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January 14, 2019

Executive Director Earl Taylor
c/o Sharla Dillon
Tennessee Public Utility Commission
502 Deaderick Street, Fourth Floor
Nashville, Tennessee 37243

Via Hand Delivery

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

Dear Mr. Taylor:

Enclosed please find an original and five (5) copies of the public redacted version of the Review of Performance Incentive Plan and Capacity Resources, dated November 2018, 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 submitted under seal.

These materials are also being filed by way of email to the Tennessee Public Utility Commission Docket Manager, Sharla Dillon. Please accept the original and four copies of these materials for filing and stamp the additional copy as "filed." Then please return the stamped copies to me by way of our courier.

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.

Very truly yours,

Paul S. Davidson

PSD:cdg
Enclosures

cc: Pia Powers (Piedmont)
Bruce Barley (Piedmont)
Dan Whitaker (TN CPAD)

REDACTED REPORT

REDACTED

CONFIDENTIAL

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

AND CAPACITY RESOURCES

November 2018

Prepared by:

EXETER
ASSOCIATES, INC.
10480 Little Patuxent Parkway, Suite 300
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1.0 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, including 173,000 in Tennessee; 700,000 in North Carolina; and 139,000 in South Carolina. The gas procurement function at Piedmont is performed jointly for all three state jurisdictions by the corporate Gas Supply & Wholesale Marketing Department in Duke Energy's Natural Gas Business Unit.

On May 31, 1996, the Tennessee Public Service Commission (Commission), the predecessor to the Tennessee Regulatory Authority (TRA) (now Tennessee Public Utility Commission [TPUC]), 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) was selected through an RFP process by the Settling Parties to perform the independent review envisioned under the 2007 Settlement for the period July 1, 2014 through June 30, 2017 (review period). Exeter was previously selected to perform the first and second triennial independent reviews provided for under the 2007 Settlement that covered the periods July 1, 2008 through June 30, 2011, and July 1, 2011 through June 30, 2014, respectively. Exeter also performed an independent review of the Plan for the period July 1, 2006 through June 30, 2008.

The purpose of this 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; (f) off-system sales; and (g) citygate purchases.

A Draft Report presenting the findings, results, and conclusions of Exeter's current review was provided to the Settling Parties on August 1, 2018. On October 3, 2018, 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 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 Asset Management Agreements (AMAs) that existed during the review period. 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. Piedmont's Gas Supply Incentive Compensation Program is also evaluated in Section 7.

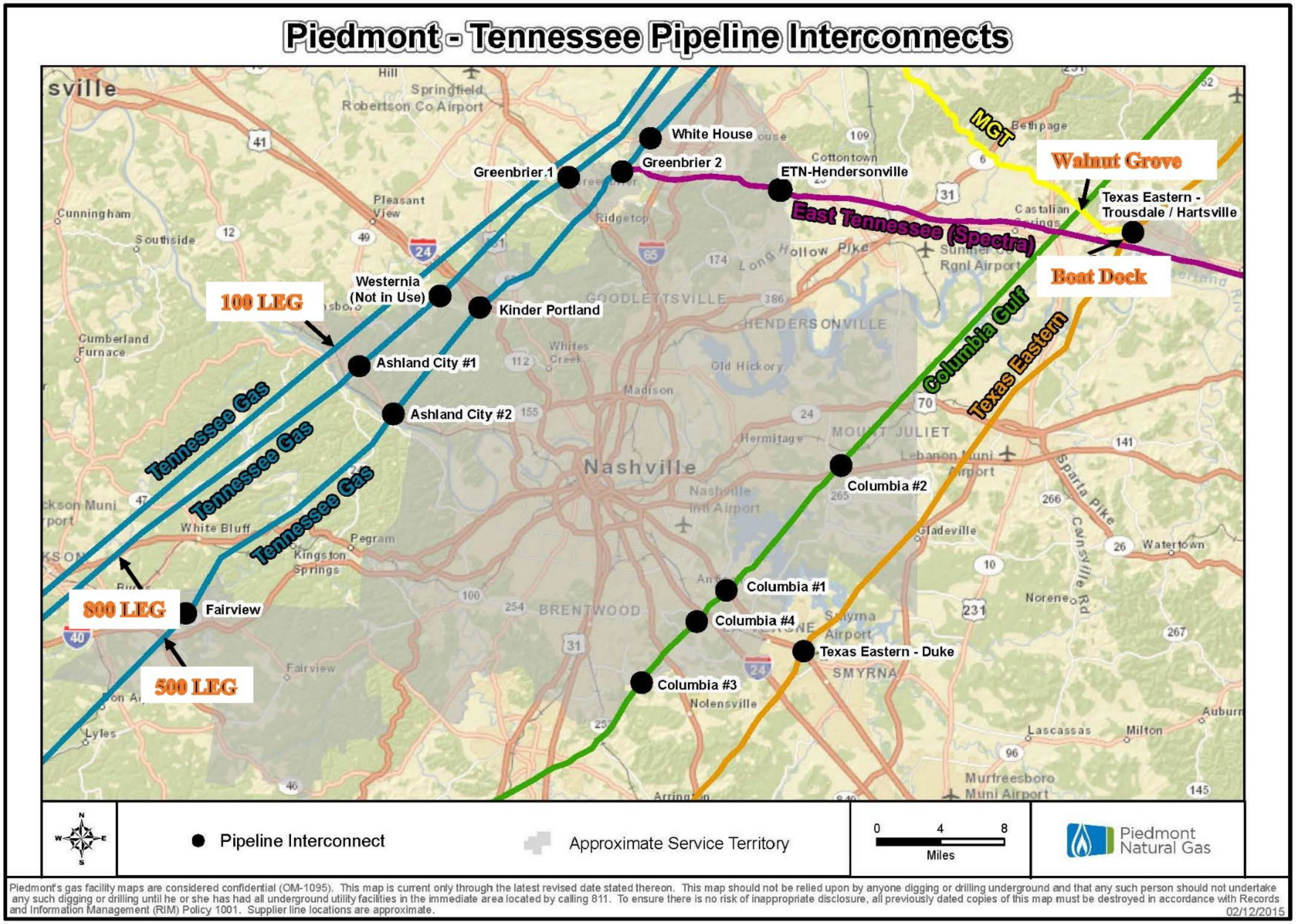
The final section of the Report summarizes Exeter's conclusions, includes findings of fact, and identifies and describes areas of concern and improvement that may warrant further consideration.

2.0 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 2.3 describes the Company's review period delivered gas supply arrangements, which serve as both capacity and gas supply resources. Section 2.4 describes post-review period changes to the Company's capacity resource portfolio. Section 2.5 discusses Piedmont's review period AMAs. Section 2.6 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.

Figure 1.
Piedmont Service Territory and Interstate Pipeline Interconnects



2.1 Interstate Pipeline Transportation Services

Piedmont's transportation arrangements with interstate pipelines Columbia Gulf, TGP, and Texas Eastern provide 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 U.S. 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 in Section 2.1.1, although Piedmont is not directly interconnected with Columbia Gas, the Company's storage service transportation arrangement with Columbia Gas provides for the delivery of gas storage supplies directly to Piedmont's system on Columbia Gulf.

Piedmont's transportation arrangement with MGT provides 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 can be delivered to the western side of 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. The Company's MGT-sourced delivery arrangements are discussed in greater detail in Section 2.1.4 of the Report.

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.

Piedmont's interstate pipeline interconnects are summarized in Table 1. Table 2 summarizes the capacity contracts and resources available to meet customer demands during the winter of 2016 – 2017.

Table 1. Summary of Interstate Pipeline Interconnects							
	Pipeline	Percent of Peak Day	Meter Number(s)	Meter Type	Area Served	County	City
1.	Columbia Gulf	[redacted]	4016	[redacted]	[redacted]	Davidson	Nashville
2.	Columbia Gulf	[redacted]	4088	[redacted]	[redacted]	Wilson	Nashville
3.	Columbia Gulf	[redacted]	4183	[redacted]	[redacted]	Williamson	Nashville
4.	Columbia Gulf	[redacted]	4241	[redacted]	[redacted]	Davidson	Nashville
5.	Texas Eastern	[redacted]	70316	[redacted]	[redacted]	Trousdale	Hartsville
6.	Texas Eastern	[redacted]	73423	[redacted]	[redacted]	Rutherford	Nashville
7.	Tennessee Gas Pipeline	[redacted]	020280-01	[redacted]	[redacted]	Robertson	City of Greenbrier
8.	Tennessee Gas Pipeline	[redacted]	020309-01	[redacted]	[redacted]	Cheatham	Ashland City
9.	Tennessee Gas Pipeline	[redacted]	020312-0, 020312-A	[redacted]	[redacted]	Davidson	Nashville
10.	Tennessee Gas Pipeline	[redacted]	020600-01	[redacted]	[redacted]	Robertson	White House
11.	Tennessee Gas Pipeline	[redacted]	020610-0	[redacted]	[redacted]	Dickson	Fairview
12.	Tennessee Gas Pipeline	[redacted]	020846-0	[redacted]	[redacted]	Cheatham	Ashland City
13.	Tennessee Gas Pipeline	[redacted]	20753-0	[redacted]	[redacted]	Robertson	Outside Greenbrier City Limits
14.	East Tennessee Natural Gas	[redacted]	59218	[redacted]	[redacted]	Sumner	Sumner

Table 2.
Summary of Design Day Capacity Contracts and Resources
(2016 – 2017 Winter Season)

Pipeline – Service	Contract No.	MDQ (Dth) Winter	MDQ (Dth) Summer	Available Quantity (Dth) Winter	Available Quantity (Dth) Annual	Contract Expiration
Columbia Gas						
Storage Service (FSS/SST)	38017/38052	10,000	5,000	611,870	611,870	3/31/2024
Columbia Gulf						
Firm Transportation (FTS-1)	43462	10,000	9,202	1,510,000	3,479,228	10/31/2022
Firm Transportation (FTS-1)	14252	31,000	11,755	4,681,000	7,196,570	10/31/2022
Midwestern Gas Transmission						
Firm Transportation (FT-A)/(FT-B)[1]	FA0342/FB0006	25,000	25,000	3,775,000	9,125,000	1/6/2023
Tennessee Gas Pipeline						
Firm Transportation (FT-A)	237	51,500	51,500	7,776,500	18,797,500	10/31/2019
Storage Service (FS-MA/FT-A)	6815/301244	49,828	0	2,901,943	2,901,943	10/31/2019
Storage Service (FS-PA/FT-A)	2400/301244	6,072	0	672,091	672,091	10/31/2019
Texas Eastern Transmission						
Firm Transportation (FT-1)	910473	10,000	0	1,510,000	1,510,000	3/31/2019
Firm Transportation (SCT)	800059	1,677	1,677	84,409	204,035	10/31/2022
Citygate Delivered Gas Supply						
Texla Energy Management		50,000	0	4,500,000	4,500,000	2/28/2017
NextEra Energy Power Marketing		86,387	0	13,044,437	13,044,437	3/31/2017
NextEra Energy Power Marketing		15,500	0	2,340,500	2,340,500	3/31/2017
Piedmont LNG	[redacted]					
TOTAL Citygate Capacity Resources:		[redacted]				

MDQ = maximum daily delivery quantity; Dth = dekatherms; LNG = liquefied natural gas.
[1] Winter and summer contract MDQ is [redacted] Indicated MDQ reflects design day deliverability.

2.1.1 Columbia Gas Transmission

Piedmont purchased unbundled firm storage transportation service from Columbia Gas under Rate Schedule SST during the review period. Piedmont purchased unbundled firm storage service from Columbia Gas under Rate Schedule FSS. 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 is 10,000 dekatherms (Dth)/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 handled through a combination of facilities jointly owned and operated by Columbia Gas and Columbia Gulf pursuant to a lease agreement between the two pipelines.[1] The gas delivered to Columbia Gas storage for injection was generally sourced from the Appalachian region during the review period.

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

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. During the review period, Piedmont purchased firm transportation service from Columbia Gulf under two Rate Schedule FTS-1 arrangements, pathed south to north, that provided for the firm delivery of Gulf Coast-sourced gas supplies directly to Piedmont's system. FTS-1 Contract No. 43462 provided for the delivery of up to 10,000 Dth/day during the winter period (November – March) and 9,202 Dth/day during the summer period (April – October). FTS-1 Contract No. 14252 provided for the delivery of up to 31,000 Dth/day during the winter period and 11,755 Dth/day during the summer period. In addition to its firm transportation agreements with Columbia Gulf, Piedmont also maintained an interruptible transportation (IT) arrangement that provided for the north to south delivery of gas to Piedmont from an interconnect with MGT at Walnut Gove, Tennessee.[2]

Prior to the winter of 2014 – 2015, the capacity under Piedmont's Columbia Gulf FTS-1 arrangement could be reliably segmented to deliver Gulf Coast production area sourced supplies from south to north to Piedmont's system and, at the same time, on a secondary basis, deliver gas supplies from north to south to Piedmont's system. However, as a result of the availability of abundant supplies from the Marcellus Shale production region, pipelines are experiencing new flow patterns. Pipelines like Columbia Gulf are delivering less supplies from the traditional Gulf Coast southern production region to northern market areas (south to north) and instead are delivering more supplies from the Marcellus Shale region to southern market areas (north to south). After extensive conversations with Columbia Gulf, Piedmont determined that this resulted in unacceptable risk to the reliability of segmented, secondary capacity being utilized to deliver gas supplies from north to south. In response to this risk, beginning with the winter of 2014 – 2015, Piedmont no longer considered volumes delivered on a secondary basis from north to south on Columbia Gulf to be a reliable design day capacity resource.

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.[3] 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

[2] The interconnect of Columbia Gulf and MGT at Walnut Grove is identified in Figure 1, shown previously.
[3] The TGP Legs are identified in Figure 1, shown previously.

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, which provided for the south to north delivery of gas from the Gulf Coast production region to Piedmont. Contract No. 237 was initially scheduled to expire on October 31, 2014, but was extended by Piedmont through October 31, 2019 at a reduced MDQ. The MDQ for the period prior to the scheduled expiration of Contract No. 237 was 74,100 Dth. Prior to expiration of the contract, Piedmont negotiated a change to Contract No. 237 that reduced the MDQ to 51,500 Dth through October 31, 2019. This reduction was accomplished by eliminating the Company's 100 Leg capacity of 22,435 Dth/day. Piedmont's 100 Leg capacity provided for the delivery of gas north of the Company's citygates, and required delivery to the citygate from north to south on the 500 Leg. With the change in the direction of flow (as explained previously in Section 2.1.2) on TGP to north to south, and per conversations with TGP, the Company determined that these north to south deliveries on a south to north contract could not be relied upon on a firm basis. In addition, operational changes made by Piedmont to its distribution system decreased the quantity of gas that could be received into the western side of its system that is served by TGP, and increased the quantity of gas than could be received into the eastern side of its system that is served by Columbia Gulf. Therefore, the 100 Leg capacity was no longer needed to meet customer demands. Piedmont's receipt point capacity under Contract No. 237 was subdivided by leg and zone as follows during the review period:

Tennessee Gas Pipeline Capacity MDQ (Dth)
(Contract No. 237)

Zone – Leg	Through October 31, 2014	Through October 31, 2019
Zone 0 – 100 Leg	22,435	0
Zone L – 500 Leg	28,204	25,750
Zone L – 800 Leg	23,461	25,750
TOTAL:	**74,100**	**51,500**

When Piedmont's liquefied natural gas (LNG) facility operates at its maximum rated capacity of [redacted] Dth/day, only 37,000 Dth/day of the Company's 51,500 Dth/day of TGP capacity under Contract No. 237 is operationally available to meet design day demands. This is because the same markets are served by the LNG facility and TGP, and the total LNG and TGP deliverability exceeds the demands of those markets. However, as explained in greater detail in Section 2.2.3 of the Report, operation of the Company's LNG facility was limited to [redacted] Dth/day during the review period. Therefore, the full 51,500 Dth/day of TGP capacity under Contract No. 237 was required to meet design day demands during the review period. Piedmont purchased the 51,500 Dth/day of capacity under Contract No. 237 at a price equivalent to the cost of 37,000 Dth/day.

Piedmont purchased a discounted rate transportation service from TGP under Contract No. 46715 (Rate Schedule FT-BH), which also expired on October 31, 2014. This contract was a backhaul transportation arrangement that provided for the north to south firm delivery of up to 81,900 Dth/day from Piedmont's TGP Market Area (FS-MA) and Production Area (FS-PA) storage accounts, and/or TGP's interconnect with MGT at Portland, Tennessee to Piedmont's system.

Upon expiration of Contract No. 46715, Piedmont entered into a replacement arrangement with TGP under Contract No. 301244 (Rate Schedule FT-A) for 55,900 Dth/day. Contract No. 301244 is a forward-haul arrangement that provides for the north to south delivery of gas from receipt points in TGP Zone 1, which includes, but is not limited to, receipts from FS-MA, FS-PA, and the MGT Portland Interconnect.

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 (referred to as "MGT West via TGP"), to the northern portion of Piedmont's distribution system by ETNG, and to the eastern side of Piedmont's distribution system by Columbia Gulf. MGT Contract No. FA0342 provides for the firm 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 provides for the firm transportation of up to 100,000 Dth/day from Portland, Tennessee with delivery of up to 75,000 Dth/day 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 to the interconnect with TGP at Portland can be delivered to Piedmont's system using TGP FT-A Contract No. 301244 in lieu of gas from the Company's FS-MA and FS-PA storage accounts. Deliveries by MGT to Walnut Grove under Contract No. FB0006 are delivered to Piedmont under segmented, secondary FTS-1 contracts or IT arrangements with Columbia Gulf, and deliveries to Boat Dock under Contract No. FB0006 are delivered from east to west to Piedmont's system utilizing an ETNG IT contract. [redacted]

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. As indicated in footnote No. 1 on page 2 of the Plan included as Appendix A to this Report, Rate Schedule SCT capacity, used to serve the City of Hartsville, Tennessee, is excluded from the commodity procurement cost component of the Plan.

2.2 Interstate Pipeline Storage Services 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 purchased at receipt points 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 MDWQs under the FS-MA and FS-PA arrangements are 50,798 Dth/day and 6,190 Dth/day, respectively.[4] 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. The LNG facility can produce at maximum levels for approximately [redacted]. The MDQ of Piedmont's LNG facility was [redacted] Dth/day for the winter of 2014-2015. Due to a federally mandated pressure reduction on one of the pipelines delivering gas from the LNG facility to Piedmont's distribution system, the MDQ from the LNG facility was reduced to [redacted] Dth/day for the remainder of the review period. Improvements to the pipeline are expected to return the deliverability of the LNG facility to [redacted] Dth/day for the winter of 2019-2020.

2.3 Citygate Delivered Supply

As explained earlier in Sections 2.1.2 and 2.1.4, Piedmont reduced its reliance on north to south deliveries utilizing secondary firm transportation capacity prior to the winter of 2014-2015 due to the physical flow change on Columbia Gulf and the resulting capacity constraints from north to south. These reductions included elimination of north to south secondary firm capacity of 41,000 Dth/day on Columbia Gulf and a 75,000 Dth/day reduction in the MGT capacity available to meet design day demands. In addition, as explained in Section 2.2.3, the deliverability of the Company's LNG facility was reduced prior to the winter of 2015-2016 by [redacted] Dth/day. In total, the Company experienced a reduction in design day capacity resources of 116,000 Dth/day for the winter of 2014-2015 and 146,000 Dth/day for the winter of 2015-2016.

To address these reductions, Piedmont acquired delivered-to-citygate supply services until the Company could secure alternative interstate pipeline capacity resources and return the deliverability of its LNG facility to full capacity. The Company referred to these delivered supply contracts as "bridging delivered supply," as they were intended to be temporary solutions until the Company could acquire firm interstate pipeline capacity to address its capacity deficiency. For the winter of 2014-2015, Piedmont acquired 122,000 Dth/day of delivered supply and 131,000 Dth/day of delivered supply for the winter of 2016-2017. The delivered cost of supplies under each of the Company's delivered supply arrangements was less than the costs Piedmont would have incurred had the Company directly contracted for capacity with the delivering interstate pipeline. However, these short-term arrangements did not provide for long-term security of supply.

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[4] After adjusting for the fuel retention charges assessed under TGP firm transportation Contract No. 301244 which is utilized for the delivery of gas from FS-MA and FS-PA storage, the delivered-to-citygate quantities are 49,828 Dth and 6,072 Dth, respectively.

For each winter during the review period, Piedmont contracted for delivered supplies with [redacted]. Contract quantities varied by month as follows:

Period	Dth/Day
November 2014	[redacted]
December 2014 – February 2015	
March 2015	
December 2015 – February 2016	
December 2016 – February 2017	

Gas supplies were delivered to Piedmont's citygate by Columbia Gulf. [redacted] The contract provided for the purchase of both monthly baseload and/or daily quantities up to the maximum contract quantities. The commodity charge was based on [redacted][5]

For the winters of 2015-2016 and 2016-2017, Piedmont entered into an agreement with [redacted] for citygate supplies delivered by TGP. The MDQ for each month under the arrangement was [redacted] Dth/day. The contract with [redacted] provided for daily purchase nominations. [redacted] Commodity charges were based on [redacted] Piedmont also entered into an agreement with [redacted] for citygate supplies delivered by Columbia Gulf for the winters of 2015-2016 and 2016-2017. The MDQ for each month under the arrangement was [redacted] Dth/day. The contract provided for daily purchase nominations. [redacted]

In addition to these delivered supply arrangements to meet the Company's projected design day capacity deficiency, Piedmont maintained a delivered supply arrangement with [redacted] for Texas Eastern-delivered supplies. [redacted] Commodity purchases under the arrangement were

5 [redacted]

priced based on [redacted]

2.4 Post-review Period Capacity Portfolio Changes

Piedmont was able to secure incremental firm transportation capacity from Columbia Gulf beginning in November 2017 under a five-year arrangement (Contract No. 194490) where the contract quantities increased each year to follow expected system design day demand growth. The winter period MDQ under the first year of the arrangement was 140,193 Dth, and the summer period MDQ was 58,052 Dth. Under the second year, the winter MDQ increased to 150,193 Dth and the summer MDQ increased to 62,193 Dth. The Company elected to secure Columbia Gulf firm transportation capacity in lieu of maintaining its Columbia Gulf-delivered supply arrangements because the Columbia Gulf capacity provided for the long-term security of service, while the delivered supply services did not provide this security of service. As indicated in Section 2.2.3, Piedmont expects to restore the deliverability of its LNG supply to [redacted] Dth/day for the winter of 2019-2020.

2.5 Asset Management Agreements

Piedmont operated under 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 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 3 summarizes Piedmont's review period AMA arrangements.

Table 3.
Review Period Asset Management Agreements

Manager	Term	Annual Fee
Tenaska Marketing Ventures	November 1, 2013 – October 31, 2014	[redacted]
Tenaska Marketing Ventures	November 1, 2014 – October 31, 2015	
Tenaska Marketing Ventures	November 1, 2015 – October 31, 2016	
Tenaska Marketing Ventures	November 1, 2016 – October 31, 2017	

Through October 2016 of the review period, Piedmont entered into gas supply contracts that provided for the purchase of supplies to be delivered under its firm transportation agreements, but did not assign those contracts to the Asset Manager. The Asset Manager generally acquired the gas necessary to meet Piedmont's requirements under its own arrangements. The Asset Manager maintained the option to acquire gas supplies under Piedmont's gas supply contracts, with

Piedmont initially purchasing the gas at the receipt point per the terms of the Company's arrangement with the supplier, and then selling the gas at the receipt point to the Asset Manager. Beginning in November 2016, the Asset Manager generally arranged for all of the gas supplies delivered to Piedmont under the firm transportation agreements released to the Asset Manager, and Piedmont did not generally enter into its own separate gas supply arrangements. During the review period, Piedmont contracted for, and arranged for, the purchase of gas under all of its citygate-delivered supply arrangements. Piedmont occasionally purchased delivered-to-citygate gas directly from the Asset Manager and/or from other suppliers.

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.

The RFPs that Piedmont issued for its review period AMAs included various pricing tiers on the total daily quantity of gas supply that an Asset Manager would be required to provide. These pricing tiers were included in the AMA contracts awarded by Piedmont. Piedmont believed that including these pricing tiers in its RFPs increased the fee that it received under the AMA. Quantities up to those listed in Table 4 were priced at applicable monthly or daily indices; quantities above those listed in Table 4 would have been priced [redacted].

Table 4. Summary of Asset Management Agreement Daily Supply Pricing Tiers (Dth/day)					
AMA Term: November 2013 – October 2014					
November – March		April & October		May – September	
Total:	MGT:	Total:	MGT:	Total:	MGT:
[redacted]					
AMA Term: November 2014 – October 2015					
November – March		April & October		May – September	
Total:	MGT:	Total:	MGT:	Total:	MGT:
[redacted]					
AMA Term: November 2015 – October 2016					
November – March		April & October		May – September	
Total:	MGT:	Total:	MGT:	Total:	MGT:
[redacted]					
AMA Term: November 2016 – October 2017					
November – March		April & October		May – September	
Total:	MGT:	Total:	MGT:	Total:	MGT:
[redacted]					

2.6 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 on the interstate markets and separately arrange for the delivery of those supplies to Piedmont's citygates. Table 5 summarizes the number of customers served and annual throughput by service class for the 12 months ended June 2015, June 2016, and June 2017.

Table 5.
Annual Customers and Volumes by Class
(12 Months Ended June)

Customers by Class	2015	2016	2017
Residential Sales	[redacted]		
Small General Sales			
Medium General Sales			
Firm Industrial Sales			
Interruptible Industrial Sales			
Natural Gas Vehicle Sales			
Sales for Resale			
Subtotal Sales Classes:			
Firm Transportation			
Interruptible Transportation			
Special Contract Transportation			
Subtotal Transportation Classes:			
TOTAL CUSTOMERS:			
Volumes by Class (Dth)	**2015**	**2016**	**2017**
Residential Sales	[redacted]		
Small General Sales			
Medium General Sales			
Firm Industrial Sales			
Interruptible Industrial Sales			
Natural Gas Vehicle Sales			
Sales for Resale			
Subtotal Sales Classes:			
Firm Transportation			
Interruptible Transportation			
Special Contract Transportation			
Subtotal Transportation Classes:			
TOTAL VOLUMES:			

Note: Excludes off-system sales.

3.0 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. A complete description of the Plan is included as Appendix A to this Report. Piedmont files an Annual Performance Incentive Plan Report (Annual Plan Report) with the TRA 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 during the review period identified several calculation errors in Piedmont's Annual Plan Report, none of which were material. Table 6 summarizes Piedmont's performance under the Plan during the review period. 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

	Gain/(Loss)		
Plan Year	**Ratepayers**	**Company**	**TOTAL Savings**
July 2014 – June 2015	[redacted]		
July 2015 – June 2016			
July 2016 – June 2017			
TOTAL:			

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) market baseload (monthly) purchases and daily purchases. Monthly purchases are generally arranged several days prior to the month of delivery, commence flow on the first day of the month, and provide for the delivery of the same quantity of gas on each day during the month. Daily purchases are arranged on the business day prior to delivery. While daily purchases typically flow for one day, deliveries over weekends (Saturday – Monday), holidays, and/or occasionally for the last several days of the month of flow may be arranged for multiple consecutive days.

There are various natural gas industry publications that identify, 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* and *Natural Gas Intelligence* (*NGI*). Daily index prices are published in *Platts Gas*

Daily and *NGI*. Trading locations at which Piedmont purchased gas with published index prices during the review period included the following:

Columbia Gas Transmission

- Appalachian Pool

Columbia Gulf Transmission

- Rayne (Louisiana) or Mainline

Midwestern Gas Transmission

- Chicago Citygate
- Rockies Express into MGT

Tennessee Gas Pipeline

- Zone 0 – 100 Leg (Texas)
- 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 IT arrangements or purchased on a delivered-to-citygate basis. If Piedmont's actual monthly costs exceed benchmark costs, 25 percent 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 percent 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 IT arrangements, and citygate delivery supply arrangements. The benchmark price for each type of purchase is weighted by actual monthly purchase quantities 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 and fuel and variable transportation charges.[6] A weighted average, delivered-to-citygate price is then calculated based on the capacity entitlements Piedmont reserves at each receipt point location and serves as the benchmark for monthly purchases. Table 7 presents a monthly summary of the capacity entitlements included in Piedmont's benchmark calculation for monthly purchases during the review period.

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

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

	Tennessee Gas Pipeline			Columbia Gulf	Texas Eastern	Midwestern Chicago Citygate		TOTAL
Month/Year	Z0-100	ZL-500	ZL-800	Mainline	ELA	West	East	Entitlements
July 2014	[redacted]							
August	[redacted]							
September	[redacted]							
October	[redacted]							
November	[redacted]							
December	[redacted]							
January 2015	[redacted]							
February	[redacted]							
March	[redacted]							
April	[redacted]							
May	[redacted]							
June	[redacted]							
July 2015	[redacted]							
August	[redacted]							
September	[redacted]							
October	[redacted]							
November	[redacted]							
December	[redacted]							
January 2016	[redacted]							
February	[redacted]							
March	[redacted]							
April	[redacted]							
May	[redacted]							
June	[redacted]							
July 2016	[redacted]							
August	[redacted]							
September	[redacted]							
October	[redacted]							
November	[redacted]							
December	[redacted]							
January 2017	[redacted]							
February	[redacted]							
March	[redacted]							
April	[redacted]							
May	[redacted]							
June	[redacted]							

For the benchmarking of daily purchases, each of Piedmont's actual daily purchases is priced at the applicable daily index price, plus the fuel and variable charges and, as applicable, IT charges.[7] The delivered costs for each purchase are totaled and divided by the actual quantity of daily purchases to derive the daily purchase benchmark included in the MBIP.

The benchmarking of citygate purchases during the review period varied by delivery pipeline and Plan year. The procedures used by Piedmont to benchmark citygate purchases are discussed in greater detail in Section 3.1.2 of the Report. The benchmark costs for each citygate purchase were totaled and divided by the actual quantity of citygate 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 December 2015. 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 capacity entitlements by purchase location. Column D of Section I identifies the percentage share of total capacity 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 7, Column F) in December 2015.

Section II shows the calculation of the combined MBIP based on the individual monthly, daily, and other 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 other purchase benchmarks were [redacted]/Dth and [redacted]/Dth, respectively. As shown in Section II, line 4, Column D, the total MBIP was [redacted]/Dth. Under the Plan, Piedmont's total purchases during December 2015 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).

[7] Under the Plan, daily purchases are benchmarked based on *Platts Gas Daily* index prices.

Table 8.
Summary of Monthly Benchmark Index Price Calculation and Commodity Procurement Incentive Gains/(Losses) (December 2015)

I. Purchase Location – Contractual Capacity	Actual FOM Purchases (Dth/Day) (A)	Actual FOM Purchases Percent (B)	Pipeline Capacity (Dth/Day) (C)	Pipeline Capacity Percent (D)	Delivered Price ($/Dth) (E)	Weighted Price ($/Dth) (F)
1. TGP Zone L – 500 Leg	[redacted]					
2. TGP Zone L – 800 Leg						
3. Columbia Gulf FTS-1						
4. Texas Eastern FT-1						
5. Midwestern East Side via Columbia Gulf – First 41,000 Dth						
6. Midwestern East via ETNG – Hendersonville						
7. TOTAL:						

II. Components of MBIP	Actual Purchases Dth (A)	Actual Purchases Percent (B)	Component Benchmark ($/Dth) (C)	Weighted Component Benchmark ($/Dth) (D)	Monthly Benchmark (E)
1. Monthly Purchases	[redacted]				[redacted]
2. Daily Purchases					
3. Other Purchases					
4. Purchases/MBIP					
5. Actual Costs					
6. Gain/(Loss) Based on MBIP:					

III. Commodity Procurement Gain/(Losses) 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]				
2. Other Purchases					
3. Citygate Purchases					
4. Purchases Gain/(Loss):					

FOM = First of the month; MBIP = Monthly Benchmark Index Price.
[1] Total differs from Piedmont calculation by $82 due to rounding.

Section III of Table 8 "unbundles" the MBIP and identifies incentive Plan savings by type of purchase. As shown there, 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). [redacted] (Section III, line 2, Column E).

3.1.2 Review Period Gas Procurement Activity

Firm Transportation Delivered Supplies. Table 9 provides a comparison of monthly index prices, adjusted for the applicable pipeline variable and fuel charges for the locations at which Piedmont could have purchased gas using its firm transportation capacity during the review period. That is, the prices in Table 9 reflect the effective delivered variable cost for purchases that would have been made at these various purchase locations. Also included in Table 9 is the effective benchmark price to which monthly purchases are compared. As indicated previously, index prices are published after trading for a location has 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. [redacted]

Table 9.
Summary of First-of-the-Month, Market-delivered Index Prices
(Dth)

	Tennessee Gas Pipeline			Columbia Gulf	Texas Eastern	Columbia Gas	Midwestern Chicago Citygate		
	Z0-100[1]	ZL-500	ZL-800	Mainline	ELA[2]	Appalachian[3]	West	East[4]	Benchmark
July 2014	[redacted]								
August									
September									
October									
November									
December									
January 2015									
February									
March									
April									
May									
June									
Winter Average:									
Annual Average:									
July 2015									
August									
September									
October									
November									
December									
January 2016									
February									
March									
April									
May									
June									
Winter Average:									
Annual Average:									
July 2016									
August									
September									
October									
November									
December									
January 2017									
February									
March									
April									
May									
June									
Winter Average:									
Annual Average:									

[1] Contract terminated October 31, 2014.
[2] Piedmont's Texas Eastern ELA transportation arrangement is a winter-only contract and, therefore, purchases from April – October are not available.
[3] [redacted].
[4] Average index price for the various MGT East Side delivery paths.

Table 10 identifies Piedmont's review period monthly purchases by location, and reveals that Piedmont generally maximized purchases under its winter FT contract with [redacted], its lowest-cost source of supply. The remainder of the Company's monthly purchase requirements were generally met with either [redacted] supplies, which reflect next-lowest available cost supplies. As indicated in Section 2.1 of the Report, TGP-sourced supplies are required to meet customer requirements on the western side of Piedmont's system, and Columbia Gulf-sourced supplies are required to meet customer requirements on the eastern side of Piedmont's system; thus, deliveries from both pipelines are required. Table 10 reveals that Piedmont minimized the purchase of [redacted] supplies, which were the highest-cost Gulf Coast production region source of supply during the review period (see Table 9). [redacted] purchases were generally Piedmont's highest-cost supply overall (see Table 9). [redacted] purchases were minimized until November 2016 when Piedmont entered into a [redacted] supply agreement that priced those purchases at [redacted] as calculated under the benchmarking procedures for [redacted] purchases delivered under the Company's firm transportation agreements.

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 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 monthly delivered prices

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

	Tennessee Gas Pipeline			Columbia Gulf Mainline	Texas Eastern ELA	Columbia Gas Appalachian	Midwestern Gas Chicago Citygate		
Month/Year	**Z0-100[1]**	**ZL-500**	**ZL-800**				**West**	**East-ETNG**	**TOTAL**
July 2014	[redacted]								
August									
September									
October									
November									
December									
January 2015									
February									
March									
April									
May									
June									
Subtotal:									
July 2015									
August									
September									
October									
November									
December									
January 2016									
February									
March									
April									
May									
June									
Subtotal:									
July 2016									
August									
September									
October									
November									
December									
January 2017									
February									
March									
April									
May									
June									
Subtotal:									
TOTAL:									
PERCENT:									

[1] Contract terminated October 31, 2014.

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

Month/Year	Tennessee Gas Pipeline Z0-100[1]	Tennessee Gas Pipeline ZL-500	Tennessee Gas Pipeline ZL-800	Columbia Gulf Mainline	Texas Eastern ELA	Columbia Gas Appalachian	Midwestern Gas Chicago Citygate West	Midwestern Gas Chicago Citygate East	TOTAL
July 2014	[redacted]								
August									
September									
October									
November									
December									
January 2015									
February									
March									
April									
May									
June									
Subtotal:									
July 2015									
August									
September									
October									
November									
December									
January 2016									
February									
March									
April									
May									
June									
Subtotal:									
July 2016									
August									
September									
October									
November									
December									
January 2017									
February									
March									
April									
May									
June									
Subtotal:									
TOTAL:									
PERCENT:									

[1] Contract terminated October 31, 2014.

Citygate Delivered Supplies. Table 12 summarizes Piedmont's citygate purchase quantities during the review period. As shown, [redacted].

The procedures used to benchmark citygate-delivered supplies varied during the review period and by delivering pipeline. Piedmont utilized two different benchmarking procedures for Columbia Gulf delivered citygate purchases during the review period. During the first Plan year of the review period, Columbia Gulf citygate purchases were benchmarked based on Columbia Gulf Mainline index prices and the applicable Columbia Gulf IT variable and fuel charges. For the second and third Plan years of the review period, Piedmont used the applicable Columbia Gulf firm transportation variable charge to the extent that the Company had open capacity under its Columbia Gulf firm transportation contracts. Columbia Gulf citygate purchase volumes in excess of Piedmont's open firm transportation capacity continued to be benchmarked utilizing Columbia's IT variable charge. The Columbia Gulf citygate delivered purchases benchmarked utilizing firm and interruptible variable charges are separately identified in Table 12.

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

	Columbia Gulf		Texas		Midwestern	
Month/Year	**IT**	**FT**	**Eastern**	**TGP**	**East via ETNG[1]**	**TOTAL**
July 2014	[redacted]					
August	[redacted]					
September	[redacted]					
October	[redacted]					
November	[redacted]					
December	[redacted]					
January 2015	[redacted]					
February	[redacted]					
March	[redacted]					
April	[redacted]					
May	[redacted]					
June	[redacted]					
Subtotal:	[redacted]					
July 2015	[redacted]					
August	[redacted]					
September	[redacted]					
October	[redacted]					
November	[redacted]					
December	[redacted]					
January 2016	[redacted]					
February	[redacted]					
March	[redacted]					
April	[redacted]					
May	[redacted]					
June	[redacted]					
Subtotal:	[redacted]					
July 2016	[redacted]					
August	[redacted]					
September	[redacted]					
October	[redacted]					
November	[redacted]					
December	[redacted]					
January 2017	[redacted]					
February	[redacted]					
March	[redacted]					
April	[redacted]					
May	[redacted]					
June	[redacted]					
Subtotal:	[redacted]					
TOTAL:	[redacted]					
PERCENT:	[redacted]					

[1] [redacted]

All Texas Eastern delivered citygate purchases were benchmarked utilizing Texas Eastern ELA index prices and the pipeline's applicable IT and fuel charges. No open capacity was available under Piedmont's firm transportation contract with Texas Eastern when Texas Eastern delivered citygate supplies were purchased during the review period.

During the first Plan year of the review period, citygate purchases delivered by TGP to the western side of Piedmont's system were benchmarked based on Chicago citygate index prices and the applicable MGT firm transportation variable and fuel charges associated with delivering gas to TGP, plus the IT and fuel charges associated with the delivery of gas by TGP to Piedmont's citygate. For the second and third Plan years of the review period, TGP delivered citygate supplies were benchmarked based on TGP Zone L-800 Leg index prices and the applicable TGP variable and fuel charges under Piedmont's firm transportation contract with TGP. At all times during the review period when TGP delivered citygate supplies were purchased, open capacity was available under Piedmont's TGP firm transportation contract.

All review period ETNG delivered citygate supplies were 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 IT and fuel charges associated with the delivery of gas from Boat Dock to Piedmont.

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, commodity procurement incentive mechanism gains were primarily achieved through monthly purchases during the review period and, to a lesser extent, through citygate-delivered purchases. 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**	**Citygate**	**TOTAL**	**Monthly**	**Daily**	**Citygate**	**TOTAL**
July 2014	[redacted]							
August								
September								
October								
November								
December								
January 2015								
February								
March								
April								
May								
June								
Subtotal:								
July 2015								
August								
September								
October								
November								
December								
January 2016								
February								
March								
April								
May								
June								
Subtotal:								
July 2016								
August								
September								
October								
November								
December								
January 2017								
February								
March								
April								
May								
June								
Subtotal:								
TOTAL:								
PERCENT:								

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 those 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. Atmos and Chattanooga Gas, two other Tennessee gas utilities that operate under gas cost incentive mechanisms, also maximize the purchase of gas at receipt point locations with the lowest total delivered cost. Neither Atmos nor Chattanooga Gas realize rewards for maximizing the purchase of the lowest-cost monthly supplies under their incentive mechanisms. The incentive mechanisms of Atmos and Chattanooga Gas are 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 out-performed 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 may have been realized without the existence of the Plan. Exeter would note, however, that the factor contributing most significantly to rewards under the monthly purchase component of the Plan was the inclusion of MGT capacity in the benchmark calculation and the relatively higher cost of MGT-delivered supplies compared to the generally lower-cost Gulf Coast-sourced supplies. Beginning with the winter of 2014-2015, as a result of the reduction to the amount of MGT capacity available to meet design day demands discussed in Section 2.1.4 of the Report, the savings achieved under the Plan associated with monthly purchases have significantly declined.

MGT Capacity Entitlements Included in the Weightings Used to Develop the Benchmark for Monthly Purchases. The Plan requires that the pipeline capacity weightings utilized to calculate the monthly benchmark be based on design day citygate delivery quantities.[8] Exeter's prior Plan audits found that Piedmont consistently adhered to this requirement. Exeter's current Plan audit found that Piedmont did not adhere to this requirement of the Plan for the period November 2014 through October 2015 and the period November 2016 through March 2017.

[8] In addition, 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 benchmark calculation.

As indicated previously in Table 7, Piedmont included 55,900 Dth/day of MGT West Side capacity in its monthly benchmark calculation for the period November 2014 through October 2015. This capacity was not a design day capacity resource and should have been excluded from the monthly calculation. This capacity was required to deliver gas from Piedmont's TGP FS-MA and FS-PA storage accounts, and was not anticipated to be used to purchase flowing supplies on a design day. TGP's index of customers included in its FERC tariff indicates that FS-MA and FS-PA storage are the primary receipt points for this capacity.

Exeter's findings concerning the inclusion of 55,900 Dth/day of MGT West Side capacity in the benchmark calculation were included in Exeter's Draft Report. In its comments on the Draft Report, Piedmont indicated that it included the 55,900 Dth/day of MGT West Side capacity in its monthly benchmark calculation because, while this capacity was not a design day resource, it was capacity that was not released and was available to be used to deliver gas to Piedmont's citygate even on a design day in lieu of TGP storage. Piedmont further explained that according to the Plan, "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 citygate delivery rights for the released capacity during such month." Piedmont claimed that since the MGT West Side capacity was available to use on a day-to-day basis in lieu of storage to manage storage balances and/or purchase flowing supplies when market prices were lower than the cost of gas in storage, Piedmont contended that the MGT West Side capacity should have been included in the monthly benchmark calculation.

As also indicated in Table 7, Piedmont included 25,000 Dth/day of MGT East Side capacity in its monthly benchmark calculation for the winter of 2014-2015, and 5,000 Dth/day for the summer of 2015. The inclusion of 25,000 Dth/day of MGT East Side capacity in the monthly benchmark calculation was appropriate because this capacity was available to meet design day requirements. No limit was in place on MGT purchases under Piedmont's AMA during the summer and, therefore, 25,000 Dth/day should have also been reflected in the monthly benchmark calculation for the summer of 2015. Adjusting calculated savings under the Plan to reflect the appropriate MGT West and East Side capacity entitlements for the period November 2014 through October 2015 would have reduced the savings calculated under the monthly purchase component of the Plan by $1,154,402.

Exeter's findings concerning the inclusion of 25,000 Dth/day of MGT East Side capacity in the benchmark calculation for the summer of 2015 were included in the Draft Report. In its comments on the Draft Report, Piedmont indicated that operationally it was determined that 5,000 Dth/day was needed during the summer period and, therefore, 5,000 Dth/day was used in the benchmark calculation for the summer of 2015. Piedmont contended that increasing the MGT East Side capacity to 25,000 Dth/day in the benchmark calculation would have artificially inflated gains under the Plan since MGT was the highest-cost supply.

For the winter of 2016-2017, Piedmont included 8,000 Dth/day of MGT West Side capacity and 25,000 Dth/day of East Side capacity in its monthly benchmark calculation. Only 25,000 Dth/day of MGT capacity was considered available to meet design day requirements. Therefore, only the 25,000 Dth/day of East Side capacity should have been reflected in its monthly benchmark calculation. However, during the winter of 2016-2017, Piedmont entered into a baseload gas supply arrangement under which it actually took delivery of 33,000 Dth/day of MGT-sourced supplies. Technical compliance with the Plan would suggest that calculated savings under the Plan should be adjusted to only include 25,000 Dth/day of East Side MGT capacity. This would have reduced calculated savings under the Plan by $45,353. Additional savings were achieved by Piedmont as a result of these purchases because they were benchmarked based on Chicago citygate index prices rather than index prices applicable for the actual location at which they were purchased. The benchmarking of the MGT-sourced baseload supplies is subsequently discussed in the Report.

Exeter's findings concerning the inclusion of 8,000 Dth/day of MGT East Side capacity in the benchmark calculation for the winter of 2016-2017 was also included in the Draft Report. Piedmont's comments on this finding were the same as those provided in response to Exeter's findings concerning the inclusion of 55,900 Dth/day of MGT West Side capacity in the benchmark calculation for the period November 2014 through October 2015. Exeter has presented Piedmont's comments on the findings included in the Draft Report on the MGT capacity entitlements included in the weightings used to develop the benchmark for monthly purchases in this Report to assist in ensuring the Report is comprehensive on this issue. However, it remains Exeter's position that the MGT capacity entitlements included in the monthly benchmark calculations should reflect design day citygate delivery quantities unless that capacity has been released or otherwise unavailable. Therefore, Exeter's findings concerning the inclusion of MGT capacity entitlements presented in the Draft Report remain unchanged.

Index Prices Used to Benchmark MGT Baseload Purchases. Piedmont benchmarked the MGT-sourced baseload supplies purchased during the period November 2016 through June 2017 based on Chicago citygate index prices. This appears consistent with the requirements of the Plan. However, these MGT-sourced baseload supplies were purchased at an interconnect between MGT and Rockies Express Pipeline (REX) located south of the Chicago citygate at Scotland, Illinois in Edgar County. Although index prices are published for the MGT/REX interconnect, Exeter was unable to obtain these prices.[9] Based on index prices for nearby REX interconnects with other interstate pipelines, it appears that index prices for the MGT/REX interconnect were generally several cents less than Chicago citygate index prices during the review period. While this price difference was not a significant concern during the review period, it may become a more significant concern under the Plan in the future.

Citygate Purchases. The procedures used by Piedmont to benchmark citygate purchases were described in detail in Section 3.1.2 of the Report – "Citygate Delivered Supplies." In summary, during the first Plan year of the review period, citygate purchases delivered by Columbia Gulf, Texas Eastern, and TGP were benchmarked utilizing the same Gulf Coast index locations used to benchmark deliveries under the Company's firm transportation arrangements, plus the delivering pipeline's applicable IT and fuel charges. For the second and third years of the Plan, the pipeline's firm transportation variable charge was used in lieu of the IT charge if there was open capacity available under the Company's firm transportation contract, and the IT charge was used if open capacity was not available under the firm transportation contract. All ETNG-delivered citygate supplies were 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 variable and fuel charges associated with the delivery of gas from Boat Dock to Piedmont.

The benchmarking of citygate purchases is not specifically addressed in the Plan. It can be argued that tariff language describing the Plan indicates that citygate purchases should be benchmarked based on index prices applicable for the receipt point location at which the gas was purchased by the supplier. The receipt point location of these purchases would be unknown to Piedmont unless the supplier was willing to provide Piedmont with this information, which is unlikely since it would reveal commercially sensitive information, and the supplier would have no obligation to disclose the information. Alternatively, it can be argued that citygate supplies should be benchmarked against an index location in close proximity to Piedmont's system, adjusted for the applicable variable charges. Finally, it can be argued that the citygate supplies were appropriately benchmarked under the approach used by Piedmont during the second and third Plan years.

Of the available options to benchmark citygate supplies, Exeter believes the most appropriate would be to benchmark citygate purchases against an index location in close proximity to Piedmont's system. However, this approach is not a viable option since there are no index locations in close proximity to Piedmont's system for the pipelines delivering gas supplies to the Company. The approach used by Piedmont during the second and third Plan years of the review

[9] Index prices for the MGT/REX interconnect are currently reported by *NGI*. MGT/REX interconnect index prices are not currently reported by *Platts Inside FERC* or *Platts Gas Daily*.

period for Columbia Gulf, Texas Eastern, and TGP appears to have been more reasonable than the approach utilized during the first Plan year of the review period. Under the approach used in the second and third Plan years, Piedmont is given the incentive to pursue the purchase of lower-cost citygate supplies when available. The benchmarking approach utilized during the first Plan year of the review period was not reasonable and, as identified in Exeter's most recent prior Plan audit, could result in ratepayers paying more for citygate supplies than for supplies delivered under the Company's firm transportation contracts. Exeter's analysis indicates that the most reasonable approach to benchmarking Columbia Gulf, Texas Eastern, and TGP delivered citygate supplies would be to use the approach utilized by Piedmont to benchmark these purchases when open capacity was available under the Company's firm transportation contracts, regardless of whether open capacity is available.[10] That is, the variable firm transportation charge should be used rather than the IT charge. Exeter's analysis indicates that this approach results in a benchmark price that is more consistent with market prices than the use of a benchmark price based on the applicable IT rates. Exeter notes that with Piedmont's acquisition of additional Columbia Gulf firm transportation capacity beginning in the winter of 2017-2018, the approach recommended by Exeter and the approach used by Piedmont during the second and third Plan years of the review period will generally be consistent going forward, with the possible exception of Texas Eastern citygate-delivered supplies.

The Company's use of Chicago citygate index prices to benchmark ETNG citygate supplies was unreasonable during the review period. Based on market conditions during the review period, it is unlikely that these supplies would have actually been delivered from the Chicago citygate by MGT to ETNG. A more likely delivery path would have been that these supplies were delivered to ETNG by TGP. The actual source of these citygate supplies is unknown to Piedmont and Exeter. Consistent with Exeter's findings concerning the benchmarking of Columbia Gulf, Texas Eastern, and TGP citygate purchases, we find that it would be more appropriate to use an average of TGP Gulf Coast index prices (100/500/800 Legs), plus the applicable TGP and ETNG firm variable and fuel charges to benchmark ETNG citygate purchases.

3.2 Supplier Reservation Fees Component

3.2.1 Background and Description

The Plan allows Piedmont to recover 100 percent of its gas supplier reservation fees with no profit or loss potential. Piedmont entered into a number of gas supply contracts with supplier reservation fees during the review period. These fees generally ranged from [redacted]/Dth to

[10] In its comments on Exeter's Draft Report, the Company indicated it believed that citygate purchases should continue to be benchmarked utilizing IT rates when open capacity is not available.

[redacted]/Dth, per day, of the contracted MDQ. A summary of Piedmont's review period supplier reservation fees is presented in Table 14. Those fees associated with Piedmont's delivered-to-citygate supply arrangements relied upon to meet the Company's design day capacity resource requirements are separately identified from those supplier reservation fees associated with Piedmont's other supply arrangements. As shown in Table 14, Piedmont significantly reduced its supplier reservation fees during the review period.

Table 14.
Supplier Reservation Fees

	Year Ended June 30			
	2015	**2016**	**2017**	**TOTAL**
Other Supplies	[redacted]			
Design Day Supplies				
TOTAL:				

Piedmont's gas supply contracts generally provided for index [redacted] commodity pricing index adders during the review period. In limited instances, Piedmont's firm gas supply contracts included [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 demand charge fees. With 100 percent 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 found 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 15 summarizes the capacity management revenues realized by Piedmont during the review period.

Table 15.
Summary of Capacity Management Revenues

		Off-system Sales		Revenues		
	Asset Management	Volume (Dth)	Margin	Total	Company 25%	Ratepayers 75%
July 2014	[redacted]					
August						
September						
October						
November						
December						
January 2015						
February						
March						
April						
May						
June						
Subtotal:						
July 2015						
August						
September						
October						
November						
December						
January 2016						
February						
March						
April						
May						
June						
Subtotal:						
July 2016						
August						
September						
October						
November						
December						
January 2017						
February						
March						
April						
May						
June						
Subtotal:						
TOTAL:						

Piedmont is entitled to retain 25 percent 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 percent Company sharing for AMA revenues is at the high end of the sharing procedures adopted in other jurisdictions, and the 25 percent 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 Table 3 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, and Piedmont was uncertain as to why AMA fees increased during the review period. It is Exeter's opinion that the AMA fees may have increased because the Asset Manager was able to sell gas to Piedmont during the review period at Gulf Coast production area prices, but deliver lower-cost Marcellus Shale production supplies to the Company.

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 Asset Manager and, therefore, Piedmont did not engage in capacity release activities during the review period.[11]

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 generally limited to such sales back to the Asset Manager. These sales are included in Table 15 above.

Piedmont sold significant quantities of gas to the Asset Manager at upstream receipt points, which were subsequently delivered to Piedmont's citygate by the Asset Manager and resold back to Piedmont at the same cost initially paid for the gas when it was sold to the Asset Manager. These off-system sales were made to comply with FERC's Shipper Must Have Title Policy, generated no margin, and are not reflected in Table 15. The majority of sales to the Asset Manager at upstream receipt points were made in conjunction with Piedmont's gas supply arrangement for MGT baseload supplies, which began in November 2016 and extended through the conclusion of the review period. These sales were necessary because the gas supply contract was an agreement that Piedmont entered into prior to the AMA that became effective in November 2016.

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

3.3.2 Results and Conclusions

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, these sales were generally made at the end of the month, and the Company frequently purchased supplies at the same location at the beginning of the next month at higher prices. Exeter's most recent prior triennial review of Piedmont's Plan 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 also initially surfaced during the current review period on three occasions; however, Piedmont was able to provide justification for these off-system transactions as necessary to manage storage inventory balances. The three occasions during the audit period initially raising concern were as follows: (1) sales at the end of November 2015 at a price of [redacted]/Dth and the purchase of supplies at [redacted]/Dth the following month (December); (2) sales at the end of April 2016 at a price of [redacted]/Dth and the purchase of supplies at [redacted]/Dth the following month (May); and (3) sales at the end of March 2017 at a price of [redacted]/Dth and the purchase of supplies at [redacted]/Dth the following month (April).

In conclusion, off-system sales activities contributed relatively little to Piedmont's capacity management revenues, totaling less than [redacted] over the three-year review period. The three instances noted above where Piedmont sold gas to the Asset Manager and subsequently purchased supplies at higher prices generated more than 80 percent of Piedmont's off-system sales margins. These sales to the Asset Manager were made to assist in the management of storage inventory balances. Exeter's audit revealed no other concerns with Piedmont's off-system sales activities.

4.0 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 on-system LNG storage facility. The Company's storage arrangements during the review period are summarized in Table 16.

Table 16.
Summary of Review Period Storage Service Arrangements

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 17 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 17 reflects Piedmont's virtual dispatch use of storage, and not the actual physical use of storage by its Asset Manager during the review period.

Table 17.
Summary of Review Period Storage Activity
(Dth)

	Tennessee Gas Pipeline (FS-MA)			Tennessee Gas Pipeline (FS-PA)			Columbia Gas Transmission (FSS)			Piedmont (LNG)		
	Activity (Inject/ Withdrawals)	Ending Inventory	% Capacity 2,901,943	Activity (Inject/ Withdrawals	Ending Inventory	% Capacity 672,091	Activity (Inject/ Withdrawals	Ending Inventory	% Capacity 611,870	Activity (Inject/ Withdrawals	Ending Inventory	% Capacity 1,000,000
July 2014	[redacted]											
August												
September												
October												
November												
December												
January 2015												
February												
March												
April												
May												
June												
July 2015												
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November												
December												
January 2017												
February												
March												
April												
May												
June												

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 80 percent of capacity prior to the start of the storage withdrawal season (November 1), and to fill Columbia Gas storage and the Company's LNG storage to [redacted] of capacity prior to the start of the storage withdrawal season. [redacted]. Piedmont plans to reduce the storage inventory balances under each of its interstate pipeline storage services to no less than [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 (i.e., 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 18. As shown, actual beginning-of-storage season balances were generally consistent with planned balances. However, end-of-storage season inventory balances, [redacted].

Table 18.
Review Period Planned and Actual Storage Inventory

	March 31		November 1	
Year	Planned	Actual	Planned	Actual
	Tennessee Gas Pipeline (FS-MA/FS-PA)			
2014	[redacted]			
2015				
2016				
2017				
	Columbia Gas (FSS)			
2014	[redacted]			
2015				
2016				
2017				

Piedmont's TGP and Columbia Gas storage inventory balances at the conclusion of the 2014-2015 winter season were at [redacted] and [redacted] of capacity, respectively, which was in excess of the [redacted] planned balances. While weather in the Company's service territory was near normal, storage balances exceeded Piedmont's planning criteria due to winter period gas prices that were significantly 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 no benefit to sales customers associated with withdrawing gas from storage.

At the conclusion of the winter of 2014-2015, TGP storage inventory balances were at [redacted] of capacity, while the Columbia Gas inventory balance was at [redacted] of capacity and consistent with the Company's [redacted] planning criteria. Weather during the winter of 2014-2015 was 31 percent warmer than normal, which contributed to TGP storage inventory balances exceeding planned balances. In addition, winter period gas prices were lower than the cost of gas in TGP storage inventory.

Piedmont's storage inventory balances at the conclusion of the winter of 2016-2017 were comparable with those experienced the prior winter, with TGP storage inventory at [redacted] of capacity and Columbia Gas storage at [redacted] of capacity. Although gas prices during the winter of 2016-2017 were slightly higher than those observed during the 2016 summer injection period, the winter of 2016-2017 was 34 percent warmer than normal, with the core winter months of January and February being nearly 50 percent warmer than normal. [redacted].

In conclusion, Exeter's review finds that Piedmont's storage inventory planning criteria were generally reasonable, and were 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.

5.0 EVALUATION OF CAPACITY PORTFOLIO AND IDENTIFICATION OF VARIABLE CHARGES

5.1 Design Day Forecasting 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. Piedmont currently utilizes a day with an average daily temperature of -5˚F, or 70 heating degree days (HDDs), as its design day criteria. This reflects the coldest average daily temperature experienced in the Company's service territory over the last 40 years (which occurred on January 20, 1985). During the prior triennial review period, Piedmont utilized a design day temperature criteria of 67 HDDs, but revised its criteria to 70 HDDs in response to the 2013-2014 Polar Vortex. It is typical 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; however, other natural gas utilities commonly utilize variables in addition to temperature to project design day demands and use of these additional variables generally increases projected demands, potentially off-setting conservative design day temperature criteria.

To assess the reasonableness of Piedmont's design day forecast methods and procedures, Exeter evaluated the Company's forecast for the winter of 2017-2018. Piedmont's design day forecast for the winter of 2017-2018 was based on an analysis of daily firm sales and firm transportation sendout for the period November 2011 through March 2017. 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 10 or fewer HDDs. The usage-per-HDD factor was determined through a regression analysis of usage on days with greater than 10 HDDS. This method attempts to take into account that usage per HDD tends to be lower on days with fewer than 10 HDDs than it is on those days with more than 10 HDDs. Relying on usage data on days with relatively low heating load usage would underestimate usage on days with higher heating loads because the relationship between usage per HDD and HDD is not linear, and usage per HDD is typically greater on days with higher HDDs. Included in the Company's forecast of design day demands is a 5 percent reserve margin. Customer growth is also reflected in the Company's forecasts. The demands of firm transportation customers electing not to purchase standby service are subtracted from the Company's firm design day forecast to determine the capacity resources to be acquired by Piedmont. A comparison of the Company's firm design day forecasts and available capacity resources for the review period and the winter of 2017-2018 are presented in Table 19.

Table 19. Comparison of Estimated Design Day Demands and Capacity Resources (Dth)			
Winter Season	Firm Demand[1]	Capacity Resource	Surplus (Deficit)
2014-2015	382,842	382,810	(32)
2015-2016	395,664	395,644	0
2016-2017	398,528	396,964	(1,564)
2017-2018	399,968	399,968	0

[1] Excludes transportation customers electing not to purchase standby service. [redacted]

Exeter's evaluation of Piedmont's design day forecasting model revealed several concerns. Piedmont relied on usage data that dated back to the winter of 2011-2012, and incorporated usage on days with relatively low heating load. Exeter is concerned that relying on data for the winter of 2011-2012 would fail to account for customer conservation efforts.[12] Exeter also noted in its prior triennial review that Piedmont found that variables other than HDDs such as windspeed and prior-day HDDs had an impact on daily customer usage. These other variables were not included in Piedmont's design day forecast model. In the prior triennial review, Piedmont indicated that it adopted its revised design day criteria to 70 HDD from 67 HDD partially to account for the impact of these other variables rather than to include these variables in its model. In the prior triennial review report, Exeter recommended that Piedmont explicitly explore including windspeed and prior-day HDD variables in its design day forecasting model. Exeter's current review indicates that Piedmont did not evaluate inclusion of these other independent variables in its model during the current review period. Finally, Exeter's review of Piedmont's design day forecasting model noted an arithmetic inconsistency. The Company's model uses separate regression analyses to determine baseload usage and the use-per-HDD factor. The baseload usage is calculated using demands for temperatures of 10 HDD or below, and the usage per HDD is calculated using demands in the same data set for temperatures of more than 10 HDD. The arithmetic inconsistency arises in that the calculation of usage-per-HDD demands should have been calculated solely based on heat-sensitive usage, not total usage that reflected both heat-sensitive and non-heat sensitive usage.

To further evaluate Piedmont's design day forecast model, Exeter independently assessed the results of Piedmont's model. Exeter performed its own regression analysis of firm daily usage

[12] In response to this concern, which was addressed in Exeter's Draft Report, Piedmont indicated that based on actual customer experience, Piedmont claims customers tend to burn more gas the day or two following the coldest day as temperatures begin to moderate.

that included independent variables for windspeed, prior-day temperature, and accounted for usage on weekends that is typically lower than usage during the week. Exeter also limited the usage data included in its analysis to days during the winter with temperatures at or below 32˚F, and to usage data from the last three heating seasons. Exeter's design day model estimated the design day demands of Piedmont's firm sales and firm transportation customers at 70 HDD to be 379,369 Dth for the 2017-2018 winter season, prior to accounting for customer growth and Piedmont's reserve margin. Under these same conditions, the design day projection of Piedmont's model was 382,673 Dth, which reflects a difference of less than one percent. Therefore, there appear to have not been adverse consequences resulting from utilization of the Piedmont model for capacity planning purposes. Nevertheless, Exeter recommends that Piedmont continue to explore improvements to its model by including windspeed, prior-day HDDs, and weekend independent variables, including only those days with a relatively high heating load such as those days with temperatures at or below freezing, and generally limiting usage data to the most recent three-year period. In its comments to Exeter's Draft Report on the Company's design day forecasting model, Piedmont has indicated that it will continue to look for opportunities to improve its analysis.

The Statement of Work for this audit required an assessment of the extent to which Piedmont's design peak day forecasting approach considered customer conservation efforts. As noted previously in this section, customer conservation efforts are not considered by the Company and could overstate design day demands. As also previously noted in this section of the Report, the Company claims that actual experience shows that customers do not practice conservation efforts during extreme cold periods, and to the contrary, customers tend to burn more gas the day or two following the coldest day as temperatures begin to moderate. As indicated above, Exeter continues to recommend that Piedmont limit the daily usage data included in its design day forecasting model to the most recent three years and to explore the inclusion of other independent variables in its design day forecast model.

5.2 Actual Peak Day and Design Day Forecasting Accuracy

A comparison of actual peak day firm requirements and forecasted requirements under actual 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 the forecasting approach and model used by the Company, Exeter compared actual firm sendout with the forecasted firm sendout under actual weather conditions. These comparisons are presented in Table 21. As shown, Piedmont's forecasting model did not produce forecasts that were unreasonable. Exeter also compared actual firm sendout with forecasted sendout under actual weather conditions using the model developed by Exeter discussed in Section

5.1 of the Report. As shown in Table 21, the forecasts prepared using the model developed by Exeter were consistently more accurate. In the Company's comments on the comparison presented in Table 20, which was presented in the Draft Report, Piedmont indicated that its slightly conservative approach and current methodology better ensured reliable service.

Table 20
Comparison of Actual Projected Firm Demand
Piedmont and Exeter Models

	Piedmont Model			Exeter Model		
Peak Day: January 7, 2015 – 54 HDDs						
Actual: [redacted]	Projected: 302,271	Variation: [redacted]	Percent: [redacted]	Projected: 280,356	Variation: [redacted]	Percent: [redacted]
Peak Day: January 18, 2016 – 46 HDDs						
Actual: [redacted]	Projected: 260,224	Variation: [redacted]	Percent: [redacted]	Projected: 244,520	Variation: [redacted]	Percent: [redacted]
Peak Day: January 7, 2017 – 49 HDDs						
Actual: [redacted]	Projected: 274,671	Variation: [redacted]	Percent: [redacted]	Projected: 260,577	Variation: [redacted]	Percent: [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 2017-2018 were previously presented in Table 19. As shown there, Piedmont's estimated design day demands and capacity resources were in balance during the review period and for the winter of 2017-2018. Details concerning the individual capacity resources available during the last winter season of the review period are presented in Table 2 of the Report.

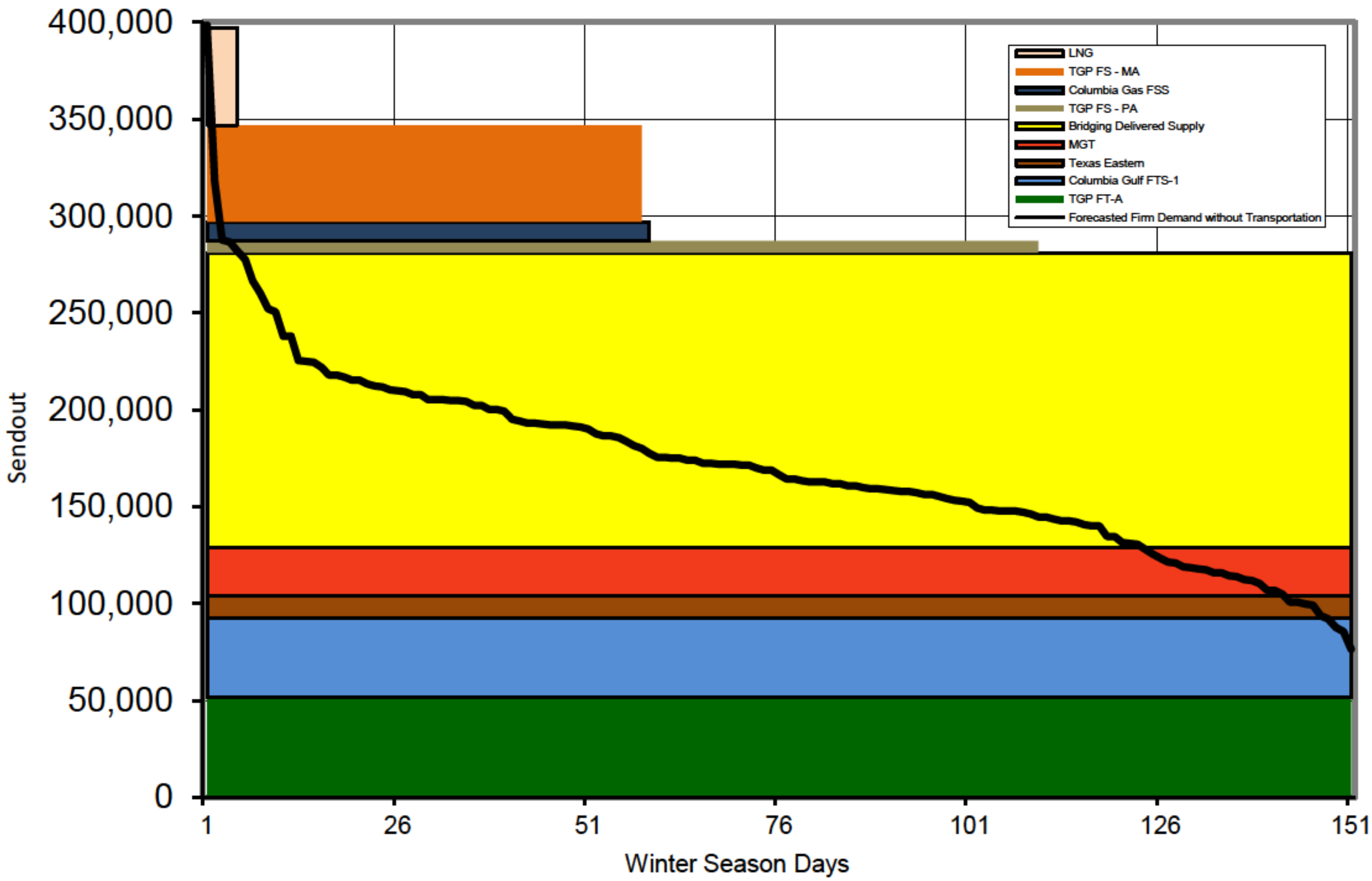
5.4 Winter Season Capacity Resources and Requirements

For winter season capacity resource planning, Piedmont uses a design winter in which the HDDs experienced each day are equal to the highest HDDs experienced on that day during the previous five years. For the winter of 2016-2017, winter capacity resource planning HDDs totaled 4,906, which reflects a winter that is approximately 35 percent colder than normal.[13] The projected demands of sales customers under a design winter for the winter of 2016-2017 were 27.3 billion cubic feet (Bcf). As previously indicated in Table 2, the capacity resources available to meet the

[13] Based on normal winter season HDDs of 3,688.

winter season requirements of Piedmont's sales customers totaled 44.4 Bcf. This would suggest that, from a planning perspective, Piedmont's winter season capacity resources exceeded [redacted]. Piedmont attempts to obtain value for unutilized firm transportation capacity by releasing that capacity under an AMA. Piedmont's load duration curve for the winter of 2016-2017 is presented in Figure 2. This demand curve illustrates the extent to which Piedmont maintained winter capacity [redacted] The Company's 2016-2017 winter demand curve is comparable to its 2017-2018 winter demand curve, with the exception that the Company's Columbia Gulf bridging-delivered supply was replaced with Columbia Gulf FTS-1 firm transportation capacity.

Figure 2.
2016-2017 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]. As shown previously in Table 2, the capacity resources available to meet Piedmont's annual requirements totaled [redacted] at the conclusion of the review period. Approximately [redacted] of this capacity is used to fill storage during the summer period. Based on annual requirements of [redacted] and summer storage injections of [redacted], Piedmont maintained an annual deliverability surplus of approximately [redacted], or approximately [redacted]. [redacted]. 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 included 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 charges associated with each non-storage-related interstate pipeline firm transportation service purchased by Piedmont during the final year of the review period are summarized in Table 21. In order to provide a more representative assessment of Piedmont's future demand charges, Columbia Gulf Contract No. 194490, which was acquired to replace a similar quantity of delivered supply, is also reflected in Table 21.

Table 21.
Summary of Interstate Pipeline Firm Transportation Charges

Pipeline/(Contract Number)	MDQ (Dth) Winter	MDQ (Dth) Summer	MDQ (Dth) Annual Commodity	Monthly Demand Charge ($/Dth)	Annual Demand Cost
Columbia Gulf				[redacted]	[redacted]
FTS-1 (43462)	10,000	9,202	3,479,228	[redacted]	[redacted]
FTS-1 (14252)	31,000	11,755	7,196,570	[redacted]	[redacted]
FTS-1 (194490)	140,193	58,052	33,592,271	[redacted]	[redacted]
Midwestern Gas Transmission				[redacted]	[redacted]
FT-A (FA0342)	100,000	100,000	36,500,000	[redacted]	[redacted]
FT-B (FB0006)	100,000	100,000	36,500,000	[redacted]	[redacted]
Tennessee Gas Pipeline				[redacted]	[redacted]
FT-A (237)	51,500	51,500	18,797,500	[redacted]	[redacted]
Texas Eastern				[redacted]	[redacted]
FT-1 (910473)	10,000	0	1,510,000	[redacted]	[redacted]
SCT (800059)[1]	1,677	1,677	204,035	[redacted]	[redacted]

[1 [redacted].

Actual review period utilization of the Company's firm transportation capacity for the final year of the review period is presented in Table 22. As shown, the Company's Texas Eastern capacity was utilized at [redacted]. The Company's other firm transportation arrangements were utilized at [redacted]. The TGP and Columbia Gulf capacity were utilized at load factors of [redacted]. The Company's MGT capacity was utilized at an annual load factor of [redacted]. The MGT capacity load factor [redacted] during the summer period. As previously indicated in Sections 2.3 and 3.1.2 of the Report, Piedmont purchased significant quantities of delivered-to-citygate supplies during the review period. These supplies resulted in lower overall costs than if Piedmont had used is firm interstate pipeline transportation contracts to deliver supplies to its citygate. Therefore, [redacted] are not an indication that Piedmont's interstate pipeline capacity entitlements were unreasonable.

Table 22.
Summary of Firm Transportation Contract Utilization
(July 2016 – June 2017 Plan Year)

Pipeline/Rate Schedule	Annual Quantity (Dth) Maximum	Annual Quantity (Dth) Actual	Load Factor
Columbia Gulf		[redacted]	
FTS-1 (43462/14252)	10,675,798		
Midwestern Gas Transmission			
FT-A / FT-B (FA0342/FB0006)	36,500,000		
Tennessee Gas Pipeline			
FT-A (237)	18,797,500		
Texas Eastern			
FT-1 (910473)	1,510,000		
TOTAL:	**67,483,298**		
TOTAL – Excluding MGT:	**30,983,298**		

Rather than assess the potential for Piedmont to reduce its demand charges by decreasing the year-round capacity included in the winter of 2016-2017 capacity portfolio that has since changed significantly, Exeter has assessed this potential based on the capacity portfolio that existed for the winter of 2017-2018. Table 23 summarizes Piedmont's design day, winter season, and annual capacity entitlements based on the Company's winter of 2017-2018 capacity portfolio.

**Table 23.
Summary of Design Day Capacity Contracts and Resources
(2017 – 2018 Winter Season)**

Pipeline – Service	Contract No.	MDQ (Dth) Winter	MDQ (Dth) Summer	Available Quantity (Dth) Winter	Available Quantity (Dth) Annual	Contract Expiration
Columbia Gas						
Storage Service (FSS/SST)	38017/38052	10,000	5,000	611,870	611,870	3/31/2024
Columbia Gulf						
Firm Transportation (FTS-1)	43462	10,000	9,202	1,510,000	3,479,228	10/31/2022
Firm Transportation (FTS-1)	14252	31,000	11,755	4,681,000	7,196,570	10/31/2022
Firm Transportation (FTS-1)	194490	140,193	58,052	21,169,143	33,592,271	10/31/2022
Midwestern Gas Transmission						
Firm Transportation (FT-A)/(FT-B)	FA0342/FB0006	25,000	25,000	3,775,000	9,125,000	1/6/2023
Tennessee Gas Pipeline						
Firm Transportation (FT-A)	237	51,500	51,500	7,776,500	18,797,500	10/31/2019
Storage Service (FS-MA/FT-A)	6815/301244	49,828	0	2,901,943	2,901,943	10/31/2019
Storage Service (FS-PA/FT-A)	2400/301244	6,072	0	672,091	672,091	10/31/2019
Texas Eastern Transmission						
Firm Transportation (FT-1)	910473	10,000	0	1,510,000	1,510,000	3/31/2019
Firm Transportation (SCT)	800059	1,677	1,677	84,409	204,035	10/31/2022
[redacted]						
Piedmont LNG		[redacted]				
Total Citygate Capacity Resources:		[redacted]				

Piedmont's projected design day firm demand for the winter of 2017-2018, inclusive of its 5 percent reserve margin and excluding the demands of firm transportation customers without standby service, was 399,968 Dth. As shown above in Table 23, Piedmont maintained 399,968 Dth of design day capacity. Compared to the winter 2016-2017, Piedmont's winter season capacity entitlements increased from 44.4 Bcf to 47.9 Bcf, indicating that winter season capacity resources exceeded requirements of 27.3 Bcf by 20.6 Bcf, or 75 percent. Annual capacity entitlements increased from 65.4 Bcf to 81.3 Bcf, indicating that annual capacity resources, including summer storage fill requirements, exceeded requirements of 36.8 Bcf by 44.5 Bcf, or 120 percent. These increases were primarily attributable to the replacement of Piedmont's Columbia Gulf bridging-delivered supply arrangements with Columbia Gulf firm transportation capacity.

A significant portion of Piedmont's 2017-2018 winter season capacity portfolio consisted of either winter season capacity or was seasonally sculpted, with winter season entitlements being higher than summer season entitlements. The Company's firm transportation contract with Texas Eastern is a winter-only contract. The capacity entitlements under the Company's three firm transportation contracts with Columbia Gulf are seasonally sculpted. In total, the Company's summer capacity entitlements are 60 percent less than its winter capacity entitlements. Piedmont has indicated, and it is consistent with Exeter's experience in reviewing interstate pipeline 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. As noted in other sections of the Report, Piedmont has reduced the MGT capacity determined to be available to meet design day demands by 75,000 Dth/day. This 75,000 Dth/day has been excluded from Exeter's comparison of the Company's 2017-2018 winter season capacity entitlements and requirements. However, Piedmont will be required to pay for this 75,000 Dth of MGT capacity until 2023.

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 require the payment of variable charges that are based on actual use. 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 a storage injection fuel charge.

A requirement included in the Statement of Work of Exeter's review was 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. Piedmont was assessed [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 as of September 1, 2016 are identified in Table 24.

Table 24.
Interstate Pipeline Variable Charges[1]

TRANSPORTATION SERVICES		
Pipeline/Rate Schedule /Contract	**Commodity Charge ($/Dth)**	**Fuel Charge**
Columbia Gas		
SST (38052) to Storage	$0.0193	2.042%
SST (38052) from Storage	$0.0179	0.000%
Columbia Gulf		
FTS-1 (43462/14252)	$0.0123	0.651%
Midwestern Gas Transmission		
FT-A (FA0342)	$0.0023	1.00%
FT-B (FB0006)	$0.0014	0.00%
Tennessee Gas Pipeline		
FT-A (237)	$0.0169	0.77%
FT-A (301244)	$0.0169	0.77%
Texas Eastern		
FT-1 (910473)	$0.0014	0.39%
SCT (800059)	$0.6782	

STORAGE SERVICES			
	Storage Variable Charge ($/Dth)		
Pipeline/Rate Schedule Contract	**Injection**	**Withdrawal**	**Injection Fuel Charge**
Columbia Gas			
FSS (38017)	$0.0153	$0.0153	0.15%
Tennessee Gas Pipeline			
FS-MA (6815)	$0.0087	$0.0087	1.37%
FS-PA (2400)	$0.0073	$0.0073	1.37%

[1] Rates as of September 1, 2016.

6.0 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 costs are limited to one percent of annual gas costs.[14] All hedging gains and losses are reflected in the Company's purchased gas cost rates. The annual gas costs can be found in the annual Actual Cost Adjustment (ACA) audit performed by Audit Staff of the TPUC under the section "ACA Audit Findings," in the table labeled "Summary of the ACA Account," and by adding the second line of the "Commodity" section and the second line of the "Demand" section labeled "Plus Gas Costs" in the "Company" or "Staff" Column, as appropriate.

Piedmont's hedging program is designed to mitigate the impact of significant price spikes for up to 45 percent 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. Piedmont's hedging activities during the review period are summarized in Table 25.

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 one percent 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 Energy Price Risk Management 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 uses a matrix created by its hedging consultant, INTL FCStone (previously Risk Management Incorporated), which 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. This adjusted historical price database is then segmented into deciles, which are presented in a matrix. Current NYMEX futures prices are compared against the matrix by season when making hedging decisions. Piedmont has established

[14] In June of each year, the recovery cap is computed utilizing the most current audited and approved annual gas costs for the Company.

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 matrix. When this occurs, Piedmont will spend 20 percent of its monthly hedging budget on call options for that month's contract. Piedmont will continue to spend an additional 20 percent of its monthly hedging budget for any month's contract any time NYMEX futures prices fall into the next-lowest decile price point. For example, if NYMEX futures prices for any month in the hedging horizon fall below the 40th decile price point, Piedmont will spend an additional 20 percent of its monthly hedging budget on call options for that NYMEX futures month. 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 percent of that budget to purchase additional call options. A sample matrix for June 2018 is presented below:

June 2018 Expiration ($/Dth)			
Decile	**Annual**	**Summer**	**Winter**
90% - MAX	[redacted]		
80% - 90%			
70% - 80%			
60% - 70%			
50% - 60%			
40% - 50%			
30% - 40%			
20% - 30%			
10% - 20%			
MIN - 10%			
Mean			
Median			

Table 25.
Summary of Call Option Hedging Activity

Hedge Month	Quantity (Dth)	Average Strike Price ($/Dth)	Average Call (Price)/Gain ($/Dth)	Call Gain/(Loss)	Fee	TOTAL COST
CALL PURCHASES						
July 2014	[redacted]					
August						
September						
October						
November						
December						
January 2015						
February						
March						
April						
May						
June						
Subtotal:						
July 2015						
August						
September						
October						
November						
December						
January 2016						
February						
March						
April						
May						
June						
Subtotal						
July 2016						
August						
September						
October						
November						
December						
January 2017						
February						
March						
April						
May						
June						
Subtotal:						
TOTAL CALL PURCHASES:						
July 2014						
December 2014						
September 2016						
October 2016						
December 2016						
January 2017						
April 2017						
TOTAL CALL SALES:						
TOTAL CALLS:						

As a general rule, Piedmont will spend 4 percent of the decile price and spend up to 20 percent 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 percent), and purchase calls with a strike price that cost $0.20/Dth. If 20 percent 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 percent of the available dollars in any one-month purchases call volumes that exceed 20 percent of the anticipated normalized purchase volume, the volume will be limited to 20 percent of the anticipated monthly purchase volume. If 20 percent of the available dollars does not purchase 20 percent of the normalized purchase volume (45 percent of normalized purchase volumes in total), the Company does not later make up the volumes 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 may 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 NYMEX futures prices for a contract month in the forward-hedging horizon remain at or below the 50th decile price point, Piedmont will spend 20 percent 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 percent of its seasonal hedging budget on call options each subsequent month, as long as the NYMEX futures prices for a contract month remain at or below the 50th decile price point, ultimately spending up to 100 percent 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 percent of its hedging target volume. If NYMEX prices are still at or below the 50th decile on July 1, the Company will hedge an additional 20 percent 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 cost recovery is limited to one percent of the Company's total annual gas cost. As shown in Table 26, Exeter's review found that Piedmont's hedging costs were less than one percent for all three years of the review period. Exeter's review also found that Piedmont hedged approximately 30 percent of normalized purchase volumes.

Table 26. Summary of Annual Hedging Costs and Limits					
Plan Year	Hedge Period	One Percent Hedging Limit[1]	Actual Hedging Costs for Calls Purchased	Actual Hedging Proceeds for Calls Sold	Actual Net Hedging Costs
July 2013 – June 2014	July 2014 – June 2015	[redacted]			
July 2014 – June 2015	July 2015 – June 2016				
July 2015 – June 2016	July 2016 – June 2017				
TOTAL:					

[1] Reflects gas costs from Docket No. 12-00114, approved on March 26, 2013. Docket No. 13-000119, resolved by Settlement approved on January 12, 2015, did not identify annual gas costs for purposes of setting the one percent hedging limit. Docket No. 14-00150 gas costs were not approved until October 28, 2015. Therefore, the one percent limit approved in Docket No. 12-00114 was applicable through the July 2015 – June 2016 Plan Year.

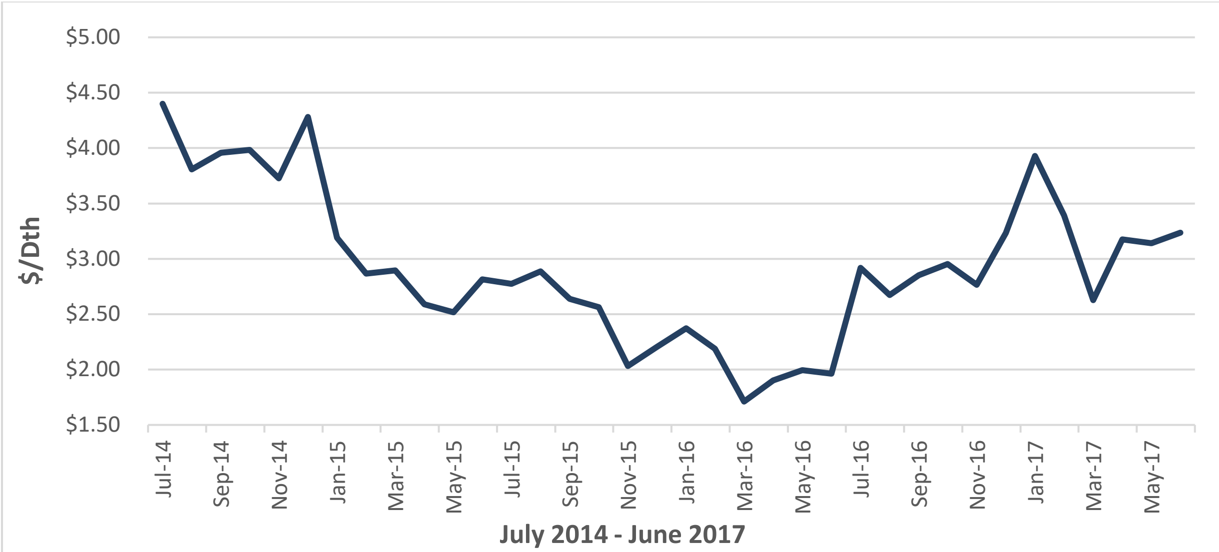
6.2 RFP Statement of Work Requirements

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 stable during the first six months of the review period, with monthly NYMEX settlement prices averaging approximately \$4.00/Dth. Prices declined in early 2015, and averaged \$2.77/Dth for the period January through October 2015. Prices declined further in November 2015, averaging approximately \$2.10/Dth through June 2016. Prices were relatively stable for the remainder of the review period, with the exception of January 2017, when NYMEX prices settled at \$3.93/Dth. For the period July 2016 through June 2017, prices averaged \$3.00/Dth, excluding January 2017. Figure 3 presents a graph of NYMEX monthly settlement prices during the review period. Piedmont did not perform a cost-benefit analysis to support its hedging program.

Figure 3.
Natural Gas Futures – NYMEX Settlement
(June 2014 – June 2017)



Source: Natural Gas Contract Settlement Price History, www.gsfi.net/common/NYMEX-settlement-history.pdf.

- *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 Public Service Commission 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 and achieves unlimited price protection above the strike price of the call 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 25, Piedmont purchased [redacted] Dth of calls during the review period at a cost of [redacted], or an average price of [redacted] per Dth. To purchase those calls, Piedmont also incurred transaction fees of [redacted]. Of those calls purchased, Piedmont sold [redacted] Dth just prior to 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. The net impact of Piedmont's hedging program during the review period was a net loss of [redacted], or an average of approximately [redacted] per 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 one percent 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 26). 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 were 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 cost of [redacted], or [redacted] per Dth sold. In addition to these tangible costs and benefits, Piedmont's hedging program provided for price mitigation in the event of a significant increase in nationwide gas prices.

- *Review and assessment of Piedmont's (hedging) documentation process.*

  Piedmont maintains a copy of all monthly RMI price matrices; time-stamped deal tickets; price matrices used in evaluation of call purchases; minutes of the Energy Price Risk Management 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.

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

  The losses experienced by Piedmont under its hedging program during the review period were minimal, averaging [redacted] per Dth sold. The losses were the result of purchasing call options for periods during which market prices did not generally increase 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 for up to 45 percent of normalized purchase volumes. The costs associated with Piedmont's hedging activities were 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 one percent is also applicable in Tennessee, which is not applicable in the Company's Carolina service territories.

  Utilities in other states that employ hedging generally rely on fixed-price purchases. Many utilities consider their hedging activities to be confidential. Utilities that utilized fixed-price purchases for hedging during the review period generally incurred losses that were greater than Piedmont's losses of [redacted] per Dth. For example, during the review period, a large utility in the Midwest utilizing a fixed-price purchase hedging strategy to hedge 20 percent of winter purchase volumes lost approximately 8 cents per Dth on total winter purchase volumes.

- *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. Piedmont's use of a decile matrix to guide its purchasing decisions and the one percent limit on hedging transaction costs are consistent with the practices of other utilities. Generally, the goal of hedging is to, over time, mitigate price volatility. However, Piedmont has taken a conservative approach to hedging, electing to use hedging to provide a degree of disaster protection in the case of unexpected fly-ups in gas prices.

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 Performance Incentive 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.

It is Exeter's view that regulators and utilities cannot expect hedging to lower the long-term price paid for natural gas. 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.

7.0 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. This section of the Report also addresses Piedmont's Gas Supply Incentive Compensation Programs as also required in the Statement of Work.

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 percent sales customer and 25 percent Company sharing of the difference between actual and benchmark costs. Piedmont's Plan does not include a deadband in calculating sharing amounts.

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 benchmark is based on a price that reflects published index prices weighted by the amount of firm interstate pipeline receipt point capacity that Piedmont reserves at each of its purchase locations. For example, if 60 percent of Piedmont's interstate pipeline capacity portfolio consisted of

Columbia Gulf capacity and the remaining 40 percent was TGP capacity, Piedmont's benchmark for monthly purchases would be based on a 60/40 percent 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 either the applicable variable firm transportation or the maximum applicable IT charge, and the applicable fuel charges. The variable firm transportation charge is used when the Company has open capacity under its firm transportation contract with the delivering pipeline, and the IT charge is used when no open capacity is available. Citygate purchases delivered by ETNG are 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 IT and fuel charges associated with the delivery of gas from Boat Dock to Piedmont. Piedmont's Plan does not provide the sharing of avoided demand charges as provided for under the subsequently discussed incentive mechanisms of Atmos and Chattanooga Gas. Typically, the rewards realized by Piedmont under the commodity procurement cost component of the Plan are generated by monthly and citygate purchases.

Under the supplier reservation fee component of the Plan, Piedmont is entitled to recover 100 percent of its gas supply reservation fees with no gain or loss potential. The capacity management component of Piedmont's Plan provides that the revenues (margins) realized from capacity release and off-system sales activities, as well as AMA fees, be subject to the same 75 percent ratepayer / 25 percent 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' Performance Based Ratemaking Mechanism (PBRM) consists of a Gas Procurement Incentive Mechanism and a Capacity Management Incentive Mechanism. The Gas Procurement Incentive Mechanism establishes a monthly benchmark against which Atmos' monthly commodity cost of gas is compared. The monthly benchmark is based on both the published index prices for the locations at which Atmos' gas supplies are purchased, as well as the type of purchase. That is, monthly purchases are benchmarked against monthly index prices, and daily prices are benchmarked against daily index prices. For citygate purchases, the benchmark is adjusted for the avoided pipeline demand transportation charges that would have been paid for the delivery of gas to the citygate, less any demand charges paid to the supplier providing the service. If Atmos' total monthly commodity cost of gas falls within a deadband of the total monthly benchmark amount, there are no incentive savings or costs to share. If Atmos' total monthly commodity cost of gas is below the deadband, Atmos is permitted to retain, as a reward, 50 percent of the difference. If the total monthly commodity cost of gas is above the deadband, Atmos is denied recovery of 50 percent of the difference. During the period most recently reviewed by Exeter (April 1, 2011 through March 31, 2014), all of the Gas Procurement Incentive Mechanism savings achieved by Atmos were attributable to avoided demand charges.

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

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.[15] If Chattanooga Gas' total actual commodity gas costs for a plan year do not exceed the total benchmark amount by one percent, 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 percent, it 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 April 1, 2013 through June 30, 2016. For the plan year ended June 2016, Chattanooga Gas' actual gas costs exceeded benchmark costs by 3.3 percent, requiring a prudence review of Chattanooga Gas'

[15] Chattanooga Gas has interpreted upstream transportation charges to include variable charges, while Atmos has interpreted this provision to include demand charges.

purchased gas costs. That review was conducted by Exeter as part of its most recent PBRM review. Exeter's review found the purchased gas costs incurred by Chattanooga Gas for the plan year ended June 2016 to be prudent.

Chattanooga Gas' IMCR provides for a 50 percent 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 included 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 revenues (margins) realized from capacity release and off-system sales activities, as well as AMA fees, and provides for a 75 percent sales customer / 25 percent Company sharing. More than 98 percent of the revenues available for sharing under the capacity management component during the review period were generated from AMA fees. The remaining revenues were generally from off-system sales made to its 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 percent customer / 10 percent utility to 75 percent customer / 25 percent 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 percent customer / 25 percent 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 percent customer / 25 percent Company sharing of savings. Different benchmarking procedures are applicable for monthly purchases, daily purchases, and other 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 and IT arrangements are evaluated based on a benchmark that reflects published index prices weighted by the amount of firm interstate pipeline receipt point capacity Piedmont reserves at each purchase location. Piedmont realizes a reward for monthly purchases if those purchases are made at the lowest-cost receipt points. The forecasted relative price relationship for the 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, Piedmont earned a reward of approximately [redacted] during the review period. Exeter's most recent review of the gas cost incentive plans of Atmos and Chattanooga Gas revealed that each of these utilities also maximizes the purchase of gas supplies at the lowest-cost receipt points. However, neither utility realizes a reward for doing so under their respective gas cost incentive mechanisms but do gain under the avoided transportation costs component of these PBRM. Therefore, Exeter concludes that the monthly benchmarking procedures under the commodity procurement cost component of the Plan are unbalanced in Piedmont's favor; however, it does not necessarily provide for a direct comparison of the balance of the incentives under the three utilities' plans because the Plan does not include an avoided transportation cost component.

Daily purchases delivered under firm and IT 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 percent sales customer / 25 percent 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 percent customer / 50 percent utility sharing procedures when purchases are benchmarked based on actual index prices for the actual purchase location.

As previously described in Section 7.1.1 of the Report, the procedures used to benchmark Piedmont's citygate purchases varied during the review period. Section 3.1.3 of the Report identified several concerns with those procedures, and recommended several modifications to those procedures. Like all other purchases under the commodity procurement cost component of the Plan, 75 percent sales customer / 25 percent Company sharing procedures are applicable for citygate purchases. Piedmont realized a reward of [redacted] during the review period for citygate purchases. Exeter finds that the existing sharing procedures for citygate purchases are reasonable and provide the Company with sufficient incentive to pursue such purchases when they reduce purchased gas costs. Unlike daily purchases, citygate purchases are not benchmarked against actual index prices for the actual purchase location and, therefore, Exeter finds that a higher Company share of rewards would not be warranted.

7.2.3 $1.6 Million Plan Cap

Consistent with the findings of a study evaluating gas procurement incentive mechanisms conducted by the National Regulatory Research Institute, Exeter concurs that caps can weaken or eliminate incentives.[16] [redacted]. Exeter believes that the savings associated with monthly purchases that Piedmont is able to generate under the Plan are achievable under traditional regulation and should not result in a reward for Piedmont. These monthly purchases generated approximately [redacted] of Piedmont's forward rewards during the review period. For these reasons, Exeter recommends that the $1.6 million cap be maintained.

7.3 Gas Supply Incentive Compensation Program

[redacted]

[redacted]

[redacted]

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[16] *A Hard Look at Incentive Mechanisms for Natural Gas Procurement*, National Regulatory Research Institute, November 2006.

[17] The incentive programs in place in North and South Carolina provide for a 75 percent customer / 25 percent Company share of margins from secondary marketing activities, similar to those included in the capacity management component of the Plan. The Carolina incentive programs do not include a component similar to the commodity gas cost procurement component of the Plan. There are no revenue sharing caps under the Carolina programs.

[redacted]

8.0 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 purchased several delivered-to-citygate gas supply services during the review period.
- Piedmont served an average of 176,500 sales and transportation customers during the review period, and total annual system throughput averaged 29,867,000 Dth.
- Piedmont engaged in no transactions with affiliates during the review period.
- Plan-determined savings during the review period were [redacted], and Piedmont's share of savings was [redacted].
- Savings of [redacted] were realized under the commodity procurement cost component of the Plan on monthly purchases, and savings of [redacted] were realized on citygate purchases. A Plan loss of [redacted] was incurred on daily purchases.
- Piedmont earned a reward of [redacted] from its AMAs and off-system sales activities during the review period.
- The fees received by Piedmont under its AMAs increased substantially during the review period.
- 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.
- Although there are a number of concerns with Piedmont's design day forecasting model, there were no adverse consequences resulting from the utilization of the model for capacity planning purposes during the review period.

- Piedmont maintains year-round and winter season firm transportation capacity to meet the projected design day demands, 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 2017-2018 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 use of a partially price- 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 one percent limit on hedging transaction costs are consistent with observed industry practices.

- Piedmont's hedging activity did not exceed the one percent of annual gas cost cap.

- [redacted]

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 procedures used to benchmark monthly and daily citygate purchases are not clearly defined in the tariff language describing the Plan, and modifying the Plan language to provide further clarification should be considered.

- Piedmont purchased significant quantities of Columbia Gulf, Texas Eastern, and TGP citygate delivered supplies during the review period that were [redacted] in total cost than supplies [redacted]. During the first Plan Year of the review period, these citygate delivered supplies were benchmarked based on IT rates. The benchmarking of citygate delivered supplies based on IT rates can lead to higher costs to sales customers than higher cost purchases delivered under Piedmont's firm transportation arrangements due to the sharing provisions of the Plan. This approach was, therefore, unreasonable. During the second and third years of the review period, for citygate purchases delivered by Columbia Gulf, Texas Eastern, and TGP, the applicable pipeline's firm transportation variable charge was used for benchmarking purposes in lieu of the IT charge when there was open capacity available under the Company's firm transportation contract for that pipeline, and the IT charge was used if open capacity was not available under the firm transportation contract. The approach used by Piedmont during the second and third Plan Years of the review period for Columbia Gulf, Texas Eastern, and TGP appears to have been more reasonable given the market conditions during the review period.

- Exeter's analysis indicates that the most reasonable approach to benchmarking Columbia Gulf, Texas Eastern, and TGP delivered citygate supplies would be to use the approach utilized by Piedmont to benchmark these purchases when open capacity was available under the Company's firm transportation contracts, regardless of whether open capacity is actually available. That is, the variable firm transportation charge should be used rather than the IT charge. Exeter's analysis indicates that this approach results in a benchmark price that is more consistent with market prices than the use of a benchmark price based on the applicable IT rates. Exeter notes that with Piedmont's acquisition of additional Columbia Gulf firm transportation capacity beginning with the winter of 2017-2018, the approach recommended by Exeter and the approach used by Piedmont during the second and third Plan years of the review period will be consistent going forward, with the possible exception of Texas Eastern citygate-delivered supplies.

- Piedmont's use of Chicago citygate index prices to benchmark ETNG citygate supplies was unreasonable during the review period. Benchmarking ETNG citygate-delivered supplies would be more reasonably benchmarked based on an average of TGP Gulf Coast index prices, plus the applicable TGP and ETNG firm variable transportation and fuel charges.

- Piedmont benchmarked MGT-sourced baseload supplies purchased during the period November 2016 through June 2017 based on Chicago citygate index prices. These purchases were not made at the Chicago citygate, but at the MGT/REX interconnect for which index prices are available. In Exeter's view, purchases delivered under the Company's firm transportation arrangements should be benchmarked based on the location at which the supplies where purchased. While MGT/REX interconnect index prices were slightly lower than Chicago citygate index prices during the review period, the difference was not significant. However, this difference in index prices may become a more significant concern under the Plan in the future.

- The Plan required that the pipeline capacity weightings utilized to calculate the monthly benchmark be based on design day citygate delivery quantities. Piedmont did not include the appropriate MGT weightings in the monthly benchmark calculations for the period

November 2014 through October 2015. Adjusting calculated Plan savings to reflect the appropriate MGT capacity entitlements would have reduced Plan savings by $1,154,402.

- Piedmont also did not utilize the appropriate MGT weightings in its monthly benchmark calculation for winter of 2016-2017. Reflecting the appropriate MGT weightings would have reduced calculated Plan savings by $45,353. However, during this period, Piedmont actually purchased, on a daily basis, MGT-sourced supplies equal to the entitlements reflected in the monthly benchmark calculations.

- Piedmont should further evaluate the inclusion of windspeed, prior day temperature, and weekend independent variables in its design day forecast model. In developing its model, Piedmont should also consider including only those days with a relatively high heating load, such as those days with temperatures at or below freezing and limiting usage data to the most recent three-year period.

- Due to multiple 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 Regulatory Authority (Authority or TRA). The Plan does not preclude the Authority 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 Authority or (b) the Plan is modified, amended or terminated by the Authority 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 TRA 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 Authority Staff, and supply a copy to the Consumer Advocate and Protection Division of the Tennessee Attorney General (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:

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

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 ~~maximum~~ 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]

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[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 TRA 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 entries to IPA gains or losses will be recorded to income or expense, as appropriate. At its

[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 TRA docket as of the first day of the month, 12 months prior to the first day of the period under audit.

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 TRA, 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 Authority
The Company will file calculations of shared savings and shared costs quarterly with the Authority 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 Authority 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 Authority 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 Authority. Unless the Authority 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.

Gas Supply Incentive Compensation Program
The Company has in place a Gas Supply Incentive Compensation Program (the Program) designed to provide incentive compensation to selected Gas Supply non-executive employees involved in the implementation of the Company's Incentive Plan and Secondary Marketing

Programs in a manner consistent with the benefits achieved for customers and shareholders through improvements in gas procurement and secondary marketing activities. Participants in the program receive incentive compensation as recognition for their contribution to the customers and shareholders of the Company through lower gas costs and gains related thereto. Performance measures are established for the Program each year.

During the time this tariff is in effect, the Company will continue to have in place the Gas Supply Incentive Compensation Program, as detailed to the Authority, as it relates to the Company's Incentive Plan. The Company will advise the Authority in writing of any changes to the Program, and unless the Company is advised within 60 days, said changes will become effective. The Authority may expand the time for consideration of such changes upon written notification to the Company. No filing for prior approval is required for changes in the performance measures.

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 TRA 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 TRA Staff, after consultation with the Company and the CAD. For each review, the TRA Staff shall select three (3) prospective independent consultants from that list. Each such consultant shall possess the expertise necessary to conduct the review. The TRA Staff shall provide the list of prospective independent consultants to the 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 TRA Staff within thirty (30) days from the date the list is e-mailed. The TRA Staff shall select the independent consultant from those remaining on the list after 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 TRA Staff, and/or the CAD shall be disclosed, and the independent consultant shall have had no prior relationship with either the Company, the TRA Staff, or the CAD for at least the preceding five (5) years unless the Company, the TRA Staff and the CAD agree in writing to waive this requirement. The TRA 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 TRA Staff, or the CAD relative to the operation or results of the Performance Incentive Plan.

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

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

The independent consultant shall not propose changes to the structure of the Performance Incentive Plan itself; however, the TRA Staff, the Company, or the CAD may use the report of the independent consultant as grounds for making recommendations or proposed changes to the Authority, and the TRA Staff, 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 Authority, shall be implemented on a prospective basis only beginning with the incentive Plan Year immediately following such agreement or ruling.

The cost of the triennial reviews shall be paid initially by the Company and recovered through the ACA account. The TRA 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.