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

FORM 10-Q

(Mark One)

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES
EXCHANGE ACT OF 1934

For the quarterly period ended September 30, 2005

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 000-50039

OLD DOMINION ELECTRIC COOPERATIVE
(Exact Name of Registrant as Specified in Its Charter)

VIRGINIA
(State or Other Jurisdiction of
Incorporation or Organization)

23-7048405
(I.R.S. Employer
Identification No.)

4201 Dominion Boulevard, Glen Allen, Virginia
(Address of Principal Executive Offices)

23060
(Zip Code)

(804) 747-0592
(Registrant's Telephone Number, Including Area Code)

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 No

Indicate by check mark whether the Registrant is an accelerated filer (as defined in the Exchange Act of Rule 12b-2).
Yes No

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

The Registrant is a membership corporation and has no authorized or outstanding equity securities.

OLD DOMINION ELECTRIC COOPERATIVE

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OLD DOMINION ELECTRIC COOPERATIVE
PART 1. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS
CONDENSED CONSOLIDATED BALANCE SHEETS

	September 30, 2005	December 31, 2004
	(in thousands)	
ASSETS:		
Electric Plant:		
In service	\$ 1,518,309	\$ 1,511,848
Less accumulated depreciation	(462,113)	(431,678)
	1,056,196	1,080,170
Nuclear fuel, at amortized cost	6,250	10,493
Construction work in progress	17,311	10,832
Net Electric Plant	1,079,757	1,101,495
Investments:		
Nuclear decommissioning trust	78,500	75,917
Lease deposits	160,568	156,909
Other	30,698	17,694
Total Investments	269,766	250,520
Current Assets:		
Cash and cash equivalents	155,950	17,564
Deposits	42,447	-
Accounts receivable	19,626	9,438
Accounts receivable - members	72,055	62,402
Fuel, materials and supplies	25,257	29,153
Deferred energy	33,815	-
Prepayments	2,171	2,866
Total Current Assets	351,321	121,423
Deferred Charges:		
Regulatory assets	46,336	53,920
Other	62,596	22,980
Total Deferred Charges	108,932	76,900
Total Assets	\$ 1,809,776	\$ 1,550,338
CAPITALIZATION AND LIABILITIES:		
Capitalization:		
Patronage capital	\$ 268,565	\$ 259,724
Non-controlling interest	30,986	8,225
Long-term debt	855,149	852,910
Total Capitalization	1,154,700	1,120,859
Current Liabilities		
Long-term debt due within one year	22,917	22,917
Accounts payable	124,213	59,798
Accounts payable-members	66,019	38,655
Accounts payable-deposits	42,447	-
Accrued expenses	36,859	14,527
Deferred energy	-	4,807
Deferred taxes	13,970	-
Total Current Liabilities	306,425	140,704
Deferred Credits and Other Liabilities		
Asset retirement obligation	48,149	46,295
Obligations under long-term leases	163,351	159,902
Regulatory liabilities	98,384	41,782
Other	38,767	40,796
Total Deferred Credits and Other Liabilities	348,651	288,775
Commitments and Contingencies		
Total Capitalization and Liabilities	\$ 1,809,776	\$ 1,550,338

The accompanying notes are an integral part of the condensed consolidated financial statements.

OLD DOMINION ELECTRIC COOPERATIVE

**CONDENSED CONSOLIDATED STATEMENTS OF REVENUES,
EXPENSES AND PATRONAGE CAPITAL (UNAUDITED)**

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2005	2004	2005	2004
	(in thousands)		(in thousands)	
Operating Revenues	\$ 207,491	\$ 145,169	\$ 539,539	\$ 412,776
Operating Expenses:				
Fuel	62,754	25,700	112,539	67,300
Purchased power	118,171	92,194	325,908	239,730
Deferred energy	(22,144)	(7,360)	(38,622)	(14,797)
Operations and maintenance	9,190	2,817	25,614	23,538
Administrative and general	10,175	6,425	25,942	20,994
Depreciation, amortization and decommissioning	9,798	7,817	29,113	22,485
Amortization of regulatory asset/(liability), net	175	1,577	1,348	5,863
Taxes other than income taxes	1,562	1,390	4,724	3,809
Accretion	618	558	1,854	1,664
Total Operating Expenses	<u>190,299</u>	<u>131,118</u>	<u>488,420</u>	<u>370,586</u>
Operating Margin	<u>17,192</u>	<u>14,051</u>	<u>51,119</u>	<u>42,190</u>
Other (Expense)/Income, net	(76)	15	(202)	47
Investment Income	1,362	262	3,602	2,225
Interest Charges, net	<u>(14,717)</u>	<u>(11,517)</u>	<u>(44,033)</u>	<u>(35,700)</u>
Net Margin Before Income Taxes and Non-Controlling Interest	<u>3,761</u>	<u>2,811</u>	<u>10,486</u>	<u>8,762</u>
Income Taxes	(322)	-	(658)	-
Non-Controlling Interest	<u>(483)</u>	<u>-</u>	<u>(987)</u>	<u>-</u>
Net Margin	<u>2,956</u>	<u>2,811</u>	<u>8,841</u>	<u>8,762</u>
Patronage Capital - Beginning of Period	<u>265,609</u>	<u>253,541</u>	<u>259,724</u>	<u>247,590</u>
Patronage Capital - End of Period	<u>\$ 268,565</u>	<u>\$ 256,352</u>	<u>\$ 268,565</u>	<u>\$ 256,352</u>

OLD DOMINION ELECTRIC COOPERATIVE

**CONDENSED CONSOLIDATED STATEMENTS
OF COMPREHENSIVE INCOME (UNAUDITED)**

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2005	2004	2005	2004
	(in thousands)		(in thousands)	
Net Margin	\$ 2,956	\$ 2,811	\$ 8,841	\$ 8,762
Unrealized gain on derivative contracts ⁽¹⁾	14,712	-	21,850	-
Comprehensive Income	<u>\$ 17,668</u>	<u>\$ 2,811</u>	<u>\$ 30,691</u>	<u>\$ 8,762</u>

⁽¹⁾ Unrealized gain on derivative contracts net of tax expense of \$9.4 million for the three months ended September 30, 2005, and net of tax expense of \$14.0 million for the nine months ended September 30, 2005.

The accompanying notes are an integral part of the condensed consolidated financial statements.

OLD DOMINION ELECTRIC COOPERATIVE

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

	Nine Months Ended	
	September 30,	
	2005	2004
	(in thousands)	
Operating Activities:		
Net Margin	\$ 8,841	\$ 8,762
Adjustments to reconcile net margins to net cash provided by (used for) operating activities:		
Depreciation, amortization and decommissioning	29,113	22,485
Other non-cash charges	7,586	3,345
Non-controlling interest	987	-
Amortization of lease obligations	7,766	7,465
Interest on lease deposits	(7,453)	(7,148)
Change in current assets	(57,696)	(3,684)
Change in deferred energy	(38,622)	(14,797)
Change in current liabilities	156,558	(26,224)
Change in regulatory assets and liabilities	63,857	8,697
Deferred charges and credits	(3,830)	351
Net Cash Provided by (Used for) Operating Activities	<u>167,107</u>	<u>(748)</u>
Financing Activities:		
Obligations under long-term leases	<u>(523)</u>	<u>(529)</u>
Net Cash Used for Financing Activities	<u>(523)</u>	<u>(529)</u>
Investing Activities:		
Purchases of available for sale securities	(60,693)	(108,400)
Proceeds from sale of available for sale securities	45,000	155,901
Decrease (Increase) in other investments	435	(6,181)
Electric plant additions	<u>(12,940)</u>	<u>88</u>
Net Cash (Provided by) Used for Investing Activities	<u>(28,198)</u>	<u>41,408</u>
Net Change in Cash and Cash Equivalents	138,386	40,131
Cash and Cash Equivalents - Beginning of Period	<u>17,564</u>	<u>31,758</u>
Cash and Cash Equivalents - End of Period	<u>\$ 155,950</u>	<u>\$ 71,889</u>

The accompanying notes are an integral part of the condensed consolidated financial statements.

OLD DOMINION ELECTRIC COOPERATIVE

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

1. In the opinion of our management, the accompanying unaudited condensed consolidated financial statements contain all adjustments, which include only normal recurring adjustments, necessary for a fair statement of our consolidated financial position as of September 30, 2005, and our consolidated results of operations, comprehensive income, and cash flows for the three and nine months ended September 30, 2005 and 2004. The consolidated results of operations for the three and nine months ended September 30, 2005, are not necessarily indicative of the results to be expected for the entire year. These financial statements should be read in conjunction with the financial statements and notes thereto included in our 2004 Annual Report on Form 10-K filed with the Securities and Exchange Commission.
2. *Presentation.* The accompanying financial statements reflect the consolidated accounts of Old Dominion Electric Cooperative (“Old Dominion” or “we” or “our”) and TEC Trading, Inc. (“TEC”). We are a not-for-profit wholesale power supply cooperative, incorporated under the laws of the Commonwealth of Virginia in 1948. We have two classes of members. Our Class A members are twelve customer-owned electric distribution cooperatives engaged in the retail sale of power to member consumers located in Virginia, Delaware, Maryland, and parts of West Virginia. Our sole Class B member is TEC, a taxable corporation owned by our member distribution cooperatives. Our board of directors is composed of two representatives from each of the member distribution cooperatives and one representative from TEC.

TEC was formed in 2001 for the primary purpose of purchasing from us, to sell in the market, power that is not needed to meet the actual needs of our member distribution cooperatives, acquiring natural gas and forward purchase contracts to hedge the price of natural gas to supply our combustion turbine facilities, and taking advantage of other power-related trading opportunities in the market which will help lower our member distribution cooperatives’ costs. TEC does not engage in speculative trading. TEC is a taxable corporation and a provision for income taxes has been established based upon TEC’s pre-tax income using statutory tax rates of 35% for federal purposes and 4% for state purposes.

In accordance with Financial Accounting Standards Board (“FASB”) Interpretation No. 46R, “Consolidation of Variable Interest Entities, an Interpretation of Accounting Research Bulletin No. 51” (the “Interpretation”), TEC is considered a variable interest entity for which we are the primary beneficiary. We became the primary beneficiary of TEC in 2001. We first consolidated TEC’s financial position as of December 31, 2004, and beginning January 1, 2005, TEC’s operations were also consolidated as a result of our adoption of the Interpretation. We have eliminated all balances and transactions in consolidation. The assets and liabilities and non-controlling interest of TEC are recorded at carrying value and the net assets consolidated were \$37.7 million and \$10.2 million at September 30, 2005, and December 31, 2004, respectively. As TEC is 100% owned by our twelve member distribution cooperatives, its equity is presented as a non-controlling interest in our consolidated financial statements. Our non-controlling, 50% or less, ownership interest in other entities is recorded using the equity method of accounting.

Our rates are not regulated by the respective states’ public service commissions, but are set periodically by a formula that was accepted for filing by the Federal Energy Regulatory Commission (“FERC”) on December 23, 2003. An amendment to the formula was accepted for filing by FERC on February 19, 2005, subject to the outcome of our other pending FERC proceedings.

We comply with the Uniform System of Accounts as prescribed by FERC. In conformity with accounting principles generally accepted in the United States (“GAAP”), the accounting policies and practices applied by us in the determination of rates are also employed for financial reporting purposes.

The preparation of our consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported therein. Actual results could differ from those estimates.

3. *Financial Instruments (including Derivatives).* Financial instruments included in the decommissioning fund are classified as available for sale, and accordingly, are carried at fair value. Unrealized gains and losses on investments held in the decommissioning fund are deferred as a regulatory liability and a regulatory asset until realized.

Our investments in marketable securities, which are actively managed, are classified as available for sale and are recorded at fair value. Unrealized gains or losses on these investments, if material, are reflected as a component of capitalization. Investments in debt securities that we have the positive intent and ability to hold to maturity are classified as held to maturity and are recorded at amortized cost. Other investments are recorded at cost, which approximates market value.

We primarily purchase power under both long-term and short-term forward physical delivery contracts to supply power to our member distribution cooperatives under “all requirements” wholesale power contracts. These forward purchase contracts meet the accounting definition of a derivative; however, a majority of the forward purchase derivative contracts qualify for the normal purchases/normal sales exception under Statement of Financial Accounting Standards (“SFAS”) No. 133 “Accounting for Derivative Instruments and Hedging Activities.” As a result, these contracts are not recorded at fair value. We record a liability and purchased power expense when the power under the forward physical delivery contract is delivered. We also purchase natural gas futures generally for two years or less to hedge the price of natural gas for the operation of our combustion turbine facilities and for use as a basis in determining the price of power in certain forward power purchase agreements. These derivatives do not qualify for the normal purchases/normal sales exception.

For all derivative contracts that do not qualify for the normal purchases/normal sales accounting exception, we may elect cash flow hedge accounting in accordance with SFAS No. 133. Accordingly, gains and losses on derivative contracts are deferred into Other Comprehensive Income until the hedged underlying transaction occurs or is no longer likely to occur. For derivative contracts where hedge accounting is not utilized, or for which ineffectiveness exists, we defer all remaining gains and losses on a net basis as a regulatory asset or liability in accordance with SFAS No. 71 “Accounting for the Effects of Certain Types of Regulation.” These amounts are subsequently reclassified as purchased power or fuel expense in our Consolidated Statements of Revenues, Expenses, and Patronage Capital as the power or fuel is delivered and/or the contract settles.

Generally, derivatives are reported on the Consolidated Balance Sheet at fair value. The measurement of fair value is based on actively quoted market prices, if available. Otherwise, we seek indicative price information from external sources, including broker quotes and industry publications. For individual contracts, the use of differing assumptions could have a material effect on the contract’s estimated fair value. Hedge ineffectiveness was immaterial for the three and nine months ended September 30, 2005 and 2004.

We are exposed to credit risk in our business operations. We have adopted a Credit Risk Policy that establishes the basis for determining counterparty credit standards and processes to determine credit limits. Our risk management committee monitors credit exposure on a regular basis. Formal counterparty credit reviews are performed at least annually and informal reviews are performed on an ongoing basis. At September 30, 2005, due to significant increases in energy prices, our counterparties were required to post \$42.4 million in deposits in accordance with the terms of our respective master power purchase and sales agreements with them. We have separately shown these deposits in our balance sheet as deposits and accounts payable—deposits.

4. *Commitments and Contingencies.* See Note 15—Commitments and Contingencies to the Notes to the Consolidated Financial Statements in our 2004 Annual Report on Form 10-K.

On April 1, 2005, during the discovery phase of our litigation with Ragnar Benson, Inc. (“RBI”), RBI revised its claim from \$15.0 million to \$33.0 million. During the trial, which began on October 11, 2005, and concluded October 26, 2005, RBI further revised its claim from \$33.0 million to \$36.0 million. We have reviewed the asserted claims of RBI and believe they are without merit. We do not believe any liability is estimable or probable and we intend to vigorously defend these claims.

5. *New Accounting Pronouncement.* In March 2005, the FASB issued Interpretation No. 47 “Accounting for Conditional Asset Retirement Obligations, an Interpretation of FASB Statement No. 43” (“FIN 47”). FIN 47 is a further clarification of SFAS No. 143 “Accounting for Asset Retirement Obligations” and requires the establishment of a liability for conditional asset retirement obligations. A conditional asset retirement obligation is a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Uncertainty about the timing and/or method of settlement is required to be considered in the measurement of the liability when sufficient information exists. FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. FIN 47 is effective for us December 31, 2005. We are currently evaluating the impact that FIN 47 may have on our results of operations and financial condition.
6. *Reclassifications.* Certain reclassifications have been made to the prior year’s condensed consolidated financial statements to conform to the current year’s presentation.
7. *Subsequent Event.* On October 12, 2005, our Board of Directors approved an increase to our fuel factor adjustment rate, resulting in an increase to our total energy rate of approximately 8.1%, effective October 1, 2005. This increase was implemented due to continued rising energy costs.

OLD DOMINION ELECTRIC COOPERATIVE

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Caution Regarding Forward-Looking Statements

Management's Discussion and Analysis of Financial Condition and Results of Operations contains forward-looking statements regarding matters that could have an impact on our business, financial condition, and future operations. These statements, based on our expectations and estimates, are not guarantees of future performance and are subject to risks, uncertainties, and other factors that could cause actual results to differ materially from those expressed in the forward-looking statements. These risks, uncertainties, and other factors include, but are not limited to, general business conditions, increased competition in the electric utility industry, changes in our tax status, demand for energy, federal and state legislative and regulatory actions and legal and administrative proceedings, changes in and compliance with environmental laws and policies, weather conditions, the cost of commodities used in our industry, and unanticipated changes in operating expenses and capital expenditures. Our actual results may vary materially from those discussed in the forward-looking statements as a result of these and other factors. Any forward-looking statement speaks only as of the date on which the statement is made, and we undertake no obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which the statement is made even if new information becomes available or other events occur in the future.

Critical Accounting Policies

As of September 30, 2005, there have been no significant changes in our critical accounting policies as disclosed in our Annual Report on Form 10-K for the fiscal year ended December 31, 2004. These policies include the accounting for rate regulation, deferred energy, asset retirement obligations, derivative contracts and our margin stabilization plan.

Basis of Presentation

The accompanying financial statements reflect the consolidated accounts of Old Dominion Electric Cooperative ("Old Dominion" or "we" or "our") and TEC Trading, Inc. ("TEC") effective December 31, 2004. See Note 2—Notes to Condensed Consolidated Financial Statements in Part 1, Item 1.

Overview

Old Dominion is a not-for-profit power supply cooperative owned entirely by its twelve member distribution cooperatives and a thirteenth member, TEC. We supply our member distribution cooperatives' power requirements, consisting of capacity requirements and energy requirements through a portfolio of resources including generating facilities, power purchase contracts, and forward, short-term and spot market energy purchases.

The event having the most significant effect on our financial results for the nine months ended September 30, 2005, was a delay encountered by Virginia Electric and Power Company ("Virginia Power") in becoming a member of PJM Interconnection, LLC ("PJM") and the resulting postponement of the transfer of operational control of its transmission facilities to PJM. See "Other Information" in Part II, Item 5 of our Quarterly Report on Form 10-Q for the three-months ended March 31, 2005, for more information relating to the effects of Virginia Power's joining PJM.

In anticipation of Virginia Power's becoming a member of PJM on January 1, 2005, we purchased several forward energy contracts for delivery to the PJM control area beginning on that date for the purpose of serving the needs of our member distribution cooperatives on the Virginia mainland. Virginia Power did not join PJM and transfer operational control of its transmission facilities to PJM until May 1, 2005. Although we could have arranged for the energy under these forward energy contracts to be transmitted to our member distribution cooperatives, it was more economical to sell this energy to non-members and procure a similar amount of energy from other sources. As a result, our sales to non-members increased dramatically because we sold significant amounts of energy to the market that we had initially scheduled for delivery to the PJM control area. Relatedly, our purchased power expense also rose 35.9% for the nine months ended September 30, 2005, because we procured significant replacement energy outside of the PJM control area to serve these requirements.

Our non-member revenues also increased as a result of the consolidation of TEC Trading, Inc. (“TEC”), our sole Class B member, in accordance with Financial Accounting Standards Board Interpretation No. 46R, “Consolidation of Variable Interest Entities, an Interpretation of Accounting Research Bulletin No. 51 (“the Interpretation”). Under the Interpretation, revenues from sales by TEC are presented as non-member revenues effective January 1, 2005. Previously, our sales of energy to TEC were reflected as member revenues and TEC’s sales to third parties were not reflected in our financial statements.

Other factors impacting our financial results include changing conditions in the energy markets and increases in fuel costs, which have impacted our purchased power costs. Additionally, as a result of these increases, our derivative activity includes significant unrealized gains. Sales of energy to non-members increased as a result of our strategy to hedge a greater percentage of our exposure to spot market prices under purchasing arrangements. Also, our 2005 financial results were affected by the availability of our Marsh Run combustion turbine facility (“Marsh Run”) for commercial operation effective in September 2004. As a result, depreciation, amortization and decommissioning expense and fuel expense increased; and interest charges, net increased because we ceased capitalizing interest with respect to the facility.

Results of Operations

Operating Revenues

Our power sales are comprised of two power products – energy and capacity (also referred to as demand). Energy is the physical electricity delivered through transmission and distribution facilities to customers. We must have sufficient committed energy available to us for delivery to our member distribution cooperatives to meet their maximum energy needs at any time, with limited exceptions. This committed available energy at any time is referred to as capacity.

The rates we charge our member distribution cooperatives for sales of energy and capacity are determined by a formulary rate accepted by the Federal Energy Regulatory Commission (“FERC”), which is intended to permit collection of revenues which will equal the sum of:

- all of our costs and expenses;
- 20% of our total interest charges; and
- additional equity contributions approved by our board of directors.

The formulary rate has three components: a demand rate, a base energy rate and a fuel factor adjustment rate. The formulary rate identifies the cost components that we can collect through rates, but not the actual amounts to be collected. With limited exceptions, we can change our rates periodically to match the costs we have incurred and we expect to incur without seeking FERC approval.

Energy costs, which are primarily variable costs, such as nuclear, coal and natural gas fuel costs and the energy costs under our power purchase contracts with third parties, are recovered through two separate energy rates, the base energy rate and the fuel factor adjustment rate. The base energy rate is a fixed rate that requires FERC approval prior to adjustment. However, to the extent the base energy rate over- or under-collects all of our energy costs, we refund or collect the difference through a fuel factor adjustment rate. We review our energy costs at least every six months to determine whether the base energy rate and the current fuel factor adjustment rate together are adequately recovering our actual and anticipated energy costs, and revise the fuel factor adjustment rate accordingly. Because the fuel factor adjustment rate can be revised without FERC approval, we can effectively change our total energy rate to recover all of our energy costs without seeking the approval of FERC.

Capacity costs, which are primarily fixed costs, such as depreciation expense, interest expense, administrative and general expenses, capacity costs under power purchase contracts with third parties, transmission costs, and our margin requirements and additional amounts approved by our board of directors are recovered through our demand rate. The formulary rate allows us to change the actual demand rate we charge as our capacity-related costs change, without seeking FERC approval, with the exception of extraordinary deductions, and decommissioning cost, which is a fixed amount in the formulary rate that requires FERC approval prior to any adjustment. Our demand rate is revised automatically to recover the costs contained in our annual budget and any revisions made by our Board of Directors to our annual budget.

Our operating revenues are derived from power sales to our members and non-members. Sales to members include sales to our Class A members, which are our twelve member distribution cooperatives. Prior to January 1, 2005, sales to members also included sales to our single Class B member, TEC. We consolidated TEC’s financial position as of December 31, 2004, and beginning January 1, 2005, TEC’s operations were also consolidated as a result of the adoption of the Interpretation. Subsequent to

January 1, 2005, sales between Old Dominion and TEC have been eliminated from our financial statements. TEC's sales to third parties are reflected as non-member revenues. See Note 2—Notes to Condensed Consolidated Financial Statements in Part 1, Item 1. Our operating revenues by type of purchaser for the three and nine months ended September 30, 2005 and 2004, were as follows:

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2005	2004	2005	2004
	(in thousands)		(in thousands)	
Member revenues:				
Member distribution cooperatives	\$ 181,607	\$ 142,585	\$ 484,367	\$ 405,336
TEC	-	1,596	-	3,497
Total member revenues	181,607	144,181	484,367	408,833
Non-member revenues	25,884	988	55,172	3,943
Total revenues	\$ 207,491	\$ 145,169	\$ 539,539	\$ 412,776

Non-member revenues for 2005 include our sales to TEC of \$25.6 million and \$50.7 million for the three and nine months ended September 30, 2005, respectively. TEC is our sole Class B member, the sales of which are now recorded as non-member sales as a result of the consolidation of TEC. Non-member revenues for the three months ended September 30, 2005, are higher than the prior year as a result of an increase in the prices at which we sold excess energy to non-members and an increase in the volume of excess energy sales. Non-member revenues for the three and nine months ended September 30, 2005, are higher than the prior year as a result of increased sales of excess energy due to changes in our purchased power portfolio, differences between actual and forecasted energy needs, as well as changes in market conditions. Non-member revenues for the nine months ended September 30, 2005, also include increased sales of excess energy as a result of the delay of Virginia Power joining PJM from January 1, 2005, to May 1, 2005.

Our energy sales in megawatt hours (“MWh”) to our members and non-members for the three months and nine months ended September 30, 2005 and 2004, were as follows:

	Three Months Ended		Nine Months Ended	
	September 30,		September 30.	
	2005	2004	2005	2004
	(in MWh)		(in MWh)	
Member energy sales:				
Member distribution cooperatives	3,164,270	2,780,422	8,462,122	8,033,709
TEC	-	35,662	-	82,059
Total energy sales to members	3,164,270	2,816,084	8,462,122	8,115,768
Non-member energy sales	298,634	12,737	967,141	68,979
Total energy sales	3,462,904	2,828,821	9,429,263	8,184,747

Sales to Member Distribution Cooperatives. Revenues from sales to our member distribution cooperatives are a function of our formulary rate for sales of power to our member distribution cooperatives and our member distribution cooperatives' consumers' requirements for power. Operating revenues on our Condensed Consolidated Statements of Revenues, Expenses and Patronage Capital reflect the actual capacity-related costs we incurred plus the energy costs that we collected during the quarter. Estimated capacity-related costs are collected during the period through the demand component of our formulary rate. Under our formulary rate, we make adjustments for the refund or recovery of amounts under our Margin Stabilization Plan. We adjust demand revenues and accounts payable—members or accounts receivable—members each quarter to reflect these adjustments. See “Critical Accounting Policies—Margin Stabilization Plan” in Part II, Item 7 of our Annual Report on Form 10-K for the fiscal year ended December 31, 2004, for a discussion of our Margin Stabilization Plan.

Revenues from sales to our member distribution cooperatives by formulary rate component and average costs to our member distribution cooperatives in MWh for the three and nine months ended September 30, 2005 and 2004, were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
	(in thousands)		(in thousands)	
Revenues from sales to member distribution cooperatives:				
Base energy revenues	\$ 56,655	\$ 50,249	\$151,980	\$145,301
Fuel factor adjustment revenues	<u>67,503</u>	<u>39,301</u>	<u>165,512</u>	<u>101,358</u>
Total energy revenues	124,158	89,550	317,492	246,659
Demand (capacity) revenues	<u>57,449</u>	<u>53,035</u>	<u>166,875</u>	<u>158,677</u>
Total revenues from sales to member distribution cooperatives	<u>\$181,607</u>	<u>\$142,585</u>	<u>\$484,367</u>	<u>\$405,336</u>
Average costs to member distribution cooperatives (per MWh) ⁽¹⁾	\$ 57.39	\$ 51.28	\$ 57.24	\$ 50.45

⁽¹⁾ Our average costs to member distribution cooperatives are based on the blended cost of power.

Growth in the number of consumers and growth in consumers' requirements for power significantly affect our member distribution cooperatives' consumers' requirements for power. Factors affecting our member distribution cooperatives' consumers' requirements for power include the amount, size, and usage of electronics and machinery and the expansion of operations among their commercial and industrial customers. Weather also affects the requirement for electricity. Relatively higher or lower temperatures tend to increase the requirement for energy to use air conditioning and heating systems. Mild weather generally reduces the requirement because air conditioning and heating systems are operated less.

Three Months Ended September 30, 2005 compared to Three Months ended September 30, 2004:

Total revenues from sales to our member distribution cooperatives for the three months ended September 30, 2005, increased \$39.0 million, or 27.4%, over the same period in 2004, primarily as a result of higher energy rates, a 13.8% increase in energy sales volume and higher incurred capacity costs (which are reflected in revenues in the period in which they are expensed).

Our total energy rate (including our base energy rate and our fuel factor adjustment rate) was 21.8% higher during the three months ended September 30, 2005, as compared to the same period in 2004. We increased our fuel factor adjustment rate effective October 1, 2004, and April 1, 2005, resulting in an increase to our total energy rate of approximately 6.3% and 14.6%, respectively. These increases were implemented due to continued rising energy costs in 2004 and 2005 resulting in increased fuel and purchased power costs.

The capacity costs we incurred, and thus the capacity-related revenues we reflected pursuant to the formulary rate, for the three months ended September 30, 2005, as compared to the same period in 2004, increased \$4.4 million, or 8.3%, primarily as a result of legal fees which were previously capitalized and are now reflected in administrative and general expense associated with the litigation against Ragnar Benson, Inc., ("RBI") and slightly higher depreciation and interest expense because of the commercial operation of Marsh Run which began in September 2004. See "Interest Charges" for a discussion of interest expenses.

Our average costs to member distribution cooperatives per MWh increased \$6.11 per MWh, or 11.9%, for the three months ended September 30, 2005, as compared to the same period in 2004, primarily as a result of the increase in our total energy rates related to increased fuel and purchased power costs.

Nine Months Ended September 30, 2005 compared to Nine Months Ended September 30, 2004:

Total revenues from sales to our member distribution cooperatives for the nine months ended September 30, 2005, increased \$79.0 million, or 19.5%, as compared to the same period in 2004 primarily as a result of higher energy rates, a 5.3% increase in energy sales volume and slightly higher incurred capacity costs (which are reflected in revenues in the period in which they are expensed).

Our total energy rate (including our base energy rate and our fuel factor adjustment rate) was 22.2% higher during the nine months ended September 30, 2005, as compared to the same period in 2004. We increased our fuel factor adjustment rate effective October 1, 2004, and April 1, 2005, resulting in an increase to our total energy rate of approximately 6.3% and 14.6%, respectively. These increases were implemented due to higher than anticipated energy costs in 2004 and 2005 related to continued increased fuel and purchased power costs.

The capacity costs we incurred for the nine months ended September 30, 2005, as compared to the same period in 2004, increased \$8.2 million, or 5.2%, primarily as a result of slightly higher depreciation and interest expense because of the commercial operation of Marsh Run which began in September 2004 as well as legal fees which were previously capitalized and are now reflected in administrative and general expense associated with the litigation against RBI. For the nine months ended September 30, 2004, costs for Marsh Run, including interest, were being capitalized. See “Interest Charges” for a discussion of interest expenses.

Our average costs to member distribution cooperatives per MWh increased \$6.79 per MWh, or 13.5%, for the nine months ended September 30, 2005, as compared to the same period in 2004, primarily as a result of the increase in our total energy rates related to increased fuel and purchased power costs.

Sales to TEC. Beginning January 1, 2005, we reported no sales to TEC because TEC is now consolidated as a result of the adoption of the Interpretation. Sales between Old Dominion and TEC have been eliminated in consolidation and TEC’s sales to third parties are reflected as non-member revenues. See Note 2—Notes to Condensed Consolidated Financial Statements in Part 1, Item 1. Prior to January 1, 2005, sales to TEC consisted primarily of sales of excess energy that we did not need to meet the actual needs of our member distribution cooperatives. We sold the portion of this energy that could not be utilized by our member distribution cooperatives to TEC for resale into the market, or to non-members.

Sales to Non-Members. Sales to non-members consist of sales of excess purchased energy and sales of excess generated energy. We primarily sell excess purchased energy to PJM under its rates for providing energy imbalance services. Prior to May 1, 2005, we also sold excess energy from the Clover Power Station (“Clover”) to Virginia Power pursuant to the requirements of the Clover operating agreement. Beginning in 2005, TEC’s sales to third parties are also reflected as sales to non-members. Non-member revenue increased by \$24.9 million and \$51.2 million in the three and nine months ended September 30, 2005, respectively, over the same periods in 2004. The increase in non-member revenue for the three months ended September 30, 2005, is primarily due to an increase in the prices at which we sold excess energy to non-members and an increase in the volume of excess energy sales. The increase in non-member revenue for the three and nine months ended September 30, 2005, is primarily due to increased sales of excess energy. Excess energy, which is sold to third parties, is the result of changes in our purchased power portfolio, differences between actual and forecasted energy needs, as well as changes in market conditions. The increase in non-member sales in MWh is driven by our strategy to hedge a greater percentage of our exposure to spot market prices under purchasing arrangements. Additionally, sales to non-members for the nine months ended September 30, 2005, also include increased sales of excess energy as a result of the delay of Virginia Power joining PJM from January 1, 2005, to May 1, 2005.

Operating Expenses

We supply our member distribution cooperatives’ power requirements, consisting of capacity requirements and energy requirements, through (i) our owned or leased interests in electric generating facilities which consist of a 50% interest in Clover, an 11.6% interest in the North Anna Nuclear Power Station (“North Anna”), our Louisa combustion turbine facility (“Louisa”), Marsh Run, our Rock Springs combustion turbine facility (“Rock Springs”), and our distributed generation facilities, and (ii) power purchases from third parties through power purchase contracts and forward, short-term and spot market energy purchases. Our energy supply for the three and nine months ended September 30, 2005 and 2004, was as follows:

	Three Months Ended				Nine Months Ended			
	September 30,		September 30,		September 30,		September 30,	
	2005	2004	2005	2004	2005	2004	2005	2004
	(in MWh and percentages)				(in MWh and percentages)			
Generated:								
Clover	879,854	24.9 %	904,361	30.7 %	2,338,480	24.2 %	2,438,161	28.8 %
North Anna	457,806	13.0	421,587	14.3	1,389,300	14.4	1,263,297	14.9
Louisa	144,271	4.1	73,035	2.5	174,990	1.8	198,490	2.3
Marsh Run	137,400	3.9	1,417	-	198,473	2.1	1,417	-
Rock Springs	86,348	2.4	26,878	0.9	108,876	1.1	110,318	1.3
Distributed generation	1,534	-	277	-	2,171	-	277	-
Total generated	<u>1,707,213</u>	<u>48.3</u>	<u>1,427,555</u>	<u>48.4</u>	<u>4,212,290</u>	<u>43.6</u>	<u>4,011,960</u>	<u>47.3</u>
Purchased:								
Total purchased	<u>1,830,414</u>	<u>51.7</u>	<u>1,522,137</u>	<u>51.6</u>	<u>5,458,631</u>	<u>56.4</u>	<u>4,467,968</u>	<u>52.7</u>
Total available energy	<u>3,537,627</u>	<u>100.0 %</u>	<u>2,949,692</u>	<u>100.0 %</u>	<u>9,670,921</u>	<u>100.0 %</u>	<u>8,479,928</u>	<u>100.0 %</u>

We satisfy the majority of our member distribution cooperatives’ capacity requirements and a portion of their energy

requirements through our ownership interests in Clover, North Anna, Louisa, Marsh Run and Rock Springs. We purchase capacity and energy from the market to supply the remaining needs of our member distribution cooperatives.

Our operating expenses are significantly affected by the extent to which we purchase power and, relatedly, the availability of our base load generating facilities, Clover and North Anna. Base load generating facilities, particularly nuclear power plants such as North Anna, generally have relatively high fixed costs, but nuclear facilities operate with relatively low variable costs due to lower fuel costs and technological efficiencies. In addition, coal-fired facilities also have relatively low variable costs, as compared to combustion turbine facilities such as Louisa, Marsh Run and Rock Springs. Owners of nuclear and other power plants incur the embedded fixed costs of these facilities whether or not the units operate. When either Clover or North Anna is off-line, we must purchase replacement energy from the PJM market, which may be more or less costly. Our combustion turbine facilities have relatively low fixed costs and greater operational flexibility, but are more expensive to operate; therefore, we operate them only when the market price of energy makes their operation economical. As a result, our operating expenses, and consequently our rates to our member distribution cooperatives, are more significantly affected by the operations of Clover and North Anna than by our combustion turbine facilities. The output of Clover and North Anna for the three and nine months ended September 30, 2005 and 2004, as a percentage of the maximum net dependable capacity rating of the facilities was as follows:

	Clover				North Anna			
	Three Months Ended		Nine Months Ended		Three Months Ended		Nine Months Ended	
	September 30,		September 30,		September 30,		September 30,	
	2005	2004	2005	2004	2005	2004	2005	2004
Unit 1	91.5 %	93.9 %	86.3 %	78.5 %	97.6 %	78.8 %	99.8 %	90.8 %
Unit 2	91.5	93.6	77.8	91.4	96.5	99.5	99.2	88.9
Combined	91.5	93.8	82.1	85.0	97.1	89.2	99.5	89.9

Clover. During the three months ended September 30, 2005, both Clover Units 1 and 2 were available for dispatch. Clover Units 1 and 2 experienced minor unscheduled outages during the nine months ended September 30, 2005, and September 30, 2004. On May 1, 2005, operational control of Virginia Power's transmission facilities was transferred to PJM. With that transfer, all of our member distribution cooperatives' capacity and energy requirements are now within the PJM control area and our generating facilities are now under dispatch control of PJM. Accordingly, Clover Units 1 and 2 are operated pursuant to PJM dispatching requirements. During the nine months ended September 30, 2005, Clover Units 1 and 2 were dispatched less by PJM based upon economic factors. When our generating facilities are dispatched less, we purchase more power to meet the needs of our member distribution cooperatives. Clover Unit 1 was off-line for 37 days for scheduled maintenance outages during the nine months ended September 30, 2004.

North Anna. North Anna Units 1 and 2 experienced minor unscheduled outages during the three and nine months ended September 30, 2005. North Anna Unit 1 was off-line for 19 days for a scheduled refueling outage during the three and nine months ended September 30, 2004. North Anna Unit 2 was off-line for 28 days for a scheduled refueling outage during the nine months ended September 30, 2004.

Combustion turbine facilities. During the three and nine months ended September 30, 2005, the operational availability of our Louisa, Marsh Run and Rock Springs combustion turbine facilities was as follows:

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2005	2004	2005	2004
Louisa	98.9 %	94.9 %	97.6 %	95.9 %
Marsh Run ⁽¹⁾	93.6	-	96.6	-
Rock Springs	97.9	99.9	97.6	96.0

⁽¹⁾ Marsh Run became commercially operable in September 2004.

The components of our operating expenses for the three and nine months ended September 30, 2005 and 2004, were as follows:

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2005	2004	2005	2004
	(in thousands)		(in thousands)	
Fuel	\$ 62,754	\$ 25,700	\$ 112,539	\$ 67,300
Purchased power	118,171	92,194	325,908	239,730
Deferred energy	(22,144)	(7,360)	(38,622)	(14,797)
Operations and maintenance	9,190	2,817	25,614	23,538
Administrative and general	10,175	6,425	25,942	20,994
Depreciation, amortization and decommissioning	9,798	7,817	29,113	22,485
Amortization of regulatory asset/(liability), net	175	1,577	1,348	5,863
Taxes, other than income taxes	1,562	1,390	4,724	3,809
Accretion	618	558	1,854	1,664
Total Operating Expenses	<u>\$ 190,299</u>	<u>\$ 131,118</u>	<u>\$ 488,420</u>	<u>\$ 370,586</u>

Three Months Ended September 30, 2005 compared to Three Months ended September 30, 2004:

Aggregate operating expenses increased \$59.2 million, or 45.1%, for the three months ended September 30, 2005, as compared to the same period in 2004, primarily due to increases in fuel and purchased power expense, partially offset by the change in deferred energy expense.

Fuel expense increased \$37.1 million, or 144.2%, for the three months ended September 30, 2005, as compared to the same period in 2004, primarily as a result of the 70.2% increase in the average cost of natural gas, the 25.6% increase in the average cost of coal and the increased operation of our combustion turbine facilities.

Purchased power expense increased \$26.0 million, or 28.2%, for the three months ended September 30, 2005, as compared to the same period in 2004, primarily due to a 20.3% increase in the volume of purchased power and a 6.6% increase in the average cost of purchased power. The increase in the average cost of purchased power is reflective of the overall price increases in energy costs across all markets.

Deferred energy expense changed \$14.8 million, or 200.9%, for the three months ended September 30, 2005, as compared to the same period in 2004. During the three months ended September 30, 2005, we under-collected \$22.1 million in energy costs; whereas in the three months ended September 30, 2004, we under-collected \$7.4 million in energy costs. At September 30, 2005, we had an under-collected deferred energy balance of \$33.8 million.

Nine Months Ended September 30, 2005 compared to Nine Months Ended September 30, 2004:

Aggregate operating expenses increased \$117.8 million, or 31.8%, for the nine months ended September 30, 2005, as compared to the same period in 2004, primarily due to increases in purchased power, fuel, and depreciation, amortization and decommissioning expense, partially offset by the change in deferred energy.

Purchased power expense increased \$86.2 million, or 35.9%, for the nine months ended September 30, 2005, as compared to the same period in 2004, due to a 22.2% increase in the volume of purchased power and a 11.3% increase in the average cost of purchased power. The increase in the average cost of purchased power is reflective of the overall price increases in energy costs across all markets. As described above, on May 1, 2005, operational control of Virginia Power's transmission facilities was transferred to PJM. With this transfer, all of our member distribution cooperatives' capacity and energy requirements are now within the PJM control area and our generating facilities are now under dispatch control of PJM.

Fuel expense increased \$45.2 million, or 67.2%, for the nine months ended September 30, 2005, as compared to the same period in 2004, primarily as a result of a 62.8% increase in the average cost of natural gas, a 40.3% increase in the average cost of coal and the increased operation of Marsh Run.

Depreciation, amortization and decommissioning increased \$6.6 million, or 29.5%, for the nine months ended September 30, 2005, primarily as a result of nine months of depreciation expense related to our Marsh Run combustion turbine facility in 2005

versus only one half of a month of depreciation for the nine months ended September 30, 2004. Marsh Run became commercially operable in September 2004.

Deferred energy expense changed \$23.8 million, or 161.0%, for the nine months ended September 30, 2005, as compared to the same period in 2004. During the first nine months of 2005, we under-collected \$38.6 million in energy costs; whereas in the first nine months of 2004 we under-collected \$14.8 million in energy costs. At September 30, 2005, we had an under-collected deferred energy balance of \$33.8 million.

On April 13, 2005, our Board of Directors approved an increase to our fuel factor adjustment rate, resulting in an increase to our total energy rate of approximately 14.6% effective April 1, 2005, due to continued rising energy costs. Additionally, our Board of Directors approved a decrease in our demand rate of approximately 4.3%, effective April 1, 2005. This decrease was implemented due to an overall decline in fixed costs. The increase to our total energy rate effective April 1, 2005, was not sufficient to permit us to collect all incurred energy expenses and on October 12, 2005, our Board of Directors approved an increase to our fuel factor adjustment rate, resulting in an increase to our total energy rate of approximately 8.1%, effective October 1, 2005.

Other Items

Investment Income. Investment income increased \$1.1 million, or 420.2%, for the three months ended September 30, 2005, and \$1.4 million or 61.9% for the nine months ended September 30, 2005, as compared to the same periods in 2004, primarily due to income earned on our increased balance in cash and temporary investments.

Interest Charges, net. The primary factors affecting our interest expense are scheduled payments of principal on our indebtedness, issuance of new indebtedness and capitalized interest.

The major components of interest charges, net for the three and nine months ended September 30, 2005 and 2004, were as follows:

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2005	2004	2005	2004
	(in thousands)		(in thousands)	
Interest expense on long-term debt	\$ (14,161)	\$ (14,148)	\$ (42,546)	\$ (42,153)
Other	(614)	99	(1,657)	(1,658)
Total Interest Charges	(14,775)	(14,049)	(44,203)	(43,811)
Allowance for borrowed funds used during construction	58	2,532	170	8,111
Interest Charges, net	<u>\$ (14,717)</u>	<u>\$ (11,517)</u>	<u>\$ (44,033)</u>	<u>\$ (35,700)</u>

Interest charges, net increased by \$3.2 million, or 27.8%, for the three months ended September 30, 2005, and \$8.3 million, or 23.3%, for the nine months ended September 30, 2005, as compared to the same periods in 2004, primarily due to the reduction in capitalized interest associated with Marsh Run. We ceased capitalizing interest on Marsh Run in September 2004 when the facility became commercially operable. Capitalized interest is computed monthly using an interest rate, which reflects our embedded cost of indebtedness, multiplied by our investment in projects under construction.

Net Margin. Our net margin, which is a function of our total interest charges, remained relatively flat for the three and nine months ended September 30, 2005, as compared to the same period in 2004.

Financial Condition

The principal changes in our financial condition from December 31, 2004 to September 30, 2005, were caused by increases in accounts payable, regulatory liabilities, accounts payable—deposits, deferred charges—other, accounts payable—members, non-controlling interest related to the consolidation of TEC, and the change in deferred energy. Accounts payable increased \$64.4 million as a result of increased purchased power. Regulatory liabilities increased \$56.6 million primarily due to deferred derivative activity. Accounts payable—deposits increased \$42.4 million because our counterparties were required to post deposits pursuant to credit terms in our master power purchase and sales agreements with them. Deferred charges—other increased \$39.6 million as a result of derivative activity. Accounts payable—members increased \$27.4 million primarily due to increased sales as well as member prepayments. Non-controlling interest related to the consolidation of TEC increased \$22.8 million due to the increase in unrealized gains on derivatives recorded on TEC's financial statements as a result of a change in the market value of its contracts for delivery of gas in the future at specified prices. Our deferred energy balance represents the net under- or over-

collection of energy costs as of the end of the reporting period. These amounts are recovered from or refunded to our member distribution cooperatives in subsequent periods. The deferred energy balance changed from a \$4.7 million liability (over-collection of costs) at December 31, 2004, to a \$33.8 million asset (under-collection of costs) at September 30, 2005.

Liquidity and Capital Resources

Operations. Historically, our operating cash flows have been sufficient to meet our short- and long-term capital expenditures related to our existing generating facilities, our debt service requirements, and our ordinary business operations. Our operating activities provided cash flow of \$167.1 million during the first nine months of 2005. During the first nine months of 2004, our cash needs exceeded our cash flows from operating activities by \$0.7 million. Operating activities in the first nine months of 2005 were primarily impacted by the change in current liabilities, the change in regulatory assets and liabilities, partially offset by the change in deferred energy. Current liabilities increased \$156.6 million primarily as a result of increased accounts payable related to purchased power and fuel costs, accounts payable—members as a result of increased sales and member prepayments, accounts payable—deposits as a result of our counterparties posting deposits in accordance with the terms of our respective master power purchase and sales agreements with them, and accrued interest. Regulatory assets and liabilities changed \$63.9 million primarily due to deferred derivative activity. Also, the increase in the price of natural gas has increased the aggregate value of our natural gas futures portfolio, allowing us to withdraw equity from our portfolio account in the form of cash. At September 30, 2005, we had an under-collected deferred energy balance of \$33.8 million as compared to an over-collected deferred energy balance of \$4.8 million at December 31, 2004, which resulted in a cash outflow of \$38.6 million.

Financing Activities. In addition to liquidity from our operating activities, we maintain committed lines of credit to cover short-term funding needs. As of September 30, 2005, we had short-term committed variable rate lines of credit in an aggregate amount of \$230.0 million. Of this amount, \$180.0 million was available for general working capital purposes and \$50.0 million was available for capital expenditures related to our generating facilities. Additionally, we have a \$50.0 million three-year revolving credit facility, which expires on March 18, 2007.

At September 30, 2005 and 2004, we had no short-term borrowings or letters of credit outstanding under any of these arrangements. We expect the working capital lines of credit to be renewed as they expire. We expect the construction-related line of credit to be renewed until such time as we determine it is not needed.

Investing Activities. Investing activities in the first nine months of 2005 was primarily impacted by activity related to available for sale securities, interest earned on investments-other and cash and cash equivalents, as well as electric plant additions for our generation facilities.

OLD DOMINION ELECTRIC COOPERATIVE

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

No material changes occurred in our exposure to market risk during the third quarter of 2005.

ITEM 4. CONTROLS AND PROCEDURES

As of the end of the period covered by this report, our management, including the President and Chief Executive Officer and Senior Vice President and Chief Financial Officer conducted an evaluation of the effectiveness of our disclosure controls and procedures. Based upon that evaluation, the President and Chief Executive Officer and Senior Vice President and Chief Financial Officer concluded that our disclosure controls and procedures are effective in ensuring that all material information required to be filed in this report has been made known to them in a timely matter. We have established a Disclosure Assessment Committee comprised of members from senior and middle management to assist in this evaluation. There have been no significant changes in our internal controls over financial reporting or in other factors that could significantly affect such controls during the past fiscal quarter.

OLD DOMINION ELECTRIC COOPERATIVE

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

FERC Proceedings Related to Potential Reorganization

The hearing at the Federal Energy Regulatory Commission (“FERC”) regarding the proposed assignment of our wholesale power contracts with our member distribution cooperatives to New Dominion Energy Cooperative (“New Dominion”) was conducted on October 18 through 20, 2005, and concluded on November 2, 2005. The initial decision is scheduled to be issued no later than February 6, 2006.

On August 30, 2005, a joint motion to revise the procedural schedule related to the applications for an amended cost-of service formula for New Dominion’s sales to the member distribution cooperatives and for the cost allocation formula for our sales to New Dominion, was filed in light of continuing settlement discussions and on September 1, 2005, the request for the revision in the procedural schedule was granted. On October 5, 2005, a joint motion to suspend the procedural schedule was filed as a result of progressing settlement discussions and on October 6, 2005, the motion was granted and the procedural schedule was suspended.

On October 14, 2005, we filed an offer of partial settlement with Bear Island Paper Company and the Virginia State Corporation Commission to settle all the issues in the FERC proceedings related to the applications for an amended cost-of service formula for New Dominion’s sales to the member distribution cooperatives and for the cost allocation formula for our sales to New Dominion. Initial comments on the proposed partial settlement were filed on November 3, 2005, and reply comments are due by November 14, 2005. We cannot predict whether a settlement will be reached on the basis of this or another proposal.

For further description of our legal proceedings for the FERC Proceedings Related to Potential Reorganization, see “Legal Proceedings” in our Quarterly Report on Form 10-Q for the quarter ended June 30, 2005, and in Part 1, Item 3 of our 2004 Annual Report on Form 10-K.

Ragnar Benson, Inc.

On September 27, 2005, the U.S. District Court for the Eastern District of Virginia, Richmond Division, ruled on motions for partial summary judgment in our claims against the EPC contractor of the Marsh Run facility. Specifically, the court granted Old Dominion’s motion for partial summary judgment pertaining to claims of entitlement to a change order and fraud allegations, it dismissed six of Ragnar Benson, Inc.’s (“RBI”) counterclaims, including all counterclaims pertaining to fraud, and it limited Old Dominion’s possible recovery of liquidated damages to the liquidated damages cap of approximately \$4.7 million. The trial began October 11, 2005 and concluded October 26, 2005. During the trial, RBI revised its claim from \$33.0 million to \$36.0 million. The case is pending in the U.S. District Court for the Eastern District of Virginia, Richmond Division.

RBI and its parent companies, The Austin Company and Austin Holdings, Inc., filed for bankruptcy under Chapter 11 of the bankruptcy code on October 14, 2005. The automatic litigation stay was lifted for the case between RBI and Old Dominion.

Other Matters

No material developments have occurred in our legal proceedings with Norfolk Southern Railway Company since the filing of our Annual Report on Form 10-K for the fiscal year ended December 31, 2004. See “Legal Proceedings” in Part 1, Item 3 of our 2004 Annual Report on Form 10-K. Other than legal proceedings arising out of the ordinary course of business, which management believes will not have a material adverse impact on our results of operations or financial condition, there is no other litigation pending or threatened against us.

ITEM 6. EXHIBITS

- 31.1 Certification of the Chief Executive Officer pursuant to Rule 13a-14(a)
- 31.2 Certification of the Chief Financial Officer pursuant to Rule 13a-14(a)
- 32.1 Certification of the Chief Executive Officer pursuant to 18 U.S.C. § 1350
- 32.2 Certification of the Chief Financial Officer pursuant to 18 U.S.C. § 1350

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.

OLD DOMINION ELECTRIC COOPERATIVE
Registrant

Date: November 10, 2005

/s/Daniel M. Walker
Daniel M. Walker
Senior Vice President and Chief Financial Officer
(Principal Financial and Accounting Officer)

EXHIBIT INDEX

<u>Exhibit Number</u>	<u>Description of Exhibit</u>
31.1	Certification of the Chief Executive Officer pursuant to Rule 13a-14(a)
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32.2	Certification of the Chief Financial Officer pursuant to 18 U.S.C. § 1350

**OLD DOMINION ELECTRIC COOPERATIVE
CERTIFICATION OF PRESIDENT AND CHIEF EXECUTIVE OFFICER
PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002**

I, Jackson E. Reasor, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Old Dominion Electric Cooperative;
2. Based on my knowledge, this quarterly report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:
 - a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - c) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the Audit Committee of registrant's Board of Directors (or persons performing the equivalent function):
 - a) all significant deficiencies in the design and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 10, 2005

 /s/ JACKSON E. REASOR
Jackson E. Reasor
President and Chief Executive Officer
(Principal Executive Officer)

**OLD DOMINION ELECTRIC COOPERATIVE
CERTIFICATION OF PRINCIPAL FINANCIAL AND ACCOUNTING OFFICER
PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002**

I, Daniel M. Walker, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Old Dominion Electric Cooperative;
2. Based on my knowledge, this quarterly report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:
 - a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - c) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the Audit Committee of registrant's Board of Directors (or persons performing the equivalent function):
 - a) all significant deficiencies in the design and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 10, 2005

/s/ DANIEL M. WALKER

**Daniel M. Walker
Senior Vice President and Chief Financial Officer
(Principal Financial and Accounting Officer)**

**OLD DOMINION ELECTRIC COOPERATIVE
CERTIFICATION OF PRESIDENT AND CHIEF EXECUTIVE OFFICER
PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Quarterly Report of Old Dominion Electric Cooperative (the "Company") on Form 10-Q for the period ending September 30, 2005 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Jackson E. Reasor, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

- 1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- 2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: November 10, 2005

/s/JACKSON E. REASOR

**Jackson E. Reasor
President and Chief Executive Officer
(Principal Executive Officer)**

