Chattanooga Gas Company Testimony of Tim Sherwood for Docket 07-00224

Q. Please state your name and position.

A. My name is Tim Sherwood. I am Managing Director of Capacity Planning for AGL Services Company. I am testifying on behalf of Chattanooga Gas Company ("CGC" or "Company").

Q. Have you provided an outline of your background and professional experience?

A. Yes. Attached is Exhibit TSS-1, which contains a summary of my background and professional experience.

Q. Are you sponsoring exhibits in connection with your testimony?

A. Yes. I am sponsoring four exhibits:

SP Exhibit TSS-1, professional experience and background of Timothy Sherwood;

SP Exhibit TSS-2, design day load and capacity comparison;

SP Exhibit TSS-3, cost analysis of Saltville Storage;

SP Exhibit TSS-4, CGC system map with ETNG facilities;

Q. What will your testimony address?

A. In my testimony, I will provide a general overview of the capacity planning and gas supply function of CGC, respond to certain issues and items raised in the testimony of Dr. Stephen Brown and Mr. Terry Buckner in Docket 07-00224, and address the items on the issues list filed in this docket. With respect to the testimony of Dr. Brown and Mr. Buckner, I will: (1) address Dr. Brown's assertion that CGC "does not have a planning process which joins the needs of firm customers to transportation, peaking, and storage capacity"; (2) address the assertion that CGC is holding more firm capacity than is needed to reliably serve its firm customers and explain why an analysis of annual firm usage is inappropriate to evaluate the level of firm transportation capacity that is required to meet firm customer needs; (3) refute Dr. Brown's statement that "the need for CGC's LNG facilities is declining" and demonstrate that the need for CGC's LNG ("Liquified Natural Gas") peaking facility has actually increased to meet firm customer design day usage at a cost significantly lower than cost associated with LNG service that could be purchased from East Tennessee Natural Gas ("ETNG"); (4) explain why up to this point CGC firm customers are not benefited in contracting for capacity from Saltville storage; (5) clear up some of the apparent confusion associated with CGC's reduction of firm transportation capacity in 2006 as well as the mistaken assumption by Dr. Brown that seasonal firm capacity to CGC's system is available on ETNG; and (6) address Mr. Buckner's statement regarding the appropriateness of CGC's asset management arrangement with Sequent Energy Management.

Capacity Planning and Gas Supply Overview

Q. Who is responsible for the capacity planning and gas supply function for CGC?

A. The load forecasting, pipeline transportation capacity, storage service levels, peaking capability requirements, daily supply resource management, system monitoring, and asset manager compliance are functions that are all performed by AGL Service Company employees, who exclusively work for the AGL Resources' LDCs, including CGC.

Q. Can you provide an overview of the capacity planning function for CGC?

A. Yes. The capacity planning objective of CGC is to be able to meeting the gas supply needs of its firm service customers under the coldest weather conditions that can reasonably be expected to occur in the service territory utilizing either pipeline services that are contracted for on a firm basis or using resources under the operational control of the utility.

The fundamental analysis performed to determine the level of daily natural gas delivery service or daily capacity needed to reliably meet the needs for firm customers under extreme cold weather is a design day load forecast. The analysis involves performing statistical regressions on historical firm load levels under historical weather conditions to determine a load to temperature relationship. Once this relationship is determined, the factors developed can be applied to extreme weather conditions that have occurred in the service territory to project how much gas will be needed by the firm customers on the most extreme day or design day. Similar analysis is performed to project heating season and full year load patterns.

We then review what capacity resources are available to meet the projected load patterns. These resources are made up of pipeline firm transportation, pipeline storage, pipeline peaking, and on-system peaking.

Firm transportation provides for uninterrupted movement of natural gas from a particular receipt point to a defined delivery point. Reserving this capacity in the pipeline typically results in a monthly demand fee paid independent of utilization of the capacity.

Pipeline storage service generally consists of some type of cavern underground in which natural gas is stored under pressure. This gas can be injected into storage or withdrawn from storage and allows for flexibility in matching gas demand with supply as well as some opportunity to manage gas acquisition costs. Normally some level of firm pipeline transportation is needed to deliver the gas from the storage facility to the LDC's distribution system.

Pipeline peaking is most often provided in the form of LNG. Natural gas is delivered to the facility in the summer period, liquified and stored in tanks. In the winter during periods of extreme demand, the customer can have the pipeline vaporize the LNG and deliver it to the LDC system through firm transportation.

On-system peaking operates very much similar to pipeline peaking service with the exception that it is located on the LDC's distribution system and therefore does not require additional firm transportation on the pipeline to be delivered.

Through review of continuing service contracts and available service alternatives, CGC enters into contracts for service that will meet the needs of its firm customers.

Q. Can you provide an overview of the gas supply function at CGC?

A. Yes. Under the asset management agreement ("AMA"), CGC has the right to call for delivery of natural gas supplies in the same manner as if the AMA were not in place. Therefore, personnel working exclusively for the utility determine the level of natural gas that will be purchased and transported through the firm transportation, the amount of natural gas that will be injected or withdrawn from storage for the utility, and also decide if the on-system LNG facility will be used to meet customer demand.

Gas to be transported to the LDC through firm transportation is normally purchased in one of two ways. The utility can make a commitment in the last week of a month to purchase the same amount of natural gas everyday for the entire next month. These purchases are normally called base load purchases. This type of purchase locks in the price of the supply for the entire month and does not provide flexibility to deal with load variations. In addition, the LDC can purchase gas for next day delivery or "swing gas" to be transported in its pipeline firm transportation. This form of purchase provides much more flexibility, but greater price risk, since the price of the gas is reset each day.

Each month the historical loads and weather are reviewed and CGC indicates to the asset manager how much gas is to be delivered on a base load basis. Similarly, each day a next day forecast is developed for the system and a decision as to the level of swing gas to be delivered is communicated to the asset manager. Typically, CGC targets to purchase 50% - 60% of its pipeline transportation supply on a base load basis in order to balance price certainty with operation flexibility.

CGC uses pipeline storage services to mitigate the impact of volatile natural gas prices, to protect access to supply, and to meet the operational flexibility needs of the system. Natural gas injected into storage provides a physical price hedge to customers by locking in the cost at the injection price. Therefore, if prices rise significantly in the winter, gas withdrawn from storage is priced to customers at its original injection cost. Equally important, the storage provides protection from loss of traditional well head supplies as happened in the wake of hurricane's Katrina and Rita. Also, given that load on the CGC system is so significantly driven by temperature, it is important to have access to supplies that can be accessed during the day, in the event that actual temperatures vary from what was forecasted.

Pipeline storage services have various tariff based limitations and constraints that are designed to align the service being provided with the operational characteristics of the physical facilities. These tariff requirements include maximum and minimum storage inventory levels, limits on daily withdrawal and injections, as well as seasonal service restrictions. In order to ensure tariff compliance and reliable service to the firm customers, storage inventory management is performed and communicated to the asset manager.

CGC's LNG peaking facility is located on the distribution system and therefore benefits the system by allowing the LDC to contract for a lower level of firm pipeline transportation. It also protects customer from events that may make traditional sources of supply unavailable. This resource can only provide deliverability for a few days due to storage limitations. Because of this limitation, the LNG plant is only used under extreme cold conditions or toward the end of the winter period, when the need for design day coverage has passed. Its dispatch and operation is under the direct control of personnel working for CGC.

<u>Response to Testimony of Dr. Brown and Mr. Buckner</u>

Q. Do you agree with Dr. Brown's assertion that CGC's capacity planning process does not join the portfolio development with the needs of firm service customer?

A. No. CGC's pipeline transportation, storage, and peaking capacity planning process is solely and exclusively focused on meeting the needs of firm customer under certain extreme weather conditions, when natural gas space heating needs of the firm service customers is most critical.

Q. How does the Company determine the level of capacity needed to meet firm customers' demand?

A. The Company begins this determination by projecting the design day usage of firm customers. Design day usage is the maximum daily firm load for firm customers with firm supply rights on CGC's distribution system. This projection is done by performing a number of statistical analyses on actual, historical customer load under actual weather conditions to establish a load to temperature relationship on a per customers basis. Based on this relationship, a design day load forecast is developed using the projected number of customers with firm supply rights at the design temperature. The design temperature represents one of the coldest days expected in the service territory based on historical observations. Applying all of these factors produces a design day load forecast for firm supply customers. CGC review's the supply portfolio to make sure enough firm gas will be available to meet firm customers' needs on a design day.

Q. Does the Company's analysis include the need to provide firm service to non-firm customers in determining the firm capacity portfolio?

A. No, however, the Company does continue to have an obligation to meet the firm supply needs of rate class customer T-2 (Interruptible Transportation Service with Firm Gas Supply Backup) and T-3 (Low Volume Transport Service) Rate Schedules, which have the right to switch between firm supply and self supply and were excluded from Dr. Brown's annual volume analysis. In addition CGC has an obligation to its industrial customers serviced under the F-1 (Large Volume Firm Service) Rate Schedule that were also excluded in the list of customers that Dr. Brown classified as firm customers.

Q. Do you agree with Dr. Brown's testimony that CGC holds more firm capacity than is needed to reliably service its firm service obligation?

A. No. As outlined in exhibit TSS-2, CGC maintains an amount of firm design day capacity to reliably meet the needs of customers with firm supply rights under certain extreme weather conditions, when the need for reliable natural gas service for space heating is most important to our customers. The only change that has been made to CGC's capacity since its purchase has been to reduce capacity.

Q. Why is Dr. Brown's reliance on a review of firm customer throughput not the appropriate way to determine the necessary level of firm capacity?

A. Capacity is a measure of daily take rights and is associated with the amount of gas that must be available to meet the daily needs of the system. Therefore annual usage, which is the sum of usage over the entire year, is not the appropriate way to determine how much gas is needed on the maximum day. CGC acquires firm capacity to meet the needs of customers with firm supply rights for the coldest day that may reasonably occur in the service territory, not the average temperatures that happened to have occurred over the past few years.

Q. Did Dr. Brown identify the amount of firm interstate capacity that CGC needs to service its firm customers?

A. No.

Q. Did Dr. Brown provide any study or analysis to show the amount of firm interstate capacity that CGC requires to serve its customers?

A. No.

Q. Is Dr. Brown's statement that "the need for CGC's LNG facilities is declining" accurate?

A. No. To the contrary, CGC is relying on a higher amount of daily peaking capacity now than in the past to meet the firm supply needs of its customer. CGC's LNG plant was originally designed to provide 60,000 dths per day of vaporized natural gas into the distribution system with a redundant vaporizer to enhance single contingency reliability. The facility was designed with this level of capability because internal distribution pipe constraints and localized load levels only allowed for approximately 60,000 dths of load to be served under peak load conditions. As load in proximity to the plant has grown, CGC has increased the level of capacity needed from the plant under design day conditions from 60,000 dths to 70,000 dths.

Q. What are the benefits to CGC customers associated with the LNG facility?

A. Benefits of the LNG Plant include the ability to shape the portfolio to best meet the needs of space heat load customers and avoid year round pipeline capacity charges, reduced reliance of gas that must be delivered through existing and constrained pipeline gate stations, and supply diversity.

Q. How does the cost of CGC's LNG Plant compare with ETNG's LNG service?

A. In order to utilize ETNG LNG service, CGC would have to contract for 70,000 dth per day of LNG service as well as 70,000 dths of firm pipeline capacity to transport gas to and from the LNG facility to the CGC system. The cost of acquiring this capacity would be approximately $7.7 million per year. The annual cost of CGC LNG Plant is approximately $4.1 million per year. These additional costs of utilizing ETNG LNG service do not include the added capital required to expand CGC's gate station interconnections with ETNG or the internal distribution pipelines from those gate stations to the load areas.

Additional costs to the customers would include, the loss of supply security associated with gas stored locally, loss in pressure support capability associated with an on-system resource, and the loss of operation balancing flexibility afforded by the CGC Plant allowing for better capacity utilization.

Q. Would you recommend CGC replace CGC's LNG Plant with ETNG's LNG service?

A. Absolutely not.

Q. Why has CGC not included Saltville storage in the CGC capacity portfolio?

A. In short, CGC does not currently need the capacity to reliably serve its customers and adding the service to the portfolio would increase costs.

Q. Has CGC evaluated the cost of holding capacity in the Saltville Storage facility?

A. Yes, CGC has made such an analysis as shown in exhibit TSS-3

Q. What were the results of CGC's analysis of potential service from the Saltville Storage facility?

A. CGC evaluated the fixed and variable charges associated with the Saltville facility with those of the Tennessee Gas Pipeline and Southern Natural Gas Pipeline services currently under contract. Saltville showed to be a more expensive service than those currently contracted by CGC.

Q. Are there other considerations CGC would have to make in securing service from the Saltville storage facility on East Tennessee pipeline?

A. Yes, As is illustrated in exhibit TSS-4, Saltville Storage as well as ETNG peaking facility are both located east of CGC's service territory and not along the path of its existing FT capacity, which is sourced from the west end of the system and provides for firm rights to the CGC system. Therefore, CGC would need to subscribe to incremental FT capacity to and from the Saltville Storage facility to receive delivery from and make injections to the storage. The cost of this additional capacity would be a further economic disadvantage to holding the service.

Q. Why would CGC need incremental FT?

A. The Saltville Storage facility does not lie in the path of CGC's current receipt and delivery point entitlements on ETNG as illustrated in exhibit TSS-4. To receive firm delivery of withdrawals from the storage an FT-A transport agreement would be required. The same is true when CGC would need to direct gas to Saltville Storage for injection.

Q. Can you explain the sequence of events that lead to CGC's contract reduction of 5,000 Dth/d?

A. Yes. The company originally held a single firm transport contract on ETNG for 46,350 Dth/d. For added contract level flexibility the company negotiated with ETNG to break this single contract down into 3 separate contracts. Contracts 410203 for 13,000 Dth/d, 410204 for 28,350 Dth/d and 410199 for 5,000 Dth/d. In total the contracted capacity matched the single contract being replaced. As a part of the negotiations with the pipeline to disaggregate the capacity contract, the utility elected to move 5,000 Dth/d of receipt capacity off of Ridgetop and move it to Hartsville. This capacity was destined to be turned back to the pipeline. Without breaking the capacity contract into 3 separate contracts any reduction would have to be made on a pro-rata basis across all the receipt and delivery points under contract. CGC did not want to proceed in that manner. The parties agreed to move receipt capacity off of Ridgetop to allow the pipeline to offer that capacity in the marketplace. So the pipeline was able to re-market capacity and the utility was able to reduce its contracted capacity per the pipeline's FERC approved tariff.

Q. Was there an agreement between CGC and Sequent on the receipt point modifications?

A. No. The company did not knowingly reduce or shift receipt point capacity to facilitate the needs of Sequent. The capacity changes described here were all handled in accordance with the provisions of the pipeline's FERC approved tariff.

Q. Do you know how Sequent added Ridgetop receipt capacity?

A. It is CGC's understanding that Sequent had placed a request for a receipt point shift for existing capacity in the pipeline's firm service queue. When the capacity became available it was awarded by the pipeline to the parties in the queue in accordance with the provisions of the pipeline's FERC approved tariff.

Q. What is your response to Dr. Brown's suggestion that CGC replace existing year round capacity with seasonal capacity?

A. First, Dr. Brown's suggestion does not appear to take into account the need to utilize transportation service to refill LNG Peaking and storage service in the non-winter period. More importantly, neither Southern Natural Gas nor East Tennessee have firm seasonal capacity posted as available on their systems and both have specifically refused to provide such service to CGC, if CGC were not willing to accept interruptions in service in the winter period or pay the same annual price for the service.

Q. If CGC were to agree to curtail in the winter period, would it mean that CGC would in effect be purchasing interruptible service during the winter period?

A. Yes.

Q. Could CGC depend on interruptible interstate pipeline service to provide service to its firm customers?

A. No.

Q. What is the appropriate level and mix of firm transportation, peaking and storage capacity and what assurance does the TRA have that the level and mix is appropriate?

A. CGC's planning process ensures that these aspects of the gas supply portfolio are continually reviewed. At this point the mix of firm transportation, peaking and storage capacity are appropriate for the characteristics of the customer load served by the gas supply assets under contract.

The annual Actual Gas Cost (ACA) filing submitted by the Company is thoroughly reviewed by the TRA Staff. The Staff prepares and issues a report of its findings along with recommendations. The TRA Directors, after review of the report, adopts the report, modifies the report, or takes other action as it sees fit. In addition, the TRA Directors have the authority to review the level of capacity at any time if it determines such a review is warranted.

CGC believes that the current review process affords the TRA Staff and the TRA the oversight required to ensure that CGC continues to subscribe to the proper level and mix of firm transportation, peaking, and storage capacity.

Q. What is the process that CGC uses to determine the amount and timing for injecting gas into storage?

A. CGC develops plans prior to the summer injection season that considers the level of injections to be achieved, injection entitlements available under its contracted storage services, and known constraints to injection service such as annual reservoir testing performed by the service providers. The utility does not control the cost of the commodity at the time of injections but it does consider the timing of injections subject to the constraints of what must be accomplished during the injection period. When the injection plan allows flexibility on the timing of injections to accommodate cost considerations the utility will and does adjust its plans.

Since the cost of stored gas flows through the PGA it is subject to the TRA's annual ACA review. During this review the TRA staff can address any concerns that it has with CGG injections and withdrawal from storage to insure that the Company uses its storage assets to benefit its customers. If necessary, the Staff can recommend that the TRA take additional action. In addition the TRA can direct the Staff to review CGC injections into storage and its use if it determines additional review is warranted.

Q. What assurance does the TRA have that CGC sales and purchases of natural gas have been prudent ?

A. CGC's sales and purchases of natural gas have been prudent. The purchases are subject to the requirements of the PBR provisions included in its tariff and the TRA Staff reviews CGC's compliance with the tariff provisions each year.

Q. Can you provide an overview of CGC's asset management agreement?

A. Yes. Under the terms of the agreement CGC makes certain pipeline capacity assets available to the asset manager on a agency basis in order to allow the asset manager to market the services to other markets when the assets are not needed to meet the needs of CGC's firm customers. The utility retains the right to call on services in the same manner that it would absent the asset management agreement.

The utilities obligations under the agreement are consistent with those described earlier in my testimony. They are required to forecast load, determine the appropriate services required, contract for the services, determine gas purchase levels, decide and communicate storage utilization, verify gas delivery, monitor system integrity and pipeline flow, and operate the LNG facility.

The asset manager is required to source commodity gas as nominated by CGC. Arrange for physical delivery of the gas on the pipeline system, market available assets to other markets, manage credit risk with gas suppliers and alternative market customers, maintain auditable records of all transactions, and coordinate its use of all assets with Gas Control.

Under the terms of the current agreement approved by the TRA, the asset manager is required to pay to CGC 50% of gross margins from transactions using CGC assets, with a guaranteed minimum payment paid quarterly, regardless of the level of gross margin.

Q. Can you provide some background as to the value sharing included in the latest asset management arrangement put out to bid and approved by the TRA?

A. Yes. Prior to utilizing asset management to extract value from the gas supply assets of CGC when not needed to serve its customers, CGC would either attempt to release capacity through the pipeline process or attempt to sell delivered gas to other customers. The margin derived to off-system sales were shared between the CGC and firm customers on a 50/50 basis.

When CGC introduced asset management the 50/50 sharing concept remained, but with CGC's affiliate asset manager, Sequent, retaining the company's portion. Given the success that asset management had at enhancing value, CGC came to the conclusion that continuing with this capacity optimization method was in the best interest of its customers.

When the TRA required CGC to competitively bid the most recent asset management agreement the Utility decided to maintain the 50/50 sharing as before, but required a minimum annual guarantee from the asset manager, which would have to be paid regardless of the amount of value extracted from the assets. This would allow the bid process to result in a clear winner, since one bidder's offer of 60% to CGC might result in a lower value to customers than a more successful manager's offer of 50% to CGC.

As a result of this value sharing methodology the actual percentage provided to the customers is at a minimum 50% and potentially greater than 100%. Sharing in excess of 50% would occur whenever the asset manager's actual value creation were less than two times the minimum annual guarantee.

Through past asset management agreements, CGC has been very successful in returning very favorable gains to its customers. Over the past thirty-nine months, CGC's customers have received approximately $7.9 million for the non-jurisdictional sale of gas supply assets that otherwise would have been sitting idle. These are very favorable results considering the small size of CGC with approximately 62,000 firm customers.

Q. Are the current affiliate guidelines sufficient?

A. CGC's ratepayers are properly compensated under the current affiliate guidelines and the Company does not recommend a change to them.

Q. Does Sequent manage any of CGC's physical assets?

A. No. Sequent manages only the assets listed on Exhibit A to the asset management agreement approved by the TRA. There are no physical assets listed on Exhibit A.

Q. Do you agree that based on Mr. Buckner's analysis that ratepayer compensation under the asset management arrangement is too low?

A. No. In his testimony Mr. Buckner says that "CGC's Agreement compensation is favorable comparable to the compensation of the two other regulated LDC in Tennessee." He relies on a relatively small number of examples that have fixed sharing levels greater than 50%, but does not indicate if these agreements include a minimum guarantee.

Q. Why do you think it is inappropriate to use the sharing levels in other jurisdictions to establish the appropriate level of sharing in Tennessee?

A. Given the detailed and complicated nature of asset management arrangements and gas cost recovery mechanisms a percentage in one state applied to one particular LDC may not be comparable to an agreement that was reviewed by the TRA Staff and considered and voted on by the Directors.

Q. Should the current CGC sharing mechanism for the gain from asset management and off-system sales be revised?

A. No, the current sharing mechanism for the gain from asset management and off-system sales should not be revised. These matters underlie the currently effective and approved asset management agreement that CGC has with its asset manager. Changing them at this point would negate the favorable results and benefits that the ratepayers will receive as the direct result of a competitive bidding process for the asset management services.

Q. Does the RFP process as required by CGC's tariff as approved by the TRA insure that CGC's ratepayers are properly compensated by Sequent?

A. The current AMA is the result of fair competitive bid process that resulted in bids being received from a group of highly skilled and highly competent asset managers. Sequent was selected as a result of its having the highest guaranteed payments. In addition to minimum payment, CGC customers benefit if Sequent is able to generate additional value. The RFP process followed in selecting Sequent as the asset manager ensures that the ratepayers are being properly compensated.

Q. In his testimony, Mr. Buckner raises a concern that CGC might change the assets included in the agreement or that CGC might transfer such assets to the parent of affiliate. He states: "However, there is no audit mechanism in place to verify the detailed records and to verify transactions are in the public interest." Can you respond to the concern with the possible change in the assets covered by the Asset Management Agreement? Can you respond to the concern that CGC might add assets or transfer assets to an affiliate?

A. Yes. First, CGC is not aware of any instances where the Company has intentionally removed contracted assets from the asset mix with the intention of letting them be contracted for by an affiliate or parent company. Modifications to the assets managed under the asset management agreement are a provision of the agreement between the company and the asset manager and was included in the agreement recently reviewed and approved by the TRA. It would have been inappropriate not to have included such a provision in the agreement to address a possible change if conditions warranted a change in the supply assets needed by CGC to service its customers.

As for his position that no audit mechanism is in place, I disagree. As I have previously explained, the TRA Staff conducts an annual review of CGC's ACA filing. This review not only addresses the cost of gas recovered from CGC's customer but it includes the review of the gain from asset management and off-system sales. If during these reviews, the Staff has a concern with the related transactions, it can recommend action to the Directors.

Q. Should the TRA be concerned the monitoring CGC's asset management activities if it elects to engage in asset management itself?

A. No. Monitoring of CGC's asset management activities are unnecessary since the Company does not have and does not plan to develop the capability to undertake asset management functions. The costs to enter into these activities, secure the systems required and hire the expertise necessary to effectively bring these tasks in house are a strong deterrent.

Q. What is your response to the testimony provided by Mr. Buckner regarding changes to the asset management agreement?

A. The Company has fully briefed its position on the changes that the Consumer Advocate has argued in TRA Docket 08-00012. The Company relies on the information provided in its brief and reply brief filed in TRA Docket 08-00012.

Q. Are there any payments mandated by FERC?

A. There are no current FERC provisions for mandated payments.

Q. Does this conclude your testimony?

A. Yes it does.

Exhibit TSS-1

Mr. Timothy Scott Sherwood
Professional Experience and Educational Background

After graduating from Illinois State University with a Bachelors Degree in Economics, Mr. Sherwood began his professional career in August of 1985 as a Rate Analyst in the Rates and Planning Department of Illinois Power Company, a combination gas and electric utility serving approximately 600,000 customers in downstate and southern Illinois. In that role, he was responsible for managing informal customer complaints filed with the Illinois Commerce Commission, administering the data request responses and testimony development for routine regulatory filings with the Commission. In addition he performed cost of service and cost allocation studies in support of rate filings.

In August 1987, Mr. Sherwood was promoted to Gas Marketing Specialist in the Industrial Gas Sales Department. While in this position, he was tasked with administration of the new gas transportation program available to commercial and industrial customers of Illinois Power. His job responsibilities included establishing relationships with gas technology developers and vendors and conducting technology sales programs. He was also charged with monitoring and evaluating Federal Energy Regulatory Commission (FERC) rules and policies regarding Order 436.

Mr. Sherwood was promoted to the position of Industrial Sales Specialist in the Marketing Department in June of 1989. In this position, he was responsible for the sales and customer service relationship for the company's largest 30 gas and electric customers. He worked with the Engineering, Accounting, and Regulatory Affairs Departments to coordinate customer expansions, resolve billing issues, and win approval of special service contracts.

In February 1991, Mr. Sherwood was promoted to Administrator Federal Regulatory Matters in the Gas Supply Department of Illinois Power Company. This position required that Mr. Sherwood monitor FERC matters impacting the company's gas business, represent Illinois Power at FERC technical conferences, manage activities of outside FERC counsel, interpret pipeline tariffs related to transportation and storage services, and supporting company positions within various Pipeline customer groups. He was the company's lead participant in the development of a settlement of Order 500 / 528 gas supply realignment costs allocations and recovery. He also acted as the lead negotiator for the unbundling of wholesale natural gas services consistent with Order 636 on ANR Pipeline, Mississippi River Transmission Corporation, Panhandle Eastern Pipeline, and Natural Gas Pipeline Company.

Mr. Sherwood became the Supervisor of Gas Supply in October 1993. He had supervisory responsibilities for 13 employees with various gas supply functions, including short and long-term load forecasting, transportation capacity and supply planning, interstate pipeline and gas producer contracting, gas control and system operations, supply scheduling and nominating, as well as invoice review and processing.

In May of 1995, Mr. Sherwood was promoted to Electric Arrangements Manager in Electric Supply Department of Illinois Power Company. In this role, he directed and coordinated cross functional teams from Electric Supply, Regulatory Affairs, and the Office of General Counsel to develop FERC Order 888, compliant, electric open access transmission tariffs for filing with the FERC. He also performed market power studies to support the company market-based power marketing certificate with FERC. He also negotiated wholesale power and transmission contracts with the Soyland Power Cooperative and the Illinois Municipal Electric Agency.

In January 1998 Mr. Sherwood joined Washington Gas Light Company a local distribution company serving approximately 1,000,000 customers in the Washington D.C. metropolitan area as their Area Head (Manager) of Energy Acquisition in the Energy Acquisition Department. He and his staff were responsible for short and long-term system load forecasting, the purchase and nomination of daily gas supplies, and expert witness support of regulatory gas cost recovery filings. His role included supervision of the transportation and supply planning process, and negotiating pipeline storage and transportation contracts. In this position, he developed the company's first comprehensive asset management arrangements. He also had management responsibility for the personnel administering the gas supplier choice programs for all gas customers.

Mr. Sherwood was promoted to Director of Energy Acquisition for Washington Gas in May of 1999. In this position he provided supervisory direction of staff of 25 professionals responsible for all aspects of natural gas supply for the Company. He had oversight of a team of staff employees and external consultants that develop the design day, winter season, and annual load projections for firm and interruptible natural gas users as well as the staff responsible for gas volume tracking, cost classification, and invoice processing. He also was responsible for directing activities of company personnel tasked with development and administration of the firm and interruptible transportation program. His role included the supervision of the Gas Control function, which operates the company gate-stations, monitors of the distribution system critical pressure stations, and dispatched company owned propane/air and natural gas storage resources. Mr. Sherwood functioned as the company's lead negotiator with interstate pipelines and was the primary company witness in regulatory proceedings related to gas supply matters before the District of Columbia Public Service Commission, Maryland Public Service Commission, and the Virginia State Corporation Commission.

Mr. Sherwood joined AGL Resources in November 2005 as Managing Director of Gas Supply and Capacity Planning in the Gas Operations Group. He has management responsibility for all aspects of natural gas supply for the corporation's retail natural gas customers in six states. He supervises a team of staff employees and external consultants that develop load forecasts for firm and non-firm gas users. His responsibilities includes directing the development and management of a portfolio of gas supply resources designed to meet the needs of the local distribution systems of Atlanta Gas Light Company, Chattanooga Gas Company, Elkton Gas, Elizabethtown Gas Company, and Florida City Gas.

In 2006, Mr. Sherwood was a speaker at Platt's Gas Storage Outlook conference. During his career with Washington Gas, Mr. Sherwood represented the company with the American Gas Association (AGA). He presented to the U.S. Senate Advisory Staff regarding natural gas price volatility in 2001. He was an instructor for AGA's Gas Rates Course in 2005. He has served as a host for a panel on LNG imports at the 2004 Gas / Electric Partnership conference. He also made a presentation for Washington Gas at its 2003 Financial Analyst Conference. In addition, Mr. Sherwood has taken graduate courses in Labor Management Relations, Accounting, Finance, and Economics.

Chattanooga Gas Company Capacity

FT Services	**Contract**	**MDQ (Dth)**	**Type**	**Service Expiration**	**Notification**
Southern Natural Gas	FSNG130	13,221	Citygate	8/31/2010	365 Days
Southern Natural Gas	FSNG130	14,346	Citygate	8/31/2010	365 Days
East Tennessee	410203	13,000	Citygate	10/31/2012	1 Year
East Tennessee	410204	28,350	Citygate	10/31/2010	1 Year
East Tennessee *	410199	5,000	Citygate	10/31/2006	
Tennessee Gas Pipeline	48082	37,819	Upstream	10/31/2010	30 Days
Storage Services	**Contract**	**MDQ (Dth)**	**Type**	**Service Expiration**	**Notification**
Southern Natural Gas	SSNG69	14,346	Upstream	8/31/2010	30 Days
Tennessee Gas Pipeline	3947	7,741	Upstream	11/1/2010	30 Days
Tennessee Gas Pipeline	22923	13,659	Upstream	10/31/2010	30 Days
Company Owned Resource	**Contract**	**MDQ (Dth)**	**Type**		
Chattanooga LNG	n/a	70,000	Citygate		

** Contract 410199 expired on October 31, 2006 and was not renewed.*

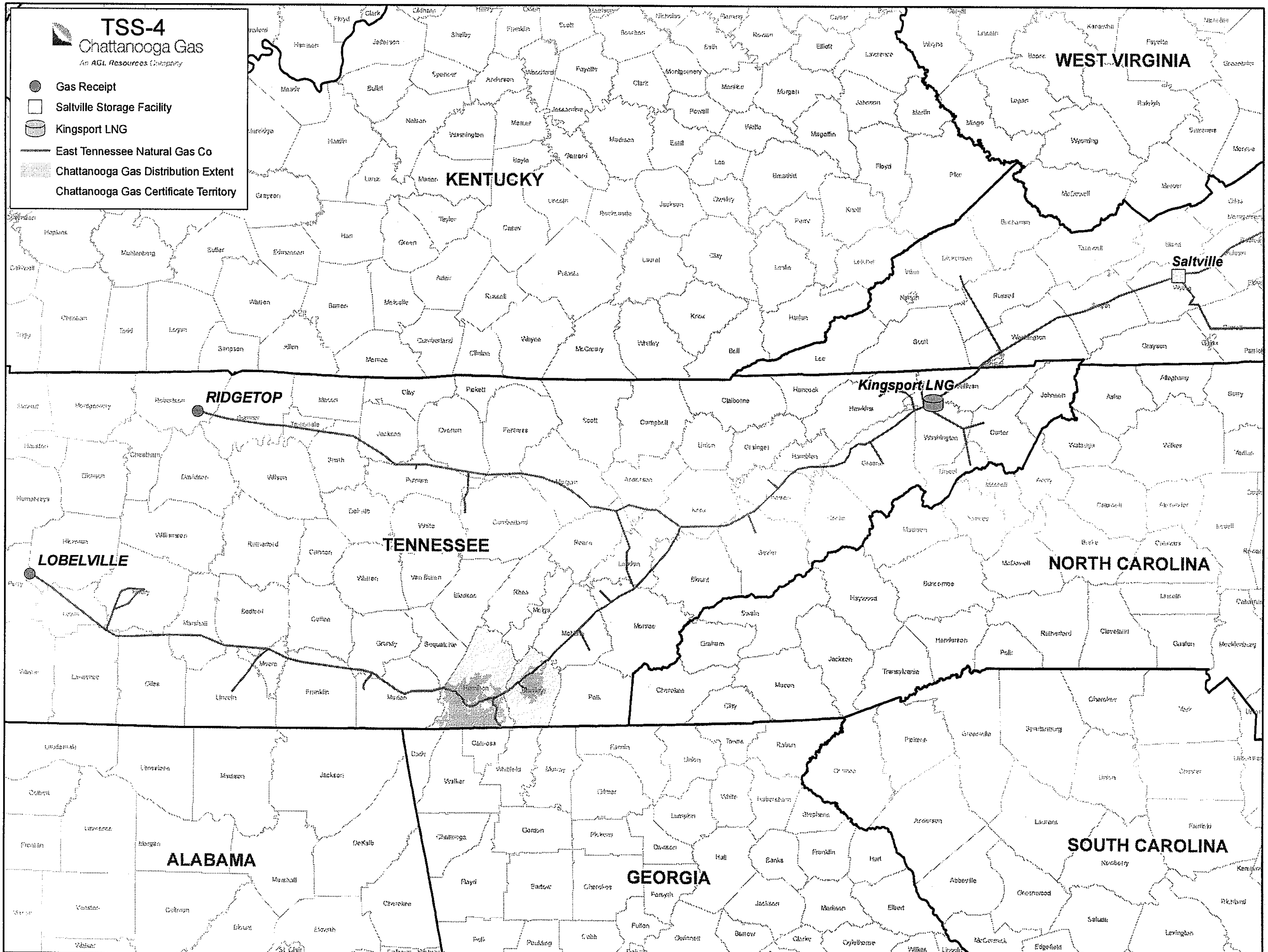
Citygate delivered capacity: 138,917

Projected 2009 Design Day Load: 129,761

Pipeline	Type	Deliverability (Dth)	Capacity (Dth)	Injection (Dth)	Monthly Demand Charge ($/Dth)	Capacity Charge ($/Dth)	Inj Charge ($/Dth)	W/D Charge ($/Dth)	Inj Fuel (%)	W/D Fuel (%)	Annual Fixed Costs: Demand Charge	Injection Charge	Capacity Charge	Single Turn Variable Costs: Injection Cost ($)	Withdrawal Cost ($)	Total Costs
TGP	FS-MA	7,741	852,286	5,682	1.15	0.0185	0.0102	0.0102	1.49	0	106,826	0	189,207	8,693	8,693	313,419
TGP	FS-PA	13,659	2,042,390	13,616	2.02	0.0248	0.0053	0.0053	1.49	0	331,094	0	607,815	10,825	10,825	960,559
SONAT	CSS	14,346	710,484	5,465	1.531	0.02946	0.007	0.007	0.82	0.82	263,565	0	251,170	4,973	4,973	524,681

		Deliverability (Dth)	Capacity (Dth)	Injection (Dth)	Reservation Charges: Capacity	Inj	Withd	Commodity Charges: Inj	Withd	Annual Fixed Costs: Demand Charge	Injection Charges	Capacity Charges	Single Turn Variable Costs: Injection Cost ($)	Withdrawal Cost ($)	Total Costs
Saltville	as FS-MA	7,741	852,286	5,682	0.085	2.043	1.109	0.061	0.061	103,017	139,300	869,332	51,989	51,989	1,215,628
	as FS-PA	13,659	2,042,390	13,616	0.085	2.043	1.109	0.061	0.061	181,774	333,810	2,083,238	124,586	124,586	2,847,994
	as CSS	14,346	710,484	5,465	0.085	2.043	1.109	0.061	0.061	190,917	133,980	724,694	43,340	43,340	1,136,270

Assumptions:
1. Saltville storage would be willing and able to contract for a service that exactly matches that of CGC's existing upstream storage contracts
2. All storages are turned one time; a turn meaning that the service is injected fully and withdrawn fully
3. This analysis excludes intervening transport to get the delivery to CGC's system which would increase the costs for Saltville but not necessarily the others
4. This analysis excludes the costs of natural gas used for injection service and the volumes potentially displaced by withdrawal service



AGL Resources, GIS Support Services, July 2008

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