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OFFICE OF THE
EXECUTIVE SECRETARY

BEFORE THE TENNESSEE REGULATORY AUTHORITY

NASHVILLE, TENNESSEE

May 13, 1999

IN RE:	)	
	)	
CHATTANOOGA GAS COMPANY	)	**Docket No. 98-00776**
ACTUAL COST ADJUSTMENT AUDIT	)	

NOTICE OF FILING BY THE ENERGY AND WATER DIVISION OF THE TENNESSEE REGULATORY AUTHORITY

Pursuant to Tenn. Code Ann. §§ 65-4-104, 65-4-111 and 65-3-108, the Energy and Water Division of the Tennessee Regulatory Authority hereby gives notice of its filing of the Compliance Audit Report of the Actual Cost Adjustment Audit (hereafter "ACA") Component of the Purchased Gas Adjustment Rule for Chattanooga Gas Company in this docket and would respectfully state as follows:

1. The present docket was opened by the Authority to hear matters arising out of the ACA audit of Chattanooga Gas Company (the "Company").

2. The Company's ACA filing was received on October 5, 1998, and the Staff completed its audit of the filing on April 23, 1999.

3. On April 27, 1999, the Energy and Water Division issued its preliminary ACA audit findings to the Company, and on May 7, 1999, the Company responded thereto.

4. The preliminary ACA audit report was modified to reflect the Company's responses and a final ACA audit report (hereafter the "Report") resulted therefrom. The

Report is attached hereto as Exhibit A and is fully incorporated herein by this reference. In addition to the recommendations of the Energy and Water Division, the Report contains the audit findings of the Energy and Water Division and the Company's responses thereto.

5. The Energy and Water Division hereby files its Report with the Tennessee Regulatory Authority for deposit as a public record and approval of the recommendations and findings contained therein.

Respectfully Submitted:

Laura J. Foreman
Energy and Water Division of the
Tennessee Regulatory Authority

CERTIFICATE OF SERVICE

I hereby certify that on this 13 day of May, 1999, a true and exact copy of the foregoing has been either hand-delivered or delivered via U.S. Mail, postage pre-paid, to the following persons:

Mr. K. David Waddell
Executive Secretary
Tennessee Regulatory Authority
460 James Robertson Parkway
Nashville, TN 37243

Mr. Harry Thompson
President
Chattanooga Gas Company
6125 Preservation Drive
Chattanooga, TN 37416

Mr. Gerald A. Hinesley
Director - Utility Accounting
AGL Resources Service Company
PO Box 4569
Atlanta, GA 30302-9470

Laura J. Foreman

Laura J. Foreman

COMPLIANCE AUDIT REPORT
of the
ACTUAL COST ADJUSTMENT COMPONENT
of the
PURCHASED GAS ADJUSTMENT RULE
for
CHATTANOOGA GAS COMPANY
for the Year Ended June 30, 1998

Docket No. 98-00776

Prepared by:
THE ENERGY AND WATER DIVISION
of the
TENNESSEE REGULATORY AUTHORITY
MAY 1999

Exhibit A

COMPLIANCE AUDIT REPORT
of the
ACTUAL COST ADJUSTMENT COMPONENT
of the
PURCHASED GAS ADJUSTMENT RULE
for
CHATTANOOGA GAS COMPANY
for the Year ended June 30, 1998

Docket No. 98-00776

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I. INTRODUCTION

The subject of this audit is Chattanooga Gas Company's (hereafter the "Company" or "Chattanooga Gas") compliance with the Actual Cost Adjustment and Refund Adjustment of the Purchased Gas Adjustment Rule (hereafter "PGA") of the Tennessee Regulatory Authority (hereafter the "TRA" or the "Authority"). The objective of the audit was to determine whether the Purchased Gas Adjustments, which are encompassed by the Actual Cost Adjustment (hereafter "ACA") as more fully described below, for the year ended June 30, 1998, were calculated correctly and were supported by appropriate source documentation.

II. AUDIT OPINION

The Company reported the results of the activity in the Deferred Gas Cost account for the ACA year ended June 30, 1998, as a net under-recovery of $2,985,682. **Fifty-five exceptions were noted by the Staff during the audit, the net effect of which is a reduction of $1,806,996 in the Deferred Gas Cost account. A detail of these exceptions can be found in Section VII of this Report. The correct balance in the Deferred Gas Cost account at June 30, 1998, therefore, should be $1,178,686.**

A prudence audit of the Company's gas purchasing activities is also required by the PGA Rule. Such an audit was performed by TB&A Management Consultants (hereafter "TB&A") and is attached hereto as Attachment 1. Per their report, TB&A has determined:

> Based on our review and analysis of the information provided, Chattanooga Gas Company is continuing to be proactive and responsive to the ongoing changes in the natural gas supply and local gas distribution marketplace in a manner comparable to the actions of LDCs across the country. The gas supply management department at AGL Energy Services acting on behalf of Chattanooga Gas Company appears to be appropriately organized and staffed to assure that customers will continue to enjoy secure, reliable gas supplies at reasonable prices. Actual gas cost performance has been consistent or better than market indicators.

Although TB&A concluded in its prudence audit that the gas supply management department "appears to be appropriately organized and staffed," the Authority's Staff audit of the ACA has not resulted in a similar conclusion regarding the accounting for such gas purchasing activities. It is apparent from the number of the current ACA audit findings, the total dollar amount of such audit findings, and the reasons for each finding, that the Company's procedures for accounting of its gas purchases and recoveries are deficient. **Therefore, the Staff concludes that the Company has failed to comply with the Actual Cost Adjustment component of the Purchased Gas Adjustment Rule.**

This adverse opinion for the year ended June 30, 1998, is of great concern to the Staff. Just two years ago, the ACA audit for the year ended June 30, 1996, did not produce any findings and, therefore, the Staff issued an unqualified opinion. One year ago, the Staff issued a qualified opinion for the year ended June 30, 1997, that, subject to certain procedures being implemented, the Company was deemed to be in compliance. **It is, therefore, imperative that the Company immediately implement the necessary internal accounting controls and procedures to reverse this trend and ensure that the next ACA audit does not result in another adverse opinion.**

One of the most important responsibilities of the Tennessee Regulatory Authority is to ascertain that the public utilities under its jurisdiction are operating with the proper level of expertise wherein the TRA can say in good faith to the ratepayers that the rates they are being charged throughout the year are just and reasonable. A significant part of those rates is the Purchased Gas Adjustment factor and the subsequent related Actual Cost Adjustment factor, both of which are the subject of this audit. Due to Findings 1 through 5 of the audit report for the ACA year ended June 30, 1997, and all of the findings cited in this ACA audit report for the year ended June 30, 1998, the Staff of the TRA does not have an adequate comfort level with the accounting procedures of Chattanooga Gas Company to provide the ratepayers with such assurance.

III. BACKGROUND INFORMATION ON COMPANY

Chattanooga Gas is located at 6125 Preservation Drive, Chattanooga, Tennessee, and is a wholly owned subsidiary of Atlanta Gas Light Company, which has its main office at 235 Peachtree Street, Atlanta, Georgia. As a local distribution company (hereafter "LDC") Chattanooga Gas provides service to customers in Chattanooga and Cleveland, Tennessee, and environs in Hamilton and Bradley Counties in Tennessee, respectively. The natural gas used to serve these areas is purchased from three natural gas pipelines in accordance with separate and individual tariffs approved by the Federal Energy Regulatory Commission. The three interstate pipelines are Tennessee Gas Pipeline, East Tennessee Natural Gas, and Southern Natural Gas.

The Company submitted the ACA filing which is the subject of this audit on October 5, 1998. It was mutually agreed to by the Company and TRA Staff to extend the 180 day notification date to June 1, 1999. The extension was necessary to enable the Company to complete its responses to the Staff's data requests and to enable the Staff sufficient time to properly analyze the Company's responses.

As of the date of this report, the Company had not initiated a surcharge for the results of this ACA period. **It is, therefore, recommended that the Company implement a surcharge with the July 1999 billing for the corrected amount of under-recovery of $1,178,686 and use its best efforts to have the same fully surcharged by June 30, 2000.**

IV. JURISDICTION OF THE TENNESSEE REGULATORY AUTHORITY

Tennessee Code Annotated (T.C.A.) gave jurisdiction and control over public utilities to the Tennessee Regulatory Authority (hereafter the "Authority" or "TRA"). T.C.A. § 65-4-104 states:

> The Authority shall have general supervisory and regulatory power, jurisdiction, and control over all public utilities, and also over their property, property rights, facilities, and franchises, so far as may be necessary for the purpose of carrying out the provisions of this chapter.

Further, T.C.A. § 65-4-105 grants the same power to the Authority with reference to all public utilities within its jurisdiction as chapters 3 and 5 of Title 65 of the T.C.A. has conferred on the Department of Transportation's oversight of the railroads or the Department of Safety's oversight of transportation companies. By virtue of T.C.A. § 65-3-108 said power includes the right to audit:

> The department is given full power to examine the books and papers of the said companies, and to examine, under oath, the officers, agents, and employees of said companies... to procure the necessary information to intelligently and justly discharge their duties and carry out the provisions of this chapter and chapter 5 of this title.

The Energy and Water Division of the TRA is responsible for auditing those companies under the Division's jurisdiction to ensure that each company is abiding by Tennessee statute as well as the Rules and Regulations of the Authority. This audit was performed by Laura J. Foreman of the Energy and Water Division.

V. DESCRIPTION OF PURCHASED GAS ADJUSTMENT RULE

Actual Cost Adjustment Audits:

The PGA Rule can be found in Chapter 1220-4-7 of the Rules of the Tennessee Regulatory Authority. The PGA Rule permits the Company to recover, in a timely fashion, the total cost of gas purchased for delivery to its customers and to assure that the Company does not over-collect or under-collect gas costs from its customers. The PGA consists of three major components:

1. **The Actual Cost Adjustment (hereafter the "ACA")**
2. **The Gas Charge Adjustment (hereafter the "GCA")**
3. **The Refund Adjustment (hereafter the "RA")**

The ACA is the difference between the revenues billed customers by means of the GCA and the cost of gas invoiced the Company by suppliers plus margin loss (if allowed by order of the TRA in another docket) as reflected in the Deferred Gas Cost account. The ACA then "trues-up" the difference between the actual gas costs and the gas costs recovered from the customer through a surcharge or a refund. The RA refunds the "true-up" along with other supplier refunds. For a more complete definition of the GCA and RA, please see the PGA Formula in Appendix A of this Report.

Section 1220-4-7-.03 (2) of the PGA rule requires:

> Each year, the Company shall file with the [Authority] an annual report reflecting the transactions in the Deferred Gas Cost Account. Unless the [Authority] provides written notification to the Company within one hundred eighty (180) days from the date of filing the report, the Deferred Gas Cost Adjustment Account shall be deemed in compliance with the provisions of this Rule. This 180 day notification period may be extended by mutual consent of the Company and the [Authority] Staff or by order of the [Authority].

Prudence Audit of Gas Purchases:

Section 1220-4-7-.05 of the PGA Rule requires, unless otherwise ordered by the Authority, an "Audit of Prudence of Gas Purchases" by a qualified consultant. This specialized audit is to evaluate and report annually on the prudence of any gas costs included in the PGA. On October 1, 1998, TB&A Management Consultants issued their "Report on the Gas Purchasing Activities of Chattanooga Gas Company for the Combined Periods: July 1, 1997, to June 30, 1998," which is attached hereto as Attachment 1. As discussed in Section II of this ACA audit report, TB&A determined the Company to be prudent in its gas purchasing activity during the year ended June 30, 1998.

VI. SCOPE OF ACA AUDIT

The Company's filing summarized the balance in the Deferred Cost Account at June 30, 1998, as follows:

Beginning Balance @ 6/30/97	$ 1,647,068
Activity during year ended 6/30/98:	
Gas Purchases	43,880,443
Gas Recoveries	(42,871,223)
Interest accrued during year ended 6/30/98	329,394
ENDING BALANCE @ 6/30/98	2,985,682

This audit was performed to ascertain that the Company's calculations of gas costs incurred and recovered were correct. Also included in this audit were four prior period adjustments: a refund adjustment effective October 1, 1994; a surcharge adjustment which should have been effective November 1, 1996; a refund adjustment effective July 1, 1997; and a surcharge adjustment which should have been effective November 1, 1997.

An audit of a sample of customer bills was also performed to determine if the proper PGA rates were being applied in the Company's calculation of the customers' bills. Since the Company's billing process is computerized, a sample of 68 bills were tested. These bills were selected to be representative of the residential, commercial, industrial and interruptible customers in the Company's service area. The sample was selected from the twelve month period of July 1, 1997, through June 30, 1998. After recalculating each sample bill, it was determined that the calculation methods utilized by the Company are correct.

During the current audit, the Staff also analyzed the off-system sales of the Company. An off-system sale is a sale of gas to a customer who is not within the jurisdictional territory of the LDC. Treatment of the profit from any off-system sale is addressed in the "Interruptible Margin Credit Rider" of the Company's tariff which states:

> This Interruptible Margin Credit Rider is intended to authorize the Company to recover not more than fifty percent (50%) of the gross profit margin that results from off-system sales of gas should such sales be made to off-system customers by the Company.

Prior to July 1, 1996, the total of the Company's off-system sales was insignificant. For the years ended June 30, 1997, and June 30, 1998, however, not only did the off-systems sales activity increase substantially but the Company's sales of gas to its "off-system" affiliates also increased significantly. During the year ended June 30, 1997, the Company's off-system sales totaled $16,083,482 of which $6,405,136, or 40%, were to various affiliates of the Company. During the year ended June 30, 1998, however, the percentage increased by 36% to 76% when $7,739,584 of the Company's off-system sales of $10,123,453 were to affiliates of the Company. Although the Staff's analysis of the gross profit percentages derived from these sales did not indicate the existence of any affiliate preference, the Staff questions whether the framers of the Interruptible Margin Credit Rider anticipated that the majority of its off-system sales would be to affiliated companies when they allowed the Company to retain 50% of the gross profit from these sales. **The Staff will continue to carefully scrutinize all future off-system sales of Chattanooga Gas to ascertain that no preference is being afforded the affiliates and to ensure that the Company's reserve margin does not exceed a reasonable level to adequately serve its ratepayers. Should any affiliate preference with off-system sales be indicated in the future, the Staff recommends that the Authority consider a show cause proceeding as to why the Company's tariff should not be amended to exclude sales to off-system affiliates from the profit sharing allowed in the Interruptible Margin Credit Rider.**

VII. ACA FINDINGS

As previously stated, the Company's Actual Cost Adjustment filing dated October 5, 1997, reflected a net under-collection of gas costs from customers for the year ended June 30, 1998, of $2,985,682. The net effect of the Staff's findings, which are detailed below, reduce the under-collection by $1,806,996 to $1,178,686. The Company has responded to the majority of the Staff's findings by stating that the Company will "adjust the ACA schedule and its general ledger accordingly." As the Staff has discussed with the Company in prior audits, any adjustments to the ACA should be held in abeyance by the Company until the final ACA report has been issued by the Authority. In the month following the issuance of the audit report, the Company should then record, in the current ACA, **all** adjustments required to comply with said audit findings.

SUMMARY:

FINDING #1	Pipeline Refunds		Procedural	
FINDING #2	Inventory		no effect	
FINDING #3	Inventory		no effect	
FINDING #4	Inventory		no effect	
FINDING #5	Inventory		no effect	
FINDING #6	Billing		Procedural	
FINDING #7	Commodity Accrual	$	11,452.16	under-recovery
FINDING #8	Commodity Accrual		(172.14)	over-recovery
FINDING #9	Demand Accrual		(74.55)	over-recovery
FINDING #10	Commodity Accrual		197.57	under-recovery
FINDING #11	Commodity Accrual		671.44	under-recovery
FINDING #12	Demand Accrual		(254.28)	over-recovery
FINDING #13	Commodity Accrual		(29.45)	over-recovery
FINDING #14	Commodity Accrual		(1,269,540.34)	over-recovery
FINDING #15	Commodity Accrual		21.49	under-recovery
FINDING #16	Commodity Accrual		49.66	under-recovery
FINDING #17	Demand Accrual		(9.64)	over-recovery
FINDING #18	Commodity Accrual		24,345.48	under-recovery
FINDING #19	Commodity Accrual		1,280.55	under-recovery
FINDING #20	Demand Accrual		(2,944.00)	over-recovery
FINDING #21	Commodity Accrual		95.64	under-recovery
FINDING #22	Commodity Accrual		(9,077.24)	over-recovery
FINDING #23	Commodity Accrual		(2,061.00)	over-recovery
FINDING #24	Commodity Accrual		73.96	under-recovery
FINDING #25	Commodity Accrual		(677,984.00)	over-recovery
FINDING #26	Commodity Accrual		5,441.14	under-recovery

FINDING #29	Demand Accrual	.00	no effect
FINDING #30	Demand Accrual	8.35	under-recovery
FINDING #31	Commodity Accrual	214.16	under-recovery
FINDING #32	Commodity Accrual	153,274.00	under-recovery
FINDING #33	Demand Accrual	(4,783.00)	over-recovery
FINDING #34	Commodity Accrual	677,984.00	under-recovery
FINDING #35	Commodity Accrual	10,000.00	under-recovery
FINDING #36	Commodity Accrual	(17,393.25)	over-recovery
FINDING #37	Commodity Accrual	7,999.74	under-recovery
FINDING #38	Commodity Accrual	(12,377.14)	over-recovery
FINDING #39	Commodity Accrual	(153,274.00)	over-recovery
FINDING #40	Demand Accrual	4,783.00	under-recovery
FINDING #41	Commodity Accrual	(16,463.15)	over-recovery
FINDING #42	Commodity Accrual	(749,766.00)	over-recovery
FINDING #43	Demand Accrual	(45,616.00)	over-recovery
FINDING #44	Commodity Accrual	(6,856.04)	over-recovery
FINDING #45	Commodity Accrual	749,766.00	under-recovery
FINDING #46	Demand Accrual	(642,187.00)	over-recovery
FINDING #47	Commodity Accrual	11,389.75	under-recovery
FINDING #48	Commodity Accrual	336,286.16	under-recovery
FINDING #49	Commodity Accrual	(10,997.98)	over-recovery
FINDING #50	Commodity Accrual	1,692.91	under-recovery
FINDING #51	Commodity Accrual	(56,534.24)	over-recovery
FINDING #52	Demand Accrual	5,576.69	under-recovery
FINDING #53	Commodity Accrual	36,221.89	under-recovery
FINDING #54	Commodity Accrual	(103,076.22)	over-recovery
FINDING #55	Demand Accrual	(17,768.76)	over-recovery
	Net Result	**$ (1,806,995.72)**	**over-recovery**

A detail explanation for each of the above findings can be found beginning at page 8 of this report.

FINDING #1:

Exception:

The Company had not refunded all of the pipeline refunds received during the year ended June 30, 1998.

Discussion:

As of June 30, 1998, the Company received $1,124,086.58 in refunds from the pipelines during the year then ended but had included only $1,051,985.33 in its calculation of the refund due ratepayers.

Company Response:

The Company will include the remaining pipeline refunds in the next Purchase Gas Refund filing.

FINDING #2:

Exception:

The June 1998 injections shown on the Company's inventory schedule for account #145-710-8000 is incorrect.

Discussion:

The amount posted for injections for June 1998 on the inventory schedule for account #145-710-8000 was an estimate of $48,392.77. The actual amount of injections for June 1998 was $47,977.79.

Company Response:

The Company will adjust the inventory schedule and its general ledger accordingly.

FINDING #3:

Exception:

The amount shown for the April 1998 cash-out on the Company's inventory schedule for account #145-720-8000 was recorded incorrectly.

Discussion:

The April 1998 cash-out of $168,143.08 was posted incorrectly as a debit to the inventory schedule for account #145-720-8000. The amount should have been posted to the inventory schedule as a credit.

Company Response:

The Company will adjust the inventory schedule and its general ledger accordingly. See also response to Finding #48.

FINDING #4:

Exception:

The Company failed to post the cost of vaporization to the inventory schedule.

Discussion:

The March 1998 vaporization cost of $108,926.04 was not posted to LNG inventory schedule #145-900-8000 during the audit period.

Company Response:

The Company will adjust the inventory schedule and its general ledger accordingly.

FINDING #5:

Exception:

The Company failed to post the June 1998 withdrawals from storage to the inventory schedule.

Discussion:

The June 1998 withdrawals from storage in the amount of $330.31 was not posted to Inventory Schedule #145-720-8000 which was provided to the Authority with the ACA audit.

Company Response:

The Company will adjust the inventory schedule and its general ledger accordingly.

FINDING #6:

Exception:

The Company failed to issue a credit to an industrial customer for a billing error.

Discussion:

In response to a data request regarding the Company's calculation of margin loss for September 1997, the Company stated it had incorrectly invoiced a customer. According to the Staff's calculations, the customer is due a credit of $1,287. When asked to provide a copy of the credit invoice, the Company acknowledged that a credit has not been issued.

Company Response:

The Company will provide a credit to the customer in May's billing cycle.

FINDING #7:

Exception:

*The Staff calculated an **under-recovery** of **$11,452.16** in the July 1997 margin loss.*

Discussion:

In response to the Staff's request for copies of the customer invoices to substantiate the margin loss incurred in July 1997, the Company revised its schedule entitled "Calculation of Loss in Gross Profit from Sales using Special Service Rate Schedule SS-1." Based on the revised schedule, the total margin loss allowed to be recovered by the Company is $68,792.45 rather than the $57,340.29 which was included in the Company's ACA filing.

Company Response:

The Company will adjust the ACA schedule and its general ledger accordingly.

FINDING #8:

Exception:

*The Staff calculated an **over-recovery** of **$172.14** in the July 1997 commodity cost of gas used by the Company.*

Discussion:

The Company used incorrect volumes to compute the commodity cost of the gas used by the Company during the month of July 1997.

Company Response:

The Company will adjust the ACA schedule and its general ledger accordingly.

FINDING #9:

Exception:

*The Staff calculated an **over-recovery** of **$74.55** in the July 1997 demand cost of gas used by the Company.*

Discussion:

The Company used incorrect volumes to compute the demand cost of the gas used by the Company during the month of July 1997.

Company Response:

The Company will adjust the ACA schedule and its general ledger accordingly.

FINDING #10:

Exception:

*The Staff calculated an **under-recovery** of **$197.57** in the Company's July 1997 commodity interest accrual.*

Discussion:

The Company failed to include the margin loss for the month of July 1997 in its computation of the commodity interest accrual for the month.

Company Response:

The Company will adjust the ACA schedule and its general ledger accordingly.

FINDING #11:

Exception:

The Staff calculated an ***under-recovery*** *of* ***$671.44*** *in the Company's July 1997 commodity interest accrual.*

Discussion:

The Company used an incorrect interest rate to calculate the commodity interest accrual for July 1997. An interest rate of 8.25% was used by the Company instead of the correct rate of 8.43%.

Company Response:

The Company will adjust the ACA schedule and its general ledger accordingly.

FINDING #12:

Exception:

The Staff calculated an ***over-recovery*** *of* ***$254.28*** *in the Company's July 1997 demand interest accrual.*

Discussion:

The Company used an incorrect interest rate to calculate the demand interest accrual for July 1997. An interest rate of 8.25% was used by the Company instead of the correct rate of 8.43%.

Company Response:

The Company will adjust the ACA schedule and its general ledger accordingly.

FINDING #13:

Exception:

*The Staff calculated an **over-recovery** of **$29.45** in the July 1997 commodity gas purchases.*

Discussion:

The Company recorded $108,616.39 as the total cost of gas purchased from Other Suppliers for the month of July 1997. The correct total should have been $108,586.94.

Company Response:

The Company will adjust the total cost of gas purchased from Other Suppliers on the ACA schedule and its general ledger accordingly.

FINDING #14:

Exception:

*The Staff calculated an **over-recovery** of **$1,269,540.34** in the storage injections for August 1997.*

Discussion:

The amount the Company injects into storage each month is treated as a reduction in the purchased gas costs. As the gas is withdrawn from storage, the cost of the withdrawals is added back to the purchased gas costs. Rather than crediting the ACA filing with the amount of gas injected into storage for August, the Company added the total of storage injections to the cost of gas thereby overstating the ending balance in the commodity cost of gas purchased for the month by $1,269,540.34.

Company Response:

The Company will adjust the commodity cost of gas on the ACA schedule and its general ledger accordingly.

FINDING #15:

Exception:

The Staff calculated an ***under-recovery*** *of* ***$21.49*** *in the Company's August 1997 commodity interest accrual.*

Discussion:

The Company failed to include the margin loss for the month of August 1997 in its computation of the commodity interest accrual for the month.

Company Response:

The Company will adjust the ACA schedule and its general ledger accordingly.

FINDING #16:

Exception:

The Staff calculated an ***under-recovery*** *of* ***$49.66*** *in the August 1997 commodity cost of gas.*

Discussion:

The Company used September 1997 rates to compute the commodity cost of gas which was used by the Company during the month of August 1997.

Company Response:

The Company will adjust the commodity cost of gas on the ACA schedule and its general ledger accordingly.

FINDING #17:

Exception:

*The Staff calculated an **over-recovery** of **$9.64** in the August 1997 demand cost of gas.*

Discussion:

The Company used September 1997 rates to compute the demand cost of the gas which was used by the Company during the month of August 1997.

Company Response:

The Company will adjust the demand cost of gas on the ACA schedule and its general ledger accordingly.

FINDING #18:

Exception:

*The Staff calculated an **under-recovery** of **$24,345.48** in the commodity recoveries.*

Discussion:

The Company applied September 1997 rates to August 1997 volumes to compute the total actual billings for August.

Company Response:

The Company will adjust the total actual commodity billings on the ACA schedule and its general ledger accordingly.

FINDING #19:

Exception:

*The Staff calculated an **under-recovery** of **$1,280.55** in margin loss August 1997.*

Discussion:

In response to the Staff's request for copies of the customer invoices to substantiate the margin loss incurred in August 1997, the Company revised its schedule entitled "Calculation of Loss in Gross Profit from Sales using Special Service Rate Schedule SS-1." The Company's revised schedule reduced the margin loss allowed to be recovered by the Company from $5,990.52 to $5,449.06. Upon the Staff's review of the revised schedule it was noted that the Company failed to include the margin loss incurred from the sale to a customer in the total margin loss. This adjustment increased the margin loss allowed to be recovered by the Company to $7,271.07.

Company Response:

The Company will adjust the ACA schedule and its general ledger accordingly.

FINDING #20:

Exception:

*The Staff calculated an **over-recovery** of **$2,944.00** in the August 1997 demand recoveries.*

Discussion:

The Company applied September 1997 rates to August 1997 volumes to compute the total actual demand billings for August.

Company Response:

The Company will adjust the total actual demand billings on the ACA schedule and its general ledger accordingly.

FINDING #21:

Exception:

The Staff calculated an ***under-recovery*** *of* ***$95.64*** *in the Company's September 1997 commodity interest accrual.*

Discussion:

The Company failed to include the margin loss for the month of September 1997 in its computation of the commodity interest accrual for the month.

Company Response:

The Company will adjust the ACA schedule and its general ledger accordingly.

FINDING #22:

Exception:

The Staff calculated an ***over-recovery*** *of* ***$9,077.24*** *in margin loss for the month of September 1997.*

Discussion:

In response to the Staff's request for copies of the customer invoices to substantiate the margin loss incurred in September 1997, the Company revised its schedule entitled "Calculation of Loss in Gross Profit from Sales using Special Service Rate Schedule SS-1." The revised schedule reduced the monthly margin loss allowed to be recovered by the Company from $27,197.33 to $18,221.84. Upon Staff's review of the revised schedule, it was noted that the Company had used August rates to compute the September margin loss on the sale to Rock Tenn Co. which further reduced the allowed margin loss for September by $101.75. Therefore, the correct allowed margin loss for September 1997 is $18,120.09.

Company Response:

The Company will adjust the ACA schedule and its general ledger accordingly.

FINDING #23:

Exception:

The Staff calculated an ***over-recovery*** *of* ***$2,061.00*** *in the September 1997 commodity cost of gas.*

Discussion:

The Company included incorrect amounts in the total cost of gas paid to other suppliers for the month of September 1997. Invoices from three suppliers were posted incorrectly.

Company Response:

The Company will adjust the total cost of gas paid to Other Suppliers on the ACA schedule and its general ledger accordingly.

FINDING #24:

Exception:

The Staff calculated an ***under-recovery*** *of* ***$73.96*** *in the Company's October 1997 commodity interest accrual.*

Discussion:

The Company failed to include the margin loss for October 1997 in its computation of the commodity interest accrual for the month.

Company Response:

The Company will adjust the ACA schedule and its general ledger accordingly.

FINDING #25:

Exception:

*The Staff calculated an **over-recovery** of **$677,984.00** in the October 1997 commodity recoveries.*

Discussion:

The Company posted demand recoveries of $489,660 as both the commodity and demand recoveries for October's unbilled volumes. The correct commodity amount for October's unbilled volumes is $1,167,644.

Company Response:

The Company will adjust the commodity recoveries on the ACA schedule and its general ledger accordingly.

FINDING #26:

Exception:

*The Staff calculated an **under-recovery** of **$5,441.14** in the October 1997 commodity cost of gas.*

Discussion:

The Company erroneously included a cashout amount of $206.36 and excluded the cancellation of a cashout in the amount of $5,647.50 when computing total cost of gas purchased from other suppliers during the month of October 1997.

Company Response:

The Company will adjust the total cost of gas purchased from Other Suppliers on the ACA schedule and its general ledger accordingly.

FINDING #27:

Exception:

*The Staff calculated an **over-recovery** of **$33,952.82** in the October 1997 commodity cost of gas.*

Discussion:

The total paid for October 1997 to Southern Natural Gas was overstated $33,952.82. This was due to the failure to include a cashout injection credit of $42,551.80, the inclusion in error of a prior month imbalance adjustment of $689.52, and the incorrect posting of a cashout adjustment in the amount of $4,644.23.

Company Response:

The Company will adjust the commodity cost of gas on the ACA schedule and its general ledger accordingly.

FINDING #28:

Exception:

*The Staff calculated an **over-recovery** of **$12,629.22** in the October 1997 margin loss.*

Discussion:

In response to the Staff's request for copies of the customer invoices to substantiate the margin loss incurred in October 1997, the Company revised its schedule entitled "Calculation of Loss in Gross Profit from Sales using Special Service Rate Schedule SS-1." This revised schedule reduced the October 1997 margin loss allowed to be recovered by the Company by $11,393.33. Upon the Staff's review of the revised schedule it was noted that incorrect volumes had been utilized in the computation of the margin loss. This further reduced the October 1997 margin loss allowed to be recovered by the Company by $1,235.89.

Company Response:

The Company will adjust the ACA schedule and its general ledger accordingly.

FINDING #29:

Exception:

The Staff calculated an ***under-recovery*** *of* ***$111,140.00*** *in the November 1997 demand recoveries.*

Discussion:

The Company incorrectly calculated the adjustment necessary to correct the rates the Company initially used in computing the actual demand billings for November 1997.

Company Response:

The Company made an adjustment for $111,140.00 in November 1997. The details of this correction are provided in response to Question #36 of the 12/31/98 data requests.

Staff Rebuttal:

The confusion surrounding this finding is due to the Company having prepared more than one "Actual MCF Billed" schedule for November 1997 and not providing the Authority with the schedule which was used by the Company in preparing the ACA filing. The schedule provided the Authority did not include the $111,140 in the "Actual MCF Billed" amount; therefore, the Staff determined a finding was necessary. The Company has now provided a copy of the "Actual MCF Billed" schedule which was used by the Company in preparing the ACA filing. Upon review of this schedule, the Staff agrees that the Company made an adjustment to correct this error in November 1997. Therefore, the dollar amount of this finding has been deleted from the total of the audit findings.

This finding, and the Company's Response and the Staff's Rebuttal thereto, illustrates the necessity for the Company to ensure that the schedules provided with the ACA filing are, in fact, the schedules which were used in preparing the ACA filing. The Company was made aware of the problems associated with incorrect schedules being provided during the audit of the ACA for the year ended June 30, 1997, as evidenced by the discussion included with Finding #1 of that audit report.

FINDING #30:

Exception:

The Staff calculated an ***under-recovery*** *of* ***$8.35*** *in the November 1997 demand cost of gas.*

Discussion:

The Company used December 1997 rates to compute the demand cost of gas used by the Company in November 1997.

Company Response:

The Company will adjust the demand cost of gas used on the ACA schedule and its general ledger accordingly.

FINDING #31:

Exception:

The Staff calculated an ***under-recovery*** *of* ***$214.16*** *in the November 1997 commodity cost of gas.*

Discussion:

The Company used December 1997 rates to compute the commodity cost of gas used by the Company in November 1997.

Company Response:

The Company will adjust the commodity cost of gas used on the ACA schedule and its general ledger accordingly.

FINDING #32:

Exception:

*The Staff calculated an **under-recovery** of **$153,274.00** in the commodity recoveries for November 1997.*

Discussion:

The Company used December 1997 rates to compute the November 1997 current month unbilled commodity recoveries.

Company Response:

The Company will adjust the unbilled commodity recoveries on the ACA schedule and its general ledger accordingly.

FINDING #33:

Exception:

*The Staff calculated an **over-recovery** of **$4,783.00** in the demand recoveries for November 1997.*

Discussion:

The Company used December 1997 rates to compute the November 1997 current month unbilled demand recoveries.

Company Response:

The Company will adjust the unbilled demand recoveries on the ACA schedule and its general ledger accordingly.

FINDING #34:

Exception:

*The Staff calculated an **under-recovery** of **$677,984.00** in the November 1997 commodity recoveries.*

Discussion:

As cited in Finding #25, the Company recorded the demand amount for the current month as the unbilled commodity recoveries. Since the actual billings recorded each month include the prior month unbilled recoveries, the Company must reverse the prior month unbilled amount to prevent the overstatement of recoveries. Therefore, due to the correction of the October error in unbilled recoveries, the November reversal also needs to be corrected.

Company Response:

The Company will adjust the unbilled commodity recoveries on the ACA schedule and its general ledger accordingly.

FINDING #35:

Exception:

*The Staff calculated an **under-recovery** of **$10,000.00** in the November 1997 commodity cost of gas.*

Discussion:

The total cost of gas purchased from other suppliers during November 1997 was understated by $10,000.00.

Company Response:

The Company will adjust the commodity cost of gas on the ACA schedule and its general ledger accordingly.

FINDING #36:

Exception:

*The Staff calculated an **over-recovery** of **$17,393.25** in the margin loss for November 1997.*

Discussion:

In response to the Staff's request for copies of the customer invoices to substantiate the margin loss incurred in November 1997, the Company revised its schedule entitled "Calculation of Loss in Gross Profit from Sales using Special Service Rate Schedule SS-1." The revised schedule reduced the margin loss allowed to be recovered by the Company $14,735.06. Upon review of the revised schedule, it was noted that incorrect volumes had been used which, when corrected, further reduced the recoverable margin loss by an additional $2,658.19.

Company Response:

The Company will adjust the ACA schedule and its general ledger accordingly.

FINDING #37:

Exception:

*The Staff calculated an **under-recovery** of **$7,999.74** in the December 1997 commodity cost of gas.*

Discussion:

The Company understated the amounts paid to three suppliers when calculating the total December 1997 cost of gas purchased from other suppliers.

Company Response:

The Company will adjust the cost of gas purchased from other suppliers on the ACA schedule and its general ledger accordingly.

FINDING #38:

Exception:

The Staff calculated an ***over-recovery*** *of* ***$12,377.14*** *in the December 1997 commodity cost of gas.*

Discussion:

In response to the Staff's request for copies of the customer invoices to substantiate the margin loss incurred in December 1997, the Company revised its schedule entitled "Calculation of Loss in Gross Profit from Sales using Special Service Rate Schedule SS-1." The revision reduced the margin loss allowed to be recovered by the Company by $3,624.65. Upon review of the revised schedule by the Staff, it was noted that due to incorrect volumes being utilized in the calculation, the recoverable margin loss should be further reduced by $8,752.49.

Company Response:

The Company will adjust the ACA schedule and its general ledger accordingly.

FINDING #39:

Exception:

The Staff calculated an ***over-recovery*** *of* ***$153,274.00*** *in the December 1997 commodity recoveries.*

Discussion:

As cited in Finding #32, the Company used December 1997 rates to compute the November 1997 current month unbilled commodity recoveries. As the actual billings recorded each month include the prior month unbilled recoveries, it is necessary that the prior month unbilled recoveries be reversed each month to prevent overstating the monthly recoveries. Therefore, since the November unbilled commodity recoveries were recorded incorrectly by the Company, the reversal in the subsequent month must also be corrected.

Company Response:

The Company will adjust the unbilled commodity recoveries on the ACA schedule and its general ledger accordingly.

FINDING #40:

Exception:

The Staff calculated an ***under-recovery*** *of* ***$4,783.00*** *in the December 1997 demand recoveries.*

Discussion:

As cited in Finding #33, the Company used December 1997 rates to compute the November 1997 current month unbilled demand recoveries. As the actual billings recorded each month include the prior month unbilled recoveries, it is necessary that the prior month unbilled recoveries be reversed each month to prevent the overstatement of the monthly recoveries. Therefore, since the November unbilled demand recoveries were recorded incorrectly by the Company, the reversal in the subsequent month must also be corrected.

Company Response:

The Company will adjust the demand recoveries on the ACA schedule and its general ledger accordingly.

FINDING #41:

Exception:

The Staff calculated an ***over-recovery*** *of* ***$16,463.15*** *in the margin loss for January 1998.*

Discussion:

In response to the Staff's request for copies of the customer invoices to substantiate the margin loss incurred in January 1998, the Company revised its schedule entitled "Calculation of Loss in Gross Profit from Sales using Special Service Rate Schedule SS-1." Based on the revised schedule, the total margin loss allowed to be recovered by the Company is $7,488.26 rather than the $23,951.41 which was included in the Company's ACA filing.

Company Response:

The Company will adjust the ACA schedule and its general ledger accordingly.

FINDING #42:

Exception:

*The Staff calculated an **over-recovery** of **$749,766.00** in the February 1998 commodity recoveries.*

Discussion:

The Company used March 1998 rates to calculate the unbilled commodity recoveries for February 1998.

Company Response:

The Company will adjust the unbilled commodity recoveries on the ACA schedule and its general ledger accordingly.

FINDING #43:

Exception:

*The Staff calculated an **over-recovery** of **$45,616.00** in the February 1998 demand recoveries.*

Discussion:

The Company used March 1998 rates to calculate the unbilled demand recoveries for February 1998.

Company Response:

The Company will adjust the unbilled demand recoveries on the ACA schedule and its general ledger accordingly.

FINDING #44:

Exception:

*The Staff calculated an **over-recovery of $6,856.04** in the February 1998 commodity cost of gas.*

Discussion:

The total cost of gas paid to other suppliers in February 1998 was overstated due to incorrect invoice amounts being recorded by the Company.

Company Response:

The Company will adjust the total cost of gas paid to other suppliers on the ACA schedule and its general ledger accordingly.

FINDING #45:

Exception:

*The Staff calculated an **under-recovery of $749,766.00** in the March 1998 commodity recoveries.*

Discussion:

As cited in Finding #42, the Company incorrectly used March 1998 rates to calculate the unbilled commodity recoveries for February 1998. As the prior month unbilled recoveries are included in the current month's actual billings, it is necessary for the Company to reverse the prior month's unbilled accrual to avoid overstating total recoveries. Therefore, since the prior month unbilled was recorded incorrectly by the Company, the subsequent reversal must also be corrected.

Company Response:

The Company will adjust the commodity recoveries on the ACA schedule and its general ledger accordingly.

FINDING #46:

Exception:

*The Staff calculated an **over-recovery** of **$642,187.00** in the March 1998 demand recoveries.*

Discussion:

Each month it is necessary for the Company to reverse the prior month unbilled demand recoveries since the actual billings for the month include the prior month unbilled recoveries. The amount reversed by the Company in March 1998 for the February 1998 unbilled demand recoveries was incorrect.

Company Response:

The Company will adjust the demand recoveries on the ACA schedule and its general ledger accordingly.

FINDING #47:

Exception:

*The Staff calculated an **under-recovery** of **$11,389.75** in the March 1998 commodity cost of gas.*

Discussion:

The total recorded by the Company as the amount paid to other suppliers for gas purchased in March 1998 was understated by $11,389.75 due to two invoices being excluded and one invoice being recorded incorrectly.

Company Response:

The Company will adjust the total cost of gas paid to other suppliers on the ACA schedule and its general ledger accordingly.

FINDING #48:

Exception:

*The Staff calculated an **under-recovery of $336,286.16** in the April 1998 commodity cost of gas.*

Discussion:

The Company reduced the storage withdrawals for April 1998 for a prior month imbalance adjustment when the adjustment should have been added to the total storage withdrawals.

Company Response:

The Company will adjust the commodity cost of gas on the ACA schedule and its general ledger accordingly.

FINDING #49:

Exception:

*The Staff calculated an **over-recovery of $10,997.98** in margin loss for April 1998.*

Discussion:

In response to the Staff's request for copies of the customer invoices to substantiate the margin loss incurred in April 1998, the Company revised its schedule entitled "Calculation of Loss in Gross Profit from Sales using Special Service Rate Schedule SS-1." The revised schedule reduced the margin loss allowed to be recovered by the Company from $19,248.12 to $9,299.61. Based on the Staff's review of the revised schedule, however, it was noted that the Company used an incorrect negotiated rate for 23,321.5 MCF. This error further reduced the total margin loss allowed to be recovered by the Company by $1,049.47 to $8,250.14.

Company Response:

The Company will adjust the ACA schedule and its general ledger accordingly.

FINDING #50:

Exception:

The Staff calculated an ***under-recovery*** *of* ***$1,692.91*** *in the margin loss for May 1998.*

Discussion:

Incorrect negotiated rates were applied by the Company in its computation of the May 1998 margin loss.

Company Response:

The Company will adjust the ACA schedule and its general ledger accordingly.

FINDING #51:

Exception:

The Staff calculated an ***over-recovery*** *of* ***$56,534.24*** *in the May 1998 commodity cost of gas.*

Discussion:

At the conclusion of the ACA audit for the year ended June 30, 1997, the Company was instructed to record six adjustments in the current audit period to the commodity portion of the ACA. The net effect of the six adjustments was a credit of $39,904.45. The Company posted eleven adjustments which netted to a debit of $16,629.79, thereby overstating the commodity portion of the ACA by $56,534.24.

Company Response:

The Company will adjust the commodity cost of gas on the ACA schedule and its general ledger accordingly.

FINDING #52:

Exception:

The Staff calculated an ***under-recovery*** *of* ***$5,576.69*** *in the May 1998 demand cost of gas.*

Discussion:

At the conclusion of the ACA audit for the year ended June 30, 1997, the Company was instructed to record two adjustments in the current audit period to the demand portion of the ACA. The net effect of the two adjustments was a credit of $586.54. The Company posted six adjustments which netted to a credit of $6,163.23, thereby understating the demand portion of the ACA by $5,576.69.

Company Response:

The Company will adjust the demand cost of gas on the ACA schedule and its general ledger accordingly.

FINDING #53:

Exception:

The Staff calculated an ***under-recovery*** *of* ***$36,221.89*** *in the June 1998 commodity cost of gas.*

Discussion:

At the conclusion of the prior ACA audit for the year ended June 30, 1997, the Company was instructed to record certain adjustments to the Company's general ledger in order to reconcile the general ledger with the ACA audit. Two of these adjustments were posted by the Company to the ACA in error.

Company Response:

The Company will adjust the ACA.

FINDING #54:

Exception:

*The Staff calculated an **over-recovery** of **$103,076.22** in the commodity interest accrual.*

Discussion:

As a result of the above findings related to the commodity portion of the ACA, the commodity interest accrual has been overstated by $103,076.22.

Company Response:

The Company will adjust the commodity interest accrual on the ACA schedule and its general ledger accordingly.

FINDING #55:

Exception:

*The Staff calculated an **over-recovery** of **$17,768.76** in the demand interest accrual.*

Discussion:

As a result of the above findings related to the demand portion of the ACA, the demand interest accrual has been overstated by $17,768.76.

Company Response:

The Company will adjust the demand interest accrual on the ACA schedule and its general ledger accordingly.

APPENDIX A

PGA FORMULA

The computation of the GCA can be broken down into the following formulas:

$$\text{Firm GCA} = \frac{D + DACA}{SF} - DB + \frac{P + T + SR + CACA}{ST} - CB$$

$$\text{Non-Firm GCA} = \frac{P + T + SR \;\; CACA}{ST} - CB$$

where

GCA	=	The Gas Charge Adjustment in dollars per Ccf/Therm, rounded to no more than five decimal places.
D	=	The sum of all fixed Gas Costs.
DACA	=	The demand portion of the ACA.
P	=	The sum of all commodity/gas charges.
T	=	The sum of all transportation charges.
SR	=	The sum of all FERC approved surcharges.
CACA	=	The commodity portion of the ACA.
DB	=	The per unit rate of demand costs or other fixed charges included in base rates in the most recently completed general rate case (which may be zero if the Company so elects and the Commission so approves).
CB	=	The per unit rate of variable gas costs included in base rates in the most recently completed general rate case (which may be zero if the Company so elects and the Commission so approves).
SF	=	Firm Sales.
ST	=	Total Sales.

The computation of the RA can be computed using the following formulas:

$$\text{Firm RA} = \frac{DR1 - DR2}{SFR} + \frac{CR1 - CR2 + CR3 + i}{STR}$$

$$\text{Non-Firm RA} = \frac{CR1 - CR2 + CR3 + i}{STR}$$

where

RA =	The Refund Adjustment in dollars per Ccf/Therm, rounded to no more than five decimal places.
DR1 =	Demand refund not included in a currently effective Refund Adjustment, and received from suppliers by check, wire transfer, or credit memo.
DR2 =	A demand surcharge from a supplier not includable in the GCA, and not included in a currently effective Refund Adjustment.
CR1 =	Commodity refund not included in a currently effective Refund Adjustment, and received from suppliers by check, wire transfer, or credit memo.
CR2 =	A commodity surcharge from a supplier not includable in the GCA, and not included in a currently effective Refund Adjustment.
CR3 =	The residual balance of an expired Refund Adjustment.

i = Interest on the "Refund Due Customers" account, using the average monthly balances based on the beginning and ending monthly balances. The interest rates for each calendar quarter used to compute such interest shall be the arithmetic mean (to the nearest one-hundredth of one percent) of the prime rate value published in the "Federal Reserve Bulletin" or in the Federal Reserve's "Selected Interest Rates" for the 4th, 3rd, and 2nd months preceding the 1st month of the calendar quarter.

SFR = Firm sales as defined in the GCA computation, less sales under a transportation or negotiated rate schedule.

STR = Total sales as defined in the GCA computation, less sales under a transportation or negotiated rate schedule.

Report on the Gas Purchasing Activities of Chattanooga Gas Company for the Combined Periods:

July 1, 1997 to June 30, 1998

For the Tennessee Regulatory Authority

October 1, 1998

Attachment 1

REPORT ON THE GAS PURCHASING ACTIVITIES
OF CHATTANOOGA GAS COMPANY

Table of Contents

CHAPTER I

Introduction

The Purchased Gas Adjustment rider adopted by the Tennessee Public Service Commission (predecessor to the Tennessee Regulatory Authority) requires an independent review of the prudence of the investor-owned local gas distribution companies (LDCs) that operate in Tennessee and purchase gas during the period of the rider's operation. Such a review is intended to facilitate the regulator's ability to determine that the rate and price flexibility granted by the rider to the LDCs is accompanied by prudent purchasing practices.

The following background briefly describes the sequence of events leading to this report.

A. BACKGROUND

In April 1990, the Tennessee Public Service Commission approved an experimental rider to its Purchased Gas Adjustment (PGA) rule (1220-4-1-.12) for local distribution companies in the state (order dated April 11, 1990, in Docket No. G-86-1). This rule allowed the LDCs certain flexibility with regard to price adjustments to customer charges based upon the costs of purchased gas to the utility. The rider mitigated the need for frequent rate hearings, as prudently incurred gas costs could be factored into rates within a month of the new cost to the utility. The Commission ordered the companies to hire a consultant to oversee the implementation of the rider to ensure that this flexibility was accompanied by prudent purchasing practices. A consultant was contracted to conduct the study over the ensuing two years, and a final report was issued on the purchases made by the three LDCs during the time the rider was experimental (July 1, 1990 to June 30, 1992).

The rider now in effect contains a provision requiring an independent audit of the prudence of the LDCs' gas purchases (see PGA rider p. 12 section [5][a]). At the end of the year in which the new rule had been put into effect, the Commission sought a consultant to perform an audit for the two-year period July 1, 1993 to June 30, 1995. TB&A was selected for the work. At the conclusion of that contract, TB&A was awarded a new contract to perform such an audit of Chattanooga Gas Company and Nashville Gas Company for the two-year period July 1, 1995 to June 30, 1997. On October 31, 1996, TB&A submitted the first annual review of the new contract period. Since Piedmont Natural Gas has switched Nashville Gas Company to an incentive based rate system, this review will serve as an interim report for only AGL Energy Services on behalf of Chattanooga Gas Company.

Planning and managing gas supply is one of the most critical LDC enterprise activities, influencing as it does both the cost and the reliability of service. Since the adoption of FERC Order 636 with the greater complexity of the natural gas markets, many more gas supply opportunities and choices have become available to LDC management. The challenge for

LDCs has been to transform their organizations, their gas purchase practices, and their transportation and storage arrangements in order to take maximum advantage of the new opportunities while protecting their customers from the volatility and unpredictability of the new market.

The scope of this review is limited to the evaluation of the prudence of any gas costs as identified in the Purchased Gas Adjustment rider, section 2, or as defined as *gas costs* and *fixed gas costs* in section 1, parts a and c, for the period July 1, 1997 through June 30, 1998. This review is to determine if purchases and decisions made during this period were prudent and reasonable under the circumstances that existed at the time of the decision. This review, however, *does not* constitute a comprehensive or operational audit.

On April 8, 1998, TB&A provided a report to the Commission covering the gas purchasing activities of AGL Energy Services on behalf of Chattanooga Gas Company during the non-heating season quarter July 1, 1997 through September 30, 1997, and the partial heating season quarter October 1, 1997 through December 31, 1997. The current report covers the entire twelve-month period July 1, 1997 through June 30, 1998.

B. DATA SOURCES

AGL Energy Services on behalf of its affiliate Chattanooga Gas Company has provided data used in this review. In addition to the data presented for the initial data request, supplemental data tables have also been provided by AGL in an effort to refine the cost calculations. For data pertaining to the East Tennessee Gas Pipeline, cost data supplied has Tennessee Gas Pipeline costs embedded in the per city gate volume cost data.

C. METHODOLOGY

The following discussion is provided to clarify the methodology of calculating the costs presented in **Exhibits 1** and **2** for Chattanooga. These tables provide information that breaks down the total unit delivered cost of gas into its subcosts. In describing the methodology, the intent of each calculation will also be illustrated. Cost presented in these tables may be referred to by a line number. These numbers represent the same "buckets" of costs between the various pipelines covered in this review. Please refer to the above-mentioned exhibits for reference. The cost calculations contain three main elements: 1) costs associated with purchase of supply; 2) costs associated with transportation; and 3) costs associated with storage.

1) The costs associated with the purchase of gas supply are presented in four different ways. The first is the Commodity Cost of Supply (Term+Spot Purchases), (Line 1). This data point is intended to show how much Chattanooga is paying for gross volumes of gas supply. The cost figures include mid-month spot purchases as well as term purchases and is calculated by dividing the gross dollars expended on gas purchases by the gross volume.

2) The second version of gas supply costs is represented in Line 2 and is called Weighted Average Cost of Gas Supply (Term+Spot+Storage). This cost figure includes volumes withdrawn from storage and the commodity costs associated with the gas coming out of storage. It should be noted that the commodity cost of gas coming out of storage includes the purchase cost of the gas, the transportation costs to get the gas into storage, and injection costs. There are also accounting practices associated with keeping track of inventory (LIFO vs. FIFO, etc.) that affect the cost of gas withdrawn from storage. This cost measure is the primary point of comparison to the Inside FERC index and the NYMEX index because the storage effects help show the effectiveness of management in utilizing storage capabilities to economically manage supply in addition to meeting reliability needs.

3) The intent of the last two purchase cost measures is to build up to a delivered cost and show the impacts of two additional sources of significant expenditures. The third measure called Adjusted Weighted Average Cost of Gas (WACOG) in Line 5 adds in reservation fees to the cost calculation in Line 2.

4) Finally, Line 6 shows an Adjusted WACOG to include LNG withdrawals. For those pipelines with LNG storage available to Chattanooga, Line 6 shows the impact of LNG usage on purchase costs and sheds some light on the prudence of the usage of such facilities.

Lines 7-12 show the incremental impacts of costs associated with transportation and storage on the delivered cost of gas. For all of the pipelines reviewed, the fuel costs and the surcharges are embedded in the city gate volumes and the firm transportation costs respectively. Accrued accounting adjustments have been omitted from the calculation because they: 1) adjust for events outside of the review period; and 2) do not represent significant impacts on the unit cost figures. The sum of the LNG adjusted WACOG and the groups of storage and transportation costs yield the Delivered Cost of Gas (Line 11). The expenses for Lines 7-12 are normalized by the city gate volume (Line 12).

City gate volumes were supplied by AGL Energy Services. The city gate volume figure is intended to more accurately show the costs associated with moving gas through the system. Unit costs can be diluted when transportation volumes are used to normalize costs because of the volumes that move in and out of storage; sometimes in the same month. In addition, variable costs to transport gas to storage were broken out of the monthly variable cost of transportation in order to prevent double counting of injection costs, transportation costs to storage facilities and the commodity costs which come out with the units of gas during withdrawal. For fixed reservation and demand fees there may be over reporting during injection months, but this effect will be offset by lower unit costs during withdrawal months. It should be also noted that the derived city gate volume does not equal the sales figures reported by industry segment for the utilities. This difference can at least partially be explained by transportation volumes/costs that are passed on to some industrial customers and sales to customers that do not fall into residential, commercial and industrial classifications. Other factors have not been explored as a part of this review.

The individual costs for the individual pipeline are averaged into a set of system unit costs of purchased gas, transportation, demand charges, and other costs associated with the delivery of gas supply. The costs are weighted by the city gate volumes for the individual pipelines. The sum of the individual costs build up to the system average cost of delivered gas to the city gate (Line 13).

For additional detail on the methodology of the analysis, **Appendix A** offers a summary report of the equations that were used in the calculations.

D. REPORT ORGANIZATION

This report is organized into three major chapters:

• Chapter I	Introduction (this chapter)
• Chapter II	Findings and Conclusions
• Appendix A	Gas Cost Calculation Sheet
• Appendix B	Gas Supply Plan
• Appendix C	Organizational Chart

As before, the data request has been attached to the Findings and Conclusions section.

CHAPTER II

Findings and Conclusions

Based on our review and analysis of the information provided, Chattanooga Gas Company is continuing to be proactive and responsive to the ongoing changes in the natural gas supply and local gas distribution marketplace in a manner comparable to the actions of LDCs across the country. The gas supply management department at AGL Energy Services acting on behalf of Chattanooga Gas Company appears to be appropriately organized and staffed to assure that customers will continue to enjoy secure, reliable gas supplies at reasonable prices. Actual gas cost performance has been consistent or better than market indicators. Those months where performance has been poorer than market, AGL Energy Services has offered an explanation that will be discussed later.

Exhibits 1 through **2** provide summary breakdowns of the cost of gas for Chattanooga Gas Company. For the purposes of this report, we are examining and comparing the total cost of gas, including the cost of gas used for injection and for system use. Gas costs are calculated a number of different ways. Basically, the relationship between gas purchases and gas delivered to the city gate is as follows:

Purchases - Injection + Withdrawal = Gas Delivered (System Burn)

Some adjustments do need to be made for fuel consumption. Furthermore, we are attempting to capture the costs associated with storage withdrawals. This method, therefore, reflects the costs of injection and withdrawal in the month incurred.

Further conclusions and data specific to Chattanooga Gas Company follows this section. Based on analysis of the following:

- Supply Plan completeness
- Reserve Requirements
- Gas Cost Data
- Changes to Supply Plan and portfolio
- Organizational and Process Changes
- Description and status of improvement projects

Our assessment of AGL Energy Services acting of behalf of Chattanooga Gas Company is, for the purpose of this audit, that they were prudent, overall, in the areas of supply planning and procurement.

Finding: Based on only cost analysis, AGL Energy Services on behalf of Chattanooga Gas Company appears to have been prudent in its gas purchasing activities during the period July 1, 1997 –June 30, 1998, although significantly higher-than-index performance in February and March for Southern Natural Pipeline warrants an explanation.

- In February and March, AGL purchased gas on Southern at an average price above the Inside FERC Index of $0.33 per DTH and $0.38 per DTH respectively. AGL provides the following explanation for the events of February and March. Spot gas purchases for February and March reflect prices locked in on the futures markets for those months, in November, 1997. CGC purchased this gas on behalf of a bundled sales customer for delivery in the months of February and March on the Southern Natural Gas (SNG) system. The bundled sales customer had a corresponding commitment from the end use market for this gas and CGC recovered the cost and made a margin on the sale to the bundled sales customer. If the spot gas purchase volume and cost per unit related to the bundled sales transaction were backed out of the overall purchase price for the months of February and March for Southern, AGL would have purchased gas on the Southern pipeline at an average price of $2.02 (February) AND $2.23 (March) respectively. These prices are competitive with the FERC Index prices for the coinciding months. Thus the circumstances do not suggest any imprudence by AGL or Chattanooga.

- The impact of the use of storage was very pronounced in the month of November for East Tennessee. AGL outperformed Inside FERC by $0.22 per DTH on East Tennessee. For Southern, AGL utilized storage facilities in November and December by outperforming Inside FERC by $0.09 per DTH and $0.07 per DTH respectively. **Exhibits 9** and **10** isolate the incremental impact of storage use as both charts compare the average cost of term plus spot gas with the average cost of term, spot and stored gas. **Exhibits 7** and **8** along with **Exhibits 3 through 6** also highlight the impact of storage usage since **Exhibits 7** and **8** show the cost of term plus spot gas being higher than the Inside FERC index in February and March for Southern. East Tennessee remains virtually equal to that of the Inside FERC index. **Exhibits 4** and **6** show a cost advantage for AGL during November and December for Southern and November for East Tennessee when storage gas is factored into the analysis.

- The cost advantages earned by AGL appears to primarily come from the arbitrage value of storage usage rather than performance on the spot market. This supports the finding that AGL acted prudently in its activities as the use of storage offers added reliability to gas supply in addition to cost savings.

***Finding:** Chattanooga's Capacity Release program as such is inactive, but AGL is engaging in other activities which are functional alternatives to capacity brokering and which are designed to optimize utilization of its supply and transportation capacity resources.*

- There was not any capacity release activity for either pipe during the twelve month period.

- AGL Energy Services reports that it continues to have authorization to rebundle supply and capacity off of Southern for resale to other entities such as marketers. AGL resources on the Southern system have been supplemented with added use of supply and capacity off of East Tennessee to serve customers in Chattanooga. AGL reports that it can recall any sales to third parties off of Southern to serve Chattanooga customers if the occasion ever arises. Such rebundled sales activity took place during the months of December 1997 through June of 1998. Chattanooga has a 50/50 sharing mechanism for any additional revenues made from off system sales of bundled gas that is incremental to servicing the firm customers. Cost for getting gas into SONAT's storage facility is netted out of the revenues before the sharing mechanism takes effect. For the purposes of this study, the volumes of gas sold off-system on SONAT was treated as city gate volume so that the costs incurred would match the volumes associated with the costs. AGL Energy Services appears to be working creatively to optimize the value of its resources through the use of off-system sales rather than standard capacity brokering. Analysis of the performance of the off-system sales, in terms of how much was returned to the ratepayer, was not in the scope of this study.

***Finding:** AGL Energy Services has made addition/changes to its portfolio that are favorable to the ratepayer.*

- AGL acquired 5,567 DTH of additional firm capacity on Southern Natural Gas effective November 1, 1996. The reasoning for the addition is that Chattanooga has always been capacity-constrained. The send-out model indicated that Chattanooga could use all of the additional capacity and SONAT capacity was the only capacity available at the time. The additional capacity was acquired at the same rate as Chattanooga's other SONAT capacity.

- AGL renewed a long-term supply contract with Equitable Resources through October 31, 1998, for 4,899 DTH per day. The contract was extended through October 31, 1999 and month to month thereafter unless notified by purchaser 6 months prior to term of contract. Equitable was the only supplier for a particular leg of the NORA line. In comparing the cost of getting gas from the production site to the city gate through ETENN and TENN versus using gas from Equitable at the end of TENN, gas from Equitable turned out to be cheaper.

- AGL terminated a long-term supply contract with Tenneco Gas Marketing and replaced it with LG&E Gas Marketing effective November 1, 1996, for 6,532 DTH per day. LG&E had the lowest price and no reservation fee. LG&E would charge index plus a premium (which equates to a reservation fee if all of the gas is taken). If the gas is not taken, no reservation fee would apply. The contract expires when the capacity contract on TENN and ETENN expires. The LG&E supply contract term ends on October 31, 2000.

Finding: Since the last annual report, AGL has supplied a narrative and a design day requirements forecast which can be found in Appendix B.

- The narrative does an adequate job of describing the assumptions used to develop the requirements to meet the design day peak demand. It also outlines the objective of the supply plan and the tools used to execute the supply plan. AGL has made progress in the development of their supply plan. In future years they should consider formalizing some guidelines and procedures for executing the plan as well as a documented methodology and time frame for the development of the design day requirements forecast.

Finding: The organizational structure has not changed significantly since the last annual report.

- An organization chart found in Appendix C shows some of the minor changes in staffing.

Finding: AGL has been granted by the Georgia Commission the ability to lock in the forward price for 20% of supply through the use of hedges. AGL is interested in applying a similar plan with respect to Chattanooga, and the TRA may wish to investigate this possibility.

- The Georgia commission has set the threshold at $0.05 above carrying cost and has granted AGL the right but not obligation to lock in the forward price for gas within one fiscal year for 20% of the supply. This hedging plan allows the ratepayer to share in the benefit of smoothing out the peaks and valleys of the PGA. It also is a move in the direction of shifting the financial responsibility to those people who buy the gas. Currently, it can be argued, the firm commercial customers subsidize gas (during the summer) that residential customers use during the winter.

Further details of the performance of AGL Energy Services are illustrated in the following exhibits.

SUPPORTING DATA:
CHATTANOOGA GAS COMPANY

Exhibits

- Gas Purchasing Cost Comparisons
  - — East Tennessee Natural Gas
  - — Southern Natural Gas Pipeline
- Weighted Average Cost of Gas Supply (Term+Spot+Storage) for Chattanooga
  - — Purchases through East Tennessee Natural Gas
- Weighted Average Cost of Gas Supply (Term+Spot+Storage) Deviation from Index for Chattanooga
  - — Purchases through East Tennessee Natural Gas vs. Inside FERC Index
- Weighted Average Cost of Gas Supply (Term+Spot+Storage) for Chattanooga
  - — Purchases through Southern Natural
- Weighted Average Cost of Gas Supply (Term+Spot+Storage) Deviation from Index for Chattanooga
  - — Purchases through Southern Natural vs. Inside FERC Index
- Commodity Cost of Term and Spot Gas for Chattanooga
  - — Purchases through East Tennessee Natural Gas
  - — Purchases through Southern Natural
- Incremental Impact of Storage Usage on Weighted Average Cost of Gas
  - — Purchases through East Tennessee Natural Gas
  - — Purchases through Southern Natural
- Total Delivered Cost of Gas for Chattanooga
  - — System Average
  - — Purchases through East Tennessee Natural Gas
  - — Purchases through Southern Natural
- Customer Use Summary
- System Sales by Customer Segment
- Chattanooga Gas Company 1997-1998 Heating Season Peak Day Estimates
- Chattanooga Transportation Capacity
- Chattanooga Storage Capacity
- Chattanooga Storages at the end of the Heating Season (March 31)

Exhibit 1

CHATTANOOGA GAS COMPANY
1997-1998 COST OF GAS

Line	East Tennessee Gas Pipeline	Jul-97	Aug-97	Sep-97	Oct-97	Nov-97	Dec-97	Jan-98	Feb-98	Mar-98	Apr-98	May-98	Jun-98
1	Commodity Cost of Supply (Spot+Term)	$2.09	$2.12	$2.47	$3.02	$3.20	$2.43	$2.19	$1.94	$2.19	$2.24	$2.22	$1.97
2	Weighted Average Commodity Cost of Gas Supply (Term+Spot+Storage)*	$2.09	$2.12	$2.47	$3.03	$2.97	$2.40	$2.25	$1.97	$2.19	$2.25	$2.23	$1.97
3	NYMEX Index	$2.15	$2.16	$2.52	$3.35	$3.27	$2.58	$2.31	$2.00	$2.29	$2.30	$2.26	$2.02
4	Inside FERC Index**	$2.07	$2.11	$2.45	$3.01	$3.19	$2.41	$2.17	$1.93	$2.18	$2.23	$2.21	$1.96

* Includes weighted average cost of spot and term gas and accounts for gas flowing from storage at commodity cost by LIFO method.

** Index price is mean of the prices from zone 1 and zone 0.

5	Adjusted WACOG*	$2.14	$2.21	$2.57	$3.07	$3.01	$2.43	$2.28	$2.02	$2.23	$2.30	$2.27	$2.01
6	Adjusted WACOG to Include LNG W/D***	$2.14	$2.21	$2.57	$3.07	$3.01	$2.43	$2.28	$2.02	$2.23	$2.30	$2.27	$2.01

7	Variable Transportation Cost	0.05	0.07	0.08	0.06	0.07	0.07	$0.07	$0.06	$0.06	$0.05	$0.04	$0.04
8	Demand Charge for Transportation	$1.59	$2.53	$2.38	$1.04	$0.57	$0.51	$0.54	$0.71	$0.60	$0.95	$1.49	$1.73
9	Storage Inj./WD Cost	$0.00	$0.00	$0.00	$0.06	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.00
10	Storage Demand Charge	$0.27	$0.44	$0.41	$0.18	$0.09	$0.01	$0.09	$0.12	$0.11	$0.17	$0.27	$0.32

11	Delivered Cost of Gas	$4.05	$5.26	$5.43	$4.41	$3.75	$3.03	$2.98	$2.93	$3.01	$3.50	$4.16	$4.22
12	City Gate Gas Volume Delivered	406,821	249,394	265,683	608,286	1,104,292	1,236,187	1,179,627	846,507	931,478	598,615	380,627	327,450

*Line 2 Value along with the addition to the per unit Supply Reservation Fee

** Includes volumetric surcharges (ACA/GRI/TCRA/TRANSP.)

Intended to show the effect of LNG Use. Commodity costs may change due to increases in commodity costs due to accounting treatment and cost of injection into storage.

Exhibit 2

CHATTANOOGA GAS COMPANY
1997-1998 COST OF GAS

Line	Southern Natural Pipeline	Jul-97	Aug-97	Sep-97	Oct-97	Nov-97	Dec-97	Jan-98	Feb-98	Mar-98	Apr-98	May-98	Jun-98
1	Commodity Cost of Supply (Spot+Term)	$2.10	$2.14	$2.55	$3.09	$3.20	$2.45	$2.30	$2.35	$2.61	$2.28	$2.25	$2.01
2	Weighted Average Commodity Cost of Gas Supply (Term+Spot+Storage)*	$2.11	$2.14	$2.55	$3.09	$3.16	$2.45	$2.30	$2.32	$2.55	$2.33	$2.25	$2.01
3	NYMEX Index	$2.15	$2.16	$2.52	$3.35	$3.27	$2.58	$2.31	$2.00	$2.29	$2.30	$2.26	$2.02
4	Inside FERC Index**	$2.10	$2.14	$2.50	$3.05	$3.25	$2.52	$2.27	$2.02	$2.23	$2.28	$2.25	$2.01

* Includes weighted average cost of spot and term gas and accounts for gas flowing from storage at commodity cost by LIFO method.

5	Adjusted WACOG*	$2.11	$2.15	$2.56	$3.11	$3.16	$2.46	$2.31	$2.33	$2.55	$2.34	$2.26	$2.02
6	Adjusted WACOG to Include LNG W/D***	$2.11	$2.15	$2.56	$3.11	$3.16	$2.49	$2.32	$2.39	$2.57	$2.37	$2.31	$2.08

7	SONAT Variable Transportation Cost	$0.09	$0.09	$0.09	$0.10	$0.10	$0.10	$0.07	$0.03	$0.05	$0.02	$0.02	$0.02
8	SONAT Demand Charge for Transportation	$1.98	$1.94	$2.51	$1.14	$1.13	$0.78	$1.04	$0.77	$0.76	$0.63	$1.59	$1.63
9	Storage Inj./WD Cost	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
10	Storage Demand Charge	$0.27	$0.26	$0.34	$0.15	$0.15	$0.11	$0.14	$0.10	$0.10	$0.08	$0.21	$0.22

11	Delivered Cost of Gas	$4.46	$4.45	$5.50	$4.50	$4.55	$3.48	$3.57	$3.31	$3.49	$3.11	$4.14	$3.96
12	City Gate Gas Volume Delivered	157,991	161,149	125,110	274,376	277,913	399,517	301,239	406,191	410,605	495,873	196,898	191,909

*Line 2 Value along with the addition to the per unit Supply Reservation Fee

No LNG on Southern

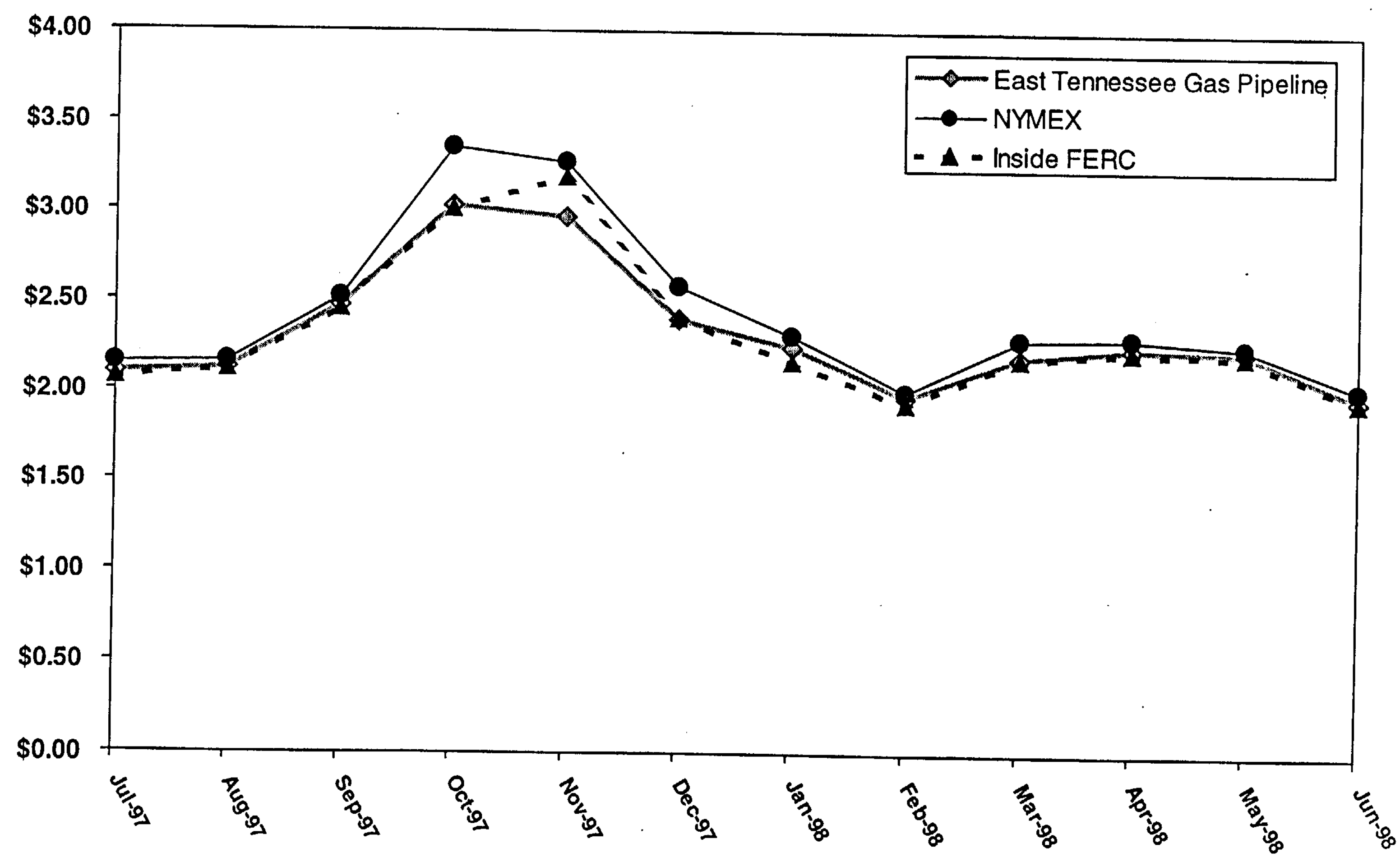
** Includes volumetric surcharges (ACA/GRI/TCRA/TRANSP.)

System Average Cost Analysis

		Jul-96	Aug-96	Sep-96	Oct-96	Nov-96	Dec-96	Jan-97	Feb-97	Mar-97	Apr-97	May-97	Jun-97
13	Average System Total Cost of Delivered Gas to the City Gate	$4.17	$4.94	$5.45	$4.44	$3.91	$3.14	$3.10	$3.05	$3.16	$3.32	$4.15	$4.12
	Average Commodity Cost of Gas Delivered	$2.13	$2.19	$2.56	$3.08	$3.04	$2.45	$2.29	$2.14	$2.33	$2.33	$2.29	$2.04
	Variable Transportation Cost	$0.06	$0.08	$0.08	$0.07	$0.08	$0.07	$0.07	$0.05	$0.06	$0.05	$0.08	$0.11
	Demand Charge	$1.70	$2.30	$2.42	$1.07	$0.68	$0.58	$0.64	$0.73	$0.65	$0.80	$1.52	$1.69
	Other Costs	$0.27	$0.37	$0.39	$0.21	$0.11	$0.04	$0.10	$0.13	$0.12	$0.14	$0.26	$0.28

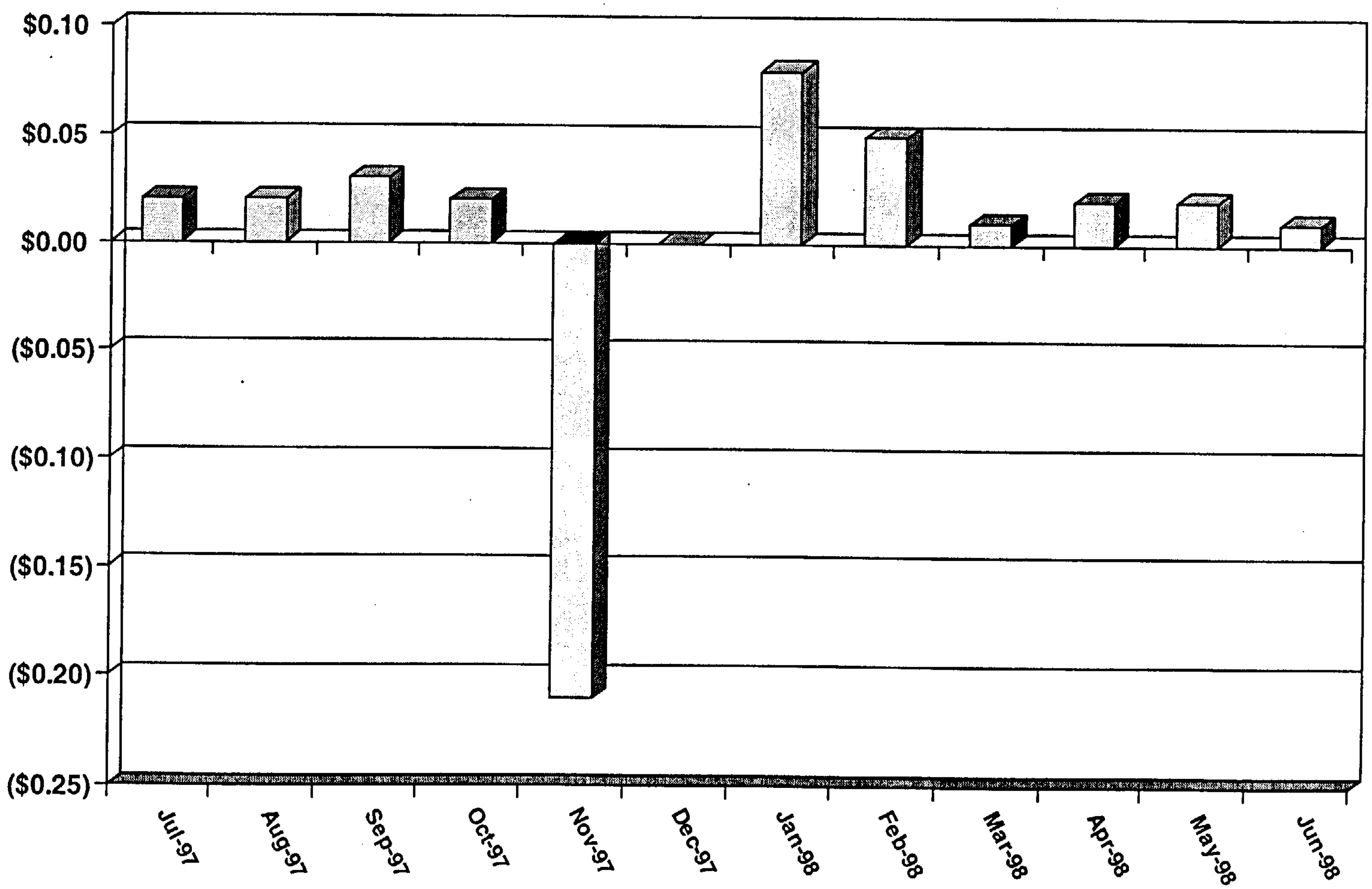
Weighted Average Cost of Gas Supply (Term+Spot+Storage) for Chattanooga

Purchases Through East Tennessee Natural Gas



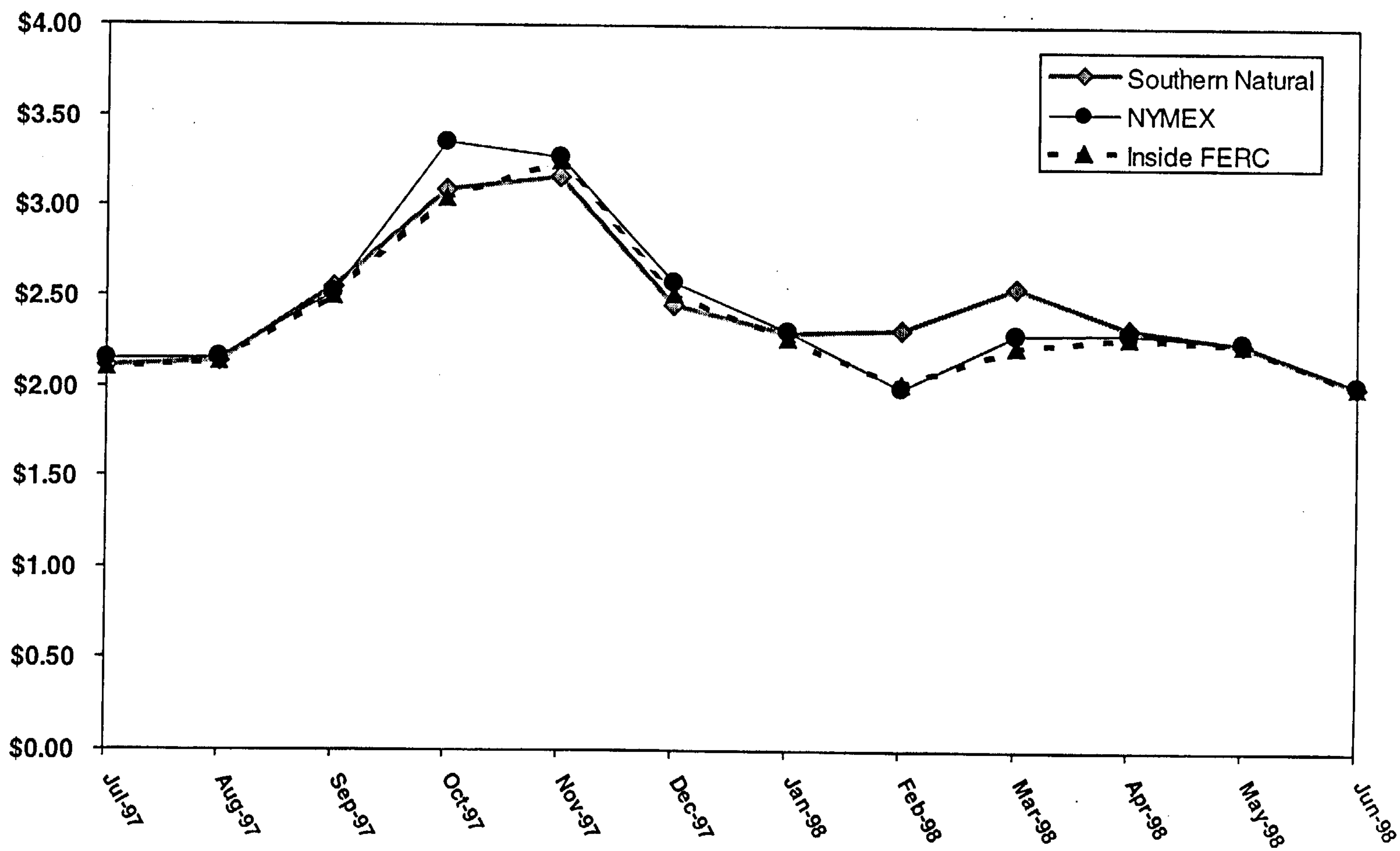
Weighted Average Cost of Gas Supply (Term+Spot+Storage) Deviation from Index for Chattanooga

Purchases Through East Tennessee Natural Gas vs. Inside FERC Index



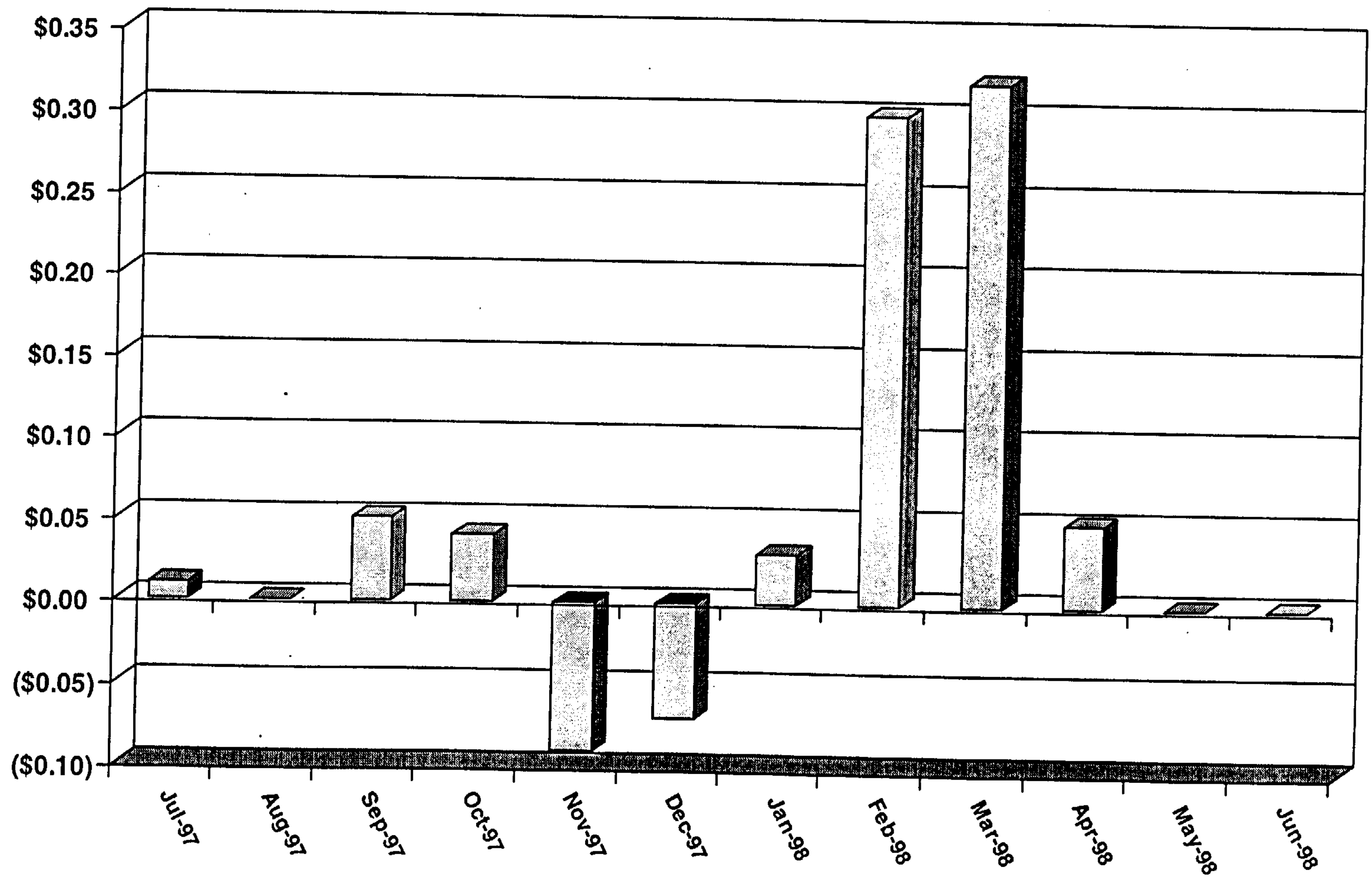
Weighted Average Cost of Gas Supply (Term+Spot+Storage) for Chattanooga

Purchases Through Southern Natural



Weighted Average Cost of Gas Supply (Term+Spot+Storage) Deviation from Index for Chattanooga

Purchases Through Southern Natural vs. Inside FERC Index



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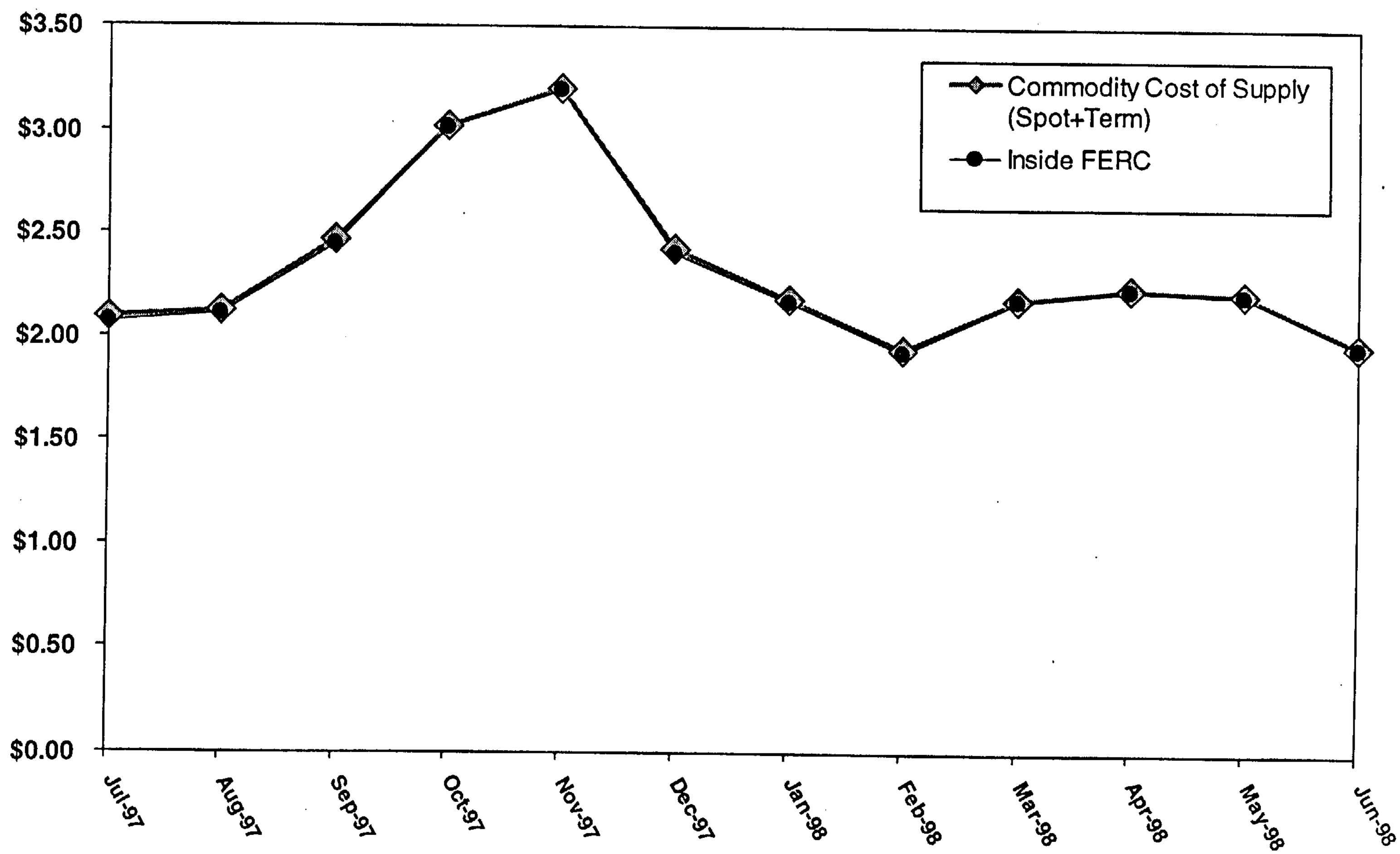
Commodity Cost of Term and Spot Gas for Chattanooga

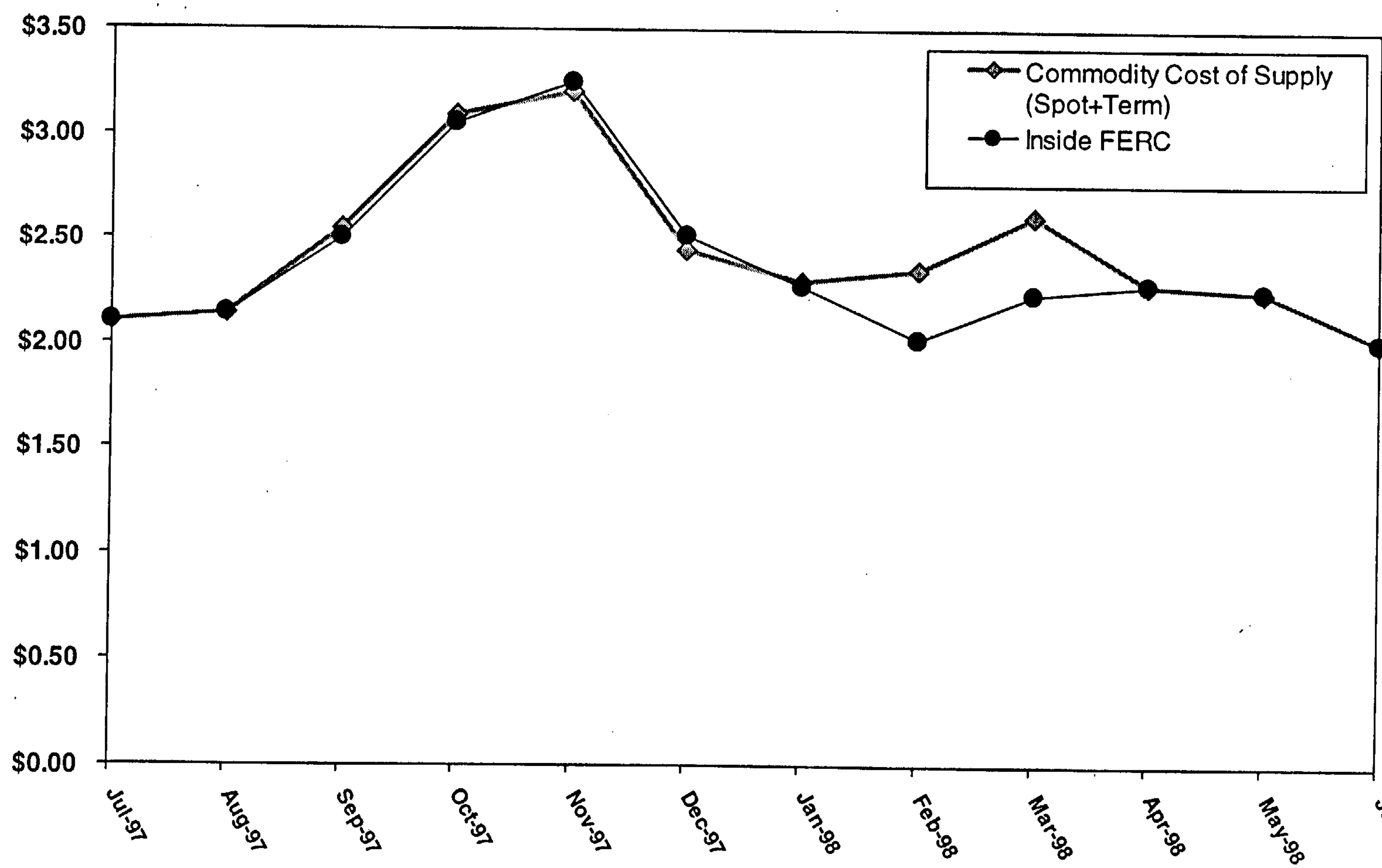
Purchases Through East Tennessee Natural Gas



TB&A Consultants to Management

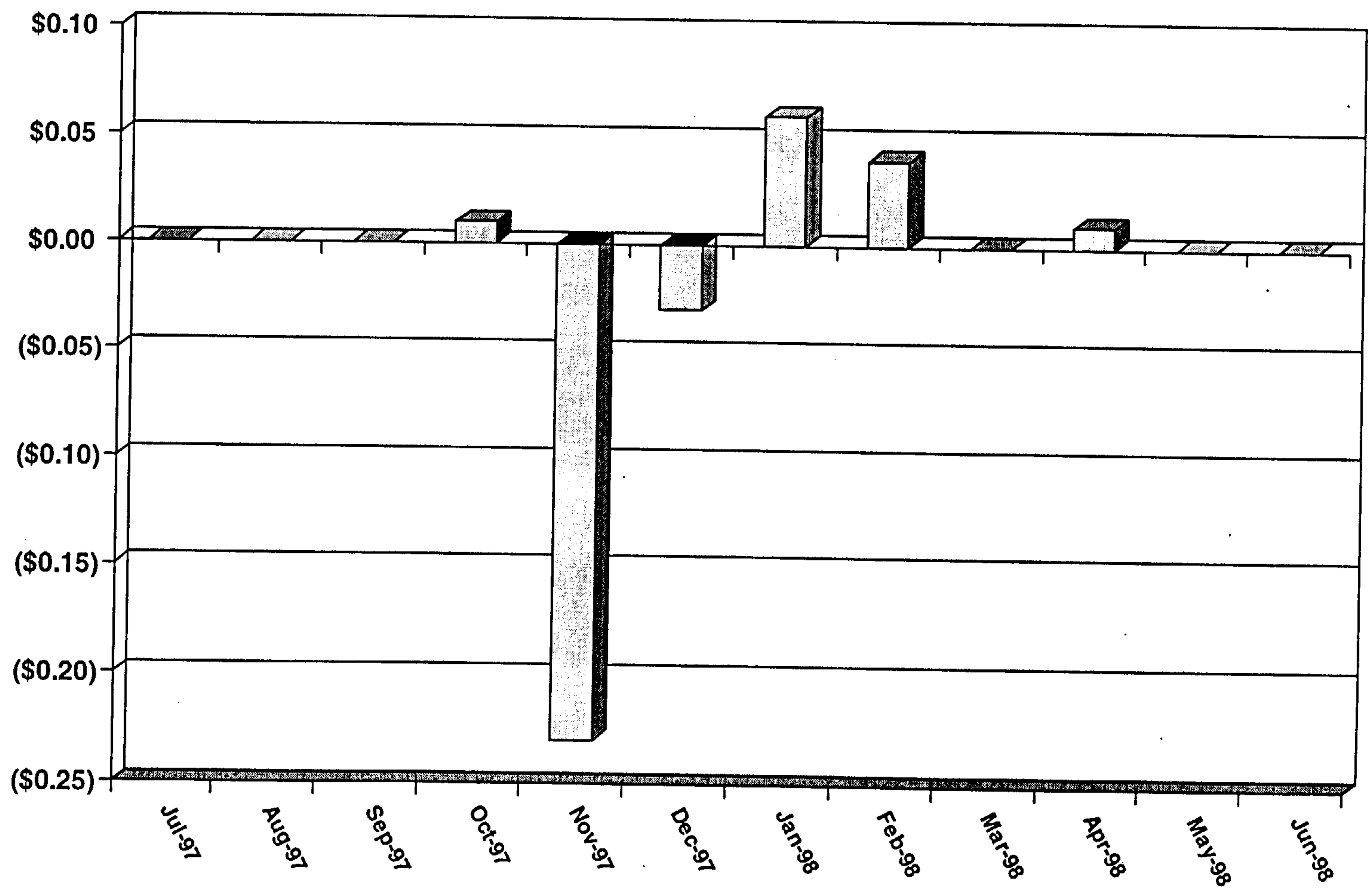
Commodity Cost of Term and Spot Gas for Chattanooga

Purchases Through Southern Natural



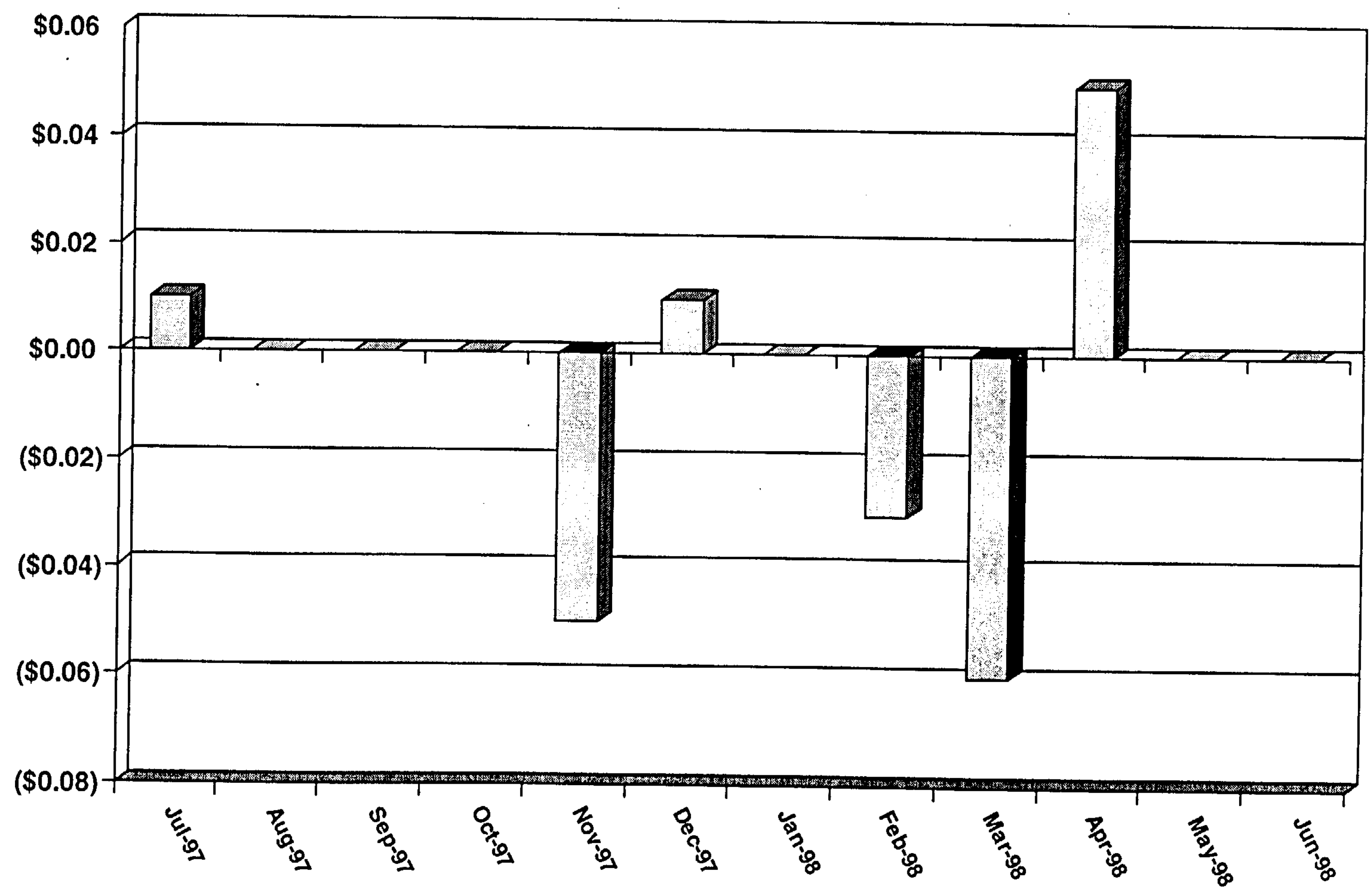
Incremental Impact of Storage Usage on the WACOG

Purchases Through East Tennessee



Incremental Impact of Storage Usage on the WACOG

Purchases Through Southern Natural



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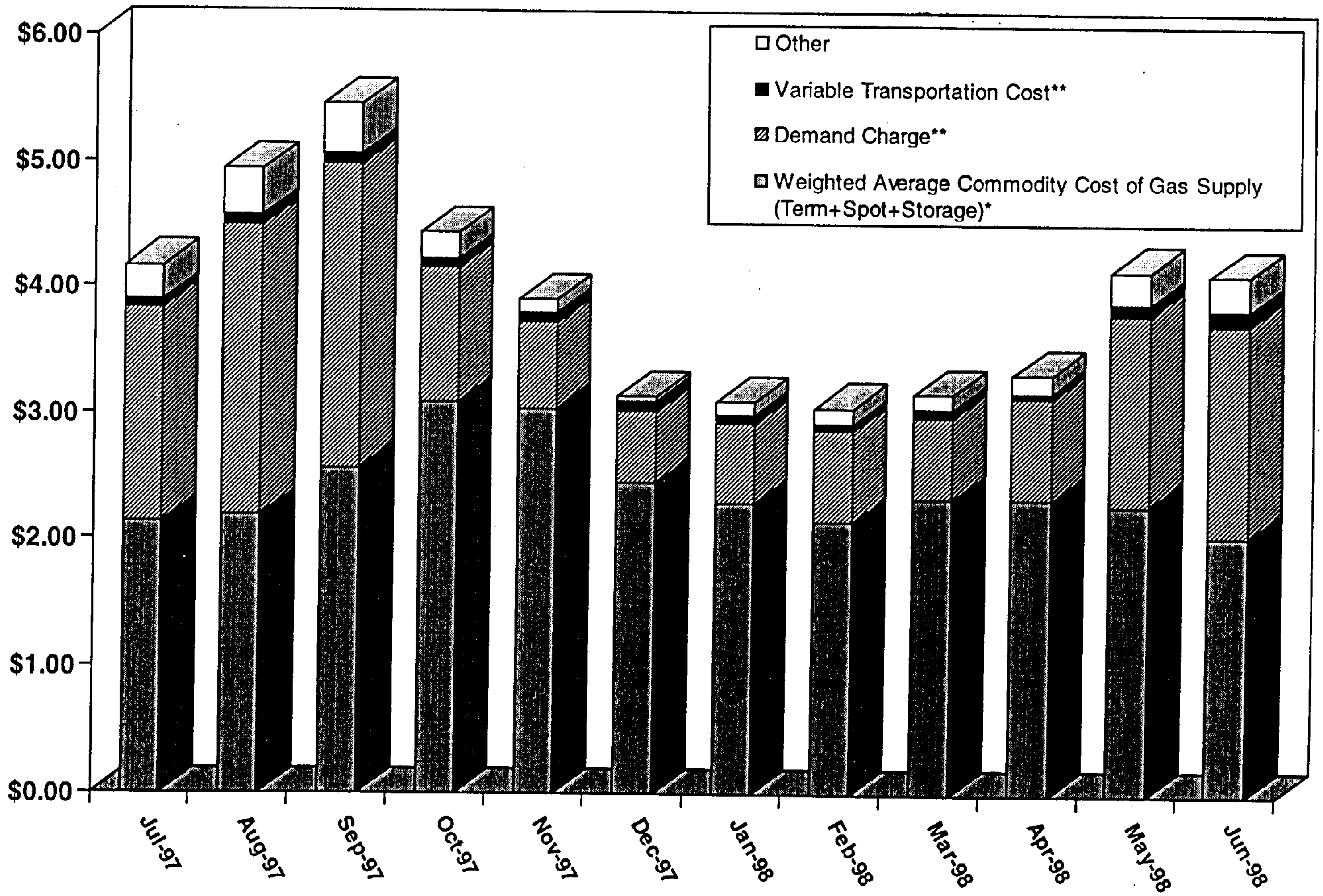
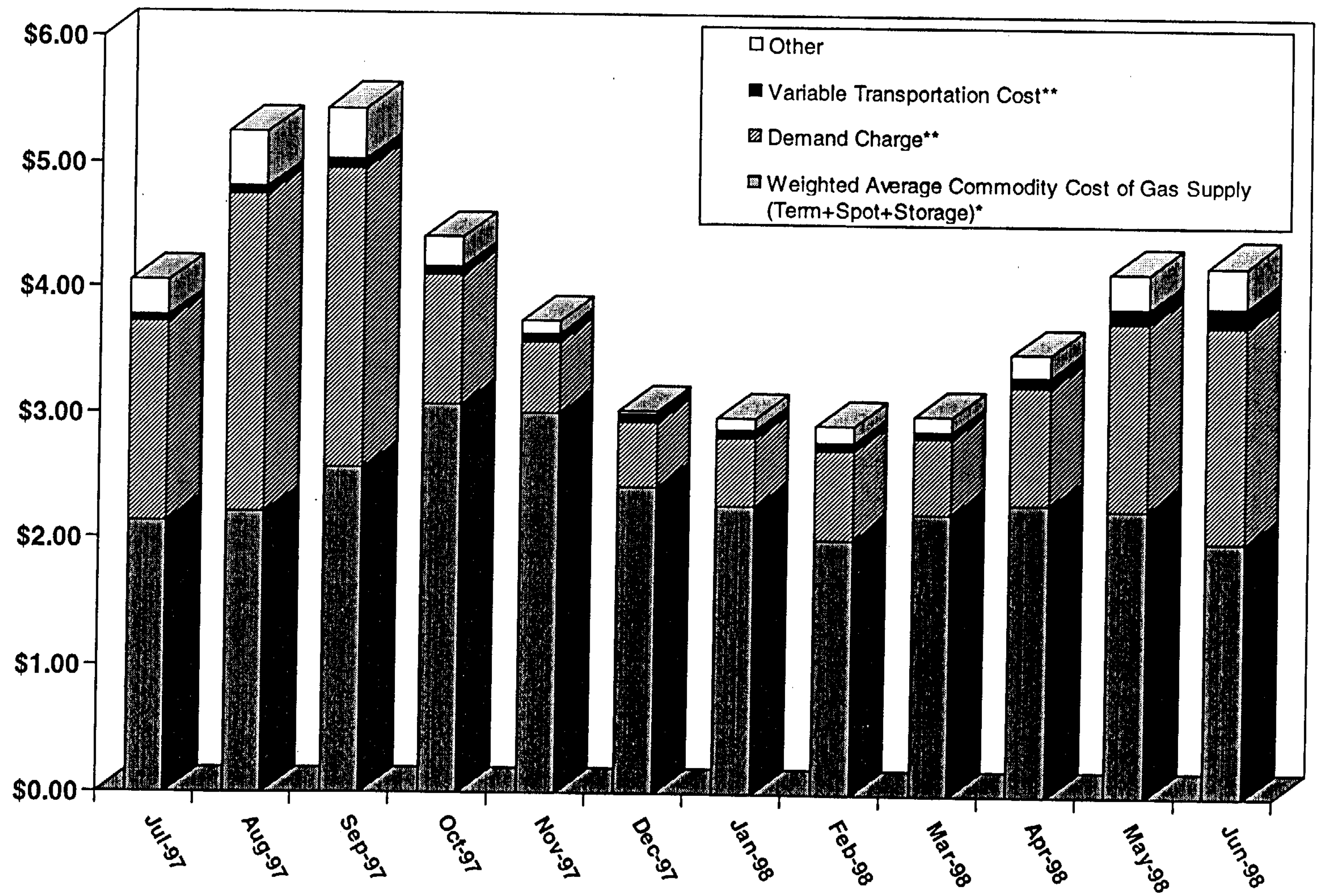
Total Delivered Cost of Gas for Chattanooga

System Average



Total Delivered Cost of Gas for Chattanooga

Purchases Through East Tennessee Natural Gas



TB&A Consultants to Management

Total Delivered Cost of Gas for Chattanooga

Purchases Through Southern Natural

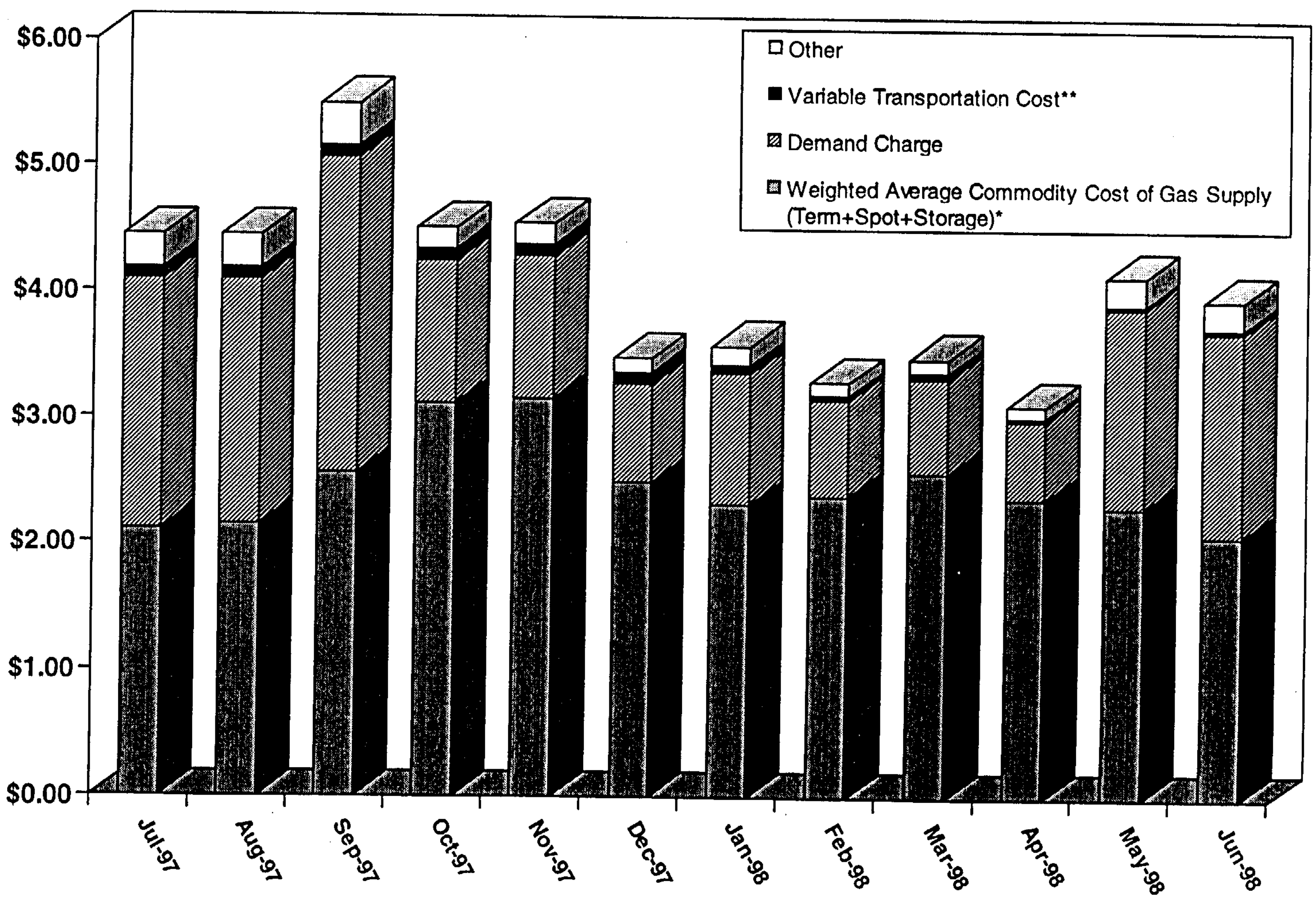


Exhibit 14

CHATTANOOGA GAS COMPANY
CUSTOMER USE

Line No.	Degree Days	Jul-97	Aug-97	Sep-97	Oct-97	Nov-97	Dec-97	Jan-98	Feb-98	Mar-98	Apr-98	May-98	Jun-98	Data Source
1	Actual 1997-1998	0	0	0	18	28	34	33	31	38	22	8	8	Monthly Financial Report
2	Actual 1996-1997													
	Number of Customers (1997-1998)													
3	Residential	45,109	44,994	45,126	45,938	47,345	48,028	48,494	48,403	48,434	48,090	47,508	46,952	Monthly Financial Report
4	Commercial	7,240	7,209	7,200	7,320	7,634	7,801	7,870	9,266	7,883	7,781	7,657	7,536	Monthly Financial Report
5	Industrial	324	325	332	344	334	333	332	352	345	317	359	365	Monthly Financial Report
	Volume DTH Sales (1997-1998)													
6	Residential	76,535	69,227	72,988	238,166	475,042	938,458	669,017	569,763	520,010	227,418	74,097	78,213	Monthly Financial Report
7	Commercial	157,850	128,483	136,085	241,799	329,527	704,800	533,265	531,752	417,539	201,440	112,137	122,219	Monthly Financial Report
8	Industrial	834,457	797,569	912,789	871,373	919,979	952,225	1,077,175	998,364	1,600,799	948,042	876,538	861,654	Monthly Financial Report
	Offsystem Sales	439,975	647,744	647,423	63,600	295,664	233,750	457,060	611,316	196,747	0	19,009	60,849	

Please provide gas quantities in DTH.

Chattanooga System Sales by Customer Segment

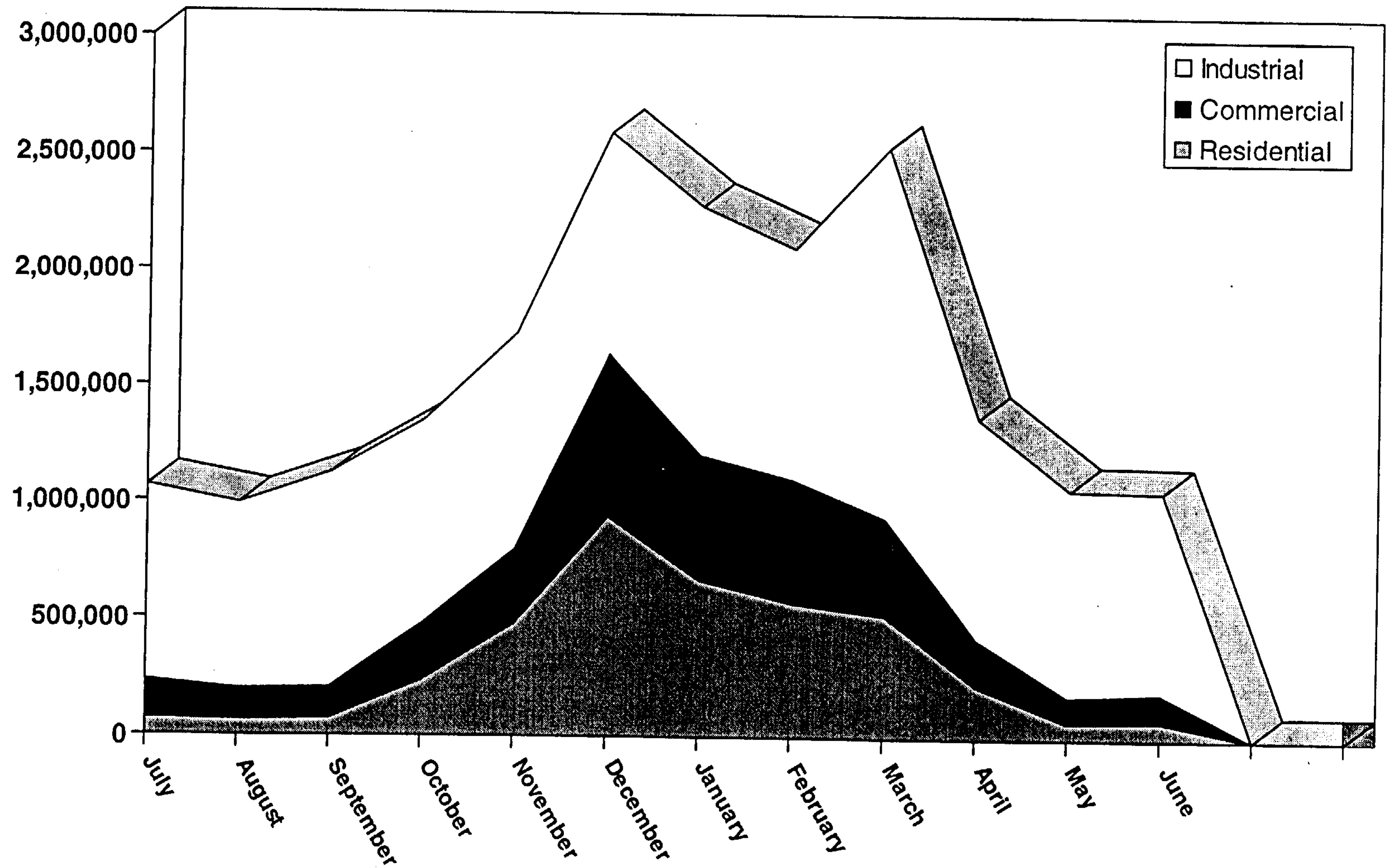


Exhibit 16

Chattanooga Actual Peak Day 1997-1998

Date	Pipelines	City	Actual Peak Day Temp.	Actual 1997-1998 Peak Day Demand	Customers Interrupted
February 4, 1998	SONAT	Chattanooga	34 degrees	35,605	
	E.Tenn.			51,615	
	LNG			17,802	
	Total			105,022	

Gas Quantities Reported in DTH

Types of Customers Interrupted: Industrial

Exhibit 17

Chattanooga Transportation Capacity

	Jul-97	Aug-97	Sep-97	Oct-97	Nov-97	Dec-97	Jan-98	Feb-98	Mar-98	Apr-98	May-98	Jun-98
SONAT												
"Total Firm Transportation Capacity Rights	27,567	27,567	27,567	27,567	27,567	27,567	27,567	27,567	27,567	27,567	27,567	27,567
"Total Interruptible Transportation Capacity Rigl	56,768	56,768	56,768	56,768	56,768	56,768	56,768	56,768	56,768	56,768	56,768	56,768
East Tennessee												
"Total Firm Transportation Capacity Rights	46,350	46,350	46,350	46,350	46,350	46,350	46,350	46,350	46,350	46,350	46,350	46,350
"Total Interruptible Transportation Capacity Rigl	45,000	45,000	45,000	45,000	45,000	45,000	45,000	45,000	45,000	45,000	45,000	45,000
Tennessee												
"Total Firm Transportation Capacity Rights	39,972	39,972	39,972	39,972	39,972	39,972	39,972	39,972	39,972	39,972	39,972	39,972
"Total Interruptible Transportation Capacity Rigl	45,918	45,918	45,918	45,918	45,918	45,918	45,918	45,918	45,918	45,918	45,918	45,918

Exhibit 18

Chattanooga Storage Capacity

Company Owned Storage	Jul-97	Aug-97	Sep-97	Oct-97	Nov-97	Dec-97	Jan-98	Feb-98	Mar-98	Apr-98	May-98	Jun-98
Total Capacity of Working Gas Inventory	1,207,574	1,207,574	1,207,574	1,207,574	1,207,574	1,207,574	1,207,574	1,207,574	1,207,574	1,207,574	1,207,574	1,207,574
Maximum Daily Withdrawal Capability	90,000	90,000	90,000	90,000	90,000	90,000	90,000	90,000	90,000	90,000	90,000	90,000
Maximum Daily Injection Capability	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
Any Other Restrictions (Y/N)	N	N	N	N	N	N	N	N	N	N	N	N

Contracted Storage	Jul-97	Aug-97	Sep-97	Oct-97	Nov-97	Dec-97	Jan-98	Feb-98	Mar-98	Apr-98	May-98	Jun-98
Facility: FSP - Bear Creek												
Total Firm Capacity Storage Rights	2,042,390	2,042,390	2,042,390	2,042,390	2,042,390	2,042,390	2,042,390	2,042,390	2,042,390	2,042,390	2,042,390	2,042,390
Total Interruptible Capacity Storage Right	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE
Parking/Daily Balancing Rights	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE
Daily Firm Withdrawal Rights	13,659	13,659	13,659	13,659	13,659	13,659	13,659	13,659	13,659	13,659	13,659	13,659
Daily Interruptible Withdrawal Rights	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE
Daily Firm Injection Rights	13,616	13,616	13,616	13,616	13,616	13,616	13,616	13,616	13,616	13,616	13,616	13,616
Daily Interruptible Injection Rights	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE
Any Other Restrictions on Use (Y/N)	N	N	N	N	N	N	N	N	N	N	N	N

Contracted Storage	Jul-97	Aug-97	Sep-97	Oct-97	Nov-97	Dec-97	Jan-98	Feb-98	Mar-98	Apr-98	May-98	Jun-98
Facility: FSM - Portland												
Total Firm Capacity Storage Rights	852,287	852,287	852,287	852,287	852,287	852,287	852,287	852,287	852,287	852,287	852,287	852,287
Total Interruptible Capacity Storage Right	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE
Parking/Daily Balancing Rights	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE
Daily Firm Withdrawal Rights	7,741	7,741	7,741	7,741	7,741	7,741	7,741	7,741	7,741	7,741	7,741	7,741
Daily Interruptible Withdrawal Rights	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE
Daily Firm Injection Rights	5,682	5,682	5,682	5,682	5,682	5,682	5,682	5,682	5,682	5,682	5,682	5,682
Daily Interruptible Injection Rights	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE
Any Other Restrictions on Use (Y/N)	N	N	N	N	N	N	N	N	N	N	N	N

Contracted Storage	Jul-97	Aug-97	Sep-97	Oct-97	Nov-97	Dec-97	Jan-98	Feb-98	Mar-98	Apr-98	May-98	Jun-98
Facility: CNG - Cornwell												
Total Firm Capacity Storage Rights	151,974	151,974	151,974	151,974	151,974	151,974	151,974	151,974	151,974	151,974	151,974	151,974
Total Interruptible Capacity Storage Right	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE
Parking/Daily Balancing Rights	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE
Daily Firm Withdrawal Rights	2,483	2,483	2,483	2,483	2,483	2,483	2,483	2,483	2,483	2,483	2,483	2,483
Daily Interruptible Withdrawal Rights	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE
Daily Firm Injection Rights	844	844	844	844	844	844	844	844	844	844	844	844
Daily Interruptible Injection Rights	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE
Any Other Restrictions on Use (Y/N)	N	N	N	N	N	N	N	N	N	N	N	N

Contracted Storage	Jul-97	Aug-97	Sep-97	Oct-97	Nov-97	Dec-97	Jan-98	Feb-98	Mar-98	Apr-98	May-98	Jun-98
Facility: CSS												
Total Firm Capacity Storage Rights	710,484	710,484	710,484	710,484	710,484	710,484	710,484	710,484	710,484	710,484	710,484	710,484
Total Interruptible Capacity Storage Right	52,000,000	52,000,000	52,000,000	52,000,000	52,000,000	52,000,000	52,000,000	52,000,000	52,000,000	52,000,000	52,000,000	52,000,000
Parking/Daily Balancing Rights	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE
Daily Firm Withdrawal Rights	14,346	14,346	14,346	14,346	14,346	14,346	14,346	14,346	14,346	14,346	14,346	14,346
Daily Interruptible Withdrawal Rights	1,072,050	1,072,050	1,072,050	1,072,050	1,072,050	1,072,050	1,072,050	1,072,050	1,072,050	1,072,050	1,072,050	1,072,050
Daily Firm Injection Rights	5,423	5,423	5,423	5,423	5,423	5,423	5,423	5,423	5,423	5,423	5,423	5,423
Daily Interruptible Injection Rights	408,400	408,400	408,400	408,400	408,400	408,400	408,400	408,400	408,400	408,400	408,400	408,400
Any Other Restrictions on Use (Y/N)	N	N	N	N	N	N	N	N	N	N	N	N

Exhibit 19

Chattanooga Storages at the end of the Heating Season (March 31)

Year	1995	1996	1997	1998
CSS	262337	96118	260,040	240,258
Fss	26635	0	0	
FSP	51739	122310	504,856	715,338
FSM	223251	7753	245,089	424,938
CNG	34174	9272	33,009	0
LNG	862339	635938	739,531	935,830
	1460475	871391	1782525	2316364

Note: FSS and FSP were combined into one storage service in 1996.

July 29, 1998

Mr. Mike Wingo
Manager, Gas Supply
Location 1462
Atlanta Gas Light Company
P.O. Box 4569
Atlanta, GA 30302-4569

Dear Mike:

Enclosed is a Document/Information Request for the Theodore Barry & Associates (TB&A) review of the gas procurement activities of Chattanooga Gas Company for the Tennessee Regulatory Authority.

For the purposes of the annual review of period July 1, 1997 through June 30, 1998, TB&A is requesting the data for Chattanooga Gas Company described in the following page.

We have enclosed data worksheets to assist in the reporting of the requested information. These worksheets were based on the methodology of the annual report for the prior review period. We may be requesting further information to help refine the cost analysis that is required for the mid-term report.

Copies of the data will be sent to Denise Dotson via mail and fax to help expedite the data reporting process. Please send completed worksheets to TB&A at the address given below by August 29, 1998.

If you have any questions, please call me or Jai Choi at 213/689-0770.

Sincerely,

Dan Gibson
Principal

TENNESSEE PUBLIC SERVICE COMMISSION

Document / Information Request

Requested By: Dan Gibson Date Requested: 7/29/98

Requested From: Chattanooga Gas Company Date Promised: 8/29/98

Documents / Information Requested	**Doc. No.**	**Date**
1. January 1998-June 1998 Gas Cost Data		
2. January 1998-June 1998 Customer Use Data		
3. July 1997-June 1998 Capacity Release Data		
4. 1997-1998 Heating Season Actual Peak Day Data		
5. Gas Storage Capacity and Rights Data		
6. Gas Transportation Capacity and Rights Data		
7. Significant Changes to/Additions to Storage, Transportation, or Supply Contracts/Portfolio Which Occurred During July 1997-July 1998		
8. Peak Day Requirements Forecast		
9. Copy of the Gas Supply Plan*/Updates		
10. Description of any updates to the Gas Supply Plan or gas supply planning strategy		
11. Pipeline System Schematics Diagram*		

Suggested Format:
Enclosed are worksheets for data requests one through three above. Please fill them out being careful to include the data source for further reference. A disk copy of the Microsoft Excel [version 5.0] spreadsheet has been included and information may be directly entered into this spreadsheet if you have the applicable software. There is one Cost of Gas worksheet for each pipeline and one left 'blank' in case there is an additional pipeline. Please contact me or my associate Jai Choi at (213) 689-0770 with any questions.

* Note that the Gas Supply Plan has been requested in prior review periods but was not provided or not available. In lieu of a published plan, AGL Energy Services can draft/provide a narrative discussion of the gas supply plan as it exists to date.

AGL Energy Services, Inc.

P.O. Box 4569
Atlanta, Georgia 30302-4569
Telephone (404) 584-9470

September 4, 1998

Mr. Jai H. Choi
Theodore Barry & Associates
515 South Figueroa Street, Suite 1500
Los Angeles, California 90071

Dear Mr. Choi:

Enclosed for your review are the completed data worksheets and diskette per your request of the gas procurement activities of Chattanooga Gas Company for the purpose of the annual review, July 1, 1997 through June 30, 1998.

Documents Completed:

- January 1998 – June 1998 Gas Cost Data (Includes Capacity Release)
- January 1998 – June 1998 Customer Use Data
- 1997 – 1998 Heating Season Actual Peak Day Data
- Gas Storage Capacity and Rights Data
- Gas Transportation Capacity and Rights Data
- Peak Day Requirements Forecast
- There were no significant changes to additions to storage, transportation, or supply contacts/portfolio which occurred during July 1997 – June 1998.

Documents Pending:

- Pipeline System Schematics Diagram (Pending receipt from pipeline).
- Description of any updates to the Gas Supply Plan or Gas Supply Planning strategy. (Pending completion from AGL Forecasting Group – Target completion – October 1, 1998.)

Should you have any questions, please do not hesitate to call me at (404) 584-3864 or Mike Wingo at (404) 584-3798.

Sincerely,

Denise Dotson
Gas Supply Analyst

c: Mr. M. P. Wingo

Gas Cost Calculation Sheet

Definitions

	CGV:	City Gate Volume
	TGE:	Total Expenses for Purchases*
	TGV	Total Volume of Gas Purchased*
	SGC$	Cost of Gas From Storage
	VGS	Volume of Gas From Storage
	SRF	Supply Reservation Fee
	TVT$	Fuel Adjusted Total Variable Transportation Cost
	UVT$	Unit Variable Transportation Cost
	TDC	Transportation Demand Charge
	SWD$	Variable Storage W/D Cost
	SDC	Storage Demand Charge
	LNG$	Cost of LNG Gas (Fully loaded**)
	LNGV	Volume of Gas W/D from LNG
	SPOT$	Expenditures for Mid Month Spot Purchases
	SPOT Vol.	Volume of Midmonth Spot Purchases

Chattanooga

Line #	East Tennessee	Southern
1	TGE/TGV	TGE/TGV
2	(TGE+SGC$)/(TGV+VGS)	(TGE+SGC$)/(TGV+VGS)
3	NYMEX Reported	NYMEX Reported
4	Weighted Average cost of Cost Of Zone 1 and Zone 0 Index	Inside FERC Reported
5	(TGE+SGC$+SRF)/(TGV+VGS)	(TGE+SGC$+SRF)/(TGV+VGS)
6	(TGE+SGC$+SRF+LNG$)/(TGV+VGS+LNGV)	N/A
7	(TVT$-(VSI*UVT$))/CGV	TVT$/CGV
8	TDC/CGV	TDC/CGV
9	SVWD$/CGV	SVWD$/CGV
10	SDC/CGV	SDC/CGV
11	Sum of Lines 6-10: Lines 5-10 if no LNG	Sum of Lines 6-10: Lines 5-10 if no LNG
12	Reported	Reported
13	System Deliver Cost=The sum of the weighted average of WACOG, variable transportation cost, demand charge for transportation and other costs***	

* For Chattanooga on Tennessee and Southern, TGE includes Midmonth Spot Purchases

**LNG Costs Include Fuel, Inj., W/D, and Variable Transportation Costs for LNG Gas.

***Calculations for cost componants as follows:

WACOG= [(SONAT Total Commodity Cost (Spot+Term+Storage))+(ETGP Tot. Com. Cost (Spot+Term+Storage))]/(SONAT Total Volume+ETGP Total Volume)

Variable trans. cost=(SONAT var. trans. cost+ETGP var. trans. cost)/(SONAT CGV+ETGP CGV)

Demand cost for trans.=(SONAT Dem. Cost+ETGP Dem. Cost+TGP Dem. Cost)/(SONAT CGV+ETGP CGV)

Other costs={[SONAT(inj./WD charge+Storage Demand Cost)+Supply Reservation Fee]+[ETGP (inj./WD Charge+Storage Demand Cost)+(Supply Reservation Fee+Incremental Cost of LNG]}/(SONAT CGV+ETGP CGV)

Gas Supply Plan Summary

Background: The gas supply plan is developed based on the following assumptions. First, the assets which comprise the portfolio of services under the gas supply plan are for the benefit of the firm customers. To the extent those services and facilities are not being utilized by the firm customers, they are available to provide service to interruptible customers. Second, the portfolio of services is developed to meet a design day (peak) demand at a mean temperature of five degrees Fahrenheit (sixty degree days). Third, the portfolio of services is designed to meet a winter consisting of 30 year average degree days which are supplied by the Tennessee Regulatory Authority.

Purpose and Objective. The objective of the Gas supply plan is to identify an array of services, including sufficient wellhead, transportation, storage and peaking assets, to provide reliable firm service at the best cost during a fiscal year. The process begins with a forecast of normalized firm and interruptible demand for the plan year. A linear optimization model is then used to meet this demand with services which produce a best cost plan consistent with existing contracts and facilities of the Company under known physical system operating constraints.

Demand Forecast. Firm sales are projected using a use-per-customer estimate and an estimate of the rate of growth in the number of customers. The forecast is prepared initially by using 10-year normal cycle-billed heating degree days as the basis for estimating the impact of weather on sales. The 10-year normal demand is then adjusted by a heat sensitive factor to reflect 30-year normal cycle-billed demand. Finally, the forecast is adjusted from cycle-billed sales to a calendar month basis, since gas is generally purchased in this manner. The demand forecast provides an estimate of the quantities of gas that must be purchased by the Company to serve the requirements of firm customers during the plan year under normal weather conditions. The demand forecast consists of a peak design day demand, winter season demand, and annual gas consumption.

Supply Forecast. EDS' Sendout model is the tool utilized to identify gas supply assets which best meet the firm demand forecast. Sendout employs an algorithm that uses a full linear program in conjunction with a network optimization component to determine the use of wellhead supply contracts, storage injections and withdrawals, and firm pipeline transportation which minimizes the total variable cost while meeting demand. Other inputs to the model consist of terms and conditions, minimum and maximum volumes, storage ratchets and the fixed and variable costs of the various services. Another input would be physical delivery limitations such as the inability to move Southern supply from Chattanooga to Cleveland.

The model is run with all demand and supply inputs. The results are analyzed to determine whether the portfolio produced by these inputs is adequate to supply the forecast demand, and to estimate the costs.

Chattanooga Gas Company Design Day Requirements Forecast

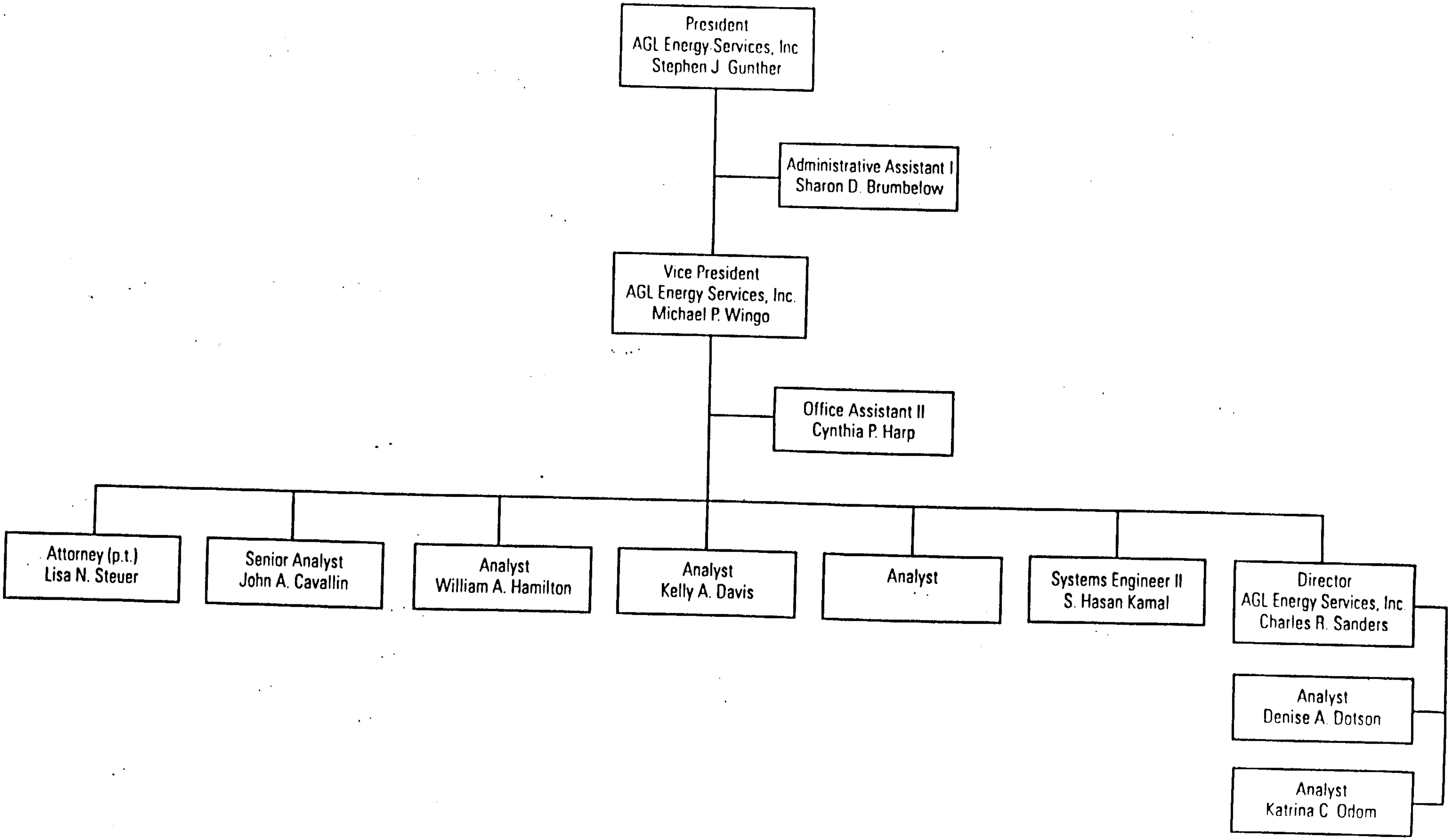
	1997-1998	1998-1999	1999-2000	2000-2001	2001-2002
Design Day Temperature	5	5	5	5	5
Forecasted Design Day Demand	141,355	147,249	139,843	143,345	Not Available
Contracted Pipeline Capacity	68,812	73,917	73,917	73,917	73,917
LNG	90,000	90,000	90,000	90,000	90,000
Reserve Volume	17,457	16,668	24,074	20,572	Not Available
% Reserve	11.0%	10.2%	14.7%	12.6%	Not Available

N/A - Not Available

Gas Quantities Reported in DTH

AGL Energy Services, Inc.

May 1, 1997



Organizational Chart is not to be photocopied