DOMINION RESOURCES INC /VA/
Form 10-Q
August 08, 2007
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark one)

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2007

or

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

Commission File Number 001-08489

DOMINION RESOURCES, INC.

(Exact name of registrant as specified in its charter)

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

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

(804) 819-2000

(Registrant s telephone number)

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

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

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

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

At June 30, 2007, the latest practicable date for determination, 348,905,095 shares of common stock, without par value, of the registrant were outstanding.

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DOMINION RESOURCES, INC.

PART I. FINANCIAL INFORMATION

ITEM 1. CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED STATEMENTS OF INCOME

(Unaudited)

	Three Months Ended June 30, 2007	Three Months Ended June 30, 2006	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
	(millions, except per share amounts)			
Operating Revenue	**$ 3,730**	$ 3,496	**$ 8,391**	$ 8,402
Operating Expenses				
Electric fuel and energy purchases	**910**	758	**1,828**	1,523
Purchased electric capacity	**109**	116	**228**	239
Purchased gas	**530**	432	**1,678**	1,810
Other energy-related commodity purchases	**64**	318	**120**	718
Other operations and maintenance	**1,934**	875	**2,762**	1,621
Depreciation, depletion and amortization	**423**	393	**832**	757
Other taxes	**140**	130	**323**	308
Total operating expenses	**4,110**	3,022	**7,771**	6,976
Income (loss) from operations	**(380)**	474	**620**	1,426
Other income	**43**	49	**92**	91
Interest and related charges:				
Interest expense	**239**	214	**459**	440
Interest expense junior subordinated notes payable[1]	**35**	33	**70**	60
Subsidiary preferred dividends	**4**	4	**8**	8
Total interest and related charges	**278**	251	**537**	508
Income (loss) before income taxes, minority interest and extraordinary item	**(615)**	272	**175**	1,009
Income tax expense (benefit)	**(232)**	126	**78**	329
Minority interest	**9**		**14**	
Income (loss) from continuing operations before extraordinary item	**(392)**	146	**83**	680
Extraordinary item[2]	**(158)**		**(158)**	
Income (loss) from discontinued operations[3]	**20**	15	**(2)**	15
Net Income (Loss)	**$ (530)**	$ 161	**$ (77)**	$ 695
Earnings Per Common Share - Basic				
Income (loss) from continuing operations before extraordinary item	**$ (1.13)**	$ 0.42	**$ 0.24**	$ 1.96
Extraordinary item	**(0.45)**		**(0.45)**	
Income (loss) from discontinued operations	**0.06**	0.04	**(0.01)**	0.04
Net income (loss)	**$ (1.52)**	$ 0.46	**$ (0.22)**	$ 2.00

Earnings Per Common Share - Diluted				
Income (loss) from continuing operations before extraordinary item	**$ (1.13)**	$ 0.42	**$ 0.24**	$ 1.95
Extraordinary item	**(0.45)**		**(0.45)**	
Income (loss) from discontinued operations	**0.06**	0.04	**(0.01)**	0.04
Net income (loss)	**$ (1.52)**	$ 0.46	**$ (0.22)**	$ 1.99
Dividends paid per common share	**$ 0.71**	$ 0.69	**$ 1.42**	$ 1.38

(1) Includes affiliated interest expense of $22 million and $29 million for the three months ended June 30, 2007 and 2006, respectively, and $44 million and $57 million for the six months ended June 30, 2007 and 2006, respectively.

(2) Net of income tax benefit of $101 million for the three and six months ended June 30, 2007.

(3) Net of income tax expense of $114 million and $113 million for the three and six months ended June 30, 2007, respectively. Includes income tax benefit of $16 million for the three and six months ended June 30, 2006.

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

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DOMINION RESOURCES, INC.

CONSOLIDATED BALANCE SHEETS

(Unaudited)

	June 30, 2007	December 31, 2006[1]
	(millions)	
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 40**	$ 138
Customer receivables (less allowance for doubtful accounts of $29 and $26)	**2,308**	2,395
Other receivables (less allowance for doubtful accounts of $11 and $13)	**284**	358
Inventories	**926**	1,101
Derivative assets	**1,123**	1,593
Assets held for sale	**1,093**	1,391
Other	**1,458**	1,122
Total current assets	**7,232**	8,098
Investments		
Nuclear decommissioning trust funds	**2,912**	2,791
Other	**1,097**	1,034
Total investments	**4,009**	3,825
Property, Plant and Equipment		
Property, plant and equipment	**44,069**	43,575
Accumulated depreciation, depletion and amortization	**(14,565)**	(14,193)
Total property, plant and equipment, net	**29,504**	29,382
Deferred Charges and Other Assets		
Goodwill	**4,234**	4,298
Pension and other postretirement benefit assets	**1,282**	1,246
Other	**2,118**	2,420
Total deferred charges and other assets	**7,634**	7,964
Total assets	**$ 48,379**	$ 49,269

(1) The Consolidated Balance Sheet at December 31, 2006 has been derived from the audited Consolidated Financial Statements at that date.
The accompanying notes are an integral part of the Consolidated Financial Statements.

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DOMINION RESOURCES, INC.

CONSOLIDATED BALANCE SHEETS

(Unaudited)

	June 30, 2007	December 31, 2006[1]
	(millions)	
LIABILITIES AND SHAREHOLDERS EQUITY		
Current Liabilities		
Securities due within one year:		
Junior subordinated notes payable to affiliates	$ **206**	$
Other	**2,386**	2,478
Short-term debt	**2,745**	2,332
Accounts payable	**1,986**	2,142
Derivative liabilities	**1,739**	2,276
Liabilities held for sale	**413**	497
Other	**1,196**	1,504
Total current liabilities	**10,671**	11,229
Long-Term Debt		
Long-term debt	**12,609**	12,842
Junior subordinated notes payable:		
Affiliates	**929**	1,151
Other	**798**	798
Total long-term debt	**14,336**	14,791
Deferred Credits and Other Liabilities		
Deferred income taxes and investment tax credits	**5,901**	5,858
Asset retirement obligations	**1,924**	1,930
Regulatory liabilities	**1,159**	614
Other	**1,517**	1,654
Total deferred credits and other liabilities	**10,501**	10,056
Total liabilities	**35,508**	36,076
Commitments and Contingencies (see Note 18)		
Minority Interest	**37**	23
Subsidiary Preferred Stock Not Subject to Mandatory Redemption	**257**	257
Common Shareholders Equity		
Common stock no par[2]	**11,268**	11,250
Other paid-in capital	**151**	128
Retained earnings	**1,329**	1,960
Accumulated other comprehensive loss	**(171)**	(425)
Total common shareholders equity	**12,577**	12,913

Total liabilities and shareholders equity	**$ 48,379**	$ 49,269

(1) The Consolidated Balance Sheet at December 31, 2006 has been derived from the audited Consolidated Financial Statements at that date.
(2) 500 million shares authorized; 349 million shares outstanding at June 30, 2007 and December 31, 2006.

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

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DOMINION RESOURCES, INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS (Unaudited)

	Six Months Ended June 30, 2007	2006
	(millions)	
Operating Activities		
Net income (loss)	**$ (77)**	$ 695
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Dresden generation facility impairment loss	**387**	
Gain on sale of Canadian E&P operations	**(194)**	
Extraordinary item, net of income taxes	**158**	
Charges related to termination of volumetric production payment agreements	**139**	
Dominion Capital, Inc. impairment losses	**8**	89
Charges related to pending sale of gas distribution subsidiaries		178
Net realized and unrealized derivative (gains) losses	**517**	(234)
Depreciation, depletion and amortization	**922**	862
Deferred income taxes and investment tax credits, net	**(108)**	242
Other adjustments to income, net	**7**	(29)
Changes in:		
Accounts receivable	**118**	964
Inventories	**191**	93
Deferred fuel and purchased gas costs, net	**59**	202
Accounts payable	**(116)**	(884)
Accrued interest, payroll and taxes	**(27)**	33
Deferred revenues	**(71)**	(143)
Margin deposit assets and liabilities	**(46)**	(142)
Other operating assets and liabilities	**106**	63
Net cash provided by operating activities	**1,973**	1,989
Investing Activities		
Plant construction and other property additions	**(947)**	(913)
Additions to gas and oil properties, including acquisitions	**(1,409)**	(1,018)
Proceeds from sale of gas and oil properties	**16**	20
Net proceeds from sale of merchant generation peaking facilities	**254**	
Proceeds from sale of Canadian E&P operations, net of cash disposed	**448**	
Acquisition of businesses		(91)
Proceeds from sale of securities and loan receivable collections and payoffs	**610**	493
Purchases of securities and loan receivable originations	**(657)**	(530)
Other	**11**	87
Net cash used in investing activities	**(1,674)**	(1,952)
Financing Activities		
Issuance (repayment) of short-term debt, net	**413**	(553)
Issuance of long-term debt	**600**	1,300
Repayment of long-term debt	**(935)**	(723)
Net proceeds from the issuance of common stock	**116**	372
Repurchase of common stock	**(117)**	
Common dividend payments	**(497)**	(483)
Other	**22**	(13)
Net cash used in financing activities	**(398)**	(100)

Decrease in cash and cash equivalents	**(99)**	(63)
Cash and cash equivalents at beginning of period [1]	**142**	146
Cash and cash equivalents at end of period[2]	**$ 43**	$ 83
Noncash Investing and Financing Activities:		
Accrued capital expenditures	**$ 165**	$ 166
Proceeds held in escrow from sale of Canadian E&P operations	**156**	
Issuance of long-term debt and establishment of trust		47

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

(2) 2007 and 2006 amounts include $3 million and $2 million, respectively, of cash classified as held for sale in the Consolidated Balance Sheets.

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

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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. On June 30, 2007, we merged our wholly-owned subsidiary, Consolidated Natural Gas Company (CNG), with our holding company, Dominion. As a result of the merger, all of CNG s subsidiaries became direct subsidiaries of Dominion.

We have sold or entered into agreements to sell our non-Appalachian natural gas and oil exploration and production (E&P) operations. We chose to retain our Appalachian assets due to their strategic fit with our natural gas transmission and storage assets. These transactions are discussed in Note 6.

Following the sales of our non-Appalachian E&P operations, our principal subsidiaries are Virginia Electric and Power Company (Virginia Power), Dominion Energy, Inc. (DEI), Dominion Transmission, Inc. (DTI) and Virginia Power Energy Marketing, Inc. (VPEM).

Virginia Power is a regulated public utility that generates, transmits and distributes electricity for sale in Virginia and northeastern North Carolina. As of June 30, 2007, Virginia Power served approximately 2.4 million retail customer accounts, including governmental agencies and wholesale customers such as rural electric cooperatives and municipalities. Virginia Power is a member of PJM Interconnection, LLC (PJM), a regional transmission organization (RTO), and its electric transmission facilities are integrated into the PJM wholesale electricity markets.

DEI is involved in merchant generation, energy marketing and price risk management activities and natural gas exploration and production in the Appalachian basin of the United States (U.S.).

DTI operates a regulated interstate natural gas transmission pipeline and underground storage system in the Northeast, Mid-Atlantic and Midwest states and is engaged in the production, gathering and extraction of natural gas in the Appalachian basin.

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

We also have subsidiaries that operate in all phases of the natural gas business, including a variety of energy marketing services. As of June 30, 2007, our 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 our nonregulated retail energy marketing businesses served approximately 1.6 million residential and commercial customer accounts in the Northeast, Mid-Atlantic and Midwest regions of the U.S. We also operate a liquefied natural gas (LNG) import and storage facility in Maryland. Our producer services operations involve the aggregation of natural gas supply and related wholesale activities.

We have substantially exited the core operating businesses of Dominion Capital, Inc. (DCI) whose primary business was financial services, including loan administration, commercial lending and residential mortgage lending. Refer to Note 15 for information on a third-party collateralized debt obligation (CDO) entity that we consolidate in accordance with Financial Accounting Standards Board (FASB) Interpretation No. 46 (revised December 2003), *Consolidation of Variable Interest Entities* (FIN 46R).

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

The terms Dominion, Company, we, our and us are used throughout this report and, depending on the context of their use, may represent any 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.

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Note 2. Significant Accounting Policies

As permitted by the rules and regulations of the Securities and Exchange Commission (SEC), our accompanying unaudited Consolidated Financial Statements contain certain condensed financial information and exclude certain footnote disclosures normally included in annual audited consolidated financial statements prepared in accordance with accounting principles generally accepted in the United States of America (GAAP). These unaudited Consolidated Financial Statements should be read in conjunction with our Consolidated Financial Statements and Notes in our Annual Report on Form 10-K for the year ended December 31, 2006 and our Quarterly Report on Form 10-Q for the quarter ended March 31, 2007.

In our opinion, the accompanying unaudited Consolidated Financial Statements contain all adjustments, including normal recurring accruals, necessary to present fairly our financial position as of June 30, 2007, our results of operations for the three and six months ended June 30, 2007 and 2006, and our cash flows for the six months ended June 30, 2007 and 2006.

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

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

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

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

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

As discussed further in Note 5, we reapplied the provisions of Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation* (SFAS No. 71), to the Virginia jurisdiction of our utility generation operations upon enactment of reregulation legislation in Virginia on April 4, 2007. In connection with the reapplication of SFAS No. 71 to these operations, we prospectively changed certain of our accounting policies to those used by cost-of-service rate-regulated entities.

Note 3. Newly Adopted Accounting Standards

FIN 48

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

Unrecognized tax benefits represent those tax benefits related to tax positions that have been taken or are expected to be taken in tax returns, including refund claims, that are not recognized in the financial statements because, in accordance with FIN 48, management has either measured the tax benefit at an amount less than the benefit claimed, or expected to be claimed, or concluded that it is not more-likely-than-not that the tax position will be ultimately sustained. Unrecognized tax benefits may result in an increase in income taxes payable, a reduction of an income tax refund receivable, an increase in deferred tax liabilities, or a decrease in deferred tax assets. Noncurrent income taxes payable related to unrecognized tax benefits are classified in other deferred credits and other liabilities; current payables are included in other current liabilities, except when such amounts are presented net with amounts receivable from or amounts prepaid to taxing authorities in other current assets.

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In May 2007, the FASB issued FASB Staff Position No. FIN 48-1**,** *Definition of Settlement in FASB Interpretation No. 48* (FSP FIN 48-1), to provide guidance on how to determine whether a tax position is effectively settled for the purpose of recognizing previously unrecognized tax benefits. FSP FIN 48-1 should have been applied in the initial adoption of FIN 48. In light of its delayed issuance, if an enterprise did not implement FIN 48 in a manner consistent with the provisions of FSP FIN 48-1, it is required to retrospectively apply its provisions to the date of its initial adoption of FIN 48. In our Quarterly Report on Form 10-Q for the quarter ended March 31, 2007, we reported that our unrecognized tax benefits totaled $642 million as of January 1, 2007. In accordance with FSP FIN 48-1, we have reduced our January 1, 2007 balance of unrecognized benefits to $625 million to adjust for effectively settled tax positions. For the majority of our unrecognized tax benefits, the ultimate deductibility is highly certain, but there is uncertainty about the timing of such deductibility. For the six months ended June 30, 2007, the activity for unrecognized tax benefits for tax positions taken in prior years included gross increases of $33 million and reductions of $43 million due to settlements with taxing authorities; the activity for unrecognized tax benefits for tax positions taken in the current year included gross decreases of $22 million.

Unrecognized tax benefits as of January 1, 2007, included $76 million that, if recognized, would lower the effective tax rate. For the six months ended June 30, 2007, the activity for such unrecognized tax benefits related to tax positions taken in the current year included gross decreases of $14 million.

Our unrecognized tax benefits include amounts related to certain income tax benefits, for which we have received assessments from the taxing authorities. We have filed appeals of the assessments and believe that it is reasonably possible that we could reach negotiated settlements within twelve months, resulting in changes in unrecognized tax benefits of up to $27 million.

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

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

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

The U.S. Congressional Joint Committee on Taxation has recently completed its review of our settlement for tax years 1993 1998 with the Appellate Division of the Internal Revenue Service (IRS). As a result, we will receive a tax refund of approximately $42 million. Receipt of this refund will not impact our results of operations. We are also currently engaged in settlement negotiations with the Appellate Division of the IRS regarding certain adjustments proposed during the examination of tax years 1999-2001. With settlement negotiations possibly concluding later this year, unrecognized tax benefits could be reduced by approximately $24 million. At this time, we cannot estimate the impact on unrecognized tax benefits that may result in the next twelve months from settlement negotiations with the IRS for those adjustments remaining in dispute. In addition, the examination of our 2002 and 2003 returns by the IRS was completed in June 2007. In July 2007, we filed protests for certain proposed adjustments with the Appellate Division of the IRS.

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

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

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

EITF 04-13

We have entered into buy/sell and related agreements primarily as a means to reposition our offshore Gulf of Mexico crude oil production to more liquid marketing locations onshore and to facilitate gas transportation. In September 2005, the FASB ratified the Emerging Issues Task Force s (EITF) consensus on Issue No. 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty* (EITF 04-13), that requires buy/sell and related agreements to be presented on a net basis in the Consolidated Statements of Income if they are entered into in contemplation of one another. We adopted the provisions of EITF 04-13 on April 1, 2006 for new arrangements entered into, and modifications or renewals of existing arrangements after that date. As a result, a significant portion of our activity related to buy/sell arrangements is presented on a net basis in our Consolidated Statement of Income for the three months and six months ended June 30, 2007; however, there was no impact on our results of operations or cash flows. Pursuant to the transition provisions of EITF 04-13, activity related to buy/sell arrangements that were entered into prior to April 1, 2006 and have not been modified or renewed after that date continue to be reported on a gross basis and are summarized below:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	**2006**	**2007**	**2006**
	(millions)			
Sale activity included in operating revenue	**$ 24**	$ 223	**$ 59**	$ 505
Purchase activity included in operating expenses[1]	**26**	220	**62**	499

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

EITF 06-3

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

Note 4. Recently Issued Accounting Standards

SFAS No. 157

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

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Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities, and SFAS No. 155*, Accounting for Certain Hybrid Financial Instruments*. We are currently evaluating the impact that SFAS No. 157 will have on our results of operations and financial condition.

SFAS No. 159

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

EITF 06-4

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

EITF 06-11

In June 2007, the FASB ratified the consensus reached by the EITF on Issue No. 06-11, *Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards* (EITF 06-11). EITF 06-11 addresses the recognition of income tax benefits realized from dividends or dividend equivalents that are charged to retained earnings and are paid to employees for nonvested equity-classified share-based payment awards. Effective January 1, 2008, we will recognize such income tax benefits as an increase to additional paid-in capital rather than as a reduction to income tax expense. We do not expect EITF 06-11 to have a material impact on our results of operations or financial condition.

FSP FIN 39-1

In April 2007, the FASB issued FASB Staff Position No. FIN 39-1, *Amendment of FASB Interpretation No. 39, Offsetting of Amounts Related to Certain Contracts* (FSP FIN 39-1). FSP FIN 39-1 amends FIN 39 to permit the offsetting of amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral against amounts recognized for derivative instruments executed with the same counterparty under the same master netting arrangement that have been offset. FSP FIN 39-1 will become effective for us beginning January 1, 2008 and must be applied retroactively to all financial statements presented, unless it is impracticable to do so. We are currently evaluating the impact that FSP FIN 39-1 may have on our financial condition. We do not expect FSP FIN 39-1 to have an impact on our results of operations or cash flows.

Note 5. Reapplication of SFAS No. 71

In March 1999, we discontinued the application of SFAS No. 71 to the majority of our utility generation operations upon the enactment of deregulation legislation in Virginia. Our utility transmission and distribution operations continued to apply the provisions of SFAS No. 71 since they remained subject to cost-of-service rate regulation.

In April 2007, the Virginia General Assembly passed legislation that returns the Virginia jurisdiction of our utility generation operations to cost-of-service rate regulation. As a result, we reapplied the provisions of SFAS No. 71 to those operations on April 4, 2007, the date the legislation was enacted. The accounting impacts of the reapplication of SFAS No. 71 are described below.

Extraordinary Item

The reapplication of SFAS No. 71 to the Virginia jurisdiction of our utility generation operations resulted in a $259 million ($158 million after tax) extraordinary charge and the reclassification of $195 million ($119 million after tax) of unrealized gains from accumulated other comprehensive income (AOCI). This was done in order to establish a $454 million long-term regulatory liability for amounts collected from Virginia jurisdictional customers and placed in external trusts (including income, losses and changes in fair value thereon) for the future decommissioning of our utility nuclear generation stations, in excess of amounts recorded pursuant to SFAS No. 143, *Accounting for Asset Retirement Obligations* (SFAS No. 143).

Pension and Other Postretirement Benefits

Upon reapplication of SFAS No. 71 to the Virginia jurisdiction of our utility generation operations, we reclassified $110 million ($67 million after tax) of pension and other postretirement benefit costs attributable to those operations previously recorded in AOCI to a regulatory asset. These costs represent net unrecognized actuarial (gains) losses, unrecognized prior service cost (credit) and unrecognized transition obligation remaining from our initial adoption of SFAS No. 106, *Employers   Accounting for Postretirement Benefits Other Than Pensions*, that will be recognized as a component of future net periodic benefit cost based on our historical accounting policy for amortizing such amounts and are expected to be recovered through future rates.

Accounting Policy Changes

In connection with the reapplication of SFAS No. 71, we prospectively changed certain of our accounting policies for the Virginia jurisdiction of our utility generation operations to those used by cost-of-service rate-regulated entities. Other than the extraordinary item discussed above, the overall impact of these changes, summarized below, was not material to our results of operations or financial condition.

Utility Nuclear Decommissioning Trust Funds

Net realized and unrealized gains and losses are now recorded to the regulatory liability established upon reapplication of SFAS No. 71 as described above. Previously, realized gains and losses and any other-than-temporary declines in fair value were included in other income and unrealized gains were reported as a component of AOCI, net of tax.

Property, Plant and Equipment

Early retirements of generation-related utility property are now recorded to accumulated depreciation rather than recognizing gains and losses upon retirement. Cost of removal incurred or salvage proceeds realized in connection with a retirement of utility generation property, plant and equipment is now recorded to accumulated depreciation rather than being charged to expense as incurred. We discontinued capitalizing interest on all utility generation construction projects since the Virginia State Corporation Commission (Virginia Commission) has historically allowed for current recovery of construction financing costs.

Asset Retirement Obligations

Accretion and depreciation associated with utility nuclear decommissioning asset retirement obligations, previously charged to expense, are now recorded to a regulatory liability in order to match the recognition for rate-making purposes.

Derivative Instruments

Previously, unrealized gains and losses resulting from changes in the fair value of derivative instruments designated as cash flow or fair value hedges under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* (SFAS No. 133), were recorded in AOCI, or long-term debt, respectively. Also, ineffectiveness and gains and losses excluded from the measurement of ineffectiveness, were recorded through earnings as incurred. Following the reapplication of SFAS No. 71, changes in the fair value of these derivative instruments will be classified as regulatory assets or regulatory liabilities as these instruments now receive regulatory treatment. Gains or losses on the derivative instruments will be recognized when the related transactions impact net income.

Note 6. Dispositions

Sale of Non-Appalachian Natural Gas and Oil E&P Operations and Assets

We have sold or agreed to sell all of our non-Appalachian natural gas and oil E&P operations and assets. At December 31, 2006, our non-Appalachian natural gas and oil assets included about 5.5 trillion cubic feet of proved reserves. The Appalachian assets that we will retain constituted approximately 15% of our total reserves at December 31, 2006.

Due to the sale of our entire Canadian cost pool, the results of operations for our Canadian E&P business are reported as discontinued operations in our Consolidated Statements of Income. The results of operations for our U.S. non-Appalachian E&P business will not be reported as discontinued operations in our Consolidated Statements of Income since we are not selling our entire cost pool, which includes the retained Appalachian assets.

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We intend to use the after-tax proceeds from these dispositions to reduce our outstanding debt by $3.2 billion to $3.5 billion and to use the remaining net proceeds for repurchasing shares of our common stock. See Note 16 for a discussion of significant financing transactions.

The E&P operations we have sold or have entered into agreements to sell are as follows:

Canadian Operations

On June 26, 2007, we completed the sale of our Canadian E&P operations to Paramount Energy Trust and Baytex Energy Trust for approximately $624 million, subject to post-closing adjustments. These operations included approximately 267 billion cubic feet equivalent (bcfe) of proved reserves in western Canada as of December 31, 2006. The sale resulted in an after-tax gain of $61 million ($0.17 per share). As required by the sale agreement, $156 million of the proceeds are being held in escrow to ensure the payment of our Canadian tax obligation, resulting from the gain recognized on the sale. The funds are expected to be released from escrow during the third quarter of 2007, after the Canadian Revenue Authority (CRA) reviews our filing to notify the CRA of the gain and our resulting tax obligation. We will pay the tax related to the gain on the sale by the end of the first quarter of 2008.

The following table presents selected information regarding the results of operations of our Canadian E&P operations, which are reported as discontinued operations in our Consolidated Statements of Income:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	**2006**	**2007**	**2006**
	(millions)			
Operating revenue	**$ 41**	$ 40	**$ 82**	$ 76
Income before income taxes	**141**(1)	7	**149**(1)	15

(1) Amount includes pre-tax gain of $194 million recognized on the sale.

Offshore Operations

On July 2, 2007, we completed the sale of substantially all of our offshore E&P operations to Eni Petroleum Co. Inc. (Eni) for approximately $4.73 billion, subject to post-closing adjustments. Our offshore operations included approximately 967 bcfe of proved natural gas and oil reserves in the outer continental shelf and deepwater areas of the Gulf of Mexico at December 31, 2006. Of this total, approximately 961 bcfe were sold to Eni. Remaining offshore E&P operations were disposed of in a separate transaction in June 2007.

Certain Onshore Operations

On July 31, 2007, we completed the sale to HighMount Exploration & Production LLC, a newly formed subsidiary of Loews Corporation, of our E&P operations in the Alabama, Michigan and Permian basins for approximately $4 billion, subject to post-closing adjustments. These operations included approximately 2.5 trillion cubic feet equivalent (Tcfe) of proved natural gas and oil reserves at December 31, 2006.

Also on July 31, 2007, we completed the sale to XTO Energy Inc., of our E&P operations in the Gulf Coast, Rocky Mountains, South Louisiana and San Juan Basin of New Mexico for approximately $2.5 billion, subject to post-closing adjustments. These operations included approximately 1 Tcfe of proved natural gas and oil reserves at December 31, 2006.

In June 2007, we reached an agreement to sell our E&P operations in the Mid-Continent Basin to Linn Energy, LLC for approximately $2.05 billion. As of December 31, 2006, these operations, located primarily in Oklahoma, had proved reserves of approximately 780 bcfe. This transaction is expected to close by the end of the third quarter 2007, subject to customary closing conditions and adjustments.

Costs Associated with Disposal of Non-Appalachian E&P Operations

The sales of our non-Appalachian E&P operations resulted in the discontinuance of hedge accounting for certain cash flow hedges since it became probable that the forecasted sales of gas and oil will not occur. In connection with the discontinuance of hedge accounting for these contracts, we recognized a $536 million ($341 million after-tax) charge, recorded in other operations and maintenance expense in our Consolidated Statement of Income, reflecting the reclassification of losses from AOCI to earnings and subsequent changes in fair value of these contracts in the three months ended June 30, 2007. We have entered into offsetting derivative contracts for these gas and oil derivatives that will minimize the future volatility in earnings that may result from these contracts being marked to market. We recognized a similar charge of $15 million ($9 million after-tax) related to our Canadian operations, which is reflected in discontinued operations in our Consolidated Statement of Income.

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During the three months ended June 30, 2007, we also recorded a charge of approximately $171 million ($108 million after-tax) for the recognition of certain forward gas contracts that previously qualified for the normal purchase and sales exemption under SFAS No. 133. The $171 million charge includes $139 million associated with volumetric production payment (VPP) agreements to which we were a party. We paid $250 million to terminate the VPP agreements and are retaining the repurchased fixed-term overriding royalty interests formerly associated with these agreements.

Additionally, we have recognized expenses for severance, retention, legal and other costs of $64 million ($40 million after-tax) and $76 million ($48 million after-tax) for the three and six months ended June 30, 2007, respectively. The majority of these costs will be paid in the third quarter in connection with closing of the related sales. We also recognized expenses for severance, retention, legal and other costs of $30 million ($18 million after-tax) for the three and six months ended June 30, 2007 related to the sale of our Canadian E&P operations, which are reflected in discontinued operations in our Consolidated Statement of Income.

We expect to recognize a pre-tax gain of approximately $4.0 billion to $4.5 billion from the disposition of our non-Appalachian E&P operations. The expected gain includes expenses related to the disposition plan for transaction costs, including severance, retention, legal and other costs, but excludes costs associated with the discontinuance of hedge accounting and recognition of forward gas contracts recognized in the three months ended June 30, 2007. The actual gain will depend on the final adjusted purchase price and the book values of the disposed properties and related liabilities at the closing date.

Disposition of Partially Completed Generation Facility

As part of our ongoing strategic asset review to improve Dominion s return on invested capital and the evaluation of investments in new generating capacity supported by the new electric re-regulation legislation in Virginia, we began the process of exploring the sale of the Dresden Energy merchant generation facility (Dresden) in May 2007. Dresden is a partially completed 580-megawatt (Mw) combined-cycle gas-powered generating plant located in Muskingum County, Ohio, with a carrying amount of $472 million, before any impairment.

Based on our evaluation of the bids received during this process, we believe that it is likely that Dresden will be sold rather than completed and operated in our merchant fleet. This change in intended use represented a triggering event for us to evaluate whether we could recover the carrying amount of our investment in Dresden. This analysis indicated that the carrying amount of Dresden will not be recovered. As a result, in June 2007 we recorded a $387 million ($252 million after-tax) impairment charge in other operations and maintenance expense to reduce Dresden s carrying amount to its estimated fair value. In August 2007, we reached an agreement to sell Dresden to AEP Generating Company (AEP) for approximately $85 million. The transaction is expected to close by the end of the third quarter of 2007, subject to customary closing conditions and adjustments.

Sale of Certain DCI Operations

In May 2007, we committed to a plan to dispose of certain DCI operations for $30 million. The sale includes substantially all of the assets of Gichner LLC (Gichner), all of the issued and outstanding shares of the capital stock of Gichner, Inc. (an affiliate of Gichner), as well as all of the membership interests in Dallastown Realty II (Dallastown). Gichner designs, manufactures, integrates, markets, distributes, sells and services tactical and logistic shelters and related products for military commercial applications. Dallastown owns the land and buildings in which Gichner conducts its principal operations in the U.S.

The sale is expected to close in August 2007. The consideration to be received indicated that the goodwill associated with these operations was impaired and in June 2007, we recorded a goodwill impairment charge in other operations and maintenance expense in our Consolidated Statement of Income of $8 million related to the DCI reporting unit.

The carrying amounts of the major classes of assets and liabilities classified as held for sale in our Consolidated Balance Sheet at June 30, 2007 were comprised of property, plant and equipment, net ($11 million), other current assets ($17 million) and current liabilities ($6 million).

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
	(millions)			
Operating revenue	**$ 12**	$ 12	**$ 22**	$ 22
Income (loss) before income taxes	**(7)**	1	**(6)**	2

Sale of Merchant Generation Facilities

In March 2007, we sold three of our natural gas-fired merchant generation peaking facilities (Peaker facilities) for net cash proceeds of $254 million. The sale resulted in a $24 million after-tax loss ($0.07 per share). The Peaker facilities are:

- Armstrong, a 625 Mw station in Shelocta, Pennsylvania;
- Troy, a 600 Mw station in Luckey, Ohio; and
- Pleasants, a 313 Mw station in St. Mary s, West Virginia.

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
	(millions)			
Operating revenue	**$**	$ 8	**$ 5**	$ 14
Loss before income taxes		(9)	**(31)**	(17)

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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 subject to regulatory approval, as discussed in *Future Issues and Other Matters* in Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations. The carrying amounts of the major classes of assets and liabilities classified as held for sale in our Consolidated Balance Sheets are as follows:

	June 30, 2007	December 31, 2006
	(millions)	
ASSETS		
Current Assets		
Customer receivables	**$ 106**	$ 144
Other	**78**	125
Total current assets	**184**	269
Property, Plant and Equipment		
Property, plant and equipment	**1,141**	1,129
Accumulated depreciation, depletion and amortization	**(370)**	(375)
Total property, plant and equipment, net	**771**	754
Deferred Charges and Other Assets		
Regulatory assets	**106**	106
Other	**4**	4
Total deferred charges and other assets	**110**	110
Assets held for sale	**$ 1,065**	$ 1,133
LIABILITIES		
Current Liabilities	**$ 149**	$ 236
Deferred Credits and Other Liabilities		
Deferred income taxes and investment tax credits	**187**	187
Other	**71**	71
Total deferred credits and other liabilities	**258**	258
Liabilities held for sale	**$ 407**	$ 494

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
	(millions)			
Operating revenue	**$ 108**	$ 92	**$ 417**	$ 449

Income (loss) before income taxes	**1**	**55**	(128)

In the six months ended June 30, 2006, we recognized a $162 million ($98 million after-tax) charge, recorded in other operations and maintenance expense in our Consolidated Statement of Income, resulting from the write-off of certain regulatory assets related to the pending sale of Peoples and Hope, since the recovery of those assets is no longer probable. At June 30, 2007, our Consolidated Balance Sheet reflects $138 million of deferred tax liabilities, which were recorded in accordance with EITF Issue No. 93-17, *Recognition of Deferred Tax Assets for a Parent Company s Excess Tax Basis in the Stock of a Subsidiary that is Accounted for as a Discontinued Operation* (EITF 93-17). Although these subsidiaries are not classified as discontinued operations, EITF 93-17 requires that the deferred tax impact of the excess of the financial reporting basis over the tax basis of a parent s investment in a subsidiary be recognized when it is apparent that this difference will reverse in the foreseeable future. This difference and related deferred taxes will reverse and will partially offset current tax expense recognized upon closing of the sale.

Note 7. Pro Forma Financial Statements

The following unaudited Pro Forma Condensed Consolidated Balance Sheet reflects the disposition of our non-Appalachian E&P operations as if it had occurred on June 30, 2007. The accompanying unaudited Pro Forma Condensed Consolidated Statements of Income for the six months ended June 30, 2007 and for the year ended December 31, 2006, reflect the disposition of our non-Appalachian E&P operations as if it had occurred on January 1, 2007 and 2006, respectively.

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The pro forma adjustments have been based on the operations of our non-Appalachian E&P operations during the periods presented, the impact of the disposition of these operations and other transactions resulting from the disposition. The pro forma adjustments have been made to illustrate the anticipated financial impact of the disposition upon Dominion and are based upon available information and assumptions that we believe to be reasonable at the date of this filing. Consequently, the pro forma financial information presented is not necessarily indicative of the consolidated results of operations that would have been reported had the transaction actually occurred on the dates presented. Moreover, the pro forma financial information does not purport to indicate the future results that Dominion will experience.

PRO FORMA CONDENSED CONSOLIDATED STATEMENT OF INCOME

Six Months Ended June 30, 2007

(Unaudited)

	As Reported	Less: E&P Dispositions	Pro Forma Adjustments	Pro Forma Results
	(millions, except per share amounts)			
Operating Revenue	$ 8,391	$ 1,204	$	$ 7,187
Operating Expenses				
Electric fuel and energy purchases	1,828			1,828
Purchased electric capacity	228			228
Purchased gas	1,678	62		1,616
Other energy-related commodity purchases	120			120
Other operations and maintenance	2,762	1,017		1,745
Depreciation, depletion and amortization	832	385		447
Other taxes	323	72		251
Total operating expenses	7,771	1,536		6,235
Income (loss) from operations	620	(332)		952
Other income	92			92
Interest and related charges	537		(127)(1)	410
Income (loss) from continuing operations before income tax expense and minority interest	175	(332)	127	634
Income tax expense (benefit)	78	(69)	49 (2)	196
Minority interest	14			14
Income (loss) from continuing operations	$ 83	$ (263)	$ 78	$ 424
Earnings Per Share				
Income from continuing operations Basic	$ 0.24			$ 1.46
Income from continuing operations Diluted	$ 0.24			$ 1.45
Weighted average shares outstanding Basic	348.8		(57.9)(3)	290.9
Weighted average shares outstanding Diluted	351.1		(57.9)(3)	293.2

(1) Represents the decrease in interest expense expected to result from the repayment of $3.4 billion in debt with a portion of the expected proceeds from the disposition of our non-Appalachian E&P operations (disposition). This amount is comprised of $2.5 billion in long term debt retired in connection with our debt tender offer completed on July 12, 2007; $500 million of bank debt incurred at our CNG subsidiary which was repaid prior to the merger of that subsidiary with and into Dominion, effective June 30, 2007; $200 million of senior

notes originally issued by our and CNG s subsidiary Dominion Oklahoma Texas Exploration & Production, Inc., which were redeemed on June 29, 2007 and $200 million of junior subordinated notes originally issued by CNG, which were redeemed on July 17, 2007.

(2) Reflects the income tax effects of the pro forma adjustments associated with the disposition of our non-Appalachian E&P operations based on the weighted average statutory rates for all jurisdictions that would have applied during the period.

(3) Reflects the preliminary results of our equity tender offer discussed in Note 16. We expect to purchase approximately 57.9 million shares at a price of $91 per share, with a portion of the proceeds received from the disposition.

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PRO FORMA CONDENSED CONSOLIDATED STATEMENT OF INCOME

Year Ended December 31, 2006

(Unaudited)

	As Reported[1]	Less: E&P Dispositions	Pro Forma Adjustments	Pro Forma Results
	(millions, except per share amounts)			
Operating Revenue	$ 16,296	$ 2,838	$	$ 13,458
Operating Expenses				
Electric fuel and energy purchases	3,236			3,236
Purchased electric capacity	481			481
Purchased gas	2,937	165		2,772
Other energy-related commodity purchases	1,022	409		613
Other operations and maintenance	3,177	352		2,825
Depreciation, depletion and amortization	1,557	695		862
Other taxes	568	125		443
Total operating expenses	12,978	1,746		11,232
Income from operations	3,318	1,092		2,226
Other income	173			173
Interest and related charges	1,028		(254)[2]	774
Income from continuing operations before income tax expense and minority interest	2,463	1,092	254	1,625
Income tax expense	927	417	99 [3]	609
Minority interest	6			6
Income from continuing operations	$ 1,530	$ 675	$ 155	$ 1,010
Earnings Per Share				
Income from continuing operations Basic	$ 4.38			$ 3.46
Income from continuing operations Diluted	$ 4.35			$ 3.44
Weighted average shares outstanding Basic	349.7		(57.9)[4]	291.8
Weighted average shares outstanding Diluted	351.6		(57.9)[4]	293.7

(1) Reflects the reclassification of Gichner, Dallastown and our Canadian E&P operations to discontinued operations.

(2) Represents the decrease in interest expense expected to result from the repayment of $3.4 billion in debt with a portion of the expected proceeds from the disposition of our non-Appalachian E&P operations. This amount is comprised of $2.5 billion in long term debt retired in connection with our debt tender offer completed on July 12, 2007; $500 million of bank debt incurred at our CNG subsidiary which was repaid prior to the merger of that subsidiary with and into Dominion, effective June 30, 2007; $200 million of senior notes originally issued by our and CNG s subsidiary Dominion Oklahoma Texas Exploration & Production, Inc., which were redeemed on June 29, 2007 and $200 million of junior subordinated notes originally issued by CNG, which were redeemed on July 17, 2007.

(3) Reflects the income tax effects of the pro forma adjustments associated with the disposition of our non-Appalachian E&P operations based on the weighted average statutory rates for all jurisdictions that would have applied during the period.

(4) Reflects the preliminary results of our equity tender offer discussed in Note 16. We expect to purchase approximately 57.9 million shares at a price of $91 per share, with a portion of the proceeds received from the disposition.

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PRO FORMA CONDENSED CONSOLIDATED BALANCE SHEET

As of June 30, 2007

(Unaudited)

	As Reported	Less: E&P Dispositions	Pro Forma Adjustments	Pro Forma Results
	(millions)			
ASSETS				
Current Assets	$ 7,232	$ 36	$ 13,153 (1)	$ 11,926
			(5,269)(2)	
			(2,933)(3)	
			(221)(4)	
Investments	4,009	7		4,002
Property, Plant and Equipment	29,504	8,897		20,607
Deferred Charges and Other Assets	7,634	857	(118)(4)	6,659
Total assets	48,379	9,797	4,612	43,194
LIABILITIES AND SHAREHOLDERS EQUITY				
Current Liabilities	10,671	46	(234)(3)	13,852
			3,461 (4)	
Long-Term Debt	14,336		(2,495)(3)	11,841
Deferred Credits and Other Liabilities				
Deferred income taxes and investment tax credits	5,901		(2,189)(4)	3,712
Other	4,600	237		4,363
Total deferred credits and other liabilities	10,501	237	(2,189)	8,075
Total liabilities	35,508	283	(1,457)	33,768
Minority Interest	37			37
Subsidiary Preferred Stock Not Subject to Mandatory Redemption	257			257
Common Shareholders Equity				
Common stock no par	11,268		(5,269)(2)	5,999
Other	1,309	9,514	11,338	3,133
Total common shareholders equity	12,577	9,514	6,069	9,132
Total liabilities and shareholders equity	$ 48,379	$ 9,797	$ 4,612	$ 43,194

(1) Represents expected net cash proceeds of $13.2 billion from the remaining dispositions.

(2) Reflects the preliminary results of our equity tender offer discussed in Note 16. We expect to purchase approximately 57.9 million shares at a price of $91 per share for a total cost of approximately $5.3 billion, excluding fees and expenses related to the tender, with a portion of the proceeds received from the disposition.

(3) Reflects the impact of the use of a portion of the proceeds from the disposition to decrease our outstanding debt. This primarily reflects $2.5 billion in long-term debt retired in connection with our debt tender offer completed on July 12, 2007 and $200 million of junior subordinated notes originally issued by CNG, which were redeemed on July 17, 2007. This amount also includes any related accrued interest and call premiums.

(4) Represents the estimated reversal of historic deferred taxes on the remaining dispositions as of June 30, 2007, and the assumed current income taxes payable associated with the gain on sale calculated using the estimated weighted average statutory rates for all applicable jurisdictions.

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NOTES TO CONDENSED PRO FORMA CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

Nonrecurring items related to the dispositions

Certain nonrecurring items resulting from the disposition of our non-Appalachian E&P operations have not been reflected in the accompanying Condensed Pro Forma Consolidated Statements of Income. See *Costs Associated with Disposal of Non-Appalachian E&P Operations* in Note 6.

Note 8. Operating Revenue

Our operating revenue consists of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	**2006**	**2007**	**2006**
	(millions)			
Operating Revenue				
Electric sales:				
Regulated	**$ 1,386**	$ 1,283	**$ 2,797**	$ 2,581
Nonregulated	**724**	543	**1,460**	1,137
Gas sales:				
Regulated	**184**	175	**743**	975
Nonregulated	**466**	374	**1,343**	1,256
Other energy-related commodity sales	**162**	412	**306**	903
Gas transportation and storage	**212**	201	**561**	486
Gas and oil production	**522**	456	**1,044**	955
Other	**74**	52	**137**	109
Total operating revenue	**$ 3,730**	$ 3,496	**$ 8,391**	$ 8,402

Note 9. Income Taxes

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

	Six Months Ended June 30,	
	2007	**2006**
U.S. statutory rate	**35.0%**	35.0%
Increases (reductions) resulting from:		
Amortization of investment tax credits	**(0.1)**	(0.5)
Employee pension and other benefits	**(0.1)**	(0.4)
Employee stock ownership plan and restricted stock dividends	**(0.2)**	(0.5)
State taxes, net of federal benefit	**4.7**	6.5
Changes in valuation allowances	**1.9**	(20.0)
Recognition of deferred taxes stock of subsidiaries held for sale	**(0.1)**	13.4
Other, net	**3.2**	(0.8)
Effective tax rate	**44.3%**	32.7%

Our estimated 2007 annual effective tax rate reflects the effects of the announced sales of our non-Appalachian E&P operations, including the impact of goodwill, not recognized for tax purposes, that is deducted in the determination of book gain on the sale. A tax benefit is being recognized for the elimination of $124 million of valuation allowances on deferred tax assets that relate to federal carryforwards, since these carryforwards will be utilized to offset capital gain income generated from the sale. In addition, to reflect changes in our state income tax profile, deferred tax expense of $84 million, net of $29 million of related federal deferred taxes, is being recognized. The effective state tax rate will be higher for ongoing operations. Our 2006 effective tax rate includes a $222 million tax benefit from the reduction of previously recorded valuation allowances on deferred tax assets that arose from federal and state tax loss carryforwards, since these carryforwards are expected to be utilized to offset capital gain income that is expected to be generated from the pending sale of Peoples and Hope. This benefit was partially offset by the establishment of $135 million of deferred tax liabilities, in 2006, associated with the excess of our financial reporting basis over the tax basis in the stock of Peoples and Hope, in accordance with EITF 93-17.

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Note 10. Earnings Per Share

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

	Three Months Ended June 30, 2007	Three Months Ended June 30, 2006	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
	(millions, except EPS)			
Income (loss) from continuing operations before extraordinary item	**$ (392)**	$ 146	**$ 83**	$ 680
Extraordinary item, net of tax	**(158)**		**(158)**	
Income (loss) from discontinued operations	**20**	15	**(2)**	15
Net income (loss)	**$ (530)**	$ 161	**$ (77)**	$ 695
Basic EPS				
Average shares of common stock outstanding basic	**349.1**	349.0	**348.8**	347.8
Income (loss) from continuing operations before extraordinary item	**$ (1.13)**	$ 0.42	**$ 0.24**	$ 1.96
Extraordinary item, net of tax	**(0.45)**		**(0.45)**	
Income (loss) from discontinued operations	**0.06**	0.04	**(0.01)**	0.04
Net income (loss)	**$ (1.52)**	$ 0.46	**$ (0.22)**	$ 2.00
Diluted EPS				
Average shares of common stock outstanding	**349.1**	349.0	**348.8**	347.8
Net effect of potentially dilutive securities(1)(2)		1.5	**2.3**	1.5
Average shares of common stock outstanding diluted	**349.1**	350.5	**351.1**	349.3
Income (loss) from continuing operations before extraordinary item	**$ (1.13)**	$ 0.42	**$ 0.24**	$ 1.95
Extraordinary item, net of tax	**(0.45)**		**(0.45)**	
Income (loss) from discontinued operations	**0.06**	0.04	**(0.01)**	0.04
Net income (loss)	**$ (1.52)**	$ 0.46	**$ (0.22)**	$ 1.99

(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.

(2) As a result of the net loss from continuing operations for the three months ended June 30, 2007, the issuance of approximately 2.3 million common shares under potentially-dilutive securities was considered anti-dilutive and therefore was not included in the calculation of the diluted loss per share for the period.

Potentially dilutive securities with the right to acquire approximately 1.5 million common shares for the three months and six months ended June 30, 2006 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 six months ended June 30, 2007.

Note 11. Goodwill

The changes in the carrying amount of goodwill during the six months ended June 30, 2007 are presented below:

	Dominion Generation	Dominion Energy	Dominion Delivery	Dominion E&P	Corporate	Total

			(millions)			
Balance at December 31, 2006	$ 1,479	$ 740	$ 1,184	$ 877	$ 18	$ 4,298
Sale of Canadian E&P business				**(32)**		**(32)**
Sale of Peaker facilities	**(24)**					**(24)**
DCI impairment loss					**(8)**	**(8)**
Balance at June 30, 2007	**$ 1,455**	**$ 740**	**$ 1,184**	**$ 845**	**$ 10**	**$ 4,234**

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Note 12. Comprehensive Income

The following table presents total comprehensive income (loss):

	Three Months Ended June 30, 2007	Three Months Ended June 30, 2006	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
	(millions)			
Net income (loss)	**$ (530)**	$ 161	**$ (77)**	$ 695
Other comprehensive income (loss):				
Net other comprehensive income associated with effective portion of changes in fair value of derivatives designated as cash flow hedges, net of taxes and amounts reclassified to earnings	**539** (1)	404 (2)	**324** (1)	1,123 (2)
Other	**(81)**(3)	(31)(4)	**(70)**(3)	(11)(4)
Other comprehensive income	**458**	373	**254**	1,112
Total comprehensive income (loss)	**$ (72)**	$ 534	**$ 177**	$ 1,807

(1) Principally due to the de-designation of certain E&P cash flow hedges, in connection with the announced sales of our non-Appalachian E&P operations.

(2) 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.

(3) Primarily reflects the impact of foreign currency translation adjustments due to the sale of our Canadian E&P operations and the reclassification of pension-related amounts and gross unrealized gains on investments held in nuclear decommissioning trusts, both associated with the Virginia jurisdiction of our utility generation operations, previously recorded in AOCI to regulatory assets and regulatory liabilities, respectively, as a result of the reapplication of SFAS No. 71 to those operations.

(4) Primarily represents the impact of net unrealized gains (losses) on investments held in nuclear decommissioning trusts and foreign currency translation adjustments.

Note 13. Hedge Accounting Activities

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

	Three Months Ended June 30, 2007	Three Months Ended June 30, 2006	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
	(millions)			
Portion of gains (losses) on hedging instruments determined to be ineffective and included in net income:				
Fair value hedges	**$ (2)**	$ (1)	**$ 2**	$ (8)
Cash flow hedges	**28**	5	**43**	24
Net ineffectiveness	**$ 26**	$ 4	**$ 45**	$ 16

Gains and losses on hedging instruments that were excluded from the measurement of effectiveness and included in net income for the three and six months ended June 30, 2007 and 2006 were not material.

Due to the announced sales of our non-Appalachian E&P business and the expected repayment of certain debt securities with a portion of the proceeds from the sales, we discontinued cash flow hedge accounting for certain hedges during the second quarter since it became probable that forecasted payments of interest would not occur. In connection with the discontinuance of hedge accounting for these contracts we reclassified $3 million of pre-tax losses from AOCI to earnings during the second quarter. In addition, see Note 6 for a discussion of the discontinuance of hedge accounting for gas and oil hedges during the three months ended June 30, 2007.

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The following table presents selected information related to cash flow hedges included in AOCI in our Consolidated Balance Sheet at June 30, 2007:

	AOCI After-Tax	Amounts Expected to be Reclassified to Earnings during the next 12 Months After-Tax	Maximum Term
	(millions)		
Commodities:			
Gas	$ (22)	$ (39)	45 months
Oil	(4)	(32)	30 months
Electricity	(43)	(41)	68 months
Other	(5)	(5)	35 months
Interest rate	(26)	(3)	228 months
Foreign currency	2	1	47 months
Total	$ (98)	$ (119)	

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 14. Ceiling Test

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

Approximately 9% of the anticipated production from our Appalachian operations and fixed-term overriding royalty interests formerly associated with the VPP agreements is hedged by qualifying cash flow hedges, for which hedge-adjusted prices were used to calculate estimated future net revenue. Whether period-end market prices or hedge-adjusted prices were used for the portion of production that is hedged, there was no ceiling test impairment as of June 30, 2007.

Note 15. Variable Interest Entities

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

As of June 30, 2007, no further information has been received from the two remaining potential VIEs. We will continue our efforts to obtain information and will complete an evaluation of our relationship with each of these potential VIEs if sufficient information is ultimately obtained. We have remaining purchase commitments with these two potential VIE supplier entities of $1.2 billion at June 30, 2007. We are not subject to any risk of loss from these potential VIEs, other than the remaining purchase commitments. We paid $24 million for electric generation capacity from these entities in the three months ended June 30, 2007 and 2006. We paid $23 million and $19 million for electric energy from these entities in the three months ended June 30, 2007 and 2006, respectively. We paid $50 million and $49 million for electric generation capacity and $49 million and $37 million for electric energy from these entities in the six months ended June 30, 2007 and 2006, respectively.

In 2006, we restructured three long-term power purchase contracts with two VIEs, of which we are not the primary beneficiary. The restructured contracts expire between 2015 and 2017. We have remaining purchase commitments with these two VIE supplier entities of $1 billion at June 30, 2007. We are not subject to any risk of loss from these VIEs, other than the remaining purchase commitments. We paid $30 million and $29 million for electric generation capacity from these entities in the three months ended June 30, 2007 and 2006, respectively. We paid $13 million for electric energy from these entities in the three months ended June 30, 2007 and 2006. We paid $59 million and $58 million for electric generation capacity and $27 million and $28 million for electric energy from these entities in the six months ended June 30, 2007 and 2006, respectively.

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During 2005, we entered into four long-term contracts with unrelated limited liability companies (LLCs) to purchase synthetic fuel produced from coal. Certain variable pricing terms in the contracts protect the equity holders from variability in the cost of their coal purchases, and therefore, the LLCs were determined to be VIEs. After completing our FIN 46R analysis, we concluded that although our interests in the contracts, as a result of their pricing terms, represent variable interests in the LLCs, we are not the primary beneficiary. We paid $121 million and $104 million to the LLCs for coal and synthetic fuel produced from coal in the three months ended June 30, 2007 and 2006, respectively, and $221 million and $215 million to the LLCs for coal and synthetic fuel produced from coal in the six months ended June 30, 2007 and 2006, respectively. We are not subject to any risk of loss from the contractual arrangements, as our only obligation to the VIEs is to purchase the synthetic fuel that the VIEs produce according to the terms of the applicable purchase contracts. These contracts will terminate on December 31, 2007.

In 2006, we, along with three other gas and oil exploration companies, entered into a long-term contract with an unrelated LLC whose only current activities are to design, construct, install and own the Thunder Hawk facility, a semi-submersible production facility, to be located in the deep water Gulf of Mexico. Certain variable pricing terms and guarantees in the contract protect the equity holder from variability, and therefore, the LLC was determined to be a VIE. After completing our FIN 46R analysis, we concluded that although our 25% interest in the contract, as a result of its pricing terms and guarantee, represents a variable interest in the LLC, we are not the primary beneficiary. Our maximum exposure to loss from the contractual arrangement is approximately $63 million. As of June 30, 2007, we have not made any payments to the LLC. Following the sale of our offshore E&P operations in July 2007, Eni indemnified us and assumed our post-closing obligations related to this arrangement.

Our Consolidated Balance Sheets as of June 30, 2007 and December 31, 2006, reflect net property, plant and equipment of $332 million and $337 million, respectively and $370 million of debt, related to the consolidation, in accordance with FIN 46R, of a variable interest lessor entity through which we have financed and leased a power generation plant for our utility operations. The debt is non-recourse to us and is secured by the entity s property, plant and equipment. The lease under which we operate the power generation facility terminates in August 2007. We intend to take legal title to the facility through repayment of the lessor s related debt at the end of the lease term, subject to regulatory approval.

As discussed in Note 27 to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2006, DCI held an investment in the subordinated notes of a third-party CDO entity. The CDO entity s primary focus is the purchase and origination of middle market senior secured first and second lien commercial and industrial loans in both the primary and secondary loan markets. We concluded that the CDO entity is a VIE and that DCI is the primary beneficiary of the CDO entity, which we have consolidated in accordance with FIN 46R. At June 30, 2007, the CDO entity had $385 million of notes payable that mature in January 2017 and are nonrecourse to us. The CDO entity held the following assets that serve as collateral for its obligations at June 30, 2007:

	Amount (millions)
Other current assets	$ 174
Loans receivable, net	391
Other investments	33
Total assets	$ 598

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Note 16. Significant Financing Transactions

Credit Facilities and Short-Term Debt

As a result of the merger of CNG with Dominion, all of CNG s former credit facilities have been assumed by Dominion. We use short-term debt, primarily commercial paper, to fund working capital requirements, as a bridge to long-term debt financing and as bridge financing for acquisitions, if applicable. The levels of borrowing may vary significantly during the course of the year, depending upon the timing and amount of cash requirements not satisfied by cash from operations. In addition, we utilize cash and letters of credit to fund collateral requirements under our commodities hedging program. Collateral requirements are impacted by commodity prices, hedging levels and the credit quality of our companies and their counterparties. At June 30, 2007, we had committed lines of credit totaling $4.9 billion. These lines of credit support commercial paper borrowings and letter of credit issuances. At June 30, 2007, we had the following commercial paper and letters of credit outstanding and capacity available under credit facilities:

	Facility Limit	Outstanding Commercial Paper	Outstanding Letters of Credit	Facility Capacity Available
		(millions)		
Five-year joint revolving credit facility[(1)]	$ 3,000	$ 1,149	$ 238	$ 1,613
Five-year Dominion credit facility[(2)]	1,700	1,396	304	
Five-year Dominion bilateral facility[(3)]	200	200		
Totals	$ 4,900	$ 2,745	$ 542	$ 1,613

(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. The facility was entered into in February 2006 and terminates in August 2010.
(3) The $200 million five-year facility was entered into in December 2005 and terminates in December 2010. This credit facility can be used to support commercial paper and letter of credit issuances.

In addition to the facilities above, we also entered into a $100 million bilateral credit facility in August 2004 that terminates in August 2009. At June 30, 2007, there were no letters of credit outstanding under this facility.

Long-Term Debt

In May 2007, Virginia Power issued $600 million of 6.0% senior notes that mature in 2037. The proceeds were used for general corporate purposes, including the repayment of short-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 all funds from the trust as of June 30, 2007.

We repaid $935 million of long-term debt during the six months ended June 30, 2007, which included the early redemption of $200 million of 6.875% senior notes that were scheduled to mature in December 2007.

In July 2007, we completed a debt tender offer repurchasing $2.5 billion of our debt securities. We expect to recognize pre-tax costs in the third quarter of 2007 of between approximately $205 to $215 million in connection with the early redemption of this debt.

Also in July 2007, we redeemed all 8 million units of the $200 million 7.8% Dominion CNG Capital Trust I debentures due October 31, 2041. The securities were redeemed at a price of $25 per preferred security plus accrued and unpaid distributions.

Convertible Securities

In December 2003, we issued $220 million of contingent convertible senior notes that are convertible by holders into a combination of cash and shares of our common stock under certain circumstances. At June 30, 2007, since none of these conditions had been met, these senior notes are not yet subject to conversion. In 2004 and 2005, we entered into exchange transactions with respect to these contingent convertible senior notes in contemplation of EITF Issue No. 04-8, *The Effect of Contingently Convertible Instruments on Diluted Earnings per Share*. We exchanged the outstanding notes for new notes with a conversion feature that requires that the principal amount of each note be repaid in cash. The notes are valued at a conversion rate of 13.5865 shares of common stock per $1,000 principal amount of senior notes, which represents a conversion price of $73.60. Amounts payable in excess of the principal amount will be paid in common stock. The conversion rate is subject to adjustment upon certain events such as subdivisions, splits, combinations of common stock or the issuance to all common stock holders of certain common stock rights, warrants or options and certain dividend increases.

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

Issuance of Common Stock

During the six months ended June 30, 2007, we issued 2.2 million shares and received net cash proceeds of $116 million, primarily in connection with the exercise of employee stock options.

Repurchases of Common Stock

As discussed in Note 20 to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2006, we entered into a prepaid accelerated share repurchase agreement (ASR) with a financial institution as the counterparty. Under the ASR, we would receive between 5.6 million and 6.5 million shares in exchange for the prepayment. At the time of execution of the ASR, we made a prepayment of $500 million and the counterparty initially delivered approximately 5 million shares to us. The final number of shares to be delivered to the Company was determined by the volume weighted average price of our common stock over the period commencing on December 12, 2006 and terminating on May 16, 2007. In May 2007, the counterparty delivered approximately 813 thousand additional shares to us in completion of the ASR.

In June 2007, we repurchased 1.4 million shares for approximately $117 million. In July 2007, we launched an equity tender offer to repurchase up to 55 million of our outstanding common shares, representing nearly 16% of outstanding shares, for not less than $82 per share and not more than $92 per share. We also have the discretion to repurchase up to an additional 7 million shares under the equity tender offer. The equity tender offer expired on August 7, 2007. Based on the preliminary results of the offer, we expect to purchase approximately 57.9 million shares at a price of $91 per share for a total cost of approximately $5.3 billion, excluding fees and expenses related to the tender.

In addition to the equity tender offer previously described, in June 2007, our Board of Directors increased our existing common stock repurchase authorization by 18 million shares with the aggregate purchase amount not to exceed $2 billion. At June 30, 2007, the remaining repurchase authorization is the lesser of 31.5 million shares or $3.1 billion of our outstanding common stock.

Note 17. 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). The 2005 Incentive Plan permits stock-based awards that include restricted stock, performance grants, goal-based stock and stock options and the Non-Employee Directors Plan permits restricted stock and stock options. 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 the Compensation, Governance and Nominating (CGN) Committee of the Board of Directors or the Board of Directors itself, as provided under each individual plan. Prior to April 2005, we had an incentive compensation plan that provided stock options and restricted stock awards to directors, executives and other key employees with vesting periods from one to five years. Stock options generally had contractual terms from six and one half to ten years in length.

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Our results for the three months ended June 30, 2007 and 2006 include $15 million and $11 million, respectively, of compensation costs and $6 million and $4 million, respectively, of income tax benefits related to our stock-based compensation arrangements. Our results for the six months ended June 30, 2007 and 2006 include $24 million and $15 million, respectively, of compensation costs and $9 million and $5 million, respectively, of income tax benefits related to our stock-based compensation arrangements. Stock-based compensation cost is reported in other operations and maintenance expense in our Consolidated Statements of Income.

Stock Options

The following table provides a summary of changes in amounts of stock options outstanding as of and for the six months ended June 30, 2007.

	Shares (thousands)	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life (years)	Aggregated intrinsic value[1] (millions)
Outstanding and exercisable at January 1, 2007	7,246	$ 60.51		
Exercised	**(2,032)**	**59.97**		**$ 56**
Outstanding and exercisable at June 30, 2007	**5,214**	**$ 60.72**	**2.91**	**$ 133**

(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 $123 million and $5 million in the six months ended June 30, 2007 and 2006, respectively. SFAS No. 123R, *Share-Based Payment*, requires the benefits of tax deductions in excess of the compensation cost recognized for stock-based compensation (excess tax benefits) to be classified as a financing cash flow. Approximately $22 million and $1 million of excess tax benefits were realized for the six months ended June 30, 2007 and June 30, 2006, respectively.

Restricted Stock

The fair value of our restricted stock awards is equal to the market price of our stock on the date of grant. These awards generally vest over a three-year service period and are settled by issuing new shares. The following table provides a summary of restricted stock activity for the six months ended June 30, 2007:

	Shares (thousands)	Weighted-Average Grant Date Fair Value
Nonvested at January 1, 2007	1,246	$ 65.43
Granted	**241**	**89.07**
Vested	**(258)**	**63.66**
Cancelled and forfeited	**(4)**	**72.53**
Nonvested at June 30, 2007	**1,225**	**$ 70.44**

As of June 30, 2007, unrecognized compensation cost related to nonvested restricted stock awards totaled approximately $39 million and is expected to be recognized over a weighted-average period of 1.5 years. Restricted stock awards granted prior to January 1, 2006 contain terms that accelerate vesting upon retirement. We continue to recognize compensation cost over the stated vesting term for existing restricted stock awards, but are now required to recognize compensation cost over the shorter of the stated vesting term or period from the date of grant to the date of retirement eligibility for newly issued or modified restricted stock awards with similar terms. We recognized compensation cost related to awards previously granted to retirement-eligible employees of approximately $1 million for the three months ended June 30, 2007 and June 30, 2006, respectively, and approximately $2 million and $3 million in the six months ended June 30, 2007 and June 30, 2006, respectively.

At June 30, 2007, unrecognized compensation cost for restricted stock awards held by retirement-eligible employees totaled approximately $3 million.

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Goal-Based Stock

Goal-based stock awards are generally granted to key non-officer employees on an annual basis. The issuance of awards is based on the achievement of multiple performance metrics during a two-year period, including return on invested capital and total shareholder return relative to that of a peer group of companies. Goal-based stock awards were also granted in lieu of cash-based performance grants to certain officers who had not achieved a certain level of share ownership. At June 30, 2007, the targeted number of shares to be issued is approximately 172 thousand, 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. These awards generally vest over a three-year service period and are settled by issuing new shares. The following table provides a summary of goal-based stock activity:

	Targeted Number of Shares (thousands)	Weighted-Average Grant Date Fair Value
Nonvested at January 1, 2007	97	$ 69.53
Granted	**77**	**88.53**
Cancelled and forfeited	**(2)**	**70.12**
Nonvested at June 30, 2007	**172**	**$ 78.10**

At June 30, 2007, unrecognized compensation cost related to nonvested goal-based stock awards totaled approximately $9 million and is expected to be recognized over a weighted-average period of 1.7 years.

Cash-Based Performance Grant

In April 2006, a cash-based performance grant was made to officers. Payout of the performance grant will occur by March 15, 2008 and is based on the achievement of two performance metrics during 2006 and 2007: return on invested capital and total shareholder return relative to that of a peer group companies. At June 30, 2007, the targeted amount of the grant is $14.3 million, but actual payout will vary between zero and 200% of the targeted amount depending on the level of performance metrics achieved.

In April 2007, a cash-based performance grant was made to officers. Payout of the performance grant will occur by March 15, 2009 and is based on the achievement of two performance metrics during 2007 and 2008: return on invested capital and total shareholder return relative to that of a peer group of companies. At June 30, 2007, the targeted amount of the grant is $11.5 million, but actual payout will vary between zero and 200% of the targeted amount depending on the level of performance metrics achieved.

For our E&P officers, the CGN Committee approved a separate 2007 Long-Term Compensation Program which consists of two components: a restricted stock grant and a cash-based performance grant. The restricted stock is subject to a one year vesting period, while the payout of the performance grant will be based on the achievement of funding and payout goals established for the Dominion E&P segment under Dominion s 2007 Annual Incentive Plan. At June 30, 2007, the targeted amount of the E&P performance grant is $1.3 million, but actual payout will vary between zero and 200% of the targeted amount depending on the level of performance metrics achieved.

At June 30, 2007, a liability of $20 million has been accrued for these awards.

Note 18. Commitments and Contingencies

Other than the following matters, there have been no significant developments regarding the commitments and contingencies disclosed in Note 23 to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2006, or Note 15 to the Consolidated Financial Statements in our Quarterly Report on Form 10-Q for the quarter ended March 31, 2007, nor have any significant new matters arisen during the three months ended June 30, 2007.

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Long-Term Purchase Agreements

In connection with the sale of our offshore E&P operations, Eni has indemnified us and assumed the post-closing unconditional purchase obligations associated with these operations. As a result, the following long-term commitments at December 31, 2006 that are noncancelable or are cancelable only under certain conditions, and that third parties have used to secure financing for the facilities that will provide the contracted goods or services, are now the responsibility of Eni:

	2007	2008	2009	2010	2011	Thereafter	Total
				(millions)			
Production handling for gas and oil production operations	$ 54	$ 43	$ 26	$ 15	$ 11	$ 5	$ 154

Lease Commitments

In connection with the sales of our non-Appalachian E&P operations, the purchasers will indemnify us and assume the post-closing obligations associated with non-Appalachian lease commitments. Following the completion of the sales of our non-Appalachian E&P operations, our lease commitments, as shown in our Annual Report on Form 10-K for the year ended December 31, 2006, will be reduced as follows:

	2007	2008	2009	2010	2011	Thereafter	Total
				(millions)			
Total lease commitments	$ 209	$ 182	$ 163	$ 131	$ 119	$ 294	$ 1,098
Less: non-Appalachian E&P operations	(81)	(62)	(55)	(33)	(26)	(40)	(297)
Total lease commitments as adjusted at December 31, 2006	$ 128	$ 120	$ 108	$ 98	$ 93	$ 254	$ 801

Nuclear Operations

The Price-Anderson Act provides the public up to $10.8 billion of liability protection per nuclear incident via obligations required of owners of nuclear power plants. The Price-Anderson Act Amendment of 1988 allows for an inflationary provision adjustment every five years. We have purchased $300 million of coverage from the commercial insurance pools with the remainder provided through a mandatory industry risk-sharing program. In the event of a nuclear incident at any licensed nuclear reactor in the U.S., we could be assessed up to $100.6 million for each of our seven licensed reactors not to exceed $15 million per year per reactor. There is no limit to the number of incidents for which this retrospective premium can be assessed. The Price-Anderson Act was first enacted in 1957 and was renewed again in 2005.

Our current level of property insurance coverage ($2.55 billion for North Anna, $2.55 billion for Surry, $2.75 billion for Millstone, and $1.8 billion for Kewaunee) exceeds the Nuclear Regulatory Commission s (NRC) minimum requirement for nuclear power plant licensees of $1.06 billion per reactor site and includes coverage for premature decommissioning and functional total loss. The NRC requires that the proceeds from this insurance be used first, to return the reactor to and maintain it in a safe and stable condition and second, to decontaminate the reactor and station site in accordance with a plan approved by the NRC. Our nuclear property insurance is provided by Nuclear Electric Insurance Limited (NEIL), a mutual insurance company, and is subject to retrospective premium assessments in any policy year in which losses exceed the funds available to the insurance company. The maximum assessment for the current policy period is $99 million. Based on the severity of the incident, the board of directors of our nuclear insurer has the discretion to lower or eliminate the maximum retrospective premium assessment. We have the financial responsibility for any losses that exceed the limits or for which insurance proceeds are not available because they must first be used for stabilization and decontamination.

We purchase insurance from NEIL to cover the cost of replacement power during the prolonged outage of a nuclear unit due to direct physical damage of the unit. Under this program, we are subject to a retrospective premium assessment for any policy year in which losses exceed funds available to NEIL. The current policy period s maximum assessment is $35 million.

Old Dominion Electric Cooperative, a part owner of North Anna Power Station, and Massachusetts Municipal Wholesale Electric Company and Central Vermont Public Service Corporation, part owners of Millstone s Unit 3, are responsible to us for their share of the nuclear decommissioning obligation and insurance premiums on applicable units, including any retrospective premium assessments and any losses not covered by insurance.

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Insurance for E&P Operations

As discussed in Note 23 to our Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2006, efforts to replace 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. Following the sale of our offshore E&P operations in July 2007, this lack of insurance will not have an adverse effect on our results of operations.

Guarantees

At June 30, 2007, we had issued $36 million of guarantees to support third parties, equity method investees and employees affected by Hurricane Katrina. We also enter into guarantee arrangements on behalf of our consolidated subsidiaries primarily to facilitate their commercial transactions with third parties. To the extent that a liability subject to a guarantee has been incurred by one of our consolidated subsidiaries, that liability is included in our Consolidated Financial Statements. We are not required to recognize liabilities for guarantees issued on behalf of our subsidiaries unless it becomes probable that we will have to perform under the guarantees. No such liabilities have been recognized as of June 30, 2007. We believe it is unlikely that we would be required to perform or otherwise incur any losses associated with guarantees of our subsidiaries obligations. At June 30, 2007, we had issued the following subsidiary guarantees:

	Stated Limit	Value(1)
	(millions)	
Subsidiary debt(2)	$ 423	$ 423
Commodity transactions(3)	3,010	582
Lease obligation for power generation facility(4)	898	898
Nuclear obligations(5)	383	302
Offshore drilling commitments(6)		493
Other	596	344
Total	$ 5,310	$ 3,042

(1) Represents the estimated portion of the guarantee s stated limit that is utilized as of June 30, 2007 based upon prevailing economic conditions and fact patterns specific to each guarantee arrangement. For those guarantees related to obligations that are recorded as liabilities by our subsidiaries, the value includes the recorded amount.

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

(3) Guarantees related to energy trading and marketing activities and other commodity commitments of certain subsidiaries, including subsidiaries of Virginia Power 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 these subsidiaries fail to perform or pay under the contracts and the counterparties seek performance or payment, we would be obligated to satisfy such obligation. We and our subsidiaries receive similar guarantees as collateral for credit extended to others. The value provided includes certain guarantees that do not have stated limits.

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

(5) Guarantees related to certain DEI subsidiaries potential retrospective premiums that could be assessed if there is a nuclear incident under our nuclear insurance programs and guarantees for a DEI subsidiary s and Virginia Power s commitment to buy nuclear fuel. In addition to the guarantees listed above, we have also agreed to provide up to $150 million and $60 million to two DEI subsidiaries, to pay operating expenses of Millstone and Kewaunee power stations, respectively, in the event of a prolonged outage as part of satisfying certain 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. There are no stated limits for these guarantees. Following the sale of our offshore E&P operations in July 2007, Eni has indemnified us and assumed our post-closing obligations under these agreements.

Surety Bonds and Letters of Credit

As of June 30, 2007, we had also purchased $131 million of surety bonds and authorized the issuance of standby letters of credit by financial institutions of $542 million. We enter into these arrangements to facilitate commercial transactions by our subsidiaries with third parties.

Indemnifications

As part of commercial contract negotiations in the normal course of business, we may sometimes agree to make payments to compensate or indemnify other parties for possible future unfavorable financial consequences resulting from specified events. The specified events may involve an adverse judgment in a lawsuit or the imposition of additional taxes due to a change in tax law or interpretation of the tax law. We are unable to develop an estimate of the maximum potential amount of future payments under these contracts because events that would obligate us have not yet occurred

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or, if any such event has occurred, we have not been notified of its occurrence. However, at June 30, 2007, we believe future payments, if any, that could ultimately become payable under these contract provisions, would not have a material impact on our results of operations, cash flows or financial position.

We have entered into other types of contracts that require indemnifications, such as purchase and sale agreements and financing agreements. These agreements may include, but are not limited to, indemnifications around certain title, tax, contractual and environmental matters. With respect to sale agreements, our exposure generally does not exceed the sale price and is typically limited in duration depending on the nature of the indemnified matter. Since January 1, 2004, we have entered into sale agreements with maximum exposure related to the collective purchase prices of approximately $16 billion, for breach of certain corporate representations (e.g. title to shares, due authorization), with maximum indemnity exposure for other general business representations (e.g. environmental, contracts, employee matters, etc.) being generally limited to approximately 10% or less of the purchase price for a set period of time after closing. We believe that it is unlikely that we would be required to perform under these indemnifications and have not recognized any significant liabilities related to these arrangements.

Note 19. Credit Risk

Credit risk is our risk of financial loss if counterparties fail to perform their contractual obligations. In order to minimize overall credit risk, we maintain credit policies, including the evaluation of counterparty financial condition, collateral requirements and the use of standardized agreements that facilitate the netting of cash flows associated with a single counterparty. We maintain a provision for credit losses based on factors surrounding the credit risk of our customers, historical trends and other information. We believe, based on our credit policies and our June 30, 2007 provision for credit losses, that it is unlikely that a material adverse effect on our financial position, results of operations or cash flows would occur as a result of counterparty nonperformance.

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

Our exposure to credit risk is concentrated primarily within our sales of gas and oil production and energy marketing and price risk management activities, as we transact with a smaller, less diverse group of counterparties and transactions may involve large notional volumes and potentially volatile commodity prices. Energy marketing and price risk management activities include trading of energy-related commodities, marketing of merchant generation output, structured transactions and the use of financial contracts for enterprise-wide hedging purposes. Our gross credit exposure for each counterparty is calculated as outstanding receivables plus any unrealized on or off-balance sheet exposure, taking into account contractual netting rights. Gross credit exposure is calculated prior to the application of collateral. At June 30, 2007, our gross credit exposure totaled $1 billion. After the application of collateral, our credit exposure remained approximately $1 billion. Of this amount, investment grade counterparties represented 83% and no single counterparty exceeded 7%.

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Note 20. Employee Benefit Plans

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

	Pension Benefits		Other Postretirement Benefits	
	2007	**2006**	**2007**	**2006**
	(millions)			
Three Months Ended June 30,				
Service cost	**$ 30**	$ 30	**$ 13**	$ 19
Interest cost	**59**	50	**19**	21
Expected return on plan assets	**(105)**	(86)	**(18)**	(15)
Amortization of prior service cost (credit)	**1**	1	**(1)**	(1)
Amortization of transition obligation			**1**	1
Amortization of net loss	**10**	22	**2**	7
Benefit enhancement (1)	**3**		**9**	
Settlements and curtailments (2)	**7**			
Net periodic benefit cost (3)	**$ 5**	$ 17	**$ 25**	$ 32
Six Months Ended June 30,				
Service cost	**$ 53**	$ 65	**$ 28**	$ 40
Interest cost	**102**	108	**38**	44
Expected return on plan assets	**(181)**	(185)	**(36)**	(32)
Amortization of prior service cost (credit)	**2**	2	**(3)**	(2)
Amortization of transition obligation			**2**	2
Amortization of net loss	**18**	47	**3**	15
Benefit enhancement (1)	**3**		**9**	
Settlements and curtailments (2)	**7**	6		
Net periodic benefit cost (3)	**$ 4**	$ 43	**$ 41**	$ 67

(1) Represents a one-time benefit enhancement for certain employees in connection with the disposition of our non-Appalachian E&P operations.
(2) Relates to the pending sale of Peoples and Hope and sales of our non-Appalachian E&P operations.
(3) Reduction in pension and other postretirement benefit costs, primarily reflecting an increase in the associated discount rate.

Employer Contributions

We made no contributions to our defined benefit pension plans or other postretirement benefit plans during the six months ended June 30, 2007. We expect to contribute approximately $23 million to our other postretirement benefit plans during the remainder of 2007. Under our funding policies, we evaluate pension and other postretirement benefit plan funding requirements annually, usually in the second half of the year after receiving updated plan information from our actuary. Based on the funded status of each plan and other factors, the amount of additional contributions to be made in 2007 will be determined at that time.

Note 21. Operating Segments

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

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

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

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

Dominion E&P includes our gas and oil exploration, development and production operations. These operations are located in several major producing basins in the lower 48 states, including the outer continental shelf and deepwater areas of the Gulf of Mexico, West Texas, Mid-Continent, the Rockies and Appalachia. We have sold or entered into agreements to sell our non-Appalachian natural gas and oil E&P operations.

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Corporate includes our corporate, service company and other functions (including unallocated debt), corporate-wide enterprise commodity risk management, the remaining assets of DCI and the net impact of the discontinued operations of the Peaker facilities and the Canadian E&P business. In addition, the contribution to net income by our primary operating segments is determined based on a measure of profit that executive management believes represents the segments core earnings. As a result, certain specific items attributable to those segments are not included in profit measures evaluated by executive management in assessing the segment s performance or allocating resources among the segments and are instead reported in the Corporate segment. In the six months ended June 30, 2007 and 2006, we reported net expenses of $989 million and $102 million, respectively, in the Corporate segment attributable to our operating segments.

The net expenses in 2007 largely resulted from:

A $536 million ($341 million after-tax) charge due to the discontinuance of hedge accounting for certain gas and oil hedges and subsequent changes in the fair value of these hedges, attributable to Dominion E&P. As a result of the announced sales of our non-Appalachian E&P operations, it became probable that the forecasted sales of gas and oil will not occur;

A $387 million ($252 million after-tax) charge related to the impairment of the partially-completed Dresden generation facility, attributable to Dominion Generation;

A $259 million ($158 million after-tax) extraordinary charge in connection with the reapplication of SFAS No. 71 to the Virginia jurisdiction of our utility generation operations, attributable to Dominion Generation;

A $171 million ($108 million after-tax) charge for the recognition of certain forward gas contracts that no longer qualify for the normal purchase and sales exemption as a result of the announced sales of our non-Appalachian E&P operations, attributable to Dominion E&P;

$41 million ($26 million after-tax) of incremental expenses, primarily related to retention and severance expenses associated with the announced sales of our non-Appalachian E&P operations, attributable to Dominion E&P; and

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

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

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

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The following table presents segment information pertaining to our operations:

	Dominion Delivery	Dominion Energy	Dominion Generation	Dominion E&P (millions)	Corporate	Adjustments/ Eliminations	Consolidated Total
Three Months Ended June 30,							
2007							
Total revenue from external customers	**$ 814**	**$ 215**	**$ 1,737**	**$ 618**	**$ 21**	**$ 325**	**$ 3,730**
Intersegment revenue	**3**	**411**	**39**	**60**	**154**	**(667)**	
Total operating revenue	**817**	**626**	**1,776**	**678**	**175**	**(342)**	**3,730**
Extraordinary item, net of tax					**(158)**		**(158)**
Income from discontinued operations, net of tax					**20**		**20**
Net income (loss)	**83**	**69**	**81**	**145**	**(908)**		**(530)**
2006							
Total revenue from external customers	$ 737	$ 248	$ 1,568	$ 739	$ (30)	$ 234	$ 3,496
Intersegment revenue	3	287	39	50	187	(566)	
Total operating revenue	740	535	1,607	789	157	(332)	3,496
Income from discontinued operations, net of tax					15		15
Net income (loss)	80	68	65	93	(145)		161
Six Months Ended June 30,							
2007							
Total revenue from external customers	**$ 2,428**	**$ 604**	**$ 3,516**	**$ 1,233**	**$ 30**	**$ 580**	**$ 8,391**
Intersegment revenue	**16**	**703**	**67**	**113**	**315**	**(1,214)**	
Total operating revenue	**2,444**	**1,307**	**3,583**	**1,346**	**345**	**(634)**	**8,391**
Extraordinary item, net of tax					**(158)**		**(158)**
Loss from discontinued operations, net of tax					**(2)**		**(2)**
Net income (loss)	**282**	**171**	**220**	**276**	**(1,026)**		**(77)**
2006							
Total revenue from external customers	$ 2,409	$ 845	$ 3,222	$ 1,577	$ (78)	$ 427	$ 8,402
Intersegment revenue	6	563	81	118	382	(1,150)	
Total operating revenue	2,415	1,408	3,303	1,695	304	(723)	8,402
Income from discontinued operations, net of tax					15		15
Net income (loss)	236	175	203	318	(237)		695

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DOMINION RESOURCES, INC.

ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS

OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

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

Contents of MD&A

Our MD&A consists of the following information:

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

Forward-Looking Statements

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

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

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

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

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

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

Risks associated with the operation of nuclear facilities;

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

Counterparty credit risk;

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

Fluctuations in interest rates;

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

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

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

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

Receipt of approvals for and timing of closing dates for acquisitions and divestitures, including our divestiture of Peoples and Hope and the divestiture of our remaining non-Appalachian E&P operations;

Risks associated with any realignment of our operating assets, including the potential dilutive effect on earnings in the near term and costs associated with the sale of most of our E&P operations;

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

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

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Additionally, other risks that could cause actual results to differ from predicted results are set forth in Item 1A. Risk Factors in this report, in our Quarterly Report on Form 10-Q for the quarter ended March 31, 2007, and in our Annual Report on Form 10-K for the year ended December 31, 2006.

Our forward-looking statements are based on our beliefs and assumptions using information available at the time the statements are made. We caution the reader not to place undue reliance on our forward-looking statements because the assumptions, beliefs, expectations and projections about future events may, and often do, differ materially from actual results. We undertake no obligation to update any forward-looking statement to reflect developments occurring after the statement is made.

Accounting Matters

Critical Accounting Policies and Estimates

As of June 30, 2007, there have been no significant changes with regard to the critical accounting policies and estimates disclosed in MD&A in our Annual Report on Form 10-K for the year ended December 31, 2006. The policies disclosed included the accounting for derivative contracts at fair value, goodwill and long-lived asset impairment testing, asset retirement obligations, employee benefit plans, regulated operations, gas and oil operations, and income taxes.

Other

See Notes 3 and 4 to our Consolidated Financial Statements for a discussion of newly adopted and recently issued accounting standards. See Note 5 to our Consolidated Financial Statements for a discussion of the reapplication of SFAS No. 71 to the Virginia jurisdiction of our utility generation operations.

Results of Operations

Presented below is a summary of our consolidated results for the quarter and year-to-date periods ended June 30, 2007 and 2006:

	2007	2006	$ Change
	(millions, except EPS)		
Second Quarter			
Net income (loss)	**$ (530)**	$ 161	$ (691)
Diluted EPS	**(1.52)**	0.46	(1.98)
Year-To-Date			
Net income (loss)	**$ (77)**	$ 695	$ (772)
Diluted EPS	**(0.22)**	1.99	(2.21)

Overview

Second Quarter 2007 vs. 2006

We reported a net loss of $530 million in 2007, as compared to net income of $161 million in 2006. Unfavorable drivers include charges related to the announced sales of our non-Appalachian E&P operations, an impairment charge related to the pending sale of the partially-completed Dresden generation facility, an extraordinary charge in connection with the reapplication of SFAS No. 71 to the Virginia jurisdiction of our utility generation operations, a decrease in oil and gas production at certain deepwater projects and an increase in unrecovered Virginia fuel expenses. Favorable drivers include higher realized prices for our gas and oil production and higher margins at our merchant generation business.

Year-To-Date 2007 vs. 2006

We reported a net loss of $77 million in 2007, as compared to net income of $695 million in 2006. Unfavorable drivers include charges related to the announced sales of our non-Appalachian E&P operations, an impairment charge related to the pending sale of the partially-completed

Dresden generation facility, an extraordinary charge in connection with the reapplication of SFAS No. 71 to the Virginia jurisdiction of our utility generation operations, a decrease in oil and gas production at certain deepwater projects and an increase in unrecovered Virginia fuel expenses. Favorable drivers include higher realized prices for our gas and oil production, higher margins at our merchant generation business and the impact of weather and customer growth on our regulated electric sales.

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Analysis of Consolidated Operations

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

	Second Quarter			Year-To-Date		
	2007	2006	$ Change	2007	2006	$ Change
	(millions)					
Operating Revenue	**$ 3,730**	$ 3,496	$ 234	**$ 8,391**	$ 8,402	$ (11)
Operating Expenses						
Electric fuel and energy purchases	**910**	758	152	**1,828**	1,523	305
Purchased electric capacity	**109**	116	(7)	**228**	239	(11)
Purchased gas	**530**	432	98	**1,678**	1,810	(132)
Other energy-related commodity purchases	**64**	318	(254)	**120**	718	(598)
Other operations and maintenance	**1,934**	875	1,059	**2,762**	1,621	1,141
Depreciation, depletion and amortization	**423**	393	30	**832**	757	75
Other taxes	**140**	130	10	**323**	308	15
Other income	**43**	49	(6)	**92**	91	1
Interest and related charges	**278**	251	27	**537**	508	29
Income tax expense (benefit)	**(232)**	126	(358)	**78**	329	(251)
Extraordinary item, net of tax	**(158)**		(158)	**(158)**		(158)
Income (loss) from discontinued operations, net of tax	**20**	15	5	**(2)**	15	(17)

An analysis of our results of operations for the second quarter and year-to-date periods of 2007 compared to the second quarter and year-to-date periods of 2006 follows:

Second Quarter 2007 vs. 2006

Operating Revenue increased 7% to $3.7 billion, primarily reflecting:

- A $134 million increase for merchant generation operations, primarily reflecting higher realized prices for nuclear and fossil operations, increased volumes for fossil operations and higher capacity revenue associated with new capacity markets in the New England Power Pool (NEPOOL) and PJM. This increase was partially offset by lower volumes for nuclear operations due to an increase in planned refueling outage days;
- A $100 million increase in revenue from our electric utility operations, largely resulting from:
  - A $42 million increase in sales to retail customers due to an increase in the number of heating and cooling degree days;
  - A $36 million increase in sales to retail customers attributable to new customer connections ($16 million) primarily in our residential and commercial customer classes and variations in rates resulting from changes in sales mix and other factors ($20 million); and
  - An $18 million increase in sales to wholesale customers largely due to an increase in the number of heating and cooling degree days.
- A $66 million increase in sales of gas and oil production due to higher realized prices ($168 million), partially offset by lower volumes ($102 million);

A $62 million increase in our producer services business as the result of an increase in volumes associated with gas aggregation activities and higher margins related to price risk management activities. These increases were more than offset by a corresponding increase in *Purchased gas expense*;

A $60 million increase associated with hedging activities for our merchant generation assets. The effect of this increase was more than offset by a corresponding increase in *Other operations and maintenance expense*; and

A $30 million increase in gas sales by retail energy marketing activities due to increased customer accounts ($22 million) and higher contracted sales prices ($8 million). These increases were largely offset by a corresponding increase in *Purchased gas expense*;

These increases were partially offset by:

A $190 million decrease in revenue from sales of oil purchased by E&P operations, primarily due to the impact of netting sales and purchases of oil under buy/sell arrangements associated with the implementation of EITF 04-13 in 2006. This decrease was largely offset by a corresponding decrease in *Other energy-related commodity purchases expense;* and

A $74 million decrease in nonutility coal sales, primarily from lower sale volumes related to exiting certain sales activities. This decrease was largely offset by a corresponding decrease in *Other energy-related commodity purchases expense*.

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Operating Expenses and Other Items

Electric fuel and energy purchases expense increased 20% to $910 million, primarily reflecting the combined effects of:

- A $104 million increase related to our utility generation operations, primarily due to increased consumption of fossil fuel and higher purchased power costs, due to an increase in the number of heating and cooling degree days and higher commodity prices; and
- A $20 million increase for our merchant generation operations primarily due to higher commodity prices and increased fossil fuel consumption, partially offset by lower purchases of replacement power due to an unplanned nuclear plant outage in 2006.

Purchased gas expense increased 23% to $530 million, principally resulting from the following factors, both of which are discussed in *Operating Revenue*:

- A $74 million increase associated with our producer services business; and
- A $22 million increase associated with retail energy marketing activities.

Other energy-related commodity purchases expense decreased 80% to $64 million, primarily resulting from the following factors, both of which are discussed in *Operating Revenue*:

- A $185 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; and
- A $72 million decrease in the cost of nonutility coal sales.

Other operations and maintenance expense increased 121% to $1.9 billion, primarily reflecting the combined effects of:

- A $536 million charge due to the discontinuance of hedge accounting for certain gas and oil hedges and subsequent changes in the fair value of these hedges. As a result of the announced sales of our non-Appalachian E&P operations it became probable that the forecasted sales of gas and oil will not occur;
- A $387 million impairment charge related to the pending sale of the partially-completed Dresden generation facility;
- A $171 million charge primarily due to the termination of VPP agreements as a result of the announced sales of our non-Appalachian E&P operations;
- A $74 million increase primarily related to hedging activities associated with our merchant generation assets. The effect of this increase is largely offset by a corresponding increase in *Operating Revenue;*

$64 million of charges primarily consisting of retention, severance, employee benefit, legal and other expenses incurred as a result of the announced sales of our non-Appalachian E&P operations; and

An $18 million increase in outage costs, primarily due to an increase in the number of scheduled merchant nuclear refueling outage days.

These charges were partially offset by:

A $29 million mark-to-market gain on interest rate swap derivatives used to economically hedge the repurchase of $2.5 billion of debt securities in connection with our debt tender offer announced in June 2007; and

A benefit resulting from the absence of the following 2006 items:

An $85 million charge resulting from the impairment of a DCI investment; and

A $60 million charge due to the elimination of hedge accounting for certain interest rate swaps associated with our junior subordinated notes payable to affiliated trusts.

Interest and related charges increased 11% to $278 million, resulting principally from additional commercial paper borrowings and the issuance of junior subordinated notes in 2006, partially offset by a decrease resulting from the early redemption and maturity of certain debt securities.

Income tax expense reflects a tax benefit for the loss from continuing operations in 2007, as compared to tax expense for income from continuing operations in 2006.

Extraordinary item reflects a $158 million after-tax charge in connection with the reapplication of SFAS No. 71 to the Virginia jurisdiction of our utility generation operations.

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Income from discontinued operations increased 33% to $20 million primarily reflecting a gain on the disposal of our Canadian E&P assets in June 2007.

Year-To-Date 2007 vs. 2006

Operating Revenue decreased by less than 1% to $8.4 billion, primarily reflecting:

- A $422 million decrease in revenue from sales of oil purchased by E&P operations, primarily due to the impact of netting sales and purchases of oil under buy/sell arrangements associated with the implementation of EITF 04-13 in 2006. This decrease was largely offset by a corresponding decrease in *Other energy-related commodity purchases expense;*
- A $232 million decrease in gas sales by our gas distribution operations reflecting a $194 million decrease resulting from the migration of customers to energy choice programs and a $196 million decrease reflecting lower gas prices, partially offset by a $158 million increase in volumes due to colder weather, primarily in the first quarter of 2007, and changes in customer usage patterns and other factors. This decrease was largely offset by a corresponding decrease in *Purchased gas expense;*
- A $154 million decline in nonutility coal sales, primarily from lower sales volumes related to exiting certain sales activities. This decrease was largely offset by a corresponding decrease in *Other energy-related commodity purchases expense*;
- A $42 million decrease in sales of emissions allowances held for resale, primarily reflecting lower overall sales volume. This decrease was largely offset by a corresponding decrease in *Other energy-related commodity purchases expense*; and
- A $46 million decrease in revenue from our producer services business as a result of a decrease in prices associated with gas aggregation activities and lower margins related to price risk management activities due to reduced market volatility.

These decreases were partially offset by:

- A $209 million increase in revenue from our electric utility operations, largely resulting from:
  - A $95 million increase in sales to retail customers due to an increase in the number of heating and cooling degree days;
  - A $79 million increase in sales to retail customers attributable to new customer connections ($33 million) primarily in our residential and commercial customer classes and variations in rates resulting from changes in sales mix and other factors ($46 million); and
  - A $27 million increase in sales to wholesale customers primarily resulting from an increase in the number of heating and cooling degree days.
- A $208 million increase for merchant generation operations, primarily reflecting higher realized prices for nuclear and fossil operations, increased volumes for fossil operations and higher capacity revenue associated with new capacity markets in NEPOOL and PJM. This increase was partially offset by lower volumes for nuclear operations due to a planned refueling outage;

A $159 million increase associated with hedging activities for our merchant generation assets. The effect of this increase was largely offset by a corresponding increase in *Other operations and maintenance expense*;

A $143 million increase in gas sales by retail energy marketing operations due to the net impact of increased customer accounts ($178 million), partially offset by lower contracted sales prices ($35 million). This increase was largely offset by a corresponding increase in *Purchased gas expense*;

An $89 million increase in sales of gas and oil production, due to higher realized prices ($239 million), partially offset by lower volumes ($150 million); and

A $73 million increase in gas transportation and storage revenue primarily attributable to our gas distribution operations due to increased volumes and higher prices.

Operating Expenses and Other Items

Electric fuel and energy purchases expense increased 20% to $1.8 billion, primarily reflecting:

A $223 million increase related to our utility generation operations, primarily due to increased consumption of fossil fuel and higher purchased power costs, due to an increase in the number of heating and cooling degree days and higher commodity prices; and

A $49 million increase for our merchant generation operations primarily due to higher commodity prices and increased fossil fuel consumption.

Purchased gas expense decreased 7% to $1.7 billion, principally resulting from:

A $191 million decrease in costs attributable to gas distribution operations, primarily reflecting lower prices as discussed in *Operating Revenue*;

- A $29 million decrease in gas purchased by E&P operations primarily due to the implementation of EITF 04-13; and

- A $9 million decrease associated with our producer services business, due to the net impact of lower prices partially offset by an increase in volumes.

These decreases were partially offset by:

- A $115 million increase associated with retail energy marketing activities, due to higher volumes ($163 million), partially offset by lower prices ($48 million), as discussed in *Operating Revenue*.

Other energy-related commodity purchases expense decreased 83% to $120 million, primarily attributable to the following factors:

- A $409 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, as discussed in *Operating Revenue*;

- A $149 million decrease in the cost of nonutility coal sales, as discussed in *Operating Revenue*; and

- A $34 million decrease in the cost of sales of emissions allowances held for resale.

Other operations and maintenance expense increased 70% to $2.8 billion, resulting from:

- A $536 million charge due to the discontinuance of hedge accounting for certain gas and oil hedges and subsequent changes in the fair value of these hedges. As a result of the announced sales of our non-Appalachian E&P operations it became probable that the forecasted sales of gas and oil will not occur;

- A $387 million impairment charge related to the pending sale of the partially-completed Dresden generation facility;

- A $171 million charge primarily due to the termination of VPP agreements as a result of the announced sales of our non-Appalachian E&P operations;

- A $171 million increase primarily related to hedging activities associated with our merchant generation assets. The effect of this increase is largely offset by a corresponding increase in *Operating Revenue;*

- A $129 million increase primarily due to the absence of a 2006 benefit from favorable changes in the fair value of certain gas and oil hedges that were dedesignated following the 2005 hurricanes;

- $76 million of charges primarily consisting of retention, severance, employee benefit, legal and other expenses incurred as a result of the announced sales of our non-Appalachian E&P operations;

- A $30 million increase in outage costs, primarily due to an increase in scheduled merchant nuclear refueling outage days; and

A $26 million charge resulting from the accrual of litigation reserves.

These charges were partially offset by:

- A $29 million mark-to-market gain on interest rate swap derivatives used to economically hedge the repurchase of $2.5 billion of debt securities in connection with our debt tender offer announced in June 2007; and
- A benefit resulting from the absence of the following 2006 items:
  - A $162 million charge related to the write-off of certain regulatory assets in connection with the pending sale of Peoples and Hope;
  - An $89 million charge resulting from the impairment of a DCI investment; and
  - A $60 million charge due to the elimination of hedge accounting for certain interest rate swaps associated with our junior subordinated notes payable to affiliated trusts.

Depreciation, depletion and amortization expense increased 10% to $832 million, largely due to higher E&P finding and development costs.

Income tax expense decreased, reflecting lower income from continuing operations.

Extraordinary item reflects a $158 million after-tax charge in connection with the reapplication of SFAS No. 71 to the Virginia jurisdiction of our utility generation operations.

Loss from discontinued operations was $2 million as compared to income from discontinued operations of $15 million in 2006, primarily due to a loss on the sale of the Peaker facilities in March 2007.

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Segment Results of Operations

Segment results include the impact of intersegment revenues and expenses, which may result in intersegment profit or loss. Intersegment profit or loss is eliminated in our consolidated results. Presented below is a summary of contributions by operating segments to net income (loss) for the quarter and year-to-date periods ended June 30, 2007 and 2006:

	Net Income (Loss)			Diluted EPS		
Second Quarter	**2007**	**2006**	**$ Change**	**2007**	**2006**	**$ Change**
			(millions, except EPS)			
Dominion Delivery	**$ 83**	$ 80	$ 3	**$ 0.24**	$ 0.23	$ 0.01
Dominion Energy	**69**	68	1	**0.20**	0.20	
Dominion Generation	**81**	65	16	**0.23**	0.19	0.04
Dominion E&P	**145**	93	52	**0.42**	0.26	0.16
Primary operating segments	**378**	306	72	**1.09**	0.88	0.21
Corporate	**(908)**	(145)	(763)	**(2.61)**	(0.42)	(2.19)
Consolidated	**$ (530)**	$ 161	$ (691)	**$ (1.52)**	$ 0.46	$ (1.98)
Year-To-Date						
			(millions, except EPS)			
Dominion Delivery	**$ 282**	$ 236	$ 46	**$ 0.80**	$ 0.68	$ 0.12
Dominion Energy	**171**	175	(4)	**0.49**	0.50	(0.01)
Dominion Generation	**220**	203	17	**0.63**	0.58	0.05
Dominion E&P	**276**	318	(42)	**0.79**	0.91	(0.12)
Primary operating segments	**949**	932	17	**2.71**	2.67	0.04
Corporate	**(1,026)**	(237)	(789)	**(2.93)**	(0.68)	(2.25)
Consolidated	**$ (77)**	$ 695	$ (772)	**$ (0.22)**	$ 1.99	$ (2.21)

Dominion Delivery

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

	Second Quarter			Year-To-Date		
	2007	**2006**	**% Change**	**2007**	**2006**	**% Change**
Electricity delivered (million mwhrs) [(1)]	**20.0**	18.7	7%	**41.0**	38.2	7%
Degree days (electric service area):						
Cooling[(2)]	**481**	396	21	**493**	409	21
Heating[(3)]	**367**	245	50	**2,360**	2,041	16
Average electric delivery customer accounts[(4)]	**2,356**	2,322	1	**2,354**	2,318	2
Gas throughput (bcf):						
Gas sales	**14**	12	17	**60**	62	(3)
Gas transportation	**46**	43	7	**153**	130	18
Heating degree days (gas service area)[(3)]	**729**	656	11	**3,761**	3,236	16
Average gas delivery customer accounts[(4)]:						
Gas sales	**792**	864	(8)	**787**	925	(15)
Gas transportation	**895**	827	8	**905**	770	18
Average retail energy marketing customer accounts[(4)]	**1,540**	1,341	15	**1,513**	1,268	19

mwhrs = megawatt hours

bcf = billion cubic feet

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

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

	Second Quarter 2007 vs. 2006 Increase (Decrease) Amount	EPS	Year-To-Date 2007 vs. 2006 Increase (Decrease) Amount	EPS
	(millions, except EPS)			
Regulated electric sales:				
Weather	$ 6	$ 0.02	$ 13	$ 0.04
Customer growth	2		5	0.01
Regulated gas sales - weather	2	0.01	15	0.04
Interest expense	(3)	(0.01)	2	0.01
Retail energy marketing operations(1)	(1)		9	0.02
Other	(3)	(0.01)	2	
Change in net income contribution	$ 3	$ 0.01	$ 46	$ 0.12

(1) Increase in the year-to-date period reflects higher revenues largely attributable to an increase in the number of gas customers.

Dominion Energy

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

	Second Quarter 2007	2006	% Change	Year-To-Date 2007	2006	% Change
Gas transportation throughput (bcf)	**131**	122	7%	**409**	356	15%

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

	Second Quarter 2007 vs. 2006 Increase (Decrease) Amount	EPS	Year-To-Date 2007 vs. 2006 Increase (Decrease) Amount	EPS
	(millions, except EPS)			
Producer services(1)	$ 9	$ 0.02	$ (13)	$ (0.04)
Electric transmission operations	3	0.01	3	0.01
Gas transmission operations(2)	(12)	(0.03)	4	0.01
Other	1		2	0.01
Change in net income contribution	$ 1	$	$ (4)	$ (0.01)

(1) Increase in the quarter reflects higher margins on gas storage and gains from gas supply management activities, partially offset by a lower value in gas transportation positions. Decrease in the year-to-date period is related to price risk management activities and certain transportation contracts, as a result of reduced market volatility, as compared to the post-2005 hurricane market conditions in 2006.

(2) For the quarter, decrease is primarily due to timing losses associated with economic hedges on replacement gas related to extracted products and a decline in market center services. For the year, increase is primarily due to lower fuel costs resulting from reduced gas usage and lower gas prices.

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Dominion Generation

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

	Second Quarter			Year-To-Date		
	2007	**2006**	**% Change**	**2007**	**2006**	**% Change**
Electricity supplied (million mwhrs)						
Utility	**20.0**	18.7	7%	**41.0**	38.2	7%
Merchant	**10.2**	9.9	3	**21.5**	20.9	3
Degree days (electric utility service area):						
Cooling	**481**	396	21	**493**	409	21
Heating	**367**	245	50	**2,360**	2,041	16

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

	Second Quarter 2007 vs. 2006 Increase (Decrease)		Year-To-Date 2007 vs. 2006 Increase (Decrease)	
	Amount	**EPS**	**Amount**	**EPS**
	(millions, except EPS)			
Merchant generation margin[1]	$ 45	$ 0.13	$ 58	$ 0.18
Regulated electric sales:				
Weather	12	0.03	27	0.08
Customer growth	5	0.01	9	0.02
Other	9	0.02	12	0.03
Ancillary service revenue	4	0.01	12	0.03
Unrecovered Virginia fuel expenses[2]	(41)	(0.11)	(90)	(0.26)
Interest expense	(13)	(0.04)	(9)	(0.02)
Outage costs[3]	(11)	(0.03)	(17)	(0.05)
Sales of emissions allowances	(7)	(0.02)	(11)	(0.03)
Other	13	0.04	26	0.07
Change in net income contribution	$ 16	$ 0.04	$ 17	$ 0.05

(1) Primarily reflects higher volumes and realized prices for our New England generating assets.
(2) Increase is primarily due to increased consumption of fossil fuel and higher purchased power costs due to an increase in the number of heating and cooling degree days and an increase in commodity prices.
(3) Primarily due to an increase in the number of scheduled merchant nuclear refueling outage days.

Dominion E&P

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

	Second Quarter			Year-To-Date		
	2007	**2006**	**% Change**	**2007**	**2006**	**% Change**
Gas production (bcf)	**76.4**	74.8	2%	**148.7**	142.7	4 %
Oil production (million bbls)	**5.1**	6.1	(16)	**10.4**	11.9	(13)
Average realized prices without hedging results:						
Gas (per mcf)[1]	**$ 6.93**	$ 6.36	9	**$ 6.75**	$ 7.14	(5)
Oil (per bbl)	**54.96**	59.20	(7)	**50.81**	56.59	(10)

Average realized prices with hedging results:						
Gas (per mcf) [(1)]	**$ 5.81**	$ 4.00	45	**$ 5.78**	$ 4.45	30
Oil (per bbl)	**38.91**	34.69	12	**36.90**	36.59	1
DD&A (unit of production rate per mcfe)	**$ 1.90**	$ 1.64	16	**$ 1.90**	$ 1.64	16

bbl(s) = barrel(s)

mcf = thousand cubic feet

mcfe = thousand cubic feet equivalent

(1) Excludes $24 million and $63 million for the three months ended June 30, 2007 and 2006, respectively, and $71 million and $143 million for the six months ended June 30, 2007 and 2006, respectively, of revenue recognized under the VPP agreements, which were terminated in the second quarter of 2007, as described in Note 6 to our Consolidated Financial Statements.

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

	Second Quarter 2007 vs. 2006 Increase (Decrease) Amount	EPS	Year-To-Date 2007 vs. 2006 Increase (Decrease) Amount	EPS
	(millions, except EPS)			
Gas and oil - prices	$ 100	$ 0.30	$ 119	$ 0.34
Operations and maintenance[1]	8	0.02	(67)	(0.19)
Gas and oil - production[2]	(45)	(0.13)	(62)	(0.18)
DD&A[3]	(14)	(0.04)	(34)	(0.10)
Interest expense	(9)	(0.02)	(14)	(0.04)
Other	12	0.03	16	0.05
Change in net income contribution	$ 52	$ 0.16	$ (42)	$ (0.12)

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

(2) Represents a decrease in oil production associated with lower deepwater Gulf of Mexico production from the Devils Tower, Green Canyon and Triton projects and the impact of lower gas deliveries under VPP contracts.

(3) Higher DD&A, primarily reflecting higher industry finding and development costs.

Included below are the volumes and weighted-average prices associated with hedges in place for our Appalachian operations and fixed-term overriding royalty interests formerly associated with the VPP agreements as of June 30, 2007 by applicable time period.

	Natural Gas Hedged Production	Average Hedge Price
Year	(bcf)	(per mcf)
2007	30.7	$ 6.91
2008	51.7	8.57
2009	6.7	8.43

Corporate

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

	Second Quarter 2007	2006	$ Change	Year-To-Date 2007	2006	$ Change
			(millions, except EPS)			
Specific items attributable to operating segments	**$ (954)**	$ (9)	$ (945)	**$ (989)**	$ (102)	$ (887)
Peaker discontinued operations		(6)	6	**(28)**	(11)	(17)
Canadian E&P discontinued operations	**26**	20	6	**32**	25	7
Other corporate operations	**20**	(150)	170	**(41)**	(149)	108
Total net expense	**$ (908)**	$ (145)	$ (763)	**$ (1,026)**	$ (237)	$ (789)
Earnings per share impact	**$ (2.61)**	$ (0.42)	$ (2.19)	**$ (2.93)**	$ (0.68)	$ (2.25)

Specific Items Attributable to Operating Segments

Corporate includes specific items attributable to our operating segments that have been excluded from profit measures evaluated by management, either in assessing segment performance or in allocating resources among the segments. See Note 21 to our Consolidated Financial Statements for discussion of these items.

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Peaker Discontinued Operations

Year-To-Date 2007 vs. 2006

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

Other Corporate Operations

Second Quarter 2007 vs. 2006

We reported a net benefit of $20 million in 2007, as compared to net expenses of $150 million in 2006, primarily reflecting a $126 million tax benefit from the partial reduction of previously recorded valuation allowances on deferred tax assets, representing certain federal and state tax loss carryforwards, since these losses are expected to be utilized to offset income generated from the sales of our non-Appalachian E&P operations. The increased benefit also reflects the absence of an $85 million impairment charge related to a DCI investment recorded in 2006. These benefits were partially offset by a higher effective tax rate.

Year-To-Date 2007 vs. 2006

Net expenses decreased $108 million, primarily reflecting a net tax benefit from the reduction of previously recorded valuation allowances on deferred tax assets, described above. The decrease in net expenses also reflects the absence of an $85 million impairment charge related to a DCI investment and the absence of a $135 million charge related to the establishment of deferred tax liabilities, in accordance with EITF 93-17, recorded in 2006. These benefits were partially offset by a higher effective tax rate in 2007 and the absence of a $194 million tax benefit from the partial reduction of previously recorded valuation allowances on deferred tax assets recorded in 2006 in connection with the pending sale of Peoples and Hope.

Selected Information Energy Trading Activities

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

A summary of the changes in the unrealized gains and losses recognized for our energy-related derivative instruments held for trading purposes during the six months ended June 30, 2007 follows:

	Amount (millions)
Net unrealized gain at December 31, 2006	$ 42
Contracts realized or otherwise settled during the period	**(46)**
Net unrealized gain at inception of contracts initiated during the period	
Changes in valuation techniques	
Other changes in fair value	**21**
Net unrealized gain at June 30, 2007	**$ 17**

The balance of net unrealized gains and losses recognized for our energy-related derivative instruments held for trading purposes at June 30, 2007, is summarized in the following table based on the approach used to determine fair value and contract settlement or delivery dates:

Source of Fair Value	**Maturity Based on Contract Settlement or Delivery Date(s)** Less than	1-2	2-3	3-5	Total

	1 year	years	years	years	In excess of 5 years	
			(millions)			
Actively quoted[1]	$	$ 12	$ 3	$	$	$ 15
Other external sources[2]		(1)	(1)	3	1	2
Total	$	$ 11	$ 2	$ 3	$ 1	$ 17

(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.

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Liquidity and Capital Resources

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

At June 30, 2007, we had $1.7 billion of unused capacity under our credit facilities, comprised of approximately $1.6 billion under our core credit facilities and $100 million available under a bilateral credit facility.

A summary of our cash flows for the six months ended June 30, 2007 and 2006 is presented below:

	2007	2006
	(millions)	
Cash and cash equivalents at January 1,[1]	**$ 142**	$ 146
Cash flows provided by (used in):		
Operating activities	**1,973**	1,989
Investing activities	**(1,674)**	(1,952)
Financing activities	**(398)**	(100)
Net decrease in cash and cash equivalents	**(99)**	(63)
Cash and cash equivalents at June 30,[2]	**$ 43**	$ 83

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

(2) 2007 and 2006 amounts include $3 million and $2 million, respectively, of cash classified as held for sale in our Consolidated Balance Sheets.

Operating Cash Flows

For the six months ended June 30, 2007, net cash provided by operating activities decreased by $16 million as compared to the six months ended June 30, 2006. The decrease was primarily due to higher unrecovered fuel costs and higher income taxes paid. Our operations are subject to risks and uncertainties that may negatively impact the timing or amounts of operating cash flows which are discussed in Item 1A. Risk Factors in this report, our Quarterly Report on Form 10-Q for the quarter ended March 31, 2007 and in our Annual Report on Form 10-K for the year-ended December 31, 2006.

Credit Risk

Our exposure to potential concentrations of credit risk results primarily from our energy marketing and price risk management activities and sales of gas and oil production. Presented below is a summary of our gross credit exposure as of June 30, 2007, for these activities. Our gross credit exposure for each counterparty is calculated as outstanding receivables plus any unrealized on or off-balance sheet exposure, taking into account contractual netting rights. Gross credit exposure is calculated prior to the application of collateral.

	Gross Credit Exposure	Credit Collateral	Net Credit Exposure
		(millions)	
Investment grade[1]	$ 660	$ 1	$ 659
Non-investment grade[2]	44		44
No external ratings:			
Internally rated - investment grade[3]	182		182
Internally rated - non-investment grade[4]	127	4	123

Total	$ 1,013	$ 5	$ 1,008

(1) Designations as investment grade are based upon minimum credit ratings assigned by Moody s Investors Service (Moody s) and Standard & Poor s Ratings Services. The five largest counterparty exposures, combined, for this category represented approximately 21% of the total net credit exposure.
(2) The five largest counterparty exposures, combined, for this category represented approximately 3% of the total net credit exposure.
(3) The five largest counterparty exposures, combined, for this category represented approximately 12% of the total net credit exposure.
(4) The five largest counterparty exposures, combined, for this category represented approximately 4% of the total net credit exposure.

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Investing Cash Flows

Significant cash flows used in investing activities for the six months ended June 30, 2007, included:

- $1.4 billion of capital expenditures for the purchase and development of gas and oil producing properties, drilling and equipment costs and undeveloped lease acquisitions;
- $947 million of capital expenditures, including environmental upgrades, routine capital improvements, purchase of nuclear fuel, and construction and improvements of gas and electric transmission and distribution assets; and
- $520 million for purchases of securities held as investments in our nuclear decommissioning trusts.

Cash flows used in investing activities for the six months ended June 30, 2007, were partially offset by:

- $481 million of proceeds from sales of securities held as investments in our nuclear decommissioning trusts;
- $448 million of net proceeds from the sale of our Canadian E&P operations; and
- $254 million of net proceeds from the sale of the Peaker facilities.

Financing Cash Flows and Liquidity

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

Significant financing activities for the six months ended June 30, 2007 included:

- $935 million for the repayment of long-term debt;
- $497 million of common dividend payments; and
- $117 million for the repurchase of common stock; partially offset by
- $600 million from the issuance of long-term debt;
- $413 million from the net issuance of short-term debt; and

$116 million from the issuance of common stock.

See Note 16 to our Consolidated Financial Statements for further information regarding our credit facilities, liquidity and significant financing transactions, including our debt and equity tender offers.

Credit Ratings and Debt Covenants

Credit ratings are intended to provide banks and capital market participants with a framework for comparing the credit quality of securities and are not a recommendation to buy, sell or hold securities. In the *Credit Ratings* and *Debt Covenants* sections of MD&A in our Annual Report on Form 10-K for the year ended December 31, 2006, we discussed the use of capital markets by Virginia Power, CNG and us (the Dominion Companies), as well as the impact of credit ratings on the accessibility and costs of using these markets. In addition, these sections of MD&A discussed various covenants present in the enabling agreements underlying the Dominion Companies debt. As a result of the merger of CNG with Dominion, all of CNG s former rights and obligations under its indentures have been assumed by Dominion. Subsequent to the merger, Moody s lowered its rating of CNG Senior Unsecured debt from Baa1 to Baa2 to equal their rating of Dominion s Senior Unsecured debt. As of June 30, 2007, there have been no changes to or events of default under the Dominion Companies debt covenants.

Future Cash Payments for Contractual Obligations

As of June 30, 2007, there have been no material changes outside the ordinary course of business to the contractual obligations disclosed in MD&A in our Annual Report on Form 10-K for the year ended December 31, 2006, with the exception of the following.

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In connection with the sales of our non-Appalachian E&P operations, the purchasers will indemnify us and assume our contractual obligations associated with these operations. Following the completion of the sales of our non-Appalachian E&P operations, our contractual obligations at December 31, 2006 will be reduced as follows:

	Less than 1 year	1-3 years	3-5 years (millions)	More than 5 years	Total
Total cash payments	$ 7,017	$ 6,459	$ 5,418	$ 23,682	$ 42,576
Less: non-Appalachian E&P operations	(218)	(148)	(79)	(71)	(516)
Total cash payments as adjusted at December 31, 2006	$ 6,799	$ 6,311	$ 5,339	$ 23,611	$ 42,060

Planned Capital Expenditures

In connection with the sales of our non-Appalachian E&P operations, our planned capital expenditures for 2008 have been reduced to $2.4 billion from approximately $4.6 billion, as shown in MD&A in our Annual Report on Form 10-K for the year ended December 31, 2006.

Use of Off-Balance Sheet Arrangements

As of June 30, 2007, there have been no material changes in the off-balance sheet arrangements disclosed in MD&A in our Annual Report on Form 10-K for the year ended December 31, 2006.

Following the sale of our offshore E&P operations in July 2007, Eni has indemnified us and assumed our post-closing obligations under the off-balance sheet arrangements related to the Thunder Hawk facility and an ultra-deepwater drilling rig discussed in MD&A in our Annual Report on Form 10-K for the year ended December 31, 2006.

Future Issues and Other Matters

The following discussion of future issues and other information includes current developments of previously disclosed matters and new issues arising during the period covered by and subsequent to our Consolidated Financial Statements. This section should be read in conjunction with *Future Issues and Other Matters* in our Annual Report on Form 10-K for the year ended December 31, 2006 and our Quarterly Report on Form 10-Q for the quarter ended March 31, 2007.

Regulatory Approval of Sale of Peoples and Hope

In March 2006, Peoples and Equitable Resources, Inc. (Equitable) filed a joint petition with the Pennsylvania Public Utility Commission (Pennsylvania Commission) seeking approval of the purchase by Equitable of all of the stock of Peoples and Hope. In April 2006, Hope and Equitable filed a joint petition seeking West Virginia Public Service Commission (West Virginia Commission) approval of the purchase by Equitable of all of the stock of Hope. In April 2007, the Pennsylvania Commission approved a joint settlement approving the sale in Pennsylvania. Following the approval of the sale of Peoples by the Pennsylvania Commission, the Federal Trade Commission (FTC) filed an action in federal court seeking to block the transaction. Such action was denied and the case is currently on appeal by the FTC in the 3rd U.S. Circuit Court of Appeals. A decision in such case is expected by October 2007. In West Virginia, the regulatory process had been delayed by the West Virginia Commission s decision to include certain gas purchasing practices in its examination of the sale. However, in July 2007, the West Virginia Commission ordered that the matter of the acquisition of Hope by Equitable and the matter related to certain gas purchasing practices of Hope be separated allowing the West Virginia Commission to move forward with its review of the sale. Dominion and Equitable have extended the agreement to sell at least until September 1, 2007. The parties also agreed to further extend the termination date of the sale until November 1, 2007, if they are able to reach an agreement to close the sale of Peoples earlier than the sale of Hope.

Virginia Fuel Expenses

In April 2007, we filed our Virginia fuel factor application with the Virginia Commission, requesting an increase in our Virginia fuel factor from 1.891¢ per kilowatt hour (kWh) to 2.232¢ per kWh, an increase of $219 million. The application established a need for an annual increase in fuel expense recovery for the period July 1, 2007 through June 30, 2008 of approximately $662 million. However, under the 2007 amendments to the fuel cost recovery statute, the requested increase as of July 1, 2007 was limited to an amount that results in the residential customer class not receiving an increase of more than 4% of total rates in effect as of June 30, 2007. The percentage increase for individual residential customers, and for other customer classes, depended on their current rates and respective usage. The 4% limitation to the residential class limited the fuel factor increase for Virginia jurisdictional customers to approximately $219 million, effective July 1, 2007; the balance of approximately $443 million will be deferred and subsequently recovered, without interest, during the period commencing July 1, 2008 and ending June 30, 2011. As a result of these changes, deferred fuel accounting will be applied for the over and under recovery of fuel costs. The Virginia Commission held a public hearing on June 19, 2007 and, on June 26, 2007, entered an order approving the requested increase effective July 1, 2007.

Disposition of Non-Appalachian E&P Operations

In November 2006, we announced our decision to pursue the disposition of our non-Appalachian E&P operations and assets. At December 31, 2006, our non-Appalachian natural gas and oil assets included about 5.5 Tcfe of proved reserves. The Appalachian assets that we will retain constituted approximately 15% of our total reserves at December 31, 2006.

We have sold or entered into agreements to sell the following E&P operations:

- On June 26, 2007, we completed the sale of our Canadian E&P operations to Paramount Energy Trust and Baytex Energy Trust for approximately $624 million, subject to post-closing adjustments. These operations included approximately 267 bcfe of proved reserves in western Canada at December 31, 2006.

- On July 2, 2007, we completed the sale to Eni of substantially all of our offshore E&P operations for approximately $4.73 billion, subject to post-closing adjustments. Our offshore operations included approximately 967 bcfe of proved natural gas and oil reserves in the outer continental shelf and deepwater areas of the Gulf of Mexico at December 31, 2006. Of this total, approximately 961 bcfe were sold to Eni. Remaining offshore E&P operations were disposed of in a separate transaction at the end of June 2007.

- On July 31, 2007, we completed the sale of our E&P operations in the Alabama, Michigan and Permian basins to a subsidiary of Loews Corporation for approximately $4 billion, subject to post-closing adjustments. These operations included approximately 2.5 Tcfe of proved reserves at December 31, 2006.

- On July 31, 2007, we completed the sale of our E&P operations in the Gulf Coast, Rockies, South Louisiana and San Juan basin of New Mexico to XTO Energy Inc. for approximately $2.5 billion, subject to post-closing adjustments. These operations included approximately 1 Tcfe of proved reserves at December 31, 2006.

- In June 2007, we reached an agreement to sell our E&P operations in the Mid-Continent basin to Linn Energy, LLC for approximately $2.05 billion. The transaction is expected to close by the end of the third quarter of 2007, subject to customary closing conditions and adjustments. These operations included approximately 780 bcfe of proved reserves at December 31, 2006.

With the announcement of the Mid-Continent sale in July, we have now sold or agreed to sell all of the E&P operations that we plan to divest. We have previously announced our intention to use the after-tax proceeds from these dispositions to reduce our outstanding debt by between $3.2 billion to $3.5 billion and to use the remaining net proceeds for repurchasing shares of our common stock.

Transmission Expansion Plan

Each year, as part of PJM s Regional Transmission Expansion Plan (RTEP) process, reliability projects are authorized. In June 2006, PJM, through the RTEP process, authorized construction of numerous electric transmission upgrades through 2011. We are involved in two of the major construction projects. The first project is an approximately 270-mile 500-kilovolt (kV) transmission line from southwestern Pennsylvania to northern Virginia, of which we will construct approximately 65 miles in Virginia and a subsidiary of Allegheny Energy, Inc. will construct the remainder. The second project is an approximately 60 mile 500 kV transmission line that we will construct in southeastern Virginia. These transmission upgrades are designed to improve the reliability of service to our customers and the region. The siting and construction of these transmission lines will be subject to applicable state and federal permits and approvals. In April 2007, we filed an application with the Virginia Commission requesting approval of the proposed construction of the 65-mile transmission line in northern Virginia. In May 2007, we filed an application with the Virginia Commission requesting approval of the proposed construction of the 60-mile transmission line in southeastern Virginia.

Generation Expansion

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

In July 2007 we filed an application with the Virginia Commission requesting approval to construct and operate a 585 Mw (nominal) carbon capture compatible, clean coal powered electric generation facility to be located in Wise County, Virginia. We also requested approval to continue to accrue allowance for funds used during construction (AFUDC) until capped rates end and, beginning January 1, 2009, current recovery of financing costs including a return on common equity of 11.75% together with a 200 basis point enhancement through a rate adjustment clause. Pending regulatory approval and necessary permits, the facility is expected to be in operation by 2012 at an estimated cost of approximately $1.6 billion, at that time.

Impairment Relating to Dresden Generating Facility

As part of our ongoing strategic asset review to improve our return on invested capital, we began the process of exploring the sale of Dresden in May 2007. Non-binding indicative bids for this partially completed 580 Mw combined-cycle gas-powered generating plant were received in late June 2007. Based on our evaluation of these bids, we believe that it is likely that Dresden will be sold rather than completed. This change in intended use caused us to evaluate whether we could recover the carrying amount of our investment in Dresden. As a result of such evaluation, for the quarter ended June 30, 2007, we recorded an impairment charge of $387 million ($252 million after-tax). In August 2007, we reached an agreement to sell Dresden to AEP for approximately $85 million. The transaction is expected to close by the end of the third quarter of 2007, subject to customary closing conditions and adjustments.

PJM Rate Design

In May 2005, the Federal Energy Regulatory Commission (FERC) issued an order finding that PJM s existing transmission service rate design may not be just and reasonable, and ordered an investigation and hearings into the matter. In April 2007, FERC reaffirmed PJM s existing transmission service rate design. FERC also determined that the costs of new, PJM-planned transmission facilities that operate at or above 500 kV will be allocated on a PJM region-wide basis, while the costs of new, PJM-planned facilities that operate below 500 kV will be assigned to zones within the PJM region based on a new model to be developed in further proceedings. Settlement discussions among stakeholders in the PJM region are underway, which may address these cost allocations. We cannot predict how the cost of the facilities below 500 kV will be allocated, or whether the FERC decision will be modified upon rehearing or appeal.

Collective Bargaining Agreement

Virginia Power and the International Brotherhood of Electrical Workers, Local 50 (Local 50), have reached an agreement for a six-year collective bargaining agreement expiring March 31, 2013. Local 50 represents approximately 3,200 Virginia Power employees in Virginia, North Carolina and the Mount Storm Power Station in West Virginia.

Ohio Rate Case

During the second quarter of 2007, The East Ohio Gas Company (East Ohio) made the decision to file a base rate case in the third quarter of 2007. In this rate case, East Ohio will request approval of an increase in operating revenues of over $73 million to provide a rate of return on rate base of 8.59%, which includes a 12% return on common equity. As part of its request, East Ohio is proposing to install automated meter reading devices for all of its 1.2 million customers over a 5-year period and to spend up to an additional $5.5 million per year over a three-year period on demand side management programs if the Public Utilities Commission of Ohio (Ohio Commission) approves a decoupling mechanism that would automatically adjust base rates in order to maintain base rate revenues per customer at the level approved in the rate case. In addition, East Ohio is proposing to expand its gross receipts tax rider to apply to all amounts billed, rather than just gas costs, thereby excluding gross receipts tax from base rates.

East Ohio s formal notice of intent to file an application to increase rates was filed at the Ohio Commission on July 20, 2007. The application detailing the proposed changes will be filed after August 20, 2007.

Environmental Matters

In April 2007, the U.S. Supreme Court ruled that the Environmental Protection Agency (EPA) has the authority to regulate greenhouse gas emissions under the Clean Air Act which could result in future EPA action. In June 2007, the President announced U.S. support for an effort to develop a new post-2012 framework on climate change involving the top 10 to 15 greenhouse gas emitting countries that would focus on establishing a long-term global goal to reduce greenhouse gas emissions with each country establishing its own mid-term targets and programs. Although we expect federal legislative or regulatory action on the regulation of greenhouse gas emissions in the future, the outcome in terms of specific requirements and timing is uncertain, and we cannot predict the financial impact on our operations at this time.

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Clean Air Act Compliance

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

Clean Water Act Compliance

In July 2004, the EPA published regulations that govern existing utilities that employ a cooling water intake structure and that have flow levels exceeding a minimum threshold. The EPA s rule presents several compliance options. We have been evaluating information from certain of our existing power stations and had expected to spend approximately $8 million over the next two years conducting studies and technical evaluations. However, in January 2007, the U.S. Court of Appeals for the Second Circuit issued a decision on an appeal of the regulations, remanding the rule to the EPA. On July 9, 2007, the EPA suspended the regulations pending further rulemaking consistent with the decision issued by the U.S. Court of Appeals for the Second Circuit. We cannot predict the outcome of the EPA regulatory process or determine with any certainty what specific controls may be required.

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DOMINION RESOURCES, INC.

ITEM 3. QUANTITATIVE AND QUALITATIVE

DISCLOSURES ABOUT MARKET RISK

The matters discussed in this Item may contain forward-looking statements as described in the introductory paragraphs under Part I, Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations of this Form 10-Q. The reader s attention is directed to those paragraphs for discussion of various risks and uncertainties that may affect our future.

Market Risk Sensitive Instruments and Risk Management

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

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

Commodity Price Risk

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

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

A hypothetical 10% unfavorable change in market prices for our non-trading commodity-based financial derivative instruments would have resulted in a decrease in fair value of approximately $342 million and $597 million as of June 30, 2007 and December 31, 2006, respectively. The decrease is primarily due to the execution of offsetting derivatives related to the divestiture of the majority of our E&P business. A hypothetical 10% unfavorable change in commodity prices would have resulted in a decrease of approximately $4 million and $3 million in the fair value of our commodity-based financial derivative instruments held for trading purposes as of June 30, 2007 and December 31, 2006, respectively.

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

Foreign Currency Exchange Risk

We manage our foreign currency exchange risk exposure associated with anticipated future purchases of nuclear fuel processing services denominated in foreign currencies by utilizing currency forward contracts. As a result of holding these contracts as hedges, our exposure to foreign currency risk is minimal. A hypothetical 10% decrease in relevant foreign exchange rates would have resulted in a decrease of approximately $1 million and $3 million in the fair value of currency forward contracts held by us at June 30, 2007 and December 31, 2006, respectively.

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Interest Rate Risk

We manage our interest rate risk exposure predominantly by maintaining a balance of fixed and variable rate debt. We also enter into interest rate sensitive derivatives, including interest rate swaps and interest rate lock agreements. For financial instruments outstanding at June 30, 2007, a hypothetical 10% increase in market interest rates would have resulted in a decrease in annual earnings of approximately $26 million. A hypothetical 10% increase in market interest rates, as determined at December 31, 2006, would have resulted in a decrease in annual earnings of approximately $25 million.

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

Investment Price Risk

We are subject to investment price risk due to marketable securities held as investments in decommissioning trust funds. These marketable securities are managed by third-party investment managers and are reported in our Consolidated Balance Sheets at fair value. We recognized net realized gains (including investment income) on nuclear decommissioning trust investments of $37 million and $41 million for the six months ended June 30, 2007 and 2006, respectively, and $63 million for the year ended December 31, 2006. We recorded, in AOCI, gross unrealized gains on these investments of $50 million for the six months ended June 30, 2007, and net unrealized losses on these investments of $18 million for the six months ended June 30, 2006. For the year ended December 31, 2006, we recorded, in AOCI, gross unrealized gains on these investments of $194 million.

Following the reapplication of SFAS No. 71 to the Virginia jurisdiction of our utility generation operations, gains or losses on those decommissioning trust investments are deferred as regulatory liabilities or regulatory assets, respectively.

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.

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.

In December 2006 and January 2007, we submitted self-disclosure notifications to EPA Region 8 regarding three E&P facilities in Utah that have potentially violated Clean Air Act permitting requirements. A draft Consent Decree (CD) is currently being negotiated with EPA and the U. S. Department of Justice. Management believes that the ultimate resolution of the CD will not have a material effect on the Company.

In March 2006, Peoples and Equitable filed a joint petition with the Pennsylvania Commission seeking approval of the purchase by Equitable of all of the stock of Peoples and Hope. In April 2006, Hope and Equitable filed a joint petition seeking West Virginia Commission approval of the purchase by Equitable of all of the stock of Hope. In April 2007, the Pennsylvania Commission approved a joint settlement approving the sale in Pennsylvania. Following the approval of the sale of Peoples by the Pennsylvania Commission, the FTC filed an action in federal court seeking to block the transaction. Such action was denied and the case is currently on appeal by the FTC in the 3rd U.S. Circuit Court of Appeals. A decision in such case is expected by October 2007. In West Virginia, the regulatory process had been delayed by the West Virginia Commission s decision to include certain gas purchasing practices in its examination of the sale. However, in July 2007, the West Virginia Commission ordered that the matter of the acquisition of Hope by Equitable and the matter related to certain gas purchasing practices of Hope be bifurcated allowing the West Virginia Commission to move forward with its review of the sale. Dominion and Equitable have extended the agreement to sell at least until September 1, 2007. The parties also agreed to further extend the termination date of the sale until November 1, 2007 if they are able to reach an agreement to close the sale of Peoples earlier than the sale of Hope.

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ITEM 1A. RISK FACTORS

Our business is influenced by many factors that are difficult to predict, involve uncertainties that may materially affect actual results and are often beyond our control. We have identified a number of these risk factors in our Annual Report on Form 10-K for the year ended December 31, 2006 and our Quarterly Report on Form 10-Q for the quarter ended March 31, 2007, which factors should be taken into consideration when reviewing the information contained in this report. With the exception of the risk factors below, there have been no material changes with regard to the risk factors previously disclosed in our most recent Form 10-K and our Quarterly Report on Form 10-Q for the quarter ended March 31, 2007. For other factors that may cause actual results to differ materially from those indicated in any forward-looking statement or projection contained in this report, see *Forward-Looking Statements* in MD&A.

We are exposed to cost-recovery shortfalls because of capped base rates in effect in Virginia for our regulated electric utility. Under the 1999 Virginia Restructuring Act (Restructuring Act), as amended in 2007, our base rates remain capped through December 31, 2008 unless sooner modified or terminated. Although the Restructuring Act allows for the recovery of certain generation-related costs during the capped rates period, we remain exposed to risks of cost-recovery shortfalls, such as costs related to hurricanes or other unanticipated events.

Our E&P business is affected by 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, but are not limited to: 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, our ability to acquire additional land positions in competitive lease areas, operational risks that could disrupt production and geological and other uncertainties inherent in the estimate of gas and oil reserves.

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.

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. In July 2007, we completed the sale of substantially all of our offshore E&P operations for approximately $4.73 billion. We also completed the sale of our E&P operations in the Alabama, Michigan and Permian basins for approximately $4 billion and the sale of our E&P operations in the Gulf Coast, Rockies, South Louisiana and San Juan Basin of New Mexico for approximately $2.5 billion. Additionally, we have sold or entered into agreements to sell the remainder of our non-Appalachian E&P operations. We expect that the sale of most of our E&P assets will reduce future earnings in the near term. While our management believes it will be able to execute the remaining sale in the third quarter of 2007, we may not be able to sell our E&P assets within the expected time frame and we cannot be certain of the impact that such sales and the use of proceeds from such sales will have on our results of operations. Additionally, we may also incur significant costs or be required to record certain charges in connection with the sales and in connection with transactions related to the deployment of the proceeds from such sales.

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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
4/1/07-4/30/07	30,617	$90.36	N/A	15,738,572 shares/ $1.23 billion
5/1/07-5/31/07	843,632	85.62[2]	813,498	14,925,074 shares/ $1.18 billion
6/1/07-6/30/07	1,400,093	83.68	1,400,000	31,525,074 shares/ $3.07 billion[3]
Total	2,274,342	$84.49	2,213,498	31,525,074 shares/ $3.07 billion

(1) Amount includes registered shares tendered by employees to satisfy tax withholding obligations on vested restricted stock.
(2) Includes shares repurchased under a prepaid accelerated share repurchase agreement as discussed in Note 16 to our Consolidated Financial Statements. The average price attributable to these shares reflects our prepayment of $500 million divided by total shares received of 5,849,926.
(3) In June 2007, our Board of Directors increased our existing common stock repurchase authorization by 18 million shares with the aggregate purchase amount not to exceed $2 billion, as discussed in Note 16 to our Consolidated Financial Statements.

In addition to the table above, in July 2007, we launched an equity tender offer approved by our Board of Directors, which is discussed in Note 16 to our Consolidated Financial Statements.

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

A summary of matters voted upon at our Annual Shareholders Meeting that was held on April 27, 2007 are listed below:

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

Deloitte & Touche LLP was ratified as our independent auditor for 2007;

Shareholders did not approve the following:

A proposal requesting a report to shareholders on how we are responding to regulatory and public pressure to reduce carbon dioxide and other emissions; and

A proposal requesting that the Board prepare a report evaluating the environmental, health and cultural impacts created by utilizing a National Interest Electric Transmission Corridor, and how those impacts would differ if a power line were constructed without such utilization.

See our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2007 for detailed voting results.

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ITEM 6. EXHIBITS

(a) Exhibits:

2	Agreement and Plan of Merger, dated as of June 27, 2007 by and among Dominion Resources, Inc. and Consolidated Natural Gas Company (Exhibit 2, Form 8-K filed July 3, 2007, File No. 1-8489).
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	Amended and Restated Bylaws effective on June 20, 2007 (Exhibit 3.1, Form 8-K filed June 22, 2007, File No. 1-8489, incorporated by reference).
4.1	Dominion Resources, Inc. agrees to furnish to the Securities and Exchange Commission upon request any other instrument with respect to long-term debt as to which the total amount of securities authorized does not exceed 10% of its total consolidated assets.
4.2	Indenture, dated as of May 1, 1971, between Consolidated Natural Gas Company and The Bank of New York (as successor trustee to JP Morgan Chase Bank (formerly The Chase Manhattan Bank and Manufacturers Hanover Trust Company)) (Exhibit (5) to Certificate of Notification at Commission File No. 70-5012, incorporated by reference); Fifteenth Supplemental Indenture dated as of October 1, 1989 (Exhibit (5) to Certificate of Notification at Commission File No. 70-7651, incorporated by reference); Seventeenth Supplemental Indenture dated as of August 1, 1993 (Exhibit (4) to Certificate of Notification at Commission File No. 70-8167, incorporated by reference); Eighteenth Supplemental Indenture dated as of December 1, 1993 (Exhibit (4) to Certificate of Notification at Commission File No. 70-8167, incorporated by reference); Nineteenth Supplemental Indenture dated as of January 28, 2000 (Exhibit (4A)(iii), Form 10-K for the fiscal year ended December 31, 1999, File No. 1-3196, incorporated by reference); Twentieth Supplemental Indenture dated as of March 19, 2001 (Exhibit 4.1, Form 10-Q for the quarter ended September 30, 2003, File No. 1-3196, incorporated by reference); Twenty-First Supplemental Indenture dated as of June 27, 2007 (Exhibit 4.2, Form 8-K filed July 3, 2007, File No. 1-8489, incorporated by reference).
4.3	Indenture, dated as of April 1, 1995, between Consolidated Natural Gas Company and The Bank of New York (as successor trustee to United States Trust Company of New York) (Exhibit (4) to Certificate of Notification at Commission File No. 70-8107); First Supplemental Indenture dated January 28, 2000 (Exhibit (4A)(ii), Form 10-K for the fiscal year ended December 31, 1999, File No. 1-3196, incorporated by reference); Securities Resolution No. 1 effective as of April 12, 1995 (Exhibit 2 to Form 8-A filed April 21, 1995 under File No. 1-3196 and relating to the 7 $^{3}/8$% Debentures Due April 1, 2005); Securities Resolution No. 2 effective as of October 16, 1996 (Exhibit 2 to Form 8-A filed October 18, 1996 under file No. 1-3196 and relating to the 6 $^{7}/8$% Debentures Due October 15, 2006); Securities Resolution No. 3 effective as of December 10, 1996 (Exhibit 2 to Form 8-A filed December 12, 1996 under file No. 1-3196 and relating to the 6 $^{5}/8$% Debentures Due December 1, 2008); Securities Resolution No. 4 effective as of December 9, 1997 (Exhibit 2 to Form 8-A filed December 12, 1997 under file No. 1-3196 and relating to the 6.80% Debentures Due December 15, 2027); Securities Resolution No. 5 effective as of October 20, 1998 (Exhibit 2 to Form 8-A filed October 22, 1998 under file No. 1-3196 and relating to the 6% Debentures Due October 15, 2010); Securities Resolution No. 6 effective as of September 21, 1999 (Exhibit 4A(iv), Form 10-K for the fiscal year ended December 31, 1999, File No. 1-3196, and relating to the 7 $^{1}/4$% Notes Due October 1, 2004, incorporated by reference); Second Supplemental Indenture, dated as of June 27, 2007 (Exhibit 4.4, Form 8-K filed July 3, 2007, File No. 1-8489, incorporated by reference).
4.4	Indenture, dated April 1, 2001, between Consolidated Natural Gas Company and The Bank of New York (as successor trustee to Bank One Trust Company, National Association) (Exhibit 4.1, Form S-3 File No. 333-52602, as filed on December 22, 2000 incorporated by reference); as supplemented by the Form of First Supplemental Indenture, dated April 1, 2001 (Exhibit 4.2, Form 8-K, File dated April 12, 2001, File No. 1-3196 incorporated by reference); Second Supplemental Indenture, dated October 25, 2001 (Exhibit 4.1, Form 8-K, dated October 23, 2001, File No. 1-3196, incorporated by reference); Third Supplemental Indenture, dated October 25, 2001 (Exhibit 4.3, Form 8-K, dated October 23, 2001, File No. 1-3196, incorporated by reference); Fourth Supplemental Indenture, dated May 1, 2002 (Exhibit 4.4, Form 8-K, dated May 22, 2002, Form 1-3196, incorporated by reference); Form of Fifth Supplemental Indenture (Exhibit 4.2, Form 8-K filed November 25, 2003, File No. 1-3196, incorporated by reference); Form of Sixth Supplemental Indenture (Exhibit 4.2, Form 8-K filed November 16, 2004, File No. 1-3196, incorporated by reference); Seventh Supplemental Indenture, dated as of June 27, 2007 (Exhibit 4.6, Form 8-K , as filed July 3, 2007, File No. 1-8489, incorporated by reference).

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4.5	Form of Indenture for Junior Subordinated Debentures, dated October 1, 2001, between Consolidated Natural Gas Company and The Bank of New York (as successor trustee to Bank One Trust Company, National Association) (Exhibit 4.2, Form S-3 Registration No. 333-52602, as filed on December 22, 2000, incorporated by reference); as supplemented by the First Supplemental Indenture, dated October 23, 2001 (Exhibit 4.7, Form 8-K, dated October 16, 2001, File No. 1-3196, incorporated by reference); and Second Supplemental Indenture dated as of June 27, 2007 (Exhibit 4.8, Form 8-K as filed July 3, 2007, File No. 1-8489, incorporated by reference).
4.6	Form of Senior Indenture, dated as of June 1, 1998, between Virginia Electric and Power Company and The Bank of New York (as successor trustee to JP Morgan Chase Bank (formerly The Chase Manhattan Bank)) as supplemented by the First Supplemental Indenture (Exhibit 4.2, Form 8-K, dated June 12, 1998, File No. 1-2255, incorporated by reference); Second Supplemental Indenture (Exhibit 4.2, Form 8-K, dated June 3, 1999, File No.1-2255, incorporated by reference); Third Supplemental Indenture (Exhibit 4.2, Form 8-K, dated October 27, 1999, File No. 1-2255, incorporated by reference); Form of Fourth Supplemental Indenture (Exhibit 4.2, Form 8-K, dated March 22, 2001, File No. 1-2255, incorporated by reference); and Form of Fifth Supplemental Indenture (Exhibit 4.3, Form 8-K, dated March 22, 2001, File No. 1-2255, incorporated by reference); Form of Sixth Supplemental Indenture (Exhibit 4.2, Form 8-K, dated January 24, 2002, incorporated by reference); Seventh Supplemental Indenture dated September 1, 2002 (Exhibit 4.4, Form 8-K filed September 11, 2002, File No. 1-2255, incorporated by reference); Form of Ninth Supplemental Indenture (Exhibit 4.2, Form 8-K filed December 4, 2003, File No. 1-2255, incorporated by reference); Form of Eighth Supplemental Indenture (Exhibit 4.2, Form 8-K filed February 27, 2003, File No. 1-2255, incorporated by reference); Form of Tenth Supplemental Indenture (Exhibit 4.3, Form 8-K filed December 4, 2003, File No. 1-2255, incorporated by reference); Form of Eleventh Supplemental Indenture (Exhibit 4.2, Form 8-K filed December 11, 2003, File No. 1-2255, incorporated by reference); Form of Twelfth Supplemental Indenture (Exhibit 4.2, Form 8-K filed January 12, 2006, File No. 1-2255, incorporated by reference); Form of Thirteenth Supplemental Indenture (Exhibit 4.3, Form 8-K filed January 12, 2006, File No. 1-2255, incorporated by reference); Form of Fourteenth Supplemental Indenture (Exhibit 4.2, Form 8-K filed May 16, 2007, File No. 1-2255, incorporated by reference).
10.1	Alabama/Permian Package Purchase Agreement between Dominion Resources, Inc., through certain of its wholly-owned subsidiaries and HighMount Exploration & Production LLC dated as of June 1, 2007 (Exhibit 99.1, Form 8-K filed June 7, 2007, File No. 1-8489, incorporated by reference).
10.2	Gulf Coast/Rockies/San Juan Package Purchase Agreement between Dominion Resources, Inc., through certain of its wholly-owned subsidiaries and XTO Energy, Inc. dated as of June 1, 2007 (Exhibit 99.2, Form 8-K filed June 7, 2007, File No. 1-8489, incorporated by reference).
10.3	Mid-Continent Onshore Package Purchase Agreement between Dominion Resources, Inc., through certain of its wholly-owned subsidiaries and Linn Energy, LLC dated June 29, 2007 (Exhibit 10, Form 8-K filed July 6, 2007, File No. 1-8489, incorporated by reference).
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).

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SIGNATURE

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

DOMINION RESOURCES, INC.

Registrant

August 8, 2007

/s/ Steven A. Rogers
Steven A. Rogers

Senior Vice President and Chief Accounting Officer