Holland & Knight

Nashville City Center | 511 Union Street, Suite 2700 | Nashville, TN 37219 | T 615.244.6380 | F 615.244.6804
Holland & Knight LLP | www.hklaw.com

Paul S. Davidson
+1 615-850-8942
Paul.Davidson@hklaw.com

Electronically Filed in TPUC Docket Room
on August 30, 2024 at 12:15 p.m.

August 30, 2024

David Jones, Chairman
c/o Ectory Lawless
Tennessee Public Utility Commission
502 Deaderick Street, Fourth Floor
Nashville, Tennessee 37243

**Re: Review of Piedmont Natural Gas Company, Inc.'s Incentive Plan Account Relating to Asset Management Fees
Docket No. 05-00165**

Chairman Jones:

Enclosed for electronic filing with the Commission is the public redacted version of the Review of Performance Incentive Plan, dated August 2024, which has been prepared in compliance with the Order Approving Settlement dated December 14, 2007 issued in the above referenced docket. Also enclosed is a confidential unredacted version of this report which is being submitted under seal.

Piedmont is transmitting an original and (4) copies of this filing, along with certain confidential materials included therewith from Charlotte today for delivery to Ms. Lawless.

Thank you for your assistance with this matter. Should you have any questions concerning this matter, please do not hesitate to contact me at the email address or telephone number listed above.

HOLLAND & KNIGHT LLP

Paul S. Davidson

PSD/mjv
Enclosures

Cc: Pia Powers (Piedmont)
Kally Couzens (Piedmont)
Mindy McGrath (Piedmont)
Joe Shirley (TPUC)
Victoria Glover (TN CAD)

FINAL REPORT

PIEDMONT NATURAL GAS COMPANY

AUDIT STAFF OF THE TENNESSEE PUBLIC UTILITY COMMISSION

CONSUMER ADVOCATE DIVISION OF THE TENNESSEE ATTORNEY GENERAL

REVIEW OF PERFORMANCE INCENTIVE PLAN

Piedmont Natural Gas

AUGUST 2024

Prepared by:

EXETER
ASSOCIATES, INC.
10480 Little Patuxent Parkway, Suite 300
Columbia, Maryland 21044

TABLE OF CONTENTS

Page

LIST OF TABLES

LIST OF FIGURES

1. Introduction

Piedmont Natural Gas Company, Inc. (Piedmont or Company) is a wholly-owned subsidiary of Duke Energy Corporation (Duke Energy). Piedmont is an energy services company whose principal business is the distribution of natural gas. Acquired by Duke Energy in October 2016, Piedmont is headquartered in Charlotte, North Carolina. Duke Energy is also headquartered in Charlotte. Piedmont provides natural gas distribution service to over one million customers in Tennessee, North Carolina, and South Carolina. The gas procurement function at Piedmont is performed jointly for all three state jurisdictions by the corporate Gas Supply Department.

On May 31, 1996, the Tennessee Regulatory Authority (TRA), the predecessor to the Tennessee Public Service Commission (TPUC or Commission), issued an Order in Docket No. 96-00805 approving a gas cost Performance Incentive Plan (Plan) for Nashville Gas Company, the predecessor to Piedmont. Since its inception in 1996, the Plan has been reviewed and modified in several proceedings, including in Docket No. 05-00165. In that proceeding, Piedmont, the Audit Staff of the TRA (Staff), and the Consumer Advocate Division of the Tennessee Attorney General (CAD) (collectively, the "Settling Parties") filed a Settlement Agreement (2007 Settlement), which was approved by the TRA effective December 14, 2007.

The 2007 Settlement, among other things, provided for triennial reviews of Piedmont's activities under the Plan by an independent consultant. Exeter Associates, Inc. (Exeter) has been selected through a request for proposals (RFP) process by the Settling Parties to perform the independent review envisioned under the 2007 Settlement for the period July 1, 2020 through June 30, 2023 (review period or audit period).[1] Exeter was previously selected to perform the first, second, third, and fourth triennial independent reviews provided for under the 2007 Settlement that covered the periods July 1, 2008 through June 30, 2011, July 1, 2011 through June 30, 2014, July 1, 2014 through June 30, 2017, and July 1, 2017 through June 30, 2020, respectively. Exeter also performed an independent review of the Plan for the period July 1, 2006 through June 30, 2008. The purpose of the independent review, as specified in the RFP, is to evaluate and report on the transactions and activities conducted by Piedmont and/or its affiliates under the Plan, including, but not limited to: (a) natural gas procurement; (b) capacity management; (c) storage; (d) hedging; (e) reserve margins; and (f) off-system sales.

A Draft Report presenting the findings, results, and conclusions of Exeter's current review was provided to the Settling Parties on June 3, 2024. On July 24, 2024, Piedmont provided the Settling Parties and Exeter its comments on the Draft Report. Piedmont's comments were intended to clarify certain facts regarding its Plan and gas procurement activities, as well as

[1] Piedmonts' performance under the Plan is determined and evaluated on an annual basis, consisting of the 12-month period July through June ("Plan Year"). Therefore, subject to review by Exeter are the 2020-2021 Plan Year, the 2021-2022 Plan Year, and the 2022-2023 Plan Year.

respond to several findings set forth in the Draft Report. Exeter has incorporated the Company's comments into this final report (Report), as Exeter deemed appropriate.

Exeter's Report consists of eight sections including this introductory section. Section 2 of the Report identifies the interstate pipelines serving Piedmont as well as the services the Company purchases from each pipeline. Included in Section 2 is a summary of the Company's review period Asset Management Agreements (AMAs) and gas supply contracts. Section 2 also provides a description of the Piedmont system and the markets it serves.

Section 3 of the Report summarizes each component of the Plan and reviews Piedmont's performance by component. These include the commodity procurement cost, gas supply reservation fee, off-system sales, and capacity management components of the Plan. Section 4 of the Report evaluates Piedmont's storage management activities.

Section 5 of the Report reviews and examines the design peak day, winter season, and annual capacity resources, or entitlements, acquired and maintained by Piedmont to meet customer demands; assesses the manner in which Piedmont forecasts the design day demands of its customers; and evaluates whether Piedmont maintains a reasonable balance between its capacity entitlements and the anticipated demands of its customers. Section 5 includes an evaluation of the design day criteria selected by Piedmont for capacity planning purposes and identifies actual winter season peak day demands experienced during the review period. A discussion of the various commodity, or variable, charges incurred by Piedmont from its interstate pipeline service providers and the collection of these costs from customers is also included in Section 5. Finally, Section 5 includes a discussion of potential modifications to Piedmont's interstate pipeline capacity portfolio.

Section 6 of the Report summarizes and evaluates Piedmont's hedging activities. Section 7 begins with a comparison of Piedmont's Plan with the performance-based gas procurement incentive mechanisms of Chattanooga Gas Company (Chattanooga Gas) and Atmos Energy Corporation (Atmos), two Tennessee natural gas utilities that also operate under gas cost incentive mechanisms. This is followed by an evaluation of the balance of incentives between sales customers and Piedmont under the Plan.

The final section of the Report, Section 8, summarizes Exeter's conclusions, includes findings of fact, and identifies and describes areas of concern and improvement that may warrant further consideration.

2. Piedmont System Capacity and Gas Supply Resources and Markets

Piedmont provides natural gas sales and distribution service to the Nashville, Tennessee metropolitan area. Piedmont purchased firm services from five interstate pipelines during the review period: Columbia Gas Transmission (Columbia Gas), Columbia Gulf Transmission (Columbia Gulf), Midwestern Gas Transmission (MGT or Midwestern), Tennessee Gas Pipeline (TGP or Tennessee), and Texas Eastern Transmission (Texas Eastern). Of these five interstate pipelines, Piedmont is interconnected to three: Columbia Gulf, TGP, and Texas Eastern. Piedmont is also interconnected with East Tennessee Natural Gas (ETNG); however, the Company does not purchase firm services directly from ETNG. Figure 1 presents a map of the Company's service territory and the interstate pipelines serving Piedmont. The interstate pipeline services purchased by Piedmont during the review period are described in Sections 2.1 and 2.2. Section 2.2 also discusses Piedmont's on-system liquified natural gas (LNG) storage facility. Section 2.3 discusses Piedmont's review period AMAs. Section 2.4 describes Piedmont's review period citygate-delivered gas supply arrangements, which serve as both capacity and gas supply resource, and the Company's upstream receipt point gas supply contracts. Section 2.5 identifies the markets served by Piedmont. The information included in these sections is provided to assist in understanding the various components of the Plan, evaluating Piedmont's compliance with the Plan, and evaluating the reasonableness of Piedmont's capacity and gas supply resources.

2.1. Interstate Pipeline Transportation Services

Piedmont's transportation arrangements with TGP and Texas Eastern, and several of its review period arrangements with Columbia Gulf, provided for the delivery of gas supplies directly to Piedmont's system. Each of these pipelines was initially designed to transport gas from the Gulf Coast natural gas production region to markets in the Northeast United States. Today, the Marcellus and Utica Shale production region (collectively, "Marcellus Shale"), located in Pennsylvania, Ohio, and West Virginia, is now the most prolific natural gas production region in the U.S. As a result, the historical south to north gas flows on these pipelines have been altered. The physical flow of gas on Columbia Gulf, TGP, and Texas Eastern is now bi-directional, with gas supplies being transported north to south from the Marcellus Shale production region and south to north from the Gulf Coast production region. The current physical flow of gas on each of these pipelines in Piedmont's service territory is generally north to south.

The pipeline facilities of Columbia Gas are generally located in the Appalachian region. As subsequently explained, although Piedmont is not directly interconnected with Columbia Gas, the Company's storage transportation arrangements with Columbia Gas are operated as though Columbia Gas provides for the delivery of gas supplies directly to Piedmont's system. Piedmont's review period transportation arrangements with MGT provided for the delivery of gas from the Chicago market area to TGP, ETNG, and Columbia Gulf, but not directly to Piedmont's system. MGT-sourced gas supplies were deliverable to the western side of

Figure 1. Piedmont Service Territory and Pipeline Interconnects

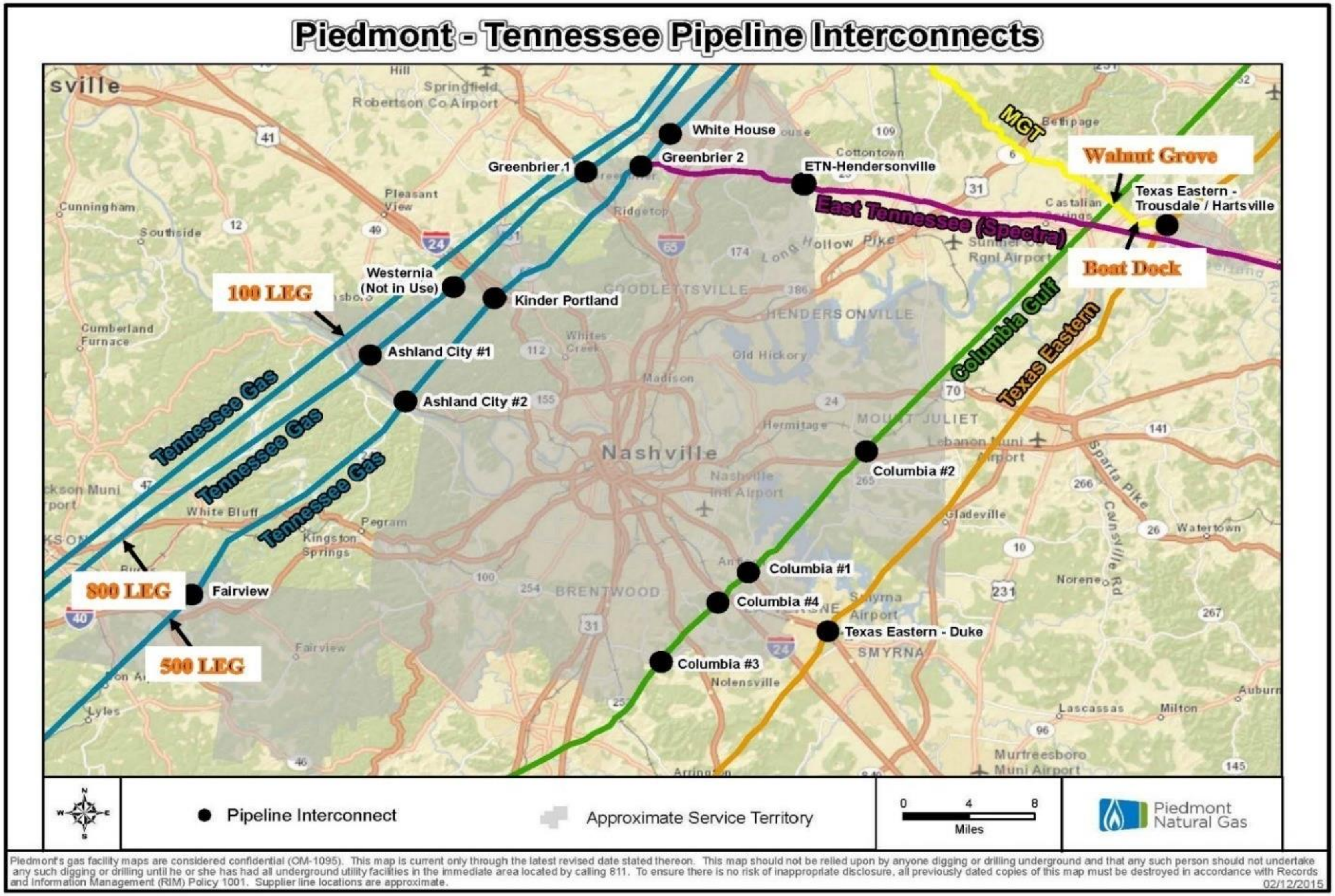


Table 1. Summary of Piedmont Interstate Pipeline Interconnects

	Pipeline	Percent of Peak Day	Meter Number(s)	Meter Type	Area Served	County	City	Pipeline Interconnect in Figure 1 Map
1.	Texas Eastern	[redacted]	70316	[redacted]	[redacted]	Trousdale	Hartsville	Texas Eastern Trousdale / Hartsville
2.	Texas Eastern	[redacted]	73423	[redacted]	[redacted]	Rutherford	Nashville	Texas Eastern – Duke
3.	Tennessee Gas	[redacted]	420280	[redacted]	[redacted]	Robertson	City of Greenbrier	Greenbrier 1
4.	Tennessee Gas	[redacted]	420309	[redacted]	[redacted]	Cheatham	Ashland City	Ashland City #1
5.	Tennessee Gas	[redacted]	420312	[redacted]	[redacted]	Robertson	Nashville	Kinder Portland
6.	Tennessee Gas	[redacted]	420600	[redacted]	[redacted]	Robertson	White House	White House
7.	Tennessee Gas	[redacted]	420610	[redacted]	[redacted]	Dickson	Fairview	Fairview
8.	Tennessee Gas	[redacted]	420846	[redacted]	[redacted]	Cheatham	Cheatham Co Industrial Park	Ashland City #2
9.	Tennessee Gas	[redacted]	420753	[redacted]	[redacted]	Robertson	Outside Greenbrier City Limits	Greenbrier 2
10.	Columbia Gulf	[redacted]	4016	[redacted]	[redacted]	Davidson	Nashville	Columbia #1
11.	Columbia Gulf	[redacted]	4088	[redacted]	[redacted]	Wilson	Nashville	Columbia #2
12.	Columbia Gulf	[redacted]	4183	[redacted]	[redacted]	Williamson	Nashville	Columbia #3
13.	Columbia Gulf	[redacted]	4241	[redacted]	[redacted]	Davidson	Nashville	Columbia #4
14.	East Tennessee Natural Gas	[redacted]	59218	[redacted]	[redacted]	Sumner	Sumner	ETN – Hendersonville

Piedmont's system by TGP, to the northern portion of Piedmont's system by ETNG, and to the eastern side of Piedmont's system by Columbia Gulf and Texas Eastern. Piedmont terminated its MGT transportation arrangements during the review period and replaced them with an arrangement with Columbia Gulf that provided for the delivery of supply directly to ETNG. Piedmont's terminated review period transportation arrangements with MGT are discussed in greater detail in Section 2.1.4 of the Report. The replacement arrangement with Columbia Gulf is discussed in greater detail in Section 2.1.2. Although Piedmont's distribution system is directly supplied by Columbia Gulf, TGP, Texas Eastern, and ETNG, the distribution systems "behind the meters" served by each pipeline are generally operated as independent systems. Customers located on the western side of Piedmont's distribution system are generally supplied with gas delivered by TGP; customers located on the eastern and southern portions of the system are generally served with gas delivered by Columbia Gulf and Texas Eastern; and customers located on the northern portion of the system are generally served by ETNG.[2] Customers located on the western side of Piedmont's distribution system are also served by the Company's LNG facility. Piedmont's interstate pipeline interconnects are summarized in Table 1. Table 1 also identifies the location of each interconnect on the map presented in Figure 1. Table 2 summarizes the capacity contracts and resources available to meet customer demands at the conclusion of the review period.

Table 2. Summary of Design Day Capacity Contracts and Resources, Conclusion of Review Period

Pipeline – Service	Contract No.	MDQ (Dth) Winter	MDQ (Dth) Summer	Available Quantity (Dth) Winter	Available Quantity (Dth) Annual	Contract Expiration
Columbia Gas Transmission						
Storage Service (FSS/SST)	53017/38052	10,000	5,000	611,870	611,870	3/31/2024
Columbia Gulf Transmission						
Firm Transportation (FTS-1)	266480	10,000	9,202	1,510,000	3,479,228	10/31/2027
Firm Transportation (FTS-1)	269151	25,000	25,000	3,775,000	9,125,000	3/31/2025
Firm Transportation (FTS-1)	194490	200,193	81,815	30,229,143	47,737,553	10/31/2027
Tennessee Gas Pipeline						
Firm Transportation (FT-A)	237	51,500	51,500	7,776,500	18,797,500	10/31/2024
Storage Service (FS-MA/FT-A)	6815/301244	50,798	0	2,901,943	2,901,943	4/30/2025[1]
Storage Service (FS-PA/FT-A)	2400/301244	6,190	0	672,091	672,091	4/30/2025[1]
Texas Eastern Transmission						
Firm Transportation (FT-1)	910473	10,000	0	1,510,000	1,510,000	3/31/2022
Firm Transportation (SCT)	800059	1,677	1,677	253,227	612,105	10/31/2023
Piedmont LNG		[redacted]	[redacted]	[redacted]	[redacted]	
Total Citygate Capacity Resources:		[redacted]		[redacted]		

Note: MDQ = maximum daily delivery quantity; Dth = dekatherm; LNG = liquefied natural gas.
[1] FS-MA and FS-PA storage contracts expire 4/30/2025.

[2] Typically, during the months of May through October, the valve at the ETNG interconnect is closed, and the requirements of the northern portion of Piedmont's system are met by TGP.

2.1.1. Columbia Gas Transmission

Piedmont purchased unbundled firm storage transportation service from Columbia Gas under Rate Schedule SST (Contract No. 38052), and unbundled firm storage service from Columbia Gas under Rate Schedule FSS (Contract No. 53017) during the review period. Storage transportation service under Rate SST is utilized to transport gas to and from the storage facilities of Columbia Gas and Piedmont's system. The maximum daily delivery quantity (MDQ) under Piedmont's SST arrangement with Columbia Gas was 10,000 dekatherms (Dth) per day during the months of October through March, and 5,000 Dth/day during the months of April through September. Gas deliveries to and from Columbia Gas are provided through a combination of facilities jointly owned and operated by Columbia Gas and Columbia Gulf pursuant to a lease agreement between the two pipelines.[3] The gas delivered to Columbia Gas storage for injection was generally purchased by Piedmont in the Marcellus Shale production region during the review period.

2.1.2. Columbia Gulf Transmission

The pipeline facilities of Columbia Gulf extend from the Gulf Coast production region in Louisiana to Leach, Kentucky, at which point Columbia Gulf interconnects with Columbia Gas. Piedmont purchased firm transportation service from Columbia Gulf under Rate Schedule FTS-1 during the review period that provided for the delivery of Gulf Coast-sourced gas supplies directly to Piedmont's system under several different contracts. For the period November 1, 2012 through October 31, 2022, FTS-1 Contract No. 43462 provided for the delivery of 10,000 Dth/day during the winter period (November – March) and 9,202 Dth/day during the summer period (April - October). Contract No. 43462 expired October 31, 2022, and was replaced by FTS-1 Contract No. 266480 which had the same winter and summer period delivery entitlements as Contract No. 43462.

For the period December 1, 2013 through October 31, 2022, FTS-1 Contract No. 14252 provided for the delivery of 31,000 Dth/day during the winter period and the delivery of 11,755 Dth/day during the summer period. Upon expiration of this contract, Piedmont extended the contract and combined the contract quantities with subsequently discussed FTS-1 Contract No. 194490.

Effective November 1, 2017, Piedmont entered into a five-year FTS-1 firm transportation contract with Columbia Gulf under Rate Schedule FTS-1 (Contract No. 194490). The MDQ under Contract No. 194490 increased each year as, indicated in Table 3 below.

[3] Federal Energy Regulatory Commission (FERC) Docket No. CP13-480.

Table 3. Columbia Gas Contract No. 194490 Entitlements		
	MDQ	
Annual Period	Winter	Summer
November 2017 – October 2018	140,193	58,052
November 2018 – October 2019	150,193	62,193
November 2019 – October 2020	155,193	64,263
November 2020 – October 2021	162,193	67,162
November 2021 – October 2022	169,193	70,060

Effective November 1, 2022, the term of Contract No. 194490 was extended by Piedmont and as previously indicated, the contract quantities under FTS-1 Contract No. 145252 were consolidated with Contract No. 194490. As indicated in Table 2, the winter MDQ under Contract No. 194490 was 200,193 Dth at the conclusion of the review period, and the summer MDQ was 81,815 Dth.

As discussed in additional detail in Section 2.1.4, when initially executed, Piedmont's firm transportation arrangements with MGT were scheduled to expire January 6, 2023. During the review period, Piedmont replaced its 25,000 Dth of MGT capacity that provided for the delivery of gas supplies to ETNG at Boat Dock with Columbia Gulf FTS-1 capacity (Contact No. 269151) effective November 1, 2023. Piedmont replaced the MGT capacity with Columbia Gulf capacity because it was the lowest-cost alternative at the time. In addition to Columbia Gulf, Piedmont evaluated maintaining capacity on MGT and acquiring additional capacity on Texas Eastern. Piedmont was required to execute the Columbia Gulf replacement arrangement prior to the MGT contract expiration date to ensure the capacity would be available when required.

2.1.3. Tennessee Gas Pipeline

The TGP system originates in the Texas and Louisiana Gulf Coast natural gas production region and extends to New England. In the production region, the TGP system consists of three primary transmission lines, referred to as the 100, 500, and 800 Legs.[4] The TGP system is also divided into eight zones for rate purposes (Zones 0, L, and 1-6). The State of Texas is designated as Zone 0, Zone L consists largely of the State of Louisiana, and Zone 1 extends from the Texas border with Louisiana to the Kentucky/Tennessee border. Piedmont purchased firm transportation service from TGP under Contract No. 237 (Rate Schedule FT-A) during the review period, at a fixed discount rate. Contract No. 237 provided for the south-to-north delivery of gas from the Gulf Coast production region to Piedmont. Piedmont's receipt point capacity under Contract No. 237 was subdivided by leg and zone, as follows, during the review period:

[4] The TGP Legs are identified in Figure 1, shown previously.

Tennessee Gas Pipeline Capacity
Contract No. 237

Zone – Leg	MDQ (Dth)
Zone L – 500 Leg	25,750
Zone L – 800 Leg	25,750
TOTAL:	51,500

Piedmont also purchased firm transportation service from TGP under Contract No. 301244 (Rate Schedule FT-A) during the review period. This contract provided for the delivery of up to 55,900 Dth/day from Piedmont's TGP Market Area (FS-MA) and Production Area (FS-PA) firm storage accounts, which are subsequently discussed in Section 2.2.2. Contract No. 301244 is a forward-haul arrangement that provides for the north-to-south delivery of gas in TGP Zone 1.

2.1.4. Midwestern Gas Transmission

Effective November 2007, Piedmont contracted for 20,000 Dth/day of capacity with MGT. This arrangement provided for the upstream delivery of gas from the Chicago market area to MGT's TGP interconnect at Portland, Tennessee, with final delivery effectuated to the western side of Piedmont's system by TGP. This arrangement expired effective with the completion of MGT's Eastern Expansion Project.

Through its participation in MGT's Eastern Expansion Project, Piedmont increased its contractual capacity to 100,000 Dth/day effective with the completion of the project on January 7, 2008. The Eastern Expansion Project also allowed MGT to interconnect with Columbia Gulf at Walnut Grove, Tennessee and ETNG at Boat Dock in Sumner, Tennessee. MGT-sourced gas supplies can be delivered to the western side of Piedmont's distribution system by TGP ("MGT West via TGP"), to the northern portion of Piedmont's distribution system by ETNG ("MGT East via ETNG"), and to the eastern side of Piedmont's distribution system by Columbia Gulf ("MGT East via Gulf").

Initially during the review period, Piedmont maintained two firm transportation arrangements with MGT. MGT Contract No. FA0342 under Rate Schedule FT-A provided for the firm upstream transportation of up to 100,000 Dth/day from an interconnect with ANR Pipeline in Joliet, Illinois near the Chicago area to an interconnect with TGP at Portland, Tennessee. MGT Contract No. FB0006 under Rate Schedule FT-B provided for the firm upstream transportation of up to 75,000 Dth/day from Portland, Tennessee to an interconnect with Columbia Gulf at Walnut Grove, Tennessee, and up to 25,000 Dth/day to an interconnect with ETNG at Boat Dock in Sumner, Tennessee. Deliveries by MGT under Contract No. FA0342 to TGP could be delivered to Piedmont under TGP FT-A Contract No. 301244 when that capacity was not required to deliver gas from the Company's FS-MA and FS-PA storage accounts with TGP. Deliveries by MGT to Walnut Grove under Contract No. FB0006 could be delivered to Piedmont under interruptible backhaul transportation arrangements with Columbia Gulf, and deliveries by MGT to Boat Dock under Contract No. FB0006 could be delivered to Piedmont by backhaul (east to west), utilizing ETNG's interruptible transportation service. Deliveries by ETNG are made to Piedmont at Piedmont's Hendersonville meter station located in Sumner, Tennessee.

Since completion of MGT's Eastern Expansion Project, as a result of the availability of abundant supplies from the Marcellus Shale production region, pipelines like Columbia Gulf began taking receipt of reduced quantities of traditional Gulf Coast production. Piedmont believed that this resulted in a risk to the reliability of backhaul deliveries by Columbia Gulf. In response to this risk, beginning in the winter of 2014-2015, Piedmont no longer considered backhaul deliveries by Columbia Gulf to be a reliable design day capacity resource. Therefore, Piedmont only considered the 25,000 Dth/day of MGT capacity delivered to ETNG at Boat Dock to be a reliable design day capacity resource during the review period.

When executed, MGT Contract Nos. FA0342 and FB0006 were scheduled to expire on January 6, 2023. As previously indicated in Section 2.1.2, Piedmont elected to replace its firm transportation arrangements with MGT with lower-cost Columbia Gulf FTS-1 capacity (Contract No. 269151) effective November 1, 2023. Effective October 31, 2023, Piedmont permanently released MGT Contract No. FA0342, and MGT Contract No. FB0006 expired January 6, 2023.

2.1.5. Texas Eastern Transmission

Piedmont purchased firm transportation service from Texas Eastern under two different rate schedules during the review period. The Company purchased 10,000 Dth/day of winter season firm transportation service under Rate Schedule FT-1. Piedmont also purchased small customer firm transportation service under Rate Schedule SCT. Service under Rate Schedule SCT is a no-notice, firm transportation service. Piedmont utilizes both of these Texas Eastern transportation arrangements to acquire Gulf Coast-sourced gas supplies. Rate Schedule SCT capacity, used to serve the City of Hartsville, Tennessee, is excluded from the Plan.

2.2. Interstate Pipeline and On-System Storage

Piedmont purchased contract storage service from Columbia Gas and TGP during the review period. These arrangements are further described below. Piedmont also operates an on-system LNG facility.

2.2.1. Columbia Gas Transmission

Piedmont purchased firm storage from Columbia Gas under Rate Schedule FSS during the review period. Gas is delivered to and from Columbia Gas storage under Piedmont's SST arrangement with Columbia Gas. The maximum daily withdrawal quantity (MDWQ) under Piedmont's FSS arrangement is 10,000 Dth/day and the maximum seasonal storage quantity (MSQ) is 611,870 Dth.

2.2.2. Tennessee Gas Pipeline

During the review period, Piedmont purchased unbundled, market-area firm storage service from TGP under Rate Schedule FS-MA, and unbundled production-area firm storage service under Rate Schedule FS-PA. Gas delivered to both market- and production-area storage is primarily sourced on TGP and purchased in the Gulf Coast production region. Deliveries to Piedmont's system from market- and production-area storage are nominated at TGP's Portland, Tennessee station. Gas from storage is delivered to Piedmont by TGP under FT-A Contract No. 301244. The MDQs under the FS-MA and FS-PA arrangements are 50,798 Dth/day and 6,190 Dth/day, respectively. The MSQs are 2,901,943 Dth and 672,091 Dth, respectively.

2.2.3. Liquefied Natural Gas

Piedmont operates an on-system LNG facility. When initially constructed, the maximum rated capacity of Piedmont's LNG facility was [redacted] Dth/day. However, due to a pressure reduction on one of the pipelines delivering gas from the LNG facility to Piedmont's distribution system, the capacity of the LNG facility was reduced to [redacted] Dth/day beginning with the 2014-2015 winter season. The pressure of the pipeline was reduced because the pipeline was reclassified from transmission to distribution in accordance with Piedmont's pipeline integrity plan. It was initially anticipated that improvements to the pipeline would subsequently return the deliverability of the LNG facility to [redacted] Dth/day for the 2018-2019 winter season. However, the pipeline upgrades restoring the deliverability of the LNG facility were not completed until prior to the 2020-2021 winter season. Piedmont determined that it was prudent to keep the expected deliverability of the LNG facility at the reduced [redacted] Dth/day until the pipeline upgrades experienced a full winter of service to ensure that the upgrades performed as anticipated. The deliverability of the LNG facility was restored to [redacted] Dth/day for the 2021-2022 winter season. Subsequent system improvements have increased the maximum rated deliverability capacity of the LNG facility to [redacted] Dth/day for the 2022-2023 winter season. The storage capacity of the LNG facility is approximately [redacted] Dth. As such, the LNG facility can currently operate at maximum levels for approximately [redacted] days.

2.3. Asset Management Agreements

Piedmont operated under four AMAs during the entire review period. Each AMA was awarded through an RFP process. Under the AMAs, Piedmont released all of its interstate pipeline transportation and storage capacity contracts, or assets, to the AMA service provider, or Asset Manager. Piedmont was paid a fee under each AMA but remained responsible for all pipeline demand charges associated with the released capacity. Table 4 summarizes Piedmont's review period AMA arrangements.

Table 4. Review Period Asset Management Agreements		
Manager	**Annual Term**	**Annual Fee**
Tenaska Marketing Ventures	November 2019 – October 2020	[redacted]
Tenaska Marketing Ventures	November 2020 – October 2021	[redacted]
United Energy Trading	November 2021 – October 2022	[redacted]
Tenaska Marketing Ventures	November 2022 – October 2025	[redacted]

With the exception of the citygate-delivered supplies and the upstream receipt point contract discussed in Section 2.4, certain supplies delivered by MGT, and under the Company's Texas Eastern SCT contract discussed below, the Asset Manager generally arranged for all of the gas supplies delivered to Piedmont. The supplies arranged for delivery by the Asset Manager were generally delivered under the firm transportation agreements released to the Asset Manager. Piedmont did not generally enter into its own separate gas supply arrangements. Piedmont occasionally purchased delivered-to-citygate gas directly from the Asset Manager and from other suppliers on an interruptible basis.

Under the review period AMAs, each day, Piedmont would determine the quantity of gas required under the released capacity assets to meet its customers' requirements (by delivering pipeline) and its daily storage injection and withdrawal activity, and would convey this information, referred to as "virtual dispatch," to the Asset Manager. The Asset Manager was then entitled to use the capacity and gas supply assets available under the AMA, or any other assets available to the Asset Manager, to meet Piedmont's daily requirements. The Asset Manager was entitled to utilize the assigned capacity that was not required to serve Piedmont to pursue the Asset Manager's own business interests (i.e., optimization strategies). Piedmont paid the applicable fuel and pipeline variable charges to the Asset Manager based on virtual dispatch. Each review period AMA separately specified the maximum daily gas supply quantities the Asset Manager was obligated to deliver to Piedmont under each firm transportation contract released to the Asset Manager during the months of November through March, during the months of April and October, and during the months of May through September.

2.4. Gas Supply Contracts

As discussed in Section 2.3, the Asset Manager generally arranged for the purchase of the gas supplies delivered to Piedmont during the review period under the firm transportation capacity that was assigned to the Asset Manager. However, as subsequently discussed, Piedmont entered into a firm citygate-delivered supply arrangement and purchased gas under a firm upstream receipt point contract for the period November 2020 – March 2021. In addition to purchases under these firm gas supply contracts, Piedmont also purchased citygate-delivered supplies on an interruptible basis during the review period.

2.4.1. Citygate-Delivered Supply Services

Due to the reduction in the deliverability of its LNG facility previously discussed in Section 2.2.3, Piedmont was forecasting a small design day deliverability deficiency for the western portion of its system for the 2020-2021 winter season that is served by TGP and the LNG facility. To address this deficiency, Piedmont entered into a firm citygate-delivered gas supply arrangement with [redacted] that provided for the deliverability of up to [redacted] Dth/day to Piedmont's Nashville Roberts meter. The [redacted] Dth/day was sufficient to meet Piedmont's projected design day deficiency of the 2020-2021 winter season. The term of the contract was December 1, 2020 through February 28, 2021.

The contract with [redacted] provided for the delivery of citygate supplies by TGP and required a demand charge equal to [redacted] times the MDQ, times the number of days in the month. The commodity charge was equal to the applicable [redacted][5]

2.4.2. Upstream Receipt Point Gas Supply Contracts

In addition to the citygate-delivered gas supply contract discussed in Section 2.4.1, Piedmont maintained a gas supply contract with [redacted]. This contract provided for the delivery of gas supplies to Piedmont's citygate by ETNG at the Hendersonville meter station. The contract provided for the delivery of up to [redacted] Dth/day during the period November 2020 – March 2021. The contract with [redacted] required the payment of a demand charge equal to [redacted] times the MDQ, times the number of days in the month. The commodity charge was equal to the applicable [redacted]. During the effective period of this contract, deliveries to Hendersonville were outside the scope of the AMA.

Piedmont also maintained firm upstream receipt point contracts for the delivery of gas supplies under its Texas Eastern SCT contract for [redacted] Dth/day for the period November 2020 – March 2021. Piedmont did not maintain firm upstream receipt point supply contracts to fill its SCT capacity beyond the winter of 2020-2021 because the Company determined that supply was readily available in the gas supply markets to fill its SCT capacity without the need to maintain firm contracts. As previously indicated in Section 2.1.5, the SCT contract is excluded from the Plan, as are the purchases delivered under the SCT contract.

2.5. Markets Served by Piedmont

Piedmont 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 that acquire their own gas supplies in the interstate markets and separately arrange for the delivery of those supplies to Piedmont's citygates. Table 5 summarizes the

[5] Index prices are discussed in greater detail in Section 3.1.1 of the Report.

number of customers served and annual throughput, by service class, for the 12 months ended June 2021, June 2022, and June 2023.

Table 5. Annual Customers and Volumes, by Class (12 Months Ended June)			
Customers, by Class	**2020**	**2021**	**2022**
Residential Sales	[redacted]	[redacted]	[redacted]
Small General Sales	[redacted]	[redacted]	[redacted]
Medium General Sales	[redacted]	[redacted]	[redacted]
Firm Industrial Sales	[redacted]	[redacted]	[redacted]
Interruptible Industrial Sales	[redacted]	[redacted]	[redacted]
Resale Service	[redacted]	[redacted]	[redacted]
Subtotal Sales Classes:	[redacted]	[redacted]	[redacted]
Firm Transportation	[redacted]	[redacted]	[redacted]
Interruptible Transportation	[redacted]	[redacted]	[redacted]
Special Contract Transportation	[redacted]	[redacted]	[redacted]
Subtotal Transportation Classes:	[redacted]	[redacted]	[redacted]
Total Customers:	[redacted]	[redacted]	[redacted]
Volumes, by Class (Dth)	**2020**	**2021**	**2022**
Residential Sales	[redacted]	[redacted]	[redacted]
Small General Sales	[redacted]	[redacted]	[redacted]
Medium General Sales	[redacted]	[redacted]	[redacted]
Firm Industrial Sales	[redacted]	[redacted]	[redacted]
Interruptible Industrial Sales	[redacted]	[redacted]	[redacted]
Resale Service	[redacted]	[redacted]	[redacted]
Subtotal Sales Classes:	[redacted]	[redacted]	[redacted]
Firm Transportation	[redacted]	[redacted]	[redacted]
Interruptible Transportation	[redacted]	[redacted]	[redacted]
Special Contract Transportation	[redacted]	[redacted]	[redacted]
Subtotal Transportation Classes:	[redacted]	[redacted]	[redacted]
Total Volumes:	[redacted]	[redacted]	[redacted]

Note: Excludes off-system sales.

3. Performance Incentive Plan

This section of Exeter's Report summarizes and evaluates Piedmont's activities under the Performance Incentive Plan by component. These components include: (a) commodity procurement costs; (b) supplier reservation fees; and (c) capacity management. The Plan is included as Service Schedule No. 316 of Piedmont's tariff. A copy of the Plan is included as Appendix A of the Report. Piedmont files an Annual Performance Incentive Plan Report (Annual Plan Report) with the TPUC for each Plan Year. TPUC Staff audits each Annual Plan Report and presents its findings in an Annual Compliance Audit Report (Audit Report). TPUC Staff's Audit Reports for the review period only identified material findings for the July 2020 – June 2021 Plan Year. The TPUC Staff's audit report for this Plan year, filed in Docket No. 22-00086, found that Piedmont had overstated the Company's share of plan savings by $15,248 and overstated ratepayer savings by $45,745. Table 6 summarizes Piedmont's performance under the Plan during the review period, inclusive of TPUC Staff's findings in Docket No. 22-00086.[6] Additional detail concerning Piedmont's activities and performance under the Plan is subsequently presented in this section.

Table 6. Performance Incentive Plan – Summary of Review Period Results

	Total Gains		
Plan Year	**Ratepayers**	**Company**	**Total Savings**
July 2020 – June 2021	[redacted]	[redacted]	[redacted]
July 2021 – June 2022	[redacted]	[redacted]	[redacted]
July 2022 – June 2023	[redacted]	[redacted]	[redacted]
Total:	[redacted]		[redacted]

3.1. Commodity Procurement Cost Component

3.1.1. Background and Description

In the natural gas industry, there are generally two types of physical gas supply purchase arrangements: first-of-the-month (FOM) baseload (monthly) purchases and daily purchases. Monthly purchases are generally arranged several days prior to the month of delivery during a period referred to as "bid week," 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 arranged on the business day prior to delivery. While daily purchases typically flow for one day, these purchases may also be arranged for multiple consecutive days.

[6] Included in Table 6 is an adjustment to the gain initially calculated by Piedmont for October 2022. Exeter's review discovered that the gain initially calculated by the Company for October 2022 was incorrectly based on Columbia Gulf FTS-1 capacity entitlements for October 2021. This correction increased the gain for October 2022 by [redacted]. [redacted]

Shippers on interstate pipelines such as Piedmont must place nominations with a pipeline in order to schedule service. There are currently five nomination opportunities (cycles) for each gas day. The standard time for the gas day is 9 AM Central Clock Time (CCT) to 9 AM CCT (10 AM Eastern Time to 10 AM Eastern Time the next gas day). The current nomination cycle timelines for the gas day are as follows:

Nomination Cycle Timelines (CCT)

Cycle	Nomination Deadline	Start of Gas Flow
Timely	1 PM prior to gas day	9 AM on gas day
Evening	6 PM prior to gas day	9 AM on gas day
Intraday 1	10 AM on gas day	2 PM on gas day
Intraday 2	2:30 PM on gas day	6 PM on gas day
Intraday 3	7 PM on gas day	10 PM on gas day

Most of the next-day trading for the purchase of daily gas supplies typically takes place between 7 AM and 11 AM CCT with nominations made for the timely cycle. This is the normal gas trading and nomination cycle followed in the natural gas industry. Very little trading occurs after the timely nomination cycle deadline. Trading for weekends and holidays generally occurs on a ratable basis. For example, the quantity of gas purchased from a supplier for the Saturday gas day would also be purchased for the following Sunday and Monday gas days. If Monday is a holiday, the same quantity purchased for the Saturday gas day would also be purchased for the Monday holiday gas day.

There are various natural gas industry publications that report, after the fact, the average price paid for monthly and daily gas purchases at major natural gas trading locations. These average, or market, prices are referred to as "index prices." Monthly index prices are published in Platts *Inside FERC Gas Market Report* (*Inside FERC*) and by *Natural Gas Intelligence* (*NGI*). Daily index prices are published in Platts *Gas Daily (Gas Daily*). Trading locations at which Piedmont purchased gas with published index prices during the review period included the following:

Columbia Gas Transmission
- Appalachia

Columbia Gulf Transmission
- Rayne (Louisiana) or Mainline

Midwestern Gas Transmission
- Chicago Citygate

Tennessee Gas Pipeline
- Zone L – 500 Leg (Louisiana)
- Zone L – 800 Leg (Louisiana)

Texas Eastern
- East Louisiana (ELA)

Under the commodity procurement cost component of the Plan, Piedmont's actual total monthly citygate (delivered) commodity cost of gas is compared to a monthly benchmark cost. The actual total citygate commodity cost of gas includes the amount paid for gas supply commodity purchases, plus the applicable pipeline fuel and variable transportation charges associated with delivering gas from the purchase (receipt) point to Piedmont's system. Gas supplies may be delivered to Piedmont's system under firm or interruptible transportation arrangements or purchased on a delivered-to-citygate basis. If Piedmont's actual monthly costs exceed benchmark costs, 25% of the difference is assessed to Piedmont, and sales customers' gas costs are reduced by the amount assessed to Piedmont. If benchmark costs exceed actual monthly costs, 25% of the difference is retained by Piedmont, and sales customers' gas costs are increased by the amount retained by Piedmont.

The monthly benchmark cost is calculated by multiplying the actual quantity of gas delivered to Piedmont's citygate during a month by a Monthly Benchmark Index Price (MBIP). The MBIP includes different benchmarking procedures for monthly and daily purchases delivered under Piedmont's firm interstate pipeline transportation arrangements, purchases delivered under interruptible transportation arrangements, and purchases made at the citygate. Citygate purchases are also referred to by Piedmont as purchases using transportation other than firm transportation. Piedmont made no purchases upstream of its citygate during the review period that were delivered under interruptible transportation arrangements, although some of the Company's citygate purchases may have been delivered to the citygate by the supplier under interruptible transportation arrangements. The benchmark price for each type of purchase (i.e., monthly purchases delivered under firm transportation arrangements, daily purchases delivered under firm transportation arrangements, and citygate purchases) is weighted by the actual monthly purchase quantity percentage to derive the MBIP.

For the benchmarking of monthly purchases, a delivered-to-citygate price is first calculated for each geographic receipt point location accessed by Piedmont's firm transportation arrangements based on the applicable monthly index price, plus the applicable firm fuel and variable transportation charges. A weighted average delivered-to-citygate price is then calculated based on the daily capacity entitlements Piedmont has determined to be available at each receipt point location and serves as the benchmark for monthly purchases.[7] Table 7 presents a monthly summary of the daily supply entitlements included in Piedmont's benchmark calculation for monthly purchases during the review period.

[7] To determine the capacity available at each receipt point, the Plan requires that the pipeline capacity weightings utilized to calculate the benchmark for monthly purchases be based on design day citygate delivery entitlements. The Plan also requires that if capacity was released or otherwise unavailable to be used to deliver gas to Piedmont's citygate, that capacity should be excluded from the monthly purchase benchmark calculation.

Table 7. Capacity Entitlements Included in the Benchmark Calculation for Monthly Purchases (Dth/Day)

	Tennessee Gas Pipeline Zone L				Midwestern Chicago Citygate				
Month/ Year	500 Leg	800 Leg	Columbia Gulf Rayne	Texas Eastern ELA	Via TGP	Via Columbia Gulf	Via ETNG	Columbia Gulf via ETNG	Total
Jul 2020	[redacted]								
Aug	[redacted]								
Sep	[redacted]								
Oct	[redacted]								
Nov	[redacted]								
Dec	[redacted]								
Jan 2021	[redacted]								
Feb	[redacted]								
Mar	[redacted]								
Apr	[redacted]								
May	[redacted]								
Jun	[redacted]								
Jul 2021	[redacted]								
Aug	[redacted]								
Sep	[redacted]								
Oct	[redacted]								
Nov	[redacted]								
Dec	[redacted]								
Jan 2022	[redacted]								
Feb	[redacted]								
Mar	[redacted]								
Apr	[redacted]								
May	[redacted]								
Jun	[redacted]								
Jul 2022	[redacted]								
Aug	[redacted]								
Sep	[redacted]								
Oct	[redacted]								
Nov	[redacted]								
Dec	[redacted]								
Jan 2023	[redacted]								
Feb	[redacted]								
Mar	[redacted]								
Apr	[redacted]								
May	[redacted]								
Jun	[redacted]								

For the benchmarking of daily purchases made under firm transportation arrangements, each of Piedmont's actual daily purchases is priced at the applicable daily index price, plus the applicable fuel and variable charges. The delivered costs for each purchase are totaled and divided by the actual quantity of daily purchases delivered under firm transportation arrangements to derive the daily purchase benchmark included in the MBIP.

Piedmont purchased citygate supplies delivered by TGP, Columbia Gulf, Texas Eastern, and ETNG during the review period. All citygate purchases during the review period were daily purchases. Piedmont maintained firm transportation contracts with TGP, Columbia Gulf, and Texas Eastern during the review period. All TGP citygate purchases made by Piedmont during the review period were made outside of the normal gas trading and nomination schedule to meet unanticipated increases in customer requirements. Purchases made outside the normal gas trading and nomination schedule are not considered deliveries under the firm transportation capacity released to the Asset Manager under Piedmont's AMAs. This is because under Piedmont's AMAs and consistent with industry practice, the AMAs were structured to allow the Asset Manager to optimize the released capacity assets when not required to serve Piedmont. If the Asset Manager were required to serve Piedmont with supplies purchased outside the normal trading and nomination cycle (i.e., a purchase initially nominated outside the timely cycle or not made on a ratable basis over the weekend), the AMA would have less value to the Asset Manager because the Asset Manager would be required to have capacity available to accommodate a purchase not initially nominated for delivery within the timely cycle or on a ratable basis. Therefore, all review period TGP citygate purchases were benchmarked based on the applicable daily index prices, plus the applicable interruptible transportation variable and fuel charges.

For citygate purchases delivered by Columbia Gulf, the benchmark was determined based on the applicable daily index price, plus the applicable interruptible fuel and variable charges. Piedmont used this method for citygate purchases delivered by Columbia Gulf for two reasons. First, the purchases were lower in cost than if the Company had purchased the supplies from the Asset Manager and, therefore, the Columbia Gulf firm transportation capacity released to the Asset Manager was not utilized to deliver the citygate supplies, or the purchases were made outside the normal gas trading and nomination schedule.

All of Piedmont's review period ETNG-delivered citygate purchases were made to the Company's interconnect with ETNG in Hendersonville. Prior to its acquisition of Columbia Gulf FTS-1 capacity to replace its MGT firm transportation capacity effective November 2022, Piedmont benchmarked these purchases as if they were delivered from the Chicago citygate utilizing the Company's MGT firm transportation capacity to ETNG at Boat Dock, and subsequently delivered utilizing ETNG's interruptible transportation service. That is, the benchmark was determined based on the applicable Chicago citygate index price, plus the applicable MGT firm transportation and variable and fuel charges, plus the applicable ETNG interruptible transportation variable and fuel charges. After acquisition of the Columbia Gulf FTS-1 capacity, the ETNG-delivered citygate purchases were benchmarked based on the

Columbia Gulf index price, plus the applicable Columbia Gulf variable and fuel charges, plus the applicable ETNG interruptible transportation variable and fuel charges. The benchmark costs for each purchase delivered using transportation other than firm transportation service were totaled and divided by the actual quantity of these purchases to derive the other purchase benchmark reflected in the MBIP.

Shown in Table 8, for illustrative purposes, is the calculation of the MBIP for January 2023. Also shown are the commodity procurement cost gains and losses. Section I of Table 8 shows the calculation of the monthly purchase benchmark included in the MBIP. Column C of Section I identifies Piedmont daily supply entitlements by purchase location. Column D of Section I identifies the percentage share of total supply for each purchase location. Column E identifies the delivered cost of gas sourced under each transportation arrangement based on the applicable published monthly index price. Column F calculates the monthly component of the MBIP. As shown there, the benchmark price against which Piedmont's monthly purchases were compared under the Plan was [redacted]/Dth (Section I, line 6, Column F) in January 2023.

Section II shows the calculation of the combined MBIP based on the individual monthly, daily, and citygate purchase benchmarks. Due to the extensive detail, calculations of the daily and citygate benchmarks included in the MBIP are only summarized in Table 8 (Section II, lines 2 and 3). As shown in Section II, lines 2 and 3, Column C, the daily and citygate purchase benchmarks were [redacted]/Dth and [redacted]/Dth, respectively. Also shown in Section II, line 4, Column D, the total MBIP was [redacted]/Dth. Under the Plan, Piedmont's total purchases during January 2023 of [redacted] Dth were multiplied by the MBIP of [redacted]/Dth to calculate total benchmark costs of [redacted] (Section II, line 4, Column E). As shown in Section II, line 5, Column E, the actual costs associated with Piedmont's purchases of [redacted] Dth were [redacted], resulting in incentive Plan savings of [redacted] (Section II, line 6, Column E).

Section III of Table 8 "unbundles" the MBIP and identifies incentive Plan savings by type of purchase. As shown, monthly purchase incentive Plan savings were [redacted] (Section III, line 1, Column E), and citygate purchase incentive Plan savings were [redacted] (Section III, line 3, Column E). No daily purchase incentive Plan savings were realized in January 2023 (Section III, line 2, Column E). The calculated unbundled savings total [redacted]. Actual savings for the month of January 2023 were [redacted] and vary from the amounts calculated in Sections II and III due to rounding.

Table 8. Summary of Monthly Benchmark Index Price Calculation and Commodity Procurement Incentive Gains/(Losses) (January 2023)

Monthly Benchmark	Actual FOM Purchases		Pipeline Capacity		Price ($/Dth)	
I. Purchase Location – Contractual Capacity	**(Dth/Day) (A)**	**Percent (B)**	**(Dth/Day) (C)**	**Percent (D)**	**Delivered (E)**	**Weighted (F)**
1. TGP Zone L – 500 Leg	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2. TGP Zone L – 800 Leg	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3. Columbia Gulf FTS-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4. Texas Eastern FT-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5. Columbia Gulf via ETNG – Hendersonville	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6. Total:	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
	Actual Purchases					
II. Components of MBIP	**Dth (A)**	**Percent (B)**	**Component Benchmark ($/Dth) (C)**	**Weighted Component Benchmark ($/Dth) (D)**	**Monthly Benchmark (E)**	
1. Monthly Purchases	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
2. Daily Purchases	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
3. Citygate Purchases	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
4. Purchases/MBIP	[redacted]	[redacted]		[redacted]	[redacted]	
5. Actual Costs					[redacted]	
6. Gain/(Loss) Based on MBIP:					[redacted] [1]	
III. Commodity Procurement Gain/(Loss) by Component	**Actual Purchases (Dth) (A)**	**Component Benchmark ($/Dth) (B)**	**Actual Cost ($/Dth) (C)**	**Unit Gain/(Loss) ($/Dth) (D)**	**Total Savings/(Loss) (E)**	
1. Monthly Purchases	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
2. Daily Purchases	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
3. Citygate Purchases	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
4. Purchases Gain/(Loss):	[redacted]	[redacted]	[redacted]		[redacted] [1]	

Note: FOM = First of the month; MBIP = Monthly Benchmark Index Price.
[1] Differences are due to rounding. Piedmont's calculated gain is [redacted].

3.1.2. Review Period Gas Procurement Activity

Firm Transportation Delivered Supplies. Table 9 provides a comparison of monthly benchmark prices for the locations at which Piedmont could have purchased gas using its firm transportation capacity during the review period.[8] That is, the prices in Table 9 reflect the effective delivered variable cost for purchases that would have been made at these various locations. The prices identified in Table 9 were used to calculate the monthly component of the MBIP. As indicated previously, index prices are published after trading for a location has

[8] Under the Plan, monthly MGT purchases are benchmarked based on *NGI* index prices. All other monthly purchases are benchmarked based on *Inside FERC* index prices.

Table 9. Summary of First-of-the-Month, Monthly Benchmark Prices (Dth)

	Tennessee Zone L					Midwestern Chicago Citygate			
Month/ Year	500 Leg	800 Leg	Columbia Gulf Rayne	Texas Eastern ELA[1]	Columbia Gas Appalachia[2]	Via TGP	Via Columbia Gulf	Via ETNG	Columbia Gulf via ETNG[3]
Jul 2020	[redacted]								
Aug	[redacted]								
Sep	[redacted]								
Oct	[redacted]								
Nov	[redacted]								
Dec	[redacted]								
Jan 2021	[redacted]								
Feb	[redacted]								
Mar	[redacted]								
Apr	[redacted]								
May	[redacted]								
Jun	[redacted]								
Winter Average:	[redacted]								
Annual Average:	[redacted]								
Jul 2021	[redacted]								
Aug	[redacted]								
Sep	[redacted]								
Oct	[redacted]								
Nov	[redacted]								
Dec	[redacted]								
Jan 2022	[redacted]								
Feb	[redacted]								
Mar	[redacted]								
Apr	[redacted]								
May	[redacted]								
Jun	[redacted]								
Winter Average:	[redacted]								
Annual Average:	[redacted]								
Jul 2022	[redacted]								
Aug	[redacted]								
Sep	[redacted]								
Oct	[redacted]								
Nov	[redacted]								
Dec	[redacted]								
Jan 2023	[redacted]								
Feb	[redacted]								
Mar	[redacted]								
Apr	[redacted]								
May	[redacted]								
Jun	[redacted]								
Winter Average:	[redacted]								
Annual Average:	[redacted]								
Review Period									
Winter Average:	[redacted]								
Annual Average:	[redacted]								

[1] Piedmont's Texas Eastern ELA transportation arrangement is a winter-only contract; therefore, purchases during the period April-October are not available.

[2] Piedmont only purchased Columbia Gas supplies during the summer to inject into Columbia Gas FSS Storage.

[3] Piedmont replaced its MGT transportation arrangements with Columbia Gulf capacity effective November 1, 2022.

concluded. Therefore, while market participants will have a close estimate of an index price during the trading period, the precise index price will not be known until it is published. As indicated by the prices identified in Table 9, during the audit period, [redacted]

Table 10 identifies Piedmont's review period monthly purchases by location, and reveals that Piedmont generally maximized purchases under its firm transportation contract with [redacted], its lowest-cost source of supply. As indicated in Section 2.1 of the Report, TGP-delivered supplies are required to meet customer requirements on the western side of Piedmont's system, and Columbia Gulf-delivered supplies are required to meet customer requirements on the eastern side of Piedmont's system. Therefore, deliveries from both Columbia Gulf and TGP are required. TGP-delivered supplies serving the western side of Piedmont's system may initially be delivered to TGP by MGT. Table 10 reveals that Piedmont minimized the purchase of [redacted], which were the highest-cost Gulf Coast production region source of supply during the review period (see Table 9). As indicated previously, [redacted] (see Table 9). However, during the summer of 2022, [redacted]. During the months in which [redacted] were anticipated to be lower-cost, Piedmont purchased [redacted] to serve the western side of its system. Exeter's review of Piedmont's purchases that were delivered under the Company's firm transportation arrangements found these purchases to be consistent with least-cost procurement.

Table 10. Summary of First-of -the-Month Market Purchases (Dth)

Month/ Year	Tennessee Zone L		Columbia Gulf Rayne	Texas Eastern ELA	Columbia Gas Appalachia	Midwestern Chicago Citygate			Columbia Gulf via ETNG	Total
	500 Leg	800 Leg				Via TGP	Via Columbia Gulf	Via ETNG		
Jul 2020	[redacted]									
Aug	[redacted]									
Sep	[redacted]									
Oct	[redacted]									
Nov	[redacted]									
Dec	[redacted]									
Jan 2021	[redacted]									
Feb	[redacted]									
Mar	[redacted]									
Apr	[redacted]									
May	[redacted]									
Jun	[redacted]									
Subtotal:	[redacted]									
Jul 2021	[redacted]									
Aug	[redacted]									
Sep	[redacted]									
Oct	[redacted]									
Nov	[redacted]									
Dec	[redacted]									
Jan 2022	[redacted]									
Feb	[redacted]									
Mar	[redacted]									
Apr	[redacted]									
May	[redacted]									
Jun	[redacted]									
Subtotal:	[redacted]									
Jul 2022	[redacted]									
Aug	[redacted]									
Sep	[redacted]									
Oct	[redacted]									
Nov	[redacted]									
Dec	[redacted]									
Jan 2023	[redacted]									
Feb	[redacted]									
Mar	[redacted]									
Apr	[redacted]									
May	[redacted]									
Jun	[redacted]									
Subtotal:	[redacted]									
Total:	[redacted]									
Percent:	[redacted]									

Table 11 identifies Piedmont's total purchases (monthly and daily) that were delivered under firm transportation arrangements during the review period. Due to the extensive amount of data, daily delivered prices for each transportation arrangement are not provided; however, these prices exhibited the same relative relationship, by location, as the monthly delivered prices shown in Table 9.

Table 11. Summary of First-of-the Month Baseload and Daily Purchases (Dth)

	Tennessee Zone L					Midwestern Chicago Citygate				
Month/ Year	500 Leg	800 Leg	Columbia Gulf Rayne	Texas Eastern ELA	Columbia Gas Appalachia	Via TGP	Via Columbia Gulf	Via ETNG	Columbia Gulf via ETNG	Total
Jul 2020	[redacted]									
Aug										
Sep										
Oct										
Nov										
Dec										
Jan 2021										
Feb										
Mar										
Apr										
May										
Jun										
Subtotal:										
Jul 2021										
Aug										
Sep										
Oct										
Nov										
Dec										
Jan 2022										
Feb										
Mar										
Apr										
May										
Jun										
Subtotal:										
Jul 2022										
Aug										
Sep										
Oct										
Nov										
Dec										
Jan 2023										
Feb										
Mar										
Apr										
May										
Jun										
Subtotal:										
Total:										
Percent:										

Citygate-Delivered Supplies. Table 12 summarizes Piedmont's citygate purchase quantities during the review period. Piedmont's citygate-delivered supplies during the review period represented [redacted]

[redacted]

Table 12. Summary of Interruptible and Citygate-Delivered Purchases (Dth)

Month/Year	TGP Citygate	MGT Via ETNG to Boat Dock	Columbia Gulf IT	Texas Eastern	Columbia Gulf Via ETNG	Total
Jul 2020	[redacted]					
Aug						
Sep						
Oct						
Nov						
Dec						
Jan 2021						
Feb						
Mar						
Apr						
May						
Jun						
Subtotal:						
Jul 2021						
Aug						
Sep						
Oct						
Nov						
Dec						
Jan 2022						
Feb						
Mar						
Apr						
May						
Jun						
Subtotal:						
Jul 2022						
Aug						
Sep						
Oct						
Nov						
Dec						
Jan 2023						
Feb						
Mar						
Apr						
May						
Jun						
Subtotal:						
Total:						
Percent:						

3.1.3. Results and Conclusions

Table 13 presents a summary of Piedmont's gas commodity procurement incentive mechanism purchases and gains/losses by month and type of purchase (i.e., monthly, daily, citygate). As shown in Table 13, significant gains were realized on citygate purchases during February 2021. The February 2021 gains are discussed in greater detail later in this section of the Report. Excluding the month of February 2021, commodity procurement incentive mechanism gains were almost entirely achieved through monthly purchases during the review period. No gains were achieved through daily purchases.

Table 13. Summary of Review Period Purchases and Commodity Procurement Gains/(Losses)

	Purchases by Type (Dth)				Gain/(Loss) by Type of Purchase			
Month/ Year	**Monthly**	**Daily**	**IT/ Citygate**	**Total**	**Monthly**	**Daily**	**IT/ Citygate**	**Total**
Jul 2020	[redacted]							
Aug	[redacted]							
Sep	[redacted]							
Oct	[redacted]							
Nov	[redacted]							
Dec	[redacted]							
Jan 2021	[redacted]							
Feb	[redacted]							
Mar	[redacted]							
Apr	[redacted]							
May	[redacted]							
Jun	[redacted]							
Subtotal:	[redacted]							
Jul 2021	[redacted]							
Aug	[redacted]							
Sep	[redacted]							
Oct	[redacted]							
Nov	[redacted]							
Dec	[redacted]							
Jan 2022	[redacted]							
Feb	[redacted]							
Mar	[redacted]							
Apr	[redacted]							
May	[redacted]							
Jun	[redacted]							
Subtotal:	[redacted]							
Jul 2022	[redacted]							
Aug	[redacted]							
Sep	[redacted]							
Oct	[redacted]							
Nov	[redacted]							
Dec	[redacted]							
Jan 2023	[redacted]							
Feb	[redacted]							
Mar	[redacted]							
Apr	[redacted]							
May	[redacted]							
Jun	[redacted]							
Subtotal:	[redacted]							
Total:	[redacted]							
Percent:	[redacted]							

Weighting the Benchmark for Monthly Purchases by Capacity Entitlements. The benchmark for monthly purchases included in the MBIP under the Plan provides an incentive to purchase gas at receipt point locations with the lowest total delivered variable cost. Consistent with the conclusions expressed in prior Plan reports, it remains Exeter's conclusion that the benchmark for monthly purchases provides rewards for performance that is not superior to that of other market participants. Gas utilities operating under traditional regulation routinely maximize the purchase of gas at receipt point locations with the lowest total delivered variable cost. Chattanooga Gas, another Tennessee gas utility that operates under a gas cost incentive mechanism, also maximizes the purchase of gas at receipt point locations with the lowest total delivered cost. Chattanooga Gas does not realize rewards for maximizing the purchase of the lowest-cost monthly supplies under its incentive mechanism. The incentive mechanism of Chattanooga Gas is further discussed in Section 7 of the Report.

In the Company's comments on previous Exeter Plan reports, Piedmont has indicated that the intended goal of the Plan was not to provide rewards only when the Company outperformed other market participants. Piedmont stated that the goal of the Plan was to align the interests of the Company and its customers with respect to procuring and selecting the lowest delivered cost of gas available. Exeter agrees that the interests of Piedmont and its customers are aligned under this aspect of the Plan. Nevertheless, it remains Exeter's conclusion that the benchmark for monthly purchases included in the MBIP results in gas cost "savings" that would have been realized without the existence of the Plan. An incentive mechanism such as Piedmont's Plan should provide rewards for improvements in performance, and not provide rewards for performance that would be experienced in absence of the incentive mechanism under traditional regulation.

Capacity Entitlements Included in the Weightings Utilized to Calculate the Benchmark for Monthly Purchases. The Plan requires that the pipeline capacity weightings utilized to calculate the benchmark for monthly purchases be based on design day citygate delivery entitlements (Piedmont tariff, Service Schedule No. 316, Fifth Revised page 3 of 7, footnote 4). Footnote 3 on page 2 of Piedmont service Schedule No. 316 provides that if capacity was released or otherwise unavailable to be used to deliver gas to Piedmont's citygate, that capacity should be excluded from the monthly purchase benchmark calculation. Piedmont generally followed these requirements during the audit period by reducing its design day citygate capacity entitlements to eliminate those capacity entitlements assigned to the Asset Manager under its audit period AMAs, which the Asset Manager had no obligation to deliver gas supplies. As initially discussed in footnote 7 on page 16 of the Report, Piedmont initially utilized incorrect capacity entitlements for its Columbia Gulf FTS-1 capacity for October 2022 to calculate the monthly benchmark. The Company subsequently recalculated the benchmark and Plan gains for the July 2022 – June 2023 Plan year to reflect the appropriate capacity entitlements. This resulted in an additional gain of [redacted] for the July 2022 – June 2023 Plan year. [redacted]

Hendersonville ETNG Citygate Purchases. The use of Chicago citygate index prices to benchmark ETNG citygate purchases during the portion of the review period in which Piedmont maintained MGT capacity was unreasonable and inappropriate. This is best exemplified by the unreasonable and inappropriate gains realized by Piedmont under the Plan during February 2021. During the period February 13-16, 2021, Piedmont purchased [redacted] of ETNG citygate-delivered supplies at an average cost of [redacted]/Dth. The gain realized under the Plan for the ETNG citygate purchases for these four days was [redacted], or [redacted]/Dth. The Chicago citygate index price on these four days was [redacted]/Dth. The total gain for the entire month of February 2021 for ETNG citygate purchases was [redacted].

Benchmarks under a gas cost incentive mechanism such as the Plan should be based on market prices, and rewards should be based on performance which exceeds that of other market participants. Based on the evidence presented, the benchmarking of ETNG purchases based on Chicago citygate index prices did not achieve these results during the review period. Until November 2022, Piedmont maintained firm transportation capacity on MGT, and ETNG purchases were benchmarked based on the assumption that these purchases were delivered to ETNG from the Chicago area by MGT. Based on the differences between Chicago citygate index prices observed during the period February 13-16, 2021 and the prices at which Piedmont was able to purchase ETNG delivered supplies, the assumption that the ETNG purchases were delivered to ETNG from the Chicago area by MGT was unreasonable and inappropriate. Exeter's 2021 audit report noted these concerns with respect to benchmarking ETNG purchases based on Chicago citygate index prices and recommended that alterative index prices for ETNG purchases be considered. However, during the review period, effective November 2022, Piedmont replaced its MGT capacity with Columbia Gulf capacity. As a result, ETNG purchases are now benchmarked based on Columbia Gulf index prices. This should alleviate the concerns with benchmarking ETNG purchases based on Chicago citygate index prices.

3.2. Supplier Reservation Fees Component

3.2.1. Background and Description

The Plan allows Piedmont to recover 100% of its gas supplier reservation fees with no profit or loss potential. Piedmont entered into one citygate gas supply contract with a reservation fee during the review period. That contract, which was previously described in Section 2.4.1, was with [redacted]. The term of this contract was December 1, 2020 through February 28, 2021, and provided for the delivery of up to [redacted] Dth/day. The reservation fee was equal to [redacted] times the MDQ, times the number of days in the month. Reservation fees under this contract totaled [redacted]. The commodity charge under the [redacted] contract was equal to the [redacted] price minus [redacted]/Dth. The Plan requires that for gas supply contracts with a reservation charge and a discount to the commodity index price, the Company is required to modify the commodity index price to reflect such a discount. Piedmont purchased no gas supplies under the [redacted] contract and, therefore, no adjustments to the commodity index price were necessary during the review period.

In addition to the citygate contract with [redacted] Piedmont maintained a gas supply contract with [redacted] which was subject to the Plan during the review period. The contract with [redacted] was previously discussed in Section 2.4.6. The term of the contract with [redacted] was November 1, 2020, through March 31, 2021, and provided for the delivery of up to [redacted]/day. The reservation fee was equal to [redacted] times the MDQ, times the number of days in the month. Reservation charges under the [redacted] contract totaled [redacted].

3.2.2. Results and Conclusions

Gas supply contracts can be arranged to provide for a discount on commodity index prices in exchange for higher demand charge supplier reservation fees. The Plan requires modifications to the applicable index price to reflect such discounts. Gas supply contracts can also be arranged that provide for the ability to purchase gas at FOM index prices after the first of the month, when daily market gas prices are higher (FOM call option) in exchange for higher supplier reservation fees. With 100% recovery of supplier reservation fees, monthly call option contracts could improperly reward Piedmont. All of the Company's contracts with supplier reservation fees during the review period included index commodity pricing, with no FOM price purchase rights. Therefore, Exeter has no concerns with Piedmont's administration of supplier reservation fees under the commodity procurement cost component of the Plan during the review period.

3.3. Capacity Management Component

3.3.1. Background and Description

Piedmont realized revenues under the capacity management component of the Plan through AMAs and off-system sales during the review period. Table 14 summarizes the capacity management revenues realized by Piedmont during the review period.

Table 14. Summary of Capacity Management Revenues

		Off-System Sales			Revenues	
Month/ Year	**Asset Management**	**Volume (Dth)**	**Margin**	**Total**	**Company 25%**	**Ratepayers 75%**
Jul 2020	[redacted]					
Aug	[redacted]					
Sep	[redacted]					
Oct	[redacted]					
Nov	[redacted]					
Dec	[redacted]					
Jan 2021	[redacted]					
Feb	[redacted]					
Mar	[redacted]					
Apr	[redacted]					
May	[redacted]					
Jun	[redacted]					
Subtotal:	[redacted]					
Jul 2021	[redacted]					
Aug	[redacted]					
Sep	[redacted]					
Oct	[redacted]					
Nov	[redacted]					
Dec	[redacted]					
Jan 2022	[redacted]					
Feb	[redacted]					
Mar	[redacted]					
Apr	[redacted]					
May	[redacted]					
Jun	[redacted]					
Subtotal:	[redacted]					
Jul 2022	[redacted]					
Aug	[redacted]					
Sep	[redacted]					
Oct	[redacted]					
Nov	[redacted]					
Dec	[redacted]					
Jan 2023	[redacted]					
Feb	[redacted]					
Mar	[redacted]					
Apr	[redacted]					
May	[redacted]					
Jun	[redacted]					
Subtotal:	[redacted]					
Total:	[redacted]					

Piedmont is entitled to retain 25% of capacity management revenues, up to a cap of $1.6 million, including gains under the commodity procurement cost component of the Plan. The 25% Company sharing for AMA revenues is at the high end of the sharing procedures approved in other jurisdictions and the 25% Company sharing for off-system sales margin is consistent with Exeter's experience in other jurisdictions.

Piedmont's review period AMAs were previously summarized in Section 2.4 of the Report. As shown there, the annual AMA fees received increased during the review period. The business activities and records of Piedmont's Asset Manager are not available for review to investigate why the AMA fees increased. The Company believes that the AMA fees it received increased during the review period because its capacity portfolio increased in value due to an increase in gas market prices and price volatility. These prices increases, and the increase in price volatility is shown in Table 9. In addition, the most recent AMA was contracted for a three-year term instead of a one-year term, and the longer term provided more value to an Asset Manager. Exeter concurs with Piedmont's evaluation.

Capacity release revenues are also subject to sharing under the capacity management component of the Plan. However, Piedmont released all of its interstate pipeline capacity to the AMA Asset Manager and, therefore, Piedmont did not engage in capacity release activities during the review period.[9]

The release of all of Piedmont's capacity to the Asset Manager also limited Piedmont's ability to engage in off-system sales activities during the review period. Under Piedmont's AMA, Piedmont had the option to sell to the Asset Manager, at daily index prices, monthly baseload purchases that were in excess of Piedmont's requirements. Piedmont's off-system activities during the review period were limited to such sales back to the Asset Manager. These sales are included in Table 14 above.

3.3.2. Results and Conclusions

In prior triennial reviews of Piedmont's Plan, Exeter identified a general concern with Piedmont's off-system sales activities in that the supplies being sold off-system were frequently later being replaced with higher-cost supplies, adversely impacting the gas costs of sales customers. This concern has also surfaced during the current review period; however, off-system sales activity occurred significantly less frequently than was observed during the prior audits, and the adverse impact was relatively insignificant.

Piedmont released all of its review period interstate pipeline capacity under its AMAs and, therefore, the Company was generally unable to use its interstate pipeline capacity to engage in off-system sales activity. Piedmont's review period off-system sales profit opportunities were largely limited to the sale of baseload supplies back to the Asset Manager. When Piedmont engaged in these off-system sales, the sales were often made towards the end of

[9] The release of all of a gas utility's interstate pipeline capacity under an AMA is standard industry practice.

the month, and the Company frequently purchased supplies at the same location at the beginning of the next month at higher prices. Had Piedmont not sold monthly baseload supplies off-system, and instead injected those supplies into storage, the Company could have potentially reduced the following month's higher-priced monthly baseload purchases. Exeter's audit noted two instances where this occurred during the review period: (1) the sale of gas at the end of June 2020 with an average cost of [redacted]/Dth, and the purchase of supplies at [redacted]/Dth the following month (July 2020); and (2) the sale of gas at the end of June 2023 with an average cost of [redacted]/Dth, and the purchase of supplies at [redacted]/Dth the following month (July 2023).

In conclusion, off-system sales activities contributed relatively little to Piedmont's capacity management revenues, totaling [redacted] over the three-year review period. The two instances noted above where Piedmont sold gas to the Asset Manager and subsequently purchased supplies at higher prices generated all of Piedmont's off-system sales margins. These sales to the Asset Manager appear to have had an adverse impact on the gas costs of sales customers of approximately [redacted], while generating a reward for Piedmont under the Plan. Although this adverse impact was relatively insignificant during the review period, the potential exists for the adverse impact to be significantly greater in the future. Therefore, except for potentially operational reasons, Exeter concludes, as it did in the most recent prior audit, that it would be in the best interests of ratepayers if Piedmont did not engage in off-system sales when all of the Company's capacity is assigned under an AMA.

4. Storage Activity

The Statement of Work for this audit, as identified in the RFP, requires the review of Piedmont's gas procurement, capacity management, and off-system sales activities and transactions. These transactions and activities were reviewed in detail in Section 3 of the Report. Also required for review are Piedmont's storage activities, which are described in this section of the Report.

4.1. Storage Arrangements and Activity

As discussed in greater detail in Section 2 of the Report, Piedmont purchased unbundled storage service from TGP under Rate Schedules FS-MA and FS-PA, and from Columbia Gas under Rate Schedule FSS. Piedmont also owns and operates an LNG storage facility. The Company's storage resources during the review period are summarized in Table 15.

Table 15. Summary of Review Period Storage Service Resources

Service	Rate Schedule	Maximum Withdrawal Quantity (Dth)	
		Daily	Seasonal
Tennessee Gas Pipeline	FS-MA	50,798	2,901,943
Tennessee Gas Pipeline	FS-PA	6,190	672,091
Columbia Gas Transmission	FSS	10,000	611,870
Piedmont LNG	-	[redacted]	[redacted]
Total:		[redacted]	[redacted]

Table 16 identifies the monthly storage activity (injections/withdrawals) and the inventory balances under each of Piedmont's storage arrangements at the conclusion of each month of the review period. Also shown are storage inventory balances as a percent of the Company's maximum seasonal contract quantity. The storage activity presented in Table 16 reflects Piedmont's virtual dispatch use of storage, not the actual physical use of storage by its Asset Manager during the review period.

Table 16. Summary of Review Period Storage Activity (Dth)

	Tennessee Gas Pipeline (FS-MA)			Tennessee Gas Pipeline (FS-PA)			Columbia Gas Transmission (FSS)			Piedmont (LNG)		
Month/ Year	Activity (Inject/ With-drawals)	Ending Inven-tory	% Capacity 2,901,943	Activity (Inject./ With-drawals	Ending Inven-tory	% Capacity 672,091	Activity (Inject./ With-drawals	Ending Inven-tory	% Capacity 611,870	Activity (Inject./ With-drawals	Ending Inven-tory	% Capacity 1,000,000
Jul 2020	[redacted]											
Aug												
Sep												
Oct												
Nov												
Dec												
Jan 2021												
Feb												
Mar												
Apr												
May												
Jun												
Jul 2021												
Aug												
Sep												
Oct												
Nov												
Dec												
Jan 2022												
Feb												
Mar												
Apr												
May												
Jun												
Jul 2022												
Aug												
Sep												
Oct												
Nov												
Dec												
Jan 2023												
Feb												
Mar												
Apr												
May												
Jun												

4.2. Storage Planning Guidelines

Piedmont has established general storage planning guidelines that identify the inventory balances the Company plans to maintain. Piedmont targets to fill TGP FS-MA and FS-PA storage to [redacted] of capacity by December 1, and to fill Columbia Gas storage and the Company's LNG storage to [redacted] of capacity by November 1. [redacted] Piedmont plans to reduce the storage inventory balances under each of its interstate pipeline storage services to [redacted] by the conclusion of the storage withdrawal season (March 31). Columbia Gas' FERC tariff for FSS includes storage inventory cycling requirements that Piedmont is required to follow. No cycling requirements exist under TGP's tariff for FS-MA or FS-PA storage. LNG storage is used when needed to meet customer demands and/or meet the operational requirements of the facility to cycle gas (e.g., if the British thermal unit [Btu] value is high, the gas may need to be cycled). Piedmont's actual and planned interstate pipeline inventory balances during the review period are summarized in Table 17. As shown, actual beginning-of-storage season inventory balances were generally consistent with planned balances. However, end-of-storage season inventory balances, and specifically TGP inventory balances, [redacted]

Table 17. Review Period Planned and Actual Storage Inventory

	March 31		November 1		December 1	
Year	Planned	Actual	Planned	Actual	Planned	Actual
			Tennessee Gas Pipeline (FS-MA/FS-PA)			
2020	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
			Columbia Gas Transmission (FSS)			
2020	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

At the conclusion of the winter of 2020-2021, TGP storage inventory balances were at [redacted] of capacity, while the Columbia Gas inventory balance was at [redacted] of capacity. [redacted]

Piedmont's TGP storage inventory balances at the conclusion of the winter of 2021-2022 were at [redacted] of capacity, and the Columbia Gas storage inventory balance was at [redacted] of capacity. [redacted].

Piedmont's TGP and Columbia Gas storage inventory balances at the conclusion of the 2022-2023 winter season were at [redacted] of capacity, respectively. Storage balances exceeded Piedmont's planning criteria largely due to winter period gas prices that were generally less than the cost of gas in storage inventory that was injected the previous summer (see Table 9). As a result of these low prices, there was little price benefit to sales customers associated with withdrawing gas from storage. [redacted]

In conclusion, Exeter's review finds that Piedmont's storage inventory planning criteria are generally reasonable, and are consistent with the criteria used by other gas distribution companies. Piedmont generally adhered to those criteria unless market conditions or operational requirements indicated that deviations were appropriate. Therefore, Piedmont's review period storage activity appears reasonable.

5. Evaluation of Capacity Portfolio and Identification of Variable Charges

5.1. Design Day Forecast and Criteria

Piedmont secures sufficient capacity resources to meet the forecasted design day requirements of its sales customers and those transportation customers that select standby service. For the winters of 2020-2021 and 2021-2022, Piedmont utilized a day with an average daily temperature of -5°F, or 70 heating degree days (HDDs), as its design day criteria. This criteria was initially adopted by Piedmont for the 2014-2015 winter season and reflected the coldest average daily temperature experienced in the Company's service territory over the last 30 years (which occurred on January 20, 1985). It is common industry practice for natural gas utilities to utilize the coldest day experienced in the last 30 years for their design day criteria. Therefore, Piedmont's use of temperatures experienced in 1985 is slightly conservative.

Piedmont's design day forecasts for the winters of 2020-2021 and 2021-2022 were based on an analysis of daily firm sales and firm transportation sendout for the most recent five-year period available. Through this analysis, Piedmont determined baseload usage and usage-per-HDD factors, and utilized these usage factors to determine forecasted firm design day demands at 70 HDDs. Baseload usage was determined through a regression analysis of usage on days with ten or fewer HDDs. The usage-per-HDD factor was determined through a regression analysis of usage on days with greater than ten HDDs. Included in the Company's forecast of design day demands was a 5% reserve margin.

In our 2021 audit report, Exeter recommended that Piedmont evaluate the inclusion of independent variables in addition to HDDs such as windspeed in its design day forecasting model. In 2022, Piedmont retained Marquette Energy Analytics (MEA) to perform a design day study for the winter of 2022-2023 through the winter of 2026-2027. The purpose of the study was to develop a forecast of Piedmont's design day requirements. The study performed by MEA recommended that Piedmont utilize a wind-adjusted average daily temperature, or WHDDs, rather than the average daily temperatures or HDDs as its design day criteria, as windspeed also affects customer gas usage. MEA's WHDDs are calculated as follows.

[redacted]

The MEA study recommended retention of the one-in-30 year design day criteria, and based on this criteria through a statistical analysis, MEA determined that the wind-adjusted HDD criteria for Piedmont's design day should be 72.9 WHDD, or a wind-adjusted temperature of -7.9°F. This is equivalent to a day with 70 HDDs, or an average temperature of -5°F, and an average windspeed of 11.3 MPH. Piedmont adopted the MEA wind-adjusted design day criteria for the winter of 2022-2023. MEA also prepared a forecast of Piedmont's design day requirements for the winter of 2022-2023 based on the 72.9 WHDD design day criteria. MEA's forecast included adjustments that recognize customer growth and conservation impacts. A comparison of the Company's firm design day forecasts and available capacity resources for the review period and the winter of 2023-2024 is presented in Table 18. Included in the Company's design day forecasts for each winter season is a reserve margin of 5% to account statistical anomalies, unanticipated supply or capacity interruptions, *force majeure* declarations by the Company's interstate pipeline service providers, and colder-than-design-day weather.

Table 18. Comparison of Estimated Design Day Demands and Capacity Resources (Dth)

Winter Season	Firm Demand[1]	Capacity Resources	Surplus (Deficit)	Percent
2020-2021	404,153	407,270	3,117	0.8%
2021-2022	413,441	444,270	30,829	6.9%
2022-2023	438,401	464,270	25,869	5.6%
2023-2024	437,686	464,270	26,584	5.7%

[1] Includes transportation customer standby service requirements for the winters of 2020-2021 and 2021-2022. Standby service requirements were not included by MEA in the estimated demand for the winters of 2022-2023 and 2023-2024.

The Statement of Work for this audit requires an assessment of the extent to which Piedmont's design peak day forecasting approach considered customer conservation efforts. The design peak day forecast model prepared by Piedmont for the winters of 2020-2021 and 2021-2022 did not explicitly consider customer conservation efforts. The design peak day forecast model prepared by MEA for the winter of 2022-2023 did explicitly consider customer conservation efforts. The design peak day forecast prepared by MEA for the winter of 2022-2023 reflected a reduction of 1,459 Dth to account for conservation efforts.

5.2. Actual Peak Day and Design Day Model Forecasting Accuracy

A comparison of actual peak day firm requirements and forecasted requirements under actual peak weather conditions using Piedmont's design day forecasting model can provide an indication of the predictive capability of the Company's design day forecasting model. To assess the predictive capability of a forecasting approach and model used by a gas utility, Exeter would typically compare actual firm sendout with the forecasted firm sendout under actual peak weather conditions on the five coldest non-holiday/non-weekend days during the winter season for which the model was developed. When the Company was requested to provide a comparison of actual and forecasted sendout under actual peak weather conditions for the 2022-2023 winter season, the Company indicated that the MEA design day model is the result of an ensemble of multiple models based on the design day conditions that MEA calculates. Therefore, the Company is not able to calculate sendout requirements that would have been projected by MEA's design day model based on actual WHDDs. In response to Exeter's request, Piedmont provided the daily forecasts based on actual WHDDs that are prepared by MEA and used by the Company for operations and planning purposes. A comparison of actual and forecasted sendout based on MEA's daily forecasting model and actual WHDDs for the five coldest non-holiday/non-weekend days during the winter of 2022-2023 is presented in Table 19. As shown in Table 19, MEA's forecasting daily model has been extremely accurate.

Table 19. Comparison of Actual and Projected Firm Demand on Five Coldest Non-Weekend/Non-Holidays During the 2022-2023 Winter Season (Dth)

Date	WHDD	Actual	Forecast	Variation	Percent
November 20, 2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
December 20, 2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
December 26, 2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
January 31, 2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
February 1, 2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

5.3. Balance of Capacity Resources and Design Day Requirements

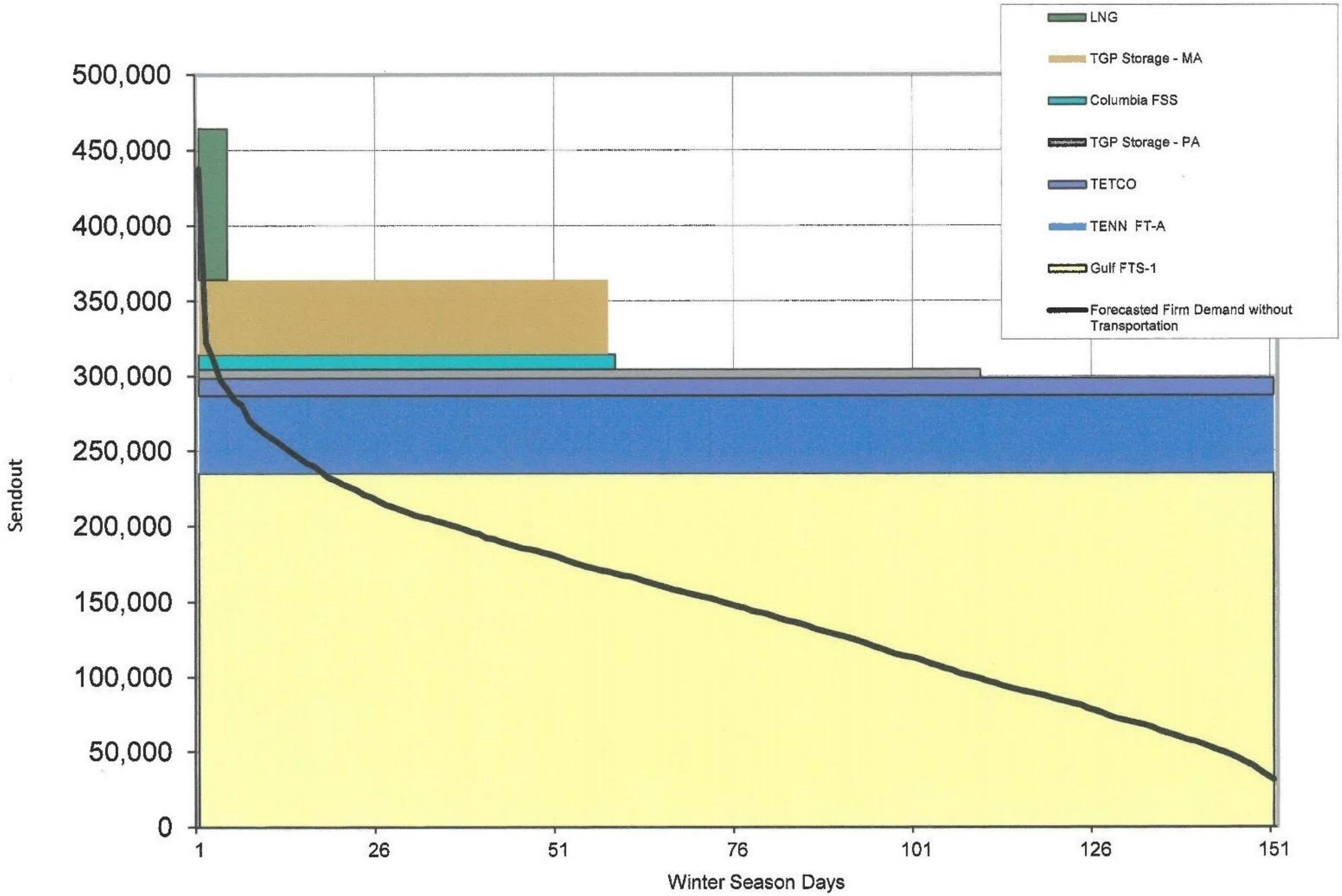
A comparison of Piedmont's estimated design day demands and the capacity resources available to meet those demands for the review period and the winter of 2023-2024 was previously presented in Table 18. The increases in capacity resources reflected in Table 18 were attributable to the increase in LNG facility deliverability discussed in Section 2.2.3 of this Report. Based on MEA's design day projections, the 5.7% capacity resources surplus that existed at the conclusion of the winter of 2023-2024 is expected to decline to 2.9% with anticipated increases in firm demand by the winter of 2026-2027. Exeter does not find this slight capacity resource surplus to be unreasonable.

5.4. Winter Season Capacity Resources and Requirements

Exeter's 2021 audit noted that for winter season capacity resource planning, Piedmont historically used a design winter in which the HDDs experienced each day were equal to the highest HDDs experienced on that day during the previous five years. Effective for the winter of 2017-2018, the Company modified its design winter planning criteria to reflect the coldest winter in the last five years. Exeter's 2021 audit report expressed a concern with this modified approach because it resulted in Piedmont utilizing a winter design criteria that was warmer than a normal winter. When engaged by Piedmont to perform a design day study for the winters of 2022-2023 through 2026-2027, MEA also calculated a design winter criteria for Piedmont also based on a one-in-30-year criteria, consistent with the one-in-30-year design day criteria selected by Piedmont. To develop this winter season design criteria, MEA utilized daily data dating back 73 years to the winter of 1949-1950. The design winter season criteria was determined by MEA to be 3,993 WHDD. The estimated requirements of Piedmont's sales customers during a design winter are 22.8 million Dth. As shown in Table 2, the capacity resources available to meet the winter season requirements of Piedmont's sales customers totaled 50.2 million Dth at the conclusion of the review period. This indicates that from a planning perspective, Piedmont's winter season capacity resources [redacted]

It is Exeter's experience that gas utilities typically maintain winter entitlements that significantly exceed their customers' design requirements. Piedmont obtains value for its unutilized firm transportation capacity by releasing that capacity under an AMA. Piedmont's load duration curve for the winter of 2023-2024 is presented in Figure 2. This demand curve illustrates the extent to which Piedmont maintained winter capacity resources in excess of its customers' requirements. The Company's 2023-2024 winter load duration curve is comparable to its load duration winter curve for the winter of 2022-2023.

Figure 2. 2023-2024 Load Duration Curve (Design Winter)



5.5. Annual Capacity Resources and Requirements

The estimated requirements of Piedmont's sales customers during a year in which a design winter season is experienced are approximately [redacted] Dth. As shown previously in Table 2, the capacity resources available to meet Piedmont's annual requirements totaled [redacted] Dth at the conclusion of the review period. Approximately [redacted] Dth of this capacity is used to fill storage during the summer period. Based on annual requirements of [redacted] Dth and summer storage injections of [redacted] Dth, Piedmont maintained an annual deliverability surplus of approximately [redacted] Dth. Piedmont's annual capacity resource and requirements balance is further discussed in Section 5.6 below.

5.6. Capacity Portfolio Utilization and Potential Modifications

The Statement of Work for Exeter's review includes examination and identification of: (a) the cost of year-round firm transportation and seasonal firm transportation utilized by Piedmont during the review period to meet peak demand; (b) the potential cost of meeting peak demand with more seasonal firm transportation and less year-round firm transportation; and (c) the potential cost of meeting peak demand with more year-round firm transportation and less seasonal firm transportation. Exeter interprets this aspect of the Statement of Work as requiring Exeter to evaluate whether Piedmont's annual interstate pipeline demand charges can be reduced by modifying the Company's current capacity portfolio. The annual costs associated with each non-storage-related interstate pipeline firm transportation service purchased by Piedmont at the conclusion of the review period are summarized in Table 20.

Table 20. Summary of Interstate Pipeline Firm Transportation Charges

Pipeline/ (Contract No.)	MDQ (Dth) Winter	MDQ (Dth) Summer	Annual Commodity (Dth)	Monthly Demand Charge ($/Dth)	Annual Demand Cost
Columbia Gulf Transmission					
FTS-1 (266480)	10,000	9,202	3,479,228	$5.0490	**$577,676**
FTS-1 (269151)	25,000	25,000	9,125,000	$5.0490	**$1,514,700**
FTS-1 (194490)	200,193	81,815	47,737,553	$5.0490	**$7,945,460**
Tennessee Gas Pipeline					
FT-A (237)	51,500	51,500	18,797,500	[redacted]	[redacted]
Texas Eastern Transmission					
FT-1 (910473)	10,000	0	1,510,000	[redacted]	[redacted]
SCT (800059)	1,677	1,677	612,105	[redacted]	[redacted]
Total:					[redacted]

Actual review period utilization of the Company's firm transportation capacity for the final year of the review period is presented in Table 21. As shown, the Company's firm transportation arrangements were utilized [redacted] The Columbia Gulf and TGP capacity were utilized [redacted] respectively. The Company's MGT capacity was utilized [redacted] The Texas Eastern capacity load factor [redacted]

Table 21. Summary of Firm Transportation Contract Utilization (July 2022 – June 2023 Plan Year)

Pipeline/Rate Schedule	Annual Quantity (Dth) Maximum	Annual Quantity (Dth) Actual	Load Factor
Columbia Gulf Transmission			
FTS-1 (266480/269151/194490)	60,341,781[1]	[redacted][1]	[redacted]
Tennessee Gas Pipeline			
FT-A (237)	18,797,500	[redacted]	[redacted]
Texas Eastern Transmission			
FT-1 (910473)	1,510,000	[redacted]	[redacted]
Total:	**80,649,281**	[redacted]	[redacted]

[1] Columbia Gulf Contract No. 269151 replaced 25,000 Dth of capacity under MGT Contract Nos. FA0342 and FB0006 effective November 1, 2022. To provide for a more representative likely utilization of Columbia Gulf Contract No. 269151, the maximum quantities reflect volumes moved under the MGT contracts during the period July – October 2022.

With respect to the potential for Piedmont to reduce its demand charges by decreasing the year-round and increasing seasonal capacity, Exeter notes the following. As previously shown in Table 2, a significant portion of Piedmont's 2022-2023 capacity portfolio at the conclusion of the review period consists of either winter season capacity or is sculpted, with winter season entitlements being higher than summer season entitlements. That capacity portfolio will remain unchanged for the winter of 2023-2024. Total capacity entitlements under the Company's firm transportation with Columbia Gulf are seasonally sculpted. In total, the Company's summer capacity entitlements will be nearly 65% less than its winter capacity entitlements. Piedmont has indicated, and it is consistent with Exeter's experience in reviewing interstate pipeline contracting practices, that interstate pipelines are not willing to enter into winter-only capacity contracts. Therefore, the potential for Piedmont to rely more on winter season capacity and reduce year-round capacity is limited. Finally, as noted in Section 2.1.4. of the Report. At the commencement of the review period, Piedmont maintained [redacted] Dth of [redacted] firm transportation capacity. As also explained in Section 2.1.4, as a result of the availability of abundant supplies from the [redacted] production regions, Piedmont only considered [redacted] Dth of its [redacted] capacity to be a reliable design day capacity resource. During the review period, Piedmont terminated its MGT firm transportation arrangements and replaced that capacity with [redacted] Dth of [redacted] capacity. This reduced Piedmonts' annual interstate pipeline demand charges by approximately [redacted]

5.7. Commodity, Fuel, and Storage Charges

In addition to requiring the payment of demand charges, which are fixed and not based on actual usage, the firm transportation services Piedmont purchases from its interstate pipelines service providers require the payment of variable charges that are based on actual usage. Piedmont is also assessed in-kind fuel charges based on actual purchase quantities. Under its pipeline storage arrangements, Piedmont is assessed volumetric injection and withdrawal charges, and is also assessed storage injection fuel charges.

A requirement included in the Statement of Work of Exeter's review is to identify the various commodity costs charged to Piedmont under each of the Company's interstate pipeline service arrangements as well as those billed to Piedmont's Tennessee customers. During the course of Exeter's review, Piedmont indicated that it did not maintain information in a manner that would enable Exeter to identify the specific charges by type. [redacted] Piedmont recovers the interstate pipeline commodity charges it is assessed for the services used to serve its Tennessee customers on a dollar-for-dollar basis. The various interstate pipeline commodity rates in effect at the conclusion of the review period are identified in Table 22.

Table 22. Interstate Pipeline Variable Charges

Transportation Services		
Pipeline/Rate Schedule (Contract)	**Commodity Charge ($/Dth)**	**Fuel Charge**
Columbia Gas Transmission		
SST (38052) to Storage	$0.0132	2.132%
Columbia Gulf Transmission		
FTS-1 (266480/269151/194490)	$0.0109	3.306%
Tennessee Gas Pipeline		
FT-A (237)	$0.0099	1.01%
FT-A (301244)	$0.0099	1.01%
Texas Eastern Transmission		
FT-1 (910473)	$0.1688	0.44%

Storage Services			
Pipeline/Rate Schedule (Contract)	**Variable Charge ($/Dth)**		**Injection Fuel Charge**
	Injection	**Withdrawal**	
Columbia Gas Transmission			
FSS (53017)	$0.0153	$0.0153	0.405%
Tennessee Gas Pipeline			
FS-MA (6815)	$0.0087	$0.0087	1.29%
FS-PA (2400)	$0.0073	$0.0073	1.29%

Note: Rates as of July 2023.

6. Hedging Activity

6.1. Background and Description

The 2007 Settlement provided for the recovery of hedging costs as a purchased gas cost, and defined hedging transactions to include futures contracts, financial derivative products, storage swap arrangements, or other private agreements to hedge, manage, or reduce gas costs. Piedmont's allowable hedging purchase costs are limited to 1% of annual gas costs.[10] All hedging gains and losses are reflected in the Company's purchased gas cost rates, and the gains and losses are excluded from the 1% cost limit. Piedmont's hedging program is designed to mitigate the impact of significant price spikes for up to 45% of normalized purchases. Hedges are limited to the purchase and sale of call options. Options are purchased on the New York Mercantile Exchange (NYMEX), and there are no over-the-counter (OTC) transactions. Typically, the Company purchases European call options that are held to maturity and will either expire worthless out-of-the-money or settle in-the-money. On November 17, 2020, the Company's broker inadvertently purchased an American call option instead of a European call option. This American call option could be exercised at any time before expiration and was sold on December 24, 2020, for a [redacted] Piedmont's hedging activities during the review period, exclusive of the inadvertent American call option purchase, are summarized in Table 23.

The Company's forward-hedging horizon is one year. Piedmont hedges for both the winter and summer seasons, and the annual budget for hedging set by the 1% cost limit is allocated between months based on anticipated normalized purchases, including purchases for injection into storage. Purchases under the Company's hedging program are guided by price- and time-driven parameters. Piedmont's hedging activities are overseen by the Gas Market Risk Committee.

Price-dependent hedging purchases are determined as follows: Piedmont will utilize a portion of its pre-established hedging budget to purchase call options any time the futures price for any month in the 12-month, forward-hedging horizon reaches specific seasonal threshold levels compared with historical prices. The Company collects historical daily prompt-month settlement prices over the most recent four years, applies an inflation adjustment, and weights data for the most recent 12 months more heavily.[11] This adjusted historical price database is then segmented into deciles, which are presented in a matrix. Current futures prices are compared against the matrix by season when making hedging decisions. Piedmont has established the first hedging threshold level at the point when futures prices for any month in the hedging horizon close at or below the 50th seasonal decile price point of the

[10] The recovery cap is computed from the most current audited and approved gas costs for the Company in a TRA docket as of the first day of the month, 12 months prior to the first day of the period under audit.

[11] This information is provided to the Company by Stone X, an external party.

Table 23. Summary of Call Option Hedging Activity

Hedge Month	Quantity (Dth)	Average Strike Price ($/Dth)	Average Call (Price)/ Gain ($/Dth)	Purchase Cost Sale Gain/(Loss)	Fee	Total Purchase Cost Sale Gain/(Loss)
			Call Purchases			
Jul 2020	[redacted]					
Aug	[redacted]					
Sep	[redacted]					
Oct	[redacted]					
Nov	[redacted]					
Dec	[redacted]					
Jan 2021	[redacted]					
Feb	[redacted]					
Mar	[redacted]					
Apr	[redacted]					
May	[redacted]					
Jun	[redacted]					
Subtotal:	[redacted]					
	[redacted]					
Jul 2021	[redacted]					
Aug	[redacted]					
Sep	[redacted]					
Oct	[redacted]					
Nov	[redacted]					
Dec	[redacted]					
Jan 2022	[redacted]					
Feb	[redacted]					
Mar	[redacted]					
Apr	[redacted]					
May	[redacted]					
Jun	[redacted]					
Subtotal:	[redacted]					
	[redacted]					
Jul 2022	[redacted]					
Aug	[redacted]					
Sep	[redacted]					
Oct	[redacted]					
Nov	[redacted]					
Dec	[redacted]					
Jan 2023	[redacted]					
Feb	[redacted]					
Mar	[redacted]					
Apr	[redacted]					
May	[redacted]					
Jun	[redacted]					
Subtotal:	[redacted]					
Total Call Purchases:	[redacted]					
	[redacted]					
Sep 2020	[redacted]					
Nov 2020	[redacted]					
Apr 2021	[redacted]					
May 2021	[redacted]					
Jun 2021	[redacted]					
Jul 2021	[redacted]					
Nov 2021	[redacted]					
Dec 2021	[redacted]					
Mar 2022	[redacted]					
Apr 2022	[redacted]					
May 2022	[redacted]					
Jun 2022	[redacted]					
Total Call Sales:	[redacted]					
Net Hedging Impact:	[redacted]					

matrix. When this occurs, Piedmont will spend 20% of its monthly hedging budget on call options for that month's contract. Piedmont will continue to spend an additional 20% of its monthly hedging budget for any month's contract any time futures prices fall into the next-lowest decile price point. For example, if futures prices for any month in the hedging horizon fall below the 40th decile price point, Piedmont will spend an additional 20% of its monthly hedging budget on call options. If prices were to fall below the 10th decile price point and into the first decile, then Piedmont will have exhausted its monthly hedging budget when it utilizes the last 20% of that budget to purchase additional call options. A sample matrix for June 2023 is presented below:

June 2023 Expiration ($/Dth)

Decile	Annual	Summer	Winter
90% - MAX	[redacted]	[redacted]	[redacted]
80% - 90%	[redacted]	[redacted]	[redacted]
70% - 80%	[redacted]	[redacted]	[redacted]
60% - 70%	[redacted]	[redacted]	[redacted]
50% - 60%	[redacted]	[redacted]	[redacted]
40% - 50%	[redacted]	[redacted]	[redacted]
30% - 40%	[redacted]	[redacted]	[redacted]
20% - 30%	[redacted]	[redacted]	[redacted]
10% - 20%	[redacted]	[redacted]	[redacted]
MIN - 10%	[redacted]	[redacted]	[redacted]
Mean:	[redacted]	[redacted]	[redacted]
Median:	[redacted]	[redacted]	[redacted]

As a general rule, Piedmont will spend 4% of the decile price and spend up to 20% of the allowed dollars for that month. For example, if the 50th decile is $5.00, Piedmont will spend $0.20/Dth ($5.00 x 4%), and purchase calls with a market based strike price when spending $0.20/Dth. If 20% of the allowed dollars for a given month is $50,000, that number is divided by $0.20 to arrive at a volume of 250,000 Dth to hedge. If spending 20% of the available dollars in any one month purchases call volumes that exceed 20% of the anticipated normalized purchase volume, the volume will be limited to 20% of the anticipated monthly purchase volume. If 20% of the available dollars does not purchase 20% of the normalized purchase volume (45% of normalized purchase volumes in total), the Company does not make up the volumes later even if additional funds at lower decile strike prices are available. No purchases will be made under the price-driven component of the hedging program if the 50th or lower decile price point is not breached during the one-year hedging horizon.

If all of the price-dependent hedging thresholds are not reached during the planning horizon, Piedmont will purchase calls under the time-dependent component of its hedging program. These time-dependent purchases are made until Piedmont's hedging volume target is reached, as long as NYMEX futures prices are at or below the 50th decile price point. No price- or time-dependent purchases are made above the 50th decile. Under the time-dependent component of Piedmont's hedging program, if futures prices for a contract month in the forward-hedging horizon remain below the 60th decile price point, Piedmont will spend 20% of its seasonal hedging budget on call options when the date reaches five months before the start of the season. Piedmont will continue to spend an additional 20% of its seasonal hedging budget on call options each subsequent month, ultimately spending up to 100% of its seasonal hedging budget prior to the start of a season.

For example, if NYMEX prices for a winter month are at the 50th decile price point, Piedmont will have already hedged 20% of its hedging target volume. If NYMEX prices are still at the 50th decile on July 1, the Company will hedge an additional 20% of normalized sales. The Company will continue to purchase additional time-dependent hedges until October 1 for the winter months, as long as monthly NYMEX prices remain at or below the 50th decile.

As indicated previously, hedging purchase cost recovery is limited to 1% of the Company's total annual gas cost. As shown in Table 24, Exeter's review found that Piedmont's hedging costs were less than 1% for each Plan year. Exeter's review also found that Piedmont hedged approximately 30% of normalized purchase volumes.

Table 24. Summary of Annual Hedging Costs and Limits

Plan Year	1% Hedging Limit	Actual Hedging Costs
July 2020 – June 2021	[redacted]	[redacted]
July 2021 – June 2022	[redacted]	[redacted]
July 2022 – June 2023	[redacted]	[redacted]
Total:	[redacted]	[redacted]

6.2. RFP Statement of Work Requirements

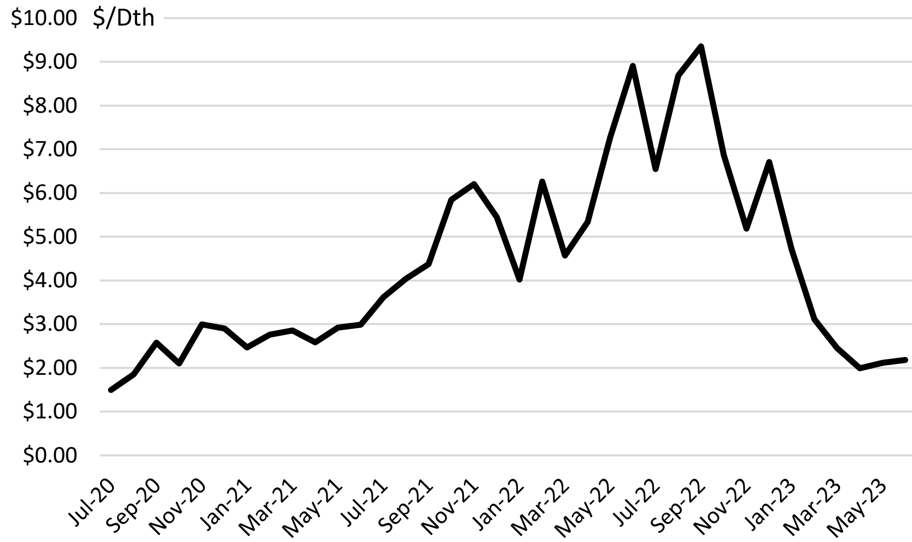
The RFP for the review of Piedmont's performance under the Plan identified, for review and assessment, specific aspects of Piedmont's hedging program. These review requirements are addressed in this section of the Report.

- *What were the market conditions during the review period and did Piedmont perform a cost-benefit analysis to support the hedging program?*

  Natural gas prices were relatively low at the start of the review period, with the monthly NYMEX price for July 2020 settling at $1.495/Dth, and the August 2020 NYMEX price settling at $1.854/Dth. NYMEX settlement prices for the period September 2020 through June 2021 were relatively stable, averaging $2.7148/Dth. In July 2021, NYMEX settlement prices became extremely volatile and overall increased significantly until September 2022, with the July 2021 NYMEX price settling at $3.617/Dth and the September 2022 NYMEX price settling at $9.353/Dth. After

September 2022, NYMEX prices generally declined, settling at $2.181/Dth for June 2023.

Figure 3. Natural Gas Futures – NYMEX Settlement (July 2020 – June 2023)



- *What hedging tools did Piedmont consider and what criteria were used to select hedging tools?*

  After sustaining substantial losses caused by a market decline and the sale of puts, North Carolina Utilities Commission (NCUC) Staff indicated their preference for a hedging policy that provided for all upside market protection from established hedges, all market participation at lower prices in a falling market, and no additional cost associated with a falling market after hedges are established. The Company subsequently chose to eliminate the sale of puts from its hedging program and to hedge exclusively by purchasing calls. This caps hedging losses to the cost of the call options and achieves unlimited price protection above the strike price of the call options purchased, while allowing full downside market participation.

- *What costs were associated with the different hedging tools used and the potential of losses for Piedmont?*

  As shown previously in Table 23, Piedmont purchased [redacted] Dth of European call options during the review period at a cost of [redacted], or an average price of [redacted]/Dth. To purchase those calls, Piedmont also incurred transaction fees of [redacted]. Of those calls purchased, Piedmont sold [redacted] Dth at expiration, which had value, or were in-the-money" Piedmont realized a gain of [redacted] on the sale of those calls, and incurred [redacted] in transaction costs. As previously indicated, in addition to the purchase of European call options, Piedmont also purchased an American call option that it sold for a net gain of [redacted]. The net impact of Piedmont's hedging program during the review period was a gain of [redacted] or an average of approximately [redacted]/Dth sold. The only potential for losses is the costs associated with purchasing call options, including transaction fees.

- *What was Piedmont's budget for hedging during the review period and were hedges staggered over a predefined period?*

  Piedmont's allowable hedging costs are limited to 1% of annual gas costs. During the review period, Piedmont's maximum allowable spending limit was [redacted]. Piedmont's actual review period hedging expenditures were [redacted], including transaction fees (see Table 23). Piedmont's hedges were staggered over time pursuant to the procedures discussed in Section 6.1 of the Report.

- *Were there price triggers for determining hedging volumes and timing?*

  The price triggers for hedging volumes and timing are described in Section 6.1 of the Report.

- *Identify benefits and costs of the hedging program during the review period, including costs and benefits to customers (both tangible and intangible). Compare costs to customers with estimated costs in the absence of a hedging program.*

  Piedmont's total hedging costs for the review period, including transaction fees, were [redacted]. A gain of [redacted] was realized by Piedmont as a result of its review period hedging activities, resulting in a net benefit of [redacted], or [redacted]/Dth sold (See Table 23).

- *Review and assess Piedmont's hedging documentation process.*

  Piedmont maintains a copy of all monthly Stone X price matrices; time-stamped deal tickets; price matrices used in evaluation of call purchases; minutes of the meetings of the Gas Market Risk Committee, which oversees the Company's hedging program; and daily positions and market-to-market reports. Exeter's review found Piedmont's documentation process satisfactory.

[redacted]

- *Review hedging losses during the period and assess the cause(s).*

  During the review period, a net gain was realized by Piedmont under its hedging program. This gain averaged [redacted]/Dth sold. The net gain was the result of purchasing call options for periods during which market prices were increasing and at times increased above call option strike prices.

- *How do losses incurred compare to losses of comparable utilities and to losses incurred in Piedmont's hedging plans in other states?*

  Piedmont employs nearly identical hedging strategies and programs in its Tennessee, North Carolina, and South Carolina service territories. The hedging programs in all three service territories provide for the purchase of calls, and price protection up to 45% of normalized purchase volumes. The cost of Piedmont's hedging activities was lower in Tennessee than in the Carolinas due to normalized sales in Tennessee being lower than in the Carolina service territories. In addition, an annual gas cost limit of 1% is also applicable in Tennessee, which is not applicable in the Company's Carolina service territories.

  Utilities in other states that employ hedging strategies generally rely on fixed-price purchases. Utilities generally consider their hedging activities to be confidential. Exeter does not have sufficient information available to compare the results of Piedmont's hedging program with the hedging program of comparable utilities in other states.

- *Overall assessment of the operation, performance and results of Piedmont's hedging plan.*

  Exeter's overall assessment of Piedmont's hedging plan is discussed in Section 6.3 of the Report.

6.3. Results and Conclusions

Piedmont adhered to the hedging activities approved under the Plan during the review period. The use of both a price- and time-dependent approach to hedging is reasonable.

Most utilities that have adopted hedging programs rely heavily, and many exclusively, on forward, fixed-price purchases for a significant percentage of their gas supply purchases. The Company does not utilize forward, fixed-price purchases because those purchases would be reflected in the Plan. As such, if the price of the Company's forward fixed-price purchases exceeded market prices at the time of delivery, the Company would experience a loss under the Plan. Piedmont has indicated that it is unwilling to take such a risk. In other jurisdictions with incentive mechanisms similar to Piedmont's Plan, forward fixed-price purchases are excluded from the incentive mechanism.

Generally, the goal of hedging is to, over time, mitigate price volatility. It is Exeter's view that regulators and utilities cannot expect hedging to lower the long-term price paid for natural gas supplies. Hedging programs take many forms and use many different tools, both physical and financial. There are no industry standards to compare hedging program results. Exeter's review of Piedmont's hedging activities did not reveal any unreasonable practices that were inconsistent with industry practices. Exeter has no recommended modifications to Piedmont's existing hedging program.

7. Assessment of Piedmont Plan Incentives and Design

Section 7 of Exeter's Report begins with a comparison of Piedmont's Performance Incentive Plan with the gas procurement incentive mechanisms of Atmos Energy Corporation and Chattanooga Gas Company. This comparison is provided for informational purposes as well as to assist in addressing the Statement of Work requirement to evaluate the balance of incentives under the Plan, which is addressed in this section.

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

7.1. Comparison of Piedmont Plan with Similar Incentive Mechanisms of other Tennessee Natural Gas Distribution Companies

7.1.1. Piedmont Performance Incentive Plan

Piedmont's Plan consists of three components: (1) a commodity procurement cost component; (2) a supplier reservation fee component; and (3) a capacity management component. Under the commodity procurement cost component of the Plan, Piedmont's actual total monthly citygate (delivered) commodity cost of gas is compared to costs based on a Monthly Benchmark Index Price. The actual total citygate commodity cost of gas includes the amount paid for gas supply commodity purchases, plus the applicable pipeline fuel and variable transportation charges associated with delivering gas from the purchase (receipt) point to Piedmont's system. The commodity procurement cost component provides for a 75% sales customer and 25% Company sharing of the difference between actual and benchmark costs.

Under the commodity procurement cost component of the Plan, separate benchmarking procedures are provided for in the MBIP for monthly, daily, and citygate purchases. The monthly purchase benchmark is based on a price that reflects published index prices generally weighted by the amount of firm interstate pipeline receipt point capacity that Piedmont reserves at each of its purchase locations. For example, if 70% of Piedmont's interstate pipeline capacity portfolio consisted of Columbia Gulf capacity and the remaining 30% was TGP capacity, Piedmont's benchmark for monthly purchases would be based on a 70% / 30% weighting of Columbia Gulf and TGP monthly index prices, adjusted for variable and fuel charges. Daily purchases are benchmarked against the actual daily published index prices for the purchase location, plus the applicable variable and fuel charges. Citygate purchases delivered by Columbia Gulf, TGP, and Texas Eastern are generally benchmarked based on

Gulf Coast production area commodity index prices, plus the maximum applicable interruptible transportation charge, and the applicable fuel charges. Citygate purchases delivered by ETNG during the audit period were generally benchmarked based on Chicago citygate index prices, plus the MGT firm variable and fuel charges associated with the delivery of gas to ETNG at Boat Dock, plus the ETNG interruptible transportation and fuel charges associated with the delivery of gas from Boat Dock to Piedmont. Piedmont's Plan does not provide for the sharing of avoided demand charges, as provided for under the subsequently discussed incentive mechanisms of Atmos and Chattanooga Gas. The rewards realized by Piedmont under the commodity procurement cost component of the Plan were generated solely by monthly and citygate purchases during the review period.

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

7.1.2. Atmos Performance Based Ratemaking Mechanism

Atmos' current Performance Based Ratemaking Mechanism (PBRM) consists of four components: (1) gas procurement incentive mechanism; (2) capacity management incentive mechanism; (3) avoided cost incentive mechanism; and (4) off-system sales revenue incentive mechanism. The gas procurement incentive mechanism establishes a predefined benchmark index to which Atmos' commodity cost of gas is compared. It also addresses the use of financial instruments or private contracts in managing gas costs. For commodity costs, on a monthly basis, Atmos' commodity cost of gas is compared to a benchmark amount. The benchmark amount is computed by multiplying actual purchase quantities for the month by the appropriate published index price. The gas procurement incentive mechanism provides for a 75% sales customer and 25% Atmos sharing of the difference between actual and benchmark costs.

Under the capacity management incentive mechanism, to the extent Atmos is able to release transportation or storage capacity, the associated revenues are shared by Atmos' sales customers and Atmos on a 75% / 25% basis, respectively. The capacity management incentive mechanism also addresses the sharing of AMA fees which are shared between sales customers and Atmos on a 75% / 25% basis, respectively.

The avoided cost incentive mechanism is designed to encourage Atmos to explore ways to reduce upstream fixed and variable capacity costs associated with the transportation of gas supplies. Avoided costs can be accomplished through delivered services, transportation discounts obtained from pipelines, the acquisition of discounted released capacity, variation from an existing transportation delivery path, or the acquisition of seasonal capacity that avoids year-round demand changes. Net savings realized under this mechanism are shared between the sales customers and the Company on an 85% / 15% basis, respectively.

The off-system sales revenue incentive mechanism is designed to encourage the Company to generate revenue from the off-system sale of gas supplies. The net margins on off-system sales are determined based on published index prices and are shared between sales customers and the Company on a 75% / 25% basis, respectively. Atmos' total share of savings under the PBRM are capped at $2.0 million per year. Atmos' current PBRM was approved in 2016. Exeter performed an independent review and evaluation of Atmos' PBRM for the period April 1, 2017 through March 31, 2020.

7.1.3. Chattanooga Gas Performance Based Ratemaking Mechanism

The gas cost incentive plan under which Chattanooga Gas operates is also referred to as the Performance Based Ratemaking Mechanism. Chattanooga Gas also operates under a separate Interruptible Margin Credit Rider (IMCR) that addresses the sharing of revenues (margins) generated from capacity release and off-system sales activities, as well as AMA fees.

Under Chattanooga Gas' PBRM, each month, Chattanooga Gas' actual commodity cost of gas is compared to a monthly benchmark amount. For monthly and daily purchases, the benchmark amount is based on the applicable published index price for the location at which gas is purchased. For citygate purchases, the PBRM provides for the inclusion of the avoided transportation charges that would have been paid if upstream capacity was purchased versus the demand charges paid to the supplier. If Chattanooga Gas' total actual commodity gas costs for a plan year do not exceed the total benchmark amount by 1%, its commodity gas costs are deemed prudent, and the audit required by TPUC Administrative Rule 1220-4-7-.05 is waived. If, during any month of a plan year, Chattanooga Gas' commodity gas costs exceed the benchmark amount by greater than 2%, the company is required to file a report with the TPUC fully explaining why costs exceeded the benchmark. There is no sharing of any savings or losses under the PBRM. Exeter's most recent review of Chattanooga Gas' PBRM encompassed the period July 1, 2016 through March 30, 2019. During this period, Chattanooga Gas' actual gas costs did not exceed benchmark costs by 1% during any plan year.

Chattanooga Gas' IMCR provides for a 50% ratepayer sharing of the revenues (margins) generated from capacity release and off-system sales activities, as well as AMA fees. There is no cap on the amounts eligible for sharing under the IMCR.

7.2. Balance of Plan Incentives

Piedmont is able to generate savings and realize rewards under the commodity procurement cost and capacity management components of the Plan. Rewards under the Plan are capped at $1.6 million. The Statement of Work includes the requirement to evaluate the balance of incentives between Piedmont and its sales customers under the Plan.

7.2.1. Capacity Management Component

The capacity management component of the Plan addresses the margins realized from capacity release and off-system sales activities, as well as AMA fees, and provides for a 75% sales customer / 25% Company sharing. Nearly 100% of the margins available for sharing under the capacity management component during the review period were generated from AMA fees. The remaining margins were generated from off-system sales made to the Company's Asset Manager. Piedmont did not engage in capacity release activities or other off-system sales during the review period because the capacity necessary to perform these activities was released to an Asset Manager under an AMA. It is Exeter's experience that in other jurisdictions, sharing percentages that range from 90% customer / 10% utility to 75% customer / 25% utility have been adopted for AMA fees, with the lower end of the sharing range for the utility being more prevalent. With respect to capacity release revenues and off-system sales margins, 75% customer / 25% utility sharing percentages are common in other jurisdictions. Exeter concludes that there is a relatively reasonable balance of incentives between Piedmont and customers under the capacity management component of the Plan.

7.2.2. Commodity Procurement Cost Component

The commodity procurement cost component of the Plan also provides for a 75% customer / 25% Company sharing of savings. Different benchmarking procedures are applicable for monthly purchases, daily purchases, and citygate purchases under the commodity procurement cost component of the Plan. The balance of incentives for each type of purchase is addressed separately.

As previously explained, Piedmont's monthly purchases delivered under firm transportation arrangements are evaluated based on a benchmark that reflects published index prices weighted by the amount of firm interstate pipeline receipt point capacity available to Piedmont to purchase gas supplies at each purchase location. Piedmont realizes a reward for monthly purchases if those purchases are made at the lowest-cost receipt points. The relative price relationship for Piedmont's various receipt point locations is generally known by all participants in the natural gas market. Other utilities operating under traditional regulation maximize the purchase of gas supplies at the lowest-cost receipt points, as Piedmont did during the review period. For doing so, as shown on Table 13, Piedmont realized a gain under the Plan of approximately [redacted] during the review period, of which it was entitled to retain 25% subject to a total annual cap of $1.6 million under all aspects of the Plan. Exeter's most recent review of the gas cost incentive plan of Chattanooga Gas revealed that it also maximizes the purchase of gas supplies at the lowest-cost receipt points. However, Chattanooga Gas does not realize a reward for doing so under its gas cost incentive plan. Therefore, Exeter concludes that the monthly benchmarking procedures under the commodity procurement cost component of the Plan are unbalanced in the Company's favor.

Daily purchases delivered under firm transportation arrangements are benchmarked against the actual published index prices for the actual purchase location. Piedmont did not earn rewards during the review period under the Plan for daily purchases. The 75% sales customer / 25% Company sharing procedures adopted for daily purchases under the commodity procurement cost component of the Plan are somewhat conservative in that similar incentive mechanisms in other jurisdictions have adopted 50% customer / 50% utility sharing procedures when purchases are benchmarked against actual index prices for the actual purchase location.

As previously described in Section 3.1.3 of the Report, Exeter found the procedures used by Piedmont to benchmark ETNG citygate purchases when Piedmont maintained MGT firm transportation capacity to be inappropriate and unreasonable. As explained in Section 2.1.4 of the Report, Piedmont terminated its MGT firm transportation capacity arrangements during the review period and replaced the MGT capacity with Columbia Gulf firm transportation capacity. This reduced Piedmont's annual interstate pipeline demand charges by approximately [redacted] With this change, ETNG citygate purchases will no longer be benchmarked based on Chicago citygate index prices but will be benchmarked based on Columbia Gulf index prices. Therefore, the concerns expressed by Exeter in Section 3.1.3 of the Report will no longer be applicable under the Plan, and Exeter finds that going forward, the existing sharing procedures for citygate purchases under the Plan appear to be reasonable and will provide the Company with sufficient incentive to pursue such purchases when they reduce purchased gas costs.

7.2.3. Plan Cap of $1.6 Million

Piedmont realizes rewards under the commodity procurement and capacity management components of the Plan. During the review period, approximately 60% of the gains realized under the Plan were from AMA fees, 10% were gains associated with monthly purchases, and 30% were gains associated with citygate purchases. [redacted] As noted previously in Section 3.3.1 of the Report, the 25% Company sharing for AMA fees is at the high end of the sharing procedures adopted in other jurisdictions. In addition, the gains associated with monthly purchases that Piedmont is able to generate, which are shared under the Plan, are achievable under traditional regulation and should not result in a reward for Piedmont. Finally, Exeter's review did not find that $1.6 million cap reduced Piedmont's incentive or efforts to realize rewards under the Plan. For these reasons, Exeter recommends that the $1.6 million cap be maintained.

8. Findings of Fact and Areas of Concern

Findings of fact from Exeter's triennial review are as follows:

- Piedmont purchased firm transportation and storage services from five interstate pipelines during the review period.
- Piedmont released its interstate pipeline firm transportation and storage capacity to a third party under Asset Management Agreements during the review period.
- Piedmont served an average of 196,850 sales and transportation customers during the review period, and total annual system throughput averaged 31,960,000 Dth.
- Piedmont engaged in no transactions with affiliates during the review period.
- Performance Incentive Plan determined savings during the review period were [redacted], and Piedmont's share of savings were [redacted].
- A gain of [redacted] was realized under the commodity procurement cost component of the Plan on monthly purchases, and a gain of [redacted] was realized on citygate purchases. No Plan gains were realized on daily purchases.
- A gain of [redacted] was realized under the capacity management component of the Plan from AMAs and off-system sales activities during the review period.
- The fees received by Piedmont under its AMAs increased substantially during the review period compared to those received in prior audit review periods.
- The capacity management component of the Plan provides a reasonable balance of incentives between Piedmont and its customers.
- Piedmont's review period storage activity was reasonable.
- Piedmont's review period gas supply purchases delivered under firm transportation arrangements were reasonable.
- The design day forecasting model developed by Marquette Energy Analytics during the review period appears reasonable and accurately forecasts customer requirements on peak days. The design day model developed by MEA includes windspeed as an independent variable. In Exeter's 2021 audit report, it was recommended that Piedmont consider independent variables such as windspeed in its design day model.
- Piedmont's estimated design day demands and capacity resources were in relative balance during the review period.
- Piedmont maintains sufficient year-round and winter season firm transportation capacity, and increasing the amount of year-round capacity would only serve to increase the Company's annual pipeline demand charges.

- Based on Piedmont's capacity portfolio for the winter of 2023-2024 and the availability of winter season interstate pipeline capacity, the potential for the Company to rely more on winter season capacity and reduce year-round capacity is limited.

- Piedmont's termination of its Midwestern Gas Transmission firm transportation capacity during the review period and the replacement of that capacity with Columbia Gulf Transmission capacity reduced the Company's annual interstate pipeline demand charges by approximately [redacted].

- Piedmont's use of a partially price-dependent and partially time-dependent hedging approach and hedging through call options is reasonable.

- Piedmont's use of a decile matrix to guide its hedging purchasing decisions and the 1% limit on hedging transaction costs are consistent with observed industry practices.

Exeter's review noted the following areas of concern and potential areas of improvement under the Performance Incentive Plan:

- The current design of the monthly purchase benchmark included in the Monthly Benchmark Index Price results in gas cost savings that would have been realized without the existence of the Plan.

- The use of Chicago citygate index prices to benchmark East Tennessee Gas Pipeline citygate purchases during the portion of the review period in which Piedmont maintained Midwestern Gas Transmission capacity was unreasonable and inappropriate. This is best exemplified by the unreasonable and inappropriate gains realized by Piedmont under the Plan during February 2021. During the period February 13-16, 2021, Piedmont purchased [redacted] Dth of ETNG citygate-delivered supplies at an average cost of [redacted]/Dth. The gain realized under the Plan for the ETNG citygate purchases for these four days was [redacted] million, or [redacted]/Dth. The Chicago citygate index price on these four days was [redacted]/Dth. The total gain for the entire month of February 2021 for ETNG citygate purchases was [redacted].

  Benchmarks under a gas cost incentive mechanism such as the Plan should be based on market prices, and rewards should be based on performance which exceeds that of other market participants. Based on the evidence presented, the benchmarking of ETNG purchases based on Chicago citygate index prices did not achieve these results during the review period. Until November 2022, Piedmont maintained firm transportation capacity on MGT, and ETNG purchases were benchmark based on the assumption that these purchases were delivered to ETNG from the Chicago area by MGT. Based on the differences between Chicago citygate index prices observed during the period February 13-16, 2021 and the prices at which Piedmont was able to purchase ETNG delivered supplies, the assumption that the ETNG purchases were delivered to ETNG from the Chicago area by MGT was unreasonable and inappropriate.

  In response to the concerns noted in Exeter's 2021 audit report with respect to benchmarking ETNG purchases based on Chicago citygate index prices, during the review period, effective November 2022, Piedmont replaced its MGT capacity with Columbia Gulf capacity. As a result, ETNG purchases are now benchmarked based on Columbia Gulf index prices. This should alleviate the concerns with benchmarking ETNG purchases based on Chicago citygate index prices, and Exeter finds that going forward, the existing sharing procedures for citygate purchases under the Plan appear to be reasonable and will provide the Company with sufficient incentive to pursue such purchases when they reduce purchased gas costs.

- Piedmont's two off-system sales transactions during the review period potentially had an adverse impact on sales customers; however, the impact was not material.

- Due to the concerns with the current structure of the Plan described in the Report, Exeter recommends that the $1.6 million Plan cap be maintained.

APPENDIX A:

PIEDMONT NATURAL GAS COMPANY

PERFORMANCE INCENTIVE PLAN

SERVICE SCHEDULE NO. 316
Performance Incentive Plan

Applicability
The Performance Incentive Plan (the Plan) replaces the annual reasonableness or prudence review of the Company's gas purchasing activities overseen by the Tennessee Public Utility Commission (Commission or TPUC). The Plan does not preclude the Commission from conducting an independent investigation into or examination of any aspect of the Plan or the Company's conduct thereunder. The Plan is designed to provide incentives to the Company in a manner that will produce rewards for its customers and its stockholders and improvements in the Company's gas procurement and capacity management activities. Each plan year (Plan Year) will begin July 1st. The annual provisions and filings herein would apply to this annual period. The Plan will continue until the Plan is either (a) terminated at the end of a Plan Year by not less than 90 days notice by the Company to the Commission or (b) the Plan is modified, amended or terminated by the Commission on a prospective basis.

Overview of Structure
The Plan establishes a predefined benchmark index to which the Company's commodity cost of gas is compared. It also addresses the recovery of gas supply reservation fees and the treatment of off-system sales and wholesale interstate sale for resale transactions. The net incentive benefits or costs will be shared between the Company's customers and the Company on a 75%-customers / 25%- stockholders basis for the Plan Year commencing on July 1, 2006.

The Plan also is designed to encourage the Company to actively market off-peak unutilized transportation and storage capacity on pipelines in the secondary market. It also addresses the sharing of asset management fees paid by asset managers, and other forms of compensation received by the Company for the release and/or utilization of the Company's transportation and storage assets by third-parties. The Company shall notify the TPUC Staff and the Consumer Advocate and Protection Division of the Office of the Attorney General (CAD) of all "other forms of compensation" prior to inclusion of such compensation in the Plan. The net incentive benefits or costs of such activities will be shared between the Company's customers and the Company utilizing a 75%-customers / 25%-stockholders formula commencing on July 1, 2006.

Every three years the Company's activities under the Plan will be reviewed comprehensively by an independent consultant. The first triennial review shall occur in the autumn of 2008. The scope of the review may include all transactions and activities related to the Performance Incentive Plan, including, but not limited to, natural gas procurement, capacity management, storage, hedging, reserve margins, and off-system sales.

The Company is subject to a cap on overall incentive gains or losses of $1.6 million annually. In connection with the Performance Incentive Plan, the Company shall file with the TPUC Staff, and supply a copy to the CAD, and update each year, a Three Year Supply Plan. The Company will negotiate/obtain firm capacity, interruptible capacity and/or gas supply pursuant to such plan.

Commodity Costs

Each month the Company will compare its *total city gate commodity and cost of gas*[1] to a benchmark dollar amount. The benchmark gas cost will be computed by multiplying total actual purchase quantities for the month by a price index. The monthly price index is defined as:

$$I = F_f(P_0K_0 + P_1K_1 + P_cK_c + \ldots P_\alpha K_\alpha) + F_0O + F_dD; \text{ where}$$
$$F_f + F_0 + F_d = 1; \text{ and}$$

I = the monthly city gate commodity gas cost index.

F_f = the fraction of gas supplies purchased in the first-of-the-month market which are transported to the city gate under the Company's FT, negotiated FT, and IT service agreements.

P = the Inside FERC Gas Market Report price index for the first-of-the-month edition for a geographic pricing region, where subscript 0 denotes Tennessee Gas Pipeline (TGP) Rate Zone 0; subscript 1 denotes TGP Rate Zone 1; subscript C denotes Columbia Gulf Transmission (CGT) - mainline, and subscript α denotes new incremental firm services to which the Company may subscribe in the future.[2] The indices used for calculating Midwestern capacity shall be those produced by Natural Gas Intelligence for monthly purchases and Gas Daily for daily purchases. The commodity index prices will be adjusted to include the appropriate pipeline firm transportation (FT) and interruptible transportation (IT) commodity transportation charges and fuel retention to the city gate under the Company's FT, negotiated FT, and IT service agreements.[3]

---

[1] Gas purchases associated with service provided under Texas Eastern Transmission Company Rate Schedule SCT shall be excluded from the incentive mechanism. The Company will continue to recover 100 percent of these costs through its PGA with no profit or loss potential. Extension or replacement of such contract shall be subject to the same competitive bidding procedures that will apply to other firm gas supply agreements. In addition, the Plan will measure storage gas supplies against the benchmark index during the months such quantities are purchased for injection. For purposes of comparing such gas purchase costs against the monthly city gate index price, the Company will exclude any commodity costs incurred downstream of the city gate to storage so that the Company's actual costs and the benchmark index are calculated on the same basis.

[2] To the extent that the Company renegotiates existing reservation fee supply contracts or executes new reservation fee supply contracts with commodity pricing provisions at a discount to the first-of-the-month price index, the Company shall modify the monthly commodity price index to reflect such discount.

[3] Capacity released for a month shall be excluded from the benchmark calculation for that month, excluding capacity released under an agreement where the Company maintains city gate delivery rights for the released capacity during such month.

K = the fraction (relative to total maximum daily contract entitlement) of the Company's total firm, negotiated firm, and interruptible transportation capacity under contract in a geographic pricing region, where the subscripts are as above.[4]

F_o = the fraction of gas supplies purchased in the first-of-the-month spot market which are delivered to the Company's system using transportation arrangements other than the Company's FT, negotiated FT, and IT contracts.

0 = the weighted average of Inside FERC Gas Market Report first-of-the-month price indices, plus applicable IT rates and fuel retention, from the source of the gas to the city gate, where the weights are computed based on actual purchases of gas supplies purchased by the Company and delivered to the Company's system using transportation arrangements other than the Company's FT, negotiated FT, and IT contracts.

F_d = the fraction of gas supplies purchased in the daily spot market.

D = the weighted average of daily average index commodity prices taken from Gas Daily for the appropriate geographic pricing regions, where the weights are computed based on actual purchases made during the month. The commodity index prices will be adjusted to include the appropriate transportation commodity charges and fuel retention to the city gate.

Gas Supply Reservation Fees

The Company will continue to recover 100% of gas supply reservation fee costs through its PGA with no profit or loss potential. For new contracts and/or contracts subject to renegotiation during the Plan Year, the Company will solicit bids for gas supply contracts containing a reservation fee.

Off-System Sales And Sale For Resale Transactions

Margin on off-system sales and wholesale sale-for-resale transactions using the Company's firm, negotiated firm, and interruptible transportation and capacity entitlements (the costs of which are recovered from the Company's ratepayers) shall be credited to the Plan and will be shared with ratepayers. Margin on such sales will be defined as the difference between the sales proceeds and the total variable costs incurred by the Company in connection with the transaction, including transportation and gas costs, taxes, fuel, or other costs. For purposes of gas costs, the Company will impute such costs for its related

---

[4] Because the aggregate maximum daily contract quantities in the Company's FT contract portfolio vary by month over the course of the year, the weights will be recalculated each month to reflect actual contract demand quantities for such month. The contract weights, and potentially the price indices used, will also vary as the Company renegotiates existing or adds new FT contracts. As new contracts are negotiated, the Company shall modify the index to reflect actual contract demand quantities and the commodity price indices appropriate for the supply regions reached by such FT agreements. Citygate benchmark calculations shall be computed utilizing the Company's Design Day delivery requirements (deliveries required on a peak day).

supply purchases at the benchmark first-of-the-month or daily index, as appropriate, on the pipeline and in the zone in which the sale takes place. The difference between the Company's actual costs and such index price is taken into account under the Plan. After deducting the total transaction costs from the sales proceeds, any remaining margin will be credited to commodity gas costs and shared with customers on a 75%- customer / 25%-stockholders basis.

Capacity Management
To the extent the Company is able to release transportation or storage capacity, or generate transportation or storage margin associated with off-system or wholesale sales-for-resale, the associated cost savings and/or asset management fees, or other forms of compensation associated with such activities, shall be shared by the Company and customers according to the following sharing formula: 75%-customers / 25%-stockholders. The Company shall notify the TPUC Staff and the Consumer Advocate and Protection Division of the Office of the Attorney General (CAD) of all "other forms of compensation" prior to inclusion of such compensation in the Plan.

Hedging Activities
The Company may engage in hedging transactions[5] within the PGA/ACA mechanism. Costs related to hedging transactions may be recovered through the ACA account; provided, however, that such costs recovered through the ACA account shall not exceed one percent (1%) of total annual gas costs.[6] Costs related to hedging transactions recoverable through the ACA account shall be defined as all direct, transaction related costs arising from the Company's prudent efforts to stabilize or hedge its commodity gas costs including, without limitation, brokerage fees, and the costs of financial instruments.

All costs related to hedging transactions, in addition to all gains and losses from hedging transactions, shall be credited/debited to the ACA account in the respective month that each hedging transaction closes. Costs related to hedging transactions that are incurred prior to the month that the hedging transaction closes shall be temporarily recorded in a separate, non-interest-bearing account for tracking purposes.

Determination of Shared Saving
Each month during the term of the Plan, the Company will compute any gains or losses in accordance with the Plan. If the Company earns a gain, a separate Incentive Plan Account (IPA) will be debited with such gain. If the Company incurs a loss, that same IPA will be credited with such loss. During a Plan Year, the Company will be limited to overall gains or losses totaling $1.6 million. Interest shall be computed on balances in the IPA using the same interest rate and methods as used in the Company's Actual Cost Adjustment (ACA) account. The offsetting

[5] Hedging transactions, as used herein, shall include but not be limited to futures contracts, financial derivative products, storage swap arrangements, or other private agreements to hedge, manage or reduce gas costs.

[6] One percent (1%) of total annual gas costs, for the purposes of establishing a recovery cap, shall be computed from the most current audited and approved gas costs for the Company in a TPUC docket as of the first day of the month, 12 months prior to the first day of the period under audit.

entries to IPA gains or losses will be recorded to income or expense, as appropriate. At its option, however, the Company may temporarily record any monthly gains in a non-regulatory deferred credit balance sheet account until results for the entire Plan Year are available.

Gains or losses accruing to the Company under the Plan will form the basis for a rate increment or decrement to be filed and placed into effect separate from any other rate adjustments to recover or refund such amount over a prospective twelve-month period. The Company is subject to a cap on overall incentive gains or losses of $1.6 million annually.

Each year, effective November 1, the rates for all customers, excluding transportation customers who receive no direct benefit from any gas cost reductions resulting from the Plan, will be increased or decreased by a separate rate increment or decrement designed to amortize the collection or refund of the June 30 IPA balance over the succeeding twelve-month period. The increment or decrement will be established by dividing the June 30 IPA balance by the appropriate volumetric billing determinants for the twelve months ended June 30. During the twelve-month amortization period, the amount collected or refunded each month will be computed by multiplying the billed volumetric determinants for such month by the increment or decrement, as applicable. The product will be credited or debited to the IPA, as appropriate. The balance in the IPA will be tracked as a separate collection mechanism. Subject to approval by the TPUC, the Company may also propose to refund positive IPA balances on an intra-year basis by making direct bill credits to all customers (except transportation customers) where such direct bill credit would be beneficial to customers.

Filing with the Commission
The Company will file calculations of shared savings and shared costs quarterly with the Commission not later than 60 days after the end of each interim fiscal quarter and will file an annual report not later than 60 days following the end of each Plan Year. Unless the Commission provides written notification to the Company within 180 days of the annual reports, the Incentive Plan Account shall be deemed in compliance with the provisions of this Service Schedule. The TPUC Staff may expand the time for consideration of the annual reports by up to an additional sixty (60) days upon written notification to the Company or longer by mutual agreement or upon a showing of good cause.

Periodic Index Revisions
Because of changes in the natural gas marketplace, the price indices utilized by the Company, and the composition of the Company's purchased gas portfolio may change. The Company shall, within sixty (60) 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 justification to the Company within sixty (60) days of such notice, the price indices shall be deemed approved as proposed by the Company.

Triennial Review

A comprehensive review of the transactions and activities related to the Performance Incentive Plan shall be conducted by an independent consultant once every three years. The initial triennial review shall be conducted in the autumn of 2008 and subsequent triennial reviews shall be conducted every third year thereafter. The TPUC Staff, the CAD, and the Company shall make an effort to maintain a list of no less than five (5) mutually agreeable independent consultants or consulting firms qualified to conduct the aforementioned review. Any dispute concerning whether an independent consultant shall be added to the list shall be resolved by the TPUC Staff, after consultation with the Company and the CAD. For each review, the TPUC Staff shall select three (3) prospective independent consultants from that list. Each such consultant shall possess the expertise necessary to conduct the review. The TPUC Staff shall provide the list of prospective independent consultants to the Company and the CAD via e-mail. The Company and the CAD shall have the right, but not the obligation, to strike one (1) of the prospective independent consultants from the list by identifying the stricken consultant in writing to the TPUC Staff within thirty (30) days from the date the list is e-mailed. The TPUC Staff shall select the independent consultant from those remaining on the list after the Company's and the CAD's rights to strike have expired. The cost of the review shall be reasonable in relation to its scope. Any and all relationships between the independent consultant and the Company, the TPUC Staff, and/or the CAD shall be disclosed, and the independent consultant shall have had no prior relationship with either the Company, the TPUC Staff, or the CAD for at least the preceding five (5) years unless the Company, the TPUC Staff and the CAD agree in writing to waive this requirement. The TPUC Staff, the CAD and the Company may consult amongst themselves during the selection process; provided, however, that all such communications between the parties shall be disclosed to any party not involved in such communication so that each party may participate fully in the selection process.

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

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

The independent consultant shall make findings of fact, as well as identify and describe areas of concern and improvement, if any, that in the consultant's opinion warrant further consideration; however, the independent consultant shall not propose changes to the structure of the

Performance Incentive Plan itself. The independent consultant shall complete and issue a written report of its findings and conclusions by July 1 of the year immediately following the triennial review. The report deadline may be waived by the written consent of the TPUC Staff, the Company, and the CAD.

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

The cost of the triennial reviews shall be paid initially by the Company and recovered through the ACA account. The TPUC Staff may continue its annual audits of the IPA and the ACA account, and the triennial reviews shall not in any way limit the scope of such annual audits. The CAD retains all of its statutory rights, and the triennial reviews shall not in any way affect such rights.