BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. G-5, SUB 635

In the Matter of: Application of Public Service Company of North Carolina, Inc. for Annual Review of Gas Costs Pursuant to N.C.G.S. § 62-133.4(c) and Commission Rule R1-17(k)(6)	)))))))	MOTION TO CORRECT THE RECORD

Haw River Assembly moves to correct a recently discovered mathematical error in the hearing testimony of Witness Gregory M. Lander.

1. A mathematical error came to undersigned counsel's attention on September 29, 2021, and Counsel for Public Staff and PSNC were contacted once undersigned counsel confirmed the cause and scope of the error. The error involves a single miscalculation that resulted in an incorrect estimate for the total annual fixed cost of PSNC's purchase of year-round firm capacity on the MVP and MVP Southgate pipelines. The correct total cost estimate is approximately $115 million per year rather than approximately $120 million per year.

2. The underlying miscalculation occurred after Witness Lander made an estimate for the amount that MVP and MVP Southgate would charge PSNC for its capacity reservations on the two pipelines based on publicly available information. He estimated that it would cost PSNC about $1.27 per dekatherm per day. Tr. p. 151, line 20. That figure is unchanged. But a mathematical error occurred when he converted that daily cost estimate to an annual cost estimate. Tr. p. 151, lines 23–25. The correct calculation of $1.27/Dth times 250,000 Dth/day times 365 days in a year is $115,887,500, not

$120,509,745 per year. Tr. p. 151, line 24. Subsequent cost comparisons in Witness Lander's testimony were derived from the annual total and thus need to be corrected to reflect the actual estimate provided.

3. These corrections fix a mathematical error but otherwise do not change the substance of Witness Lander's testimony. Although there are several figures that need to be corrected, these changes all stem from one single error that had a ripple effect on other figures that were based on the annual total cost estimate for MVP/MVP Southgate. The calculation error did not affect any of Witness Lander's modeling inputs. This miscalculation also did not affect his findings and recommendations to the Commission given that the difference between the incorrect and correct figures are small relative to the estimated costs involved.

4. A red-lined version of the official transcript is attached, with the incorrect figures stricken through and the corrected figures inserted. The following table contains the requested changes to the hearing transcript necessary to remedy the calculation error:

Page and Line Numbers	Current Version	Requested Change
Page 135, Line 3	$120 million	$115 million
Page 135, Line 4	$324.22	$311.92
Page 146, Line 15	$5.95	$5.595
Page 150, Line 25	$324.22	$311.92
Page 151, Line 10	$324.22	$311.92
Page 151, Line 24	$120,509,745	$115,887,500
Page 152, Line 1	$320.72	$308.42
Page 152, Line 3	$324.22	$311.92
Page 153, Line 21	$324.22	$311.92
Page 163, Line 2	$120,509,745	$115,887,500
Page 163, Line 3	$2.20	$2.11
Page 163, Line 5	$0.22	$0.21
Page 163, Line 11	$0.22	$0.21
Page 163, Line 12	$0.465	$0.455
Page 164, Line 12	$2.20	$2.11
Page 164, Line 13	$0.22	$0.21
Page 165, Line 9	$2.20	$2.11

Page 165, Line 11	$1.10	$1.055
Page 165, Line 19	$2.20	$2.11
Page 165, Line 20	$17.56	$16.84
Page 165, Line 20	$0.0175	$0.0168
Page 171, Line 8	$120 million	$115 million
Page 171, Line 9	$324.22	$311.92

5. Counsel for Public Staff and PSNC have informed undersigned counsel that they do not object to the relief sought by this motion.

6. Haw River Assembly asks the Commission to grant this motion and to allow corrections to the record as set forth above and included in the attached corrected transcript.

Respectfully submitted this 30th day of September, 2021.

s/ David Neal
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CERTIFICATE OF SERVICE

I certify that a copy of the foregoing Motion to Correct the Record as filed today in Docket No. G-5, Sub 635 has been served on all parties of record by electronic mail.

This the 30th day of September, 2021.

s/ David L. Neal

PLACE: Via Videoconference

DATE: Tuesday, August 10, 2021

TIME: 10:30 a.m. - 12:50 p.m.

DOCKET NO: G-5, Sub 635

BEFORE: Commissioner ToNola D. Brown-Bland, Presiding

Commissioner Jeffrey A. Hughes

Commissioner Floyd B. McKissick, Jr.

IN THE MATTER OF:

Application of

Public Service Company of North Carolina, Inc.,

for Annual Review of Gas Costs Pursuant

to N.C.G.S. § 62-133.4(c) and

Commission Rule R1-17(k)(6)

A P P E A R A N C E S:

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T A B L E O F C O N T E N T S

E X A M I N A T I O N S

E X A M I N A T I O N S (Cont'd)

E X H I B I T S

P R O C E E D I N G S

COMMISSIONER BROWN-BLAND: Good morning. Let's come to order and go on the record. I am Commissioner ToNola D. Brown-Bland with the North Carolina Utilities Commission and the Presiding Commissioner for this hearing. With me this morning by remote means are Commissioners Jeffrey A. Hughes and Floyd B. McKissick, Jr.

I now call for hearing Docket Number G-5, Sub 635, which is In The Matter of Application of Public Service Company of North Carolina, Inc., for Annual Review of Gas Costs Pursuant to G.S. § 62-133.4(c) and Commission Rule R1-17(k)(6). G.S. § 62-133.4 authorizes gas cost adjustment proceedings for natural gas local distribution companies. Subsection C of the Statute provides that the Utilities Commission shall conduct annual review proceedings to compare each natural gas utility's prudently incurred costs with costs actually recovered from all the utility's customers served during the test period. Commission Rule R1-17(k)(6) prescribes the procedures for annual reviews of natural gas costs.

On June 1st, 2021, Public Service Company of

North Carolina, Inc., d/b/a Dominion Energy North Carolina, hereafter PSNC or the Company, filed the direct testimony and exhibits of witnesses Rose M. Jackson and Glory J. Creel regarding the Company's actual gas cost for the 12-month test period ended March 31, 2021.

On June 7th, 2021, the Commission issued an Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice. The Order scheduled a hearing for this date and time, Tuesday, August the 10th, 2021, at 10:00 a.m., by remote means using the Webex platform.

On July 9th, 2021, Haw River Assembly filed a Petition to Intervene which was granted by the Commission by an Order issued July 19th, 2021.

On July 26th, 2021, the Public Staff filed the testimony and appendices of witnesses Shawn L. Dorgan, Neha R. Patel, and Julie G. Perry.

On July 26th, 2021, Haw River Assembly filed the direct testimony and exhibits of Gregory M. Lander.

Also, on July 26th, 2021, all parties filed statements of consent to holding this hearing by remote means.

On July 29th, 2021, PSNC filed the Motion to Strike the direct testimony and exhibits of Gregory M. Lander and requested expedited treatment.

On July 30th, 2021, PSNC filed Affidavits of Publication of public notice of hearing.

And on August the 2nd, 2021, Haw River Assembly filed its response opposing PSNC's Motion to Strike. Also, Haw River Assembly filed a list of confidential potential cross exam exhibits.

On August 3rd, the Commission issued an Order denying PSNC's Motion to Strike testimony.

On August 3rd, 2021, PSNC and the Public Staff filed a Joint Motion to Excuse Witnesses.

The rebuttal testimony of PSNC witness Jackson was filed on August 5th, 2021.

And finally, on August 6th, 2021, the Commission issued an Order granting the Joint Motion to excuse PSNC witness Creel and all three Public Staff witnesses from attending the hearing and directing that their testimony -- the testimony of the excused witnesses and their exhibits be admitted into hearing at this -- into evidence at this hearing.

Now, in compliance with the requirement of

Chapter 163A of the State Government Ethics Act, I remind the members of the Commission of our responsibility to avoid conflicts of interest, and I inquire whether any member has a conflict of interest with respect to the matter before us this morning?

(No response)

Let the record reflect that no conflicts have been identified.

I now call for appearances of counsel, beginning with Public Service or PSNC.

MS. GRIGG: Good morning, Presiding Commissioner Brown-Bland, Commissioner McKissick, Commissioner Hughes. I'm Mary Lynne Grigg with the Law Firm of McGuireWoods appearing on behalf of the Company.

COMMISSIONER BROWN-BLAND: Good morning. Public Staff?

MS. HOLT: Good morning. I'm Gina Holt with the Public Staff here on behalf of the Using and Consuming Public.

COMMISSIONER BROWN-BLAND: And Haw River Assembly?

MR. NEAL: Good morning, Presiding Commissioner Brown-Bland. This is David Neal with the

Southern Environmental Law Center appearing this morning on behalf of the Haw River Assembly.

MS. GRIGG: Commissioner Brown-Bland, we also have Ms. Kristin Athens is appearing on behalf of the Company as well.

COMMISSIONER BROWN-BLAND: Kristin Athens?

MS. GRIGG: Yes, ma'am, from McGuireWoods.

COMMISSIONER BROWN-BLAND: Good morning, Ms. Athens.

MS. ATHENS: Good morning, Commissioner.

COMMISSIONER BROWN-BLAND: Before we get started, are there preliminary matters that need to be addressed before we start?

MR. NEAL: Good morning, Presiding Commissioner Brown-Bland. This is David Neal again. Just pursuant to the Commission's Order, I just wanted to alert the Commission that the confidential cross examination exhibits that we intend to use, I'm not sure what procedure the Commission wants to follow for introducing those exhibits, for how the Commission would go into closed session.

COMMISSIONER BROWN-BLAND: Do we need to -- are you going to be eliciting testimony where we need to bring out the confidential materials?

MR. NEAL: My intention is to introduce the two confidential exhibits in cross examination of Company witness Jackson. And I do not know what material on those exhibits is considered confidential. So, in an abundance of caution, I would -- I'm seeking guidance on how to proceed.

COMMISSIONER BROWN-BLAND: Does Ms. Grigg have anything to add about the confidential nature of the proposed exhibits?

MS. GRIGG: Just to note, Commissioner Brown-Bland, that I have confirmed with the Company that that is sensitive operating information and needs to be treated confidentially. I'm sorry for the inconvenience.

COMMISSIONER BROWN-BLAND: That's all right. Did we secure -- I'm not aware that we secured a confidential line? Did we do that, anyone? Did the Company do that?

MS. GRIGG: No, ma'am. I'm sorry. We did not.

COMMISSIONER BROWN-BLAND: Is someone for the Company able to get us a number while we proceed?

MS. GRIGG: Yes, ma'am. Yes, ma'am, we would --

COMMISSIONER BROWN-BLAND: You can ask somebody --

MS. GRIGG: -- be happy to do that.

COMMISSIONER BROWN-BLAND: -- to do that. And then I would request that you have email, or have someone email that number to me and to the court reporter and we'll make sure it gets to everybody else.

MS. GRIGG: Yes, ma'am. We'll do that right now.

COMMISSIONER BROWN-BLAND: If you could do that before --

COURT REPORTER: Excuse me.

COMMISSIONER BROWN-BLAND: Mr. Neal, do you need to get to that matter at the front end of your cross examination?

MR. NEAL: I think it would make the most sense to do it at the front end, because it's foundational.

COMMISSIONER BROWN-BLAND: Okay. Then we might, when we get there which will be just a few minutes, we might take a brief recess until Ms. Grigg can help us get that number.

MR. NEAL: Thank you.

COMMISSIONER BROWN-BLAND: Madam Court Reporter?

COURT REPORTER: Yes, ma'am. I'm sorry to interrupt. My email is not on this computer so if you could --

COMMISSIONER BROWN-BLAND: I'll make sure you get it.

COURT REPORTER: Thank you.

COMMISSIONER BROWN-BLAND: Okay. Ms. Grigg, you might -- it might be helpful if you confirm when it's sent. Just -- I'll be looking for it but just in case.

MS. GRIGG: Yes, ma'am, we will do so. Our practice assistant is going to be sending that momentarily. So, if you'd like we could call Ms. Jackson and have her provide her summary of her testimony and -- while that email is heading down Fayetteville Street.

COMMISSIONER BROWN-BLAND: But just a moment, we've got a little bit more to take care of.

So, other than that, Mr. Neal, does that take care of your preliminary matters?

MR. NEAL: Yes. Yes, ma'am. Thank you so many so much.

COMMISSIONER BROWN-BLAND: And Ms. Holt, did any public witnesses sign up for the public witness hearing portion of the hearing this morning?

MS. HOLT: No. No public witnesses have signed up.

COMMISSIONER BROWN-BLAND: All right. So the record will reflect that we inquired and there were no public witnesses wishing to testify this morning.

Ms. Grigg, we will let you get Ms. Jackson on the stand virtually.

MS. GRIGG: Thank you very much, Commissioner Brown-Bland.

PSNC calls Ms. Rose M. Jackson to the stand.

ROSE M. JACKSON;

having been duly affirmed,

testified as follows:

COMMISSIONER BROWN-BLAND: Ms. Grigg?

MS. GRIGG: Thank you.

DIRECT EXAMINATION BY MS. GRIGG:

Q Good morning, Ms. Jackson.

A Good morning.

Q Will you please state your name and business address for the record?

A My name is Rose M. Jackson and my business address is 220 Operation Way, Casey, South Carolina.
Q By whom are you employed and in what capacity?
A I'm employed by Dominion Energy Services, Incorporated, as the Director of Gas Supply Services.
Q Did you cause to be prefiled in this docket on June 1st, 2021, direct testimony in question or answer form consisting of 18 pages and three exhibits of which attachment to Exhibit 2 was confidential?
A Yes, ma'am.
Q Are there any corrections you would like to make to your testimony at this time?
A No, ma'am.
Q If I ask you the questions in your direct testimony today, would your answers be the same?
A Yes, ma'am.
Q Do you have a summary of your testimony?
A Yes, ma'am, I do.
Q Would you please provide it now to the Commission?
A Good morning, Commissioners. I discuss in my

testimony the gas supply policies and procedures of PSNC, which does business as Dominion Energy North Carolina. The purpose of my testimony is to demonstrate that all PSNC gas costs were prudently incurred during the review period ended March 31, 2021, and therefore meet the requirement for recovery.

PSNC's system and its gas supply procurement policy are designed to serve firm customers reliably on a design day. In providing sales service, the Company must acquire supplies of natural gas and arrange for their delivery to PSNC's system. The most appropriate description of PSNC's procurement policy has been, and continues to be, a best-cost supply strategy. This strategy is based on three primary criteria: Supply security, operational flexibility, and the cost of gas. PSNC is committed to acquiring cost-effective supplies of natural gas while maintaining the necessary security and flexibility to serve our customers.

PSNC acquires capacity to meet its customers' demand. PSNC's design-day demand forecast projects firm customer load and is used to determine total asset needs. This forecast is updated annually, and capacity alternatives are evaluated on an on-going basis. If needed, PSNC secures incremental transportation and/or storage capacity to meet the growth requirements of its firm sales customers consistent with its best-cost strategy. To acquire long-term expansion capacity precisely in balance with customer needs is impossible due to many external factors beyond the Company's control. In assessing the type of resources needed to meet its design-day demand, PSNC attempts to minimize the per unit delivered gas cost. This analysis incorporates any transportation charges, storage costs, and supplier reservation fees required to deliver gas to PSNC's system, as well as the reliability and timing of new services.

PSNC also utilizes a hedging program to help mitigate natural gas price volatility at a reasonable cost. The hedging program meets its objective by using financial instruments such as call options or futures.

In conclusion, it is my opinion that all of PSNC's gas costs were prudently incurred under its gas supply acquisition policy and I respectfully request that these costs be approved. This concludes my summary.

Q Thank you.

MS. GRIGG: Commissioner Brown-Bland, I move that Ms. Jackson's direct testimony be copied into the record as if given orally from the stand and that her three exhibits be marked for identification as prefiled with the attachment to Exhibit 2 containing confidential information continue to be protected as such.

COMMISSIONER BROWN-BLAND: That motion is granted as counsel expressed it.

MS. GRIGG: Thank you very much.

(WHEREUPON, Jackson Direct Exhibits 1 - 3 are marked for identification as prefiled. Confidential Attachment to Jackson Direct Exhibit 2 is filed under seal.)

(WHEREUPON, the prefiled direct testimony of ROSE M. JACKSON is copied into the record as if given orally from the stand.)

BEFORE THE

NORTH CAROLINA UTILITIES COMMISSION

PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INCORPORATED

DOCKET NO. G-5, SUB 635

DIRECT TESTIMONY

OF

ROSE M. JACKSON

JUNE 1, 2021

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, BY WHOM YOU ARE EMPLOYED, AND IN WHAT CAPACITY.

A. My name is Rose M. Jackson and my business address is 220 Operation Way, Cayce, South Carolina. I am employed by Dominion Energy Services, Inc. ("DE Services") as Director- Gas Supply Services.

Q. WHAT ARE YOUR RESPONSIBILITIES?

A. I am responsible for managing the group that supports the gas supply and capacity management functions for Public Service Company of North Carolina, Incorporated, d/b/a Dominion Energy North Carolina ("PSNC" or the "Company"), and its affiliate Dominion Energy South Carolina, Inc., formerly South Carolina Electric & Gas Company. Our group's specific responsibilities include planning and procurement of gas supply and pipeline capacity, nominations and scheduling related to natural gas transportation and storage services on interstate pipelines and the Company's system, gas cost accounting, state and federal regulatory issues concerning supply and capacity, asset and risk management, and gas transportation administration.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I graduated from the University of South Carolina in 1988 with a Bachelor of Science degree in Accounting. Following graduation, I worked as an accountant for a national security services firm. In 1992, I began my employment with SCANA Corporation ("SCANA") as an accountant. Over the years, I have held various positions of increasing responsibility related to gas procurement, interstate pipeline and local distribution company scheduling, and preparation of gas accounting information. In May 2002, I became Manager of Operations and Gas Accounting at SCANA and was responsible for gas scheduling on interstate pipelines and gas accounting for all SCANA subsidiaries. In November 2003, I was made Fuels Planning Manager and assisted all SCANA subsidiaries with strategic planning and special projects associated with natural gas. I held this position until promoted to General Manager – Supply and Asset Management in December 2005. On January 1, 2021, I became the Director of Gas Supply Services for DE Services.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I have presented testimony on behalf of the Company many times, including its last eight gas cost reviews.

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

A. North Carolina General Statute Section 62-133.4 allows the Company to track and recover from its customers the cost of natural gas supply and transportation and to adjust customer charges to reflect changes in those costs. This is done through Rider D to the Company's tariff. Under subsection (c) of the statute, the Commission must conduct an annual review of the Company's gas costs, comparing the Company's prudently incurred costs with the costs recovered from customers during a 12-month test period. To facilitate this review, Commission Rule R1-17(k)(6) requires the Company to submit to the

Commission, on or before June 1 of each year, certain information for the 12-month test period ended March 31.

The purpose of my testimony is to demonstrate that all the Company's gas costs were prudently incurred during the 12-month review period ended March 31, 2021, and therefore meet the requirement for recovery. My testimony also provides the Commission with information pursuant to the Order Requiring Reporting issued in Docket No. G-100, Sub 91, and describes the Federal Energy Regulatory Commission ("FERC") proceedings in which the Company participated, as required by the Commission's Order on Annual Review of Gas Costs issued in Docket No. G-5, Sub 533. In addition to my testimony, the Company is submitting the direct testimony and schedules of Glory Creel for the purpose of providing the Commission with data necessary to true-up the Company's gas costs during the review period.

Q. PLEASE BRIEFLY DESCRIBE PSNC AND THE COMPOSITION OF ITS MARKET.

A. PSNC is a local distribution company primarily engaged in the purchase, transportation, distribution, and sale of natural gas to more than 600,000 customers in North Carolina. Approximately half of the Company's throughput during the review period consisted of deliveries to industrial or large commercial customers, including electric generation, many of whom either purchased or transported gas under interruptible rate schedules. The remainder of the Company's throughput consisted of firm sales service to residential and small and medium-sized commercial customers.

Q. PLEASE DESCRIBE PSNC'S GAS SUPPLY PROCUREMENT POLICY.

A. PSNC's system and its gas supply procurement policy are designed to serve firm customers reliably on a peak day. In providing sales services, the Company must acquire supplies of natural gas and arrange for their delivery to the Company's system. The most appropriate description of PSNC's gas supply procurement policy is a best-cost supply strategy, which is based on three primary criteria: supply security, operational flexibility, and cost of gas.

The first and foremost criterion is security of gas supply, which refers to the assurance that gas will be available when needed for firm sales customers. Supply security is obtained through a diverse portfolio of suppliers, receipt points, purchase quantity commitments, and terms. Potential suppliers are evaluated on a variety of factors, including past performance, creditworthiness, available terms, gas deliverability options, and supply location.

The second criterion is maintaining the necessary operational flexibility that will enable the Company to react to the effects of unpredictable weather on firm sales customer usage. The Company's gas supply portfolio must be capable of handling the monthly, daily, and hourly changes in these customers' demand needs. Operational flexibility largely results from gas supply agreements having different purchase commitments and swing capabilities (for example, the ability to adjust purchased gas within the contract volume on either a monthly or daily basis) and from injections into and withdrawals out of storage.

The third criterion is the cost of gas. In evaluating costs, it is important to consider not only the actual commodity cost, but also any transportation-related charges such as reservation, usage, and fuel charges. The Company routinely requests gas supply bids from suppliers to help ensure cost-effective proposals. In requests for proposal, suppliers are asked to submit alternative pricing options they believe may be of interest or value to the Company and its customers. In furtherance of the Company's natural gas sustainability initiative, the Company recently began asking that bids include suppliers' net zero goals or strategies. The Company will evaluate these strategies and may consider incorporating them into the Company's best-cost supply strategy in the future.

Typically, the greater the flexibility the Company has with a supply contract, the higher the premium assessed. In securing natural gas supply for its customers, the Company remains committed to acquiring the most cost-effective supplies of gas available while maintaining the necessary supply security and operational flexibility.

Q. WHAT TYPES OF SUPPLY CONTRACTS DOES PSNC HAVE IN ITS PORTFOLIO?

A. PSNC has developed a gas supply portfolio made up of long-term agreements and supplemental short-term agreements with a variety of suppliers, including both producers and independent marketers. The portfolio includes:

- Baseload contracts, which provide fixed volumes of gas each day of the contract term.

- Physical option contracts, which provide flexibility to modify the volumes delivered on a monthly or daily basis to address changing demands and weather patterns.
- No-notice contracts, which provide flexibility to increase or decrease delivered volumes daily to respond to changing operational demands and weather.
- Spot (daily) market contracts, which are primarily used for price mitigation, system balancing, and peak shaving.

The Company's gas supply portfolio had approximately 208,000 dekatherms per day (dts/day) under term contracts with eight different suppliers as of November 1, 2020, the beginning of the winter heating season for the period under review. These contracts all included provisions to ensure the prices paid were market based. The remaining contracts were for purchases in the spot market. Spot purchase contracts do not include reservation fees but reflect only commodity cost, generally by reference to standard indices or negotiated prices.

Q. What impact did the Texas cold weather event during February 2021 have on PSNC?

A. Natural gas spot prices approached record highs during the week of February 14, 2021, as significantly colder-than-normal weather affected most of the country. Natural gas production declined because of freeze-offs and demand increased for heating and electric generation. Prices at the Henry Hub trading benchmark reached $23.86 per dt on February 17, 2021, the highest inflationadjusted price since 2003. The elevated spot prices were short lived, however, as rising temperatures alleviated supply constraints and lowered demand. Natural gas spot prices at the Henry Hub quickly began to decline to prior levels, reaching $2.84 per dt on February 22, 2021. PSNC relied heavily on its storage assets during this weather event to mitigate the impact of the short-term price spike.

Q. HOW DOES PSNC CALCULATE ITS FIRM CUSTOMERS' DEMAND REQUIREMENTS?

A. Projected design-day demand of the Company's firm customers is calculated using a statistical modeling program prepared by DE Services Resource Planning personnel. The model assumes a 50 heating degree-day on a 60-degree Fahrenheit base and uses historical weather to estimate peak-day demand.

Firm peak-day demand reflects the natural gas usage of those customers whose service depends upon the Company acquiring the gas commodity and arranging for it to be transported to the Company's system, that is, firm sales service to residential and small and medium-sized commercial customers. It does not include usage by industrial or large commercial customers, including electric generation, who are responsible for purchasing their own gas supplies and arranging for transportation to the Company's system.

Q. WHAT DESIGN-DAY REQUIREMENTS DID PSNC USE DURING THE REVIEW PERIOD AND HOW DID THE COMPANY PLAN TO MEET THOSE REQUIREMENTS?

A. Column (1) of the table in Jackson Direct Exhibit 1 shows the forecasted firm peak-day demand requirements for the review period and the assets that were available to meet those requirements. The assets included year-round, seasonal, and peaking capabilities and consisted of firm transportation and storage capacity on interstate pipelines as well as the peaking capability of PSNC's on-system liquefied natural gas ("LNG") facility at the Cary Energy Center. They also included short-term peaking services the Company acquired to cover a temporary shortfall of assets.

Columns (2) through (6) on Jackson Direct Exhibit 1 show the current forecast for each of the next five winter seasons and the assets currently available to meet the projected peak-day requirements. Later in my testimony I will discuss the Company's plans for obtaining additional assets to meet those growing demands.

Q. WHAT PROCESS DOES PSNC UNDERTAKE TO ACQUIRE CAPACITY TO MEET ITS CUSTOMER DEMAND?

A. PSNC's design-day demand forecast projects firm customer load growth and is used to determine total asset needs. This forecast is updated annually, and capacity alternatives are evaluated on an on-going basis. If needed, PSNC secures incremental storage or transportation capacity to meet the growth requirements of its firm sales customers consistent with its best-cost strategy.

In assessing the type of resources needed to meet its design-day demand, the Company attempts to minimize the per unit delivered gas cost. This analysis incorporates any transportation charges, storage costs, and supplier reservation fees required to deliver gas to the city gate, as well as the reliability and timing of new services.

As I have noted on other occasions, to acquire long-term expansion capacity precisely in balance with customer needs is impossible due to many external factors beyond the Company's control. A significant concern continues to be the long lead time and uncertainty involved in acquiring capacity from new interstate pipeline projects in order to meet growing customer demand.

Q. PLEASE DESCRIBE PSNC'S INTERSTATE CAPACITY.

A. PSNC subscribes to interstate capacity so that natural gas can be delivered from supply areas or gas storage facilities to PSNC's local distribution system. The interstate transportation and storage providers with whom PSNC has contracted for service include Transcontinental Gas Pipe Line Company, LLC ("Transco"); Columbia Gas Transmission, LLC ("Columbia Gas"); Dominion Energy Cove Point LNG, LP, now known as Cove Point LNG, LP ("Cove Point"); Dominion Energy Transmission, Inc., now known as Eastern Gas Transmission and Storage, Inc. ("Eastern Gas"); East Tennessee Natural Gas, LLC ("East Tennessee"); Pine Needle LNG Company, LLC ("Pine Needle"); Saltville Gas Storage Company, L.L.C. ("Saltville"); and Texas Gas Transmission, LLC ("Texas Gas"). Most of PSNC's firm transportation and storage capacity is obtained from Transco, which currently is the only interstate pipeline having a direct interconnection with the Company's system. PSNC has used segmentation of its Transco capacity to receive natural gas from the other interstate providers.

Q. WHAT IS SEGMENTATION?

A. Segmentation allows a shipper on an interstate pipeline to double the amount of its contracted-for capacity by scheduling deliveries of natural gas from both directions. Thus, PSNC can use one segment of its contracted firm transportation capacity on Transco to schedule forward-haul deliveries (in the same direction as the aggregate physical flow) of gas, on a primary firm basis, from supply points in the Gulf production area northward to the Company's city gate. At the same time, PSNC can use a different, non-overlapping segment of Transco capacity to schedule backhaul deliveries (in the opposite direction of the aggregate physical flow) of gas, on a secondary firm basis, from Columbia Gas, Cove Point, Eastern Gas, East Tennessee/Saltville, Pine Needle, and Texas Gas southward to the Company's city gate. In addition, when that segment is not needed to serve customers, PSNC can release it to other shippers, which generates revenue that mitigates the Company's capacity costs.

Q. WHAT DO YOU MEAN BY "PRIMARY FIRM" AND "SECONDARY FIRM"?

A. These terms refer to levels of scheduling priority on Transco's system. A "primary firm" nomination is one within the shipper's primary transportation path, which is established by the receipt and delivery points specified in the shipper's service agreement with Transco. A "secondary firm" nomination uses a transportation path in the opposite direction of the shipper's primary path. Primary firm nominations have the highest scheduling priority, while secondary firm nominations are lower in priority. Because of this lower priority, PSNC sometimes cannot schedule reverse path nominations using segmentation of its Transco capacity. As I have testified in previous gas cost reviews, the Company increasingly has been unable to use segmentation due to bidirectional gas flows on the Transco system. In addition, Transco implemented tariff changes in July 2019 that further restricted the Company's ability to use segmentation.

Q. WHAT STEPS HAS PSNC TAKEN TO ADDRESS THESE LIMITATIONS ON ITS USE OF SEGMENTATION?

A. In 2017, PSNC entered into a precedent agreement with Transco for 60,000 dts/day of firm transportation capacity on Transco's Southeastern Trail Expansion project. The project was fully completed in January 2021. Prior to full completion, Transco offered partial service beginning in November 2020.

The Southeastern Trail capacity provides the Company additional firm transportation service with a receipt point at the existing Pleasant Valley Transco-Cove Point interconnection in Fairfax County, Virginia, and a delivery point at the existing Transco Station 65 pooling point in St. Helena Parish, Louisiana. This allows PSNC to schedule the transportation of natural gas from storage facilities and pipelines north of the Company's city gate in a southerly direction on a primary firm, forward-haul basis.

Q. WHEN DID PSNC BEGIN USING THE SOUTHEASTERN TRAIL CAPACITY?

A. On November 1, 2020, PSNC begin receiving partial service on Southeastern Trail in the amount of 55,400 dts/day and, effective January 1, 2021, commenced service for the full contract amount of 60,000 dts/day.

Q. WHAT OTHER ASSETS DID PSNC ACQUIRE TO MEET EXPECTED PEAK-DAY REQUIREMENTS DURING THE REVIEW PERIOD?

A. To meet an expected capacity shortfall during the 2020-21 winter season, PSNC contracted for a total of 40,000 dts/day of firm peaking services from three different suppliers. These contracts each allowed the Company to call on delivered gas supply of up to 20,000 dts/day for a specified number of days during the winter.

For the past two winter seasons PSNC needed short-term peaking assets because its plans to acquire capacity on the Atlantic Coast Pipeline ("ACP") interstate pipeline were not realized as the project was delayed and, ultimately, cancelled. In supplemental testimony filed in the Company's gas cost review last year, I summarized the history of the Company's participation in the ACP project from 2015 until its cancellation in July 2020 and discussed alternate plans to acquire capacity on a new interstate pipeline being constructed by Mountain Valley Pipeline ("MVP"). The Company entered into a contract for 24,000 dts/day of short-term peaking supply for the upcoming winter season and will obtain 36,000 dts/day of similar supply, which will result in a reserve margin of approximately 1% for the 2021-22 winter season.

Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF THE MVP PIPELINE AND THE ARRANGEMENTS THE COMPANY MADE FOR SERVICE ON THE PIPELINE.

A. When completed, MVP's mainline project will consist of approximately 303 miles of transmission pipeline, with compression facilities, extending from northwestern West Virginia to southern Virginia. Its 75-mile Southgate lateral project, also with compression facilities, will connect the mainline with the Company's system at delivery points in Rockingham and Alamance Counties, North Carolina.

PSNC has entered into precedent agreements for 250,000 dts/day of mainline capacity and 300,000 dts/day of Southgate lateral capacity to serve the growing natural gas demands I previously discussed. This capacity will provide the Company a second direct interstate pipeline interconnection, with access to natural gas produced in the Marcellus and Utica shale regions of West Virginia, Pennsylvania, and Ohio. In addition, Southgate will connect directly with East Tennessee's pipeline, which will enable PSNC to make firm forward-haul deliveries from Saltville storage to the Company's system and replace less reliable secondary firm backhaul deliveries using Transco segmented capacity. That is why PSNC contracted for 50,000 dts/day more of capacity on Southgate than on the MVP mainline.

Q. WHEN ARE THE MVP PROJECTS EXPECTED TO BE IN SERVICE?

A. As of early 2021, the mainline project was more than 92% complete, with the project's three compressor stations and three original interconnects 100%

complete. The most recent estimated in-service date for the project is the summer of 2022.

In June 2020, FERC issued its order granting a certificate of public convenience and necessity for Southgate. The project currently is expected to be placed into service by the spring of 2023.

Q. WHAT WILL THE COMPANY DO UNTIL THE MVP CAPACITY BECOMES AVAILABLE?

A. Until the MVP mainline and MVP Southgate projects are both placed into service, the Company will continue take steps to address the shortfall in available assets. We will continue to monitor the situation closely and, using our best-cost strategy, take steps to address any developments at the appropriate time.

Q. HAVE YOU PROVIDED THE INFORMATION CONCERNING CAPACITY ACQUISITION AS REQUIRED BY THE COMMISSION'S ORDER IN DOCKET NO. G-100, SUB 91?

A. Yes. PSNC's responses to the ten questions set forth in that order are attached as Jackson Direct Exhibit 2.

Q. WHAT ADDITIONAL ACTIONS HAS PSNC TAKEN TO ACCOMPLISH ITS BEST-COST POLICY?

A. PSNC continues to take the following steps to keep its gas costs as low as possible while accomplishing its stated policy goals of maintaining security of supply and delivery flexibility:

- Optimize the flexibility available within its supply and capacity contracts to realize their value.
- Monitor and intervene in matters before the FERC whose actions could impact the rates the Company pays and the services it receives from interstate pipelines and storage facilities.
- Work with industrial customers to facilitate transportation of customer-acquired natural gas.
- Communicate directly with customers, suppliers, and other industry participants and actively monitor developments in the industry.
- Conduct frequent internal discussions concerning gas supply policy and major purchasing decisions.
- Utilize deferred gas cost accounting to calculate the Company's benchmark cost of gas to provide a smoothing effect on gas price volatility.
- Conduct a hedging program to mitigate price volatility.

Q. PLEASE DESCRIBE THE FERC PROCEEDINGS THAT PSNC PARTICIPATED IN DURING THE REVIEW PERIOD.

A. Jackson Exhibit 3 is a complete listing of the new FERC matters that PSNC intervened in during the review period. PSNC may not have stated a position in a proceeding but filed an intervention without protest or comment. Such interventions typically are made in proceedings where the Company has an interest and the issues or dollar impact appears to be relatively minor but might escalate and become significant at a later date or where the Company would like to receive more information from the participants on an issue in order to monitor future developments. Unless specifically indicated in the last column of Jackson Direct Exhibit 3, PSNC did not express a position during its participation in a matter listed.

Q. WHAT IS THE PURPOSE OF PSNC'S HEDGING PROGRAM?

A. The primary objective of PSNC's hedging program has always been to help mitigate the price volatility of natural gas for firm sales customers at a reasonable cost. The hedging program meets this objective by having financial instruments such as call options or futures in place to mitigate in a cost-effective manner the impact of unexpected or adverse price fluctuations to customers.

Q. PLEASE DESCRIBE PSNC'S HEDGING PROGRAM.

A. PSNC's hedging program provides protection from higher prices through the purchase of call options for up to 25% of estimated firm sales volume. To help control costs, the call options are purchased at a price no higher than 10% of the underlying commodity price. Hedges also are limited to a 12-month future period, which allows the Company to obtain favorable option pricing terms and better react to changing market conditions. The hedging program continues to utilize two proprietary models developed by Kase and Company that assist in determining the appropriate timing and volume of hedging transactions. The total amount available to hedge is divided equally between the two models.

Q. HAS PSNC MADE ANY CHANGES TO ITS HEDGING PROGRAM?

A. No changes were made to PSNC's hedging program during the review period. However, the Company continues to analyze and evaluate the program and will implement changes as warranted.

Q WHAT WAS THE NET ECONOMIC RESULT OF THE HEDGING PROGRAM DURING THE REVIEW PERIOD?

A. During this period, New York Mercantile Exchange prices at the Henry Hub in Louisiana ranged from a low of $1.43 per dt for the July 2020 contract set on June 26, 2020, to a high of $3.40 per dt for the December 2020 contract set on October 30, 2020. Overall, the hedging program decreased gas costs by $436,502 during the review period.

Q. Did the hedging program mitigate price volatility during the Texas weather event in February 2021?

A. No, PSNC's hedging program requires the purchase of options at certain strike prices as determined by the models developed by Kase and Company. The February options had strike prices that were higher than the first of the month settlement price; therefore, no hedges were exercised for the month of February. Even if PSNC had exercised hedges during February, the price spike occurred outside of the settlement period and therefore would not have been mitigated by PSNC's financial hedging program.

Q. IN YOUR OPINION, WERE ALL OF THE REVIEW PERIOD GAS COSTS PRUDENTLY INCURRED?

A. Yes. All gas costs were incurred under PSNC's best-cost supply strategy, which this Commission has consistently upheld. In my opinion, they are the result of reasonable business judgments considering the conditions under which the gas purchasing decisions were made.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

MS. GRIGG: I understand that my practice assistant is working on getting that dial-in information sent to you and it should be coming your way momentarily. And I apologize for any delay.

COMMISSIONER BROWN-BLAND: It's understandable at this point. We're ready for all contingencies apparently. So let's stand in recess. And what I'll have everyone do once we all have the number is mute your Webex platform and also stop your video at the time when we go over. And Mr. McCoy who's the host for our call, he'll maintain this call, and we will all convene on the confidential conference line, all of us who are authorized to be privy to the confidential information. I think that's -- is that all of us, Ms. Grigg?

MS. GRIGG: Yes, ma'am. It should be all counsel have signed NDAs and the witnesses have as well.

COMMISSIONER BROWN-BLAND: And our Commission staff.

MS. GRIGG: Yes, ma'am.

COMMISSIONER BROWN-BLAND: Okay. So we will stand in recess and I -- let's sit tight and I'll come back and I'll indicate when we have the number and

I'll try to make sure every one has it. If your assistant can email to as many as she can like Mr. Neal.

MS. GRIGG: Yes. And Ms. Holt.

COMMISSIONER BROWN-BLAND: Yes. That will be helpful.

MS. GRIGG: Yes. I will go check on that right this moment.

COMMISSIONER BROWN-BLAND: We stand in recess.

MS. GRIGG: Thank you.

COMMISSIONER BROWN-BLAND: But standby please.

(Recess was taken at 10:48 a.m.)

COMMISSIONER BROWN-BLAND: Will every one put your cameras back on so I'll know you're hearing me? Commissioner Hughes? Ms. Holt?

COMMISSIONER HUGHES: I'm calling in. I had logged in so I didn't want to be on both at the same time. So, I'm calling in to the second one.

COMMISSIONER BROWN-BLAND: So, who still needs the number? Anybody didn't get the number? I'm going to make sure you get it.

MR. GREEN: Commissioner Brown-Bland, I

don't think I've gotten an email with the number.

COMMISSIONER BROWN-BLAND: All right.

COMMISSIONER McKISSICK: If an email was sent out I'll check it now. I did not know --

COMMISSIONER BROWN-BLAND: One may not have been sent to you, that's why I'm just making sure who needs it and then I'll send it.

Commissioner Hughes has it apparently.

COMMISSIONER McKISSICK: If you could send it to me, Commissioner Brown-Bland, that would be great. I haven't checked my email yet. It may be there but better safe than sorry.

COMMISSIONER BROWN-BLAND: Witness Jackson and Witness Lander, do you have the number for the confidential call in?

WITNESS JACKSON: Yes, ma'am.

WITNESS LANDER: Lander on the line. Thank you.

COMMISSIONER BROWN-BLAND: So, what I want to make you aware of, it's been sent out, or what I received in any case, as a Webex and we want to maintain this current Webex that we're on. So, do not leave this Webex. Use the call-in number and the access code. This is going to be by telephone only.

All right? So, Mr. Neal, are we ready to go over to the confidential session?

MR. NEAL: Yes, ma'am.

COMMISSIONER BROWN-BLAND: Everybody is able to follow me over there? Ms. Holt, did you come back?

(Pause).

She might be over there.

COMMISSIONER McKISSICK: I will call in now from a landline.

COMMISSIONER BROWN-BLAND: Everyone stop your --

MR. GREEN: Commissioner Brown-Bland?

COMMISSIONER BROWN-BLAND: Yes.

MR. GREEN: I have not received the number I don't believe.

COMMISSIONER BROWN-BLAND: I'm getting ready to send it to you.

MR. GREEN: Okay.

COMMISSIONER BROWN-BLAND: And so everyone stop your video on this call and mute.

(WHEREUPON, the following testimony was heard in confidential session. Post hearing, counsel for Public ervice Company reviewed the

Stestimony and determined it is non-confidential. Therefore, the following testimony taken in confidential session will be included as non-confidential testimony in the record.)

COMMISSIONER BROWN-BLAND: Let me start over. I have Len Green from Commission Staff. Ellen Burns from Commission Staff. Any other Commission Staff?

(Pause).

Is Poornima Jayasheela on? Poornima?

MS. JAYASHEELA: Yes, Commissioner Brown-Bland, I'm in. Thank you.

COMMISSIONER BROWN-BLAND: Is that all of the Commission staff? I have three. Anybody else?

MR. GREEN: Ellen, Poornima and Len, I believe that is all of Commission staff.

COMMISSIONER BROWN-BLAND: All right. I have Commissioner Hughes?

COMMISSIONER HUGHES: I'm here.

COMMISSIONER BROWN-BLAND: And Commissioner McKissick?

COMMISSIONER McKISSICK: I am present, too. Yes.

COMMISSIONER BROWN-BLAND: I have -- Madam Court Reporter is on.

COURT REPORTER: Yes, ma'am.

COMMISSIONER BROWN-BLAND: Mr. Neal?

MR. NEAL: Yes. The responsible party is still here.

(Laughing)

COMMISSIONER BROWN-BLAND: Mr. Lander?

WITNESS LANDER: Lander here. Yes. Can you hear me?

COMMISSIONER BROWN-BLAND: Yes, I do. Ms. Athens?

MS. ATHENS: Present.

COMMISSIONER BROWN-BLAND: And Ms. Grigg?

MS. GRIGG: Yes, ma'am.

COMMISSIONER BROWN-BLAND: Ms. Holt?

MS. HOLT: Present.

COMMISSIONER BROWN-BLAND: Very good. And Ms. Jackson?

WITNESS JACKSON: Yes, ma'am, I'm here.

COMMISSIONER BROWN-BLAND: Is anyone missing to anyone's knowledge? And is anyone on whose name I haven't picked up?

MS. BURNS: Commissioner Brown-Bland, you put down Ellen Burns, didn't you? I just want to make sure.

COMMISSIONER BROWN-BLAND: Yes, I did.

MS. BURNS: Thank you.

COMMISSIONER BROWN-BLAND: Is that it? Ms. Grigg, are you satisfied with the security of this line?

MS. GRIGG: Yes, ma'am. And I thank everyone for the inconvenience and apologize for it as well.

COMMISSIONER BROWN-BLAND: And with those in attendance all have -- you're satisfactory in terms of receiving the Company's confidential information?

MS. GRIGG: Yes, ma'am, we are. And Ms. Jackson is available for cross examination on that matter.

COMMISSIONER BROWN-BLAND: Mr. Neal, finally, I believe it's with you.

MR. NEAL: Thank you, Commissioner Brown-Bland.

CROSS EXAMINATION BY MR. NEAL:

Q Ms. Jackson, can you hear me all right?

A Yes, sir. Good morning. How are you?
Q Good morning. I'm doing great. I'm glad we're getting through this logistical hurdle.

MR. NEAL: I would like I guess first to mark -- request to mark an exhibit, Presiding Commissioner Brown-Bland. We previously shared what was marked Haw River Assembly Confidential Cross Examination Exhibit 1 which is PSNC's response to Public Staff Data Request 6-8. I would ask that to be marked as HRA Jackson Confidential Cross Exhibit 1.

COMMISSIONER BROWN-BLAND: It will be so marked as HRA Jackson Cross Examination Exhibit 1.

MR. NEAL: And I don't know if we need to put confidential in that designation.

COMMISSIONER BROWN-BLAND: I'm sorry. I apologize. Confidential Cross Examination Exhibit 1.

MR. NEAL: Thank you.

(WHEREUPON, HRA Jackson Confidential Cross Examination Exhibit 1 is marked for identification.)

BY MR. NEAL:
Q Ms. Jackson, do you have what's now been marked as HRA Jackson Confidential Cross Exhibit 1?

A Yes, sir, I do.
Q Wonderful. And you would agree that this is the Company's response to a Public Staff Data Request, again 6-8, which requested a load duration curve for the 2020-2021 winter season assuming design day weather conditions; is that right?
A Yes, sir.
Q And the design day is an estimate of the coldest temperature conditions that the Company expects or possible to occur; is that right?
A Yes, sir, that's right.
Q And so another way I guess of saying it is that HRA Jackson Confidential Cross Exhibit 1 shows how the Company plans to satisfy demand on that hypothetical design day; is that right?
A What this graph also assumes is that all of the assets are fully available. So it is a comparison of the design day demand versus the assets available at full levels.
Q And the blue line that's labeled dekatherms is showing that peak design day demand that's just over I guess around 850,000 dekatherms on this chart; is that right?

A Yes, sir, that's correct.
Q And you would agree that -- so that 850,000 dekatherms approximately of available capacity on the left side of the chart, that includes the 50,000 dekatherms, again, roughly 50,000 dekatherms of Saltville storage capacity; is that right?
A Yes, sir.
Q And just so we're clear, that 50,000 dekatherms a day of Saltville capacity would also be included in the 300,000 dekatherms a day of capacity that PSNC is planning to acquire on MVP Southgate; isn't that right?
A Yes, sir. What the MVP Southgate capacity will do is it will allow us to move the Saltville volume of approximately 50,000 dekatherms from secondary firm service on Transco as a backhaul to primary firm service as a forward haul on MVP Southgate.
Q Again, just so we're clear, if we were talking about that 300,000 dekatherms a day of capacity on MVP Southgate as additional to what's shown here on HRA Jackson Confidential Cross Exhibit 1, I could either say that that 250,000 dekatherms a

day of capacity, or 300,000 but then subtract the 50,000 from Saltville, either way, it's the same thing, right?

A Yes, sir. The incremental deliverability that MVP and Southgate will provide is the 250,000.

Q So with respect to the load duration curve for design day, let's assume that we insert it at the top of the chart an additional --

COMMISSIONER BROWN-BLAND: Mr. Neal?

MR. NEAL: Yes.

COMMISSIONER BROWN-BLAND: Just a minute before you complete that question.

Ms. Jackson, are you on a speakerphone?

THE WITNESS: Yes, ma'am. Is it echoing?

COMMISSIONER BROWN-BLAND: Well, it just makes it a little difficult to hear.

THE WITNESS: Okay.

COMMISSIONER BROWN-BLAND: If you'll pick --

THE WITNESS: Yes, ma'am. I'll pick up the phone. Hold on one sec. Is that better?

COMMISSIONER BROWN-BLAND: It is better. I'm thinking my court reporter will think it's better.

COURT REPORTER: Yes, I do.

COMMISSIONER BROWN-BLAND: Continue,

Mr. Neal.

MR. NEAL: Thank you.

BY MR. NEAL:

Q So again, with respect to the load duration curve for design day, let's assume that you insert it at the top of this chart, the HRA Jackson Confidential Cross Exhibit 1, an additional 250,000 dekatherms a day of year-round capacity, that would mean that PSNC has 250,000 dekatherms a day more capacity than your design day needs as of 2021; isn't that right?

A Well, I think you're taking -- you're not taking out -- taking into consideration the short-term peaking service. So, if you look at when the 250,000 of MVP Southgate is scheduled to come in with their revised dates, that would be in the year 2023-'24, the winter of 2023-2024, and that would leave us with a reserve margin of roughly 160,000 dekatherms.

Q And so currently you're -- PSNC is meeting its peak design day requirements or capacity requirements by contracting for short-term peaking services as you just alluded to; isn't that right?

A Yes, sir. They're a delivered service.
Q And PSNC is comfortable that it is meeting its requirements to provide reliable service by contracting for those short-term peaking services; isn't that right?
A We are comfortable in a temporary arrangement. However, we are concerned that as our volumes increase on our design day forecasted need for serving firm demand that the availability for these short-term winter delivered peaking options are going to be more and more difficult and more and more costly to obtain, because these resources rely on interstate capacity and it's been very difficult to add interstate capacity in today's market.
Q Now -- but again, looking at HRA Jackson Confidential Cross Exhibit 1 with those short-term peaking services included as part of how PSNC is meeting its obligations to serve potential peak demand, you would agree that adding an additional 250,000 dekatherms to this chart here would be essentially a big rectangle of additional capacity all year round; isn't that right?

A Yes, sir, it would be year-round capacity.
Q And that would take you, in fact, off the chart. The Y axis here goes up to 900,000 dekatherms a day and this would go up to something like 100 -- a 1,100,000 dekatherms a day; isn't that right?
A Yes, sir. It would be approximately 1,059,000; yes, sir.

MR. NEAL: At this time, Commissioner Brown-Bland, I would like to mark a second exhibit. It was previously shared as Haw River Assembly Confidential Cross Exhibit 2. And I would I guess like to mark that as HRA Jackson Confidential Cross Exhibit 2.

COMMISSIONER BROWN-BLAND: It will be identified as HRA Jackson Confidential Cross Examination Exhibit 2.

MR. NEAL: Thank you.

(WHEREUPON, HRA Jackson Confidential Cross Examination Exhibit 2 is marked for identification.)

BY MR. NEAL:
Q And, Ms. Jackson, do you also have what's now been marked as HRA Jackson Confidential Cross

Exhibit 2?
A Is that the response that we filed related to Public Staff Data Request 6-9?
Q Yes, ma'am.
A Okay. Yes, sir, I have that one.
Q And so you would agree that this document requested load duration curve for the 2020-2021 winter season showing actual weather conditions; isn't that right?
A That was it. That was the question; yes, sir.
Q And so you would agree that your actual peak day demand in the 12-month test period was just over 500,000 dekatherms on the peak days; isn't that right?
A Yes, sir, because we had a warmer than normal winter.
Q And so, again, if we added the 250,000 dekatherms of additional capacity from MVP Southgate to the approximate 800,000 or 850,000 dekatherms of existing capacity, which again I recognize includes those short-term peaking services, that would again as we discussed take you up to about a million just less than a hundred thousand dekatherms of peak capacity for that highest

demand days; isn't that right?

A It would take you up to that for total assets available.

Q And that one million, again, just less than 100,000 dekatherms a day is more than twice the 500,000 or so dekatherms a day of actual peak demand experienced in the last 12-month period; isn't that right?

A It is; however, I want to state that our responsibility is to serve our firm customers reliably on every day of the year and this is just an example of the previous review period that had warmer than normal winter.

If you were to go back in time and look at events such as the Polar Vortex of 2014 or 2018, you would see that we were very close to our total asset utilization. And this also assumes that all the assets are available. So it doesn't take into account that if we experience a design day, let's say in late February, all of these assets would not be available at full volume, or maybe not at all the days that we could pull on these assets.

So that is the value of year-round

capacity. It gives us the flexibility that in the event that one of our peaking services has been utilized previously in the winter season we can look at buying flow and supply. We can look at dispatching interstate storage. So it gives us the flexibility to ensure reliability 365 days a year no matter what the weather conditions are.

Q And you would agree that the -- going back to HRA Jackson Confidential Cross Exhibit 1, the design day requirements that, other than that sort of needle peak on the very far left-hand side that gets over again to that 850,000 dekatherms, it otherwise drops off rather precipitously again as the design day projections to around 500,000 dekatherms within just a couple of days; isn't that right?

A Once again, this solves for one day, the design day, and it assumes that the full capacity is available in every one of these assets. When you look at the real world, that's not going to be the case, probably not going to be the case, because we typically don't hit a design day on November 1st which is the beginning of the winter season.

Q And your -- again, it's your testimony that PSNC's current efforts to contract for both contracted capacity, seasonal capacity, and peaking capacity is obligating the Company's requirements to reliably serve demand; isn't that right?

A Can you restate that question, please?

Q Isn't it your testimony that PSNC's, in the 2020-2021 test year, test period, that the Company reliably met its obligations to have design day peak capacity available; isn't that right?

A In the amount of 40,000 dekatherms; yes, sir.

Q Again, that 40,000 is the short-term peaking service. I was referring to the entire stack of capacity that gets you up to about 850,000 dekatherms as shown on HRA Jackson Confidential Cross Exhibit 1?

A Yes, sir. Okay. That -- you're talking about all the assets that we label in my Exhibit 1 to my testimony --

Q Yes.

A -- as peaking capacity?

Q Yes.

A Okay. Yes, sir.
Q And -- now, if PSNC does not end up receiving the MVP/MVP Southgate capacity -- I'm sorry -- if it does end up receiving that MVP/MVP Southgate capacity, you mentioned that PSNC would consider turning back some of those short-term peaking services; is that right?
A There won't be a need to turn back. Those contracts are short term in nature and would be terminated prior to the in-service date.
Q Are there any other -- would PSNC turn back any other of the capacity listed on Jackson Direct Exhibit 1 in the event that the MVP/MVP Southgate went online?
A What MVP/MVP Southgate gives us the ability to do is to firm up the backhaul associated with a number of the storage facilities. And, as you're probably aware, it's very difficult to obtain new storage in today's marketplace, so we would evaluate that. However, at this point in time we don't see the need to do so because those storage facilities give us operational flexibility and supply security in these colder than normal events. And the concern that we've raised over

the last few years is that with a bidirectional flow of Transco's system now, prior to that time period of three to four years ago, we were able to rely on Transco's backhaul, secondary backhaul rights that we had with our primary rights but that has diminished over time. So what does the MVP and Southgate capacity will do is give us the ability to firm up some of those storage facilities.

Q And just to reiterate, do I understand the answer is no at this time you do not have concrete plans to turn back any of the capacity listed on Jackson Direct Exhibit 1?

A No, sir, because MVP Southgate is not in service yet. As we get closer to the in-service date all of the assets in our portfolio will be reevaluated.

MR. NEAL: At this time, Commissioner Brown-Bland, I don't have any other questions about the two confidential exhibits, so I think we could come back.

COMMISSIONER BROWN-BLAND: Just a minute. So does the Public Staff have any cross examination on the confidential exhibits?

MS. HOLT: I have no questions.

COMMISSIONER BROWN-BLAND: Is there any redirect on the confidential exhibits?

MS. GRIGG: I will have some redirect questions for Ms. Jackson but they are not confidential. I'm happy for us to go back on to the hearing for Mr. Neal to continue and I'll take my redirect once he finishes with his cross.

MR. NEAL: And, Commissioner Brown-Bland, I if could ask maybe if it's appropriate to inquire of counsel for PSNC, if Ms. Grigg can confirm whether or not at some point anything that was said in the confidential cross examination is in fact confidential. I expect it's not. I know that the exhibits themselves are confidential. But at the appropriate time I'd love clarification about whether or not the responses to the questions are themselves confidential.

MS. GRIGG: Absolutely. The only thing that I can think of is when we're talking volume, but I'd need to confer with the Company and get back with you, Mr. Neal.

MR. NEAL: Thank you.

COMMISSIONER BROWN-BLAND: All right. And on that, Ms. Grigg, I'll also need for you and Mr. Neal to get back with the court reporter to be sure it's marked appropriately before anything is made public.

MS. GRIGG: Yes, ma'am.

COMMISSIONER BROWN-BLAND: Let me go to Commissioners Hughes and McKissick, do you have questions on the confidential exhibits?

COMMISSIONER McKISSICK: I do not, Commissioner Brown-Bland.

COMMISSIONER HUGHES: I do not on the confidential exhibit per se.

COMMISSIONER BROWN-BLAND: With that said, Madam Court Reporter, have I covered the bases? Anything that I need to consider before we close down the confidential session?

COURT REPORTER: No, ma'am, I think we're fine. Thank you.

COMMISSIONER BROWN-BLAND: Well, that concludes the confidential session. I will meet you back on the Webex platform and we will be back before the public.

(Paused to rejoin Webex platform)

COMMISSIONER BROWN-BLAND: Let's go back on the record. We're coming out of the confidential session, back to the public session.

Mr. Neal, cross examination continues with you, non-confidential.

MR. NEAL: Thank you, Commissioner Brown-Bland.

BY MR. NEAL:

Q Ms. Jackson, can you hear me okay now that we're back on the Webex?

A Yes, sir. Can you hear me?

Q Yes.

A Okay. Thank you.

Q Thank you. So you would agree that -- I'm going to refer I guess to Jackson Direct Exhibit 1 again, which is part of your prefiled testimony.

A Yes, sir.

Q You list as the -- at the top line there under Contracted Capacity Transco FT; is that firm transportation?

A Yes, sir.

Q And that's again roughly 390,000 dekatherms a day of capacity; is that right?

A Yes, sir.

Q And you would agree that Transco has a

FERC-approved tariff with a listing of maximum rates by rate schedule; is that right?
A Yes, sir.
Q And you would agree that some of your Transco capacity contracts are for dekatherms that are from Transco Zone 2 to Transco Zone 5; is that right?
A Yes, sir.
Q And for daily reservation rates on Transco from Zone 2 two to Zone 5, do you recall the published maximum reservation non-incremental rate that it's approximately $0.47 per dekatherm per day; is that right?
A I don't recall the exact dollar amount. I apologize.
Q And again, I believe that your colleague in Creel Exhibit 1, Schedule 5 included the various Transco rates that were effective as of June 1st during the test period. Does that sound familiar?
A I'm pulling it up right as we speak.
Q And I believe, again --
A Okay. Yes, sir, I have it. I have it.
Q And so you would agree that if we wanted to go

and see what those prices are that they've been listed, at least as of June 1st, 2020, they've been listed there on Creel Exhibit 1, Schedule 5?
A For the 12 months, it would be as of March 31st. Yes, sir.
Q And again, that's roughly $0.47 per dekatherm?
A For Zone 2 to Zone 5?
Q Yes, ma'am.
A I'm showing $0.58, if I'm reading this correctly.
Q Well again, I'm looking at the second part of Schedule 5.
A Oh $0.469. Yes, sir. Okay.
Q Where I think it's effective June 1st, 2020.
A Yes, sir. Okay. I see it now.
Q And so that means that PSNC pays again about $0.47 for every Zone 2 to Zone 5 reserved dekatherm every day of the year; isn't that right? For what you -- as long as that price is in effect.
A Right. For the volumes that we have from Zone 2 to Zone 5 that would be correct.
Q And similarly you would agree that some of the Transco capacity is for dekatherms from Transco Zone 4 to Zone 5?

A Yes, sir.
Q And similarly we could look at Creel Exhibit 1, Schedule 5 to see what the price is for those dekatherms and that that's again roughly $0.38; isn't that right?
A Yes, sir.

MR. NEAL: All right. That is all the cross I have until rebuttal. Thank you, Commissioner Brown-Bland.

COMMISSIONER BROWN-BLAND: Is there any cross from the Public Staff?

MS. HOLT: No cross.

COMMISSIONER BROWN-BLAND: Ms. Grigg, is there redirect?

MS. GRIGG: Yes, ma'am. I just have a couple of brief questions on redirect.

REDIRECT EXAMINATION BY MS. GRIGG:

Q Ms. Jackson, when Mr. Neal was asking you questions about HRA Cross Exhibit 1 (sic), you stated that short-term solutions were more difficult to achieve because of constrained pipeline capacity. Do you recall that statement as I paraphrased it?
A Yes, ma'am.

Q Could you --

COMMISSIONER BROWN-BLAND: Ms. Grigg, is that the confidential exhibit?

MS. GRIGG: Yes, ma'am. I'm not going to ask for any confidential information.

COMMISSIONER BROWN-BLAND: Just clearing it for the record. Thank you.

MS. GRIGG: Yes, ma'am. I appreciate you asking, but I'm not going to ask her to divulge anything that's confidential.

BY MS. GRIGG:

Q Could you please elaborate, Ms. Jackson, on how short-term solutions are more difficult to access because of constrained pipeline capacity?

A Yes, ma'am. As demand grows throughout the U.S., and it continues to do so for natural gas usage, and the amount of pipeline capacity that's coming into the same marketplace is longer term.

In the past, we have used - I would say five to seven years ago - we would use three years as an estimated timeline from the date that a pipeline project prefiled at FERC to the time that the project would come into service. And in today's world we are estimating seven plus years for a pipeline project to be prefiled and go into service. And it's been very difficult to estimate just how long it might take. And it's not related to the FERC process, it's related to litigation associated with these projects.

Q So, if you have a very cold period, there may be natural gas located somewhere but you may or may not be able to access it; is that correct?

A Yes, ma'am. Yes, ma'am. If you look at the Marcellus region, for example, that is plentiful with shale deposits for natural gas. The problem that we've had is that there has been -- there are fewer projects that were originally planned that transport that gas from the Marcellus region to let's say our market in the southeast. And so when you hit these timeframes such as the Polar Vortex event that we actually incurred in 2014 and 2018, gas prices go -- the market price of gas ended up being $150.00 a dekatherm. So, that is the key component of reliability is ensuring that you have a firm transportation resource that will enable you to deliver gas to our firm customers.

Q (Inaudible).

COMMISSIONER BROWN-BLAND: Ms. Grigg, you're on mute.

MS. GRIGG: Yes, ma'am.

BY MS. GRIGG:

Q So, when you -- when Mr. Neal was asking you questions about Exhibit 1, you said that that assumes all assets are available; correct?

A Yes, ma'am, at full capacity. Because what we do -- and I can use my Exhibit 1 that's not confidential that's attached to my direct testimony. What it does here is it compares the total design day demand which is one day to the assets that we have currently contracted for to meet on that day. But let's take, for instance, Pine Needle which is an LNG facility that we contract for with Transco. If the design day occurs on November 1st, then that full capacity would be available. However, it -- to my knowledge we haven't hit a design day on November 1st. Historically, our cold weather, we encounter that in the January/February timeframe.

So, as the winter season progresses we are going to pull volumes, maybe not at that maximum amount but we're going to pull volumes out of Pine Needle so that the total number of days and volumes may not be available there when we hit a design day. And that is the value of year-round capacity. It allows us to fill in the holes, if you will, if we've utilized all of our peaking assets on a given day and the design day does occur later in the winter season.

Q Thank you. So, if I understand you correctly, if you have a Polar Vortex in February, your available capacity will likely or may not look like this Cross Exhibit 1; is that correct?

A Yes, ma'am. This assumes that all the assets are there at full capacity.

Q Thank you. Mr. Neal asked you some questions about if you have MVP in 2023 -- capacity in 2023 or 2024, for example, what Exhibit 1 looks like. Do you recall those questions?

A Yes, ma'am.

Q If the Company does at any point in time have excess capacity for whatever reason, what does it do with excess capacity?

A We go into the marketplace and we try to optimize those assets as secondary market transactions, which means that we would retain the contractual rights for those assets, but we may do a short-term capacity release, if you will. So as MVP -- let's assume that MVP comes online and we'll have reserve margin much greater than our less than 1 percent reserve margin that we have today, then we would go into the marketplace and try to place that capacity that we wouldn't need to utilize on a seasonal basis and on a daily basis, because if we're forecasting let's say lower than normal demand we try to place those unutilized assets on a daily basis as well.

Q And that's a benefit to the customers?

A Yes, ma'am. They receive 75 percent of secondary market transaction proceeds back as a credit to the cost of gas.

Q Thank you.

MS. GRIGG: I don't have any further questions for Ms. Jackson.

COMMISSIONER BROWN-BLAND: All right. Are there questions from the Commissioners? Commissioner Hughes?

COMMISSIONER HUGHES: (Inaudible).

COMMISSIONER BROWN-BLAND: And Commissioner

McKissick?

COMMISSIONER McKISSICK: I have no questions.

COMMISSIONER BROWN-BLAND: Ms. Jackson, I have just a couple of questions for you just for clarification for myself.

THE WITNESS: Yes, ma'am.

EXAMINATION BY COMMISSIONER BROWN-BLAND:

Q On page 5 of your direct testimony you mention there that, around line 7, *In furtherance of the Company's sustainability initiative, the Company recently began asking that the bids include the suppliers' net zero goals or strategies.* Have you -- when you say recently, when is recently, and I ask that just to say have you received -- have you begun receiving that requested info in the bids?

A Yes, ma'am. We included that request for information as part of our annual RF -- our RFPs in January for our annual supply, so we did receive some information back. We issued the RFP to roughly 60 suppliers, 16 of those responded with 107 offers, which is roughly a 27 percent participation rate, and of those 16 four of those

sent in RSG or net zero responses to help us understand what their long-term strategies are.
Q And from the Company's point of view, can you shed any light at this point on kind of what that looks like? Nothing specific or confidential but what that looks like. What you would be expecting from this information.
A I think that our industry as a whole is looking at the opportunity to reduce methane, methane emissions, and move towards a net zero carbon goal. However, trying to figure out how to compare each on an apples-to-apples basis is where we've got to get to. So, what standard are we going to use and how are we going to apply that going forward is what we're working on.
We have become members of a coalition. We participate in both ONE Future and Next Generation Natural Gas where we're trying to figure out as LDCs how do we take in this information, process it, and compare it so we know what we're comparing and the cost that we're comparing.
Q Is your industry -- is that an indication that your industry is mostly at a similar level? Is

anyone out to your knowledge ahead of where you are at this point?

A We're in the process of evaluating peer companies as well, so I should have more information to report on that next year. But I think we're very much so similarly situated if not ahead of some other LDCs that are comparable to us.

Q Thank you. Then on page 8 of your direct you mention there the term the "short-term peaking services". Is that just the supply capacity or is the use of the word "services" there indicate more? What is indicated by a short-term --

A The short-term peaking services is a temporary shortfall in assets on lines 10 and 11 that was what -- I'm sorry, regarding the 40,000 dekatherms of the delivered winter service.

Q And so that's just about the gas, the capacity?

A It's actually a delivered service so it combines the supply and the transportation.

Q All right. Thank you.

A Yes, ma'am.

Q Now, has anything that occurred in Texas in any of the information you've heard since that event happened back in February of this year, 2021, has anything that you learned there, have knowledge of caused any changes or adjustments in supply and capacity planning for the Company?

A I think it just -- it reiterated some of the same things that we've been talking about with the Commission and with Public Staff over the last few years, the fact that we are served from one interstate pipeline that we do not have a secondary source. There's no redundancy, if you will full. Also, it has become a clear indication that I appreciate the regulatory structure that we're in, that our Commission has been very supportive of the acquisition of firm transportation to ensure reliable service to our firm customers.

If you look at the Texas market and the fact that they are completely unbundled, what that regulatory structure does not encourage is it doesn't encourage contracting for firm transportation; it doesn't encourage energy providers to spend sufficient funds on O&M costs, or operation and maintenance, to support their facilities because they are competing on a daily basis to sell energy. And, therefore, when you hit these colder than normal or in their case a Polar Vortex event, a one in 100-year weather event, that's when you see where there is a problem with the deregulated marketplace with regards to trying to take the cheapest way out, if you will, or the lowest cost alternative all the time. They don't focus on reliability. They're purely focused on what is the least cost path to serve our customers.

Q And I ask about supply and capacity if you know and I take it -- I ask that because I believe that's your area that you work in, but if you know that it has the Texas experience and the lessons learned, et cetera, resulted in any operational changes?

A We -- because of the Polar Vortex events that we encountered in 2014 and 2018, I think that we were -- we had done an assessment during those time periods. And, once again, because we are in a regulated regulatory structure we are required to serve our customers, our firm customers every day of the year. So, as part of this annual process we work with Public Staff and we work with the Commission to make sure that y'all properly evaluate the assets that we have and what our firm demand is going to be. We're very blessed to live in an area where we have positive growth. You know I deal with my counterparts throughout the U.S. and that's not necessarily true. They have decreased in growth our demand on their system.

So, I think what it tells me is we need to ensure that our customers can be served not just on normal weather conditions but in these Polar Vortex or much colder than normal events. And reliability is a huge concern, not just what the cost of gas is but can you get the gas when you need it.

Q And, finally, my last question just has to do with hedging. Times are changing weather-wise and economically and so your testimony, your direct testimony you indicate there had been no changes made to the hedging program. From where you sit today, are you foreseeing or expecting the need for any change in the hedging program?

A I think where we sit today is a good balance between the cost of a financial hedging program. That coupled with our physical hedging through our interstate storage and our own system storage at the Cary LNG plant, and the deferred gas accounting mechanism that we have. All of those work together to mitigate volatility to our customers. And I think our hedging program has been able to add to that reduction of volatility.

However, if you look in my testimony as I state the financial hedging program would not have helped us in a Texas Polar Vortex event because that was a short-term event around the middle of the month, right around February 14th, and so the financial hedging models look at the upcoming month. And what did help us though was we were able to dispatch our physical storages on the interstate pipelines and we were able to avoid having to buy those much higher daily market prices of gas during that time period.

Q Thank you, Ms. Jackson.

COMMISSIONER BROWN-BLAND: Is there -- are there questions on the Commission's questions, starting with Haw River?

COMMISSIONER HUGHES: Before you do that, Commissioner Brown-Bland, can I ask -- I know I said I wasn't going to ask a question but can I ask a follow-up question based on your questions?

COMMISSIONER BROWN-BLAND: We haven't had enough things go wrong this morning? (Laughing).

COMMISSIONER HUGHES: Well, I just --

COMMISSIONER BROWN-BLAND: I'm just kidding. I'm just kidding.

COMMISSIONER HUGHES: No, I can wait until rebuttal. The question I have could easily be asked on rebuttal, so I'll just wait.

COMMISSIONER BROWN-BLAND: No, no, go ahead. Go ahead. I was just teasing.

EXAMINATION BY COMMISSIONER HUGHES:

Q Well, it's just about the concept of best cost which is mentioned quite a bit both in your testimony and some of the other intervenor's testimonies.

If I understand the concept it's essentially, at least in my mind, including the cost of reliability underneath a sort of definition of cost. So, where the least cost --

A Yes, sir.

Q -- least cost traditionally only looks at the utility financial cost. So, in terms of how you approach that, has the Company done any efforts to actually estimate the cost of a lack of reliability? So something that occurred as in occurred in Texas, is there an effort to say well if you go down for one of these two-hour periods that we've been talking about, what will be the cost to your customers? So, has that been quantified at all? And is there any kind of risk analysis based on that that is going on?

A Yes, sir, Commissioner Hughes. We look at the penalties associated with non-delivery. So, in the event that our customers use gas and we haven't delivered enough supply, then those penalties are $50.00 a dekatherm plus the cost of gas. But then if you look, for instance, at the Texas Polar Vortex event, if you just take 250,000 dekatherms, which is the number of incremental deliverability that the MVP project will provide PSNC with, on one day that 250,000 dekatherms, if we had been on the market trying to buy delivered gas at $400.00 a dekatherm, that would have been $100 million.

Q And I appreciate that answer but my question was a little bit different. Because in Texas they just couldn't do it and there was actual times where they could not supply the gas and the gas was not supplied.

Have you done any calculations about the alternative of not spending the money you just described and having to -- I mean, I know you don't want to do this but just saying we just can't do it and figuring out what that would cost your customers in terms of lost productivity, just human hardship, however you want to present it?

A Well, it would by loss of heat to homes is what we're most concerned with. And so if you take, for instance, the Texas Polar Vortex event, while the $400.00 per dekatherm, if we go the least cap cost route then we would assume we can go out on the market every day, as Mr. Lander would suggest, and find delivered gas on a daily basis. So, we would be in the marketplace paying that-- $400.00 a dekatherm.

The other option that he put forth in his direct testimony was to rely on satellite LNG facilities that are on the back of tractor trailers that can go out to different regions within our service territory and we would truck in LNG to be vaporized on satellite LNG facilities. However, if you just take this upcoming winter season, the 60,000 dekatherms that we show as a short fall for our design day, if you take the numbers and his analysis for trucking, we would be looking at using 45 to 71 truckloads of LNG in a coldest weather scenario.

So, number one, is the LNG going to be available? I would say probably not. The second one is even more problematic. Are the LNG tankers going to be available to deliver the LNG if we can find it? And the third thing is will the road conditions, even if we could find the LNG supply, the trucks that could haul it, could it get to these remote areas such as in our Asheville region or even in the Raleigh area they experience ice and snow.

So that's -- I think when we say the difference between a hypothetical analysis and real world conditions, we have to be able to serve our customers during the worst weather scenarios, not just the best weather or the normal weather scenarios. And we have an

obligation to serve.
Q Okay. I think you answered the question that your obligation to serve is your whole entire planning point. You don't have a scenario where you can even imagine not serving for two hours and having calculated what costs that would be for your customers? Just they don't have gas, they're in the dark, they don't produce things. I mean, it's an economic question and I don't want to belabor it, but I was just curious if the Company had ever done a survey of its customers; have ever looked at what it would cost two hours without gas going to --
A Well, I think that -- Commissioner Hughes, the one thing that's a little more difficult from a gas user standpoint rather than let's say an electric outage, with the electric outage my power can go out for two hours and we don't have -- the electric company doesn't have to come to my house and relight anything in order for me to get gas, I mean, get electric service again, but in a situation of natural gas consumption in a home, we would have to dispatch someone out to that home to relight their pilot light. So, if

you can imagine how many customers we could potentially lose, it will be difficult to say it's only two hours that we might lose them, because it will be dependent upon how long it would take us to relight those pilot lights to get them back on gas.

Q Well, I appreciate -- this isn't the venue for me to keep going with this, but I would maybe in the future be interested in an estimate of the cost of dealing with this curtailment like you just said. You know, how much would it cost the Company to go out and relight? But for now I'm satisfied with your answer. Thank you very much for humoring me.

COMMISSIONER HUGHES: Commissioner Brown-Bland and Ms. Rose, thank you.

THE WITNESS: Uh-huh.

EXAMINATION BY COMMISSIONER BROWN-BLAND:

Q Ms. Jackson, just a little bit of a follow up, I guess. Did the Polar Vortex that we experienced here in North Carolina and the Company's experience, would that have shed any light on what Commissioner Hughes was asking about? Did you experience outages? Or you didn't have outages just people using in violation of their curtailment obligations?

A Well, I want to point out something that we might be getting a little bit mixed up with what type of customers we're serving.

Q Right.

A The only customers that we could curtail or interrupt are our interruptible industrial customers. The commercial and residential customers are served on firm rate schedules; therefore, we don't have the ability to interrupt them for economic, you know, so that they can have a lower rate or lower cost in exchange for interruptible service.

And, since our rate case in 2016, we have had much fewer curtailments of industrial customers. Because what that change in our tariff that provided for the Company to be able to issue operational orders, what it does is it allows the industrial interruptible customer to work with their pooler and as long as the pooler can deliver sufficient supply to meet the demands of that interruptible customer then they do not incur a penalty. And they can take the customers in their pool, if some customers are long and some customers are short, they can net those two together. Now, if that pooler and an industrial interruptible customer elect to curtail or to limit service, then they can do so. But it's not -- the only time the Company now curtails interruptible customers on the industrial side is when we have a localized problem on the system like let's say a low pressure problem, if you will.

Q And so during that Polar Vortex incident the Company's firm customers, residential, did not experience an outage, correct?

A No, ma'am, we did not.

Q All right.

COMMISSIONER BROWN-BLAND: Are there questions on Commission's questions starting with Haw River Assembly?

MR. NEAL: Thank you, Commissioner Brown-Bland. Just briefly.

EXAMINATION BY MR. NEAL:

Q Ms. Jackson, in response to a question from Commissioner Brown-Bland, I believe you said that North Carolina is served by only one pipeline; is

that correct?
A PSNC only interconnects with one pipeline; yes, sir.
Q And I heard you to say that North Carolina is only served by one interstate pipeline and just to be clear the Transco has four, three or four different main lines in parallel; isn't that right?
A But it's still one pipeline.
Q But it's -- but actually what I'm trying to get across is that there are -- it is one maybe pipeline system but there are multiple pipelines that serve Transco's system?
A I'm sorry, I'm not sure I understand the question.
Q So that Transco itself has it -- the pipeline that moves through North Carolina has at least three and in some places four main lines in parallel; isn't that right?
A Oh, you're talking about the physical infrastructure?
Q Yes.
A Yes, sir. But I think the concern we would have is similar to what Colonial Pipeline encountered

earlier this year. What if all of their pipelines were to be shut down?

Q Again, just the question was do you agree that they have multiple pipelines as part of their system; yes?

A They have multiple lines as part of their overall interstate pipeline system.

Q And those -- that pipeline system, the Transco system, is served from multiple different supply sources; isn't that right?

A That is correct.

Q Including some from the Marcellus shale; isn't that right?

A They are beginning to have supply from that and that's part of that bi-directional feed. So, yes, sir, they have added some facilities that interconnect with that area.

Q Thank you.

MR. NEAL: That's all I have, Commissioner Brown-Bland.

COMMISSIONER BROWN-BLAND: Public Staff, any questions on Commission's questions?

MS. HOLT: I have no questions.

COMMISSIONER BROWN-BLAND: And PSNC?

MS. GRIGG: No questions.

COMMISSIONER BROWN-BLAND: Do you have any motions for me?

MS. GRIGG: Yes, ma'am. I would like to move Jackson direct testimony and exhibits into the record.

COMMISSIONER BROWN-BLAND: Without objection, the -- I believe the testimony is already in and the exhibits will be received and marked as they were identified when prefiled.

MS. GRIGG: Thank you.

(WHEREUPON, Jackson Direct Exhibits 1 - 3 are received into evidence. Confidential Attachment to Jackson Direct Exhibit 2 is filed under seal.)

COMMISSIONER BROWN-BLAND: And the confidential shall remain confidential.

MR. NEAL: And, Commissioner Brown-Bland, we would move into admittance the two cross examination exhibits that have been marked confidential, HRA Jackson Confidential Cross Exhibits 1 and 2.

COMMISSIONER BROWN-BLAND: Without objection, those two exhibits will be received into evidence and will remain confidential.

(WHEREUPON, HRA Jackson Confidential Cross Exhibits 1 and 2 are received into evidence.)

COMMISSIONER BROWN-BLAND: Ms. Jackson, you are excused.

THE WITNESS: Thank you.

COMMISSIONER BROWN-BLAND: Well, no you're not because I believe your counsel will bring you back on rebuttal so stay on standby.

THE WITNESS: Thank you.

(The witness is excused)

COMMISSIONER BROWN-BLAND: Does the Company have anything further?

MS. GRIGG: Not at this time. Thank you. I could if you want me to go ahead and at this point I was going to wait until the end but could move Ms. Glory Creel's testimony and exhibits into the record at this time.

COMMISSIONER BROWN-BLAND: Now would be a good time. Thank you.

MS. GRIGG: Okay. Thank you. Commissioner Brown-Bland, we'd like to move into the record the direct testimony of Glory Creel, the six pages of direct testimony and her two exhibits.

COMMISSIONER BROWN-BLAND: Without objection, that motion will be allowed and the testimony and exhibits of Glory J. Creel will be received into evidence with the exhibits identified as they were marked when prefiled.

MS. GRIGG: Thank you, ma'am.

(WHEREUPON, Creel Exhibits 1 and 2 are marked for identification as prefiled and received into evidence.)

(WHEREUPON, the prefiled direct testimony of GLORY J. CREEL is copied into the record as if given orally from the stand.)

BEFORE THE

NORTH CAROLINA UTILITIES COMMISSION

PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INCORPORATED

DOCKET NO. G-5, SUB 635

DIRECT TESTIMONY

OF

GLORY J. CREEL

June 1, 2021

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, BY WHOM YOU ARE EMPLOYED AND IN WHAT CAPACITY.

A. My name is Glory J. Creel. My business address is 800 Gaston Road, Gastonia, North Carolina. I am employed by Dominion Energy Services, Inc. as Rates and Regulatory Affairs Analyst III for Public Service Company of North Carolina, Incorporated d/b/a Dominion Energy North Carolina ("the Company").

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND, WORK EXPERIENCE AND OTHER QUALIFICATIONS.

A. I graduated from Winthrop University in 2003 with a Bachelor of Science degree in Accounting and in 2004 with a Master of Business Administration with emphasis in Accounting. Following graduation, I worked as an accountant with SCANA Corporation in the Cost of Gas department and as an analyst in the Rates and Regulatory group. Over the years, I have held various positions of increasing responsibility including corporate accounting and budgeting and forcasting. In May 2019, I assumed my current position with the Company.

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

A. The purpose of my testimony is to provide the data necessary to true-up the Company's actual gas costs with the gas costs billed to our customers during the 12-month review period ended March 31, 2021. Commission Rule R1-17(k)(6) sets forth the filing requirements for the annual review of gas costs. Subsection (c) requires the Company to file certain data showing actual gas costs, volumes of gas purchased, and such other information as may be directed by the Commission.

Q. HAVE YOU CAUSED TO BE PREPARED AND FILED THE DATA REQUIRED BY COMMISSION RULE R1-17(k)(6)(c)?

A. Yes. The required information provided in Schedules 1 through 10 of Creel Direct Exhibit 1 attached to my testimony was prepared under my supervision. The following schedules were prepared in the prescribed format:

Schedule 1:	Summary of Cost of Gas Expense
Schedule 2:	Summary of Demand and Storage Charges
Schedule 3:	Summary of Commodity Gas Cost
Schedule 4:	Summary of Other Cost of Gas Charges (Credits)
Schedule 5:	Summary of Demand and Storage Rate Changes
Schedule 6:	Summary of Demand and Storage Capacity Level Changes
Schedule 7:	Summary of Demand and Storage Costs Incurred Versus Collected
Schedule 8:	Summary of Deferred Account Activity - Sales Customers Only Account
Schedule 9:	Summary of Deferred Account Activity - All Customers Account
Schedule 10:	Summary of Gas Supply

In addition, Creel Direct Exhibit 2 sets forth the review period Hedging Deferred Account Activity.

Q. DID THE COMPANY FOLLOW THE GAS COST ACCOUNTING PROCEDURES PRESCRIBED BY RULE R1-17(k) FOR THE TWELVE MONTHS ENDED MARCH 31, 2021?

A. Yes. The Company followed the gas cost accounting procedures in accordance with Sections (4) and (5) of Rule R1-17(k).

Q. HAS THE COMPANY FILED MONTHLY AN ACCOUNTING OF GAS COSTS AND DEFERRED ACCOUNT ACTIVITY WITH THE COMMISSION AND THE PUBLIC STAFF?

A. Yes, the required filings were made.

Q. HAVE THERE BEEN ANY CHANGES DURING THE REVIEW PERIOD THAT WOULD NECESSITATE ADJUSTMENTS TO THE INTEREST RATE CALCULATION?

A. The Company has reviewed its interest rate calculations and does not recommend an adjustment to the interest rate at this time.

Q. WHAT ACTIVITY OCCURRED IN THE SALES CUSTOMERS ONLY DEFERRED ACCOUNT DURING THE TWELVE MONTHS ENDED MARCH 31, 2021?

A. The activity in the Sales Customers Only deferred account is set forth below:

Over-Collection as of March 31, 2020	($4,785,803)
Commodity Cost Under-Collections	$6,530,737
Hedging Deferred Account Balance as of March 31, 2020	$2,959,771
Uncollectible Gas Cost	$130,146
Miscellaneous Adjustments	($3,332)
Accrued Interest	($329,793)
Under-Collection as of March 31, 2021	$4,501,726

Q. WHAT ACTIVITY OCCURRED IN THE ALL CUSTOMERS DEFERRED ACCOUNT DURING THE TWELVE MONTHS ENDED MARCH 31, 2021?

A. The activity in the All Customers deferred account is set forth below:

Under-Collection as of March 31, 2020	$8,101,647
Demand Cost Under-Collections	$34,815,218
Commodity Cost Over-Collections	($64,687)
All Customers Increment	($3,478,910)
Miscellaneous Adjustments	($4,911)
Secondary Market Transaction Credits	($19,253,677)
Supplier Refunds	($13,097,646)
Accrued Interest	$1,048,570
Under-Collection as of March 31, 2021	$8,065,604

Q. WHY WERE SUPPLIER REFUNDS HIGHER DURING THIS REVIEW PERIOD?

A. Pursuant to the settlement approved by the Federal Energy Regulatory Commission on March 24, 2020, in Docket No. RP18-1126-003, the Company received from Transcontinental Gas Pipe Line Company a refund totaling $13,112,646. Of this amount $15,000 was recorded in the NCUC Restricted Account #254.0002 as required by the Commission’s order dated February 23, 1993, in Docket No. G-100, Sub 57.

Q. DID THE COMPANY ACCOUNT FOR CAPACITY RELEASE AND OTHER SECONDARY MARKET TRANSACTIONS DURING THE REVIEW PERIOD

IN ACCORDANCE WITH THE COMMISSION'S ORDER IN DOCKET NO. G-100, SUB 67?

A. Yes, seventy-five percent of the net compensation received from secondary market transactions was recorded in the All Customers deferred account.

Q. PLEASE DISCUSS CREEL DIRECT EXHIBIT 2.

A. Creel Direct Exhibit 2 reflects the cash transactions associated with the Company's hedging program during the 12-month review period ended March 31, 2021. As of the end of the review period, there was a credit (over-collection) balance of ($436,502) due to the sales customers in the Hedging deferred account. When netted with the $4,501,726 debit (under-collection) balance in the Sales Customers Only deferred account, the total is $4,065,224 due from sales customers.

Q. DOES THE COMPANY CURRENTLY HAVE ANY TEMPORARY RATE INCREMENTS OR DECREMENTS RELATED TO ITS SALES CUSTOMERS ONLY AND ALL CUSTOMERS DEFERRED ACCOUNTS?

A. No. Temporary increments applicable to the All Customers deferred account were removed effective November 1, 2020.

Q. DOES THE COMPANY PROPOSE NEW TEMPORARY RATE INCREMENTS OR DECREMENTS?

A. The Company is not proposing new temporary rate increments or decrements at this time.

Q. IN DOCKET NO. G-5, SUB 442, THE COMMISSION STATED THAT IN FUTURE GAS COST PRUDENCE REVIEWS THE COMPANY SHOULD DISCUSS ANY SIGNIFICANT ACCOUNTING CHANGES THAT

OCCURRED DURING THE REVIEW PERIOD. WERE THERE ANY SUCH CHANGES DURING THIS REVIEW PERIOD?

A. The Company did not make any significant accounting changes during the review period.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

COMMISSIONER BROWN-BLAND: The Public Staff?

MS. HOLT: Yes. At this time I'd like to move the testimony and appendices of the Public Staff witnesses. I move that the testimony of Neha R. Patel consisting of seven pages be admitted into evidence and that her appendix be identified as marked and admitted into evidence.

COMMISSIONER BROWN-BLAND: That motion will be allowed.

(WHEREUPON, Patel Appendix A is marked for identification as prefiled and received into evidence.)

(WHEREUPON, the prefiled direct testimony of NEHA R. PATEL is copied into the record as if given orally from the stand.)

PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INC.

DOCKET NO. G-5, SUB 635

TESTIMONY OF NEHA R. PATEL

ON BEHALF OF

THE PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

July 26, 2021

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND PRESENT POSITION.

A. My name is Neha R. Patel and my business address is 430 North Salisbury Street, Raleigh, North Carolina. I am the Manager of the Natural Gas Section of the Energy Division of the Public Staff. My qualifications and experience are provided in Appendix A.

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

A. The purpose of my testimony is (1) to provide recommendations based on my conclusions regarding whether the gas costs incurred by Public Service Company of North Carolina, Inc. (PSNC or Company), during the 12-month review period ended March 31, 2021, were prudently incurred, (2) provide my conclusions regarding PSNC's projected peak day demand, and (3) discuss my recommendations regarding temporary rate increments and/or decrements.

Q. PLEASE EXPLAIN HOW YOU CONDUCTED YOUR REVIEW.

A. I reviewed the testimony and exhibits of the Company's witnesses, the Company's monthly deferred account reports, monthly financial and operating reports, gas supply, pipeline transportation and storage contracts, monthly reports filed with the Commission in Docket No. G-100, Sub 24A, and the Company's responses to Public Staff data requests.

Even though the scope of Commission Rule R1-17(k) is limited to a historical review period, I reviewed other information received in response to data requests in order to anticipate the Company’s requirements for future needs, including design day estimates, forecasted gas supply needs, projected capacity additions and supply changes, and customer load profile changes.

Q. WHAT IS THE RESULT OF YOUR EVALUATION OF PSNC’S GAS COSTS?

A. Based on my investigation and review of the data in this docket, I believe that PSNC’s gas costs were prudently incurred for the 12-month review period ending March 31, 2021.

<u>DESIGN-DAY REQUIREMENTS</u>

Q. MS. PATEL, DO YOU HAVE ANY COMMENTS REGARDING COMPANY WITNESS JACKSON’S EXHIBIT 1 AND DISCUSSION REGARDING DESIGN-DAY DEMAND?

A. Yes.

I reviewed the Company's testimony and other information submitted by the Company in response to data requests, and also had discussions with Company personnel regarding how well the Company's projected firm demand requirements aligned with the available capacity over the next five years. PSNC's design-day demand model shows that PSNC has a need for additional assets to meet projected design-day demand requirements beginning in the 2021-2022 winter period, which is discussed further in testimony.

The Energy Division also performs independent calculations to determine peak-day (design-day) demand levels as compared to the assets the Company has available or is planning to have available in the future to meet that demand. The Public Staff uses the review period data of customer usage and heating degree days (HDDs), which are calculated by taking the average of the minimum and maximum daily temperatures and subtracting that quotient from a 65 degrees base (for example, a low of 10 degrees and a high of 30 would yield 45 HDDs). Base load demand, which is usage that does not fluctuate with weather, plus a usage per HDD factor is developed, and the projected peak-day demand is calculated. The assumption in developing a peak design-day demand is 55 HDDs, which is the accepted peak coldest day that would be anticipated to be experienced in PSNC's service territory. The results of our analysis are slightly lower than the levels presented by PSNC in Jackson Exhibit 1.

Q. DO YOU HAVE ANY COMMENTS REGARDING THE COMPANY'S FUTURE AVAILABLE CAPACITY RESOURCES?

A. Yes. The Public Staff has reviewed the Company's filed testimony and exhibits, as well as data request responses provided by PSNC in regards to the Company's capacity resources. Company witness Jackson's testimony (Jackson Direct Exhibit 1) shows that PSNC has a need for additional capacity to meet projected design-day demand requirements beginning in the 2021-2022 winter period. In the 2019-2020 review period, the Company projected the Southeastern Trail (SET) project capacity to be available in the fourth quarter of 2020 and to be fully in service by the first quarter of 2021. Prior to full project completion, Transco offered a partial service beginning November 1, 2020 on SET in the amount of 55,400 dts per day. Upon project completion, effective January 1, 2021, Transco commenced firm transportation service for the full contract amount of 60,000 dts/day.

To meet the expected capacity shortfall for the 2020-2021 winter season the Company contracted for a total of 40,000 dts per day of firm peaking services from three different suppliers. These contracts each allowed the Company to call on delivered gas supply at Zone 5 of up to 20,000 dts per day at a time for a specified number of days during the winter.

Consistent with the past two winter seasons, PSNC has needed to acquire short-term peaking assets to meet its capacity shortfalls. For the upcoming 2021-2022 winter season, Company witness Jackson stated that the Company has entered into a firm delivery short-term peaking supply contract for 24,000 dts per day and has plans to issue an RFP for 36,000 dts/day of similar supply.

PSNC witness Jackson stated that FERC has issued its order granting the certificate of public convenience and necessity for the Mountain Valley Pipeline (MVP) Southgate project and that the project is expected to be placed in service by the spring of 2023. Witness Jackson has noted that until the MVP mainline and MVP Southgate projects are both placed into service, the Company would closely monitor the capacity shortfall situation and continue to address the shortfall in available assets using the Company's best-cost strategy by taking steps to address any developments at the appropriate time. The Company has not included the MVP capacity in its design-day capacity planning.

The Public Staff agrees with PSNC witness Jackson's testimony that if the MVP mainline and the MVP Southgate projects are not placed into service as of the anticipated time period, PSNC will need to make arrangements to address the shortfall in available assets using their best-cost strategy to serve customers' forecasted firm peak-day demand.

Q. DO YOU HAVE ANY RECOMMENDATIONS REGARDING PSNC'S DEFERRED ACCOUNT BALANCES AND ANY PROPOSED TEMPORARY INCREMENTS OR DECREMENTS?

A. Yes, I do. The All Customers' Deferred Account reflects a debit balance of $8,065,604, owed by customers to the Company as of March 31, 2021.

The Public Staff notes that deferred account balances naturally vary between winter and summer months, since fixed gas costs are typically over-collected during the winter period when throughput is higher due to heating load, and under-collected during the summer when throughput is lower.

Pursuant to Article IV of the Stipulation and Agreement filed on December 31, 2019, in the Federal Energy Regulatory Commission Docket RP18-1126, the Company received a refund in the amount of $13,112,646 on July 1, 2020 (July Transco Refund). On October 16, 2020, the Company filed with the Commisison to remove temporary increments applicable to the All Customers' Deferred Account in Docket No. G-5, Sub 626, effective November 1, 2020. Due to the July Transco Refund, the Company projected the balance in the All Customers' Deferred Account, without implementation of the removal of the increments, would be a significant over-collection through the end of March 2021.

The Sales Customers' Only Deferred Account balance reflects a debit balance of $4,501,726, owed by the customers to the Company as of March 31, 2021. The Public Staff notes that this balance increased to a balance of $5,182,079 at the end of May 2021. Therefore, I agree with the Company's proposal not to implement any temporary rate increments and/or decrements in this proceeding.

I further recommend that PSNC continue to monitor the balances in both the All Customers' and Sales Customers' Only Deferred Accounts, and, if needed, file an application for authority to change the benchmark commodity cost of gas or implement new temporary increments or decrements through the Purchased Gas Adjustment mechanism, pursuant to N. C. Gen. Stat. § 62-133.4 in order to keep the deferred account balances at reasonable levels.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

MS. HOLT: I move that the testimony of Shawn L. Dorgan consisting of 15 pages be copied into the record and admitted into evidence and that his appendix be identified as premarked and admitted into evidence.

COMMISSIONER BROWN-BLAND: Without objection, that motion is also allowed.

(WHEREUPON, Dorgan Appendix A is marked for identification as prefiled and received into evidence.)

(WHEREUPON, the prefiled direct testimony of SHAWN L. DORGAN is copied into the record as if given orally from the stand.)

PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INC.

DOCKET NO. G-5, SUB 635

TESTIMONY OF SHAWN L. DORGAN

ON BEHALF OF

THE PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

July 26, 2021

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND PRESENT POSITION.

A. My name is Shawn L. Dorgan, and my business address is 430 North Salisbury Street, Raleigh, North Carolina. I am an Accountant with the Public Staff's Accounting Division. My qualifications and experience are provided in Appendix A.

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

A. The purpose of my testimony is: (1) to provide recommendations regarding whether the gas costs incurred by Public Service Company of North Carolina, Inc. (PSNC or Company) during the 12-month review period ended March 31, 2021 were properly accounted for; (2) to present the results of my review of gas costs as filed by the Company in accordance with N. C. Gen. Stat. § 62-133.4(c), and Commission Rule R1-17(k)(6); and (3), discuss the Company's deferred account reporting during the review period.

Q. PLEASE EXPLAIN HOW THE PUBLIC STAFF CONDUCTED ITS REVIEW.

A. I reviewed the testimony and exhibits of the Company's witnesses, the Company's monthly deferred account reports, monthly financial and operating reports, gas supply, pipeline transportation and storage contracts, and the Company's responses to Public Staff data requests. Each month, the Public Staff reviews all deferred account reports filed by the Company for accuracy and reasonableness, and performs various analytical procedures on the underlying calculations.

Q. HAS THE COMPANY PROPERLY ACCOUNTED FOR ITS GAS COSTS DURING THE REVIEW PERIOD?

A. Yes. In my opinion PSNC properly accounted for its gas costs during the review period April 1, 2020 through March 31, 2021.

ACCOUNTING FOR AND ANALYSIS OF GAS COSTS

Q. HOW DOES THE PUBLIC STAFF ACCOUNTING DIVISION CONDUCT ITS REVIEW OF THE COMPANY'S FILED GAS COSTS?

A. Each month the Accounting Division reviews all Deferred Account reports filed by the Company for accuracy and reasonableness, and performs various analytical procedures, including the following:

(1) **Commodity Gas Cost True-Up** - The actual commodity gas costs incurred are verified, the calculations and data supporting the commodity gas costs collected from customers are checked, and the overall calculation is reviewed for mathematical accuracy.

(2) **Fixed Gas Cost True-Up** - The actual fixed gas costs incurred are compared with pipeline tariffs and gas contracts, the rates and volumes underpinning the Company's reported collections from customers are verified, and the overall calculation is reviewed for mathematical accuracy.

(3) **Negotiated Losses** - Negotiated prices for each customer are reviewed to ensure that the Company does not sell gas to any customer below cost, or the price of the customer's alternative fuel.

(4) **Temporary Increments and/or Decrements** – All collections and/or refunds from customers that impact deferred account balances, supporting data and calculations are verified.

(5) **Interest Accrual** – All calculations of accrued interest are verified in conformity with N. C. Gen. Stat. § 62-130 (e), and the Commission's Orders in Docket No. G-5, Subs 565, 595, 607, and 608.

(6) **Secondary Market Transactions** - The secondary market transactions conducted by the utility are reviewed and verified to the

financial books and records, asset manager agreements, and the monthly Deferred Gas Cost Accounts.

(7) **<u>Uncollectibles</u>** – In Docket No. G-5, Sub 473, the Commission approved a mechanism to recover the gas cost portion of the difference between the Company's cost of gas incurred and the amount collected from customers, effective for service rendered on and after December 1, 2005. The Company records a journal entry each month in the Sales Customers' Only Deferred Account for the gas cost portion of its uncollectibles write-offs. The Public Staff reviews the calculations supporting those journal entries to ensure that the proper amounts are recorded.

(8) **<u>Supplier Refunds</u>** – In Docket No. G-100, Sub 57, the Commission held that, unless it orders refunds to be handled differently, supplier refunds shall be flowed through to ratepayers in the All Customers' Deferred Account, or applied to the NCUC Legal Fund Reserve Account. As such, the Public Staff reviews supplier refund documentation to verify that all amounts received by the Company are flowed through to ratepayers.

Q. HOW DO THE COMPANY'S FILED GAS COSTS FOR THE CURRENT REVIEW PERIOD COMPARE WITH THOSE FOR THE PRIOR REVIEW PERIOD?

A. Per Creel Exhibit 1, Schedule 1, the Company has filed total gas costs of $220,684,628 for the current review period, as compared with $171,361,359 for the prior period. The components of filed gas costs for the two periods are shown in the table below[1]:

	12 Months Ended		Increase	
	March 31, 2021	March 31, 2020	(Decrease)	% Change
Demand & Storage	$105,081,205	$108,719,294	($3,638,089)	(3.35%)
Commodity	128,838,351	120,268,623	8,569,728	7.13%
Other Costs	(13,234,928)	(57,626,558)	44,391,630	(77.03%)
Totals	$220,684,629	$171,361,359	$49,323,270	28.78%

/1 See Footnote 1

Q. PLEASE EXPLAIN ANY SIGNIFICANT INCREASES OR DECREASES IN DEMAND AND STORAGE CHARGES.

A. The Demand and Storage Charges for the current review period and the prior 12-month review period are as follows:

[1] Footed totals in the following schedules may not sum due to rounding.

	12 Months Ended March 31, 2021	12 Months Ended March 31, 2020	Increase (Decrease)	% Change
Transco:				
FT Reservation	$52,234,211	$57,777,290	($5,543,079)	(9.59%)
FT Momentum	2,073,564	2,324,267	(250,703)	(10.79%)
Southern Expansion	2,278,195	2,724,443	(446,248)	(16.38%)
Southeast Expansion	11,075,585	7,759,043	3,316,542	42.74%
GSS	1,800,118	2,097,241	(297,123)	(14.17%)
WSS	680,128	713,155	(33,027)	(4.63%)
LGA	351,483	196,890	154,593	78.52%
ESS	1,137,570	2,515,995	(1,378,425)	(54.79%)
Total Transco Charges	$71,630,854	$76,108,324	($4,477,470)	(5.88%)
Other Charges:				
Pine Needle LNG	$2,986,316	$3,453,549	($467,233)	(13.53%)
Cardinal	5,577,982	5,598,349	(20,367)	(0.36%)
Dominion Transmission Service	5,089,110	5,088,037	1,073	0.02%
Texas Gas Transmission	546,880	548,378	(1,499)	(0.27%)
Texas Eastern	563,328	563,328	-	0.00%
Columbia FSS/SST	4,352,913	3,851,796	501,117	13.01%
Eminence Demand and Capacity	1,156,471	-	1,156,471	
East Tennessee (Patriot Expansion)	5,735,300	5,674,450	60,850	1.07%
Saltville Gas Storage	3,440,304	3,320,683	119,621	3.60%
EDF Trading FT Reservation	1,873,250	1,793,750	79,500	4.43%
Cove Point LNG	1,165,508	1,024,620	140,888	13.75%
Piedmont Redelivery Agreement	9,120	9,120	-	0.00%
Firm Backhaul Capacity on Transco	910,800	1,641,600	(730,800)	(44.52%)
City of Monroe	43,072	43,311	(239)	(0.55%)
Total Other Charges	$33,450,353	$32,610,971	$839,382	2.57%
Total Demand & Storage Charges	$105,081,205	$108,719,294	($3,638,089)	(3.35%)

/1 See Footnote 1

The primary reason for the overall decrease in Transcontinental Gas Pipe Line Company, LLC (**Transco**) **Firm Transportation (FT) Reservation, Southern Expansion, Southeast Expansion, Transco General Storage Service (GSS), Washington Storage Service (WSS), LGA, and Eminence Storage Service (ESS) charges** of 5.88% is the result of reductions in Transco rates, as ordered in the following Federal Energy Regulatory Commission (FERC) Docket Nos: RP20-575-000 (rates effective April 1, 2020) and RP19-01126-004 (rates effective June 1, 2020). The Public Staff notes that the new rates ultimately stem from the outcome in

FERC Docket No. RP18-1126-003 (a sub-docket of the 2018 Transco Rate Case), in which Transco filed an uncontested stipulation and settlement agreement in resolution of all outstanding rate case issues, and which the Commission approved in its order dated March 24, 2020. The 2018 Transco rate case was addressed at length in the Company's prior Annual Review of Gas Costs (Docket No. G-5, Sub 622).

The decrease in Pine Needle LNG Company, LLC (**Pine Needle**) charges is due primarily to rate decreases ordered in the following FERC Dockets: RP20-720-000 (rates effective May 1, 2020), and RP20-780-001 (settlement rates effective June 1, 2020). The two aforementioned FERC proceedings address, respectively: (1) changes to Pine Needle's annual fuel retention percentage and electric power rates; and (2), changes per the settlement agreement approved by the Commission in FERC Docket No. RP17-204-001.

The increase in Columbia Gas Transmission LLC (**Columbia FSS/SST**) demand and storage charges is attributable to rate increases filed in the following FERC Dockets: RP21-351-000 and RP20-1060-000. In FERC Docket No. RP21-351-000 Columbia filed to implement an annual adjustment to its Capital Cost Recovery Mechanism (CCRM) pursuant to the Stipulation and Agreement reached in FERC Docket No. RP16-314-000 (Modernization II Settlement), and in FERC Docket No. RP20-1060-000 Columbia filed an application for a general rate increase under Section 4 of the Natural Gas Act.

The increase in **Dominion Cove Point LNG** charges is due primarily to an increase in reservation charges, as ordered in FERC Docket RP20-004677-000 (rates effective August 1, 2020).

The decrease in **Firm Backhaul Capacity on Transco** is due to a reduction in the transportation rate, effective November 1, 2020.

Q. PLEASE EXPLAIN THE CHANGE IN COMMODITY GAS COSTS.

A. Commodity gas costs for the current review period and the prior 12-month period are as follows:

	12 Months Ended		Increase	
	March 31, 2021	March 31, 2020	(Decrease)	% Change
Gas Supply Purchases	$119,272,275	$119,675,415	($403,140)	(0.34%)
Transportation Charges from Pipelines	1,751,831	1,322,742	429,089	32.44%
Storage Injections	(15,946,430)	(23,318,153)	7,371,723	(31.61%)
Storage Withdrawals	23,760,675	22,588,618	1,172,057	5.19%
Total Commodity Gas Costs Expensed	$128,838,351	$120,268,623	$8,569,728	7.13%
Gas Supply for Deliveries (dt)	52,587,485	49,577,913	3,009,572	6.07%
Commodity Cost per dt	$2.4500	$2.4259	$0.0241	0.99%

/1 See Footnote 1

Gas Supply Purchases decreased by $403,140 during the current review period, as compared with the prior 12-month review period, a slight decline in spite of a 6.07% increase in delivery volumes purchased. As indicated in the chart above, for the current review period the average commodity cost of gas increased fractionally, up

$0.02 or less than 1%, when compared with the prior review period. The small increase is generally consistent with movements in market indices and spot market prices experienced between the two periods.

The decrease in **Storage Injections** was due to the lower average cost of gas supply injected into storage. The average cost of gas injected into storage during the current review period was $1.9338 per dt as compared with $2.3278 per dt for the prior period.

The increase in **Storage Withdrawal** charges was primarily due to a lower average cost of supply withdrawn from storage. PSNC's average cost of gas withdrawn was $2.2365 per dt in this review period as compared with $2.6479 per dt in the prior review period.

Q. PLEASE EXPLAIN THE CHANGE IN OTHER GAS COSTS.

A. Other gas costs for the current review period and the prior 12-month period are as follows:

	12 Months Ended		Increase
	March 31, 2021	March 31, 2020	(Decrease)
Deferred Account Activity	($37,794,115)	($27,453,960)	($10,340,155)
Estimate to Actual Gas Cost True-Up	6,862,663	(9,404,717)	16,267,380
CUT Deferral	(11,478,607)	(28,371,847)	16,893,240
CUT Increment/Decrement	27,568,767	9,371,933	18,196,834
High Efficiency Discount Rate	(408,430)	(386,572)	(21,858)
IMT Deferral	2,033,724	(1,386,961)	3,420,685
Gas Loss - Facilities Damages	(18,930)	5,567	(24,497)
Total Other Gas Costs	($13,234,928)	($57,626,558)	$44,391,630

/1 See Footnote 1

The **CUT Deferral** entries relate to the Order issued in Docket No. G-5, Sub 495 (Sub 495 Order), in which the Commission approved the use of a Customer Usage Tracker (CUT) by the Company beginning November 1, 2008. The Company charges or credits other cost of gas in its accounting journal entry that offsets the CUT deferral.

The **CUT Increment/Decrement** entries relate to the Sub 495 Order in which the Commission authorized the Company to collect or refund outstanding balances in the CUT Deferred Account by imposing either an increment or a decrement to customer rates, effective April and October of each year. The increase in the current review period is due to higher under-collections in the current review period as compared to the prior review period.

The **Deferred Account Activity** amounts reflect offsetting accounting journal entries for most of the information recorded in the Company's Deferred Gas Cost Accounts during the review periods.

The **Estimate to Actual Gas Cost True-Up** amount results from the Company's monthly account closing process. Each month, the Company estimates its current month's gas costs for financial reporting purposes and trues-up the prior month's estimate to reflect the actual cost incurred.

The **High Efficiency Discount Rate** and the **Conservation Program Accrual** entries represent nine months of accruals and expenses associated with $750,000 of annual conservation-related expenses, as allowed in the Sub 495 Order.

SECONDARY MARKET ACTIVITIES

Q. PLEASE SUMMARIZE THE COMPANY'S SECONDARY MARKET ACTIVITIES DURING THE REVIEW PERIOD.

A. During the review period, the Company recorded $25,671,569 of margin on secondary market transactions. These transactions include capacity releases, asset management arrangements, and other similar dealings. Of this amount, $19,253,677 ($25,671,569 x 75%) was credited to the All Customers' Deferred Account for the benefit of ratepayers.

Below is a chart that compares the margins recorded by PSNC on the various types of secondary market transactions in which the Company engaged during both the current review period and the prior review period.

	Actual 12 Month Period Ended		Increase	
	March 31, 2021	March 31, 2020	(Decrease)	Change
Capacity Release	$2,290,999	$2,108,109	$182,890	8.68%
Asset Management	22,606,318	23,962,994	(1,356,676)	(5.66%)
Bundled Sales	33,402	337,886	(304,484)	(90.11%)
Straddles	740,850	673,700	67,150	9.97%
Spot Sales	-	59,433	(59,433)	(100.00%)
Total Secondary Market Margins	$25,671,569	$27,142,122	($1,470,553)	(5.42%)

/1 See Footnote 1

Capacity Release is the short-term posting of unutilized firm capacity on the electronic bulletin board that is released to third parties at a biddable price. The overall net compensation from capacity release transactions increased by 8.68%, due primarily to a slight increase on the margin earned for volumes released during the current review period, as compared with the prior period.

Asset Management Agreements (AMAs) are contractual relationships where a party agrees to manage gas supply and delivery arrangements, including transportation and storage capacity, for another party. Typically a shipper holding firm transportation and/or storage capacity on a pipeline or multiple pipelines temporarily releases all or a portion of that capacity along with associated gas production and gas purchase agreements to an asset manager. The asset manager uses that capacity to serve the gas supply requirements of the releasing shipper, and, when the capacity is not needed for that purpose, uses the capacity to make releases or bundled sales to third parties. The 5.68% decrease in net compensation from AMAs results from a decrease, for the second consecutive review period, in the value of the interstate pipeline and storage capacity that PSNC has subject to AMAs.

Bundled Sales are sales of delivered gas supply to a third-party consisting of gas supply and pipeline capacity at a specified receipt point. For the second consecutive review period, PSNC's bundled sales decreased, with net compensation for the 12-month period ended March 31, 2021 dropping by 90.11%. As was the case in the prior review period, the decline was attributable to lower sales volumes.

Straddle transactions are the physical exchange of gas allowing a third-party to either put gas to the LDC or call on gas from an LDC for a fee. For the review period, total net compensation from straddles increased, principally due to higher fee revenue from options written.

Spot Sales are the sales of gas supply on the daily market when the daily spot price is higher than the first of the month index price. The Company did not make any spot sales during the current review period.

DEFERRED ACCOUNT REPORTING

Q. BASED ON YOUR REVIEW OF GAS COSTS IN THIS PROCEEDING, WHAT ARE THE APPROPRIATE DEFERRED ACCOUNT BALANCES AS OF MARCH 31, 2021?

A. The appropriate All Customers' Deferred Account balance is a debit balance of $8,065,604, owed to the Company, as filed by PSNC. This balance consists of the following deferred account activity:

Beginning Balance as of April 1, 2020	**$8,101,647**
Commodity Cost (Over) Under Collections	(64,687)
Demand Costs (Over) Under Collections	34,815,218
(Increment) / Decrement Activity	(3,478,910)
Secondary Market Transactions	(19,253,677)
Supplier Refunds	(13,097,646)
Miscellaneous	(4,911)
Interest	1,048,570
Ending Balance as of March 31, 2021	**$8,065,604**

Regarding the Sales Customers' Only Deferred Account balance at March 31, 2021, Creel Exhibit 1, Schedule 8 reflects a debit balance of $4,501,726, owed to the Company. Public Staff witness Perry recommends transferring the Company's Hedging Deferred Account credit balance of $436,502, as of March 31, 2021, to the Sales Customers' Only Deferred Account. Therefore, the recommended balance in the Sales Customers' Only Deferred Account is a net debit balance of $4,065,224, owed by the customers to the Company, as follows:

Balance per Creel Exhibit I, Schedule 8	**$4,501,726**
Transfer of Hedging Balance	(436,502)
Balance per Public Staff	**$4,065,224**

Q. HAVE YOU REVIEWED THE COMPANY'S INTEREST RATE IN THE DEFERRED ACCOUNTS?

A. Yes. Decretal paragraph numbers four and five of the Commission's Order in the Company's prior annual review proceeding in Docket No. G-5, Sub 622 (Sub 622 Order), provide in part that "PSNC shall continue to use 6.96% as the applicable interest rate on all amounts overcollected or under collected from customers reflected in its Deferred Gas Cost Account(s) . . . and that it is appropriate for PSNC to continue to review the interest rate calculation and file for approval of any necessary adjustments, in compliance with the Commission's prior orders."

The Public Staff has reviewed the Company's interest rate calculations and found that PSNC continues to use the 6.96% interest rate and has made the appropriate adjustments in its deferred accounts, consistent with the Commission's Sub 622 Order. The Public Staff will continue to review the interest rate each month to determine if an adjustment is needed.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

MS. HOLT: I move that the testimony of Julie G. Perry consisting of 16 -- of six pages be copied into the record and admitted into evidence and I move that Ms. Perry's appendix be identified as premarked and also admitted into evidence.

COMMISSIONER BROWN-BLAND: And, without objection, that motion is also allowed. So, those testimonies are received into the record and treated as if given orally from the stand.

(WHEREUPON, PERRY APPENDIX A is marked for identification as prefiled and received into evidence.)

(WHEREUPON, the prefiled direct testimony of JULIE G. PERRY is copied into the record as if given orally from the stand.)

PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INC.

DOCKET NO. G-5, SUB 635

TESTIMONY OF JULIE G. PERRY

ON BEHALF OF

THE PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

July 26, 2021

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND PRESENT POSITION.

A. My name is Julie G. Perry and my business address is 430 North Salisbury Street, Raleigh, North Carolina. I am the Accounting Manager of the Natural Gas & Transportation Section in the Accounting Division of the Public Staff. My qualifications and experience are provided in Appendix A.

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

The purpose of my testimony is to provide my conclusions regarding the prudence of Public Service Company of North Carolina, Inc.'s (PSNC) hedging decisions during the review period.

Q. PLEASE EXPLAIN HOW YOU CONDUCTED YOUR REVIEW.

A. I reviewed the testimony and exhibits of the Company's witnesses, the Company's monthly Deferred Gas Cost Account reports, monthly financial and operating reports, the gas supply and pipeline transportation contracts, and the Company's responses to Public Staff data requests. The responses to the Public Staff data requests contained information related to PSNC's gas purchasing philosophies, customer requirements, and gas portfolio mixes.

HEDGING ACTIVITIES

Q. PLEASE EXPLAIN HOW THE PUBLIC STAFF CONDUCTED ITS REVIEW OF THE COMPANY'S HEDGING ACTIVITIES.

A. The Public Staff's review of the Company's hedging activities is performed on an ongoing basis and includes the analysis and evaluation of the following information:

1. The Company's monthly hedging deferred account reports;
2. Detailed source documentation, such as broker statements, which provide support for the amounts spent and received by the Company for financial instruments;
3. Workpapers supporting the derivation of the maximum hedge volumes targeted for each month;
4. Periodic reports on the status of hedge coverage for each month;
5. Periodic reports on the market values of the various financial instruments used by the Company to hedge;
6. The monthly Hedging Program Status Report;

7. The monthly report reconciling the Hedging Program Status Report and the Hedging Deferred Account Report;

8. Minutes from meetings of Service Company risk management personnel;

9. Minutes from meetings of Service Company risk management personnel and its committees that pertain to hedging activities;

10. Reports and correspondence from the Company's external and internal auditors that pertain to hedging activities;

11. Hedging plan documents that set forth the Company's gas price risk management policy, hedge strategy, and gas price risk management operations;

12. Communications with Company personnel regarding key hedging events and plan modifications under consideration by Service Company risk management personnel; and

13. Testimony and exhibits of the Company's witnesses in the annual review proceeding.

Q. WHAT IS THE STANDARD SET FORTH BY THE COMMISSION FOR EVALUATING THE PRUDENCE OF A COMPANY'S HEDGING DECISIONS?

A. In its February 26, 2002, Order on Hedging in Docket No. G-100, Sub 84 (Hedging Order), the Commission stated that the standard for reviewing the prudence of hedging decisions is that the decision "must have been made in a reasonable manner and at an appropriate time on the basis of what was reasonably known or should have been known at that time." Hedging Order, 92 NCUC 4, 11-12 (2002).

Q. PLEASE DESCRIBE THE ACTIVITY REPORTED IN THE COMPANY'S HEDGING DEFERRED ACCOUNT DURING THE REVIEW PERIOD.

A. The Company experienced a net debit of $2,959,771 in its Hedging Deferred Account during the review period. This net debit amount at March 31, 2021, is composed of the following items:

Economic (Gain)/Loss - Closed Positions	($1,282,338)
Premiums Paid	670,730
Brokerage Fees & Commissions	23,120
Interest on Hedging Deferred Account	151,986
Hedging Deferred Account Balance	($436,502)

The first item shown in the chart above, Economic (Gain)/Loss – Closed Positions, is the gain on hedging positions that the Company realized during the review period. Premiums Paid is the amount spent by the Company on futures and options positions during the current review period. As of March 31, 2021, this amount includes call options purchased by PSNC for the March 2022 contract period, a contract period, which is 12 months beyond the end of the current review period and 11 months beyond the April 2021 prompt month.[1] Brokerage Fees and Commissions are the amounts paid to brokers to complete the transactions. The Interest on Brokerage Account amount is the interest earned by the Company on amounts deposited with its broker, and the Interest on Hedging Deferred Account is the amount accrued by the Company on its Hedging Deferred Account in accordance with N. C. Gen. Stat. § 62-130(e).

The Company proposed that the $436,502 credit balance in the Hedging Deferred Account as of the end of the review period be transferred to its Sales Customers' Only Deferred Account. The hedging charges result in an annual credit of $0.54 for the average residential customer, which equates to approximately $0.04 per month. PSNC's weighted average hedged cost of gas for the review period was $3.01 per dt.

Q. WHAT IS YOUR CONCLUSION REGARDING THE PRUDENCE OF THE COMPANY'S HEDGING ACTIVITIES?

A. Based on what was reasonably known or should have been known at the time the Company made its hedging decisions affecting the review period, as opposed to the outcome of those decisions, our analysis leads us to the conclusion that the decisions were prudent. I recommend that the $436,502 credit balance in the Hedging

[1] Prompt month refers to the futures contract that is closest toexpiration and is usually for delivery in the next calendar month (e.g., prompt month contracts traded in February are typically for delivery in March).

Deferred Account as of the end of the review period be transferred to the Company’s Sales Customers’ Only Deferred Account.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

COMMISSIONER BROWN-BLAND: So with that, the case is now with Haw River.

MR. NEAL: Thank you. I would ask if Mr. Greg Lander could be sworn in?

COMMISSIONER BROWN-BLAND: Mr. Lander, if you could come on camera.

(Pause).

Mr. Lander, are you there?

MR. NEAL: I hope he's not having technical difficulties.

COMMISSIONER BROWN-BLAND: Are you able to check with him, Mr. Neal?

MR. NEAL: I'm trying to do that now.

MR. LANDER: I apologize.

COMMISSIONER BROWN-BLAND: There he is. Mr. Lander, your counsel has called you to the stand, and let me give you the oath.

GREGORY M. LANDER;

having been duly affirmed,

testified as follows:

COMMISSIONER BROWN-BLAND: Mr. Neal, your witness.

MR. NEAL: Thank you.

DIRECT EXAMINATION BY MR. NEAL:

Q Mr. Lander, could you state your name, title and business address for the record?
A My name is Gregory M. Lander. I am President of Skipping Stone, LLC. We're located at 83 Pine Street in Peabody, Mass., 01960.
Q Mr. Lander, on July 26th, 2021, did you cause to be prefiled in this Docket Number G-5, Sub 635, direct testimony consisting of 38 pages as well as eight exhibits?
A Indeed, yes.
Q Do you have any changes or corrections to your prefiled direct testimony?
A No, I do not.
Q If I asked you the same questions here today, would your answers be the same?
A Yes.
Q And do you have any changes or corrections to the exhibits to your direct testimony?
A Not of substance, no. There's one letter that's wrong but it's nothing.
Q Okay.

MR. NEAL: Commissioner Brown-Bland, I would move that Mr. Lander's prefiled direct testimony be entered into the record and copied into the record as if given orally from the stand and that Mr. Lander's exhibits be marked for identification as Exhibits GML-1 through GML-8.

COMMISSIONER BROWN-BLAND: That motion will be allowed and Mr. Lander's prefiled direct testimony is received into evidence treated as if given orally from the witness stand, and the exhibits that were prefiled will remain identified as they were marked when prefiled.

MR. NEAL: Thank you.

(WHEREUPON, Exhibits GML-1 through GML-8 are marked for identification as prefiled.)

(WHEREUPON, the prefiled direct testimony of GREGORY M. LANDER is copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of:	)	
Application of Public Service Company	)	**DOCKET NO. G-5, SUB 635**
of North Carolina, Inc. for Annual	)	
Review of Gas Costs Pursuant to N.C.	)	
Gen. Stat. § 62-133.4 and Commission	)	
Rule R1-17(k)(6)	)	

DIRECT TESTIMONY AND EXHIBITS OF

GREGORY M. LANDER

ON BEHALF OF

HAW RIVER ASSEMBLY

July 26, 2021

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I. Introduction and Qualifications

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND EMPLOYMENT.

A. My name is Gregory M. Lander. My business address is 83 Pine Street, Suite 101, Peabody, MA 01960. I am President of Skipping Stone, LLC ("Skipping Stone"). With Skipping Stone, I head-up our Energy Logistics and Energy Contracting practice line.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. The Haw River Assembly ("HRA").

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I graduated from Hampshire College in Amherst, Massachusetts, in 1977, with a Bachelor of Arts degree. In 1981, I began my career in the energy business at Citizens Energy Corporation in Boston, Massachusetts ("Citizens Energy"). I became involved in the natural gas business of Citizens Energy in 1983. Between 1983 and 1989, I served as Manager, Vice President, President and Chairman of Citizens Gas Supply Corporation (a subsidiary of Citizens Energy). I started and ran an energy consulting firm, Landmark Associates, from 1989 to 1993, during which time I consulted on numerous pipeline open access matters, a number of Federal Energy Regulatory Commission ("FERC") Order No. 636 rate cases, pipeline certificate cases, fuel supply and gas transportation issues for independent power generation projects, international arbitration cases involving renegotiation of pipeline gas supply contracts, and natural gas market information requirements cases (FERC Order Nos. 587 et seq.). In 1993, I founded TransCapacity LP, a software and natural gas information services company. Since 1994, I have also been a Services Segment board member of the Gas Industry Standards Board ("GISB") and its successor organization, the North American Energy Standards Board ("NAESB"). During the period 1994 to 2002, I served as a Chairman of the Business Practices Subcommittee, the Interpretations Committee, the Triage Committee, and several GISB/NAESB Task Forces.

I am currently a Board Member of NAESB and have served continuously in that capacity since 1997. Skipping Stone, Inc. acquired TransCapacity in 1999, and since that time I have headed up Skipping Stone's Energy Logistics and Energy Contracting practices, where my specialization has been interstate pipeline capacity issues, information, research, pricing, acquisition due diligence and planning.

From 1984 to present, I have maintained a deep familiarity with a wide range of pipeline transportation and contracting issues, beginning with access to pipeline capacity to make competitive sales, resolution of the pipeline take-or-pay contracting regime, pipeline affiliate marketer concerns, restructuring of the pipelines from merchants to transporters and thereafter, and definitions of what constituted a pipeline capacity "right" for the purposes of formulating the then newly commenced capacity release and capacity rights trading business process. I continue to be involved in nearly all facets of the capacity information and trading business as part of my duties at Skipping Stone. In addition, I have been the lead principal on all 50 plus pipeline and storage mergers and acquisitions transactions as well as all pipeline and storage facility expansion projects for which Skipping Stone has been retained by potential purchasers and project sponsors to provide economic due diligence consulting and market analysis.

Q. HAVE YOU FILED TESTIMONY IN REGULATORY PROCEEDINGS PREVIOUSLY?

A. I have filed testimony in several regulatory proceedings. Since 2004, I have filed testimony and/or reports in several proceedings before FERC and state public utilities commissions, including in Maine, Massachusetts, New York, New Jersey, Missouri, California, the District of Columbia, Virginia and South Carolina. Please refer to Exhibit GML-1 for my current CV and Exhibit GML-2 for a full list of case names in which I have filed direct and surrebutttal testimony.

II. Testimony Overview

Q. WHAT DO YOU ADDRESS IN YOUR TESTIMONY?

A. The purpose of my testimony is to present my All-In Cost Analysis of Public Service Company of North Carolina, Inc.'s (PSNC or the Company) acquisition of firm pipeline capacity on the Mountain Valley Pipeline (MVP) and the MVP Southgate pipeline. I reviewed the Company's application materials, its responses to data requests, and publicly available information about the MVP and MVP Southgate projects. Using this information, I performed an All-In Cost Analysis of PSNC's MVP and MVP Southgate capacity and reached the following conclusions.

First, PSNC projects increasing winter-peak demand from its customers. Because its projected increase in demand is both modest and of short duration, only occurring for a few hours on the coldest winter days, PSNC's purchase of year-round firm capacity on the MVP and MVP Southgate projects is an extremely expensive solution. The total fixed cost of this capacity is over $115 ~~$120~~ million per year, equal to an estimated 2022-23 All-In Cost of $311.92 ~~$324.22~~ (fixed cost) for each Dth of gas estimated to be actually used by PSNC's customers through the incremental capacity represented by the MVP/MVP Southgate contracts.

Second, PSNC has other alternatives available to meet its projected demand, including contracting directly with gas producers and marketers that own capacity on the existing Transco pipeline and able to deliver to PSNC. PSNC already contracts with some of these types of companies to meet its winter-peak demand, and my analysis shows that this merchant capacity will be sufficient to meet PSNC's demand projections until at least 2035. The All-In Cost of gas delivered by merchants on the existing Transco system is likely substantially lower than the All-In Cost (including gas cost) of PSNC's MVP and MVP Southgate capacity. PSNC's application provides no indication that the Company has evaluated this—or any other alternative option—to identify the lowest-cost resource for its customers.

Third, PSNC's decision to contract for MVP/MVP Southgate capacity will not only affect its firm gas customers, but also large commercial and industrial gas users that transport gas on the PSNC system and electric ratepayers in North Carolina whose rates reflect changes in PSNC's fixed demand costs.

In light of these conclusions, I recommend that the Commission put PSNC on notice in its final order in this case that the contracted capacity on the MVP and MVP Southgate pipelines is far in excess of PSNC's demonstrated need. Alerting the Company now that it is at risk for not recovering the costs of its excess pipeline subscription will allow PSNC to take advantage of viable market alternatives for disposing of its MVP and MVP Southgate capacity to reduce these significant and unjustified costs.

Q: WHAT MATERIALS HAVE YOU REVIEWED FOR THE PURPOSE OF THIS TESTIMONY?

A: I reviewed the following: Public Service North Carolina's (PSNC)'s contract data; Transcontinental Gas Pipe Line (Transco) filed contract data known as its Index of Customers; Transco posted capacity release data for releases of capacity which releases were effective during the review period of this case. I also reviewed PSNC's witnesses Jackson's and Creel's respective testimony and Exhibits; the November 15, 2018 North Carolina Department of Environmental Quality letter to the Federal Energy Regulatory Commission (FERC) with regards to the proposed Southgate extension of the Mountain Valley Pipeline; PSNC's August 16, 2018 application to the North Carolina Utilities Commission with respect to its Mountain Valley Pipeline (MVP) and Southgate (MVP Southgate) precedent agreements (PSNC Application); the Commission's October 9, 2018 Order with respect to PSNC's MVP and MVP Southgate precedent agreements; NCUC Rule R1-17(k) - Procedure for Rate Adjustments

Under GS 62-133.4 In addition, I also reviewed PSNC Responses to Data Requests submitted for HRA by Southern Environmental Law Center (SELC).[1]

III. PSNC'S Approach to Gas Procurement

Q: WITH RESPECT TO YOUR REVIEW OF PSNC WITNESS JACKSON'S TESTIMONY, DO YOU HAVE ANY INITIAL OBSERVATIONS?

A: As stated by Jackson, with respect to its priorities as regards gas procurement, PSNC puts supply security first, above cost; next is operational flexibility; and then third is cost. They call this 3-part gas procurement approach a "best-cost" supply strategy. Jackson Direct at 4:5-7.

Q: IS THIS "BEST-COST" STRATEGY A COMMON ONE AMONG LOCAL DISTRIBUTION COMPANIES (LDCS) THAT YOU ARE FAMILIAR WITH?

A: This is the first articulation of this sort of strategy that I have encountered. Usually, LDCs articulate a "least-cost" procurement process as their primary strategic priority followed by supply security.

Q: DOES PSNC'S "BEST-COST" ARTICULATION RAISE ANY ISSUES IN YOUR OPINION?

A: On the face of it, the primary problem with this approach is that there is no monetarily quantifiable measure for either of the first two of these "best-cost" metrics. They are entirely subjective. Another way to characterize "best-cost" is "best price." To identify "best price," we would need to first look at the likely result, in terms of what *is* the cost, in dollars per dekatherm (Dth) of meeting peak-day demand; and what *is* the cost in dollars per Dth of incremental gas that

[1] Because PSNC's responses to data requests were provided in one document that contained both confidential and non-confidential information, I have included as exhibits to my testimony only those individual requests and PSNC's responses to those individual requests that I reference, none of which were designated as confidential. The Company's responses are otherwise unchanged.

will be used (i.e., burned) as a result following such approach, especially relative to possible alternatives.

Q: DOES PSNC'S "BEST-COST" ADEQUATELY CONSIDER LESSER-COST OPTIONS THAT COULD ALSO MEET THE COMPANY'S NEEDS?

A: No. In short, the question is, or should be: at what price is PSNC asking ratepayers to agree with PSNC that PSNC is in fact pursuing a "best price/best-cost" approach? This question is especially relevant here with respect to a multi-decade cost stream that is potentially facing PSNC ratepayers, namely the costs of its MVP/MVP Southgate subscription decision. Essentially, PSNC is asking ratepayers to bear and accept the costs for MVP Southgate capacity as the "best-cost" option, but PSNC has provided no evidence that it compared the costs of this new pipeline capacity with other options.

In order to answer such a question, or take PSNC's characterization as accurate or dispositive, we should have seen in the PSNC Application a presentation of MVP/MVP Southgate versus a presentation of ***alternatives*** and at what other price(s) could there be for meeting the same peak demand and Dth of incremental usage as between such ***alternatives.***

While I recognize that no costs resulting from PSNC's contracts for MVP/MVP Southgate capacity have yet been incurred or passed along to PSNC's ratepayers, there may be few remaining opportunities for the Commission to consider the risks to ratepayers before such costs are incurred and proposed to be recovered. For this reason, my recommendations are focused on action(s) the

Commission could take in this docket to put PSNC on notice of being at risk for not recovering imprudently incurred costs.

Q: DID PSNC EVALUATE A RANGE OF ALTERNATIVES FOR MEETING ITS PROJECTED INCREASED DEMAND?

A: I do not know. However, based upon the plain language in the PSNC Application, PSNC did not state that it circulated RFPs for a wide range of solutions to meet proposed peak demand over time. Instead, they essentially asked "who has a pipeline proposal for me?" In particular, PSNC did not state that it asked for energy efficiency (EE) proposals that would reduce peak demand by 2%, 4%, or by any amount, and the Company did not identify what such alternatives would cost. PSNC also did not articulate that it looked for non-pipeline alternatives (NPAs), like increasing liquefied natural gas (LNG) vaporization at its existing Cary LNG facility, adding a satellite LNG or satellite compressed natural gas (CNG) station(s), or identify what these approaches would cost.

In its own words, PSNC did not ask any of these questions, nor, according to the PSNC Application, did it get any RFPs to evaluate potential other solutions to evaluate against a massive pipeline solution. It appears from the PSNC Application that the Company took the view that there was only one way to solve what it perceived as the "problem." It is not clear whether PSNC bounded the problem it sought to solve. This is evident because a simple calculation of how long it would take for PSNC's load to grow into the MVP/MVP Southgate pipeline expansion, based upon its own forecasted growth rate, shows that it will take 12 or more years of the 20 years that PSNC has contracted for, to make use of the capacity to meet design day demand. In my opinion, PSNC has vastly over-purchased new pipeline capacity in light of its projected growth.

IV. <u>Introduction to All-In Cost Analysis</u>

Q: HOW, IN YOUR OPINION, WOULD SUCH A COMPARATIVE EVALUATION BE CONDUCTED?

A: The Company should use "All-In Cost Analysis" in evaluating capacity resource renewal, expansion of its capacity resources, and viable alternatives, including non-pipeline alternatives. Jackson Direct at 9:1-5.

Q: IS ALL-IN COST ANALYSIS USED IN THE GAS INDUSTRY?

A: Yes. As an example, in recently filed testimony before the New York Public Service Commission, I testified that National Grid should adopt All-In Cost Analysis. Like PSNC, National Grid is a local gas distribution company. The settlement filed in that case adopted that All-In Cost Analysis be used in evaluation of proposed capacity resource expansion measures proposed by National Grid to meet projected peak period demand increases.

Q: WHAT IS ALL-IN COST AND HOW IS IT USED?

A: All-In Cost is a method of analysis that enables the apples-to-apples comparison of respective costs of alternative means for achieving a defined goal.

Q: PLEASE EXPLAIN.

A: The first step in the All-in Cost analysis process is to define the problem (i.e., the "<u>*what*</u>" to be addressed) and to define as the goal, addressing and eliminating the problem (i.e., the "<u>*how*</u>"). PSNC does that in this case: The Company projects that it and its customers face a potential shortfall in PSNC resources to meet Design Day Requirements, or, said another way, PSNC has stated that meeting

Design Day Requirements is the "*what*" that PSNC will have to be prepared to meet. That "*what*" is its firm customers' maximum single day demand (i.e., Design Day Demand).

Q: DOES PSNC ACCURATELY IDENTIFY THE PROBLEM IT FACES?

A: Not entirely. I note that having a single measure of the "problem" to be solved misses at least one corollary aspect. That corollary aspect is an equally important component of the "problem" to be solved; namely the forecasted *duration* of requirements exceeding projected or known PSNC resources.

Q: WHY IS FORECASTED DURATION IMPORTANT?

A: Forecasted duration is important because there are different, economically superior, or inferior, means of achieving the "goal", (i.e., solving the "problem") depending on how long each year PSNC's projected resource shortfall exists. In other words, to accurately assess PSNC's options, we need to know the following: what is the period of time—either consecutive or intermittent—that projected demand exceeds PSNC resources and in what magnitude are resources exceeded across the pertinent period.

Q: BEFORE YOU CONTINUE, DO YOU HAVE ANY KNOWLEDGE THAT DURATION OF INCREASED DEMAND WAS *NOT* AN IMPORTANT CONSIDERATION OF PSNC?

A: Yes. When asked in a data request about what market PSNC has for the balance of the capacity beyond that to serve peak day growth, PSNC responded: "The question incorrectly assumes that PSNC acquires capacity to meet the annual needs of its customers. Rather, the capacity is maintained ***at a level to meet PSNC's firm demand on the coldest day*** to ensure reliable service to firm sales customers."[2] [emphasis added] This means that duration of demand was not a primary consideration, if it was considered at all.

Q: PLEASE EXPLAIN HOW DURATION WOULD INFLUENCE PSNC'S DEFINITION OF ITS PROBLEM.

A: Let me give three examples. First, if projected maximum demand is forecasted to exceed PSNC resources during a single day and, for all other days, demand can be met by existing resources, that is one problem to be solved. Second, if projected maximum demand is forecasted to exceed PSNC resources for an entire year, then that is another, and different, problem to be solved. And, third, if projected maximum demand is forecasted to exceed PSNC resources on a day, or, number of days, and on other days over a defined period, demand is expected to exceed existing resources, but to a lesser extent, that is yet a different problem to be a solved.

This set of simple examples makes it clear that correctly defining the problem correctly defines the goal for which a right-sized solution can be identified to meet.

Q: HOW DOES THIS RELATE TO AN ALL-IN COST ANALYSIS OF PSNC'S PROJECTED RESOURCE SHORTFALL?

A: There are, as we see from the three examples, two components to PSNC's shortfall. First, there is the maximum demand that a proposed solution must address and, with it, its corollary cost per unit of demand met. Second, there is the total incremental demand (i.e., units of individual demand that must be met) over the duration where demand exceeds resources to any extent. When

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[2] PSCNC's Response to Haw River Assembly's Data Request, Item 1-29 in the Annual Review of Gas Costs Docket NO. G-5, SUB 635 (July 9, 2021) (Attached as Ex. GML-3)

performing All-in Cost Analysis, there is a cost per unit to each of these two components. And, to enable comparison between different means of meeting these two components of the problem, All-in Cost Analysis presents each of these two components in per unit amounts enabling apples-to-apples comparisons between the different alternatives capable of solving the same defined problem.

Q: CAN YOU PROVIDE AN EXAMPLE OF HOW THE ALL-IN COST ANALYSIS WORKS?

A: The first component of an All-in Cost Analysis involves presenting the cost in per Dth per day or the cost per Dth per hour of meeting the maximum demand. A simple example is as follows: assume that the maximum shortfall of existing resources is projected to be 1,500 Dth per hour on the Design Day.

Q: BEFORE YOU CONTINUE, WHY DID YOU USE DTH PER HOUR AS YOUR MEASURE?

A: Because local gas distribution companies (LDCs) typically experience their peak daily demand in one or more hours between 6:00 and 8:00 AM in the winter, and, for that demand, LDCs have to make the gas be there when it is needed. It is not all right for gas needed at 7:00 AM to come at 12:00 Noon. If it is needed at 7:00 AM, it has to be there at 7:00 AM, period. It is rare, but possible, that the peak hourly demand persists for much of a day. In general, on very cold days, as much as 10% of daily firm customers' demand is experienced in the peak hour with the remaining 90% of firm customers' daily demand spread, in varying hourly percentages, across the other 23 hours of the day.

What this means is that the solution has to address the peak hourly demand. Of note, in the pipeline business, the vast majority of pipeline capacity contracts provide for "ratable delivery obligations." This means that the pipeline is only obligated to make delivery of 1/24th of the daily contracted quantity every hour. Often the pipeline is able to make non-ratable deliveries, and they do when they can, but they are only obligated to make "ratable deliveries." In part, this is because gas production, out of the ground, is even throughout the day. In addition, when a pipeline's system is experiencing maximum demand on a day, it does not have slack capacity to hold, or provide to its customers gas at rates other than ratable because the line is completely full and fully pressurized. The significance of this is that if an LDC needs 1,500 Dth per Hour, then, to contractually meet that hourly demand (with pipeline capacity), the LDC has to contract for 36,000 Dth per day (1,500 times 24) even though they may only need a total of 15,000 Dth for the whole day. In regard to pipeline operations, the differences between these two numbers (i.e., 36,000 and 15,000) is handled by injections into and withdrawals out of storage throughout the day. But in order to have 1,500 Dth per hour available, the pipeline has to have the equivalent of 36,000 Dthd of capacity.

As an aside, these operational facts are why LDCs often have on-system storage, and in the case of PSNC, that on-system storage is LNG that PSNC can vaporize (or not) hourly to meet demand more economically than having pipeline capacity coupled with storage service attached to the pipeline to meet that peak hourly demand and handle excess and deficient hourly supply relative to daily demand.

Q: RETURNING TO YOUR DISCUSSION OF MAXIMUM DEMAND, HOW DOES AN "ALL-IN COST ANALYSIS" RELATE TO THE PROBLEM THAT PSNC SAYS THAT IT NEEDS TO SOLVE?

A: Getting back to the "hourly problem" to be solved, assume that one solution, a year-round pipeline capacity solution, costs $1.50 per Dthd for a 36,000 Dthd amount of capacity to provide the 1,500 Dth per hour. That $1.50 per Dthd would cost $54,000 per day. And, were that that solution a pipeline capacity solution, it would have to be paid for every day for 365 days per year, which then means that the $54,000 per day turns into a solution costing $19,710,000 per year. Stated on a Dth per hour basis the $19,710,000 cost works out to a cost of $13,140 per Dth hour (i.e., $19,710,000 divided by 1,500 Dth per hour). In other words, the All-in Cost Analysis allows us to see very clearly something that is intuitive but often overlooked with regard to pipeline capacity: a year-round solution for a short-term maximum demand problem is often unreasonably expensive.

Q: HOW DOES THE ANALYSIS OF THE SECOND COMPONENT, TOTAL INCREMENTAL DEMAND, WORK?

A: For the second component of the All-in Cost Analysis, we need to look at how many incremental Dth in total are needed to meet the demand that exceeds existing resources at any given time (even though it may exceed by a de minimis amount in any hour) over the excess demand period. For simplicity, assume that there are 501 hours over the winter that firm hourly demand exceeds existing resources: these 501 hours is the *duration*. Continuing this hypothetical, assume that the maximum hourly demand is experienced once and the other 500 hours have excess demand spread proportionately over the range of 1 Dth per hour to 1,499 Dth per hour above existing resources. This total demand then would be

375,750 Dth of total *use* of the resource that provided 1,500 Dth per hour of capacity.

Q: IN THIS EXAMPLE, HOW DO YOU ASSESS THE COST RELATED TO THE TOTAL INCREMENTAL DEMAND COMPONENT?

A: To assess the fixed cost of the solution spread over the *usage* of the solution, we take the $19,710,000 of total cost and divide it by the 375,750 units of usage. This calculation yields a fixed cost per Dth used of $52.45 per Dth used. Now, to complete the second measure of the All-in Cost Analysis we have to assume a gas cost, (i.e., the variable cost of the gas that the solution will use). Given that we are considering the winter season, we can assume an average cost for the duration period of $3.50 per Dth. The cost per Dth used will fluctuate, but the $3.50 per Dth average will suffice for this analysis. Adding the $3.50 per Dth average gas cost brings the All-in Cost per Dth actually used to $55.95. Or, for the purposes of how LDCs charge their customers, the incremental cost of the gas *used* is ~~$5.95~~ $5.595 per Therm for this solution.

Q: FOR THE PURPOSES OF MAKING A COMPARISON, IS THERE AN ALTERNATIVE SOLUTION FOR WHICH YOU COULD PROVIDE THE SAME ALL-IN COST ANALYSIS?

A: Yes. One alternative could be a non-pipeline alternative (NPA) which used a satellite LNG station.

Q: WHAT IS LNG?

A: LNG is liquefied natural gas. Satellite LNG is usually a trailer truck borne solution where the LNG is in insulated tanks that are moved to and from the refill location and the satellite injection location. To establish a satellite LNG location, a header is constructed with a vaporizer to accept hookups to multiple stationary

LNG trailers (that are refilled by the LNG truck borne trailers) and a tap from the header is made into an LDC's mainline.

Q: HOW WOULD YOU CALCULATE THE COSTS FOR AN LNG SOLUTION?

A: A typical LNG Trailer will hold between 10,500 and 16,400 gallons of LNG. That means that each LNG trailer holds between 850 Dth and 1,340 Dth. An installation capable of delivering 1,500 Dth per hour and 15,000 Dth per day (also referred to as Dthd) would conservatively require 20 trailers of LNG. At \$150,000 per trailer (\$3 million or 20 times \$150,000) and an equal amount for site work and related costs, a satellite LNG location would cost about \$6 million. Rounding this up for engineering and overheads to even as much as \$10 million of capital expense; and, then earning a 15% return and depreciating this asset over 5-10 years would yield a first-year fixed cost (before taxes) of \$3.5 million per year (using 5-year useful life). This would equate to a bit less than \$9,600 per day compared to \$54,000 per day for the pipeline solution.

Then, for variable cost, we have to include staffing of the location during the winter period, and the cost of LNG to fill and to be used during the same period as that for the pipeline solution. Assuming 24/7 staffing by three trained personnel and accounting for time-off and related staffing costs, it would require 14 persons at about \$120,000 per year or a total O&M variable of \$1.7 million. Then we also have to account for the cost of the LNG. Even assuming a \$10 per Dth LNG cost for each of the 375,750 Dth used plus the 17,500 Dth of initial fill gas for a total of about 400,000 Dth (inclusive of refill boil-off not used during peak period refills) you have about $4 million of gas cost. This would bring variable cost to $5.7 million ($1.7 million O&M plus $4.0 million gas cost).

Q: WHAT IS THE END RESULT OF THE ALL-IN COST ANALYSIS FOR THE LNG ALTERNATIVE?

A: Then, to complete the apples-to-apples comparison, we take the sum of annual fixed costs ($3.5 million) plus annual "variable" or "use" costs ($5.7 million) for a total of $9.2 million and divide that by Dth used by the solution. That then works out to $24.48 per Dth used "All-in" ($9.2 million divided by 375,750 Dth = $24.48 per Dth) or about half of the cost of the pipeline alternative (52% of the pipeline costs or 48% less than the pipeline alternative).

Q: ARE YOU SAYING THAT YOU KNOW THE LNG SATELLITE ALTERNATIVE IS CHEAPER ON AN ALL-IN COST PER DTH USED THAN THE PIPELINE ALTERNATIVE?

A: Not exactly. To know about the cost of the LNG Alternative, RFPs for construction and/or leasing (as well as possibly staffing) of the facility, plus RFPs for trucked in supply should be issued, along with an internal study of staffing costs and LNG acquisition costs.

Q: WOULD THIS LNG FACILITY BE PERMANENT?

A: Not likely. It would instead be a temporary solution. Leaving the trailers on wheels ensures that this solution is regarded as temporary. In addition, assuming that even after energy efficiency measures are applied, the annual load from the addition of new customers grows, it would be prudent to then find a solution that would reduce gas demand (such as electrification) or a small expansion of Transco (in the range of 36,000 Dthd to 72,000 Dthd). These more permanent solutions could both meet accumulated increase in peak demand plus the peak demand expected to occur over the next few years. Then, to the extent a NPA might be needed again in the more distant future, alternatives would again be evaluated.

Q: IS THE NON-PIPELINE ALTERNATIVE YOU PROVIDED AS AN EXAMPLE ABOVE RELEVANT TO PSNC AND ITS LIKELY PROPOSAL TO SEEK COST RECOVERY OF THE MVP/MVP SOUTHGATE PROJECTS SHOULD THEY GO IN-SERVICE?

A: I believe so. To the extent that PSNC faces 1,500 Dth per hour of peak demand growth, this sort of non-pipeline alternative should be a relevant alternative to PSNC's MVP/MVP Southgate plans. Likewise, to the extent the total demand usage of 375,750 Dth is needed, the non-pipeline alternative sketched out above is a relevant and potentially viable alternative. However, the MVP/MVP Southgate project is not a 36,000 Dth per day project; and, thus the All-in Cost Analysis would yield a very different result from the $55.95 per Dth of use that was modeled above.

V. <u>All-In Cost Analysis of the MVP/MVP Southgate Project</u>

Q: HAVE YOU DONE A SIMILAR ALL-IN COST ANALYSIS OF THE MVP/MVP SOUTHGATE PROJECT?

A: Yes. I have done a back of the envelope All-In Cost Analysis of the project, at the magnitude of PSNC's subscription to the MVP/MVP Southgate project.

Q: PLEASE ELABORATE.

A: First, the MVP portion of the project subscribed to by PSNC is 250,000 Dth per day and PSNC's portion of MVP Southgate is sized at 300,000 Dth per day. The 50,000 Dth per day of PSNC's MVP Southgate capacity that is greater than the Company's MVP capacity does make sense as far as meeting an existing need to firm up deliveries from East Tennessee Natural Gas/Saltville storage to PSNC facilities. Thus, I used 250,000 Dth per day for my analysis.

Q: WHAT IS THE NEW MAXIMUM DEMAND THAT PSNC CLAIMS IT NEEDS THE MVP/MVP SOUTHGATE CAPACITY TO MEET?

A: For my analysis of near-term cost impact, I will use the same 1,500 Dth per hour (36,000 Dth per day of pipeline capacity) that I used in my example above. I calculated this by comparing the Company's Design Day Requirements for 2022-23 to Design Day Requirements for 2020-2021 as reported in Jackson Direct, Exhibit 1. This comparison shows an increase in design day requirements of 14,856 Dth per day (after an assumed continuation of the 24,000 Dth per day of Short-Term Peaking Service into 2022-23 as PSNC shows for 2021-22) which yields a design hour (at 10% of daily in peak hour) of approximately the same 1,485.6 per hour as my modeled 1,500 Dth per hour.

Q: WHAT ARE YOU ABLE TO CONCLUDE?

A: The difference between my initial example and PSNC's capacity on the MVP/MVP Southgate projects is that the cost of a 250,000 Dth per day solution to a 1,500 Dth per hour and 15,000 Dth per day problem, on an All-In Cost per Dth of *use* basis, will be vastly more expensive.

Q: DO YOU HAVE AN ESTIMATE OF THE ALL-IN COST ON A PER DTH OF USE BASIS BASED UPON THE 250,000 DTH PER DAY SOLUTION TO PSNC'S 2022-23 DESIGN DAY DEMAND INCREASE OF APPROXIMATELY 36,000 DTH PER DAY?

A: Yes, my rough calculations result in an All-In Cost for the period (i.e., assuming the same 375,750 Dth of incremental use above existing resources -- over the winter period -- as I used in my example) to be $311.92 ~~$324.22~~ per Dth used. Here the incremental use is of the total demand estimated to be met by MVP/MVP Southgate for demand in excess of existing resources pre-MVP/MVP Southgate.

Q: PLEASE EXPLAIN AGAIN WHY THE 375,750 DTH OF USE IS WHAT YOU SPREAD THE FIXED AND VARIABLE COSTS OVER?

A: Outside of the winter period, which is the only time that sales demand may exceed PSNC's existing resources, the existing resources can meet the demand. Thus, the incremental cost is divided by the *incremental use* not met by existing facilities/resources to calculate the cost per Dth used.

Q: CAN YOU TELL US WHAT THE TOTAL COSTS WERE THAT WHEN DIVIDED BY 375,750 DTH YIELDED THE ~~$324.22~~ $311.92 PER DTH USED?

A: Yes. As I said, it is a rough estimate of the rates that MVP and MVP Southgate will charge PSNC for its capacity reservations on the two pipelines based on publicly available information. I pulled the total project cost information from MVP's and MVP Southgate's Exhibits N and P from their respective certificate applications to FERC. These exhibits identified daily reservation recourse rates of $0.9729 and $0.6170, respectively. Then, I applied a negotiated rate discount of 20% to the sum of these two as an estimate of typical negotiated rate discounts to recourse rates to arrive at a PSNC rate for the 250,000 Dth per day of common capacity (i.e., excluding the East Tennessee Natural Gas/Saltville 50,000 Dth per day on MVP Southgate) for MVP/MVP Southgate of $1.27 per Dth per day.

Q: WHAT IS THE TOTAL MODELED ANNUAL COST FOR PSNC USING THIS $1.27 PER DTH PER DAY?

A: Multiplying this modeled $1.27 per Dth per day times 250,000 and then multiplied by 365 equals ~~$120,509,745~~ $115, 887,500 per year of fixed cost associated with MVP/MVP Southgate. Then, I divided this fixed cost by the 375,750 of incremental Dth of demand which results in a fixed cost per Dth used of ~~$320.72~~ $308.42. Then, adding the same modeled $3.50 per Dth of average gas cost for the gas used, we arrive at the ~~$324.22~~ $311.92 per Dth of incremental gas used through the 250,000 Dth per day solution. Based on my analysis, PSNC's purchase of year-round capacity on the MVP and MVP Southgate projects to meet its projected incremental demand is an extremely expensive solution to what the Company identifies as a short duration problem only occurring on the coldest winter days each year.

Q: YOU HAVE DONE AN ALL-IN COST ANALYSIS OF TWO METHODS TO MEET INCREMENTAL DESIGN DAY DEMAND NOT MET BY EXISTING RESOURCES, SPECIFICALLY THE MVP/MVP SOUTHGATE CAPACITY ALTERNATIVE AND THE LNG ALTERNATIVE IN YOUR INITIAL EXAMPLE. ARE THOSE TWO ALTERNATIVES THE ONLY ONES AVAILABLE TO PSNC?

A: No.

VI. <u>Other Means of Meeting Peak Demand</u>

Q: WHAT OTHER ALTERNATIVES DOES PSNC HAVE TO MEET ITS PROJECTED DEMAND?

A: First of all, PSNC is currently planning to, and did during the review period, avail itself of means of meeting its design day demand other than through the combination of owned, on-system, resources (i.e., LNG vaporization) or pipeline capacity directly contracted for by PSNC (i.e., the MVP/MVP Southgate capacity). Specifically, PSNC currently plans to contract for supply from a wholesale gas merchant(s) (i.e., one or more producer(s) or marketer(s)) that holds capacity in its own name and agrees, by contract, to sell to PSNC when PSNC calls for deliveries of such contracted supply. This is generally referred to as contracting for "delivered gas" and is very common in the wholesale market, especially on pipelines where producers and marketers hold substantial capacity.

Q: IS THE PIPELINE THAT SERVES PSNC, TRANSCONTINENTAL GAS PIPE LINE (TRANSCO) SUCH A PIPELINE?

A: Yes. In fact, from my research of Transco's firm transportation (FT) contracts, the shippers holding such contracts, and the capacity paths of those contracts, I have determined that there is a total of 860,002 Dth per day of Transco capacity with primary path capacity flowing past PSNC that is held by merchants. This capacity is North-to-South capacity. All of this North-to-South capacity originates in Transco's Marcellus production supply area and terminates in Transco's Zone 4A in Choctaw County, Alabama.

Q: WHAT IS THE SIGNIFICANCE OF THIS FACT?

A: Its significance is that these shippers, if approached either by RFP or through direct negotiations, might well be willing to contract with PSNC for stated quantities both daily and over a season, that would be sold to PSNC at PSNC's existing receipt locations (a.k.a Transco delivery locations) at market prices during PSNC high demand period(s).

Q: WHAT IF THOSE "MARKET PRICES" WERE VERY HIGH?

A: Well, all one has to do is consider the results of the All-In Cost Analysis above, to see that PSNC would have to buy delivered gas at very inflated prices greater than $311.92 ~~$324.22~~ per Dth on average across an entire winter period to justify the MVP/MVP Southgate pipeline alternative. In my experience, market prices fluctuate but only very rarely get that high – and have never persisted for an entire winter period.

Q: PSNC'S DESIGN DAY DEMAND PROJECTIONS CONTINUE TO SHOW GROWTH BEYOND THE 2022-23 PERIOD YOU ANALYZED. TO SUPPLY PROJECTED DESIGN DAY DEMAND GROWTH THROUGH SAY 2035, WHAT LEVEL OF SUPPLY RELATIVE TO THIS 860,002 DTH PER DAY OF MERCHANT-HELD CAPACITY WOULD HAVE TO BE CONTRACTED FOR BY PSNC?

A: In 2022-23, even assuming the Short-Term Peaking Service identified by PSNC as applicable to 2021-22 was to not continue, the quantity of delivered service that PSNC would need to contract for would be about 39,000 Dth per day or 4.5% of the available merchant capacity on Transco. And, even if none of energy efficiency, electrification, nor demand response were to reduce peak day demand, and peak day demand continued to grow at 2.17% from 2022-23 to 2034-35, the resulting increase over current design day would be 297,284 Dth per day or 34.5% of available merchant capacity on Transco. In my opinion, PSNC's demand can grow at its projected rates and still be served by existing pipeline capacity at prices lower than the cost of capacity on the MVP and MVP Southgate projects.

I would further note that the states of New York and New Jersey as well as Massachusetts are targeting 2% year over year reductions in total LDC gas demand from current levels via electrification and energy efficiency. The effect on PSNC of these moves will be to potentially provide PSNC access to capacity turned back by LDCs in those states. This means that not only could existing merchant capacity be available, but PSNC access to turnback capacity from New York, New Jersey, and Massachusetts distribution companies could also be available. In addition, as the state and the nation move towards net-zero greenhouse gas emission targets and as Dominion Energy itself takes steps to meet its goal of net-zero carbon pollution by 2050,[3] the Company will likely need to take significant steps to reduce demand over the coming decades, particularly given that it has not yet explored significant available options to reduce greenhouse gas pollution from its operations, including direct air capture with carbon sequestration.[4]

In addition, I would note that PSNC currently has an annual sales load of about 53 Million Dth and an annualized year-round capacity level of 145.3 Million Dth (i.e., its firm year-round city gate capacity times 365) or uses that year-round capacity at an overall 36% load factor. In addition, PSNC has 17% load factor of its annualized 2020-21 design day to 2020-21 annual load. Using this 17% load factor, (because MVP/MVP Southgate is in PSNC's words for the coldest day), then, at a 2034-35 increased design day of 297,284 Dth per day, PSNC could contract for an additional 50,538 Dth per day of year round (possibly even turnback) capacity and maintain essentially the same usage load factor (i.e., the 17%) for the total of its year-round and peaking capacity. This would reduce delivered gas requirements from merchants in 2034-35 to 247,000 Dth per day or so and thus only 29% of merchant-held capacity.

[3] "By 2050, we will achieve net zero greenhouse gas emissions across all of our electric and natural gas operations in all 16 states where we do business. We are taking immediate action to reduce emissions as quickly as possible, while also exploring new technologies to accelerate future progress." Dominion Energy, Delivering Clean Energy, (https://www.dominionenergy.com/our-company/clean-energy).

[4] When asked to "[p]lease provide a narrative explaining the steps is PSNC taking to study or assess Direct Air Capture and subsequent sequestration or use of CO2 emitted by PSNC's natural gas customers as one way to reduce atmospheric CO2 and contribute to meeting the state's CO2 reduction goals?" PSNC responded "PSNC has not studied or assessed such steps." PSCNC's Response to Haw River Assembly's Data Request, Item 1-27(d) in the Annual Review of Gas Costs Docket NO. G-5, SUB 635 (July 9, 2021) (Attached as Ex. GML-4).

I would also note that this 50,538 Dth per day of year-round capacity in 2034-35 is quite a bit less than 250,000 Dth per day of year-round capacity as early as 2022-23.

The significance of these load factor figures is that low load factor usage of high fixed-cost year-round resources is very expensive on a per unit of use basis. Moreover, even if peak day demand were to continue to grow, from a ratepayer impact point-of-view, adding high cost year-round resources should only be considered prudent to meet peak demand if the load factor of their usage will be commensurate to or greater than current load factor usage of existing year-round resources retained to meet peak demand.

Q: WITH RESPECT TO RELIANCE ON MERCHANT DELIVERED GAS CONTRACTS, WHAT IF THEY WORK ONE YEAR, BUT THE NEXT, THE MERCHANT DECIDES TO SELL TO SOMEONE ELSE?

A: One way to deal with that risk would be to enter into a series of contracts extending out, respectively, for 5, 4, 3, 2 and 1 year(s); with each being for 20% of projected requirements. Then, for the one-year contract, at renewal, or going back to the market, enter into another five-year contract to cover the new (i.e., year two) design day requirement(s) for the period of the deal. And, do this at the next expiration as well so that PSNC is always covered for the next 5 years and can use that coverage to decide what and how to meet requirements in year 6 and after at any given time. In this way, PSNC and its ratepayers are not at risk for a "cliff" of expirations occurring in any "next year" and PSNC has a five-year time horizon to evaluate its load factor of usage of these contracts and whether there are more economical options to be considered for the future.

Q: WHAT IF THOSE MERCHANT DELIVERED GAS SALES CONTRACTS HAVE RESERVATION FEES?

A: Some level of reservation fees is not uncommon and it will be up to PSNC to evaluate such reservation fees against the cost of the gas or index/indices and expected usage to negotiate the best deals.

Q: IS THERE ANY EVIDENCE IN THIS CASE OF PSNC HAVING FAMILIARITY WITH CONTRACTING WITH PRODUCER-MARKETER MERCHANTS FOR DELIVERED GAS SALES?

A: Yes. PSNC has a contract with EDF (Electricte de France) a major North American merchant (See Creel Exhibit 1 Schedule 2, line 32) as an example. In addition, I researched all Transco capacity releases by PSNC collected directly from the Transco computers[5] with release periods effective during the period covered by this case. In that analysis, I found that for the November 2020 through March 2021 period, it released, under Asset Management Agreements (AMAs), 161,782 Dth per day of its Transco capacity. This figure is approximately equal to 41% of the year-round capacity figure on Jackson Exhibit 1 for Transco of 390,743 Dth per day. Contracting with merchants for 41% of winter capacity is a clear indication that PSNC is comfortable relying on merchants that hold capacity (along with likely arrangements typical under AMAs for the acquiring shipper to supply gas to the releaser when called for by the releaser, in this case PSNC).

Q: YOU RECEIVED A DATA RESPONSE FROM PSNC WITH RESPECT TO CAPACITY RELEASES FOR THIS REVIEW PERIOD, CORRECT? DO YOUR FIGURES WITH RESPECT TO THESE AMAS MATCH THEIRS?

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[5] Skipping Stone's Capacity Center employs direct computer-to-computer electronic data interchange (EDI) to collect all capacity release data from over 100 pipelines, including Transco.

A: No. For the Winter 2020-21, PSNC indicated total Dthd released of only 82,832 Dth per day.[6] I cannot account for this difference. In preparing this testimony, my staff reviewed the Transco online bulletin board and confirmed that our EDI data for the AMA releases totaling 161,782 Dth per day (winter period) was the same as what is showing on the Transco bulletin board as released for the same winter period as of July 22, 2021.

Q: DID PSNC PROVIDE ANY ADDITIONAL INFORMATION THAT CALLS INTO QUESTION THE REASONABLENESS OR PRUDENCE OF PSNC'S DECISION TO CONTRACT FOR FIRM PIPELINE CAPACITY FROM MVP/MVP SOUTHGATE?

A: Yes. In a data request, we asked with respect to the capacity provided by the MVP/MVP Southgate capacity, "[w]hat market does PSNC have to absorb the approximately 250,000 Dthd (i.e., the quantity over and above the East Tennessee Natural Gas/Saltville 48,778 Dthd of winter 2022-23 "Seasonal Capacity" (see Jackson Exhibit 1)." PSNC responded that its "design day is growing by approximately 20,000 [Dth] every year."[7]

Even if its market does in fact grow at 20,000 Dth per day per year, it would take a dozen or so years (i.e., until possibly as late as 2034-35) for PSNC to grow into the 250,000 Dthd referenced in the question. And it is important to remember that the 250,000 Dthd only refers to the peak day/hour demand, leaving much of the additional firm capacity fallow much of the rest of the year. The question then becomes "Should ratepayers be 'on the hook' for this dozen

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[6] PSCNC's Response to Haw River Assembly's Data Request, Item 1-17 in the Annual Review of Gas Costs Docket NO. G-5, SUB 635 (July 9, 2021) (Attached as Ex. GML-5).

[7] PSCNC's Response to Haw River Assembly's Data Request, Item 1-23(b) in the Annual Review of Gas Costs Docket NO. G-5, SUB 635 (July 9, 2021) (Attached as Ex. GML-6)

year period?", or, as I recommend above, "Should PSNC be put on notice that this level of capacity is far in excess of needs and PSNC should look to the market and not to ratepayers to support/defray this cost?"

In essence, by its own words, PSNC has told this Commission, that for years and years to come, they have (or will have) excess capacity subscribed versus their maximum modeled need.

Q: DO YOU HAVE ANY OTHER SUPPORT FOR YOUR CONCLUSION THAT PSNC CAN RELIABLY MEET ITS PROJECTED PEAK DEMAND GROWTH IN LESS EXPENSIVE WAYS THAN BY SUBSCRIBING FOR FIRM PIPELINE CAPACITY ON THE MVP/MVP SOUTHGATE?

A: Yes. In response to a data request about where PSNC expects "to receive deliveries off of <u>MVP directly into facilities of PSNC</u>?" PSNC responded that the Company expects to receive deliveries from the <u>Southgate lateral</u> at interconnects in Rockingham and Alamance counties.[8] In other words, PSNC will <u>*not get direct deliveries*</u> of gas from its subscription to MVP, but rather only from facilities associated with its subscription to MVP Southgate.

Q: WHAT IS THE SIGNIFICANCE OF THAT RESPONSE?

A: It means that PSNC could likely meet future demands by:

1) Buying gas on a delivered basis at the terminus of MVP (from a supplier with MVP capacity) and then moving it to its system "interconnects in Rockingham and Alamance counties" via MVP Southgate; or,

[8] PSCNC's Response to Haw River Assembly's Data Request, Item 1-22 in the Annual Review of Gas Costs Docket NO. G-5, SUB 635 (July 9, 2021) (Attached as Ex. GML-7).

2) Buying gas out of Southgate on a delivered basis (from one or more suppliers with MVP/MVP Southgate capacity) at its system "interconnects in Rockingham and Alamance counties"; or,

3) As noted above, buying gas on a delivered basis from existing suppliers with capacity on Transco; and

in all three cases above, doing so, only when and to the degree required, thereby avoiding the fixed costs associated with MVP and/or MVP Southgate.

This finding is consistent with my conclusion that PSNC has sufficient capacity when taking into account PSNC held contracts and available merchant capacity available to PSNC via delivered gas sales to meet it infrequent and short duration design day needs.

Q: ARE THERE DATA RESPONSES FROM PSNC WHICH SUPPORT THIS RECOMMENDATION?

A: One in particular does.

Q: WHAT IS THAT ONE?

A: In response to the request to "identify the pipeline(s), contract(s) and Path(s) that such' [Short-Tern Peaking Service LNG]' supply follows to PSNC's service area(s) location(s)," PSNC responded that it "does not determine the flow of gas or its origination under these contracts, which are for bundled peaking services to PSNC's city gate."[9]

Q: WHICH MEANS?

[9] PSCNC's Response to Haw River Assembly's Data Request, Item 1-19(a) in the Annual Review of Gas Costs Docket NO. G-5, SUB 635 (July 9, 2021) (Attached as Ex. GML-8).

A: Because in a confidential portion of the response to HRA 1-19, PSNC does state the parties and origination of the service, this means that PSNC has the ability; when contracting for delivered supplies, to be confident in the services' certainty enough to be able to list it as meeting is Design Day Requirements. Thus, even though PSNC may "not *determine* the flow of the gas or its origin", it does now, and can in the future, know the origin and thus assure itself of supply verity. What this means is that should PSNC contract for just the quantities and time frames it actually needs instead of incurring the fixed costs of MVP and/or MVP Southgate, it could avail itself of gas available from the MVP capacity without contracting directly with MVP for the capacity. It could even require the sellers to certify that they have the necessary firm transportation to support the sales under a delivered gas transaction.

Q: COULD ALL-IN COST ANALYSIS BE APPLIED TO PEAK PERIOD DELIVERED GAS TRANSACTIONS AS PART OF THE APPLES-TO-APPLES COMPARISONS?

A: Absolutely. To the extent such peak period delivered gas transactions had reservation charges, the first component of All-In Cost Analysis could be derived to identify the All-in Cost per Dth per day; and to the extent there was a stated commodity charge (or indexed commodity charge) then the estimated use of that transaction (i.e., the Dth that would be estimated to be bought by PSNC under the arrangement) would enable the calculation of the second component. I should note here that while I think the All-In Cost Analysis approach that I have described in this testimony is ideally suited to make the kind of cost-comparison that the Commission should require before accepting fixed costs of a new pipeline as prudently incurred, the broader point is that some kind of apples-to-apples comparison needs to be made to compare an expensive pipeline solution to other viable, less expensive options to meet PSNC's peak demand needs. Were the Commission to fashion its own apples-to-apples methodology, it would be important to measure the two components: (1) the cost per Dth per day (or hour) of demand to be met; and (2) the effective cost per Dth of the incremental use (i.e., the load factor of use) of the proposed means of meeting the incremental demand over the period of incremental demand not able to be met with existing resources.

VII. Estimate of Significant Increases in Costs to PSNC Sales Customers and Other PSNC Customers

Q: RETURNING TO THE POTENTIAL COSTS COMING TO PSNC SALES CUSTOMER RATEPAYERS FROM PSNC'S SUBSCRIPTION TO MVP/MVP SOUTHGATE, DO YOU HAVE AN ESTIMATE OF THE POTENTIAL IMPACT OF THOSE COSTS ON GAS COSTS AS COMPARED TO GAS COSTS IN THIS CASE?

A: Yes, the All-In Cost Analysis related to evaluating one alternative versus other methods for meeting Design Day Demand; however, it is possible to employ some of the same analysis that enabled the All-In Cost Analysis to project impacts to ratepayers' gas costs from these same underlying Fixed Cost streams.

Q: HOW DID YOU ESTIMATE THEM, AND WHAT DO YOU ESTIMATE THOSE PER DTH COST IMPACTS TO BE?

A: To do this, I first took PSNC's projected design day demand growth factor year-over-year of 2.17% and applied that to total throughput of sales in this case of just under 53 Million Dth in this 2020-21 year and escalated that to 2022-23 to get a figure of just under 55 Million Dth (54,894,508 Dth in the 2022-23 gas year). Then, I divided the estimated Fixed Cost of MVP/MVP Southgate (that I derived for the All-In Cost Analysis of ~~$120,509,745~~ $115,887,500) by this approximately 55 Million Dth number and arrived at a ~~$2.20~~ $2.11 per Dth increase in sales ratepayer gas costs – for ***all gas sold*** to ratepayers. This equates to an increase for ***each unit*** sold by PSNC over the course of the year of ~~$0.22~~ $0.21 per Therm.

Comparing this to a simple, back of the envelope, view of current gas costs in this case, I took "TOTAL COMMODITY COSTS EXPENSED" of $128,838,351 (Creel Exhibit 1, Schedule 3, bottom right) and divided this by "GAS SUPPLY FOR DELIVERY" of 52,287,485 Dth (Creel Exhibit 1 Schedule 10, bottom right) to arrive at an indicative $2.45 per Dth or $0.245 per Therm. The modeled ~~$0.22~~ $0.21 increase discussed above would take this $0.245 per Therm to ~~$0.465~~ $0.455 per Therm, a near doubling of this view of gas cost[10].

Q: DOES THIS MEAN THAT PSNC SALES CUSTOMERS WOULD BEAR ALL OF THE COSTS OF MVP/MVP SOUTHGATE?

A: If done this way, yes. However, having read the NCUC regulations with respect to increases/decreases in demand and storage costs on PSNC's transportation rates, it is not clear from those regulations that only sales customers of PSNC will be impacted.

Pursuant to NCUC regulations R1-17-(k) Procedure for Rate Adjustments Under G.S. 62-133.4. Section 3(b), firm and interruptible transportation rates (i.e., those paid by industrial users transporting gas on PSNC) will see large increases due to MVP because "[f]irm and/or interruptible

[10] I present this calculation in this way, because the increased costs from MVP/MVP Southgate are not yet "fixed", they are avoidable ratepayer costs and this as such, in this indicative view are presented as variable/potential increases in ratepayer costs.

transportation rates shall be computed on a per unit basis by subtracting the per unit Commodity and Other Charges included in the applicable firm or interruptible sales rate schedule from the applicable firm or interruptible rate schedule exclusive of any decrements or increments. Commodity deferred account increments or decrements shall not apply to transportation rates unless the Commission specifically directs otherwise. ***Demand and storage increments or decrements shall apply to transportation rates***." [emphasis added]

Q: WHAT DOES THIS MEAN?

A. Industrial customers of PSNC often use the PSNC distribution system for gas transportation only. By my reading of this language, it could very well mean that PSNC's choice to contract for MVP/MVP Southgate will also negatively impact industrial customers of PSNC by as much as the same ~~$2.20~~ $2.11 per transported Dth (or ~~$0.22~~ $0.21 per transported Therm).

Because the fixed costs of MVP/MVP Southgate would essentially double PSNC's total fixed costs as reported in this review period, by this reading of the regulations, the fixed demand cost component of transport rates could also essentially double. Nowhere in the testimony or exhibits filed by PSNC in this case did I see any calculation of, or deduction from, its fixed costs, of any fixed costs associated with transportation revenues (which also contain an allocation of fixed costs) received by PSNC from on-system transportation.

Q: WHAT WOULD BE THE IMPACT OF THE MVP/MVP SOUTHGATE FIXED COSTS IF SUCH FIXED COSTS WERE ALLOCATED TO BOTH SALES AND TRANSPORTATION?

A: I cannot say for certain. As PSNC witness Jackson stated, "Approximately half of the Company's throughput during the review period consisted of deliveries to industrial or large commercial customers, including electric generation, many of whom either ***purchased or transported*** gas under interruptible rate schedules." Jackson Direct, p. at 18:21 (emphasis added). Because I do not know what portion of that half of throughput was made up of "interruptible sales" versus "interruptible transport," and thus is counted in the approximately 53 Million Dth of sales, I am not able to estimate the per Dth increase in transport rates, were such an allocation of fixed costs to occur. Nevertheless, even if the $2.11 ~~$2.20~~ per Dth increases in 2022-23 were only half that amount, an increase in transport rates of $1.055 ~~$1.10~~ per Dth is a large increase in any event.

Q: IF EITHER IMPACT WERE TO BE AFFECTED IN TRANSPORT RATES, DO YOU HAVE ANY ESTIMATE OF THE IMPACT ON ELECTRIC RATES FOR GAS DELIVERED BY PSNC USED TO GENERATE ELECTRICITY IN 2022-23?

A: Yes. From my work related to Duke Energy in the Carolinas, I know that PSNC, at least, delivers gas to some Duke Energy power plants. A very coarse measure, using an 8,000 Btu per kW heat rate (the Btus of gas needed to generate a kW), and the $2.11 ~~$2.20~~ per Dth increase in the demand component of transport rates would be an increase of $16.84 ~~$17.56~~ per MWH or a $0.0168 ~~$0.0175~~ per kWh for the electricity generated in North Carolina from gas delivered by PSNC.

VIII. <u>Conclusions and Recommendations</u>

Q: WHAT IS THE BOTTOM LINE FOR PSNC'S DECISION TO CONTRACT FOR CAPACITY ON THE MVP AND MVP SOUTHGATE PROJECT?

A: My conclusion is that PSNC's decision to contract for MVP/MVP Southgate capacity not only affects firm gas customers of PSNC, but also large commercial and industrial gas users of PSNC as well as electric customers in North Carolina.

Q: DO YOU HAVE ANY RECOMMENDATIONS FOR MEASURES THAT THE COMMISSION COULD TAKE TO MITIGATE THESE COST IMPACTS FROM PSNC'S DECISION TO CONTRACT FOR THE 250,000 OF MVP/MVP SOUTHGATE THAT YOU HAVE IDENTIFIED?

A: Yes. In the Commission's Order approving the MVP/MVP Southgate agreements, the Commission specifically stated that it could reject the agreements and/or disallow costs associated with the contracts. In part, because there is no reasonable projection of increased demand sufficient to justify the expenditures of the magnitude that will come in the near future, that recovery should be limited.

Q: PLEASE EXPLAIN WHY THIS IS IMPORTANT.

A: In assessing what costs from MVP/MVP Southgate that ratepayers should be required to absorb, one way to mitigate the cost to ratepayers of this decision by PSNC would be for the Commission to put PSNC on notice, in this case, that the 250,000 Dth per day decision is far in excess of demonstrated PSNC need. The Commission should alert PSNC that it is at risk for recovery of such excess subscription. In effect, the Commission can warn PSNC that it may not be allowed recovery of dollars in excess of the All-In Cost of non-pipeline alternatives that would address PSNC's stated need. Using this measure, non-pipeline alternatives that could be benchmarked against would be like the satellite LNG alternative I discussed above or a combination of one or more of the following:

1) peaking CNG facilities,

2) expanded LNG vaporization at existing facilities,

3) energy efficiency measures,

4) demand response measures, and/or

5) electrification of heating or hot water, (to the extent the increased electrical demand can be met by increased renewables able to supply such electrified demand at the times of day that electrical demand from such electrification is forecasted to materialize).

Q: IS THERE ANOTHER APPROACH THE COMMISSION COULD TAKE?

A: Alternatively, the Commission could put PSNC on notice that it will only allow recovery of reservation cost of capacity associated with the lower of Commission approved increase in forecasted Design Day demand (i.e., that increase presented and approved in these gas-cost adjustment proceedings) or actual increases in peak-day demand (from that increase presented in these gas cost proceedings). In the absence of an IRP-like proceeding, these annual gas cost dockets are one of the few opportunities to raise concerns about potential imprudently incurred costs and present alternatives that could protect customers from excess costs associated with acquiring or holding capacity in excess of capacity needed to supply PSNC firm customers' demand.

Q: ARE YOU RECOMMENDING THAT PSNC SHAREHOLDERS ABSORB ALL SUCH EXCESSIVE COSTS?

A: In light of this recommendation as to the level of permitted recovery, I also recommend that PSNC be permitted to mitigate such costs to shareholders by being permitted to retain all secondary market revenues associated with releasing MVP and/or MVP Southgate capacity into the secondary market and/or earned from its making "bundled sales" to non-firm customers of PSNC (on or off of the PSNC system) utilizing the MVP and/or MVP Southgate facilities. This approach varies from the current practice of PSNC sharing a portion of such revenues with ratepayers. With respect to these "bundled sales," the gas sold, and the imputed margin from those sales, should be calculated as having used the most expensive gas available to PSNC at the time of the "bundled sale," thus ensuring that PSNC's firm customers are not paying more for gas supplied to them because less expensive gas available to PSNC was diverted to such "bundled sales."

In short, in light of ratepayers being fully protected against these excess costs, and should PSNC nevertheless proceed with *not disposing* of those costs (by means discussed below), this alternative would allow PSNC to retain secondary market revenues from releases of MVP/MVP Southgate as well as margin from bundled sales utilizing those facilities, instead of sharing those revenues with ratepayers, so as to provide shareholders a means of mitigating their costs.

Q: IF THE COMMISSION WERE TO ADVISE PSNC AGAIN THAT IT WAS AT RISK OF NON-RECOVERY OF A LARGE PORTION OF THE MVP/MVP SOUTHGATE FIXED COSTS, IS THERE ANYTHING THAT PSNC COULD DO BETWEEN NOW AND 2022-23 TO MITIGATE THE PROBLEM ITS SHAREHOLDERS MIGHT FACE?

A: Yes, as just alluded to, there are several. First, there are a number of shippers that had subscribed to capacity on the now cancelled Atlantic Coast Pipeline (ACP) who might be interested in purchasing MVP/MVP Southgate capacity.

Second, there are potentially producers with current or future gas production in the MVP supply area (i.e., the Southwest Pennsylvania Marcellus drilling region) looking for outlets for that supply that could take assignment of PSNC's excess capacity. Moreover, knowing now that it was at risk of non-recovery, PSNC would have the next year or more to pursue one or more such strategies. In some regards, it is not unlike PSNC's having sold off its ownership share of the MVP Southgate project to a willing buyer, and, in the case of the excess capacity, there might well be a willing, creditworthy, "buyer" of, or "assignee" for, that portion of PSNC's subscription which is in excess of near to mid-term "need".

Lastly in this regard, PSNC could assign all of its capacity and capacity-related financial obligations to a producer or marketer and offer that same entity a contract to supply delivered gas to meet PSNC's design day needs going forward.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BY MR. NEAL:

Q Mr. Lander, did you prepare a summary of your testimony?

A I did.

Q Could you provide it to the Commission at this time?

A Sure. Thank you.

The purpose of my testimony is to present my All-In Cost Analysis of Public Service Company of North Carolina's (PSNC or the Company) acquisition of firm pipeline capacity in response to Company witness Jackson's testimony regarding PSNC's precedent agreements with the Mountain Valley Pipeline (MVP) and MVP Southgate pipeline. I reviewed the Company's application materials, its responses to data requests, and publicly available information about the MVP and MVP Southgate projects. I also offered the All-In Cost Analysis framework as an alternative to the best-cost supply strategy described by Company witness Jackson. I performed an All-In Cost Analysis of PSNC's MVP and MVP Southgate capacity and reached the following conclusions.

First, PSNC projects increasing

winter-peak demand from its customers. Because its projected increase in demand is both modest and of short duration, only occurring for a few hours on the coldest days in the winter, PSNC's purchase of year-round firm capacity on MVP and MVP Southgate projects is an extremely expensive solution. The total fixed cost of this capacity is over ~~$120~~ $115 million a year, equal to an estimated 2022-2023 all-in cost of ~~$324.22~~ $311.92, just fixed cost, for each dekatherm of gas estimated to actually be used by PSNC's customers through the incremental capacity represented by the MVP/MVP Southgate contracts. This enormous per unit cost of gas, actually projected to be used, is because the duration of the demand that PSNC experiences for its rate-paying sales customers, i.e., their load by day sorted from highest to lowest, makes such capacity very underutilized, especially relative to its annual cost. Notably, PSNC does not consider load duration as a factor in its capacity procurement process.

Second, as PS -- excuse me. Second, PSNC has other alternatives available to meet its projected demand, including contracting directly with gas producers and marketers that own capacity on the existing Transco pipeline and able to deliver to PSNC. As referenced in PSNC's filing, the Company already contracts with some of these types of companies to meet its winter-peak demand, and my analysis shows that this merchant capacity will be sufficient to meet PSNC's demand projections until at least 2035. The all-in cost of gas delivered by merchants on the existing Transco system is likely substantially lower than the all-in cost including gas cost, of PSNC's MVP and MVP Southgate capacity. PSNC's application provides no indication that the Company has evaluated this, or any other alternative option, to identify the lowest-cost resources for customers.

Third, PSNC's decision to contract for MVP/MVP Southgate will not only affect its firm gas customers, but also large commercial and industrial gas users that transport gas on the PSNC system, and electric ratepayers in North Carolina whose rates reflect changes in -- whose transport rates reflect changes in PSNC's fixed demand costs.

In light of these conclusions, I recommend that the Commission put PSNC on notice in its final order in this case that the contracted capacity on the MVP and MVP Southgate pipelines is far in excess of PSNC's demonstrated need. Alerting the Company now that it is at risk for not recovering the costs of its excess pipeline subscription will allow PSNC to take advantage of viable market alternatives for disposing of its MVP and MVP Southgate capacity to reduce these significant and unjustified costs.

Q Thank you.

MR. NEAL: Commissioner Brown-Bland, Mr. Lander is available for cross examination and questions from the Commission?

COMMISSIONER BROWN-BLAND: All right. Does the Company have cross examination?

MS. GRIGG: No questions.

COMMISSIONER BROWN-BLAND: Public Staff, any cross examination?

MS. HOLT: No questions.

COMMISSIONER BROWN-BLAND: Any questions from the Commission?

COMMISSIONER McKISSICK: I have no questions. Pretty straight forward.

COMMISSIONER BROWN-BLAND: Commissioner Hughes?

COMMISSIONER HUGHES: Just a quick question.

EXAMINATION BY COMMISSIONER HUGHES:

Q Mr. Lander, were you listening in on my question to the last witness?

A Yes.

Q I essentially have the same question for you. You call yours an All-In Cost Analysis. I didn't see in your testimony any alternative for what would happen if service was curtailed to even sales customers at the household level. Is that some analysis that you have done or you've seen done anywhere?

A Yes, I have. It's usually called L-O-L-E, loss of load equivalent. It's done throughout the northeast - I've seen it done in New Jersey, Massachusetts, New York - where they estimate for a certain level of load loss. Let's say they lose a neighborhood or a town, they then estimate what it would take to relight that area and what level of capacity loss that would entail. So, if they lost 50,000 a day what would be the load loss. And the typical tiering of that is the utility. When it's facing a load loss, you usually, due to a local constraint as mentioned by Witness Jackson, will take off its biggest customers first, it's interruptible customers, and then try to maintain load -- excuse me, maintain sufficient supply to the remaining firm customers the remaining and only firm customers. So that the occurrence they generally plan for is either a 1/10 percent meaning a once in a 100 years occurrence so that if the cost of avoiding the problem is more than -- I'm not going to say this correctly -- they come up with -- the cost of preventing it has to be less than this percentage over some period of time, a loss of load equivalence. And I apologize for not having directly at the tip of my tongue the math. But one of the things that's also important to keep in mind with respect to PSNC, they have a 500,000 a day typical winter peak load and they plan for a 800,000 typical design day. And you should ask them what their throughput is on a cold day. Because one of the things you'll find is that somehow with existing capacity on Transco, being the only pipeline that serves PSNC, there's a tremendous amount of gas on every day over and above the firm sales load that PSNC serves that's getting to those customers with existing capacity. And so what we're talking about in the testimony that we're providing is that contrary to the view that, well, relying entirely on LNG or entire reliably (sic) on this, it's to maintain your all of the above and add to your all of the above approach meaning you have year-round capacity sufficient. You have storage and incremental winter period capacity that will last and be useful for 10 to 60 days. And so that would mean, looking at that incremental -- that additional existing storage and winter period capacity, that you'd have to have between 10 and 60 design days in a year to have used up that resource. And so stating that you have it on November 1st and you may not have it in February, you'd have had to have six or eight design days between November and February to not have enough in February based upon the very diligent plan that they have.

And so when I've looked at the plan they have and the demand that they have, I don't have any argument with the existing panoply of services and the mix of long-term baseload, intermittent and peaking resources. The thing that was mystifying to me -- and those are resources that would cost between $0.38 and $0.60 depending on their duration and whatnot, and whether you'd measure that over an annual basis or just over the duration of the service. Why you would add, almost double your year-round capacity at rates two to three or four times existing capacity, didn't make sense to me. And when you talk about mitigating that cost with 75 percent going to ratepayers and 25 percent going to the Company, the ratepayers start with 100 percent of a $1.27 in a market that might get them in the secondary market between $0.10 and $0.30. And so what costs $1.27 might have revenue of say $0.30 and 25 percent of that goes to the Company which, you know, a quarter to seven and a half cents. And, you know, the ratepayers only have like a $0.25 reduction against $1.27 cost. And that, to me, doesn't make economic sense.

And so the recommendation that we made was if they feel they have to go through with this or they want to go through with this, let them go through with it, put them on notice that any money they make in the secondary market on this they get to keep, but the ratepayers don't pay for firm capacity on these projects that exceeds the projected peak day demand going out two to three years. And let -- you know, ratepayers will take that cost on, but the Company should take on the rest of the cost unless they find a place to mitigate it. And there's lots of companies out there that didn't get ACP, Atlantic Coast capacity that might take this off their hands and/or take all of it off their hand and then turn around and sell the company just like they buy --

MS. GRIGG: Commissioner Brown-Bland? Excuse me for interrupting. Commissioner Brown-Bland, this is Mary Lynne Grigg. I think we've gone well beyond Commissioner Hughes' question into reciting the rest of Mr. Lander's testimony, so I will object at this point.

COMMISSIONER BROWN-BLAND: All right. Mr. Neal, do you have something to say?

MR. NEAL: Commissioner Hughes had a very broad question about reliability. I would ask if this is responsive. I would ask, I guess, if Commissioner Hughes thinks this is responsive.

COMMISSIONER HUGHES: I am satisfied now. I think we can move on.

COMMISSIONER BROWN-BLAND: So we'll leave it there. So, any other questions, Commissioner Hughes? Commissioner McKissick?

COMMISSIONER HUGHES: (Shakes head no).

COMMISSIONER McKISSICK: (Shakes head no).

COMMISSIONER BROWN-BLAND: I had just one.

EXAMINATION BY COMMISSIONER BROWN-BLAND:

Q Witness Lander, you indicate, you call your analysis the All-In Cost. Is that synonymous with or the same as a Least Cost Analysis?

A No, it is not. What all-in cost does is primarily says when you define a problem you have a problem of a certain magnitude and you have a problem of a certain duration. And so when you're solving a problem of a magnitude and duration you want to see what are the costs of solving that magnitude of problem over the duration. And so there are different sizes of solutions and the size of the solution, you should -- what you should evaluate the solution against is how does that solution fit against the magnitude and duration of the problem as opposed to a problem -- you have a solution oh and it fits this problem.

So, what all-in cost does is it says what's the cost of meeting this magnitude of demand and then what is cost of meeting this duration. So it's not a measure of least cost. It says what is a cost comparison between solutions.

So what all-in cost does is it enables comparison. It doesn't drive solutions. It allows a comparison of two different solutions to solve one problem. So, the problem is defined and there are multiple different solutions possible and you evaluate between the solutions based upon the All-In Cost Analysis. Because if one all-in cost is $400.00 a dekatherm and another all-in cost is fifty you say, huh, fifty is cheaper than $400.00 if both solutions can solve the problem. And into both of those equations and analyses, you would bring reliability. Will the solution - you know, with the correct O&M, with the correct training, with the correct execution - be a reliable solution? Because as Ms. Jackson has said, the gas has to be there when the gas is there. You know, like I say in my testimony, it's not good to have gas at noon when you need it at seven. You have to have the gas at seven when you need it at seven. And so unlike the electric business where the lights can go off and the lights go on, you really don't want that to happen in the gas business. You'd rather not have that happen unless the cost of not having that happen is so huge that you're willing to have a low risk, excuse me, five-risk, low frequency occurrence rather than a high-cost, permanent solution to a very low frequency event.

Q All right.

A But I'm not recommending that. I'm just saying all-in cost is used for comparison purposes. It doesn't drive the solution. It allows you to look at different ways of solving the same problem on a cost-of-meeting-that-problem basis.

Q Once you perform an all-in analysis, do the cost outcomes dictate the choice or does discretion remain in your view?

A So there's when you have to use a risk adjustment against the magnitude of difference. If something is $0.20 different, it becomes a matter of discretion and preference. If the difference between two solutions is 10 to 15 times, you've got to wonder, you know, is -- under almost any circumstance is that magnitude of difference justified. And so it's like a -- it's a continuum. If the differences are small, discretion plays the day. You know, I feel like even two to three times discretion plays the -- pays the -- determines the outcome. When you get in the areas of four to five, six, and seven times difference in cost, you've got to wonder whether that risk is something that it's up -- whether the ratepayers should buy into that risk as opposed to the Company buying into that risk.

Q All right.

A It's who takes the risk.

Q All right.

A Was that helpful?

Q That's very helpful. Thank you for that.

COMMISSIONER BROWN-BLAND: Are there questions on Commission's questions starting with the Company?

MS. GRIGG: No questions.

COMMISSIONER BROWN-BLAND: Public Staff?

MS. HOLT: No questions.

COMMISSIONER BROWN-BLAND: And Mr. Neal?

MR. NEAL: Just briefly, Commissioner Brown-Bland.

EXAMINATION BY MR. NEAL:

Q Mr. Lander, in response to Commissioner Hughes' question about interruptibility, I just want to be clear, your All-In Cost Analysis did not presume that PSNC would have to interrupt service to its firm customers, did it?

A Correct. No, it would not. That wouldn't even be remotely in the plan.

MR. NEAL: That's all I have.

COMMISSIONER BROWN-BLAND: Mr. Neal, do you have a motion?

MR. NEAL: Yes, Commissioner Brown-Bland. At this time I would move Mr. Lander's direct exhibits that have been marked for identification as GML-1 through GML-8 be entered into the record.

COMMISSIONER BROWN-BLAND: Without objection, those exhibits will be received into evidence.

(WHEREUPON, Exhibits GML-1 through GML-8 are received into evidence.)

MR. NEAL: And I believe we already moved his testimony into the record, so --

COMMISSIONER BROWN-BLAND: And I do believe Mr. Lander also had some confidential material in at least one of his exhibits so it will remain confidential.

MR. NEAL: I believe we did not leave any confidential information in any of his exhibits. I think we noted where in a response there had been some confidential information but we left it out of the exhibit.

COMMISSIONER BROWN-BLAND: And that's true of Exhibit 8.? It's the one I had made note of.

MR. NEAL: Yes.

COMMISSIONER BROWN-BLAND: All right. Mr. Lander, you are excused.

(The witness is excused)

COMMISSIONER BROWN-BLAND: Madam Court

Reporter, do you need a break?

COURT REPORTER: (Shakes head no).

COMMISSIONER BROWN-BLAND: We will go back to the Company for rebuttal. You're on mute.

MS. GRIGG: Thank you, Commissioner Brown-Bland. We would like to recall Ms. Rose Jackson for her rebuttal testimony.

COMMISSIONER BROWN-BLAND: There she is.

ROSE M. JACKSON;
having been previously affirmed,
returned to the stand and
testified as follows:

DIRECT EXAMINATION BY MS. GRIGG:

Q Good afternoon, Ms. Jackson.

A Good afternoon.

Q Did you -- are you the same Ms. Jackson who provided direct testimony this morning?

A Yes, ma'am.

Q Did you also cause to be prefiled in this docket on August 5th, 2021, rebuttal testimony in question and answer form consisting of nine pages?

A Yes, ma'am.

Q Are there any corrections you would like to make

to your rebuttal testimony at this time?
A No, ma'am.
Q If I asked you the questions in your rebuttal testimony today, would your answers be the same?
A Yes, ma'am, they would.
Q Do you have a summary of your rebuttal testimony?
A Yes, ma'am, I do.
Q Would you please read it now?
A Good afternoon, Commissioners. My rebuttal testimony provides support for PSNC's best-cost supply strategy and rebuts Witness Lander's recommended All-In Cost Analysis. I begin by explaining how the best-cost strategy is well-established and, contrary to Witness Lander's suggestions, considers least-cost options as well as alternatives for meeting both current and future demand. I then explain how Witness Lander's All-In Cost Analysis is based on hypothetical scenarios that ignore many real world factors that PSNC must address in order to provide reliable natural gas service to firm customers. I conclude by explaining how the best-cost supply strategy has consistently allowed PSNC to serve its firm customers reliably

and cost-effectively. This concludes my summary.

MS. GRIGG: Thank you, Ms. Jackson.

Commissioner Brown-Bland, Ms. Jackson is available for cross examination and questions from the Commission.

COMMISSIONER BROWN-BLAND: Was there cross examination on the rebuttal?

MR. NEAL: Yes, Commissioner Brown-Bland. May I proceed?

COMMISSIONER BROWN-BLAND: Yes.

MR. NEAL: Thank you.

CROSS EXAMINATION BY MR. NEAL:

Q Good afternoon now, Ms. Jackson.

A Good afternoon.

Q Good to see you again. I'd first like to turn your attention to your rebuttal testimony on page 7, line 13. Is it still your testimony that Witness Lander completely ignores reliability in his analysis?

A Based on Mr. Lander's direct testimony, and it was difficult to follow how he calculated some of the numbers he utilized because he did state that they were hypothetical or back-of-the-envelop calculations, and based on the proposals he put

forth I do believe he ignored reliability.
Q I would like to refer you to page 12 of the direct testimony of Mr. Lander. Do you have that in front of you?
A Yes, sir. Page 12?
Q Yes, ma'am.
A Okay.
Q If you could, for me, please read the question and first two sentences of his answer on lines 12 through 18?
A Let's see, where it says *Before you continue*?
Q That's right.
A Okay. The question states, *Before you continue, why did you use dekatherm per hour as your measure*? And you want me to read -- I'm sorry.
Q The first two sentences of the answer. It goes from lines 14 through 18.
A It says *because local distribution companies, or LDCs, typically experience their peak daily demand in one or more hours between 6:00 and 8:00 AM in the winter, and, for that demand, LDCs have to make the gas be there when it is needed.*
Q And then the next sentence.
A *It is not all right for gas needed at 7:00 AM to*

come at 12:00 noon.

Q And sorry, there's one more sentence there. I didn't see the period.

A *If it is needed at 7:00 AM, it has to be there at 7:00 AM, period.*

Q Now, Ms. Jackson, you would agree that having gas when it is needed, right down to the hour it is needed, is an essential part of reliability of the service for an LDC, right?

A Reliability -- well, when we look at reliability we're typically looking at a gas day but, yes, we also consider where the peaks occur. But I think this was more consistent with looking at electric demand rather than LDC demand.

Q And so you don't think his testimony where he talks about local gas distribution companies or LDCs as he does on line 14 was referring to LDCs?

A He's making a generalized statement that typically LDCs experience peaks between 6:00 and 8:00. We can also experience peaks in the evening hours as well.

Q But don't you agree that he also says that it's essential for the gas to be there at the hour at the time it is needed; isn't that right?

A It appears -- it says LDCs have to make the gas be there when it is needed.
Q Do you disagree with that statement?
A No.
Q And would you agree that as a general matter an LDC that has entered into contracts for firm short-term peaking capacity, to provide that company with assurance that it can meet its demand day requirements for the next five years, has assured itself of more reliability than an LDC that has no contracts for required short-term peaking beyond the next year?
A I'm sorry. Can you repeat that again, that question again? I'm sorry.
Q Sure. I know it's a long question. But just as a general matter, imagine an LDC that has entered into contracts for firm short-term peaking capacity, that provide that company with some level of assurance that it can meet its demand day requirements for the next five years. So you've got that in your head?
A Yes, sir.
Q That hypothetical?
A Yes.

Q So, wouldn't that LDC have assured itself of more reliability than one that had no contracts for required short-term peaking needs beyond the next year?

A I think it will be dependent upon who the provider of that short-term winter peaking option would be. And so I think that goes into looking at what type of assets back up that winter peaking option. But, I mean, that's a generalized statement and I would have to see the details.

Q Well, are you generally familiar with PSNC's contract with a company known as EDF or Électricité de France, de France?

A Yes, sir.

Q And I believe that's referenced on Creel Exhibit 1, Schedule 2 at line 32.

A Yes, sir.

Q And you would agree that the EDF trading FT reservation that's listed there, that's not for a pipeline company is it?

A No, sir, it's for a winter peaking option.

Q And EDF is a marketer; isn't that right?

A Yes, they are.

Q And so they sell delivered gas to PSNC at your city gates using their contracted for firm transportation capacity; isn't that right?
A Yes, sir, but they've been fully vetted by our credit department and our gas supply department. So, that's all I'm stating is that to make a hypothetical or generalized decision based on that, I would have to look at the details to state whether or not that would be a reliable source of supply.
Q And -- but you do think that your EDF contract is a reliable source of supply?
A Yes, sir. It's a short-term contract. Yes, sir.
Q And going back to your Direct Exhibit 1, it shows I believe for the 2020-2021 year of 40,000 dekatherms per day in the category of short-term peaking services; is that right?
A Yes, sir, that's correct.
Q And the following year, again at the time you filed for 2021-2022, it shows 24,000 dekatherms per day; is that right?
A Yes, sir, that's correct.
Q And the years that follow, you would agree 2022 to 2023 and there on out, there's nothing listed

for those short-term peaking services; is that right?
A That's correct.
Q And if you would please, can you turn back to Lander, Mr. Lander's direct testimony at page 21?
A Okay.
Q And do you see where, in response to the question, I think this is somewhere on line 22 or so, *What other alternatives does PSNC have to meet its projected demand*? Do you see that question?
A Yes, sir.
Q And do you see his response that *Specifically PS* -- starting at line 23, *Specifically, PSNC currently plans to contract for supply from a wholesale gas merchant or merchants, i.e., one or more producers or marketers, that holds capacity in its own name and agrees, by contract, to sell to PSNC when PSNC calls for deliveries of such contracted supply.* Do you see that testimony?
A Yes, sir.
Q And would you agree that Mr. Lander is referring to delivered service contracts much like the EDF trading contract we discussed a moment ago?

A Yes, sir.
Q And finally, could you turn to page 25 of Mr. Lander's direct testimony? Starting at line 11, there's a question, *With respect to reliance*; do you see that?
A Yes, sir.
Q And I won't have you read this whole thing or you may, I guess, feel free to read it to yourself, but do you remember his -- this exchange where he was asked, *With respect to reliance on merchant delivered gas contracts, what if they work one year, but the next, the merchant decides to sell to someone else*? Reading his response, again to yourself if you'd like, from lines 14 to 24. Let me know when you're ready for the question.
A Okay.
Q So you -- would you agree that here Mr. Lander is testifying about entering into contracts for delivered service and staggered five-year strips; isn't that right?
A That's what he appears to be suggesting. I will say that over the last three years, three to four years where we've been out in the marketplace trying to find delivered winter peaking options,

there have been less and less parties willing to bid on that type of service. And the terms, when he says five, four, three, two and one-year terms, it is difficult together find anyone that's willing to go out beyond that two-year term.

I mean, since the time that we filed my Exhibit 1, we have a shortfall for this upcoming winter season of 60,000 dekatherms and we have only contracted for 55,000. We're continuing to solicit the market to find the remaining five, and I think it's going to become even more difficult to find this type of service. Number one, demand is growing, especially in the southeast. But, number two, with less and less pipeline capacity being available, or new capacity being available in the marketplace there are going to be less assets to provide this type of service. And I think the cost is going to go up because demand is going to go up.

Q And -- if you'll bear with me for one moment. You would agree in any event that a five-year term if you can get it is longer than a one or two-year term; isn't that right?

A   Yes, sir.

MR. NEAL: I have no further questions.

COMMISSIONER BROWN-BLAND: Are there questions from the Public Staff?

MS. HOLT: (Shakes head no).

COMMISSIONER BROWN-BLAND: Ms. Holt indicates no.

Redirect?

MS. GRIGG: No redirect.

COMMISSIONER BROWN-BLAND: Questions by the Commission?

COMMISSIONER HUGHES: None here.

COMMISSIONER McKISSICK: (Inaudible).

COMMISSIONER BROWN-BLAND: Commissioner McKissick, that was none from you as well?

COMMISSIONER McKISSICK: That's correct.

COMMISSIONER BROWN-BLAND: Ms. Jackson, for once, I don't have any questions.

So, Ms. Grigg, do you have a motion for me?

MS. GRIGG: Yes, ma'am. I move that Ms. Jackson's rebuttal testimony be copied in the record as if given orally from the stand.

COMMISSIONER BROWN-BLAND: That motion is allowed.

MS. GRIGG: Thank you.

(WHEREUPON, the prefiled rebuttal testimony of ROSE M. JACKSON is copied into the record as if given orally from the stand.)

BEFORE THE

NORTH CAROLINA UTILITIES COMMISSION

PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INCORPORATED

DOCKET NO. G-5, SUB 635

REBUTTAL TESTIMONY

OF

ROSE M. JACKSON

AUGUST 5, 2021

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, BY WHOM YOU ARE EMPLOYED, AND IN WHAT CAPACITY.

A. My name is Rose M. Jackson, and my business address is 220 Operation Way, Cayce, South Carolina. I am employed by Dominion Energy Services, Inc. ("DE Services") as Director-Gas Supply Services.

Q. ARE YOU THE SAME ROSE M. JACKSON WHO FILED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes. I filed direct testimony in this proceeding on June 1, 2021.

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

A. The purpose of my rebuttal testimony is to provide Public Service Company of North Carolina, Inc., d/b/a Dominion Energy North Carolina's ("PSNC" or the "Company") response to the direct testimony of Gregory M. Lander filed on behalf of the Haw River Assembly.

Q. HAS WITNESS LANDER PROVIDED ANY RECOMMENDATIONS REGARDING PSNC'S GAS COSTS INCURRED DURING THE 12-MONTH REVIEW PERIOD ENDED MARCH 31, 2021?

A. No. Witness Lander has not recommended any changes to the Company's gas costs incurred during the 12-month review period ended March 31, 2021, and does not opine on the prudence of such costs. Rather, his testimony criticizes the Company's best-cost strategy and recommends the Company use an "all-in costs" approach in evaluating potential gas purchases.

Q. DO YOU AGREE WITH WITNESS LANDER'S TESTIMONY AND RECOMMENDATIONS?

A. No. Witness Lander's testimony is based on hypothetical scenarios and ignores many "real world" factors that PSNC must address in order to provide reliable natural gas service to firm customers. I explain how his conclusions are erroneous, speculative, and based on unsubstantiated assumptions.

Q. PLEASE EXPLAIN WITNESS LANDER'S CRITICISMS OF PSNC'S BEST-COST STRATEGY.

A. Witness Lander makes several unsupported generalizations regarding PSNC's best-cost strategy. He argues that he has never "encountered" "this sort of strategy" before, and goes on to contend, without any supporting examples, that "[u]sually, [local distribution companies] articulate a "least-cost" procurement process…"[1] Witness Lander next argues that the best-cost strategy is "problematic" because the first two prongs of the strategy—supply security and operational flexibility—are "entirely subjective" and that the Company should instead focus its evaluations on cost.[2] He continues his criticism of PSNC's best-cost strategy by stating as a matter-of-fact that the best-cost strategy does not allow PSNC to adequately consider lesser-cost options.

Q. ARE WITNESS LANDER'S CRITICISMS VALID?

A. No. The Company's best-cost strategy is a long-standing approach which has been utilized by all the LDCs in North Carolina, in which security of supply, operational

[1] Direct Testimony of Gregory M. Lander, P. 6, Ln. 10-15.
[2] *Id.* at P. 6, Ln. 16-20.

flexibility and **all cost options** are thoroughly evaluated, not just the least-cost supply under any circumstances.

Q. PLEASE PROVIDE AN OVERVIEW OF THE HISTORY OF THE BEST-COST STRATEGY IN NORTH CAROLINA.

A. In 1991, the North Carolina General Assembly enacted N.C. Gen. Stat.§ 62-133.4, of which subsection (c) requires what is known as "Annual Gas Cost Reviews." The Commission initiated a rulemaking proceeding in Docket No. G-100, Sub 58 on August 21, 1991, for the purpose of considering the manner in which the statute should be implemented, and on April 9, 1992, issued its Final Order Adopting Rule R1-17(k). Pursuant to that order, on June 1, 1993, Franklin H. Yoho filed testimony on behalf of PSNC in its first annual review proceeding.

Q. IN THAT TESTIMONY, DID MR. YOHO TESTIFY REGARDING THE COMPANY'S "BEST-COST STRATEGY"?

A. Yes. In fact, in every PSNC annual gas cost review since then—almost 30 years—witnesses on the Company's behalf have described its gas supply policy as a "best-cost strategy," the criteria of which include supply security, operational flexibility, and cost of gas.

Q. HAS THE COMMISSION CONSISTENTLY FOUND THAT PSNC'S GAS COSTS HAVE BEEN PRUDENTLY INCURRED?

A. Yes. The Commission has consistently determined that PSNC's incurred gas costs to be reasonable and prudent. These costs, of course, were incurred under the Company's best-cost strategy for its gas supply acquisitions. I am not aware of any instances where the Commission has disapproved of, or otherwise taken issue with, PSNC's best-cost strategy. Also, as explained below, I am aware of instances where the Commission has accepted a best-cost strategy as utilized by other North Carolina natural gas utilities.

Q. HAS THE PUBLIC STAFF EVER TAKEN ISSUE WITH PSNC'S BEST-COST STRATEGY?

A. No. Rather, it is my understanding that the Public Staff has thoroughly investigated the Company's gas supply acquisitions in each of its annual reviews since 1993 and has consistently found that PSNC's gas costs were prudently incurred. Again, the Company's gas costs were incurred as a result of the decisions made pursuant to the best-cost strategy. Likewise, in this proceeding, the Public Staff does not take issue with the Company's best-cost strategy.

Q. HAS THE COMMISSION OTHERWISE ADDRESSED THE BEST-COST METHODOLOGY?

A. Yes. In its Order Approving Merger Subject to Regulatory Conditions and Code of Conduct in Docket No. G-5, Sub 585, the Commission adopted a regulatory condition requiring PSNC to manage its contracts in conformance with its best-cost strategy.[3] Regulatory Condition 15.2 states:

> Ownership and Control of Contracts. Except as provided in Code of Conduct Section III.D.5 (Joint purchases), PSNC shall retain title, ownership, and management of all gas contracts necessary to ensure the provision of reliable Natural Gas Services consistent with **PSNC's best cost gas and capacity procurement methodology**. (emphasis added).

[3] *Order Approving Merger Subject to Regulatory Condition,* at 29, Docket No. G-5, Sub 585 (Nov. 19, 2018).

Q. HAVE OTHER NATURAL GAS UTILITIES USED A BEST-COST STRATEGY?

A. Yes. In North Carolina, I am aware that the other natural gas utilities regulated by this Commission have relied upon a best-cost strategy, and have testified to this strategy before the Commission during annual review proceedings.

Q. HOW DO YOU RESPOND TO WITNESS LANDER'S POSITION THAT THE SUPPLY SECURITY AND OPERATIONAL FLEXIBILITY CRITERIA OF THE BEST-COST SUPPLY STRATEGY ARE "SUBJECTIVE"[4]?

A. Supply security and operational flexibility are not "subjective" criteria. As I explained in my direct testimony, PSNC evaluates supply security based on several objective criteria: (1) the number of suppliers available to the Company; (2) the number of receipt points available to the Company; (3) the number of purchase quantity commitments; and (4) the existence (or not) of favorable contractual terms in gas supply agreements. Moreover, the availability of gas supply is not subjective—there either is, or is not, a specific amount of supply available.

Regarding the subjectivity of PSNC's need for operational flexibility, as explained in my direct testimony, operational flexibility results from gas supply agreements having different purchase commitments and swing capabilities, as well as from injections into and withdrawals out of storage. The inclusion of favorable terms in PSNC's gas supply agreements is not subjective—those terms allow PSNC flexibility to increase or decrease the amount of supply received under such

[4] Direct Testimony of Gregory M. Lander, at P. 6, Ln. 20.

agreements. Witness Lander's generalized assertion that PSNC's best-cost strategy is subjective should be rejected as unsupported and incorrect.

If PSNC made its supply decisions only on the basis of least-cost with little or no regard to supply security and operational flexibility, it is highly likely the Company may not have been able to serve its firm customers during the Polar Vortex experienced here in North Carolina in 2014. Similarly, the Polar Vortex experienced in Texas in 2021 exposed the risk associated with not planning for supply security and operational flexibility. Gas supply that is acquired without considering reliability is of no value whatsoever if the gas is not available when it is needed.

Q. DOES PSNC'S BEST-COST STRATEGY CONSIDER LEAST-COST AND ALTERNATIVE OPTIONS?

A. Of course. Witness Lander states that PSNC's best-cost strategy "does not adequately consider lesser-cost options that could also meet the Company's needs,"[5] and that he "do[es] not know"[6] whether PSNC has "evaluate[d] a range of alternatives for meeting its projected increased demand."[7] To clarify, PSNC's best-cost analysis *does* consider least-cost options and PSNC has considered alternatives for meeting both current and future demand. As stated in my direct testimony, ". . . the Company remains committed to acquiring the most cost-effective supplies of gas available while maintaining the necessary supply security and operational

[5] Direct Testimony of Gregory M. Lander, at P. 7, Ln. 3-6.
[6] *Id.* at P. 8, Ln. 3-5.
[7] *Id.*

flexibility."[8] PSNC has on-going discussions with existing and potential supply providers and, as a need for additional capacity is identified, PSNC solicits competitive gas supply bids to ensure cost-effective proposals.

Q. IS IT YOUR OPINION THAT THE BEST-COST SUPPLY STRATEGY IS REASONABLE, PRUDENT, AND WELL-ESTABLISHED?

A. Yes. The best-cost supply strategy is utilized by multiple natural gas utilities in North Carolina and has repeatedly been accepted by this Commission and the Public Staff. The best-cost strategy analyzes alternatives to ensure customers receive reliable supply at the most reasonable and prudent cost available.

Q. WITNESS LANDER RECOMMENDS PSNC REPLACE ITS BEST-COST STRATEGY WITH AN "ALL-IN COST" ANALYSIS. DO YOU HAVE CONCERNS WITH WITNESS LANDER'S "ALL-IN COST" ANALYSIS?

A. Yes. Witness Lander completely ignores reliability in his analysis. His analysis focuses solely on the cost of gas and disregards supply security and operational flexibility. As mentioned earlier, the Polar Vortex event that occurred earlier this year is a prime example of the least-cost option not being the most reliable option to serve firm customers. PSNC has an obligation to serve its firm customers reliably. Commission Rule R6-23 states:

> The production and/or storage capacity of the utility's plant, supplemented by the gas supply regularly available from other sources, must be sufficiently large to meet all reasonably expectable demands for firm service.

[8] Direct Testimony of Rose M. Jackson, at P. 5, Ln. 13-15.

Q. DO YOU HAVE ADDITIONAL CONCERNS WITH THE "ALL-IN COST" ANALYSIS?

A. Yes. Witness Lander's analysis is based on conjecture and ignores real world market conditions. For example, Witness Lander himself characterizes the volumes he uses in his analysis as "hypothetical"[9] and fails to consider actual demand volumes. He also assumes that his proposed alternatives will be readily available on the coldest days of the year, and at a price that does not reflect a premium for periods of high demand.[10] Historically, this has not been the case. Alternatives like those proposed by Witness Lander have not been readily available in extreme cold weather, such as that experienced in the Polar Vortex events of the last decade, and certainly not at prices assumed by Witness Lander. Witness Lander assumes a $3.50 per dekatherm ("Dth") average price which ignores daily and monthly price volatility. Currently, market prices are above $4.00 per Dth for the winter period. During periods of high demand, such as the 2018 Polar Vortex Event, daily prices delivered in Transco Zone 5 where PSNC is located were as high as $150.00 per Dth, over forty times higher than the assumption given by Witness Lander. This $150.00 price is significantly lower than prices during the Texas Polar Vortex Event which reached $400.00 per Dth.

Another concern I have is his proposal to truck LNG to temporary, satellite locations to meet peak demand. The scenario he presents is faulty on many accounts. Witness Lander assumes 1500 Dth per hour or 15,000 Dth per day, yet

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[9] Direct Testimony of Gregory M. Lander, at P. 14, Ln. 22.
[10] *Id.* at P. 15, Ln. 11-12.

PSNC faces an incremental demand of approximately 60,000 Dth per day for the upcoming winter. Using the assumptions that Witness Lander makes in his testimony, and applying them to the Company's actual 60,000 Dth incremental requirement, the Company would need to obtain delivery of 45-71 truckloads of LNG on a design day, depending upon the size of the trucks. That would require three truck deliveries every hour to various delivery points on days when LNG is in its highest demand and lowest availability. This hypothetical solution disregards the reality of icy and impassable road conditions in colder than normal weather scenarios, along with the limited availability of LNG tankers and LNG on the coldest days of the year. Once again, reliability is not the concern of Witness Lander.

Q. DO YOU RECOMMEND THAT PSNC BE REQUIRED TO USE THE "ALL-IN COST" ANALYSIS?

A. No. PSNC has utilized the best-cost strategy for nearly thirty years, and as a result, PSNC has served its customers reliably and cost-effectively.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

COMMISSIONER BROWN-BLAND: And she didn't have exhibits with the rebuttal, did she?

MS. GRIGG: No, ma'am, she did not.

COMMISSIONER BROWN-BLAND: So we're good. So, Ms. Jackson, you are excused.

(The witness is excused)

COMMISSIONER BROWN-BLAND: Anything else from the parties that -- outside of the proposed orders? Anything else?

(No response)

Proposed orders good with everybody 30 days from the availability and posting of the transcript?

MR. NEAL: Yes, Commissioner Brown-Bland.

MS. GRIGG: Yes, ma'am.

MS. HOLT: That's fine.

COMMISSIONER BROWN-BLAND: That will be so ordered. If there is nothing else for us at this time, I, despite the surprises we had on the front end, I think we had a productive and good hearing. So again, thank you for your patience and we will be adjourned.

(The proceedings were adjourned)

C E R T I F I C A T E

I, KIM T. MITCHELL, DO HEREBY CERTIFY that the Proceedings in the above-captioned matter were taken before me, that I did report in stenographic shorthand the Proceedings set forth herein, and the foregoing pages are a true and correct transcription to the best of my ability.

Kim T. Mitchell

Kim T. Mitchell