First Supplemental Indenture.
4.3	Replacement Capital Covenant entered into by Dominion Resources, Inc. dated June 23, 2006 (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

August 3, 2006

/s/ Steven A. Rogers
Steven A. Rogers
Senior Vice President and Controller
(Principal Accounting Officer)