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June 30, 2023

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Earl Taylor, Executive Director
Tennessee Public Utility Commission
c/o Ectory Lawless, Esq. Docket Clerk
Andrew Jackson State Office Building
502 Deaderick Street, 4th Floor
Nashville, Tn 37243-0001

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

Mr. Taylor,

On behalf of Chattanooga Gas Company (the "Company" or "CGC"), enclosed please find for filing with the Tennessee Public Utility Commission ("TPUC") an original and four (4) copies of the public redacted version of the report on the Review of Performance Based Ratemaking Mechanism Transactions and Activities, dated June 2023 which has been prepared by Exeter Associates, Inc. ("Exeter") in compliance with the TPUC Order dated October 27, 2020, in Docket No. 07-00224, and as the Audit of Prudence of Gas Purchases, pursuant to the Term. Comp. R. & Regs. 1220-04-07-.05 and the TPUC Order dated October 13, 2009, in Docket No. 07-00224 (the "Report"). Also included with this letter is a confidential version of the Report, submitted under seal.

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

Sincerely,

J. W. Luna

Enclosures
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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 2023

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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 was selected through an RFP process to perform this review. Exeter submitted its report for the period July 2016 – March 2019 in June 2020.

In an Order issued in Docket No. 07-00224 on October 27, 2020, the TPUC voted to extend the triennial review period process for the period April 2019 – March 2022. 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 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 April 2019 – March

2022 (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 Cost Adjustment (ACA) 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 June 9, 2023. On June 22, 2023, 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 five sections in addition to this introductory section. Section 2 of the Report identifies the interstate pipeline transmission companies serving CGC, the services the Company purchases from each pipeline, and the Company's review period gas supply arrangements. Included in Section 2 is a description of the Company's review period AMA with Sequent Energy Management, L.P. (Sequent), a former affiliate of CGC.[1] Section 2 also provides a description of the CGC system and the markets it serves, and provides 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. This section also summarizes and evaluates CGC's citygate purchases which were excluded from 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. The final section of the Report summarizes Exeter's conclusions, includes findings of fact, and identifies and describes any areas of concern and improvement that may warrant further consideration.

[1] Sequent was sold by Southern Company Gas, CGC's corporate parent, to the Williams Companies, Inc. effective July 1, 2021.

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 ten interconnects with ETNG and one interconnect with SONAT. The services and rates of CGC's interstate pipeline service providers are regulated by the Federal Energy Regulatory Commission (FERC).

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), an interstate pipeline with an index receipt point location that was initially utilized during the audit period as a benchmark under the PBRM, and as discussed in greater detail in Sections 3.2 and 3.4 of the Report, utilized to evaluate the reasonableness of CGC's citygate purchases. CGC operated under an AMA with its former affiliate, Sequent, during the review period. CGC's AMA with Sequent is described in Section 2.2 of the Report. CGC's review period gas supply arrangements under the AMA are described in Section 2.3 of the Report. Section 2.4 of the Report 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

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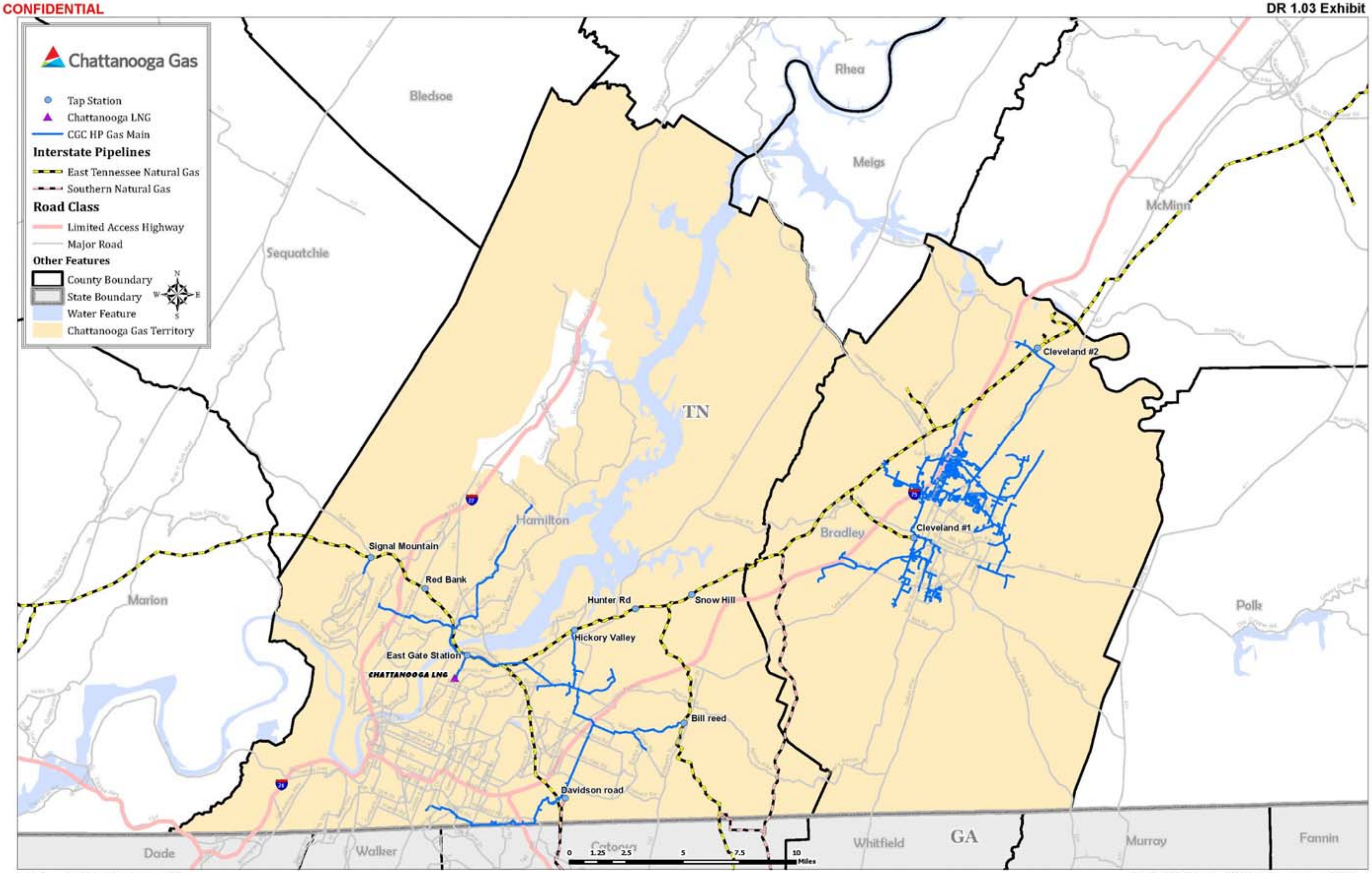
DR 1.03 Exhibit



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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 distribution 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 at the conclusion of the audit period. 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 Capacity Resources (March 31, 2022)

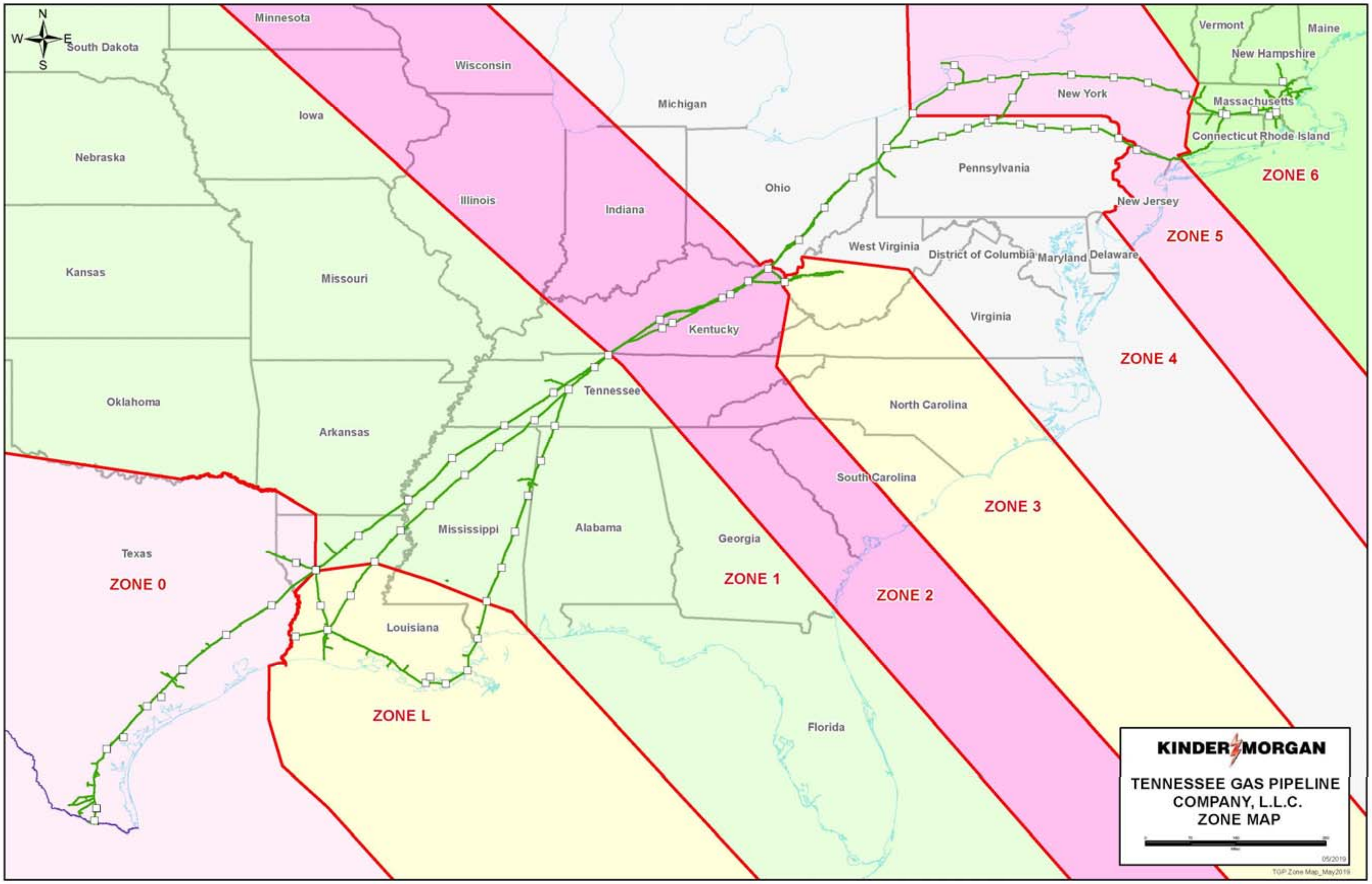
Pipeline – Service	Contract No.	MDQ Winter (Dth)	MDQ Summer (Dth)	Winter Season (Dth)	Total Annual Quantity (Dth)	Contract Expiration
UPSTREAM RESOURCES						
Tennessee Gas Pipeline						
Firm Transportation (FT-A)	48082	37,819	37,819	5,710,669	13,803,935	10/31/2025
Storage Service (FS-MA)[1]	3947	7,741	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	10/31/2027
Firm Transportation (FT-A)[2]	410204	23,451	23,451	3,541,101	8,559,615	10/31/2028
Firm Transportation (FT-A)[3]	410691	48,000	48,000	7,248,000	17,520,000	10/31/2055
Subtotal ETNG:		*84,451*	*84,451*	*12,752,101*	*30,824,615*	
Southern Natural Gas						
Firm Transportation (FT)	[4]	13,221	13,221	1,996,371	4,825,665	08/31/2024
Firm Transportation (FT-NN)	[5]	14,346	14,346	2,166,246	5,236,290	08/31/2024
Storage Service (CSS)[6]	[7]	14,346	0	710,484	0	08/31/2024
Subtotal SONAT:		*27,567*	*27,567*	*4,162,617*	*10,061,955*	
CGC LNG		91,630	0	1,207,574	1,207,574	
Total Citygate Resources:		**203,648**	**112,018**	**18,122,292**	**42,094,144**	

Notes: 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 a contract quantity of 50,000 Dth per day less a 2,000 Dth per day release of capacity.
[4] Contract No. 456076 - FTSNG.
[5] Contract No. 450814 - FTSNG.
[6] Delivered under SONAT FT-NN service.
[7] Contract No. 450813 - MCSSSNG.

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.[2] 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**

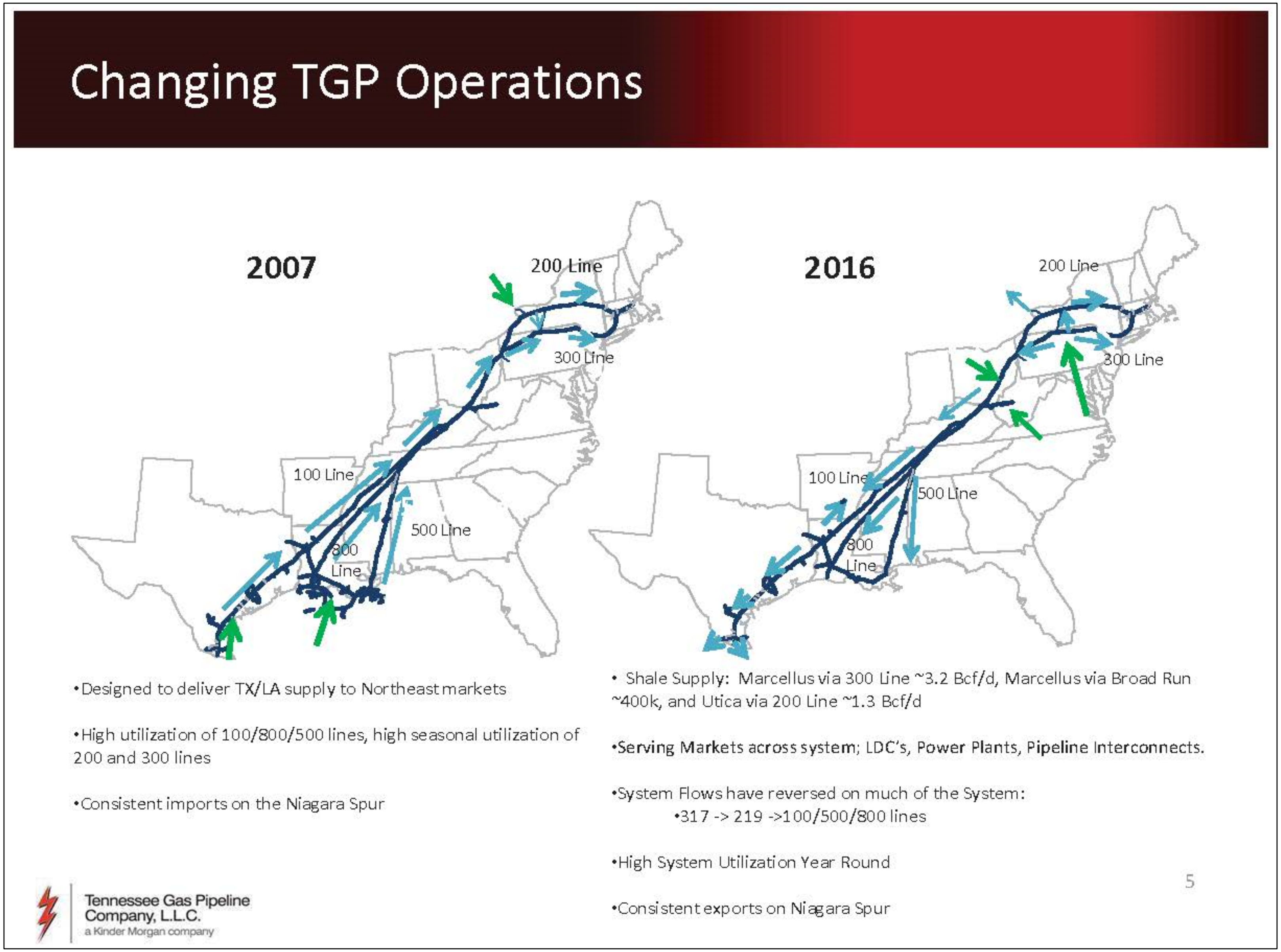
CGC also maintained market area firm storage service with TGP under Rate Schedule FS-MA (Contract No. 3947) and production area firm storage service with TGP under Rate Schedule FS-PA (Contract No. 22923). Gas was delivered to and from FS-MA and FS-PA storage under CGC's FT-A firm transportation arrangement with TGP. FS-MA provided for a maximum daily withdrawal quantity (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.[3] 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 previously 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.

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

[3] Marcellus Shale gas supplies averaged approximately $0.60/Dth less than Gulf Coast supplies during the final year of the review period.

Figure 3. TENNESSEE GAS PIPELINE – Changing Operations



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. As shown in Figure 4, ETNG interconnects with TGP at the Ridgetop and Lobelville receipt points. Initially 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 ETNG's Nora Lateral located in Dickenson County in southwest Virginia (see Figure 4) under Contract No. 410204. 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 audit period.[4] Exeter's prior audit recommended that in its next contract negotiation with ETNG, CGC attempt to modify its receipt points under Contract No. 410204 to eliminate the Nora Lateral capacity. Contract No. 410204 was scheduled to expire in 2021. CGC discussed modifying its receipt point entitlements with ETNG during the review period, but ETNG's tariff requires that a shipper such as CGC take *pro rata* reductions across all receipt points under a firm transportation contract to effect such a change. CGC elected not to move forward with a modification to its receipt points because it would have required the Company to reduce firm receipt point capacity that is currently necessary to support firm deliveries to CGC's system. 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 was 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 January 31, 2022.

When it released 25,000 Dth per day of capacity to CGC, OPC maintained an FT-A contract with ETNG for 50,000 Dth per day. OPC terminated its FT-A contract with ETNG upon expiration of the contract on January 31, 2022. Therefore, CGC's capacity release

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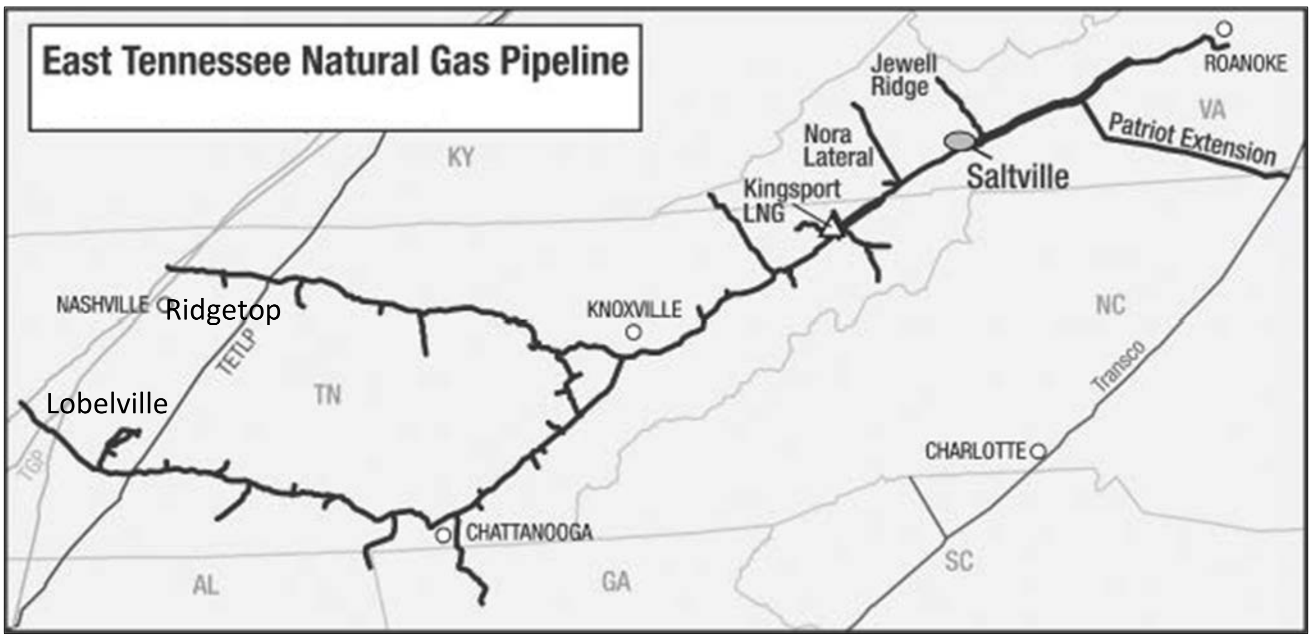
[4] In 2015, Range Resources – Appalachian, LLC (Range) was the only major supplier with production facilities supplying gas to ETNG's Nora Lateral. In late 2015, Range agreed to sell its production facilities that supplied the Nora Lateral to another producer. CGC negotiated and entered into a baseload gas supply contract with Sequent for Nora Lateral supplies for the winter of 2015-2016. Since no index price is published specifically for the Nora Lateral location, the commodity pricing provisions under this contract were based on monthly New York Mercantile Exchange (NYMEX) settlement prices plus a substantial commodity adder. CGC also subsequently negotiated and entered into a contract with Sequent for Nora Lateral baseload supplies for the period April 2016 – March 2017. The Company claims it was necessary to enter into an annual baseload gas supply contract for Nora Lateral supplies because supplies were no longer being offered on a seasonal basis. In return for an annual contract, CGC was able to negotiate a lower, but still substantial, commodity adder. CGC claims that its summer load profiles made it difficult to manage the baseload Nora Lateral supplies. Therefore, after expiration of the April 2016 – March 2017 arrangement, the Company elected not to pursue a subsequent arrangement for Nora Lateral supplies. As subsequently discussed above, the acquisition of the released ETNG capacity from OPC eliminated the need for CGC to purchase baseload Nora Lateral supplies.

arrangement with OPC also expired January 31, 2022. The 50,000 Dth per day of capacity under the contract OPC had maintained with ETNG was made available through an open season held by ETNG. Under an open season, capacity is awarded to the party offering the bid with the highest net present value for the capacity, and rates are capped at the pipeline's maximum FERC-approved rates for the capacity being made available. CGC was the successful bidder under ETNG's open season, and effective February 1, 2022, CGC executed a firm transportation arrangement with ETNG under Rate Schedule FT-A (Contract No. 410691) to replace the expired OPC capacity release arrangement. Contract No. 410691 provided for the delivery of 50,000 Dth per day from ETNG's interconnect with Texas Eastern at Mt. Pleasant to CGC's citygate. The term of Contract No. 410691 extends through March 31, 2055. CGC subsequently released 2,000 Dth per day of the capacity under Contract No. 410691 to Jat Oil for the period February 1, 2022 through March 31, 2023.

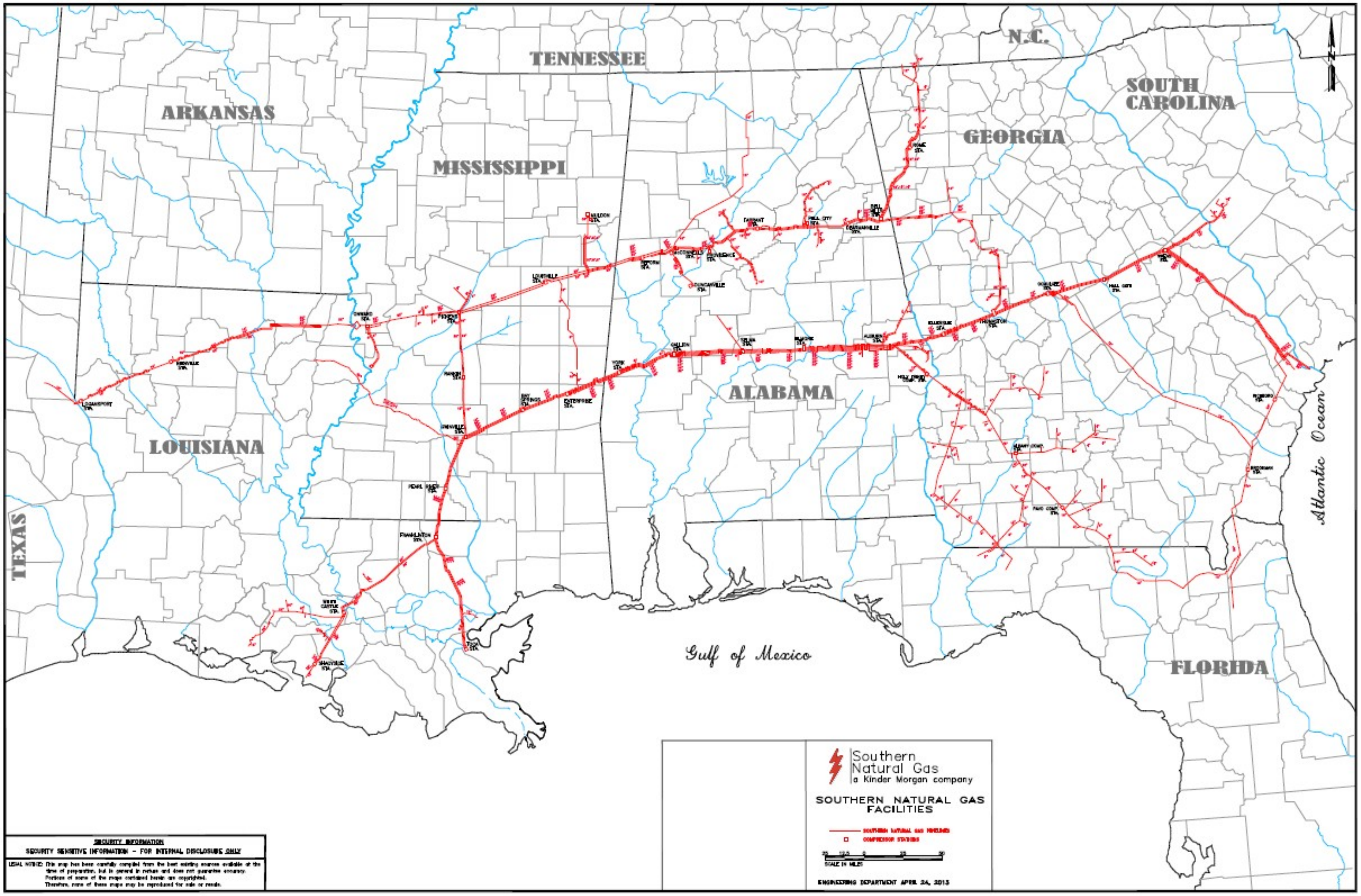
Figure 4. EAST TENNESSEE NATURAL GAS – System Map



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.

Figure 5. SOUTHERN NATURAL GAS – System Map



CGC maintained a firm transportation contract with SONAT under Rate Schedule FT (Contract No. 456076-FTSNG) during the review period. This contract provided for the delivery of 13,221 Dth per day directly to CGC's distribution system.

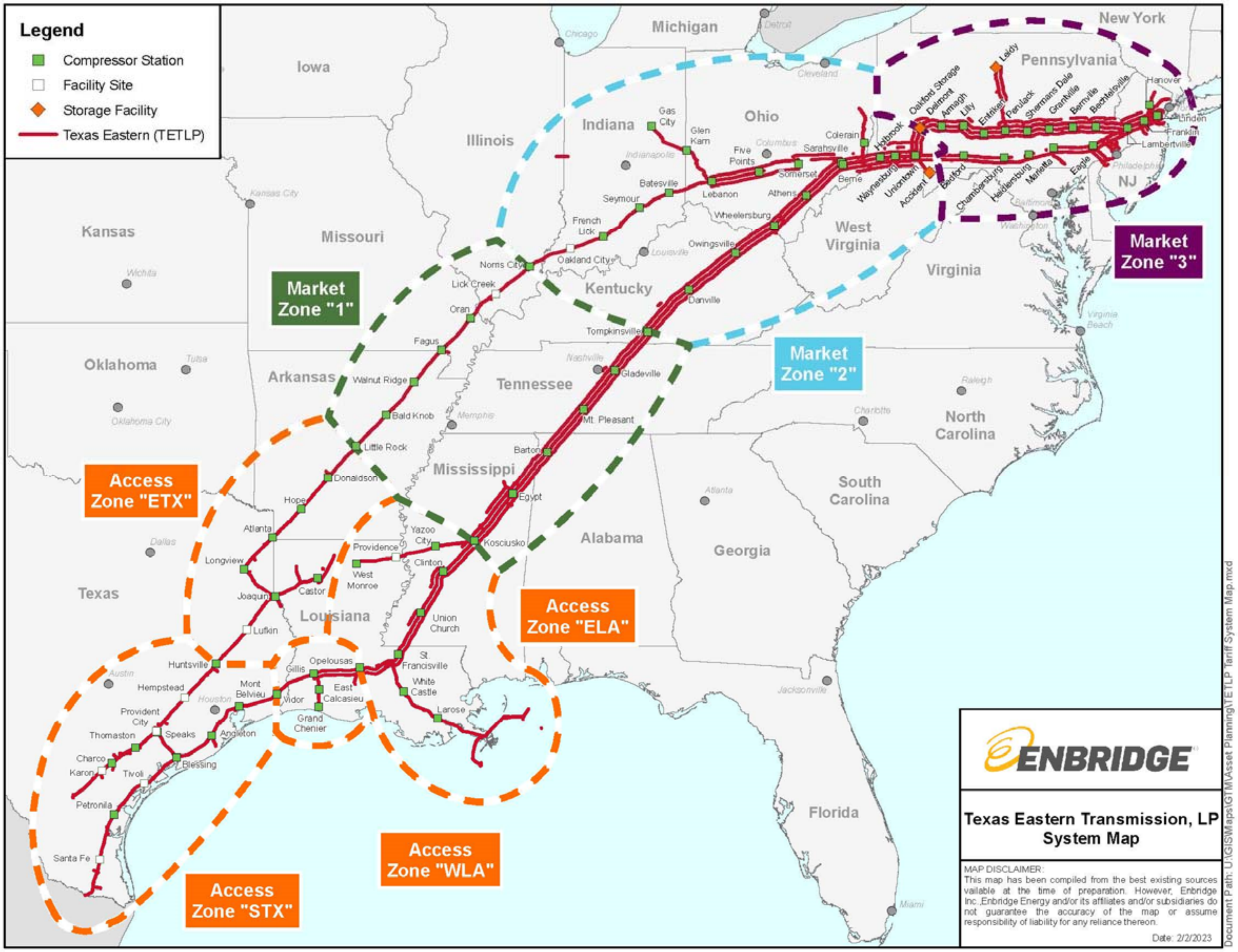
Under SONAT's standard Rate Schedule FT service, the pipeline is generally only obligated to deliver, and the shipper (e.g., CGC) is entitled to take, the quantity of gas delivered to the pipeline on the shipper's behalf on a daily basis. Shippers provide SONAT notice (through nominations) of the quantity 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 (Contract No. 450814-FTSNG). 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. 450813-MCSSSNG). 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.

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 (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. Prior to February 1, 2022, these purchases were delivered to CGC utilizing the ETNG capacity that CGC acquired from OPC. After February 1, 2022, these purchases were delivered to CGC utilizing ETNG FT-A Contract No. 410691.

Figure 6. TEXAS EASTERN TRANSMISSION, LP – System Map



2.1.5 Liquefied Natural Gas

CGC operates an on-system liquefied natural gas (LNG) facility. The maximum daily rated deliverability of its LNG facility is currently 120,000 Dth. The actual deliverability from the LNG facility into CGC's distribution system is limited by on-system infrastructure constraints, and load growth allows for slight increases in forecasted LNG deliverability each year. For the winter of 2021-2022, the maximum daily deliverability of LNG supplies into CGC's distribution system was estimated by the Company to be 91,630 Dth. The 91,630 Dth/day is the estimated maximum that can be delivered on an emergency basis. For reliability, the LNG facility has redundant vaporizers, that on a short-term emergency basis may be operated simultaneously. On a non-emergency basis, the maximum reliable deliverability is 60,000 Dth/day. In past years, the 91,630 Dth volume was required to serve design day load prior to CGC acquiring the new ETNG FT contract for 50,000 Dth/day. With the acquisition of the 50,000 Dth/day of FT, the operation of the LNG facility has been returned to its design deliverability. The LNG facility has a storage capacity of 1,207,574 Dth and can reliably produce at the design deliverability of 60,000 Dth/day for approximately 20 days.

2.2 Asset Management and Agency Agreement

CGC operated under an AMA with Sequent during the entire review period.[5] The AMA was initially approved by the TPUC for the three-year period April 1, 2018 – March 31, 2021 in Docket No. 17-000137. On April 14, 2020, CGC filed a request with the TPUC to extend the term of the AMA by one year due to the economic uncertainty associated with the COVID-19 pandemic and other factors. The TPUC approved CGC's requested one-year extension. The AMA was initially awarded through an RFP process. The RFP issued for the AMA was sent to 67 potential service providers. The Company received two bids in response to its AMA RFP. [redacted], and 50% of the fixed annual payment was shared with ratepayers through CGC's IMCR. Under the AMA, with the exception of CGC's SONAT no-notice assets (FT-NN Contract No. 450814-FTSNG and CSS Contract No. 450813-MCSSSNG), CGC's interstate pipeline firm transportation and contract storage capacity assets were managed by Sequent.[6] These SONAT no-notice assets were identified as "Excluded Assets" in the AMA. The AMA 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 AMA.

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[5] CGC operated under a similar AMA with Sequent during the period April 1, 2015 – March 31, 2018.

[6] The SONAT no-notice assets were excluded from the AMA 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.

Under the AMA, 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 AMA 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.

2.3 Gas Supply Arrangements

Under the AMA in effect during the review period, 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. [redacted]

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. Effective October 1, 2020, Rate Schedule R-4 became available to any customer using gas for multi-family Residential housing that contracted for gas service for a period of not less than one year. 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. Deliveries in excess of monthly consumption are purchased by the Company at published index prices. 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.

Table 2. CHATTANOOGA GAS COMPANY – Annual Customers and Volumes, by Class				
	April-December 2019	**2020**	**2021**	**January-March 2022**
CUSTOMERS BY RATE SCHEDULE				
Residential Sales (R-1)	58,108	59,221	59,916	60,924
Multi-Family Housing Sales (R-4)	2	2	2	2
Small Commercial & Industrial Sales (C-1)	6,490	6,537	6,551	6,779
Medium Commercial & Industrial Sales (C-2)	1,940	1,971	1,963	1,920
Commercial & Industrial Interruptible Sales (I-1)	0	0	0	0
Large Volume Commercial & Industrial				
Sales/Transportation with Full Standby (F-1/T-2)	36	36	36	35
Sales/Transportation with Partial Standby (F-1/T-2/T-1)	13	14	14	14
Interruptible Transportation (T-1)	17	17	17	17
Low Volume Commercial & Industrial				
Sales/Transportation with Standby (T-3/C-2)	45	48	49	49
Special Contract	3	1	1	1
Total Customers:	**66,654**	**67,861**	**68,549**	**69,743**
VOLUMES BY RATE SCHEDULE (Dth)				
Residential Sales (R-1)	1,508,717	3,308,538	3,687,486	1,876,409
Multi-Family Housing Sales (R-4)	3,374	7,104	7,713	3,438
Small Commercial & Industrial Sales (C-1)	277,534	571,488	664,576	391,135
Medium Commercial & Industrial Sales (C-2)	1,464,306	2,451,453	2,697,221	1,108,359
Commercial & Industrial Interruptible Sales (I-1)	0	0	0	0
Large Volume Commercial & Industrial				
Sales/Transportation with Full Standby (F-1/T-2)	1,867,740	2,956,979	2,710,373	1,195,082
Sales/Transportation with Partial Standby (F-1/T-2/T-1)	1,668,081	2,897,596	2,936,934	829,172
Interruptible Transportation (T-1)	1,301,560	1,806,876	1,740,056	481,304
Low Volume Commercial & Industrial				
Sales/Transportation with Standby (T-3/C-2)	344,198	594,034	545,159	283,432
Special Contract	655,795	608,504	327,344	235,149
Total Volumes:	**9,091,305**	**15,202,573**	**15,316,861**	**6,403,481**

3.0 PERFORMANCE BASED RATEMAKING MECHANISM RESULTS AND CITYGATE PURCHASES

This section of Exeter's Report summarizes and evaluates CGC's activities and performance under the Performance Based Ratemaking Mechanism. This section also discusses and evaluates CGC's citygate purchases which are currently excluded from the PBRM.[7] 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 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

[7] In CGC's base rate proceeding at Docket No. 18-00017, the TPUC approved a proposal presented by CGC to exclude citygate purchases from the PBRM.

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 at the Texas Eastern/ETNG Mt. Pleasant interconnect in Texas Eastern Zone M-1. The gas supplies CGC purchased at the Mt. Pleasant interconnect prior to July 2019 were included in the PBRM. Mt. Pleasant purchases after July 2019 through the conclusion of the review period were considered to be citygate purchases which are excluded from the PBRM tariff. [redacted] A summary of CGC's review period PBRM purchases is provided in Appendix B. For comparison purposes, the prices identified in Appendix B are the benchmark prices applicable under the PBRM. The Mt. Pleasant purchases which CGC excluded from the PBRM are summarized in Appendix C, and are further discussed in the following section and Section 3.4 of the Report. As subsequently discussed, CGC generally paid the benchmark price for the gas supplies it purchased from Sequent during the review period. The AMA provided that the gas supplies purchased by CGC would be priced based on index prices for the receipt points CGC deemed to be the most cost-effective delivery path for the firm transportation assets assigned to Sequent by CGC. If an index price was not available or published for a receipt point, Sequent and CGC would mutually agree upon a price.

3.2 PBRM Benchmark Calculation and Citygate Purchases

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 were applicable under the PBRM for gas delivered to CGC's citygate or injected into storage.

The first exception is for gas injected into SONAT storage. Under the Sequent AMA, 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.

Prior to July 2019, when Mt. Pleasant purchases were included in the PBRM, gas purchases made by CGC at the Texas Eastern/ETNG Mt. Pleasant [redacted] 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 restriction on ETNG, these secondary deliveries were subject to additional variable transportation and fuel charges. CGC referred 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 prior to July 2019. The price CGC paid Sequent for purchases at the Texas Eastern/ETNG Mt. Pleasant interconnect was dependent on whether the delivered purchases were Bounce or No-Bounce transactions.

In 2020, CGC contacted TPUC Staff proposing to revise its current PBRM tariff with respect to the benchmarking of Mt. Pleasant purchases. There is currently no published index price for the Mt. Pleasant receipt point. Therefore, CGC sought to also exclude Mt. Pleasant purchases from the PBRM. CGC claims that in discussions, TPUC Staff indicated that a tariff revision was not necessary, and the Mt. Pleasant purchases could be treated as citygate purchases pursuant to the PBRM tariff revision proposed by CGC and approved by the TPUC in CGC's base rate proceeding in Docket No. 18-0007. Subsequently, beginning with the annual PBRM filing for the 12 months ended June 30, 2020, Mt. Pleasant purchases were treated as citygate purchases. A separate tariff filing was not made to effectuate this change.

From the commencement of the audit period through December 2020 [redacted] to Mt. Pleasant. From Mt. Pleasant to CGC's citygate, the gas was transported using CGC's firm transportation capacity. Therefore, the variable charges associated with delivering gas from Mt. Pleasant to CGC's citygate were paid directly by CGC to ETNG [redacted], and CGC made the decision to accept or decline the purchase of Mt. Pleasant supplies [redacted]. [redacted] CGC continued to pay the ETNG variable charges associated with delivering Mt. Pleasant purchases to the citygate.

Exeter's prior audit 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, Exeter found that CGC was billed twice for these ETNG variable charges—once by Sequent and once by ETNG. After the conclusion of the prior audit, CGC reviewed its Texas Eastern-priced purchases from Sequent to determine the amount of the incorrect billings. CGC determined the improperly billed amount to [redacted] included this amount as a credit to sales customers in its 2020 ACA filing.

3.3 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. Our review found no discrepancies in CGC's calculations.

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.

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	7,173,824	($3)	0.0%
In-Ground	2,017,931	($24,863)	-0.5%
Zone L 100/500 Leg:			
Delivered	570,315	($20)	0.0%
In-Ground	0	$0	0.0%
Zone L 800 Leg:			
Delivered	7,833,574	($90)	0.0%
In-Ground	153,990	($1,349)	-0.3%
Southern Natural Gas			
Zone 1:			
Delivered	4,716,726	($1,925)	0.0%
In-Ground	0	$0	0.0%
Texas Eastern[2]			
[redacted]			
Delivered No-Bounce	41,294	$306	0.3%
Delivered Bounce	0	0	0.0%
Total:	**22,507,654**	**($27,944)**	**0.0%**

[1] (+) Costs exceed benchmark; (-) costs below benchmark.
[2] After June 2019, Texas Eastern deliveries were excluded from the PBRM.

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.

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 Texas Eastern ELA 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

[redacted]

supplies regardless of the TGP purchase index location. *Gas Daily* index prices for daily purchases exhibited the same relationship.

As previously discussed in Sections 3.1 and 3.2 of the Report and discussed in additional detail in Section 3.4, CGC purchased supplies at the Texas Eastern/ETNG Mt. Pleasant interconnect during the review period. From the commencement of the audit period through December 2020, these purchases were priced based on [redacted]. As shown in Table 4, based on monthly index prices during the review period, [redacted], the delivered cost of these purchases was generally comparable to the delivered cost of TGP-delivered supplies. CGC determined whether to purchase Mt. Pleasant supplies on a daily basis, and made such purchases only when the delivered costs of the supplies were less than the cost of TGP-delivered supplies.

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 Location (Dth)

Location	Total	Percent
Monthly		
TGP Zone 0	7,748,800	65.5%
TGP Zone L 100/500 Leg	0	0.0%
TGP Zone L 800 Leg	1,641,093	13.9%
SONAT	215,313	1.8%
Texas Eastern	2,228,284	18.8%
Subtotal Monthly:	*11,833,490*	*100.0%*
Daily		
TGP Zone 0	1,442,955	11.2%
TGP Zone L 100/500 Leg	570,315	4.4%
TGP Zone L 800 Leg	6,346,471	49.2%
SONAT	4,501,413	34.9%
Texas Eastern	41,294	0.3%
Subtotal Daily:	*12,902,448*	*100.0%*
Total		
TGP Zone 0	9,191,755	37.2%
TGP Zone L 100/500 Leg	570,315	2.3%
TGP Zone L 800 Leg	7,987,564	32.3%
SONAT	4,716,726	19.1%
Texas Eastern[1]	2,269,578	9.2%
Total:	**24,735,938**	**100.0%**

[1] Includes citygate deliveries excluded from PBRM.

3.4 Mt. Pleasant Citygate Purchases

As previously discussed in Sections 3.1 and 3.2, Mt. Pleasant purchases were considered citygate purchases after July 2019 and were excluded from the PBRM. Under a citygate purchase arrangement, all of the costs associated with delivering gas to the citygate would be paid for by the supplier. Under the AMA with Sequent, CGC paid the variable costs associated with delivering gas from the ETNG interconnect with Texas Eastern to the citygate. Therefore, the Mt. Pleasant purchases may not technically qualify as citygate purchases. However, as subsequently explained, Exeter finds that excluding the Mt. Pleasant purchases from the PBRM and considering the purchases to be citygate purchases appears to currently be the most appropriate treatment for those purchases.

Including the Mt. Pleasant purchases in the PBRM may not provide for a reasonable assessment of the price CGC paid for these purchases because Mt. Pleasant, which is located in Texas Eastern rate zone M-1, is not a liquid trading location, and there are no index prices published for this location. There are index prices published for other locations in Texas Eastern rate zone M-1; however, these locations are also not very liquid and index prices for these locations are not published on a regular basis. Based on current market pricing and gas flows on the Texas Eastern system, ELA index prices would serve as a reasonable location to determine a PBRM benchmark for Mt. Pleasant purchases. However, to purchase gas supplies in Texas Eastern rate zone ELA, CGC would be required to acquire Texas Eastern firm transportation capacity which provided for the delivery of gas supplies from rate zone ELA to Mt. Pleasant in rate zone M-1. This would increase CGC interstate pipeline capacity costs. Exeter believes that the reasonableness of CGC’s AMA Mt. Pleasant purchases during the review period is best addressed by directly evaluating the ratepayer benefits associated with CGC’s Mt. Pleasant purchases rather than including these purchases in the PBRM. Mt. Pleasant purchases would be necessary to meet design peak day demands of CGC’s customers.

CGC presented the ratepayer benefits associated with its Mt. Pleasant purchase arrangements with Sequent in Attachment D of its 2020, 2021, and 2022 PBRM filings. In its 2020 PBRM filing the Company identified a ratepayer benefit of [redacted] associated with purchasing Mt. Pleasant supplies from Sequent compared to the cost of acquiring Texas Eastern rate zone ELA to rate zone M-1 capacity and purchasing gas supplies at ELA index prices. Attachment D of the 2021 PBRM filing identified the benefit to be [redacted] Attachment D of the 2022 PBRM filing identified the benefit to be [redacted] increase in the benefit for the 2022 PBRM period was attributable to the filing of a base rate case by Texas Eastern at the FERC which increased its firm transportation rates. CGC generally purchased Mt. Pleasant supplies when the delivered prices for its other gas supply commodity options were anticipated to exceed Mt. Pleasant delivered prices. Therefore, Exeter finds that CGC’s audit period Mt. Pleasant purchase arrangements with Sequent provided for a significant ratepayer benefit.

4.0 STORAGE ACTIVITY, OFF-SYSTEM LNG SALES, AND SONAT-EXCLUDED ASSET OFF-SYSTEM 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 FSMA and FSPA 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	MDWQ	Percent of MDWQ
60-100%	14,346	100%
50-59%	12,624	88%
25-49%	11,190	78%
0-24%	8,034	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, and generally increases each year as customer design day demands increase. For the winter of 2021-2022, the maximum production volume was 91,630 Dth per day for 13 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.

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

	TENNESSEE GAS PIPELINE (FSPA)			TENNESSEE GAS PIPELINE (FSMA)				SOUTHERN NATURAL GAS (CSS)[2]				LIQUEFIED NATURAL GAS[3]		
	Chattanooga Gas			Chattanooga Gas			TGP FS-PA/MA	Chattanooga Gas				Chattanooga Gas		
Month	**Activity**	**Inventory**	**% Full**	**Activity**	**Inventory**	**% Full**	**Optimization Inventory**	**Activity**	**Inventory**	**% Full**	**Optimization Inventory**	**Activity**	**Inventory**	**% Full**
April 2019	204,630	461,650	23%	83,790	171,248	20%	177,142	(65,810)	67,765	10%	1	(19,165)	1,125,990	93%
May	214,272	675,922	33%	86,087	257,335	30%	216,782	87,494	155,259	22%	1	53,546	1,179,536	98%
June	207,900	883,822	43%	83,220	340,555	40%	204,984	104,155	259,414	37%	(259)	(18,221)	1,161,315	96%
July	214,830	1,098,652	54%	85,994	426,549	50%	(13,507)	123,825	383,239	54%	(259)	(19,517)	1,141,798	95%
August	214,830	1,313,482	64%	85,994	512,543	60%	(2,067)	119,816	503,055	71%	(20)	(19,351)	1,122,447	93%
September	207,870	1,521,352	74%	83,250	595,793	70%	91,927	108,946	612,001	86%	(20)	(18,522)	1,103,925	91%
October	214,830	1,736,182	85%	85,994	681,787	80%	2,265	32,972	644,973	91%	(20)	(23,115)	1,080,810	90%
November	(156,194)	1,579,988	77%	(44,596)	637,191	75%	214	(45,584)	599,389	84%	(1,516)	46,393	1,127,203	93%
December	(318,391)	1,261,597	62%	(39,719)	597,472	70%	38,977	(9,330)	590,059	83%	78	39,666	1,166,869	97%
January 2020	(293,658)	967,939	47%	(224,489)	372,983	44%	138,626	(206,704)	383,355	54%	1,011	(53,296)	1,113,573	92%
February	(325,746)	642,193	31%	(153,740)	219,243	26%	205,039	(92,896)	290,459	41%	1,011	(44,003)	1,069,569	89%
March	(349,059)	293,134	14%	(102,531)	116,712	14%	237,758	(70,612)	219,847	31%	0	(17,652)	1,051,917	87%
April 2020	201,510	494,644	24%	81,390	198,102	23%	390,282	(36,352)	183,496	26%	26	(16,485)	1,035,432	86%
May	209,157	703,801	34%	81,499	279,601	33%	432,018	79,543	263,038	37%	26	(16,858)	1,018,574	84%
June	202,410	906,211	44%	78,870	358,471	42%	400,558	82,967	346,005	49%	28	(18,042)	1,000,532	83%
July	209,188	1,115,399	55%	81,499	439,970	52%	165,781	117,589	463,594	65%	1,376	(18,788)	981,744	81%
August	209,157	1,324,556	65%	81,499	521,469	61%	404,714	107,750	571,344	80%	2,132	(17,455)	964,289	80%
September	202,440	1,526,996	75%	78,840	600,309	70%	643,151	60,116	631,460	89%	2,367	217,492	1,181,781	98%
October	209,039	1,736,035	85%	81,596	681,905	80%	93,850	(4,246)	627,214	88%	1,012	(15,683)	1,166,098	97%
November	(110,772)	1,625,263	80%	(43,494)	638,411	75%	107,438	(74,812)	552,402	78%	1,012	(43,377)	1,122,721	93%
December	(258,343)	1,366,920	67%	(99,367)	539,044	63%	140,297	(58,760)	493,642	69%	70	(48,356)	1,074,365	89%
January 2021	(363,176)	1,003,744	49%	(192,406)	346,638	41%	113,501	(59,031)	434,611	61%	70	(27,579)	1,046,786	87%
February	(492,092)	511,652	25%	(171,176)	175,462	21%	137,091	(71,167)	363,444	51%	70	(171,076)	875,710	73%
March	(311,617)	200,035	10%	(134,900)	40,562	5%	121,013	(196,185)	167,259	24%	4,613	53,578	929,289	77%
April 2021	215,730	415,765	20%	90,000	130,562	15%	116,301	(22,645)	144,614	20%	4,613	195,092	1,124,381	93%
May	222,425	638,190	31%	92,876	223,438	26%	206,861	98,942	243,556	34%	4,613	47,777	1,172,158	97%
June	215,250	853,440	42%	89,880	313,318	37%	203,246	105,248	348,804	49%	4,573	(18,295)	1,153,863	96%
July	222,456	1,075,896	53%	92,907	406,225	48%	265,404	96,439	445,243	63%	(712)	(19,639)	1,134,224	94%
August	222,425	1,298,321	64%	92,876	499,101	59%	127,201	104,865	550,108	77%	(3,368)	(19,289)	1,114,935	92%
September	215,280	1,513,601	74%	89,910	589,011	69%	(424)	93,059	643,167	91%	2	(17,245)	1,097,690	91%
October	222,425	1,736,026	85%	92,876	681,887	80%	1,687	201	643,368	91%	4	87,065	1,184,755	98%
November	(102,077)	1,633,949	80%	(21,069)	660,818	78%	812	(31,589)	611,779	86%	4	(24,974)	1,159,781	96%
December	(180,034)	1,453,915	71%	(91,717)	569,101	67%	6,928	(145,875)	465,904	66%	4	(29,194)	1,130,587	94%
January 2022	(383,056)	1,070,859	52%	(213,894)	355,207	42%	1,698	(115,744)	350,160	49%	0	(129,501)	1,001,086	83%
February	(330,977)	739,882	36%	(176,134)	179,073	21%	46,659	(158,396)	191,764	27%	10	(64,721)	936,365	78%
March	(401,957)	337,925	17%	(136,390)	42,683	5%	326,546	(83,255)	108,509	15%	20	151,561	1,087,926	90%
Maximum Seasonal Inventory:		**2,042,390**			**852,286**				**710,484**				**1,207,574**	

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

Table 6 also shows CGC's storage inventory balances as a percent of the Company's maximum seasonal contract quantity or capacity. Under the AMA, 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.

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 FSPA and FSMA 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. 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 with 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 subsequently discussed in Section 4.4.

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

	April 1		November 1	
	Planned	**Actual**	**Planned**	**Actual**
2019				
SONAT CCS	10%	19%	90%	91%
TGP FSPA	10	13	85	85
TGP FSMA	5	10	80	80
LNG	76	95	100	90
2020				
SONAT CCS	10%	31%	90%	88%
TGP FSPA	10	14	85	85
TGP FSMA	5	14	80	80
LNG	76	87	100	97
2021				
SONAT CCS	10%	24%	90%	91%
TGP FSPA	10	10	85	85
TGP FSMA	5	5	80	80
LNG	76	77	100	98
2022				
SONAT CCS	10%	15%		
TGP FSPA	10	17		
TGP FSMA	5	5		
LNG	76	90		

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 76% 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 (November 1) during the review period, CGC's contract and LNG storage was generally refilled to planned levels. With the exception of SONAT CSS, storage was also generally depleted to planned inventory levels at the conclusion of each heating season (March 31) during the review period. However, the quantity differences between planned and actual SONAT CSS inventory balances were not significant. 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 Zone 0 FSPA		TGP Zone 0 FSMA		TGP Zone L 800 Leg FSPA		TGP Zone L 800 Leg FSMA	
Month/Year	**Quantity**	**Price**	**Quantity**	**Price**	**Quantity**	**Price**	**Quantity**	**Price**
May 2019	51,987	$2.55	0	$0.00	0	$0.00	0	$0.00
July	138,198	2.24	49,042	2.24	0	0.00	0	0.00
October	43,834	2.30	45,880	2.30	0	0.00	0	0.00
April 2020	38,700	$1.56	54,690	$1.56	0	$0.00	0	$0.00
May	13,671	1.76	4,650	1.76	0	0.00	0	0.00
June	141,810	1.66	62,640	1.65	0	0.00	0	0.00
July	187,705	1.43	77,810	1.43	0	0.00	0	0.00
August	90,427	1.84	51,553	1.84	0	0.00	0	0.00
September	139,770	2.54	63,720	2.54	0	0.00	0	0.00
October	209,157	2.03	81,499	2.02	0	0.00	0	0.00
June 2021	0	$0.00	0	$0.00	111,990	$2.96	42,000	$2.97
July	143,902	3.60	55,986	3.60	0	0.00	0	0.00
August	99,727	3.99	39,649	3.99	0	0.00	0	0.00
September	88,740	4.34	38,460	4.34	0	0.00	0	0.00
December	4,724	5.48	0	0.00	0	0.00	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 under Rate Schedule FT-NN.

4.4 Off-System LNG Sales

Prior to August 2018, CGC engaged in off-system LNG tanker sales through Pivotal LNG, Inc. (Pivotal), a former affiliate of CGC. Pivotal was 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.

[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.

[redacted]. In March 2020, Pivotal was acquired from Southern Company by Dominion Energy, a power and energy company headquartered in Richmond, Virginia. CGC did not engage in off-system LNG tanker sales during the audit period.

In the prior PBRM report prepared by Exeter for the period June 2016 – March 2019, which was filed in June 2020, Exeter recommended that in its next AMA RFP, CGC include provisions in the RFP that would provide the Asset Manager the ability to engage in off-system LNG tanker and displacement optimization sales. In Docket No. 21-00069, the Company filed a petition with the Commission on June 14, 2021 for approval of the RFP to be issued to secure its next Asset Manager under an AMA upon expiration of the then effective AMA with Sequent which was scheduled to expire on March 31, 2022. In its petition in Docket No. 21-00069, CGC claimed that as customer demand for natural gas continues to grow and upstream resources become further limited and constrained, the Company increasingly relies on the firm deliverability and inventory of its on-system LNG facilities. The Company believed the operational risk of LNG inventory being unavailable to meet customer demand because it was used by the Asset Manager to make off-system LNG tanker and displacement sales to be too great for the Company to allow the LNG assets to be made available to an Asset Manager for optimization under an AMA. Therefore, the Company did not include the off-system LNG sales provisions recommended in Exeter's prior PBRM report. In its Order in Docket No. 21-00069, the Commission agreed with CGC's position not to include the optimization of the Company's LNG facility in its next AMA RFP.

4.5 SONAT Off-System Sales

Under the audit period AMA with Sequent, and the prior AMA with Sequent which was in effect for the period April 1, 2015 – March 31, 2018, 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. Under the prior AMA, CGC designated Sequent as its agent to optimize the SONAT Excluded Assets, and Sequent used the unneeded Excluded Assets to engage in off-system sales. 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. During months in which margins were realized under the prior AMA, Sequent realized an average of [redacted] in off-system sales margins which were shared 50% with CGC's sales customers under the IMCR. 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. Therefore, no off-system sales margins utilizing the SONAT Excluded Assets were realized during the audit period.

In the PBRM report prepared by Exeter for the period June 2016 – March 2019, Exeter recommended that to eliminate uncertainty, CGC should revise its next AMA RFP to provide that the Asset Manager would be designated the agent to optimize the SONAT Excluded Assets when not needed by CGC for its on-system requirements, and to include a three-year history of Excluded Asset availability. In the RFP filed for Commission approval in Docket No. 21-00069, CGC revised the language in its AMA to remove the option to select a third party or designate the Asset Manager to be its agent for the purpose of optimizing the Excluded Assets to only allow the Asset Manager to optimize the Excluded Assets. This revised language was approved by the Commission. CGC did not include a three-year history of daily Excluded Asset availability in the proposed RFP, as the Company claimed it had not retained the information which would allow it to retrospectively determine whether the Excluded Assets could have been made available if requested. In lieu of providing potential AMA bidders with Excluded Asset availability, CGC proposed to provide three years of daily customer demands, three years of historical daily storage usage, three years of historical interstate pipeline transportation usage, and the Company's annual summer storage injection and winter storage withdrawal plans. In its Order in Docket No. 21-00069, the Commission found CGC's proposal to include the alternative daily data and storage plans reasonable, and approved CGC's proposed RFP.

4.6 Mutual Aid Assistance

Atlanta Gas Light Company, an affiliate, provided mutual aid to CGC after tornadoes struck the Company's service territory in April 2020, and in October 2020 in conjunction with the repair of an 8-inch distribution main. This aid was provided at cost in accordance with the Southern Company Gas affiliate transaction rules. During the wildfires in Boulder, Colorado in January 2022, CGC sent employees with the Southern Company Gas team to Xcel Energy. The mutual aid received by and provided by CGC during the audit period had no direct impact on the Company's gas costs.

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 75 years, there have been seven occurrences where temperatures of 8°F or colder have been experienced. This equates to a design day probability of occurrence of approximately once every 10 years. Temperatures as cold as or colder than CGC's current design day have been observed as follows:

Year	Mean Temperature
1985	-5°F
1966	1°F
1984	3°F
1982	4°F
1963	5°F
1962	8°F
1996	8°F

The one-in-10-year probability of occurrence design day criteria selected by CGC is within the range of probabilities utilized by other gas distribution utilities, but is somewhat less conservative than the criteria typically utilized. It is Exeter's experience that other gas utilities typically utilize a design day probability of occurrence of once in 30 years. For CGC, this would equate to a design day criteria of 3°F.

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; prior seven-day average HDDs; wind speed; indicators for Friday, Saturday, and Sunday; variables to account for Christmas Eve, Christmas Day, the day after Christmas, and New Year's 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 2020-2021 and 2021-2022, each based on data from the prior five winter seasons and the design day criteria of 8°F, is summarized below in Table 9. Utilizing a design day criteria of 3°F would have increased CGC's forecasted design day requirements for the winter of 2021-2022 by an estimated 5,275 Dth, to approximately 157,100 Dth.

Table 9. CHATTANOOGA GAS COMPANY – Summary of Design Peak Day Requirements (Dth)

Description	Chattanooga	Cleveland	Total
Winter 2020-2021			
Sales	111,550	15,301	**126,852**
Transport Firm Backup	20,417	1,858	**22,275**
Load Additions	249	0	**249**
Total:	**132,217**	**17,160**	**149,376**
Winter 2021-2022			
Sales	112,385	15,863	**128,248**
Transport Firm Backup	20,638	2,064	**22,702**
Load Additions	433	445	**878**
Total:	**133,456**	**18,372**	**151,828**

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 forecasts are trend variables that account for changes in customer usage per HDD due to energy conservation or other factors. CGC's design day analysis found that customer usage per HDD is increasing slightly, offsetting any customer energy efficiency or conservation efforts. For the Chattanooga service territory, the annual increase was approximately 0.5%, and for the Cleveland service territory, the annual increase was approximately 1.3%. Gas utilities in other jurisdictions that evaluate the impact of energy efficiency and customer conservation efforts have found that customer energy efficiency and conservation efforts reduce design day demands by less than 1% per year.

5.2 Actual Peak Day Demands

Table 10, below, summarizes the total requirements of CGC's sales and transportation customers on the actual peak day observed during each winter season of the review period.

The peak day requirements of sales and transportation customers are not available by service territory. 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 3% of actual demands. This supports the reasonableness of the Company's models.

Table 10. CHATTANOOGA GAS COMPANY – Summary of Actual Firm Peak Day Sendout (Dth)

	2020	2021	2022
	Peak Day: January 20 **HDD: 37.0**	**Peak Day: February 16** **HDD: 41.2**	**Peak Day: January 21** **HDD: 34.4**
Chattanooga			
Sales	70,275	78,352	65,031
Transport	26,074	24,291	23,395
Total:	**96,349**	**102,643**	**88,426**
Cleveland			
Sales	10,851	11,084	9,587
Transport	3,783	4,292	4,421
Total:	**14,634**	**15,376**	**14,008**
Company Total			
Sales	81,126	89,436	74,618
Transport	29,857	28,583	27,816
Total:	**110,983**	**118,019**	**102,434**

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 2021-2022 winter season totaled 203,648 Dth. For the winter of 2021-2022, as shown previously in Table 9, projected design day requirements were 151,828 Dth. CGC has historically attempted to maintain a capacity reserve margin of approximately 5%, which Exeter did not find unreasonable in prior audits. Exeter's most recent prior audit report found that the reserve margin maintained by CGC at the conclusion of the winter of 2019-2020 was 8%, which Exeter also did not find unreasonable. The actual reserve margin maintained by CGC for the 2020-2021 winter season was 20%. This increase in the reserve margin was due to several factors, including (1) slight reductions to the projected design day requirements of sales customers; and (2) the elimination of certain distribution system constraints which limited the flow of LNG into CGC's distribution system and, therefore, increased the availability of LNG to meet design day requirements. By the conclusion of the winter of 2021-2022, the reserve margin increased to approximately 35%. This increase in the reserve margin was primarily attributable to the incremental acquisition of 25,000 Dth per day of ETNG firm transportation capacity effective February 1, 2022, which was previously discussed in Section 2.1.2 of the Report. Effective January 31, 2022, OPC's firm transportation contract with ETNG expired, as did CGC's capacity release arrangement with OPC for 25,000 Dth per day. Effective February 1, 2022, CGC acquired the 50,000 Dth per day of firm transportation capacity that OPC had maintained with ETNG through an open season under which the capacity was awarded to the bidder offering the highest net present value for the capacity. Had CGC not increased its ETNG firm transportation capacity by 25,000 Dth per day, its reserve margin would have been approximately 20% for the winter of 2021-2022, which is approximately 19,200 Dth per day more than required to maintain a 5% capacity reserve margin.

However, if CGC had not acquired the additional 50,000 Dth per day, the capacity available to meet design day requirements would have been reduced by 23,000 Dth per day due to the expiration of the capacity release arrangement with OPC. Had the capacity made available under the capacity release arrangement with OPC not been replaced, CGC would not have maintained sufficient capacity resources to meet its customers' forecasted design day requirements for the winter of 2021-2022 and a 5% reserve margin. The design day delivery shortfall would have been nearly 4,000 Dth per day, and would have increased by each year by approximately 1,000 to 2,000 Dth per day due to load growth. There is currently no unsubscribed capacity available on ETNG and, therefore, if the OPC capacity had not been available and CGC sought to increase its ETNG firm transportation capacity to eliminate the design day deficiency, ETNG would have been required to construct incremental facilities to meet CGC's additional requirements. The rates charged to CGC for the incremental facilities would have reflected the costs associated with the construction of those facilities, and CGC would not have been assessed ETNG's existing firm transportation rates. Furthermore, as described in Section 2.1.5, the additional FT capacity allows CGC to return the LNG facility to its design deliverability and provides CGC the ability to serve future growth.

ETNG currently provides firm transportation under several rate schedules where incremental facilities were constructed to provide service. Those incremental rate schedules are identified in ETNG's tariff as FT-A (Gateway), FT-A (Wacker), FT-A (Kingsport), and FT-A (Loudon). The rates for those services are nearly twice ETNG's current rates for non-incremental facility transportation service.

ETNG is currently proposing a new incremental project to increase its pipeline capacity. This project is referred to as the Ridgeline Expansion Project (FERC Docket No. PF22-7-000). It is anticipated that it will take five years from the date ETNG files for FERC authorization for the project until project completion. The rates for service under the Ridgeline Expansion Project are not currently known, but are likely to be higher than the rates under ETNG's existing incremental services because the length of the pipeline facilities being proposed is significantly greater than the length of ETNG's previous incremental projects. The length of the pipeline installed under each of ETNG's previous incremental projects was 10 miles or less. The length of the pipeline being installed under the Ridgeline Expansion Project is 117 miles.

In order to ensure it was awarded the 50,000 Dth per day of capacity made available through ETNG's open season, CGC was required to offer the bid with the highest net present value. CGC's offer to pay ETNG's maximum non-incremental FERC-approved rates for 30 years was successful in acquiring the capacity. Had CGC not been successful, the construction of incremental facilities would have been required in order for CGC to meet its customers' future design day requirements, and the rates for service under the incremental capacity would have likely been at least twice ETNG's current maximum rates for non-incremental service, which CGC was paying for the OPC-released capacity. Therefore, by acquiring the 50,000 Dth per day of capacity through ETNG's open season, CGC was paying for 25,000 Dth of incremental service, which after adjustment for the release of 2,000 Dth per day of that capacity to Jat Oil, CGC is in effect paying for 24,000 Dth per day of incremental capacity (50,000 Dth – 2,000 Dth released to Jat Oil at rates twice that of ETNG's standard maximum rates for FT-A service). Given CGC's options at the time, the costs associated with those options, the anticipated increasing design day demands of its customers, and a likely five year time estimate to place new facilities in service, Exeter finds CGC's acquisition of the 50,000 Dth per day of ETNG firm transportation capacity through an open season to be appropriate and reasonable, and the only practical option available to CGC.

The overall 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 7 and Figure 8 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 winter HDDs are 25% 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 7 and Figure 8 also include purchases made for storage injection.[8]

[8] 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 7. CHATTANOOGA GAS COMPANY – Load Duration Curve – Chattanooga Service Territory 2021-2022 Winter Season

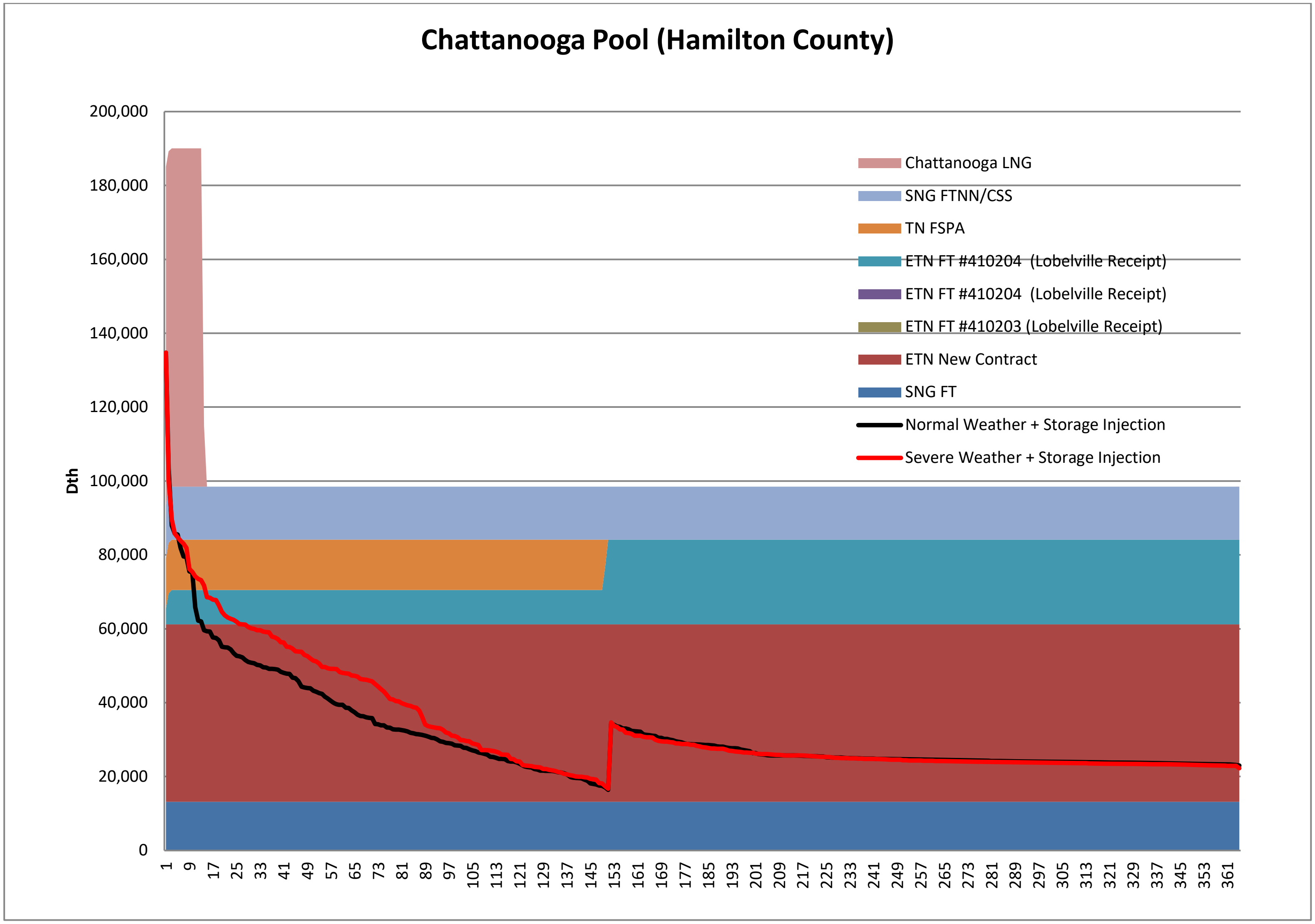

Figure 8. CHATTANOOGA GAS COMPANY – Load Duration Curve – Cleveland Service Territory 2021-2022 Winter Season

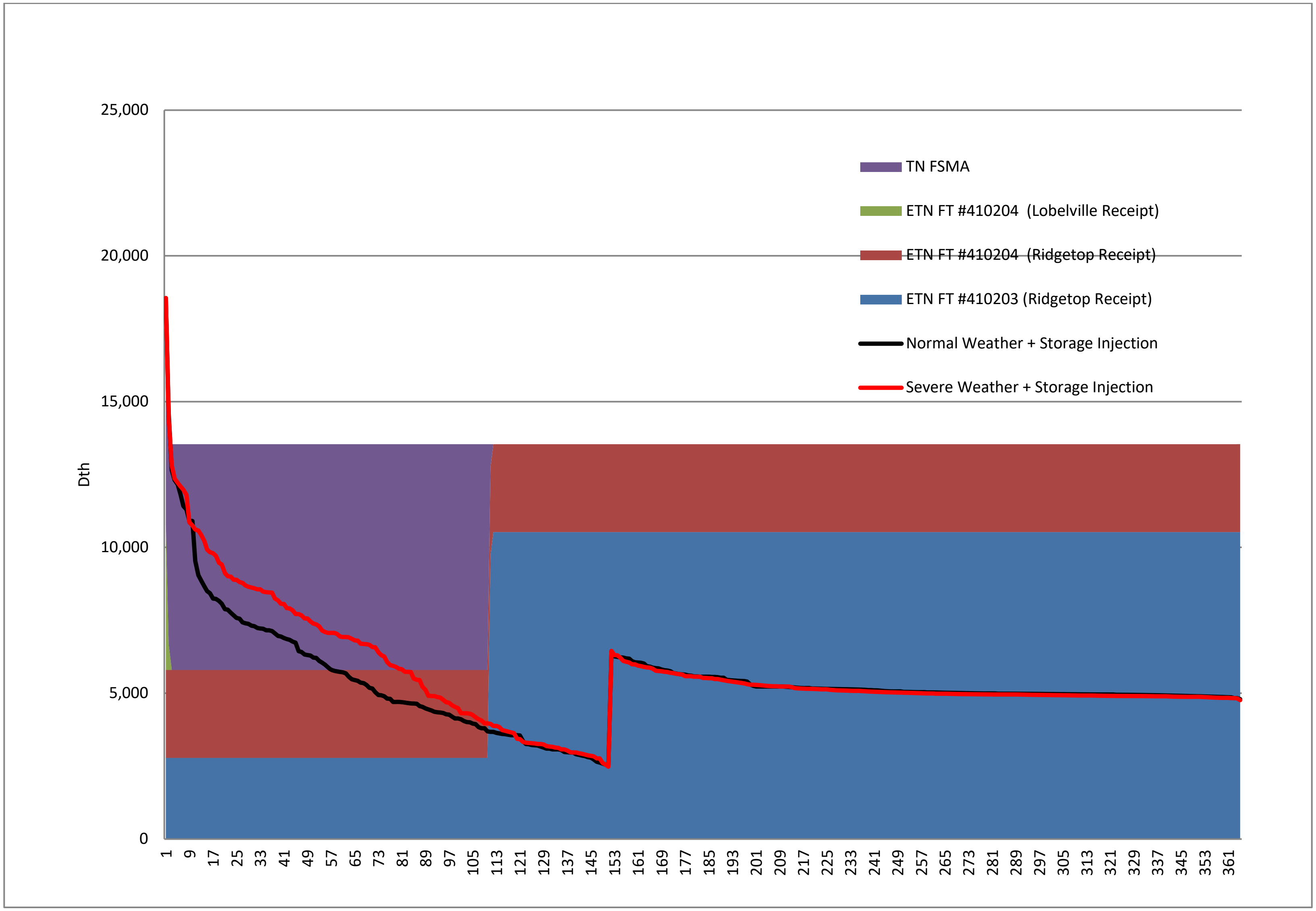

Figure 7 and Figure 8 reveal that under severe weather conditions, as noted by the capacity resources identified above severe weather load, CGC maintains capacity resources significantly in excess of its requirements.[9] As indicated previously in this section of the Report, CGC currently maintains a 35% capacity reserve margin. That is, CGC's design day capacity resources currently exceed anticipated design day requirements, inclusive of a 5% reserve margin, by nearly 45,000 Dth. CGC's total load requirements during a winter in which severe weather conditions are experienced is projected to be 7,550,000 Dth. As shown previously in Table 1, CGC's winter season capacity resources total 18,122,000 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 9,280,000 Dth, plus approximately 4,800,000 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 42,094,000 Dth, or more than four times the anticipated annual requirements. These figures include the higher LNG deliverability of 91,630 Dth. CGC has returned the LNG facility back to its intended design deliverability of 60,000 Dth/day, which results in a reserve margin of approximately 13%, or 20,000 Dth. 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 11. As shown, these charges currently total nearly $15.5 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 relying 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.

[9] Figure 8 indicates that the design day requirements and the resources available to meet those requirements are in balance. However, CGC's design day interstate pipeline capacity resources can generally serve either the Chattanooga or Cleveland service territory, and overall, CGC's design day capacity resources significantly exceed design day requirements.

Table 11. 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	$7.8016	$3,540,585
ETNG			
FT-A (410203)	13,000	$8.35	$1,302,600
FT-A (410204)	28,350	$8.35	$2,349,790
FT-A (661664)	48,000	$8.35	$4,809,600
SONAT			
FT (456076-FTSNG)	13,221	$10.46	$1,659,500
FT-NN (1450814-FTSNG)	14,346	$10.46	$1,800,710
Total:			**$15,462,785**

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. Although Exeter has found that CGC's winter and annual capacity resources significantly exceed its requirements, exclusive of the incremental acquisition of 25,000 Dth per day of ETNG firm transportation capacity effective February 1, 2022 which Exeter found to be reasonable, CGC's excess capacity resources are relatively consistent with those of other gas utilities without options to obtain peaking supply services and winter seasonal services.

6.0 FINDINGS OF FACT AND AREAS OF CONCERN

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

- Chattanooga Gas Company contracted for firm transportation and storage 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 an Asset Management and Agency Agreement with Sequent Energy Management, which was an affiliate of CGC until July 1, 2021, that was approved by the Tennessee Public Utility Commission.
- At the conclusion of the review period, CGC served nearly 69,800 sales and transportation customers with annual throughput of approximately 15,000,000 Dth.
- CGC's interstate pipeline capacity firm transportation and storage service arrangements during the review period were reasonable, and CGC's acquisition of 50,000 Dth per day of ETNG firm transportation capacity through an open season was appropriate and reasonable.
- CGC's storage inventory planning criteria were reasonable, CGC generally adhered to those criteria, and CGC's review period storage activity was reasonable.
- CGC engaged in no off-system sales activities during the review period.
- The one-in-10-year probability of occurrence 8°F design day mean day temperature criteria selected by CGC is within the range of probabilities utilized by other gas distribution utilities, but is somewhat less conservative than the criteria typically utilized. However, the current capacity reserve margin of 35% maintained by CGC as a result of its incremental acquisition of 50,000 Dth of ETNG firm transportation capacity will ensure that CGC will be able to provide firm service to its sales customers in the event that temperatures colder than CGC's design day criteria are experienced.
- CGC's review period forecasts of design day demands were reasonable and evaluated the potential impact of customer conservation efforts.
- 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, 2019, June 30, 2020, and June 30, 2021 did not exceed benchmark costs by 1%.

- CGC's treatment of Mt. Pleasant purchases as citygate purchases and the exclusion of those purchases from the PBRM was reasonable, and CGC's audit period Mt. Pleasant purchase arrangements with Sequent provided for a significant ratepayer benefit.

- Exeter's prior audit found that CGC had been improperly billed twice for the variable ETNG transportation charges incurred to deliver Mt. Pleasant supplies to its citygate—once by Sequent and once by ETNG. CGC included a credit to sales customers to reflect the improper charges in its 2020 ACA filing.

Exeter's audit noted no areas of concern with the Performance Based Ratemaking Mechanism during the review period.

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 Commission or (b) modified, amended or terminated by the Commission.

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 gas cost amount. The benchmark gas cost amount will be computed by multiplying actual quantities purchased during the month, by the applicable benchmark price. All purchases shall be included in the actual commodity cost and benchmark gas cost calculations, including quantities purchased for injection into storage; however, supply purchased at the NORA receipt point with a term of one month or greater and supply purchased at the citygate, shall be excluded from these calculations and reported separately from, but in conjunction with the Company's annual PBRM filing.

First-of-the-Month (FOM) Purchases:

The benchmark price shall be the FOM index price as published in S&P Global *Gas Daily Price Guide* in the table titled "Monthly Bidweek Spot Gas Prices," denoted in the column labeled "Index" and the row for the applicable "purchase locations."

Daily Priced Purchases

The benchmark price shall be the daily index price as published in the issue of S&P Global *Gas Daily* for the applicable gas day in the table title "Final Daily Price Survey-Platts Locations" denoted in the column labeled "Midpoint" and the row for the applicable purchase location. In the event a pricing point location's daily benchmark price is not published for a gas day, the benchmark price shall be the daily index price published for that purchase location for the nearest subsequent gas day.

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 Public Utility Commission'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 Commission fully explaining why the cost exceeded the benchmark.

FILING WITH THE COMMISSION

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 Commission 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 Commission. Unless the Commission provides written notice to Chattanooga within 30 days of the Company's notice to the Commission, 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-BASEDRATEMAKING
(Continued)

Standards of Conduct

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

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

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

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

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

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

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

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

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

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

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

1. In each instance in which Chattanooga Gas Company (Company) intends to engage the services of an asset manager to provide system gas supply requirements and/or manage its assets regulated by the Tennessee Public Utility Commission (TPUC), 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 of five (5) days through a systematic notification process that includes, the publication in trade journals as reasonably available.

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

PERFORMANCE-BASEDRATEMAKING
(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 TPUC 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.

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 TPUC 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 TPUC 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
April 2019	35,100	$ 2.6200	0	$0.0000	0	$ 2.6500	0	$0.0000	0	$ 2.6100	251,331	$ 2.5151	6,270	$ 2.6500	0	$0.0000
May	32,550	2.4400	0	0.0000	0	2.5000	0	0.0000	102,021	2.4600	131,718	2.4483	6,479	2.5000	0	0.0000
June	0	2.5100	20,137	2.1810	0	2.5600	5,916	2.2300	0	2.5200	80,167	2.2395	6,270	2.5700	0	0.0000
July	0	2.1400	30,201	2.1195	0	2.2000	0	0.0000	0	0.0000	59,911	2.2718	6,479	2.2100	18,392	2.2493
August	0	1.9400	25,809	1.9982	0	2.0600	0	0.0000	0	0.0000	82,517	2.0711	6,479	2.0800	26,777	2.1358
September	0	2.0500	17,910	2.3701	0	2.1900	0	0.0000	0	0.0000	109,803	2.3581	0	2.1900	31,350	2.5005
October	32,085	2.2000	0	0.0000	0	2.3800	0	0.0000	63,767	2.2300	152,312	2.1248	0	2.3700	21,609	2.2352
November	287,580	2.4000	40,608	2.4413	0	2.5400	0	0.0000	0	2.4700	280,929	2.4868	6,180	2.5500	147,444	2.6573
December	264,895	2.3000	22,905	2.0961	0	2.4100	0	0.0000	0	2.3500	57,520	2.1630	6,386	2.4100	145,365	2.2290
January 2020	0	2.0000	99,810	1.8617	0	2.0800	0	0.0000	0	2.0400	131,288	1.8426	6,386	2.1000	95,009	1.9353
February	0	1.7600	77,630	1.8257	0	1.8000	0	0.0000	0	1.7600	297,451	1.7763	5,974	1.8100	187,656	1.8300
March	0	1.6900	78,878	1.6119	0	1.7500	0	0.0000	0	1.7100	7,371	1.7150	6,386	1.7600	7,206	1.7850
April 2020	24,780	$ 1.5000	14,404	$1.6073	0	$1.5700	0	$0.0000	0	$ 1.5400	296,434	$ 1.6101	6,210	$ 1.5700	22,041	$1.6942
May	0	1.6900	34,440	1.5946	0	1.7300	3,194	1.6400	0	1.7100	189,090	1.7064	6,417	1.7400	14,904	1.7219
June	0	1.5900	24,395	1.5097	0	1.6500	14,362	1.4600	0	1.6500	140,177	1.5161	6,210	1.6500	0	0.0000
July	0	1.3700	18,642	1.6293	0	1.4200	0	0.0000	0	1.4000	143,902	1.6901	6,417	1.4400	0	0.0000
August	0	1.7700	14,350	2.1240	0	1.8000	0	0.0000	0	1.7800	172,056	2.1169	6,417	1.8100	0	0.0000
September	0	2.4500	1,435	2.0450	0	2.5000	13,908	1.8900	0	2.4700	304,599	1.7332	6,210	2.5100	79,697	1.8532
October	0	1.9500	0	0.0000	0	1.9900	51,049	2.3097	0	1.8900	179,181	2.1606	6,479	2.0200	0	0.0000
November	0	2.8400	43,935	2.1236	0	2.8500	0	0.0000	326,021	2.8500	0	0.0000	6,270	2.8900	27,190	2.9750
December	0	2.7500	7,613	2.5900	0	2.7700	51,285	2.6046	314,185	2.7700	46,189	2.5242	6,479	2.8000	127,808	2.5720
January 2021	323,888	2.3500	8,102	2.5962	0	2.3900	0	0.0000	0	2.3900	110,104	2.6021	6,479	2.4200	236,136	2.6744
February	0	2.6800	56,320	2.8940	0	2.6900	96,156	7.3667	0	2.6900	182,770	4.7793	5,852	2.7100	241,000	5.5385
March	0	2.7800	105,848	2.4533	0	2.7900	0	0.0000	0	2.7700	154,195	2.3891	6,479	2.8200	0	0.0000
April 2021	0	$ 2.4400	82,061	$2.3966	0	$2.5200	0	$0.0000	154,020	$ 2.4800	421,369	$ 2.5439	6,330	$ 2.5300	119,313	$2.5341
May	23,653	2.8500	0	0.0000	0	2.8500	0	0.0000	37,231	2.8300	319,754	2.7774	6,541	2.8700	0	0.0000
June	0	2.8500	100,559	3.1134	0	2.9100	35,113	3.1203	0	0.0000	147,616	3.1203	6,330	2.9200	0	0.0000
July	0	3.4700	10,654	3.6107	0	3.5200	13,220	3.5950	0	3.5000	220,692	3.6495	6,541	3.5400	0	0.0000
August	0	3.8500	6,867	3.8589	0	3.9300	21,619	4.1847	0	3.8900	231,002	3.8994	6,541	3.9500	0	0.0000
September	0	4.1900	9,893	4.9400	0	4.3000	26,284	4.5750	0	4.2500	215,477	4.9733	6,330	4.2900	0	0.0000
October	0	5.5500	20,314	5.2024	0	5.7700	136,632	5.2684	0	5.7400	339,179	5.3601	6,386	5.7800	13,310	4.9640
November	337,890	6.0300	0	0.0000	0	6.1600	19,041	4.8890	10,080	6.1300	447,009	4.9636	6,180	6.1500	167,712	4.9103
December	278,120	5.2800	9,716	3.5618	0	5.3700	6,237	3.6550	0	5.3900	84,061	3.7020	6,386	5.4400	58,614	3.8038
January 2022	280,560	3.9900	51,597	4.0580	0	3.9700	23,535	3.5628	0	3.9600	136,574	4.1634	6,386	4.0200	501,532	4.1689
February	0	6.1700	159,116	4.0136	0	6.2500	0	0.0000	0	6.2100	164,636	4.7224	5,768	6.2800	208,480	4.6342
March	0	4.2900	248,806	4.5496	0	4.4800	52,764	5.2457	0	4.4600	58,087	4.7193	6,386	4.4900	91,749	4.7679
Total	1,921,101		1,442,955		0		570,315		1,007,325		6,346,471		215,313		2,590,294	

APPENDIX B

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

	TEXAS EASTERN						TGP ZONE 0 FSPA IN GROUND				TGP ZONE 0 FSMA IN GROUND			
	MONTHLY		DAILY NO BOUNCE		DAILY BOUNCE		MONTHLY		DAILY		MONTHLY		DAILY	
	Quantity	Benchmark	Quantity	Benchmark	Quantity	Benchmark	Quantity	Benchmark	Quantity	Benchmark	Quantity	Benchmark	Quantity	Benchmark
April 2019	0	$0.0000	10,696	$2.6286	0	$0.0000	0	$2.7471	0	$0.0000	0	$ 2.7485	0	$0.0000
May	0	0.0000	0	0.0000	0	0.0000	51,987	2.5607	0	0.0000	0	2.5621	0	0.0000
June	0	0.0000	30,598	2.3378	0	0.0000	0	2.6332	0	0.0000	0	2.6346	0	0.0000
July	0	0.0000	0	0.0000	0	0.0000	138,198	2.2501	0	0.0000	49,042	2.2515	0	0.0000
August	0	0.0000	0	0.0000	0	0.0000	0	2.0430	0	0.0000	0	0.0000	0	0.0000
September	0	0.0000	0	0.0000	0	0.0000	0	2.1569	0	0.0000	0	0.0000	0	0.0000
October	0	0.0000	0	0.0000	0	0.0000	43,834	2.3122	0	0.0000	45,880	2.3136	0	0.0000
November	0	0.0000	0	0.0000	0	0.0000	0	2.5193	0	0.0000	0	2.5207	0	0.0000
December	0	0.0000	0	0.0000	0	0.0000	0	2.4158	0	0.0000	0	2.4172	0	0.0000
January 2020	0	0.0000	0	0.0000	0	0.0000	0	2.1051	0	0.0000	0	2.1065	0	0.0000
February	0	0.0000	0	0.0000	0	0.0000	0	1.8566	0	0.0000	0	1.8580	0	0.0000
March	0	0.0000	0	0.0000	0	0.0000	0	1.7841	0	0.0000	0	1.7855	0	0.0000
April 2020	0	$0.0000	0	$0.0000	0	$0.0000	38,700	$1.5733	0	$0.0000	54,690	$ 1.5747	0	$0.0000
May	0	0.0000	0	0.0000	0	0.0000	13,671	1.7690	0	0.0000	4,650	1.7704	0	0.0000
June	0	0.0000	0	0.0000	0	0.0000	141,810	1.6660	0	0.0000	62,640	1.6674	0	0.0000
July	0	0.0000	0	0.0000	0	0.0000	187,705	1.4394	0	0.0000	77,810	1.4408	0	0.0000
August	0	0.0000	0	0.0000	0	0.0000	90,427	1.8513	0	0.0000	51,553	1.8527	0	0.0000
September	0	0.0000	0	0.0000	0	0.0000	139,770	2.5516	0	0.0000	63,720	2.5530	0	0.0000
October	0	0.0000	0	0.0000	0	0.0000	209,157	2.0366	0	0.0000	81,499	2.0380	0	0.0000
November	0	0.0000	0	0.0000	0	0.0000	0	2.9540	0	0.0000	0	2.9554	0	0.0000
December	0	0.0000	0	0.0000	0	0.0000	0	2.8613	0	0.0000	0	2.8627	0	0.0000
January 2021	0	0.0000	0	0.0000	0	0.0000	0	2.4494	0	0.0000	0	2.4508	0	0.0000
February	0	0.0000	0	0.0000	0	0.0000	0	2.7892	0	0.0000	0	2.7906	0	0.0000
March	0	0.0000	0	0.0000	0	0.0000	0	2.8922	0	0.0000	0	2.8936	0	0.0000
April 2021	0	$0.0000	0	$0.0000	0	$0.0000	0	$2.5489	0	$0.0000	0	$ 2.5503	0	$0.0000
May	0	0.0000	0	0.0000	0	0.0000	0	2.9722	0	0.0000	0	2.9736	0	0.0000
June	0	0.0000	0	0.0000	0	0.0000	0	2.9722	0	0.0000	0	2.9736	0	0.0000
July	0	0.0000	0	0.0000	0	0.0000	143,902	3.6123	0	0.0000	55,986	3.6137	0	0.0000
August	0	0.0000	0	0.0000	0	0.0000	99,727	4.0046	0	0.0000	39,649	4.9960	0	0.0000
September	0	0.0000	0	0.0000	0	0.0000	88,740	4.3556	0	0.0000	38,460	4.3570	0	0.0000
October	0	0.0000	0	0.0000	0	0.0000		5.7597	0	0.0000	0	5.7611	0	0.0000
November	0	0.0000	0	0.0000	0	0.0000		6.2555	0	0.0000	0	6.2569	0	0.0000
December	0	0.0000	0	0.0000	0	0.0000	4,724	5.4813	0	0.0000	0	5.4827	0	0.0000
January 2022	0	0.0000	0	0.0000	0	0.0000		4.1495	0	0.0000	0	4.1509	0	0.0000
February	0	0.0000	0	0.0000	0	0.0000		6.4001	0	0.0000	0	6.4015	0	0.0000
March	0	0.0000	0	0.0000	0	0.0000		4.4592	0	0.0000	0	4.4606	0	0.0000
Total	0		41,294		0		1,392,352		0		625,579		0	

APPENDIX B

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

	TGP ZONE 0 FSPA TO STORAGE				TGP ZONE 0 FSMA TO STORAGE				SONAT TO STORAGE				TGP ZONE 0/1 800 LEG FSPA IN GROUND			
	MONTHLY		DAILY		MONTHLY		DAILY		MONTHLY		DAILY		MONTHLY		DAILY	
	Quantity	Benchmark	Quantity	Benchmark	Quantity	Benchmark	Quantity	Benchmark	Quantity	Benchmark	Quantity	Benchmark	Quantity	Benchmark	Quantity	Benchmark
April 2019	211,890	$2.6200	0	$0.0000	86,760	$2.6200	0	$0.0000	0	$2.7573	0	$0.0000	0	$2.7157	0	$0.0000
May	168,051	2.4400	0	0.0000	89,125	2.4400	0	0.0000	0	2.6034	126,858	2.5889	0	2.5611	0	0.0000
June	215,280	2.5100	0	0.0000	86,160	2.5100	0	0.0000	0	2.6752	138,872	2.3136	0	2.6229	0	0.0000
July	79,360	2.1400	0	0.0000	38,254	2.1400	0	0.0000	0	2.3058	140,275	2.2984	0	2.2726	0	0.0000
August	222,456	1.9400	0	0.0000	89,032	1.9400	0	0.0000	0	2.1724	139,735	2.1912	0	2.1078	0	0.0000
September	215,280	2.0500	0	0.0000	86,160	2.0500	0	0.0000	0	2.2823	122,185	2.5717	0	2.2108	0	0.0000
October	177,072	2.2000	0	0.0000	41,540	2.2000	0	0.0000	0	2.4447	45,089	2.1923	0	2.3242	0	0.0000
November	0	2.4000	0	0.0000	0	2.4000	0	0.0000	0	2.6277	0	0.0000	0	2.5714	0	0.0000
December	0	2.3000	0	0.0000	0	2.3000	0	0.0000	0	2.4854	0	0.0000	0	2.4478	0	0.0000
January 2020	0	2.0000	0	0.0000	0	2.0000	0	0.0000	0	2.1726	0	0.0000	0	2.1284	0	0.0000
February	0	1.7600	0	0.0000	0	1.7600	0	0.0000	0	1.8778	0	0.0000	0	1.8399	0	0.0000
March	0	1.6900	0	0.0000	0	1.6900	0	0.0000	0	1.8269	0	0.0000	0	1.7884	0	0.0000
April 2020	151,170	$1.5000	0	$0.0000	43,980	$1.5000	0	$0.0000	0	$1.6441	0	$0.0000	0	$1.6012	0	$0.0000
May	201,314	1.6900	0	0.0000	79,143	1.6900	0	0.0000	0	1.8180	117,801	1.7113	0	1.7754	0	0.0000
June	62,400	1.5900	0	0.0000	16,710	1.5900	0	0.0000	0	1.7259	111,709	1.5794	0	1.6729	0	0.0000
July	22,134	1.3700	0	0.0000	3,813	1.3700	0	0.0000	0	1.5097	137,627	1.7310	0	1.4577	0	0.0000
August	122,264	1.7700	0	0.0000	30,814	1.7700	0	0.0000	0	1.8883	115,905	2.2549	0	1.8472	0	0.0000
September	64,530	2.4500	0	0.0000	15,570	2.4500	0	0.0000	0	2.6046	108,997	1.9415	0	2.5543	0	0.0000
October	0	1.9500	0	0.0000	0	1.9500	0	0.0000	0	2.1110	26,320	1.8862	0	1.9599	0	0.0000
November	0	2.8400	0	0.0000	0	2.8400	0	0.0000	0	3.0048	0	0.0000	0	2.8626	0	0.0000
December	0	2.7500	0	0.0000	0	2.7500	0	0.0000	0	2.9123	0	0.0000	0	2.9343	0	0.0000
January 2021	0	2.3500	0	0.0000	0	2.3500	0	0.0000	0	2.5220	0	0.0000	0	2.4731	0	0.0000
February	0	2.6800	0	0.0000	0	2.6800	0	0.0000	0	2.8199	0	0.0000	0	2.7703	0	0.0000
March	0	2.7800	0	0.0000	0	2.7800	0	0.0000	0	2.9329	0	0.0000	0	2.8626	0	0.0000
April 2021	0	$2.4400	0	$0.0000	0	$2.4400	0	$0.0000	0	$2.6579	0	$0.0000	0	$2.5727	0	$0.0000
May	229,617	2.8500	0	0.0000	95,883	2.8500	0	0.0000	0	3.0102	99,663	2.9220	0	2.9324	0	0.0000
June	0	2.8500	0	0.0000	0	2.8500	0	0.0000	0	3.0620	116,750	3.2680	111,990	2.9749	0	0.0000
July	81,096	3.4700	0	0.0000	38,130	3.4700	0	0.0000	0	3.7045	113,313	3.8227	0	3.6209	0	0.0000
August	126,666	3.8500	0	0.0000	54,932	3.8500	0	0.0000	0	4.1294	120,903	4.1262	0	4.0217	0	0.0000
September	130,620	4.1900	0	0.0000	53,100	4.1900	0	0.0000	0	4.4817	116,365	5.1690	0	4.3917	0	0.0000
October	229,617	5.5500	0	0.0000	95,883	5.5500	0	0.0000	0	5.9150	12,752	5.6919	0	5.9230	0	0.0000
November	0	6.0300	0	0.0000	0	6.0300	0	0.0000	0	0.0000	0	6.2913	0	6.3241	0	0.0000
December	44,618	5.2800	0	0.0000	0	5.2800	0	0.0000	0	0.0000	0	5.5692	0	5.5636	0	0.0000
January 2022	9,344	3.9900	0	0.0000	0	3.9900	0	0.0000	0	0.0000	0	4.1266	0	4.0940	0	0.0000
February	0	6.1700	0	0.0000	0	6.1700	0	0.0000	0	0.0000	0	6.4252	0	6.4063	0	0.0000
March	0	4.2900	0	0.0000	0	4.2900	0	0.0000	0	0.0000	0	4.6046	0	4.6079	0	0.0000
Total	2,764,779		0		1,044,989		0		0		1,911,119		111,990		0	

APPENDIX B

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

	TGP ZONE 0/1 800 LEG FSMA IN GROUND				TGP ZONE 0/1 800 LEG FSPA/FSMA TO STORAGE			
	MONTHLY		DAILY		MONTHLY		DAILY	
	Quantity	Benchmark	Quantity	Benchmark	Quantity	Benchmark	Quantity	Benchmark
April 2019	0	2.7171	0	$0.0000	0	2.6100	0	$0.0000
May	0	2.5625	0	0.0000	0	2.4600	0	0.0000
June	0	2.6243	0	0.0000	0	2.5200	0	0.0000
July	0	2.2740	0	0.0000	0	2.1800	0	0.0000
August	0	2.1092	0	0.0000	0	2.0200	0	0.0000
September	0	2.2122	0	0.0000	0	2.1200	0	0.0000
October	0	2.3256	0	0.0000	0	2.2300	0	0.0000
November	0	2.5728	0	0.0000	0	2.4700	0	0.0000
December	0	2.4492	0	0.0000	0	2.3500	0	0.0000
January 2020	0	2.1298	0	0.0000	0	2.0400	0	0.0000
February	0	1.8413	0	0.0000	0	1.7600	0	0.0000
March	0	1.7898	0	0.0000	0	1.7100	0	0.0000
April 2020	0	1.6026	0	$0.0000	0	1.5400	0	$0.0000
May	0	1.7768	0	0.0000	0	1.7100	0	0.0000
June	0	1.6743	0	0.0000	0	1.6100	0	0.0000
July	0	1.4591	0	0.0000	0	1.4000	0	0.0000
August	0	1.8486	0	0.0000	0	1.7800	0	0.0000
September	0	2.5557	0	0.0000	0	2.4700	0	0.0000
October	0	1.9613	0	0.0000	0	1.8900	0	0.0000
November	0	2.9357	0	0.0000	10,248	2.8400	0	0.0000
December	0	2.8640	0	0.0000	0	2.7700	0	0.0000
January 2021	0	2.4745	0	0.0000	0	2.3900	0	0.0000
February	0	2.7717	0	0.0000	0	2.6800	0	0.0000
March	0	-	0	0.0000	0	2.7700	0	0.0000
April 2021	0	2.5741	0	$0.0000	314,190	2.4800	0	$0.0000
May	0	2.9338	0	0.0000	0	2.8300	0	0.0000
June	42,000	2.9749	0	0.0000	155,340	2.8700	0	0.0000
July	0	3.6223	0	0.0000	0	3.5000	0	0.0000
August	0	4.0231	0	0.0000	0	3.8900	0	0.0000
September	0	4.3931	0	0.0000	0	4.2500	0	0.0000
October	0	5.9244	0	0.0000	0	5.7400	0	0.0000
November	0	6.3255	0	0.0000	0	6.1300	0	0.0000
December	0	5.5650	0	0.0000	0	5.3900	0	0.0000
January 2022	0	4.0954	0	0.0000	0	3.9600	0	0.0000
February	0	6.4077	0	0.0000	0	6.2100	0	0.0000
March	0	4.6093	0	0.0000	0	4.4600	0	0.0000
Total	42,000		0		479,778		0	

APPENDIX C

CHATTANOOGA GAS COMPANY

SUMMARY OF MT. PLEASANT PURCHASES

APPENDIX C

CHATTANOOGA GAS COMPANY
Summary of Mt. Pleasant Purchases
(Dth)

	Quantity		Total Cost
July 2019	29,916	[redacted]	$ 66,886
August	0		$0
September	0		$0
October	26,306		59,524
November	46,193		128,548
December	385,885		915,965
January 2020	232,740		502,639
February	74,645		150,741
March	0		$0
Subtotal/Average	795,685		$ 1,824,302
April 2020	0	[redacted]	$0
May	0		$0
June	0		$0
July	0		$0
August	0		$0
September	57,233		$ 104,311
October	73,099		$ 145,152
November	37,642		$ 105,684
December	538,712		$ 1,383,253
January 2021	229,965		$ 675,731
February	63,800		$ 196,397
March	0		$0
Subtotal/Average	1,000,451		$ 2,610,528
April 2021	8,148	[redacted]	$ 21,999
May	0		$0
June	0		$0
July	0		$0
August	0		$0
September	0		$0
October	0		$0
November	17,000		$ 89,760
December	0		$0
January 2022	366,200		$ 1,893,390
February	58,000		$ 320,766
March	15,000		$ 74,939
Subtotal/Average	464,348		$ 2,400,853
Total/Average	2,260,484	[redacted]	$ 6,835,683