IN THE TENNESSEE PUBLIC UTILITY COMMISSION
AT NASHVILLE, TENNESSEE

IN RE:	)	
	)	
DOCKET TO EVALUATE CHATTANOOGA GAS COMPANY'S PURCHASES AND RELATED SHARING INCENTIVES	)	**DOCKET NO. 20-00139**
	)	
	)	
	)	

DIRECT TESTIMONY

OF

DAVID N. DITTEMORE

October 11, 2021

I. Background

Q1. PLEASE STATE YOUR NAME AND OCCUPATION FOR THE RECORD.

A1. My name is David N. Dittemore. I am a self-employed consultant working in the utility regulatory sector.

Q2. PLEASE PROVIDE A SUMMARY OF YOUR BACKGROUND AND PROFESSIONAL EXPERIENCE.

A2. I received a Bachelor of Science Degree in Business Administration from the University of Central Missouri in 1982. I am a Certified Public Accountant licensed in the state of Oklahoma (#7562). I was previously employed by the Kansas Corporation Commission ("KCC") in various capacities, including Managing Auditor, Chief Auditor, and Director of the Utilities Division. I was self-employed as a Utility Regulatory Consultant for approximately four years, representing primarily the KCC Staff in regulatory issues. I also participated in proceedings in Georgia and Vermont, evaluating issues involving electricity and telecommunications regulatory matters.

Additionally, during this time frame, I performed a consulting engagement for Kansas Gas Service ("KGS"), my subsequent employer. For eleven years, I served as Manager and subsequently Director of Regulatory Affairs for KGS, the largest natural gas utility in Kansas serving approximately 625,000 customers. KGS is a division of One Gas, a natural gas utility serving about two million customers in Kansas, Oklahoma, and Texas. I joined the Tennessee Attorney General's Office in September 2017 as a Financial Analyst. In July 2021, I began my consulting practice. Overall, I have thirty years of experience in the field of public utility regulation. I have presented testimony as an expert witness on many occasions. Attached as Exhibit DND-1 is a detailed overview of my background.

Q3. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY BEFORE THE TENNESSEE PUBLIC UTILITY COMMISSION (TPUC OR THE "COMMISSION")?

A3. Yes. I have submitted testimony in many TPUC dockets.

Q4. ON WHOSE BEHALF ARE YOU APPEARING?

A4. I am appearing on behalf of the Consumer Advocate unit of the Financial Division of the Tennessee Attorney General's Office.

II. <u>Purpose of Testimony</u>

Q5. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A5. The purpose of my testimony is to support a modification of the sharing percentage currently incorporated within the Chattanooga Gas Company (CGC or the "Company") Performance-Based Ratemaking Mechanism (PBRM).

Q6. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S PBRM MECHANISM.

A6. The PBRM mechanism evaluates the Company's performance in its purchasing practices and provides incentives to the Company to maximize off-system revenues. Concerning the Company's natural gas purchases, if the actual commodity gas costs are within 1% of monthly benchmark indices, the purchases are deemed to be prudent. The PBRM also incorporates an Interruptible Margin Credit Rider (IMCR), which provides a fifty percent sharing of the gross profit margin that results from transactions with non-jurisdictional

Customers that rely on the Company's gas supply assets.[1] These proceeds include funds received through Asset Management Agreement (AMA) fees as well as capacity release[2] and off-system sales transactions.

Q7. HAS THE COMMISSION AUTHORIZED A REVIEW OF COMPANY PERFORMANCE UNDER THE PBRM ON AN ONGOING BASIS?

A7. Yes. On September 23, 2009, the Commission issued an order in TRA[3] Docket No. 07-00224, which established a triennial review of transactions related to the PBRM to be conducted by an independent consultant beginning in 2012.[4]

Q8. HAVE YOU HAD AN OPPORTUNITY TO REVIEW THE RESULTS OF THE CONFIDENTIAL EXETER REVIEW OF PERFORMANCE BASED RATEMAKING MECHANISM AND TRANSACTIONS AND ACTIVITIES WRITTEN BY EXETER ("REPORT") FILED ON JUNE 29, 2020 IN TRA DOCKET NO. 07-00224?

A8. Yes.

Q9. DOES EXETER HAVE SIGNIFICANT EXPERIENCE IN REVIEWING INCENTIVE PROCUREMENT MECHANISMS?

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[1] Chattanooga Gas Company Gas Tariff, Twelfth Revised Sheet No. 48, "Interruptible Margin Credit Rider" (https://www.chattanoogagas.com/content/dam/southern-co-gas/chattanooga-gas/rates/rates-and-tariffs/2021-rates-and-tariffs/october-2021/Revised%20Tarrif%2010-1-21.pdf) (last viewed 10/6/2021).

[2] Capacity release refers to the marketing of interstate pipeline capacity during periods when such capacity exceeds that needed to serve the load of firm sales customers.

[3] The Tennessee Regulatory Authority, or TRA, is the predecessor agency to the TPUC, just as the Tennessee Public Service Commission predated the TRA. While the nomenclature has changed, the scope and function of these entities has remained essentially the same.

[4] *Order, In re: Docket to Evaluate Chattanooga Gas Company's Purchases and Related Sharing Incentives*, TPUC Docket No. 07-00224 (September 23, 2009). A copy of this Order is attached as Exhibit DND-2.

A9. Yes. Exeter identifies its significant experience in reviewing gas incentive mechanisms in non-Tennessee jurisdictions.[5]

Q10. DOES EXETER COMPARE THE INCENTIVES AVAILABLE TO CGC WITH THOSE AVAILABLE TO ATMOS AND PIEDMONT?

A10. The Report continues by identifying the CGC incentives afforded under the PBRM, specifically the Company's retention of fifty percent of the AMA fees, capacity release, and off-system sales margins with the remaining funds credited to the ratepayers through its purchased gas recovery mechanism.[6] The Report then identifies the incentives/penalties applicable to mechanisms in place for Atmos and Piedmont.[7]

The Atmos gas procurement incentive mechanism is symmetrical. It allows the Company to retain incentives or incur penalties based upon comparing its commodity costs to benchmark prices outside a dead-band. For city-gate purchases, the benchmark is adjusted to reflect the avoided pipeline demand charges. Atmos's capacity management incentive mechanism provides for retention by the Company of 10% of its capacity release and off-system sales margins.[8] Atmos is subject to an overall cap of its incentives of $1.25 million per year.[9] As of December 2020, Atmos served approximately 155 thousand residential and commercial customers (i.e., customers who incur purchase gas costs charges).[10] The incentive retention approximates $8 per customer per year.[11]

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5 *Chattanooga Gas Company Review of Performance Based Ratemaking Mechanism Transactions and Activities*, p. 43, TPUC Docket No. 07-000224 (June 29, 2020). A copy of the full un-redacted version of this Report is attached as CONFIDENTIAL Exhibit DND-3.

6 Exhibit DND-3 at p. 43.

7 *Id.* at pp. 44-45.

8 *Id.* at p. 44.

9 *Id.*

10 Atmos December 2020 Form 3.03 Report submitted to the Tennessee Public Utility Commission.

11 The $8 per person calculation is the result of $1,250,000 divided by 155,000.

The Piedmont incentive includes a commodity procurement cost component and a capacity management component. The Company retains 25% of commodity costs to the extent they are less than a monthly benchmark price.[12] The Company also is eligible to retain 25% of asset management agreement fees, capacity release revenues, and off-system sales margins. The retention of these incentive proceeds is $1.6 million annually.[13] Piedmont serves approximately 194 thousand residential and commercial customers.[14] The Company's incentive retention approximates $8.25 per customer per year.[15]

Q11. DOES EXETER'S REPORT IDENTIFY TYPICAL SHARING PERCENTAGES APPLIED TO UTILITIES IN OTHER JURISDICTIONS?

A11. Yes. Exeter indicates in its Report that Company retention of asset management fees, capacity release revenues, and off-system sales margins range from 10% to 25% in other jurisdictions.[16]

Q12. WHAT IS YOUR RECOMMENDATION IN THIS PROCEEDING?

A12. I recommend that the Company retention percentage associated with asset management fees, capacity release revenues, and off-system sales be set at 25% with an annual cap of $550 thousand, implemented on a prospective basis. This cap is in line with the Company's peers, both within and outside of Tennessee. The annual cap approximates Company retention of $8.25 per customer and is consistent with the caps of both Atmos and Piedmont.

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12 Exhibit DND-3 at p. 45.
13 *Id.*
14 Piedmont February 2021 Form 3.03 report submitted to the Tennessee Public Utility Commission.
15 The $8.25 per person calculation is the result of $1,600,000 divided by 194,000.
16 Exhibit DND-3, Section 6.2: Balance of Incentives, p. 45.

Q13. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A13. The basis for my recommendation is the information provided within the June 2020 Exeter Report.

Q14. HAS THE COMMISSION PREVIOUSLY RECOGNIZED THAT OTHER PARTIES MAY USE THE INDEPENDENT CONSULTANT REPORT AS THE BASIS TO MAKE RECOMMENDATIONS TO MODIFY THE PROVISIONS OF THE PBRM MECHANISM?

A14. Yes. The Commission has clearly stated that "the TRA, Staff, CGC or the CAD may use the Report of the independent consultant as grounds for making recommendations or proposed changes to the Authority, and the TRA, Staff, CGC, or the CAD may support or oppose such recommendations or proposed changes."[17]

Q15. DOES THIS CONCLUDE YOUR TESTIMONY?

A15. Yes.

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[17] *See* Exhibit DND-2, Exhibit 1.

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AT NASHVILLE, TENNESSEE

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AFFIDAVIT

I, David N. Dittemore, on behalf of the Consumer Advocate Unit of the Attorney General's Office, hereby certify that the attached Direct Testimony represents my opinion in the above-referenced case and the opinion of the Consumer Advocate Unit.

David N. Dittemore
DAVID N. DITTEMORE

Sworn to and subscribed before me
this 6th day of October, 2021.

Terra Allen
NOTARY PUBLIC

My commission expires: September 28, 2022

TERRA ALLEN STATE OF TENNESSEE NOTARY PUBLIC HICKMAN COUNTY

Exhibit DND-1

David Dittemore

Experience

Areas of Specialization
Approximately thirty-years experience in evaluating and preparing regulatory analysis, including revenue requirements, mergers and acquisitions, utility accounting and finance issues and public policy aspects of utility regulation. Presented testimony on behalf of my employers and clients in natural gas, electric, telecommunication and transportation matters covering a variety of issues.

Self-Employed; **Consultant July 1 - Current**; Responsible for providing evaluation of utility ratemaking issues on behalf of clients. Prepare analysis and expert witness testimony.

Tennessee Attorney General's Office; **Financial Analyst September, 2017 – June 2021;** Responsible for evaluation of utility proposals on behalf of the Attorney General's office including water, wastewater and natural gas utility filings. Prepare analysis and expert witness testimony documenting findings and recommendations.

Kansas Gas Service; **Director Regulatory Affairs 2014 - 2017; Manager Regulatory Affairs, 2007 - 2014**
Responsible for directing the regulatory activity of Kansas Gas Service (KOS), a division of ONE Gas, serving approximately 625,000 customers throughout central and eastern Kansas. In this capacity I have formulated strategic regulatory objectives for KOS, formulated strategic legislative options for KOS and led a Kansas inter-utility task force to discuss those options, participated in ONE Gas financial planning meetings, hired and trained new employees and provided recommendations on operational procedures designed to reduce regulatory risk. Responsible for the overall management and processing of base rate cases (2012 and 2016). I also played an active role, including leading negotiations on behalf of ONE Gas in its Separation application from its former parent, ONEOK, before the Kansas Corporation Commission. I have monitored regulatory earnings, and continually determine potential ratemaking outcomes in the event of a rate case filing. I ensure that all required regulatory filings, including surcharges are submitted on a timely and accurate basis, I also am responsible for monitoring all electric utility rate filings to evaluate competitive impacts from rate design proposals.

Strategic Regulatory Solutions; 2003 -2007
Principal; Serving clients regarding revenue requirement and regulatory policy issues in the natural gas, electric and telecommunication sectors

Williams Energy Marketing and Trading; 2000-2003
Manager Regulatory Affairs; Monitored and researched a variety of state and federal electric regulatory issues. Participated in due diligence efforts in targeting investor owned electric utilities for full requirement power contracts. Researched key state and federal rules to identify potential advantages/disadvantages of entering a given market.

MCI WorldCom; 1999 - 2000

Manager, Wholesale Billing Resolution; Manage a group of professionals responsible for resolving Wholesale Billing Disputes greater than $SOK. During my tenure, completed disputes increased by over 100%, rising to $150M per year.

Kansas Corporation Commission; 1984- 1999

Utilities Division Director - 1997 - 1999; Responsible for managing employees with the goal of providing timely, quality recommendations to the Commission covering all aspects of natural gas, telecommunications and electric utility regulation; respond to legislative inquiries as requested; sponsor expert witness testimony before the Commission on selected key regulatory issues; provide testimony before the Kansas legislature on behalf of the KCC regarding proposed utility legislation; manage a budget in excess of $2 Million; recruit professional staff; monitor trends, current issues and new legislation in all three major industries; address personnel issues as necessary to ensure that the goals of the agency are being met; negotiate and reach agreement where possible with utility personnel on major issues pending before the Commission including mergers and acquisitions; consult with attorneys on a daily basis to ensure that Utilities Division objectives are being met.

Asst. Division Director - 1996 - 1997; Perform duties as assigned by Division Director.

Chief of Accounting 1990 - 1995; Responsible for the direct supervision of9 employees within the accounting section; areas of responsibility included providing expert witness testimony on a variety of revenue requirement topics; hired and provided hands-on training for new employees; coordinated and managed consulting contracts on major staff projects such as merger requests and rate increase proposals;

Managing Regulatory Auditor, Senior Auditor, Regulatory Auditor 1984 - 1990; Performed audits and analysis as directed; provided expert witness testimony on numerous occasions before the KCC; trained and directed less experienced auditors on-site during regulatory reviews.

Amoco Production Company 1982 - 1984

Accountant Responsible for revenue reporting and royalty payments for natural gas liquids at several large processing plants.

<u>Education</u>

- B.S.B.A. (Accounting) Central Missouri State University
- Passed CPA exam; (Oklahoma certificate # 7562) - Not a license to practice

BEFORE THE TENNESSEE REGULATORY AUTHORITY

NASHVILLE, TENNESEE

September 23, 2009

IN RE:	)	
	)	
DOCKET TO EVALUATE CHATTANOOGA GAS COMPANY'S GAS PURCHASES AND RELATED SHARING INCENTIVES	)))	**DOCKET NO. 07-00224**

ORDER

This docket came before Chairman Sara Kyle, Director Eddie Roberson and Director Mary W. Freeman of the Tennessee Regulatory Authority (the "Authority" or "TRA"), the voting panel assigned to this docket, at a regularly scheduled Authority Conference held on August 24, 2009 for deliberations on this matter.

RELEVANT PROCEDURAL BACKGROUND

On July 9, 2007, the panel assigned to *In re: Petition of Chattanooga Gas Company for Approval of Adjustment of Its Rates and Charges, Comprehensive Rate Design Proposal and Revised Tariff* (Docket No. 06-00175) voted unanimously to approve *Chattanooga Gas Company's Request to Close Docket* and determined that a separate docket would be opened in which to consider matters raised by the intervening parties,[1] specifically, issues related to asset management and capacity release.[2] Additionally, the panel voted to permit the parties that had intervened in

[1] The Consumer Advocate and Protection Division of the Office of the Attorney General ("Consumer Advocate") and the Chattanooga Manufacturers Association were granted intervention in Docket No. 06-00175.

[2] *In re: Petition of Chattanooga Gas Company for Approval of Adjustment of Its Rates and Charges, Comprehensive Rate Design Proposal and Revised Tariff,* TRA Docket No. 06-00175, *Order Closing Phase II of Docket* (December 17, 2007).

Docket No. 06-00175 to file a petition to intervene in the new docket for the consideration of the Authority or Hearing Officer, as appropriate.[3]

On September 26, 2007, the Authority opened Docket No. 07-00224 for the evaluation of Chattanooga Gas Company's ("CGC" or "Company") gas purchases and related sharing incentives. On December 28, 2007, the Consumer Advocate and Protection Division of the Office of the Attorney General filed its *Petition to Intervene* in the docket. On January 25, 2008, the Authority filed its *Order Convening a Contested Case and Appointing a Hearing Officer*. On February 19, 2008, an *Order on February 11, 2008 Status Conference* was issued by the Hearing Officer in which the Consumer Advocate's intervention was granted and a procedural schedule was adopted.

On April 8, 2008, CGC filed a *Motion to Dismiss*. The *Consumer Advocate's Response To Chattanooga Gas Company's Motion To Dismiss For Failure To State A Claim Upon Which Relief Can Be Granted And For Lack Of Subject Matter Jurisdiction By The Tennessee Regulatory Authority ("Consumer Advocate's Response")* was filed on April 22, 2008. On June 20, 2008, the Authority issued its *Order Denying Motion to Dismiss.*

Both prior to and subsequent to the *Order Denying Motion to Dismiss*, the parties engaged in extensive activity in this docket, including four rounds of discovery, direct testimony from the Consumer Advocate, rebuttal testimony from both parties, supplemental testimony from CGC, surrebuttal testimony from the Consumer Advocate, and numerous motions. On June 16, 2009, the Hearing Officer issued the *Notice of Hearing and Pre-Hearing Conference* setting the Hearing on the matter for July 13, 2009. On July 2, 2009, the Consumer Advocate withdrew Dr. Steve Brown as a witness along with his direct, rebuttal, surrebuttal testimony and exhibits.

On July 8, 2009, the parties filed a proposed settlement agreement. On July 9, 2009, the Authority issued a *Notice of Administrative Notice*. On July 17, 2009, the Authority filed its *Order*

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[3] *Id.*

Affirming Hearing Officer's Order on Third Round Discovery Disputes, which memorialized the Authority's deliberations and decision that occurred at the regularly scheduled Authority Conference held on June 15, 2009.

THE HEARING AND POST HEARING FILINGS

The Hearing in this matter was held before the voting panel on July 13, 2009. Participating in the Hearing were the following parties and their respective counsel:

> **CGC** – **L. Craig Dowdy, Esq.,** McKenna Long & Aldridge, LLP, 303 Peachtree Street, Suite 5300, Atlanta, GA 30308, and **J.W. Luna, Esq.** and **Jennifer L. Brundige, Esq.,** Farmer & Luna, PLLC, 333 Union Street, Suite 300, Nashville, TN 37201; and,
>
> **Consumer Advocate** – **Vance L. Broemel, Esq., T. Jay Warner, Esq.,** and **Mary White, Esq.,** Office of the Attorney General, P.O. Box 20207, Nashville, Tennessee, 37202.

The panel initially reviewed the proposed settlement agreement. Based on statements from counsel and the entire record, the panel found that the proposed settlement was not in the best interest of consumers, CGC, or the Authority's resources. Thereafter, the panel voted unanimously to reject the proposed settlement agreement and to proceed with the Hearing. Testimony was presented by Mr. Terry Buckner for the Consumer Advocate and Mr. Timothy Sherwood for the Company with each witness being subject to cross-examination. Each party filed a post-hearing brief on July 31, 2009.

POSITION OF THE PARTIES

Consumer Advocate: The Consumer Advocate argues that, although CGC's asset management agreement compares favorably to those of Atmos Energy Corporation and Nashville Gas Company,[4] agreements exist in other states with more favorable sharing arrangements.[5] Accordingly, the Consumer Advocates suggests that the sharing percentage in CGC's asset

[4] Buckner direct p. 10
[5] Buckner direct p. 14

management agreement be changed from 50% for CGC and 50% for the asset manager, Sequent, to 85% for CGC and 15% for Sequent.[6] The Consumer Advocate further contends that Chattanooga should share 90% of its 85% share of asset management profits with its customers, resulting in a final allocation of asset management profits of 76.5% for customers, 15% for the asset manager, and 8.5% for CGC.[7] The Consumer Advocate adds that establishing this sharing structure prevents CGC from sharing 50% of Asset Management Agreement profits if a non-affiliate asset manager is chosen as is currently allowed by its tariff.[8]

The Consumer Advocate argues that the bidding process is not entirely fair and reasonable because the criteria for evaluating the winning bid are ambiguous.[9] The Consumer Advocate also expressed concerns about the content of the Request for Proposal ("RFP") and suggests that the TRA review the contract before it is placed out for bid.[10] The Consumer Advocate contends that because Sequent retains a portion of the profits from managing CGC's assets, CGC necessarily receives less than market value for those assets.[11]

The Consumer Advocate withdrew its witness and all testimony on the issue of the proper level and mix of storage, peaking and transportation capacity.

CGC: CGC criticizes the Consumer Advocates' analysis of sharing percentages based on the size of the sample and the lack of detail regarding the terms of the agreement to determine if the contracts are truly comparable. Additionally, CGC argues that the sharing percentages in the current asset management agreement were reached through a competitive bidding process and approved by the TRA. CGC contends that changing the terms of the agreement would negate the

[6] Terry Buckner Direct Testimony, p. 13.
[7] *Id.*, p. 14.
[8] *Id.*, pp. 26-27.
[9] *Id.*, p. 21.
[10] *Id.*, p. 22.
[11] *Id.*, p. 23

benefits customers expect to receive.[12] CGC opines that the current audits performed by TRA Staff as well as the TRA Directors' discretion to review CGC's capacity levels and asset mix at any time provide sufficient oversight and safeguards.[13]

CGC asserts that it subscribes to the proper level and mix of storage, peaking and transportation capacity.

FINDINGS AND CONCLUSIONS

The panel deliberated this matter at the regularly scheduled Authority Conference held on August 24, 2009. Based on the entire record, the panel unanimously voted as follows:

1. CGC shall submit future asset management RFPs for approval prior to placing them out for bid.

2. CGC subscribes to an appropriate level and mix of storage, peaking and transportation capacity.

3. While CGC's asset mix appears reasonable at this time, changes in customer mix, weather, and usage patterns necessitate periodic review of CGC capacity planning. Therefore, a triennial review of capacity planning shall occur beginning in 2012 with the selection of an independent consultant. Implementation of this triennial review requires the adoption of procedures and processes; therefore, the parties shall provide comments regarding the proposed procedures/criteria[14] within ten days.

4. The Hearing Officer's ruling that CGC file for recovery of litigation costs upon completion of this docket is upheld.

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[12] Timothy Sherwood, Rebuttal Testimony, p. 18.
[13] *Id.*, p. 14
[14] Policies and procedures were distributed to the parties at the Authority Conference. Copies of the same are attached to this Order as Exhibit 1.

IT IS THEREFORE ORDERED:

1. Chattanooga Gas Company shall submit future asset management Request for Proposals for approval prior to placing them out for bid.

2. A triennial review of capacity planning shall occur beginning in 2012 with the selection of an independent consultant. The parties shall provide comments regarding the proposed procedures/criteria for such triennial review (attached as Exhibit 1) within ten days.

3. The Hearing Officer's ruling that CGC file for recovery of litigation costs upon completion of this docket is upheld.

Sara Kyle, Chairman

Eddie Roberson, Director

Mary W. Freeman, Director

Docket 05-00165, *Review of Nashville Gas Company's Incentive Plan Account Relating to Asset Management Fees*, Exhibit A wherein it states: ["CGC" is substituted for "NGC" or "Company]:

Triennial Review

A comprehensive review of the transactions and activities related to the Performance-Based Ratemaking Mechanism (PBRM") shall be conducted by an independent consultant once every three years. The initial triennial review shall be started in the autumn of 2012 and subsequent triennial reviews shall be conducted every third year thereafter. The TRA Staff, the CAD, and CGC shall make an effort to maintain a list of no less than five (5) mutually agreeable independent consultants or consulting firms qualified to conduct the aforementioned review. Any dispute concerning whether an independent consultant shall be added to the list shall be resolved by the TRA Staff, after consultation with CGC and the CAD. For each review, the TRA Staff shall select three (3) prospective independent consultants from that list. Each such consultant shall possess the expertise necessary to conduct the review. The TRA Staff shall provide the list of prospective independent consultants to the CGC and the CAD via e-mail. CGC and the CAD shall have the right, but not the obligation, to strike one (1) of the prospective independent consultants from the list by identifying the stricken consultant in writing to the TRA Staff within thirty (30) days from the date the list is e-mailed. The TRA Staff shall select the independent consultant from those remaining on the list after CGC's and the CAD's rights to strike have expired. The cost of the review shall be reasonable in relation to its scope. Any and all relationships between the independent consultant and CGC, the TRA Staff and/or the CAD shall be disclosed and the independent consultant shall have had no prior relationship with either CGC, the TRA Staff, or the CAD for a least the preceding five (5) years unless CGC, the TRA Staff and CAD agree in writing to waive this requirement. The TRA Staff, the CAD and CGC may consult amongst themselves during the selection process; provided, however, that all such communications between the parties shall be disclosed to any party not involved in such communication so that each party may participate fully in the selection process.

The scope of the triennial reviews may include all transactions and activities related either directly or indirectly to the PBRM as conducted by CGC or its affiliates, including, but not limited to, the following areas of transactions and activities: (a) natural gas procurement; (b) capacity management; (c) storage; (d) hedging; (e) reserve margins; and (f) off-system sales. The scope of each triennial review shall include a review of each of the foregoing matters as well as such additional matters as may be reasonable identified by CGC, the TRA Staff, or the CAD relative to the operation or results of the PBRM.

CGC, the TRA Staff, or the CAD may present documents and information to the independent consultant for the independent consultant's review and consideration. Copies of all such documents and information shall be presented simultaneously to the independent consultant and all other parties.

The independent consultant shall make findings of fact, as well as identify and describe areas of concern and improvement, if any, that in the consultant's opinion warrant further consideration; however, the independent consultant shall not propose changes to the structure of the PBRM itself. The independent consultant shall complete and issue a written report of its findings and conclusions by July 1 of the year immediately following the triennial review. The report deadline may be waived by the written consent of the TRA Staff, CGC, and the CAD.

The independent consultant shall not propose changes to the structure of the PBRM itself; however, the TRA Staff, CGC, or the CAD may use the report of the independent consultant as grounds for making recommendations or proposed changes to the Authority, and the TRA Staff, CGC, or the CAD may support or oppose such recommendations or proposed changes. Any proposed changes to the structure of the PBRM resulting from the initial triennial review or subsequent triennial reviews, whether adopted by agreement or pursuant to a ruling of the Authority, shall be implemented on a prospective basis only beginning with the incentive plan year immediately following such agreement or ruling.

The cost of the triennial reviews shall be paid initially by CGC and recovered through the ACA account. The TRA Staff may continue its annual audits of the PBR and the ACA account and the triennial reviews shall not in any way limit the scope of such annual audits.

Exhibit DND-3

PUBLIC VERSION
Confidential Information Has Been Redacted

Chattanooga Gas

REVIEW OF PERFORMANCE BASED RATEMAKING MECHANISM TRANSACTIONS AND ACTIVITIES

Prepared for:

UTILITY DIVISION OF THE TENNESSEE PUBLIC UTILITY COMMISSION

CONSUMER ADVOCATE UNIT IN THE FINANCIAL DIVISION OF THE TENNESSEE ATTORNEY GENERAL'S OFFICE

JUNE 2020

Prepared by:

EXETER
ASSOCIATES, INC.

10480 Little Patuxent Parkway, Suite 300
Columbia, Maryland 21044

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1.0 INTRODUCTION AND SCOPE OF INVESTIGATION

On October 13, 2009, the Tennessee Public Utility Commission (TPUC 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) for the period April 2010 – March 2013. This review was to be conducted by an independent consultant. Following a required RFP selection process, Exeter Associates, Inc. (Exeter) was selected as the independent consultant to perform this triennial review. In June 2014, Exeter submitted a report presenting the results of its review of CGC's PBRM for the period April 2010 – March 2013.

In an Order issued in Docket No. 07-00224 on December 29, 2014, the TPUC voted to extend the PBRM triennial review process for the period April 2013 – March 2016. Exeter was selected through an RFP process to perform this review. Under its PBRM, CGC'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 one percentage point for that Plan Year, CGC's gas costs will be deemed prudent and the audit required by TPUC Administrative Rule 1220-4-7-.05(1)(a) is waived. On August 26, 2016, CGC submitted its annual PBRM filing for the 12-month period ended June 30, 2016. That filing indicated that CGC's commodity costs exceeded the benchmark amount by 3.3%. As a result, a prudency review of CGC's purchased gas costs was required. On October 10, 2016, CGC filed a motion with the Commission for a waiver of TPUC Administrative Rule 1220-4-7-.05(1)(a) to expand the scope of the previously ordered April 2013 – March 2016 triennial PBRM review to include the review of CGC's PBRM through June 2016, and to address the prudence of CGC's gas costs for the period July 2015 – June 2016. The Utility Division of the TPUC (TPUC Staff) and the Consumer Advocate Unit in the Financial Division of the Tennessee Attorney General's Office (Consumer Advocate) both supported CGC's motion, and the motion was approved in an Order issued on January 31, 2017 in Docket No. 16-00098. Exeter submitted its report for the period April 2013 – June 2016 in July 2017.

In an Order issued in Docket No. 07-00224 on November 9, 2017, the TPUC voted to extend the triennial review process for the period July 2016 – March 2019. Exeter has been selected through an RFP process to perform this review. Exeter has also previously been selected to perform similar audits of the performance based incentive programs of the Piedmont Natural Gas Company (Piedmont) and Atmos Energy Corporation (Atmos).

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 July 2016 – March 2019 (audit period or review period). This audit includes review of: (1) CGC's actual gas procurement transactions and costs, including storage activity, as 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 annual 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 and Agency 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, TPUC Staff, and the Consumer Advocate on May 26, 2020. On June 19, 2020, CGC provided its comments on the draft report to Exeter. 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.

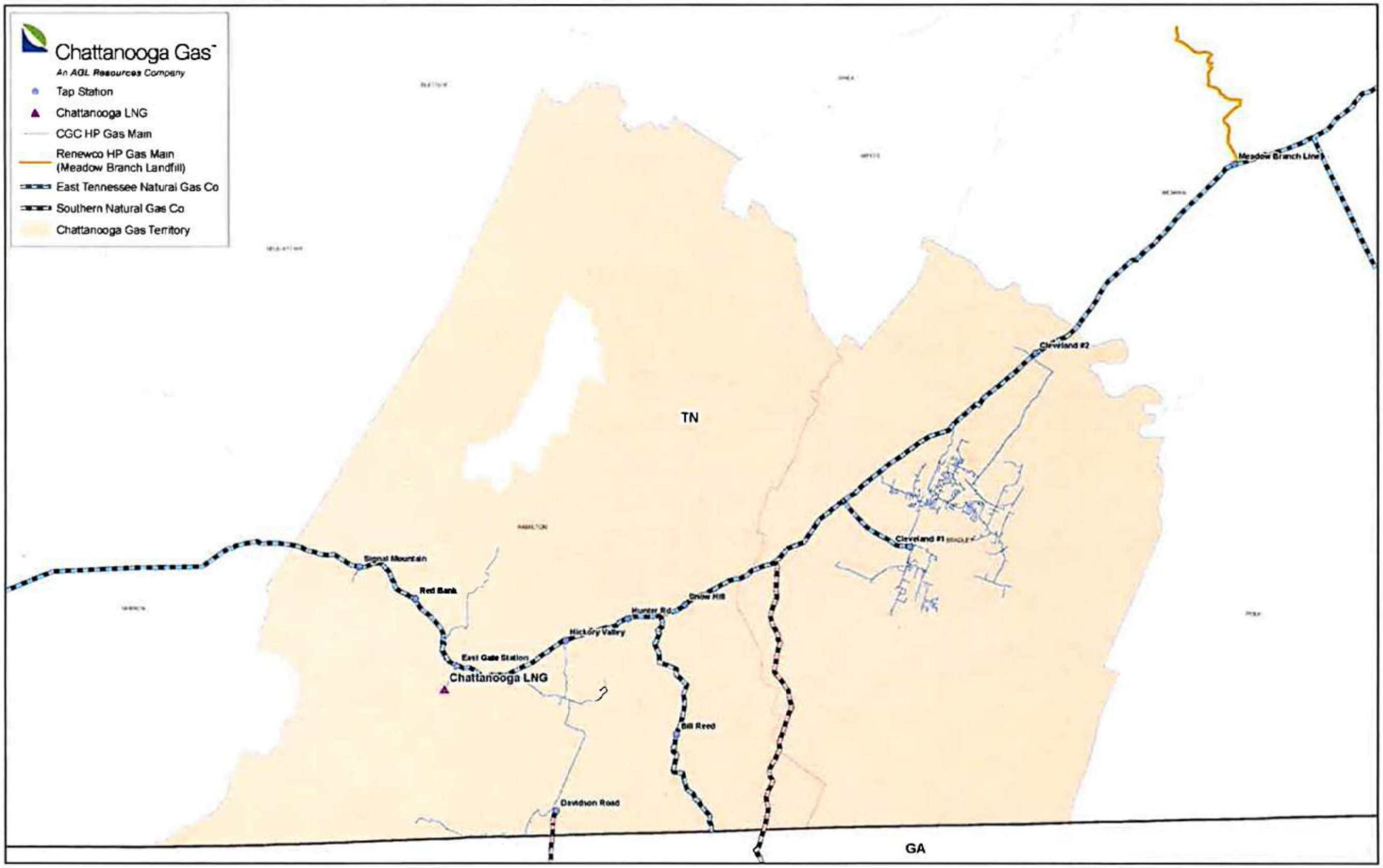
Exeter's Report consists of six sections in addition to this introductory section. Section 2 of the Report identifies the interstate pipeline transmission companies serving CGC, the services the Company purchases from each pipeline, and the Company's review period gas supply arrangements. Included in 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. Section 4 evaluates CGC's storage and off-system sales activities. The reasonableness of CGC's capacity portfolio is evaluated in Section 5. This includes an evaluation of CGC's design peak day forecasting procedures and the balance between CGC's capacity resources and its customers' requirements. Section 6 evaluates the balance of incentives between CGC and its customers relative to the sharing of AMA fees and off-system sales margins under CGC's IMCR. The final section of the Report summarizes Exeter's conclusions, includes findings of fact, and identifies and describes areas of concern and improvement that may warrant further consideration.

2.0 CHATTANOOGA GAS COMPANY – SYSTEM AND MARKETS

The Chattanooga Gas Company is a wholly owned subsidiary of Southern Company Gas. CGC 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 contracted 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, below, presents a map of the Company's service territory and the interstate pipelines serving CGC. The interstate pipeline services reserved by CGC during the audit period are described in Section 2.1, below. Section 2.1 also describes the facilities of Texas Eastern Transmission Corporation, LP (Texas Eastern) and Transcontinental Gas Pipe Line Company, LLC (Transco), two interstate pipelines with receipt point locations that were utilized as benchmarks under the PBRM. CGC operated under two AMAs with its affiliate, Sequent, during the review period. CGC's AMAs with Sequent are described in Section 2.2 of the Report. CGC's review period gas supply arrangements are described in Section 2.3, and Section 2.4 summarizes the jurisdictional services provided by CGC, identifies the number of customers served, and provides annual throughput statistics.

Figure 1.
CHATTANOOGA GAS COMPANY
System Map



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, below, summarizes the pipeline services purchased by CGC to meet customer requirements for the winter of 2018-2019. This information is provided to assist in evaluating CGC's gas procurement transactions and activities and the reasonableness of CGC's capacity resources.

Table 1.
CHATTANOOGA GAS COMPANY
Summary of Design Day Capacity Resources (2018-2019 Winter Season)

Pipeline – Service	Contract No.	MDQ (Dth) Winter	MDQ (Dth) Summer	Winter Season (Dth)	Total Annual Quantity (Dth)	Contract Expiration
UPSTREAM RESOURCES						
Tennessee Gas Pipeline						
Firm Transportation (FT-A)	48082	37,819	37,819	5,710,669	13,803,935	10/31/2025
Storage Service (FS-MA)[1]	3947	7,741	0	852,286	0	11/01/2025
Storage Service (FS-PA)[1]	22923	13,659	0	2,042,390	0	10/31/2025
TOTAL Upstream Resources:		**37,819**	**37,819**	**5,710,669**	**13,803,935**	
CITYGATE RESOURCES						
East Tennessee Natural Gas						
Firm Transportation (FT-A)	410203	13,000	13,000	1,963,000	4,745,000	10/31/2022
Firm Transportation (FT-A)[2]	410204	23,451	23,451	3,541,101	8,559,615	10/31/2021
Firm Transportation (FT-A)[3]	661664	23,000	23,000	3,473,000	8,395,000	10/31/2022
Subtotal ETNG:		*59,451*	*59,451*	*8,977,101*	*21,699,615*	
Southern Natural Gas						
Firm Transportation (FT)	FSNG130	13,221	13,221	1,996,371	4,825,665	08/31/2023
Firm Transportation (FT-NN)	FSNG130	14,346	14,346	2,166,246	5,236,290	08/31/2023
Storage Service (CSS)[4]	SSNG69	14,346	0	710,484	0	08/31/2023
Subtotal SONAT:		*27,567*	*27,567*	*4,162,617*	*10,061,955*	
CGC LNG	None	85,672	0	1,207,574	1,207,574	
TOTAL Citygate Resources:		**172,690**	**87,018**	**14,347,292**	**32,969,144**	

Dth = dekatherms; MDQ = maximum daily delivery quantity; LNG = liquefied natural gas.

[1] Delivered under TGP FT-A service.

[2] Excludes Nora Lateral capacity of 4,899 Dth per day.

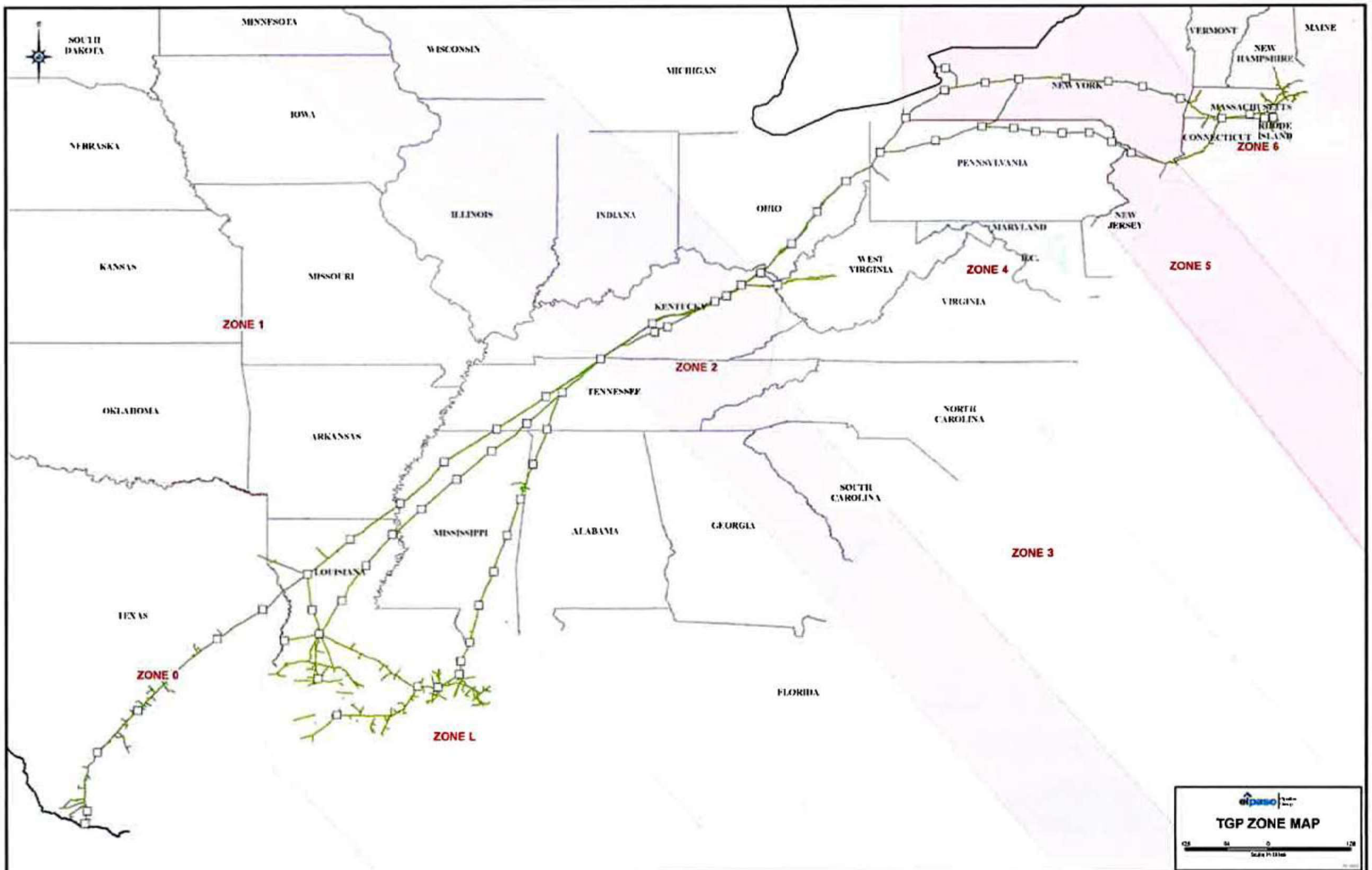
[3] Reflects the acquisition of 25,000 Dth per day of released capacity less a subsequent 2,000 Dth per day release of the acquired released capacity.

[4] Delivered under SONAT FT-NN service.

2.1.1 Tennessee Gas Pipeline

The TGP system was initially designed to transport gas from the Texas, Louisiana, and Gulf of Mexico (collectively, "Gulf Coast") natural gas production region to markets in the Northeast. In the Gulf Coast 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 below in Figure 2.

Figure 2.
TENNESSEE GAS PIPELINE
System Map



During the review period, CGC maintained a firm transportation service arrangement 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 primary receipt point capacity under TGP Contract No. 48082 is subdivided by zone and leg as follows:

Tennessee Gas Pipeline Capacity

Zone – Leg	MDQ (Dth)
Zone 0 – 100 Leg	11,090
Zone 1 – 100 Leg	21,139
Zone L – 500 Leg	700
Zone L – 800 Leg	4,890
TOTAL:	**37,819**

CGC also maintained 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 FS-MA and FS-PA storage under CGC's FT-A firm transportation arrangement with TGP. FS-MA provided for a maximum daily withdrawal (MDWQ) of 7,741 Dth, and a maximum winter season deliverability of 852,286 Dth. FS-PA provided for an MDWQ of 13,659 Dth, and a maximum winter season deliverability of 2,042,390 Dth.

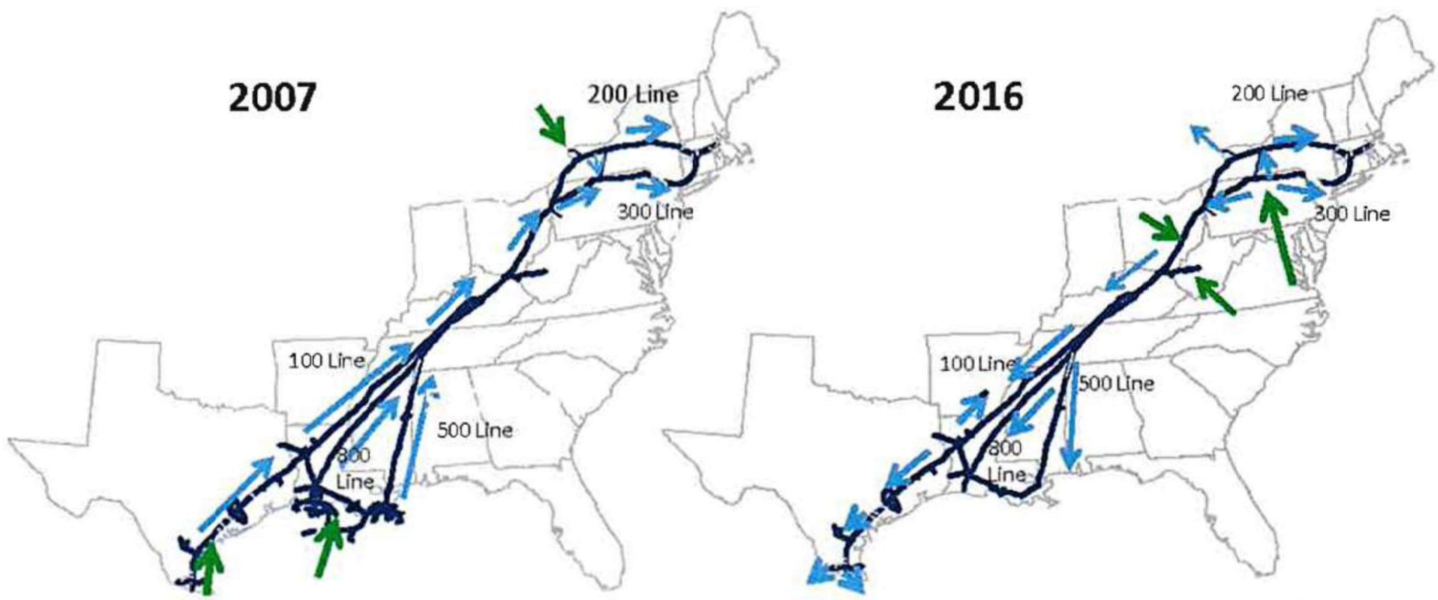
The flow of gas supplies on the TGP system has changed dramatically since 2007 as a result of the significant increase in natural gas production in the Marcellus and Utica Shale (collectively, "Marcellus") region in Pennsylvania, Ohio, West Virginia, and New York. The Marcellus region is now the most prolific natural gas production region in the U.S. As shown below in Figure 3, in 2007, the flow of gas on the TGP system was northerly from the Gulf Coast production region to markets in the Northeast. Today, as also shown in Figure 3, the flow of gas on the TGP system is largely southerly from the Marcellus region to the Gulf Coast production region. Marcellus Shale gas supplies were generally lower cost than Gulf Coast production area supplies during the review period.[2] CGC was unable to access Marcellus Shale supplies during the review period because the Company's primary receipt points under its FT-A firm transportation arrangement with TGP were in the Gulf Coast production region. The inability of CGC to access Marcellus Shale supplies was confirmed through a discussion with a representative of TGP during the audit conducted by Exeter for the period April 2013 – June 2016, and all of the TGP-delivered supplies CGC purchased during the review period were sourced from the Gulf Coast production region.

[1] ETNG interconnects with TGP at East Lobelville and Ridgetop, Tennessee.

[2] Marcellus Shale gas supplies averaged approximately $0.50/Dth less than Gulf Coast supplies during the review period.

Figure 3.
TENNESSEE GAS PIPELINE
Changing Operations

Changing TGP Operations



- Designed to deliver TX/LA supply to Northeast markets
- High utilization of 100/800/500 lines, high seasonal utilization of 200 and 300 lines
- Consistent imports on the Niagara Spur

- Shale Supply: Marcellus via 300 Line ~3.2 Bcf/d, Marcellus via Broad Run ~400k, and Utica via 200 Line ~1.3 Bcf/d
- Serving Markets across system; LDC's, Power Plants, Pipeline Interconnects.
- System Flows have reversed on much of the System:
  - 317 -> 219 ->100/500/800 lines
- High System Utilization Year Round
- Consistent exports on Niagara Spur

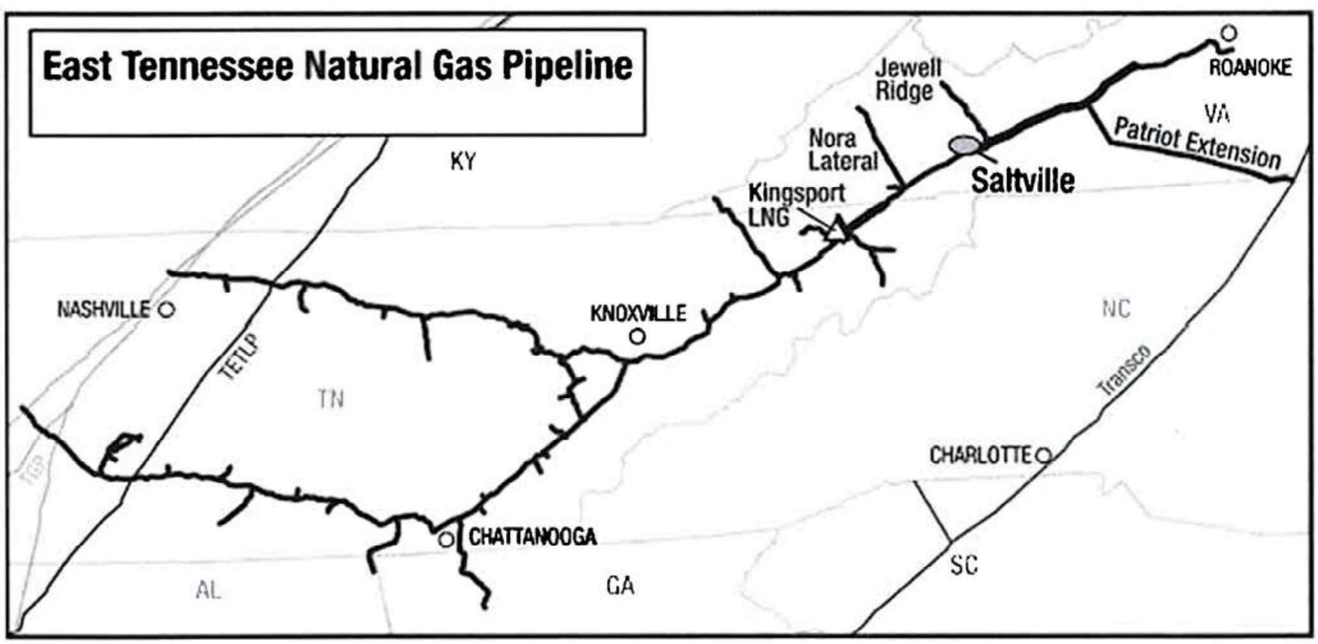
5

Tennessee Gas Pipeline Company, L.L.C.
a Kinder Morgan company

2.1.2 East Tennessee Natural Gas

ETNG consists of two mainline pipeline laterals in central Tennessee that converge near Knoxville and extend to an area just south of Roanoke, Virginia. ETNG provides for the delivery of gas supplies from TGP to CGC. A map of the ETNG system is presented below in Figure 4. During the review period, CGC maintained two firm transportation service arrangements with ETNG under Rate Schedule FT-A (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 exceeded its delivered TGP capacity by approximately 4,899 Dth per day during the review period. The firm receipt point for this 4,899 Dth of capacity was on the Nora Lateral located in Dickenson County in southwest Virginia (see Figure 4). Due to reduced liquidity of supply at ETNG's Nora Lateral receipt point, CGC was unable to rely on this capacity on a firm basis during the entire audit period. Effective for the period August 1, 2017 – January 31, 2022, CGC acquired 25,000 Dth per day of released ETNG capacity from Oglethorpe Power Corporation (OPC). The receipt point for this capacity is ETNG's interconnect with Texas Eastern at Mt. Pleasant in Giles County, Tennessee. Effective November 1, 2017, CGC subsequently released 2,000 Dth per day of the ETNG capacity acquired from OPC to Jat Oil, Inc. through October 31, 2020.

Figure 4.
EAST TENNESSEE NATURAL GAS
System Map



2.1.3 Southern Natural Gas

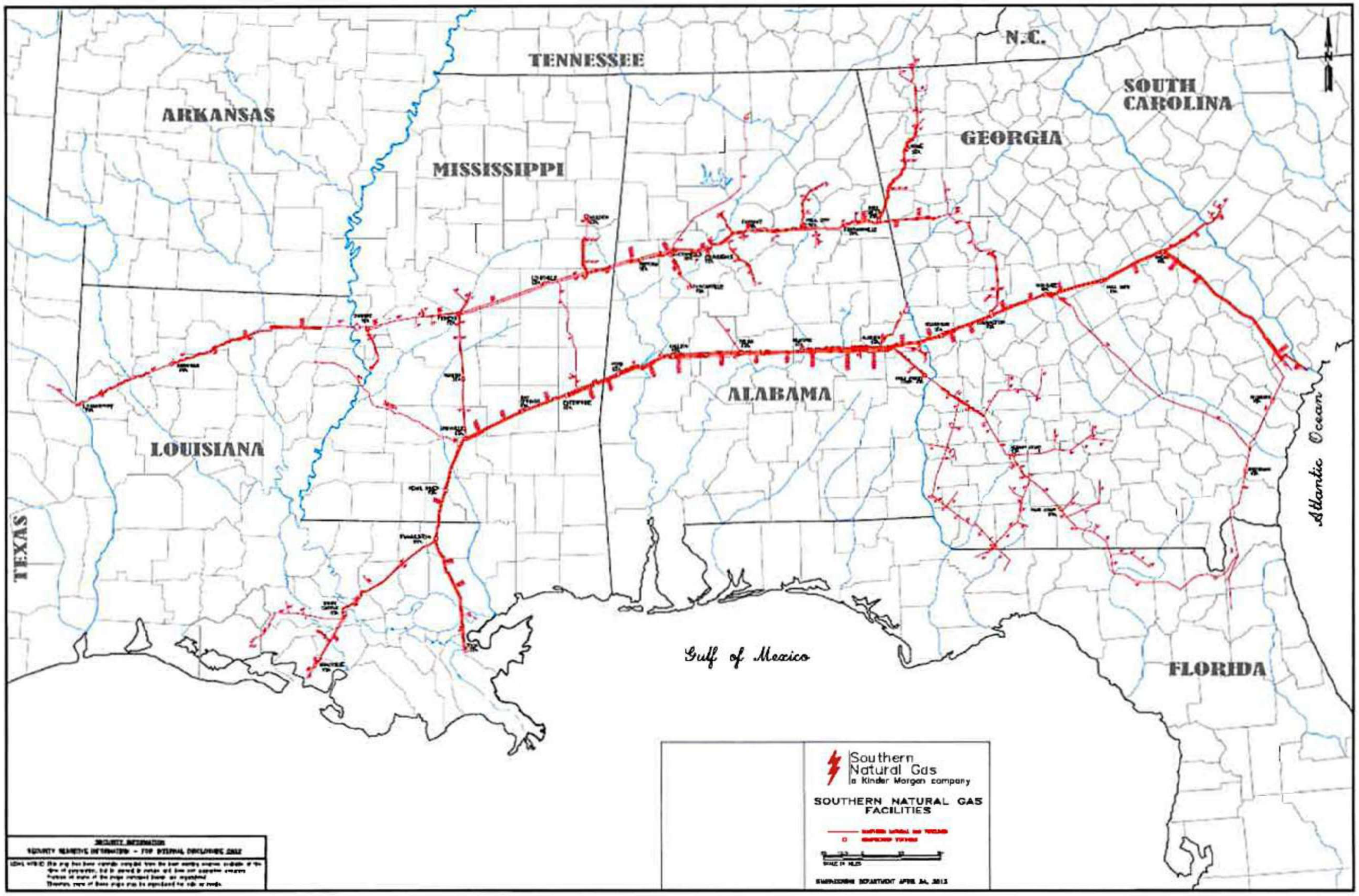
The pipeline facilities of SONAT extend from natural gas supply basins in Texas, Louisiana, Mississippi, Alabama, and the Gulf of Mexico to market areas in Louisiana, Mississippi, Alabama, Florida, Georgia, South Carolina, and Tennessee, including the metropolitan areas of Atlanta and Birmingham. SONAT's system consists of four rate zones (Zones 0-3). CGC is located in Zone 3. A map of the SONAT system is presented below in Figure 5.

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 service, the pipeline is generally only obligated to deliver, and the shipper (e.g., CGC) is entitled 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 maintained 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 conjunction with its FT-NN service, CGC held a firm storage service with SONAT under Rate Schedule CSS (Contract No. SSNG69). This service provided for an MDWQ 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 Rate Schedule CSS was 710,484 Dth.

Figure 5.
SOUTHERN NATURAL GAS
System Map



2.1.4 Texas Eastern Transmission, LP

The Texas Eastern system consists of pipeline facilities that extend from the Gulf Coast production region to markets in the Northeast. The Texas Eastern system consists of four Gulf Coast production area access rate zones and three market area rate zones. The Gulf Coast production area access rate zones are South Texas (STX), East Texas (ETX), West Louisiana (WLA), and East Louisiana (ELA). The three market zones are Market Zones 1, 2, and 3. These zones are identified below in Figure 6. Texas Eastern has an interconnect with ETNG at its Mt. Pleasant, Tennessee compressor station in Texas Eastern Market Zone 1 (Zone M-1). Due to the significant increase in production from the Marcellus region, the historical northerly gas flows from the Gulf Coast production region to the Northeast have changed, and flows on Texas Eastern are now bi-directional. During the review period, CGC purchased gas at the Texas Eastern/ETNG Mt. Pleasant interconnect. These purchases were delivered to CGC utilizing the ETNG capacity that CGC acquired from OPC.

Figure 6.
TEXAS EASTERN TRANSMISSION, LP
System Map

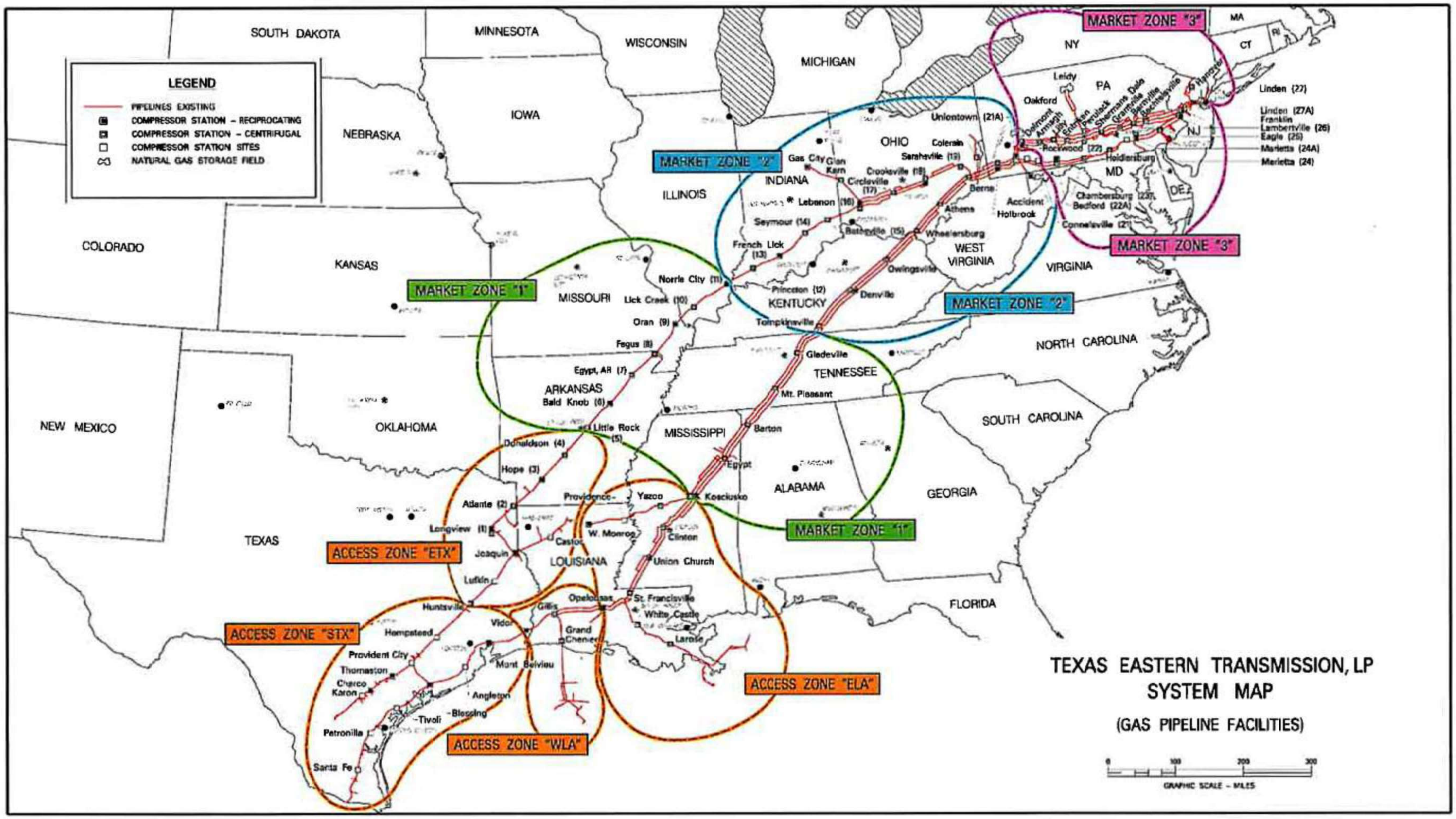
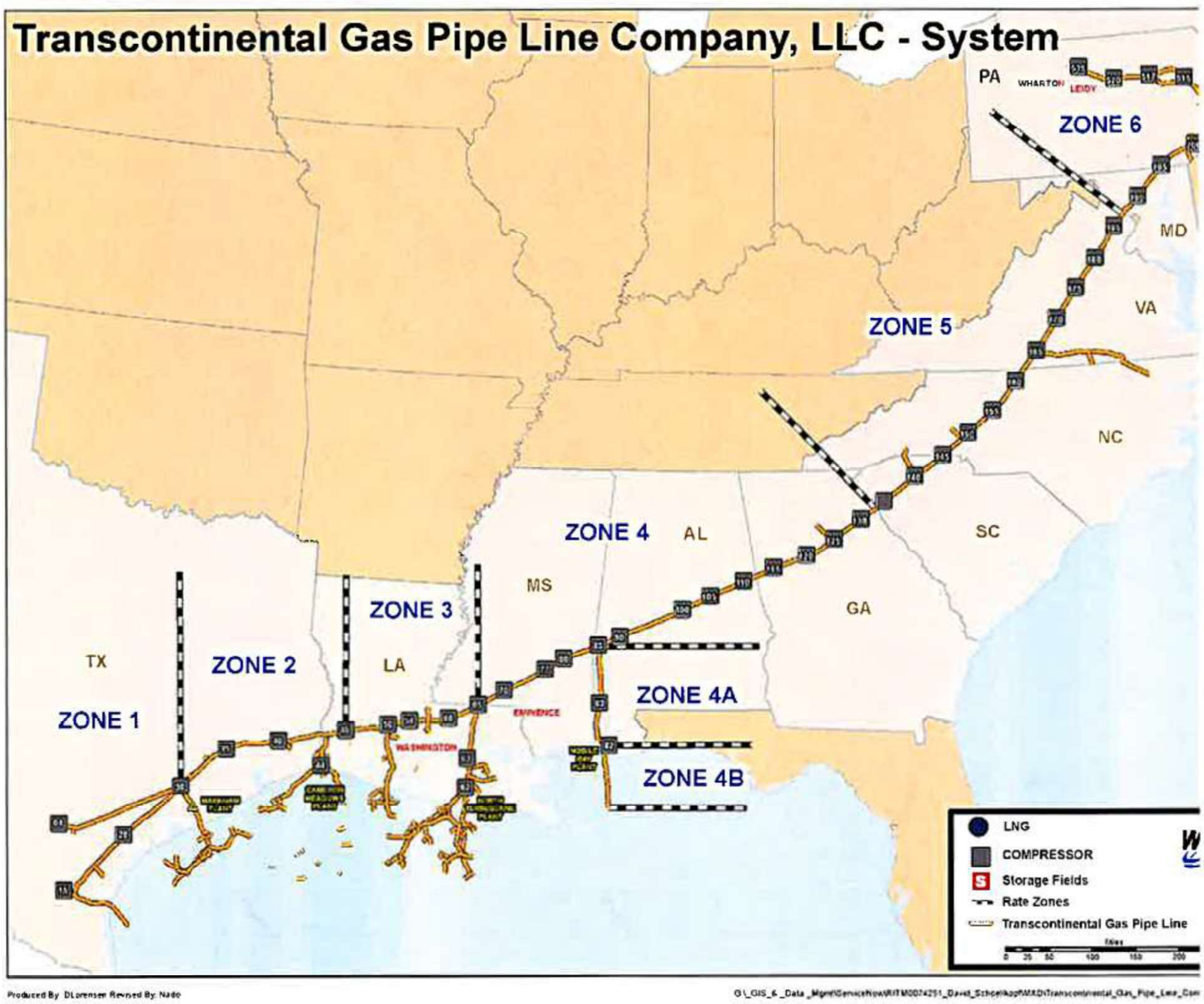


Exhibit DND-3

2.1.5 Transcontinental Gas Pipe Line Company, LLC

The Transco system also consists of pipeline facilities that extend from the Gulf Coast production region to markets in the Northeast. The Transco system consists of six rate zones. These zones are identified below in Figure 7. Transco interconnects with ETNG in Transco Zone 5 near Cascade Creek, North Carolina (refer to Figure 4). Separate North and South commodity index price reporting locations have been established for Transco Zone 5. The Zone 5 North/South demarcation point is Transco's compressor Station 165. In Figure 7, Station 165 is the southernmost compressor station in Virginia. [redacted]

Figure 7.
TRANSCONTINENTAL GAS PIPE LINE COMPANY, LLC
System Map



2.1.6 Liquefied Natural Gas

CGC operates an on-system liquefied natural gas (LNG) facility. The daily rated deliverability of its LNG facility is currently 120,000 Dth. The deliverability from the LNG facility can vary from year to year. The LNG facility has a storage capacity of 1,207,574 Dth, and can produce at maximum daily deliverability for approximately 14 days.

2.2 Asset Management and Agency 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, 2015 – March 31, 2018 (2015 AMA). The term of the second AMA is April 1, 2018 – March 31, 2021 (2018 AMA). The AMAs were both awarded through an RFP process. Under each AMA, with the exception of CGC's SONAT no-notice assets (FT-NN Contract No. FSNG130 and CSS Contract No. SSNG69), CGC's interstate pipeline firm transportation and contract storage capacity assets were managed by Sequent.[3] Under the AMAs, the SONAT no-notice assets were identified as "Excluded Assets". The AMAs also provided that CGC would purchase the gas supplies delivered under the managed assets from Sequent. While the SONAT Excluded Assets were not managed by Sequent under the AMA, CGC purchased the gas supplies delivered under the Excluded Assets from Sequent at CGC's receipt points. 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 that were not incurred consistent with CGC's logical dispatch instructions.

The TPUC approved the 2015 AMA in Docket No. 14-00137. [redacted] Fifty percent of the fixed annual payment received by CGC was shared with ratepayers through CGC's IMCR. The released ETNG capacity CGC acquired from OPC during the term of the 2015 AMA was not added to the capacity assets to be managed by Sequent under the 2015 AMA. However, CGC granted Sequent agency authority to manage the capacity acquired from OPC under a separate agreement as though it was an AMA asset for the period November 1, 2017 through March 31, 2018. This agreement provided that any margins generated by Sequent

[3] The SONAT no-notice assets were excluded from the AMAs to enable CGC to use those assets to meet on-system balancing requirements. The no-notice assets were available for use by Sequent to make off-system sales when the assets were deemed unnecessary by the Company to meet on-system balancing requirements.

utilizing the OPC capacity would be shared 50% with CGC's ratepayers. [redacted]

The TPUC approved the 2018 AMA in Docket No. 17-00137. [redacted] Like the 2015 AMA, Sequent was entitled to retain all of the margins generated by its use of CGC's transportation and storage assets, and 50% of the fixed annual payment was shared with ratepayers through CGC's IMCR.

2.3 Gas Supply Arrangements

Under the AMAs, CGC was generally required to purchase from Sequent all of its gas supplies delivered under the transportation arrangements assigned to Sequent and under the SONAT Excluded Assets. Sequent could offer, but was not required to provide, CGC gas supplies delivered under other transportation arrangements. All of CGC's review period gas supplies were purchased through Sequent. With one exception, the AMA gas supply purchases from Sequent during the review period were made [redacted].

2.3.1 Nora Lateral Purchases

[redacted] The acquisition of the released ETNG capacity from OPC eliminated the need for CGC to purchase baseload Nora Lateral supplies.

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, below, summarizes the number of CGC customers served and annual throughput by rate schedule for the review period.

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 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.

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

	July-Dec 2016	2017	2018	Jan-Mar 2019
CUSTOMERS BY RATE SCHEDULE				
Residential Sales (R-1)	55,737	56,826	57,378	58,590
Multi-Family Housing Sales (R-4)	2	2	2	2
Small Commercial & Industrial Sales (C-1)	6,406	6,639	6,607	6,693
Medium Commercial & Industrial Sales (C-2)	1,841	1,753	1,813	1,971
Commercial & Industrial Interruptible Sales (I-1)	1	1	1	0
Large Volume Commercial & Industrial				
Sales/Transportation with Full Standby (F-1/T-2)	29	31	34	34
Sales/Transportation with Partial Standby (F-1/T-2/T-1)	15	14	13	13
Interruptible Transportation (T-1)	18	18	16	17
Low Volume Commercial & Industrial				
Sales/Transportation with Standby (T-3/C-2)	48	48	46	45
Special Contract	2	2	2	2
TOTAL Customers:	**64,099**	**65,334**	**65,912**	**67,367**
VOLUMES BY RATE SCHEDULE (Dth)				
Residential Sales (R-1)	867,246	2,975,956	3,936,791	1,848,683
Multi-Family Housing Sales (R-4)	1,988	6,181	7,692	3,300
Small Commercial & Industrial Sales (C-1)	148,292	613,030	836,487	396,318
Medium Commercial & Industrial Sales (C-2)	838,739	2,394,443	2,824,124	1,161,551
Commercial & Industrial Interruptible Sales (I-1)	23,880	44,967	34,698	0
Large Volume Commercial & Industrial				
Sales/Transportation with Full Standby (F-1/T-2)	884,149	2,055,526	2,590,418	750,911
Sales/Transportation with Partial Standby (F-1/T-2/T-1)	977,594	2,010,691	1,852,319	514,640
Interruptible Transportation (T-1)	940,366	1,923,777	1,718,544	443,273
Low Volume Commercial & Industrial				
Sales/Transportation with Standby (T-3/C-2)	272,610	600,904	580,792	184,090
Special Contract	617,103	903,053	1,030,050	296,323
TOTAL Volumes:	**5,571,967**	**13,528,528**	**15,411,915**	**5,599,089**

3.0 PERFORMANCE BASED RATEMAKING MECHANISM RESULTS

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 do not exceed the total benchmark amount by 1%, the Company's gas costs will be deemed prudent and the audit required by TPUC Administrative Rule 1220-4-7-.05(1)(a) is waived. The tariff sheets governing CGC's PBRM are included as Appendix A to the 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—monthly baseload and daily purchase arrangements. Monthly baseload 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 that identify, after the fact, the average price paid for gas supplies at major natural gas trading locations. These average or market prices are referred to as "index prices." First-of-the-month (FOM) index prices are published in *Inside FERC's Gas Market Report* (*Inside FERC*) and are applicable for monthly baseload purchases. Daily prices are published in *Gas Daily* and are applicable for a particular day or weekend/holiday period. Index prices are also included in other natural gas industry publications. Monthly baseload supply can be purchased at a FOM price or prices that would vary daily. The primary gas trading index locations at which CGC purchased gas during the review period are as follows:

Tennessee Gas Pipeline

- Louisiana Zone L – 500 Leg
- Louisiana Zone L – 800 Leg
- Texas Zone 0 – 100 Leg

Southern Natural Gas

- Louisiana

Each of these trading locations is located in the Gulf Coast production region. In addition to baseload and daily purchases at these primary locations, CGC purchased supplies on ETNG's

Nora Lateral, and at the Texas Eastern/ETNG Mt. Pleasant interconnect in Texas Eastern Zone M-1. CGC also made in-ground storage inventory purchases during the review period. A summary of CGC's review period purchases is provided in Appendix B. For comparison purposes, the prices identified in Appendix B are the benchmark prices applicable under the PBRM. As subsequently discussed, CGC generally paid the benchmark price for the gas supplies it purchased during the review period.

3.1.2 Benchmark Calculation

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

For FOM baseload purchases made by CGC, the *Inside FERC* index price for each receipt point transaction location is applied to the actual quantity of gas purchased by CGC at each location to determine the applicable benchmark cost. For daily purchases, the *Gas Daily* index price for each receipt point transaction location is applied to the actual quantity of gas purchased by CGC at that location to determine the applicable benchmark cost. With several exceptions, these benchmarking procedures are applicable for gas delivered to CGC's citygate or injected into storage.

The first exception is for gas injected into SONAT storage. Under the AMAs, CGC purchases the volumes delivered to and injected into SONAT storage. Therefore, the purchases from Sequent that are injected into storage are adjusted to reflect the SONAT fuel charge associated with delivering gas to storage. For in-ground storage inventory purchases, the interstate pipeline variable transportation fuel charges are included in the benchmark calculation, as are variable storage injection charges.

Gas purchases made by CGC at the Texas Eastern/ETNG Mt. Pleasant interconnect [redacted] These purchases were benchmarked on a delivered-to-citygate basis to be consistent with how these purchases from Sequent were priced. The ETNG capacity used to effectuate these deliveries was the released capacity CGC had acquired from OPC. CGC's ETNG delivery points were not the primary delivery points under the acquired capacity and as such were considered secondary deliveries. During periods of restrictions on ETNG, these secondary deliveries were subject to additional variable transportation and fuel charges. CGC refers to the Texas Eastern transactions subject to the additional ETNG charges as "Bounce" transactions, and the Texas Eastern transactions not subject to the ETNG additional charges as "No-Bounce" transactions. The price CGC paid Sequent for purchases at the Texas Eastern/ETNG interconnect was dependent on whether the delivered purchases were Bounce or No-Bounce transactions.

[redacted] The AMAs under which CGC operated required purchases from Sequent to be priced based on the index prices applicable for the receipt point capacity under the contracts assigned to Sequent. Therefore, Exeter's audit finds that the purchases made by CGC at the Texas Eastern/ETNG Mt. Pleasant interconnect would have been more appropriately benchmarked based on Texas Eastern Zone M-1 index prices.

Exeter's audit also found that the prices paid by CGC for the gas purchased from Sequent at the Texas Eastern/ETNG interconnect were improperly calculated. The prices paid by CGC included the variable ETNG transportation charges associated with delivering gas from the Texas Eastern/ETNG interconnect to CGC's citygate. When Sequent utilized the released capacity acquired from OPC to deliver these purchases to CGC's citygate, the ETNG variable charges associated with these deliveries were directly billed to CGC by ETNG. Therefore, it appears that CGC was billed twice for these ETNG variable charges — once by Sequent and once by ETNG. CGC has indicated that Sequent may have billed CGC for ETNG variable charges in error. CGC will review its Texas Eastern-priced purchases from Sequent to determine the amount of the incorrect billings. CGC will include a credit to sales customers to reflect the improper charges in its next ACA filing.

[redacted]

3.1.3 PBRM Performance

CGC's performance under the PBRM is included in the *Annual Report of Actual Cost of Gas Purchased and Applicable Indices* filed with the TPUC each year for each Plan Year. As part of Exeter's review, a selected sample of CGC's benchmark and actual cost calculations was reviewed for accuracy and compliance with the terms of the PBRM. In addition to the incorrect billing of ETNG variable costs for Texas Eastern-priced purchases discussed in Section 3.1.2, our review found one minor discrepancy in CGC's calculations; however, the other discrepancy had no material impact on CGC's PBRM performance.[4]

CGC's performance under the PBRM is summarized below in Table 3. Delivered purchases include monthly and daily purchases delivered to either CGC's citygate or to storage, and in-ground purchases reflect monthly and daily purchases of gas in storage inventory. As shown in Table 3, there was little to no variation between CGC's actual gas costs and benchmark gas costs for delivered supplies during the audit period. This is because CGC generally purchased these supplies from Sequent at the applicable monthly and daily index prices.

[4] CGC's benchmark and actual cost calculations failed to include 35,660 Dth of daily Texas Eastern purchases made in August and September 2018. The actual cost of those purchases was equal to the benchmark.

 Exhibit DND-3

Table 3.
CHATTANOOGA GAS COMPANY
Summary of Review Period Performance Under the PBRM

	Purchases (Dth)	PBRM Performance[1]	Performance Variance
TENNESSEE GAS PIPELINE			
Zone 0			
Delivered	6,101,612	$22	0.0%
In-Ground	2,645,352	($40,678)	-1.5%
Zone L 100/500 Leg			
Delivered	343,368	$12	0.0%
In-Ground	0	$0	0.0%
Zone L 800 Leg			
Delivered	4,972,534	($235)	0.0%
In-Ground	20,725	$0	0.0%
SOUTHERN NATURAL GAS			
Zone 1			
Delivered	4,355,772	($44)	0.0%
In-Ground	0	$0	0.0%
NORA LATERAL			
[redacted]			
Delivered	1,393,945	($66)	0.0%
TEXAS EASTERN			
[redacted]			
Delivered No-Bounce	3,137,393	($18,033)	-0.6%
Delivered Bounce	261,046	($6,687)	-2.6%
TOTAL:	**23,231,747**	**($65,710)**	**-0.3%**

[1] (+) Costs exceed benchmark; (-) Costs below benchmark.

The actual costs of CGC's monthly in-ground storage inventory purchases, or transfers, from Sequent were slightly less than benchmark costs. The benchmark for these purchases is based on the applicable monthly index prices plus the variable pipeline transportation and storage injection charges. During the review period, these in-ground storage purchases were made under the CGC's TGP FS-MA and FS-PA storage arrangements.

During the review period, CGC made monthly baseload Nora Lateral purchases from Sequent under the arrangement previously discussed in Section 2.3.1. of this Report. As explained in Section 2.3.1., the Nora Lateral purchases [redacted]

[redacted]

Table 4, below, provides a comparison of the monthly *Inside FERC* index prices for the four primary receipt point locations under CGC's firm transportation arrangements with TGP and SONAT. Also shown for comparison purposes are [redacted] Texas Eastern [redacted] Zone M-1 index prices, and monthly NYMEX settlement prices. As shown in Table 4, the index prices at the four primary locations did not vary significantly from one another. If the variable costs of delivering supplies from each of these four primary receipt point locations to ETNG's citygate is considered, prices at these locations, and in particular the TGP locations, on average, varied by only a few cents, with TGP Zone 0 purchases being the least expensive location. The delivered cost of monthly SONAT supplies was generally higher than TGP/ETNG delivered supplies regardless of the TGP purchase index location. *Gas Daily* index prices for daily purchases exhibited the same relationship.

CGC purchased Nora Lateral supplies only during the Plan Year ended June 30, 2017. [redacted]

CGC purchased supplies at the Texas Eastern/ETNG Mt. Pleasant interconnect during the Plan Years ended June 30, 2018 and June 30, 2019. These purchases were priced [redacted]. As shown in Table 4, based on monthly index prices during these periods, the delivered cost for these purchases was comparable to the delivered cost of TGP-delivered supplies. However, the delivered cost of the [redacted] supplies was slightly higher than the delivered cost of Texas Eastern Zone M-1-priced supplies.

Exhibit DND-3

Table 4.
CHATTANOOGA GAS COMPANY
Summary of Prices by Pipeline Location – *Inside FERC* First-of-the-Month Index Prices ($/Dth)

	TENNESSEE GAS PIPELINE				[redacted]	TEXAS EASTERN		
Month	**Zone 0**	**ZL 100/ 500 Leg**	**ZL 800 Leg**	**SONAT**	[redacted]	[redacted]	**Zone M-1**	**NYMEX**
July 2016	$2.81	$2.86	$2.85	$2.88	[redacted]	[redacted]	$2.85	$2.92
August	2.55	2.61	2.59	2.62	[redacted]	[redacted]	2.60	2.67
September	2.73	2.79	2.77	2.79	[redacted]	[redacted]	2.79	2.85
October	2.87	2.90	2.89	2.90	[redacted]	[redacted]	2.90	2.95
November	2.88	2.70	2.69	2.70	[redacted]	[redacted]	2.66	2.76
December	3.13	3.17	3.16	3.18	[redacted]	[redacted]	3.13	3.23
January 2017	3.81	3.88	3.86	3.88	[redacted]	[redacted]	3.85	3.93
February	3.24	3.31	3.30	3.32	[redacted]	[redacted]	3.34	3.39
March	2.48	2.54	2.52	2.53	[redacted]	[redacted]	2.49	2.63
April	3.06	3.09	3.07	3.10	[redacted]	[redacted]	3.06	3.18
May	3.00	3.05	3.05	3.06	[redacted]	[redacted]	3.02	3.14
June	3.07	3.15	3.14	3.16	[redacted]	[redacted]	3.15	3.24
Average:	**$2.97**	**$3.00**	**$2.99**	**$3.01**	[redacted]	[redacted]	**$2.99**	**$3.07**
Delivered:	**$3.06**	**$3.09**	**$3.10**	**$3.17**	[redacted]	[redacted]	**$3.05**	**n/a**
July 2017	$2.90	$2.97	$2.97	$2.99	[redacted]	[redacted]	$2.96	$3.07
August	2.80	2.88	2.88	2.88	[redacted]	[redacted]	2.900	2.97
September	2.80	2.89	2.87	2.88	[redacted]	[redacted]	2.880	2.96
October	2.80	2.88	2.87	2.88	[redacted]	[redacted]	2.890	2.97
November	2.61	2.66	2.65	2.66	[redacted]	[redacted]	2.660	2.75
December	2.92	3.01	2.98	3.02	[redacted]	[redacted]	3.000	3.07
January 2018	2.62	2.67	2.65	2.68	[redacted]	[redacted]	2.670	2.74
February	3.51	3.59	3.54	3.58	[redacted]	[redacted]	3.600	3.63
March	2.50	2.57	2.55	2.57	[redacted]	[redacted]	2.519	2.64
April	2.57	2.62	2.60	2.63	[redacted]	[redacted]	2.620	2.69
May	2.70	2.76	2.75	2.76	[redacted]	[redacted]	2.760	2.82
June	2.76	2.81	2.79	2.82	[redacted]	[redacted]	2.820	2.88
Average:	**$2.79**	**$2.86**	**$2.84**	**$2.86**	[redacted]	[redacted]	**$2.86**	**$2.93**
Delivered:	**$2.88**	**$2.94**	**$2.95**	**$3.02**	[redacted]	[redacted]	**$2.91**	**n/a**
July 2018	$2.83	$2.92	$2.90	$2.94	[redacted]	[redacted]	$2.98	$3.00
August	2.66	2.75	2.76	2.76	[redacted]	[redacted]	2.76	2.82
September	2.77	2.83	2.82	2.84	[redacted]	[redacted]	2.83	2.90
October	2.90	2.96	2.92	2.96	[redacted]	[redacted]	2.99	3.02
November	3.10	3.15	3.12	3.15	[redacted]	[redacted]	3.24	3.19
December	4.62	4.71	4.67	4.70	[redacted]	[redacted]	4.70	4.72
January 2019	3.53	3.59	3.54	3.60	[redacted]	[redacted]	3.60	3.64
February	2.83	2.88	2.85	2.89	[redacted]	[redacted]	2.89	2.95
March	2.76	2.79	2.76	2.80	[redacted]	[redacted]	2.80	2.86
Average:	**$3.11**	**$3.18**	**$3.15**	**$3.18**	[redacted]	[redacted]	**$3.20**	**$3.23**
Delivered:	**$3.20**	**$3.26**	**$3.27**	**$3.35**	[redacted]	[redacted]	**$3.26**	**n/a**

[1] Index price adjusted to reflect delivery to Nora Lateral on ETNG.

Exhibit DND-3

Table 5, below, provides a comparison of CGC's monthly and daily purchases at each of the Company's receipt point locations. As shown, consistent with least-cost procurement, CGC maximized the purchase of TGP Zone 0 supplies, its lowest-cost supply, generally by base loading these supplies on a monthly basis, and relying on its higher-cost supplies to meet incremental daily purchase requirements.

Table 5.
CHATTANOOGA GAS COMPANY
Summary of Monthly and Daily Purchases by Receipt Point Locations (Dth)

	Plan Year				
Location	**9 M/E June 2017**	**2018**	**6 M/E March 2019**	**TOTAL**	**Percent**
MONTHLY					
TGP Zone 0	2,299,067	3,082,201	1,643,578	**7,024,846**	69.1%
TGP Zone L 100/500 Leg	0	0	0	**0**	0.0
TGP Zone L 800 Leg	185,592	298,563	578,407	**1,062,562**	10.4
SONAT	352,781	321,267	37,674	**711,722**	7.0
Nora Lateral	1,372,349	0	0	**1,372,349**	13.5
Texas Eastern	0	0	0	**0**	0.0
Subtotal Monthly:	***4,209,789***	***3,702,031***	***2,259,659***	***10,171,479***	***100.0%***
DAILY					
TGP Zone 0	705,609	482,959	533,550	**1,722,118**	13.2%
TGP Zone L 100/500 Leg	284,871	0	58,497	**343,368**	2.6
TGP Zone L 800 Leg	1,085,599	1,705,276	1,139,822	**3,930,697**	30.1
SONAT	1,236,711	1,351,787	1,055,552	**3,644,050**	27.9
Nora Lateral	21,596	0	0	**21,596**	0.2
Texas Eastern	0	1,778,990	1,619,449	**3,398,439**	26.0
Subtotal Daily:	***3,334,386***	***5,319,012***	***4,406,870***	***13,060,268***	***100.0%***
TOTAL					
TGP Zone 0	3,004,676	3,565,160	2,177,128	**8,746,964**	37.7%
TGP Zone L 100/500 Leg	284,871	0	58,497	**343,368**	1.5
TGP Zone L 800 Leg	1,271,191	2,003,839	1,718,229	**4,993,259**	21.5
SONAT	1,589,492	1,673,054	1,093,226	**4,355,772**	18.7
Nora Lateral	1,393,945	0	0	**1,393,945**	6.0
Texas Eastern	0	1,778,990	1,619,449	**3,398,439**	14.6
TOTAL:	**7,544,175**	**9,021,043**	**6,666,529**	**23,231,747**	**100.0%**

4.0 STORAGE ACTIVITY AND OFF-SYSTEM LNG SALES

The scope of this investigation requires the review of CGC's actual gas procurement transactions and costs, including storage activity, as reported in the Company's PBRM and 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 monthly baseload and daily gas supply purchase transactions were reviewed in Section 3.0 of the 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 off-system sales activities.

4.1 Storage Arrangements

As discussed in greater detail in Sections 2.1.1 and 2.1.3 of the Report, CGC maintained contract storage service with TGP and SONAT during the review period. The FS-MA and FS-PA arrangements with TGP provided for an MDWQ of 21,400 Dth per day and a maximum winter season deliverability of 2,894,676 Dth. CGC's storage service arrangement with SONAT under Rate Schedule CSS provided for an MDWQ of 14,346 Dth per day and a maximum winter season deliverability of 710,484 Dth. CGC's TGP FSMA and SONAT CSS storage arrangements include deliverability ratchets under which the MDWQ is reduced as storage inventory declines. Under the TGP FSMA storage arrangement, the MDWQ is reduced by 18% to 6,314 Dth per day when the inventory balance is reduced to 30%. The deliverability ratchets under the SONAT CSS storage arrangement are as follows:

SONAT CSS DELIVERABILITY

Inventory	Percent of MDWQ
60-100%	100%
50-59%	88%
25-49%	78%
0-24%	56%

In total, the MDWQ 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. The maximum daily production volume of the LNG facility is determined by customer demand in the portion of CGC's distribution system that can be served by the LNG facility. Therefore, the maximum production volume can change from year to year. For the winter of 2018-2019, the maximum production volume was 85,672 Dth per day for 14 days. Table 6, below, 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 conclusion 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 quantity or capacity. Under the AMAs, 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 its interstate pipelines, as long as Sequent met CGC's requirements in the manner directed by CGC. The storage to which Sequent has access 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 managed by Sequent for asset optimization purposes are also identified in Table 6.

CHATTANOOGA GAS

Review of Performance Based Ratemaking Mechanism Transactions and Activities

Table 6.
CHATTANOOGA GAS COMPANY
Summary of Audit Period End-of-Month Storage Inventory Balances (Dth)[1]

	TENNESSEE GAS PIPELINE (FS-PA)			TENNESSEE GAS PIPELINE (FS-MA)			TGP FS-PA/MA	SOUTHERN NATURAL GAS (CSS)[2]				LIQUEFIED NATURAL GAS[3]		
	Chattanooga Gas			Chattanooga Gas				Chattanooga Gas				Chattanooga Gas		
Month	Activity	Inventory	% Full	Activity	Inventory	% Full	Optimization Inventory	Activity	Inventory	% Full	Optimization Inventory	Activity	Inventory	% Full
July 2016	249,966	1,195,824	59	90,272	413,762	49	810,490	92,158	424,431	60	39	(64,708)	1,073,971	89
August	182,063	1,377,887	67	90,303	504,065	59	576,452	113,067	537,498	76	39	117,341	1,191,312	99
September	176,190	1,554,077	76	87,390	591,455	69	250,742	84,074	621,572	87	39	(27,169)	1,164,143	96
October	182,063	1,736,140	85	90,272	681,727	80	33,152	40,630	662,202	93	39	(57,957)	1,106,186	92
November	(169,851)	1,566,289	77	(53,032)	628,695	74	255,498	(88,918)	573,284	81	87	94,897	1,201,083	99
December	(290,070)	1,276,219	62	(103,238)	525,457	62	271,745	(76,063)	497,221	70	87	(90,361)	1,110,722	92
January 2017	(246,935)	1,029,284	50	(156,409)	369,048	43	523,316	(130,953)	366,268	52	1,319	(9,886)	1,100,836	91
February	(264,327)	764,957	37	(130,348)	238,700	28	925,388	(98,271)	267,997	38	50	71,795	1,172,631	97
March	(228,947)	536,010	26	(106,262)	132,438	16	1,196,397	(100,648)	167,349	24	50	(46,397)	1,126,234	93
April	168,240	704,250	34	77,010	209,448	25	1,091,203	(9,048)	158,301	22	50	14,847	1,141,081	94
May	173,848	878,098	43	79,577	289,025	34	1,128,368	79,735	238,036	34	2,240	75,914	1,216,996	100
June	168,240	1,046,338	51	77,010	366,035	43	1,084,292	86,473	324,509	46	2,240	(67,076)	1,149,919	95
July	173,848	1,220,186	60	79,577	445,612	52	730,685	92,793	417,302	59	(386)	(60,412)	1,089,508	90
August	173,848	1,394,034	68	79,577	525,189	62	381,377	154,245	571,547	80	(386)	(65,049)	1,024,459	85
September	168,240	1,562,274	76	77,010	602,199	71	124,780	62,197	633,744	89	(1,277)	(11,275)	1,013,184	84
October	173,848	1,736,122	85	79,577	681,776	80	(9,075)	(2,280)	631,464	89	507	174,502	1,187,685	98
November	(228,166)	1,507,956	74	(88,614)	593,162	70	84,904	(64,177)	567,287	80	(1,004)	(56,983)	1,130,702	94
December	(334,114)	1,173,842	57	(149,154)	444,008	52	149,201	(139,711)	427,576	60	(1,004)	(85,213)	1,045,489	87
January 2018	(306,153)	867,689	42	(168,236)	275,772	32	181,958	(4,033)	423,543	60	13,099	(486,790)	558,700	46
February	(214,738)	652,951	32	(72,324)	203,448	24	143,102	(103,417)	320,126	45	0	30,229	588,929	49
March	(349,142)	303,809	15	(159,412)	44,036	5	383,592	(161,012)	159,114	22	0	227,498	816,426	68
April	203,790	507,599	25	87,660	131,696	15	193,158	(27,128)	131,986	19	0	263,748	1,080,174	89
May	216,977	724,576	35	92,659	224,355	26	252,816	114,513	246,499	35	0	81,774	1,161,948	96
June	211,395	935,971	46	89,700	314,055	37	253,076	87,219	333,718	47	4,623	(47,291)	1,114,657	92
July	248,681	1,184,652	58	92,690	406,745	48	249,264	76,728	410,446	58	4,647	(54,372)	1,060,285	88
August	192,448	1,377,100	67	92,690	499,435	59	44,819	92,152	502,598	71	5,552	(56,882)	1,003,403	83
September	177,840	1,554,940	76	89,700	589,135	69	27,690	84,279	586,877	83	8,852	(8,123)	995,280	82
October	181,226	1,736,166	85	92,659	681,794	80	8,205	45,631	632,508	89	8,852	191,715	1,186,995	98
November	(136,044)	1,600,122	78	(60,948)	620,846	73	18,411	(94,150)	538,358	76	(1,678)	(26,797)	1,160,198	96
December	(346,348)	1,253,774	61	(93,166)	527,680	62	29,187	(103,019)	435,339	61	5,096	(28,099)	1,132,099	94
January 2019	(345,704)	908,070	44	(178,699)	348,981	41	21,088	(55,622)	379,717	53	500	(10,969)	1,121,130	93
February	(287,890)	620,180	30	(127,848)	221,133	26	36,952	(94,970)	284,747	40	500	68,102	1,189,232	98
March	(363,160)	257,020	13	(133,675)	87,458	10	56,006	(151,172)	133,575	19	1	(44,077)	1,145,155	95
Maximum Seasonal Inventory:		**36,744,406**			**13,418,370**				**13,606,738**				**35,560,750**	

[1] Negative monthly activity reflects withdrawals; positive monthly activity reflects injections. Monthly activity includes inventory transfers.
[2] Includes cashouts.
[3] Volumes in Mcf.

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 TGP 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 above in Table 6 was generally consistent with these requirements.[5] CGC depletes storage inventory during the winter months (November – March). In addition to dispatching gas for storage injection or withdrawal, CGC engages in storage inventory transfers. Under CGC's transportation arrangements with SONAT, differences between the Company's nominated supplies and actual deliveries are reconciled through no-notice storage injections or withdrawals.

CGC has established storage planning guidelines that 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 below in Table 7. As shown, CGC plans to fill its contract storage services to 80-90% of capacity prior to the beginning of the storage withdrawal season on November 1 of each year. This provides CGC the ability to inject gas into storage during November if warmer-than-normal weather is experienced. CGC plans to fill its LNG facility to 100% of capacity to serve its firm customers during peak demand periods and as a backup supply source to utilize in the event of curtailed supply, pipeline capacity disruptions or force majeure events that prevent the delivery of gas supplies to CGC's system. Off-system LNG sales are subordinate to serving CGC's on-system customers and are available only at CGC's sole discretion. Off-system LNG sales are subsequently discussed in Section 4.4.

[5] CGC's injections under its TGP FS-PA storage arrangement were generally not ratable during summer 2018. During the period June 19 – July 29, 2018, ETNG issued operational flow orders (OFOs) that restricted CGC's ability to take more gas from the pipeline than was scheduled. This increased CGC's TGP FS-PA storage injections in July 2018. To account for additional injections, less gas was injected into TGP FS-PA during the period August – October 2018.

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

	April 1		November 1	
	Planned	**Actual**	**Planned**	**Actual**
2016				
SONAT CCS			90%	93%
TGP FS-PA			85	85
TGP FS-MA			80	80
LNG			100	99
2017				
SONAT CCS	10%	24%	90%	89%
TGP FS-PA	10	26	85	85
TGP FS-MA	5	16	80	80
LNG	70	93	100	98
2018				
SONAT CCS	10%	22%	90%	89%
TGP FS-PA	10	15	85	85
TGP FS-MA	5	5	80	80
LNG	70	68	100	98
2019				
SONAT CCS	10%	19%		
TGP FS-PA	10	13		
TGP FS-MA	5	10		
LNG	55	95		

By the conclusion of the storage withdrawal season, CGC plans on depleting its contract storage inventories to 5-10% of capacity. CGC plans to deplete its LNG inventory to 70% of capacity prior to the conclusion of the storage withdrawal season. This level of LNG inventory is consistent with the inventory level that 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 liquefying gas supplies. CGC's storage planning guidelines are consistent with those of other gas utilities and appear reasonable.

As shown above in Table 7, prior to the commencement of each heating season during the review period (November 1), CGC's contract and LNG storage was refilled to plan levels. Storage was not fully depleted to planned inventory levels at the conclusion of each heating season during the review period (March 31). This was due to warmer-than-normal weather in the Chattanooga service territory during the review period, particularly during the months of February and March.

CGC's storage inventory planning criteria were reasonable and CGC generally adhered to those criteria. Therefore, CGC's review period storage activity appears reasonable.

4.3 In-Ground Storage Purchases and Transfers

As indicated in Section 3.1.1 of the 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 below in Table 8. At times, these in-ground storage inventory purchases reflect a transfer of gas from Sequent's 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 during the summer injection period. The in-ground storage inventory transfers were invoiced at costs that were equivalent to the costs CGC would have incurred if the gas had been purchased in the Gulf Coast production region and delivered to and injected into storage.

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

	TGP FS-PA		TGP FS-MA	
Month	Quantity (Dth)	Price ($/Dth)	Quantity (Dth)	Price ($/Dth)
July 2016	201,706	$2.91	90,272	$2.91
August	162,037	2.64	71,920	2.64
September	161,712	2.82	87,390	2.83
October	162,759	2.97	90,272	2.97
April 2017	168,240	$3.18	77,010	$3.18
June	31,170	3.19	5,970	3.19
July	173,848	3.01	79,577	3.02
August	173,848	2.91	79,577	2.91
September	168,240	2.91	77,010	2.91
October	86,211	2.91	36,952	2.91
April 2018	150,240	$2.67	68,100	$2.68
August	158,162	2.77	46,283	2.77
September	12,000	2.88	5,130	2.88
October	13,857	3.02	5,859	3.02
November	13,659	4.52	0	0.00

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 through Pivotal LNG, Inc. (Pivotal), which during the audit period was an affiliate of CGC. Pivotal is engaged in the sale of LNG as a substitute fuel for transportation and other mechanical uses in the wholesale LNG market. Pivotal received no direct compensation for acting on behalf of CGC. The margins from CGC's LNG tanker sales were shared 50% with ratepayers, and the margins were reflected in the Company's IMCR filings made at the end of each May for the 12-month period ended the prior March 31.

The LNG supplies marketed by Pivotal were transferred by CGC to Pivotal, as agent, at cost. [redacted]

The margin realized by Pivotal when gas was sold in the wholesale LNG market was determined based on the difference between the revenues received from the sale, less the cost of gas sold. The cost of gas sold was based on the price paid to Sequent for the gas.

A summary of CGC's off-system LNG tanker sales activities and total margins for the review period is presented below in Table 9. [redacted] In March 2020, Pivotal was acquired from Southern Company by Dominion Energy, a power and energy company headquartered in Richmond, Virginia.

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

Period	Sales (Mcf)	Total Margin
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
TOTAL:	[redacted]	[redacted]

4.5 SONAT Off-System Sales

Under the AMAs with Sequent, CGC was entitled to, at its option, select a third party, including the Asset Manager, to be its agent for the purpose of optimizing the SONAT Excluded Assets deemed by CGC to be unnecessary to meet on-system requirements. During the audit period, CGC designated Sequent as its agent to optimize the SONAT Excluded Assets. Sequent used the unneeded Excluded Assets to engage in off-system sales during the review period. CGC was credited with 50% of the net margins generated by

Sequent's off-system sales which were generated utilizing the Excluded Assets, and the credit was fully assigned to CGC's sales customers under the IMCR. Table 10, below, presents a summary of Sequent's Excluded Assets off-system sales activity during the review period. For the period November 1, 2017 through March 31, 2018, Table 10 also includes the margins generated through Sequent's utilization and management of the released capacity CGC acquired from OPC previously discussed in Sections 2.1.2 and 2.2 of the Report. With the exception of January 2018, during months in which margins were realized, Sequent realized an average of [redacted] in off-system sales margins which were shared 50% with CGC's sales customers under the IMCR. Off-system sales margins realized in January 2018 were significantly higher due to colder-than-normal weather during the first week of January which resulted in significant differences between Gulf Coast production region and ETNG and SONAT delivered gas prices. The first week in January 2018 was the coldest on record for numerous cities in the Northeast to the South. Sequent ceased its off-system sales activities utilizing the SONAT Excluded Assets after January 2018. CGC believes that Sequent terminated its SONAT Excluded Assets off-system sales activity due to the lack of economic value available to be generated by these transactions.

Table 10.
CHATTANOOGA GAS COMPANY
Summary of Excluded Asset Off-System Sales Activity (Dth)

Month	Volume	Total Margin
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
TOTAL:	[redacted]	[redacted]

4.6 Mutual Aid Assistance

As a result of very low temperatures in January 2018, CGC experienced a severe decline in distribution system pressure in the Lookout Mountains area. In order to avoid the loss of service to customers in the area, CGC requested that Atlanta Gas Light Company (AGLC) open a valve to allow gas to flow from its distribution system to CGC's system. AGLC provided the requested assistance and made the required filings with the Federal Energy Regulatory Commission (FERC) for the emergency interstate transportation of gas. AGLC provided CGC 15 Dth of gas that CGC repaid through an in-ground storage transfer.

5.0 EVALUATION OF CAPACITY PORTFOLIO AND LOAD DURATION CURVES

Section 5 of Exeter's Report evaluates the reasonableness of CGC's design day forecasting model upon which the Company relies to determine its maximum capacity resource requirements, and presents a history of the Company's actual annual peak day demands during the review period. This section also evaluates the balance of CGC's capacity resources and the design day, winter season, and annual requirements of its customers.

5.1 Design Day Forecast

CGC secures sufficient capacity resources to meet the forecasted design day requirements of its sales customers and those transportation customers that 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 72 years, there have been seven occurrences where temperatures colder than 8°F have been experienced. This equates to a design day probability of occurrence of approximately once every 10 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. The independent variables in the analysis include current and prior-day HDDs; wind speed; indicators for Friday, Saturday, and Sunday; variables to account for Christmas and New Year's Eve and Day; and a trend variable that is discussed later in this section of the Report. 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 as independent variables. The regression analysis performed each year is based on daily data from the core winter months (December – March) for the prior five years.

For transportation customers selecting firm backup service, the contracted level of backup service is used in 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 winters of 2018-2019 and 2019-2020, each based on data from the prior five winter seasons, is summarized below in Table 11.

Table 11. CHATTANOOGA GAS COMPANY Summary of Design Peak Day Requirements (Dth)			
Description	**Chattanooga**	**Cleveland**	**TOTAL**
WINTER 2018-2019			
Sales	108,753	15,588	**124,340**
Transport Firm Backup	20,498	2,341	**22,839**
Load Additions	1,341	2	**1,343**
TOTAL:	**130,591**	**17,931**	**148,522**
WINTER 2019-2020			
Sales	113,845	15,161	**129,006**
Transport Firm Backup	20,550	2,040	**22,590**
Load Additions	190	0	**190**
TOTAL:	**134,585**	**17,201**	**151,786**

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. Included in the Company's design day forecast is a trend variable that accounts for the decline in customer usage per HDD due to energy conservation or other factors. The impact of the trend variable is to reduce CGC's design day forecasts for each service territory by approximately 0.5% per year. Gas utilities in other jurisdictions that evaluate the impact of energy efficiency and customer conservation efforts have found the annual impact on design day demands to be less than 1% per year, which is consistent with CGC's findings.

5.2 Actual Peak Day Demands

Table 12, below, 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 HDDs. The reasonableness of CGC's design day forecast model can be assessed by comparing projected demands under peak day, or near design day, conditions with actual demands. Exeter's review found that CGC's design day forecasting model has forecasted sales customer requirements under actual peak day weather conditions within 2% of actual demands. This supports the reasonableness of the Company's model.

Table 12. CHATTANOOGA GAS COMPANY Summary of Actual Firm Peak Day Sendout (Dth)			
	2017	**2018**	**2019**
	Peak Day: January 7 HDD: 44.0	**Peak Day: January 17 HDD: 47.5**	**Peak Day: January 30 HDD: 35.4**
Chattanooga			
Sales	77,965	87,150	66,173
Transport	15,750	24,361	26,313
TOTAL:	**93,715**	**111,511**	**92,486**
Cleveland			
Sales	11,385	13,719	10,259
Transport	2,938	4,194	5,147
TOTAL:	**14,323**	**17,912**	**15,405**
Company Total			
Sales	**89,350**	**100,869**	**76,432**
Transport	**18,688**	**28,555**	**31,460**
TOTAL:	**108,038**	**129,423**	**107,891**

5.3 Balance of Capacity Resources and Customer Requirements

As initially shown on Table 1 in Section 2.1 of the Report, the capacity resources available to meet CGC's design day requirements for the 2018-2019 winter season totaled 172,690 Dth. For the winter of 2018-2019, as shown previously in Table 11, projected design day requirements were 148,522 Dth. CGC attempts to maintain a capacity reserve margin of 5%, which Exeter does not find unreasonable. Estimated design day firm requirements, including the 5% reserve margin, totaled 156,339 Dth for the winter of 2018-2019. The actual reserve margin maintained by CGC for the 2018-2019 winter season was 11%. For the winter of 2019-2020, the reserve margin declined to 8%.

The overall reasonableness of the balance between CGC's capacity portfolio resources and requirements can be assessed by load duration curves, which compare the daily demands of CGC's customers with the capacity resources available to meet those demands. Below, Figure 8 and Figure 9 present load duration curves for CGC's Chattanooga and Cleveland service territories, respectively, under severe weather planning conditions, which CGC identifies as a year in which HDDs are 30% higher than normal. The requirements reflected in the load duration curves are those of sales customers on all days except on the design day, which also includes the standby service requirements of transportation customers. The requirements reflected in Figure 8 and Figure 9 also include purchases made for storage injection.[6]

[6] Storage injections are reflected on days 152 through 365 (the storage injection period), and account for the spike in demand observed on day 152.

Figure 8.
CHATTANOOGA GAS COMPANY
Load Duration Curve – Chattanooga Service Territory
2018-2019 Winter Season

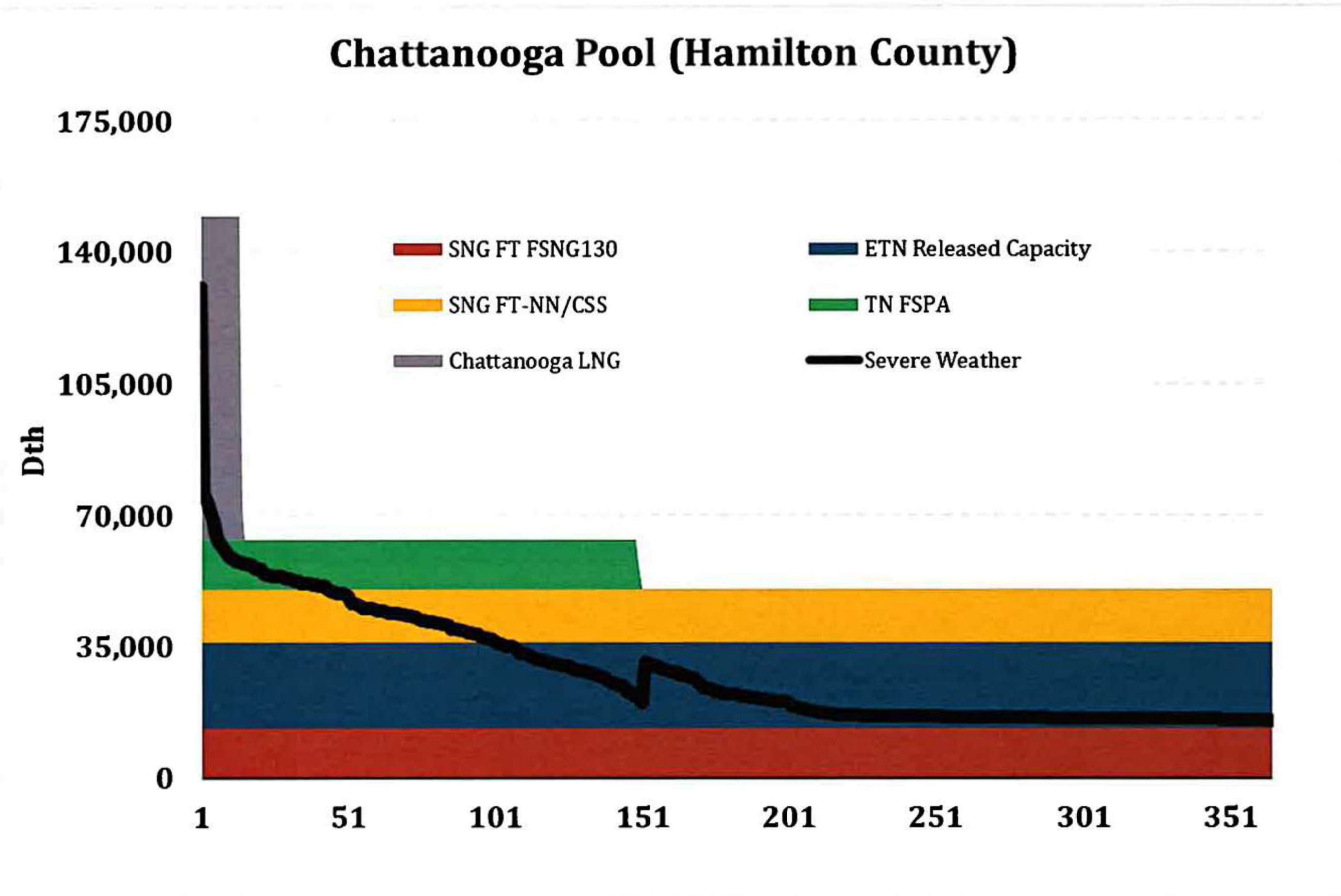
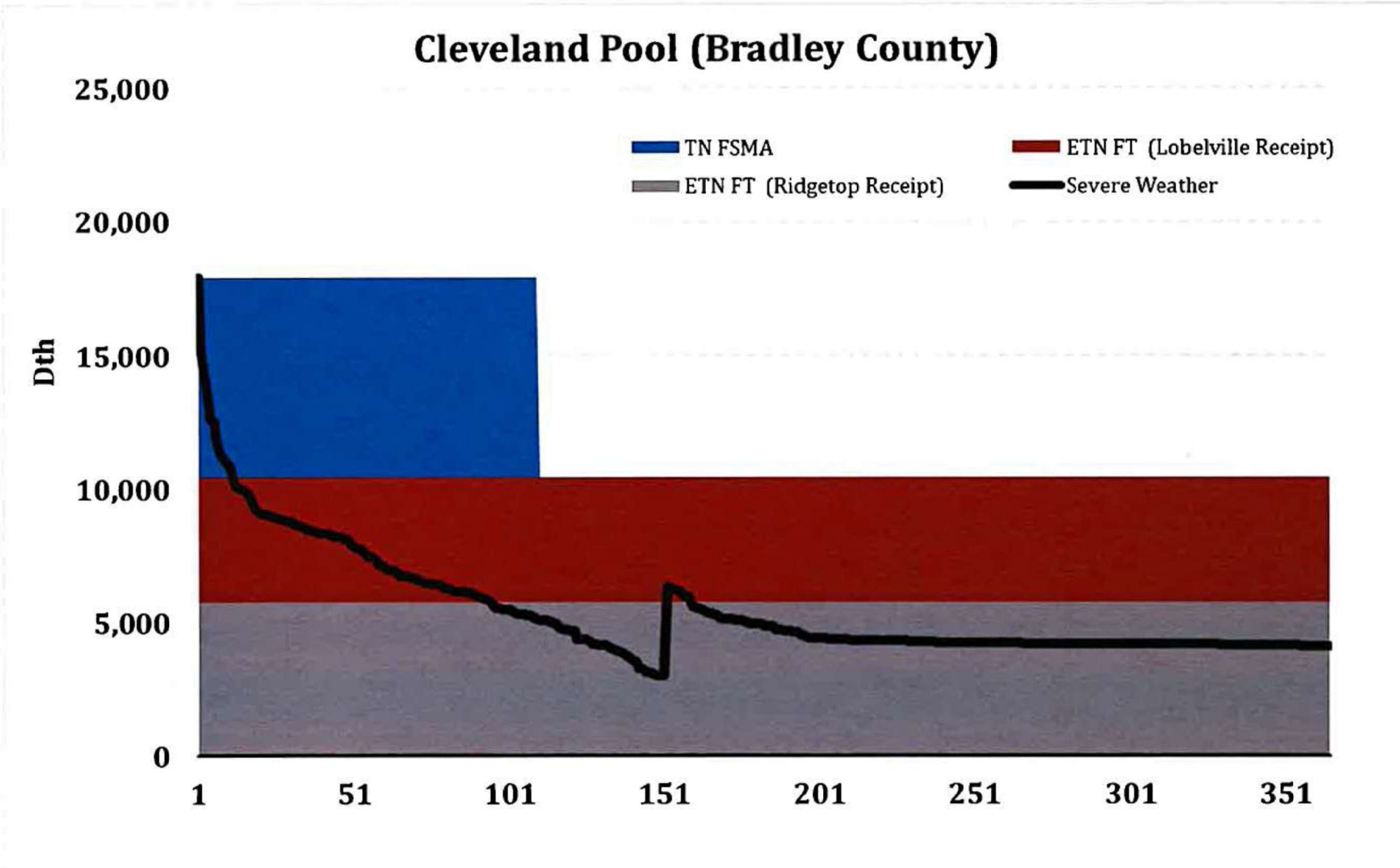


Figure 9.
CHATTANOOGA GAS COMPANY
Load Duration Curve – Cleveland Service Territory
2018-2019 Winter Season



As just explained, although CGC's design peak day capacity resources exceeded requirements inclusive of the 5% reserve margin during the 2018-2019 and 2019-2020 winter seasons, they are close to being in relative balance. However, Figure 8 and Figure 9 reveal that even under severe weather conditions, as noted by the capacity resources identified above severe weather load, CGC maintains capacity resources significantly in excess of its requirements at most other times, particularly in the Cleveland service territory. During a winter in which severe weather conditions are experienced, it would be expected that CGC would require use of only approximately 5% of its maximum LNG storage inventory of 1,208,000 Dth. CGC's total load requirements during a winter in which severe weather conditions are experienced is projected to be 7,518,000 Dth. As shown previously in Table 1, CGC's winter season capacity resources total 14,347,000 Dth, or nearly twice the requirements anticipated under severe weather conditions. CGC's total load requirements during a year in which severe weather conditions are experienced is projected to be 9,294,000 Dth, plus approximately 3,600,000 Dth that may be required to fill its contract storage services and its LNG facility during the summer. As shown in Table 1, CGC's annual capacity resources total nearly 33,000,000 Dth, or more than three times the anticipated annual requirements. The potential for CGC to adjust its capacity resources to better match its load requirements is addressed in the next section of the Report.

5.4 Capacity Portfolio Modifications

The RFP scope of work for Exeter's review included examination and identification of: (1) the total fixed cost of CGC's year-round firm transportation capacity to meet design day demand; (2) the total fixed cost of available seasonal firm transportation; and (3) the availability of seasonal firm transportation capacity. Exeter interprets this aspect of the scope of work as requiring an evaluation of whether CGC's annual interstate pipeline demand charges can be reduced by modifying the Company's current capacity portfolio.

The charges associated with each interstate pipeline firm transportation service purchased by CGC at the conclusion of the review period are summarized below in Table 13. As shown, these charges currently total nearly $13.2 million per year. As indicated in the previous section of the Report, CGC maintains excess year-round firm capacity. If available, the Company could potentially reduce its demand costs by decreasing its year-round capacity and placing greater reliance on winter season capacity and/or citygate peaking supply services. With respect to citygate peaking supply services, in the past, CGC has issued RFPs to secure such services, but has generally found peaking services to be unavailable.

Table 13. CHATTANOOGA GAS COMPANY Summary of Interstate Pipeline Firm Transportation Charges			
Pipeline Service/Contract	**MDQ (Dth)**	**Monthly Demand Charge ($/Dth)**	**Annual Demand Cost**
TGP			
FT-A (48082)	37,819	$8.8772	$4,028,722
ETNG			
FT-A (410203)	13,000	$6.613	$1,031,628
FT-A (410204)	28,350	$6.613	$2,249,743
FT-A (661664)	23,000	$7.163	$2,148,938
SONAT			
FT (FSNG130)	13,221	$11.26	$1,786,422
FT-NN (FSNG130)	14,346	$11.26	$1,938,432
TOTAL:			**$13,183,884**

Replacing year-round capacity arrangements with winter season arrangements could also reduce CGC's annual demand charges. Capacity on TGP and ETNG is fully subscribed and, therefore, winter season capacity would be unavailable and neither pipeline has offered such services. 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 capacity would be available for optimization by the Asset Manager.

As previously shown in Table 1, the Company's year-round firm transportation service contract with TGP expires in 2025. CGC's contracts with ETNG will expire in 2021 and 2022, and its contracts with SONAT expire in 2023. Each of these contracts has a one-year notice requirement for cancellation or potential modification. CGC's capacity release arrangement with OPC expires in 2022. CGC has indicated that it will attempt to eliminate its ETNG firm transportation capacity on the Nora Lateral when the contract for that capacity expires in 2021. Although Exeter has found that CGC's winter and annual capacity resources significantly exceed its requirements, CGC's excess capacity resources are consistent with those of other gas utilities without options to obtain peaking supply services and winter season services.

6.0 EVALUATION OF AMA AND OFF-SYSTEM INCENTIVES

This section of Exeter's Report begins with a comparison of CGC's PBRM and IMCR with the gas procurement incentive mechanisms of Atmos Energy Corporation and Piedmont Natural Gas Company. This comparison is provided for informational purposes as well as to assist in addressing the Statement of Work requirement to evaluate the balance of incentives between CGC and its customers relative to the sharing of AMA fees and off-system sales margins.

Exeter's experience in reviewing gas incentive mechanisms in jurisdictions other than Tennessee includes a now-terminated program of Nicor Gas Company in Illinois, and the terminated programs of Vectren North, Vectren South, and Citizens Gas & Coke Utility in Indiana. Exeter continues to review, on a quarterly basis, the Gas Cost Incentive Mechanism (GCIM) of Northern Indiana Public Service Company. In multiple jurisdictions in which Exeter regularly performs gas cost procurement reviews, capacity release revenues, off-system sales margins, and AMA fees are subject to sharing with the utility. These jurisdictions include Delaware, Louisiana, Massachusetts, Ohio, and Pennsylvania.

6.1 <u>Comparison of CGC Incentives with Similar Incentive Mechanisms of other Tennessee Natural Gas Distribution Companies</u>

6.1.1 CGC Incentives

As discussed in greater detail previously in this Report, under CGC's PBRM, each month, the Company's actual commodity cost of gas is compared to a monthly benchmark amount. This benchmark amount is based on the applicable published index price for the location at which gas is purchased. If CGC's total actual commodity gas costs for a Plan Year do not exceed the total benchmark amount by 1%, the Company's commodity gas costs are deemed prudent and the audit required by TRA Administrative Rule 1220-4-7-.05 is waived. There is no sharing of savings or losses under the PBRM. The interstate pipeline costs incurred by CGC are not directly evaluated under the PBRM, and these costs are not subject to an incentive mechanism.

CGC's IMCR provides for a 50% ratepayer sharing of the AMA fees received by the Company, as well as 50% of the revenues (margins) generated from capacity release and off-system sales activities. Under the AMAs that CGC operated during the review period, CGC's ETNG, SONAT and TGP pipeline resources were assigned to the Asset Manager, except for CGC's SONAT FT-NN and CSS contracts (Excluded Assets). Since CGC's ETNG, TGP, and SONAT FT assets were assigned to the Asset Manager under the AMAs, CGC could not utilize these assets to engage in capacity release on off-system sales activities to generate revenues. The SONAT Excluded Assets were available to CGC to generate capacity release and off-system sales revenues; however, CGC elected to designate the AMA Asset Manager to engage in these activities on the Company's behalf. Under the AMAs, the Asset Manager was entitled to retain 50% of the margins generated from capacity release and off-system sales activities that utilized the SONAT Excluded Assets and the remaining 50% was credited to ratepayers under the IMCR. During the review period, CGC received between [redacted] in annual AMA fees from Sequent, its Asset Manager, 50% of which was credited to ratepayers under the IMCR. CGC's off-system LNG tanker sales generated [redacted] in margins during the review period, 50% of which was credited to ratepayers under the IMCR. Pivotal elected to discontinue off-system LNG sales after August 2018. Also during the review period, Sequent generated [redacted] in off-system sales margins utilizing the SONAT Excluded Assets, 50% of which was assigned to ratepayers under the IMCR. Over 80% of the Excluded Assets off-system sales revenues were generated during January 2018. Sequent elected to discontinue its Excluded Assets off-system sales activities after January 2018. There is no cap on the amounts eligible for sharing under the IMCR.

6.1.2 Atmos Performance Based Ratemaking Mechanism

Atmos' PBRM consists of a Gas Procurement Incentive Mechanism and a Capacity Management Incentive Mechanism. The Gas Procurement Incentive Mechanism establishes a monthly benchmark against which Atmos' monthly commodity cost of gas is compared. The monthly benchmark is based on the published index prices for the locations at which Atmos' gas supplies are purchased, as well as the type of purchase. Monthly purchases are benchmarked against monthly index prices, and daily prices are benchmarked against daily index prices. For citygate purchases, the benchmark is adjusted to reflect the avoided pipeline demand transportation charges that would have been paid for the delivery of gas to the citygate, less any demand charges paid to the supplier providing the service. If Atmos' total monthly commodity cost of gas falls within a deadband of the total monthly benchmark amount, there are no incentive savings or costs to share. If Atmos' total monthly commodity cost of gas is below the deadband, Atmos is permitted to retain, as a reward, 50% of the difference. If the total monthly commodity cost of gas is above the deadband, Atmos is denied recovery of 50% of the difference. During the period most recently reviewed by Exeter (April 1, 2011 – March 31, 2014), all of the Gas Procurement Incentive Mechanism savings achieved by Atmos were attributable to avoided demand charges.

Under the Capacity Management Incentive Mechanism, to the extent Atmos is able to release transportation or storage capacity, or achieve savings from off-system sales, the associated revenues and margins are shared by Atmos' sales customers and Atmos on a 90% / 10% basis, respectively. During the period most recently reviewed by Exeter, all Capacity Management Incentive Mechanism savings were attributable to AMA fees. Under the PBRM, Atmos is subject to an overall combined annual cap on incentive savings or costs under both incentive mechanisms of $1.25 million. Atmos' share of PBRM savings was limited by the $1.25 million cap during each Plan Year of the period most recently reviewed by Exeter.

6.1.3 Piedmont Performance Incentive Plan

Piedmont's Performance Incentive Plan (Plan) consists of three components: (1) a commodity procurement cost component; (2) a supplier reservation fee component; and

(3) a capacity management component. Under the Plan's commodity procurement cost component, Piedmont's actual total monthly citygate (delivered) commodity cost of gas is compared to costs based on a Monthly Benchmark Index Price. The actual total citygate commodity cost of gas includes the amount paid for gas supply commodity purchases, plus the applicable pipeline fuel and variable transportation charges associated with delivering gas from the purchase (receipt) point to Piedmont's system. The commodity procurement cost component provides for a 75% sales customer and 25% Piedmont sharing of the difference between actual and benchmark costs.

Under the supplier reservation fee component of the Plan, Piedmont is entitled to recover 100% of its gas supply reservation fees with no gain or loss potential. The capacity management component of the Plan provides that the revenues (margins) realized from capacity release and off-system sales activities, as well as AMA fees, be subject to the same 75% ratepayer / 25% Piedmont sharing procedures as commodity procurement cost component savings/losses. Piedmont's Plan includes a $1.6 million sharing cap.

6.2 Balance of Incentives

CGC is entitled to retain 50% of the fees it receives under AMAs. The remaining 50% is credited to ratepayers under the IMCR. Ratepayers were credited with 50% of the margins generated from off-system LNG tanker sales that were made by affiliate Pivotal, and 50% of the margins generated by affiliate Sequent from off-system sales utilizing the SONAT Excluded Assets. Pivotal and Sequent retained the remaining 50% of the margins generated by off-system LNG and Excluded Asset sales, respectively. Pivotal ceased off-system LNG tanker sales after August 2018. Sequent ceased making off-system sales utilizing the Excluded Assets after January 2018.

In other jurisdictions, sharing percentages that range from 90% customer / 10% utility to 75% customer / 25% utility have generally been adopted for AMA fees, capacity release revenues and off-system sales margins realized by the utility. In Tennessee, AMA fees realized by Atmos are subject to a 90% customer / 10% utility sharing incentive, and for Piedmont, a 75% customer / 25% utility sharing incentive. Exeter has observed no material differences in the resource efforts of natural gas utilities to generate AMA fees, capacity release revenues, or off-system sales margins under a 25% sharing incentive compared to a 10% sharing incentive, nor has Exeter observed a natural gas utility failing to devote sufficient resources to maximize these revenues/margins when provided a sharing incentive. An incentive mechanism should provide a utility with an incentive sufficient to ensure ratepayer benefits are maximized since it is resources paid for by ratepayers that are used to generate AMA fees, capacity release revenues, and off-system sales margins. Therefore, Exeter concludes that for AMA fees, a 75% customer / 25% utility sharing incentive would be more appropriate for CGC and reflect a reasonable balance of incentives.

Pivotal, an unregulated entity, ceased its off-system LNG tanker sales efforts after August 2018 due to what CGC believes was the availability of LNG from other sources which did not require a 50% sharing of the margins realized by Pivotal with CGC's ratepayers. Thus, it is reasonable to conclude that Pivotal found the balance of incentives under the sharing mechanism insufficient to continue to pursue the off-system sale of CGC's LNG. Pivotal is no longer an affiliate of CGC. Therefore, it is uncertain whether Pivotal or another entity would be interested in making off-system LNG sales under an alternative incentive mechanism. Exeter has not observed the marketing of utility off-system LNG tanker sales by unregulated entities in other jurisdictions.

As an alternative to supporting off-system LNG tanker sales, CGC's LNG facility could be utilized to make off-system sales by displacement. That is, during periods of peak demand, interstate pipeline flowing supplies being delivered to CGC could be diverted to off-system markets and replaced with supplies from CGC's LNG facility. Exeter has observed the use of third parties by utilities to support off-system LNG displacement sales. To evaluate the potential to generate revenue from off-system LNG sales, both by tanker and by displacement, Exeter recommends that in its next AMA RFP, CGC include provisions in the RFP that would provide an Asset Manager the ability to engage in off-system LNG tanker and displacement sales. The RFP should specify the terms and conditions under which LNG would be available for such sales. The RFP should also request bids inclusive and exclusive of the option of utilizing CGC's LNG facilities to support off-system sales, and the option to exclusively bid on the LNG aspect of the AMA to encourage off-system LNG tanker sales which would not require the use of CGC's interstate pipeline capacity resources.

Sequent, also an unregulated entity, ceased utilizing the SONAT Excluded Assets to support off-system sales after January 2018 for what CGC believes was the relatively minimal economic value generated by these transactions that Sequent was able to retain. Excluding the margins realized in January 2018 which were significantly higher than margins in other months due to record cold weather, these transactions generated an average of approximately [redacted] of which Sequent was entitled to retain 50%. It is uncertain whether Sequent found the balance of incentives under the sharing mechanism insufficient to continue to pursue Excluded Assets off-system sales, or the relatively minimal revenue in total generated by these transactions that caused Sequent to discontinue these off-system transactions.

The RFP most recently issued for AMA services indicated that at its option, CGC may select the Asset Manager or another third party to utilize the SONAT Excluded Assets to generate off-system sales margins when the Excluded Assets are deemed unnecessary for CGC's on-system requirements. This provision adds uncertainty to the RFP evaluations that would be prepared by a potential bidder. To eliminate this uncertainty and provide an Asset Manager the incentive to generate revenues through Excluded Asset off-system sales, Exeter recommends that the RFP provisions be revised to provide that the Asset Manager would be designated to utilize the Excluded Assets when deemed unnecessary for CGC's on-system requirements.

7.0 FINDINGS OF FACT AND AREAS OF CONCERN

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

- Chattanooga Gas Company contracted for 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 Management, which were approved by the Tennessee Public Utility Commission.
- At the conclusion of the review period, CGC served 67,400 sales and transportation customers with annual throughput of approximately 15,500,000 Dth.
- CGC's storage inventory planning criteria were reasonable, CGC generally adhered to those criteria, and CGC's review period storage activity was reasonable.
- CGC realized net margins of [redacted] from its off-system LNG sales activities during the period July 1, 2016 – March 31, 2019, 50% of which was shared with ratepayers.
- Net margins of [redacted] were realized by Sequent from off-system sales utilizing the SONAT Excluded Assets during the period July 1, 2016 through March 31, 2019 and the capacity CGC acquired from OPC during the period November 1, 2017 through March 31, 2018, 50% 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 and incorporated the impact of customer conservation efforts.
- CGC's planned use of a 5% capacity reserve margin, when viewed in conjunction with its design day criteria of 57 HDDs, was reasonable.
- CGC could reduce its interstate pipeline demand costs by decreasing its year-round capacity and instead rely on winter season capacity; however, there are currently no opportunities for the Company to do so.
- Under the PBRM, if CGC's total actual commodity gas costs for a Plan Year do not exceed benchmark costs by 1%, the Company's gas costs are deemed prudent and the audit required by TPUC Administrative Rule 1220-4-7-.05(1)(a) is

waived. CGC's actual gas costs during the Plan Years ended June 30, 2017 and June 30, 2018 did not exceed benchmark costs by 1%.

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

- CGC selects its AMAs through an RFP process. Sequent has been CGC's AMA Asset Manager for nearly 20 years. Thus, Sequent has significant experience with respect to how CGC utilizes its interstate pipeline resources to provide natural gas service to its customers. This experience provides Sequent with a significant competitive advantage when responding to CGC's RFPs for AMA services. [redacted] To level the playing field for bidders responding to CGC's RFPs for AMA services and increase the competitiveness of the process, CGC should include three years of historical daily interstate pipeline usage data in its next RFP. This data is already maintained and reported by CGC in its annual PBRM filings with the TPUC. It is common for gas utilities to provide such information in RFPs for AMA services. Appendix C to this Report includes an RFP recently issued for AMA services by the City of Dalton, Georgia which describes the historical usage data to be provided to potential bidders. The information provided with the RFP should include the use of in-ground storage purchases to meet CGC storage fill requirements to ensure that the use of this option is recognized by potential bidders.
- The RFPs issued by CGC for AMA services state that all bidders must be willing to accept in their entirety the Asset Management and Agency Agreement and Gas Purchase and Sales Agreement and Exhibits (AMA Agreements) included in the RFP. This may unnecessarily discourage potential bidders from responding to the RFP. Exeter recommends that CGC modify the language in its RFP to indicate that changes may be considered by CGC. Exeter recommends that when CGC files for Commission approval of its next AMA, the Company identify all bidder-requested AMA Agreement modifications and indicate whether the modification was accepted by CGC. If a modification was not accepted, CGC should identify the basis for not accepting the modification. This will assist in assuring that CGC's RFPs are not unreasonably reducing bidder interest and competition.
- CGC maintains 4,899 Dth per day of ETNG firm transportation capacity with a receipt point on ETNG's Nora Lateral in southwest Virginia. After the winter of 2016-2017, due to reduced liquidity of supply on the Nora Lateral, CGC was unable to secure gas supplies at its Nora Lateral primary receipt point under reasonable terms and conditions, and the Company was unable to rely on this capacity for gas supplies on a firm basis. To address the inability to rely on the Nora Lateral ETNG capacity on a firm basis and address growth in the design day capacity requirements of its customers, CGC acquired 25,000 Dth per day of

ETNG capacity from OPC effective August 1, 2017. The primary receipt point for this capacity is ETNG's interconnect with Texas Eastern in Mt. Pleasant, Tennessee. CGC subsequently released 2,000 Dth per day of the ETNG capacity acquired from OPC to Jat Oil for the period November 1, 2017 – October 31, 2020. The acquisition of the released capacity as an alternative to the Nora Lateral capacity and to address CGC's increasing design day capacity requirements appears reasonable.

- The RFP issued for AMA services indicates that at its option, CGC may select the Asset Manager or another third party to utilize the SONAT Excluded Assets to generate off-system sales margins when the Excluded Assets are deemed unnecessary for CGC's on-system requirements. This provision adds uncertainty to the RFP evaluations that would be prepared by a potential bidder. To eliminate this uncertainty, Exeter recommends that this provision be revised to provide that the Asset Manager would be designated to utilize the Excluded Assets when deemed unnecessary for CGC's on-system requirements. CGC should also include a three-year history of daily Excluded Asset availability in its AMA RFPs to reduce RFP evaluation uncertainty for potential bidders.
- Until August 2018, Pivotal, then an affiliate of CGC, engaged in off-system LNG tanker sales which generated revenues, 50% of which were credited to ratepayers. The RFP issued by CGC for AMA services does not provide for the optimization of CGC's LNG facility by the Asset Manager. To evaluate the potential to generate revenue from off-system LNG tanker and displacement sales due to Pivotal's election to discontinue its off-system sales activity, CGC should include provisions in its next AMA RFP that would provide an Asset Manager the ability to engage in off-system LNG tanker and displacement sales as discussed in greater detail in Section 6.2 of this Report.
- CGC utilized the ETNG released capacity acquired from OPC to deliver gas supplies purchased at the Texas Eastern/ETNG interconnect in Mt. Pleasant, Tennessee. These supplies were sold to CGC by Sequent and benchmarked under the PBRM based on [redacted]. The Texas Eastern/ETNG interconnect is located in Texas Eastern Zone M-1. Under the AMA with Sequent, gas supplies purchased by CGC were to be priced based on index prices applicable for the receipt point under the delivering firm transportation arrangement. Therefore, the purchases under the capacity acquired from OPC should have been priced and benchmarked based on Texas Eastern Zone M-1 index prices. For the Plan Year ended June 30, 2018, pricing and benchmarking the purchases under the capacity acquired from OPC at Texas Eastern Zone M-1 index prices would have decreased CGC's purchased gas costs and benchmark costs by an estimated $132,460, and by $201,824 for the period July 1, 2018 – March 31, 2019. Adjusting benchmark costs under the PBRM for the Plan Year

ended June 30, 2018 to reflect Zone M-1 pricing for purchases delivered under the ETNG capacity acquired from OPC would not have resulted in CGC's actual commodity gas costs exceeding benchmark costs by 1%. Although the review period does not extend through the end of the Plan Year ended June 30, 2019, Exeter's analysis indicates that adjusting benchmark costs to reflect Zone M-1 index prices would also not have resulted in CGC's actual commodity costs exceeding benchmark costs by 1% for the Plan Year ended June 30, 2019.

- CGC was responsible for all variable charges related to the use of the assets assigned to Sequent under AMAs, and Sequent reimbursed CGC for the variable charges incurred under those assets not associated with providing service to CGC. The price paid by CGC for the purchases from Sequent at the Texas Eastern/ETNG interconnect were improperly calculated. The price paid by CGC included the variable ETNG transportation charges associated with delivering gas from the Texas Eastern/ETNG interconnect to CGC's citygate. The ETNG capacity utilized to deliver these purchases to CGC's citygate was the released capacity acquired from OPC and, therefore, the variable charges associated with these deliveries were directly billed to CGC by ETNG. Therefore, it appears that CGC was billed twice for these deliveries—once by Sequent and once by ETNG. CGC has indicated that Sequent may have incorrectly billed CGC for ETNG variable charges. CGC will review its Texas Eastern-priced purchases from Sequent to determine the amount of the incorrect billings. CGC will include a credit to sales customers to reflect the improper charges in its next ACA filing.
- CGC's PBRM benchmark and actual cost calculations failed to include 35,660 Dth of daily Texas Eastern purchases made in August and September 2018. The actual cost of those purchases was equal to the benchmark. This discrepancy had no material impact on CGC's PBRM performance.

APPENDIX A

CHATTANOOGA GAS COMPANY
PERFORMANCE BASED RATEMAKING MECHANISM

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.

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.

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.

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

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.

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.

APPENDIX B

CHATTANOOGA GAS COMPANY

REVIEW PERIOD PURCHASES

APPENDIX B

CHATTANOOGA GAS COMPANY
Summary of PBRM Review Period Purchases
(Dth)

	TGP ZONE 0				TGP ZONE 0/1 100/500 Leg				TGP ZONE 0/1 800 Leg				SONAT			
	MONTHLY		DAILY		MONTHLY		DAILY		MONTHLY		DAILY		MONTHLY		DAILY	
	Quantity	Benchmark	Quantity	Benchmark	Quantity	Benchmark	Quantity	Benchmark	Quantity	Benchmark	Quantity	Benchmark	Quantity	Benchmark	Quantity	Benchmark
July 2016	0	$2.8100	5,600	$2.6090	0	$2.8600	0	$0.0000	0	$2.8500	14,996	$2.6963	7,626	$2.8800	26,072	$2.7574
August	0	2.5500	44,176	2.6261	0	2.6100	8,241	2.7035	0	2.5900	124,598	2.6446	8,091	2.6200	85,209	2.7397
September	0	2.7300	10,440	2.9290	0	2.7900	0	0.0000	0	2.7700	48,602	2.9232	18,780	2.7900	15,675	3.0533
October	0	2.8700	27,157	2.9742	0	2.9000	0	0.0000	0	2.8900	81,020	2.9187	34,038	2.9000	10,354	2.9525
November	0	2.8800	3,538	2.2150	0	2.7000	61,928	2.4533	171,270	2.6900	42,801	2.1608	35,680	2.7000	27,957	2.5350
December	0	3.1300	265,529	3.4096	0	3.1700	3,092	3.6000	14,322	3.1600	143,883	3.4952	35,774	3.1800	232,501	3.5235
January 2017	252,433	$3.8100	45,285	$3.1453	0	$3.8800	0	$0.0000	0	$3.8800	89,365	$3.2012	35,433	$3.8800	204,389	$3.2526
February	124,157	3.2400	81,639	2.8544	0	3.3100	0	0.0000	0	3.3000	40,296	2.9356	34,944	3.3200	63,049	2.9885
March	0	2.4800	98,891	2.8627	0	2.5400	0	0.0000	0	2.5200	46,143	2.9353	35,836	2.5300	59,329	2.9808
April	78,930	3.0600	1,626	2.9381	0	3.0900	144,172	3.0739	0	3.0700	184,690	3.0113	36,150	3.1000	0	0.0000
May	7,533	3.0000	60,975	2.9214	0	3.0500	60,300	2.9909	0	3.0500	222,735	3.0369	34,379	3.0600	38,296	3.0394
June	0	3.0700	60,753	2.7614	0	3.1500	7,138	2.8303	0	3.1400	66,470	2.8695	36,150	3.1600	0	0.0000
July	0	2.9000	71,023	0.0000	0	2.9700	0	0.0000	0	2.9700	51,731	2.9190	36,425	2.9900	31,086	2.9817
August	0	2.8000	58,788	0.0000	0	2.8800	0	0.0000	0	2.8800	80,557	2.7918	35,588	2.8800	0	0.0000
September	40,200	2.8000	29,209	0.0000	0	2.8900	0	0.0000	0	2.8700	154,320	2.8776	35,340	2.8800	0	0.0000
October	83,142	2.8000	1,031	0.0000	0	2.8800	0	0.0000	48,391	2.8700	342,190	2.8053	35,030	2.8800	0	0.0000
November	201,930	2.6100	42,343	0.0000	0	2.6600	0	0.0000	0	2.6500	17,418	2.9400	3,060	2.6600	25,495	2.8700
December	204,538	2.9200	98,824	2.6373	0	3.0100	0	0.0000	0	2.9800	129,923	2.7016	35,371	3.0200	213,605	2.7488
January 2018	343,790	$2.6200	0	$0.0000	0	$2.6700	0	$0.0000	46,066	$2.6500	101,605	$3.6710	35,371	$2.6800	413,555	$3.7077
February	175,682	3.5100	34,664	0.0000	0	3.5900	0	0.0000	0	3.5400	41,605	2.8940	83,552	3.5800	17,572	2.9800
March	0	2.5000	146,202	0.0000	0	2.5700	0	0.0000	0	2.5500	101,785	2.6342	0	2.5700	45,098	2.7006
April	32,970	2.5700	0	0.0000	0	2.6200	0	0.0000	139,650	2.6000	474,147	2.6702	7,597	2.6300	35,490	2.7254
May	31,444	2.7000	0	0.0000	0	2.7600	0	0.0000	64,456	2.7500	38,208	2.7082	7,843	2.7600	0	0.0000
June	32,610	2.7600	875	0.0000	0	2.8100	0	0.0000	0	2.7900	171,787	2.8336	6,090	2.8200	0	0.0000
July	30,478	2.8300	936	2.6585	0	2.9200	0	0.0000	0	2.9000	78,590	2.7196	0	2.9400	26,672	2.7192
August	0	2.6600	41,829	2.8253	0	2.7500	0	0.0000	0	2.7600	119,719	2.8643	0	2.7600	7,310	2.8960
September	0	2.7700	25,228	2.8240	0	2.8300	0	0.0000	0	2.8200	90,399	2.8502	0	2.8400	7,682	2.9079
October	58,714	2.9000	1,806	3.1014	0	2.9600	0	0.0000	101,866	2.9200	253,180	3.1666	6,417	2.9600	0	0.0000
November	283,770	3.1000	28,951	4.1462	0	3.1500	50,584	3.9868	0	3.1200	166,369	4.0387	6,210	3.1500	49,912	4.3952
December	0	4.6200	131,656	4.2196	0	4.7100	0	0.0000	231,867	4.6700	8,856	4.4039	6,417	4.7000	124,506	4.1536
January 2019	113,522	$3.5300	141,132	$3.0042	0	$3.5900	0	$0.0000	0	$3.5400	202,068	$2.9834	6,417	$3.6000	296,160	$3.0606
February	0	2.8300	138,974	2.5619	0	2.8800	0	0.0000	237,608	2.8500	17,529	2.5850	5,796	2.8900	45,572	2.5953
March	0	2.7600	23,038	2.9125	0	2.7900	7,913	3.0300	0	2.7600	127,934	3.1415	6,417	2.8000	67,335	3.3060
Total	2,095,843		1,722,118		0		343,368		1,055,496		3,855,539		711,722		2,169,881	

APPENDIX B

CHATTANOOGA GAS COMPANY
Summary of PBRM Review Period Purchases
(Dth)

	NORA LATERAL				TEXAS EASTERN						TGP ZONE 0 FSPA IN GROUND			
	MONTHLY		DAILY		MONTHLY		DAILY NO BOUNCE		DAILY BOUNCE		MONTHLY		DAILY	
	Quantity	Benchmark	Quantity	Benchmark	Quantity	Benchmark	Quantity	Benchmark	Quantity	Benchmark	Quantity	Benchmark	Quantity	Benchmark
July 2016	155,310	$3.0202	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000	201,706	$2.9100	0	$0.0000
August	155,310	2.7763	0	0.0000	0	0.0000	0	0.0000	0	0.0000	162,037	2.6436	0	0.0000
September	149,909	2.9491	0	0.0000	0	0.0000	0	0.0000	0	0.0000	161,712	2.8280	0	0.0000
October	155,310	3.0506	0	0.0000	0	0.0000	0	0.0000	0	0.0000	162,759	2.9714	0	0.0000
November	150,300	2.9273	0	0.0000	0	0.0000	0	0.0000	0	0.0000	0	2.9816	0	0.0000
December	155,310	3.8273	0	0.0000	0	0.0000	0	0.0000	0	0.0000	0	3.2378	0	0.0000
January 2017	155,310	$5.9545	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000	0	$3.9345	0	$0.0000
February	140,280	4.2057	0	0.0000	0	0.0000	0	0.0000	0	0.0000	0	3.3505	0	0.0000
March	155,310	2.7126	0	0.0000	0	0.0000	0	0.0000	0	0.0000	0	2.5717	0	0.0000
April	0	3.2335	0	0.0000	0	0.0000	0	0.0000	0	0.0000	168,240	3.2078	0	0.0000
May	0	3.1928	19,596	3.0849	0	0.0000	0	0.0000	0	0.0000	0	3.1456	0	0.0000
June	0	3.3046	2,000	3.0150	0	0.0000	0	0.0000	0	0.0000	31,170	3.2182	0	0.0000
July	0	0.0000	0	0.0000	0	3.1420	0	0.0000	0	0.0000	173,848	3.0419	0	0.0000
August	0	0.0000	0	0.0000	0	3.0607	0	0.0000	0	0.0000	173,848	2.9382	0	0.0000
September	0	0.0000	0	0.0000	0	3.0302	0	0.0000	0	0.0000	168,240	2.9382	0	0.0000
October	0	0.0000	0	0.0000	0	3.0404	208,689	2.8913	0	0.0000	86,211	2.9382	0	0.0000
November	0	0.0000	0	0.0000	0	2.8778	40,000	2.9779	0	0.0000	0	2.7412	0	0.0000
December	0	0.0000	0	0.0000	0	0.0000	69,000	2.8135	74,600	2.9569	0	3.0627	0	0.0000
January 2018	0	$0.0000	0	$0.0000	0	$0.0000	399,740	$3.7371	9,798	$3.5658	0	$2.7516	0	$0.0000
February	0	0.0000	0	0.0000	0	0.0000	151,164	2.9663	0	0.0000	0	3.6745	0	0.0000
March	0	0.0000	0	0.0000	0	0.0000	364,449	2.7476	0	0.0000	0	2.6271	0	0.0000
April	0	0.0000	0	0.0000	0	0.0024	250,469	2.8212	0	0.0000	150,240	2.6868	0	0.0000
May	0	0.0000	0	0.0000	0	0.0000	211,081	2.7981	0	0.0000	0	2.8208	0	0.0000
June	0	0.0000	0	0.0000	0	0.0000	0	0.0000	0	0.0000	0	2.8827	0	0.0000
July	0	0.0000	0	0.0000	0	0.0000	0	0.0000	0	0.0000	0	2.9549	0	0.0000
August	0	0.0000	0	0.0000	0	0.0000	2,957	2.8687	0	0.0000	158,162	2.7796	0	0.0000
September	0	0.0000	0	0.0000	0	0.0000	32,703	2.8513	0	0.0000	12,000	2.8930	0	0.0000
October	0	0.0000	0	0.0000	0	0.0000	174,370	3.1864	0	0.0000	13,857	3.0271	0	0.0000
November	0	0.0000	0	0.0000	0	0.0000	295,988	4.3383	0	0.0000	0	3.2330	0	0.0000
December	0	0.0000	0	0.0000	0	0.0000	430,268	3.9833	0	0.0000	0	4.8004	0	0.0000
January 2019	0	$0.0000	0	$0.0000	0	$0.0000	351,415	$3.2203	130,000	$3.2141	0	$3.6764	0	$0.0000
February	0	0.0000	0	0.0000	0	0.0000	17,100	2.7873	46,648	2.8478	0	2.9546	0	0.0000
March	0	0.0000	0	0.0000	0	0.0000	138,000	3.3607	0	0.0000	0	2.8824	0	0.0000
Total	1,372,349		21,596		0		3,137,393		261,046		1,824,030		0	

APPENDIX B

CHATTANOOGA GAS COMPANY
Summary of PBRM Review Period Purchases
(Dth)

	TGP ZONE 0 FSMA IN GROUND				TGP ZONE 0/1 800 LEG FSMA IN GROUND				TGP ZONE 0 FSPA TO STORAGE				TGP ZONE 0 FSMA TO STORAGE			
	MONTHLY		DAILY		MONTHLY		DAILY		MONTHLY		DAILY		MONTHLY		DAILY	
	Quantity	Benchmark	Quantity	Benchmark	Quantity	Benchmark	Quantity	Benchmark	Quantity	Benchmark	Quantity	Benchmark	Quantity	Benchmark	Quantity	Benchmark
July 2016	90,272	$2.9114	0	$0.0000	0	$0.0000	0	$0.0000	0	$2.8100	0	$0.0000	0	$2.8100	0	$0.0000
August	71,920	2.6450	0	0.0000	0	0.0000	0	0.0000	20,522	2.5500	0	0.0000	18,817	2.5500	0	0.0000
September	87,390	2.8294	0	0.0000	0	0.0000	0	0.0000	0	2.7300	0	0.0000	0	2.7300	0	0.0000
October	90,272	2.9728	0	0.0000	0	0.0000	0	0.0000	0	2.8700	0	0.0000	0	2.8700	0	0.0000
November	0	2.9830	0	0.0000	0	0.0000	0	0.0000	0	2.8800	0	0.0000	0	2.8800	0	0.0000
December	0	3.2392	0	0.0000	0	0.0000	0	0.0000	0	3.1300	0	0.0000	0	3.1300	0	0.0000
January 2017	0	$3.9359	0	$0.0000	0	$0.0000	0	$0.0000	0	$3.8100	0	$0.0000	0	$3.8100	0	$0.0000
February	0	3.3519	0	0.0000	0	0.0000	0	0.0000	7,579	3.2400	0	0.0000	0	3.2400	0	0.0000
March	0	2.5731	0	0.0000	0	0.0000	0	0.0000	0	2.4800	0	0.0000	0	2.4800	0	0.0000
April	77,010	3.2092	0	0.0000	0	0.0000	0	0.0000	0	3.0600	0	0.0000	0	3.0600	0	0.0000
May	0	3.1470	0	0.0000	0	0.0000	0	0.0000	180,296	3.0000	0	0.0000	82,522	3.0000	0	0.0000
June	5,970	3.2198	0	0.0000	0	0.0000	0	0.0000	142,140	3.0700	0	0.0000	73,680	3.0700	0	0.0000
July	79,577	3.0433	0	0.0000	0	0.0000	0	0.0000	0	2.9000	0	0.0000	0	2.9000	0	0.0000
August	79,577	2.9396	0	0.0000	0	0.0000	0	0.0000	0	2.8000	0	0.0000	0	2.8000	0	0.0000
September	77,010	2.9396	0	0.0000	0	0.0000	0	0.0000	0	2.8000	0	0.0000	0	2.8000	0	0.0000
October	36,952	2.9396	0	0.0000	0	0.0000	0	0.0000	90,892	2.8000	0	0.0000	44,206	2.8000	0	0.0000
November	0	2.7426	0	0.0000	0	0.0000	0	0.0000	0	2.6100	0	0.0000	0	2.6100	0	0.0000
December	0	3.0641	0	0.0000	0	0.0000	0	0.0000	0	2.9200	0	0.0000	0	2.9200	0	0.0000
January 2018	0	$2.7530	0	$0.0000	0	$0.0000	0	$0.0000	0	$2.6200	0	$0.0000	0	$2.6200	0	$0.0000
February	0	3.6759	0	0.0000	0	0.0000	0	0.0000	13,514	3.5100	0	0.0000	0	3.5100	0	0.0000
March	0	2.6285	0	0.0000	0	0.0000	0	0.0000	0	2.5000	0	0.0000	0	2.5000	0	0.0000
April	68,100	2.6882	0	0.0000	0	0.0000	0	0.0000	55,200	2.5700	0	0.0000	20,160	2.5700	0	0.0000
May	0	2.8222	0	0.0000	0	0.0000	0	0.0000	223,737	2.7000	0	0.0000	95,543	2.7000	0	0.0000
June	0	2.8841	0	0.0000	0	0.0000	0	0.0000	206,550	2.7600	0	0.0000	92,490	2.7600	0	0.0000
July	0	2.9563	0	0.0000	0	2.9000	0	0.0000	216,650	2.8300	0	0.0000	95,573	2.8300	0	0.0000
August	46,283	2.7810	0	0.0000	0	2.7600	0	0.0000	35,371	2.6600	0	0.0000	47,864	2.6600	0	0.0000
September	5,130	2.8944	0	0.0000	0	2.8200	0	0.0000	171,030	2.7700	0	0.0000	87,210	2.7700	0	0.0000
October	5,859	3.0285	0	0.0000	0	2.9200	0	0.0000	172,608	2.9000	0	0.0000	89,497	2.9000	0	0.0000
November	0	3.2344	0	0.0000	0	3.1200	13,659	4.5154	0	3.1000	0	0.0000	0	3.1000	0	0.0000
December	0	4.8018	0	0.0000	7,066	4.6700	0	0.0000	0	4.6200	0	0.0000	0	4.6200	0	0.0000
January 2019	0	$3.6778	0	$0.0000	0	$3.5400	0	$0.0000	0	$3.5300	0	$0.0000	0	$3.5300	0	$0.0000
February	0	2.9560	0	0.0000	0	2.8500	0	0.0000	0	2.8300	0	0.0000	0	2.8300	0	0.0000
March	0	2.8838	0	0.0000	0	2.7600	0	0.0000	0	2.7600	0	0.0000	0	2.7600	0	0.0000
Total	821,322		0		7,066		13,659		1,538,089		0		747,562		0	

Exhibit DND-3

APPENDIX B

CHATTANOOGA GAS COMPANY
Summary of PBRM Review Period Purchases
(Dth)

	TGP ZONE 0/1 800 LEG FSPA TO STORAGE				TGP ZONE 0/1 800 LEG FSPA TO STORAGE				SONAT TO STORAGE			
	MONTHLY		DAILY		MONTHLY		DAILY		MONTHLY		DAILY	
	Quantity	Benchmark	Quantity	Benchmark	Quantity	Benchmark	Quantity	Benchmark	Quantity	Benchmark	Quantity	Benchmark
July 2016	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000	0	$2.9970	87,144	$2.8099
August	0	0.0000	0	0.0000	0	0.0000	0	0.0000	0	2.7299	106,237	2.8007
September	0	0.0000	0	0.0000	0	0.0000	0	0.0000	0	2.9045	73,800	2.9949
October	0	0.0000	0	0.0000	0	0.0000	0	0.0000	0	3.0022	24,000	2.7125
November	0	0.0000	0	0.0000	0	0.0000	0	0.0000	0	2.7978	0	0.0000
December	0	0.0000	0	0.0000	0	0.0000	0	0.0000	0	3.2884	0	0.0000
January 2017	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000	0	$4.0051	0	$0.0000
February	0	0.0000	0	0.0000	0	0.0000	0	0.0000	0	3.4327	0	0.0000
March	0	0.0000	0	0.0000	0	0.0000	0	0.0000	0	2.6254	0	0.0000
April	0	0.0000	0	0.0000	0	0.0000	0	0.0000	0	3.2154	0	0.0000
May	0	0.0000	0	0.0000	0	0.0000	0	0.0000	0	3.1744	97,557	3.1480
June	0	0.0000	0	0.0000	0	0.0000	0	0.0000	0	3.2768	85,142	2.9399
July	0	0.0000	0	0.0000	0	0.0000	0	0.0000	0	3.0629	112,290	2.9638
August	0	0.0000	0	0.0000	0	0.0000	0	0.0000	0	2.9900	113,491	2.9059
September	0	0.0000	0	0.0000	0	0.0000	0	0.0000	0	2.9900	68,545	3.0035
October	0	0.0000	0	0.0000	0	0.0000	0	0.0000	0	2.9515	0	0.0000
November	0	0.0000	0	0.0000	0	0.0000	0	0.0000	0	2.7291	0	0.0000
December	0	0.0000	0	0.0000	0	0.0000	0	0.0000	0	3.0931	0	0.0000
January 2018	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000	0	$2.7488	0	$0.0000
February	0	0.0000	0	0.0000	0	0.0000	0	0.0000	0	3.6588	0	0.0000
March	0	0.0000	0	0.0000	0	0.0000	0	0.0000	0	2.6376	0	0.0000
April	0	0.0000	0	0.0000	0	0.0000	0	0.0000	0	2.6951	15,114	2.7837
May	0	0.0000	0	0.0000	0	0.0000	0	0.0000	0	2.8263	141,803	2.7892
June	0	0.0000	0	0.0000	0	0.0000	0	0.0000	0	2.8869	118,643	2.9185
July	0	0.0000	39,614	2.7065	0	0.0000	0	0.0000	0	3.0081	126,107	2.7735
August	0	0.0000	0	0.0000	0	0.0000	0	0.0000	0	2.8263	118,235	2.9192
September	0	0.0000	0	0.0000	0	0.0000	0	0.0000	0	2.9071	124,797	2.9365
October	0	0.0000	0	0.0000	0	0.0000	0	0.0000	0	3.0529	61,264	3.2418
November	0	0.0000	14,025	4.2150	0	0.0000	7,860	4.2150	0	3.2464	0	0.0000
December	0	0.0000	0	0.0000	0	0.0000	0	0.0000	0	4.7911	0	0.0000
January 2019	0	$0.0000	0	$0.0000	0	$0.0000	0	$0.0000	0	$3.6779	0	$0.0000
February	0	0.0000	0	0.0000	0	0.0000	0	0.0000	0	2.9600	0	0.0000
March	0	0.0000	0	0.0000	0	0.0000	0	0.0000	0	2.8691	0	0.0000
Total	0		53,639		0		7,860		0		1,474,169	

APPENDIX C

CITY OF DALTON, GEORGIA d/b/a DALTON UTILITIES

RFP FOR NATURAL GAS SUPPLY AND PIPELINE CAPACITY MANAGEMENT

REQUEST FOR PROPOSALS FOR NATURAL GAS SUPPLY AND PIPELINE CAPACITY MANAGEMENT TO MEET THE REQUIREMENTS
FOR
THE BOARD OF WATER, LIGHT AND SINKING FUND COMMISSIONERS OF THE CITY OF DALTON, GEORGIA D/B/A DALTON UTILITIES

Introduction

Dalton Utilities (Dalton) has operated as a public utility since 1889. It provides electrical, natural gas, potable water and wastewater treatment services to the City of Dalton and portions of Whitfield, Murray, Gordon, Catoosa and Floyd counties. Beginning in 1999, Dalton branched into telecommunications with broadband services to large industrial/commercial customers. In 2003, Dalton launched its OptiLink family of services and now provides broadband, cable tv, telephone and internet services to area residents and businesses. Dalton serves approximately 78,000 customers and employs over 300 area residents.

Dalton Utilities has over $900M in assets with approximately $200M in annual revenues. Dalton is currently rated A2 by Moody's but there is no outstanding debt. Audited financial reports are available upon request

Dalton serves approximately 7,500 customers as a retail natural gas service provider with a 2016 retail load of approximately 4,340,290 dth. Within its customer mix, there is approximately 3,327,974 dth of year-round load that accounts for almost 77% of Dalton's annual requirements. Residential load is less than 6% of Dalton's consumption profile. Dalton has a small group of customers that deliver third party gas to its city gate for transportation on Dalton's distribution system (Transportation Customers). Transportation Customers' load accounted for 2,563,270 dth in 2016 with Dalton's total system load being 6,903,560 dth for the same year.

Dalton has contract pipeline and storage capacity in varying amounts on Southern Natural Gas (SNG), East Tennessee Natural Gas (ETNG) and Texas Eastern Transmission (TETCO). The detail of these contracts will be provided in additional documentation.

Objective

Dalton is requesting proposals from entities for commitments to meet its natural gas supply requirements for a term of eighteen (18) months beginning October 1, 2017 and ending March 31, 2019. Bidders' proposals will be required to facilitate firm service to Dalton for resale to retail customers as well as balancing Dalton's Transportation Customers. Dalton will begin daily balancing all Transportation Customers on April 1, 2018.

Dalton reserves the right to select the bid that provides the overall best value to its customers which MAY NOT be the absolute lowest cost solution. This will allow Dalton to accept the most diverse proposal from qualified, reliable sources. Dalton will only evaluate opportunities proposed in the RFP Bid submittals; it will not make an attempt to fabricate "creative solutions" outside the bounds of each documented proposal. PLEASE ENSURE THAT THE PROPOSAL SUBMITTED ON THE DATE STATED BELOW IS THE ABSOLUTE BEST AND FINAL PROPOSAL INTENDED FOR SUBMISSION.

Anticipated Schedule (Approximate)

- Public Release of This Proposal: June 21, 2017
- Notice of Intent to Respond and Submission of Prequalification Requirements: July 12, 2017

- Execution of Nondisclosure Agreements and Data Exchange with Qualified Bidders: July 19, 2017
- RFP Response Due: August 11, 2017
- Selection of Awarded Party/Parties: August 21, 2017

Communications

Any questions regarding the RFP after July 19, 2017 SHALL BE submitted to Dalton **NO LATER THAN** the Close of Business July 31, 2017. Responses to inquiries will be provided by August 4, 2017 and made available to all qualified bidders via electronic communication. Any inquiries submitted after the date above may not receive a response and any response to such inquiry is at the sole discretion of Dalton.

The primary point of contact regarding all matters of this RFP is Tom Bundros at:

USPS:
Chief Executive Officer
Dalton Utilities
PO Box 869
Dalton, Georgia 30722

FEDEX/UPS
Chief Executive Officer
Dalton Utilities
1200 V. D. Parrott Jr. Parkway
Dalton, Georgia 30720

Telephone: 706-529-1003

Email: tbundros@dutil.com

Confidentiality

Dalton will provide a Nondisclosure Agreement (Attachment 1), approved by its counsel, as part of the required prequalification package. Dalton will execute Nondisclosure Agreements with parties deemed to be qualified bidders.

Data Provided to Bidders

Dalton will provide load and resource data to all qualified bidders after the mutual execution of a Nondisclosure Agreement. Data expected to be provided will include:

- Daily natural gas system load data from January 1, 2014 to April 30, 2017
- Daily retail load data from January 1, 2014 to April 30, 2017
- Forecasted future supply from Municipal Energy Resources Corporation
- List of new and existing customer loads with forecasted growth.
- List of Dalton's interstate pipeline meter points
- List of Dalton's pipeline contracts

Description of Services:

1. Bidder is to provide for firm delivery of all Dalton natural gas requirements. Dalton shall retain the right, at its sole discretion, to enter into long term natural gas prepay agreements with any prepay supplier. For the purposes of this RFP, all proposals shall provide a daily commodity price based on the Gas Daily Average pricing formula published in Platts' Methodology and Specifications Guide for North American Gas dated June 2017. Dalton reserves the right to negotiate daily pricing structures with the winning bidder
2. Bidder shall provide for the purchase of swing gas in short term intervals acceptable to Dalton.
3. Bidder shall have access to all of Dalton's excess capacities for its own benefit on any given day within the term however, said resources MUST be made available to Dalton under some stipulated circumstance. Dalton does not contemplate any release of storage capacity deliverability for the sake of injection and withdrawal rights.
4. A portion of Dalton's supply is derived from a long term prepay contract with Municipal Energy Resources Corporation. Bidder will be required to facilitate the delivery of natural gas under that agreement on a "first delivered" basis throughout the term of this agreement.

Bidder shall provide the following:

- An exhaustive list identifying any charges, and their method of being calculated, that will OR CAN be charged to Dalton associated with meeting the above requirements.
- A sample bill for the month of February 2017 using historical data provided by Dalton. Assume:
  - 12,000 dth baseload at index on SNG
  - 1,900 dth baseload at index on TETCO
  - 2,000 dth at GDA SNG LA, Monday through Thursday of each week.
- A sample natural gas supply contract representative of Bidders proposal.

All proposals shall include the following:

- Pricing for natural gas supplied to Dalton based on monthly, Daily (Cycles 1and 2) and intra-day (Cycles 3 and 4) nominations.
- Pricing for any natural gas delivered to Dalton's City Gate delivered on the same intervals as above.
- Any incremental cost to Dalton associated with increases in Dalton's planned prepay purchases.
- Identification of the point(s) of origin from which Dalton's natural gas will be sourced.
- Pricing for natural gas delivered to Dalton as part of Dalton's balancing its Transportation Customers.
- Pricing for Dalton in the event that Dalton's requirements exceed its forecast on any given day.
- Forecasted reimbursement, if any, to Dalton for the use of its interstate pipeline capacities and storage space.
- Forecasted increase in before mentioned reimbursement to Dalton if available pipelines capacities include an increase in FT on ETNG with similar receipt and delivery point designations to the contract Dalton has provided. Assume additional capacity volumes between 4,000 and 6,000 dth.
- A list of daily, weekly and monthly processes and activities required to fully support Dalton's requirements. This outline shall name the party (Dalton or Bidder) that is responsible for each activity therein.
- Outline of the proposed timeline for settling commodity transactions and billing activities.
- A list of additional services or benefits that bidder will provide during the term of this agreement.

Prequalification Package and Final Proposal Submittal

The bidding entity's pre-qualification package shall include an introductory cover letter signed by an officer of the company. If the bid is submitted by a joint venture, all parties to the joint venture must individually satisfy the pre-qualification requirements. Final determination of the applicant's qualification is determined by Dalton. This package shall be sent to the primary point of contact listed above.

Prequalification Package

The package must be received by Dalton Utilities no later than **5:00 p.m.** on **July 12, 2017**. No bid will be opened unless the bidder has been approved by Dalton Utilities prior to **July 19, 2017**.

Final Proposal Submittal

Final proposals shall be sent to the primary point of contact listed above and received by Dalton NO LATER THAN **August 11, 2017. No proposal received after 5:00 p.m. Eastern Time August 11, 2017 will be opened.**