NORTH CAROLINA

PUBLIC STAFF

UTILITIES COMMISSION

August 11, 2021

Ms. A. Shonta Dunston, Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

Re: Docket No. G-9, Sub 722 – Petition for Consolidated Construction/Redelivery Agreement; G-9, Sub 781 – Application for General Rate Increase; and G-9, Sub 786 – Application of Piedmont Natural Gas Company, Inc., for Modifications to Existing Energy Efficiency Program and Approval of New Energy Efficiency Programs

Dear Ms. Dunston:

Attached for filing in the above-referenced docket is the confidential testimony and exhibit(s) of Dustin R. Metz, Utilities Engineer, Electric Section, Energy Division.

By copy of this letter, I am forwarding a copy of the redacted version to all parties of record by electronic delivery. The confidential version will be provided to those parties that have entered into a confidentiality agreement.

Sincerely,

Electronically submitted
s/ Elizabeth D. Culpepper
Staff Attorney
elizabeth.culpepper@psncuc.nc.gov

s/ Megan Jost
Staff Attorney
megan.jost@psncuc.nc.gov

Attachment

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-9, SUB 722
DOCKET NO. G-9, SUB 781
DOCKET NO. G-9, SUB 786

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<td>DOCKET NO. G-9, SUB 722

In the Matter of
Consolidated Natural Gas Construction and Redelivery Services Agreement Between Piedmont Natural Gas Company, Inc., and Duke Energy Carolinas, LLC

DOCKET NO. G-9, SUB 781

In the Matter of
Application of Piedmont Natural Gas Company, Inc., for an Adjustment of Rates, Charges, and Tariffs Applicable to Service in North Carolina

DOCKET NO. G-9, SUB 786

In the Matter of
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DUSTIN R. METZ
PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION</td>
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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-9, SUB 722
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TESTIMONY OF DUSTIN R. METZ

ON BEHALF OF THE PUBLIC STAFF
NORTH CAROLINA UTILITIES COMMISSION

AUGUST 11, 2021

Q. PLEASE STATE YOUR NAME AND ADDRESS FOR THE RECORD.

A. My name is Dustin R. Metz. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina.

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.

A. My qualifications and duties are included in Appendix A.

Q. WHAT IS YOUR POSITION WITH THE PUBLIC STAFF?

A. I am an engineer in the Electric Section – Operations and Planning in the Public Staff's Energy Division.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to present the results of my investigation into the application of Piedmont Natural Gas Company, Inc. (Piedmont or the Company) for a general rate increase in this proceeding.

Q. WHAT WERE YOUR AREAS OF INVESTIGATIVE RESPONSIBILITY IN THIS CASE?

A. While I participated in and contributed to a number of areas of the Public Staff's investigation, I specifically reviewed or supervised the review of the following areas:

- General capital additions to liquefied natural gas (LNG) plant in service, including the Company's Robeson LNG facility and LNG pipeline, and the Company's Huntersville LNG facility
- Cost allocation of transmission assets
- Multiple transmission pipeline projects
- Design day margin
- Safety and regulatory compliance
- Company vehicles
- Materials and supplies
- Staffing levels for specific work groups

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS IN THIS CASE.

A. As a result of my investigation, I make the following recommendations in this case:

- That the Robeson LNG facility, Lines 456 and 457, and all of the Company's pro forma adjustments associated with the Robeson LNG project be removed from rate base at this time.
- That demand allocation factors of 83.16% and 16.84% be applied to North Carolina and South Carolina, respectively.
- That the same demand allocation factors be applied to any accounts already allocated using the 2-state jurisdictional allocators set forth in the Company's G-1, Item 5.
- That the Commission order the Company, the Public Staff, and any other interested parties, prior to the earlier of the Company's next general rate case or its 2023 annual review of gas costs proceeding (2023 Annual Review), to undertake, report on the status of, and complete a study of whether the Company's current method of allocating its transmission plant assets to North Carolina and South Carolina is fair to each state's customers in light of the fact that the Company plans for future supply and capacity resources based on a combination of both North Carolina and South Carolina demands.

- That the Commission order the Company, the Public Staff, and any other interested parties, prior to the earlier of the Company's next general rate case or its 2023 Annual Review, to initiate, report on the status of, and complete a study of an updated regression analysis to determine a more accurate breakdown of system usage among customer classes and the North Carolina and South Carolina jurisdictions.

General Capital Additions to Plant In Service

Q. PLEASE DESCRIBE THE CAPITAL ADDITIONS TO THE COMPANY'S RATE BASE THAT YOU REVIEWED IN THIS CASE.

A. In his prefiled direct testimony, Piedmont witness Brian R. Weisker discusses the addition of approximately $1.65 billion of capital plant that was either placed in service prior to the Company's filing of its application in this proceeding, or was expected to be placed in service by June 30, 2021.[1] As part of the Public Staff's investigation, I evaluated multiple categories of capital expenditures for reasonableness and prudence, and to determine whether the underlying assets were used in providing service to ratepayers.

My investigation included the following: (1) a review of the prefiled direct testimony of Piedmont witness Weisker; (2) an audit of specific expenditures (i.e., sampling of specific costs); (3) initial and follow-

[1] Direct Testimony of Piedmont witness Weisker at 9.

up discovery; (4) teleconferences between the Company and Public Staff; (5) interviews with Company witnesses and staff, including detailed discussions regarding specific aspects of certain projects; (6) a site visit to the Robeson LNG facility; and (7) a review of projects with Company management and technical staff.

Specific Capital Additions

Q. HAS THE NEW ROBESON LNG PLANT BEEN PLACED IN SERVICE?

A. No. Not at the time of filing of this testimony, nor by the May 31, 2021 cut-off date. The Robeson LNG facility is not complete, is not providing service to customers, and has not been closed to plant (i.e., transferred from the applicable CWIP account(s) to the applicable plant in service account(s)).

Q. WHEN DO YOU EXPECT THE ROBESON LNG FACILITY TO BE COMPLETE?

A. Based on discussions with Company staff, the Company believes the Robeson LNG facility will be in service before the end of the evidentiary hearing in this case, which is scheduled to begin September 7, 2021. However, based on my personal observations during a site visit on July 12, 2021, and on follow-up communications with the Company, I have doubts as to whether the entire Robeson

LNG plant will be completed and able to be placed in service by that time.

Q. WHAT IS THE ESTIMATED COST OF THE ROBESON LNG FACILITY?

A. It is my understanding that the final estimated cost is approximately $274M. This equates to approximately 21%[2] of the Company's proposed overall revenue requirement increase in this proceeding.

Q. DO YOU HAVE ANY RECOMMENDATIONS FOR COST DISALLOWANCE OF THE ROBESON LNG FACILITY OR ANY OTHER PROJECTS RELATED TO THE OVERALL OPERATION OF THE FACILITY?

A. Yes. At this time, I recommend that no costs related to any portion of the Robeson LNG facility be included for cost recovery. This includes any pro forma adjustments, land, and any transmission required to interconnect the facility.[3] The adjustments related to my recommendation are shown in the exhibits of Public Staff witness Perry.

[2] Per Public Staff witness Julie G. Perry, an approximation of new plant impact to the revenue requirement would be the cost of the plant ($274M) multiplied by 0.08. This revenue requirement percentage is based on the current estimate of capital costs and excludes all other pro forma adjustments associated with the Robeson LNG facility.

[3] The Robeson LNG facility requires two transmission lines for interconnection – Lines 456 and 457 – which I discuss later in my testimony. No other customers are connected to these dedicated lines from Piedmont's existing transmission system to the LNG facility.

Allocation of Transmission Assets

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF PIEDMONT'S SYSTEM IN THE CAROLINAS.

A. Piedmont is a local distribution company (LDC) which operates in both North Carolina and South Carolina, but does not fall under the jurisdiction of the Federal Energy Regulatory Commission (FERC). Piedmont's primary interstate pipeline service (capacity used to transport natural gas supply) is from Transcontinental Gas Pipeline Company, LLC (Transco). Piedmont is reliant on Transco as its capacity provider because there are currently no other interstate pipelines with significant delivery to meet Piedmont's customers' needs in the Carolinas. Piedmont has no directly owned natural gas transmission or distribution lines that connect its North Carolina and South Carolina service territories; therefore, it is reliant upon Transco as the connection between the two service territories. Metz Table 1 below summarizes the differences between the Company's North Carolina and South Carolina service territories. Metz Exhibit 1 is a graphical illustration of the Company's transmission system and service territories.

Metz Table 1

Jurisdiction	LNG Facilities[4]	Gross LNG Plant[5] ($M)	Total Transmission Piping	Gross Transmission Plant Assets ($M)	Total Customers[6]
North Carolina	3	$511	2701 Miles	$3,295	774,275
South Carolina	0	$0	79 Miles	$193	153,497

Q. MR. METZ, WHAT IS YOUR UNDERSTANDING OF HOW PIEDMONT EVALUATES AND SELECTS SUPPLY, OR FUTURE CAPACITY, AND STORAGE RESOURCES?

A. Piedmont must evaluate different options for meeting total customer demand based on the amplitude (peak maximum) and duration (total time over which the peak occurs, as well as frequency of occurrence) as part of a design day study. A detailed explanation of this evaluation can be found in Piedmont's annual gas cost reviews, which are similar in some respects to an electric utility's integrated resource plans (IRP). While there are some aspects of the

[4] This includes the soon to be completed Robeson LNG facility.

[5] Robeson LNG + Existing LNG (through June update) = ~$511M. An estimate of $274M was included in this case as a placeholder for Robeson LNG facility + gross book value of Huntersville and Bentonville LNG (based on the Company's responses to Public Staff Data Requests 110-1, 113-14, and 120-33).

[6] Total Customers are year ending 2020 values. The Company's G-1, Item 5 Pro-Forma Worksheet.

Company's annual review calculations with which I have concerns, they are outside the scope of my investigation in this case, and will instead be addressed in future annual review proceedings.

Q. DOES THE COMPANY PLAN FOR FUTURE CAPACITY AND STORAGE RESOURCES TO MEET NORTH CAROLINA AND SOUTH CAROLINA DEMAND SEPARATELY?

A. No. When the Company plans for future capacity and storage resources, it takes into account an aggregated weighted contribution of customers and customer demands in the respective service territories for both North Carolina and South Carolina. In other words, the planned-for resources are used to meet a combination of both North Carolina and South Carolina demand. In Piedmont's most recent annual review of gas costs proceeding (Docket No. G-9, Sub 771), the Robeson LNG facility was determined by the Company to be the "optimal" resource to meet the new incremental demand in both states, in combination with existing supply sources.

Q. FROM AN ANNUAL REVIEW AND SYSTEM PLANNING PERSPECTIVE, ARE EXISTING LNG FACILITIES AND EXISTING CAPACITY CONTRACTS INCLUDED IN THE ANALYSIS?

A. Yes. Piedmont's annual review lists interstate pipeline capacity and storage contracts as supply capacity in its system design day analysis filed each year. Supply capacity can be year-round firm transportation, winter only firm transportation, seasonal storage, and peaking capacity (LNG). The capacity levels and the availability of these various supply capacity contracts are included in the annual review analysis. Confidential Metz Exhibit 2 is provided to illustrate a load duration curve, produced by the Company in a recent annual review.[7] Simply stated, the load duration curve evaluates expected demands (loads) over the total days of demand that are expected to require service for the review period. Similar to how utility-scale electric generating resources are selected to meet demand, natural gas resources are selected on a "best cost" basis to supply the area under the curve (demand line).

Q. PLEASE DESCRIBE HOW LNG FACILITY COSTS ARE ALLOCATED BETWEEN NORTH CAROLINA AND SOUTH CAROLINA.

A. Because LNG facilities are built to meet the combined North Carolina and South Carolina peak demands, the associated capital and ongoing maintenance costs are allocated based on a jurisdictional (2-state) demand factor. This factor, which the Company has proposed in this case, is set out in Metz Exhibit 3, which is Attachment 1 of 2 to the Company's G-1, Item 5 Jurisdictional Allocators that was supplied in response to a Public Staff discovery request. Note (1) on the bottom

[7] Testimony of Piedmont witness Jeffrey Patton filed in Docket No. G-9, Sub 771.

of the Company's Pro Forma Design Day Allocation indicates that certain LNG-related accounts (e.g., LNG storage plant and LNG-related O&M accounts) are allocated between North Carolina and South Carolina. This Pro Forma Design Day allocation is not a demand allocation based on actual test year data, but is escalated to an "expected" demand based on a 1985 winter event, which is the coldest temperature experienced to date on Piedmont's system. In other words, these test year costs are not allocated solely on the basis of historical test year system operating data, but rather, the historical data is extrapolated to a theoretical expectation that may or may not occur again at some future time. Therefore, I have concerns regarding the usage of the Pro Forma Design Day allocation proposed by the Company that I discuss later in my testimony.

Q. HOW ARE PIEDMONT-OWNED LNG FACILITIES CONNECTED TO PIEDMONT'S SYSTEM?

A. Piedmont's three LNG facilities (Bentonville, Huntersville, and the proposed Robeson LNG) are connected to Piedmont's natural gas transmission pipelines. Similar to large utility-scale electric generating stations that provide generation (supply) to meet demand (load), natural gas supply is connected to transmission-level facilities to achieve better system efficiencies.

Q. DOES AN LNG FACILITY FUNCTION AS BOTH DEMAND AND SUPPLY WITH RESPECT TO THE GAS TRANSMISSION SYSTEM?

A. Yes. The economics and the operation of an LNG facility are similar to those of a pumped storage hydroelectric generating station. The system operator charges the facility during off-peak times to provide service during on-peak times. The economics of price arbitrage (filling the system at low prices and discharging the system at high prices) determines whether a project or supply asset is cost effective, i.e., whether the economics of price arbitrage is large enough to cover the capital and expected ongoing costs of the asset.

With the recent modification to Piedmont's Huntersville LNG facility,[8] and pending the successful commissioning of the Robeson LNG facility, Piedmont's three LNG facilities have the capability to inject (fill) over the course of the year. Each LNG facility uses the transmission system, ideally during low system loads, to convert natural gas to a liquid state and store it for future use. In addition, when the system experiences high demands or high natural gas prices, the Company can dispatch (withdraw) the LNG, converting it back to a gaseous phase, and inject it back onto the system for use. The LNG facility also withdraws daily amounts from the storage tank from the boil-off gas

[8] Prior to modification, the costs of which Piedmont seeks to recover in this rate case, the Huntersville LNG facility required 200 days to fill.

process.[9] The daily withdrawals from the LNG storage tank place small volumes of gas back onto the transmission system. During the test year, the Huntersville and Bentonville LNG plants withdrew or injected gas from the transmission system approximately 99.7% of the total days of the year.[10]

Q. DO THE COMPANY'S LNG FACILITIES PROVIDE SERVICES OTHER THAN PEAK DAY SERVICE?

A. Yes. Based on Company data request responses, the LNG facilities provide hydraulic (pressure regulation) benefits to Piedmont's overall system and are a supply resource. The LNG facilities currently in operation either inject or withdraw gas from Piedmont's transmission system nearly year-round; therefore, the hydraulic benefits and supply resource are also provided year-round to all users of the system, inclusive of North Carolina and South Carolina customers.

Q. WOULD IT BE ACCURATE TO CHARACTERIZE THE TRANSMISSION SYSTEM AS AN INTEGRAL EXTENSION OF THE LNG FACILITY?

A. Yes. In order for Piedmont's three LNG facilities, which are all located in North Carolina, to function and provide services to ratepayers,

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[9] Boil-off gas is a natural process of storage due to variations in temperatures (storage temperatures and external temperatures). The boil-off gas is removed, in part, to maintain proper storage tank pressures.

[10] Based on the Company's responses to Public Staff Data Requests 120-4 and 120-5.

including the North Carolina and South Carolina aggregate loads they were designed to meet, the transmission system must logically be considered an integral extension of the LNG facilities.

Q. DID THE ROBESON LNG FACILITY REQUIRE NEW TRANSMISSION TO INTERCONNECT TO PIEDMONT'S SYSTEM?

A. Yes. The Robeson LNG facility required two approximately four-mile-long transmission pipeline extensions to tie the LNG facility to the Company's main transmission system. Line 456 is a 24-inch gas line that is the main supply to and from the LNG facility, and Line 457 is an 8-inch line for secondary functions.

Q. HOW ARE THE TRANSMISSION COSTS CURRENTLY ALLOCATED BETWEEN NORTH CAROLINA AND SOUTH CAROLINA?

A. Currently, each state is assigned 100% of the costs of all transmission assets physically located in that state, including capital, transmission-related operations and maintenance expenses, the Integrity Management Rider costs, and the Transmission Integrity Management Program costs.

Q. ARE TRANSMISSION ASSETS BUILT SOLELY FOR LNG OPERATION?

A. Generally, no. However, dedicated lines (spurs), such as Lines 456 and 457 discussed above, are sometimes built to interconnect the

LNG facility to the transmission system. These situations are limited and are dependent upon the specific siting of the facility. Gas transmission lines are typically built and sized to meet loads, including peak loads, for all customers receiving service from that transmission line, whether directly or indirectly, which includes special contract and electric generation customers. An example would be customers such as Duke Energy Progress, LLC (DEP), whose Sutton Combined Cycle generation plant is located on the same transmission line with which the Robeson LNG facility interconnects.

Q. PLEASE EXPLAIN, ON AN OPERATIONAL BASIS, THE PEAK DAY RELATIONSHIP BETWEEN THE COMPANY'S NORTH CAROLINA AND SOUTH CAROLINA SERVICE TERRITORIES.

A. Based on responses to discovery[11] and conversations with the Company, it is the Public Staff's understanding that when LNG is withdrawn from the LNG storage tank, re-gasified, and injected into

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[11] In response to Public Staff Data Request 70-4(a), the Company stated:

> The Company plans to meet its system under design day conditions [peak day event] on a combined basis for North and South Carolina and [the] Company utilizes interstate pipeline capacity, storage, and LNG to meet the supply requirements of its firm sales customers. Although the Company's North and South Carolina [service territories] are not interconnected by the Company's transmission or distribution systems, both [service territories] are interconnected with Transco. Given the Company has multiple delivery points on Transco in both North and South Carolina it is able to manage these deliveries on an **aggregated basis**. As such the Company is able to <u>utilize LNG</u> to make physical deliveries **to meet demand** in North Carolina, which the[n] reduces the Company's need for Transco deliveries in North Carolina. As a result, **this frees up or displaces** the need in North Carolina which enable deliveries in South Carolina.

(Emphasis added.)

Piedmont's transmission system, it is used to meet the aggregated load of both North Carolina and South Carolina. When LNG is injected into the transmission system, the LNG gas is a supply capacity resource that reduces the overall scheduled deliveries from Transco at the given takeoff station or node. Since all of the Company's LNG resources are located in North Carolina, the aggregate impact of LNG placed on Piedmont's system reduces the scheduled North Carolina deliveries from Transco and displaces gas on Transco for use in Piedmont's South Carolina service territory to meet total system load.

Q. DO YOU HAVE A RECOMMENDATION REGARDING THE ALLOCATION OF TRANSMISSION FACILITIES AND RELATED COSTS?

A. Yes. My recommendation takes into account the overarching consideration, and the fundamental concept of cost causation and responsibility, that users of the system should be allocated a share of total system costs incurred to optimally serve customer loads while minimizing cross-subsidization. As described in more detail above, I discovered through my investigation that Piedmont's LNG facilities are allocated on a system demand basis, yet transmission facilities and ongoing transmission costs are not. As explained above, the LNG facilities provide peaking and ancillary services (i.e. pressure regulation) which necessitate connection to the transmission system and which minimize costs to both North Carolina and South Carolina ratepayers. Therefore, it is apparent that the transmission system is an integral extension of the LNG facilities. I also would like to note that the LNG facilities utilize the transmission system throughout the entire year, and the usage of the transmission system is not isolated to a few discrete days during the winter or system peaking periods.

I believe that the results of my investigation in this proceeding warrant further investigation into whether the allocation method currently used by the Company is fair to both North Carolina and South Carolina ratepayers given that they rely on utilization of the transmission system to realize year round LNG system benefits. Therefore, I recommend that the Commission order Piedmont, the Public Staff, and any other interested parties to study this issue before the Company's next general rate case is filed. The exact scope and milestones of this study should be determined with input from all interested parties before work begins on the study itself.

Demand Allocation

Q. PLEASE EXPLAIN HOW THE COMPANY CALCULATES AND APPLIES THE DEMAND ALLOCATION TO LNG PLANT.

A. Based on my review of the workpapers supporting the Company's G-1, Item 5, Jurisdictional Allocators, as well as G-1, Item 4e, the pro forma design day study is the basis of the Company's pro forma demand allocation. My understanding of the Company's demand allocation calculations is that the Company uses an aggregate of 12 months of historic test year data and, through linear regression analyses (best R^2 fit), calculates customer class usage based on temperature. More specifically, the Company's allocation methodology evaluates the 2020 test year monthly usage for each individual customer class and then compares that usage to cumulative hours in the same month in which the weighted average temperature was less than 65 degrees (i.e., Heating Degree Days or HDDs) for the gas day. A simple regression is then performed and the base usage level (the starting point of expected usage at 65 degrees) and a heat sensitivity factor (the amount of natural gas used per customer class based on a decrease in temperature) are calculated.

Once the Company has completed the regression analyses, it applies the design day temperature (DDT), which is determined in the Company's annual review of gas costs proceeding. The starting point of the DDT calculation is the simple average of the high and low daily temperatures from a 1985 cold weather event recorded at various weather stations in the Company's service area. The simple average for each respective weather station is then applied to the total customers in the service territory represented by the weather station and a system-weighted average is derived. The weighted DDT is then subtracted from 65 degrees, as the difference is the total HDDs expected in the one extreme peak condition. The DDT calculation attempts to capture the system-weighted impact of the combined customers in both North Carolina and South Carolina given the design temperature of the one extreme peak. Based on my review, I have identified components of the Company's demand allocation methodology that appear to introduce errors into the regression analysis that relies upon a linear relationship between independent and dependent variables.

The Company's methodology utilizes test year usage (demand) but escalates the usage to represent a theoretical total volume demand that assumes the reoccurrence of an event that has occurred only once, in 1985. This theoretical usage is then allocated between North Carolina and South Carolina. The Company has proposed an allocation to North Carolina of 85.39% and to South Carolina of 14.61%, with an aggregate expected firm sales usage of 1,354,754 dekatherms (dts), excluding electric generation usage.

Q. WHAT WERE THE COMPANY'S TOP FIVE FIRM SALES CUSTOMER PEAKS IN THE LAST FIVE YEARS?

A. The Company's combined North Carolina and South Carolina top five firm sales peaks for the last five years are shown in Metz Table 2 below:

Metz Table 2[12]

Date	Actual HDDs	Design Day HDDs	Difference in HDD	North Carolina (dts)	South Carolina (dts)	Total Firm Sales Sendout (dts)
1/8/2017	44.7	56.29	(11.59)	837,672.30	150,395.00	988,067.30
1/4/2018	44.2	56.29	(12.09)	865,101.50	210,781.00	1,075,882.50
1/21/2019	38.4	56.29	(17.89)	773,581.00	141,852.20	915,433.20
1/21/2020	35.3	56.29	(20.99)	719,701.40	139,553.40	859,254.80
12/25/2020	39.7	56.29	(16.59)	664,777.50	140,761.60	805,539.10

Q. WHAT IS THE ACTUAL DIVISION OF TOTAL SYSTEM USAGE BETWEEN NORTH CAROLINA AND SOUTH CAROLINA BASED ON THE COMPANY'S TOP FIVE PEAKS?

A. The actual total system usage of firm sales customers for each state, excluding power generation users on the system, is shown in Metz Table 3 below. As shown in Metz Table 3, each of the top five peaks shown for the total system usage in North Carolina is less than the 85.39% allocation recommended by the Company.

Metz Table 3

Date	NC Usage	SC Usage
1/8/2017	84.78%	15.22%
1/4/2018	80.41%	19.59%
1/21/2019	84.50%	15.50%
1/21/2020	83.76%	16.24%
12/25/2020	82.53%	17.47%

[12] The data contained in Metz Table 2 are derived from the Company's response to Public Staff Data Request No. 70-1.e.

Q. PLEASE SUMMARIZE YOUR OBSERVATIONS REGARDING THE COMPANY'S DEMAND ALLOCATION METHODOLOGY AND COMPARE IT TO THE PUBLIC STAFF'S PROPOSED ALLOCATION OF HISTORIC PEAK USAGE.

A. There is a fundamental difference between how a system is planned and how it is used. While there is merit in evaluating how 2-state usage and various customer classes contribute to a peak day planning event, the actual system usage illustrates how the planned demand allocation of test year usage can differ throughout the entire year.

One approach to cost allocation is to base it on a recent system peak[13]. Applying this methodology to data from the top five peaks in the last five years, North Carolina ratepayers should never be allocated more than that 84.78% of costs (based on a 2017 cold weather day). The benefit of this approach is that peak system usage would be more reflective of the current users of the system and rely less on linear regression estimates.

Another approach is to evaluate a weighted average of the top five peaks occurring in the last five years. The total system usage of each state across the five coldest weather peaks, weighted appropriately,

[13] This approach is consistent with the manner in which production plant and transmission plant were allocated in DEC's and DEP's most recent general rate cases, Docket No. E-7, Sub 1214, and Docket No. E-2, Sub 1219, respectively.

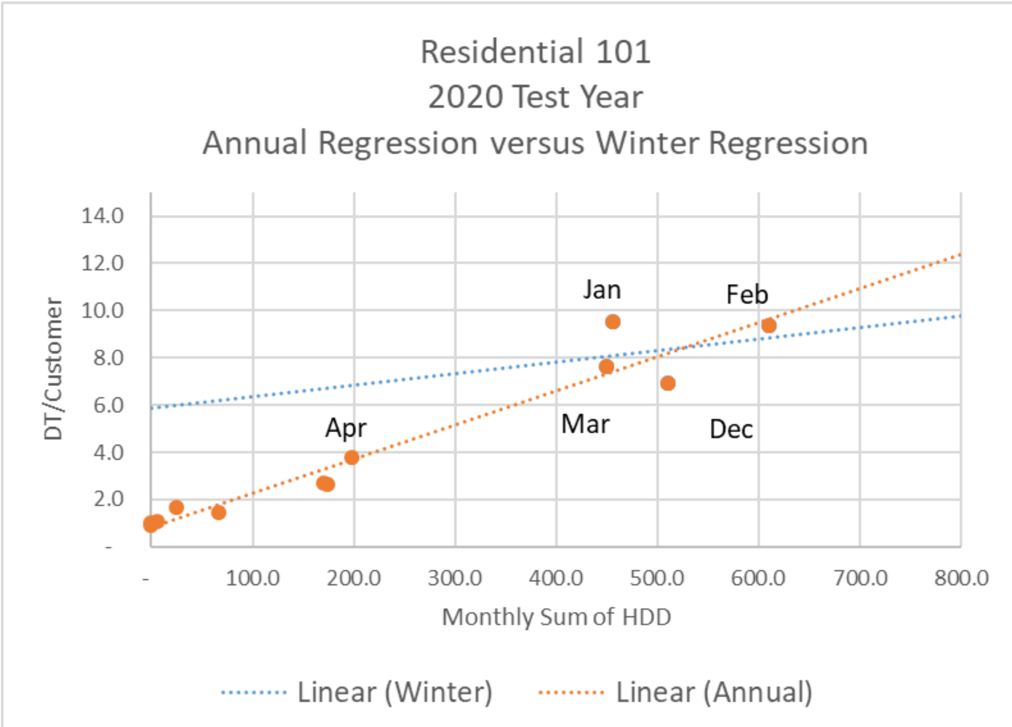
would result in an allocation of approximately 83.13% to North Carolina and approximately 16.87% to South Carolina.

A key takeaway from the above approaches to cost allocation that rely on the use of historic usage data versus a regression analysis is that there are not enough data points to feel confident with the statistical equation for the basis of a cost allocation and rate making. This is in part because improper data resolution (usage months) distorts projected loads and the relationship of base factor and heating coefficient are not consistent. Therefore, I propose an allocation methodology based on recent peak usage data, which is more reflective of how actual users of the system utilize the current plant in service.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY IMPROPER DATA FIELDS AND DISTORTION OF PROJECTED LOADS.

A. Metz Figure 1 below, which is based on data contained in the Company's G-1, Item 4(e), illustrates my point.

Metz Figure 1



The Company provided monthly data from the 15th day of one month to the 15th day of the following month (i.e., customer billing cycle). The monthly data includes usage per customer and the number of HDDs. The points on the bottom left of the graph are the summer and shoulder months and the points on the top right are winter months. The orange dotted line connecting the data points is a standard best line fit (linear regression) of all the data fields (all 12 months), which represents the regression model the Company uses to predict future usage in this general rate case proceeding. The equation that defines the linear regression trend line provides a customer coefficient (y-axis intercept), base factor, and a heating coefficient (line slope), and allows for the projection of future load. The accuracy of the projection is only as good as the correlation of system usage based on those temperatures during the test year coupled with the amount of observations (data points) used to determine the correlation. I compared the Company's annual regression based on how system loads are evaluated in the annual review. The annual review excludes non-winter months from the regression and the starting point of the regression excludes data points greater than 10 HDD (55 degrees Fahrenheit). As Metz Figure 1 shows, the slope or rate of change to temperature and per customer usage (dt/customer) is much less in the winter as compared to the annual regression. Using the Company's proposed method, as temperatures decrease and HDDs increase, the demand continues to increase at the slope or rate of change it is plotted against. The Linear Winter and Linear Annual lines on Metz Figure 1 illustrate the differences in expected demand as you project to a future HDD. The Company used the Linear Annual method in its G-1, Item 5 Jurisdictional Allocation.

The shortcomings inherent in using annual regression to determine future usage described above are further compounded when the Company attempts to assign/allocate costs from a temperature and projected usage from actual/recent system historic utilization. While the linear regression of annual per customer usage has a high R^2

value, implying a high degree of correlation, the predictive value of the model is not as strong for the winter months. For example, the R^2 value of the annual regression model is 0.94; the R^2 value of the winter months compared to the annual regression model is 0.08. The regression with the higher R^2 value (0.94) is results from multiple months with low HDDs (eight data points out of twelve) that bias the results. This relationship can be seen in Metz Figure 1, comparing the DT/Customer difference between the Winter and Annual dotted lines on an “extreme” HDD planning event, the dt/customer usage is approximately 20% higher if one uses the Annual regression compared to the Winter regression.

For example, if the temperature gets cold enough, heat produced from a natural gas source will never satisfy demand and, thus, a saturation point or plateau occurs. Colder temperatures and longer duration compound this phenomenon. Further, not all residential class customers have a gas furnace, and usage patterns may vary when all users are aggregated into one rate class. I conducted a similar analysis of the correlation between customer class usage and temperature in the Company’s last annual review. In that instance, a linear regression appeared to introduce error, and I believe another regression-type analysis could have been used to improve the correlation (e.g., polynomial regression).

Q. WHAT ALTERNATIVE METHOD DO YOU RECOMMEND FOR ALLOCATING DEMAND?

A. For purposes of this general rate case, I recommend that the demand allocation be based on two peak events occurring in 2020. The two 2020 peak events are two of the Company's five highest firm sales send out peaks over the past five years, both occurred in the test year, and they more accurately reflect the current users of the system. From an annual review perspective, the system is designed (future resources are selected) primarily for firm sales customers' demand on the overall system and is a large part of the overall planning for future resources to meet demand. I have concerns that the predictive value of the Company's proposed regression, using all 12 months of annual usage, breaks down slightly when higher numbers of HDDs are used.

My recommended demand allocation results in an assignment of 83.16% to North Carolina and 16.84% to South Carolina. The 2020 weighted average of usage between North Carolina and South Carolina is nearly identical to the same ratio of peak events over the last five years and the weighted average takes into account system usage factors, growth over those five years, and how the system is planned for cold weather (high demand) events. I have provided this allocation adjustment to Public Staff witnesses Patel and Perry, and they are reflected these witnesses' exhibits as applicable.

Further, based on my investigation, I recommend that the Commission order the Company, the Public Staff, and any other interested parties, prior to the earlier of the Company's next general rate case or its 2023 Annual Review, to initiate, report on the status of, and complete a study of an updated regression analysis to determine a more accurate breakdown of system usage among customer classes and the North Carolina and South Carolina jurisdictions.

General Findings and Observations

Q. BASED ON YOUR REVIEW OF TEST YEAR USAGE, PLEASE DESCRIBE HOW THE SYSTEM WAS USED BY CUSTOMER CLASSES.

A. Metz Exhibits 4 and 5 illustrate usage for the test year by month and customer class. Metz Exhibit 4 lists all individual North Carolina classes, and Metz Exhibit 5 groups the individual classes from Metz Exhibit 4 into three main groups for ease of identifying usage by class.

There are several observations based on my review of test year usage that I would like to bring to the Commission's attention. First, the 2020 test year was impacted by user changes in gas demand in reaction to the COVID-19 pandemic (beginning around April 2020). Second, power generation is by far the most significant user of throughput (dekatherms supplied by Piedmont's transmission and distribution system). Third, firm sales customer classes,[14] in aggregate, appear to be mostly winter peaking. Fourth, and finally, DEP's and Duke Energy Carolinas, LLC's (DEC), most recent integrated resource plans still project additional future natural gas generation, thus power generation through put may continue to increase in the future.

Based on a cursory review of system usage shown in Metz Exhibits 4 and 5 and a review of Public Staff witness Jack L. Floyd's testimony, I concur with witness Floyd's recommendation to conduct a deeper investigation into the cost of service in a future docket. Changes to the cost of service may influence other recommendations discussed in my testimony.

Q. WHAT ARE YOUR COMMENTS REGARDING THE COMPANY'S UPDATE FILING MADE ON JULY 28, 2021 (JUNE UPDATE)?

A. The Public Staff is aware of the June Update; however, given the timing of the update filing and the due date of the Public Staff's testimony, the Public Staff could not reasonably perform its investigation of the Company's updated information in the short

[14] Public Staff witness Patel identified the firm sales customer classes as: RS 101, RS 102, RS 152, RS 103, RS 143/102, RS 143/152, RS 143/103, and unique special contracts with firm sale requirements. Based on the data presented in the G-1 Item 4(e), I was not able to determine which specific special contracts were part of firm sales. For the purpose of Metz Exhibits 4 and 5, special contract load was removed because not all special contracts are firm sales.

amount of time before it was due to file testimony. The Public Staff reserves the right to file supplemental testimony related to the Company's June Update once its investigation of the updated information is completed.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

DUSTIN R. METZ

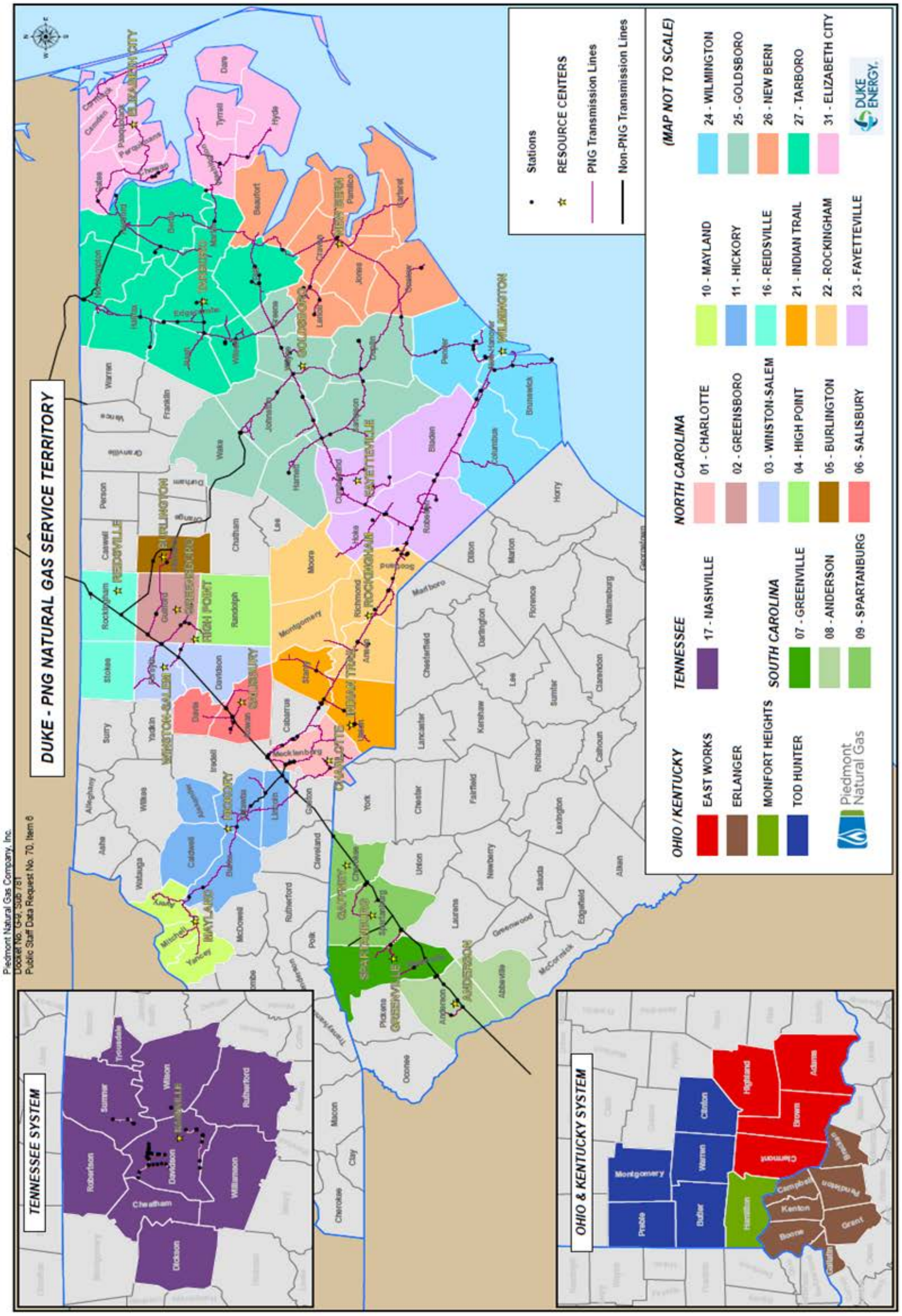
Through the Commonwealth of Virginia Board of Contractors, I hold a current Tradesman License certification of Journeyman and Master within the electrical trade, awarded in 2008 and 2009, respectively. I graduated from Central Virginia Community College, receiving Associates of Applied Science degrees in Electronics and Electrical Technology (Magna Cum Laude) in 2011 and 2012 respectively, and an Associates of Arts in Science in General Studies (Cum Laude) in 2013. I graduated from Old Dominion University in 2014, earning a Bachelor of Science degree in Engineering Technology with a major in Electrical Engineering and a minor in Engineering Management. I completed engineering graduate course work in 2019 and 2020 at North Carolina State University.

I have over 12 years of combined experience in engineering, electromechanical system design, troubleshooting, repair, installation, commissioning of electrical and electronic control systems in industrial and commercial nuclear facilities, predictive statistical analysis, calibration, project planning and management, and general construction experience, including six years with direct employment with Framatome, where I provided onsite technical support, craft oversight, and engineer change packages and participated in root cause analysis teams at commercial nuclear power plants, including plants owned by both Duke Energy and Dominion.

I joined the Public Staff in the fall of 2015. Since that time, I have worked on electric and natural gas general rate cases, fuel cases, natural gas annual reviews, applications for certificates of public convenience and necessity, service and power quality, customer complaints, North American Electric Reliability Corporation (NERC) Reliability Standards, nuclear decommissioning, National Electric Safety Code (NESC) Subcommittee 3 (Electric Supply Stations) member, avoided costs and PURPA, interconnection procedures, and power plant performance evaluations. I have also participated in multiple technical working groups and been involved in other aspects of utility regulation.

Public Staff

Metz Exhibit 1



Public Staff

Confidential Metz Exhibit 2

Docket No. G-9, Subs 722, 781 & 786

CONFIDENTIAL

Public Staff

Metz Exhibit 3

Piedmont Natural Gas Company, Inc.				G-1, Item 5
Docket No. G-9, Sub 781				Attachment 1 of 2
Test Period ending December 31, 2020				Page 4 of 4
Proposed Design Day Allocation				
PRO FORMA DESIGN DAY ALLOCATION	**BASE LOAD FACTOR**	**HEAT SENSITIVITY FACTOR**	**DECEMBER 2018 CUSTOMERS**	**DESIGN DAY DTs**
NORTH CAROLINA				
Design Day Temperature (F)	8.71			
Design Day HDD	56.29			
Rate Schedule 101 - Residential	0.85361	0.01442	701,548	589,311.22
Rate Schedule 102 - Small General	11.15644	0.06688	71,832	296,759.07
Rate Schedule 143 / 102 - Small General Motor Fuel	109.94167	-	9	32.53
Rate Schedule 152 - Medium General	524.07422	1.08208	503	39,304.57
Rate Schedules 103, 113 - Firm Large General	6,911.17845	2.97327	368	145,206.15
Rate Schedules 143 / 103, 143 / 113 - Firm Large General Motor Fuel	7,851.68333	-	11	2,839.51
Rate Schedule T-10 - Firm Military	63,201.46233	180.29121	1	12,226.45
Special Contract - Firm Municipals	113,409.73490	355.37948	3	71,198.55
Total North Carolina Design Day Dts				**1,156,878**
SOUTH CAROLINA				
Design Day Temperature (F)	8.71			
Design Day HDD	56.29000			
Rate Schedule 201 - Residential	0.80692	0.01493	138,577	120,153.38
Rate Schedule 202 - Small General	9.71336	0.06222	14,762	56,415.47
Rate Schedule 252 - Medium General	558.74707	1.03612	86	6,595.61
Rate Schedules 203, 213 - Firm Large General	2975.54579	1.83150	71	14,265.40
Special Contract - Firm Large General	13564.55833	-	1	445.96
Total South Carolina Design Day Dts				**197,876**
Grand Total Carolinas Design Day Dts				**1,354,754**
North Carolina Design Day Pro Forma Allocation %				**85.39%** (1)
South Carolina Design Day Pro Forma Allocation %				**14.61%**

(1) This factor is used to allocate Piedmont 2-state LNG storage plant utility account balances (balances in accounts 26XXX) to NC. This factor is also used to allocate Piedmont 2-state LNG-related O&M expenses to NC; such LNG O&M expenses are charged to accounts 0843200, 0843400, 0843500, 0843600, 0843700, 0843800, 0843900, 0844100, 0845200 and 0846201.

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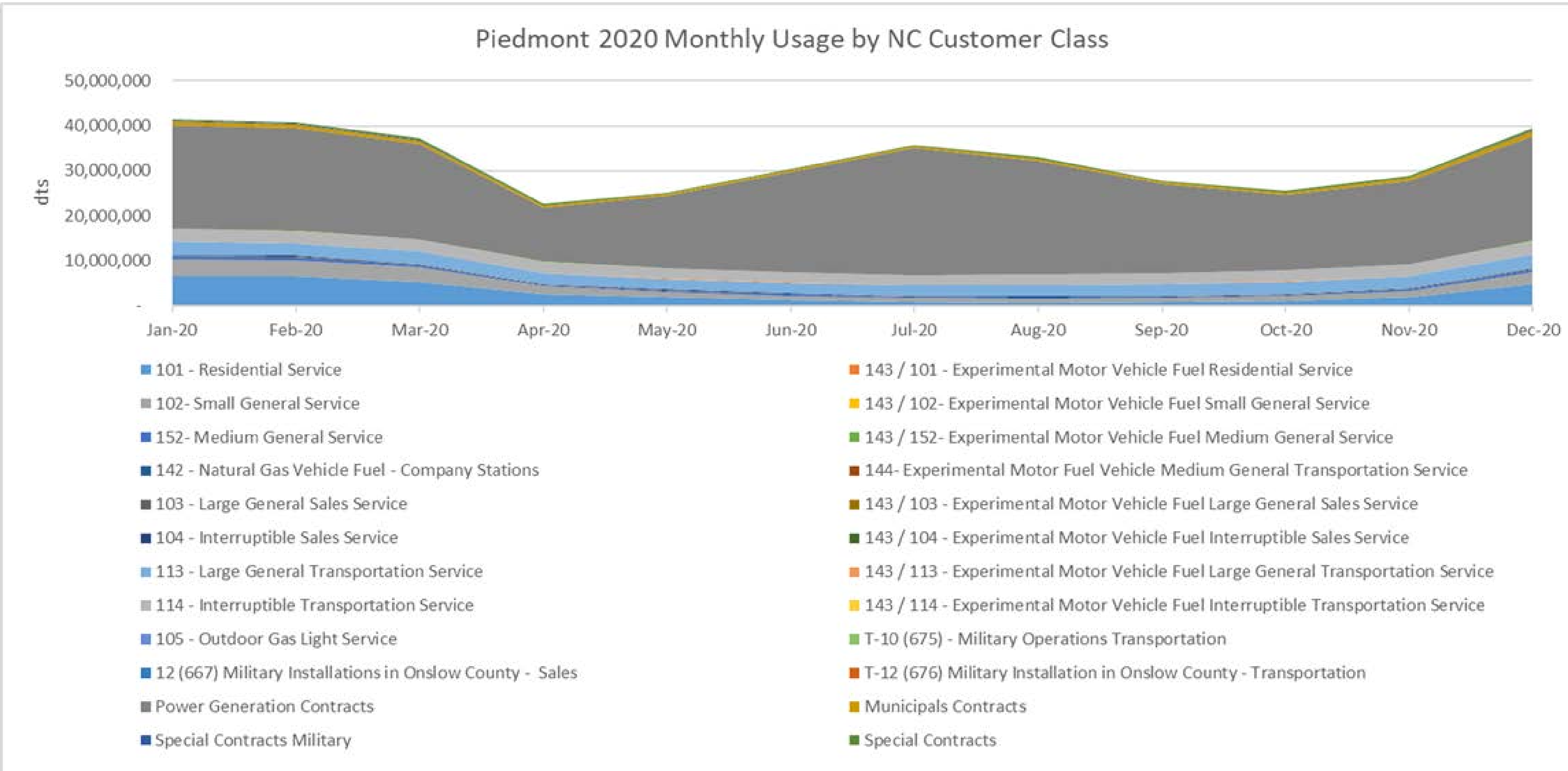
Public Staff

Metz Exhibit 4



Public Staff

Metz Exhibit 5