

**UNITED STATES  
SECURITIES AND EXCHANGE COMMISSION  
Washington, DC 20549**

**FORM 10-Q**

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

**For the quarterly period ended September 30, 2006**

**OR**

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

**For the Transition Period from \_\_\_\_\_ to \_\_\_\_\_**

Commission File Number	Registrant, State of Incorporation, Address and Telephone Number	I.R.S. Employer Identification No.
1-8809	SCANA Corporation (a South Carolina corporation) 1426 Main Street, Columbia, South Carolina 29201 (803) 217-9000	57-0784499
1-3375	South Carolina Electric & Gas Company (a South Carolina corporation) 1426 Main Street, Columbia, South Carolina 29201 (803) 217-9000	57-0248695
1-11429	Public Service Company of North Carolina, Incorporated (a South Carolina corporation) 1426 Main Street, Columbia, South Carolina 29201 (803) 217-9000	56-2128483

Indicate by check mark whether the registrants: (1) have 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 registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. SCANA Corporation Yes  No  South Carolina Electric & Gas Company Yes  No  Public Service Company of North Carolina, Incorporated Yes  No

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

SCANA Corporation	Large accelerated filer <input checked="" type="checkbox"/>	Accelerated filer <input type="checkbox"/>	Non-accelerated filer <input type="checkbox"/>
South Carolina Electric & Gas Company	Large accelerated filer <input type="checkbox"/>	Accelerated filer <input type="checkbox"/>	Non-accelerated filer <input checked="" type="checkbox"/>
Public Service Company of North Carolina, Incorporated	Large accelerated filer <input type="checkbox"/>	Accelerated filer <input type="checkbox"/>	Non-accelerated filer <input checked="" type="checkbox"/>

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

SCANA Corporation Yes  No  South Carolina Electric & Gas Company Yes  No  Public Service Company of North Carolina, Incorporated Yes  No

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Registrant	Description of Common Stock	Shares Outstanding at October 31, 2006
SCANA Corporation	Without Par Value	116,493,638
South Carolina Electric & Gas Company	\$4.50 Par Value	40,296,147 <sup>(a)</sup>
Public Service Company of North Carolina, Incorporated	Without Par Value	1,000 <sup>(a)</sup>

<sup>(a)</sup>Owned beneficially and of record by SCANA Corporation.

This combined Form 10-Q is separately filed by SCANA Corporation, South Carolina Electric & Gas Company and Public Service Company of North Carolina, Incorporated. Information contained herein relating to any individual company is filed by such company on its own behalf. Each company makes no representation as to information relating to the other companies.

Public Service Company of North Carolina, Incorporated meets the conditions set forth in General Instruction H(1)(a) and (b) of Form 10-Q and therefore is filing this form with the reduced disclosure format allowed under General Instruction H(2).

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SEPTEMBER 30, 2006

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**SCANA CORPORATION  
FINANCIAL SECTION**

**PART I. FINANCIAL INFORMATION**

**ITEM 1. FINANCIAL STATEMENTS**

SCANA CORPORATION  
CONDENSED CONSOLIDATED BALANCE SHEETS  
(Unaudited)

Millions of dollars	September 30, 2006	December 31, 2005
<b>Assets</b>		
Utility Plant In Service	\$ 9,195	\$ 8,999
Accumulated Depreciation and Amortization	(2,776)	(2,688)
	6,419	6,311
Construction Work in Progress	258	175
Nuclear Fuel, Net of Accumulated Amortization	41	28
Acquisition Adjustments	230	230
Utility Plant, Net	6,948	6,744
Nonutility Property and Investments:		
Nonutility property, net of accumulated depreciation of \$69 and \$62	122	108
Assets held in trust, net - nuclear decommissioning	55	52
Other investments	90	87
Nonutility Property and Investments, Net	267	247
Current Assets:		
Cash and cash equivalents	101	62
Receivables, net of allowance for uncollectible accounts of \$12 and \$25	496	881
Receivables - affiliated companies	24	24
Inventories (at average cost):		
Fuel	284	284
Materials and supplies	95	79
Emission allowances	24	7
Prepayments and other	43	54
Deferred income taxes	32	26
Total Current Assets	1,099	1,417
Deferred Debits and Other Assets:		
Pension asset, net	313	303
Emission allowances	27	47
Regulatory assets	641	617
Other	136	154
Total Deferred Debits and Other Assets	1,117	1,121
<b>Total</b>	<b>\$ 9,431</b>	<b>\$ 9,529</b>

Millions of dollars	September 30, 2006	December 31, 2005
<b>Capitalization and Liabilities</b>		
Shareholders' Investment:		
Common equity	\$ 2,820	\$ 2,677
Preferred stock (Not subject to purchase or sinking funds)	106	106
<b>Total Shareholders' Investment</b>	<b>2,926</b>	<b>2,783</b>
Preferred Stock, net (Subject to purchase or sinking funds)	8	8
<b>Long-Term Debt, net</b>	<b>3,075</b>	<b>2,948</b>
<b>Total Capitalization</b>	<b>6,009</b>	<b>5,739</b>
Current Liabilities:		
Short-term borrowings	304	427
Current portion of long-term debt	44	188
Accounts payable	238	471
Accounts payable - affiliated companies	23	26
Customer deposits and customer prepayments	83	70
Taxes accrued	124	112
Interest accrued	49	52
Dividends declared	51	47
Other	115	107
<b>Total Current Liabilities</b>	<b>1,031</b>	<b>1,500</b>
Deferred Credits and Other Liabilities:		
Deferred income taxes, net	938	940
Deferred investment tax credits	121	121
Asset retirement obligations	335	322
Postretirement benefits	155	148
Regulatory liabilities	715	615
Other	127	144
<b>Total Deferred Credits and Other Liabilities</b>	<b>2,391</b>	<b>2,290</b>
Commitments and Contingencies (Note 5)		
<b>Total</b>	<b>\$ 9,431</b>	<b>\$ 9,529</b>

See Notes to Condensed Consolidated Financial Statements.

SCANA CORPORATION  
CONDENSED CONSOLIDATED STATEMENTS OF INCOME  
(Unaudited)

Millions of dollars, except per share amounts	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
<b>Operating Revenues:</b>				
Electric	\$ 584	\$ 619	\$ 1,444	\$ 1,475
Gas - regulated	185	194	914	874
Gas - nonregulated	293	318	1,037	942
<b>Total Operating Revenues</b>	<b>1,062</b>	<b>1,131</b>	<b>3,395</b>	<b>3,291</b>
<b>Operating Expenses:</b>				
Fuel used in electric generation	200	217	464	482
Purchased power	7	15	19	36
Gas purchased for resale	410	447	1,624	1,484
Other operation and maintenance	153	149	460	460
Depreciation and amortization	98	89	251	423
Other taxes	38	35	114	114
<b>Total Operating Expenses</b>	<b>906</b>	<b>952</b>	<b>2,932</b>	<b>2,999</b>
<b>Operating Income</b>	<b>156</b>	<b>179</b>	<b>463</b>	<b>292</b>
<b>Other Income (Expense):</b>				
Other income	48	67	120	175
Other expenses	(32)	(54)	(76)	(136)
Interest charges, net of allowance for borrowed funds used during construction of \$2, \$1, \$5 and \$2	(52)	(52)	(159)	(160)
Preferred dividends of subsidiary	(2)	(2)	(6)	(6)
Gain on sale of investment and assets	-	-	-	8
<b>Total Other Expense</b>	<b>(38)</b>	<b>(41)</b>	<b>(121)</b>	<b>(119)</b>
<b>Income Before Income Tax Expense (Benefit), Losses from Equity Method Investments and Cumulative Effect of Accounting Change</b>	<b>118</b>	<b>138</b>	<b>342</b>	<b>173</b>
<b>Income Tax Expense (Benefit)</b>	<b>25</b>	<b>36</b>	<b>93</b>	<b>(141)</b>
<b>Income Before Losses from Equity Method Investments and Cumulative Effect of Accounting Change</b>	<b>93</b>	<b>102</b>	<b>249</b>	<b>314</b>
Losses from Equity Method Investments	(4)	(2)	(11)	(68)
Cumulative Effect of Accounting Change, net of taxes	-	-	6	-
<b>Net Income</b>	<b>\$ 89</b>	<b>\$ 100</b>	<b>\$ 244</b>	<b>\$ 246</b>
<b>Basic and Diluted Earnings Per Share of Common Stock:</b>				
Before Cumulative Effect of Accounting Change	\$ .76	\$ .88	\$ 2.06	\$ 2.16
Cumulative Effect of Accounting Change, net of taxes	-	-	.05	-
<b>Basic and Diluted Earnings Per Share</b>	<b>\$ .76</b>	<b>\$ .88</b>	<b>\$ 2.11</b>	<b>\$ 2.16</b>
<b>Weighted Average Shares Outstanding (millions)</b>	<b>116.1</b>	<b>114.1</b>	<b>115.5</b>	<b>113.6</b>

See Notes to Condensed Consolidated Financial Statements.

SCANA CORPORATION  
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS  
(Unaudited)

Millions of dollars	Nine Months Ended September 30,	
	2006	2005
<b>Cash Flows From Operating Activities:</b>		
Net income	\$ 244	\$ 246
Adjustments to reconcile net income to net cash provided from operating activities:		
Cumulative effect of accounting change, net of taxes	(6)	-
Losses from equity method investments	11	68
Depreciation and amortization	255	425
Amortization of nuclear fuel	14	4
Gain on sale of assets and investments	-	(8)
Hedging activities	(15)	12
Carrying cost recovery	(5)	(8)
Cash provided (used) by changes in certain assets and liabilities:		
Receivables, net	385	137
Inventories	(51)	(125)
Prepayments and other	(6)	(2)
Pension asset	(10)	(13)
Other regulatory assets	(49)	34
Deferred income taxes, net	(8)	22
Regulatory liabilities	26	(156)
Postretirement benefits	7	4
Accounts payable	(247)	(39)
Taxes accrued	12	(48)
Interest accrued	(3)	(2)
Changes in fuel adjustment clauses	19	(36)
Changes in other assets	13	(7)
Changes in other liabilities	21	18
<b>Net Cash Provided From Operating Activities</b>	<b>607</b>	<b>526</b>
<b>Cash Flows From Investing Activities:</b>		
Utility property additions and construction expenditures	(311)	(267)
Proceeds from sale of assets and investments	18	8
Nonutility property additions	(27)	(11)
Investments	(21)	(29)
<b>Net Cash Used For Investing Activities</b>	<b>(341)</b>	<b>(299)</b>
<b>Cash Flows From Financing Activities:</b>		
Proceeds from issuance of debt	132	197
Proceeds from issuance of common stock	60	66
Repayment of debt	(148)	(459)
Redemption of preferred stock	-	(1)
Dividends on equity securities	(148)	(134)
Short-term borrowings, net	(123)	156
<b>Net Cash Used For Financing Activities</b>	<b>(227)</b>	<b>(175)</b>
Net Increase In Cash and Cash Equivalents	39	52
Cash and Cash Equivalents, January 1	62	119
<b>Cash and Cash Equivalents, September 30</b>	<b>\$ 101</b>	<b>\$ 171</b>
<b>Supplemental Cash Flow Information:</b>		
Cash paid for - Interest (net of capitalized interest of \$5 and \$2)	162	163
- Income taxes	67	45
<b>Noncash Investing and Financing Activities:</b>		
Accrued construction expenditures	16	14

See Notes to Condensed Consolidated Financial Statements.

SCANA CORPORATION  
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME  
(Unaudited)

Millions of dollars	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
Net Income	\$ 89	\$ 100	\$ 244	\$ 246
Other Comprehensive Income, net of tax:				
Unrealized gains (losses) on hedging activities	(12)	7	(15)	11
<b>Total Comprehensive Income <sup>(1)</sup></b>	<b>\$ 77</b>	<b>\$ 107</b>	<b>\$ 229</b>	<b>\$ 257</b>

<sup>(1)</sup> Accumulated other comprehensive loss totaled \$18.9 million as of September 30, 2006 and \$4.2 million as of December 31, 2005.

See Notes to Condensed Consolidated Financial Statements.

SCANA CORPORATION  
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS  
September 30, 2006  
(Unaudited)

The following notes should be read in conjunction with the Notes to Consolidated Financial Statements appearing in SCANA Corporation's (SCANA, and together with its consolidated subsidiaries, the Company) Annual Report on Form 10-K for the year ended December 31, 2005. These are interim financial statements, and due to the seasonality of the Company's business and matters that may occur during the rest of the year, the amounts reported in the Condensed Consolidated Statements of Income are not necessarily indicative of amounts expected for the full year. In the opinion of management, the information furnished herein reflects all adjustments, all of a normal recurring nature, which are necessary for a fair statement of the results for the interim periods reported.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. Basis of Accounting

The Company accounts for its regulated utility operations, assets and liabilities in accordance with the provisions of Statement of Financial Accounting Standards (SFAS) 71, "Accounting for the Effects of Certain Types of Regulation." SFAS 71 requires cost-based rate-regulated utilities to recognize in their financial statements certain revenues and expenses in different time periods than do enterprises that are not rate-regulated. As a result, the Company has recorded the regulatory assets and regulatory liabilities summarized as follows.

Millions of dollars	September 30, 2006	December 31, 2005
<b>Regulatory Assets:</b>		
Accumulated deferred income taxes	\$ 177	\$ 177
Under-collections - electric fuel and gas cost adjustment clauses	82	61
Purchased power costs	11	17
Environmental remediation costs	29	28
Asset retirement obligations and related funding	262	250
Franchise agreements	55	56
Regional transmission organization costs	9	11
Other	16	17
<b>Total Regulatory Assets</b>	<b>\$ 641</b>	<b>\$ 617</b>
<b>Regulatory Liabilities:</b>		
Accumulated deferred income taxes	\$ 38	\$ 39
Over-collections - electric fuel and gas cost adjustment clauses	7	20
Other asset removal costs	589	498
Storm damage reserve	43	38
Planned major maintenance	21	9
Other	17	11
<b>Total Regulatory Liabilities</b>	<b>\$ 715</b>	<b>\$ 615</b>

Accumulated deferred income tax liabilities arising from utility operations that have not been included in customer rates are recorded as a regulatory asset. Accumulated deferred income tax assets arising from deferred investment tax credits are recorded as a regulatory liability.

Under- and over-collections - electric fuel and gas cost adjustment clauses, net, represent amounts under- or over-collected from customers pursuant to the fuel adjustment clause (electric customers) or gas cost adjustment clause (gas customers) as approved by the Public Service Commission of South Carolina (SCPSC) or the North Carolina Utilities Commission (NCUC) during annual hearings. Included in these amounts are regulatory assets or liabilities arising from the natural gas hedging programs of the Company's regulated operations.

Purchased power costs represent costs that were necessitated by outages at two of South Carolina Electric & Gas Company's (SCE&G) base load generating plants in winter 2000-2001. The SCPSC approved recovery of these costs in base rates over a three-year period beginning January 2005.

Environmental remediation costs represent costs associated with the assessment and clean-up of manufactured gas plant (MGP) sites currently or formerly owned by the Company. Costs incurred at sites owned by SCE&G are being recovered through rates, of which \$18.3 million remain to be recovered. A portion of the costs incurred at sites owned by Public Service Company of North Carolina, Incorporated (PSNC Energy) has been recovered through rates. Through June 30, 2006, PSNC Energy incurred and deferred \$3.6 million, net of insurance settlements, that were not being recovered through rates. In connection with an October 2006 NCUC rate order, such costs are now being recovered through rates over a three-year period. In addition, management believes that costs incurred subsequent to June 30, 2006, totaling \$0.7 million at September 30, 2006, and the estimated remaining costs of \$5.9 million, will be recoverable by PSNC Energy through rates.

Asset retirement obligations (ARO) and related funding represents the regulatory asset associated with the legal obligation to decommission and dismantle V. C. Summer Nuclear Station (Summer Station) and conditional AROs recorded as required by SFAS 143, "*Accounting for Asset Retirement Obligations*," and Financial Accounting Standards Board Interpretation (FIN) 47, "*Accounting for Conditional Asset Retirement Obligations*."

Franchise agreements represent costs associated with electric and gas franchise agreements with the cities of Charleston and Columbia, South Carolina. These amounts are being amortized through cost of service rates and are expected to be fully amortized over approximately 20 years.

Regional transmission organization costs represent costs incurred by SCE&G in the United States Federal Energy Regulatory Commission (FERC)-mandated formation of GridSouth. The project was suspended in 2002. Effective January 2005, the SCPSC approved the amortization of these amounts through cost of service rates over approximately five years.

Other asset removal costs represent net collections through depreciation rates of estimated costs to be incurred for the removal of assets in the future.

The storm damage reserve represents an SCPSC approved reserve account for SCE&G capped at \$50 million to be collected through rates. The accumulated reserve can be applied to offset incremental storm damage costs in excess of \$2.5 million in a calendar year. For the nine months ended September 30, 2006, no amounts were drawn from this reserve account.

Planned major maintenance related to certain fossil and hydro-turbine equipment and nuclear refueling outages is accrued in advance of the time the costs are incurred, as approved through specific SCPSC orders. SCE&G is allowed to collect \$8.5 million annually over an eight-year period through electric rates to offset turbine maintenance expenditures. Nuclear refueling charges are accrued during each 18-month refueling outage cycle. Nuclear refueling charges are a component of cost of service and do not receive special rate consideration.

The SCPSC and the NCUC (collectively, state commissions) have reviewed and approved through specific orders most of the items shown as regulatory assets. Other items represent costs which are not approved for recovery by a state commission. In recording these costs as regulatory assets, management believes the costs will be allowable under existing rate-making concepts that are embodied in rate orders received by the Company. However, ultimate recovery is subject to state commission approval. In the future, as a result of deregulation or other changes in the regulatory environment, the Company may no longer meet the criteria for continued application of SFAS 71 and could be required to write off its regulatory assets and liabilities. Such an event could have a material adverse effect on the Company's results of operations, liquidity or financial position in the period the write-off would be recorded.

## B. Share-Based Compensation

The SCANA Corporation Long-Term Equity Compensation Plan provides for grants of incentive nonqualified stock options, stock appreciation rights, restricted stock, performance shares and performance units to certain key employees and non-employee directors. The plan currently authorizes the issuance of up to five million shares of the Company's common stock, no more than one million of which may be granted in the form of restricted stock.

SFAS 123 (revised 2004), “*Share-Based Payment*” (SFAS 123(R)), requires compensation costs related to share-based payment transactions to be recognized in the financial statements. With limited exceptions, compensation cost is measured based on the grant-date fair value of the instruments issued and is recognized over the period that an employee provides service in exchange for the award. The cumulative effect of the adoption of SFAS 123(R) on January 1, 2006 resulted in a \$.05 per share (net of tax) gain in the first quarter of 2006 based on a reduction of prior compensation accruals for performance awards (discussed below) granted in 2004 and 2005.

#### *Liability Awards*

Certain executives are granted a target number of performance shares on an annual basis that vest over a three-year period. Each performance share has a value that is equal to, and changes with, the value of a share of SCANA common stock, and dividend equivalents are accrued on, and reinvested in, the performance shares. Payout of performance share awards is determined by SCANA's performance against pre-determined measures of total shareholder return (TSR) as compared to a peer group of utilities (weighted 60%) and growth in earnings per share (weighted 40%) over the three year plan cycle. TSR is calculated by dividing stock price increase over the three-year period, plus cash dividends, by the stock price as of the beginning of the period. Payouts vary according to SCANA's ranking against the peer group and relative earnings per share projection achievement. Awards are designated as target shares of SCANA common stock and may be paid in stock or cash or a combination of stock and cash at SCANA's discretion.

Under SFAS 123(R) compensation cost of these liability awards is recognized over the three-year performance period based on the estimated fair value of the award, which is periodically updated based on expected ultimate cash payout, and is reduced by estimated forfeitures. Cash-settled liabilities totaling \$6.4 million were paid during the nine months ended September 30, 2006. No such payments were made during the corresponding period in 2005.

Fair value adjustments for performance awards resulted in a reduction to compensation expense recognized in the condensed statements of income, exclusive of the cumulative effect adjustment discussed previously, totaling \$(0.8) million and \$(1.0) million for the three and nine months ended September 30, 2006, respectively, and an increase to compensation expense totaling \$1.6 million and \$3.6 million for the corresponding periods ended September 30, 2005, respectively. Fair value adjustments resulted in a net credit to capitalized compensation cost of approximately \$(0.2) million during the nine months ended September 30, 2006, compared to capitalized costs of approximately \$0.8 million during the corresponding period in 2005.

#### *Equity Awards*

A summary of activity related to nonqualified stock options since December 31, 2005 follows:

	<b>Number of Options</b>	<b>Weighted Average Exercise Price</b>
Outstanding-December 31, 2005	439,270	\$27.53
Exercised	(11,341)	\$27.12
Outstanding-March 31, 2006	427,929	\$27.54
Exercised	(6,805)	\$27.48
Outstanding-June 30, 2006	421,124	\$27.54
Exercised	(33,064)	\$27.52
Outstanding-September 30, 2006	388,060	\$27.54

No stock options have been granted since August 2002, and all options were fully vested in August 2005. The options expire ten years after the grant date. At September 30, 2006, all outstanding options were currently exercisable at prices ranging from \$25.50-\$29.60, and had a weighted-average remaining contractual life of 5.1 years.

All options were granted with exercise prices equal to the fair market value of SCANA's common stock on the respective grant dates; therefore, no compensation expense was recognized in connection with such grants. If the Company had recognized compensation expense for the issuance of options based on the fair value method described in SFAS 123(R), pro forma net income and earnings per share would have been unchanged from that reported for the three and nine months ended September 30, 2005.

The exercise of stock options during the period was satisfied using original issue shares of the Company's common stock. The Company realized \$0.7 million and \$1.2 million in cash upon the exercise of options in the three and nine months ended September 30, 2006, respectively. In addition, tax benefits resulting from the exercise of those stock options totaling \$0.1 million and \$0.2 million were credited to additional paid in capital in these periods. The Company realized \$0.3 million and \$7.9 million in cash upon the exercise of options in the three and nine months ended September 30, 2005, respectively, and tax benefits resulting from the exercise of those options totaling \$0.1 million and \$1.3 million were credited to additional paid in capital in those periods.

C. Pension and Other Postretirement Benefit Plans

Components of net periodic benefit income or cost recorded by the Company were as follows:

Millions of dollars	Pension Benefits		Other Postretirement Benefits	
	2006	2005	2006	2005
<b>Three months ended September 30,</b>				
Service cost	\$ 3.5	\$ 3.1	\$ 1.1	\$ 0.9
Interest cost	10.0	9.7	3.0	2.4
Expected return on assets	(18.8)	(19.0)	-	-
Prior service cost amortization	1.7	1.8	0.4	0.1
Transition obligation amortization	0.2	0.2	0.2	0.2
Amortization of actuarial loss	0.1	-	0.6	-
<b>Net periodic benefit (income) cost</b>	<b>\$ (3.3)</b>	<b>\$ (4.2)</b>	<b>\$ 5.3</b>	<b>\$ 3.6</b>
<b>Nine months ended September 30,</b>				
Service cost	\$ 10.5	\$ 9.2	\$ 3.5	\$ 2.7
Interest cost	29.8	28.7	8.7	8.0
Expected return on assets	(56.4)	(57.2)	-	-
Prior service cost amortization	5.1	5.2	0.8	0.6
Transition obligation amortization	0.4	0.6	0.6	0.6
Amortization of actuarial loss	0.5	-	1.3	0.9
<b>Net periodic benefit (income) cost</b>	<b>\$ (10.1)</b>	<b>\$ (13.5)</b>	<b>\$ 14.9</b>	<b>\$ 12.8</b>

D. Earnings Per Share

In accordance with SFAS 128, "Earnings Per Share," the Company computes basic earnings per share by dividing net income by the weighted average number of common shares outstanding for the period. The Company computes diluted earnings per share using this same formula, after giving effect to securities considered to be dilutive potential common stock. The Company uses the treasury stock method in determining total dilutive potential common stock. The Company has no securities that would have an antidilutive effect on earnings per share.

E. Transactions with Affiliates

SCE&G holds equity-method investments in two partnerships involved in converting coal to synthetic fuel. SCE&G's receivables from these affiliated companies were \$24.0 million and \$24.6 million at September 30, 2006 and December 31, 2005, respectively. SCE&G's payables to these affiliated companies were \$23.5 million and \$25.3 million at September 30, 2006 and December 31, 2005, respectively. SCE&G purchased \$72.6 million and \$70.2 million of synthetic fuel from these affiliated companies for the three months ended September 30, 2006 and 2005, respectively. SCE&G purchased \$201.9 million and \$183.9 million of synthetic fuel from these affiliated companies for the nine months ended September 30, 2006 and 2005, respectively.

F. New Accounting Matters

SFAS 123(R) requires compensation costs related to share-based payment transactions to be recognized in the financial statements. With limited exceptions, compensation cost is measured based on the grant-date fair value of the instruments issued and is recognized over the period that an employee provides service in exchange for the award. SFAS 123(R) replaces SFAS 123, "Accounting for Stock-Based Compensation," and supersedes Accounting Principles Board (APB) Opinion 25, "Accounting for Stock Issued to Employees." The Company adopted SFAS 123(R) in the first quarter of 2006. The impact on the Company's results of operations is discussed at Note 1B.

The Company adopted SFAS 154, "Accounting Changes and Error Corrections," in the first quarter of 2006. SFAS 154 requires retrospective application to financial statements of prior periods for every voluntary change in accounting principle unless such retrospective application is impracticable. SFAS 154 replaces APB 20, "Accounting Changes," and SFAS 3, "Reporting Accounting Changes in Interim Financial Statements." The adoption of SFAS 154 had no material impact on the Company's results of operations, cash flows or financial position.

SFAS 157, "Fair Value Measurements," was issued in September 2006. SFAS 157 establishes a framework for measuring fair value to increase the consistency and comparability in fair value measurements. The Company will adopt SFAS 157 in the first quarter of 2008, and does not expect that the initial adoption will have a material impact on the Company's results of operations, cash flows or financial position.

In September 2006, SFAS 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans," amended SFAS 87 and SFAS 106 to require recognition of the overfunded or underfunded status of pension and other postretirement benefit plans on the balance sheet. Under SFAS 158, gains and losses, prior service costs and credits, and any remaining transition amounts under SFAS 87 and SFAS 106 that have not yet been recognized through net periodic benefit cost will be recognized in accumulated other comprehensive income, net of tax effects, until they are amortized as a component of net periodic cost. SFAS 158 is effective for publicly-held companies for fiscal years ending after December 15, 2006. SCANA will adopt the balance sheet recognition provisions of SFAS 158 at December 31, 2006. Because a substantial majority of the Company's pension and other postretirement costs recorded under SFAS 87 and SFAS 106 are attributable to employees in its regulated operations, the adoption of this Standard will primarily result in the recording of additional regulatory assets. The adoption is not expected to have a material impact on the Company's financial position, results of operations or cash flows.

FIN 48, "Accounting for Uncertainty in Income Taxes," was issued in June 2006. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with SFAS 109, "Accounting for Income Taxes." FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of tax positions taken or expected to be taken in a tax return. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. The Company will adopt FIN 48 in the first quarter of 2007. The Company is continuing to evaluate the impact that adoption of FIN 48 may have on the Company's results of operations, cash flows or financial position.

FASB Staff Position (FSP) AUG AIR-1 "Accounting for Planned Major Maintenance Activities," was issued in September 2006. This Standard amends APB 28, "Interim Financial Reporting," to prohibit the use of the accrue-in-advance method of accounting for planned major maintenance in annual and interim financial reporting periods. As disclosed in Note 1A, the Company has received specific SCPSC orders providing for use of accrue-in-advance accounting for certain planned major maintenance activities. Accordingly, the Company will continue to rely on SFAS 71 when accounting for these activities. The Company will adopt FSP AUG AIR-1 in the first quarter of 2007, and does not expect that the initial adoption will have a material impact on the Company's results of operations, cash flows or financial position.

The United States Securities and Exchange Commission (SEC) issued Staff Accounting Bulletin 108 (SAB 108) in September 2006. SAB 108 provides guidance on the consideration of the effects of prior year misstatements in quantifying and assessing the materiality of current year misstatements. SAB 108 also provides transition guidance for correcting errors existing from prior years. The Company will adopt SAB 108 in December 2006, and does not expect that the initial adoption will have a material impact on the Company's results of operations, cash flows or financial position.

## 2. RATE AND OTHER REGULATORY MATTERS

### *South Carolina Electric & Gas Company (SCE&G)*

#### Electric

SCE&G's rates are established using a cost of fuel component approved by the SCPSC which may be modified periodically to reflect changes in the price of fuel purchased by SCE&G. SCE&G's cost of fuel component was as follows:

Rate Per KWh	Effective Date
\$.01764	January-April 2005
.02256	May 2005-April 2006
.02516	May-September 2006

In connection with the May 2006 fuel component increase, SCE&G agreed to spread the recovery of previously under-collected fuel costs of \$38.5 million over a two-year period.

## Gas

In October 2005, the SCPSC granted SCE&G an overall increase of \$22.9 million, or 5.69 percent, in retail gas base rates. The new rates are based on an allowed return on common equity of 10.25 percent, and became effective with the first billing cycle in November 2005.

In June 2006, SCE&G reported to the SCPSC that its return on common equity for the twelve months ended March 31, 2006 was more than 0.5 percent below the allowed return, and as provided under South Carolina's Natural Gas Rate Stabilization Act, SCE&G requested an annualized increase in certain natural gas base rates. In September 2006, the SCPSC approved an annual increase of \$17.4 million. The rate adjustment was effective with the first billing cycle in November 2006.

SCE&G's rates are established using a cost of gas component approved by the SCPSC which may be modified periodically to reflect changes in the price of natural gas purchased by SCE&G. SCE&G's cost of gas components by class were as follows (rate per therm):

Effective Date	Residential	Small/Medium	Large
January-October 2005	\$.903	\$.903	\$.903
November 2005	1.297	1.222	1.198
December 2005	1.362	1.286	1.263
January 2006	1.297	1.222	1.198
February-September 2006	1.227	1.152	1.128

On October 25, 2006, the SCPSC approved a reduction in the cost of gas component of SCE&G's retail natural gas rates, effective with the first billing cycle of November 2006. The SCPSC also authorized SCE&G to adjust its cost of gas on a monthly, rather than an annual, basis beginning in December 2006.

Prior to November 2005, the SCPSC allowed SCE&G to recover through a billing surcharge to its gas customers the costs of environmental cleanup at the sites of former MGPs. Effective with the first billing cycle of November 2005, the billing surcharge was eliminated. In its place, SCE&G defers certain MGP environmental costs in regulatory asset accounts and collects and amortizes these costs through base rates.

### *Public Service Company of North Carolina, Incorporated (PSNC Energy)*

PSNC Energy's rates are established using a benchmark cost of gas approved by the NCUC, which may be modified periodically to reflect changes in the market price of natural gas. PSNC Energy revises its tariffs with the NCUC as necessary to track these changes and accounts for any over- or under-collections of the delivered cost of gas in its deferred accounts for subsequent rate consideration. The NCUC reviews PSNC Energy's gas purchasing practices annually.

PSNC Energy's benchmark cost of gas was as follows:

Rate Per Therm	Effective Date
\$.825	January 2005
.725	February-July 2005
.825	August-September 2005
1.100	October 2005
1.275	November-December 2005
1.075	January 2006
0.875	February 2006
0.825	March-September 2006

On October 24, 2006, the NCUC granted PSNC Energy an annual increase in retail natural gas margin revenues of approximately \$15.2 million, or 2.6 percent, which was offset by a \$9.2 million decrease in fixed-gas cost revenues, for an overall increase of \$6 million, or 1.0 percent. The new rates are based on an allowed overall rate of return of 8.9 percent, and became effective with the first billing cycle in November 2006. In connection with the rate increase, the NCUC approved PSNC Energy's recovery through rates, over a three-year period, of certain costs for environmental remediation and pipeline integrity management.

In September 2006, in connection with PSNC Energy's 2006 Annual Prudence Review, the NCUC determined that the Company's gas costs, including all hedging transactions, were reasonable and prudently incurred during the 12-month review ended March 31, 2006.

In March 2006, the NCUC authorized PSNC Energy to place pipeline supplier refunds that it presently holds and future supplier refunds into the appropriate deferred accounts for the over- or under-recovery of gas costs. Prior to this authorization, refunds from PSNC Energy's interstate pipeline transporters were placed in a state-approved expansion fund to provide financing for expansion into areas that otherwise would not be economically feasible to serve. In September 2005, the NCUC approved PSNC Energy's request for disbursement of up to \$1.1 million from the state expansion fund to extend natural gas service to Louisburg, North Carolina. The project is expected to be completed by the end of 2006.

#### *South Carolina Pipeline Corporation (SCPC)*

SCPC's purchased gas adjustment for cost recovery and gas purchasing policies are reviewed annually by the SCPSC. In a June 2006 order, the SCPSC found that for the period January through December 2005 SCPC's gas purchasing policies and practices were prudent and SCPC properly adhered to the gas cost recovery provisions of its gas tariff.

In July 2006, FERC approved the application for merger of SCG Pipeline, Inc., into SCPC to form Carolina Gas Transmission Corporation (CGTC). The merger was finalized and CGTC commenced operations as an open access transportation-only interstate pipeline company on November 1, 2006.

### 3. DEBT AND CREDIT FACILITIES

In June 2006, SCE&G issued \$125 million of first mortgage bonds having an annual interest rate of 6.25% and maturing July 1, 2036. The proceeds from the sale of these bonds, together with available cash, were used for the payment at maturity of \$131 million of SCE&G's first and refunding mortgage bonds due July 15, 2006, which bore interest at 9.0%.

In August 2006 SCANA obtained a \$30 million uncommitted short-term credit facility. In September 2006 SCANA extended a \$125 million nine month committed credit facility for a duration of 364 days and renewed two \$50 million committed 364-day credit facilities. A \$125 million nine month committed credit facility expired in September 2006 and was not renewed.

In anticipation of the issuance of debt, the Company uses interest rate lock or similar agreements to manage interest rate risk. Payments received or made upon termination of such agreements are recorded within long term debt on the balance sheet and are amortized to interest expense over the term of the underlying debt. In connection with the issuance of first mortgage bonds in June 2006, SCE&G received approximately \$8.8 million upon the termination of an interest rate lock agreement. These proceeds are being amortized over the life of the related debt, thereby reducing its effective interest rate. As permitted by SFAS 104, "Statement of Cash Flows - Net Reporting of Certain Cash Receipts and Cash Payments and Classification of Cash Flows from Hedging Transactions," these proceeds have been classified as a financing activity in the condensed consolidated statement of cash flows.

Substantially all of SCE&G's and GENCO's electric utility plant is pledged as collateral in connection with long-term debt.

### 4. FINANCIAL INSTRUMENTS

The Company utilizes various financial derivatives, including those designated as cash flow hedges related to natural gas. The Company also utilizes swap agreements to manage interest rate risk. These transactions are more fully described in Note 9 to the consolidated financial statements in SCANA's Annual Report on Form 10-K for the year ended December 31, 2005.

At September 30, 2006 the estimated fair value of the Company's swaps totaled \$0.1 million loss related to combined notional amounts of \$44.2 million.

The Company's regulated gas operations (SCE&G and PSNC Energy) hedge gas purchasing activities using over-the-counter options and swaps and New York Mercantile Exchange (NYMEX) futures and options. SCE&G's tariffs include a purchased gas adjustment (PGA) clause that provide for the recovery of actual gas costs incurred. The SCPSC has ruled that the results of these hedging activities are to be included in the PGA. As such, costs of related derivatives utilized to hedge gas purchasing activities are recoverable through the weighted average cost of gas calculation. The offset to the change in fair value of these derivatives is recorded as a regulatory asset or liability. PSNC Energy's tariffs include a provision for the recovery of actual gas costs incurred. PSNC Energy records premiums, transaction fees and any realized and unrealized gains or losses from derivatives acquired as part of its hedging program in deferred accounts as a regulatory asset or liability for the over- or under-recovery of gas costs.

The Company's nonregulated gas operations recognize gains and losses as a result of qualifying cash flow hedges whose hedged transactions occur during the reporting period and record them, net of taxes, in cost of gas. The Company recognized losses of \$(3.3) million and \$(21.0) million for the three and nine months ended September 30, 2006, respectively, and recognized a gain of \$2.4 million and a loss of \$(0.4) million for the corresponding periods ended September 30, 2005, respectively. Because these gains and losses resulted from hedging activities, their effects were necessarily offset by the recording of the related hedged transactions. The Company estimates that the September 30, 2006 unrealized loss balance of \$(17.4) million, net of tax, will be reclassified from accumulated other comprehensive income (loss) to earnings in 2006 as an increase to gas cost if market prices remain at current levels. As of September 30, 2006, all of the Company's cash flow hedges settle by their terms before the end of December 2008.

PSNC Energy utilizes asset management and supply service agreements with counterparties for certain of its natural gas storage facilities. At September 30, 2006, such counterparties held 52% of PSNC Energy's natural gas inventory, with a carrying value of \$48.3 million. This natural gas will be delivered to PSNC Energy at its city gate during the winter period (November 2006 through March 2007), or on the contract settlement date, as applicable. Under the terms of the asset management agreements, PSNC Energy receives storage asset management fees and, in certain instances, a share of excess profits. No fees are received under supply service agreements. The agreements expire at various times from October 31, 2006 through March 31, 2007.

## 5. COMMITMENTS AND CONTINGENCIES

Reference is made to Note 10 to the consolidated financial statements appearing in SCANA's Annual Report on Form 10-K for the year ended December 31, 2005. Commitments and contingencies at September 30, 2006 include the following:

### A. Nuclear Insurance

The Price-Anderson Indemnification Act deals with public liability for a nuclear incident and establishes the liability limit for third-party claims associated with any nuclear incident at \$10.5 billion. Each reactor licensee is currently liable for up to \$100.6 million per reactor owned for each nuclear incident occurring at any reactor in the United States, provided that not more than \$15 million of the liability per reactor would be assessed per year. SCE&G's maximum assessment, based on its two-thirds ownership of Summer Station, would be \$67.1 million per incident, but not more than \$10 million per year.

SCE&G currently maintains policies (for itself and on behalf of Santee Cooper, a one-third owner of Summer Station) with Nuclear Electric Insurance Limited. The policies, covering the nuclear facility for property damage, excess property damage and outage costs, permit retrospective assessments under certain conditions to cover insurer's losses. Based on the current annual premium, SCE&G's portion of the retrospective premium assessment would not exceed \$14.1 million.

To the extent that insurable claims for property damage, decontamination, repair and replacement and other costs and expenses arising from a nuclear incident at Summer Station exceed the policy limits of insurance, or to the extent such insurance becomes unavailable in the future, and to the extent that SCE&G's rates would not recover the cost of any purchased replacement power, SCE&G will retain the risk of loss as a self-insurer. SCE&G has no reason to anticipate a serious nuclear incident. However, if such an incident were to occur, it likely would have a material adverse impact on the Company's results of operations, cash flows and financial position.

### B. Environmental

#### *South Carolina Electric & Gas Company*

In March 2005, the Environmental Protection Agency (EPA) issued a final rule known as the Clean Air Interstate Rule (CAIR). CAIR requires the District of Columbia and 28 states, including South Carolina, to reduce nitrogen oxide and sulfur dioxide emissions in order to attain mandated state levels. SCE&G has petitioned the United States Court of Appeals for the District of Columbia Circuit to review CAIR. Several other electric utilities have filed separate petitions. The petitioners seek a change in the method CAIR uses to allocate sulfur dioxide emission allowances to a method the petitioners believe is more equitable. The Company believes that installation of additional air quality controls will be needed to meet the CAIR requirements. The Company is reviewing the final rule. Compliance plans and cost to comply with the rule will be determined once the Company completes its review. Such costs may be material and are expected to be recoverable through rates.

In March 2005, the EPA issued a final rule establishing a mercury emissions cap and trade program for coal-fired power plants that requires limits to be met in two phases, in 2010 and 2018. Although the Company expects to be able to meet the Phase I limits through those measures it already will be taking to meet its CAIR obligations, it is uncertain as to how the Phase II limits will be met. Assuming Phase II limits remain unchanged, installation of additional air quality controls likely will be required to comply with the rule's Phase II mercury emission caps. Final compliance plans and costs to comply with the rule are still under review. Such costs will be material and are expected to be recoverable through rates.

SCE&G has been named, along with 29 others, by the EPA as a potentially responsible party (PRP) at the Carolina Transformer Superfund site located in Fayetteville, North Carolina. The Carolina Transformer Company (CTC) conducted an electrical transformer rebuilding and repair operation at the site from 1967 to 1984. During that time, SCE&G occasionally used CTC for the repair of existing transformers and the purchase of new transformers. In 1984, EPA initiated a cleanup of PCB-contaminated soil and groundwater at the site. EPA reports that it has spent \$36 million to date. SCE&G's records indicate that only minimal quantities of used transformers were shipped to CTC, and it is not clear if any contained PCB-contaminated oil. Although a basis for the allocation of clean-up costs among the PRPs is unclear, SCE&G does not believe that its involvement at this site would result in an allocation of costs that would have a material adverse impact on its results of operations, cash flows or financial condition. Any cost allocated to SCE&G is expected to be recoverable through rates.

SCE&G has been named, along with 53 others, by the EPA as a PRP at the Alternate Energy Resources, Inc. (AER) Superfund site located in Augusta, Georgia. The EPA placed the site on the National Priorities List on April 19, 2006. AER conducted hazardous waste storage and treatment operations from 1975 to 2000, when the site was abandoned. While operational, AER processed fuels from waste oils, treated industrial coolants and oil/water emulsions, recycled solvents and blended hazardous waste fuels. During that time, SCE&G occasionally used AER for the processing of waste solvents, oily rags and oily wastewater. EPA and the State of Georgia have documented that a release or releases have occurred at the site leading to contamination of groundwater, surface water and soils. EPA and the State of Georgia have conducted a preliminary assessment and site inspection. The site has not been cleaned up nor has a cleanup cost been estimated. Although a basis for the allocation of clean-up costs among the PRPs is unclear, SCE&G does not believe that its involvement at this site would result in an allocation of costs that would have a material adverse impact on its results of operations, cash flows or financial condition. Any cost allocated to SCE&G arising from the remediation of this site is expected to be recoverable through rates.

The Company maintains an environmental assessment program to identify and evaluate current and former sites that could require environmental cleanup. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and clean up each site. These estimates are refined as additional information becomes available; therefore, actual expenditures could differ significantly from the original estimates. Amounts estimated and accrued to date for site assessments and cleanup relate solely to regulated operations.

SCE&G defers site assessment and cleanup costs and recovers them through rates (see Note 1). Deferred amounts, net of amounts previously recovered through rates and insurance settlements, totaled \$18.3 million at September 30, 2006. The deferral includes the estimated costs associated with the following matters.

SCE&G owns a decommissioned MGP site in the Calhoun Park area of Charleston, South Carolina. SCE&G anticipates that remediation for contamination at the site will be completed in 2007, with certain monitoring and retreatment activities continuing until 2011. As of September 30, 2006, SCE&G had spent \$21.9 million to remediate the site and expects to spend an additional \$1.4 million prior to entering a monitoring and reporting stage. In addition, the National Park Service of the Department of the Interior made an initial demand to SCE&G for payment of \$9.1 million for certain costs and damages relating to this site. Any cost arising from the remediation of this site is expected to be recoverable through rates.

SCE&G owns three other decommissioned MGP sites in South Carolina which contain residues of by-product chemicals. One of the sites has been remediated and will undergo routine monitoring until released by the South Carolina Department of Health and Environmental Control (DHEC). The other sites are currently being investigated under work plans approved by DHEC. SCE&G anticipates that major remediation activities for the three sites will be completed by 2010. As of September 30, 2006, SCE&G had spent \$4.6 million related to these three sites, and expects to spend an additional \$11.4 million. Any cost arising from the remediation of these sites is expected to be recoverable through rates.

#### *Public Service Company of North Carolina, Incorporated*

PSNC Energy is responsible for environmental cleanup at five sites in North Carolina on which MGP residuals are present or suspected. PSNC Energy's remediation costs for these sites will depend on a number of factors, such as actual site conditions, third-party claims and recoveries from other PRPs. PSNC Energy has recorded a liability and associated regulatory asset of \$5.9 million, which reflects its estimated remaining liability at September 30, 2006. Any cost allocable to PSNC Energy arising from the remediation of these sites is expected to be recoverable through rates.

#### C. Claims and Litigation

In 1999, an unsuccessful bidder for the purchase of certain propane gas assets of the Company filed suit against SCANA in Circuit Court, seeking unspecified damages. The suit alleged the existence of a contract for the sale of assets to the plaintiff and various causes of action associated with that contract. On October 21, 2004, the jury issued an adverse verdict on this matter against SCANA for four causes of action for damages totaling \$48 million. In accordance with generally accepted accounting principles, in the third quarter of 2004 SCANA accrued a liability of \$18 million, which was its reasonable estimate of the minimum liability that was probable if the final judgment were to be consistent with the jury verdict. While the judgment was being appealed, in May 2006 SCANA paid the plaintiff \$11 million in settlement of its claims.

A claim against SCANA for \$2.7 million for reimbursement of legal fees and expenses under an indemnification and hold harmless agreement in the contract for the sale of the propane gas assets was settled in November 2006. A provision for this loss had been previously recorded.

In August 2003, SCE&G was served as a co-defendant in a purported class action lawsuit styled as *Collins v. Duke Energy Corporation, Progress Energy Services Company, and SCE&G* in South Carolina's Circuit Court of Common Pleas for the Fifth Judicial Circuit. Since that time, the plaintiffs have dismissed defendants Duke Energy and Progress Energy and are proceeding against SCE&G only. The plaintiffs are seeking damages for the alleged improper use of electric transmission and distribution easements but have not asserted a dollar amount for their claims. Specifically, the plaintiffs contend that the licensing of attachments on electric utility poles, towers and other facilities to nonutility third parties or telecommunication companies for other than the electric utilities' internal use along the electric transmission and distribution line rights-of-way constitutes a trespass. It is anticipated that this case may go to trial in 2007. SCANA & SCE&G are confident of the propriety of SCE&G's actions and intend to mount a vigorous defense. SCANA and SCE&G further believe that the resolution of these claims will not have a material adverse impact on their results of operations, cash flows or financial condition.

In May 2004, the Company was served with a purported class action lawsuit styled as *Douglas E. Gressette, individually and on behalf of other persons similarly situated v. South Carolina Electric & Gas Company and SCANA Corporation*. The case was filed in South Carolina's Circuit Court of Common Pleas for the Ninth Judicial Circuit. The plaintiff alleges the Company made improper use of certain easements and rights-of-way by allowing fiber optic communication lines and/or wireless communication equipment to transmit communications other than the Company's electricity-related internal communications. The plaintiff asserted causes of action for unjust enrichment, trespass, injunction and declaratory judgment. The plaintiff did not assert a specific dollar amount for the claims. The Company believes its actions are consistent with governing law and the applicable documents granting easements and rights-of-way. The court granted the Company's motion to dismiss and issued an order dismissing the case in June 2005. The plaintiff appealed to the South Carolina Supreme Court. The Supreme Court recently overruled the Circuit Court and returned the case to the Circuit Court for further consideration saying the question of assignability of the easements requires construction of the easements themselves. The Company will continue to mount a vigorous defense and believes that the resolution of these claims will not have a material adverse impact on its results of operations, cash flows or financial condition.

A complaint was filed in October 2003 against SCE&G by the State of South Carolina alleging that SCE&G violated the Unfair Trade Practices Act by charging municipal franchise fees to some customers residing outside a municipality's limits. The complaint alleged that SCE&G failed to obey, observe or comply with the lawful order of the SCPSC by charging franchise fees to those not residing within a municipality. The complaint sought restitution to all affected customers and penalties of up to \$5,000 for each separate violation. The claim against SCE&G has been settled by an agreement between the parties, and the settlement has been approved by South Carolina's Circuit Court of Common Pleas for the Fifth Judicial Circuit. In addition, SCE&G filed a petition with the SCPSC in October 2003 pursuant to S. C. Code Ann. R.103-836. The petition requests that the SCPSC exercise its jurisdiction to investigate the operation of the municipal franchise fee collection requirements applicable to SCE&G's electric and gas service, to approve SCE&G's efforts to correct any past franchise fee billing errors, to adopt improvements in the system which will reduce such errors in the future, and to adopt any regulation that the SCPSC deems just and proper to regulate the franchise fee collection process. A hearing on this petition has not been scheduled. The Company believes that the resolution of these matters will not have a material adverse impact on its results of operations, cash flows or financial condition.

The Company is also engaged in various other claims and litigation incidental to its business operations which management anticipates will be resolved without a material adverse impact on the Company's results of operations, cash flows or financial condition.

#### D. Other Contingency

In 2004 and early 2005, SCANA and certain of its affiliates, like other integrated utilities, were the subject of an investigation by FERC's Office of Market Oversight and Investigations (OMOI) focusing, among other things, on the relationship between SCE&G's merchant and transmission functions. These relationships are among those addressed in FERC Order 2004, a primary purpose of which order is to ensure that affiliates of transmission providers have no marketplace advantage over non-affiliated market participants. In connection with that investigation, SCE&G was assessed no monetary damages or penalties; however, under terms of a Settlement and Consent Agreement entered into on April 1, 2005, and approved by FERC order dated April 27, 2005, SCE&G agreed to the implementation of a compliance plan which includes periodic reports to OMOI, now known as FERC's Office of Enforcement.

On January 2, 2006, SCE&G provided to FERC a quarterly update on this compliance plan, which included an acknowledgment of SCE&G's discovery that it may have improperly utilized network transmission services, rather than point-to-point transmission services, for purchases and sales of electricity in violation of SCE&G's open access transmission tariff and applicable FERC orders under the Federal Power Act that prohibit the use of network transmission service in support of certain "off-system" sales. This acknowledgement was in part the result of SCE&G's preliminary review of a FERC order issued following its examination of another energy provider in September 2005. Upon further review of that order and an internal investigation, SCE&G determined, and notified FERC, that it did improperly utilize network transmission service in a significant number of purchase and sale transactions.

In response to its internal findings, SCE&G also notified FERC that it had ceased participation in such transactions, instituted additional self-restrictive procedures as safeguards to ensure full compliance in this area in the future, and committed to certain modifications to its compliance plan, including increased levels of training and monitoring. SCE&G also has fully cooperated with FERC staff in its investigation of this matter.

In the fourth quarter of 2005, SCE&G recorded a loss accrual in the amount of \$0.8 million based on its estimation of net revenues from the subject transactions that occurred after the date of the Settlement and Consent Agreement and that might be deemed to be in violation of FERC's rule on the use of network transmission service and be subject to disgorgement pursuant to FERC orders. In the third quarter of 2006, SCE&G increased its loss accrual to \$3.7 million. However, there remains uncertainty as to what actions ultimately may be taken by FERC. Potential actions could include penalties of up to a maximum of \$1 million per violation or per day since August 8, 2005, the effective date of the Energy Policy Act of 2005; disgorgement of profits on the subject transactions; and further modification to SCE&G's compliance plan or other non-monetary remedies. SCE&G continues to believe that no market participants were harmed or disadvantaged by the transactions in question. For this reason and in light of SCE&G's self-reporting and other cooperation in the investigation of this matter, and SCE&G's institution of appropriate safeguards referred to above, SCE&G does not believe that material monetary sanctions are warranted.

SCE&G desires to resolve this matter in a reasonable and satisfactory manner. Nonetheless, SCE&G cannot predict what, if any, actions FERC ultimately will take with respect to this matter, and is unable to determine if the resolution of this matter will have a material adverse impact on its operations, cash flows or financial condition.

## 6. SEGMENT OF BUSINESS INFORMATION

The Company's reportable segments are listed in the following table. The Company uses operating income to measure profitability for its regulated operations; therefore, net income is not allocated to the Electric Operations, Gas Distribution and Gas Transmission segments. The Company uses net income to measure profitability for its Retail Gas Marketing and Energy Marketing segments. Gas Distribution is comprised of the local distribution operations of SCE&G and PSNC Energy which meet SFAS 131 criteria for aggregation. All Other includes equity method investments and other nonreportable segments.

Millions of dollars	External Revenue	Intersegment Revenue	Operating Income (Loss)	Net Income (Loss)	Segment Assets
<b><i>Three Months Ended September 30, 2006</i></b>					
Electric Operations	\$584	\$3	\$167	n/a	
Gas Distribution	136	-	(13)	n/a	
Gas Transmission	49	63	5	n/a	
Retail Gas Marketing	73	-	n/a	\$(3)	
Energy Marketing	220	48	n/a	1	
All Other	21	81	n/a	(3)	
Adjustments/Eliminations	(21)	(195)	(3)	94	
<b>Consolidated Total</b>	<b>\$1,062</b>	<b>\$-</b>	<b>\$156</b>	<b>\$89</b>	
<b><i>Nine Months Ended September 30, 2006</i></b>					
Electric Operations	\$1,444	\$7	\$376	n/a	\$5,476
Gas Distribution	747	-	41	n/a	1,706
Gas Transmission	167	288	21	n/a	327
Retail Gas Marketing	435	-	n/a	\$21	139
Energy Marketing	602	79	n/a	-	90
All Other	50	235	n/a	(5)	603
Adjustments/Eliminations	(50)	(609)	25	228	1,090
<b>Consolidated Total</b>	<b>\$3,395</b>	<b>\$-</b>	<b>\$463</b>	<b>\$244</b>	<b>\$9,431</b>

**Three Months Ended September 30, 2005**

Electric Operations	\$619	\$1	\$186	n/a
Gas Distribution	140	-	(10)	n/a
Gas Transmission	54	69	5	n/a
Retail Gas Marketing	77	-	n/a	\$(3)
Energy Marketing	241	67	n/a	2
All Other	17	83	n/a	(1)
Adjustments/Eliminations	(17)	(220)	(2)	102
<b>Consolidated Total</b>	<b>\$1,131</b>	<b>\$-</b>	<b>\$179</b>	<b>\$100</b>

**Nine Months Ended September 30, 2005**

Electric Operations	\$1,475	\$3	\$194	n/a	\$5,315
Gas Distribution	712	-	45	n/a	1,516
Gas Transmission	162	264	17	n/a	334
Retail Gas Marketing	408	-	n/a	\$20	125
Energy Marketing	534	110	n/a	1	143
All Other	52	238	n/a	(65)	586
Adjustments/Eliminations	(52)	(615)	36	290	939
<b>Consolidated Total</b>	<b>\$3,291</b>	<b>\$-</b>	<b>\$292</b>	<b>\$246</b>	<b>\$8,958</b>

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

### SCANA CORPORATION

The following discussion should be read in conjunction with Management's Discussion and Analysis of Financial Condition and Results of Operations appearing in SCANA Corporation's (SCANA, and together with its consolidated subsidiaries, the Company) Annual Report on Form 10-K for the year ended December 31, 2005.

Statements included in this discussion and analysis (or elsewhere in this quarterly report) which are not statements of historical fact are intended to be, and are hereby identified as, "forward-looking statements" for purposes of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Readers are cautioned that any such forward-looking statements are not guarantees of future performance and involve a number of risks and uncertainties, and that actual results could differ materially from those indicated by such forward-looking statements. Important factors that could cause actual results to differ materially from those indicated by such forward-looking statements include, but are not limited to, the following: (1) that the information is of a preliminary nature and may be subject to further and/or continuing review and adjustment, (2) regulatory actions or changes in the utility and nonutility regulatory environment, (3) current and future litigation, (4) changes in the economy, especially in areas served by subsidiaries of SCANA, (5) the impact of competition from other energy suppliers, including competition from alternate fuels in industrial interruptible markets, (6) growth opportunities for SCANA's regulated and diversified subsidiaries, (7) the results of financing efforts, (8) changes in accounting principles, (9) weather conditions, especially in areas served by SCANA's subsidiaries, (10) performance of SCANA's pension plan assets, (11) inflation, (12) changes in environmental regulations, (13) volatility in commodity natural gas markets and (14) the other risks and uncertainties described from time to time in SCANA's periodic reports filed with the United States Securities and Exchange Commission. SCANA disclaims any obligation to update any forward-looking statements.

### RESULTS OF OPERATIONS FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2006 AS COMPARED TO THE CORRESPONDING PERIODS IN 2005

#### Earnings Per Share

The Company's reported earnings are prepared in accordance with generally accepted accounting principles (GAAP). Management believes that, in addition to reported earnings under GAAP, the Company's GAAP-adjusted net earnings from operations provides a meaningful representation of its fundamental earnings power and can aid in performing period-over-period financial analysis and comparison with peer group data. In management's opinion, GAAP-adjusted net earnings from operations is a useful indicator of the financial results of the Company's primary businesses. This measure is also a basis for management's provision of earnings guidance and growth projections, and it is used by management in making resource allocation and other budgetary and operational decisions. This non-GAAP performance measure is not intended to replace the GAAP measure of net earnings, but is offered as a supplement to it. A reconciliation of reported (GAAP) earnings per share to GAAP-adjusted net earnings from operations per share is provided in the table below:

	Third Quarter		Year to Date	
	2006	2005	2006	2005
Reported (GAAP) earnings per share:	\$ .76	\$ .88	\$ 2.11	\$ 2.16
Deduct:				
Cumulative effect of accounting change, net of tax	-	-	.05	-
Reduction in propane litigation accrual upon settlement	-	-	.04	-
Realized gain from sale of telecommunications investment	-	-	-	.03
<b>GAAP-adjusted net earnings per share from operations</b>	<b>\$ .76</b>	<b>\$ .88</b>	<b>\$ 2.02</b>	<b>\$ 2.13</b>

#### Discussion of adjustments

The cumulative effect of accounting change resulted from the Company's adoption of Statement of Financial Accounting Standard (SFAS) 123 (revised 2004), "Share-Based Payment" (SFAS 123(R)). The reduction in propane litigation accrual resulted from the propane litigation being settled for an amount that was less than had been accrued in 2004. This reduction appears in the income statement as a reduction to other expenses. The realized gain from sale of telecommunications investment resulted from the receipt of additional proceeds from the prior sale of the Company's investment in ITC Holding Company in 2003. These additional proceeds had been held in escrow pending resolution of certain contingencies.

### Third Quarter

GAAP-adjusted net earnings per share from operations decreased primarily due to decreases in electric margins of \$.05, increases in operation and maintenance expenses of \$.02, increased depreciation expense of \$.03, increased property taxes of \$.02 and the effects of dilution of \$.02, partially offset by increases in gas margins of \$.01 and other lower expenses of \$.01. Accelerated depreciation on the Lake Murray back-up dam and recognition of synthetic fuel tax credits and related items had no effect on net income, as discussed at *Recognition of Synthetic Fuel Tax Credits*.

### Year to Date

GAAP-adjusted net earnings per share from operations decreased primarily due to decreases in gas margins of \$.02, increased depreciation expense of \$.03, the effects of dilution of \$.04 and other increased expenses of \$.04, which were partially offset by higher electric margins of \$.02. Accelerated depreciation on the Lake Murray back-up dam and recognition of synthetic fuel tax credits and related items had no effect on net income, as discussed at *Recognition of Synthetic Fuel Tax Credits*.

Management believes that the adjustments are appropriate in determining the non-GAAP financial performance measure. Management utilizes such measure itself in exercising budgetary control, managing business operations and determining eligibility for incentive compensation payments. The non-GAAP measure, GAAP-adjusted net earnings per share from operations, provides a consistent basis upon which to measure performance by excluding the effects on per share earnings of the cumulative effect of the accounting change resulting from the Company's adoption of SFAS 123(R), of litigation related to the sale of a prior business and of transactions involving the Company's telecommunications investments.

### Dividends Declared

The Company's Board of Directors has declared the following dividends on common stock during 2006:

Declaration Date	Dividend Per Share	Record Date	Payment Date
February 16, 2006	\$.42	March 10, 2006	April 1, 2006
April 27, 2006	.42	June 9, 2006	July 1, 2006
August 3, 2006	.42	September 11, 2006	October 1, 2006
November 1, 2006	.42	December 11, 2006	January 1, 2007

### Electric Operations

Electric Operations is comprised of the electric operations of South Carolina Electric & Gas Company (SCE&G), South Carolina Generating Company, Inc. and South Carolina Fuel Company, Inc. Electric operations sales margins (including transactions with affiliates) were as follows:

Millions of dollars	Third Quarter			Year to Date		
	2006	% Change	2005	2006	% Change	2005
Operating revenues	\$ 584.5	(5.6)%	\$ 619.2	\$ 1,444.0	(2.1)%	\$ 1,475.1
Less: Fuel used in generation	199.7	(8.0)%	217.1	463.8	(3.8)%	482.1
Purchased power	7.0	(53.6)%	15.1	19.0	(46.8)%	35.7
Margin	\$ 377.8	(2.4)%	\$ 387.0	\$ 961.2	0.4%	\$ 957.3

### Third Quarter

Margin decreased by \$10.4 million due to lower off-system sales, by \$2.4 million due to lower industrial sales and by \$4.4 million due to unfavorable weather. These decreases were partially offset by \$8.2 million due to customer growth and \$1.3 million due to other electric revenue.

### Year to Date

Margin increased by \$20.9 million due to customer growth and by \$4.6 million due to higher other electric revenue, partially offset by \$5.2 million in decreased off-system sales, by \$6.7 million due to unfavorable weather and by \$5.3 million due to lower industrial sales.

## Gas Distribution

Gas Distribution is comprised of the local distribution operations of SCE&G and Public Service Company of North Carolina, Incorporated (PSNC Energy). Gas distribution sales margins (including transactions with affiliates) were as follows:

Millions of dollars	Third Quarter		2005	Year to Date		2005
	2006	% Change		2006	% Change	
Operating revenues	\$ 136.0	(2.6)%	\$ 139.7	\$ 747.2	5.1%	\$ 711.1
Less: Gas purchased for resale	96.8	(6.3)%	103.3	553.5	6.4%	520.3
<b>Margin</b>	<b>\$ 39.2</b>	<b>7.7%</b>	<b>\$ 36.4</b>	<b>\$ 193.7</b>	<b>1.5%</b>	<b>\$ 190.8</b>

### Third Quarter

Margin increased by \$1.6 million due to increased retail base rates at SCE&G which became effective with the first billing cycle in November 2005, by \$1.2 million due to higher firm margin and by \$0.6 million due to other increased revenue.

### Year to Date

Margin increased by \$16.4 million due to increased retail base rates at SCE&G which became effective with the first billing cycle in November 2005 and by \$1.2 million due to increased transportation and other increased revenue at SCE&G. These increases were offset by \$6.9 million due to milder weather and the effects of customer conservation efforts, primarily at PSNC Energy, and by \$5.1 million due to lower firm margin at SCE&G.

## Gas Transmission

Gas Transmission is comprised of the operations of South Carolina Pipeline Corporation. Gas transmission sales margins (including transactions with affiliates) were as follows:

Millions of dollars	Third Quarter		2005	Year to Date		2005
	2006	% Change		2006	% Change	
Operating revenues	\$ 112.2	(8.9)%	\$ 123.1	\$ 455.8	7.0%	\$ 426.0
Less: Gas purchased for resale	99.1	(10.1)%	110.2	412.9	7.0%	386.0
<b>Margin</b>	<b>\$ 13.1</b>	<b>1.6%</b>	<b>\$ 12.9</b>	<b>\$ 42.9</b>	<b>7.3%</b>	<b>\$ 40.0</b>

### Third Quarter

Margin increased by \$0.9 million due to increased revenue from capacity charges and by \$0.8 million due to higher interruptible transportation revenue, offset by \$1.5 million due to lower industrial margin.

### Year to Date

Margin increased by \$2.3 million due to increased revenue from capacity charges and by \$1.4 million due to higher interruptible transportation revenue, offset by \$0.8 million due to lower industrial margin.

## Retail Gas Marketing

Retail Gas Marketing is comprised of SCANA Energy, which operates in Georgia's natural gas market. Retail Gas Marketing revenues and net income (loss) were as follows:

Millions of dollars	Third Quarter		2005	Year to Date		2005
	2006	% Change		2006	% Change	
Operating revenues	\$ 72.6	(5.6)%	\$ 76.9	\$ 434.7	6.6%	\$ 407.7
Net income (loss)	\$ (2.8)	6.7%	\$ (3.0)	\$ 20.9	3.0%	\$ 20.3

### Third Quarter

Operating revenues decreased primarily as a result of lower customer usage. Net loss decreased primarily due to higher sales margins partially offset by higher operating and customer service expenses.

### Year to Date

Operating revenues increased primarily as a result of higher average retail prices arising from higher commodity gas costs, which were partially offset by lower customer usage. Net income increased due to lower bad debt and operating expenses which were partially offset by lower sales margins.

### Energy Marketing

Energy Marketing is comprised of the Company's non-regulated marketing operations, excluding SCANA Energy. Energy Marketing operating revenues and net income (loss) were as follows:

Millions of dollars	Third Quarter		2005		Year to Date		2005
	2006	% Change		2006	% Change		
Operating revenues	\$ 268.1	(12.9)%	\$ 307.7	\$ 681.5	5.7%	\$ 644.7	
Net income (loss)	0.2	(89.5)%	1.9	(0.4)	*	0.9	

\*Greater than 100%

### Third Quarter

Operating revenues decreased primarily as a result of decreased volumes. Net income decreased primarily due to lower margins.

### Year to Date

Operating revenues increased primarily as a result of higher commodity prices and increased volumes. Net income decreased primarily due to lower margins.

### Other Operating Expenses

Other operating expenses, incurred in the operating segments previously discussed, were as follows:

Millions of dollars	Third Quarter		2005		Year to Date		2005
	2006	% Change		2006	% Change		
Other operation and maintenance	\$ 153.0	2.8%	\$ 148.8	\$ 459.7	(0.2)%	\$ 460.5	
Depreciation and amortization	98.2	10.3%	89.0	251.5	(40.5)%	422.8	
Other taxes	38.7	9.6%	35.3	114.6	1.1%	113.4	
<b>Total</b>	<b>\$ 289.9</b>	<b>6.2%</b>	<b>\$ 273.1</b>	<b>\$ 825.8</b>	<b>(17.1)%</b>	<b>\$ 996.7</b>	

### Third Quarter

Other operation and maintenance expenses increased due to increased electric generation, transmission and distribution expenses, other increased expenses at SCE&G and reduced pension income, partially offset by lower incentive compensation accruals. Depreciation and amortization increased by \$4.4 million due to higher accelerated depreciation of the back-up dam at Lake Murray in 2005 (see *Recognition of Synthetic Fuel Tax Credits*) and by \$4.2 million due to property additions and higher depreciation rates at SCE&G. Other taxes increased due to higher property taxes.

### Year to Date

Other operation and maintenance expenses decreased due to lower incentive compensation accruals and lower operating, marketing and customer service expenses, primarily in the first quarter, in Retail Gas Marketing. These decreases were partially offset by increased electric generation, transmission and distribution expenses. Depreciation and amortization decreased \$177.8 million due to higher accelerated depreciation of the back-up dam at Lake Murray in 2005 and the lower levels of credits recognized in 2006 due to applicability of the phase-down provisions (see *Recognition of Synthetic Fuel Tax Credits*), partially offset by \$5.2 million due to property additions and higher depreciation rates. Other taxes increased due to higher property taxes.

### Other Income (Expense)

Other income (expense) includes the results of certain incidental (non-utility) activities and the activities of certain non-regulated subsidiaries.

### Third Quarter and Year to Date

Other income and expenses declined in 2006 compared to 2005 primarily due to reductions in power marketing activity (non-regulated off-system sales) and lower management and maintenance service fees received by Primesouth, Inc. due to reduced synthetic fuel tax credit availability, as discussed at *Recognition of Synthetic Fuel Tax Credits* below.

### Income Taxes

Income tax expense for the nine months ended September 30, 2006 increased primarily due to the initial application and recognition of the benefits of previously deferred synthetic fuel tax credits in the first quarter of 2005, and the applicability of the phase-down provisions in 2006, as discussed below at *Recognition of Synthetic Fuel Tax Credits*.

#### *Recognition of Synthetic Fuel Tax Credits*

SCE&G holds equity-method investments in two partnerships involved in converting coal to synthetic fuel, the use of which fuel qualifies for federal income tax credits. Under an accounting plan approved by the Public Service Commission of South Carolina (SCPSC) in June 2000, the synthetic fuel tax credits generated by the partnerships and passed through to SCE&G, net of partnership losses and other expenses, were deferred until the SCPSC approved their application to offset capital costs of the Lake Murray back-up dam project. Under the accounting methodology approved by the SCPSC in a January 2005 order, construction costs related to the project were recorded in utility plant in service in a special dam remediation account, outside of rate base, and depreciation is being recognized against the balance in this account on an accelerated basis, subject to the availability of the synthetic fuel tax credits.

The level of depreciation expense and related tax benefit recognized in the income statement is equal to the available synthetic fuel tax credits, less partnership losses and other expenses, net of taxes. As a result, the balance of unrecovered costs in the dam remediation account declines as accelerated depreciation is recorded. Although these entries collectively have no impact on consolidated net income, they can have a significant impact on individual line items within the income statement. The accelerated depreciation, synthetic fuel tax credits, partnership losses and the income tax benefit arising from such losses recognized by SCE&G during the three and nine months ended September 30, 2006 and 2005 are as follows:

Millions of dollars	Third Quarter		Year to Date	
	2006	2005	2006	2005
Depreciation and amortization expense	\$ (21.6)	\$ (17.2)	\$ (23.0)	\$ (200.8)
Income tax benefits:				
From synthetic fuel tax credits	10.5	12.9	14.6	168.1
From accelerated depreciation	13.4	6.6	14.2	76.8
From partnership losses	3.6	1.3	9.4	27.2
Total income tax benefits	27.5	20.8	38.2	272.1
Losses from Equity Method Investments	(5.9)	(3.6)	(15.2)	(71.3)
Impact on Net Income	\$ -	\$ -	\$ -	\$ -

The 2005 amounts above reflect the recognition of previously deferred tax credits, while the 2006 amounts reflect the likelihood that credits available in 2006 will be phased down pursuant to regulations which limit the credits based on the relative commodity price of crude oil.

Depreciation on the Lake Murray back-up dam remediation account will be matched to available synthetic fuel tax credits on a quarterly basis until the balance in the dam remediation account is zero or until all of the available synthetic fuel tax credits have been utilized. Under current law, the synthetic fuel tax credit program expires at the end of 2007.

The availability of the synthetic fuel tax credits is dependent on several factors, one of which is the average annual domestic wellhead price per barrel of crude oil as published by the U.S. Government. Under a phase-out provision included in the program, if the domestic wellhead reference price of oil per barrel for a given year is below an inflation-adjusted benchmark range for that year, all of the synthetic fuel tax credits that have been generated in that year would be available for use. If that price is above the benchmark range, none of the tax credits would be available. If that price falls within the benchmark range, a calculated portion of the credits would be available.

The benchmark price range for 2005, published in April 2006, was \$53 to \$67 per barrel, and no phase-out applied. However, SCE&G's analysis indicates that the available synthetic fuel tax credits for 2006 are likely to be impacted by the phase-out calculation. As such, through September 2006 the Company recorded synthetic fuel tax credits and applied those credits to allow the recording of accelerated depreciation related to the balance in the dam remediation project account based on an estimate that only 71 percent of credits generated will be available (phase-out of 29 percent). The Company cannot predict what impact, if any, the price of oil may have on the Company's ability to earn and utilize synthetic fuel tax credits in the future. However, there is significant uncertainty as to the continued availability of the credits in 2006 and 2007. The availability of these synthetic fuel tax credits is also subject to coal availability and other operational risks related to the generating plants.

If it is determined that available credits are not sufficient to fully recover the construction costs of the dam remediation, regulatory action to allow recovery of those remaining costs may be sought. As of September 30, 2006, remaining unrecovered costs, based on management's recording of accelerated depreciation and related tax benefits, were \$72.2 million.

Finally, Primesouth, Inc., a subsidiary of SCANA, provides management and maintenance services for a non-affiliated synthetic fuel production facility. Reduced synthetic fuel tax credit availability under the above phase-out provisions also adversely impacts the level of payment Primesouth receives for these services. The fees recognized by Primesouth in the year to date period ended September 30, 2006 were \$4.7 million lower than amounts recognized in the year to date period ended September 30, 2005.

## **LIQUIDITY AND CAPITAL RESOURCES**

The Company anticipates that its contractual cash obligations will be met through internally generated funds, the incurrence of additional short-term and long-term indebtedness and sales of additional equity securities. The Company expects that it has or can obtain adequate sources of financing to meet its projected cash requirements for the foreseeable future. The Company's ratio of earnings to fixed charges for the 12 months ended September 30, 2006 was 2.93.

Cash requirements for the Company's regulated subsidiaries arise primarily from their operational needs, funding their construction programs and payment of dividends to SCANA. The ability of the regulated subsidiaries to replace existing plant investment, to expand to meet future demand for electricity and gas and to install equipment necessary to comply with environmental regulations will depend on their ability to attract the necessary financial capital on reasonable terms. Regulated subsidiaries recover the costs of providing services through rates charged to customers. Rates for regulated services are generally based on historical costs. As customer growth and inflation occur and these subsidiaries continue their ongoing construction programs, rate increases will be sought. The future financial position and results of operations of the regulated subsidiaries will be affected by their ability to obtain adequate and timely rate and other regulatory relief, if requested.

For more information on significant rate and other regulatory matters, see Note 2 to the condensed consolidated financial statements.

SCE&G expects to require the addition of base load electric generation by 2015 and is evaluating alternatives, including fossil- and nuclear-fueled generation. In February 2006, SCE&G and Santee Cooper, a state-owned utility in South Carolina (joint owners of Summer Station) announced their selection of the Summer Station site as the preferred site for new nuclear generation should such generation be considered the best alternative in the future. Due to the significant lead time required for construction of nuclear generation, the joint owners are preparing an application to the Nuclear Regulatory Commission (NRC) for a combined construction and operating license (COL) that would cover two new nuclear units. The COL application, which is expected to be completed and filed in 2007, would be reviewed by the NRC for an estimated three years. Issuance of a COL would not obligate the joint owners to build nuclear generation. The final decision to build nuclear generation will be influenced by several factors, including NRC licensing attainment, construction and operating costs, the cost of competing fuels, regulatory and environmental requirements and financial market conditions.

SCE&G also periodically reassesses its other capital investment requirements. Based on recent developments, significant increases in the estimated cost for scrubbers and other environmental abatement equipment will be necessary to comply with environmental regulations. Preliminary estimates indicate that expenditures for these environmental requirements in 2007 and 2008 could increase by approximately \$200 million over the amounts reflected in the Liquidity and Resources section of Management's Discussion and Analysis of Financial Condition and Results of Operations in Form 10-K for the year ended December 31, 2005. These capital expenditures would be expected to become part of SCE&G's rate base and thereby be subject to recovery through future rate proceedings.

The following table summarizes how the Company generated and used funds for property additions and construction expenditures during the nine months ended September 30, 2006 and 2005:

Millions of dollars	Nine Months Ended September 30,	
	2006	2005
Net cash provided from operating activities	\$ 607	\$ 526
Net cash used for financing activities	(227)	(175)
Cash provided from sale of investment and assets	18	8
Cash and cash equivalents available at the beginning of the period	62	119
Funds used for utility property additions and construction expenditures	(311)	(267)
Funds used for nonutility property additions	(27)	(11)
Funds used for investments	(21)	(29)

The Company's issuance of various securities, including long-term and short-term debt, is subject to customary approval or authorization by state and federal regulatory bodies, including state public service commissions, the Securities and Exchange Commission and Federal Energy Regulatory Commission (FERC).

Pursuant to Section 204 of the Federal Power Act, SCE&G and GENCO must obtain FERC authority to issue short-term debt. Effective February 8, 2006 the FERC has authorized SCE&G and GENCO to issue up to \$700 million and \$100 million, respectively, of unsecured promissory notes or commercial paper with maturity dates of one year or less. This authorization expires February 7, 2008.

In June 2006, SCE&G issued \$125 million of first mortgage bonds having an annual interest rate of 6.25% and maturing July 1, 2036. The proceeds from the sale of these bonds, together with available cash, were used for the payment at maturity of \$131 million of SCE&G's first and refunding mortgage bonds due July 15, 2006, which bore interest at 9.0%.

In August 2006 SCANA obtained a \$30 million uncommitted short-term credit facility. In September 2006 SCANA extended a \$125 million nine month committed credit facility for a duration of 364 days and renewed two \$50 million committed 364-day credit facilities. A \$125 million nine month committed credit facility expired in September 2006 and was not renewed.

## ENVIRONMENTAL AND REGULATORY MATTERS

See notes to the condensed consolidated financial statements for information related to environmental matters (Note 5B) and Regulatory Matters (Note 2).

### ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

All financial instruments held by the Company described below are held for purposes other than trading.

Interest rate risk - The table below provides information about long-term debt issued by the Company and other financial instruments that are sensitive to changes in interest rates. For debt obligations, the table presents principal cash flows and related weighted average interest rates by expected maturity dates. For interest rate swaps, the figures shown reflect notional amounts and related maturities. Fair values for debt and swaps represent quoted market prices.

As of September 30, 2006	Expected Maturity Date							Fair Value
Millions of dollars	2006	2007	2008	2009	2010	There-After	Total	
<b>Liabilities</b>								
Long-Term Debt:								
Fixed Rate (\$)	3.7	33.2	123.2	108.1	14.8	2,642.9	2,925.9	3,094.8
Average Fixed Interest Rate (%)	7.78	7.17	5.95	6.27	6.87	6.15	6.16	n/a
Variable Rate (\$)			100.0				100.0	100.0
Average Variable Interest Rate (%)			5.55				5.55	n/a
Interest Rate Swaps:								
Pay Variable/Receive Fixed (\$)	-	28.2	3.2	3.2	3.2	6.4	44.2	(0.1)
Average Pay Interest Rate (%)	-	8.52	8.56	8.56	8.56	8.56	8.54	n/a
Average Receive Interest Rate (%)	-	7.11	8.75	8.75	8.75	8.75	7.70	n/a

While a decrease in interest rates would increase the fair value of debt, it is unlikely that events which would result in a significant realized loss will occur.

Commodity price risk - The following tables provide information about the Company's financial instruments that are sensitive to changes in natural gas prices. Weighted average settlement prices are per 10,000 dekatherms. Fair value represents quoted market prices.

Expected Maturity:

	Futures Contracts		Options			
	Long	Short	Purchased Call	Sold Call (Short)	Sold Put (Long)	
<b>2006</b>						
Settlement Price <sup>(a)</sup>	6.52	6.94	Strike Price <sup>(a)</sup>	9.13	9.10	7.1
Contract Amount <sup>(b)</sup>	18.9	1.8	Contract Amount <sup>(b)</sup>	5.0	0.3	0.2
Fair Value <sup>(b)</sup>	14.0	1.2	Fair Value <sup>(b)</sup>	0.1	-	-
<b>2007</b>						
Settlement Price <sup>(a)</sup>	7.66	7.67	Strike Price <sup>(a)</sup>	10.3	11.0	6.5
Contract Amount <sup>(b)</sup>	42.1	5.5	Contract Amount <sup>(b)</sup>	2.7	1.6	1.7
Fair Value <sup>(b)</sup>	34.5	4.2	Fair Value <sup>(b)</sup>	0.1	(0.1)	(0.2)

<sup>(a)</sup> Weighted average, in dollars

<sup>(b)</sup> Millions of dollars

Swaps	Expected Maturity		
	2006	2007	2008
<b>Commodity Swaps:</b>			
Pay fixed/receive variable <sup>(b)</sup>	73.2	185.0	32.8
Average pay rate <sup>(a)</sup>	9.3256	9.4777	10.9983
Average received rate <sup>(a)</sup>	6.6504	7.7448	9.0349
Fair value <sup>(b)</sup>	52.2	151.2	26.9
Pay variable/receive fixed <sup>(b)</sup>	0.9	0.2	-
Average pay rate <sup>(a)</sup>	5.9405	8.0369	-
Average received rate <sup>(a)</sup>	8.1520	10.7769	-
Fair value <sup>(b)</sup>	1.2	0.3	-
<b>Basis Swaps:</b>			
Pay variable/receive variable <sup>(b)</sup>	18.3	17.7	-
Average pay rate <sup>(a)</sup>	5.2816	7.9249	-
Average received rate <sup>(a)</sup>	5.2760	7.9021	-
Fair value <sup>(b)</sup>	18.3	17.6	-

<sup>(a)</sup> Weighted average, in dollars

<sup>(b)</sup> Millions of dollars

**SOUTH CAROLINA ELECTRIC & GAS COMPANY  
FINANCIAL SECTION**

## ITEM 1. FINANCIAL STATEMENTS

### SOUTH CAROLINA ELECTRIC & GAS COMPANY CONDENSED CONSOLIDATED BALANCE SHEETS (Unaudited)

Millions of dollars	September 30, 2006	December 31, 2005
<b>Assets</b>		
Utility Plant In Service	\$ 7,822	\$ 7,687
Accumulated Depreciation and Amortization	(2,414)	(2,285)
	5,408	5,402
Construction Work in Progress	235	160
Nuclear Fuel, Net of Accumulated Amortization	41	28
Utility Plant, Net	5,684	5,590
Nonutility Property and Investments:		
Nonutility property, net of accumulated depreciation	30	28
Assets held in trust, net - nuclear decommissioning	55	52
Other investments	26	28
Nonutility Property and Investments, Net	111	108
Current Assets:		
Cash and cash equivalents	19	19
Receivables, net of allowance for uncollectible accounts of \$4 and \$2	318	366
Receivables - affiliated companies	37	32
Inventories (at average cost):		
Fuel	64	62
Materials and supplies	86	72
Emission allowances	24	7
Prepayments and other	16	12
Deferred income taxes	19	22
Total Current Assets	583	592
Deferred Debits and Other Assets:		
Pension asset, net	313	303
Due from affiliates - pension and postretirement benefits	25	31
Emission allowances	27	47
Regulatory assets	566	584
Other	124	121
Total Deferred Debits and Other Assets	1,055	1,086
<b>Total</b>	<b>\$ 7,433</b>	<b>\$ 7,376</b>

Millions of dollars	September 30, 2006	December 31, 2005
<b>Capitalization and Liabilities</b>		
Shareholders' Investment:		
Common equity	\$ 2,439	\$ 2,362
Preferred stock (Not subject to purchase or sinking funds)	106	106
<b>Total Shareholders' Investment</b>	<b>2,545</b>	<b>2,468</b>
Preferred Stock, net (Subject to purchase or sinking funds)	8	8
Long-Term Debt, net	2,015	1,856
<b>Total Capitalization</b>	<b>4,568</b>	<b>4,332</b>
<b>Minority Interest</b>	<b>85</b>	<b>82</b>
Current Liabilities:		
Short-term borrowings	226	303
Current portion of long-term debt	14	183
Accounts payable	81	84
Accounts payable - affiliated companies	162	142
Customer deposits and customer prepayments	38	35
Taxes accrued	134	140
Interest accrued	30	35
Dividends declared	41	40
Other	36	38
<b>Total Current Liabilities</b>	<b>762</b>	<b>1,000</b>
Deferred Credits and Other Liabilities:		
Deferred income taxes, net	795	801
Deferred investment tax credits	119	119
Asset retirement obligations	322	309
Postretirement benefits	155	148
Due to affiliates - pension and postretirement benefits	11	12
Regulatory liabilities	543	498
Other	73	75
<b>Total Deferred Credits and Other Liabilities</b>	<b>2,018</b>	<b>1,962</b>
<b>Commitments and Contingencies (Note 4)</b>	<b>-</b>	<b>-</b>
<b>Total</b>	<b>\$ 7,433</b>	<b>\$ 7,376</b>

See Notes to Condensed Consolidated Financial Statements.

SOUTH CAROLINA ELECTRIC & GAS COMPANY  
CONDENSED CONSOLIDATED STATEMENTS OF INCOME  
(Unaudited)

Millions of dollars	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
<b>Operating Revenues:</b>				
Electric	\$ 587	\$ 620	\$ 1,451	\$ 1,478
Gas	77	80	358	321
<b>Total Operating Revenues</b>	<b>664</b>	<b>700</b>	<b>1,809</b>	<b>1,799</b>
<b>Operating Expenses:</b>				
Fuel used in electric generation	200	217	464	482
Purchased power	7	16	19	36
Gas purchased for resale	62	68	287	260
Other operation and maintenance	115	111	344	332
Depreciation and amortization	86	78	216	389
Other taxes	35	32	104	103
<b>Total Operating Expenses</b>	<b>505</b>	<b>522</b>	<b>1,434</b>	<b>1,602</b>
<b>Operating Income</b>	<b>159</b>	<b>178</b>	<b>375</b>	<b>197</b>
<b>Other Income (Expense):</b>				
Other income	24	46	59	111
Other expenses	(18)	(39)	(45)	(92)
Interest charges, net of allowance for borrowed funds used during construction of \$2, \$1, \$5 and \$2	(34)	(35)	(106)	(109)
Gain on sale of assets	-	-	-	1
<b>Total Other Expense</b>	<b>(28)</b>	<b>(28)</b>	<b>(92)</b>	<b>(89)</b>
<b>Income (Loss) Before Income Taxes (Benefit), Losses from Equity Method Investments, Minority Interest, Cumulative Effect of Accounting Change and Preferred Stock Dividends</b>				
	131	150	283	108
<b>Income Tax Expense (Benefit)</b>	<b>30</b>	<b>39</b>	<b>71</b>	<b>(166)</b>
<b>Income Before Losses from Equity Method Investments, Minority Interest, Cumulative Effect of Accounting Change and Preferred Stock Dividends</b>				
	101	111	212	274
<b>Losses from Equity Method Investments</b>	<b>(6)</b>	<b>(4)</b>	<b>(16)</b>	<b>(72)</b>
Minority Interest	2	1	5	4
<b>Cumulative Effect of Accounting Change, net of taxes</b>	<b>-</b>	<b>-</b>	<b>4</b>	<b>-</b>
<b>Net Income</b>	<b>93</b>	<b>106</b>	<b>195</b>	<b>198</b>
<b>Preferred Stock Cash Dividends Declared</b>	<b>2</b>	<b>2</b>	<b>6</b>	<b>6</b>
<b>Earnings Available for Common Shareholder</b>	<b>\$ 91</b>	<b>\$ 104</b>	<b>\$ 189</b>	<b>\$ 192</b>

See Notes to Condensed Consolidated Financial Statements.

SOUTH CAROLINA ELECTRIC & GAS COMPANY  
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS  
(Unaudited)

Millions of dollars	Nine Months Ended September 30,	
	2006	2005
<b>Cash Flows From Operating Activities:</b>		
Net income	\$ 195	\$ 198
<b>Adjustments to Reconcile Net Income to Net Cash Provided From Operating Activities:</b>		
Cumulative effect of accounting change, net of taxes	(4)	-
Losses from equity method investments	16	72
Minority interest	5	4
Depreciation and amortization	216	389
Amortization of nuclear fuel	14	4
Gain on sale of assets	-	(1)
Carrying cost recovery	(5)	(8)
<b>Cash provided (used) by changes in certain assets and liabilities:</b>		
Receivables, net	49	(83)
Inventories	(50)	(98)
Prepayments	(4)	16
Pension asset	(9)	(13)
Other regulatory assets	(16)	30
Deferred income taxes, net	(3)	11
Regulatory liabilities	22	(163)
Postretirement benefits	7	4
Accounts payable	(63)	(15)
Taxes accrued	(6)	(44)
Interest accrued	(5)	(5)
Changes in fuel adjustment clauses	38	(46)
Changes in other assets	1	(5)
Changes in other liabilities	6	3
<b>Net Cash Provided From Operating Activities</b>	<b>404</b>	<b>250</b>
<b>Cash Flows From Investing Activities:</b>		
Utility property additions and construction expenditures	(248)	(255)
Proceeds from sale of assets	-	1
Investments	(23)	(17)
<b>Net Cash Used For Investing Activities</b>	<b>(271)</b>	<b>(271)</b>
<b>Cash Flows From Financing Activities:</b>		
Proceeds from issuance of debt	132	97
Repayment of debt	(144)	(253)
Redemption of preferred stock	-	(1)
Dividends on equity securities	(122)	(117)
Contribution from parent	3	95
Short-term borrowings - affiliate, net	75	(3)
Short-term borrowings, net	(77)	197
<b>Net Cash Provided From (Used For) Financing Activities</b>	<b>(133)</b>	<b>15</b>
Net Increase (Decrease) In Cash and Cash Equivalents	-	(6)
Cash and Cash Equivalents, January 1	19	20
<b>Cash and Cash Equivalents, September 30</b>	<b>\$ 19</b>	<b>\$ 14</b>
<b>Supplemental Cash Flow Information:</b>		
Cash paid for - Interest (net of capitalized interest of \$5 and \$2)	89	103
- Income taxes	64	23
<b>Noncash Investing and Financing Activities:</b>		
Accrued construction expenditures	14	12

See Notes to Condensed Consolidated Financial Statements.

SOUTH CAROLINA ELECTRIC & GAS COMPANY  
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS  
September 30, 2006  
(Unaudited)

The following notes should be read in conjunction with the Notes to Consolidated Financial Statements appearing in South Carolina Electric & Gas Company's (SCE&G, and together with its consolidated affiliates, the Company) Annual Report on Form 10-K for the year ended December 31, 2005. These are interim financial statements, and due to the seasonality of the Company's business and matters that may occur during the rest of the year, the amounts reported in the Condensed Consolidated Statements of Income are not necessarily indicative of amounts expected for the full year. In the opinion of management, the information furnished herein reflects all adjustments, all of a normal recurring nature, which are necessary for a fair statement of the results for the interim periods reported.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. Variable Interest Entity

Financial Accounting Standards Board Interpretation (FIN) 46 (Revised 2003), "*Consolidation of Variable Interest Entities*," requires an enterprise's consolidated financial statements to include entities in which the enterprise has a controlling financial interest. SCE&G has determined that it has a controlling financial interest in South Carolina Generating Company, Inc. (GENCO) and South Carolina Fuel Company, Inc. (Fuel Company), and accordingly, the accompanying condensed consolidated financial statements include the accounts of SCE&G, GENCO and Fuel Company. The equity interests in GENCO and Fuel Company are held solely by SCANA Corporation (SCANA), the Company's parent. Accordingly, GENCO's and Fuel Company's equity and results of operations are reflected as minority interest in the Company's condensed consolidated financial statements.

GENCO owns and operates a coal-fired electric generating station with a 615 megawatt net generating capacity (summer rating). GENCO's electricity is sold solely to SCE&G under the terms of power purchase and related operating agreements. Fuel Company acquires, owns and provides financing for SCE&G's nuclear fuel, fossil fuel and sulfur dioxide emission allowances. The effects of these transactions are eliminated in consolidation. Substantially all of GENCO's property (carrying value of \$255 million) serves as collateral for its long-term borrowings.

B. Basis of Accounting

The Company accounts for its regulated utility operations, assets and liabilities in accordance with the provisions of Statement of Financial Accounting Standards (SFAS) 71, "*Accounting for the Effects of Certain Types of Regulation*." SFAS 71 requires cost-based rate-regulated utilities to recognize in their financial statements certain revenues and expenses in different time periods than do enterprises that are not rate-regulated. As a result, the Company has recorded the regulatory assets and regulatory liabilities summarized as follows.

Millions of dollars	September 30, 2006	December 31, 2005
<b>Regulatory Assets:</b>		
Accumulated deferred income taxes	\$ 170	\$ 170
Under-collections - electric fuel and gas cost adjustment clauses	38	56
Purchased power costs	11	17
Environmental remediation costs	18	18
Asset retirement obligations and related funding	252	240
Franchise agreements	55	56
Regional transmission organization costs	9	11
Other	13	16
<b>Total Regulatory Assets</b>	<b>\$ 566</b>	<b>\$ 584</b>
<b>Regulatory Liabilities:</b>		
Accumulated deferred income taxes	\$ 34	\$ 36
Other asset removal costs	428	404
Storm damage reserve	43	38
Planned major maintenance	21	9
Other	17	11
<b>Total Regulatory Liabilities</b>	<b>\$ 543</b>	<b>\$ 498</b>

Accumulated deferred income tax liabilities arising from utility operations that have not been included in customer rates are recorded as a regulatory asset. Accumulated deferred income tax assets arising from deferred investment tax credits are recorded as a regulatory liability.

Under-collections - electric fuel and gas cost adjustment clauses, represent amounts under-collected from customers pursuant to the fuel adjustment clause (electric customers) or gas cost adjustment clause (gas customers) as approved by the Public Service Commission of South Carolina (SCPSC) during annual hearings. Included in these amounts are regulatory assets or liabilities arising from the Company's natural gas hedging program.

Purchased power costs represent costs that were necessitated by outages at two of SCE&G's base load generating plants in winter 2000-2001. The SCPSC approved recovery of these costs in base rates over a three-year period beginning January 2005.

Environmental remediation costs represent costs associated with the assessment and clean-up of manufactured gas plant (MGP) sites currently or formerly owned by SCE&G. Costs incurred by SCE&G at such sites are being recovered through rates, of which \$18.3 million remain to be recovered.

Asset retirement obligations (ARO) and related funding represents the regulatory asset associated with the legal obligation to decommission and dismantle V. C. Summer Nuclear Station (Summer Station) and conditional AROs recorded as required by SFAS 143, "*Accounting for Asset Retirement Obligations*," and FIN 47, "*Accounting for Conditional Asset Retirement Obligations*."

Franchise agreements represent costs associated with electric and gas franchise agreements with the cities of Charleston and Columbia, South Carolina. These amounts are being amortized through cost of service rates and are expected to be fully amortized over approximately 20 years.

Regional transmission organization costs represent costs incurred by SCE&G in the United States Federal Energy Regulatory Commission (FERC)-mandated formation of GridSouth. The project was suspended in 2002. Effective January 2005, the SCPSC approved the amortization of these amounts through cost of service rates over approximately five years.

Other asset removal costs represent net collections through depreciation rates of estimated costs to be incurred for the removal of assets in the future.

The storm damage reserve represents an SCPSC approved reserve account capped at \$50 million to be collected through rates. The accumulated reserve can be applied to offset incremental storm damage costs in excess of \$2.5 million in a calendar year. For the nine months ended September 30, 2006, no amounts were drawn from this reserve account.

Planned major maintenance related to certain fossil and hydro-turbine equipment and nuclear refueling outages is accrued in advance of the time the costs are incurred, as approved through specific SCPSC orders. SCE&G is allowed to collect \$8.5 million annually over an eight-year period through electric rates to offset turbine maintenance expenditures. Nuclear refueling charges are accrued during each 18-month refueling outage cycle. Nuclear refueling charges are a component of cost of service and do not receive special rate consideration.

The SCPSC has reviewed and approved through specific orders most of the items shown as regulatory assets. Other items represent costs which are not approved for recovery by the SCPSC. In recording these costs as regulatory assets, management believes the costs will be allowable under existing rate-making concepts that are embodied in rate orders received by SCE&G. However, ultimate recovery is subject to SCPSC approval. In the future, as a result of deregulation or other changes in the regulatory environment, the Company may no longer meet the criteria for continued application of SFAS 71 and could be required to write off its regulatory assets and liabilities. Such an event could have a material adverse effect on the Company's results of operations, liquidity or financial position in the period the write-off would be recorded.

#### C. Transactions with Affiliates

SCE&G has entered into agreements with certain affiliates to purchase all gas for resale to its distribution customers. SCE&G purchases natural gas for resale and for electric generation from South Carolina Pipeline Corporation (SCPC) and had \$20.3 million and \$72.1 million payable to SCPC for such gas purchases at September 30, 2006 and December 31, 2005, respectively.

SCE&G purchases natural gas and related pipeline capacity to supply its Jasper County Electric Generating Station from SCANA Energy Marketing, Inc. (SEMI). Such purchases totaled \$43.4 million and \$66.8 million for the three and nine months ended September 30, 2006, respectively and totaled \$66.5 million and \$111.9 million for the three and nine months ended September 30, 2005, respectively. SCE&G had \$6.3 million and \$8.0 million payable to SEMI for such purposes as of September 30, 2006 and December 31, 2005, respectively.

At September 30, 2006, SCE&G owed an affiliate \$75 million arising from advances from a consolidated cash management utility money pool. At December 31, 2005, no such money pool advances had been drawn.

SCE&G holds equity-method investments in two partnerships involved in converting coal to synthetic fuel. SCE&G's receivables from these affiliated companies were \$24.0 million and \$24.6 million at September 30, 2006 and December 31, 2005, respectively. SCE&G's payables to these affiliated companies were \$23.5 million and \$25.3 million at September 30, 2006 and December 31, 2005, respectively. SCE&G purchased \$72.6 million and \$70.2 million of synthetic fuel from these affiliated companies for the three months ended September 30, 2006 and 2005, respectively. SCE&G purchased \$201.9 million and \$183.9 million of synthetic fuel from these affiliated companies for the nine months ended September 30, 2006 and 2005, respectively.

On October 31, 2006, SCE&G acquired SCPC's liquefied natural gas (LNG) plant facilities and related inventory at its net book value, which totaled \$33.3 million. In the nine months ended September 30, 2005, SCE&G purchased 342 miles of gas distribution pipeline from SCPC at its net book value, which totaled \$20.9 million.

#### D. Pension and Other Postretirement Benefit Plans

Components of net periodic benefit income or cost recorded by the Company were as follows:

Millions of dollars	Pension Benefits		Other Postretirement Benefits	
	2006	2005	2006	2005
<i>Three months ended September 30,</i>				
Service cost	\$ 3.5	\$ 3.1	\$ 1.1	\$ 0.9
Interest cost	10.0	9.7	3.0	2.4
Expected return on assets	(18.8)	(19.0)	-	-
Prior service cost amortization	1.7	1.8	0.4	0.1
Transition obligation amortization	0.2	0.2	0.2	0.2
Amortization of actuarial loss	0.1	-	0.6	-
Amount attributable to Company affiliates	(0.6)	(0.5)	(1.4)	(1.0)
<b>Net periodic benefit (income) cost</b>	<b>\$ (3.9)</b>	<b>\$ (4.7)</b>	<b>\$ 3.9</b>	<b>\$ 2.6</b>
<i>Nine months ended September 30,</i>				
Service cost	\$ 10.5	\$ 9.2	\$ 3.5	\$ 2.7
Interest cost	29.8	28.7	8.7	8.0
Expected return on assets	(56.4)	(57.2)	-	-
Prior service cost amortization	5.1	5.2	0.8	0.6
Transition obligation amortization	0.4	0.6	0.6	0.6
Amortization of actuarial loss	0.5	-	1.3	0.9
Amount attributable to Company affiliates	(1.9)	(1.4)	(4.1)	(3.6)
<b>Net periodic benefit (income) cost</b>	<b>\$ (12.0)</b>	<b>\$ (14.9)</b>	<b>\$ 10.8</b>	<b>\$ 9.2</b>

#### E. Share-Based Compensation

The Company participates in the SCANA Corporation Long-Term Equity Compensation Plan. The plan provides for grants of incentive nonqualified stock options, stock appreciation rights, restricted stock, performance shares and performance units to certain key employees and non-employee directors. The plan currently authorizes the issuance of up to five million shares of the Company's common stock, no more than one million of which may be granted in the form of restricted stock.

SFAS 123 (revised 2004), "Share-Based Payment" (SFAS 123(R)), requires compensation costs related to share-based payment transactions to be recognized in the financial statements. With limited exceptions, compensation cost is measured based on the grant-date fair value of the instruments issued and is recognized over the period that an employee provides service in exchange for the award. The cumulative effect of the adoption of SFAS 123(R) on January 1, 2006 resulted in a \$4 million (net of tax) gain in the first quarter of 2006 based on a reduction of prior compensation accruals for performance awards (discussed below) granted in 2004 and 2005.

### Liability Awards

Certain executives are granted a target number of performance shares on an annual basis that vest over a three-year period. Each performance share has a value that is equal to, and changes with, the value of a share of SCANA common stock, and dividend equivalents are accrued on, and reinvested in, the performance shares. Payout of performance share awards is determined by SCANA's performance against pre-determined measures of total shareholder return (TSR) as compared to a peer group of utilities (weighted 60%) and growth in earnings per share (weighted 40%) over the three year plan cycle. TSR is calculated by dividing stock price increase over the three-year period, plus cash dividends, by the stock price as of the beginning of the period. Payouts vary according to SCANA's ranking against the peer group and relative earnings per share projection achievement. Awards are designated as target shares of SCANA common stock and may be paid in stock or cash or a combination of stock and cash at SCANA's discretion.

Under SFAS 123(R) compensation cost of these liability awards is recognized over the three-year performance period based on the estimated fair value of the award, which is periodically updated based on expected ultimate cash payout, and is reduced by estimated forfeitures. Cash-settled liabilities totaling \$1.2 million were paid during the nine months ended September 30, 2006. No such payments were made during the corresponding period in 2005.

Fair value adjustments for performance awards resulted in a reduction to compensation expense recognized in the condensed statements of income, exclusive of the cumulative effect adjustment discussed previously, totaling \$(0.5) million and \$(1.0) million for the three and nine months ended September 30, 2006, respectively, and an increase to compensation expense totaling \$1.2 and \$4.3 million for the corresponding periods ended September 30, 2005, respectively. Fair value adjustments resulted in a net credit to capitalized compensation cost of approximately \$(0.1) million during the nine months ended September 30, 2006, compared to capitalized costs of approximately \$0.7 million during the corresponding period in 2005.

### Equity Awards

A summary of activity related to nonqualified stock options since December 31, 2005 follows:

	<b>Number of Options</b>	<b>Weighted Average Exercise Price</b>
Outstanding-December 31, 2005	439,270	\$27.53
Exercised	(11,341)	\$27.12
Outstanding-March 31, 2006	427,929	\$27.54
Exercised	(6,805)	\$27.48
Outstanding-June 30, 2006	421,124	\$27.54
Exercised	(33,064)	\$27.52
Outstanding-September 30, 2006	388,060	\$27.54

No stock options have been granted since August 2002, and all options were fully vested in August 2005. The options expire ten years after the grant date. At September 30, 2006, all outstanding options were currently exercisable at prices ranging from \$25.50-\$29.60, and had a weighted-average remaining contractual life of 5.1 years.

All options were granted with exercise prices equal to the fair market value of SCANA's common stock on the respective grant dates; therefore, no compensation expense was recognized in connection with such grants. If the Company had recognized compensation expense for the issuance of options based on the fair value method described in SFAS 123(R), pro forma earnings available for the common shareholder would have been unchanged from that reported for the three and nine months ended September 30, 2005.

The exercise of stock options during the period was satisfied using original issue shares of SCANA's common stock. Cash and the related tax benefits realized from stock option exercises during the period were retained at SCANA.

### F. New Accounting Matters

SFAS 123(R) requires compensation costs related to share-based payment transactions to be recognized in the financial statements. With limited exceptions, compensation cost is measured based on the grant-date fair value of the instruments issued and is recognized over the period that an employee provides service in exchange for the award. SFAS 123(R) replaces SFAS 123, "Accounting for Stock-Based Compensation," and supersedes Accounting Principles Board (APB) Opinion 25, "Accounting for Stock Issued to Employees." The Company adopted SFAS 123(R) in the first quarter of 2006. The impact on the Company's results of operations is discussed at Note 1E.

The Company adopted SFAS 154, "Accounting Changes and Error Corrections," in the first quarter of 2006. SFAS 154 requires retrospective application to financial statements of prior periods for every voluntary change in accounting principle unless such retrospective application is impracticable. SFAS 154 replaces APB 20, "Accounting Changes," and SFAS 3, "Reporting Accounting Changes in Interim Financial Statements." The adoption of SFAS 154 had no material impact on the Company's results of operations, cash flows or financial position.

SFAS 157, "Fair Value Measurements," was issued in September 2006. SFAS 157 establishes a framework for measuring fair value to increase the consistency and comparability in fair value measurements. The Company will adopt SFAS 157 in the first quarter of 2008, and does not expect that the initial adoption will have a material impact on the Company's results of operations, cash flows or financial position.

In September 2006, SFAS 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans," amended SFAS 87 and SFAS 106 to require recognition of the overfunded or underfunded status of pension and other postretirement benefit plans on the balance sheet. Under SFAS 158, gains and losses, prior service costs and credits, and any remaining transition amounts under SFAS 87 and SFAS 106 that have not yet been recognized through net periodic benefit cost will be recognized in accumulated other comprehensive income, net of tax effects, until they are amortized as a component of net periodic cost. SFAS 158 is effective for publicly-held companies for fiscal years ending after December 15, 2006. SCANA will adopt the balance sheet recognition provisions of SFAS 158 at December 31, 2006. Because a substantial majority of the Company's pension and other postretirement costs recorded under SFAS 87 and SFAS 106 are attributable to employees in its regulated operations, the adoption of this Standard will primarily result in the recording of additional regulatory assets. The adoption is not expected to have a material impact on the Company's financial position, results of operations or cash flows.

FIN 48, "Accounting for Uncertainty in Income Taxes," was issued in June 2006. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with SFAS 109, "Accounting for Income Taxes." FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of tax positions taken or expected to be taken in a tax return. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. The Company will adopt FIN 48 in the first quarter of 2007. The Company is continuing to evaluate the impact that adoption of FIN 48 may have on the Company's results of operations, cash flows or financial position.

FASB Staff Position (FSP) AUG AIR-1 "Accounting for Planned Major Maintenance Activities," was issued in September 2006. This Standard amends APB 28, "Interim Financial Reporting," to prohibit the use of the accrue-in-advance method of accounting for planned major maintenance in annual and interim financial reporting periods. As disclosed in Note 1A, the Company has received specific SCPSC orders providing for use of accrue-in-advance accounting for certain planned major maintenance activities. Accordingly, the Company will continue to rely on SFAS 71 when accounting for these activities. The Company will adopt FSP AUG AIR-1 in the first quarter of 2007, and does not expect that the initial adoption will have a material impact on the Company's results of operations, cash flows or financial position.

The United States Securities and Exchange Commission (SEC) issued Staff Accounting Bulletin 108 (SAB 108) in September 2006. SAB 108 provides guidance on the consideration of the effects of prior year misstatements in quantifying and assessing the materiality of current year misstatements. SAB 108 also provides transition guidance for correcting errors existing from prior years. The Company will adopt SAB 108 in December 2006, and does not expect that the initial adoption will have a material impact on the Company's results of operations, cash flows or financial position.

## 2. RATE AND OTHER REGULATORY MATTERS

### Electric

SCE&G's rates are established using a cost of fuel component approved by the SCPSC which may be modified periodically to reflect changes in the price of fuel purchased by SCE&G. SCE&G's cost of fuel component was as follows:

Rate Per KWh	Effective Date
\$.01764	January-April 2005
.02256	May 2005-April 2006
.02516	May-September 2006

In connection with the May 2006 fuel component increase, SCE&G agreed to spread the recovery of previously under-collected fuel costs of \$38.5 million over a two-year period.

## Gas

In October 2005, the SCPSC granted SCE&G an overall increase of \$22.9 million, or 5.69 percent, in retail gas base rates. The new rates are based on an allowed return on common equity of 10.25 percent, and became effective with the first billing cycle in November 2005.

In June 2006, SCE&G reported to the SCPSC that its return on common equity for the twelve months ended March 31, 2006 was more than 0.5 percent below the allowed return, and as provided under South Carolina's Natural Gas Rate Stabilization Act, SCE&G requested an annualized increase in certain natural gas base rates. In September 2006, the SCPSC approved an annual increase of \$17.4 million. The rate adjustment was effective with the first billing cycle in November 2006.

SCE&G's rates are established using a cost of gas component approved by the SCPSC which may be modified periodically to reflect changes in the price of natural gas purchased by SCE&G. SCE&G's cost of gas components by class were as follows (rate per therm):

Effective Date	Residential	Small/Medium	Large
January-October 2005	\$.903	\$.903	\$.903
November 2005	1.297	1.222	1.198
December 2005	1.362	1.286	1.263
January 2006	1.297	1.222	1.198
February-September 2006	1.227	1.152	1.128

On October 25, 2006, the SCPSC approved a reduction in the cost of gas component of SCE&G's retail natural gas rates, effective with the first billing cycle of November 2006. The SCPSC also authorized SCE&G to adjust its cost of gas on a monthly, rather than an annual, basis beginning in December 2006.

Prior to November 2005, the SCPSC allowed SCE&G to recover through a billing surcharge to its gas customers the costs of environmental cleanup at the sites of former MGPs. Effective with the first billing cycle of November 2005, the billing surcharge was eliminated. In its place, SCE&G defers certain MGP environmental costs in regulatory asset accounts and collects and amortizes these costs through base rates.

### 3. LONG-TERM DEBT

In June 2006, SCE&G issued \$125 million of first mortgage bonds having an annual interest rate of 6.25% and maturing July 1, 2036. The proceeds from the sale of these bonds, together with available cash, were used for the payment at maturity of \$131 million of SCE&G's first and refunding mortgage bonds due July 15, 2006, which bore interest at 9.0%.

In anticipation of the issuance of debt, the Company uses interest rate lock or similar agreements to manage interest rate risk. Payments received or made upon termination of such agreements are recorded within long term debt on the balance sheet and are amortized to interest expense over the term of the underlying debt. In connection with the issuance of first mortgage bonds in June 2006, SCE&G received approximately \$8.8 million upon the termination of an interest rate lock agreement. These proceeds are being amortized over the life of the related debt, thereby reducing its effective interest rate. As permitted by SFAS 104 "Statement of Cash Flows - Net Reporting of Certain Cash Receipts and Cash Payments and Classification of Cash Flows from Hedging Transactions," these proceeds have been classified as a financing activity in the condensed consolidated statement of cash flows.

Substantially all of SCE&G's and GENCO's electric utility plant is pledged as collateral in connection with long-term debt.

### 4. COMMITMENTS AND CONTINGENCIES

Reference is made to Note 10 to the consolidated financial statements appearing in SCE&G's Annual Report on Form 10-K for the year ended December 31, 2005. Commitments and contingencies at September 30, 2006 include the following:

#### A. Nuclear Insurance

The Price-Anderson Indemnification Act deals with public liability for a nuclear incident and establishes the liability limit for third-party claims associated with any nuclear incident at \$10.5 billion. Each reactor licensee is currently liable for up to \$100.6 million per reactor owned for each nuclear incident occurring at any reactor in the United States, provided that not more than \$15 million of the liability per reactor would be assessed per year. SCE&G's maximum assessment, based on its two-thirds ownership of Summer Station, would be \$67.1 million per incident, but not more than \$10 million per year.

SCE&G currently maintains policies (for itself and on behalf of Santee Cooper, a one-third owner of Summer Station) with Nuclear Electric Insurance Limited. The policies, covering the nuclear facility for property damage, excess property damage and outage costs, permit retrospective assessments under certain conditions to cover insurer's losses. Based on the current annual premium, SCE&G's portion of the retrospective premium assessment would not exceed \$14.1 million.

To the extent that insurable claims for property damage, decontamination, repair and replacement and other costs and expenses arising from a nuclear incident at Summer Station exceed the policy limits of insurance, or to the extent such insurance becomes unavailable in the future, and to the extent that SCE&G's rates would not recover the cost of any purchased replacement power, SCE&G will retain the risk of loss as a self-insurer. SCE&G has no reason to anticipate a serious nuclear incident. However, if such an incident were to occur, it likely would have a material adverse impact on SCE&G's results of operations, cash flows and financial position.

## B. Environmental

In March 2005, the Environmental Protection Agency (EPA) issued a final rule known as the Clean Air Interstate Rule (CAIR). CAIR requires the District of Columbia and 28 states, including South Carolina, to reduce nitrogen oxide and sulfur dioxide emissions in order to attain mandated state levels. SCE&G has petitioned the United States Court of Appeals for the District of Columbia Circuit to review CAIR. Several other electric utilities have filed separate petitions. The petitioners seek a change in the method CAIR uses to allocate sulfur dioxide emission allowances to a method the petitioners believe is more equitable. The Company believes that installation of additional air quality controls will be needed to meet the CAIR requirements. The Company is reviewing the final rule. Compliance plans and cost to comply with the rule will be determined once the Company completes its review. Such costs may be material and are expected to be recoverable through rates.

In March 2005, the EPA issued a final rule establishing a mercury emissions cap and trade program for coal-fired power plants that requires limits to be met in two phases, in 2010 and 2018. Although the Company expects to be able to meet the Phase I limits through those measures it already will be taking to meet its CAIR obligations, it is uncertain as to how the Phase II limits will be met. Assuming Phase II limits remain unchanged, installation of additional air quality controls likely will be required to comply with the rule's Phase II mercury emission caps. Final compliance plans and costs to comply with the rule are still under review. Such costs will be material and are expected to be recoverable through rates.

SCE&G has been named, along with 29 others, by the EPA as a potentially responsible party (PRP) at the Carolina Transformer Superfund site located in Fayetteville, North Carolina. The Carolina Transformer Company (CTC) conducted an electrical transformer rebuilding and repair operation at the site from 1967 to 1984. During that time, SCE&G occasionally used CTC for the repair of existing transformers and the purchase of new transformers. In 1984, EPA initiated a cleanup of PCB-contaminated soil and groundwater at the site. EPA reports that it has spent \$36 million to date. SCE&G's records indicate that only minimal quantities of used transformers were shipped to CTC, and it is not clear if any contained PCB-contaminated oil. Although a basis for the allocation of clean-up costs among the PRPs is unclear, SCE&G does not believe that its involvement at this site would result in an allocation of costs that would have a material adverse impact on its results of operations, cash flows or financial condition. Any cost allocated to SCE&G is expected to be recoverable through rates.

SCE&G has been named, along with 53 others, by the EPA as a PRP at the Alternate Energy Resources, Inc. (AER) Superfund site located in Augusta, Georgia. The EPA placed the site on the National Priorities List on April 19, 2006. AER conducted hazardous waste storage and treatment operations from 1975 to 2000, when the site was abandoned. While operational, AER processed fuels from waste oils, treated industrial coolants and oil/water emulsions, recycled solvents and blended hazardous waste fuels. During that time, SCE&G occasionally used AER for the processing of waste solvents, oily rags and oily wastewater. EPA and the State of Georgia have documented that a release or releases have occurred at the site leading to contamination of groundwater, surface water and soils. EPA and the State of Georgia have conducted a preliminary assessment and site inspection. The site has not been cleaned up nor has a cleanup cost been estimated. Although a basis for the allocation of clean-up costs among the PRPs is unclear, SCE&G does not believe that its involvement at this site would result in an allocation of costs that would have a material adverse impact on its results of operations, cash flows or financial condition. Any cost allocated to SCE&G arising from the remediation of this site is expected to be recoverable through rates.

SCE&G maintains an environmental assessment program to identify and evaluate current and former sites that could require environmental cleanup. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and clean up each site. These estimates are refined as additional information becomes available; therefore, actual expenditures could differ significantly from the original estimates. Amounts estimated and accrued to date for site assessments and cleanup relate solely to regulated operations.

SCE&G defers site assessment and cleanup costs and recovers them through rates (see Note 1). Deferred amounts, net of amounts previously recovered through rates and insurance settlements, totaled \$18.3 million at September 30, 2006. The deferral includes the estimated costs associated with the following matters.

SCE&G owns a decommissioned MGP site in the Calhoun Park area of Charleston, South Carolina. SCE&G anticipates that remediation for contamination at the site will be completed in late 2007, with certain monitoring and retreatment activities continuing until 2011. As of September 30, 2006, SCE&G had spent \$21.9 million to remediate the site and expects to spend an additional \$1.4 million prior to entering a monitoring and reporting stage. In addition, the National Park Service of the Department of the Interior made an initial demand to SCE&G for payment of \$9.1 million for certain costs and damages relating to this site. Any cost arising from the remediation of this site is expected to be recoverable through rates.

SCE&G owns three other decommissioned MGP sites in South Carolina which contain residues of by-product chemicals. One of the sites has been remediated and will undergo routine monitoring until released by the South Carolina Department of Health and Environmental Control (DHEC). The other sites are currently being investigated under work plans approved by DHEC. SCE&G anticipates that major remediation activities for the three sites will be completed in 2010. As of September 30, 2006, SCE&G had spent \$4.6 million related to these three sites, and expects to spend an additional \$11.4 million. Any cost arising from the remediation of these sites is expected to be recoverable through rates.

### C. Claims and Litigation

In August 2003, SCE&G was served as a co-defendant in a purported class action lawsuit styled as *Collins v. Duke Energy Corporation, Progress Energy Services Company, and SCE&G in South Carolina's Circuit Court of Common Pleas for the Fifth Judicial Circuit*. Since that time, the plaintiffs have dismissed defendants Duke Energy and Progress Energy and are proceeding against SCE&G only. The plaintiffs are seeking damages for the alleged improper use of electric transmission and distribution easements but have not asserted a dollar amount for their claims. Specifically, the plaintiffs contend that the licensing of attachments on electric utility poles, towers and other facilities to nonutility third parties or telecommunication companies for other than the electric utilities' internal use along the electric transmission and distribution line rights-of-way constitutes a trespass. It is anticipated that this case may go to trial in 2007. SCE&G is confident of the propriety of its actions and intends to mount a vigorous defense. SCE&G further believes that the resolution of these claims will not have a material adverse impact on its results of operations, cash flows or financial condition.

In May 2004, the Company was served with a purported class action lawsuit styled as *Douglas E. Gressette, individually and on behalf of other persons similarly situated v. South Carolina Electric & Gas Company and SCANA Corporation*. The case was filed in South Carolina's Circuit Court of Common Pleas for the Ninth Judicial Circuit. The plaintiff alleges the Company made improper use of certain easements and rights-of-way by allowing fiber optic communication lines and/or wireless communication equipment to transmit communications other than the Company's electricity-related internal communications. The plaintiff asserted causes of action for unjust enrichment, trespass, injunction and declaratory judgment. The plaintiff did not assert a specific dollar amount for the claims. The Company believes its actions are consistent with governing law and the applicable documents granting easements and rights-of-way. The court granted the Company's motion to dismiss and issued an order dismissing the case in June 2005. The plaintiff appealed to the South Carolina Supreme Court. The Supreme Court recently overruled the Circuit Court and returned the case to the Circuit Court for further consideration saying the question of assignability of the easements requires construction of the easements themselves. The Company will continue to mount a vigorous defense and believes that the resolution of these claims will not have a material adverse impact on its results of operations, cash flows or financial condition.

A complaint was filed in October 2003 against SCE&G by the State of South Carolina alleging that SCE&G violated the Unfair Trade Practices Act by charging municipal franchise fees to some customers residing outside a municipality's limits. The complaint alleged that SCE&G failed to obey, observe or comply with the lawful order of the SCPSC by charging franchise fees to those not residing within a municipality. The complaint sought restitution to all affected customers and penalties of up to \$5,000 for each separate violation. The claim against SCE&G has been settled by an agreement between the parties, and the settlement has been approved by South Carolina's Circuit Court of Common Pleas for the Fifth Judicial Circuit. In addition, SCE&G filed a petition with the SCPSC in October 2003 pursuant to S. C. Code Ann. R.103-836. The petition requests that the SCPSC exercise its jurisdiction to investigate the operation of the municipal franchise fee collection requirements applicable to SCE&G's electric and gas service, to approve SCE&G's efforts to correct any past franchise fee billing errors, to adopt improvements in the system which will reduce such errors in the future, and to adopt any regulation that the SCPSC deems just and proper to regulate the franchise fee collection process. A hearing on this petition has not been scheduled. The Company believes that the resolution of these matters will not have a material adverse impact on its results of operations, cash flows or financial condition.

The Company is also engaged in various other claims and litigation incidental to its business operations which management anticipates will be resolved without material loss to the Company.

#### D. Other Contingency

In 2004 and early 2005, SCANA and certain of its affiliates, like other integrated utilities, were the subject of an investigation by FERC's Office of Market Oversight and Investigations (OMOI) focusing, among other things, on the relationship between SCE&G's merchant and transmission functions. These relationships are among those addressed in FERC Order 2004, a primary purpose of which order is to ensure that affiliates of transmission providers have no marketplace advantage over non-affiliated market participants. In connection with that investigation, SCE&G was assessed no monetary damages or penalties; however, under terms of a Settlement and Consent Agreement entered into on April 1, 2005, and approved by FERC order dated April 27, 2005, SCE&G agreed to the implementation of a compliance plan which includes periodic reports to OMOI, now known as FERC's Office of Enforcement.

On January 2, 2006, SCE&G provided to FERC a quarterly update on this compliance plan, which included an acknowledgment of SCE&G's discovery that it may have improperly utilized network transmission services, rather than point-to-point transmission services, for purchases and sales of electricity in violation of SCE&G's open access transmission tariff and applicable FERC orders under the Federal Power Act that prohibit the use of network transmission service in support of certain "off-system" sales. This acknowledgement was in part the result of SCE&G's preliminary review of a FERC order issued following its examination of another energy provider in September 2005. Upon further review of that order and an internal investigation, SCE&G determined, and notified FERC, that it did improperly utilize network transmission service in a significant number of purchase and sale transactions.

In response to its internal findings, SCE&G also notified FERC that it had ceased participation in such transactions, instituted additional self-restrictive procedures as safeguards to ensure full compliance in this area in the future, and committed to certain modifications to its compliance plan, including increased levels of training and monitoring. SCE&G also has fully cooperated with FERC staff in its investigation of this matter.

In the fourth quarter of 2005, SCE&G recorded a loss accrual in the amount of \$0.8 million based on its estimation of net revenues from the subject transactions that occurred after the date of the Settlement and Consent Agreement and that might be deemed to be in violation of FERC's rule on the use of network transmission service and be subject to disgorgement pursuant to FERC orders. In the third quarter of 2006, SCE&G increased its loss accrual to \$3.7 million. However, there remains uncertainty as to what actions ultimately may be taken by FERC. Potential actions could include penalties of up to a maximum of \$1 million per violation or per day since August 8, 2005, the effective date of the Energy Policy Act of 2005; disgorgement of profits on the subject transactions; and further modification to SCE&G's compliance plan or other non-monetary remedies. SCE&G continues to believe that no market participants were harmed or disadvantaged by the transactions in question. For this reason and in light of SCE&G's self-reporting and other cooperation in the investigation of this matter, and SCE&G's institution of appropriate safeguards referred to above, SCE&G does not believe that material monetary sanctions are warranted.

SCE&G desire to resolve this matter in a reasonable and satisfactory manner. Nonetheless, SCE&G cannot predict what, if any, actions FERC ultimately will take with respect to this matter, and is unable to determine if the resolution of this matter will have a material adverse impact on its operations, cash flows or financial condition.

#### 5. SEGMENT OF BUSINESS INFORMATION

The Company's reportable segments are listed in the following table. The Company uses operating income to measure profitability for its regulated operations. Therefore, earnings available to the common shareholder is not allocated to the Electric Operations and Gas Distribution segments. Intersegment revenues were not significant. All Other includes equity method investments.

<b>Millions of Dollars</b>	<b>External Revenue</b>	<b>Operating Income (Loss)</b>	<b>Earnings (Loss) Available to Common Shareholder</b>	<b>Segment Assets</b>
<b><i>Three Months Ended September 30, 2006</i></b>				
Electric Operations	\$ 587	\$ 166	n/a	
Gas Distribution	77	(6)	n/a	
All Other	-	-	\$ (6)	
Adjustments/Eliminations	-	(1)	97	
<b>Consolidated Total</b>	<b>\$ 664</b>	<b>\$ 159</b>	<b>\$ 91</b>	

*Nine Months Ended September 30, 2006*

Electric Operations	\$ 1,451	\$ 376	n/a	\$ 5,476
Gas Distribution	358	9	n/a	408
All Other	-	-	\$ (16)	1
Adjustments/Eliminations	-	(10)	205	1,548
<b>Consolidated Total</b>	<b>\$ 1,809</b>	<b>\$ 375</b>	<b>\$ 189</b>	<b>\$ 7,433</b>

*Three Months Ended September 30, 2005*

Electric Operations	\$ 620	\$ 186	n/a	
Gas Distribution	80	(7)	n/a	
All Other	-	-	\$ (3)	
Adjustments/Eliminations	-	(1)	107	
<b>Consolidated Total</b>	<b>\$ 700</b>	<b>\$ 178</b>	<b>\$ 104</b>	

*Nine Months Ended September 30, 2005*

Electric Operations	\$ 1,478	\$ 194	n/a	\$ 5,315
Gas Distribution	321	5	n/a	388
All Other	-	-	\$ (72)	3
Adjustments/Eliminations	-	(2)	264	1,350
<b>Consolidated Total</b>	<b>\$ 1,799</b>	<b>\$ 197</b>	<b>\$ 192</b>	<b>\$ 7,056</b>

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

**SOUTH CAROLINA ELECTRIC & GAS COMPANY**

The following discussion should be read in conjunction with Management's Discussion and Analysis of Financial Condition and Results of Operations appearing in South Carolina Electric & Gas Company's (SCE&G, and together with its consolidated affiliates, the Company) Annual Report on Form 10-K for the year ended December 31, 2005.

Statements included in this discussion and analysis (or elsewhere in this quarterly report) which are not statements of historical fact are intended to be, and are hereby identified as, "forward-looking statements" for purposes of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Readers are cautioned that any such forward-looking statements are not guarantees of future performance and involve a number of risks and uncertainties, and that actual results could differ materially from those indicated by such forward-looking statements. Important factors that could cause actual results to differ materially from those indicated by such forward-looking statements include, but are not limited to, the following: (1) that the information is of a preliminary nature and may be subject to further and/or continuing review and adjustment, (2) regulatory actions or changes in the utility regulatory environment, (3) current and future litigation, (4) changes in the economy, especially in SCE&G's service territory, (5) the impact of competition from other energy suppliers, including competition from alternate fuels in industrial interruptible markets, (6) growth opportunities, (7) the results of financing efforts, (8) changes in accounting principles, (9) weather conditions, especially in areas served by SCE&G, (10) performance of SCANA Corporation's (SCANA) pension plan assets and the impact on SCE&G's results of operations, (11) inflation, (12) changes in environmental regulations and (13) the other risks and uncertainties described from time to time in SCE&G's periodic reports filed with the United States Securities and Exchange Commission. The Company disclaims any obligation to update any forward-looking statements.

**RESULTS OF OPERATIONS  
FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2006  
AS COMPARED TO THE CORRESPONDING PERIODS IN 2005**

Net Income

Net income was as follows:

Millions of dollars	Third Quarter 2006		2005		Year to Date 2006		2005	
Net income	\$	92.6	\$	105.9	\$	194.6	\$	197.9

*Third Quarter*

Net income decreased due to decreases in electric margins of \$4.7 million, increased operating and maintenance expenses of \$2.2 million, increased property taxes of \$1.7 million and increased depreciation expense of \$1.2 million partially offset by increases in gas margins of \$2.1 million and other increased expenses. Accelerated depreciation on the Lake Murray back-up dam and recognition of synthetic fuel tax credits and related items had no effect on net income, as discussed at *Recognition of Synthetic Fuel Tax Credits*.

*Year to Date*

Net income decreased due to increased operating and maintenance expenses of \$7.0 million, increased depreciation expense of \$3.2 million, decreased dam remediation carrying costs of \$3.6 million and other increased expenses, partially offset by increases in electric and gas margins of \$5.1 million and \$6.1 million, respectively, and by \$3.8 million due to the favorable impact of the cumulative effect of an accounting change resulting from the Company's adoption of Statement of Financial Accounting Standard (SFAS) 123 (revised 2004), "Share-Based Payment" (SFAS 123(R)). See Note 1E of the condensed consolidated financial statements. Accelerated depreciation on the Lake Murray back-up dam and recognition of synthetic fuel tax credits and related items had no effect on net income, as discussed at *Recognition of Synthetic Fuel Tax Credits*.

## Dividends Declared

SCE&G's Board of Directors has declared the following dividends on common stock held by SCANA during 2006:

Declaration Date	Amount	Quarter Ended	Payment Date
February 16, 2006	\$39.2 million	March 31, 2006	April 1, 2006
April 27, 2006	39.2 million	June 30, 2006	July 1, 2006
August 3, 2006	39.2 million	September 30, 2006	October 1, 2006
November 1, 2006	21.0 million	December 31, 2006	January 1, 2007

## Electric Operations

Electric Operations is comprised of the electric operations of SCE&G, South Carolina Generating Company, Inc. and South Carolina Fuel Company, Inc. Electric operations sales margins (including transactions with affiliates) were as follows:

Millions of dollars	Third Quarter			Year to Date		
	2006	% Change	2005	2006	% Change	2005
Operating revenues	\$ 587.0	(5.4)%	\$ 620.2	\$ 1,450.9	(1.8)%	\$ 1,477.7
Less: Fuel used in generation	199.7	(8.0)%	217.1	463.8	(3.8)%	482.1
Purchased power	7.0	(53.6)%	15.1	19.0	(46.8)%	35.7
<b>Margin</b>	<b>\$ 380.3</b>	<b>(2.0)%</b>	<b>\$ 388.0</b>	<b>\$ 968.1</b>	<b>0.9%</b>	<b>\$ 959.9</b>

### Third Quarter

Margin decreased by \$10.4 million due to lower off-system sales, by \$2.4 million due to lower industrial sales and by \$4.4 million due to unfavorable weather. These decreases were partially offset by \$8.2 million due to customer growth and \$1.3 million due to higher other electric revenue.

### Year to Date

Margin increased by \$20.9 million due to customer growth and by \$4.6 million due to higher other electric revenue, partially offset by \$5.2 million in decreased off-system sales, by \$6.7 million due to unfavorable weather and by \$5.3 million due to lower industrial sales.

## Gas Distribution

Gas Distribution is comprised of the local distribution operations of SCE&G. Gas distribution sales margins (including transactions with affiliates) were as follows:

Millions of dollars	Third Quarter			Year to Date		
	2006	% Change	2005	2006	% Change	2005
Operating revenues	\$ 76.5	(3.9)%	\$ 79.6	\$ 358.1	11.5%	\$ 321.3
Less: Gas purchased for resale	61.5	(9.4)%	67.9	286.6	10.4%	259.6
<b>Margin</b>	<b>\$ 15.0</b>	<b>28.2%</b>	<b>\$ 11.7</b>	<b>\$ 71.5</b>	<b>15.9%</b>	<b>\$ 61.7</b>

### Third Quarter

Margin increased by \$1.6 million due to increased retail base rates which became effective with the first billing cycle in November 2005, by \$1.2 million due to higher firm margin and by \$0.5 million due to other increased revenue.

### Year to Date

Margin increased by \$16.4 million due to increased retail base rates which became effective with the first billing cycle in November 2005, partially offset by \$5.1 million due to lower firm margin and by \$1.5 million due to other increased expenses.

## Other Operating Expenses

Other operating expenses were as follows:

Millions of dollars	Third Quarter		2005		Year to Date		2005
	2006	% Change	2005	2006	% Change		
Other operation and maintenance	\$ 115.0	3.2%	\$ 111.4	\$ 343.6	3.4%	\$ 332.3	
Depreciation and amortization	86.4	11.1%	77.8	216.5	(44.3)%	389.0	
Other taxes	35.1	9.7%	32.0	104.1	1.2%	102.9	
<b>Total</b>	<b>\$ 236.5</b>	<b>6.9%</b>	<b>\$ 221.2</b>	<b>\$ 664.2</b>	<b>(19.4)%</b>	<b>\$ 824.2</b>	

### Third Quarter

Other operation and maintenance expenses increased by \$4.8 million due to increased electric generation, transmission and distribution expenses, by \$0.9 million due to reduced pension income and by \$1.4 million due to other increased expenses, partially offset by \$3.5 million due to lower incentive compensation accruals. Depreciation and amortization increased \$4.4 million due to accelerated depreciation of the back-up dam at Lake Murray (see *Recognition of Synthetic Fuel Tax Credits*) and by \$4.2 million due to property additions and higher depreciation rates. Other taxes increased due to higher property taxes.

### Year to Date

Other operation and maintenance expenses increased by \$10.7 million due to increased electric generation, transmission and distribution expenses, by \$5.0 million due to increased customer service expenses, by \$2.9 million due to reduced pension income and by \$2.7 million due to other increased expenses, partially offset by \$10.0 million due to lower incentive compensation accruals. Depreciation and amortization decreased \$177.8 million due to accelerated depreciation of the back-up dam at Lake Murray in 2005 and the lower levels of credits recognized in 2006 due to applicability of the phase-down provisions (see *Recognition of Synthetic Fuel Tax Credits*), partially offset by \$5.2 million due to property addition and higher depreciation rates. Other taxes increased due to higher property taxes.

## Other Income (Expense)

Other income (expense) includes the results of incidental (non-utility) activities.

### Third Quarter and Year to Date

Other income and expenses declined in 2006 compared to 2005 primarily due to reductions in power marketing activity (non-regulated off-system sales).

## Income Taxes

Income tax expense for the nine months ended September 30, 2006 increased primarily due to the initial application and recognition of the benefits of previously deferred synthetic fuel tax credits in the first quarter of 2005, and the applicability of the phase-down provisions in 2006, as discussed below at *Recognition of Synthetic Fuel Tax Credits*.

### Recognition of Synthetic Fuel Tax Credits

SCE&G holds equity-method investments in two partnerships involved in converting coal to synthetic fuel, the use of which fuel qualifies for federal income tax credits. Under an accounting plan approved by the Public Service Commission of South Carolina (SCPSC) in June 2000, the synthetic fuel tax credits generated by the partnerships and passed through to SCE&G, net of partnership losses and other expenses, were deferred until the SCPSC approved their application to offset capital costs of the Lake Murray back-up dam project. Under the accounting methodology approved by the SCPSC in a January 2005 order, construction costs related to the project were recorded in utility plant in service in a special dam remediation account outside of rate base, and depreciation is being recognized against the balance in this account on an accelerated basis, subject to the availability of the synthetic fuel tax credits.

The level of depreciation expense and related tax benefit recognized in the income statement is equal to the available synthetic fuel tax credits, less partnership losses and other expenses, net of taxes. As a result, the balance of unrecovered costs in the dam remediation account declines as accelerated depreciation is recorded. Although these entries collectively have no impact on consolidated net income, they can have a significant impact on individual line items within the income statement. The accelerated depreciation, synthetic fuel tax credits, partnership losses and the income tax benefit arising from such losses recognized by SCE&G during the three and nine months ended September 30, 2006 and 2005 are as follows:

Millions of dollars	Third Quarter		Year to Date	
	2006	2005	2006	2005
Depreciation and amortization expense	\$ (21.6)	\$ (17.2)	\$ (23.0)	\$ (200.8)
Income tax benefits:				
From synthetic fuel tax credits	10.5	12.9	14.6	168.1
From accelerated depreciation	13.4	6.6	14.2	76.8
From partnership losses	3.6	1.3	9.4	27.2
Total income tax benefits	27.5	20.8	38.2	272.1
Losses from Equity Method Investments	(5.9)	(3.6)	(15.2)	(71.3)
Impact on Net Income	\$ -	\$ -	\$ -	\$ -

The 2005 amounts above reflect the recognition of previously deferred tax credits, while the 2006 amounts reflect the likelihood that credits available in 2006 will be phased down pursuant to regulations which limit the credits based on the relative commodity price of crude oil.

Depreciation on the Lake Murray back-up dam remediation account will be matched to available synthetic fuel tax credits on a quarterly basis until the balance in the dam remediation account is zero or until all of the available synthetic fuel tax credits have been utilized. Under current law, the synthetic fuel tax credit program expires at the end of 2007.

The availability of the synthetic fuel tax credits is dependent on several factors, one of which is the average annual domestic wellhead price per barrel of crude oil as published by the U.S. Government. Under a phase-out provision included in the program, if the domestic wellhead reference price of oil per barrel for a given year is below an inflation-adjusted benchmark range for that year, all of the synthetic fuel tax credits that have been generated in that year would be available for use. If that price is above the benchmark range, none of the tax credits would be available. If that price falls within the benchmark range, a calculated portion of the credits would be available.

The benchmark price range for 2005, published in April 2006, was \$53 to \$67 per barrel, and no phase-out applied. However, SCE&G's analysis indicates that the available synthetic fuel tax credits for 2006 are likely to be impacted by the phase-out calculation. As such, through September 2006 the Company recorded synthetic fuel tax credits and applied those credits to allow the recording of accelerated depreciation related to the balance in the dam remediation project account based on an estimate that only 71 percent of credits generated will be available (phase-out of 29 percent). The Company cannot predict what impact, if any, the price of oil may have on the Company's ability to earn and utilize synthetic fuel tax credits in the future. However, there is significant uncertainty as to the continued availability of the credits in 2006 and 2007. The availability of these synthetic fuel tax credits is also subject to coal availability and other operational risks related to the generating plants.

If it is determined that available credits are not sufficient to fully recover the construction costs of the dam remediation, regulatory action to allow recovery of those remaining costs may be sought. As of September 30, 2006, remaining unrecovered costs, based on management's recording of accelerated depreciation and related tax benefits, were \$72.2 million.

## LIQUIDITY AND CAPITAL RESOURCES

The Company anticipates that its contractual cash obligations will be met through internally generated funds and the incurrence of additional short-term and long-term indebtedness. The Company expects that it has or can obtain adequate sources of financing to meet its projected cash requirements for the foreseeable future. The Company's ratio of earnings to fixed charges for the 12 months ended September 30, 2006 was 3.20.

The Company's cash requirements arise primarily from its operational needs, funding its construction programs and payment of dividends to SCANA. The ability of the Company to replace existing plant investment, to expand to meet future demand for electricity and gas and to install equipment necessary to comply with environmental regulations will depend upon its ability to attract the necessary financial capital on reasonable terms. SCE&G recovers the costs of providing services through rates charged to customers. Rates for regulated services are generally based on historical costs. As customer growth and inflation occur and SCE&G continues its ongoing construction program, SCE&G expects to seek increases in rates. The Company's future financial position and results of operations will be affected by SCE&G's ability to obtain adequate and timely rate and other regulatory relief, if requested.

For more information on significant rate and other regulatory matters, see Note 2 to the condensed consolidated financial statements.

SCE&G expects to require the addition of base load electric generation by 2015 and is evaluating alternatives, including fossil- and nuclear-fueled generation. On February 10, 2006, SCE&G and Santee Cooper, a state-owned utility in South Carolina (joint owners of Summer Station) announced their selection of the Summer Station site as the preferred site for new nuclear generation should such generation be considered the best alternative in the future. Due to the significant lead time required for construction of nuclear generation, the joint owners are preparing an application to the Nuclear Regulatory Commission (NRC) for a combined construction and operating license (COL) that would cover two new nuclear units. The COL application, which is expected to be completed and filed in 2007, would be reviewed by the NRC for an estimated three years. Issuance of a COL would not obligate the joint owners to build nuclear generation. The final decision to build nuclear generation will be influenced by several factors, including NRC licensing attainment, construction and operating costs, the cost of competing fuels, regulatory and environmental requirements and financial market conditions.

SCE&G also periodically reassesses its other capital investment requirements. Based on recent developments, significant increases in the estimated cost for scrubbers and other environmental abatement equipment will be necessary to comply with environmental regulations. Preliminary estimates indicate that expenditures for these environmental requirements in 2007 and 2008 could increase by approximately \$200 million over the amounts reflected in the Liquidity and Resources section of Management's Discussion and Analysis of Financial Condition and Results of Operations in Form 10-K for the year ended December 31, 2005. These capital expenditures would be expected to become part of SCE&G's rate base and thereby be subject to recovery through future rate proceedings.

The following table summarizes how SCE&G generated and used funds for property additions and construction expenditures during the nine months ended September 30, 2006 and 2005:

Millions of dollars	Nine Months Ended September 30,	
	2006	2005
Net cash provided from operating activities	\$ 404	\$ 250
Net cash provided from (used for) financing activities	(133)	15
Cash provided from sale of assets	-	1
Cash and cash equivalents available at the beginning of the period	19	20
Funds used for utility property additions and construction expenditures	(248)	(255)
Funds used for investments	(23)	(17)

The Company's issuance of various securities, including long-term and short-term debt, is subject to customary approval or authorization by state and federal regulatory bodies including the SCPSC, the Securities and Exchange Commission and Federal Energy Regulatory Commission (FERC).

Pursuant to Section 204 of the Federal Power Act, SCE&G and GENCO must obtain FERC authority to issue short-term debt. Effective February 8, 2006, the FERC has authorized SCE&G and GENCO to issue up to \$700 million and \$100 million, respectively, of unsecured promissory notes or commercial paper with maturity dates of one year or less. This authorization expires February 7, 2008.

In June 2006, SCE&G issued \$125 million of first mortgage bonds having an annual interest rate of 6.25% and maturing July 1, 2036. The proceeds from the sale of these bonds, together with available cash, were used for the payment at maturity of \$131 million of SCE&G's first and refunding mortgage bonds due July 15, 2006, which bore interest at 9.0%.

For information on environmental matters, see Note 4B to the condensed consolidated financial statements.

### ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

All financial instruments held by the Company described below are held for purposes other than trading.

Interest rate risk - The table below provides information about long-term debt issued by the Company which is sensitive to changes in interest rates. The table presents principal cash flows and related weighted average interest rates by expected maturity dates. Fair values for debt represent quoted market prices.

As of September 30, 2006		Expected Maturity Date							Fair Value
Millions of dollars		2006	2007	2008	2009	2010	There-after	Total	
<b>Liabilities</b>									
Long-Term Debt:									
Fixed Rate (\$)		3.7	3.7	3.7	103.7	10.4	1,832.8	1,958.0	2,042.5
Average Interest Rate (%)		7.78	7.78	7.78	6.18	6.31	5.91	5.93	n/a

While a decrease in interest rates would increase the fair value of debt, it is unlikely that events which would result in a significant realized loss will occur.

Commodity price risk - The following table provides information about the Company's financial instruments that are sensitive to changes in natural gas prices. Weighted average settlement prices are per 10,000 dekatherms. Fair value represents quoted market prices.

Expected Maturity:

2006	Futures Contracts		Strike Price <sup>(a)</sup>	Options	
	Long	Short		Purchased Call (Long)	Sold Call (Short)
Settlement Price <sup>(a)</sup>	6.74	5.62		8.93	8.15
Contract Amount <sup>(b)</sup>	8.9	0.3	Contract Amount <sup>(b)</sup>	4.5	0.2
Fair Value <sup>(b)</sup>	6.7	0.2	Fair Value <sup>(b)</sup>	0.1	-
2007					
Settlement Price <sup>(a)</sup>	7.63	7.54	Strike Price <sup>(a)</sup>	-	-
Contract Amount <sup>(b)</sup>	33.2	2.9	Contract Amount <sup>(b)</sup>	-	-
Fair Value <sup>(b)</sup>	27.4	2.3	Fair Value <sup>(b)</sup>	-	-

Commodity Swaps	Expected Maturity	
	2006	2007
Pay fixed/receive variable <sup>(b)</sup>	13.4	32.3
Average pay rate <sup>(a)</sup>	9.3852	9.3817
Average received rate <sup>(a)</sup>	6.7539	7.6141
Fair value <sup>(b)</sup>	9.7	26.2

<sup>(a)</sup> Weighted average, in dollars

<sup>(b)</sup> Millions of dollars

**PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INCORPORATED  
FINANCIAL SECTION**

Public Service Company of North Carolina, Incorporated meets the conditions set forth in General Instruction H(1)(a) and (b) of Form 10-Q and therefore is filing this form with the reduced disclosure format allowed under General Instruction H(2).

**ITEM 1. FINANCIAL STATEMENTS****PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INCORPORATED**  
**CONDENSED CONSOLIDATED BALANCE SHEETS**  
(Unaudited)

Millions of dollars	September 30, 2006	December 31, 2005
<b>Assets</b>		
Gas Utility Plant	\$ 1,070	\$ 1,006
Accumulated Depreciation	(240)	(282)
Acquisition Adjustment	210	210
<b>Gas Utility Plant, Net</b>	<b>1,040</b>	<b>934</b>
<b>Nonutility Property and Investments, Net</b>	<b>28</b>	<b>28</b>
<b>Current Assets:</b>		
Cash and cash equivalents	1	3
Restricted cash and temporary investments	-	1
Receivables, net of allowance for uncollectible accounts of \$1 and \$3	35	182
Receivables-affiliated companies	2	9
Inventories (at average cost):		
Stored gas	98	92
Materials and supplies	7	6
Deferred income taxes, net	2	-
Other	4	3
<b>Total Current Assets</b>	<b>149</b>	<b>296</b>
<b>Deferred Debits and Other Assets:</b>		
Due from affiliate-pension asset	9	11
Regulatory assets	67	26
Other	3	3
<b>Total Deferred Debits and Other Assets</b>	<b>79</b>	<b>40</b>
<b>Total</b>	<b>\$ 1,296</b>	<b>\$ 1,298</b>

Millions of dollars	September 30, 2006	December 31, 2005
<b>Capitalization and Liabilities</b>		
Capitalization:		
Common equity	\$ 531	\$ 528
Long-term debt, net	266	270
<b>Total Capitalization</b>	<b>797</b>	<b>798</b>
Current Liabilities:		
Short-term borrowings	79	99
Current portion of long-term debt	3	3
Accounts payable	27	91
Accounts payable-affiliated companies	5	6
Customer deposits and customer prepayments	20	14
Taxes accrued	4	4
Interest accrued	4	6
Distributions/dividends declared	4	4
Derivative financial instruments	31	-
Deferred income taxes, net	-	3
Other	3	6
<b>Total Current Liabilities</b>	<b>180</b>	<b>236</b>
Deferred Credits and Other Liabilities:		
Deferred income taxes, net	106	104
Deferred investment tax credits	1	1
Due to affiliate-postretirement benefits	20	19
Regulatory liabilities	168	114
Asset retirement obligations	13	13
Other	11	13
<b>Total Deferred Credits and Other Liabilities</b>	<b>319</b>	<b>264</b>
Commitments and Contingencies (Note 4)		
Total	\$ 1,296	\$ 1,298

See Notes to Condensed Consolidated Financial Statements.

PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INCORPORATED  
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS  
(Unaudited)

Millions of dollars	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
Operating Revenues	\$ 59	\$ 60	\$ 389	\$ 390
Cost of Gas	35	35	267	261
<b>Gross Margin</b>	<b>24</b>	<b>25</b>	<b>122</b>	<b>129</b>
Operating Expenses:				
Operation and maintenance	19	18	58	58
Depreciation and amortization	9	9	27	26
Other taxes	2	2	6	6
<b>Total Operating Expenses</b>	<b>30</b>	<b>29</b>	<b>91</b>	<b>90</b>
<b>Operating Income (Loss)</b>	<b>(6)</b>	<b>(4)</b>	<b>31</b>	<b>39</b>
Other Income (Expense):				
Other income	3	3	8	9
Other expenses	(2)	(2)	(5)	(6)
Interest charges, net of allowance for borrowed funds used during construction	(6)	(5)	(17)	(15)
<b>Total Other Expense</b>	<b>(5)</b>	<b>(4)</b>	<b>(14)</b>	<b>(12)</b>
Income (Loss) Before Income Taxes, Earnings from Equity Method Investments and Cumulative Effect of Accounting Change	(11)	(8)	17	27
<b>Income Tax Expense (Benefit)</b>	<b>(4)</b>	<b>(1)</b>	<b>8</b>	<b>13</b>
Income (Loss) Before Earnings from Equity Method Investments and Cumulative Effect of Accounting Change	(7)	(7)	9	14
Earnings from Equity Method Investments	1	1	3	3
Cumulative Effect of Accounting Change, net of taxes	-	-	1	-
<b>Net Income (Loss)</b>	<b>\$ (6)</b>	<b>\$ (6)</b>	<b>\$ 13</b>	<b>\$ 17</b>

See Notes to Condensed Consolidated Financial Statements.

PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INCORPORATED  
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS  
(Unaudited)

Millions of dollars	Nine Months Ended September 30,	
	2006	2005
<b>Cash Flows From Operating Activities:</b>		
Net income	\$ 13	\$ 17
Adjustments to reconcile net income to net cash provided from operating activities:		
Cumulative effect of accounting change, net of taxes	(1)	-
Depreciation and amortization	29	28
Cash provided (used) by changes in certain assets and liabilities:		
Receivables, net	154	95
Inventories	(8)	(20)
Regulatory assets	(1)	(3)
Regulatory liabilities	-	1
Accounts payable	(74)	(38)
Deferred income taxes, net	(4)	4
Taxes accrued	-	1
Changes in gas adjustment clauses	(19)	21
Changes in other assets	(1)	(15)
Changes in other liabilities	-	(7)
<b>Net Cash Provided From Operating Activities</b>	<b>88</b>	<b>84</b>
<b>Cash Flows From Investing Activities:</b>		
Construction expenditures, net of AFC	(55)	(36)
Nonutility and other	(2)	5
<b>Net Cash Used For Investing Activities</b>	<b>(57)</b>	<b>(31)</b>
<b>Cash Flows From Financing Activities:</b>		
Short-term borrowings, net	(20)	(41)
Contributions from parent	2	2
Retirement of long-term debt	(3)	(3)
Distributions/dividends	(12)	(11)
<b>Net Cash Used For Financing Activities</b>	<b>(33)</b>	<b>(53)</b>
Net Decrease In Cash and Cash Equivalents	(2)	-
Cash and Cash Equivalents, January 1	3	2
<b>Cash and Cash Equivalents, September 30</b>	<b>\$ 1</b>	<b>\$ 2</b>
<b>Supplemental Cash Flow Information:</b>		
Cash paid for - Interest (net of capitalized interest of \$0.5 and \$0.4)	\$ 17	\$ 16
- Income taxes	16	18
<b>Noncash Investing and Financing Activities:</b>		
Accrued construction expenditures	2	2

See Notes to Condensed Consolidated Financial Statements.

PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INCORPORATED  
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS  
September 30, 2006  
(Unaudited)

The following notes should be read in conjunction with the Notes to Consolidated Financial Statements appearing in Public Service Company of North Carolina, Incorporated's (PSNC Energy, and together with its consolidated subsidiaries, the Company) Annual Report on Form 10-K for the year ended December 31, 2005. These are interim financial statements, and due to the seasonality of the Company's business and matters that may occur during the rest of the year, the amounts reported in the Condensed Consolidated Statements of Operations are not necessarily indicative of amounts expected for the full year. In the opinion of management, the information furnished herein reflects all adjustments, all of a normal recurring nature, which are necessary for a fair statement of the results for the interim periods reported.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. Basis of Accounting

The Company accounts for its regulated utility operations, assets and liabilities in accordance with the provisions of Statement of Financial Accounting Standards (SFAS) 71, "Accounting for the Effects of Certain Types of Regulation." SFAS 71 requires cost-based rate-regulated utilities to recognize in their financial statements certain revenues and expenses in different time periods than do enterprises that are not rate-regulated. As a result, as of September 30, 2006 the Company has recorded the regulatory assets and regulatory liabilities summarized as follows.

Millions of dollars	September 30, 2006	December 31, 2005
<b>Regulatory Assets:</b>		
Under-collections - gas cost adjustment clause	\$ 44	\$ 5
Environmental remediation costs	10	10
Asset retirement obligations	10	10
Other	3	1
<b>Total Regulatory Assets</b>	<b>\$ 67</b>	<b>\$ 26</b>
<b>Regulatory Liabilities:</b>		
Over-collections - gas cost adjustment clause	\$ 7	\$ 20
Other asset removal costs	158	91
Other	3	3
<b>Total Regulatory Liabilities</b>	<b>\$ 168</b>	<b>\$ 114</b>

Under- and over-collections-gas cost adjustment clauses represent amounts under- or over-collected from customers pursuant to the Company's Rider D mechanism approved by the North Carolina Utilities Commission (NCUC). This mechanism allows the Company to recover all prudently incurred gas costs. Included in these amounts are regulatory assets or liabilities arising from the Company's natural gas hedging program.

Environmental remediation costs represent costs associated with the assessment and cleanup of manufactured gas plant (MGP) sites currently or formerly owned by the Company. A portion of the costs incurred by the Company at such sites has been recovered through rates. Through June 30, 2006, the Company incurred and deferred \$3.6 million, net of insurance settlements, that were not being recovered through rates. In connection with an October 2006 NCUC rate order, such costs are now being recovered through rates over a three-year period. In addition, management believes that costs incurred subsequent to June 30, 2006, totaling \$0.7 million at September 30, 2006, and the estimated remaining costs of \$5.9 million, will be recoverable by the Company through rates.

Asset retirement obligations (ARO) represents the regulatory asset associated with conditional AROs recorded by SFAS 143, "Accounting for Asset Retirement Obligations," and Financial Accounting Standards Board Interpretation (FIN) 47, "Accounting for Conditional Asset Retirement Obligations."

Other asset removal costs represent net collections through depreciation rates of estimated costs to be incurred for the future removal of assets.

The NCUC has reviewed and approved through specific orders most of the items shown as regulatory assets. Other items represent costs which are not approved for recovery by the NCUC. In recording these costs as regulatory assets, management believes the costs will be allowable under existing rate-making concepts that are embodied in rate orders received by the Company. However, ultimate recovery is subject to NCUC approval. In the future, as a result of deregulation or other changes in the regulatory environment, the Company may no longer meet the criteria for continued application of SFAS 71 and could be required to write off its regulatory assets and liabilities. Such an event could have a material adverse effect on the Company's results of operations, liquidity or financial position in the period the write-off would be recorded.

#### B. Total Comprehensive Income

Total comprehensive income was not significantly different from net income for any period reported. Accumulated other comprehensive income (loss) of the Company totaled \$(0.2) million and \$(0.3) million as of September 30, 2006 and December 31, 2005, respectively.

#### C. Transactions with Affiliates

The Company has related party transactions with its equity method investees. The Company records as cost of gas the storage and transportation costs charged by these investees. These costs totaled \$11.8 million for the nine months ended September 30, 2006 and 2005. The Company owed these investees \$1.3 million at September 30, 2006 and December 31, 2005. The Company received cash distributions from equity investees of \$3.4 million and \$3.7 million for the nine months ended September 30, 2006 and 2005, respectively.

During the nine months ended September 30, 2006 and 2005, the Company made sales to an affiliate of natural gas and transportation services of \$6.4 million and \$12.5 million, respectively.

At September 30, 2006, the Company owed an affiliate \$0.1 million related to billing and collection services for energy-related products and service contracts.

#### D. New Accounting Matters

SFAS 123 (revised 2004), "*Share-Based Payment*" (SFAS 123(R)), requires compensation costs related to share-based payment transactions to be recognized in the financial statements. With limited exceptions, compensation cost is measured based on the grant-date fair value of the instruments issued and is recognized over the period that an employee provides service in exchange for the award. SFAS 123(R) replaces SFAS 123, "*Accounting for Stock-Based Compensation*," and supersedes Accounting Principles Board (APB) Opinion 25, "*Accounting for Stock Issued to Employees*." The cumulative effect of the adoption of SFAS 123(R) on January 1, 2006 resulted in a \$0.7 million (net of tax) gain in the first quarter of 2006 based on a reduction of prior compensation accruals for performance awards granted in 2004 and 2005.

The Company adopted SFAS 154, "*Accounting Changes and Error Corrections*," in the first quarter of 2006. SFAS 154 requires retrospective application to financial statements of prior periods for every voluntary change in accounting principle unless such retrospective application is impracticable. SFAS 154 replaces APB 20, "*Accounting Changes*," and SFAS 3, "*Reporting Accounting Changes in Interim Financial Statements*." The adoption of SFAS 154 had no material impact on the Company's results of operations, cash flows or financial position.

SFAS 157, "*Fair Value Measurements*," was issued in September 2006. SFAS 157 establishes a framework for measuring fair value to increase the consistency and comparability in fair value measurements. The Company will adopt SFAS 157 in the first quarter of 2008, and does not expect that the initial adoption will have a material impact on the Company's results of operations, cash flows or financial position.

FIN 48, "*Accounting for Uncertainty in Income Taxes*," was issued in June 2006. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with SFAS 109, "*Accounting for Income Taxes*." FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of tax positions taken or expected to be taken in a tax return. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. The Company will adopt FIN 48 in the first quarter of 2007. The Company is continuing to evaluate the impact that adoption of FIN 48 may have on the Company's results of operations, cash flows or financial position.

The United States Securities and Exchange Commission issued Staff Accounting Bulletin No. 108 (SAB 108) in September 2006. SAB 108 provides guidance on the consideration of the effects of prior year misstatements in quantifying and assessing the materiality of current year misstatements. SAB 108 also provides transition guidance for correcting errors existing from prior years. The Company will adopt SAB 108 in December 2006, and does not expect that the initial adoption will have a material impact on the Company's results of operations, cash flows or financial position.

## 2. RATE AND OTHER REGULATORY MATTERS

The Company's rates are established using a benchmark cost of gas approved by the NCUC, which may be modified periodically to reflect changes in the market price of natural gas. The Company revises its tariffs with the NCUC as necessary to track these changes and accounts for any over- or under-collections of the delivered cost of gas in its deferred accounts for subsequent rate consideration. The NCUC reviews the Company's gas purchasing practices annually.

The Company's benchmark cost of gas was as follows:

Rate Per Therm	Effective Date
\$0.825	January 2005
0.725	February-July 2005
0.825	August-September 2005
1.100	October 2005
1.275	November-December 2005
1.075	January 2006
0.875	February 2006
0.825	March-September 2006

On October 24, 2006, the NCUC granted the Company an annual increase in retail natural gas margin revenues of approximately \$15.2 million, or 2.6 percent, which was offset by a \$9.2 million decrease in fixed-gas cost revenues, for an overall increase of \$6 million, or 1.0 percent. The new rates are based on an allowed overall rate of return of 8.9 percent, and became effective with the first billing cycle in November 2006. In connection with the rate increase, the NCUC approved the Company's recovery through rates, over a three-year period, of certain costs for environmental remediation and pipeline integrity management.

In September 2006, in connection with the Company's 2006 Annual Prudence Review, the NCUC determined that the Company's gas costs, including all hedging transactions, were reasonable and prudently incurred during the 12-month review ended March 31, 2006.

In March 2006, the NCUC authorized the Company to place pipeline supplier refunds that it presently holds and future supplier refunds into the appropriate deferred accounts for the over- or under-recovery of gas costs. Prior to this authorization, refunds from the Company's interstate pipeline transporters were placed in a state-approved expansion fund to provide financing for expansion into areas that otherwise would not be economically feasible to serve. In September 2005, the NCUC approved the Company's request for disbursement of up to \$1.1 million from the state expansion fund to extend natural gas service to Louisburg, North Carolina. The project is expected to be completed by the end of 2006.

In January 2006, the NCUC approved the Company's request to place all impacts to its results of operation caused by the adoption of FIN 47 in regulatory deferred accounts. SFAS 143, together with FIN 47, provides guidance for recording and disclosing liabilities related to future legally enforceable obligations to retire assets (ARO).

## 3. FINANCIAL INSTRUMENTS

The Company utilizes swap agreements to manage interest rate risk. At September 30, 2006 the estimated fair value of the Company's swap was \$0.2 million related to a notional amount of \$19.2 million. These transactions are more fully described in Note 7 to the consolidated financial statements in the Company's Annual Report on Form 10-K for the year ended December 31, 2005.

The Company also utilizes derivative financial instruments for hedging natural gas purchases. The Company's tariffs include a provision for the recovery of actual gas costs incurred. Premiums, transaction fees and any gains or losses are recorded in deferred accounts as a regulatory asset or liability for the over- or under-recovery of gas costs for subsequent rate consideration. As of September 30, 2006, the Company had a deferred net realized loss of \$5.1 million. In addition, as of September 30, 2006, the Company had unrealized losses of \$32.3 million, also recorded in other regulatory assets.

The Company utilizes asset management and supply service agreements with counterparties for certain of its natural gas storage facilities. At September 30, 2006, such counterparties held 52% of the total carrying value of the Company's natural gas inventory, with a value of \$48.3 million. This natural gas will be returned to the Company at its city gate during the winter period (November 2006 through March 2007), or on the contract settlement date, as applicable. Under the terms of the asset management agreements, the Company receives storage asset management fees and, in certain instances, a share of excess profits. No fees are received under supply service agreements. The agreements expire at various times from October 31, 2006 through March 31, 2007.

#### 4. COMMITMENTS AND CONTINGENCIES

The Company is responsible for environmental cleanup at five sites in North Carolina on which MGP residuals are present or suspected. The Company's remediation costs for these sites will depend on a number of factors, such as actual site conditions, third-party claims and recoveries from other potentially responsible parties. The Company has recorded a liability and associated regulatory asset of \$5.9 million, which reflects its estimated remaining liability at September 30, 2006. Any cost allocable to the Company arising from the remediation of these sites is expected to be recoverable through rates.

#### 5. SEGMENT OF BUSINESS INFORMATION

Gas Distribution is the Company's only reportable segment. Gas Distribution uses operating income to measure profitability. Intersegment revenues were not significant. All Other includes equity method investments.

Millions of dollars	2006				2005			
	External Revenue	Operating Income (Loss)	Net Income (Loss)	Segment Assets	External Revenue	Operating Income	Net Income (Loss)	Segment Assets
<i>Three Months Ended September 30,</i>								
Gas Distribution	\$ 59	\$ (6)	\$ (6)		\$ 60	\$ (4)	\$ (6)	
All Other	-	n/a	-		-	n/a	-	
Adjustments/Eliminations	-	-	-		-	-	-	
<b>Consolidated Total</b>	<b>\$ 59</b>	<b>\$ (6)</b>	<b>\$ (6)</b>		<b>\$ 60</b>	<b>\$ (4)</b>	<b>\$ (6)</b>	
<i>Nine Months Ended September 30,</i>								
Gas Distribution	\$ 389	\$ 31	\$ 13	\$ 1,129	\$ 390	\$ 39	\$ 17	\$ 1,029
All Other	-	n/a	-	28	-	n/a	-	28
Adjustments/Eliminations	-	-	-	139	-	-	-	78
<b>Consolidated Total</b>	<b>\$ 389</b>	<b>\$ 31</b>	<b>\$ 13</b>	<b>\$ 1,296</b>	<b>\$ 390</b>	<b>\$ 39</b>	<b>\$ 17</b>	<b>\$ 1,135</b>

## ITEM 2. MANAGEMENT'S NARRATIVE ANALYSIS OF RESULTS OF OPERATIONS

### PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INCORPORATED

The following discussion should be read in conjunction with Management's Narrative Analysis of Results of Operations appearing in Public Service Company of North Carolina, Incorporated's (together with its consolidated subsidiaries, PSNC Energy) Annual Report on Form 10-K for the year ended December 31, 2005.

Statements included in this narrative analysis (or elsewhere in this quarterly report) which are not statements of historical fact are intended to be, and are hereby identified as, "forward-looking statements" for purposes of the safe harbor provided by Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Readers are cautioned that any such forward-looking statements are not guarantees of future performance and involve a number of risks and uncertainties, and that actual results could differ materially from those indicated by such forward-looking statements. Important factors that could cause actual results to differ materially from those indicated by such forward-looking statements include, but are not limited to, the following: (1) that the information is of a preliminary nature and may be subject to further and/or continuing review and adjustment, (2) regulatory actions or changes in the utility regulatory environment, (3) current and future litigation, (4) changes in the economy, especially in PSNC Energy's service territory, (5) the impact of competition from other energy suppliers, including competition from alternate fuels in industrial interruptible markets, (6) growth opportunities, (7) the results of financing efforts, (8) changes in accounting principles, (9) weather conditions, especially in areas served by PSNC Energy, (10) performance of SCANA Corporation's (SCANA) pension plan assets and the impact on PSNC Energy's results of operations, (11) inflation, (12) changes in environmental regulations and (13) the other risks and uncertainties described from time to time in PSNC Energy's periodic reports filed with the United States Securities and Exchange Commission. PSNC Energy disclaims any obligation to update any forward-looking statements.

#### Net Income and Distributions/Dividends

Net income for the nine months ended September 30, 2006 decreased \$4 million compared to the same period in 2005, primarily due to decreased margin.

The nature of PSNC Energy's business is seasonal. The quarters ending June 30 and September 30 are generally PSNC Energy's least profitable quarters due to decreased demand for natural gas related to space heating requirements.

PSNC Energy's Board of Directors has authorized the following distributions/dividends on common stock held by SCANA during 2006:

Declaration Date	Amount	Quarter Ended	Payment Date
February 16, 2006	\$3.9 million	March 31, 2006	April 1, 2006
April 27, 2006	3.9 million	June 30, 2006	July 1, 2006
August 3, 2006	3.9 million	September 30, 2006	October 1, 2006
November 1, 2006	3.5 million	December 31, 2006	January 1, 2007

#### Gas Distribution

Gas distribution is comprised of the local distribution operations of PSNC Energy. Changes in the gas distribution sales margins were as follows:

Millions of dollars	Nine Months Ended September 30,		
	2006	% Change	2005
Operating revenues	\$ 389.1	(0.2)%	\$ 389.8
Less: Gas purchased for resale	266.9	2.4%	260.7
<u>Margin</u>	<u>\$ 122.2</u>	<u>(5.3)%</u>	<u>\$ 129.1</u>

Gas distribution sales margin decreased primarily due to lower customer usage, despite a 4 percent growth in customers. This decrease in consumption is attributable to conservation due to higher natural gas prices and due to milder weather.

**Interest Charges**

Interest charges increased primarily due to an increase in commercial paper interest expense, partly due to increased working capital needs from higher natural gas prices.

**Income Taxes**

Income taxes changed primarily as a result of changes in operating and other income.

**Capital Expansion Program and Liquidity Matters**

PSNC Energy's capital expansion program includes the construction of lines, systems and facilities and the purchase of related equipment. PSNC Energy's 2006 construction budget is \$71 million, compared to actual construction expenditures through September 30, 2006 of \$66 million. PSNC Energy's ratio of earnings to fixed charges for the 12 months ended September 30, 2006 was 2.45.

#### **ITEM 4. CONTROLS AND PROCEDURES**

As of September 30, 2006 each of SCANA Corporation (SCANA), South Carolina Electric & Gas Company (SCE&G) and Public Service Company of North Carolina, Incorporated (PSNC Energy) conducted separate evaluations under the supervision and with the participation of its management, including its Chief Executive Officer (CEO) and Chief Financial Officer (CFO), of the effectiveness of the design and operation of its disclosure controls and procedures. Based on these evaluations, the CEO and CFO in each case concluded that as of September 30, 2006 disclosure controls and procedures related to each company were effective. There has been no change in SCANA's, SCE&G's or PSNC Energy's internal control over financial reporting during the quarter ended September 30, 2006 that has materially affected or is reasonably likely to materially affect SCANA's, SCE&G's or PSNC Energy's internal control over financial reporting.

## PART II. OTHER INFORMATION

### ITEM 1. LEGAL PROCEEDINGS

A claim against SCANA for \$2.7 million for reimbursement of legal fees and expenses under an indemnification and hold harmless agreement in the contract for the sale of the propane gas assets was settled in November 2006. A provision for this loss has been previously recorded.

In May 2004, the Company was served with a purported class action lawsuit styled as Douglas E. Gressette, individually and on behalf of other persons similarly situated v. South Carolina Electric & Gas Company and SCANA Corporation. The case was filed in South Carolina's Circuit Court of Common Pleas for the Ninth Judicial Circuit. The plaintiff alleges the Company made improper use of certain easements and rights-of-way by allowing fiber optic communication lines and/or wireless communication equipment to transmit communications other than the Company's electricity-related internal communications. The plaintiff asserted causes of action for unjust enrichment, trespass, injunction and declaratory judgment. The plaintiff did not assert a specific dollar amount for the claims. The Company believes its actions are consistent with governing law and the applicable documents granting easements and rights-of-way. The court granted the Company's motion to dismiss and issued an order dismissing the case in June 2005. The plaintiff appealed to the South Carolina Supreme Court. The Supreme Court recently overruled the Circuit Court and returned the case to the Circuit Court for further consideration saying the question of assignability of the easements requires construction of the easements themselves. The Company will continue to mount a vigorous defense and believes that the resolution of these claims will not have a material adverse impact on its results of operations, cash flows or financial condition.

In 2004 and early 2005, SCANA and certain of its affiliates, like other integrated utilities, were the subject of an investigation by FERC's Office of Market Oversight and Investigations (OMOI) focusing, among other things, on the relationship between SCE&G's merchant and transmission functions. These relationships are among those addressed in FERC Order 2004, a primary purpose of which order is to ensure that affiliates of transmission providers have no marketplace advantage over non-affiliated market participants. In connection with that investigation, SCE&G was assessed no monetary damages or penalties; however, under terms of a Settlement and Consent Agreement entered into on April 1, 2005, and approved by FERC order dated April 27, 2005, SCE&G agreed to the implementation of a compliance plan which includes periodic reports to OMOI, now known as FERC's Office of Enforcement.

On January 2, 2006, SCE&G provided to FERC a quarterly update on this compliance plan, which included an acknowledgment of SCE&G's discovery that it may have improperly utilized network transmission services, rather than point-to-point transmission services, for purchases and sales of electricity in violation of SCE&G's open access transmission tariff and applicable FERC orders under the Federal Power Act that prohibit the use of network transmission service in support of certain "off-system" sales. This acknowledgment was in part the result of SCE&G's preliminary review of a FERC order issued following its examination of another energy provider in September 2005. Upon further review of that order and an internal investigation, SCE&G determined, and notified FERC, that it did improperly utilize network transmission service in a significant number of purchase and sale transactions.

In response to its internal findings, SCE&G also notified FERC that it had ceased participation in such transactions, instituted additional self-restrictive procedures as safeguards to ensure full compliance in this area in the future, and committed to certain modifications to its compliance plan, including increased levels of training and monitoring. SCE&G also has fully cooperated with FERC staff in its investigation of this matter.

In the fourth quarter of 2005, SCE&G recorded a loss accrual in the amount of \$0.8 million based on its estimation of net revenues from the subject transactions that occurred after the date of the Settlement and Consent Agreement and that might be deemed to be in violation of FERC's rule on the use of network transmission service and be subject to disgorgement pursuant to FERC orders. In the third quarter of 2006, SCE&G increased its loss accrual to \$3.7 million. However, there remains uncertainty as to what actions ultimately may be taken by FERC. Potential actions could include penalties of up to a maximum of \$1 million per violation or per day since August 8, 2005, the effective date of the Energy Policy Act of 2005; disgorgement of profits on the subject transactions; and further modification to SCE&G's compliance plan or other non-monetary remedies. SCE&G continues to believe that no market participants were harmed or disadvantaged by the transactions in question. For this reason and in light of SCE&G's self-reporting and other cooperation in the investigation of this matter, and SCE&G's institution of appropriate safeguards referred to above, SCE&G does not believe that material monetary sanctions are warranted.

SCE&G desires to resolve this matter in a reasonable and satisfactory manner. Nonetheless, SCE&G cannot predict what, if any, actions FERC ultimately will take with respect to this matter, and is unable to determine if the resolution of this matter will have a material adverse impact on its operations, cash flows or financial condition.

## ITEM 5. OTHER INFORMATION

On November 1, 2006, SCANA's Board of Directors (the "Board"), by vote of at least two-thirds of the members then serving on the Board, amended certain provisions of SCANA's executive compensation and director compensation plans (the "Plans", which are listed below) to reduce the amount of any tax gross-up payment that would be payable to participants (or their beneficiaries, as applicable) under the Plans upon a Change in Control (as defined in each of the Plans) or termination of employment following a Change in Control, if applicable. Specifically, the definition of a "Gross-Up Payment" in each of the Plans was amended to limit the amount of the Gross-Up Payment to the Excise Tax (as defined in each of the Plans) imposed upon amounts paid out to a participant (or beneficiary, as applicable) thereunder and any income and employment tax and Excise Tax due with respect to the Gross-Up Payment. Prior to such amendment, a "Gross-Up Payment" under such circumstances would have also included the amount of federal, state and local income taxes imposed upon amounts paid out to a participant (or beneficiary, as applicable) as well as such income taxes and Excise Tax as would be imposed thereon. The resolutions adopted by the Board are included as an exhibit to this Form 10-Q.

The Plans subject to this change are:

SCANA Corporation Executive Deferred Compensation Plan ("EDCP")  
SCANA Corporation Supplemental Executive Retirement Plan ("SERP")  
SCANA Corporation Key Executive Severance Benefits Plan ("KESBP")  
SCANA Corporation Supplementary Key Executive Severance Benefits Plan ("SKESBP")  
SCANA Corporation Executive Benefit Plan ("EBP")  
SCANA Corporation Supplementary Executive Benefit Plan ("SEBP")  
SCANA Corporation Director Compensation and Deferral Plan ("Director Plan")  
SCANA Corporation Short-Term Annual Incentive Plan ("Short-Term Plan")

The Director Plan applies to SCANA's directors. The EDCP, SERP, KESBP and Short-Term Plan apply to SCANA's executive officers (including named executive officers), although the EBP and SEBP apply to other SCANA officers.

## ITEM 6. EXHIBITS

SCANA Corporation (SCANA), South Carolina Electric & Gas Company (SCE&G) and Public Service Company of North Carolina, Incorporated (PSNC Energy):

Exhibits filed or furnished with this Quarterly Report on Form 10-Q are listed in the following Exhibit Index.

As permitted under Item 601(b)(4)(iii) of Regulation S-K, instruments defining the rights of holders of long-term debt of less than 10 percent of the total consolidated assets of SCANA, for itself and its subsidiaries, of SCE&G, for itself and its consolidated affiliates, and of PSNC Energy, for itself and its subsidiaries, have been omitted and SCANA, SCE&G and PSNC Energy agree to furnish a copy of such instruments to the Commission upon request.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, each of the registrants has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of each registrant shall be deemed to relate only to matters having reference to such registrant and any subsidiaries thereof.

**SCANA CORPORATION**  
**SOUTH CAROLINA ELECTRIC & GAS COMPANY**  
**PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INCORPORATED**  
(Registrants)

November 3, 2006

By: /s/James E. Swan, IV

\_\_\_\_\_  
James E. Swan, IV

Controller

(Principal accounting officer)

EXHIBIT INDEX

Exhibit No.	Applicable to Form 10-K of		Description																																																						
	SCANA	SCE&G		PSNC Energy																																																					
3.01	X		Restated Articles of Incorporation of SCANA Corporation as adopted on April 26, 1989 (Filed as Exhibit 3-A to Registration Statement No. 33-49145 and incorporated by reference herein)																																																						
3.02	X		Articles of Amendment dated April 27, 1995 (Filed as Exhibit 4-B to Registration Statement No. 33-62421 and incorporated by reference herein)																																																						
3.03		X	Restated Articles of Incorporation of South Carolina Electric & Gas Company, as adopted on May 3, 2001 (Filed as Exhibit 3.01 to Registration Statement No. 333-65460 and incorporated by reference herein)																																																						
3.04		X	Articles of Amendment effective as of the dates indicated below and filed as exhibits to the Registration Statements or Exchange Act reports set forth below and are incorporated by reference herein  <table border="0" style="margin-left: 40px;"> <tr> <td>May 22, 2001</td> <td>Exhibit 3.02</td> <td>to Registration No. 333-65460</td> </tr> <tr> <td>June 14, 2001</td> <td>Exhibit 3.04</td> <td>to Registration No. 333-65460</td> </tr> <tr> <td>August 30, 2001</td> <td>Exhibit 3.05</td> <td>to Registration No. 333-101449</td> </tr> <tr> <td>March 13, 2002</td> <td>Exhibit 3.06</td> <td>to Registration No. 333-101449</td> </tr> <tr> <td>May 9, 2002</td> <td>Exhibit 3.07</td> <td>to Registration No. 333-101449</td> </tr> <tr> <td>June 4, 2002</td> <td>Exhibit 3.08</td> <td>to Registration No. 333-101449</td> </tr> <tr> <td>August 12, 2002</td> <td>Exhibit 3.09</td> <td>to Registration No. 333-101449</td> </tr> <tr> <td>March 13, 2003</td> <td>Exhibit 3.03</td> <td>to Registration No. 333-108760</td> </tr> <tr> <td>May 22, 2003</td> <td>Exhibit 3.04</td> <td>to Registration No. 333-108760</td> </tr> <tr> <td>June 18, 2003</td> <td>Exhibit 3.05</td> <td>to Registration No. 333-108760</td> </tr> <tr> <td>August 7, 2003</td> <td>Exhibit 3.06</td> <td>to Registration No. 333-108760</td> </tr> <tr> <td>May 18, 2004</td> <td>Exhibit 3.05</td> <td>to Form 10-Q for the quarter ended June 30, 2004</td> </tr> <tr> <td>June 18, 2004</td> <td>Exhibit 3.06</td> <td>to Form 10-Q for the quarter ended June 30, 2004</td> </tr> <tr> <td>August 12, 2004</td> <td>Exhibit 3.05</td> <td>to Form 10-Q for the quarter ended Sept. 30, 2004</td> </tr> <tr> <td>March 9, 2005</td> <td>Exhibit 3.11</td> <td>to Form 10-Q for the quarter ended Sept. 30, 2005</td> </tr> <tr> <td>May 16, 2005</td> <td>Exhibit 3.12</td> <td>to Form 10-Q for the quarter ended Sept. 30, 2005</td> </tr> <tr> <td>June 15, 2005</td> <td>Exhibit 3.13</td> <td>to Form 10-Q for the quarter ended Sept. 30, 2005</td> </tr> <tr> <td>August 16, 2005</td> <td>Exhibit 3.14</td> <td>to Form 10-Q for the quarter ended Sept. 30, 2005</td> </tr> </table>	May 22, 2001	Exhibit 3.02	to Registration No. 333-65460	June 14, 2001	Exhibit 3.04	to Registration No. 333-65460	August 30, 2001	Exhibit 3.05	to Registration No. 333-101449	March 13, 2002	Exhibit 3.06	to Registration No. 333-101449	May 9, 2002	Exhibit 3.07	to Registration No. 333-101449	June 4, 2002	Exhibit 3.08	to Registration No. 333-101449	August 12, 2002	Exhibit 3.09	to Registration No. 333-101449	March 13, 2003	Exhibit 3.03	to Registration No. 333-108760	May 22, 2003	Exhibit 3.04	to Registration No. 333-108760	June 18, 2003	Exhibit 3.05	to Registration No. 333-108760	August 7, 2003	Exhibit 3.06	to Registration No. 333-108760	May 18, 2004	Exhibit 3.05	to Form 10-Q for the quarter ended June 30, 2004	June 18, 2004	Exhibit 3.06	to Form 10-Q for the quarter ended June 30, 2004	August 12, 2004	Exhibit 3.05	to Form 10-Q for the quarter ended Sept. 30, 2004	March 9, 2005	Exhibit 3.11	to Form 10-Q for the quarter ended Sept. 30, 2005	May 16, 2005	Exhibit 3.12	to Form 10-Q for the quarter ended Sept. 30, 2005	June 15, 2005	Exhibit 3.13	to Form 10-Q for the quarter ended Sept. 30, 2005	August 16, 2005	Exhibit 3.14	to Form 10-Q for the quarter ended Sept. 30, 2005
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	No. SCANA	SCE&G	PSNC Energy	
3.08	X			By-Laws of SCANA as revised and amended on December 13, 2000 (Filed as Exhibit 3.01 to Registration Statement No. 333-68266 and incorporated by reference herein)
3.09		X		By-Laws of SCE&G as revised and amended on February 22, 2001 (Filed as Exhibit 3.05 to Registration Statement No. 333-65460 and incorporated by reference herein)
3.10			X	By-Laws of PSNC Energy as revised and amended on February 22, 2001 (Filed as Exhibit 3.01 to Registration Statement No. 333-68516 and incorporated by reference herein)
3.11		X		Articles of Amendment dated March 14, 2006, amending the Restated Articles of Incorporation of South Carolina Electric & Gas Company (Filed as Exhibit 3.01 to Form 8-K filed March 17, 2006)
3.12		X		Articles of Correction dated March 17, 2006, amending the Articles of Amendment dated March 14, 2006 of South Carolina Electric & Gas Company (Filed as Exhibit 3.02 to Form 8-K filed March 17, 2006)
3.13		X		Articles of Amendment dated May 11, 2006, amending the Restated Articles of Incorporation of South Carolina Electric & Gas Company (Filed as Exhibit 3.01 to Form 8-K filed May 15, 2006)
3.14		X		Articles of Amendment dated June 28, 2006, amending the Restated Articles of Incorporation of South Carolina Electric & Gas Company (filed as Exhibit 3.01 to Form 8-K filed June 29, 2006)
3.15		X		Articles of Amendment dated August 16, 2006, amending the Restated Articles of Incorporation of South Carolina Electric & Gas Company (Filed as Exhibit 3.01 to Form 8-K filed August 17, 2006)
3.16		X		Articles of Correction dated September 6, 2006, amending the Restated Articles of Incorporation of South Carolina Electric & Gas Company (Filed as Exhibit 3.01 to Form 8-K filed September 7, 2006)
*10.01	X			Amendment to SCANA Corporation Director Compensation and Deferral Plan as adopted December 20, 2005 (Filed as Exhibit 10.01 to Form 10-Q for the quarter ended March 31, 2006)
*10.02	X			Amendment to SCANA Corporation Executive Deferred Compensation Plan as adopted December 20, 2005 (Filed as Exhibit 10.02 to Form 10-Q for the quarter ended March 31, 2006)
*10.03	X			Independent contractor agreement with Neville O. Lorick (Filed as Exhibit 99.1 to Form 8-K dated June 15, 2006 and incorporated by reference herein)
*10.04	X			SCANA Supplemental Executive Retirement Plan as amended and restated as of July 1, 2000 (Filed herewith)
*10.05	X			SCANA Key Executive Severance Benefits Plan as amended and restated as of July 1, 2001 (Filed herewith)
*10.06	X			SCANA Supplementary Key Executive Severance Benefits Plan as amended and restated as of July 1, 2001 (Filed herewith)
*10.07	X			Resolution of Board of Directors of SCANA amending SCANA Corporation's Executive Deferred Compensation Plan, Supplemental Executive Retirement Plan, Key Executive Severance Benefits Plan, Supplementary Key Executive Severance Benefits Plan, Executive Benefit Plan, Supplementary Executive Benefit Plan, Director Compensation and Deferral Plan and Short-Term Annual Incentive Plan (Filed herewith)

Exhibit No.	Applicable to Form 10-K of			Description
	SCANA	SCE&G	PSNC Energy	
31.01	X			Certification of Principal Executive Officer Required by Rule 13a-14 (Filed herewith)
31.02	X			Certification of Principal Financial Officer Required by Rule 13a-14 (Filed herewith)
31.03		X		Certification of Principal Executive Officer Required by Rule 13a-14 (Filed herewith)
31.04		X		Certification of Principal Financial Officer Required by Rule 13a-14 (Filed herewith)
31.05			X	Certification of Principal Executive Officer Required by Rule 13a-14 (Filed herewith)
31.06			X	Certification of Principal Financial Officer Required by Rule 13a-14 (Filed herewith)
32.01	X			Certification of Principal Executive Officer Pursuant to 18 U.S.C. Section 1350 (Furnished herewith)
32.02	X			Certification of Principal Financial Officer Pursuant to 18 U.S.C. Section 1350 (Furnished herewith)
32.03		X		Certification of Principal Executive Officer Pursuant to 18 U.S.C. Section 1350 (Furnished herewith)
32.04		X		Certification of Principal Financial Officer Pursuant to 18 U.S.C. Section 1350 (Furnished herewith)
32.05			X	Certification of Principal Executive Officer Pursuant to 18 U.S.C. Section 1350 (Furnished herewith)
32.06			X	Certification of Principal Financial Officer Pursuant to 18 U.S.C. Section 1350 (Furnished herewith)

\*Management contract or compensation plan or arrangement