Before the

**TENNESSEE REGULATORY AUTHORITY**

**IN RE: APPLICATION OF CHATTANOOGA GAS COMPANY, A DIVISION OF AGL RESOURCES, FOR AN ADJUSTMENT OF ITS RATES AND CHARGES, THE APPROVAL OF REVISED TARIFFS AND APPROVAL OF REVISED SERVICE REGULATIONS**

**DOCKET NO. 04-00034**

**************************************************************************

**DIRECT TESTIMONY**

**OF**

**DANIEL W. McCORMAC, CPA**

**************************************************************************

**July 26, 2004**

**Q. Would you state your name for the record?**

A. My name is Daniel W. McCormac.

**Q. By whom are you employed and what is your position?**

A. I am employed by the Attorney General's Office as Coordinator of Analysts for the Consumer Advocate and Protection Division.

**Q. What is your educational background and what degrees and licenses do you hold?**

A. I have a Bachelor of Science Degree in Accounting from David Lipscomb College and I am a licensed Certified Public Accountant in the State of Tennessee.

**Q. What is your experience in the field of ratemaking and regulatory accounting?**

A. I have 28 years of experience in the field of utility ratemaking and regulatory accounting including more than two years with the Certified Public Accounting firm of Wilson, Work, Fossett & Greer as the supervisor in the utility consulting segment. I served sixteen years with the Tennessee Public Service Commission, including one year as Technical Assistant to the Commissioners. I served two years as Chief of Energy and Water at the Tennessee Regulatory Authority ("TRA") and eight years with the Office of the Attorney General. While employed by the Commission and the Attorney General's Office, I supervised the preparation of many utility rate cases and earnings reviews As part of these investigations, we developed financial exhibits to present to the Commission or TRA. These investigations supplied evidence to the TRA to enable it to set just and reasonable rates for utility services. In addition, I participated in various special studies and provided technical assistance in other cases in which I did not testify.

As the Technical Assistant to the Commissioners I observed hearings and analyzed the issues in each case from an independent technical perspective. I responded to the Commissioners' requests for expert assistance in evaluating and interpreting the financial evidence in the record. I also provided and checked calculations based on that evidence. In each position, my responsibilities have included making decisions on whether the information provided was adequate and suitable for deciding the questions presented.

My duties with the Consumer Advocate and Protection Division ("CAPD") are similar, but also include the review of various tariffs filed before the TRA. I assist in the decision making process as to whether the terms and conditions of the numerous filings are just and reasonable or whether additional evidence is needed to support the filings. When significant consumer interests appear to be in jeopardy, we investigate further and provide expert testimony before the TRA when needed.

**Q. What expertise do you have related to the natural gas industry?**

A. Since 1976 I have been involved in auditing gas companies, reviewing testimony, tariffs and exhibits, negotiating rates and preparing testimony and exhibits relating to various revenue, expense and rate base issues of all major Tennessee gas distribution companies. I have prepared testimony in every major case involving a gas utility since my employment with the Attorney General's office in 1994.

**Q. Would you please summarize the major issues that will be addressed by the CAPD?**

A. Yes. The CAPD looked at each component of Chattanooga Gas Company's ("CGC") projected cost of service and found several areas of major disagreement indicating that a 15% rate increase is not warranted.

**Q. What are the major areas of disagreement?**

A. 1. There are numerous problems with CGC's request of 8.84% for the cost of capital including the appropriate capital structure, the cost of common equity and the cost of debt. Using a more appropriate capital structure and the actual 6.72% cost of capital reduces CGC's request by $3 million.

2. CGC omitted $1.2 million of "gross profits" from the analysis of the cost of service in this rate case. CGC charges all gas and gas supply costs to consumers, but fails to refund to consumers the full benefits of revenues received from selling those gas supply assets.

3. CGC is attempting to charge $.5 million of expenses to Tennessee ratepayers even though those same expenses are billed to Virginia consumers. The pending acquisition of NUI Corporation should also reduce future costs that Tennessee consumers should pay.

4. CGC is attempting to add $.3 million of expenses related to new employees even though the facts show that employees were eliminated after the last rate case.

5. CGC has requested a rate increase that is not needed, therefore the $.1 million annual costs of this rate case should not be charged to consumers.

6. CGC proposes to shift the risk of gas inventory management to consumers. We oppose this attempt to make consumers vulnerable to cost shifts that CGC manages.

7. CGC proposes to give itself an automatic rate increase each year based on one narrow aspect of the total cost of service. CGC wishes to be reimbursed for the annual costs of replacing certain gas mains without regard to other changes in revenues, expenses, investments, or cost of capital.

8. CGC is asking ratepayers to reimburse it for donations to certain consumers selected by CGC and/or the TRA. Donations should be funded by stockholders, not ratepayers.

**Q. What is your assignment in this docket?**

A. I reviewed the projected revenues under the current rates as approved by the TRA in Docket No. 97-00982 in an order dated October 7, 1998. These base rates have been in effect since November 1, 1998. I also reviewed the proposed tariffs, forfeited discounts ratio, uncollectible accounts ratio and the proposal to pass the risk of inventory fluctuations to consumers. I supervised the review of Chattanooga Gas Company's projected expenses and investments ("rate base") for the attrition year ending June 30, 2005. In addition, I reviewed the proposed changes in tariffs and rate design. I summarized the major concerns about CGC's petition, explained the effects of each proposed adjustment and the consolidated impact on the total cost of service as shown in Exhibit CAPD-DM. I also present a recommended rate design.

I will testify in opposition to CGC's proposal to shift the risk of gas inventory management to consumers. I will testify in opposition to CGC's attempt to charge $.5 million of the expenses to Tennessee ratepayers even though those same expenses are billed to Virginia consumers. I will testify in opposition to CGC's request for ratepayers to reimburse CGC for donations to certain consumers which CGC refers to as the "CARES" program. Dr. Brown and I will also discuss the possible implications of the pending acquisition of NUI Corporation.

Mr. Michael Chrysler will testify in opposition to CGC's proposal to get an automatic rate increase each year based on one narrow aspect of CGC's cost of service related to certain main replacements. Dr. Stephen Brown will testify on the appropriate capital structure, cost of common equity and return on rate base as summarized on Exhibit CAPD-DM, Schedule 12 and supported in detail in Dr. Brown's testimony and exhibits.

**Q. How did the CAPD test the reasonableness of CGC's projected investments, revenues and expenses?**

A. We analyzed the reported financials, variances from previous years, recent trends and CGC's proposed adjustments to ascertain whether the Company has presented a reasonable estimate of these elements for the twelve months ending June 30, 2005. Where CGC has failed to provide adequate support for the projected cost of service, we propose certain adjustments to reflect that failure.

**Q. Are CGC's projections a reasonable basis for setting rates?**

A. No. The accepted and proven standard used to set rates is to properly match revenues, expenses and investment. The use of a reasonably anticipated and properly matched capital structure, revenues, investments and costs assures CGC's investors a reasonable opportunity to earn a reasonable return on those investments. However, several of CGC's projections are not supported by the evidence in this petition.

For example, CGC projected the cost of salaries and wages to increase by

16%. This projection appears to be unreasonable when compared to recent events which have shown decreases in employment levels as discussed in Michael Chrysler's testimony. CGC's proposed increase in employee levels is not supported by the evidence in the record.

**Q. What were the conclusions from the Consumer Advocate's analysis?**

A. We conclude that CGC's rates should be reduced by at least $2,572,000. The partial and preliminary results of the Consumer Advocate's analysis are presented in Exhibit CAPD-DM and Exhibit CAPD-SB. The cost of service is summarized on Schedule 1 of Exhibit CAPD-DM. Rates should be calculated on a Rate Base of $94,939,000, an Operating Income at Present Rates of $7,937,000 and a gross revenue conversion factor of 1.652121 as shown on Exhibit CAPD-DM, Schedule 1. Rates should be reduced to produce a fair rate of return of no more than 6.72% as summarized on Schedule 12 and supported by CAPD witness Dr. Brown.

**Q. Why do you use the terms "partial" and "preliminary" concerning the conclusions from the Consumer Advocate's analysis?**

A. As Mr. Chrysler discusses in greater detail in his testimony, the level of discovery and analysis in this case was severely limited due to a lack of information filed with CGC's petition and the lack of cooperation from the Company. This lack of cooperation has delayed the full analysis of the petition and information is still being discovered. Some of our questions may never be fully addressed. Cross-examination of the company's witnesses at the hearing may shed more light on the facts.

In addition, AGL Resources recently announced the planned acquisition of NUI Corporation. We would request the TRA to either hold this docket open until the results of this pending merger are clear or to open a new docket to allow the associated savings to be reflected in rates.

Q. **Besides the adjustments to the cost of service that the CAPD has identified, do other factors indicate that CGC's rates need to be reduced?**

A. Yes. While CGC's current rates for residential service are above the cost of electric heating, CGC has proposed an additional **15% increase in residential** service rates (Schedule 13).

In addition, the latest available reports from CGC show that CGC is earning in excess of a reasonable rate of return as shown on Exhibit CAPD-DM, Schedule 1. I have added lines 9 through 15 to the "traditional" calculation of revenue requirements. Line 13 shows that CGC overearned almost $2 million for the 12 months ended March 31, 2004 after adjusting CGC's reported earnings to reflect all revenues. After moving the "gas cost" portion of uncollectible accounts expense and the "consumer's share" of "non-jurisdictional" sales from the PGA to base rates, the current reported earnings support a rate reduction of $3.8 million as shown on Line 15.

Q. **How do current gas rates compare with current electric rates?**

A. CGC's "confidential" reply to TRA FG Item No. 41, page 2 of 2 shows that gas costs exceed electric power costs as of December 2003 by about **XX%** (classified as "confidential" by CGC) for the typical residential customer's heating and water heating. This shows that now is not a good time to be raising gas rates.

Q. **What is your recommendation for designing rates?**

A. The CAPD proposes that rates be reduced by 8% for each customer class. Our proposed rate design is on Exhibit CAPD-DM, Schedule 13.

Since the fuel cost of operating a heat pump are now significantly less than the costs of operating a gas furnace, raising rates for residential consumers will hinder CGC's efforts to retain current customers or add additional customers. Any rate increase now or future rate increases caused by CGC's proposed "PRP" tracker would only compound this problem. We therefore request the TRA avoid increasing CGC's rates. To do so would not only cost consumers, but would also hurt the future of CGC by causing a loss of customers to alternative sources of energy.

**Q. Would you explain your proposed adjustment to salaries and wages expense?**

A. Yes. CGC overstated the projected salaries and wages by about 10% because CGC overstated the average number of employees expected in the attrition year. Mr. Chrysler testifies as to why CGC's proposed increase is unwarranted. As shown on Exhibit CAPD-DM, Schedule 8, Line 1, reducing the number of employees back to a reasonable level will reduce the salaries and wages expense by $302,000 or by about 10% of CGC's projection. Reducing salaries and wages by 10% should also reduce pensions, insurance and taxes by about 10%. The proposed 10% reduction to these items is shown on lines 15 and 17 of Schedule 8 and line 3 of Schedule 9.

These adjustments **reduce** revenue requirements by about $347,000.

**Q. In your opinion, what adjustment should be made for Uncollectible Accounts expense?**

A. Uncollectible Accounts expense must be adjusted to exclude the Uncollectible Accounts expense related to gas costs in accordance with the TRA's ruling in Docket 03-00209. In Docket 03-00209, the TRA allowed the "gas cost" portion of Uncollectible Accounts expense to be recovered through the PGA mechanism. To avoid double recovery of this portion of Uncollectible Accounts expense, the "gas cost" portion must be removed from the cost of service recovered under base rates. I used CGC's Uncollectible Accounts expense ratio of 1.0121% times the gas costs of $60,861,234 (Exhibit CAPD-DM, Schedule 6, line 2) to make this adjustment. The resulting decrease of $615,976 is incorporated into the cost of service as summarized in Exhibit CAPD-DM, on line 10 of Schedule 8.

This adjustment **decreases** revenue requirements by about $626,000.

**Q. Do you have an opinion on CGC's attempt to charge $.5 million of expenses to Tennessee ratepayers even though those same expenses are also billed to Virginia consumers?**

A. Yes. CGC should not be allowed to "double bill" consumers. Atlanta Gas Light Resources ("AGLR") owns AGL Services Co. ("AGSC") which in turn bills costs to other affiliates. AGLR is attempting to bill the same costs to two different states at the same time. This proposal would obviously allow AGL to make excess profits and would force ratepayers to pay excessive rates.

Before AGLR acquired Virginia Natural Gas ("VNG"), AGSC's expenses were billed to consumers in Georgia and Tennessee. After AGLR acquired VNG, some of the AGSC costs were billed to VNG. CGC alleges that since some of the costs that were previously billed to Tennessee are now billed to Virginia, CGC's stockholders should get to keep $533,803 or 50% of these "savings." In other words, CGC is asking the TRA to approve a scheme that will allow it to continue billing Tennessee consumers $533,803 of costs that have already been paid by Virginia consumers.

CGC witness Michael J. Morley states on page 11, lines 10-19 that AGLR is subject to and follows the requirements of the Public Utility Holding Company Act ("PUHCA" or the "Act") of 1935. He states, "In accordance with the Act, AGLR formed AGL Services Company ("AGSC") to provide shared services to all subsidiaries of AGLR at actual cost." In contrast to this statement, MJM-2, Schedule 4, Page 2 of 2, Line 11 shows an adjustment labeled "Adjustment for economies of scale/improved efficiencies - AGL Services Company allocations." This adjustment adds $533,803 to the actual operating expenses charged to CGC from AGSC. In my opinion, adding this fictitious number as a pro forma adjustment violates the "at cost" provisions of the PUHCA.

CGC acknowledges (TRA Staff Data Request No 135) that "the total economies of scale savings resulting from the purchase of Virginia Natural Gas for CGC is $1,067,607." But the response adds "Incorporating a 50% sharing mechanism between both the Tennessee ratepayers and AGL Resources Inc. shareholders results in a cost savings to CGC of approximately $500,000." In other words, CGC is requesting permission to allow AGL Resources Inc. to continue billing $533,803 of nonexistent costs. If this scheme is approved, AGSC will recover the same costs twice.

CGC's rational for the 50% savings proposal is:

> "50% of the economies of scale savings are included in CGC's shared service allocations from AGSC as a sharing mechanism between CGC and the CGC ratepayers. The risks associated with the VNG acquisition were assumed by the shareholders of AGLR. While the acquisition of VNG benefitted the shareholders of AGLR, it also benefitted the Tennessee ratepayers in the form of lower shared service cost allocations from AGSC. A sharing rate of 50% is used consistent with industry standards for most sharing mechanisms between utility ratepayers and company shareholders" (TRA Staff Data Request No. 134, Page 2, Item e).

**Tennessee ratepayers have not received any benefit from "lower shared service cost allocations from AGSC." The only way Tennessee consumers can receive the benefits of the savings is through a rate reduction. Rates have not been reduced to reflect these savings.** The "industry standard" for sharing savings is for the stockholders to get 100% of the savings until the rates are reduced to reflect those savings. In this case, AGLR shareholders have been receiving 100% of the savings since the VNG acquisition. CGC is now requesting 50% of these savings in the future.

While the CAPD does not object to the shareholder's receipt of past savings, consumers should pay no more than the actual costs of future services provided by AGSC. CGC's proposal to add $533,803 over and above the actual costs should be denied.

Removing these excessive costs **decreases** revenue requirements by about $537,000.

**Q. What are the possible implications of AGL Resources' pending acquisition of NUI Corporation?**

A. The pending acquisition of NUI by AGL Resources could also reduce future costs that Tennessee consumers should pay. As discussed above the VNG acquisition saved $1,067,607 and VNG was smaller than NUI. Based on the cost savings of the VNG acquisition, the NUI acquisition should save well over $1 million per year.

**Q. Has CGC recently reported a $2.4 million profit from "Transactions with Non-jurisdictional Customers" which it failed to reflect in this rate case?**

A. Yes.

**Q. Is the term "profit" a misnomer?**

Yes. CGC has charged consumers 100% of the costs associated with acquiring, storing and transporting gas to the Chattanooga area. These costs are billed to consumers through the PGA mechanism so that CGC recovers 100% of these costs. CGC estimates over $63 million will be billed to consumers in the next year to recover such costs (Exhibit MJM-1, Sch. 4)

CGC allows Sequent Energy Management (CGC's affiliate company sometimes referred to as "CGC Agent") to enter transactions with "Non-jurisdictional Customers" to utilize **surplus capacity and assets that have been paid for by consumers**. The term "profit" as used by CGC in the reporting of these transactions does **<u>not</u>** include all of the costs of assets transferred to Sequent. CGC has not identified or quantified all costs associated with the sales made through Sequent, just the "cost of goods sold." However, when all costs are taken into account, it is likely that the transactions did not produce enough revenues to make a profit. CGC is using the "gross profit" measure of profit that considers only the "cost of goods sold" or commodity costs. "Net profit" takes into account all the costs associated with the transactions. It is imperative that both the "gross profit" and the "net profit" (or net loss) are considered to avoid improperly concluding that these related party transactions are in the best interest of consumers.

**Q. Which measure of profit is being reported by CGC on these Non-jurisdictional sales?**

A. CGC labels the profits "Net Gross Profit" but it appears that the reports reflect gross profits. This means that some of the costs are not reflected in the reports.

**Q. Why is the distinction between "gross profit" and "net profit" important?**

A. The distinction is critical because some of the costs that are omitted from the calculation are very real and controllable expenses. If CGC incurs costs that are not being measured in the "gross profit" calculation, consumers are paying these costs. However, consumers are not getting recovery of these costs through the sharing formula.

To illustrate, assume a transaction or sale from CGC through Sequent Energy of $1,000,000 and a cost of goods sold of $700,000. On the surface it would appear that the transaction generates a $300,000 profit. However, in utility ratemaking, the most important measure of profit is "net operating income." Utilities insist that all reasonable costs be accounted for and recovered in the rates that consumers pay. The "net profit" or "net operating income" is the profit (if any) that is left after all operating expenses (other than cost of goods sold) are subtracted from the gross profit. The difference between "gross" and "net" profits is illustrated on Exhibit CAPD-DM, Schedule 14. The "gross profit" measure is the measure which CGC used in its February report of non-jurisdictional sales. In this example, the "gross profit" measure only recognizes the Cost of Goods Sold and ignores $500,000 in other costs. After considering $500,000 of other costs, the transaction produces a **loss** of $200,000

If CGC were rewarded for "gross profits," CGC would be motivated to enter transactions that produce a $200,000 net operating **loss for consumers**. Therefore, if CGC gets what it is proposing, CGC will profit, while consumers lose money. In this example, consumers would lose $200,000 before a

$150,000 share of a "gain" for a net loss of $50,000. CGC actually profits by $150,000, while consumers lose money.

This illustrates why the consumers should get 100% of the gross profit so that CGC is not motivated to enter unprofitable transactions. This also shows why it is imperative that these related party transactions be examined in greater detail by a qualified independent auditor.

**Q. Would you explain CGC's proposal concerning the "gross profits" from "Non-jurisdictional Customers?"**

A. Yes. On February 27, 2004, Chattanooga Gas filed a proposed revision in rates "in accordance with the Interruptible Margin Credit Rider (IMCR) provision of CGC's Tariffs for the twelve months ended December 31, 2003." Attachment D, Page 2 of the filing reports profits from "Transactions with Non-jurisdictional Customers" of $2,485,317 for the 12 months ended December 31, 2003. CGC proposes that consumers will get to keep 50% of this "Total Aggregate net margin CGC book value" reported to the TRA for 2003. CGC wants "CGC Agent" or Sequent Energy Management or AGL Resources to keep the rest. (The filing is presented as Exhibit CAPD-DM-#2). Consumers are bearing the risk and paying the bills while CGC gets the "bonus" payments or rewards for selling excess capacity.

There are several disconcerting numbers in the report of profits from the sale of these surplus assets. First, Page 2 of Attachment D reports that Sequent Energy Management gained $5,229,440 on sales of over $201 Million in 2003. It is unclear what caused the "Realized financial Settlements - contracts" of $487,062 and "Unrealized Losses, net" of $2,257,061. These two items reduced the "Total Aggregate net margin CGC book value" to $2,485,317. Attachment D, Page 1 shows CGC's proposal that consumers only get $1,180,158 after subtracting "Inground Transfer-01/03 $62,500." CGC's transactions should be independently audited and verified to assure that consumers receive the appropriate compensation for the sale of assets for which consumers paid. **The TRA should require a thorough investigation into these related party transactions to determine how much consumers are paying for the assets which support the sales and what a prudent level of recovery should be.**

**Q. What does the CAPD recommend concerning these transactions?**

A. Since CGC reported profits of $2,360,317 in 2003, the **minimum** level of profits assumed in this rate case should be $2,360,317. I propose that the $2,360,317 be included in this rate case as a reduction in costs to partially offset costs already billed to consumers. All recovery or salvage value received for surplus assets above the $2,360,317 should be refunded to consumers through the PGA after a full review of the transactions by an independent auditor. This audit should assure consumers and the TRA that consumers are not paying inflated gas, transportation and storage costs enabling Sequent / AGL to make excess profits.

In light of recent events in the natural gas business, such as allegations of price manipulation, erroneous price reports and unreliability of "market price" indicators, a detailed audit and review of the current facts should be required to provide reasonable assurance that regulatory practices are appropriate before any additional incentive bonuses are paid to CGC and charged to consumers.

The effective date of this change should be whenever CGC started billing consumers for costs that were later recovered through affiliate transactions. All costs billed to consumers through the PGA should be offset by any funds received by AGL Resources or any affiliate party. The refunds to consumers should be through the PGA until the effective date of the new rates in this docket. If the full $2,360,317 level of cost recovery is credited to consumers through base rates in this case, the balance of cost recovery above (or below) that level should be credited to consumers through the PGA.

This adjustment **decreases** revenue requirements by about $2,374,000.

**Q. Does this proposal essentially reset the target for sharing from $0 to $2,360,317?**

A. No. If these funds could be shared, the answer would be yes. However, it is our understanding that the PUHCA requires **all** transactions between affiliates to be billed at cost. AGL Resources cannot make a profit from affiliated transactions. See Dr. Brown's testimony for a more thorough analysis and discussion of the PUHCA requirements.

**Q. Is your recommendation consistent with the TRA's recent ruling in Docket 03-00209?**

A. Yes. The Tennessee Regulatory Authority adopted CGC's arguments and modified the refund formula in the PGA rule (1220-4-7-.03) so **consumers bear 100% of the risk** of **cost increases** associated with gas costs that are billed to consumers but never collected by the company. In that docket, CGC argued successfully to transfer the risk of **cost increases** to consumers. CGC now claims to have produced **cost decreases**, but does not want to assign 100% of the "risk" **and** 100% of the benefits to consumers. To be consistent with Docket 03-00209, 100% of the benefits of the sales should flow to consumers. This approach also reduces risks for CGC / AGL Resources.

**Q. What other factors contributed to your analysis of this issue?**

A. Consumers should get full credit for all revenues CGC receives from the sale of assets for which consumers have paid. Consumers are 100% at risk on the costs of gas, transportation and storage costs. CGC has no risk of loss. CGC simply resells the assets that consumers have purchased.

**Q. Would you explain the adjustment to remove the rate case expenses?**

A. Yes. CGC did not substantiate a need for a rate increase. Therefore, CGC's $250,000 estimated costs associated with this case should be excluded from the cost of service in setting rates $250,000 was removed from the working capital requirements shown on Exhibit CAPD-DM, Schedule 3 and the annual amortization of $100,000 was removed from the Administrative and General Operating expenses as shown on Exhibit CAPD-DM, Schedule 8.

This adjustment **decreases** revenue requirements by about $124,000.

**Q. Would you explain why the CAPD is opposed to CGC's request to shift the risk of gas inventory management to consumers?**

A. Yes. The CAPD generally supports incentives for companies to properly manage the utilities that the managers are paid to manage. Properly structured incentives hold the companies responsible for the actions or inactions of management.

In this particular area of inventory management, CGC has some control over the timing of injections and withdrawals, as well as some control over which gas is directed into inventory and which gas is sold to consumers. If CGC's proposal were to be approved, CGC would be rewarded for mismanagement or bloating of inventory values because CGC would be allowed to automatically pass through the increased carrying charges associated with the higher inventory levels. This proposal would reward CGC for increasing expenses for consumers.

The CAPD opposes this "tracker" to allow CGC to pass cost increases to consumers. If this "tracker" is approved, we also suggest a tracker to reflect future cost savings such as mergers and acquisitions.

**Q. Do related party transactions present another layer of concern?**

A. Yes. One very recent indication that there may be a significant problem in Chattanooga's gas purchasing practices is evidenced by CGC's response to a question in the recent ACA audit in Docket 03-00516. CGC was asked "How does Sequent determine how to invoice Chattanooga, i.e., which purchases are ultimately delivered to Chattanooga Gas?" The reply was:

> "Upon reaching agreement as to CGC's requirements, Sequent determines the lowest cost path . . . Sequent procures the required volume of gas at Inside FERC index pricing for baseload, month-long purchases and at Gas Daily index pricing for daily purchases at locations along that determined path. The gas is scheduled into a pool, which holds all of Sequent's transactions, whether they be proprietary or on behalf of CGC. These index purchases enable CGC to effectively purchase gas at market prices without taking credit risk."

This answer does little to clarify the situation as to how purchases are made, from whom, or what profits may be made on the mingling of gas assets. However, it is clear that the price indices are being used as the price setting mechanism rather than using the indices to determine the reasonableness of the actual cost of the gas. The problem is that the actual costs and profits are unknown at this time. Furthermore, if the indices are wrong, consumers are paying the wrong price. This also means that if the true market price of the gas was below the index, someone is making excess profits at the expense of consumers.

To avoid overcharging consumers, we recommend that the current incentive plan be suspended until a complete audit and examination of the results to date can be obtained. The TRA should supervise an independent examination of all current policies and transactions to determine if the results are beneficial to consumers. If so, the plan may be continued. If the results are not beneficial to consumers, the plan should be discontinued and/or improved.

Q. **Would you explain the company's proposed Chattanooga Assisted Rate for Energy Service ("CARES") Tracker?**

A. CARES, as outlined by the Company, proposes to provide elderly low income customers a credit of $7.50 per month, which is equal to the summer Customer Charge minimum monthly bill for May-October. Customers who are 65 or older and who qualify for Temporary Assistance to Needy Families (TANF), previously known as AFDC, Supplemental Security Income (SSI), Food Stamps, or Medicaid, as provided under TennCare, will be eligible. Additionally, a customer 65 years of age or older with a gross annual income that does not exceed 125% of the federal poverty income guidelines may apply directly to the TRA for eligibility certification. The program is to be funded by a surcharge on each customer based on therms purchased

**Q. What is the CAPD's position on this program?**

A. The Consumer Advocate opposes the CARES program. While the intention of the program is laudable, the mechanics of assessment and implementation do not appear to be in the best interests of all of the customers of Chattanooga Gas Company. CARES is similar in purpose and function to LIHEAP (Low Income Home Energy Assistance Program), which began in 1982. LIHEAP is a federally funded program which seems to meet the same needs as CARES without requiring surcharges to other consumers. Since there is a federal program in place to assist low income customers, there does not appear to be as great a need for an additional program funded by ratepayers' dollars.

As stated previously, the Consumer Advocate is of the opinion that the program is a commendable effort on the part of the Company to benefit their locale. However, if the Company wishes to implement another assistance program, it should be funded by the Company's shareholders. In response to Discovery Request No. 10 of the Consumer Advocate's Discovery, the Company revealed that the estimated annual cost of the program is $112,000. The estimate is based on the experience of a similar program that exists in Georgia. Since the Company expects to pay $5,463,000 in dividends next year, this would not appear to be unduly burdensome to the shareholders. (See Response to CAPD Discovery Request No. 2.) Funding the program would cost stockholders just over 2% of the total dividends expected to be paid and would greatly enhance the Company's public image.

On the other hand, if the shareholders of the Company do not wish to fund the program, another alternative could be to offer a voluntary program. In voluntary programs that currently exist at other utilities in Nashville and Chattanooga such as "Project HELP" and "Warm Neighbors," customers who may not wish to participate in the program are not forced to do so. Instead of a voluntary program, CGC is proposing that consumers be forced to make a charitable donation which they may not wish to make. It does not seem equitable to force consumers who may have difficulty paying their own bills to assist in paying bills for other residents. Under CGC's proposal, customers will have no rights to decide whose bills to pay.

In addition, although it is essentially a charitable contribution, each individual consumer would not receive the benefit of a tax deduction for their "generosity." Charitable contributions have traditionally been "below the line" expenses. In other words, they are not considered in the computation of net operating income. The rationale for this accounting treatment is clear: they are discretionary expenses controlled by management which are outside the scope of a company's normal operations. A company cannot exist without expenses such as salaries, wages, rent, utilities, etc., but choosing to make a contribution is clearly not a decision that impacts a company's ability to continue to operate in it's chosen field. For this reason alone, the program should be funded by the shareholders, who may choose to fund it, or be funded by voluntary contributions from the community.

CGC's proposal would also cause hidden cost increases to the citizens of

Tennessee. Customers may apply directly to the TRA for inclusion in this program. Does the TRA have staff trained and available to screen applicants for CARES? There are obviously some costs here that would have to be incurred for training, personnel, facilities to house paperwork, etc., all at the expense of the TRA.

The Electric Power Board of Chattanooga supplies electricity to approximately 150,000 customers in the Chattanooga area. "Warm Neighbors" is the name that is given the program which the Power Board has implemented to solicit contributions from their customers to assist low-income customers pay their energy bills. In "Warm Neighbors," there is a voluntary contribution of $1.00 made each month when an electric bill is paid.

These funds are then disbursed to those who need financial assistance in order to pay their energy bill. Another important distinction between "Warm Neighbors" and CARES is that United Way is responsible for administering the funds that are collected by the Power Board, not the Power Board itself. Therefore, there is no additional cost to the customer for administration of the program, and it does not impact the staff of the TRA and increase its costs.

**Q. Does CGC already recover the costs associated with unpaid bills?**

A. Yes. CGC is recovering all unpaid bills through the PGA and through uncollectible accounts expense.

**Q. Does this conclude your pre-filed direct testimony?**

A. Yes.

ODMA\GRPWISE\sd05 IC01S01 JSB1 75437 1

**BEFORE THE TENNESSEE REGULATORY AUTHORITY**

**AT NASHVILLE, TENNESSEE**

**IN RE: APPLICATION OF CHATTANOOGA GAS COMPANY, A DIVISION OF AGL RESOURCES, FOR AN ADJUSTMENT OF ITS RATES AND CHARGES, THE APPROVAL OF REVISED TARIFFS AND APPROVAL OF REVISED SERVICE REGULATIONS**

**DOCKET NO. 04-00034**

---

**AFFIDAVIT**

---

I, Daniel W. McCormac, Coordinator of Analysts for the Consumer Advocate and Protection Division of the Attorney General's Office, hereby certify that the attached Direct Testimony represents my opinion in the above-referenced case and the opinion of the Consumer Advocate Division.

Daniel W. McCormac

DANIEL W. McCORMAC

Sworn to and subscribed before me
this 23 day of July, 2004.

Emily Knight

NOTARY PUBLIC

My commission expires: 9-22-07

# Chattanooga Gas Company
## Index to Schedules
## For the 12 Months Ending June 30, 2005

Docket No. 04-00034
Exhibit CAPD-DM
Schedule 1

Chattanooga Gas Company
Revenue Deficiency
For the 12 Months Ending June 30, 2005

| Line No. | | CAPD | | Company E/ | Difference |
|---|---|---|---|---|---|
| 1 | Rate Base | 94,939,114 | A/ | 95,564,212 | (625,098) |
| 2 | Operating Income at Present Rates | 7,936,834 | B/ | 5,687,380 | 2,249,454 |
| 3 | Earned Rate of Return | 8.36% | | 5.95% | 2.41% |
| 4 | Fair Rate of Return | 6.72% | C/ | 8.84% | -2.12% |
| 5 | Required Operating Income | 6,379,908 | | 8,447,876 | (2,067,968) |
| 6 | Operating Income Deficiency | (1,556,926) | | 2,760,496 | (4,317,422) |
| 7 | Gross Revenue Conversion Factor | 1 652121 | D/ | 1.652130 | (0.000009) |
| 8 | Revenue Deficiency (Surplus) | (2,572,230) | | 4,560,699 | (7,132,929) |
| | | | | | |
| 9 | 12 MTD 3/04 Earned Rate of Return | 7.21% | F/ | | |
| 10 | Earned Return Exceeds Fair Return | 0 49% | | | |
| 11 | Revenue Deficiency (surplus) before adjustments | (768,569) | | | |
| 12 | Adjustment to reflect 50% of cost recovery from "non-jurisdictional" sales | (1,187,083) | | | |
| 13 | Excess earnings at current rates | (1,955,652) | | | |
| 14 | Adjustments for PGA flow through items | (1,812,738) | G/ | | |
| 15 | Current Revenue Deficiency (Surplus) | (3,768,390) | | | |

A/ Schedule 2, line 11
B/ Schedule 6, line 15
C/ Schedule 12, line 5
D/ Schedule 11, line 10
E/ Company Forecast
F/ PSC 3 03, March 2004
G/ $1 2 Million "consumers' share" of "non-jurisdictional" sales
+ $ 6 million reclassification of uncollectible accounts expense as gas costs

Docket No 04-00034
Exhibit CAPD-DM
Schedule 2

Chattanooga Gas Company
Comparative Rate Base
For the 12 Months Ending June 30, 2005

| Line No | | CAPD | Company B/ | Difference |
|---|---|---|---|---|
| 1 | Utility Plant in Service | 164,561,353 | 164,561,353 | - |
| 2 | Construction Work in Progress | 3,544,977 | 3,544,977 | - |
| 3 | Working Capital | 12,600,375 A/ | 13,225,473 | (625,098) |
| 4 | Total Additions | 180,706,705 | 181,331,803 | (625,098) |
| 5 | Accumulated Depreciation | 71,307,914 | 71,307,914 | - |
| 6 | Accumulated Deferred Income Taxes | 12,012,158 | 12,012,158 | - |
| 7 | Contributions In Aid of Construction | 2,161,125 | 2,161,125 | - |
| 8 | Customer Advances for Construction | 286,394 | 286,394 | - |
| 9 | Pre-1971 Unamortized Investment Tax Credit | - | - | - |
| 10 | Total Deductions | 85,767,591 | 85,767,591 | - |
| 11 | Rate Base | 94,939,114 | 95,564,212 | (625,098) |

A/ Schedule 3, Line 13
B/ Company Exh MJM-3

Chattanooga Gas Company
Comparative Working Capital
For the 12 Months Ending June 30, 2005

| Line No. | | CAPD | | Company B/ | Difference | |
|---|---|---|---|---|---|---|
| 1 | Lead Lag Results | 1,258,312 | A/ | 1,633,410 | (375,098) | |
| 2 | Materials and Supplies | 170,409 | | 170,409 | - | |
| 3 | Gas Inventories | 14,193,526 | | 14,193,526 | - | |
| 4 | Prepayments | 20,358 | | 20,358 | - | |
| 5 | Other Accounts Receivable | 57,547 | | 57,547 | - | |
| 6 | Deferred Rate Case | - | | 250,000 | (250,000) | C/ |
| 7 | Total Additions | 15,700,152 | | 16,325,250 | (625,098) | |
| 8 | Reserve for Uncollectible Accts. | 435,822 | | 435,822 | - | |
| 9 | Customer Deposits | 1,869,853 | | 1,869,853 | - | |
| 10 | Accrued Interest on Customer Deposits | 794,102 | | 794,102 | - | |
| 11 | Other Liabilities | - | | - | - | |
| 12 | Total Deductions | 3,099,777 | | 3,099,777 | - | |
| 13 | Working Capital | 12,600,375 | | 13,225,473 | (625,098) | |

A/ Schedule 5, Line 7
B/ Company Exh MJM-3
C/ Excludes rate case expense amortization per Exh MJM-3, Sch 2

Chattanooga Gas Company
Working Capital Expense Lag
For the 12 Months Ending June 30, 2005

| Line No | | Amount A/ | Lag A/ | Dollar Days |
|---|---|---|---|---|
| 1 | Purchased Gas Expense | 60,861,234 | 39 66 | 2,413,756,540 |
| 2 | Salaries and Wages | 2,669,585 | 12 00 | 32,035,020 |
| 3 | Pension Expense | 139,649 | 166.56 | 23,260,004 |
| 4 | Employee Benefits - Insurance | 43,002 | - | - |
| 5 | Allocated Costs | 6,485,216 | 38 71 | 251,042,711 |
| 6 | Uncollectible Accounts Expense | 321,056 | - | - |
| 7 | Other Operation and Maintenance Exp | 3,207,818 | 34 60 | 110,990,501 |
| 8 | Depreciation Expense | 5,194,810 | - | - |
| 9 | Taxes Other Than Income Taxes | 3,403,518 | 177 78 | 605,077,466 |
| 10 | State Income Tax - Current | 242,535 | 59 25 | 14,370,208 |
| 11 | State Income Tax - Deferred | 118,828 | - | - |
| 12 | Federal Income Tax - Current | 804,788 | 37 75 | 30,380,729 |
| 13 | Federal Income Tax - Deferred | 1,014,537 | - | - |
| 14 | Interest on Customer Deposits | 112,191 | - | - |
| 15 | Interest Expense - Short-term Debt | 151,903 | (23 34) | (3,545,406) |
| 16 | Interest Expense - Long-term Debt | 2,857,667 | 93 38 | 266,848,976 |
| 17 | Preferred Dividends | - | 66 18 | - |
| 18 | Common Equity | 3,344,146 | - | - |
| 19 | Total Cost of Service | 90,972,482 | 41 16 | 3,744,216,749 |
| 20 | Daily Cost of Service | 249,240 | | |

A/ Company workpapers

# Chattanooga Gas Company
## Lead Lag Results
## For the 12 Months Ending June 30, 2005

| Line No. | | Amount | |
|---|---|---|---|
| 1 | Revenue Lag | 46.05 | A/ |
| 2 | Expense Lag | 41 16 | B/ |
| 3 | Net Lag | 4.89 | |
| 4 | Daily Cost of Service | 249,240 | C/ |
| 5 | Operating Funds Advanced | 1,219,359 | |
| 6 | Less: Incidental Collections | (38,953) | A/ |
| 7 | Lead Lag Results | 1,258,312 | |

A/ Company Forecast
B/ Schedule 4, Line 19
C/ Schedule 4, Line 20

# Chattanooga Gas Company
## Income Statement at Current Rates
## For the 12 Months Ending June 30, 2005

| Line No | | CAPD | | Company D/ | | Difference | |
|---|---|---|---|---|---|---|---|
| 1 | Revenues - Sales & Transportation | 92,444,773 | | 92,444,773 | | - | |
| 2 | Cost of Gas | 60,861,234 | | 63,221,551 | | (2,360,317) | F/ |
| 3 | Base Revenues | 31,583,539 | | 29,223,222 | | 2,360,317 | |
| 4 | Forfeited Discounts Revenue | 577,099 | | 577,099 | E/ | - | |
| 5 | Other revenues | 396,149 | | 396,149 | | - | |
| 6 | AFUDC | 142,441 | | 142,441 | | - | |
| 7 | Operating Margin | 32,699,228 | | 30,338,911 | | 2,360,317 | |
| 8 | Other Operation and Maintenance | 12,866,326 | A/ | 14,438,400 | | (1,572,074) | |
| 9 | Interest on Customer Deposits | 112,191 | | 112,191 | | - | |
| 10 | Depreciation and Amortization Exp. | 5,194,810 | | 5,194,810 | | - | |
| 11 | Taxes Other Than Income | 3,403,518 | B/ | 3,425,744 | | (22,226) | |
| 12 | State Excise Tax | 527,879 | C/ | 245,316 | | 282,563 | |
| 13 | Federal Income Tax | 2,657,669 | C/ | 1,235,070 | | 1,422,599 | |
| 14 | Total Operating Expense | 24,762,394 | | 24,651,531 | | 110,863 | |
| 15 | Net Operating Income for Return | 7,936,834 | | 5,687,380 | | 2,249,454 | |

| Reconciliation: | | | |
|---|---|---|---|
| Revenues - Sales & Transportation | 92,444,773 | 92,444,773 | - |
| Forfeited Discounts Revenue | 577,099 | 577,099 | - |
| Other revenues | 396,149 | 396,149 | - |
| AFUDC | 142,441 | 142,441 | - |
| Total Revenues | 93,560,462 | 93,560,462 | - |

A/ Schedule 8, Line 30
B/ Schedule 9, Line 7
C/ Schedule 10, Line 12 & Line 18
D/ Company Exh MJM-1, MJM-2
E/ Exh PGB-6, P 7 of 14
F/ Credit for "non-jurisdictional" sales

# Chattanooga Gas Company
## Income Statement at Proposed Rates
## For the 12 Months Ending June 30, 2005

| Line No. | | Current Rates | Rate Adjustments | Proposed Rates |
|---|---|---|---|---|
| 1 | Revenues - Sales & Transportation | 92,444,773 | (2,572,230) B/ | 89,872,543 |
| 2 | Cost of Gas | 60,861,234 | - | 60,861,234 |
| 3 | Base Revenues | 31,583,539 | (2,572,230) | 29,011,309 |
| 4 | Forfeited Discounts Revenue | 577,099 | (15,750) C/ | 561,349 |
| 5 | Other revenues | 396,149 | - | 396,149 |
| 6 | AFUDC | 142,441 | - | 142,441 |
| 7 | Operating Margin | 32,699,228 | (2,587,980) | 30,111,248 |
| 8 | Other Operations and Maintenance | 12,866,326 A/ | (26,193) C/ | 12,840,133 |
| 9 | Interest on Customer Deposits | 112,191 | - | 112,191 |
| 10 | Depreciation and Amortization Exp. | 5,194,810 | - | 5,194,810 |
| 11 | Taxes Other Than Income | 3,403,518 | - | 3,403,518 |
| 12 | State Excise Tax | 527,879 | (166,516) C/ | 361,363 |
| 13 | Federal Income Tax | 2,657,669 | (838,345) C/ | 1,819,325 |
| 14 | Total Operating Expense | 24,762,394 | (1,031,054) | 23,731,340 |
| 15 | Net Operating Income for Return | 7,936,834 | (1,556,926) | 6,379,908 |

Reconciliation.

| | Current Rates | Rate Adjustments | Proposed Rates |
|---|---|---|---|
| Revenues - Sales & Transportation | 92,444,773 | (2,572,230) | 89,872,543 |
| Forfeited Discounts Revenue | 577,099 | (15,750) | 561,349 |
| Other revenues | 396,149 | - | 396,149 |
| AFUDC | 142,441 | - | 142,441 |
| Total Revenues | 93,560,462 | (2,587,980) | 90,972,482 |

A/ Schedule 8, Line 30

B/ Schedule 1, Line 8

C/ Line 1 x Schedule 11 (appropriate conversion factor effects)

# Chattanooga Gas Company
## Operation & Maintenance Expenses
## For the 12 Months Ending June 30, 2005

| Line No. | | CAPD | Company A/ | Difference | |
|---|---|---|---|---|---|
| 1 | Salaries and Wages | 2,669,585 | 2,971,585 | (302,000) | B/ |
| 2 | Allocated Costs | 6,602,649 | 7,136,452 | (533,803) | C/ |
| 3 | Production Expense | - | - | - | |
| 4 | Storage Expense | 521,352 | 521,352 | - | |
| 5 | LNG Maintenance | - | - | - | |
| 6 | Distribution Expense | 1,153,546 | 1,153,546 | - | |
| 7 | Distribution - CIE | - | - | - | |
| 8 | Distribution - Maintenance | - | - | - | |
| 9 | Customer Acc. Exp. (Excl. Uncol.) | 48,447 | 48,447 | - | |
| 10 | Uncollectible Accounts Expense | 347,249 | 963,225 | (615,976) | D/ |
| 11 | GTI Funding | - | - | - | |
| 12 | Customer Service | - | - | - | |
| 13 | Sales Expense | - | - | - | |
| 14 | Sales Promotion Expense | 209,654 | 209,654 | - | |
| 15 | Pension Expense | 139,649 | 155,166 | (15,517) | B/ |
| 16 | Injuries and Damages | - | - | - | |
| 17 | Employee Benefits - Insurance | 43,002 | 47,780 | (4,778) | B/ |
| 18 | Employee Savings Plan | - | - | - | |
| 19 | Other Employee Benefits | - | - | - | |
| 20 | Property Insurance | - | - | - | |
| 21 | Other Administrative and General Exp | 1,131,193 | 1,231,193 | (100,000) | E/ |
| 22 | Reg Comm. Expense | - | - | - | |
| 23 | Outside Services | - | - | - | |
| 24 | Misc. General | - | - | - | |
| 25 | Misc Expense | - | - | - | |
| 26 | Rents | - | - | - | |
| 27 | Training | - | - | - | |
| 28 | Transferred Credit | - | - | - | |
| 29 | Corporate Office Allocation Adjust | - | - | - | |
| 30 | Total O&M Expense | 12,866,326 | 14,438,400 | (1,572,074) | |

A/ Company Forecast (MJM-2)

B/ Excludes 10% related to unsupported additional employees per testimony of MDC & DWM

C/ DR# 135

D/ Exclude Uncollectible Accounts ratio x gas costs ( 0 010121 x 60,861,234 )
Sch 11, Line 4 Sch 6, Line 2

E/ Excludes rate case expense amortization per Exh MJM-2, Sch 2

Chattanooga Gas Company
Taxes Other Than Income Taxes
For the 12 Months Ending June 30, 2005

| Line No. | | CAPD | Company A/ | Difference |
|---|---|---|---|---|
| 1 | Property Tax | 1,911,201 | 1,911,201 | - |
| 2 | State Gross Receipts Tax | 672,239 | 672,239 | - |
| 3 | Payroll Taxes | 200,032 | 222,258 | (22,226) B/ |
| 4 | Franchise Tax | 321,246 | 321,246 | - |
| 5 | Other General Taxes | 298,800 | 298,800 | - |
| 6 | TRA Utility Fee | - | - | - |
| 7 | Total Taxes Other Than Income Taxes | 3,403,518 | 3,425,744 | (22,226) |

A/ Company Forecast
B/ Excludes 10% related to unsupported additional employees per testimony of MDC & DWM

# Chattanooga Gas Company
## Excise and Income Taxes
## For the 12 Months Ending June 30, 2005

| Line No. | | Attrition Amount | | Proposed Rates Attrition Amount A/ | |
|---|---|---|---|---|---|
| 1 | Operating Margin | 32,699,228 | A/ | 30,111,248 | |
| 2 | Other Operation and Maintenance | 12,866,326 | A/ | 12,840,133 | |
| 3 | Depreciation and Amortization Expense | 5,194,810 | A/ | 5,194,810 | |
| 4 | Taxes Other Than Income | 3,403,518 | A/ | 3,403,518 | |
| 5 | NOI Before Excise and Income Taxes | 11,234,574 | | 8,672,787 | |
| 6 | less Interest on Customer Deposits | 112,191 | A/ | 112,191 | |
| 7 | less Interest Expense | 3,009,570 | B/ | 3,009,570 | B/ |
| 8 | Pre-tax Book Income | 8,112,813 | | 5,551,026 | |
| 9 | Schedule M Adjustments | 8,407 | | 8,407 | |
| 10 | Excise Taxable Income | 8,121,220 | | 5,559,433 | |
| 11 | Excise Tax Rate | 6 50% | | 6.50% | |
| 12 | Excise Tax | 527,879 | | 361,363 | |
| 13 | Pre-tax Book Income | 8,112,813 | | 5,551,026 | |
| 14 | Excise Tax | 527,879 | | 361,363 | |
| 15 | Schedule M Adjustments | 8,407 | | 8,407 | |
| 16 | FIT Taxable Income | 7,593,341 | | 5,198,070 | |
| 17 | FIT Rate | 35 00% | | 35.00% | |
| 18 | Federal Income Tax Expense | 2,657,669 | | 1,819,325 | |

A/ Schedule 7
B/ Rate Base * Weighted Cost of Debt
(Schedule 2, Line 11 * Schedule 12 Line 1 + Line 2)

Docket No. 04-00034
Exhibit CAPD-DM
Schedule 11

Chattanooga Gas Company
Revenue Conversion Factor
For the 12 Months Ending June 30, 2005

| Line No. | | Amount | | Balance |
|---|---|---|---|---|
| 1 | Operating Revenues | | | 1.000000 |
| 2 | Add: Forfeited Discounts | 0.006123 | A/ | 0.006123 |
| 3 | Balance | | | 1.006123 |
| 4 | Uncollectible Ratio | 0.010121 | A/ | 0.010183 |
| 5 | Balance | | | 0.995940 |
| 6 | State Excise Tax | 0.065000 | B/ | 0.064736 |
| 7 | Balance | | | 0.931204 |
| 8 | Federal Income Tax | 0 350000 | B/ | 0.325921 |
| 9 | Balance | | | 0 605283 |
| 10 | Revenue Conversion Factor ( 1 / Line 9) | | | 1.652121 |

A/ Exhibit MJM-1, Schedule 3
B/ Statutory rate

Chattanooga Gas Company
Cost of Capital
For the 12 Months Ending June 30, 2005

| Line No. | | Ratio | Cost | Weighted Cost |
|---|---|---|---|---|
| 1 | Short Term Debt | 12.90% | 1.26% | 0.16% |
| 2 | Long Term Debt | 44.60% | 6 74% | 3.01% |
| 3 | Preferred Stock | 0.00% | 0.00% | 0.00% |
| 4 | Stockholder's Equity | 42 50% | 8.35% | 3.55% |
| 5 | Total | 100 00% | | 6.72% |

Source Testimony of SNB

# Chattanooga Gas Company
## Transportation Rates and Revenue Summary
## For the 12 Months Ending June 30, 2005

| | (1) Current Rates | (2) CGC Proposed Rates | (3) CGC % Incr | (4) CAPD Proposed Rates | (5) CAPD Revenues | (6) CAPD % Increase |
|---|---|---|---|---|---|---|
| **Residential** | | | | | | |
| Winter Bills/ Customer Charge | $7 50 | $14 00 | 87% | $7 50 | $2,368,785 | 0% |
| Summer Bills/ Customer Charge | $7 50 | $7 50 | 0% | $7 50 | 2,293,208 | 0% |
| Winter-First 25 CCF/th | 0 2900 | 0 2472 | -13% | 0 2350 | 2,041,606 | -18% |
| Next 25 CCF/th | 0 2000 | 0 2472 | 26% | 0 1750 | 1,287,526 | -11% |
| Over 50 CCF/th | 0 1750 | 0 1500 | -13% | 0 1550 | 3,128,771 | -10% |
| Summer-First 25 CCF/th | 0 2100 | 0 2472 | 20% | 0 1700 | 788,227 | -18% |
| Next 25 CCF/th | 0 1500 | 0 2472 | 68% | 0 1200 | 106,672 | -19% |
| Over 50 CCF/th | 0 0450 | 0 1500 | 239% | 0 0400 | 35,198 | -10% |
| **Total R-1** | | | **15 3%** | | 12,049,993 | **-8.6%** |
| **Multi-Family Housing** | | | | | | |
| Winter Units Bills | $6 00 | $6 00 | 0% | $6 00 | $4,836 | 0% |
| Summer Units Bills | $6 00 | $6 00 | 0% | $6 00 | 4,794 | 0% |
| Winter - CCF/th | 0 1800 | 0 2183 | 23% | 0 1460 | 8,292 | -17% |
| Summer - CCF/th | 0 1600 | 0 2183 | 39% | 0 1460 | 2,646 | -7% |
| **Total R-4** | | | **15.3%** | | 20,568 | **-8 7%** |
| **Commercial** | | | | | | |
| Winter Bills | $20 00 | $30 00 | 50% | $20 00 | $1,020,880 | 0% |
| Summer Bills | $15 00 | $20 00 | 33% | $15 00 | 732,075 | 0% |
| Winter-First 3,000 CCF/th | 0 2750 | 0 2932 | 8% | 0 2400 | 5,099,029 | -11% |
| Next 2,000 CCF/th | 0 2510 | 0 2932 | 19% | 0 2300 | 522,407 | -7% |
| Next 10,000 CCF/th | 0 2445 | 0 1500 | -38% | 0 2200 | 889,112 | -8% |
| Over 15,000 CCF/th | 0 1265 | 0 1500 | 21% | 0 1150 | 363,365 | -8% |
| Summer-First 3,000 CCF/th | 0 2159 | 0 2932 | 38% | 0 1900 | 1,323,628 | -10% |
| Next 2,000 CCF/th | 0 1714 | 0 2932 | 74% | 0 1600 | 136,345 | -5% |
| Next 10,000 CCF/th | 0 1598 | 0 1500 | -4% | 0 1400 | 202,919 | -11% |
| Over 15,000 CCF/th | 0 1265 | 0 1500 | 21% | 0 1150 | 105,908 | -8% |
| **Total C-1** | | | **15 3%** | | 10,395,666 | **-8 7%** |
| **I1/T2 Firm Industrial** | | | | | | |
| Bills/ Customer Charge | 300 00 | 300 00 | 0% | 300 00 | $102,900 | 0% |
| Demand dekatherms | 3 0000 | 3 0000 | 2% | 2 7000 | 300,732 | -8% |
| First 1,500 MCF/Dth | 0 8888 | 1 0263 | 17% | 0 7980 | 363,781 | -9% |
| Next 2,500 MCF/Dth | 0 7598 | 0 8773 | 17% | 0 6700 | 364,528 | -10% |
| Next 11,000 MCF/Dth | 0 4312 | 0 4979 | 17% | 0 3800 | 196,132 | -10% |
| Over 15,000 MCF/Dth | 0 2650 | 0 3060 | 17% | 0 2200 | 99,913 | -16% |
| **Total I1/T2** | | | **13.1%** | | 1,427,986 | **-9.2%** |
| **L1/T1 Interruptible Ind** | | | | | | |
| Customer Charge | 300 00 | 300 00 | 0% | 300 00 | $145,200 | 0% |
| First 1,500 MCF/Dth | 0 8888 | 1 0263 | 17% | 0 7980 | 458,032 | -9% |
| Next 2,500 MCF/Dth | 0 7598 | 0 8773 | 17% | 0 6700 | 558,045 | -10% |
| Next 11,000 MCF/Dth | 0 4312 | 0 4979 | 17% | 0 3800 | 582,514 | -10% |
| Over 15,000 MCF/Dth | 0 2650 | 0 3060 | 17% | 0 2200 | 300,104 | -16% |
| **Total L1/T1** | | | **16.4%** | | 2,043,895 | **-10.1%** |
| **SS-1 Industrial** | | | | | | |
| Customer Charge | 300 00 | 300 00 | 0% | 300 00 | $13,500 | 0% |
| First 1,500 MCF/Dth | 0 8888 | 1 0263 | 17% | 0 7980 | 153,667 | -9% |
| Next 2,500 MCF/Dth | 0 7598 | 0 8773 | 17% | 0 6700 | 186,210 | -10% |
| Next 11,000 MCF/Dth | 0 4312 | 0 4979 | 17% | 0 3800 | 186,915 | -10% |
| Over 15,000 MCF/Dth | 0 2650 | 0 3060 | 17% | 0 2200 | 92,120 | -16% |
| **Total SS-1** | | | **17.1%** | | 632,413 | **-10.5%** |
| **Special Contracts** | | | | | | |
| Customer Charge | 3,500 00 | 3,500 00 | 0% | 3,500 00 | $42,000 | 0% |
| All MCF/Dth | 0 0500 | 0 0491 | 0% | 0 0491 | 38,284 | 0% |
| **Total Spec Contract** | | | **0 0%** | | 80,284 | **0.0%** |
| **Total** | 29 223,220 | 4,472,692 | **15 3%** | (2,572,414) | 26,650,806 | **-8.8%** |
| Other Revenues | 396,149 | 58,400 | **15%** | 0 | 396,149 | **0.0%** |
| Revenues before forfeited discou | 29 619 369 | 4,531,092 | **15 3%** | (2,572,414) | 27,046,955 | **-8 7%** |
| Forfeited Discounts | 577,099 | 30,549 | **5%** | (15,750) | 561,349 | **-2.7%** |
| Total Revenues | 30,196 468 | 4,561,641 | **15 1%** | (2,588,164) | 27,608,304 | **-8 6%** |

# Chattanooga Gas Company
## Transportation Rates and Revenues
## For the 12 Months Ending June 30, 2005

| | (1) | (2) | (3) | (4) | (1a) | (5) | (6) | (7) |
|---|---|---|---|---|---|---|---|---|
| | | Projected | | | | CGC | | |
| | Projected | Bills A/ and | | Current | Projected | Proposed (11/1/2004) | | % |
| | Volumes A/ | Demand | Rates A/ | Revenues | Volumes A/ | Rates A/ | Revenues | Incr |
| **Residential** | | 621,599 | | | | | | |
| Winter Bills/ Customer Charge | | 315,838 | $7 50 | $2,368,785 | | $14 00 | $4,421,732 | 87% |
| Summer Bills/ Customer Charge | | 305,761 | $7 50 | 2,293,208 | | $7 50 | 2,293,208 | 0% |
| Winter-First 25 CCF/th | 8,538,770 | | 0 2900 | 2,476,243 | 8,687,686 | 0 2472 | 2,147,596 | -13% |
| Next 25 CCF/th | 7,231,182 | | 0 2000 | 1,446,236 | 7,357,294 | 0 2472 | 1,818,723 | 26% |
| Over 50 CCF/th | 19,839,619 | | 0 1750 | 3,471,933 | 20,185,622 | 0 1500 | 3,027,843 | -13% |
| Summer-First 25 CCF/th | 4,557,155 | | 0 2100 | 957,003 | 4,636,632 | 0 2472 | 1,146,175 | 20% |
| Next 25 CCF/th | 873,695 | | 0 1500 | 131,054 | 888,932 | 0 2472 | 219,744 | 68% |
| Over 50 CCF/th | 864,857 | | 0 0450 | 38,919 | 879,940 | 0 1500 | 131,991 | 239% |
| **Total R-1** | 41,905,278 | | | 13,183,381 | 42,636,106 | | 15,207,012 | **15%** |
| **Multi-Family Housing** | | | | | | | | |
| Winter Units Bills | | 806 | $6 00 | $4,836 | | $6 00 | 4,836 | 0% |
| Summer Units Bills | | 799 | $6 00 | 4,794 | | $6 00 | 4,794 | 0% |
| Winter - CCF/th | 55,820 | | 0 1800 | 10,048 | 56,794 | 0 2183 | 12,398 | 23% |
| Summer - CCF/th | 17,814 | | 0 1600 | 2,850 | 18,125 | 0 2183 | 3,957 | 39% |
| **Total R-4** | 73,634 | | | 22,528 | 74,918 | | 25,985 | **15%** |
| **Commercial** | | 99,849 | | | | | | |
| Winter Bills | | 51,044 | 20 00 | 1,020,880 | | 30 00 | 1,531,320 | 50% |
| Summer Bills | | 48,805 | 15 00 | 732,075 | | 20 00 | 976,100 | 33% |
| Winter-First 3,000 CCF/th | 20,881,774 | | 0 2750 | 5,742,488 | 21,245,952 | 0 2932 | 6,229,313 | 8% |
| Next 2,000 CCF/th | 2,232,403 | | 0 2510 | 560,333 | 2,271,336 | 0 2932 | 665,956 | 19% |
| Next 10,000 CCF/th | 3,972,143 | | 0 2445 | 971,189 | 4,041,417 | 0 1500 | 606,213 | -38% |
| Over 15,000 CCF/th | 3,105,532 | | 0 1265 | 392,850 | 3,159,692 | 0 1500 | 473,954 | 21% |
| Summer-First 3,000 CCF/th | 6,847,053 | | 0 2159 | 1,478,279 | 6,966,466 | 0 2932 | 2,042,568 | 38% |
| Next 2,000 CCF/th | 837,547 | | 0 1714 | 143,556 | 852,154 | 0 2932 | 249,851 | 74% |
| Next 10,000 CCF/th | 1,424,574 | | 0 1598 | 227,647 | 1,449,419 | 0 1500 | 217,413 | -4% |
| Over 15,000 CCF/th | 905,149 | | 0 1265 | 114,501 | 920,935 | 0 1500 | 138,140 | 21% |
| **Total C-1** | 40,206,175 | | | 11,383,797 | 40,907,371 | | 13,130,828 | **15%** |
| **I1/T2 Firm Industrial** | | | | | | | | |
| Bills/ Customer Charge | | 343 | 300 00 | 102,900 | | 300 00 | 102,900 | 0% |
| Demand dekatherms | | 109,473 | 3 0000 | 328,419 | 111,382 | 3 0000 | 334,147 | 2% |
| First 1,500 MCF/Dth | 448,052 | | 0 8888 | 398,229 | 455,866 | 1 0263 | 467,855 | 17% |
| Next 2,500 MCF/Dth | 534,746 | | 0 7598 | 406,300 | 544,072 | 0 8773 | 477,314 | 17% |
| Next 11,000 MCF/Dth | 507,289 | | 0 4312 | 218,743 | 516,136 | 0 4979 | 256,984 | 17% |
| Over 15,000 MCF/Dth | 446,365 | | 0 2650 | 118,287 | 454,150 | 0 3060 | 138,970 | 17% |
| **Total I1/T2** | 1,936,452 | | | 1,572,877 | 1,970,224 | | 1,778,170 | **13%** |
| **L1/T1 Interruptible Ind.** | | | | | | | | |
| Customer Charge | | 484 | 300 00 | 145,200 | | 300 00 | 145,200 | 0% |
| First 1,500 MCF/Dth | 564,137 | | 0 8888 | 501,405 | 573,976 | 1 0263 | 589,071 | 17% |
| Next 2,500 MCF/Dth | 818,626 | | 0 7598 | 621,992 | 832,903 | 0 8773 | 730,706 | 17% |
| Next 11,000 MCF/Dth | 1,506,656 | | 0 4312 | 649,670 | 1,532,932 | 0 4979 | 763,247 | 17% |
| Over 15,000 MCF/Dth | 1,340,725 | | 0 2650 | 355,292 | 1,364,107 | 0 3060 | 417,417 | 17% |
| **Total L1/T1** | 4,230,144 | | | 2,273,559 | 4,303,918 | | 2,645,640 | **16%** |
| **SS-1 Industrial** | | | | | | | | |
| Customer Charge | | 45 | 300 00 | 13,500 | | 300 00 | 13,500 | 0% |
| First 1,500 MCF/Dth | 189,265 | | 0 8888 | 168,219 | 192,566 | 1 0263 | 197,630 | 17% |
| Next 2,500 MCF/Dth | 273,162 | | 0 7598 | 207,548 | 277,926 | 0 8773 | 243,824 | 17% |
| Next 11,000 MCF/Dth | 483,451 | | 0 4312 | 208,464 | 491,882 | 0 4979 | 244,908 | 17% |
| Over 15,000 MCF/Dth | 411,548 | | 0 2650 | 109,060 | 418,725 | 0 3060 | 128,130 | 17% |
| **Total SS-1** | 1,357,426 | | | 706,792 | 1,381,100 | | 827,993 | **17%** |
| **Special Contracts** | | | | | | | | |
| Customer Charge | | 12 | 3,500 | 42,000 | | 3,500 00 | 42,000 | 0% |
| All MCF/Dth | 765,726 | | 0 0500 | 38,286 | 779,080 | 0 04914 | 38,284 | 0% |
| **Total Spec Contract** | 765,726 | | | 80,286 | 779,080 | | 80,284 | 0% |
| **Total Industrial** | 8,289,748 | 884 | | 4,633,514 | 8,434,321 | | 5,332,088 | 15% |
| **Total** | | | | 29,223,220 | | 4,472,692 | 33,695,912 | 15% |
| Other Revenues | | | | 396,149 | | 58,400 | 454,549 | 15% |
| Revenues before forfeited discounts | | | | 29,619,369 | | 4 531 092 | 34,150,461 | 15% |
| Forfeited Discounts | | | | 577,099 | | 30,549 | 607,648 | 5% |
| Total Revenues | | | | 30,196,468 | | 4,561,641 | 34,758,109 | 15% |

A/ PGB-6, P 8

## Gross Profit vs Net Profit

| | |
|---|---|
| Sales | 1,000,000 |
| Less: Cost of goods sold (commodity, transportation, hedging) (Consumers pay 100% of these costs.) | 700,000 |
| **Gross profit** | 300,000 |
| Less: Other costs (Storage, reservation fees, demand) (Consumers pay 100% of theses costs.) | 500,000 |
| **Net operating income / Net profit (or loss)** | (200,000) |