DOMINION RESOURCES INC /VA/
Form 10-Q
November 01, 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 September 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 September 30, 2006, the latest practicable date for determination, 353,718,439 shares of common stock, without par value, of the registrant were outstanding.

DOMINION RESOURCES, INC.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	**2006**	2005
(millions, except per share amounts)				
Operating Revenue	**$4,033**	$4,564	**$12,546**	$12,946
Operating Expenses				
Electric fuel and energy purchases	**1,065**	1,752	**2,591**	3,536
Purchased electric capacity	**122**	121	**361**	376
Purchased gas	**342**	629	**2,152**	2,405
Other energy-related commodity purchases	**144**	387	**862**	1,029
Other operations and maintenance	**531**	1,015	**2,205**	2,368
Depreciation, depletion and amortization	**403**	355	**1,194**	1,050
Other taxes	**125**	120	**437**	419
Total operating expenses	**2,732**	4,379	**9,802**	11,183
Income from operations	**1,301**	185	**2,744**	1,763
Other income	**44**	65	**136**	148
Interest and related charges:				
Interest expense	**228**	211	**686**	627
Interest expense - junior subordinated notes payable	**34**	27	**94**	79
Subsidiary preferred dividends	**4**	4	**12**	12
Total interest and related charges	**266**	242	**792**	718
Income before income taxes and minority interest	**1,079**	8	**2,088**	1,193
Income tax expense (benefit)	**420**	(2)	**734**	422
Minority interest	**5**	--	**5**	--
Income from continuing operations	**654**	10	**1,349**	771
Income from discontinued operations[(1)]	**--**	5	**--**	5
Net Income	**$ 654**	$ 15	**$ 1,349**	$ 776
Earnings Per Common Share - Basic				
Income from continuing operations	**$1.86**	$0.03	**$3.86**	$2.26
Income from discontinued operations	**--**	0.01	**--**	0.01
Net income	**$1.86**	$0.04	**$3.86**	$2.27
Earnings Per Common Share - Diluted				
Income from continuing operations	**$1.85**	$0.03	**$3.84**	$2.25
Income from discontinued operations	**--**	0.01	**--**	0.01
Net income	**$1.85**	$0.04	**$3.84**	$2.26
Dividends paid per common share	**$0.69**	$0.67	**$2.07**	$2.01

(1) Net of income tax expense of $3 million for the three and nine months ended September 30, 2005.

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

DOMINION RESOURCES, INC.
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(millions)	**September 30, 2006**	December 31, 2005(1)
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 126**	$ 146
Accounts receivable:		
Customers (less allowance for doubtful accounts of $24 and $38)	**2,162**	3,335
Affiliates	**26**	4
Other receivables (less allowance for doubtful accounts of $10 and $9)	**217**	222
Inventories	**1,225**	1,167
Derivative assets	**2,267**	3,429
Deferred income taxes	**191**	928
Assets held for sale	**1,093**	4
Other	**718**	894
Total current assets	**8,025**	10,129
Investments		
Nuclear decommissioning trust funds	**2,678**	2,534
Available for sale securities	**38**	287
Loans receivable, net	**405**	31
Other	**652**	649
Total investments	**3,773**	3,501
Property, Plant and Equipment		
Property, plant and equipment	**43,422**	42,063
Accumulated depreciation, depletion and amortization	**(13,786)**	(13,123)
Total property, plant and equipment, net	**29,636**	28,940
Deferred Charges and Other Assets		
Goodwill	**4,298**	4,298
Intangible assets	**626**	620
Prepaid pension cost	**1,869**	1,915
Derivative assets	**923**	1,915
Regulatory assets	**433**	758
Other	**577**	584
Total deferred charges and other assets	**8,726**	10,090
Total assets	**$50,160**	$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)	**September 30, 2006**	December 31, 2005[1]
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Securities due within one year:		
Junior subordinated notes payable to affiliates	**$ 313**	$ --
Other	**3,757**	2,330
Short-term debt	**232**	1,618
Accounts payable	**2,015**	2,756
Accrued interest, payroll and taxes	**953**	694
Derivative liabilities	**3,175**	6,087
Liabilities held for sale	**435**	--
Other	**744**	995
Total current liabilities	**11,624**	14,480
Long-Term Debt		
Long-term debt	**12,427**	13,237
Junior subordinated notes payable:		
Affiliates	**1,147**	1,416
Other	**798**	--
Total long-term debt	**14,372**	14,653
Deferred Credits and Other Liabilities		
Deferred income taxes and investment tax credits	**5,678**	4,984
Asset retirement obligations	**1,913**	2,249
Derivative liabilities	**1,182**	3,971
Regulatory liabilities	**591**	607
Other	**974**	1,062
Total deferred credits and other liabilities	**10,338**	12,873
Total liabilities	**36,334**	42,006
Commitments and Contingencies (see Note 16)		
Minority Interest	**21**	--
Subsidiary Preferred Stock Not Subject to Mandatory Redemption	**257**	257
Common Shareholders' Equity		
Common stock - no par[2]	**11,741**	11,286
Other paid-in capital	**129**	125
Retained earnings	**2,172**	1,550
Accumulated other comprehensive loss	**(494)**	(2,564)
Total common shareholders’ equity	**13,548**	10,397
Total liabilities and shareholders’ equity	**$50,160**	$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; 354 million shares outstanding at September 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)

Nine Months Ended September 30, (millions)	**2006**	2005
Operating Activities		
Net income	**$ 1,349**	$ 776
Adjustments to reconcile net income to net cash provided by operating activities:		
Dominion Capital, Inc. impairment losses	**89**	17
Charges related to pending sale of gas distribution subsidiaries	**185**	--
Net realized and unrealized derivative (gains) losses	**(318)**	705
Depreciation, depletion and amortization	**1,296**	1,143
Deferred income taxes and investment tax credits, net	**417**	(51)
Gain on sale of emissions allowances held for consumption	**(65)**	(138)
Other adjustments to income, net	**(164)**	(7)
Changes in:		
Accounts receivable	**1,042**	35
Inventories	**(143)**	(215)
Deferred fuel and purchased gas costs, net	**231**	53
Prepaid pension cost	**40**	23
Accounts payable	**(656)**	202
Accrued interest, payroll and taxes	**295**	150
Deferred revenues	**(203)**	(243)
Margin deposit assets and liabilities	**(26)**	151
Other operating assets and liabilities	**117**	(103)
Net cash provided by operating activities	**3,486**	2,498
Investing Activities		
Plant construction and other property additions	**(1,365)**	(1,175)
Additions to gas and oil properties, including acquisitions	**(1,509)**	(1,243)
Proceeds from sale of gas and oil properties	**20**	580
Acquisition of businesses	**(91)**	(877)
Proceeds from sale of securities and loan receivable collections and payoffs	**750**	626
Purchases of securities and loan receivable originations	**(808)**	(706)
Proceeds from sale of emissions allowances held for consumption	**67**	189
Other	**156**	113
Net cash used in investing activities	**(2,780)**	(2,493)
Financing Activities		
Issuance (repayment) of short-term debt, net	**(1,386)**	541
Issuance of long-term debt	**1,800**	2,300
Repayment of long-term debt	**(835)**	(1,621)
Issuance of common stock	**435**	655
Repurchase of common stock	**--**	(276)
Common dividend payments	**(727)**	(690)
Other	**(11)**	(38)
Net cash provided by (used in) financing activities	**(724)**	871

Increase (decrease) in cash and cash equivalents	**(18)**	876
Cash and cash equivalents at beginning of period	**146**	361
Cash and cash equivalents at end of period[1]	**$ 128**	$1,237
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. As of September 30, 2006, Virginia Power served 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. As of September 30, 2006, its regulated gas distribution subsidiaries served approximately 1.7 million residential, commercial and industrial gas sales and transportation customer accounts in Ohio, Pennsylvania and West Virginia and its nonregulated retail energy marketing businesses served approximately 1.4 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 Reports on Form 10-Q for the quarters ended March 31, 2006 and June 30, 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 September 30, 2006, our results of operations for the three and nine months ended September 30, 2006 and 2005, and our cash flows for the nine months ended September 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 nine months ended September 30, 2005, if we had applied the fair value recognition provisions of SFAS No. 123 to stock-based employee compensation:

	Three Months Ended September 30, 2005	**Nine Months Ended September 30, 2005**
(millions, except EPS)		
Net income, as reported	$15	$776
Add: actual stock-based compensation expense, net of tax	3	9
Deduct: pro forma stock-based compensation expense, net of tax	(3)	(10)
Net income, pro forma	$15	$775
Basic EPS - as reported	$0.04	$2.27
Basic EPS - pro forma	$0.04	$2.27
Diluted EPS - as reported	$0.04	$2.26
Diluted EPS - pro forma	$0.04	$2.26

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 $2 million of excess tax benefits were realized for the nine months ended September 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 nine months ended September 30, 2006, we recognized approximately $1 million and $4 million, respectively, of compensation cost related to awards previously granted to retirement eligible employees. At September 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 and to facilitate gas transportation. 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 significant portion of our activity related to buy/sell arrangements is presented on a net basis in our Consolidated Statement of Income for the three months and nine months ended September 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 September 30,		Nine Months Ended September 30,	
	2006	2005	**2006**	2005
(millions)				
Sale activity included in operating revenue	**$40**	$195	**$547**	$480
Purchase activity included in operating expenses[1]	**39**	197	**539**	483

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

Note 4. Recently Issued Accounting Standards

SFAS No. 158

In September 2006, the FASB issued SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans*. SFAS No. 158 requires an employer to recognize the overfunded or underfunded status of their benefit plans as an asset or liability in its balance sheet and to recognize changes in that funded status in the year in which the changes occur as a component of other comprehensive income. The funded status is measured as the difference between the fair value of the plan's assets and its benefit obligation. In addition, SFAS No. 158 requires an employer to measure benefit plan assets and obligations that determine the funded status of a plan as of the end of its fiscal year, which we already do. The prospective requirement to recognize the funded status of a benefit plan and to provide the required disclosures will become effective for us on December 31, 2006. The adoption of SFAS No. 158 will have no impact on our results of operations or cash flows. Application of this standard at December 31, 2006, is expected to reduce common shareholders' equity, however the amount of the impact will depend on the measurement of pension and other postretirement benefit plan assets and liabilities at that date.

SAB 108

In September 2006, the SEC issued Staff Accounting Bulletin (SAB) No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements*. SAB 108 provides guidance on how prior year misstatements should be taken into consideration when quantifying misstatements in current year financial statements for purposes of determining whether the current year's financial statements are materially misstated. The provisions of SAB 108 are required to be applied beginning December 31, 2006. We do not expect the adoption of SAB 108 to impact our Consolidated Financial Statements.

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.

SFAS No. 157

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

Management Activities, and SFAS No. 155*, Accounting for Certain Hybrid Financial Instruments*. We are currently evaluating the impact that SFAS No. 157 will have on our results of operations and financial condition.

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:

	September 30, 2006
(millions)	
ASSETS	
Current Assets	
Cash	**$ 2**
Customer accounts receivable	**93**
Unrecovered gas costs	**28**
Other	**126**
Total current assets	**249**
Investments	**2**
Property, Plant and Equipment	
Property, plant and equipment	**1,119**
Accumulated depreciation, depletion and amortization	**(379)**
Total property, plant and equipment, net	**740**
Deferred Charges and Other Assets	
Regulatory assets	**100**
Other	**1**
Total deferred charges and other assets	**101**
Assets held for sale	**$1,092**
LIABILITIES	
Current Liabilities	
Accounts payable	**$ 68**
Payables to affiliates	**23**
Deferred income taxes	**13**
Other	**95**
Total current liabilities	**199**
Deferred Credits and Other Liabilities	
Asset retirement obligations	**33**
Deferred income taxes	**166**
Regulatory liabilities	**26**
Other	**11**
Total deferred credits and other liabilities	**236**
Liabilities held for sale	**$ 435**

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	**2006**	2005
(millions)				
Operating Revenue	**$63**	$60	**$ 512**	$472
Income (loss) before income taxes	**(6)**	(9)	**(134)**	37

In the nine months ended September 30, 2006, we recognized a $167 million ($103 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 $136 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 September 30,		Nine Months Ended September 30,	
	2006	2005	**2006**	2005
(millions)				
Operating Revenue				
Electric sales:				
Regulated	**$1,650**	$1,729	**$4,231**	$4,296
Nonregulated	**642**	1,081	**1,793**	2,336
Gas sales:				
Regulated	**96**	122	**1,071**	1,117
Nonregulated	**383**	593	**1,642**	1,813
Other energy-related commodity sales	**254**	449	**1,162**	1,234

Gas transportation and storage	**190**	180	**677**	635
Gas and oil production	**475**	358	**1,496**	1,177
Other	**343**	52	**474**	338
Total operating revenue	**$4,033**	$4,564	**$12,546**	$12,946

Note 7. Income Taxes

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

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
	2006	2005	**2006**	2005
(millions)				
Income before income taxes and minority interest	**$1,079**	$ 8	**$2,088**	$1,193
U.S. statutory rate	**35.0%**	35.0%	**35.0%**	35.0%
Income taxes at U.S. statutory rate	**378**	3	**731**	418
Increases (decreases) resulting from:				
Amortization of investment tax credits	**(3)**	(3)	**(9)**	(10)
Employee pension and other benefits	**(2)**	(11)	**(7)**	(15)
Employee stock ownership plan	**(3)**	(4)	**(10)**	(9)
Other benefits and taxes - foreign operations	**(10)**	--	**(16)**	(11)
State taxes, net of federal benefit	**45**	13	**108**	46
Changes in valuation allowances	**(2)**	--	**(183)**	1
Recognition of deferred taxes - stock of subsidiaries held for sale	**1**	--	**136**	--
Other, net	**16**	--	**(16)**	2
Income tax expense (benefit)	**$ 420**	$ (2)	**$ 734**	$ 422
Effective tax rate	**38.9%**	**(31.6)%**	**35.2%**	**35.4%**

For the three months ended September 30, 2005, the income tax benefit and negative effective tax rate primarily reflected the effects of the substantial decrease in income before income taxes and the items identified above that result in differences in the reported provision for income taxes, as compared to the amount calculated at the U.S. statutory rate.

For the nine months ended September 30, 2006, the reduction in valuation allowances reflects the expected utilization of federal and state tax loss carryforwards to offset capital gain income that will be generated from the pending sale of Peoples and Hope, partially offset by valuation allowance increases primarily associated with the deferred tax asset recognized as a result of the impairment of a DCI investment, as discussed in Note 20. The effect of the decrease to valuation allowances was partially offset by the establishment 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.

Note 8. Earnings Per Share

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	**2006**	2005
(millions, except EPS)				
Income from continuing operations	**$654**	$10	**$1,349**	$771
Income from discontinued operations	**--**	5	**--**	5
Net income	**$654**	$15	**$1,349**	$776
Basic EPS				
Average shares of common stock outstanding - basic	**351.9**	342.9	**349.1**	341.0
Income from continuing operations	**$1.86**	$0.03	**$3.86**	$2.26
Income from discontinued operations	**--**	0.01	**--**	0.01
Net income	**$1.86**	$0.04	**$3.86**	$2.27
Diluted EPS				
Average shares of common stock outstanding	**351.9**	342.9	**349.1**	341.0
Net effect of potentially dilutive securities(1)	**2.0**	2.1	**1.8**	2.1
Average shares of common stock outstanding - diluted	**353.9**	345.0	**350.9**	343.1
Income from continuing operations	**$1.85**	$0.03	**$3.84**	$2.25
Income from discontinued operations	**--**	0.01	**--**	0.01
Net income	**$1.85**	$0.04	**$3.84**	$2.26

(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 4.3 million common shares for the three months ended September 30, 2005 and 1.0 million and 2.9 million common shares for the nine months ended September 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. There were no such anti-dilutive securities outstanding during the three months ended September 30, 2006.

Note 9. Comprehensive Income

The following table presents total comprehensive income (loss):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	**2006**	2005
(millions)				
Net income	**$654**	$15	**$ 1,349**	$ 776
Other comprehensive income (loss):				
Net other comprehensive income (loss) associated with effective portion of changes in fair value of derivatives designated as cash	**888**(1)	(1,239) (2)	**2,011**(1)	(2,154)(2)

flow hedges, net of taxes and amounts reclassified to earnings				
Other(3)	**70**	29	**59**	10
Other comprehensive income (loss)	**958**	(1,210)	**2,070**	(2,144)
Total comprehensive income (loss)	**$1,612**	$(1,195)	**$3,419**	$(1,368)

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

(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 nuclear 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 September 30,		Nine Months Ended September 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	**$(15)**	$ 12	**$ (23)**	$ 17
Cash flow hedges [1]	**9**	(28)	**33**	(49)
Net ineffectiveness	**$ (6)**	$(16)	**$10**	$(32)

(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 nine months ended September 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.

Additionally, due to interruptions in Gulf of Mexico and south Louisiana gas and oil production caused by Hurricanes Katrina and Rita, we discontinued hedge accounting for certain cash flow hedges in August and September 2005 since it became probable that the forecasted sales of gas and oil would not occur. In connection with the discontinuance of hedge accounting for these contracts, we reclassified $423 million ($272 million after-tax) of losses from AOCI to earnings in the third quarter of 2005.

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

	AOCI After-Tax	Portion Expected to be Reclassified to Earnings during the next 12 Months After-Tax	Maximum Term
(millions)			
Commodities:			
Gas	$ (271)	$ (254)	54 months
Oil	(364)	(249)	39 months
Electricity	(129)	(145)	39 months

Other	1	1	3 months
Interest rate	(22)	5	237 months
Foreign currency	19	9	14 months
Total	$(766)	$(633)	

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

Note 11. Ceiling Test

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

Approximately 9% of our U.S. anticipated production is hedged by qualifying cash flow hedges, for which hedge-adjusted prices were used to calculate estimated future net revenue. Whether period-end market prices or hedge-adjusted prices were used for the portion of production that is hedged, there was no ceiling test impairment for our U.S. cost center as of September 30, 2006.

Approximately 9% of our anticipated Canadian production is hedged by qualifying cash flow hedges, for which hedge-adjusted prices were used to calculate estimated future net revenue. There was no ceiling test impairment for our Canadian cost center as of September 30, 2006, using hedge-adjusted prices. Calculation of the Canadian cost center ceiling without qualifying cash flow hedges would yield an impairment against book value of approximately $3 million after tax.

Note 12. Asset Retirement Obligations

The following table describes the changes to our asset retirement obligations during the nine months ended September 30, 2006:

	Amount
(millions)	
Asset retirement obligations at December 31, 2005[(1)]	$2,255
Obligations incurred during the period	**7**
Obligations settled during the period	**(15)**
Accretion expense	**83**
Revisions in estimated cash flows[(2)]	**(380)**
Other[(3)]	**(33)**
Asset retirement obligations at September 30, 2006[(1)]	**$1,917**

(1) Amount includes $4 million and $6 million reported in other current liabilities at September 30, 2006 and December 31, 2005, respectively.
(2) Primarily reflects a reduction in cost escalation rate assumptions that were applied to updated decommissioning cost studies received for each of our nuclear facilities during the third quarter of 2006.
(3) Reflects reclassification of $33 million associated with Peoples and Hope that is reported in liabilities held for sale.

Note 13. 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), had 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).

In September 2006 we received sufficient information from one of the potential VIEs, and performed our FIN 46R analysis. As a result of our analysis, we determined that the entity is not a VIE. As of September 30, 2006, the requested information has not been received from the two remaining potential VIEs. We will continue our efforts to obtain information and will complete an evaluation of our relationship with each of these potential VIEs if sufficient information is ultimately obtained. We have remaining purchase commitments with these two potential VIE supplier entities of $1.3 billion at September 30, 2006. We are not subject to any risk of loss from these potential VIE's, other than the remaining purchase commitments. We paid $24 million and $25 million for electric generation capacity and $31 million and $45 million for electric energy to these entities in the three months ended September 30, 2006 and 2005, respectively. We paid $72 million and $81 million for electric generation capacity and $68 million and $79 million for electric energy to these entities in the nine months ended September 30, 2006 and 2005, respectively.

In September 2006, we, along with three other gas and oil exploration companies, entered into a long-term contract with an unrelated limited liability corporation (LLC) whose only current activities are to design, construct, install and own the Thunder Hawk facility, a semi-submersible production facility, to be located in the deep water Gulf of Mexico. Certain variable pricing terms and guarantees in the contract protect the equity holder from variability, and therefore, the LLC was determined to be a VIE. After completing our FIN 46R analysis, we concluded that although our 25% interest in the contract, as a result of its pricing terms and guarantee, represents a variable interest in the LLC, we are not the primary beneficiary. Our maximum exposure to loss from the contractual arrangement is approximately $63 million. As of September 30, 2006 we have not made any payments to the LLC.

During 2005, we entered into four long-term contracts with unrelated limited liability corporations (LLCs) to purchase coal and 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 $36 million and $67 million to the LLCs for coal and synthetic fuel produced from coal during the three months ended September 30, 2006 and 2005, respectively, and $243 million and $130 million to the LLCs for coal and synthetic fuel produced from coal in the nine months ended September 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 are required to make fixed payments to the SPE, which will be used by the SPE to pay a portion of the bond investors' interest payments. We paid approximately $2.6 million in fixed payments to the SPE for the nine months ended September 30, 2006. We are also required to reimburse the SPE for certain operating costs, including bond issuance costs and other ongoing fees. We paid $1.3 million to the SPE for these operating costs in the nine months ended September 30, 2006. 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 20, 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 September 30, 2006 and December 31, 2005 reflect net property, plant and equipment of $842 million and $943 million and debt of $950 million and $1.1 billion, respectively, related to these entities. The debt is non-recourse to us and is secured by the entities' property, plant and equipment. In September 2006, our lease terminated on the corporate headquarters and aircraft and we took legal title to these assets through repayment of the lessor's related debt. Of the $950 million of debt remaining, $580 million relates to leases that terminate in November 2006 under which we operate three of the power generation facilities. We intend to take legal title to these generation facilities through the repayment of the lessor's related debt at the end of the lease term.

Note 14. Significant Financing Transactions

Credit Facilities and Short-Term Debt

We use short-term debt, primarily commercial paper, to fund working capital requirements, as a bridge to long-term debt financing and as bridge financing for acquisitions, if applicable. The levels of 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 September 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 September 30, 2006, we had the following commercial paper and letters of credit outstanding and capacity available under credit facilities:

	Facility Limit	Outstanding Commercial Paper	Outstanding Letters of Credit	Facility Capacity Available
(millions)				
Five-year revolving credit facility(1)	$3,000	$165	$ 302	$2,533
Five-year CNG credit facility(2)	1,700	--	705	995
364-day CNG credit facility(3)	1,050	--	--	1,050
Totals	$5,750	$165	$1,007	$4,578

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

Company	Facility Limit	Outstanding Letters of Credit	Facility Capacity Remaining	Facility Inception Date	Facility Maturity Date
(millions)					
CNG	$100	$ 25	$ 75	June 2004	June 2007
CNG	100	100	--	August 2004	August 2009
CNG(1)	200	--	200	December 2005	December 2010
Totals	$400	$125	$275		

(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 September 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 20, in June 2006, DCI began consolidating a CDO entity, in accordance with FIN 46R. At September 30, 2006, this CDO entity had $385 million of notes payable that mature in January 2017 and are nonrecourse to us.

In September 2006, we issued $500 million of 2006 Series B hybrids that mature in 2066. The hybrids will bear interest at 6.3% per year until September 30, 2011. Beginning September 30, 2011, the hybrids will bear interest at the three-month LIBOR plus 2.3%, reset quarterly. We used the proceeds from this issuance for general corporate purposes including the repayment of short-term debt and the redemption of trust preferred securities, discussed below.

We repaid $835 million of long-term debt during the nine months ended September 30, 2006.

In October 2006, we redeemed all 12 million units of the $300 million 8.4% Dominion Resources Capital Trust II due January 30, 2041. The securities were redeemed at a price of $25 per preferred security plus accrued and unpaid distributions.

On November 1, 2006 we repaid CNG’s $500 million 2001 Series B 5.375% Senior Notes which matured on that date, using proceeds from a short-term borrowing under CNG’s $1.7 billion credit facility.

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 September 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 nine months ended September 30, 2006, we issued 5.9 million shares of common stock and received proceeds of $435 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 15. 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 September 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 September 30, 2006 and 2005 include $8 million and $5 million, respectively, of compensation costs and $3 million and $2 million, respectively, of income tax benefits related to our stock-based compensation arrangements. Our results for the nine months ended September 30, 2006 and 2005 include $23 million and $15 million, respectively, of compensation costs and $9 million and $6 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 nine months ended September 30, 2006:

	Shares	**Weighted-Average Exercise Price**	**Weighted-Average Remaining Contractual Life**	**Aggregate intrinsic value[(1)]**
	(thousands)		(years)	(millions)
Outstanding and exercisable at January 1, 2006	8,214	$60.43		
Granted	--	--		
Exercised	(395)	59.24		$ 7
Forfeited/expired	(12)	61.66		
Outstanding and exercisable at September 30, 2006	7,807	$60.48	3.4	$125

(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 $23 million and $326 million in the nine months ended September 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 nine months ended September 30, 2006:

	Shares	**Weighted-Average Grant Date Fair Value**
	(thousands)	
Nonvested at January 1, 2006	1,131	$63.28
Granted	318	69.78
Vested	(164)	60.47
Cancelled and forfeited	(31)	67.33
Nonvested at September 30, 2006	1,254	$66.35

As of September 30, 2006, unrecognized compensation cost related to nonvested restricted stock awards totaled $37 million and is expected to be recognized over a weighted-average period of 1.6 years. In the nine months ended September 30, 2006, the fair value of restricted stock awards that vested totaled $13 million.

Goal-Based Stock

In April 2006, we granted goal-based stock awards 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 September 30, 2006, the targeted number of shares to be issued is 98,525, 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	**Weighted-Average Grant Date Fair Value**
	(thousands)	
Nonvested at January 1, 2006	--	$ --
Granted	100.0	69.53
Vested	--	--
Cancelled and forfeited	(1.5)	69.53
Nonvested at September 30, 2006	98.5	$69.53

As of September 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 1.8 years.

Cash-Based Performance Grant

In April 2006, we made a cash-based performance grant to our 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 September 30, 2006, the targeted amount of the grant is $14 million, but actual payout will vary between zero and 200% of the targeted amount depending on the level of performance metrics achieved. At September 30, 2006, a liability of $4 million has been accrued for this award.

Note 16. 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, Note 16 to the Consolidated Financial Statements in our Quarterly Report on Form 10-Q for the quarter ended March 31, 2006 or Note 15 to the Consolidated Financial Statements in our Quarterly Report on Form 10-Q for the quarter ended June 30, 2006, nor have any significant new matters arisen during the three months ended September 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 September 30, 2006 and December 31, 2005, our Consolidated Balance Sheets reflect $191 million and $144 million, respectively, of income tax-related contingent liabilities, including accrued interest. The September 30, 2006 liability includes amounts related to certain state income tax credits. Although we have not recognized the income tax benefit of such credits, we have reduced payments to the taxing authority by those credits. If our claim for the credits is not sustained, we would have to pay $53 million plus any interest assessed.

Lease Commitment

In September 2006, we, along with three other gas and oil exploration companies, executed agreements with a third party to design, construct, install and own the Thunder Hawk facility, a semi-submersible production facility to be located in the deepwater Gulf of Mexico. We anticipate that mechanical completion of the Thunder Hawk facility will occur in 2009 and that the processing of our production will start by 2010. The agreements require that we pay a demand charge of approximately $63 million over five years starting on the day after the mechanical completion of the Thunder Hawk facility. The agreements also require the payment of production processing fees including a minimum processing fee if yearly production processing fees are below specified amounts. Our maximum obligation for the minimum processing fee would be approximately $3 million per year. Our obligation for the payment of these processing fees will terminate upon the cessation of our production.

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 increased level of hurricane activity in the Gulf of Mexico 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 was terminated. All onshore property coverage (with the exception of OEE) and liability coverage commensurate with past coverage remained in place for our E&P operations under our current policy. Recently our OEE coverage for both onshore and offshore E&P operations was reinstated under a new policy. However, efforts to replace the terminated insurance for our E&P operations for offshore property damage and offshore business interruption with similar traditional insurance on commercially reasonable terms were unsuccessful. In June 2006, we also entered into a six-month weather derivative contract with an SPE. 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 (2005 hurricanes) 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. During the third quarter of 2006, we reached a settlement on our business interruption insurance and property damage claims for the 2005 hurricanes in the amount of $309 million. Of the total proceeds, we received $304 million during the third quarter of 2006 and expect to receive the remaining $5 million during the fourth quarter of 2006.

Guarantees

At September 30, 2006, we had issued $32 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.

As discussed above in *Lease Commitment,* in September 2006, we, along with three other gas and oil exploration companies executed agreements with a third party to design, construct, install and own the Thunder Hawk facility, a semi-submersible production facility to be located in the deepwater Gulf of Mexico. Due to current offshore insurance market conditions, it is anticipated that the Thunder Hawk facility will only be partially insured against a catastrophic full or partial loss. We, along with the three other participating producers will be required to continue to make demand payments in the event of a catastrophic loss if insurance payments are not sufficient to pay the lessor's outstanding debt incurred for the Thunder Hawk facility. Our obligation will terminate upon the earlier event of full payment of the lessor's debt incurred for the Thunder Hawk facility or the full payment of our demand charge obligation. We believe that it is unlikely that we would be required to perform under this guarantee and have not recognized any significant liabilities for this arrangement.

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 September 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 September 30, 2006, we had issued the following subsidiary guarantees:

	Stated Limit	**Value**(1)
(millions)		
Subsidiary debt(2)	$1,215	$1,215
Commodity transactions(3)	3,775	909
Lease obligation for power generation facility(4)	898	898
Nuclear obligations(5)	375	302
Offshore drilling commitments(6)	--	493
Other	711	443
Total	$6,974	$4,260

(1) Represents the estimated portion of the guarantee's stated limit that is utilized as of September 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 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 required 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 of the Millstone and Kewaunee power stations, respectively, in the event of a prolonged outage 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 September 30, 2006, we had also purchased $126 million of surety bonds and authorized the issuance of standby letters of credit by financial institutions of $1.1 billion. We enter into these arrangements to facilitate commercial transactions by our subsidiaries with third parties.

Note 17. Credit Risk

Credit risk is our risk of financial loss if counterparties fail to perform their contractual obligations. In order to minimize overall credit risk, we maintain credit policies, including the evaluation of counterparty financial condition, collateral requirements and the use of standardized agreements that facilitate the netting of cash flows associated with a single counterparty. We maintain a provision for credit losses based on factors surrounding the credit risk of our customers, historical trends and other information. We believe, based on our credit policies and our September 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 September 30, 2006, our gross credit exposure totaled $1.31 billion. After the application of collateral, our credit exposure is reduced to $1.27 billion. Of this amount, investment grade counterparties represented 81% and no single counterparty exceeded 8%.

Note 18. Discontinued Operations - Telecommunications Operations

The following table presents selected information related to our discontinued telecommunications operations:

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
	2006	2005	**2006**	2005
(millions)				
Operating Revenue	**$--**	$--	**$--**	$--
Income (loss) before income taxes	**$--**	$ 8	**$--**	$8

In May 2004, we completed the sale of our discontinued telecommunications operations to Elantic Telecom, Inc. (ETI). In July 2004, ETI filed a voluntary petition for reorganization under Chapter 11 of the U.S. Bankruptcy Code, which was subsequently approved by the U.S. Bankruptcy Court. ETI's plan of reorganization became effective in May 2005, and ETI emerged from bankruptcy. In September 2005, ETI, its parent and various Dominion entities reached a comprehensive settlement of various issues that was subsequently approved by the U.S. Bankruptcy Court. We recognized a benefit of $8 million ($5 million after-tax) in the three months ended September 30, 2005, from the revaluation of an outstanding guarantee associated with the sale transaction. In addition to this outstanding guarantee, we have several potential indemnification obligations related to our discontinued telecommunications operations.

Note 19. 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 September 30,				
Service cost	**$ 30**	$ 30	**$ 15**	$ 16
Interest cost	**50**	56	**17**	21
Expected return on plan assets	**(86)**	(96)	**(12)**	(13)
Amortization of prior service cost (credit)	**1**	--	**(1)**	--
Amortization of transition obligation	**--**	--	**1**	1
Amortization of net loss	**22**	22	**5**	5
Net periodic benefit cost	**$ 17**	$ 12	**$ 25**	$ 30
Nine Months Ended September 30,				
Service cost	**$ 95**	$ 86	**$ 55**	$ 48
Interest cost	**158**	161	**61**	62
Expected return on plan assets	**(271)**	(275)	**(44)**	(39)
Curtailment loss(1)	**6**	--	--	--
Amortization of prior service cost (credit)	**3**	2	**(3)**	(1)
Amortization of transition obligation	**--**	--	**3**	3
Amortization of net loss	**69**	62	**20**	15
Net periodic benefit cost	**$ 60**	$ 36	**$ 92**	$ 88

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

Employer Contributions

We made no contributions to our defined benefit pension plans or other postretirement benefit plans during the nine months ended September 30, 2006. We expect to contribute at least $70 million to our other postretirement benefit plans during the fourth quarter 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 during the fourth quarter.

Note 20. 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 September 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 September 30, 2006:

	Amount
(millions)	
Other current assets	$155
Loans receivable, net	373
Other investments	60
Total assets	$588

Note 21. 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 nine months ended September 30, 2006 and 2005, we reported net expenses of $111 million and $420 million, respectively, in the Corporate segment attributable to our operating segments.

The net expenses in 2006 primarily related to the impact of a $167 million ($103 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 $556 million ($357 million after-tax) loss related to the discontinuance of hedge accounting for certain gas and oil hedges, resulting from an interruption of gas and oil production in the Gulf of Mexico caused by the 2005 hurricanes, and subsequent changes in the fair value of those hedges, attributable to Dominion E&P; and

· A $77 million ($47 million after-tax) charge resulting from the termination of a long-term power purchase agreement, 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 September 30,							
2006							
Operating Revenue:							
External customers	**$649**	**$198**	**$2,007**	**$863**	**$ (15)**	**$ 331**	**$4,033**
Intersegment	**3**	**382**	**29**	**49**	**186**	**(649)**	**--**
Total operating revenue	**652**	**580**	**2,036**	**912**	**171**	**(318)**	**4,033**
Net income (loss)	**78**	**102**	**249**	**299**	**(74)**	**--**	**654**
2005							
Operating Revenue:							
External customers	$659	$260	$2,606	$581	$ 16	$ 442	$4,564
Intersegment	3	475	57	59	130	(724)	--
Total operating revenue	662	735	2,663	640	146	(282)	4,564
Net income (loss)	89	73	204	38	(389)	--	15
Nine Months Ended September 30,							
2006							
Operating Revenue:							
External customers	**$3,058**	**$1,043**	**$5,240**	**$2,516**	**$ (71)**	**$ 760**	**$12,546**
Intersegment	**9**	**945**	**110**	**167**	**567**	**(1,798)**	**--**
Total operating revenue	**3,067**	**1,988**	**5,350**	**2,683**	**496**	**(1,038)**	**12,546**
Net income (loss)	**314**	**277**	**441**	**643**	**(326)**	**--**	**1,349**
2005							
Operating Revenue:							
External customers	$2,897	$1,016	$6,142	$1,930	$ 24	$ 937	$12,946
Intersegment	31	978	148	149	421	(1,727)	--
Total operating revenue	2,928	1,994	6,290	2,079	445	(790)	12,946
Net income (loss)	346	236	403	339	(548)	--	776

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;
- 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 and offshore property damage 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 Reports on Form 10-Q for the quarters ended March 31, 2006 and June 30, 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 September 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

SFAS No. 158

In September 2006, the FASB issued SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans*. SFAS No. 158 requires an employer to recognize the overfunded or underfunded status of their benefit plans as an asset or liability in its balance sheet and to recognize changes in that funded status in the year in which the changes occur as a component of other comprehensive income. The funded status is measured as the difference between the fair value of the plan's assets and its benefit obligation. In addition, SFAS No. 158 requires an employer to measure benefit plan assets and obligations that determine the funded status of a plan as of the end of its fiscal year, which we already do. The prospective requirement to recognize the funded status of a benefit plan and to provide the required disclosures will become effective for us on December 31, 2006. The adoption of SFAS No. 158 will have no impact on our results of operations or cash flows. Application of this standard at December 31, 2006, is expected to reduce common shareholders' equity, however the amount of the impact will depend on the measurement of pension and other postretirement benefit plan assets and liabilities at that date.

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.

SFAS No. 157

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

Results of Operations

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

(millions, except EPS)	**2006**	2005	$ Change
Third Quarter			
Net income	**$ 654**	$ 15	$ 639
Diluted EPS	**1.85**	0.04	1.81
Year-To-Date			
Net income	**$ 1,349**	$ 776	$ 573
Diluted EPS	**3.84**	2.26	1.58

Overview

Third Quarter 2006 vs. 2005

Net income increased by $639 million to $654 million. Favorable drivers include business interruption insurance revenue related to hurricanes, an increase in gas and oil production and the absence of a $357 million after-tax loss recorded in 2005 related to the discontinuance of hedge accounting for certain gas and oil hedges. This loss resulted from hurricane-related interruptions of gas and oil production in the Gulf of Mexico. Favorable drivers also include the positive 2006 mark-to-market impact of certain gas and oil derivatives that were de-designated as hedges in 2005.

Year-To-Date 2006 vs. 2005

Net income increased 74% to $1.3 billion. Favorable drivers include higher business interruption insurance revenue in 2006 versus 2005, an increase in gas and oil production, a higher contribution from our merchant generation business and the absence of a $357 million after-tax loss recorded in 2005 related to the discontinuance of hedge accounting for certain gas and oil hedges. This loss resulted from hurricane-related interruptions of gas and oil production in the Gulf of Mexico. Favorable drivers also include the positive 2006 mark-to-market impact of certain gas and oil derivatives that were de-designated as hedges in 2005. Unfavorable drivers include charges associated with the pending sale of Peoples and Hope and the impairment of a DCI investment.

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

	Third Quarter			Year-To-Date		
	2006	2005	$ Change	**2006**	2005	$ Change
(millions)						
Operating Revenue	**$4,033**	$4,564	$ (531)	**$12,546**	$12,946	$(400)
Operating Expenses						
Electric fuel and energy purchases	**1,065**	1,752	(687)	**2,591**	3,536	(945)
Purchased electric capacity	**122**	121	1	**361**	376	(15)
Purchased gas	**342**	629	(287)	**2,152**	2,405	(253)
Other energy-related commodity purchases	**144**	387	(243)	**862**	1,029	(167)
Other operations and maintenance	**531**	1,015	(484)	**2,205**	2,368	(163)
Depreciation, depletion and amortization	**403**	355	48	**1,194**	1,050	144
Other taxes	**125**	120	5	**437**	419	18
Other income	**44**	65	(21)	**136**	148	(12)
Interest and related charges	**266**	242	24	**792**	718	74
Income tax expense (benefit)	**420**	(2)	422	**734**	422	312

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

Third Quarter 2006 vs. 2005

Operating Revenue decreased 12% to $4.0 billion, primarily reflecting:

- A $372 million decrease primarily attributable to the winding down of requirements-based power sales contracts that we have exited. This decrease is offset by a corresponding decrease in *Electric fuel and energy purchases* described below;
- A $203 million decrease in our producer services business consisting of a decrease in both volume and prices associated with gas aggregation, partially offset by favorable price changes related to price risk management and gas marketing activities;
- A $155 million decrease as a result of the impact of netting sales and purchases of oil and gas under buy/sell arrangements that were entered into or modified by E&P operations subsequent to April 1, 2006, in accordance with EITF 04-13. The effect of this decrease was largely offset by corresponding decreases in *Purchased gas expense* and *Other energy-related commodity purchases expense;*
- An $84 million decrease in electric utility operations, primarily associated with milder weather (a 13% decline in cooling degree days), partially offset by an increase due to new customer connections primarily in our residential and commercial customer classes;
- An $83 million decrease in sales of emissions allowances held for resale, resulting from lower overall sales volumes. The effect of this decrease was largely offset by a corresponding decrease in *Other energy-related commodity purchases expense*;
- A $54 million decline in nonutility coal sales, primarily reflecting lower sales volumes. The effect of this decrease was largely offset by a corresponding decrease in *Other energy-related commodity purchases expense*; and
- A $30 million decrease in our merchant generation operations, primarily reflecting lower sales volumes and prices for our fossil plants driven largely by comparably milder weather, partially offset by higher realized prices for nuclear operations; partially offset by
- $269 million of business interruption insurance revenue received in 2006, associated with the 2005 hurricanes;
- A $117 million increase in sales of gas and oil production, primarily due to increased production ($218 million), partially offset by lower prices ($101 million); and

- A $55 million increase in sales of extracted products, reflecting higher volumes ($42 million), and increased market prices ($13 million).

Operating Expenses and Other Items

Electric fuel and energy purchases expense decreased 39% to $1.1 billion, primarily reflecting the combined effects of:

- A $478 million decrease associated with the requirements-based power sales contracts described in *Operating revenue*;
- A $143 million decrease related to our utility generation operations, primarily due to lower commodity prices, including purchased power, and decreased consumption of fossil fuel, reflecting the effects of milder weather on generation operations; and
- A $60 million decrease for our merchant generation operations, due primarily to lower commodity prices and decreased consumption of fossil fuel, reflecting the effects of milder weather on fossil plant operations.

Purchased gas expense decreased 46% to $342 million, principally resulting from:

- A $244 million decrease associated with our producer services business, due to lower volumes and prices;
- A $37 million decrease related to E&P operations, as a result of lower volumes and the impact of netting sales and purchases of gas under buy/sell arrangements associated with the implementation of EITF 04-13, as discussed above;
- A $26 million decrease attributable to regulated gas distribution operations, due primarily to lower volumes; and
- A $16 million decrease related to lower system gas costs for the gas transmission operations; partially offset by
- A $43 million increase associated with nonregulated retail energy marketing activities, due to higher volumes.

Other energy-related commodity purchases expense decreased 63% to $144 million, primarily resulting from the following factors, all of which are discussed in *Operating Revenue*:

- A $121 million decrease as a result of the impact of netting sales and purchases of oil under buy/sell arrangements associated with the implementation of EITF 04-13;
- An $81 million decrease in purchases of emissions allowances held for resale; and
- A $41 million decrease in nonutility coal purchased for resale.

Other operations and maintenance expense decreased 48% to $531 million, primarily reflecting the combined effects of:

- The absence of a $556 million loss in 2005 related to the discontinuance of hedge accounting for certain gas and oil hedges, resulting from an interruption of gas and oil production in the Gulf of Mexico caused by the 2005 hurricanes, and subsequent changes in the fair value of those hedges;
- A $51 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; and
- A $28 million decrease in hedge ineffectiveness expense associated with our E&P operations, primarily due to a decrease in the fair value differential between the delivery location and commodity specifications of derivative contracts held by us as compared to our forecasted gas and oil sales and the increased use of basis swaps.

These decreases were partially offset by:

- A $40 million decrease in gains from the sale of emission allowances held for consumption;
- A $34 million increase attributable to higher production handling, transportation and operating costs related to E&P operations;
- A $25 million increase related to derivatives held in connection with merchant generation operations;
- An $18 million increase related to major storm damage and service restoration costs associated with our distribution operations, primarily resulting from tropical storm Ernesto in September 2006;
- A $17 million increase in outage costs, primarily due to a scheduled refueling outage at the Kewaunee power station (Kewaunee), with no similar outage in 2005;
- A $15 million increase due to a reduced benefit from financial transmission rights (FTRs) granted by PJM to our utility generation operations. These FTRs are used to offset congestion costs associated with PJM spot market activity, which are included in *Electric fuel and energy purchases expense*; and
- A $14 million increase resulting primarily from higher salaries, wages and benefits expenses.

Depreciation, depletion and amortization expense (DD&A) increased 14% to $403 million, largely due to the impact of increased gas and oil production, as well as higher E&P finding and development costs.

Other income decreased 32% to $44 million primarily due to the combined effect of a $10 million impairment charge associated with an equity-method investment and a $7 million decrease in net realized gains (including investment income) associated with nuclear decommissioning trust fund investments.

Interest and related charges increased 10% to $266 million, resulting principally from higher interest rates on variable rate debt.

Year-To-Date 2006 vs. 2005

Operating Revenue decreased 3% to $12.5 billion, primarily reflecting:

- An $818 million decrease primarily attributable to the winding down of requirements-based power sales contracts that we have exited. This decrease is offset by a corresponding decrease in *Electric fuel and energy purchases* described below;
- A $219 million decline in nonutility coal sales, primarily reflecting lower sales volumes. The effect of this decrease was largely offset by a corresponding decrease in *Other energy-related commodity purchases expense*;
- A $273 million decrease in our producer services business, consisting of a decrease in volumes, partially offset by an increase in price associated with gas aggregation and favorable price changes related to price risk management and gas marketing activities;
- A $121 million decrease in sales of emissions allowances held for resale, primarily resulting from lower overall sales volumes. The effect of this decrease was largely offset by a corresponding decrease in *Other energy-related commodity purchases expense;* and
- A $54 million decrease in revenue from sales of gas purchased by E&P operations, as the result of lower volumes and the impact of netting sales and purchases of gas under buy/sell arrangements associated with the implementation of EITF 04-13.

These decreases in operating revenue were partially offset by:

- A $320 million increase in sales of gas and oil production, due to increased production;
- A $293 million increase for merchant generation operations, primarily reflecting higher revenue for nuclear operations, resulting from higher realized prices and new business from Kewaunee, which was acquired in July 2005. This increase was partially offset by lower sales volume for fossil plants driven largely by comparably milder weather;
- A $187 million increase in sales of natural gas by nonregulated retail energy marketing activities, primarily reflecting higher prices ($128 million) and higher volumes ($59 million);
- A $134 million increase in sales of extracted products, reflecting higher volumes ($91 million) and increased market prices ($43 million);
- A $121 million increase in sales of purchased oil under buy/sell arrangements by E&P operations resulting from higher market prices ($68 million) and increased sales volumes ($53 million); and
- An increase of $90 million resulting from higher business interruption insurance revenue received in 2006 associated with the 2005 hurricanes ($269 million), versus business interruption insurance revenue received in 2005 ($179 million) associated with Hurricane Ivan.

Operating Expenses and Other Items

Electric fuel and energy purchases expense decreased 27% to $2.6 billion, primarily reflecting:

- An $861 million decrease associated with the requirements-based power sales contracts described in *Operating revenue*; and
- A $76 million decrease for our merchant generation operations, due primarily to lower commodity prices and decreased consumption of fossil fuel, reflecting the effects of milder weather on fossil plant operations.

Purchased gas expense decreased 11% to $2.2 billion, principally resulting from:

- A $348 million decrease associated with our producer services business reflecting a decrease in volumes, partially offset by an increase in prices; and
-

A $64 million decrease related to E&P operations, as the result of lower volumes and the impact of netting sales and purchases of gas under buy/sell arrangements associated with the implementation of EITF 04-13, as discussed above; partially offset by

- A $196 million increase from nonregulated retail energy marketing operations, due primarily to higher rates ($146 million) and increased volumes ($50 million).

Other energy-related commodity purchases expense decreased 16% to $862 million, primarily attributable to the following factors, all of which are discussed in *Operating revenue*:

- A $179 million decrease in nonutility coal purchased for resale; and
- A $109 million decrease in purchases of emissions allowances held for resale; partially offset by
- A $120 million increase associated with E&P operations, reflecting higher market prices ($69 million) and increased volumes ($51 million) of oil purchases under buy/sell arrangements.

Other operations and maintenance expense decreased 7% to $2.2 billion, resulting from:

- A $189 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 $67 million decrease in hedge ineffectiveness expense associated with our E&P operations, primarily due to a decrease in the fair value differential between the delivery location and commodity specifications of derivative contracts held by us as compared to our forecasted gas and oil sales and the increased use of basis swaps;
- A $17 million benefit related to FTRs granted by PJM to our utility generation operations. These FTRs are used to offset congestion costs associated with PJM spot market activity, which are included in *Electric fuel and energy purchases expense*;
- A benefit resulting from the net impact of the absence of the following items recognized in 2005:
  - A $556 million loss related to the discontinuance of hedge accounting for certain gas and oil hedges resulting from an interruption of gas and oil production in the Gulf of Mexico caused by the 2005 hurricanes, and subsequent changes in the fair value of those hedges;
  - A $77 million charge resulting from the termination of a long-term power purchase agreement; and
  - A $59 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.

These decreases were partially offset by:

- A $167 million charge from the write-off of certain regulatory assets related to the pending sale of Peoples and Hope;
- A $95 million increase attributable to higher production handling, transportation and operating costs related to E&P operations;
- $89 million of impairment charges related to DCI investments;
- An $83 million increase resulting from the addition of Kewaunee;
- A $78 million increase resulting primarily from higher salaries, wages and benefits expenses;
- A $74 million decrease in gains from the sale of emission allowances held for consumption;
- 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 $39 million increase in bad debt expense, primarily reflecting expenses for regulated gas operations related to low income home energy assistance programs. These expenditures are recovered through rates and do not impact our net income;
- A $28 million increase in generation-related outage costs primarily due to an increase in the number of scheduled outages;
- A $23 million increase related to major storm damage and service restoration costs associated with our distribution operations, primarily resulting from tropical storm Ernesto in September 2006; and
- An $18 million increase in insurance costs for E&P operations due to higher insurance premiums incurred following the 2005 hurricanes.

Depreciation, depletion and amortization expense increased 14% to $1.2 billion, largely due to increased gas and oil production, as well as higher E&P finding and development costs.

Other income decreased 8% to $136 million, primarily due to a $10 million impairment charge associated with an equity-method investment.

Interest and related charges increased 10% to $792 million, resulting principally from higher interest rates on variable rate debt.

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 September 30, 2006 and 2005:

	Net Income			Diluted EPS		
Third Quarter	**2006**	2005	$ Change	**2006**	2005	$ Change
(millions, except EPS)						
Dominion Delivery	**$ 78**	$ 89	$ (11)	**$ 0.22**	$ 0.26	$(0.04)
Dominion Energy	**102**	73	29	**0.29**	0.21	0.08
Dominion Generation	**249**	204	45	**0.70**	0.59	0.11
Dominion E&P	**299**	38	261	**0.85**	0.11	0.74
Primary operating segments	**728**	404	324	**2.06**	1.17	0.89
Corporate	**(74)**	(389)	315	**(0.21)**	(1.13)	0.92
Consolidated	**$ 654**	$ 15	$ 639	**$ 1.85**	$ 0.04	$ 1.81
Year-To-Date						
(millions, except EPS)						
Dominion Delivery	**$ 314**	$ 346	$ (32)	**$ 0.89**	$ 1.01	$(0.12)
Dominion Energy	**277**	236	41	**0.79**	0.69	0.10
Dominion Generation	**441**	403	38	**1.26**	1.17	0.09
Dominion E&P	**643**	339	304	**1.83**	0.99	0.84
Primary operating segments	**1,675**	1,324	351	**4.77**	3.86	0.91
Corporate	**(326)**	(548)	222	**(0.93)**	(1.60)	0.67
Consolidated	**$1,349**	$ 776	$ 573	**$ 3.84**	$ 2.26	$ 1.58

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:

	Third Quarter			Year-To-Date		
	2006	2005	% Change	**2006**	2005	% Change
Electricity delivered (million mwhrs)	**23.1**	23.8	(3)%	**61.2**	62.3	(2)%
Degree days (electric service area):						
Cooling(1)	**1,119**	1,282	(13)	**1,528**	1,652	(8)
Heating(2)	**15**	2	650	**2,056**	2,468	(17)
Average electric delivery customer accounts(3)	**2,330**	2,289	2	**2,322**	2,280	2
Gas throughput (bcf):						
Gas sales	**6**	8	(25)	**68**	90	(24)
Gas transportation	**37**	35	6	**167**	172	(3)
Heating degree days (gas service area)(2)	**111**	24	363	**3,347**	3,794	(12)
Average gas delivery customer accounts(3):						
Gas sales	**780**	1,000	(22)	**881**	1,037	(15)
Gas transportation	**893**	674	32	**807**	653	24
Average nonregulated retail energy marketing customer accounts(3)	**1,398**	1,175	19	**1,308**	1,153	13

mwhrs = megawatt hours
bcf = billion cubic feet

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

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

(3) In thousands.

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

	Third Quarter 2006 vs. 2005 Increase (Decrease)		Year-To-Date 2006 vs. 2005 Increase (Decrease)	
	Amount	**EPS**	**Amount**	**EPS**
(millions, except EPS)				
Major storm damage and service restoration[(1)]	$(11)	$(0.03)	$(14)	$(0.04)
Regulated electric sales:				
Weather	(9)	(0.03)	(21)	(0.06)
Customer growth	3	0.01	9	0.03
Interest expense[(2)]	(5)	(0.01)	(16)	(0.05)
Nonregulated retail energy marketing operations[(3)]	6	0.02	22	0.06
Regulated gas sales - weather	1	--	(13)	(0.04)
2005 North Carolina rate case settlement[(4)]	--	--	(6)	(0.02)
Other	4	0.01	7	0.02
Share dilution	--	(0.01)	--	(0.02)
Change in net income contribution	$(11)	$(0.04)	$(32)	$(0.12)

(1) Principally resulting from costs associated with tropical storm Ernesto in September 2006.
(2) Primarily reflects additional intercompany borrowings and higher interest rates on those borrowings.
(3) Largely reflects higher electric and gas margins.
(4) 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 gathering and extraction facilities, 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:

	Third Quarter			**Year-To-Date**		
	2006	2005	% Change	**2006**	2005	% Change
Gas transportation throughput (bcf)	**128**	131	(2)%	**484**	565	(14)%

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

	Third Quarter 2006 vs. 2005 Increase (Decrease)		**Year-To-Date 2006 vs. 2005 Increase (Decrease)**	
	Amount	**EPS**	**Amount**	**EPS**
(millions, except EPS)				
Producer services(1)	$19	$ 0.06	$ 28	$ 0.08
Gas transmission:				
Other margins(2)	18	0.05	35	0.10
Rate settlement(3)	--	--	(13)	(0.04)
Electric transmission operations(4)	(4)	(0.01)	(2)	(0.01)
Other	(4)	(0.01)	(7)	(0.02)
Share dilution	--	(0.01)	--	(0.01)
Change in net income contribution	$ 29	$ 0.08	$ 41	$ 0.10

(1) Higher income resulting from the impact of favorable price changes related to price risk management and gas marketing activities associated with certain contractual assets.
(2) Higher margins primarily from extracted products, natural gas production and market center service opportunities.
(3) Represents lower natural gas transportation and storage revenues as a result of a rate settlement effective July 2005.
(4) Primarily reflects milder weather in the electric utility service area and higher operations and maintenance expense.

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:

	Third Quarter			Year-To-Date		
	2006	2005	% Change	**2006**	2005	% Change
Electricity supplied (million mwhrs)						
Utility	**23.0**	23.8	(3)	**61.2**	62.3	(2)
Merchant	**11.7**	12.6	(7)	**32.6**	31.2	4
Degree days (electric utility service area):						
Cooling	**1,119**	1,282	(13)	**1,528**	1,652	(8)
Heating	**15**	2	650	**2,056**	2,468	(17)

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

	Third Quarter 2006 vs. 2005 Increase (Decrease)		Year-To-Date 2006 vs. 2005 Increase (Decrease)	
	Amount	**EPS**	**Amount**	**EPS**
(millions, except EPS)				
Unrecovered Virginia fuel expenses(1)	$60	$0.17	$ 9	$0.03
Merchant generation margin(2)	48	0.13	189	0.55
Salaries, wages and benefits expense	3	0.01	(10)	(0.03)
Interest expense	2	0.01	(10)	(0.03)
Sale of emissions allowances	(25)	(0.07)	(46)	(0.13)
Regulated electric sales:				
Weather	(24)	(0.07)	(48)	(0.13)
Customer growth	8	0.02	19	0.06
Energy supply margin(3)	(15)	(0.04)	(17)	(0.05)
Outage costs(4)	(8)	(0.02)	(19)	(0.06)
2005 North Carolina rate case settlement	--	--	(10)	(0.03)
Other	(4)	(0.01)	(19)	(0.06)
Share dilution	--	(0.02)	--	(0.03)
Change in net income contribution	$ 45	$ 0.11	$ 38	$ 0.09

(1) Lower commodity prices and decreased consumption of fossil fuel due to milder weather.
(2) Primarily reflects higher realized prices for our merchant nuclear operations.
(3) Primarily reflects a reduced benefit from FTRs in excess of congestion costs.
(4) Primarily due to an increase in the number of scheduled outages for our electric utility and certain merchant fossil plants.

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:

	Third Quarter			Year-To-Date		
	2006	2005	% Change	**2006**	2005	% Change
Gas production (bcf)	**79.5**	68.0	17%	**230.3**	211.7	9 %
Oil production (million bbls)	**6.2**	3.3	88	**18.6**	11.3	65
Average realized prices without hedging results:						
Gas (per mcf) (1)	**$ 6.30**	$ 7.96	(21)	**$ 6.84**	$ 6.95	(2)
Oil (per bbl)	**58.47**	55.04	6	**56.95**	48.32	18
Average realized prices with hedging results:						
Gas (per mcf) (1)	**$ 4.25**	$ 4.33	(2)	**$ 4.43**	$ 4.22	5
Oil (per bbl)	**33.49**	24.56	36	**35.89**	26.79	34
DD&A (unit of production rate per mcfe)	**$ 1.68**	$ 1.46	15	**$ 1.67**	$ 1.43	17

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

(1) Excludes $60 million and $81 million for the three months ended September 30, 2006 and 2005, respectively, and $203 million and $243 million for the nine months ended September 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:

	Third Quarter 2006 vs. 2005 Increase (Decrease)		**Year-To-Date 2006 vs. 2005 Increase (Decrease)**	
	Amount	**EPS**	**Amount**	**EPS**
(millions, except EPS)				
Business interruption insurance	$171	$ 0.50	$ 58	$ 0.17
Gas and oil ¾ production(1)	143	0.41	267	0.77
Gas and oil ¾ prices	(47)	(0.13)	18	0.05
Operations and maintenance(2)	38	0.11	96	0.28
DD&A(3)	(46)	(0.13)	(117)	(0.34)
Interest expense(4)	(10)	(0.03)	(21)	(0.06)
Other	12	0.03	3	0.01
Share dilution	--	(0.02)	--	(0.04)
Change in net income contribution	$261	$0.74	$ 304	$ 0.84

(1) 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. Gas and oil production in the prior year was negatively impacted during the third quarter as a result of the 2005 hurricanes.

(2)

Lower operations and maintenance expenses, primarily resulting from favorable changes in the fair value of certain gas and oil hedges that were de-designated following the 2005 hurricanes, partially offset by increased production costs and salaries, wages and benefits expenses.

(3) Higher DD&A, primarily reflecting increased gas and oil production, as well as higher industry finding and development costs. For the year-to-date period, the increase also reflects increased acquisition costs.

(4) Primarily reflects additional intercompany borrowings and higher interest rates on those borrowings.

Included below are the volumes and weighted average prices associated with hedges in place as of September 30, 2006 by applicable time period. Prior cash flow hedges for which hedge accounting was discontinued due to production interruptions caused by the 2005 hurricanes, 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	54.9	$4.61	3.5	$25.02
2007	225.2	5.90	10.0	33.41
2008	174.9	8.23	5.0	49.36
2009	36.6	7.97	0.3	75.36

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

	Third Quarter			**Year-To-Date**		
(millions, except EPS)	**2006**	2005	$ Change	**2006**	2005	$ Change
Specific items attributable to operating segments	**$ (9)**	$ (364)	$ 355	**$ (111)**	$ (420)	$ 309
DCI operations	**(4)**	--	(4)	**(88)**	(3)	(85)
Telecommunications operations	**--**	5	(5)	**--**	5	(5)
Other corporate operations	**(61)**	(30)	(31)	**(127)**	(130)	3
Total net expense	**$ (74)**	$ (389)	$ 315	**$ (326)**	$ (548)	$ 222
Earnings per share impact	**$(0.21)**	$(1.13)	$ 0.92	**$(0.93)**	$(1.60)	$ 0.67

Specific Items Attributable to Operating Segments

Third Quarter 2006 vs. 2005

We reported expenses of $9 million and $364 million in 2006 and 2005, respectively, in the Corporate segment that are attributable to our operating segments. The net expenses in 2005 primarily reflect a $556 million ($357 million after-tax) loss related to the discontinuance of hedge accounting for certain gas and oil hedges, resulting from an interruption of gas and oil production in the Gulf of Mexico caused by the 2005 hurricanes, and subsequent changes in the fair value of those hedges, attributable to Dominion E&P.

Year-To-Date 2006 vs. 2005

We reported expenses of $111 million and $420 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 $167 million ($103 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 $556 million ($357 million after-tax) loss related to the discontinuance of hedge accounting for certain gas and oil hedges, resulting from an interruption of gas and oil production in the Gulf of Mexico caused by the 2005 hurricanes, and subsequent changes in the fair value of those hedges, attributable to Dominion E&P; and
- A $77 million ($47 million after-tax) charge resulting from the termination of a long-term power purchase agreement, attributable to Dominion Generation.

DCI Operations

DCI's net loss for the third quarter and year-to-date period increased $4 million and $85 million, respectively. The increase in the year-to-date net loss is primarily due to an $85 million impairment of a DCI investment.

Other Corporate Operations

Third Quarter 2006 vs. 2005

The net expenses associated with other corporate operations for 2006 increased $31 million, primarily reflecting lower tax benefits.

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 nine months ended September 30, 2006 follows:

	Amount
(millions)	
Net unrealized loss at December 31, 2005	$ (7)
Contracts realized or otherwise settled during the period	**57**
Net unrealized gain at inception of contracts initiated during the period	**--**
Changes in valuation techniques	**--**
Other changes in fair value	**(14)**
Net unrealized gain at September 30, 2006	**$ 36**

The balance of net unrealized gains and losses recognized for our energy-related derivative instruments held for trading purposes at September 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)	$42	$(7)	$--	$(3)	$ --	$32
Other external sources(2)	--	--	(2)	3	3	4
Total	$42	$(7)	$(2)	$--	$3	$36

(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 September 30, 2006, we had cash and cash equivalents of $128 million (including $2 million classified as held for sale on our Consolidated Balance Sheet) and $4.9 billion of unused capacity under our credit facilities. The $4.9 billion of unused capacity is comprised of approximately $4.6 billion under our core credit facilities and $275 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 $3.5 billion and $2.5 billion for the nine months ended September 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 September 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)]	$ 791
Non-investment grade[(2)]	44
No external ratings:	
Internally rated - investment grade[(3)]	279
Internally rated - non-investment grade[(4)]	200
Total	$1,314

(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 15% 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 16% of the total gross credit exposure.
(4) The five largest counterparty exposures, combined, for this category represented approximately 2% of the total gross credit exposure.

Investing Cash Flows

For the nine months ended September 30, 2006 and 2005, investing activities resulted in net cash outflows of $2.8 billion and $2.5 billion, respectively. Significant investing activities in the nine months ended September 30, 2006 included:

· $1.5 billion of capital expenditures for the purchase and development of gas and oil producing properties, drilling and equipment costs and undeveloped lease acquisitions;
· $1.4 billion 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;
· $765 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
· $712 million of proceeds from the sales of securities held as investments in our nuclear decommissioning trusts; and
· $67 million of proceeds from the sales of emissions allowances.

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 $724 million for the nine months ended September 30, 2006; net cash provided by financing activities was $871 million for the nine months ended September 30, 2005.

See Note 14 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 September 30, 2006, there have been no changes in the Dominion Companies' credit ratings, other than the matters discussed in MD&A in our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2006 and June 30, 2006.

Debt Covenants

In September 2006, we executed a Replacement Capital Covenant (RCC) in connection with the offering of our $500 million 2006 Series B 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. The holders of covered debt are the beneficiaries of the covenants we made under the RCC, but those securities are not otherwise changed in any way by the RCC. Under the terms of the RCC, we agree, for the benefit of the holders of the covered debt, not to redeem or repurchase all or part of the hybrids prior to September 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 Exhibit 4.3 to this Report on Form 10-Q. Other than the RCC discussed above, as of September 30, 2006, there have been no changes to or events of default under our debt covenants.

Future Cash Payments for Contractual Obligations

As of September 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

Other than the matters discussed below, there have been no significant developments regarding the use of off-balance sheet arrangements disclosed in MD&A in our Annual Report on Form 10-K for the year ended December 31, 2005, in our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2006 and June 30, 2006, nor have any significant new matters arisen during the three months ended September 30, 2006.

Weather Derivative Contract

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.

Guarantees

In September 2006, we, along with three other gas and oil exploration companies executed agreements with a third party to design, construct, install and own the Thunder Hawk facility, a semi-submersible production facility to be located in the deepwater Gulf of Mexico. Due to current offshore insurance market conditions, it is anticipated that the Thunder Hawk facility will only be partially insured against a catastrophic full or partial loss. We, along with the three other participating producers will be required to continue to make demand payments in the event of a catastrophic loss if insurance payments are not sufficient to pay the lessor's outstanding debt incurred for the Thunder Hawk facility. Our obligation will terminate upon the earlier event of full payment of the lessor's debt incurred for the Thunder Hawk facility or the full payment of our demand charge obligation. We believe that it is unlikely that we would be required to perform under this guarantee and have not recognized any significant liabilities for this arrangement.

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 Reports on Form 10-Q for the quarters ended March 31, 2006 and June 30, 2006.

Possible Sale of E&P Business
On November 1, we announced our decision to pursue the sale of all of our oil and natural gas exploration and production operations and assets, with the exception of those located in the Appalachian Basin. Any disposition would allow us to focus on our core electric generating and energy distribution, transmission and storage businesses and realign our operations and risk profile more closely with our peer investment group of utilities. We would expect shareholder value to increase over time as a result.

As of December 31, 2005, our natural gas and oil assets -- excluding the Appalachian Basin -- included about 5.3 trillion cubic feet of proved reserves across major producing regions in the lower 48 states, including the deepwater Gulf of Mexico, West Texas, the Mid-Continent and Rockies and the Western Canadian Sedimentary Basin. The Appalachian assets that we would retain constitute approximately 16% of our total reserves.

Proceeds from any sale are expected to be used to reduce debt (including debt of our Consolidated Natural Gas Company subsidiary), repurchase shares of our common stock, and/or acquire assets related to our remaining core businesses.

We expect to conduct a formal asset auction process in early 2007. Closing of any sale or sales is targeted for mid-2007.

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 take legal title to these generation facilities through the repayment of the lessor's related debt at the end of the lease term prior to any potential sale.

In September 2006, we entered into agreements to sell certain gas and oil properties in Texas and New Mexico for approximately $351 million in cash. The properties are included in our Dominion E&P operating segment. The sales are expected to close in the fourth quarter of 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 Electric Utility 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.

Environmental Matters

On August 28, 2006, the Connecticut Department of Environmental Protection (CTDEP) issued a notice of a Tentative Determination to renew Millstone Power Station's pollution elimination discharge permit, which included a draft copy of the revised permit. An administrative hearing will be held on the draft permit with a Final Determination expected to be issued by the CTDEP within the next year. Until the final permit is reissued, it is not possible to predict the financial impact that may result.

We operate two fossil fuel-fired generating power stations in Massachusetts that are subject to the implementation of carbon dioxide (CO_2) emission regulations issued by the Massachusetts Department of Environmental Protection. The final CO_2 regulations have been promulgated and contain provisions that limit our liability through the establishment of alternative compliance payments. Based on our analysis we estimated that the impact of these regulations is not material.

Cove Point Expansion

In June 2006, the Federal Energy Regulatory Commission (FERC) approved our plans to expand our Cove Point LNG terminal including the installation of two LNG storage tanks, each capable of storing 160 thousand cubic meters of LNG, and expand the send-out capacity of our Cove Point pipeline to approximately 1.8 million dekatherms per day. FERC also approved our plans to expand our 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. Expansion construction started in August 2006 and is expected to be completed in the fourth quarter of 2008.

Offshore Oil and Gas Leases

Two bills passed by the U.S. House of Representatives -- but not yet enacted into law -- address certain federal offshore oil and gas leases issued by the United States in 1998 and 1999 and seek to impose varying sanctions on the holders of such leases. The leases, as issued, do not include a provision requiring royalties to be paid on specified royalty suspension volumes.

In response to these legislative initiatives, the U.S. Department of Interior's Minerals Management Service (MMS) has invited Dominion and other companies holding such leases to enter into voluntary renegotiations of these leases so that royalties would be payable on the suspension volumes when oil and gas commodity futures closing prices exceed specified threshold levels (as is the case under current market conditions). Without prejudice to our legal right to challenge any such sanctions should they be ultimately enacted into law, we have had preliminary discussions with the MMS regarding renegotiation of these leases.

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 derivative commodity 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 $650 million and $691 million as of September 30, 2006 and December 31, 2005, respectively. A hypothetical 10% unfavorable change in commodity prices would have resulted in a decrease of approximately $3 million in the fair value of our commodity-based financial derivative instruments held for trading purposes as of September 30, 2006 and December 31, 2005.

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 derivative commodity 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 September 30, 2006 and December 31, 2005, a hypothetical 10% increase in

market interest rates would decrease annual earnings by approximately $17 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 $4 million and $8 million in the fair value of currency forward contracts held by us at September 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 $59 million and $49 million for the nine months ended September 30, 2006 and 2005, respectively and $67 million for the year ended December 31, 2005. We recorded, in AOCI, net unrealized gains on decommissioning trust investments of $84 million and $4 million for the nine months ended September 30, 2006 and 2005, respectively and $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. Our Consolidated Balance Sheet as of September 30, 2006 reflects $502 million of property, plant and equipment and deferred charges and $580 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 for discussions on various environmental and other regulatory proceedings to which we are a party.

Dominion Transmission, Inc. (DTI) has signed a Consent Order and Agreement (COA) with the Pennsylvania Department of Environmental Protection (PADEP) which supersedes a 1990 COA between the parties and has paid a penalty of $850,000. This COA was entered into as part of the settlement of an enforcement action with PADEP and resolution of lease breaches with the Department of Conservation and Natural Resources.

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 Reports on Form 10-Q for the quarters ended March 31, 2006 and June 30, 2006, which should be taken into consideration when reviewing the information contained in this report. With the exception of the risk factors below, which reflect recent developments relating to 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 decision to pursue a sale of most of our E&P assets is expected to be dilutive to earnings, could have an adverse impact on our results of operations and may not yield the benefits that we expect. On November 1, 2006, we announced our decision to pursue a sale of all of our E&P assets, excluding those assets located in the Appalachian Basin. We expect that a sale of our E&P assets would reduce future earnings in the near term. Although we expect shareholder value to increase over time, we can give no assurance that this will occur . While our management believes it would be able to execute any sales by mid-2007, we may not be able to sell our E&P assets within the expected time frame. If we sell our E&P assets, we cannot be certain of the price we would receive or the impact that such a sale and the use of proceeds from any sale would have on our results of operations. Additionally, we may incur significant costs or be required to record certain charges in connection with any sale and in connection with transactions related to the deployment of the proceeds from any sale.

Additionally, uncertainty about the effect of the proposed disposition may have an adverse effect on the Company, particularly our E&P business. Although we have taken steps to reduce any adverse effects, including providing retention agreements for employees, these uncertainties may impair our ability to attract, retain and motivate key personnel and could cause partners, customers, suppliers and others that deal with our E&P business to seek to change future business relationships. Our E&P business could be harmed if, despite our retention efforts, key employees depart as a result of the proposed disposition.

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 at 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 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 was terminated. All onshore property coverage (with the exception of OEE) and liability coverage commensurate with past coverage remained in place for our E&P operations. Recently our OEE coverage for both onshore and offshore E&P operations was reinstated under a new policy. However, efforts to replace the terminated insurance for our E&P operations for offshore property damage and offshore business interruption with similar insurance on commercially reasonable terms were unsuccessful. We have also entered into a six-month weather derivative contract with an SPE, as further described in Note 13 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 Programs**
7/1/06-7/30/06	97	$78.70	N/A	21,275,000 shares/ $1.72 billion
8/1/06-8/31/06	--	--	N/A	21,275,000 shares/ $1.72 billion
9/1/06-9/30/06	--	--	N/A	21,275,000 shares/ $1.72 billion
Total	97	$78.70	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 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 (Exhibit 4.1, Form 10-Q for the quarter ended June 30, 2006, File No. 1-8489, incorporated by reference).
4.2	Second Supplemental Indenture to the Junior Subordinated Indenture II, dated as of September 1, 2006, pursuant to which the 2006 Series B Enhanced Junior Subordinated Notes due 2066 will be issued (filed herewith). The form of the 2006 Series B Enhanced Junior Subordinated Notes due 2066 is included as Exhibit A to the Second Supplemental Indenture.
4.3	Replacement Capital Covenant entered into by Dominion Resources, Inc. dated September 29, 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

November 1, 2006

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