NOTES

Note 1 - Summary of Significant Accounting Policies:

A - Reporting Entity - The South Carolina Public Service Authority (the "Authority" or "Santee Cooper"), a component unit of the State of South Carolina, was created in 1934 by the State legislature. The Santee Cooper Board of Directors (Board) is appointed by the Governor of South Carolina with the advice and consent of the Senate. The purpose of the Authority is to provide electric power and wholesale water to the people of South Carolina. Capital projects are funded by commercial paper in addition to bonds and internally generated funds. As authorized by State law, the Board of Directors sets rates charged to customers to pay debt service and operating expenses and to provide funds required under bond covenants.

B - System of Accounts - The accounting records of the Authority are maintained on an accrual basis in accordance with accounting principles generally accepted in the United States (GAAP) issued by the Governmental Accounting Standards Board (GASB) applicable to governmental entities that use proprietary fund accounting and the Financial Accounting Standards Board (FASB) that do not conflict with rules issued by the GASB. The Authority's combined financial statements include the accounts of the Lake Moultrie Regional Water System after elimination of inter-company accounts and transactions. The accounts are maintained substantially in accordance with the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission (FERC) for the electric system and the National Association of Regulatory Utility Commissioners (NARUC) for the water system. The Authority also complies with policies and practices prescribed by its Board of Directors and to practices common in both industries. As the Board of Directors is authorized to set rates, the Authority has historically followed FASB Statement No. 71, "Accounting for the Effects of Certain Types of Regulation" (FASB 71). This statement provides for the reporting of assets and liabilities consistent with the economic effect of the rate structure. The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results may differ from those estimates.

C - Reclassifications - Certain amounts in the prior year's financial statements have been reclassified to conform to current year presentation.

D - Cash and Cash Equivalents - For purposes of the Combined Statements of Cash Flows, the Authority considers highly liquid investments with original maturities of ninety days or less and cash on deposit with financial institutions as cash and cash equivalents. In 2001, the Authority adopted GASB Statement No. 34, "Basic Financial Statements - Management's Discussion and Analysis - for State and Local Governments" (GASB 34) which requires cash and cash equivalents to be shown as either restricted or unrestricted. "Restricted" refers to those funds limited by law, regulations or Board action as to their allowable disbursement. "Unrestricted" refers to all other funds not meeting the requirements of restricted.

E - Inventory - Material inventory and fuel inventory are carried at weighted average costs. At the time of issuance or consumption, an expense is recorded at the weighted average cost. Fuel expense for all customers are billed utilizing rates and contracts, the majority of which include fuel adjustment provisions based on either the actual costs for the previous month or the actual weighted average costs for the previous three-month period.

F - Utility Plant - Utility plant is recorded at cost, which includes materials, labor, overhead, and interest capitalized during construction. Interest is only capitalized when interest payments are funded through borrowings. There was no interest capitalized in 2006 or 2005. Other interest expense is recovered currently through rates. The costs of maintenance, repairs and minor replacements are charged to appropriate operation and maintenance expense accounts. The costs of renewals and betterments are capitalized. The original cost of utility plant retired and the cost of removal, less salvage, are charged to accumulated depreciation.

G - Depreciation - Depreciation is computed using composite rates on a straight-line basis over the estimated useful lives of the various classes of the plant. Composite rates are applied to the net carrying basis of various classes of plant which includes appropriate adjustments for cost of removal and salvage. The Authority periodically has depreciation studies performed by independent parties to assist management and the Board in establishing appropriate composite depreciation rates. Annual depreciation provisions, expressed as a percentage of average depreciable utility plant in service, were approximately 3.6 percent for each of the periods ended December 31, 2006 and 2005, respectively. Amortization of capitalized leases is also included in depreciation expense.

H - Investment in Associated Companies - The Authority is a member of The Energy Authority (TEA) along with City Utilities of Springfield (Missouri), Gainesville Regional Utilities (Florida), JEA (Florida), MEAG Power (Georgia), and Nebraska Public Power District (NPPD). The Authority is also a member of Colectric Partners (Colectric). In addition to the Authority, Colectric's member participants are: Florida Municipal Power Agency, Gainesville Regional Utilities, JEA, Lansing Board of Water & Light, MEAG Power, Nebraska Public Power District and Orlando Utilities Commission.

TEA markets wholesale power and coordinates the operation of the generation assets of its members to maximize the efficient use of electrical energy resources, reduce operating costs and increase operating revenues of the members. TEA is expected to accomplish the foregoing without impacting the safety and reliability of the electric system of each member. TEA does not engage in the construction or ownership of generation or transmission assets. In addition, TEA assists members with fuel hedging activities and acts as an agent in the execution of forward gas transactions. The Authority accounts for its investment in TEA under the equity method of accounting.

All of TEA's revenues and costs are allocated to the members. The following table summarizes the transactions applicable to the Authority:

TEA Investment	**2006**	2005
	(Thousands)	
Opening balance	**$ 6,395**	$ 6,741
Reduction to power costs and increases in electric revenues	**31,021**	44,952
Less: Distributions from TEA	**27,420**	44,164
Less: Other (includes equity losses)	**2,486**	1,134
Ending balance	**$ 7,510**	$ 6,395

At December 31, 2006, the Authority had a payable to TEA of $9.7 million for power and gas purchases. In addition, at December 31, 2006, the Authority had a receivable due from TEA of approximately $4.2 million for power sales and sales of excess gas capacity.

The Authority's exposure relating to TEA is limited to the Authority's capital investment, any accounts receivable and trade guarantees provided by the Authority. These guarantees are within the scope of FASB Financial Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, including Indirect Guarantees of Indebtedness of Others" (FIN 45). Upon the Authority making any payments under its electric guarantee, it has certain contribution rights with the other members of TEA in order that payments made under the TEA member guarantees would be equalized ratably, based upon each member's equity ownership interest in TEA. After such contributions have been effected, the Authority would only have recourse against TEA to recover amounts paid under the guarantee. The term of this guarantee is generally indefinite, but the Authority has the ability to terminate its guarantee obligations by causing to be provided advance notice to the beneficiaries thereof. Such termination of its guarantee obligations only applies to TEA transactions not yet entered into at the time the termination takes effect. The Authority's support of TEA's trading activities is limited based on the formula derived from the forward value of TEA's trading positions at a point in time. The formula was approved by the Authority's Board and at December 31, 2006, the trade guarantees are an amount not to exceed approximately $96.0 million.

Colectric provides public power utilities with key project and business management resources. Colectric also specializes in the development, project management, operations and maintenance of public power utilities' electric generation and gas infrastructure facilities. The members may elect to participate in various Colectric initiatives based on individual utility needs.

Currently, the Authority participates in two of Colectric's initiatives. The first involves managing the major gas turbine overhauls thereby promoting the sharing of spare parts and technical expertise. The second initiative is a supply chain management initiative intended to achieve major cost savings through volume purchasing leverage.

The Authority's exposure relating to Colectric is limited to its capital investment in Colectric, any accounts receivable from Colectric and any indemnifications related to agreements between Colectric and the Authority. These indemnifications are within the scope of FIN 45. The Authority's initial investment in Colectric was $413,000. The balance in the Authority's Member Equity account at December 31, 2006 was approximately $162,000.

I - Bond Issuance Costs and Refunding Activity - Unamortized debt discount, premium, and expense are amortized to income over the terms of the related debt issues. Gains or losses on refunded debt are amortized to income over the shorter of the remaining life of the refunded debt or the life of the new debt.

J - Revenue Recognition and Fuel Costs - Substantially all wholesale and industrial revenues are billed and recorded at the end of each month. Revenues for electricity delivered to retail customers that have not been billed are accrued. Accrued revenue for retail customers totaled $10.7 million in 2006 and $10.1 million in 2005.

Fuel costs are reflected in operating expenses as fuel is consumed.

K - Payment to the State - The Authority is operated for the benefit of the people of South Carolina (the "State") and was created by Act No. 887 of the Acts of the State of South Carolina for 1934 and acts supplemental thereto and amendatory thereof (Code of Laws of South Carolina 1976, as amended – Sections 58-31-10 through 58-31-50) (the "Act"). Nothing in the Act prohibits the Authority from paying to the State each year up to one percent of its projected operating revenues, as such revenues would be determined on an accrual basis from the combined electric and water systems. The Authority recognizes the distributions (shown as "Transfers out" on the Combined Statements of Revenues, Expense and Changes in Net Assets) as a reduction to net assets when paid.

Payments made to the State totaled $15.0 million in 2006 and $12.4 million in 2005.

L - Accounting for Derivative Instruments - The Authority follows the requirements of FASB No. 133, "Accounting for Derivative Instruments and Hedging Activities" (FASB 133) as amended by FASB No. 149. The majority of the Authority's derivative instruments have been determined to meet the normal purchases and normal sales exception provided by FASB 133.

Natural gas, a core business commodity input for the Authority, has historically been hedged in an effort to mitigate gas cost risk by reducing cost volatility and improving cost effectiveness. In 2006, due to the increased market volatility of crude oil and its impact on the Authority's total fuel cost, the Authority began hedging crude oil.

Unrealized gains and losses related to such activity are deferred in a regulatory account and recognized in earnings as gas or transportation costs are incurred in the production cycle. At December 31, 2006, the Authority recorded $6.1 million in net unrealized losses from natural gas and crude oil transactions using mark-to-market accounting as outlined FASB 133. During 2006, the Authority recognized $2.0 million in net gains associated with hedging transactions.

M - Retirement of Long-Lived Assets - Statement of Financial Accounting Standards No. 143 "Accounting for Asset Retirement Obligations" (SFAS 143) addresses financial accounting and reporting for legal obligations associated with the retirement of long-lived assets and the related retirement costs. The standard applies to legal obligations associated with the retirement of long-lived assets that result from acquisition, construction and/or normal use of the asset. The Authority has a one-third undivided interest in the V.C. Summer Nuclear Station ("Summer") and is therefore subject to the requirements of SFAS 143 due to legal and regulatory requirements related to nuclear decommissioning. Summer was placed in service in 1983 and in 2004, the Nuclear Regulatory Commission (NRC) extended the operating license to August 6, 2042.

SFAS 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made. The fair value of a liability is added to the carrying amount of the associated asset. This carrying amount, called the Asset Retirement Cost (ARC) is then depreciated over the life of the asset. The asset retirement obligation liability increases due to the passage of time based on the time value of money until the retirement obligation is settled.

SFAS 143 was effective for fiscal years beginning after June 15, 2002, and was adopted by the Authority on January 1, 2003. At December 31, 2006 and 2005, the Authority recorded an asset retirement obligation (ARO) on its one-third share of Summer of approximately $226.0 million and $273.1 million, respectively. Approximately $22.7 million was recorded on the accompanying balance sheet as an associated ARC within "Capital assets." The ARC was recorded commencing on the in-service date of the nuclear facility.

In March 2005, FASB issued Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations" (FIN 47). FIN 47 clarifies the accounting for conditional asset retirement obligations as used in SFAS 143. It requires that an entity recognize a liability for the fair value of a conditional asset retirement obligation when incurred if the fair value of the liability can be reasonably estimated. Uncertainty about the timing or method of settlement of a conditional asset retirement obligation is factored into the measurement of the liability when sufficient information exists.

FIN 47, together with SFAS 143, provides guidance for recording and disclosing liabilities related to future legally enforceable obligations to retire assets (ARO). At December 31, 2006 and 2005, the Authority recorded an ARO on the closing of its ash ponds of approximately $51.9 million and $49.3 million, respectively. Approximately $10.4 million was recorded as an associated ARC within "Capital assets" on the accompanying balance sheet.

The asset retirement obligation is adjusted each period for any liabilities incurred or settled during the period, accretion expense and any revisions made to the estimated cash flows. The $49.3 million listed as "Adoption of FIN47," was a first year only calculation for 2005. The additional $2.6 million Ash Pond ARO liability for 2006 is included in "Accretion Expense." The following table summarizes the Authority's transactions:

Reconciliation of Asset Retirement Obligation Liability

Years Ended December 31,	**2006**	2005
	(Millions)	
Balance as of January 1,	**$ 322.4**	$ 260.6
Accretion Expense	**15.7**	12.5
Revision in Estimated Cash Flows	**(60.2)**	0.0
Adoption of FIN 47	**0.0**	49.3
Balance as of December 31,	**$ 277.9**	$ 322.4

N - Review of New Accounting Standards - In April 2004, GASB issued statement No. 43, "Financial Reporting for Postemployment Benefit Plans Other than Pension Plans" (GASB 43) and in June, 2004 issued No. 45, "Accounting and Financial Reporting by Employers for Postemployment Benefits Other Than Pensions" (GASB 45). The purpose of these two statements is to set new accounting standards for state and local government employers that offer retiree health benefits and other non-pension postemployment benefits. In particular, these statements require the accrual of liabilities and expenses of other postemployment benefits (OPEB) over the working career of plan members.

The effective start date of GASB 43 applies for periods beginning after December 15, 2005 for companies with total annual revenues of $100.0 million or more. GASB 45 regulations come into effect one year after implementation of GASB 43. The Authority believes that it does not fall under the requirements of GASB 43 since the South Carolina Retirement System provides certain health, dental, and life insurance benefits for retired employees of the Authority. The requirements of both GASB 43 and GASB 45 are still under review by the Authority and the State of South Carolina. The implementation of GASB 43 and GASB 45 is not expected to have a material effect on the Authority's financial position or results of operations.

In May 2004, GASB issued Statement No. 44, "Economic Condition Reporting: The Statistical Section" (GASB 44). GASB 44 enhances and updates the statistical section that accompanies a state or local government's basic financial statements to reflect the significant changes that have taken place in government finance, including the more comprehensive government-wide financial information required by GASB Statement 34. The statistical section comprises schedules presenting trend information about revenues and expenses, outstanding debt, economics and demographics, and other subjects. These schedules are intended to provide financial statement users with contextual information they need to assess a government's financial health. After review and discussion with the State of South Carolina Comptroller General Office, it was determined that GASB 44 would not apply to the Authority since the Authority does not elect to provide a statistical section as defined under GASB 44. The Authority is a discrete component unit of the State and is reported within the State's Comprehensive Annual Financial Report.

In December 2004, GASB issued Statement No. 46, "Net Assets Restricted by Enabling Legislation - an amendment of GASB Statement 34" (GASB 46). This Statement clarifies that a legally enforceable enabling legislation restriction is one that a party external to a government such as citizens, public interest groups, or the judiciary can compel a government to honor. GASB 46 states that the legal enforceability of an enabling legislation restriction should be re-evaluated if any of the resources raised by the enabling legislation are used for a purpose not specified by the enabling legislation or if a government has other cause for reconsideration. The only enabling legislation affecting the Authority is that legislation (SC Code of Laws Section 58-31-10 et seq.) by which it was created. There has been no enabling legislation since inception that imposes limits on the use of new capital. Therefore, the Authority believes it does not fall under the requirements of GASB 46.

In June 2005, GASB issued Statement No. 47, "Accounting for Termination Benefits" (GASB 47). This statement establishes accounting standards for termination benefits. The Authority, a member of the South Carolina Retirement System, has established that general recognition and measurement requirements should be reported under the requirements of GASB Statement No. 27, "Accounting for Pensions by State and Local Government Employers" (GASB 27) or GASB 45. For these reasons, the Authority believes it does not fall under the requirements of GASB 47 which was effective for periods beginning after June 15, 2005.

O - Issued But Not Yet Effective Pronouncements - In September 2006, GASB issued Statement No. 48, "Sales and Pledges of Receivables and Future Revenues and Intra-Entity Transfers of Assets and Future Revenues" (GASB 48). Governments sometimes exchange an interest in their expected cash flows from collecting specific receivables or future revenues for immediate cash payments—generally, a single lump sum. This Statement establishes criteria that governments will use to ascertain whether the proceeds received should be reported as revenue or as a liability. GASB 48 is effective for periods beginning after December 15, 2006 and is not expected to have a material effect on the Authority's financial position or results of operations.

In November 2006, GASB issued Statement No. 49, "Accounting and Financial Reporting for Pollution Remediation Obligations" (GASB 49). GASB 49 addresses accounting and financial reporting standards for pollution (including contamination) remediation obligations, which are obligations to address the current or potential detrimental effects of existing pollution by participating in pollution remediation activities such as site assessments and cleanups. The scope of the document excludes pollution prevention or control obligations with respect to current operations, and future pollution remediation activities that are required upon retirement of an asset, such as landfill closure and post closure care and nuclear power plant decommissioning. GASB 49 is effective for periods beginning after December 15, 2007 and is currently under review for any impact on the Authority's financial position or results of operations. The Authority currently follows the requirements of AICPA Statement of Position (SOP) 96-1, Environmental Remediation Liabilities, which became effective in fiscal year 1997. SOP 96-1 provides guidance on specific circumstances of recognizing, measuring, accruing and disclosing environmental remediation liabilities.

Note 2 – Costs to Be Recovered from Future Revenue:

The Authority's electric rates are established based upon debt service and operating fund requirements. Depreciation is not considered in the cost of service calculation used to design rates. In accordance with FASB 71, the differences between debt principal maturities (adjusted for the effects of premiums, discounts, expenses and amortization of deferred gains and losses) and depreciation on debt financed assets are recognized as costs to be recovered from future revenue. The recovery of outstanding amounts recorded as costs to be recovered from future revenue will coincide with the repayment of the applicable outstanding debt of the Authority.

Note 3 – Cash and Investments Held by Trustee:

Cash and investments as of December 31, 2006 are classified in the accompanying financial statements as follows:

Combined Balance Sheet:		
		(Thousands)
Current assets		
Unrestricted cash and cash equivalents	$	106,179
Unrestricted investments		18,326
Restricted cash and cash equivalents		76,995
Restricted investments		109,666
Noncurrent assets		
Unrestricted cash and cash equivalents		1,674
Unrestricted investments		78,084
Restricted cash and cash equivalents		53,510
Restricted investments		284,664
Total cash and investments	$	729,098

Cash and investments as of December 31, 2006 consist of the following:

Cash/Deposits	$	14,411
Investments		714,687
Total cash and investments	$	729,098

Unexpended funds from the sale of bonds, debt service funds, other special funds, and cash and investments are held and maintained by trustees, and their use is designated in accordance with applicable provisions of various bond resolutions, lease agreements, and the Enabling Act included in the South Carolina Code of Laws.

The Authority's investments are authorized by the Enabling Act included in the South Carolina Code of Laws, the Authority's investment policy, and various debt resolutions. Authorized investment types include Federal Agency Securities, State of South Carolina General Obligation Bonds, and U.S. Treasury Obligations, all of which are limited to a ten year maximum maturity. Certificate of Deposits and Repurchase Agreements are also authorized with a maximum maturity of one year.

In 1998, the Authority adopted the provisions of GASB Statement No. 31, "Accounting and Financial Reporting for Certain Investments and for External Investment Pools" (GASB 31). GASB 31 establishes standards of accounting and financial reporting for certain investments in securities and requires that all equity and debt securities be recorded at their fair value with gains and losses in fair value reflected as a component of non-operating income in the Combined Statements of Revenues, Expenses and Changes in Net Assets. As of December 31, 2006 and 2005, the Authority had investments totaling approximately $714.7 million and $586.3 million, respectively.

As of December 31, 2006, the Authority's cash and investments carried at fair market value included nuclear decommissioning funds of $128.6 million including unrealized holding gains of $9.8 million. As of December 31, 2005, decommissioning funds totaled approximately $123.1 million including unrealized holding gains of $12.6 million. In accordance with the provisions of FASB 71, earnings, both realized and unrealized, on the decommissioning fund assets are credited to the Regulatory asset - asset retirement obligation and not as a separate component of non-operating income in the Combined Statements of Revenues, Expenses and Changes in Net Assets.

All of the Authority's investments, with the exception of decommissioning funds, are limited to a maturity of 10 years or less. For the year ended December 31, 2006, the Authority made total investment purchases and sales at cost of approximately $35.4 billion and $35.3 billion, respectively. Of these amounts, the Authority's investment purchases and sales at cost for its decommissioning funds were $229.2 million and $225.5 million, respectively. Compared to the year ended December 31, 2005, the Authority's total investment purchases and sales at cost were approximately $30.4

billion and $30.6 billion, respectively. Of these amounts, investment purchases and sales at cost for the decommissioning funds were $49.9 million and $46.7 million, respectively.

With adoption of GASB Statement No. 40, “Deposit and Investment Risk Disclosures” (GASB 40), reporting requirements for GASB Statement No. 3, “Deposits with Financial Institutions, Investments (including Repurchase Agreements), and Reverse Repurchase Agreements” (GASB 3) were modified.

Under disclosure requirements for GASB 3, the Authority’s repurchase agreements at December 31, 2006 totaled approximately $130.3 million. The Authority requires that securities underlying repurchase agreements have a market value of at least 102 percent of the cost of the repurchase agreement. Securities underlying repurchase agreements are delivered by broker/dealers to the Authority’s trust agents. Prior disclosure requirements concerning credit and market risk are now included in GASB 40 disclosures.

GASB 40 addresses modifications of disclosure requirements for common deposit and investment risks related to credit risk, custodial credit risk, concentration of credit risk, interest rate risk, and foreign currency risk. The Authority’s requirements for disclosure are as follows:

Credit Risk - Generally, credit risk is the risk that an issuer of an investment will not fulfill its obligation to the holder of the investments. This is measured by the assignment of rating by a nationally recognized statistical rating organization. State law and restrictions established by bond indenture and resolution limit investments in debt securities to those securities issued by the U.S. government and agencies or instrumentalities of the United States created pursuant to an Act of Congress. Examples of these agencies’ securities are Federal Home Loan Bank and Federal National Mortgage Association. As of December 31, 2006, all of the agency’s securities held by the Authority were rated AAA by Fitch and Aaa by Moody’s Investors.

Custodial Credit Risk - Custodial credit risk for deposits is the risk that, in the event of the failure of a depository financial institution, an entity will not be able to recover its deposits or will not be able to recover collateral securities that are in the possession of an outside party. The custodial credit risk for investments is the risk that, in the event of the failure of the counterparty to a transaction, an entity will not be able to recover the value of its investment or collateral securities that are in the possession of another party. As of December 31, 2006, all of the Authority’s investment securities are held by the Trustee or Agent of the Authority and therefore have no custodial risk.

At December 31, 2006, the Authority had deposits exposed to custodial credit risk as follows:

Depository Account Type	Bank Balance
	(Thousands)
Uninsured and collateral held by Bank's agent not in Authority's name	$ 11,462

Concentration of Credit Risk - The investment policy of the Authority contains no limitations on the amount that can be invested in any one issuer. Investments in any one issuer (other than U.S. Treasury securities) that represent 5 percent or more of total Authority investments are as follows:

Issuer	Investment Type	Fair Value
		(Thousands)
Federal Home Loan Bank	Federal agency securities	$ 217,844
Federal National Mortgage Association	Federal agency securities	$ 198,525
Federal Home Loan Mortgage Corp	Federal agency securities	$ 66,476

Interest Rate Risk - Interest rate risk is the risk that changes in market interest rates will adversely affect the fair value of an investment. Generally, the longer the maturity of an investment, the greater the sensitivity of its fair value to changes in market interest rates. The Authority manages its exposure to interest rate risk by investing in securities that mature as necessary to provide the cash flow and liquidity needed for operations.

The following table shows the distribution of the Authority’s investments by maturity:

Investment Type	Fair Value	Weighted Average Maturity
	(Thousands)	(Years)
Certificates of Deposits	$ 2,100	0.24
Federal Agency Discount Notes	178,794	0.02
Federal Agency Securities	337,272	3.91
Repurchase Agreements	130,337	0.01
U.S. Treasury Obligations	66,183	3.39
Total	$ 714,686	
Portfolio Weighted Average Maturity		2.15

The Authority holds zero coupon bonds which are highly sensitive to interest rate fluctuations in both the Nuclear Decommissioning Trust and Nuclear Decommissioning Fund. Together these accounts hold $48.6 million in U.S. Treasury Strips ranging in maturity from February 15, 2008 to May 15, 2019. They also hold $59.7 million in government agency zero coupon securities (i.e. Resolution Corp, FNMA, FICO and REFCORP Securities) in the two portfolios ranging in maturity from October 15, 2007 to November 15, 2026. Zero coupon bonds or U.S. Treasury Strips are subject to wider swings in their market value than coupon bonds. These portfolios are structured to hold these securities to maturity or early redemption. The Authority has a buy and hold strategy for these portfolios. Based on the Authority's current decommissioning assumptions, it is anticipated that no funds will be needed any earlier than 2043. The Authority has no other investments that are highly sensitive to interest rate fluctuations.

Foreign Currency Risk - Foreign currency risk exists when there is a possibility that changes in exchange rates could adversely affect investment or deposit fair market value. The Authority is not authorized to invest in foreign currency and therefore has no exposure.

Note 4 – Long-Term Debt Outstanding:

The Authority's long-term debt at December 31, 2006 and 2005 consisted of the following:

	2006	2005	Interest Rate(s) (1)	Call Price (1)
	(Thousands)		(%)	(%)
Electric Revenue Bonds - Priority Obligations: (final maturity 7/1/06)	**$ 0**	$ 4,420	N/A	N/A
Capitalized Lease Obligations (Net): (mature through 2014)	**9,896**	11,937	2.00-5.00	N/A
Revenue Bonds: (mature through 2032)				
1997 Tax-exempt Refunding Series A	**204,885**	204,885	4.875-5.125	101
1998 Tax-exempt Refunding Series B	**22,485**	23,200	4.50-5.25	101
Total Revenue Bonds	**227,370**	228,085		
Revenue Obligations: (mature through 2039)				
1999 Tax-exempt Improvement Series A	**69,960**	181,300	4.80-5.625	101
1999 Taxable Improvement Series B	**63,680**	68,135	7.12-7.42	Non-callable
2001 Tax-exempt Improvement Series A	**42,180**	44,265	4.00-5.25	101
2001 Tax-exempt Refunding Series A	**0**	3,100	N/A	N/A
2002 Tax-exempt Refunding Series A	**100,615**	104,320	5.00-5.50	101
2002 Tax-exempt Improvement Series B	**271,140**	281,140	5.00-5.375	100
2002 Taxable Improvement Series C	**51,835**	68,765	5.27-5.51	P&I Plus Make-Whole Premium
2002 Tax-exempt Refunding Series D	**395,840**	418,670	4.00-5.25	100
2003 Tax-exempt Refunding Series A	**335,030**	335,030	4.75-5.00	100
2004 Tax-exempt Improvement Series A	**434,610**	434,870	2.50.-5.00	100
2004 Taxable Improvement Series B	**17,635**	17,635	3.57-4.52	P&I Plus Make-Whole Premium
2004 Tax-exempt Improvement Series M - CIBS	**19,664**	19,756	4.25-4.90	100
2004 Tax-exempt Improvement Series M - CABS	**8,813**	8,557	4.375-5.00	Accreted Value
2005 Tax-exempt Refunding Series A	**125,295**	125,295	5.25-5.50	100
2005 Tax-exempt Refunding Series B	**278,005**	278,005	5.00	100
2005 Tax-exempt Refunding Series C	**78,150**	78,150	4.125-4.75	100
2005 Tax-exempt Improvement Series M - CIBS	**10,920**	10,925	3.65-4.35	100
2005 Tax-exempt Improvement Series M - CABS	**4,631**	4,474	4.00-4.35	Accreted Value
2006 Tax-exempt Improvement Series A	**470,765**	0	3.25-5.00	100
2006 Taxable Improvement Series B	**129,115**	0	4.90-5.05	P&I Plus Make-Whole Premium
2006 Tax-exempt Improvement Series M - CIBS	**7,268**	0	3.75-4.20	100
2006 Tax-exempt Improvement Series M - CABS	**2,654**	0	4.00-4.20	Accreted Value
2006 Tax-exempt Refunding Series C	**114,755**	0	4.00-5.00	100
Total Revenue Obligations	**3,032,560**	2,482,392		
Less: Current Portion - Long-term Debt	**79,136**	69,674		
Total Long-term Debt - (Net of current portion)	**$ 3,190,690**	$ 2,657,160		

(1) Apply only to bonds outstanding as of 12/31/2006.

Maturities of long- term debt are as follows:

Year Ending December 31,	Capitalized Leases	Revenue Bonds	Revenue Obligations	Total Principal	Total Interest	Total
			(Thousands)			
2007	$ 2,738	$ 750	$ 75,725	$ 79,213	$ 160,239	$ 239,452
2008	2,563	785	99,635	102,983	157,919	260,902
2009	2,383	825	94,400	97,608	152,936	250,544
2010	1,685	3,370	107,325	112,380	147,590	259,970
2011	1,444	10,685	102,300	114,429	141,386	255,815
2012 - 2016	2,471	74,890	655,928	733,289	608,079	1,341,368
2017 - 2021	0	57,350	846,007	903,357	394,955	1,298,312
2022 - 2026	0	8,425	440,120	448,545	216,486	665,031
2027 - 2031	0	62,580	254,605	317,185	133,067	450,252
2032 - 2036	0	7,710	259,525	267,235	57,542	324,777
2037 - 2039	0	0	96,990	96,990	5,380	102,370
Less: Capitalized Lease Cushion of Credit Account	(3,388)	0	0	(3,388)	0	(3,388)
Total	$ 9,896	$ 227,370	$ 3,032,560	$ 3,269,826	$ 2,175,579	$ 5,445,405

Refunded and defeased bonds outstanding, original loss on refunding, and the unamortized loss at December 31, 2006 are as follows:

Refunding Issue	Refunded Bonds	Refunded and Defeased Bonds Outstanding	Original Loss	Unamortized Loss
			(Thousands)	
Cash Defeasance	$ 20,000 of the 1982 Series A	$ 0	$ 2,763	$ 1,142
1997 Refunding Series A	$ 100,000 of the 1978 Series 68,325 of the 1991 Refunding & Improvement Series B 37,495 of the 1991 Series D	0	16,990	10,523
Commercial Paper	$ 76,050 of the 1973 Series 105,605 of the 1977 Series 81,420 of the 1978 Series	0	2,099	724
1998 Refunding Series B	$ 25,000 of the 1992 Series B	0	1,970	1,050
2002 Refunding Series A	$ 113,380 of the 1992 Refunding Series A	0	23,378	13,052
2002 Refunding Series D	$ 293,250 of the 1993 Refunding Series A 25,900 of the 1993 Refunding Series B-1 25,900 of the 1993 Refunding Series B-2 132,095 of the 1993 Refunding Series C	0	73,613	46,116
2003 Refunding Series A	$ 336,385 of the 1993 Refunding Series C 15,750 of the 1995 Refunding Series A	0	57,064	46,710
2005 Refunding Series A	$ 74,970 of the 1995 Refunding Series A 37,740 of the 1995 Refunding Series B 20,080 of the 1996 Refunding Series A	0	23,864	21,549
2005 Refunding Series B	$ 2,590 of the 1995 Refunding Series A 100,320 of the 1995 Refunding Series B 192,305 of the 1996 Refunding Series A 21,505 of the 1996 Refunding Series B	0	73,749	66,584
2005 Refunding Series C	$ 86,335 of the 1993 Refunding Series C	0	12,125	10,934
2006 Refunding Series C	$ 105,005 of the 1999 Series A 10,000 of the 2002 Series B	115,005	7,054	6,778
Total		$ 115,005	$ 294,669	$ 225,162

The fair value of the Authority's debt is estimated based on quoted market prices for the same or similar issues or on the current rates offered to the Authority for debt with the same remaining maturities. Based on the borrowing rates currently available to the Authority for debt with similar terms and average maturities, the fair value of debt was approximately $3.6 billion and $3.1 billion at December 31, 2006 and 2005, respectively.

On January 13, 2006, the Authority's Board authorized the sale of approximately $599.9 million Revenue Obligations, 2006 Series A & B (2006 A & B Bonds). The 2006 Tax-Exempt Series A (2006A Bonds) totaled approximately $470.8 million. The 2006 Taxable Series B (2006B Bonds) totaled approximately $129.1 million. The 2006B Bonds were issued as taxable bonds to comply with IRS Private Use Regulations. The 2006 A & B Bonds were issued February 1, 2006 at an all-in true interest cost of 4.64 percent (aggregate true interest cost). The 2006 A & B Bonds will mature between January 1, 2007 and January 1, 2039.

On October 20, 2006, the Authority's Board authorized the sale of approximately $9.9 million Revenue Obligations, 2006 Series M (2006M Bonds). The 2006M Bonds consisted of Current Interest Bearing Bonds issued in denominations of $500 and Capital Appreciation Bonds issued in denominations of $200. The 2006M Bonds were issued directly by the Authority to residents of the State, customers of the Authority, members of electric cooperatives organized under the laws of the State, and electric customers of the City of Bamberg and City of Georgetown. Interest rates ranged from 3.75 percent in 2013 to 4.20 percent on the 2023 maturity.

On November 1, 2006, the Authority's Board authorized the sale of approximately $114.8 million Revenue Obligations, 2006 Refunding Series C (2006C Bonds). This refunding reduced the Authority's total debt service over the life of its bonds by approximately $11.2 million, resulting in an economic gain of approximately $8.1 million. The debt was issued at an all-in true interest rate of 4.20 percent. Yields ranged from 3.71 percent in 2014 to 4.04 percent on the 2022 maturity.

As of December 31, 2006, the Authority is in compliance with all debt covenants. All Authority debt is secured by a lien upon and pledge of the Authority's revenues. The Authority's bond indentures provide for certain restrictions, the most significant of which are:

1. The Authority covenants to establish rates sufficient to pay all debt service, required lease payments, capital improvement fund requirements, and all costs of operation and maintenance of the Authority's electric system and all necessary repairs, replacements, and renewals thereof;
2. The Authority is restricted from issuing additional parity bonds unless certain conditions are met.

Note 5 - Commercial Paper:

The Board has authorized the issuance of commercial paper not to exceed $500.0 million. The paper is issued for valid corporate purposes with a term not to exceed 270 days. For the years ended December 31, 2006 and 2005, the information related to commercial paper was as follows:

	2006	2005
Effective interest rate (at December 31)	**3.61%**	3.22%
Average annual amount outstanding (000's)	**$ 195,831**	$ 230,471
Average maturity	**49 Days**	50 days
Average annual effective interest rate	**3.57%**	2.64%

At December 31, 2006 the Authority had a Revolving Credit Agreement with Dexia Credit Local and BNP Paribas for $450.0 million. This agreement is used to support the Authority's issuance of commercial paper. There were no borrowings under the agreement during 2006 or 2005.

Commercial Paper outstanding at December 31, was as follows:

	2006	2005
	(Thousands)	
Commercial Paper-Gross	**$ 195,131**	$ 285,617
Less: Unamortized Discount		
on Taxable Commercial Paper	**59**	168
Commercial Paper-Net	**$ 195,072**	$ 285,449

Note 6 - Summer Nuclear Station:

The Authority and South Carolina Electric and Gas (SCE&G) are parties to a joint ownership agreement providing that the Authority and SCE&G shall own the Summer Nuclear Station with undivided interests of 33 1/3 percent and 66 2/3 percent, respectively. SCE&G is solely responsible for the design, construction, budgeting, management, operation, maintenance, and decommissioning of the Summer Nuclear Station, and the Authority is obligated to pay its ownership share of all costs relating thereto. The Authority receives 33 1/3 percent of the net electricity generated. At December

31, 2006 and 2005, the plant accounts before depreciation included approximately $497.5 million and $488.1 million, respectively, representing the Authority's investment, including capitalized interest, in the Summer Nuclear Station. The accumulated depreciation at December 31, 2006 and 2005 was $272.0 million and $258.6 million, respectively. For the years ended December 31, 2006 and 2005, the Authority's operation and maintenance expenses included $53.4 million and $52.6 million, respectively, for the Summer Nuclear Station.

Nuclear fuel costs are being amortized based on energy expended, which includes a component for estimated disposal costs of spent nuclear fuel which represents the unit-of-production method. This amortization is included in fuel expense and is recovered through the Authority's rates.

In 2002, SCE&G commenced a re-racking project of the on-site spent fuel pool. The new pool storage capability will permit full core off-load through 2018. Further on-site storage, if required, will be accomplished through dry cask storage or other technology as it becomes available.

The Nuclear Regulatory Commission (NRC) requires a licensee of a nuclear reactor to provide minimum financial assurance of its ability to decommission its nuclear facilities. In compliance with the applicable NRC regulations, the Authority established an external trust fund and began making deposits into this fund in September 1990. In addition to providing for the minimum requirements imposed by the NRC, the Authority makes deposits into an internal fund in the amount necessary to fund the difference between a site-specific decommissioning study completed in 2006 and the NRC's imposed minimum requirement. Based on these estimates, the Authority's one-third share of the estimated decommissioning costs of the Summer Nuclear Station equals approximately $178.9 million in 2006 dollars. As deposits are made, the Authority debits FERC account 532 - Maintenance of Nuclear Plant, an amount equal to the deposits made to the internal and external trust funds. These costs are recovered through the Authority's rates. Based on current decommissioning cost estimates, these funds, which totaled approximately $128.6 million (adjusted to market) at December 31, 2006, along with investment earnings, are estimated to provide sufficient funds for the Authority's one-third share of the total decommissioning costs. As such, additional deposits were suspended in 2006. Deposits may be reinstated based on future studies and conditions.

In 2004, the NRC granted a twenty-year extension to Summer Nuclear Station's operating license, extending it to August 6, 2042.

The Energy Policy Act of 1992 gave the Department of Energy (DOE) the authority to assess utilities for the decommissioning of its facilities used for the enrichment of uranium included in nuclear fuel costs. In order to decommission these facilities, the DOE estimated that it would need to charge utilities a total of $150.0 million, indexed for inflation, annually for 15 years based on enrichment services used by utilities in past periods. Based on an estimate from SCE&G covering the 15 years, the Authority's remaining one-third share of the liability at December 31, 2006 totaled approximately $66,000. Such amount has been deferred and will be recovered through rates as paid. These costs are included on the accompanying balance sheets in "Deferred debits and other noncurrent assets - Other" and "Other deferred credits and noncurrent liabilities."

On October 20, 2006, the Authority's Board of Directors authorized management to expend up to $390.0 million through 2010 in continuing actions necessary to design, permit, procure, construct and install two 1100 MW units at Summer Nuclear Station. This authorization includes $31.0 million previously included in the capital improvement program for 2006 through 2008. Construction may not commence until the Board has approved a final budget and construction schedule. The Authority and SCE&G have entered into a short-term Bridge Agreement which contemplates an Authority ownership interest of 45 percent in the two units and governs the relationship of the Authority and SCE&G while proceeding toward obtaining a construction and operating license. The Authority anticipates the Bridge Agreement will be replaced by more permanent agreements governing construction, operation and decommissioning of the units. The Bridge Agreement allows either or both parties to withdraw from the project under certain circumstances.

Note 7 - Leases:

The Authority has capital lease contracts with Central Electric Power Cooperative, Inc. (Central), covering a steam electric generating plant, transmission facilities, and various other facilities. The remaining lease terms range from 1 to 8 years. Quarterly lease payments are based on a sum equal to the interest on and principal of Central's indebtedness to the Rural Utilities Service (formerly Rural Electrification Administration) for funds borrowed to construct the above mentioned facilities. The Authority has options to purchase the leased properties at any time during the period of the lease agreements for sums equal to Central's indebtedness remaining outstanding on the properties at the time the options are exercised or to return the properties at the termination of the lease. The Authority plans to exercise each and every option to acquire ownership of such facilities prior to expiration of the leases.

In addition, during 2004, the Authority became a joint participant with Central in the Rural Utilities Service (RUS) cushion of credit payments programs (COC). This program allows the borrower to build up a cushion of money for future application toward their debt while earning 5 percent interest. During 2006, approximately $833,000 in lease payments were made from the COC account. At December 31, 2006 and 2005, the balance in the Authority's portion of the joint account was approximately $3.4 million and $4.0 million, respectively.

Future minimum lease payments on Central leases at December 31, 2006 were as follows:

Year ending December 31,	(Thousands)
2007	$ 3,335
2008	3,038
2009	2,737
2010	1,934
2011	1,610
2012 - 2014	2,619
Total minimum lease payments	$ 15,273
Less amounts representing interest	1,989
Principal Balance	$ 13,284
Less: Cushion of Credit Account	3,388
Balance at December 31, 2006	$ 9,896

Property under capital leases and related accumulated amortization included in utility plant at December 31, 2006, totaled approximately $89.5 million and $81.9 million, respectively, and at December 31, 2005, totaled $89.6 million and $79.5 million, respectively.

Operating lease payments totaled approximately $7.3 million and $6.5 million during the years ended December 31, 2006 and 2005, respectively. Included in these operating lease payments are periodic expenses related to leased coal cars, which are initially reflected in fuel inventory and subsequently reported in fuel expense based on the tons burned. The terms of the current coal car leases vary from one month to twenty-six months, with the longest lease expiring in 2009. The approximate amounts for the coal car leases to be paid for the years 2007 through 2009 are $5.2 million, $4.9 million, and $296,000, respectively.

Note 8 - Contracts with Electric Power Cooperatives:

Central is a generation and transmission cooperative that provides wholesale electric service to each of the 15 distribution cooperatives and Saluda River Electric Cooperative, Inc. (Saluda) which are members of Central. Power supply and transmission services are provided to Central in accordance with a power system coordination and integration agreement (the Coordination Agreement). Under this agreement, the Authority is the sole supplier of energy needs for Central excluding energy Central and Saluda receive from the Southeastern Power Administration (SEPA) and Saluda's ownership interest in the Catawba Nuclear Station. Saluda is a generation cooperative that provides wholesale electric service to each of the five electric cooperatives (the "Saluda Cooperatives") that are members of Saluda. Under agreements between Central and the Saluda Cooperatives, each of the Saluda Cooperatives becomes a member of Central at the earlier of (i) such time as Saluda ceases its corporate existence or (ii) January 31, 2009. At such time the Saluda Cooperatives become all requirements customers of Central and receive their power requirements from the Authority under the Coordination Agreement.

Central, under the terms of the contract with the Authority, has the right to audit costs billed to them under the cost of service contract. Differences as a result of this process are accrued if they are probable and estimable under FASB Statement No. 5, “Accounting for Contingencies” (FASB 5). To the extent that differences arise due to this process, prospective adjustments are made to cost of service and are reflected in operating revenues in the accompanying Combined Statements of Revenues, Expenses and Changes in Net Assets. Such adjustments in 2006 and 2005 were not material to the Authority’s overall operating revenue.

Note 9 - Commitments and Contingencies:

Budget - The Authority’s capital budget provides for expenditures of approximately $686.4 million during the year ending December 31, 2007 and $1.2 billion during the two years thereafter. These expenditures include $1.2 billion for new generating units being constructed to begin operation in 2007, 2009, 2012, 2016 and 2019, and $49.3 million for environmental compliance expenditures. The total project costs of the new generating units to begin operation in 2007, 2009, and 2012 are $671.7 million, $755.0 million, and $998.0 million, respectively. Capital expenditures will be financed by internally generated funds and a combination of taxable and tax-exempt debt.

Purchase Commitments - The Authority has contracted for long-term coal purchases under contracts with estimated outstanding minimum obligations after December 31, 2006. The disclosure of minimum obligations below is based on the Authority's contract rates and represents management's best estimate of future expenditures under long-term arrangements.

Year ending December 31,	(Thousands)
2007	$ 387,262
2008	251,186
2009	164,366
2010	140,846
2011	119,346
2012 - 2016	65,491
Total	$ 1,128,497

The Authority has outstanding minimum obligations under an existing long-term and an existing short-term purchased power contract as of December 31, 2006. The obligations were approximately $72.9 million with a remaining term of 28 years and $75,150 with a remaining term of three months. Also, as of December 31, 2006, the Authority has entered into a lease agreement for output of a hydro electric generating facility. The lease agreement has been executed by the parties and is expected to become effective in 2007.

CSX Transportation, Inc. (CSX) provides substantially all rail transportation service for the Authority's coal-fired generating units. During 2002, a new agreement was signed with an effective date of January 1, 2003. This contract will continue to apply a price per ton of coal moved, with the minimum being set at four million tons per year.

The Authority has commitments for nuclear fuel enrichment and fabrication contracts which are contingent upon the operating requirements of the nuclear unit. As of December 31, 2006, these commitments total approximately $64.4 million over the next eight years.

In 2003, the Authority amended the Rainey Generating Station Long-Term Service Agreement (LTSA) with General Electric International, Inc. in the approximate amount of $90.0 million. The agreement provides a contract performance manager (CPM), initial spare parts, parts and services for specified planned maintenance outages, remote monitoring and diagnostics of the turbine generators, and combustion tuning for the gas turbines. In exchange for reduced pricing and added features, the contract term was extended to 2025, but can be terminated for convenience on Rainey 2A and 2B in 2008, and on Rainey 1 in 2013, depending on unit operation. The previous agreement was in the approximate amount of $76.0 million and was effective through 2009. The Authority's Board has approved recovery of the LTSA on a straight-line basis over the term of the agreement.

On January 31, 2005, the Authority entered a $4.0 million Parts and Services Agreement with General Electric International, Inc. (GEII) for maintenance of the Rainey 3, 4, and 5 gas turbines. GEII will supply parts, repair services, and technical direction for one combustion inspection and one hot gas path inspection for each of the three gas turbines. The term of the agreement, which is dependent upon unit operation, is expected to be nine years.

Effective November 1, 2000, the Authority contracted with Transcontinental Gas Pipeline Corporation (TRANSCO) to supply gas transportation needs for its Rainey Generating Station. This is a firm transportation contract covering a maximum of 80,000 decatherms per day for 15 years.

Risk Management - The Authority is exposed to various risks of loss related to torts; theft of, damage to, and destruction of assets; business interruption; and errors and omissions. The Authority purchases commercial insurance to cover these risks, subject to coverage limits and various exclusions. Settled claims resulting from these risks have not exceeded commercial insurance coverage in any of the past three years. Policies are subject to deductibles ranging from $5,000 to $1.0 million, with the exception of named storm losses which carry deductibles from $1.0 million up to $5.0 million. Also a $1.4 million general liability self-insured layer exists between the Authority's primary and excess liability policies. During 2006, there were no losses incurred or reserves recorded for general liability.

The Authority is self-insured for auto, dental, worker's compensation and environmental incidents that do not arise out of an insured event. The Authority purchases commercial insurance, subject to coverage limits and various exclusions, to cover automotive exposure in excess of $2.0 million per incident. Risk exposure for the dental plan is limited by plan provisions. There have been no third-party claims for environmental damages for 2006 or 2005. Claims expenditures and liabilities are reported when it is probable that a loss has occurred and the amount of the loss can be reasonably estimated.

At December 31, 2006, the amount of the self-insured liabilities for auto, dental, worker's compensation and environmental remediation was approximately $2.4 million. The liability is the Authority's best estimate based on available information.

Changes in the reported liability are as follows:

	2006	2005
	(Thousands)	
Unpaid claims and claim expense at beginning of year	$ 2,597	$ 2,375
Incurred claims and claim adjustment expenses:		
Provision for insured events of the current year	1,375	1,724
Payments for current and prior years	1,570	1,502
Total unpaid claims and claim expenses at end of year	$ 2,402	$ 2,597

The Authority pays insurance premiums to certain other State agencies to cover risks that may occur in normal operations. The insurers promise to pay to, or on behalf of, the insured for covered economic losses sustained during the policy period in accordance with insurance policy and benefit program limits. Several State funds accumulate assets, and the State itself assumes all risks for the following:

1. Claims of covered employees for health benefits (Employee Insurance Program); not applicable for worker's compensation injuries;
2. Claims of covered employees for basic long-term disability and group life insurance benefits (Retirement System).

Employees elect health coverage through either a health maintenance organization or through the State's self-insured plan. All other coverages listed above are through the applicable State self-insured plan except that additional group life and long-term disability premiums are remitted to commercial carriers. The Authority assumes the risk for claims of employees for unemployment compensation benefits and pays claims through the State's self-insured plan.

Nuclear Insurance - The maximum liability for public claims arising from any nuclear incident has been established at $10.9 billion by the Price-Anderson Indemnification Act. This $10.9 billion would be covered by nuclear liability insurance of about $300.0 million per site, with potential retrospective assessments of up to $100.6 million per licensee for each nuclear incident occurring at any reactor in the United States (payable at a rate not to exceed $15.0 million per incident, per year). Based on its one-third interest in Summer Nuclear Station, the Authority could be responsible for the maximum assessment of $33.5 million, not to exceed approximately $5.0 million per incident, per year. This amount is subject to further increases to reflect the effect of (i) inflation, (ii) the licensing for operation of additional nuclear reactors, and (iii) any increase in the amount of commercial liability insurance required to be maintained by the NRC.

Additionally, SCE&G and the Authority maintain, with Nuclear Electric Insurance Limited (NEIL), $500.0 million primary and $1.5 billion excess property and decontamination insurance to cover the costs of cleanup of the facility in the event of an accident. In addition to the premiums paid on the primary and excess policies, SCE&G and the Authority could also be assessed a retrospective premium, not to exceed 10 times the annual premium of each policy, in the event of property damage to any nuclear generating facility covered by NEIL. Based on current annual premiums and the Authority's one-third interest, the Authority's maximum retrospective premium would be $2.6 million for the primary policy and $2.9 million for the excess policy. SCE&G and the Authority also maintain accidental outage insurance to cover replacement power costs (within policy limits) associated with an insured property loss. This policy also carries a potential retrospective assessment of $1.5 million.

The Authority is self-insured for any retrospective premium assessments, claims in excess of stated coverage, or cost increases due to the purchase of replacement power associated with an uninsured event. Management does not expect any retrospective assessments, claims in excess of stated coverage, or cost increases for any periods through December 31, 2006.

Clean Air Act - The Authority endeavors to ensure that its facilities comply with applicable environmental regulations and standards.

In addition to the existing Clean Air Act (CAA) Federal Acid Rain (SO2) and the State NOx Implementation Plan (SIP) Call Programs, the EPA recently promulgated two Clean Air Regulations: Clean Air Interstate Rule (CAIR), and Clean Air Mercury Rule (CAMR). Both CAIR and CAMR were effective in July 2005. Together, they address further reductions in SO2, NOx, and Hg. The Authority, along with other utilities, has challenged the SO2 allocation portion of CAIR, and is participating in a stakeholders process to develop with South Carolina Department of Health and Environmental Control (DHEC) a SIP for CAIR and CAMR in South Carolina. The proposed SIP for CAIR and CAMR is currently undergoing review.

The Authority has been operating under a recent settlement agreement, called the Consent Decree, which became effective June 24, 2004. The settlement with the Environmental Protection Agency (EPA) and DHEC was related to certain environmental issues associated with coal-fired units. It involved the payment of a civil penalty, an agreement to perform certain environmentally beneficial projects, and the expenditure of capital costs of approximately $205.3 million to achieve emissions reductions over the period ending 2013. These capital costs are expected to be largely offset by savings resulting from a reduced need to purchase emission credits.

Safe Drinking Water Act - The Authority continues to monitor for Safe Drinking Water Act regulatory issues impacting electrical utilities. DHEC has primacy for regulatory authority of potable water systems in South Carolina. The State Primary Drinking Water Regulation, R.61-58, governs the design, construction, and operational management of all potable water systems in South Carolina subject to and consistent with the requirements of the Safe Drinking Water Act and the implementation of federal drinking water regulations. The Authority endeavors to manage its potable water systems for compliance with R.61-58.

Clean Water Act - The Clean Water Act (CWA) prohibits the discharge of pollutants, including heat, from point sources into waters of the United States, except as authorized in the National Pollutant Discharge Elimination System (NPDES) permit program. The CWA also requires that cooling water intake structures reflect the best technology available for minimizing adverse environmental impact. DHEC has been delegated NPDES permitting authority by the EPA and administers the program for the State. DHEC has stated that if there should be a delay in renewing permits beyond the expiration of the existing permits, the permits will be extended by operation of law and the Authority may still discharge pursuant to Section 1-23-370 of the Code of Laws of South Carolina 1976, as amended.

Each station's stormwater discharge is covered under the State's NPDES General Permit No. SCR000000. The Authority believes it is in compliance with this permit.

Industrial wastewater discharges from all stations are governed by individual NPDES permits. Cross Generating Station's NPDES permit was reissued on November 3, 2006 and it expires on August 31, 2010. The Grainger Generating Station NPDES permit was reissued effective October 1, 2002, with an expiration date of September 30, 2006. An application for renewal of the Grainger Generating Station NPDES permit was submitted on March 28, 2006. The Jefferies Generating Station NPDES permit was reissued effective March 1, 2003, with an expiration date of February 29, 2008. The Winyah Generating Station NPDES permit was reissued effective October 1, 2000, with an expiration date of September 30, 2005. An application for renewal of the Winyah Generating Station NPDES permit was submitted on March 29, 2005. The Rainey Generating Station NPDES permit was reissued effective August 1, 2003, with an expiration date of July 31, 2008. The Authority's Regional Water System's NPDES permit was reissued effective October 1, 2001 with an expiration date of October 31, 2006. An application for renewal was submitted April 24, 2006.

The EPA revised sections of the CWA relating to Spill Prevention Control and Counter-measures (SPCC). These revisions require that regulated facilities amend their current SPCC plans to meet the new standard. The Authority is in the process of compliance with the new standard before the regulatory required implementation date of July 1, 2009.

The EPA published regulations implementing Section 316(b) of the CWA for existing electric generating facilities in the Federal Register on July 9, 2004. These regulations require that cooling water intake structures reflect the Best Technology Available (BTA) for minimizing adverse environmental impacts such as the impingement of fish and shellfish on the intake structures and the entrainment of eggs and larvae through cooling water systems. These regulations, which became effective September 7, 2004, establish performance standards for reduction in impingement mortality and entrainment. The Jefferies Generating Station and the Grainger Generating Station are the Authority's only facilities affected by the new rule, and are currently in compliance with the requirements.

Hazardous Substances and Wastes - Section 311 of the CWA imposes substantial penalties for spills of Federal EPA-listed hazardous substances into water and for failure to report such spills. The Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (CERCLA) provides for the reporting requirements to cover the release of hazardous substances generally into the environment, including water, land and air. When these substances are processed, stored, or handled, reasonable and prudent methods are employed to prevent a release to the environment.

Additionally, the EPA regulations under the Toxic Substances Control Act impose stringent requirements for labeling, handling, storing and disposing of polychlorinated byphenyls (PCB) and associated equipment. There are regulations covering PCB notification and manifesting, restrictions on disposal of drained electrical equipment, spill cleanup record-keeping requirements, etc. The Authority has a comprehensive PCB management program in response to these regulations.

Under the CERCLA and Superfund Amendments and Reauthorization Act (SARA), the Authority could be held responsible for damages and remedial action at hazardous waste disposal facilities utilized by it, if such facilities become part of a Superfund effort. CERCLA liability, which is strict, joint and several, can be imposed on any generator of hazardous substances who arranged for disposal or treatment at the affected facility. Moreover, under SARA, the Authority must comply with a program of emergency planning and a "Community Right-To-Know" program designed to inform the public about more routine chemical hazards present at the facilities. Both programs have stringent enforcement provisions.

The Authority endeavors to comply with the applicable provisions of CERCLA and SARA, but it is not possible to determine if some liability may be imposed in the future for past waste disposal or compliance with new regulatory requirements. In addition to handling hazardous substances, the Authority generates solid waste associated with the combustion of coal, the vast majority of which is fly ash, bottom ash and scrubber sludge. These wastes are exempt from hazardous wastes regulation under the Resource Conservation and Recovery Act (RCRA).

Also under RCRA, the Authority may be required to undertake corrective action with respect to any leaking underground petroleum storage tank and is liable for the costs of any corrective action taken by the EPA, including compensating third parties for personal injuries and property damage. The Authority implemented a program which assessed all underground storage tanks (USTs). As a result of the assessment, the number of USTs has been significantly reduced. The Authority is required by the EPA and DHEC to maintain documentation of sufficient funds or insurance to cover environmental impacts.

Open Access Transmission Tariff - On April 24, 1996, the FERC issued Orders 888 and 889: the implementing rules for mandatory non-discriminatory open access over the transmission systems of jurisdictional entities. Order 888 required each jurisdictional transmission owner to file with FERC by July 9, 1996 a pro forma open access transmission tariff (OATT).

Order 888 also requires that a non-jurisdictional utility, such as the Authority, must agree to provide comparable transmission service over its transmission facilities in order to receive service from a jurisdictional utility under its OATT.

In order to ensure it would be able to receive transmission service from jurisdictional utilities, in 1997 the Authority adopted an open access transmission tariff substantially in conformance with the tariff required to be filed by jurisdictional utilities.

On May 19, 2006, the FERC issued a Notice of Proposed Rulemaking (NOPR) to consider possible reforms to Order 888 and the pro forma OATT. The purpose of the NOPR is to ensure that the OATT achieves its original purpose, namely, that transmission services are provided on a basis that is just, reasonable and not unduly discriminatory or preferential. This is the first comprehensive review of OATT since Order 888 was issued in 1996. FERC issued a Final Rule in this rule-making proceeding on February 16, 2007 (Order 890) making substantial revisions to the pro forma OATT. Among other things, Order 890 eliminates the existing wide discretion that transmission providers have in calculating Available Transfer Capability, requires transmission providers to participate in an open, transparent, and coordinated planning process and makes other modifications to improve and clarify ambiguous provisions, among other things.

Regional Transmission Organizations (RTOs) - Presently there are no active RTO development activities in the southeastern United States. Two previous efforts to develop a RTO for the southeastern United States have resulted in failure. In each case, the effort failed because of the lack of demonstrable benefits from forming a RTO and the lack of consensus support and acceptance from all applicable state and federal agencies for the proposed RTO structure.

Whether a new RTO development effort will arise in the southeastern United States is unknown at this time. Any potential impact on the Authority of such a new effort is likewise unknown.

Energy Policy Act of 2005 - On August 8, 2005, President Bush signed into law the Energy Policy Act of 2005 (EPACT 2005). EPACT 2005 is the first comprehensive energy legislation enacted by Congress since the Energy Policy Act of 1992 (EPACT 1992). However, unlike EPACT 1992, EPACT 2005 does not represent a fundamental change from the immediate past.

EPACT 2005 includes several provisions intended to promote the use of nuclear power, including the extension of the Price-Anderson Act for 20 years (until 2025), as well as on a limited basis, provisions intended to encourage the construction of advanced nuclear facilities including possible loan guarantees, standby support and production tax credits.

EPACT 2005 introduces a new Section 211A of the Federal Power Act (FPA), "Open Access by Unregulated Transmitting Utilities." Under Section 211A, FERC has authority to require an otherwise non-jurisdictional transmission owner owning or operating transmission facilities, such as Santee Cooper, to provide transmission services at (1) rates that are comparable to those they charge themselves, and (2) terms and conditions that are comparable to those they charge themselves and that are not unduly discriminatory or preferential. EPACT 2005 also introduces a new Section 217 of the FPA, "Native Load Service Obligation." Under this provision, any load-serving entity with a service obligation, including an otherwise non-jurisdictional transmission owner, is entitled to use its transmission capacity to meet its native load service obligation in preference to other uses of the grid.

EPACT 2005 introduces a new Section 215 of the FPA which authorizes the FERC to certify an entity as the nation’s Electric Reliability Organization (ERO) that would propose reliability standards that would be reviewed by FERC before becoming final. On July 20, 2006, the FERC issued an order certifying the North American Electric Reliability Corporation (NERC) as ERO.

On April 4, 2006, NERC submitted certain proposed reliability standards to FERC for approval under Section 215 of the FPA. FERC has opened a rulemaking proceeding to consider those proposed standards. A Final Order acting on the proposed standards is expected to be issued in the first quarter of 2007.

Legal Matters - The Authority is a party in various claims and lawsuits that arise in the conduct of its business. Although the results of litigation cannot be predicted with certainty, in the opinion of management and Authority counsel, the ultimate disposition of these matters will not have material adverse effect on the financial position or results of operations of the Authority, except as described below.

Landowners located along the Santee River contend that the Authority is liable for damage to their real estate as a result of flooding that has occurred since the U.S. Army Corps of Engineers' Cooper River Rediversion Project was completed in 1985. A jury trial held in 1997 in the U.S. District Court, Charleston, SC, returned a verdict against the Authority on certain causes of action. The Authority appealed the decision to the Fourth Circuit Court of Appeals which, after oral arguments, remanded the case to the District Court. In 2006, the Corps moved to intervene and transfer the District Court action to the Court of Federal Claims. The Authority joined in this motion. The District Court denied the motion and the issue is on appeal to the United States Court of Appeals for the Federal Circuit. No estimate relative to potential loss to the Authority can be made at this time.

The U.S. Army Contract Board of Appeals has determined that the contract between the Corps and the Authority requires that the Corps indemnify the Authority for certain claims arising out of the construction and operation of the project.

Note 10 - Retirement Plan:

Substantially all Authority regular employees must participate in one of the components of the South Carolina Retirement System (System), a cost sharing, multiple-employer public employee retirement system, which was established by Section 9-1-20 of the South Carolina Code of Laws. The payroll for active employees covered by the System for each of the years ended December 31, 2006 and 2005 was approximately $101.0 million and $96.0 million, respectively.

Vested employees who retire at age 65 or with 28 years of service at any age are entitled to a retirement benefit, payable monthly for life. The annual benefit amount is equal to 1.82 percent of their average final compensation times years of service. Benefits fully vest on reaching five years of service. Reduced retirement benefits are payable as early as age 55 with 25 years of service. The System also provides death and disability benefits. Benefits are established by State statute.

Effective January 1, 2001, Section 9-1-2210 of the South Carolina Code of Laws allowed employees eligible for service retirement to participate in the Teacher and Employee Retention Incentive (TERI) Program. TERI participants may retire and begin accumulating retirement benefits on a deferred basis without terminating employment for up to five years. Upon termination of employment or at the end of the TERI period, whichever is earlier, participants will begin receiving monthly service retirement benefits which include any cost of living adjustments granted during the TERI period. Because participants are considered retired during the TERI period, they do not earn service credit or disability retirement benefits. Effective July 1, 2005, TERI employees began "re-contributing" to the System at the prevailing rate. However, no service credit is earned under the new regulations. The group life insurance of one times annual salary was re-established for TERI participants. Each participant is entitled to be paid for up to 45 days of accumulated unused annual vacation leave upon retirement.

Article X, Section 16 of the South Carolina Constitution requires that all State-operated retirement plans be funded on a sound actuarial basis. Title 9 of the South Carolina Code of Laws (as amended) prescribes requirements relating to membership, benefits, and employee/employer contributions.

All employees are required by State statute to contribute to the System at the prevailing rate (currently 6.50 percent). The Authority is required by the same statute to contribute 8.05 percent of total payroll for retirement and an additional 0.15 percent for group life. The contribution requirement for the years ended December 31, 2006 and 2005 was approximately $8.4 million and $7.7 million, respectively, from the Authority and $6.4 million and $5.9 million, respectively from employees. The Authority made 100 percent of the required contributions for each of the years ended December 31, 2006 and 2005.

The System issues a stand alone financial report that includes all required supplementary information. The report may be obtained by writing to: South Carolina Retirement System, P.O. Box 11960, Columbia, S.C. 29211.

Effective July 1, 2002, new employees have a choice of type of retirement plan in which to enroll. The State Optional Retirement Plan (State ORP) which is a defined contribution plan is an alternative to the System retirement plan which is a defined benefit plan. The contribution amounts are the same, (6.50 percent employee cost and 8.05 percent employer cost) however, 5 percent of the employer amount is directed to the vendor chosen by the employee and the remaining 3.05 percent is to the Retirement System. As of December 31, 2006, thirty-one of the Authority's employees were participants in the State ORP and consequently the related payments are not material.

The Authority is the non-operating owner (one-third share) of SCE&G's V.C. Summer Nuclear Station. As such, the Authority is responsible for funding its share of pension requirements for the nuclear station personnel in accordance with FASB Statement No. 87, "Employers' Accounting for Pensions" (FASB 87). The established pension plan generates earnings which are shared proportionately and used to reduce the allocated funding.

As of December 31, 2006 and 2005, the Authority had over-funded its share of the plan FASB 87 requirements by $10.5 million and $10.2 million, respectively. This receivable will be applied to future years as additional expenditures are required to meet the Authority's funding obligation. The pre-funded amounts are in "Other" within "Deferred debits and other noncurrent assets" on the balance sheet.

The Authority also provides retirement benefits to certain employees designated by management and the Board under supplemental executive retirement plans. Benefits are established and may be amended by management and the Authority's Board and include retirement benefit payments for a specified number of years and death benefits. The cost of these benefits is actuarially determined annually. Beginning in 2006, the supplemental executive retirement plans were segregated into the internal and external funds. The qualified benefits are funded externally with the annual cost set aside in a trust administered by a third party. The pre-2006 retiree benefits and the non-qualified benefits are funded internally with the annual cost set aside and managed by the Authority. The cost for 2006 and 2005 was approximately $2.1 million and $2.0 million, respectively. The accrued liability at December 31, 2006 and 2005 was approximately $5.7 million and $8.0 million, respectively.

Note 11 - Other Postretirement Benefits:

The South Carolina Retirement System provides certain health, dental, and life insurance benefits for retired employees of the Authority. Substantially all of the Authority's employees may become eligible for these benefits if they retire at any age with 28 years of service or at age 60 with at least 20 years of service. Currently, approximately 509 retirees meet these requirements. The cost of the health, dental and life insurance benefits are recognized as expense as the premiums are paid. For each of the years ended December 31, 2006 and 2005, these costs totaled approximately $2.3 million and $2.0 million, respectively. The Authority is the non-operating owner (one-third share) of SCE&G's V.C. Summer Nuclear Station. As such the Authority is responsible for funding its share of other post employment benefits costs for the station's employees. The liability balances as of December 31, 2006 and 2005 were approximately $7.7 million and $7.3 million, respectively.

During their first 10 years of service, full-time employees can earn up to 15 days vacation leave per year. After 10 years of service, employees earn an additional day of vacation leave for each year of service over 10 until they reach the maximum of 25 days per year. Employees earn annually two hours per pay period, plus twenty additional hours at year-end for sick leave.

Employees may carry forward up to 45 days of vacation leave and 180 days of sick leave from one calendar year to the next. Upon termination, the Authority pays employees for accumulated vacation leave at the pay rate then in effect. In addition, the Authority pays employees upon retirement 20 percent of their accumulated sick leave at the pay rate then in effect.

Note 12 - Credit Risk and Major Customers:

Sales to two major customers for the years ended December 31, 2006 and 2005 were as follows:

	2006	2005
	(Thousands)	
Central (including Saluda)	**$ 722,000**	$ 676,000
Alumax of South Carolina	**$ 147,000**	$ 143,000

No other customer accounted for more than 10 percent of the Authority's sales for either of the years ended December 31, 2006 or 2005.

The Authority maintains an allowance for uncollectible accounts based upon the expected collectibility of all accounts receivable.

Note 13 - Storm Damage:

In August 2004, the Authority's system sustained damages from Hurricanes Charley and Gaston. As of December 31, 2006, cost estimates to repair and replace the Authority's damaged facilities are approximately $9.2 million with $3.9 million representing damage to the Jefferies Steam and Hydro Generation facilities and $3.1 million representing damage to the East and West Dams in Pinopolis. The remaining costs reflect damage to other facilities including the transmission and distribution systems, seawalls at the Wampee and Somerset properties, dump truck bodies, and costs of clearing roads and subdivisions.

The Authority has filed for and anticipates disaster relief assistance from federal sources. This assistance is expected to be 75 percent of storm damage costs or approximately $6.8 million.

Through December 31, 2006, the Authority had received $3.1 million in federal assistance on both storms. The Authority does not expect to increase rates due to the impact of Hurricanes Charley and Gaston and foresees no measurable long-term impact on its operations or the demand for electricity by its customers.

Note 14 – Subsequent Event:

The Authority's new 600-MW pulverized coal-fired facility at Cross Generating Station Unit 3 began commercial operation on January 1, 2007.