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July 1, 2014

Executive Director Earl Taylor
c/o Sharla Dillon
Tennessee Regulatory Authority
460 James Robertson Parkway
Nashville, TN 37243

Re: Review of Chattanooga Gas Company's Performance Based Ratemaking Mechanism Transactions and Activities
Docket No. 07-00224

Dear Mr. Taylor:

Enclosed please find an original and four (4) copies of the public redacted version of the report on the Review of Performance Based Ratemaking Mechanism Transactions and Activities, dated June 2014, which has been prepared in compliance with the TRA Order dated October 13, 2009, in Docket No. 07-00224. Filed along with this is a confidential version, submitted under seal.

Within thirty (30) days, Chattanooga Gas Company will submit to the TRA an amended IMCR filing that includes the customer's share of the additional LNG margins as identified in the report plus interest.

Should you have any questions concerning this matter, please do not hesitate to contact me.

Sincerely,

J.W. Luna

Enclosures

cc: Vance Broemel, Esq.

PUBLIC VERSION

Confidential Information Has Been Redacted

Final Report

Chattanooga Gas

An AGL Resources Company

REVIEW OF PERFORMANCE BASED RATEMAKING MECHANISM TRANSACTIONS AND ACTIVITIES

Prepared for:

AUDIT STAFF OF THE TENNESSEE REGULATORY AUTHORITY

CONSUMER ADVOCATE AND PROTECTION DIVISION OF THE TENNESSEE ATTORNEY GENERAL

JUNE 2014

Prepared by:

EXETER

ASSOCIATES, INC.

10480 Little Patuxent Parkway

Columbia, Maryland 21044

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1.0 INTRODUCTION AND SCOPE OF INVESTIGATION

On October 13, 2009, the Tennessee Regulatory Authority (TRA or Commission), issued an Order in Docket No. 07-00224 requiring a comprehensive triennial review (or audit) of the transactions and activities related to the Performance Based Ratemaking Mechanism (PBRM) of Chattanooga Gas Company (CGC or Company). This review was to be conducted by an independent consultant. Following a required selection process, Exeter Associates Inc. (Exeter) was selected as the independent consultant for this audit. Exeter was previously selected to perform two similar reviews of Piedmont Natural Gas Company (Piedmont) which operates under a Performance Incentive Plan.

Under CGC's PBRM, the Company's commodity gas costs are compared to a benchmark amount. If CGC's total commodity cost of gas for a plan year (12 months ended June) does not exceed the benchmark amount by 1 percentage point for that plan year, CGC's gas costs will be deemed prudent and the audit required by TRA Administrative Rule 1220-4-7-.05 is waived.

The scope of this audit is to review and evaluate the reasonableness of CGC's, and its affiliates', gas procurement transactions and activities for the period April 2010 through March 2013 (audit period). This audit includes review of (1) CGC's actual gas procurement transactions and costs, including storage activity, reported in the Company's Actual Gas Adjustment (AGA) filings which provide for a reconciliation of CGC's actual gas costs and gas cost recoveries; (2) CGC's PBRM filings which compare CGC's actual commodity gas costs with benchmark amounts to evaluate the Company's performance under the PBRM; and (3) CGC's Interruptible Margin Credit Rider (IMCR) filings which detail the sharing of revenue generated under the Company's Asset Management Agreements (AMAs) and from the Company's off-system sales activities.

A draft report presenting the findings, results, and conclusions of Exeter's review was provided to the Company, Audit Staff of the Tennessee Regulatory Authority (TRA Staff), and the Consumer Advocate and Protection Division of the Tennessee Attorney General (CAD) on June 9, 2014. On June 16, 2014, CGC provided Exeter its comments on the draft report. CGC's comments were intended to clarify certain facts regarding its PBRM and its transactions and activities as well as to respond to several findings set forth in the draft report. Exeter has incorporated CGC's comments into this final report (Report) and has responded to CGC's comments as Exeter deemed appropriate.

Exeter's Report consists of five sections in addition to this introductory section. Section 2 of the Report identifies the interstate pipeline transmission companies serving CGC, the services the Company purchases from each pipeline, and the Company's review period gas supply arrangements. Included in Section 2 is a description of the Company's AMAs with Sequent Energy Management, L.P. (Sequent), an affiliate of CGC. Section 2 also provides a description of the CGC system and the markets it serves. This section includes statistical data identifying the number of customers served and usage by customer class. Section 3 of the Report summarizes and evaluates CGC's activities and performance under the PBRM.

The fourth section of the Report evaluates CGC's storage and liquefied natural gas (LNG) off-system sales activities. Section 5 of the Report evaluates the reasonableness of CGC's capacity portfolio. This includes an evaluation of CGC's design peak day forecasting procedures and an analysis of CGC's load duration curves.

The final Report section summarizes Exeter's conclusions, includes findings of fact, and identifies and describes areas of concern and improvement, which may warrant further consideration.

2.0 CHATTANOOGA GAS COMPANY'S SYSTEM AND MARKETS

The Chattanooga Gas Company provides natural gas sales and distribution service to the counties of Hamilton and Bradley, Tennessee, which are referred to as the Chattanooga and Cleveland service territories, respectively. CGC contracts for firm transportation and storage services from three interstate pipelines during the review period: East Tennessee Natural Gas (ETNG), Tennessee Gas Pipeline (TGP), and Southern Natural Gas Company (SONAT). Of these three interstate pipelines, CGC is interconnected to two: ETNG and SONAT. CGC has nine interconnects with ETNG and one interconnect with SONAT. Figure 1 presents a map of the Company's service territory and the interstate pipelines serving CGC. The interstate pipeline services available to CGC in the audit period are described in Section 2.1, below. CGC operated under two asset management agreements with its affiliate, Sequent Energy Management, L.P., during the review period. CGC's AMAs with Sequent are described in Section 2.2 of this Report. CGC's review period gas supply arrangements are described in Section 2.3 of this Report. Section 2.4 of this Report summarizes the jurisdictional services provided by CGC, the number of customers served, and annual throughput volumes.

2.1 Interstate Pipeline Transportation Services

CGC's transportation arrangements with ETNG and SONAT provide for the delivery of gas supplies directly to CGC's system (citygate), while TGP provides for the upstream delivery of gas to ETNG. Gas supplies delivered to CGC by ETNG are generally purchased in the Gulf Coast production region and initially delivered to ETNG by TGP. Gas supplies delivered to CGC by SONAT are also generally purchased in the Gulf Coast production region and delivered directly to CGC. Table 1 summarizes the pipeline services purchased by CGC to meet customer demands for the winter of 2013-2014. This information is provided to assist in evaluating CGC gas procurement transactions and activities and in evaluating CGC's capacity resources.

Figure 1.
CHATTANOOGA GAS COMPANY
System Map

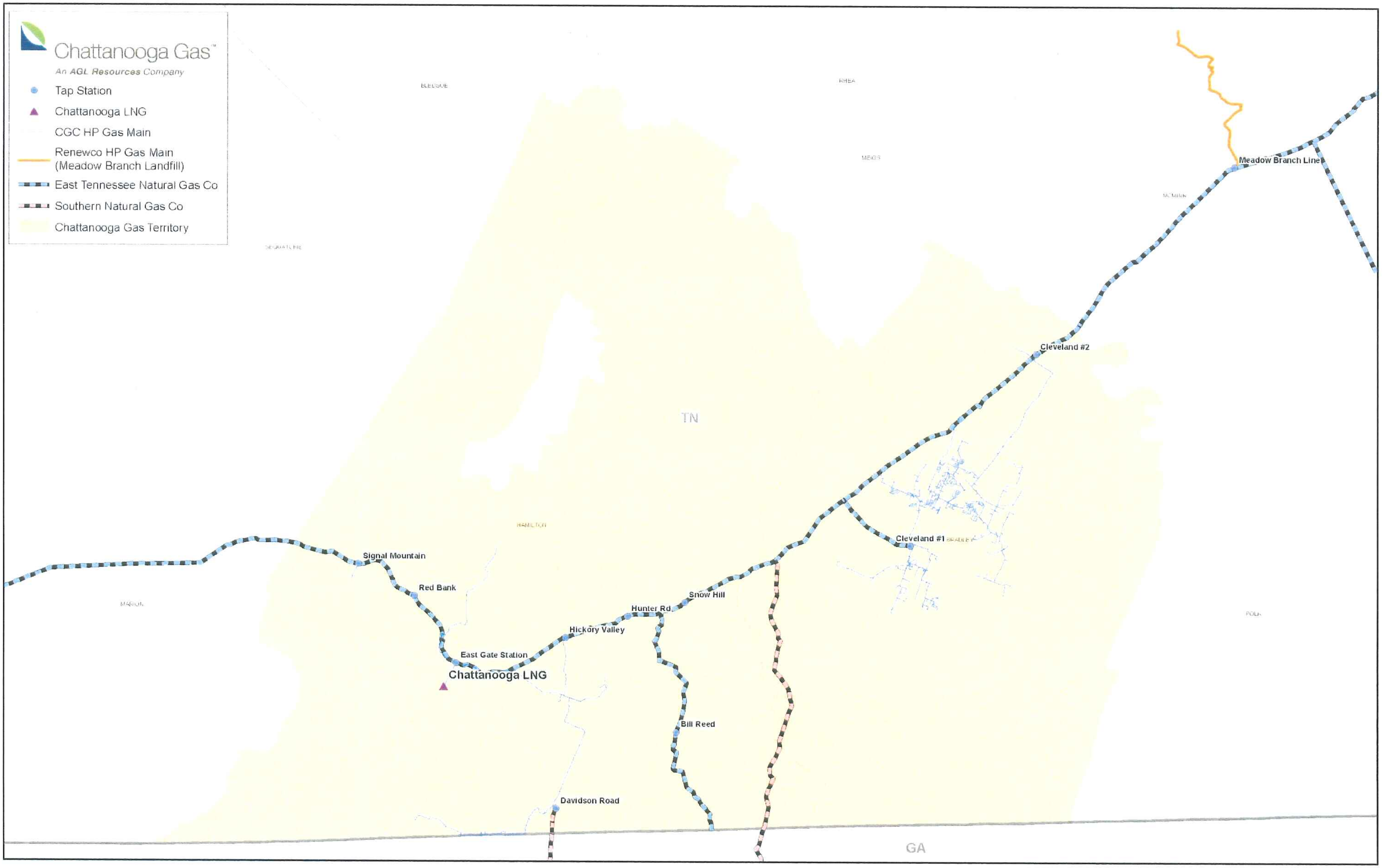


Table 1
CHATTANOOGA GAS COMPANY
Summary of Design Day Capacity Resources
2013-2014 Winter Season
(Dth)

Pipeline – Service	Contract No.	MDQ Winter	MDQ Summer	Winter Season	Annual	Contract Expiration
UPSTREAM RESOURCES						
Tennessee Gas						
Firm Transportation (FT-A)	48082	37,819	37,819	5,710,669	13,803,935	10/31/2015
Storage Service (FS-MA)[a]	3947	7,741[a]	0	852,286[a]	0	10/31/2015
Storage Service (FS-PA)[a]	22923	13,659[a]	0	2,042,390[a]	0	10/31/2015
Total Upstream Resources		**37,819**	**37,819**	**5,710,669**	**13,803,935**	
CITYGATE RESOURCES						
East Tennessee						
Firm Transportation (FT-A)	410203	13,000	13,000	1,963,000	4,745,000	10/31/2017
Firm Transportation (FT-A)	410204	28,350	28,350	4,280,850	10,347,750	10/31/2015
Firm Transportation (FT-A)[b]	--	3,000	0	453,000	453,000	03/31/2014
Subtotal East Tennessee		44,350	41,350	6,696,850	15,545,750	
Southern Natural						
Firm Transportation (FT)	FSNG130	13,221	13,221	1,996,371	4,825,665	08/31/2016
Firm Transportation (FT-NN)	FSNG130	14,346	14,346	2,166,246	5,236,290	08/31/2016
Storage Service (CSS)[c]	SSNG69	14,346[c]	0	710,484[c]	0	08/31/2016
Subtotal Southern Natural		27,567	27,567	4,162,617	10,061,955	
Twin Eagle Resources Management Citygate Supply	None	5,000	0	75,000	75,000	02/28/2014
Chattanooga LNG	None	78,500	0	1,207,574	1,207,574	None
Total Citygate Resources		**155,418**	**68,917**	**12,142,041**	**26,890,279**	

[a] Delivered under Tennessee FT-A service.
[b] Short-term capacity release acquisition.
[c] Delivered under Southern Natural FT-NN service.

2.1.1 *Tennessee Gas Pipeline*

The Tennessee Gas Pipeline system originates in the Texas, Louisiana, and Gulf of Mexico (collectively, "Gulf Coast") natural gas production region and extends to New England. In the production region, the TGP system consists of three primary transmission lines, referred to as the 100, 500 and 800 Legs. The TGP system is also divided into eight zones (Zones 0, L and 1-6) for rate purposes. The State of Texas is designed as Zone 0, Zone L consists largely of the State of Louisiana, and Zone 1 extends from the Texas border with Northern Louisiana to the Kentucky/Tennessee border. A map of the TGP system is provided in Figure 2.

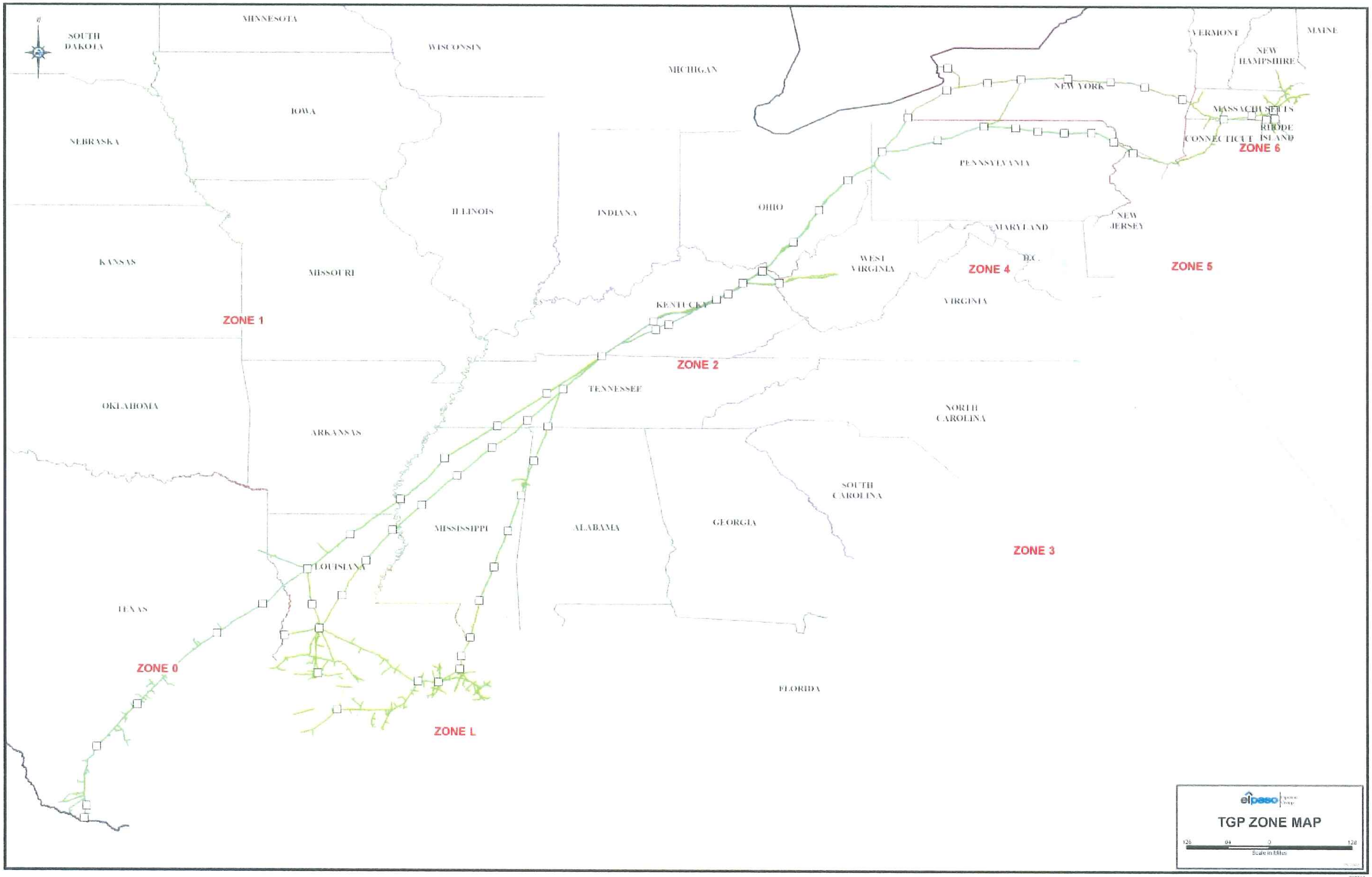
During the review period, CGC held firm transportation service with TGP under Rate Schedule FT-A (Contract No. 48082). This contract provided for the delivery of Gulf Coast supplies directly to ETNG in TGP Zone 1 at two delivery points.[1] Contract No. 48082 has a maximum daily delivery quantity (MDQ) of 37,819 Dth. CGC's receipt point capacity under TGP Contract No. 48082 was subdivided by zone and leg as follows:

Tennessee Gas Pipeline Capacity	
Zone – Leg	**MDQ (Dth)**
Zone 0 – 100 Leg	11,090
Zone 1 – 500 Leg	8,441
Zone 1 – 800 Leg	4,890
Zone 1 – 100 Leg	13,398
Total	**37,819**

CGC also held market area firm storage service with TGP under Rate Schedule FS-MA (Contract No. 3947) and production area firm storage service with TGP under Rate Schedule FS-PA (Contract No. 22923). Gas was delivered to and from storage under CGC's FT-A firm transportation arrangement with TGP. FS-MA provided for a maximum daily deliverability of 7,741 Dth, and a maximum winter season deliverability of 852,286 Dth. FS-PA provided for a maximum daily deliverability of 13,659 Dth, and a maximum winter season deliverability of 2,042,390 Dth.

[1] Delivery points are at East Lobelville and Ridgetop.

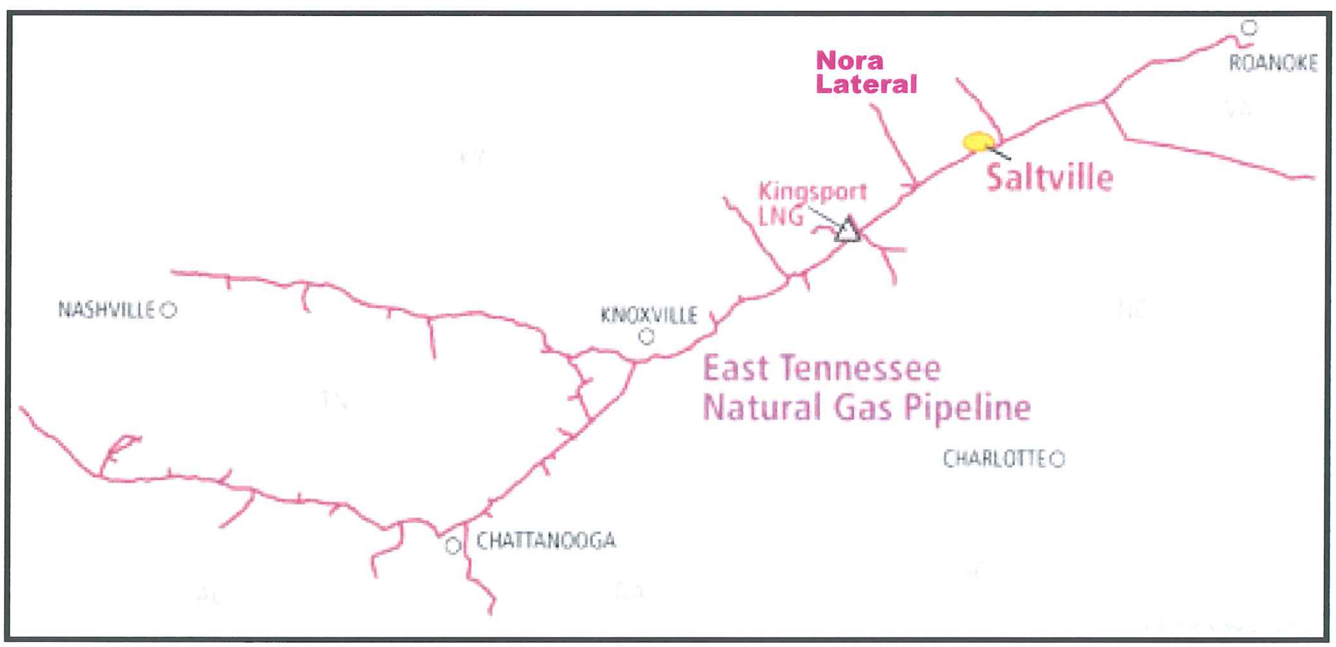
Figure 2.
TENNESSEE GAS PIPELINE
System Map



2.1.2 *East Tennessee Natural Gas*

East Tennessee Natural Gas consists of two mainline systems in Central Tennessee that converge near Knoxville and extend to an area just south of Roanoke, Virginia. ETNG primarily provides for the delivery of gas supplies from TGP to CGC. A map of the ETNG system is presented in Figure 3. During the review period, CGC held firm transportation service with ETNG under Rate Schedule FT-A under two arrangements (Contract Nos. 410203 and 410204). Contract No. 410203 provided for the delivery of 13,000 Dth per day and Contract No. 410204 provided for the delivery of 28,350 Dth per day. After adjusting for fuel retention, CGC's ETNG capacity was greater than its delivered TGP capacity by approximately 5,000 Dth per day during the review period. The firm receipt point for this 5,000 Dth of capacity was on the Nora Lateral located in Dickenson County in Southwest Virginia. CGC used this capacity to deliver gas purchased on a delivered-to-ETNG basis. CGC also acquired, through a short-term release, 3,000 Dth per day of ETNG capacity for the period October 2013 – April 2014.

Figure 3.
EAST TENNESSEE NATURAL GAS
System Map



2.1.3 *Southern Natural Gas*

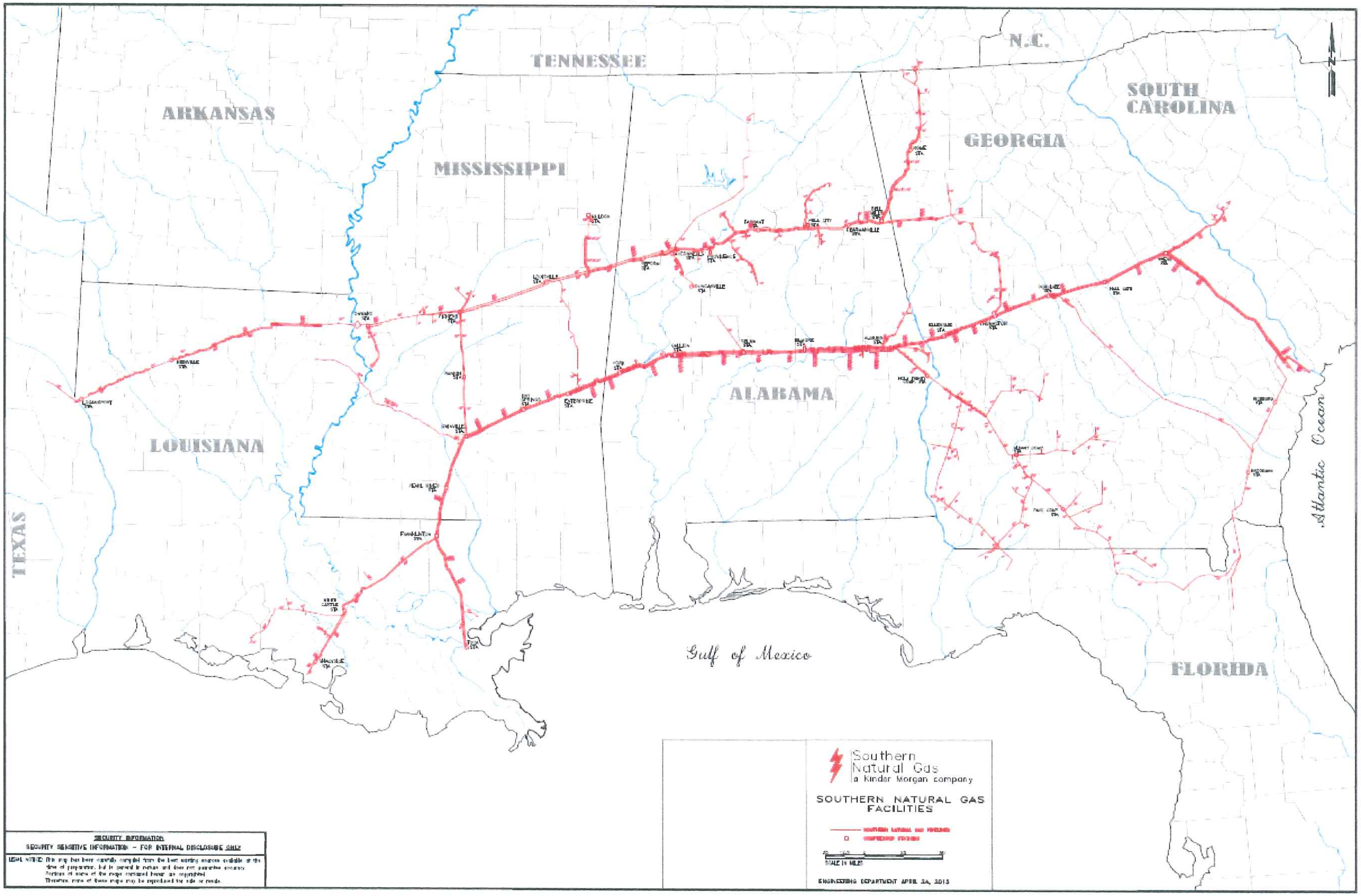
Southern Natural Gas consists of pipelines which extend from natural gas supply basins in Texas, Louisiana, Mississippi, Alabama, and the Gulf of Mexico to market areas in Louisiana, Mississippi, Alabama, Florida, Georgia, South Carolina, and Tennessee, including the metropolitan areas of Atlanta and Birmingham. SONAT's system consists of four rate zones (0-3), and CGC is located in Zone 3. A map of the SONAT system is presented in Figure 4.

CGC held firm transportation service with SONAT under Rate Schedule FT (Contract No. FSNG130) during the review period. This contract provided for the delivery of 13,221 Dth per day directly to CGC's system.

Under SONAT's standard Rate Schedule FT arrangements, the pipeline is generally only obligated to deliver, and the shipper (e.g., CGC) is obligated to take, the quantity of gas delivered to the pipeline on the shipper's behalf on a daily basis. Shippers provide SONAT notice (through nominations) of the quantity of gas to be delivered each day. Under SONAT's no-notice transportation service arrangements, a shipper is permitted to take daily deliveries of gas which vary from the nominated quantity. No-notice service is necessary to maintain system reliability for natural gas distribution companies like CGC serving temperature-sensitive usage customers. CGC held a no-notice service with SONAT under Rate Schedule FT-NN during the audit period. Under its FT-NN arrangement, CGC was permitted to take delivery of up to 14,346 Dth per day without notice, subject to the winter season limitation subsequently identified for service under Rate Schedule CSS. CGC was also allowed to use its FT-NN service to take delivery of up to 14,346 Dth per day of nominated supplies.

In addition to its FT-NN service, CGC held a firm storage service with SONAT under Rate Schedule CSS (Contract No. SSNG69). This service provided for a maximum daily delivery of 14,346 Dth, and was used to support no-notice deliveries under CGC's SONAT FT-NN service arrangement. The maximum winter season delivery quantity under CSS was 710,484 Dth.

Figure 4.
SOUTHERN NATURAL GAS
System Map



2.1.4 *Liquefied Natural Gas*

CGC operates an on-system LNG facility capable of producing up to 78,500 Dth per day. The LNG facility can produce at maximum levels for approximately 15 days. CGC is currently in the process of making distribution system enhancements which are expected to increase the daily deliverability from its LNG facility by approximately 4,700 Dth per day. These distribution system enhancements are scheduled to be completed in late 2014.

2.2 Asset Management Agreements

CGC operated under two AMAs with Sequent during the review period. The first AMA was in effect for the three-year period April 1, 2008 through March 31, 2011 (2008 AMA). The term of the second AMA was April 1, 2011 through March 31, 2014 (2011 AMA). Under each AMA, CGC's pipeline firm transportation and contract storage capacity assets were managed as an agency agreement by Sequent. The AMAs also provided that CGC would purchase its gas supplies from Sequent. CGC maintained control of its LNG facilities under the AMAs.

Under the AMAs, CGC determined how its pipeline transportation and storage assets should be used on a daily basis to meet its customers' requirements (referred to as "logical dispatch"). On a daily basis, Sequent was entitled to use CGC's assets in the manner determined by CGC, use CGC's assets in a different manner, or use other assets to which it had access as long as Sequent satisfied CGC's requirements. The billing arrangements under the AMAs provided that CGC would be responsible for all charges related to the use of CGC's assets regardless of whether those charges reflected CGC's logical dispatch decisions or Sequent's activities, and Sequent would reimburse CGC for the costs which were not incurred consistent with CGC's logical dispatch instructions. Exeter's audit reviewed a sampling of the detailed workpapers supporting the separation of costs between CGC and Sequent, and our review revealed no concerns.

The 2008 AMA was approved by the TRA in Docket No. 08-00012. [redacted]

[redacted]

[redacted]

2.3 Gas Supply Arrangements

Under the AMAs, CGC was required to purchase all of its gas supplies delivered under the transportation arrangements assigned to Sequent from Sequent. Sequent could offer, but was not required to provide, CGC gas supplies delivered under the other transportation arrangements. With one exception, all of CGC's review period gas supply purchases were purchased through Sequent. The purchases from Sequent were generally made at published index prices under the AMAs. The one exception to CGC purchasing all of its gas supplies from Sequent was a delivered-to-citygate gas supply peaking service provided by Atmos Energy Marketing (Atmos) under which purchases were made during January and February 2011. CGC also had separate citygate gas supply peaking service arrangements with Sequent in place during the winter of 2011-2012 and 2012-2013, and purchased winter period, delivered-to-ETNG baseload supplies from Sequent at negotiated prices.

Although not within the review period, for the winter of 2013-2014, CGC had a citygate gas supply peaking service arrangement with Twin Eagle Resources Management, LLC (Twin Eagle), and entered into a gas supply contract with Sequent to fill the 3,000 Dth per day of

ETNG capacity it acquired through a short-term release. CGC's gas supply arrangements outside the AMAs are subsequently described. Exeter's audit did not find CGC's arrangements outside the AMA to be unreasonable.

2.3.1 *Atmos Energy Marketing Peaking Service*

To address what the Company determined to be an incremental supply needed to meet design peak day requirements for the winter of 2010-2011, the Company issued an RFP for peaking supplies delivered to its citygate. The RFP resulted in one offer from Atmos for the delivery of citygate supplies by ETNG. The contract with Atmos provided for the delivery of up to 5,000 Dth per day for a maximum of 15 days during the months of January and February 2011. This arrangement required the payment of a monthly demand charge in addition to commodity charges. The commodity charges under the arrangement with Atmos were based on the TGP 500 Leg index price plus an adder.

2.3.2 *Sequent Energy Management Peaking Services*

During the winter of 2011-2012, CGC executed an arrangement with Sequent for a delivered-to-citygate gas supply peaking service. The arrangement provided for deliveries of up to 8,000 Dth per day for up to 15 days. An RFP was initially issued by CGC for this service; however, the RFP did not produce any offers. The arrangement with Sequent did not require the payment of a demand charge as was required under the arrangement with Atmos the prior year, and no gas was purchased under the arrangement.

CGC also executed an arrangement with Sequent for a delivered-to-citygate gas supply peaking service for the winter of 2012-2013. This arrangement provided for the delivery of up to 5,000 Dth per day for up to 15 days on an interruptible basis. An RFP was initially issued by CGC for firm service; however, the offer from Sequent for interruptible service was the only offer received by CGC. As with the arrangement for the winter of 2011-2012, this arrangement did not require the payment of a demand charge and no gas was purchased under the arrangement.

2.3.3 *Sequent Energy Management – Nora Lateral Supplies*

For each winter during the review period, the Company made arrangements with Sequent for the delivery of baseload supplies to ETNG's Nora Lateral to fill its open ETNG capacity (see Section 2.1.2). These arrangements provided for the delivery of up to 4,899 Dth per day. The arrangement in place for the winter of 2010-2011 was initially executed in 2008. No RFP was issued for this arrangement and the arrangement was negotiated by CGC and Sequent. The price negotiated for this service was significantly more favorable to CGC than the price offered in response to an RFP CGC issued the following year for a similar service.

After the 2008 arrangement with Sequent for Nora Lateral deliveries expired, CGC issued an RFP for a similar winter-period baseload supply delivered to ETNG's Nora Lateral for a term of one to three years. The RFP required suppliers to maintain firm transportation capacity for the delivery of gas to ETNG to ensure supply reliability. CGC received one response to the RFP which was non-conforming because the supplier did not maintain firm capacity to ETNG. After the RFP results were known, CGC contracted with Sequent for delivered-to-Nora Lateral baseload supplies for a three-year period. The price agreed to with Sequent was significantly more favorable to CGC than the price offered in response to the RFP.

2.3.4 *Post-Review Period Gas Supply Arrangements*

CGC had in place two post-review period gas supply arrangements which merit discussion. These arrangements are discussed to provide additional necessary background information with respect to CGC's capacity resources for the winter of 2013-2014. The balance between CGC's capacity resources and its customer requirements for the winter of 2013-2014 is addressed in Section 5.3 of this Report.

To fill the 3,000 Dth per day of ETNG capacity acquired for the winter of 2013-2014 through a short-term release, CGC entered into a delivered to ETNG gas supply arrangement for 3,000 Dth per day with Sequent. Commodity charges under the agreement were based on a Gulf Coast index price for Texas Eastern Transmission receipts plus applicable fuel retention and variable costs, plus a small adder. There were no demand charges associated with the agreement.

CGC entered into a delivered-to-citygate gas supply peaking service arrangement with Twin Eagle for the period December 2013 – February 2014. The arrangement with Twin Eagle provided for the delivery of up to 5,000 Dth per day for 15 days to CGC's citygate. Commodity charges under the agreement were based on a Transcontinental Gas Pipe Line index price plus a small adder. A small monthly demand charge was also applicable.

2.4 Markets Served by CGC

CGC provided firm bundled utility sales service during the review period, and also provided transportation service from its citygates to a customer's premises for those customers who acquire their own gas supplies on the interstate markets and separately arrange for the delivery of those supplies to CGC's citygates. Table 2 summarizes the number of CGC customers served and annual throughput by rate schedule for 2010, 2011 and 2012.

CGC provides sales service to residential customers under Rate Schedule R-1 – Residential General Service. Sales service under Rate Schedule R-4 – Multi-Family Housing Service, was closed as of July 31, 2006, and was only available to a public housing authority or private company operating a housing project. Small Commercial and Industrial General Service is available under Rate Schedule C-1 to sales customers using less than 400 Dth per year. Medium Commercial and Industrial Service is available under Rate Schedule C-2 to sales customers using more than 400 Dth per year. Commercial and Industrial Large Volume Firm Sales Service under Rate Schedule F-1 is available to customers using a minimum of 36,500 Dth per year. Commercial and Industrial Interruptible Sales Service under Rate Schedule I-1 is available to customers using a minimum of 36,500 Dth per year. Interruptible Transportation

Table 2.
CHATTANOOGA GAS COMPANY
Annual Customers and Volumes by Class

CUSTOMERS BY RATE SCHEDULE	2010	2011	2012
Residential Sales (R-1)	53,326	53,649	53,855
Multi-Family Housing Sales (R-4)	2	2	2
Small Commercial & Industrial Sales (C-1)	6,487	6,465	6,482
Medium Commercial & Industrial Sales (C-2)	1,718	1,763	1,709
Commercial & Industrial Interruptible Sales (I-1)	2	2	1
Large Volume Commercial & Industrial			
Sales/Transportation with Standby (F-1/T-2)[a]	26	25	25
Sales/Transportation with Standby (F-1/T-2/T-1)[b]	12	12	12
Interruptible Transportation (T-1)	28	27	27
Low Volume Commercial & Industrial			
Sales/Transportation with Standby (T-3/C-2)	40	43	45
Special Contract	1	1	1
Total Customers	**61,642**	**61,989**	**62,159**
VOLUMES BY RATE SCHEDULE (Dth)	**2010**	**2011**	**2012**
Residential Sales (R-1)	4,073,119	3,600,215	2,811,233
Multi-Family Housing Sales (R-4)	9,456	8,192	7,196
Small Commercial & Industrial Sales (C-1)	832,717	711,301	541,414
Medium Commercial & Industrial Sales (C-2)	2,643,660	2,514,367	2,155,915
Commercial & Industrial Interruptible Sales (I-1)	96,270	248,509	124,043
Large Volume Commercial & Industrial			
Sales/Transportation with Standby (F-1/T-2)[a]	1,475,597	1,192,700	1,347,551
Sales/Transportation with Standby (F-1/T-2/T-1)[b]	1,683,227	1,974,555	1,558,327
Interruptible Transportation (T-1)	3,808,361	3,785,418	3,631,074
Low Volume Commercial & Industrial			
Sales/Transportation with Standby (T-3/C-2)	512,983	537,528	536,376
Special Contract	590,899	940,536	806,793
Total Volumes	**15,726,289**	**15,513,321**	**13,519,922**

[a] Full Standby Service
[b] Partial Standby Service

Service under Rate Schedule T-1 is available to customers using a minimum of 36,500 Dth per year.

Under Rate Schedule T-1, differences between monthly consumption and deliveries to CGC on the customer's behalf are purchased by CGC or sold to the customer, as applicable, at published index prices. Interruptible Transportation Service with Firm Gas Supply Backup is also available to customers using at least 36,500 Dth per year under Rate Schedule T-2. If a customer under Rate Schedule T-2 consumes more gas during a month than the customer has delivered to the Company, the customer purchases the deficient quantity from the Company under Rate Schedule F-1. Deliveries in excess of monthly consumption are purchased by the Company at published index prices. Low Volume Transport Service is available to customers using more than 400 Dth per year under Rate Schedule T-3. If a customer under Rate Schedule T-3 consumes more gas during a month than the customer has delivered to the Company, the customer purchases the deficient quantity from the Company under Rate Schedule C-2. Deliveries in excess of monthly consumption are purchased by the Company at published index prices.

3.0 PERFORMANCE BASED RATEMAKING MECHANISM

This section of Exeter's Report summarizes and evaluates CGC's activities and performance under the Performance Based Ratemaking Mechanism. The PBRM is designed to encourage the Company to perform its gas purchasing activities at minimum cost. The PBRM establishes monthly benchmarks to which the Company's gas commodity costs are compared. If CGC's total monthly commodity gas costs for a plan year (12 months ended June) do not exceed the total benchmark amount by 1 percent, the Company's gas costs will be deemed prudent and the audit required by TRA Administrative Rule 1220-4-7-.05 is waived. If, during any month of a plan year, the Company's commodity gas costs exceed the benchmark amount by greater than 2 percent, the Company is required to file a report with the TRA fully explaining why costs exceeded the benchmark. CGC's commodity gas costs did not exceed the benchmark by 2 percent in any month during the review period. A complete description of the PBRM is included as Appendix A to this Report. The Company's PBRM tariff also includes Affiliate Transaction Guidelines and RFP Procedures for Selection of an Asset Manager or Gas Provider.

3.1 Commodity Gas Costs

3.1.1 *Background*

In the natural gas industry there are primarily two types of gas supply purchase arrangements—first-of-the-month monthly baseload ("first-of-the-month" or "FOM") purchases and daily purchases. FOM purchases are generally arranged several days prior to the month of delivery, commence flow on the first day of the month, and provide for the delivery of the same quantity of gas on each day during the month. Daily purchases are generally arranged the day prior to delivery. While daily purchases generally flow for one day, daily purchases may also be arranged for multiple consecutive days.

There are various natural gas industry publications which identify, after the fact, the average price paid for FOM and daily gas purchases at major natural gas trading locations. These average or market prices are referred to as "index prices." FOM index prices are published in *Inside FERC's Gas Market Report* and daily prices are published in *Gas Daily*. The primary gas trading locations at which CGC purchases gas are as follows:

Tennessee Gas Pipeline

- Louisiana 500 Leg[2]
- Louisiana 800 Leg
- Texas, Zone 0

Southern Natural Gas

- Louisiana

Each of these trading locations is located in the Gulf Coast production region. A summary of CGC's review period FOM and daily purchases is provided in Table 3. In addition to FOM and daily purchases at these locations, CGC made purchases delivered into ETNG's Nora Lateral and made purchases at the citygate. CGC also made in-ground storage inventory purchases during the review period. Directly applicable index prices are not available for ETNG, citygate, or in-ground storage purchases.

3.1.2 *Benchmark Calculation*

Under the PBRM, CGC's actual monthly commodity cost of gas is compared to a monthly benchmark cost amount. Actual and benchmark costs are separately determined for each type of purchase made by CGC during a month, and actual and benchmark costs are separately summed to evaluate CGC performance under the PBRM.

For FOM baseload purchases made at CGC's primary trading locations, the *Inside FERC's Gas Market Report* index price for each transaction location is applied to the actual quantity of gas purchased by CGC at each location to determine the applicable benchmark amount. For daily purchases at those same locations, the *Gas Daily* index price for each transaction location is applied to the actual quantity of gas purchased by CGC at that location to determine the applicable benchmark cost. On occasion, CGC will make a FOM baseload purchase which is

[2] Index is also applicable for Louisiana 100 Leg.

Table 3.
CHATTANOOGA GAS COMPANY
Summary of First-of-the-Month and Daily Purchases
(Dth)

	TENNESSEE GAS PIPELINE ZONE 0				TENNESSEE GAS PIPELINE Z1 100/500 LEG				TENNESSEE GAS PIPELINE Z1 800 LEG				SOUTHERN NATURAL				NORA LATERAL		ATMOS	
	FOM		Daily		FOM		Daily		FOM		Daily		FOM		Daily		FOM		FOM	
	Quantity	Price	Quantity	Price	Quantity	Price	Quantity	Price	Quantity	Price	Quantity	Price	Quantity	Price	Quantity	Price	Quantity	Price	Quantity	Price
July 2010	0	$4.65	14,164	$4.58	0	$4.68	10,233	$4.48	330,212	$4.68	72,561	$4.59	0	$4.74	17,591	$4.67	0	$0.00	0	$0.00
August	0	4.71	4,166	4.72	0	4.74	19,639	4.35	330,212	4.70	81,554	4.32	0	4.81	2,556	4.04	0	0.00	0	0.00
September	22,748	3.57	20,987	3.82	0	3.59	0	0.00	328,600	3.57	59,330	3.89	0	3.68	2,607	3.78	0	0.00	0	0.00
October	0	3.75	0	0.00	0	3.78	0	0.00	544,832	3.77	0	0.00	0	3.83	214,563	3.39	0	0.00	0	0.00
November	0	3.23	0	0.00	0	3.25	1,043	3.99	0	3.22	84,142	3.89	0	3.31	441,707	3.69	150,300	3.64	0	0.00
December	0	4.22	0	0.00	0	4.24	0	0.00	0	4.23	559,355	4.20	126,821	4.29	488,532	4.28	155,310	4.62	0	0.00
January 2011	0	4.18	0	0.00	0	4.22	26,150	5.24	129,270	4.20	394,560	4.42	126,821	4.27	217,583	4.53	155,310	4.57	50,000	5.37
February	59,510	4.26	0	0.00	0	4.32	7,091	4.31	245,372	4.33	85,092	4.27	0	4.35	184,046	4.37	140,280	4.67	10,000	5.91
March	0	3.73	0	0.00	0	3.74	0	0.00	0	3.73	16,160	3.78	15,841	3.80	108,919	3.79	155,310	4.14	0	0.00
April	0	4.13	18,746	4.02	0	4.19	0	0.00	311,400	4.21	158,205	4.17	30,930	4.25	42,259	4.25	0	0.00	0	0.00
May	0	4.24	0	0.00	112,158	4.34	21,293	4.21	282,475	4.38	19,223	4.42	31,961	4.40	131,726	4.18	0	0.00	0	0.00
June	287,150	4.23	45,790	4.48	0	4.33	0	0.00	1,793	4.29	5,950	4.60	30,930	4.34	91,320	4.68	0	0.00	0	0.00
July	269,328	4.25	0	0.00	0	4.36	0	0.00	0	4.35	4,104	4.40	99,045	4.37	386,247	4.43	0	0.00	0	$0.00
August	80,879	4.26	2,265	4.03	0	4.34	4,411	3.98	0	4.35	2,616	3.95	31,961	4.37	80,294	4.25	0	0.00	0	0.00
September	161,520	3.81	3,192	3.91	3,847	3.85	0	0.00	0	3.83	0	0.00	112,085	3.85	235,813	3.85	0	0.00	0	0.00
October	22,103	3.67	61,734	3.47	0	3.70	0	0.00	0	3.71	206,822	3.56	166,160	3.74	34,380	3.60	0	0.00	0	0.00
November	253,188	3.42	0	0.00	0	3.49	0	0.00	0	3.50	25,099	3.17	30,929	3.49	176,910	3.33	150,300	3.58	0	0.00
December	343,559	3.29	0	0.00	0	3.36	0	0.00	138,607	3.33	5,109	3.36	31,961	3.36	66,892	3.41	155,310	3.42	0	0.00
January 2012	343,759	3.03	0	0.00	0	3.09	0	0.00	138,880	3.06	8,532	2.77	31,961	3.09	37,788	2.96	155,310	3.14	0	0.00
February	57,826	2.55	0	0.00	0	2.69	0	0.00	0	2.62	15,573	2.50	29,899	2.69	0	0.00	145,288	2.74	0	0.00
March	0	2.40	0	0.00	0	2.44	0	0.00	0	2.45	0	0.00	31,961	2.44	0	0.00	155,310	2.51	0	0.00
April	187,020	2.08	0	0.00	0	2.14	0	0.00	0	2.13	118,420	1.89	30,960	2.16	0	0.00	0	0.00	0	0.00
May	0	1.95	70,383	2.34	0	2.01	0	0.00	0	1.98	66,638	2.32	0	2.02	68,928	2.45	0	0.00	0	0.00
June	65,160	2.40	216,155	2.39	0	2.39	0	0.00	0	2.45	64,464	2.36	0	2.41	57,672	2.48	0	0.00	0	0.00
July	17,453	2.69	88,141	2.89	0	2.72	0	0.00	0	2.70	5,024	3.10	0	2.77	186,857	2.95	0	0.00	0	$0.00
August	0	2.99	57,000	2.79	0	2.98	0	0.00	0	3.01	0	0.00	0	3.00	359,550	2.79	0	0.00	0	0.00
September	64,140	2.54	109,664	2.76	0	2.59	0	0.00	0	2.56	0	0.00	0	2.62	460,669	2.80	0	0.00	0	0.00
October	199,237	2.84	13,920	3.25	0	3.00	0	0.00	0	2.96	350,955	3.28	15,996	3.02	8,997	3.02	0	0.00	0	0.00
November	141,256	3.34	142,740	3.49	0	3.44	0	0.00	0	3.37	204,183	3.55	0	3.46	5,031	3.46	150,286	3.53	0	0.00
December	340,938	3.61	0	0.00	0	3.63	0	0.00	5,580	3.66	67,437	3.34	0	3.73	13,108	3.41	155,310	3.76	0	0.00
January 2013	346,033	3.28	36,595	3.45	0	3.35	0	0.00	67,329	3.33	19,700	3.17	4,128	3.40	8,867	3.18	155,237	3.41	0	0.00
February	88,620	3.15	96,760	3.24	0	3.22	0	0.00	0	3.18	61,596	3.25	0	3.25	27,865	3.32	140,280	3.29	0	0.00
March	0	3.35	256,479	3.74	0	3.39	0	0.00	0	3.39	202,071	3.80	0	3.45	103,948	3.94	155,310	3.49	0	0.00
April	19,770	3.90	3,225	4.10	0	3.98	0	0.00	0	3.95	424,976	4.10	0	3.98	24,346	4.01	0	0.00	0	0.00
May	12,710	4.10	0	0.00	0	4.26	0	0.00	0	4.13	273,128	4.01	0	4.16	127,049	4.14	0	0.00	0	0.00
June	12,930	4.07	4,833	3.72	0	4.17	0	0.00	0	4.12	188,552	3.80	0	4.17	129,090	3.93	0	0.00	0	0.00

priced on a daily basis at the *Gas Daily* index price. For these purchases, the benchmark is based on *Gas Daily* index prices.

The PBRM provides for the benchmarking of long-term purchases (i.e., a term more than one month) using FOM index prices and a three-year average of premiums paid to suppliers to ensure that long-term supplies are available during peak periods. No long-term purchases were made during the review period, and it is unclear as to how the benchmark for these purchases would be calculated.

In addition to purchases made at its primary trading locations, CGC also purchased gas delivered into ETNG's Nora Lateral and gas at its citygate for which index prices are not available. For these purchases, the most applicable index price by location and type of purchase (FOM or daily market) is adjusted for benchmarking purposes for the avoided variable transportation changes that would have been paid for the delivery of that gas to the Nora Lateral or CGC's citygate. Similarly, for in-ground storage inventory purchases, the most applicable index price is adjusted for benchmarking purposes for the avoided variable transportation and storage injection charges that would have been paid for the delivery of that gas into storage.

3.1.3 *PBRM Performance*

CGC's performance under the PBRM is included in an *Annual Report of Actual Cost of Gas Purchased and Applicable Indices* filed with the TRA each year for each 12-month period ended June 30. As part of Exeter's review, a selected sample of CGC's benchmark and actual cost calculations were reviewed for accuracy and compliance with the terms of the PBRM. Our review found no discrepancies in CGC's calculations. It is our understanding that TRA has performed similar reviews of CGC's PBRM calculations.

CGC's performance under the PBRM by purchase type is summarized in Table 4. Purchase types include Gulf Coast production area FOM baseload and daily purchases, FOM and daily in-ground purchase of storage inventory, FOM Nora Lateral baseload purchases, and daily citygate purchases. As shown in Table 4, CGC's plan year actual commodity gas costs did not

Table 4.
CHATTANOOGA GAS COMPANY
Summary of Performance under the Performance Based Ratemaking Mechanism

	Plan Year[1]		
	2011	**2012**	**2013**
First-of-Month (Gulf Coast)			
Performance[2]	$0	$38	($495)
Volume (Dth)	1,112,563	2,058,261	1,006,485
Unit Variance per Dth	$0.0000	$0.0000	($0.0005)
First-of-Month Storage (In-ground)			
Performance[2]	($63,041)	($4,751)	($2,303)
Volume (Dth)	2,708,459	1,663,049	1,789,801
Unit Variance per Dth	($0.0233)	($0.0029)	($0.0013)
First-of-Month Nora Lateral			
Performance[2]	$179,417	$13,792	$24,220
Volume (Dth)	756,510	761,518	756,423
Unit Variance per Dth	$0.2372	$0.0181	$0.0320
Daily (Gulf Coast)			
Performance[2]	$19,939	($73)	$111
Volume (Dth)	3,623,053	1,483,386	3,442,080
Unit Variance per Dth	$0.0055	($0.0000)	($0.0000)
Daily Storage (In-ground)			
Performance[2]	($16,162)	($16,331)	($17,267)
Volume (Dth)	425,638	545,743	640,271
Unit Variance per Dth	($0.0380)	($0.0299)	($0.0270)
Daily Citygate			
Performance[2]	$42,879	0	0
Volume (Dth)	60,000	0	0
Unit Variance per Dth	$0.7147	0	0
Total[3]			
Performance[2]	**$163,032**	**($7,325)**	**$4,266**
Volume (Dth)	**8,686,223**	**6,511,957**	**7,635,061**
Unit Variance per Dth	**$0.0188**	**($0.0011)**	**$0.0006**

[1] 12 months ended June.
[2] (+) Costs exceed benchmark; (-) Costs below benchmark.
[3] Total may not be exact due to rounding.

exceed benchmark commodity gas costs by more than 1 percent in any year during the review period.

As shown in Table 4, there has been little variance between CGC's FOM baseload and daily actual gas costs and benchmark gas costs for Gulf Coast purchases. This is because CGC purchased these supplies from Sequent under AMAs which provided for these purchases to be made at applicable (i.e., FOM or daily) index prices. The in-excess-of-benchmark daily purchase performance for plan year 2011 was attributable to purchases made from Sequent in January 2011 at negotiated prices which were in excess of index prices. Ordinarily, these in-excess-of-index-priced purchases could be a concern; however, as subsequently described, the incremental cost above index of these purchases was offset by in-ground storage purchases from Sequent at less than the benchmark formula. Exeter's audit identified no concerns related to CGC's mix of FOM and daily purchases.

The actual cost of CGC's FOM and daily in-ground storage inventory purchases, or transfers, from Sequent were consistently less than benchmark costs. The benchmark for such purchases includes variable pipeline transportation and storage injection charges. Under the AMA, the transfer price should have been computed using this benchmark formula. There were slight differences in the invoice price and the benchmark price. However, since the price Sequent billed CGC was generally less than the benchmark price, the invoices were accepted.

CGC's FOM Nora Lateral purchases were made at prices slightly in excess of the benchmark. This is consistent with expectations because the commodity price of these purchases would have included the market value of delivering gas to the Nora Lateral. This market value would have included pipeline demand and variable charges. The benchmark price under the PBRM only included pipeline variable charges and, therefore, the actual cost of the Nora Lateral purchases would necessarily exceed benchmark costs.

CGC's daily citygate purchases reflect purchases under its arrangement with Atmos. CGC's arrangement with Atmos required the payment of demand charges which, among other things, reflected the market value of delivering gas from a production region to CGC's citygate.

These demand charges were included in CGC's actual costs under the PBRM but not in the benchmark. The commodity adder under the Atmos arrangement was also greater than the variable costs included in the benchmark. Therefore, daily citygate purchases under the Atmos arrangement exceeded benchmark costs.

Table 5 provides a comparison of the FOM *Inside FERC* index prices for the four primary receipt point locations under CGC's firm transportation arrangements with TGP and SONAT. As shown in Table 5, the index prices at these locations did not vary significantly from one another. If the variable costs of delivering supplies from each of these four primary receipt point locations is considered, prices at these locations, and in particular the TGP locations, on average, varied only by a few cents. This would indicate that, although Exeter's review found no such evidence, even if CGC's affiliate relationship with Sequent improperly influenced the Company's selection of TGP receipt point commodity purchase locations, the impact on gas costs would have been immaterial.

Table 5.
CHATTANOOGA GAS COMPANY
Summary of Prices by Pipeline Location
***Inside FERC* First-of-the-Month Index Prices**
(Dth)

	Tennessee Gas Pipeline			
Month	**Zone 0**	**Z1 100/500 Leg**	**Z1 800 Leg**	**Southern Natural**
July 2010	$4.65	$4.68	$4.68	$4.74
August	4.71	4.74	4.70	4.81
September	3.57	3.59	3.57	3.68
October	3.75	3.78	3.77	3.83
November	3.23	3.25	3.22	3.31
December	4.22	4.24	4.23	4.29
January 2011	4.18	4.22	4.20	4.27
February	4.26	4.32	4.33	4.35
March	3.73	3.74	3.73	3.80
April	4.13	4.19	4.21	4.25
May	4.24	4.34	4.38	4.40
June	4.23	4.33	4.29	4.34
Yearly Average	**$4.08**	**$4.12**	**$4.11**	**$4.17**
Variable Delivered	**$4.26**	**$4.28**	**$4.27**	**$4.37**
July 2011	$4.25	$4.36	$4.35	$4.37
August	4.26	4.34	4.35	4.37
September	3.81	3.84	3.83	3.85
October	3.67	3.70	3.71	3.74
November	3.42	3.49	3.50	3.49
December	3.29	3.36	3.33	3.36
January 2012	3.03	3.09	3.14	3.09
February	2.55	2.69	2.62	2.69
March	2.40	2.44	2.45	2.44
April	2.08	2.14	2.13	2.16
May	1.95	2.01	1.98	2.02
June	2.40	2.39	2.45	2.41
Yearly Average	**$3.09**	**$3.15**	**$3.16**	**$3.17**
Variable Delivered	**$3.24**	**$3.28**	**$3.29**	**$3.34**
July 2012	$2.69	$2.72	$2.70	$2.77
August	2.99	2.98	3.01	3.00
September	2.54	2.59	2.56	2.62
October	2.84	3.00	2.96	3.02
November	3.34	3.44	3.37	3.46
December	3.61	3.63	3.66	3.73
January 2013	3.28	3.35	3.33	3.40
February	3.15	3.22	3.18	3.25
March	3.35	3.39	3.39	3.45
April	3.90	3.98	3.95	3.98
May	4.10	4.26	4.13	4.16
June	4.07	4.17	4.12	4.17
Yearly Average	**$3.50**	**$3.56**	**$3.54**	**$3.59**
Variable Delivered	**$3.66**	**$3.70**	**$3.68**	**$3.77**

4.0 STORAGE ACTIVITY AND OFF-SYSTEM LNG SALES

The scope of this investigation, as stated in the RFP, requires the review of CGC's actual gas procurement transactions and costs, including storage activity, as reported in the Company's Actual Cost Adjustment filings. The ACA filings provide for a reconciliation of CGC's actual gas costs and gas cost revenues. CGC's ACA filings include the actual purchases and costs reflected in CGC's PBRM filings. CGC's flowing first-of-the-month and daily index gas supply purchase transactions were reviewed in Section 3.0 of this Report. This section of the Report reviews CGC's storage activity, including its in-ground storage inventory purchase activity with Sequent, as well as CGC's LNG off-system sales activities.

4.1 Storage Arrangements

As discussed in greater detail in Sections 2.1.1 and 2.1.3 of this Report, CGC held contract storage service with TGP and SONAT during the review period. The FS-MA and FS-PA arrangements with TGP provided for the daily delivery of 21,400 Dth per day and a maximum winter season deliverability of 2,894,676 Dth. CGC's storage service arrangement under Rate Schedule CSS provided for a maximum daily deliverability of 14,346 Dth per day and a maximum winter season deliverability of 710,484 Dth. In total, the maximum daily deliverability of CGC's contract storage services was 35,746 Dth and the maximum winter season deliverability was 3,605,160 Dth.

In addition to its contract storage services from TGP and SONAT, CGC operates an LNG facility. During the review period, the LNG facility was capable of producing up to 78,500 Dth per day for an estimated 15 days. Distribution system enhancements expected to be completed during 2014 will increase daily deliverability by approximately 4,700 Dth.

Table 6 identifies the monthly storage activity (injections/withdrawals) and the inventory balances under each of CGC's interstate pipeline contract storage arrangements and its LNG facility at the beginning of each month of the audit period. Also identified in Table 6 are CGC's storage inventory balances as a percent of the Company's maximum seasonal contract

Table 6.
CHATTANOOGA GAS COMPANY
Summary of Audit Period Storage Inventory Balances - Beginning of Month

	TENNESSEE GAS PIPELINE (FS-PA)				TENNESSEE GAS PIPELINE (FS-MA)				SOUTHERN NATURAL GAS (CSS)				LIQUEFIED NATURAL GAS			
	Chattanooga Gas				Chattanooga Gas				Chattanooga Gas				Chattanooga Gas			
	Activity	Inventory	% Full	Optimization Inventory	Activity	Inventory	% Full	Optimization Inventory	Activity	Inventory	% Full	Optimization Inventory	Activity	Inventory	% Full	Optimization Inventory
April 2010	(181,650)	224,485	11%	5,206	(94,710)	42,220	5%	1	40,142	218,915	31%	(2,589)	14,161	419,590	36%	122,517
May	(208,636)	406,135	20%	144,823	(91,915)	136,930	16%	71,809	(104,109)	178,773	25%	(2,589)	16,239	405,429	34%	122,517
June	(220,650)	614,771	30%	261,578	(88,800)	228,845	27%	131,600	(165,227)	282,882	40%	(2,589)	16,650	389,190	33%	122,411
July	(228,005)	835,421	41%	249,440	(91,760)	317,645	37%	130,411	7,834	448,109	63%	15,515	21,225	372,540	32%	122,411
August	(228,005)	1,063,426	52%	179,474	(91,760)	409,405	48%	97,960	(156,059)	440,275	62%	10,513	29,399	351,315	30%	122,411
September	(229,401)	1,291,431	63%	71,957	(88,800)	501,165	59%	66,370	(49,369)	596,334	84%	10,513	36,290	321,916	27%	122,411
October	(223,649)	1,520,832	74%	36,889	(98,496)	589,965	69%	42,356	58,419	645,703	91%	10,513	(116,596)	285,626	24%	122,411
November	156,673	1,744,481	85%	161,407	65,709	688,461	81%	90,939	43,170	587,284	83%	10,513	(136,892)	402,222	34%	119,893
December	385,135	1,587,808	78%	280,355	117,614	622,752	73%	155,393	(26,293)	544,114	77%	10,513	(231)	539,114	46%	118,392
January 2011	368,766	1,202,673	59%	282,222	209,780	505,138	59%	151,972	155,908	570,407	80%	10,513	(21,582)	539,345	46%	91,102
February	(165,468)	833,907	41%	309,543	85,860	295,358	35%	166,152	109,649	414,499	58%	10,513	(102,734)	560,927	48%	91,102
March	464,842	999,375	49%	2	124,800	209,498	25%	82	137,674	304,850	43%	(85)	(132,442)	663,661	56%	27,131
April	(165,060)	534,533	26%	233,060	(80,940)	84,698	10%	126,283	54,159	167,176	24%	0	31,776	796,103	68%	50,935
May	(174,623)	699,593	34%	330,112	(86,924)	165,638	19%	169,424	(88,239)	113,017	16%	0	(71,323)	764,327	65%	34,209
June	(168,684)	874,216	43%	550,631	(84,120)	252,562	30%	247,620	(126,459)	201,256	28%	0	77,533	835,650	71%	9,450
July	(174,623)	1,042,900	51%	591,005	(86,924)	336,682	40%	256,740	(128,624)	327,715	46%	31,602	(108,659)	758,117	64%	200,611
August	(174,623)	1,217,523	60%	535,778	(86,924)	423,606	50%	227,785	(71,193)	456,339	64%	0	23,433	866,776	74%	275,033
September	(168,990)	1,392,146	68%	334,510	(84,120)	510,530	60%	120,326	(65,875)	527,532	74%	0	(52,419)	843,343	72%	250,536
October	(174,623)	1,561,136	76%	238,270	(96,601)	594,650	70%	203,786	(28,665)	593,407	83%	0	92,749	895,762	76%	311,104
November	(19,361)	1,735,759	85%	240,395	22,815	691,251	81%	116,606	206,754	622,072	88%	16	(114,888)	803,013	68%	286,607
December	320,734	1,755,120	86%	243,911	135,829	668,436	78%	121,520	(129,302)	415,318	58%	133,521	58,521	917,901	78%	262,110
January 2012	193,573	1,434,386	70%	253,121	108,360	532,607	62%	159,022	146,509	544,620	77%	(42,754)	26,029	859,380	73%	264,470
February	713,239	1,240,813	61%	253,126	170,280	424,247	50%	158,963	(227,359)	398,111	56%	(42,754)	72,184	833,351	71%	183,968
March	39,241	527,574	26%	424,052	37,885	253,967	30%	285,474	295,500	625,470	88%	(42,754)	(67,256)	761,167	65%	317,258
April	(191,621)	488,333	24%	864,922	(65,730)	216,082	25%	496,867	44,224	329,970	46%	(5)	26,011	828,423	70%	325,462
May	(162,180)	679,954	33%	734,923	(67,921)	281,812	33%	441,867	(65,984)	285,746	40%	(5)	30,045	802,412	68%	304,808
June	(174,030)	842,134	41%	585,879	(65,700)	349,733	41%	384,916	(125,453)	351,730	49%	(5)	32,122	772,367	66%	280,023
July	(179,832)	1,016,164	50%	562,899	(67,921)	415,433	49%	398,535	(48,658)	477,183	67%	(5)	55,671	740,245	63%	161,054
August	(166,633)	1,195,996	59%	455,010	(67,921)	483,354	57%	330,614	(87,278)	525,841	74%	(5)	(24,214)	684,574	58%	199,251
September	(174,030)	1,362,629	67%	338,013	(65,730)	551,275	65%	262,693	(5,781)	613,119	86%	(5)	(185,074)	708,788	60%	205,089
October	(199,361)	1,536,659	75%	328,023	(64,581)	617,005	72%	196,963	13,634	618,900	87%	(5)	32,190	893,862	76%	169,976
November	104,948	1,736,020	85%	288,777	42,572	681,586	80%	132,786	63,198	605,266	85%	(5)	23,295	861,672	73%	307,078
December	303,177	1,631,072	80%	285,257	123,260	639,014	75%	131,317	66,008	542,068	76%	129	(13,080)	838,377	71%	265,045
January 2013	493,756	1,327,895	65%	441,347	174,070	515,754	61%	188,654	(22,026)	476,060	67%	129	69,755	851,457	72%	213,459
February	323,161	834,139	41%	602,421	202,692	341,684	40%	299,945	280,888	498,086	70%	129	5,593	781,702	66%	155,629
March	288,728	510,978	25%	925,582	101,322	138,992	16%	502,637	149,308	217,198	31%	129	(7,274)	776,109	66%	169,221
April	222,250	222,250	11%	1,199,683	37,670	37,670	4%	593,633	67,890	67,890	10%	129	783,383	783,383	67%	313,756
Maximum Seasonal Inventory		**2,042,390**	**100%**			**852,286**	**100%**			**710,848**	**100%**			**1,177,500**	**100%**	

quantity. Under the AMA's, Sequent, acting as the agent for CGC, was entitled to generate economic gain, by managing a portion of CGC's gas inventory under CGC's contracts with the interstate pipelines, as long as Sequent met CGC's requirements in the manner directed by CGC. As agent for CGC, Sequent also had access, at CGC's discretion, to the portion of CGC's gas stored in CGC's LNG facilities that was designated as optimization inventory. While the gas was designated as optimization inventory, CGC was entitled to access this inventory and use it if it was necessary for CGC to meet customer requirements. The optimization inventory balances, owned by CGC but managed by Sequent for asset optimization purposes, are also identified in Table 6. Sequent's management of CGC's contract storage and LNG facility is identified and referred to by the Company as "storage optimization."

4.2 Storage Planning Guidelines

CGC generally fills its storage capacity during the summer months (April – October). Under the terms of the AMA, CGC is required to ratably fill its Tennessee FS-PA and FS-MA storage. That is, CGC is required to inject the same daily quantity during the summer injection period. Such a requirement is common under an AMA. CGC is not required to fill its SONAT CSS or LNG storage on a ratable basis. The monthly storage injection activity reflected in Table 6 is consistent with these requirements. CGC depletes storage inventory during the winter months (November – March).

CGC has established storage planning guidelines which identify the inventory levels the Company plans to maintain. The planned inventory levels at the start of the storage injection season (April 1) and the planned inventory levels at the start of the storage withdrawal season (November 1), as well as CGC's actual inventory levels during the review period, are identified in Table 7. As shown in Table 7, CGC plans to fill its contract storage services to 80-90 percent of capacity prior to the beginning of the storage withdrawal season. This provides CGC the ability to inject gas into storage during November if warmer-than-normal weather is experienced. CGC only plans to fill its LNG facility to 75 percent of capacity because this inventory level is sufficient to meet its customers' requirements under severe winter weather conditions.

Table 7.
CHATTANOOGA GAS COMPANY
Planned and Actual Storage Inventory as a Percent of Seasonal Capacity
(Dth)

	April 1		November 1	
	Planned	**Actual**	**Planned**	**Actual**
2010 Service				
SONAT CCS	10%	31%	90%	83%
TGP FS-PA	10	11	85	85
TGP FS-MA	5	5	80	81
LNG	52	35	75	33
2011 Service				
SONAT CCS	10	24	90	88
TGP FS-PA	10	26	85	85
TGP FS-MA	5	10	80	81
LNG	52	66	75	65
2012 Service				
SONAT CCS	10	46	90	85
TGP FS-PA	10	24	85	85
TGP FS-MA	5	25	80	80
LNG	52	67	75	71
2013 Service				
SONAT CCS	10	10	N/A	N/A
TGP FS-PA	10	11	N/A	N/A
TGP FS-MA	5	4	N/A	N/A
LNG	52	64	N/A	N/A

By the conclusion of the storage withdrawal season, CGC plans on depleting its contract storage inventories to 5-10 percent of capacity. CGC plans to deplete its LNG inventory to 52 percent of capacity prior to the conclusion of the storage withdrawal season. This level of LNG inventory is consistent with the inventory level which would remain after filling LNG to planned levels and vaporizing the supplies necessary to meet requirements under severe winter weather conditions. CGC does not plan on cycling LNG inventory as it does with contract storage because of the significant fuel requirements associated with liquidating gas supplies. CGC's storage planning guidelines are consistent with those of other gas utilities and appear reasonable.

At the conclusion of the winter of 2009-2010 (April 1, 2010), CGC's storage was depleted to levels consistent with its planning criteria and contract storage was subsequently refilled consistent with those criteria prior to the winter of 2010-2011. LNG inventory was significantly below planned levels prior to the beginning of the winter of 2010-2011 due to a major maintenance project during the summer of 2010. Storage was not fully depleted to planned inventory levels at the conclusion of the winter of 2010-2011 due to, among other things, transportation customer over-deliveries which slightly reduced storage withdrawals. Storage was refilled to planned levels prior to the winter of 2011-2012. Storage was not depleted to planned levels at the conclusion of the winter of 2011-2012 due to weather which was 23 percent warmer than normal and a decline in gas prices which made purchasing gas more economic than withdrawing gas from storage. Storage was refilled consistent with CGC's planning criteria prior to the winter of 2012-2013. Storage was depleted to planned inventory levels at the conclusion of the winter of 2012-2013.

CGC's storage inventory planning criteria were reasonable and CGC generally adhered to those criteria. Therefore, CGC's review period storage activity appears reasonable. Exeter's review noted CGC's SONAT CSS storage inventory actually increased from 58 percent to 77 percent of capacity during December 2011. This unusual activity was attributable to a CGC inventory transfer to Sequent in November 2011 which was subsequently returned to CGC in December 2011. Our review found no adverse consequences associated with these transfers.

4.3 <u>In-Ground Storage Purchases and Transfers</u>

As indicated in Section 3.1.1 of this Report, CGC made a number of in-ground storage inventory purchases from Sequent during the review period. These in-ground storage inventory purchases are summarized in Table 8. At times, these in-ground storage inventory purchases reflect a transfer of gas from optimization inventory to CGC, and at other times reflected the transfer of gas in storage held by Sequent under storage arrangements other than the CGC TGP and SONAT arrangements made available under the AMA. As shown in Table 8, these transfers generally occurred in the summer injection period. As explained in Section 3.1.3 of this Report, these in-ground storage inventory transfers were invoiced at costs which were

Table 8.
CHATTANOOGA GAS COMPANY
Summary of In-Ground Storage Purchases
(Dth)

	TGP FS-PA				TGP FS-MA				SONAT CSS			
	FOM		Daily		FOM		Daily		FOM		Daily	
	Quantity	Price	Quantity	Price	Quantity	Price	Quantity	Price	Quantity	Price	Quantity	Price
July 2010	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000	93,744	$4.7048
August	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000	105,156	$4.4258
September	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000	69,570	$3.7349	0	$0.0000
October	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000
November	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000
December	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000
January 2011	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000
February	309,545	$4.1640	0	$0.0000	0	$0.0000	0	$0.0000	92,871	$5.0100	0	$0.0000
March	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000
April	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000
May	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000	106,747	$4.3528
June	45,790	$4.4829	3,116	$4.5142	0	$0.0000	0	$0.0000	0	$0.0000	71,085	$4.7179
July	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000	98,932	$4.4796
August	174,623	$4.4385	0	$0.0000	86,521	$4.4516	0	$0.0000	0	$0.0000	25,290	$4.1681
September	96,240	$3.9731	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000	97,489	$3.9078
October	174,623	$3.8327	0	$0.0000	65,441	$3.8458	0	$0.0000	0	$0.0000	31,296	$3.5923
November	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000
December	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000
January 2012	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000
February	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000
March	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000
April	150,000	$2.2009	0	$0.0000	60,000	$2.1742	0	$0.0000	0	$0.0000	0	$0.0000
May	166,284	$2.0584	20,181	$2.4098	62,000	$2.0397	0	$0.0000	0	$0.0000	56,296	$2.4564
June	22,980	$2.5132	0	$0.0000	0	$0.0000	2,820	$2.3752	0	$0.0000	47,250	$2.4602
July	106,051	$2.8133	58,870	$2.8873	67,921	$2.8147	0	$0.0000	51,057	$2.9744	0	$0.0000
August	118,950	$3.1236	57,000	$2.7887	67,921	$3.1250	0	$0.0000	51,204	$2.8709	0	$0.0000
September	9,990	$2.6581	115,540	$2.7625	65,730	$2.6595	0	$0.0000	41,940	$2.8564	0	$0.0000
October	39,246	$2.9685	4,385	$3.4250	64,821	$2.9699	4,385	$3.4250	0	$0.0000	0	$0.0000
November	0	$0.0000	130	$3.4950	0	$0.0000	14,006	$3.5800	0	$0.0000	0	$0.0000
December	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000
January 2013	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000
February	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000
March	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000
April	209,850	$4.0579	0	$0.0000	89,580	$4.0593	0	$0.0000	0	$0.0000	0	$0.0000
May	222,022	$4.2643	0	$0.0000	93,434	$4.2657	0	$0.0000	127,049	$4.1408	0	$0.0000
June	214,860	$4.2233	0	$0.0000	99,790	$4.2347	0	$0.0000	129,090	$3.9323	0	$0.0000

lower for gas in storage inventory than if the gas was purchased in the Gulf Coast production region and delivered to and injected into storage.

Offsetting in-ground transfer transactions were found to have occurred in February 2011. Exeter's audit identified an in-ground purchase of SONAT CSS storage inventory at a price in excess of then-current market prices. However, the above-market impact of this transaction was completely offset by a TGP FS-PA in-ground storage inventory purchase in the same month.

In addition to in-ground storage inventory purchases, CGC made pipeline storage inventory transfers during the review period. These included transfers of storage inventory between its TGP FS-PA and SONAT CSS arrangements. These transfers were possible because TGP FS-PA and SONAT CSS storage services are both provided from the Bear Creek storage facility located in Louisiana, which is a joint venture equally owned by TGP and SONAT.

CGC also made other storage inventory transfers during the review period. These transfers were primarily adjustments to SONAT CSS storage to reconcile monthly differences between actual and nominated deliveries to CGC.

4.4 Off-System LNG Sales

CGC engaged in off-system LNG tanker sales during the review period. The net proceeds of these sales were shared 50 percent with ratepayers. These proceeds were reflected in the Company's Interruptible Margin Credit Rider (IMCR) filings made at the end of each May for the 12-month period ended the prior March 31. A summary of CGC's off-system LNG tanker sales for the review period, as reported in its IMCR filings, is presented in Table 9. As subsequently discussed, CGC adjusted the net LNG proceeds reported for the review period in its IMCR filing for the 12 months ended March 31, 2014 by $450,243, 50 percent of which, or $225,122, was shared with ratepayers.

For the months of April through June 2010 of the review period, CGC made no off-system sales. In July 2010, CGC began making LNG sales to Prometheus Energy (Prometheus) which markets LNG to industrial customers. CGC is not affiliated with Prometheus. LNG sales

Table 9.
CHATTANOOGA GAS COMPANY
Summary of Off-System LNG Sales

IMCR Period	Volume (Mcf)	Revenue	Cost	Net Proceeds
March 31, 2011	72,694	$445,295	$388,434	$56,861
March 31, 2012	332,740	$2,167,110	$1,865,002	$302,108
March 31, 2013	652,322	$4,394,234	$2,870,757	$1,523,482
Total	**1,057,756**	**$7,006,639**	**$5,124,193**	**$1,882,451**

by CGC to Prometheus continued until July 2011, at which time Pivotal LNG, Inc. (Pivotal), a CGC affiliate, began acting as CGC's agent for LNG sales. Pivotal is engaged in the sale of LNG as a substitute fuel for transportation and other mechanical uses in the wholesale LNG market. Pivotal made LNG sales to Prometheus and other customers on CGC's behalf through the remainder of the review period. Pivotal received no compensation for acting on behalf of CGC.

The net margins from LNG off-system sales were determined by subtracting the costs associated with the LNG sold from the revenues received. The gas sold supporting an LNG sale was specifically purchased in advance of the LNG sale and, therefore, the cost associated with the LNG sold was pre-determined. Consistent with CGC's AMA, gas purchased to support an LNG sale was purchased from Sequent. For the review period prior to January 2011, gas liquefied for LNG sales was generally purchased from Sequent on a Dth basis at the applicable SONAT FOM index price and adjusted to reflect variable transportation costs to deliver the gas to CGC. The cost per Dth was then adjusted to reflect the fuel used to liquefy the supply. Approximately 22 percent of each purchase is required for liquefaction fuel. The purchase quantities and costs were also converted from a Dth to Mcf basis. During the period January 2011 through June 2011, prior to the period Pivotal began acting as CGC's agent for LNG sales, the flowing gas rate was converted to a liquefied Mcf price for purposes of determining the margins resulting from off-system LNG sales. The gas used for the off-system sales was transferred from the LNG optimization inventory at rates based on a negotiated formula which included pipeline demand charges. After Pivotal began acting as CGC's agent for LNG sales in

July 2011, LNG was transferred from the LNG optimization inventory available to Sequent to the LNG optimization inventory available to Pivotal using the same negotiated formula.

During the review period, Pivotal acquired an LNG facility from the Utilities Board of the City of Trussville, Alabama (Trussville LNG facility). After acquisition, Pivotal invested approximately $10 million in improvements to the Trussville LNG facility. On several occasions during the review period, while the Trussville LNG facility was undergoing these improvements, the facility needed to maintain minimum LNG tank levels to avoid a potentially hazardous situation. To maintain these minimum levels, CGC sold 190,707 Mcf of LNG to the Trussville LNG facility at cost. The LNG sales to the Trussville LNG facility were excluded from CGC's IMCR filings.

Exeter's audit found that effective January 2011, Sequent applied a negotiated formula rate to determine the price of LNG used for off-system sales that included a charge for pipeline demand costs. Under CGC's AMA with Sequent, CGC was responsible for all of the pipeline demand costs associated with the pipeline capacity. Since Sequent does not incur any pipeline demand costs for such transactions, the pipeline demand charges included in the formula is a gain that should be shared with CGC's customers. The total gain as a result of this change for the period January 2011 through March 2013 was $233,518. Of this amount, $8,396 resulted from activity in March 2011. This amount was shared under the AMA that was in effect during March 2011. As a result, the additional gain that should be credited to CGC's customers for the period April 2011 through March 2013 is $225,122. When interest is included through March 31, 2014, the total is $238,770.

In its IMCR filing for the 12 months ended March 31, 2014, CGC credited $219,329 of the additional gain and $13,136 of interest, for a total of $232,465, to its customers for the period prior to April 2013. Exeter believes it is reasonable to require CGC to credit ratepayers an additional $6,305 for LNG margins and the related interest for the additional gain computed for the period of April 2011 through March 2013.

Exeter's audit found the affiliate at-cost sales of LNG to the Trussville LNG facility to be unreasonable. Exeter believes it would be reasonable to require CGC to credit ratepayers for LNG off-system sales margins for these sales based on sales prices consistent with those made to unaffiliated parties during the same period. Exeter calculates this amount to be $119,645, plus interest.

As shown previously in Table 9, after Pivotal began acting as CGC's agent for LNG sales, these sales and the resulting margins increased significantly. It is uncertain as to what extent those increases are attributable to Pivotal's efforts or to the general increase in LNG consumption in the United States experienced during the period.

5.0 EVALUATION OF CAPACITY PORTFOLIO AND LOAD DURATION CURVES

5.1 Design Day Forecast

CGC secures sufficient capacity resources to meet the forecasted design day requirements of sales customers and those transportation customers which select firm backup service. CGC's design day is a day with a mean temperature of 8˚F (57 heating degree days (HDD)). In the last 84 years, there have been six occurrences where temperatures colder than 8˚F have been experienced. This equates to a design day probability of occurrence of approximately once every 15 years. This probability of occurrence is consistent with observed industry practices.

Separate design day forecasts are prepared for the sales and transportation customers in each of the Company's two service territories (Chattanooga and Cleveland). For the sales customer forecasts, CGC performs a regression analysis of historical daily data. The Company's regression analysis includes use-per-customer as the dependent variable, and current and prior day HDDs and Friday, Saturday, and Sunday weekend days as the independent variables. The regression analysis is based on daily data from the core winter months (December – March) for the prior five years with at least 1 HDD. Bend points, which aid in capturing the measured change in customer consumption behavior at increasingly colder temperatures deemed to be of statistical significance, are also included.

For transportation customers selecting firm backup service, the contracted level of backup service is used for the Company's design day forecast. The Company's total design day forecast reflects the anticipated demands of sales customers and transportation customers selecting firm backup service, adjusted for new load additions. The Company's forecasted design day requirements by component for the winter of 2013-2014 based on data from the five prior winter seasons are summarized in Table 10. Also shown are forecasted design day requirements for the following two winter seasons. The forecasts for the 2014-2015 and 2015-2016 winter seasons are based on the forecast model prepared for the winter of 2013-2014, adjusted for customer growth and load additions.

Table 10.
CHATTANOOGA GAS COMPANY
Summary of Design Peak Day Requirements
Winter of 2013-2014
(Dth)

Description	Chattanooga	Cleveland	Total
Winter 2013-2014			
Sales	110,337	16,337	**126,674**
Transport Firm Backup	13,190	1,445	**14,635**
Load Additions	5,659	456	**6,116**
Total	**129,187**	**18,238**	**147,425**
Winter 2014-2015			
Sales	110,911	16,367	**127,278**
Transport Firm Backup	13,190	1,445	**14,635**
Load Additions	7,581	913	**8,494**
Total	**131,602**	**18,725**	**150,406**
Winter 2015-2016			
Sales	111,842	16,466	**128,308**
Transport Firm Backup	13,190	1,445	**14,635**
Load Additions	8,956	946	**9,902**
Total	**133,987**	**18,857**	**152,844**

A requirement of Exeter's audit is to analyze and evaluate the manner in which CGC includes the effect of energy conservation in its forecast of design day demands. The Company's design day forecast is prepared using the most recent five years of data, which CGC claims captures the effect of its customers' energy conservation and efficiency efforts over this time period. To assess the potential impact of customer conservation efforts on design day demands, Exeter prepared an independent design day forecast utilizing data from the three-year review period. Our forecast was nearly identical to that prepared by the Company. This suggests that conservation efforts have not had a significant impact on CGC's design day demands. It also supports the reasonableness of CGC's design day forecast.

5.2 Actual Peak Day Demands

Table 11 summarizes the requirements of CGC's sales and transportation customers on the actual peak day observed during each winter season of the review period. Also shown are actual heating degree days.

Table 11.
CHATTANOOGA GAS COMPANY
Summary of Actual Firm Peak Day Sendout
(Dth)

	HDD	Chattanooga	Cleveland	Total
December 13, 2010	45	102,081	16,839	**118,920**
February 11, 2012	40	90,640	12,637	**103,277**
January 17, 2013	28	79,413	12,798	**92,211**
January 6, 2014	54	119,759	16,304	**136,063**

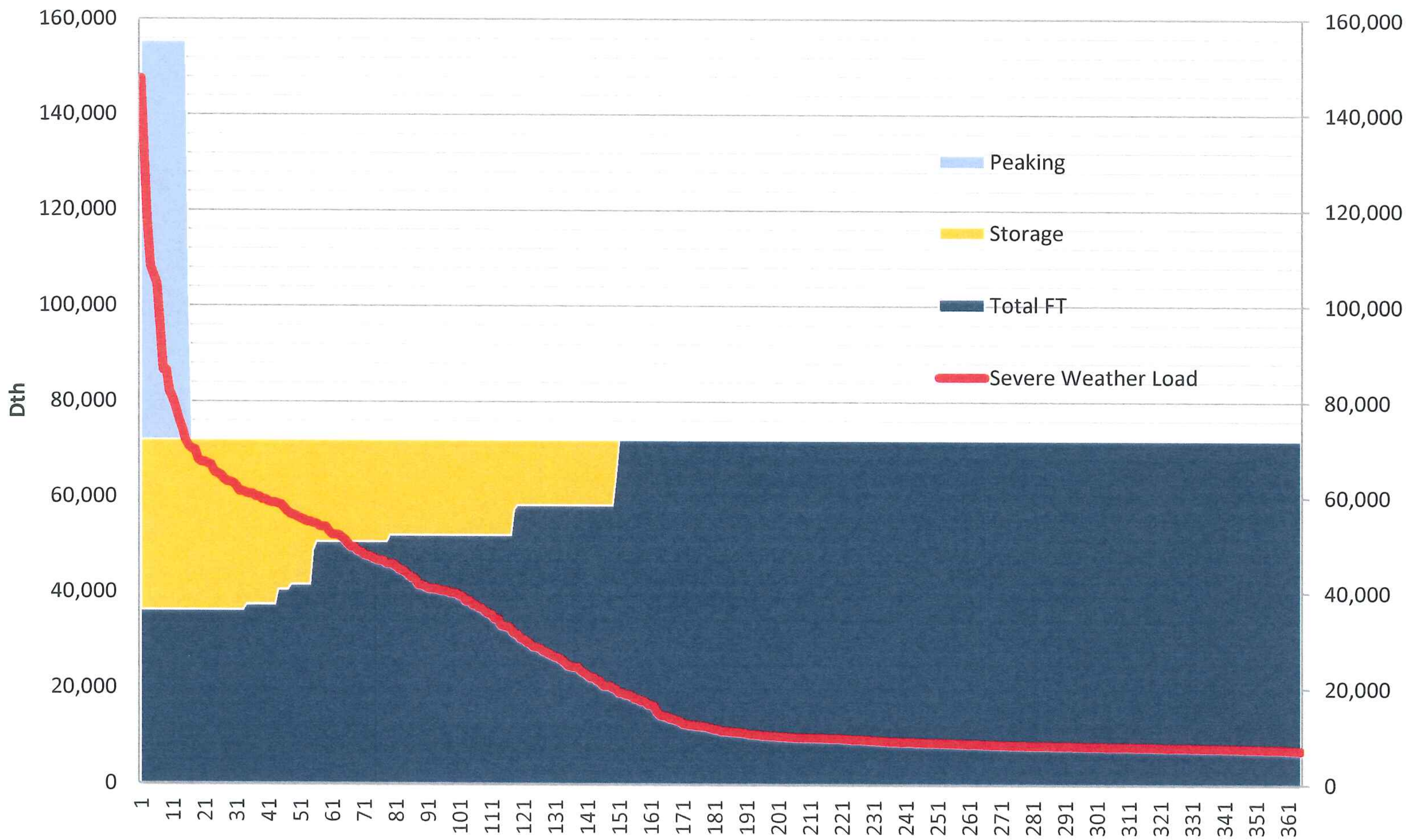
5.3 Balance of Capacity Resources and Customer Requirements

As initially shown on Table 1 in Section 2.1 of this Report, the capacity resources available to meet CGC's design day requirements for the 2013-2014 winter season totaled 155,418 Dth. CGC attempts to maintain a capacity reserve margin of 5 percent which Exeter does not find unreasonable. Estimated design day firm requirements, including the 5 percent reserve margin, totaled 154,796 Dth for the winter of 2013-2014, indicating that CGC's design peak day capacity resources and requirements were in relative balance.

The overall reasonableness of CGC's capacity portfolio resources and requirements can be assessed by a demand curve which compares the daily demands of CGC's customers with the capacity resources available to meet those demands. Figure 5 presents a load duration curve for CGC under severe weather planning conditions which CGC identifies as a year in which HDDs are 30 percent higher than normal.

As shown in Figure 5 and just explained, CGC design peak day capacity resources and requirements are in relative balance. However, Figure 5 reveals that even under severe weather conditions, as noted by the capacity resources identified above severe weather load,

Figure 5.
CHATTANOOGA GAS COMPANY
Load Duration Curve



Notes:
1. Load for transportation customers that have firm backup service is only included on the design day and the day before and day after design day.
2. Some FT is required to deliver storage gas to the citygate. As ratchets hit the storages, the FT category increases as a result of less encumbered FT.
3. Peaking includes LNG and ETN bundled peaking.

CGC maintains capacity resources in excess of its requirements at most other times. During a winter in which severe weather conditions are experienced, it would be expected that CGC would only require use of approximately 300,000 Dth of its maximum LNG storage inventory of 1,200,000 Dth. CGC's total load requirements during a winter in which severe weather conditions are experienced is projected to be 7,500,000 Dth. As shown previously in Table 1, CGC's winter season capacity resources total 12,000,000 Dth. CGC's total load requirements during a year in which severe weather conditions are experienced is projected to be 9,500,000 Dth. As shown in Table 1, CGC's annual capacity resources total over 27,000,000 Dth, less approximately 2,700,000 which may be required to fill its contract storage services during the summer. The potential for CGC to adjust its capacity resources to better match its load requirements is addressed in the next section of this Report.

5.4 Capacity Portfolio Modifications

The RFP scope of work for Exeter's review included examination and identification of: (a) the total fixed cost of CGC's year-round firm transportation capacity to meet design peak day demand; (b) the total fixed cost of available seasonal firm transportation; and (c) the availability of seasonal firm transportation capacity. Exeter interprets this aspect of the scope of work as requiring us to evaluate whether CGC's annual interstate pipeline demand charges can be reduced by modifying the Company's current capacity portfolio.

The charges associated with each non-storage-related interstate pipeline firm transportation service purchased by CGC at the conclusion of the review period are summarized on Table 12. As shown, these charges currently total $11.8 million per year. As indicated in the previous section of this Report, CGC maintains excess year-round firm capacity. If available, the Company could reduce its demand costs by decreasing its year-round capacity and placing greater reliance on winter season capacity or supply services. However, as noted in Section 2.3.2 above, winter season assets, particularly bundled peaking supply, are not readily available in the marketplace. Since the interstate pipelines would not willingly sacrifice annual revenue for seasonal revenue, striking an improved balance between winter season needs and summer refill requirements would be difficult to achieve.

Table 12. CHATTANOOGA GAS COMPANY Summary of Interstate Pipeline Firm Transportation Charges (Dth)			
Pipeline Service/Contract	MDQ	Monthly Demand Charge	Annual Demand Cost
Tennessee Gas			
FT-A (48082)	37,819	$9.4503	$4,288,811
East Tennessee			
FT-A (410203)	13,000	6.68	1,042,080
FT-A (410204)	28,350	6.68	2,272,536
Southern Natural			
FT (FSNG130)	13,221	12.77	2,025,986
FT-NN (FSNG130)	14,346	12.77	2,198,381
Total			**$11,827,794**

As previously shown in Table 1, the Company's year-round firm transportation service contract with TGP expires in 2015, as does one of its contracts with ETNG. The other ETNG year-round firm transportation contract expires in 2017, and its contracts with SONAT expire in 2016. Each of these contracts has a one-year notice requirement for cancellation or potential modification.

Replacing year-round arrangements with winter season arrangements could reduce CGC's annual demand charges. CGC has indicated that it has requested offers for winter season firm transportation services from ETNG and SONAT for the past several winters, but both pipelines have repeatedly declined to offer such services. CGC has indicated it will contact TGP approximately 90 days prior to the October 1, 2014 notice date for its year-round firm transportation contract to determine the availability of winter season capacity. CGC is unaware of TGP offering such services. CGC's understanding with respect to the unavailability of winter season arrangements is also consistent with Exeter's understanding. Any decrease in the reliance on annual firm transportation capacity and/or increase in the reliance on winter season arrangements is likely to reduce the revenues CGC would receive under future AMAs. Revenues under CGC's AMA would decline because less excess capacity would be available for use by the Asset Manager.

6.0 FINDINGS OF FACT AND AREAS OF CONCERN

Exeter's review period findings of fact are as follows:

- CGC was in technical compliance with the terms and conditions of the Performance Based Ratemaking Mechanism during the review period.
- Under the PBRM, if CGC's total monthly commodity gas costs for a plan year do not exceed the benchmark amount by 1 percent, the Company's gas costs are deemed prudent and the audit required by TRA Administrative Rule 1220-4-7-.05 is waived. During the review period, CGC's actual gas costs exceeded benchmark costs by $151,401, which is significantly less than 1 percent of benchmark commodity gas costs which totaled $84,551,961.
- CGC held services with Tennessee Gas Pipeline, East Tennessee Natural Gas, and Southern Natural Gas Company during the review period.
- During the review period, CGC operated under Asset Management Agreements with its affiliate, Sequent Energy Marketing, which were approved by the TRA.
- CGC served an average of 62,000 sales and transportation customers during the review period, and annual throughput averaged nearly 15,000,000 Dth.
- CGC's storage inventory planning criteria were reasonable and CGC generally adhered to those criteria, and CGC's review period storage activity was reasonable.
- CGC reported net margins of $2,332,695 from its off-system LNG sales activities for the review period, 50 percent of which was shared with ratepayers.
- CGC's design day probability of occurrence is consistent with observed industry practice.
- CGC's review period forecasts of design day demands were reasonable.
- Customer conservation efforts did not have a significant impact on design day demands.
- CGC's review period use of a 5 percent reserve margin, when viewed in conjunction with its design day criteria of 57 heating degree days, was reasonable.

- The balance between CGC's review period winter season capacity resources and requirements was reasonable.

- CGC could reduce its pipeline demand costs by decreasing its year-round capacity and instead rely on winter season capacity. However, the Company's opportunities to do so are currently unavailable.

Exeter's review noted the following areas of concern with the Performance Based Ratemaking Mechanism during the review period:

- The negotiated pricing formula for CGC's purchases of LNG from Sequent, adopted effective January 2011, improperly included pipeline demand charges. The pricing calculation used for LNG purchases made to support LNG sales which existed prior to January 2011 should have been maintained throughout the review period. Exeter's audit found that effective January 2011, Sequent applied a negotiated formula rate to determine the price of LNG used for off-system sales that included a charge for pipeline demand costs. Under CGC's AMA with Sequent, CGC was responsible for all of the pipeline demand costs associated with the pipeline capacity. Since Sequent does not incur any pipeline demand costs for such transactions, the pipeline demand charges included in the formula is a gain that should be shared with CGC's customers. The total gain as a result of this change for the period January 2011 through March 2013 was $233,518. Of this amount, $8,396 resulted from activity in March 2011. This amount was shared under the AMA that was in effect during March 2011. As a result, the additional gain that should be credited to CGC's customers for the period April 2011 through March 2013 is $225,122. When interest is included through March 31, 2014, the total is $238,770. In its IMCR filing for the 12 months ended March 31, 2014, CGC credited $219,329 of the additional gain and $13,136 of interest, for a total of $232,465, to its customers for the period prior to April 2013. Exeter believes it is reasonable to require CGC to credit ratepayers an additional $6,305 for LNG margins and the related interest for the additional gain computed for the period of April 2011 through March 2013.

- CGC sold LNG to an affiliate during the review period at cost and excluded these sales from its IMRC. Exeter recommends that CGC's IMRC be credited $119,645 for these sales, plus interest.

APPENDIX A

PERFORMANCE BASED RATEMAKING MECHANISM

CHATTANOOGA GAS COMPANY
GAS TARIFF
TRA NO.1 REVISED SHEET56

PERFORMANCE-BASED RATEMAKING

APPLICABILITY

This Performance-Based Ratemaking Mechanism (PBRM) is designed to encourage the utility to maximize its gas purchasing activities at minimum cost consistent with efficient operations and service reliability. Each plan year will begin July 1. The annual provision and filings herein will apply to this annual period. The PBRM will continue until it is either (a) terminated at the end of a plan year or by not less than 90 days notice by the Company to the Authority or (b) modified, amended or terminated by the Authority.

OVERVIEW OF STRUCTURE

The Performance-Based Ratemaking Mechanism establishes predefined monthly benchmark indexes to which the Company's commodity cost is compared.

BENCHMARK INDEX

Each month, Chattanooga Gas Company (Company / Chattanooga) will compare its actual commodity cost of gas to the appropriate benchmark amount. The benchmark gas cost will be computed by multiplying actual purchase quantities for the month, including quantities purchased for injection into storage, by the appropriate benchmark price index.

Spot Market Purchases:

The monthly spot market benchmark is the "Index" price published in the first issue of the delivery month of *Inside FERC's Gas Market Report* in the table titled "Price of Spot Gas Delivered to Pipelines," denoted in the column labeled "Index" and the row for the applicable "Pricing Point."

Swing Purchases

For swing purchases, the benchmark " Index" price for gas delivered on any day upon which *Gas Daily* is published, is equal to the Gas Daily-Midpoint price for the immediately following day under the heading "Daily Price Survey." For gas delivered on Saturday, Sunday, or any other day upon which *Gas Daily* is not published, the price index is equal to the Daily-Midpoint for the nearest subsequent day published by *Gas Daily*.

Long-term purchases

For long term purchases, i.e., a term more than one month, the "Index" price published in the first issue of the delivery month of *Inside FERC's Gas Market Report* in the table titled "Price of Spot Gas Delivered to Pipelines" denoted in the column labeled "Index" and the row for the applicable "Pricing Point" will be adjusted for the Company's rolling three-year average premium paid to ensure long-term supply availability during peak periods.

City Gate Purchases

For city gate purchases where gas is delivered by the supplier to the local distribution company, the indexes will be adjusted for the avoided transportation costs that would have been paid if the upstream capacity were purchased versus the demand charges actually paid to the supplier.

CHATTANOOGA GAS COMPANY
GAS TARIFF
TRA NO. 1

SECOND REVISED SHEET NO.56A

PERFORMANCE-BASED RATEMAKING
(Continued)

PRUDENCE DETERMINATION

If Chattanooga's total commodity gas cost for the plan year does not exceed the total benchmark amount by one percentage point (1%) for a plan year ending after June 30, 2000, Chattanooga's gas cost will be deemed prudent and the audit required by Tennessee Regulatory Authority's Administrative Rule 1220-4-7-. 05 is waived. If during any month of the plan year, the Company's commodity gas cost exceeds the benchmark amount by greater than two percentage points (2%), the Company shall file a report with the Authority fully explaining why the cost exceeded the benchmark.

FILING WITH THE AUTHORITY

The Company will file an annual report not later than 60 days following the end of each plan year identifying the actual cost of gas purchased and the applicable index for each month of the plan year.

Unless the Authority provides written notification to the Company within 180 days of such reports, the annual filing shall be deemed in compliance with the provisions of this Service Schedule.

PERIODIC INDEX REVISIONS

Because of changes in the natural gas marketplace, the price indices used by Chattanooga and the composition of Chattanooga's purchased gas portfolio may change. The Company shall, within 30 days of identifying a change to a significant component of the mechanism, provide notice of such change to the Authority. Unless the Authority provides written notice to Chattanooga within 30 days of the Company's notice to the Authority, the price indices shall be deemed approved as proposed by the Company.

AFFILIATE TRANSACTION GUIDELINES

Terms used in these affiliate transaction guidelines have the following meanings:

1. Affiliate, when used in reference to any person in this standard, means another entity who controls, is controlled by, or is under common control with, the first entity.

2. Control (including the terms "controlling", "controlled by", and "under common control with") as used in the affiliate transaction guidelines, includes, but is not limited to, the possession, directly or indirectly and whether acting alone or in conjunction with others, of the authority to direct or cause the direction of the management or policies of an entity. Under all circumstances, beneficial ownership of more than ten percent (10%) of voting securities or partnership interest of an entity shall be deemed to confer control for purposes of these affiliate transaction guidelines.

3. Gas supplier is any person who sells or otherwise provides gas to the Company. It does not include customers who transport their gas and as a result of an imbalance in the amount consumed and the amount delivered to the city gate sell gas to the Company in compliance with the Company's approved tariff provisions.

CHATTANOOGA GAS COMPANY
GAS TARIFF
TRA NO. 1

REVISED SHEET NO.56C

PERFORMANCE-BASED RATEMAKING
(Continued)

Standards of Conduct

The Company must conduct its business to conform to the following standards:

1. All purchases from an affiliated gas supplier of gas for system supply or storage shall be at the price and in accordance with the terms provided in a fully executed contract between the Company and the affiliated gas supplier.

2. The Company and the affiliated gas supplier shall maintain records to show that such purchases are not at a price greater than the market price at the time of the transaction.

3. All sales of gas by the Company to an affiliated gas supplier shall be in accordance with the provisions of the Company's approved tariff or at the price and in accordance with the terms provided in a fully executed contract between the Company and the affiliated gas supplier. Any sale of gas to an affiliate not in accordance with an approved tariff provision shall be at a price that is not less than the greater of the cost as recorded on the Company's books or the market price at the time of the transaction.

4. The Company shall maintain records to show that sales to an affiliated supplier are in accordance with the applicable tariff provision or, if not provided under an approved tariff provision, the price is not less than the greater of the cost as recorded on the Company's books or market price at the time of the transaction.

5. An affiliated gas supplier shall not make sales to any customer's premise that is connected to the Company's distribution facilities.

6. The Company shall not disclose to any affiliated gas supplier any information that the Company receives from a non-affiliated gas supplier that the non-affiliated gas supplier has identified as confidential unless the prior consent of the parties to which the information relates has been voluntarily given.

7. To the maximum extent practicable, the Company's operating employees and the operating employees of an affiliated gas supplier must function independently of each other.

8. The Company must maintain its books of accounts and records separately from those of an affiliated gas supplier.

9. The Company shall maintain sufficiently detailed records of all transactions with any affiliated gas supplier.

RFP PROCEDURES FOR SELECTION OF ASSET MANAGER AND/OR GAS PROVIDER

1. In each instance in which Chattanooga Gas Company (Company) intends to engage the services of an asset manager to provide system gas supply requirements and/or manage its assets regulated by the Tennessee Regulatory Authority (TRA), the Company shall develop a written request for proposal (RFP) defining the Company's assets to be managed and detailing the Company's minimum service requirements. The RFP shall also describe the content requirements of the bid proposals and shall include procedures for submission and evaluation of the bid proposals.

2. The RFP shall be advertised for a minimum period of thirty (30) days through a systematic notification process that includes, at a minimum, contacting potential asset managers, including past bidders and other approved asset managers, and publication in trade journals as reasonably available. This thirty (30)-day minimum period may be shortened with the written consent of the TRA Staff to a period of not less than fifteen (15) days.

3. The procedures for submission of bid proposals shall require all initial and follow-up bid proposals to be submitted in writing on or before a designated proposal deadline. The Company shall not accept initial or follow-up bid proposals that are not written, or that are submitted after the designated proposal deadline.

CHATTANOOGA GAS COMPANY
GAS TARIFF
TRA NO. 1 REVISED SHEET NO.56C

PERFORMANCE-BASED RATEMAKING
(Continued)

Following receipt of initial bid proposals, and on a non-discriminatory basis, the Company may solicit follow-up bid proposals from those submitting initial bid proposals in an effort to obtain the most overall value for the transaction.

4. All initial and follow-up bid proposals shall be evaluated as they are received. The criteria for choosing the winning bid proposal shall include, at a minimum, the following: (a) the total value of the bid proposal; (b) the bidder's ability to perform the RFP requirements; (c) the bidder's asset management qualifications and experience; and (d) the bidder's financial stability and strength. The winning bid proposal shall be the one with the best combination of attributes based on the evaluation criteria. If, however, the winning bid proposal is lower in amount than any other initial or follow-up bid proposal(s), the Company shall explain in writing to the TRA why it rejected each higher bid proposal in favor of the lower winning bid proposal. The Company shall maintain records demonstrating its compliance with the evaluation and selection procedures.

5. An incumbent asset manager shall not be granted an automatic right to match a winning bid proposal. If the incumbent asset manager desires to continue its asset management relationship with the Company after expiration of its asset management agreement, it shall submit a written bid proposal in accordance with the Company's RFP procedures. The bid proposal shall be evaluated pursuant to the procedures set forth in paragraph 4 above.

6. The Company may develop additional procedures for asset management selection as it deems necessary and appropriate so long as such procedures are consistent with the agreed-upon procedures described herein.

7. The Company shall retain all RFP documents and records for at least four (4) years and such documents and records shall be subject to the review and examination of the TRA Staff. The Asset Manager shall maintain documents and records of all transaction that utilize the Company's gas supply assets. All documents and records of such transactions shall be retained for two years after termination of the agreement and shall be subject to review and examination by the Company and the TRA Staff.

ISSUED: JULY 17, 2006 EFFECTIVE: SEPTEMBER 1, 2006
ISSUED BY: STEVE LINDSEY, VP