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PSEG
Services Corporation

VIA BPU ELECTRONIC MAIL

June 1, 2022

In the Matter of Public Service Electric and Gas Company's 2022/2023
Annual BGSS Commodity Charge Filing for its Residential Gas Customers
Under its Periodic Pricing Mechanism and for Changes in its Balancing Charge

Docket No. GR_____________

Carmen Diaz, Acting Secretary
New Jersey Board of Public Utilities
44 South Clinton Avenue, 1st Floor
Post Office Box 350
Trenton, New Jersey 08625-0350

Dear Acting Secretary Diaz:

Attached for electronic filing is Public Service Electric and Gas Company's ("Public Service") Motion, Testimony of David F. Caffery, and supporting attachments in the above-referenced matter, which have been uploaded to the Board of Public Utilities' E-Filing system. In this filing, Public Service is requesting to increase the current BGSS default commodity charge applicable to residential customers for service rendered on and after October 1, 2022. The Company is also requesting an increase in its Balancing Charge rate. The impact of the proposed change to the BGSS default commodity charge and the Balancing Charge on a typical residential heating customer using 172 therms per month during the winter months and 1,040 therms on an annual basis is an annual increase of approximately 24.48%.

This filing and the proposed BGSS rate is in accordance with the Board's January 6, 2003 Order Approving BGSS Price Structure, Docket No. GX01050304. Moreover, this filing includes the Minimum Filing Requirements as approved by the Board.

Furthermore, as directed by the Board's Order in Docket No. EO20030254, dated March 19, 2020, the Company hereby submits this filing via electronic delivery only to the Board Secretary, and will suspend submitting such filings as paper documents until the Board directs otherwise.

Very truly yours,

Matthew Weissman

Matthew M. Weissman

C Attached Service List (electronic)

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STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY'S 2022/2023 ANNUAL BGSS COMMODITY CHARGE FILING FOR ITS RESIDENTIAL GAS CUSTOMERS UNDER ITS PERIODIC PRICING MECHANISM AND FOR CHANGES IN ITS BALANCING CHARGE	)	MOTION DOCKET NO. GR____________

Public Service Electric and Gas Company ("PSE&G" or the "Company"), a public utility of the State of New Jersey, with its principal offices for the transaction of business at 80 Park Plaza Newark, New Jersey 07101, hereby moves before the New Jersey Board of Public Utilities ("Board") as follows:

PSE&G, as a combination electric and gas utility, is engaged in the purchase, transmission, distribution and sale of natural gas for residential, commercial and industrial customers in New Jersey, in addition to its electric operations.

GENERIC PROCEEDING ON BGSS PRICE STRUCTURE

1) On January 6, 2003, as the result of a generic proceeding, the Board issued its Order Approving the BGSS Price Structure in Docket No. GX01050304 ("BGSS Pricing Structure Order"), in which the Board approved procedures providing for annual Basic Gas Supply Service ("BGSS") Commodity Charge filings by the Company and all the other New Jersey gas distribution companies by June 1, 2003 and each year thereafter, and for two potential 5% self-implementing rate increases on December 1st and the following February 1st. These two limited self-implementing rate adjustments would be permitted each year upon notice to the Board and the New Jersey Division of Rate Counsel ("Rate Counsel") on November 1st and

January 1st of the estimated change to take effect on December 1st and February 1st, respectively.

MINIMUM FILING REQUIREMENTS

2) In addition the Board, in its January 16, 2003 Order Adopting Provisional Rates in Docket No. GR02090702, reserved an issue to itself by directing that the parties to that proceeding meet to develop mutually agreed upon minimum filing requirements for future annual BGSS Commodity Charge petitions in time for the next petition.

3) The parties to that proceeding agreed on a list of 17 Annual BGSS Minimum Filing Requirements that are applicable to the Company's June 1st annual BGSS filing. The parties included those Minimum Filing Requirements in a Settlement on Annual BGSS Minimum Filing Requirements that was approved by the Board on June 20, 2003. Also, as part of the BGSS settlement in Docket No. GR15060647 approved by the Board on February 24, 2016, Item 18 has been added to address the Company's Gas Supply Plan. Lastly, as part of the BGSS settlement in Docket No. GR17060589 approved by the Board on April 25, 2018, the parties to that proceeding agreed to modifications to Item Nos. 13 and 18.

2021/2022 ANNUAL BGSS COMMODITY CHARGE FILING

4) On June 1, 2021, the Company made its 2021/2022 Annual BGSS Commodity Charge filing for its Periodic Pricing Mechanism applicable to its residential gas customers pursuant to the BGSS Pricing Structure Order. The filing was also made in accordance with the above-referenced Minimum Filing Requirements.

5) In the 2021/2022 BGSS filing the Company requested to maintain the then current BGSS Commodity Charge rate of $0.319937 cents per therm (including losses and SUT) through

September 30, 2022. This request was supported by the direct testimony of David F. Caffery, in which he addressed all of the Minimum Filing Requirements and provided the basis for maintaining the BGSS rate.

6) The Company also requested an increase in its Balancing Charge, which recovers the cost of providing storage and peaking services. The Company requested a change in the Balancing Charge from $0.085723 per balancing therm (including losses and SUT) to the current charge of $0.093477 per balancing use therm (including losses and SUT). The increase in the balancing charge was supported by Mr. Caffery.

7) Additionally, the Company requested a change in its Storage Inventory Carrying Charge, which is recovered through the balancing and commodity charges. The requested charge was $0.002778 per balancing use therm (excluding losses & SUT) for the balancing portion and $0.004610 per therm (excluding losses & SUT) for the commodity portion using the applicable billing determinants for each.

8) The 2021/2022 filing by the Company estimated a BGSS revenue increase of $49M (excluding losses and SUT) would be required for the period of October 1, 2021 through September 30, 2022. However, based on the testimony of Mr. Caffery, the Company filed to maintain the then current BGSS rate.

9) The Company also requested the authority to execute an amendment to the Requirements Contract with PSEG Energy Resources & Trade LLC ("ER&T") providing for a five (5)-year extension, continuing on a year-to-year basis thereafter, subject to a two (2)-year termination notice requirement. The amendment did not request other changes to the terms and conditions of the Requirements Contract.

10) The Company also requested approval to potentially acquire up to 4,000Dth/day of RNG supply for inclusion in the Company's BGSS-RSG gas supply portfolio, with costs included in the Company's BGSS-RSG weighted average cost of supply in future BGSS filings.

11) Residential annual bills comparing the then current and proposed Balancing Charge, pursuant to the 2021/2022 filing were included in the form of public notice attached as Attachment C to that motion.

12) Notices setting forth the Company's June 1, 2021 request to maintain the BGSS Commodity Charge and request to increase the Balancing Charge, including the date, time, and place of the public hearings, were placed in newspapers having a circulation within PSE&G's gas service territory, and were served on the county executives and clerks of all municipalities within its gas service territory.

13) Public hearings were scheduled and conducted telephonically on September 10, 2021, at 4:30 p.m. and 5:30 p.m. No member of the public appeared or spoke at the public hearings, and no comments were filed with the Board.

14) PSE&G, Board Staff, and Rate Counsel agreed, on a provisional basis, to maintain the BGSS-RSG Commodity Charge and increase the Balancing Charge as of December 1, 2021, or as soon as possible upon the issuance of a Board Order approving the Stipulation for a Provisional BGSS Rates ("Provisional Stipulation"). The Provisional Stipulation was approved at the Board agenda meeting on November 17, 2021. As a result, the BGSS Balancing Charge was provisionally increased from $0.085723 per balancing use therm (including losses and SUT) to $0.093477 per balancing use therm (including losses and SUT) for service rendered on and after December 1, 2021.

15) In a separate November 2021 Order, the Board granted a request made by the four (4) New Jersey Gas Distribution Utilities ("GDCs") seeking waiver of the timing requirement, and authorizing the GDCs to provide notice of self-implementing 5% rate increases, effective December 1, 2021, as permitted under the Board's January 2003 BGSS Order. On November 19, 2021, PSE&G filed notice of that 5% rate increase, which would change the Company's BGSS Commodity Charges from $0.319937 per therm, including losses and SUT, to $0.363636 per therm, including losses and SUT, effective December 1, 2021.

16) In the November 2021 GSMP II Order, the Board approved a slight decrease to the Company's BGSS-RSG rate associated with approval of new rates from a cost recovery filing for the next phase of the Company's Gas System Modernization Program and Associated Cost Recovery Mechanism ("GSMP II"). Pursuant to that approval, the BGSS-RSG Commodity Charge was decreased from $0.363636 per therm, including losses and SUT, to $0.363545 per therm, including losses and SUT, effective December 1, 2021.

17) On December 29, 2021, pursuant to the Board's January 2003 BGSS Order, PSE&G filed notice of a 5% rate increase effective February 1, 2022 ("December 2021 Notice"). The self-implementing rate increase would change the Company's BGSS Commodity Charges from $0.363545 per therm, including losses and SUT, to $0.410212 per therm, including losses and SUT, effective February 1, 2022.

18) On December 6, 2021, the Board transmitted this matter to the Office of Administrative Law as a contested case, where it was subsequently assigned to the Honorable Gail Cookson, Administrative Law Judge ("ALF"). ALJ Cookson held a telephonic prehearing conference on January 6, 2022.

19) PSE&G, Board Staff, and Rate Counsel subsequently completed their review of the Company's 2021/2022 BGSS filing, and agreed that: (a) the Company's BGSS Commodity Service, tariff rate for BGSS-RSG of $0.410212 per therm (including losses and SUT) would be deemed final; (b) the Balancing Charge of $0.093477 per balancing use therm (including losses and SUT) would remain in effect and also be deemed final; and (c) the request for authorization to execute an amendment to the Requirements Contract for a five (5)-year extension, continuing on a year-to-year basis thereafter, subject to a two (2)-year termination notice, was approved. The Company withdrew without prejudice the request for inclusion of RNG and associated costs into future BGSS filings. The Board approved this stipulation for final rates on April 6, 2022.

20) Subsequent to the April Order, on May 26, 2022 the Company made a compliance filing in response to the Board's Orders *In the Matter of the Petition of Public Service Electric and Gas Company for Approval of the Next Phase of the Gas System Modernization Program and Associated Cost Recovery Mechanism ("GSMP II") (December 2021 GSMP II Rate Filing)* in BPU Docket No. GR21121256, and *In the Matter of the Petition of Public Service Electric and Gas Company for Approval of Electric and Gas Rate Adjustments Pursuant to the Energy Strong II Program* in BPU Docket Nos. ER21111209 and GR21111210. In those matters, the BGSS-RSG Commodity Charge was decreased from $0.410212 per therm (including losses and SUT) to $0.410132 per therm (including losses and SUT) effective June 1, 2022.

2022/2023 ANNUAL BGSS COMMODITY CHARGE FILING

21) The Company is making this 2022/2023 Annual BGSS Commodity Charge filing for its Periodic Pricing Mechanism applicable to its residential gas customers pursuant to the BGSS

Pricing Structure Order. This filing is also made in accordance with the above-referenced Minimum Filing Requirements.

22) In this Motion the Company is requesting to increase the current Board approved BGSS rate of $0.410132 cents per therm (including losses and SUT) to $0.651838 cents per therm (including losses and SUT) through September 30, 2023. This request is supported by the direct testimony of David F. Caffery attached hereto as Attachment A, in which he addresses the Minimum Filing Requirements and explains and supports the Company's request to increase the current BGSS-RSG rate.

23) The Company is also requesting an increase in its Balancing Charge, which recovers the cost of providing storage, peaking services, and a share of its Storage Inventory Carrying Charge. See Attachment D of the filing. The Company requests a change in the Balancing Charge from $0.093477 per balancing use therm (including losses and SUT) to $0.100691 per balancing use therm (including losses and SUT). The increase in the balancing charge is supported by Mr. Caffery (Attachment A).

24) Natural gas prices during the most recent period have increased dramatically from the levels experienced at this time last year, trading at highs not seen since 2008. NYMEX prompt month daily prices have traded between approximately $3.50/Dth and $9.00/Dth since the middle of January 2022, with June prices settling at $8.908/Dth. This compares with a NYMEX price of $3.00/Dth at this time last year during the midst of the Covid crisis. The forward (May 10) NYMEX strip used by the Company in this filing (see Item 8) shows that average prices are 120.5% higher than last year's NYMEX strip. Based upon the forward strip, prices are expected to increase for the rest of 2022, as well as in January and February

of 2023, followed by a significant decrease from the $8.00/Dth range to about $5.00/Dth during April 2023 through September 2023, the end of this BGSS period.

25) The natural gas market has undergone significant changes since last year's BGSS Filing. U.S. dry gas production levels hit a peak of 93.5 Bcf/d during 2019 only to decline dramatically during the summer of 2020 to a level of 85 Bcf/d, largely due to the demand destruction resulting from the Covid restrictions. Over the course of the past year, production volumes have increased to approximately 94 Bcf/d to meet rising demand levels – of which drivers include the lifting of Covid related restrictions (and resultant increase in economic activity) and increase in LNG exports. Regarding the latter, feed-gas volumes for the country's seven LNG export facilities have recently achieved a record of 13.5 Bcf/d, representing 14% of US dry gas production during the same timeframe.

26) Unfortunately, this increase in production volume has not kept pace with increases in demand, both domestically and internationally (related to the increase in European imports of U.S. LNG to make up for the shortfall of Russian gas supplies). Additionally, the significant increase in pipeline takeaway capacity that occurred during 2017 and 2018, primarily from the Marcellus/Utica region, has all but ended due to state and federal permitting challenges impacting pipeline construction. U.S. natural gas storage levels are currently 16% below the 5-year average and 376 Bcf, or 15%, below this time last year – which will likely add an incremental 1.7 Bcf/d to summer gas demand (associated with increased gas going towards refilling storage prior to the peak winter season).

27) In addition to the dramatic increase in the NYMEX prices, two of the Company's largest pipeline suppliers have filed rate increases at FERC, both of which went into effect earlier

this year. Texas Eastern filed a rate case in mid-2021, which increased the Company's rates by approximately 53% or $56 million/year effective February 1, 2022. In addition, Eastern Gas Transmission and Storage (formerly known as Dominion Transmission) filed a FERC rate case in late 2021 that increased the Company's rates by 66% or $26 million/year effective April 1, 2022. These increased costs are reflected in the instant filing.

28) In response to these rate case filings, the Company has formed customer groups on each pipeline consisting of the largest customers on each pipeline system to protest and aggressively seek to reduce these cost impacts through either settlement or litigation. For the purposes of this BGSS Filing, the Company has assumed that in both cases settlements will be achieved in late 2022/early 2023, with lower settlement rates being put into effect by the pipelines in the first half of 2023. As a result, the Company has included an estimate of $38 million in refunds (as a credit to BGSS-RSG customers) in the instant filing related to the anticipated settlement of these two rate cases.

29) The Company estimates that an increase in BGSS revenue of approximately $339 million (excluding losses and SUT) is required for the period of October 1, 2022 through September 30, 2023. As stated in the testimony of Mr. Caffery and shown in Item 7, the Company is requesting an increase in the current Board approved rate of $0.410132 per therm (including losses and SUT) to $0.651838 per therm (including losses and SUT) to eliminate the projected under-recovery.

30) Residential annual bills comparing the current and proposed BGSS Commodity Rate and Balancing Charge are included in the form of public notice attached hereto as Attachment C. The impact of the requested Commodity and Balancing Charge changes for a typical residential

gas heating customer using 172 therms per month during the winter months and 1,040 therms on an annual basis is an increase in the winter monthly bill of approximately 25.46% and on an annual basis the impact is an increase of approximately 24.48%. Moreover, pursuant to paragraph 10 of the BGSS Pricing Structure Order, the attached public notice also states that such proposed rates may be subject to self-implementing rate increases of up to 5% on December 1, 2022 and February 1, 2023. The impact of such potential self-implementing increases on an average residential bill (1,200 therms annually) would be an increase of approximately $12.47 per winter month on December 1, 2022 and an additional approximate increase of $12.47 per winter month on February 1, 2023.

31) The proposed tariff sheets (redlined and non-redlined) to implement the above request are attached hereto as Attachment B.

32) Contained herein in Attachment C is a draft Form of Notice of Filing and of Public Hearings. This Form of Notice sets forth the requested changes to the gas rates and will be placed in newspapers having a circulation within the Company's gas service territory upon receipt, scheduling, and publication of public hearing dates. A Notice will be served on the County Executives and Clerks of all municipalities within the Company's gas service territory upon scheduling of public hearing dates. In accordance with the Board's Covid-19[1] order, notice of this filing, the Petition, testimony, and schedules will be served upon the Department of Law and Public Safety, 124 Halsey Street, P.O. Box 45029, Newark, New Jersey 07101 and upon the Director, Division of Rate Counsel, 140 East Front Street 4th Floor, Trenton,

[1] See In the matter of the New Jersey Board of Public Utilities' Response to the Covid-19 Pandemic for a Temporary Waiver of the Requirements for Certain Non-Essential Obligations, Docket No. EO20030254, dated March 19, 2020.

N.J. 08625 by electronic mail. Electronic copies of the Petition, testimony, and schedules will also be sent to the persons identified on the service list provided with this filing.

CONCLUSION

WHEREFORE, Public Service hereby requests that the Board issue a written Order by October 1, 2022 approving:

(1) the Company's proposal to change its current Board approved BGSS-RSG Commodity Charge to $0.651838 per therm (including losses and SUT), with the costs presented herein as the basis of the cost of BGSS-RSG supply. This charge is requested to remain in effect from October 1, 2022 through September 30, 2023 or the effective date of the Company's next periodic BGSS Commodity Charge filing, subject to the potential self-implementing increases discussed in this Motion;

(2) a change in the Balancing Charge to $0.100691 per balancing use therm (including losses and SUT) effective with the billing of month of October 2022;

(3) the modifications to the Tariff for Gas Service, B.P.U.N.J. No. 16 Gas, pursuant to N.J.S.A, 48:2-21 and 48:2-21.1, that are set forth in Attachment B to this Motion.

Respectfully submitted,

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

BY: Matthew Weissman

Matthew Weissman
Managing Counsel – State Regulatory
PSEG Services Corporation
80 Park Plaza, T5G
Newark, New Jersey 07102

DATED: June 1, 2022
Newark, New Jersey

STATE OF NEW JERSEY)
ss:
COUNTY OF ESSEX)

DAVID F. CAFFERY of full age, being duly sworn according to law, on his oath deposes and says:

1. I am David F. Caffery for Public Service Energy Resources and Trade LLC who is filing this testimony on behalf of Public Service Electric and Gas Company.

2. I have read the annexed Motion and the matters contained therein, and they are true to the best of my knowledge and belief.

David F. Caffery

DAVID F. CAFFERY

Sworn to and subscribed to
before me this 1st day of
June, 2022

Deborah Marks

DEBORAH S. MARKS
Notary Public
State of New Jersey
My Commission Expires June 3, 2023
ID# 2374254

ATTACHMENT A

TESTIMONY
OF
DAVID F. CAFFERY
VICE PRESIDENT – GAS SUPPLY

OVERVIEW

My qualifications are attached as Schedule DFC-1. This testimony supports Public Service Electric and Gas Company's (Public Service, the Company) Motion to increase the current Basic Gas Supply Service (BGSS) default Commodity Charge applicable to residential customers. The requested increase for the BGSS-RSG Commodity rate is from the current charge of $0.410132 per therm (including losses and New Jersey Sales and Use Tax, SUT) to a charge of $0.651838 per therm (including losses and SUT). This charge is requested to remain in effect from October 1, 2022 through September 30, 2023 or the effective date of the Company's next periodic BGSS Commodity Charge filing, subject to the potential self-implementing increases discussed in the Company's Motion. The Company is also requesting an increase in its Balancing Charge, which recovers the cost of providing storage, peaking services, and a share of its Storage Inventory Carrying Charge. The increased charge reflects a projected increase in the costs of interstate pipeline transportation services that make up the Company's gas supply portfolio. This projected increase is largely due to rate cases filed at FERC by two of the Company's principle pipeline suppliers, Texas Eastern and Eastern Gas Transmission and Storage (formerly known as Dominion Transmission), resulting in substantial cost increases . In addition, the peaking costs are expected to increase, and the Carrying Charge component of the Balancing Charge is projected to increase due to the increase in the cost of the Company's storage inventory due to the significant increase in gas prices. As a result, the Company requests an increase in the Balancing Charge from $0.093477 per balancing use therm (including losses and SUT) to $0.100691 per balancing use therm (including losses and SUT). The annual bill impact of the proposed RSG Commodity Rate and Balancing Charge change is an increase of approximately 24.48% for a typical residential gas heating customer using 172 therms per month during the winter and 1,040 therms annually.

The RSG customer class is expected to be under-recovered by $42.6M by September 30, 2022 (see Item 7). This period began in October of 2021 with an over-recovery of $33.4 million (including interest rollover). As directed by BPU Staff, the Company utilized May 10, 2022 NYMEX forward prices for the computations included in this filing, resulting in a projected under-recovery at the end of September 2023 of $339M (excluding losses and SUT as shown on Item 7).

The filing herein complies with the provisions of the Annual BGSS Minimum Filing Requirements (comprised of 17 items) in Docket No. GR02090702, approved by the Board on June 20, 2003 (Minimum Filing Requirements Settlement). Since Item 1 is the Company's Motion, Testimony and Tariff Sheets, Items 2 through 17 are discussed below.

As part of the settlement of the 2015-2016 BGSS proceeding the Parties agreed to the following: beginning with the 2016-2017 BGSS period, the Company agrees to prepare a Gas Supply Plan with details concerning the Company's objectives, approach, and plans for supplying gas to its residential customers. The Gas Supply Plan (Item 18) will include the following elements:

- *Gas Procurement Objectives*
- *Current and Forecasted Gas Service Requirements*
- *Projected Sources of Capacity*
- *Affiliate Relationships/Asset Management*
- *Hedging Plan and Strategy*
- *Capacity Releases/Off-System Sales*

2. <u>Computation of Proposed BGSS Rates</u>

Item 2 of the filing, Computation of BGSS Commodity Charge for RSG, shows that a rate of \$0.651838 per therm (including losses and SUT), would be required to reduce the projected under-collection of \$339M (excluding losses and SUT) to zero by September 30, 2023, based on May 10th NYMEX prices.

Additional details on the cost components and applicable credits are provided in several of the other items, as specified in the Minimum Filing Requirements Settlement. This schedule (Item 2) computes the BGSS Commodity Charge to residential gas customers based on all the forecasted gas cost components and applicable credits using forecasted send-out. Also included is an adjustment for the prior period over-recovery, which is the result of a comparison of actual revenue recovered to actual cost (including applicable credits). Interest for the period is positive, therefore \$195k of interest has been included.

Natural gas prices during the most recent period have increased dramatically from the levels experienced at this time last year, trading at highs not seen since 2008. NYMEX prompt month daily prices have traded between approximately \$3.50/Dth and \$9.00/Dth since the middle of January 2022, with June prices settling at \$8.908/Dth. This compares with a NYMEX price of \$3.00/Dth at this time last year during the midst of the Covid crisis. The forward (May 10) NYMEX strip used by the Company in this filing (see Item 8) shows that average prices are 120.5% higher than last year's NYMEX strip. Based upon the forward strip, prices are expected to increase for the rest of 2022, as well as in January and February of 2023, followed by a significant decrease from the \$8.00 range to about \$5.00/Dth during April 2023 through September 2023, the end of this BGSS period.

The natural gas market has undergone significant changes since last year's BGSS Filing. U.S. dry gas production levels hit a peak of 93.5 Bcf/d during 2019 only to decline dramatically during the summer of 2020 to a level of 85 Bcf/d, largely due to the demand destruction resulting from the Covid restrictions. Over the course of the past year, production volumes have increased to approximately 94 Bcf/d to meet rising demand levels – of which drivers include the lifting of Covid related restrictions (and resultant increase in economic activity) and increase in LNG exports. Regarding the latter, feed-gas volumes for the country's seven LNG export facilities have recently achieved a record of 13.5 Bcf/d, representing 14% of US dry gas production during the same timeframe.

Unfortunately, this increase in production volume has not kept pace with increases in demand, both domestically and internationally (related to the increase in European imports of U.S. LNG to make up for the shortfall of Russian gas supplies). Additionally, the significant increase in pipeline takeaway capacity that occurred during 2017 and 2018, primarily from the Marcellus/Utica region, has all but ended due to state and federal permitting challenges impacting pipeline construction. U.S. natural gas storage levels are currently 16% below the 5-year average and 376 Bcf, or 15%, below this time last year – which will likely add an incremental 1.7 Bcf/d to summer gas demand (associated with increased gas going towards refilling storage prior to the peak winter season).

In addition to the dramatic increase in the NYMEX prices, two of the Company's largest pipeline suppliers have filed rate increases at FERC, both of which went into effect earlier this year. Texas Eastern filed a rate case in mid-2021, which increased the Company's rates by approximately 53% or $56 million/year effective February 1, 2022. In addition, Eastern Gas Transmission and Storage (formerly known as Dominion Transmission) filed a FERC rate case in late 2021 that increased the Company's rates by 66% or $26 million/year effective April 1, 2022. These increased costs are reflected in the instant filing.

In response to these rate case filings, the Company has formed customer groups on each pipeline consisting of the largest customers on each pipeline system to protest and aggressively seek to reduce these cost impacts through either settlement or litigation. For the purposes of this BGSS Filing, the Company has assumed that in both cases settlements will be achieved in late 2022/early 2023, with lower settlement rates being put into effect by the pipelines in the first half of 2023. As a result, the Company has included an estimate of $38 million in refunds (as a credit to BGSS-RSG customers) in the instant filing related to the anticipated settlement of these two rate cases.

3. <u>Public Notice with Proposed Impact on Bills</u>

Included as Attachment C is a copy of the Company's Public Notice with details concerning the impact of the proposed change the current BGSS-RSG rate and the proposed change to the balancing charge on typical residential gas bills at various winter therm utilization levels. The Notice includes a table showing the impacts at various utilization levels and also a reference to the possibility of self-implementing BGSS Commodity increases of up to 5% of the average rate based on a typical residential customer's monthly bill of 100 therms on average (or 1,200 therms annually) on December 1, 2022 and February 1, 2023, respectively, with the impact of those possible increases.

4. Actual and Forecasted Refund Amounts

The first schedule of Item 4 shows actual supplier refunds, totaling approximately \$1.9M, that were credited to BGSS-RSG recovery costs from May 2021 through April 2022. The second schedule shows that the Company has included two refunds estimated to total \$38M associated with the anticipated settlement of both the Texas Eastern and Eastern Gas Transmission and Storage rate case proceedings.

5. Cost of Gas Sendout by Component

This schedule includes monthly data showing the derivation of all cost components used to calculate the BGSS residential sendout for the projected period. The individual components are utilized to derive inventory values, which form the basis of the over/under collection for the period. All of the fixed and variable charges are allocated proportionately to the residential and commercial and industrial (C & I) customer groups monthly based on the estimated firm sendout, and are trued up when the actual firm sendout is available. Each class of customers also shares equitably in any applicable credits or contributions that serve to lower gas costs., with the exception that contributions from CSG service provided to the New Jersey generation facilities formerly owned by PSEG Power are credited 100% to the Company's residential gas customers. The gas costs are similarly allocated to the respective customer classes following the direct allocation of any volumes hedged exclusively for the residential category.

6. BGSS Contribution and Credit Offsets

This schedule provides monthly data showing the derivation of all BGSS cost offsets, including interruptible margins, off-system sales and capacity release transactions, pipeline refunds, and other credits. Included are the credits for each of the interruptible services, showing the actual credits, and the estimated credits as calculated pursuant to the Board approved rate schedule, where applicable. These total contribution amounts serve as a credit against the total gas costs for residential customers and are used to set the initial BGSS rate. The actual contributions are calculated monthly and, along with the actual gas costs incurred, are compared to the revenues collected and are reflected in the over/under recovery amounts for the customers as noted in Item 7 below.

With respect to the CSG credits from the NJ generation facilities, in July of 2020 PSEG Power announced that it was undertaking a Strategic Review of its Fossil generation portfolio. PSEG Power's NJ generation facilities were sold as of February 18, 2022 and the October 1, 2013 CSG Agreement between PSE&G and PSEG Power, which provides gas delivery service by PSE&G to these facilities, was assigned from PSEG Power to the purchaser of the facilities. Because of the sale and the assignment of the CSG Agreement, effective February 19, 2022 PSEG Power is no longer responsible for the payment of either the CSG charges or the BGSS Asset Charge provided for in the CSG Agreement. However, the CSG revenues associated with the generation facilities will continue to be credited against the RSG customer gas costs, though the Company is anticipating the BGSS Asset Charge to be eliminated in October 2022. As a result, the Company has not included estimated BGSS Asset Charge credits in this filing.

7. Over/Under Recovery Comparisons

The schedules under this Item provide the derivation of the monthly over or under recoveries plus cumulative balances for the reconciliation and projected period. For the reconciliation period, one schedule also shows the calculation of the monthly actual or estimated accrued interest. The net interest calculated during the October 2021 to September 2022 period is positive and, therefore, has been included in the calculation of the new BGSS charge on Item 2. There are two schedules that include data shown for the projected period: one of these schedules shows the projected over/(under) recovery based on the current BGSS rate. The second is based on the BGSS rate that would be necessary to achieve a zero balance at September 2023 based on the May 10, 2022 NYMEX prices. Also included are supporting work papers for the reconciliation period.

8. Wholesale Gas Pricing Assumptions

This schedule details the monthly gas prices for the end of the reconciliation period through September 2022 and the projected period through September 2023 along with a comparison of these prices with the prices included in the current BGSS rate (from last year's BGSS filing) which indicates an increase of approximately 120.5%. These estimates reflect the future NYMEX prices on May 10, 2022, when this analysis was done.

9. GCUA Recoveries and Balances

This schedule is no longer necessary since the Gas Cost Under-Recovery Adjustment (GCUA) recovery has been completed.

10. Historic Service Interruptions

This schedule provides the details of all service interruptions during the past 12 months. Included are all of the interruptible transportation and sales services, as well as the date and duration of the interruption and the number of customers affected.

11. <u>Gas Price Hedging Activities</u>

Included in this Item are the Company's last four quarterly hedging reports as filed with the Board. The reports provide gas purchase volume requirements and price-hedged volumes broken down into the Non-Discretionary Method and the Dollar Budget Method. As agreed to in the Settlement of the 2009/2010 BGSS proceeding, the Company has revised the Quarterly Hedging Report beginning with the June 30, 2010 report. The revised report provides more detail, including data on targets and a comparison of the two hedging methods.

The Company continues to utilize hedging as a means to stabilize the price of gas to the residential customer. The consistent goal of the program is to assure a reasonable level of price stability, not necessarily achieving the lowest possible price. The Company to date has hedged approximately 86% of its planned volume for the 2022 summer period, approximately 50% of its planned volume for the 2022-2023 winter period and approximately 35% of its planned volume for the 2023 summer period. Hedging for the winter 2023-2024 period has just begun in May 2022. The goal of the Company's hedging activities is to achieve a stable price through a disciplined hedging strategy that will, in the long run, result in a competitive price for the customer.

12. <u>Storage Gas Volumes, Prices and Utilization</u>

These schedules provide the Company's monthly data for LNG, LPG, and pipeline storage volumes. For the LNG and LPG, the schedules show volumes and dollars for balances at the various locations where the product is stored. The attached schedule for storage activity shows the ending balances for each storage service the Company has under contract. The Company does not value storage services individually, but treats them collectively as a total inventory.

13. Affiliate Gas Supply Transactions

As agreed to in the Settlement of the 2017/18 BGSS proceeding Item 13 now outlines all the principal terms of the Gas Requirements Contract between PSE&G and PSEG ER&T which provides BGSS services for all of PSE&G's gas customers. As noted in Item 13, the Term of the Requirements Contract has been extended for a five-year period through March 31, 2027. The Company requested the Term extension in its June 1, 2021 Annual BGSS Filing, and the Board approved the same in its Order dated April 6, 2022.

14. Supply and Demand Data

Included in this schedule is the Company's Supply/Demand data that shows the Company's firm requirements and gas supplies by component on an annual, heating season, and non-heating season basis.

15. Actual Peak Day Supply and Demand

Included in this schedule is the data for the five highest demand days for each of the last three years, showing the date, the temperature, firm and interruptible volumes, and the sources of supply used to meet the associated volume requirement.

16. Capacity Contract Changes

Included in this schedule is the most recent peak day forecast and the supplies to be utilized to meet these requirements. Included are the details for the current winter season concerning any changes to interstate pipeline contracts (entitlements, storage capacities, daily deliverability, or transportation) and the forecast for the next four (4) winter seasons. Also, as agreed to in the Settlement of the 2009/2010 BGSS proceeding, the Company has included extensive details on the forecast and forecasting process.

17. **FERC Pipeline Activities**

The attached schedule includes details on pending FERC dockets that would affect the cost of services received from the Company's interstate pipelines. The Company has also provided details concerning its participation in those dockets and included a listing of any filings or testimony made by or on behalf of the Company.

18. **Gas Supply Plan**

As discussed earlier herein, Item 18 consists of an overview of the Company's Gas Supply Plan, which provides additional information regarding the Company's procurement activities, supply planning, forecasted requirements, hedging activities, and capacity release and off-system sales.

OTHER CHARGES

Attachment D includes the supporting information for an increase in the Balancing Charge based on the eight month period of October to May, which is comprised of three components: Annual Allocated Costs for storage and peaking supplies (page 1), Storage Inventory Carrying Charge (page 2), and Revenue Requirement on Production Plants (page 3).

The Balancing Charge is applicable to rate schedules RSG, GSG, LVG, and CSG where applicable and recovers the cost of providing storage, peaking services, and a share of its Storage Inventory Carrying Charge. The requested change is from the current Balancing Charge of $0.093477 cents per balancing therm (including losses and SUT) to a Balancing Charge of $0.100691 cents per balancing therm (including losses and SUT). Attachment D provides the detail and support for this change, which is summarized on the bottom of page 1. The requested Balancing Charge is applicable in the billing months of October through May.

The base Balancing Charge includes the annual allocated cost for transportation, storage and peaking supplies used by the Company to meet the requirements of its customers. The requested charge is $0.083729 cents per balancing therm (excluding losses and SUT), which is an increase from the previous charge of $0.080193 cents per balancing therm (excluding losses and SUT).

The Storage Inventory Carrying Charge is shown on page 2 and is recovered in the balancing and commodity charges. The requested charge is $0.004597 cents per balancing therm (excluding losses & SUT) for the balancing portion and $0.007791 cents per therm (excluding losses & SUT) for the commodity portion (included in Item 2) using the applicable billing determinants for each. The current charges are $0.002778 cents per balancing therm (excluding losses & SUT) for the balancing portion and $0.004610 cents per therm for the commodity portion (excluding losses and SUT).

The revenue requirement on Production Plant is shown on page 3 and the requested charge is $0.004220 cents per balancing use therm (excluding losses & SUT), which is an increase from the previous charge of $0.002945 cents per balancing use therm (excluding losses and SUT).

Also included in Attachment D is an increase in the A&G charge. This change is reflected in Item 2. The current rate is $0.003969 per therm (excluding losses & SUT) and the updated rate is $0.004231 per therm (excluding losses & SUT). This rate recovers the administrative cost associated with PSEG Energy Resources & Trade’s provision of gas supply services to PSE&G.

Renewable Natural Gas, Certified Natural Gas, and Hydrogen

As mentioned in last year's BGSS Filing, the Company has recently begun exploring the potential to incorporate renewable gas (RNG) supplies into its gas supply mix in an effort to help meet the NJ State's 2018 Clean Energy Act targets as well the targeted methane reduction goals set forth in the State's Energy Master Plan (EMP). In addition, the Company is investigating the option of purchasing certain volumes of certified natural gas (CNG) as a further way to achieve its decarbonization efforts. The Company to-date has not purchased any CNG, and there are no CNG related purchase costs included in the instant filing. As producers operating in the Marcellus and Utica supply basins increasingly utilize various certification services to certify their gas production, the Company anticipates that CNG will become an increasingly important part of the gas supply in this region.

RNG has started to make inroads into the gas supply mix in several areas of the US from landfill sources and wastewater treatment plants, as well as from the use of anaerobic digesters, which turn food and farm waste into pipeline quality RNG. While the Company does not currently purchase any RNG, it has been in discussions with certain customers regarding the potential to accept RNG into its distribution system as part of its gas supply mix, and anticipates that additional customers and/or project developers may approach the Company with similar requests to interconnect and sell RNG supply to the Company. These projects would be supportive and are aligned with Goal 2.3.7 of the New Jersey Energy Master Plan, which aims to maximize the use of organic waste through anaerobic digestion for natural gas pipeline injection (or electric production). In addition, the Company has met with several of its major pipeline suppliers over the past several months, all of which are exploring the introduction of RNG into their pipeline systems. The Company has not included any RNG supplies or costs in the instant BGSS filing. However, the Company would encourage the BPU to consider the near-term establishment of a Stakeholder Proceeding that would examine the merits of incorporating alternative fuels (including RNG, CNG and hydrogen) into New Jersey Gas Distribution Companies' supply portfolios, including the recovery of the associated costs.

CONCLUSION

The Company's filing should be approved as reasonable and fully supported. The Company stands ready to respond to any reasonable requests for additional data. The Company seeks a Board Order by October 1, 2022 or earlier, should the Board deem it appropriate, approving: (1) the Company's proposal to increase the current BGSS Commodity Charge of $0.410132 per therm (including losses and SUT) to $0.651838 per therm (including losses and SUT) to be charged to BGSS-RSG customers, with the costs presented herein as the basis of the cost of BGSS-RSG supply, and (2) an increase in the Balancing Charge to $0.100691 per balancing use therm (including losses and SUT).

SCHEDULE DFC-1

PROFESSIONAL QUALIFICATIONS
OF
DAVID F. CAFFERY
VICE PRESIDENT – GAS SUPPLY

My name is David F. Caffery and my business address is 80 Park Plaza, Newark, New Jersey 07102-0570. I am the Vice President – Gas Supply for PSEG Energy Resources and Trade LLC (PSEG-ERT).

In May 1977, I graduated from Lafayette College with a Bachelor of Science degree in Civil Engineering. In 1982, I received a Master of Business Administration degree in Finance from Fairleigh Dickinson University. I began my employment with Public Service Electric and Gas Company in July 1977 as an Associate Engineer in the Fuel Supply Department. During the period from 1977 through 1998 I received a series of promotions to the level of Manager - Gas Supply in April 1998. In June 2002, as a result of the transfer of the gas supply contracts, I became an employee of PSEG-ERT. I was promoted to Director – Portfolio Management & Regulatory in March 2007. I assumed my present position in March 2017. In my present position I am responsible for all aspects of the BGSS and Fuels activities conducted by PSEG-ERT.

I am a member of the American Gas Association, having served as past Chairman of its Federal Regulatory Committee during 2016. I have provided testimony before the Federal Energy Regulatory Commission and the New Jersey Board of Public Utilities.

2. Computation of Proposed BGSS Rate Effective October 1, 2022

COMPUTATION OF
BGSS COMMODITY CHARGE FOR RSG
OCTOBER 2022 - SEPTEMBER 2023

($-000)

	$000	$/DTh
FIXED COSTS:		
FT DEMAND COST	$ 173,165	$1.1245
STORAGE DEMAND/CAPACITY COSTS	91,881	$0.5967
STORAGE INJ & W/D COSTS	9,355	$0.0608
PEAKING COSTS	16,917	$0.1099
	291,319	**$1.8918**
CONTRIBUTIONS	(34,269)	($0.2225)
PIPELINE REFUNDS	(37,975)	($0.2466)
OFF-SYSTEM SALES MARGIN	(39,203)	($0.2546)
ELECTRIC CONTIBUTION - CSG	0	$0.0000
NET TOTAL FIXED COST	**$ 179,871**	**$1.16810**
FIRM RSG SENDOUT (MDTh) 10/22 - 9/23	**153,991**	
TOTAL NON-GULF COAST COST ($/DTh)		**$1.16810**
Removal of Balancing Cost (incl. above)		(0.62411)
Inventory Carrying Charge Allocation		0.07791
Gas Supply A&G		0.04231
Total Adjustments		**($0.50389)**
ADJUSTED NON-GULF COAST COST ($/DTh)		**$0.66421**
(OVER)/UNDER RECOVERY @ 9/30/22 - INCL. INT.	**$42,394**	**$0.27530**
GULF COAST COST OF GAS ($/DTh)		
FT COMMODITY AND FUEL		0.00000
COST OF GAS		**5.05159**
TOTAL GULF COAST COST		**$5.05159**

SUMMARY OF CHARGE COMPONENTS

	(cents/therm)	(dollars/therm)
	BGSS-RSG	**BGSS-RSG**
Estimated Non-Gulf Coast Cost of Gas	6.6421	$ 0.066421
Estimated Gulf Coast Cost of Gas	50.5159	$ 0.505159
Adjustment to Gulf Coast Cost of Gas	-	$ -
Prior Period (Over)/Under Recovery	2.7530	$ 0.027530
Adjusted Cost of Gas	59.9110	$ 0.599110
COMMODITY CHARGE (after application of losses 2.0%)	**61.1337**	**$ 0.611337**
COMMODITY CHARGE (including SUT)	**65.1838**	**$ 0.651838**

3. Public Notice with Proposed Impact on Bills

Notice (including Typical Bills) – Attachment C

NOTICE TO PUBLIC SERVICE ELECTRIC AND GAS COMPANY GAS CUSTOMERS

IN THE MATTER OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY'S 2022/2023 ANNUAL BGSS COMMODITY CHARGE FILING FOR ITS RESIDENTIAL GAS CUSTOMERS UNDER ITS PERIODIC PRICING MECHANISM AND FOR CHANGES IN ITS BALANCING CHARGE

Notice of Filing and Notice of Public Hearings

Docket No. XXXXXXXXXX

TAKE NOTICE that, on June 1, 2022, Public Service Electric and Gas Company ("Public Service" or "Company") filed a Petition and supporting testimony with the New Jersey Board of Public Utilities ("Board" or "BPU") requesting that the Board permit Public Service to increase its Basic Gas Supply Service ("BGSS-RSG") Commodity Charge applicable to its Residential Service ("RSG") customers and to increase its Balancing Charge, which is based on winter gas usage, to customers receiving service under RSG, General Service ("GSG"), Large Volume Service ("LVG") and Contract Service ("CSG") where applicable effective October 1, 2022, or earlier should the Board deem it appropriate. Approval of the Company's request would result in an increase in annual BGSS-RSG revenues of approximately $339 million (excluding losses and New Jersey Sales and Use Tax or "SUT"). The requested increase in the BGSS-RSG Commodity Charge is from $0.410132 per therm (including losses and SUT) to $0.651838 per therm (including losses and SUT), and the requested increase in the Balancing Charge is from $0.093477 per balancing use therm (including losses and SUT) to $0.100691 per balancing use therm (including losses and SUT).

Based upon rates effective June 1, 2022, the combined effects of the requested increase in the BGSS-RSG Charge and the requested increase in the Balancing Charge on typical residential gas bills, if approved by the Board, is shown in Table #1.

Under the Company's proposal, a residential heating customer using 100 therms per month during the winter months and 610 therms on an annual basis would see an increase in their annual bill from $656.98 to $807.36, or $150.38 or approximately 22.89%. Moreover, under the Company's proposal, a typical residential heating customer using 172 therms per month during the winter months and 1,040 therms on an annual basis would see an increase in their annual bill from $1,047.22 to $1,303.60, or $256.38 or approximately 24.48%.

In addition, the Board, in its Order in Docket No. GX01050304 dated January 6, 2003, granted Public Service approval to increase its Commodity Charge rates to be effective December 1st of this year, 2022, and/or February 1st of next year, 2023, on a self-implementing basis; each increase is subject to a maximum rate increase of 5% of the average rate based on a typical residential customer's monthly bill of 100 therms on average (or 1,200 therms annually). Such rate increases shall be preconditioned upon written notice by Public Service to BPU Staff and to the New Jersey Division of Rate Counsel no later than November 1, 2022 and/or January 1, 2023 of its intention to apply a December 1st or a February 1st self-implementing rate increase, respectively, and the approximate amount of the increases based upon then current market data. These increases, if implemented, would be in accordance with the Board-approved methodology.

Should it become necessary to apply the December 1, 2022 self-implementing 5% increase, the bill impact would be an increase as illustrated in Table #2. Further, if a February 1, 2023 self-implementing 5% increase becomes necessary, then there would be an additional increase as also shown in Table #2.

The above requests will not result in any profit to the Company.

The Board has the statutory authority pursuant to N.J.S.A. 48:2-21, to establish the BGSS-RSG and Balancing charges at levels it finds just and reasonable. Therefore, the Board may establish the BGSS-RSG and Balancing charges at levels other than that proposed by PSE&G. As a result, the described charges may increase or decrease based upon the Board's decision.

The Company's filing is available for review online at the PSEG website at http://www.pseg.com/pseandgfilings.

PLEASE TAKE FURTHER NOTICE that due to the COVID-19 pandemic, telephonic public hearings have been scheduled on the following date and times so that members of the public may present their views on the Company's filing.

Date:
Time:
Dial In:
Meeting ID:
Access Code:

Representatives from the Company, Board Staff, and the New Jersey Division of Rate Counsel will participate in the telephonic public hearings. Members of the public are invited to participate by utilizing the link or Dial-In number set forth above and may express their views on the BGSS-RSG and Balancing filing. All comments will be made part of the final record of the proceeding and will be considered by the Board. In order to encourage full participation in this opportunity for public comment, please submit any requests for needed accommodations, such as interpreters or listening assistance, 48 hours prior to the above hearings to the Board Secretary at board.secretary@bpu.nj.gov.

The Board will also accept written and/or electronic comments. While all comments will be given equal consideration and will be made part of the final record of this proceeding, the preferred method of transmittal is via the Board's Public Document Search Tool (https://publicaccess.bpu.state.nj.us/). Search for the specific docket listed above, and then post the comment by utilizing the "Post Comments" button. Emailed comments may be filed with the Secretary of the Board, in PDF or Word format, to board.secretary@bpu.nj.gov.

Written comments may be submitted to the Acting Board Secretary at the Board of Public Utilities, 44 South Clinton Avenue, 1st Floor, P.O. Box 350, Trenton, New Jersey 08625-0350. All mailed or emailed comments should include the name of the petition and the docket number.

All comments are considered "public documents" for purposes of the State's Open Public Records Act. Commenters may identify information that they seek to keep confidential by submitting them in accordance with the confidentiality procedures set forth in N.J.A.C. 14:1-12.3.

Table # 1
Residential Gas Service

If Your Annual Therm Use Is:	And Your Monthly Winter Therm Use Is:	Then Your Present Monthly Winter Bill (1) Would Be:	And Your Proposed Monthly Winter Bill (2) Would Be:	Your Monthly Winter Bill Change Would Be:	And Your Monthly Percent Change Would Be:
170	25	$31.41	$37.59	$6.18	19.68%
340	50	54.27	66.60	12.33	22.72
610	100	100.91	125.68	24.77	24.55
1,040	172	167.39	210.00	42.61	25.46
1,200	201	194.24	244.04	49.80	25.64
1,816	300	285.50	359.80	74.30	26.02

(1) Based upon Delivery Rates and Basic Gas Supply Service (BGSS-RSG) in effect June 1, 2022, and assumes that the customer receives commodity service from Public Service.
(2) Same as (1) except includes the proposed change in BGSS-RSG and Balancing Charge.

Table # 2
Residential Gas Service

If Your Annual Therm Use Is:	And Your Monthly Winter Therm Use Is:	Self-Implementing 5% Increases: December 1, 2022 Monthly Winter Change Would Be:	Self-Implementing 5% Increases: February 1, 2023 Monthly Winter Change Would Be:	Self-Implementing 5% Increases: Total If both 5% Self-Implementing Increases Are Put Into Effect:
170	25	$1.55	$1.55	$3.10
340	50	3.10	3.11	6.21
610	100	6.21	6.20	12.41
1,040	172	10.67	10.67	21.34
1,200	201	12.47	12.47	24.94
1,816	300	18.61	18.61	37.22

(1) Self-implementing monthly changes would be in addition to any monthly winter bill change amounts.

Katherine E. Smith
Associate Counsel - Regulatory

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

4. Actual and Forecasted Refund Amounts

Item 4

NATURAL GAS PIPELINE REFUNDS RECEIVED May 2021 - April 2022

(000)

MONTH	SUPPLIER	AMOUNT	TOTAL
May 2021	Texas Eastern	$ 58.53	
	Texas Eastern	$ 14.08	**$ 72.61**
June 2021	Texas Eastern	$ 5.02	**$ 5.02**
July 2021	Transco	$ 9.40	**$ 9.40**
August 2021	Texas Eastern	$ 44.12	
	Texas Eastern	$ 11.29	
	Transco	$ 3.68	**$ 59.09**
September 2021	Algonquin	$ 0.02	**$ 0.02**
October 2021	Transco	$ 58.54	**$ 58.54**
November 2021	Tennessee	$ 14.27	**$ 14.27**
December 2021	Algonquin	$ 2.97	
	Algonquin	$ 0.03	
	Texas Eastern	$ 23.24	
	Texas Eastern	$ 5.71	
	Transco	$ 865.49	**$ 897.44**
January 2022	Algonquin	$ 0.05	
	Transco	$ 2.41	**$ 2.47**
February 2022	Algonquin	$ 0.13	**$ 0.13**
March 2022	Algonquin	$ 0.62	**$ 0.62**
April 2022	Algonquin	$ 0.62	
	Columbia	$ 760.43	**$ 761.05**
Total		$ 1,880.66	**$ 1,880.66**

Item 4

PENDING FERC CASES WHICH CONTAIN SOME POSSIBILITY OF REFUNDS TO PSE&G IN EXCESS OF $1 MILLION

DOCKET	SUPPLIER	STATUS
RP21-1001 & RP21-1188	Texas Eastern	The Company anticipates that a settlement of this rate case will be approved by FERC providing for refunds during the month of March. We have estimated the RSG portion of the refund to be $27.6 million.
RP21-1187	EGTS	The Company anticipates that a settlement of this rate case will be approved by FERC providing for refunds during the month of May. We have estimated the RSG portion of the refund to be $10.4 million.

5. Cost of Gas Sendout by Component

ACTUAL COST OF BGSS-RSG GAS SENDOUT BY COMPONENT

	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Total
Beginning Inventory Price $000	$217,646	$257,241	$262,342	$235,907	$169,321	$120,600	$74,947	
Fixed Pipeline Charge $000	$20,023	$21,315	$21,116	$20,841	$23,642	$23,427	$24,983	
Gas Purchases and Hedges $000	$41,126	$62,006	$48,305	$64,616	$47,719	$26,514	$57,730	
Receipt Value $000	$61,149	$83,321	$69,421	$85,457	$71,360	$49,941	$82,713	$503,362
Total Inventory Value $000	$278,796	$340,562	$331,764	$321,363	$240,682	$170,540	$157,660	
Total $/dth	$4.44	$4.65	$4.76	$4.78	$5.12	$5.39	$6.07	
Beginning Inventory Volume MDth	51,038	57,940	56,464	49,556	35,319	23,493	13,680	
Receipt Volume MDth	11,731	15,346	13,257	17,616	11,658	8,145	12,304	90,056
Total Inventory Volume MDth	62,769	73,285	69,721	67,171	46,977	31,638	25,984	
RSG Sendout MDth	4,903	16,861	20,103	31,558	23,368	17,538	11,877	126,209
Total RSG Sendout Cost $000	$21,776	$78,355	$95,660	$150,979	$119,726	$94,537	$72,067	$633,100
Ending Inventory Rebalance								
Volume	74	40	(62)	(295)	(115)	(420)	(203)	
Amount	$221	$136	($197)	($1,063)	($356)	($1,056)	($818)	

FORECASTED COST OF BGSS-RSG GAS SENDOUT BY COMPONENT

	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Total Oct - Sept
Beginning Inventory Cost $000	$84,774	$149,037	$202,220	$261,119	$300,752	$358,599	$388,758	$371,426	$276,738	$161,755	$79,750	$24,666	$29,954	$56,356	$99,453	$148,702	$185,325	
Receipt Value $000	$98,698	$83,365	$80,274	$58,244	$80,103	$79,455	$98,882	$85,596	$116,857	$107,165	$93,853	$66,798	$54,436	$64,236	$63,871	$49,412	$64,578	$945,138
Total Inventory Value $000	$183,472	$232,402	$282,494	$319,364	$380,855	$438,054	$487,640	$457,021	$393,595	$268,919	$173,603	$91,464	$84,390	$120,592	$163,323	$198,114	$249,903	
Total $/dth	$6.65	$6.90	$7.03	$7.08	$7.08	$7.05	$7.20	$7.38	$7.53	$7.59	$7.19	$5.32	$5.11	$4.92	$4.88	$4.98	$4.93	
Beginning Inventory Volume MDth	13,904	22,419	29,298	37,161	42,470	50,642	55,160	51,555	37,520	21,470	10,511	3,432	5,634	11,027	20,203	30,443	37,226	
Receipt Volume MDth	13,695	11,252	10,905	7,937	11,315	11,513	12,526	10,407	14,722	13,974	13,643	13,770	10,879	13,471	13,233	9,352	13,507	150,997
Total Inventory Volume MDth	27,599	33,671	40,203	45,098	53,785	62,155	67,686	61,963	52,242	35,444	24,154	17,202	16,512	24,498	33,437	39,795	50,733	
RSG Sendout MDth	5,180	4,373	3,042	2,628	3,143	6,994	16,131	24,443	30,772	24,933	20,722	11,568	5,485	4,294	2,993	2,569	3,085	153,991
Total RSG Sendout Cost $000	$34,435	$30,182	$21,375	$18,612	$22,256	$49,295	$116,215	$180,283	$231,840	$189,170	$148,938	$61,510	$28,034	$21,139	$14,621	$12,789	$15,195	$1,069,030

6. BGSS Contribution and Credit Offsets

Actual BGSS Contribution and Credit Offsets

($000)

			Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Total
(1)	**BGSS-I Contribution**		$106	$195	$122	$773	($189)	($327)	$32	$712
(2)	**Cogeneration Contribution**		$123	$1,276	$865	($1,546)	$2,540	($67)	$179	$3,369
(3)	**TSG-F Contribution**		$189	$364	$1,200	($771)	$755	$317	($633)	$1,421
(4)	**"Contribution"**	Sum of (1) through (4)	$419	$1,834	$2,187	($1,544)	$3,106	($78)	($423)	$5,502
(5)	**Off-System Contribution**		$536	$2,370	$8,828	$43,899	$15,296	$2,643	$635	$74,208
(6)	**Electric Contribution**		$1,500	$1,009	$729	$596	$696	$391	$687	$5,608
(7)	**FT-S Balancing Credit**		$337	$1,904	$2,967	$4,727	$3,688	$2,981	$1,791	$18,395
(8)	**Pipeline Refunds**		$59	$14	$897	$2	$0	$1	$761	$1,735

Forecasted BGSS Contribution and Credit Offsets

		May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Total Oct - Sept
(1)	**BGSS-RSG Sendout, Mdth**	5,180	4,373	3,042	2,628	3,143	6,994	16,131	24,443	30,772	24,933	20,722	11,568	5,485	4,294	2,993	2,569	3,085	153,991
(2)	**BGSS-F Sendout, Mdth**	2,085	1,329	954	1,142	950	2,077	4,689	8,255	10,251	8,756	7,454	3,426	2,043	1,299	921	1,107	917	51,196
(3)	**Total Firm Sendout, Mdth**	7,265	5,702	3,996	3,771	4,093	9,071	20,820	32,698	41,023	33,689	28,176	14,994	7,528	5,594	3,915	3,676	4,002	205,187
(4)	**Annual % BGSS-RSG of Firm Sendout**	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%
(5)	**BGSS-I Contribution**	$46.2	$38.8	($21.5)	($24.6)	$64.2	$103.5	$188.4	$122.6	$773.4	($191.5)	($333.7)	$30.9	$45.2	$38.7	($21.4)	($24.6)	$63.9	$795.5
(6)	**Cogeneration Contribution, $000**	$537.1	$262.3	$411.0	$701.3	$0.4	($0.3)	$0.8	$929.2	($1,556.8)	$2,432.0	($479.0)	$130.6	$525.5	$262.1	$409.2	$699.6	$0.4	$3,353.4
(7)	**TSG-F Contribution**	$148.6	$175.0	($11.5)	$84.5	($91.4)	$184.4	$352.5	$1,204.9	($771.1)	$765.7	$323.3	($616.0)	$145.4	$174.9	($11.5)	$84.3	($91.0)	$1,745.9
(8)	**CSG**	$322.4	$322.4	$322.4	$322.4	$322.4	$322.4	$322.4	$322.4	$322.4	$322.4	$322.4	$322.4	$322.4	$322.4	$322.4	$322.4	$322.4	$3,868.8
(9)	**"Contribution"**	$1,054.3	$798.6	$700.4	$1,083.6	$295.6	$610.0	$864.2	$2,579.1	($1,232.1)	$3,328.6	($167.0)	($132.1)	$1,038.6	$798.1	$698.8	$1,081.8	$295.7	$9,763.6
(10)	**Off-System Contribution, $000**	$546.7	$529.1	$546.7	$546.7	$529.1	$546.7	$6,599.4	$6,599.2	$6,599.2	$6,599.0	$6,599.1	$927.9	$958.9	$927.9	$958.9	$958.9	$927.9	$39,203.0
(11)	**Legacy Electric Contribution, $000**	$595.0	$1,031.3	$1,276.5	$1,257.4	$852.1	$250.0	$250.0	$250.0	$250.0	$250.0	$250.0	$250.0	$250.0	$250.0	$250.0	$250.0	$250.0	$3,000.0
(12)	**Pipeline Refund, $000**	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$27,618.1	$0.0	$10,356.8	$0.0	$0.0	$0.0	$0.0	$37,974.9
(13)	**FT-S Balancing Use, Mdth**	195.2	0.0	0.0	0.0	0.0	1,550.4	4,109.9	5,790.7	7,469.0	6,496.3	5,696.7	2,374.8	736.5	0.0	0.0	0.0	0.0	
(14)	**Balancing Charge, $/dth**	$0.8019	$0.0000	$0.0000	$0.0000	$0.0000	$0.8373	$0.8373	$0.8373	$0.8373	$0.8373	$0.8373	$0.8373	$0.8373	$0.0000	$0.0000	$0.0000	$0.0000	
(15)	**FT-S Balancing Credit, $000**	$195.2	$0.0	$0.0	$0.0	$0.0	$974.3	$2,582.6	$3,638.8	$4,693.4	$4,082.1	$3,579.7	$1,492.3	$462.8	$0.0	$0.0	$0.0	$0.0	$21,505.9
(16)	**BGSS-RSG Balancing Use, Mdth**	1,830	0	0	0	0	3,644	12,889	21,092	27,422	21,907	17,372	8,326	2,135	0	0	0	0	
(17)	**Balancing Charge, $/dth**	$0.8019	$0.0000	$0.0000	$0.0000	$0.0000	$0.8373	$0.8373	$0.8373	$0.8373	$0.8373	$0.8373	$0.8373	$0.8373	$0.0000	$0.0000	$0.0000	$0.0000	
(18)	**BGSS-RSG Balancing Rev., $000**	$1,467.2	$0.0	$0.0	$0.0	$0.0	$3,050.9	$10,791.5	$17,660.3	$22,960.0	$18,342.1	$14,545.0	$6,971.1	$1,787.4	$0.0	$0.0	$0.0	$0.0	$96,108.4

BGSS-RSG MARGIN FROM GAS TRANSPORTATION FOR ELECTRIC GENERATION

	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Total
BGSS Asset Charge ($000)	$876	$877	$591	$460	$635	$405	$687	$4,532
CSG Transportation Revenues ($000)	$624	$132	$138	$136	$61	($14)	$0	$1,077
Total BGSS-RSG Margin ($000)	$1,500	$1,009	$729	$596	$696	$391	$687	$5,608

7. Over/Under Recovery Comparisons

Summary of Monthly Over/(Under) Recoveries

Calculation of Interest on Over/(Under) Balance

Over/(Under) Balance (before & after change)

Supporting Workpapers – Actual Results

MONTHLY RECOVERIES COMPARED TO EXCESS COST
OCTOBER 2021 - SEPTEMBER 2022

(000)

		TOTAL RECOVERY	LESS: TOTAL EXPENSE	MONTHLY OVER/(UNDEF RECOVERY
Balance September 30, 2021				**$31,552**
Interest Adjustment				**1,835**
October 1, 2021 Adjusted Balance				**$33,388**
October 2021		$ 14,158	$ 22,543	(8,386)
November		57,077	77,322	(20,245)
December		88,002	87,150	852
January 2022		133,434	113,938	19,497
February		114,570	101,111	13,459
March		85,406	99,321	(13,915)
April		51,530	72,661	(21,131)
May	**(Est.)**	20,490	32,044	(11,554)
June	**(Est.)**	16,059	27,823	(11,764)
July	**(Est.)**	11,171	18,851	(7,680)
August	**(Est.)**	9,652	15,724	(6,072)
September	**(Est.)**	11,543	20,580	(9,037)
Total				**($42,589)**

INTEREST
COMPUTED AT 6.99% ROR FOR October 2021 - SEPTEMBER 2022
(000)

		OVER/(UNDER) RECOVERIES			
		Monthly	Cumulative	Average Balance	INTEREST
Balance September 30, 2021			**$31,552**		
Interest Adjustment			**1,835**		
October 1, 2021 Adjusted Balance			**$33,388**		
October 2021		$ (8,386)	25,002	$ 29,195	$ 170
November		(20,245)	4,757	$ 14,879	$ 87
December		852	5,609	5,183	$ 30
January 2022		19,497	25,106	15,358	$ 89
February		13,459	38,565	31,835	$ 185
March		(13,915)	24,650	31,607	$ 184
April		(21,131)	3,518	14,084	$ 82
May	**(Est.)**	(11,554)	(8,035)	(2,258)	$ (13)
June	**(Est.)**	(11,764)	(19,799)	(13,917)	$ (81)
July	**(Est.)**	(7,680)	(27,479)	(23,639)	$ (138)
August	**(Est.)**	(6,072)	(33,551)	(30,515)	$ (178)
September	**(Est.)**	(9,037)	(42,588)	(38,070)	$ (222)
Total					**$ 195**

BGSS-RSG 2022-2023
NYMEX====>>> May 10, 2022

NO CHANGE IN RATES

	BGSS-RSG MDTh (1)	COST (2)	REFUNDS (3)	CONTRIB (4)	OFF-SYS Margin (5)	Electric Contribution (6)	FT Balancing Credit (7)	ADJ COST (8)=(2).+.(7)	RSG Bal. Revenue (9)	BGSS RECOVERY (10)=(1)*(14)+(9)	EXCESS COST (11)=(10)-(8)	OVER/(UNDER) RECOVERY Month (12)=-(11)	Cumulative (13)	RSG Rate $/dth (14)
Apr-22 Act													$3,518	$3.6724
May-22 Est.	5,180	$34,435	$0	($1,054)	($547)	($595)	($195)	$32,044	$1,467	$20,489.96	$11,554	($11,554)	($8,036)	$3.6724
Jun-22 Est.	4,373	$30,182	$0	($799)	($529)	($1,031)	$0	$27,823	$0	$16,058.96	$11,764	($11,764)	($19,800)	$3.6724
Jul-22 Est.	3,042	$21,375	$0	($700)	($547)	($1,277)	$0	$18,851	$0	$11,171.37	$7,680	($7,680)	($27,480)	$3.6724
Aug-22 Est.	2,628	$18,612	$0	($1,084)	($547)	($1,257)	$0	$15,724	$0	$9,651.95	$6,072	($6,072)	($33,552)	$3.6724
Sep-22 Est.	**3,143**	**$22,256**	**$0**	**($296)**	**($529)**	**($852)**	**$0**	**$20,579**	**$0**	**$11,542.65**	**$9,037**	**($9,037)**	**($42,589)**	$3.6724
Oct-22 Est.	6,994	$49,295	$0	($610)	($547)	($250)	($974)	$46,914	$3,051	$28,737.27	$18,177	($18,177)	($60,766)	$3.6724
Nov-22 Est.	16,131	$116,215	$0	($864)	($6,599)	($250)	($2,583)	$105,918	$10,791	$70,031.20	$35,887	($35,887)	($96,653)	$3.6724
Dec-22 Est.	24,443	$180,283	$0	($2,579)	($6,599)	($250)	($3,639)	$167,216	$17,660	$107,423.81	$59,793	($59,793)	($156,446)	$3.6724
Jan-23 Est.	30,772	$231,840	$0	$1,232	($6,599)	($250)	($4,693)	$221,530	$22,960	$135,968.62	$85,561	($85,561)	($242,007)	$3.6724
Feb-23 Est.	24,933	$189,170	$0	($3,329)	($6,599)	($250)	($4,082)	$174,910	$18,342	$109,905.72	$65,004	($65,004)	($307,011)	$3.6724
Mar-23 Est.	20,722	$148,938	($27,618)	$167	($6,599)	($250)	($3,580)	$111,058	$14,545	$90,644.99	$20,413	($20,413)	($327,423)	$3.6724
Apr-23 Est.	11,568	$61,510	$0	$132	($928)	($250)	($1,492)	$58,971	$6,971	$49,454.62	$9,517	($9,517)	($336,940)	$3.6724
May-23 Est.	5,485	$28,034	($10,357)	($1,039)	($959)	($250)	($463)	$14,967	$1,787	$21,931.81	($6,964)	$6,964	($329,976)	$3.6724
Jun-23 Est.	4,294	$21,139	$0	($798)	($928)	($250)	$0	$19,163	$0	$15,770.62	$3,393	($3,393)	($333,369)	$3.6724
Jul-23 Est.	2,993	$14,621	$0	($699)	($959)	($250)	$0	$12,713	$0	$10,992.69	$1,721	($1,721)	($335,089)	$3.6724
Aug-23 Est.	2,569	$12,789	$0	($1,082)	($959)	($250)	$0	$10,499	$0	$9,434.46	$1,064	($1,064)	($336,154)	$3.6724
Sep-23 Est.	**3,085**	**$15,195**	**$0**	**($296)**	**($928)**	**($250)**	**$0**	$13,722	**$0**	$11,328.81	$2,393	($2,393)	($338,547)	$3.6724
Oct-22 to Sept-23	**153,991**	**$1,069,030**	**($37,975)**	**($9,764)**	**($39,203)**	**($3,000)**	**($21,506)**	**$957,582**	**$96,108**	**$661,625**	**$295,958**			

BGSS-RSG 2022-2023 NYMEX====>>> May 10, 2022	BGSS-RSG				OFF-SYS	Electric	FT Balancing		RSG Bal.	BGSS	EXCESS	OVER/(UNDER) RECOVERY		RSG Rate
ZERO BALANCE	MDTh	COST	REFUNDS	CONTRIB	Margin	Contribution	Credit	ADJ COST	Revenue	RECOVERY	COST	Month	Cumulative	$/dth
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(2).+.(7)	(9)	(10)=(1)*(14)+(9)	(11)=(10)-(8)	(12)=-(11)	(13)	(14)
Apr-22 Act.													**$3,518**	$3.6724
May-22 Est.	5,180	$34,435	$0	($1,054)	($547)	($595)	($195)	$32,044	$1,467	$20,490	$11,554	($11,554)	($8,036)	$3.6724
Jun-22 Est.	4,373	$30,182	$0	($799)	($529)	($1,031)	$0	$27,823	$0	$16,059	$11,764	($11,764)	($19,800)	$3.6724
Jul-22 Est.	3,042	$21,375	$0	($700)	($547)	($1,277)	$0	$18,851	$0	$11,171	$7,680	($7,680)	($27,480)	$3.6724
Aug-22 Est.	2,628	$18,612	$0	($1,084)	($547)	($1,257)	$0	$15,724	$0	$9,652	$6,072	($6,072)	($33,552)	$3.6724
Sep-22 Est.	**3,143**	**$22,256**	**$0**	**($296)**	**($529)**	**($852)**	**$0**	**$20,579**	**$0**	**$11,543**	**$9,037**	**($9,037)**	**($42,589)**	$3.6724
Oct-22 Est.	6,994	$49,295	$0	($610)	($547)	($250)	($974)	$46,914	$3,051	$44,114	$2,800	($2,800)	($45,389)	$5.8709
Nov-22 Est.	16,131	$116,215	$0	($864)	($6,599)	($250)	($2,583)	$105,918	$10,791	$105,495	$423	($423)	($45,812)	$5.8709
Dec-22 Est.	24,443	$180,283	$0	($2,579)	($6,599)	($250)	($3,639)	$167,216	$17,660	$161,161	$6,056	($6,056)	($51,868)	$5.8709
Jan-23 Est.	30,772	$231,840	$0	$1,232	($6,599)	($250)	($4,693)	$221,530	$22,960	$203,621	$17,908	($17,908)	($69,776)	$5.8709
Feb-23 Est.	24,933	$189,170	$0	($3,329)	($6,599)	($250)	($4,082)	$174,910	$18,342	$164,720	$10,189	($10,189)	($79,965)	$5.8709
Mar-23 Est.	20,722	$148,938	($27,618)	$167	($6,599)	($250)	($3,580)	$111,058	$14,545	$136,202	($25,145)	$25,145	($54,821)	$5.8709
Apr-23 Est.	11,568	$61,510	$0	$132	($928)	($250)	($1,492)	$58,971	$6,971	$74,887	($15,916)	$15,916	($38,905)	$5.8709
May-23 Est.	5,485	$28,034	($10,357)	($1,039)	($959)	($250)	($463)	$14,967	$1,787	$33,991	($19,024)	$19,024	($19,881)	$5.8709
Jun-23 Est.	4,294	$21,139	$0	($798)	($928)	($250)	$0	$19,163	$0	$25,212	($6,048)	$6,048	($13,833)	$5.8709
Jul-23 Est.	2,993	$14,621	$0	($699)	($959)	($250)	$0	$12,713	$0	$17,573	($4,860)	$4,860	($8,973)	$5.8709
Aug-23 Est.	2,569	$12,789	$0	($1,082)	($959)	($250)	$0	$10,499	$0	$15,082	($4,584)	$4,584	($4,389)	$5.8709
Sep-23 Est.	**3,085**	**$15,195**	**$0**	**($296)**	**($928)**	**($250)**	**$0**	**$13,722**	**$0**	**$18,111**	**($4,389)**	**$4,389**	**$0**	$5.8709
Oct-22 to Sept-23	**153,991**	**$1,069,030**	**($37,975)**	**($9,764)**	**($39,203)**	**($3,000)**	**($21,506)**	**$957,582**	**$96,108**	**$1,000,171**	**($42,589)**			

PSE&G
FOR PERIOD OCT21 TO SEP22

	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22
Beginning Balance	33,387,598	25,001,684	4,756,955	5,609,213	25,105,964	38,564,623	24,649,559
FUEL REVENUES							
Fuel Revenues	13,738,361	55,242,901	85,815,551	134,978,288	111,463,581	85,483,716	51,952,469
Interruptible Contribution	419,141	1,834,118	2,186,945	(1,543,844)	3,106,004	(77,604)	(422,880)
PSEG Holding's Affiliation Fee							
Total Fuel Revenues	14,157,501	57,077,019	88,002,496	133,434,444	114,569,585	85,406,112	51,529,589
FUEL EXPENSE							
Gas Purchases	22,601,959	77,336,016	88,047,685	113,940,159	101,111,051	99,321,798	73,421,760
Refunds	(58,544)	(14,267)	(897,447)	(2,466)	(125)	(622)	(761,050)
Total Fuel Expense	22,543,414	77,321,749	87,150,238	113,937,693	101,110,926	99,321,176	72,660,710
OVER / (UNDER) RECOVERY	(8,385,913)	(20,244,729)	852,258	19,496,751	13,458,659	(13,915,064)	(21,131,121)
Cumulative Recovery	25,001,684	4,756,955	5,609,213	25,105,964	38,564,623	24,649,559	3,518,438

BGSSR
CALCULATION OF FUEL REVENUES
FOR PERIOD OCT21 TO SEP22

	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22
RSG Fuel Revenues	$12,245,161	$43,507,201	$66,615,393	$104,087,295	$87,756,997	$67,811,080	$42,063,457
RSGM Fuel Revenues	$232,742	$863,115	$1,403,242	$2,133,397	$1,806,979	$1,492,824	$934,788
Subtotal	$12,477,903	$44,370,316	$68,018,635	$106,220,692	$89,563,975	$69,303,904	$42,998,246
FT Balancing Revenues	789,529	6,704,078	16,038,103	23,173,365	26,413,971	$18,240,232	$11,628,347
FT Balancing Revenues (Unbilled Calc)	470,929	4,639,435	6,398,248	11,982,480	7,468,115	5,407,694	2,733,570
FT Balancing Revenues (Prior Unbilled Calc)	0	-470,929	-4,639,435	-6,398,248	-11,982,480	-7,468,115	-5,407,694
Manual Rev Accrual not part of BGSSR							
Total BGSSR Fuel Recovery	$13,738,361	$55,242,901	$85,815,551	$134,978,288	$111,463,581	$85,483,716	$51,952,469
Bill Credits							
Billed Revenues							
Current Unbilled Usage							
Prior Unbilled Usage							
Net Unbilled Usage							
Rate							
Subtotal Unbilled Revenues							
Total Bill Credits							

	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22
Interruptible Contributions:							
ISG (BGSS-I):							
ISG (BGSS-I) Sales Therms	316,347	750,077	652,346	113,514	2,154,208	937,136	687,813
ISG BGSS-I) Gross Revenues	$ 228,320	$ 633,164	$ 509,482	$ 1,413,529	$ 710,819	$ 346,411	$ 555,187
ISG (BGSS-I) Cost	$ 106,323	$ 380,595	$ 333,655	$ 575,263	$ 779,990	$ 608,789	$ 503,903
PSEG Power's share of Contribution	$ 15,689	$ 58,037	$ 53,741	$ 65,291	$ 119,669	$ 64,637	$ 19,480
ISG Interuptible Contribution to BGSSR	$ 106,308	$ 194,532	$ 122,087	$ 772,975	$ (188,840)	$ (327,015)	$ 31,804
CIG:							
CIG SBC Rate adjustment (line 84)							
CIG Sales Therms	(64,720.97)	2,448,160.43	3,679,000.40	987,900.00	4,611,003.83	1,763,528.47	1,721,104.92
CIG Gross Revenues	$ 365,865	$ 1,937,048	$ 2,424,975	$ 107,072	$ 4,039,241	$ 693,110	$ 1,386,012
CIG SBC/GPRC Revenues	$ (3,639)	$ 137,636	$ 206,833	$ 55,540	$ 259,231	$ 99,146	$ 96,761
CIG Cost	$ 609,762	$ 851,032	$ 1,180,045	$ 1,523,561	$ 1,286,007	$ 1,013,833	$ 1,155,433
CIG TAC revenues	$ 502	$ (18,981)	$ (28,523)	$ (7,659)	$ (36,850)	$ (13,673)	$ (13,344)
PSEG Power's share of Contribution	$ 70,299	$ 100,897	$ 141,057	$ 91,641	$ 132,546	$ 63,234	$ 12,935
CIG Interuptible Contribution to BGSSR	$ (311,059)	$ 866,465	$ 925,563	$ (1,556,011)	$ 2,398,308	$ (469,430)	$ 134,227
TSG-F:							
TSG-F SBC Rate adjustment (line 84)							
TSG-F Sales Therms	3,140,740.84	1,305,503.27	559,893.39	3,241,105.82	5,304,896.05	4,183,663.20	1,935,695.02
TSG-F Gross Revenues	$ 442,195	$ 556,274	$ 1,319,999	$ (476,520)	$ 1,261,361	$ 851,466	$ (340,031)
TSG-F SBC/GPRC Revenues	$ 176,572	$ 73,395	$ 31,477	$ 182,215	$ 298,241	$ 235,206	$ 108,825
TSG-F TAC Revenues	$ (58,097)	$ (24,148)	$ (4,085)	$ (62,995)	$ (98,129)	$ (77,388)	$ (35,805)
TSG-F MAC Revenues	$ 20,474	$ 8,511	$ 3,259	$ 18,866	$ 30,880	$ 24,353	$ 11,268
TSG-F PSEG Power's share of Contribution	$ 113,812	$ 134,588	$ 89,239	$ 156,087	$ 275,277	$ 352,483	$ 208,914
TSG-F Interuptible Contribution to BGSSR	$ 189,433	$ 363,929	$ 1,200,109	$ (770,693)	$ 755,092	$ 316,812	$ (633,232)
CSG NON-Power:							
CSG Non-Power Therms	16,996,995.68	13,978,169.89	(2,621,407.54)	4,604,358.50	1,969,450.79	55,128,456.02	(875,639.57)
CSG Non-Power Revenues	$ 436,970	$ 403,240	$ 149,552	$ 210,493	$ 195,027	$ 631,035	$ 207,916
CSG Non Power SBC Revenues	$ 13,984	$ 10,175	$ 237,286	$ 210,095	$ 75,524	$ 241,356	$ 3,163
CSG TAC Revenues Power and NON-Power	$ (60,144)	$ (51,168)	$ (41,282)	$ (29,817)	$ (38,833)	$ (29,995)	$ 788
CSG Non-Power ER&T's share of Contribution	$ 48,671	$ 35,041	$ 14,363	$ 20,329	$ 16,892	$ 17,646	$ 159,644
CSG Non-Power Contribution to BGSSR	$ 434,459	$ 409,192	$ (60,815)	$ 9,885	$ 141,444	$ 402,029	$ 44,320
Total Interruptible Contributions	$ 419,141	$ 1,834,118	$ 2,186,945	$ (1,543,844)	$ 3,106,004	$ (77,604)	$ (422,880)
SBC & GPRC rate-CIG & TSG-F (CHECK tariff pages for rate changes)	**0.056220**	**0.056220**	**0.056220**	**0.056220**	**0.056220**	**0.056220**	**0.056220**
TEFA rate-TSG-F (Reduced 25% 2012 & 25% 2013, zero out 2014)							
Cogen Contract RAC rate (separate schedule beginning 12/02)							
MAC rate-TSG-F (Per MAC CALC Worksheet)	**0.006519**	**0.006519**	**0.005821**	**0.005821**	**0.005821**	**0.005821**	**0.005821**
PSEG Holding's Affliliation Fee							
Current Month Estimate - Gas Purchases (1) See below row 96	$ 22,483,018	$ 79,019,055	$ 89,649,523	$ 114,368,213	$ 103,629,445	$ 95,890,731	$ 75,203,266
Prior Month Actual - Gas Purchases (1) See below row 105	$ 12,811,614	$ 20,785,712	$ 76,519,769	$ 89,219,004	$ 111,849,694	$ 107,059,890	$ 93,348,174
Prior Month Estimate - Gas Purchases See below row 115	$ 12,751,218	$ 22,483,018	$ 79,019,055	$ 89,649,523	$ 114,368,213	$ 103,629,445	$ 95,890,731
Gas Purchases	$ 22,543,414	$ 77,321,749	$ 87,150,238	$ 113,937,693	$ 101,110,926	$ 99,321,176	$ 72,660,710
Gas Refunds							
ISG (BGSS-I) Cost Est. (2)	$ 106,100	$ 380,512	$ 335,109	$ 572,486	$ 768,291	$ 534,013	$ 478,762
PSEG Power's share of Contribution CMnth Est. (2)	$ 15,605	$ 56,739	$ 56,276	$ 64,976	$ 118,190	$ 62,001	$ 22,926
ISG (BGSS-I) Cost Pr Mnth Act. (2)	$ 63,050	$ 106,183	$ 379,058	$ 337,887	$ 584,184	$ 843,067	$ 559,153
PSEG Power's share of Contribution Pr Mnth Act. (2)	$ 7,872	$ 16,904	$ 54,203	$ 56,591	$ 66,455	$ 120,826	$ 58,555
ISG (BGSS-I) Cost PrMnth Est.	$ 62,828	$ 106,100	$ 380,512	$ 335,109	$ 572,486	$ 768,291	$ 534,013
PSEG Power's share of Contribution PrMnth Est.	$ 7,788	$ 15,605	$ 56,739	$ 56,276	$ 64,976	$ 118,190	$ 62,001
CIG Cost (3) - CMnth Est. (3)	$ 611,627	$ 851,150	$ 1,183,947	$ 1,513,747	$ 1,263,866	$ 991,901	$ 1,108,736
PSEG Power's share of Contribution - CMnth Est. (3)	$ 69,719	$ 95,194	$ 144,971	$ 91,525	$ 133,694	$ 71,887	$ 21,635
CIG Cost (3) - PrMnth Act. (3)	$ 967,108	$ 611,509	$ 847,248	$ 1,193,762	$ 1,535,887	$ 1,285,798	$ 1,038,599
PSEG Power's share of Contribution - PrMnth Act. (3)	$ 78,620	$ 75,421	$ 91,280	$ 145,086	$ 90,378	$ 125,041	$ 63,188
CIG Cost - PrMnth Est.	$ 968,973	$ 611,627	$ 851,150	$ 1,183,947	$ 1,513,747	$ 1,263,866	$ 991,901
PSEG Power's share of Contribution - PrMnth Est.	$ 78,039	$ 69,719	$ 95,194	$ 144,971	$ 91,525	$ 133,694	$ 71,887

	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22
TSG-F PSEG Power's share of Contribution CMth Est. (4)	$ 113,696	$ 155,643	$ 115,015	$ 153,912	$ 266,274	$ 355,345	$ 182,199
TSG-F PSEG Power's share of Contribution PrMth Actual (4)	$ 80,702	$ 92,640	$ 129,867	$ 117,190	$ 162,916	$ 263,411	$ 382,061
TSG-F PSEG Power's share of Contribution PrMth Est.	$ 80,586	$ 113,696	$ 155,643	$ 115,015	$ 153,912	$ 266,274	$ 355,345
CSC Non-Power Cost & PSEG Power's share of Contribution CMth Est. (6)	$ 51,865	$ 30,495	$ 15,899	$ 20,052	$ 15,886	$ 17,775	$ 82,845
CSC Non-Power Cost & PSEG Power's share of Contribution PMth Act. (6)	$ 31,260	$ 56,412	$ 28,959	$ 16,176	$ 21,058	$ 15,757	$ 94,574
CSC Non-Power Cost & PSEG Power's share of Contribution PMth Est.	$ 34,455	$ 51,865	$ 30,495	$ 15,899	$ 20,052	$ 15,886	$ 17,775
BGSS-RSG Prior Month Actual	$ 13,928,265	$ 21,595,728	$ 77,891,558	$ 90,952,330	$ 114,126,599	$ 109,434,621	$ 95,067,669
BGSS-RSG Cogen Contracts Prior Month Actual (6)	$ -	$ 185,954	$ 757,398	$ 868,069	$ 1,699,096	$ 1,213,516	$ 960,161
BGSS-RSG TSG Cashouts Prior Mnth Actuals	$ 296,218	$ 595,081	$ 640,889	$ 65,005	$ 355,344	$ (172,854)	$ 645,743
Subtotal	$ 15,076,589	$ 23,253,170	$ 80,164,578	$ 92,473,342	$ 116,638,596	$ 111,066,647	$ 97,198,389
Total BGSS-RSG Actual Bill	**$ 14,843,592**	**$ 22,332,338**	**$ 78,770,214**	**$ 91,110,824**	**$ 114,663,870**	**$ 109,632,270**	**$ 96,238,228**
Difference							
BGSS-RSG Current Month Estimate	$ 23,521,654	$ 80,628,448	$ 91,496,276	$ 116,779,497	$ 106,002,884	$ 97,550,533	$ 76,835,325
BGSS-RSG Cogen Contracts Prior Month Estimate (6)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal	$ 23,521,654	$ 80,628,448	$ 91,496,276	$ 116,779,497	$ 106,002,884	$ 97,550,533	$ 76,835,325
Total BGSS-RSG Estimate Bill	**$ 23,521,654**	**$ 80,628,448**	**$ 91,496,276**	**$ 116,779,497**	**$ 106,346,479**	**$ 98,004,101**	**$ 77,450,788**
Difference							
Gas Purchases Details:							
Current Month Estimate							
BGSS-RSG GAS COMMODITY VOLUMES MDTh	5,257,137	17,210,477	20,231,049	32,304,632	23,188,924	17,893,697	12,524,301
BGSS-RSG GAS COMMODITY COST	$ 23,347,250	$ 79,931,691	$ 96,280,105	$ 154,188,145	$ 116,986,396	$ 96,303,553	$ 74,796,731
BGSS-RSG Balancing	$ 586,117	$ 2,359,738	$ 2,878,221	$ 4,760,541	$ 3,386,187	$ 2,551,555	$ 1,706,325
BGSS-RSG Off System Sales	$ (341,812)	$ (2,172,648)	$ (8,792,311)	$ (43,949,675)	$ (16,013,568)	$ (2,510,809)	$ (684,327)
Electric Reservation Charge	$ (872,952)	$ (873,930)	$ (590,043)	$ (462,247)	$ (640,171)	$ (453,568)	$ (615,463)
Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CSG Revenues	**$ (235,585)**	**$ (225,797)**	**$ (126,449)**	**$ (168,550)**	**$ (89,398)**	**$ -**	**$ -**
Credit for Pipeline Refunds	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ 22,483,018	$ 79,019,055	$ 89,649,523	$ 114,368,213	$ 103,629,445	$ 95,890,731	$ 75,203,266
Prior Actual							
BGSS-RSG GAS COMMODITY VOLUMES MDTh	3,409,752	4,910,306	16,870,046	20,120,070	31,593,376	23,439,981	17,555,066
BGSS-RSG GAS COMMODITY COST	$ 14,527,133	$ 21,812,104	$ 78,389,196	$ 95,782,126	$ 151,015,001	$ 120,154,846	$ 94,606,138
BGSS-RSG Balancing	$ 306,503	$ 545,440	$ 2,349,094	$ 2,862,090	$ 4,665,017	$ 3,430,051	$ 2,489,433
BGSS-RSG Off System Sales	$ (492,261)	$ (539,628)	$ (2,208,573)	$ (8,741,321)	$ (43,232,602)	$ (16,145,903)	$ (2,461,530)
Electric Reservation Charge	$ (852,107)	$ (876,407)	$ (874,734)	$ (587,937)	$ (457,557)	$ (591,364)	$ (524,816)
CSG Revenues	**$ (619,109)**	**$ (141,529)**	**$ (237,767)**	**$ (93,489)**	**$ (140,040)**	**$ (75,715)**	**$ -**
Non Compliance Penalty	$ -	$ -	$ -	$ -	$ -	$ 176,075	$ -
Credit for Pipeline Refunds	$ (58,544)	$ (14,267)	$ (897,447)	$ (2,466)	$ (125)	$ (622)	$ (761,050)
Residential Share of Propane Contract Deficiency Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Residential Share of Property Taxes Paid	$ -	$ -	$ -	$ -	$ -	$ 112,521	$ -
Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ 12,811,614	$ 20,785,712	$ 76,519,769	$ 89,219,004	$ 111,849,694	$ 107,059,890	$ 93,348,174
Prior Estimate							
BGSS-RSG GAS COMMODITY VOLUMES MDTh	3,251,054	5,257,137	17,210,477	20,231,049	32,304,632	23,188,924	17,893,697
BGSS-RSG GAS COMMODITY COST	$ 13,836,726	$ 23,347,250	$ 79,931,691	$ 96,280,105	$ 154,188,145	$ 116,986,396	$ 96,303,553
BGSS-RSG Balancing	$ 292,237	$ 586,117	$ 2,359,738	$ 2,878,221	$ 4,760,541	$ 3,386,187	$ 2,551,555
BGSS-RSG Off System Sales	$ (298,194)	$ (341,812)	$ (2,172,648)	$ (8,792,311)	$ (43,949,675)	$ (16,013,568)	$ (2,510,809)
Electric Reservation Charge	$ (848,677)	$ (872,952)	$ (873,930)	$ (590,043)	$ (462,247)	$ (640,171)	$ (453,568)
Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Prior CSG Revenues	$ (230,874)	$ (235,585)	$ (225,797)	$ (126,449)	$ (168,550)	$ (89,398)	$ -
Credit for Pipeline Refunds	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ 12,751,218	$ 22,483,018	$ 79,019,055	$ 89,649,523	$ 114,368,213	$ 103,629,445	$ 95,890,731
Net							
BGSS-RSG GAS COMMODITY VOLUMES MDTh	5,415,835	16,863,646	19,890,618	32,193,653	22,477,668	18,144,754	12,185,670

	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22
BGSS-RSG GAS COMMODITY COST	$ 24,037,657	$ 78,396,545	$ 94,737,610	$ 153,690,165	$ 113,813,253	$ 99,472,003	$ 73,099,316
BGSS-RSG Balancing	$ 600,382	$ 2,319,062	$ 2,867,576	$ 4,744,409	$ 3,290,663	$ 2,595,419	$ 1,644,204
BGSS-RSG Off System Sales	$ (535,879)	$ (2,370,465)	$ (8,828,236)	$ (43,898,684)	$ (15,296,495)	$ (2,643,144)	$ (635,048)
Electric Reservation Charge	$ (876,382)	$ (877,385)	$ (590,847)	$ (460,142)	$ (635,481)	$ (404,761)	$ (686,711)
Other	$ -	$ -	$ -	$ -	$ -	$ 288,597	$ -
CSG Revenues	$ (623,820)	$ (131,742)	$ (138,419)	$ (135,590)	$ (60,887)	$ 13,684	$ -
Credit for Pipeline Refunds	$ (58,544)	$ (14,267)	$ (897,447)	$ (2,466)	$ (125)	$ (622)	$ (761,050)
Total	$ 22,543,414	$ 77,321,749	$ 87,150,238	$ 113,937,693	$ 101,110,926	$ 99,321,176	$ 72,660,710
BGSS-RSG GAS COMMODITY VOLUMES MDTh	5,415,835	16,863,646	19,890,618	32,193,653	22,477,668	18,144,754	12,185,670
NET SALES VOLUMES RESIDENTIAL	4,162,972	14,784,178	20,038,328	31,142,254	23,208,275	17,992,502	11,165,064
Diff	1,252,863	2,079,468	(147,710)	1,051,399	(730,607)	152,252	1,020,606

INTEREST CALCULATION
FOR PERIOD OCT21 TO SEP22

	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22
CUMULATIVE OVER/(UNDER) RECOVERY PRIOR MONTH	$33,387,598	$25,001,684	$4,756,955	$5,609,213	$25,105,964	$38,564,623	$24,649,559
CUMULATIVE OVER/(UNDER) RECOVERY CURRENT MONTH	$25,001,684	$4,756,955	$5,609,213	$25,105,964	$38,564,623	$24,649,559	$3,518,438
AVERAGE BALANCE	$29,194,641	$14,879,320	$5,183,084	$15,357,588	$31,835,293	$31,607,091	$14,083,999
MONTHLY INTEREST (Income)/Expense allowed rate of return of 6.99%	**$170,059**	**$86,672**	**$30,191**	**$89,458**	**$185,441**	**$184,111**	**$82,039**
INTEREST ACCUMULATED, (Income)/Expense	$170,059	$256,731	$286,922	$376,380	$561,821	$745,932	$827,971

8. Wholesale Gas Pricing Assumptions

Item 8

A Comparison of the Forecasted Cost of Gas as represented by the NYMEX
June 2022 Filing versus June 2021 Filing

($/Mbtu)

		June '22 Filing Nymex - 5/10/2022	June '21 Filing Nymex - 5/6/2021	Difference	Percentage Difference
2022	**May**	$7.267	$2.925	$4.342	148.4%
	June	$7.385	$2.928	$4.457	152.2%
	July	$7.467	$2.974	$4.493	151.1%
	August	$7.446	$2.984	$4.462	149.5%
	September	$7.400	$2.971	$4.429	149.1%
	October	$7.391	$2.990	$4.401	147.2%
	November	$7.457	$3.052	$4.405	144.3%
	December	$7.571	$3.180	$4.391	138.1%
2023	**January**	$7.663	$3.263	$4.400	134.8%
	February	$7.342	$3.192	$4.150	130.0%
	March	$6.302	$2.993	$3.309	110.6%
	April	$4.659	$2.604	$2.055	78.9%
	May	$4.496	$2.548	$1.948	76.5%
	June	$4.539	$2.577	$1.962	76.1%
	July	$4.581	$2.612	$1.969	75.4%
	August	$4.574	$2.618	$1.956	74.7%
	September	$4.550	$2.602	$1.948	74.9%
	Average	$6.358	$2.883	$3.475	120.5%

9. GCUA Recoveries and Balances

N/A

10. Historical Service Interruptions

Item 10

SERVICE INTERRUPTIONS

During the current winter, service to the Company's tariff gas customers was interrupted during the following time periods:

Note: All dates below represent heating season for year 2021-2022.

Rate Schedule CIG:
Number of Customers: 12 (including 4 CEGs)

- Event #1: 1/14/2022 10AM – 1/16/2022 10AM
- Event #2: 1/21/2022 10AM – 1/22/2022 10AM
- Event #1: CEG was offered Extended Gas Service
- Event #2: CEG was offered Extended Gas Service

Rate Schedule TSG-NF (BGSS-I):
Number of Customers: 25

- Event #1: 1/14/2022 10AM – 1/16/2022 10AM
- Event #2: 1/21/2022 10AM – 1/22/2022 10AM
- Event #3: 1/29/2022 10AM – 1/31/2022 10AM

Rate Schedule TSG-NF (Third Party Suppliers):
Number of Customers: 128

- Event #2: 1/21/2022 10AM – 1/22/2022 10AM

Rate Schedule CSG-I (Third Party Suppliers):
Number of Customers: 3

- Event #2: 1/21/2022 10AM – 1/22/2022 10AM

Rate Schedule CSG-I (Power Generation Stations):
Number of Customers: 3

- Event #4: 2/26/2022 10AM – 2/27/2022 10AM
- Event #5: 3/12/2022 10AM – 3/13/2022 10AM
- Event #6: 3/27/2022 10AM – 3/28/2022 10AM

11. <u>Gas Price Hedging Activities</u>

Reports Dated:

April 15, 2022

January 18, 2022

October 19, 2021

July 16, 2021

Matthew M. Weissman
Managing Counsel – State Regulatory

Law Department
PSEG Services Corporation
80 Park Plaza – T5, Newark, New Jersey 07102-4194
tel : 973-430-7052 fax: 973-430-5983
email: matthew.weissman@pseg.com

PSEG Services Corporation

VIA ELECTRONIC MAIL

April 15, 2022

In the Matter of Public Service Electric and Gas Company
Proposal for a Change in its Monthly Pricing Mechanism
Within its Levelized Gas Adjustment Clause for Residential
Gas Customers Pursuant to
N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1
Docket No. GR00070491

Paul Lupo, Acting Director
Division of Energy
Board of Public Utilities
44 South Clinton Avenue, 9th Floor
Trenton, New Jersey, 08625-0350

RE: PSE&G GAS HEDGING QUARTERLY REPORT – FIRST QUARTER 2022

Dear Acting Director Lupo:

Enclosed please find Public Service Electric and Gas Company's ("Public Service" or the "Company") quarterly status report which is filed pursuant to the Board's March 30, 2001 Decision and Order in the above-referenced matter. This quarterly report identifies the Company's outstanding hedging positions as of March 31, 2022.

As shown on the attached schedules, hedging for the 2021/2022 winter season was 88% of plan and 86% of the plan has been completed for 2022 summer. Hedging for the 2022/2023 winter season is at 47% and the 2023 summer season is at 26%. All of these periods are based on a plan of approximately 70bcf with an even split between winter and summer.

The Company will continue to monitor the performance of its hedging program and the criteria it utilizes deciding when to implement hedges, and keep the Board appraised of any changes it anticipates in the program.

Very truly yours,

Matthew Weissman

Matthew M. Weissman

Attachment

C Alice Bator
Maura Caroselli
Brian Lipman
Ben Witherell

PSE&G Residential Hedging Report November 2021 - October 2022 As of March 31, 2022	Bcf Target*	Bcf Hedged	% Hedged Target		% Hedged Actual	Current Price/ MMBtu
WINTER - Nov 21-Mar 22 Hedge Volume						
(230,000/ day) (151 days)						
Non-Discretionary Volume	17.500	**17.365**	94%	100%	99%	**$2.96**
Dollar Budget Method	17.500	**13.318**	$2.130M/mo.		76%	**$2.72**
Total Winter Hedge Volume	35.000	**30.683**			88%	**$2.85**
			Actual Settles			**$5.30**
SUMMER - Apr 22-Oct 22 Hedge Volume						
(160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**17.120**	94%	100%	98%	**$2.46**
Dollar Budget Method	17.500	**12.926**	$1.653M/mo.		74%	**$2.26**
Total Summer Hedge Volume	35.000	**30.046**			86%	**$2.37**
			Actual and 3/31/22 Settles			**$5.67**
Total Non-Discretionary Method	35.000	**34.485**				**$2.71**
Total Dollar Budget Method	35.000	**26.244**				**$2.49**
					Difference	**($0.22)**
					Percent	**-8.9%**

PSE&G Residential Hedging Report November 2022 - October 2023 As of March 31, 2022	Bcf Target*	Bcf Hedged	% Hedged Target		% Hedged Actual	Current Price/ MMBtu
WINTER - Nov 22-Mar 23 Hedge Volume						
(230,000/ day) (151 days)						
Non-Discretionary Volume	17.500	**9.815**	56%	61%	56%	**$3.16**
Dollar Budget Method	17.500	**6.523**	$1.884M/mo.		37%	**$3.14**
Total Winter Hedge Volume	35.000	**16.338**			47%	**$3.15**
			Actual and 3/31/22 Settles			**$5.78**
SUMMER - Apr 23-Oct 23 Hedge Volume						
(160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**5.350**	28%	33%	31%	**$2.50**
Dollar Budget Method	17.500	**3.702**	$1.593M/mo.		21%	**$2.54**
Total Summer Hedge Volume	35.000	**9.052**			26%	**$2.52**
			Actual and 3/31/22 Settles			**$3.98**
Total Non-Discretionary Method	35.000	**15.165**				**$2.93**
Total Dollar Budget Method	35.000	**10.225**				**$2.92**
					Difference	**($0.01)**
					Percent	**-0.2%**

Matthew M. Weissman
Managing Counsel – State Regulatory

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PSEG Services Corporation
80 Park Plaza – T5, Newark, New Jersey 07102-4194
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email: matthew.weissman@pseg.com

PSEG
Services Corporation

VIA ELECTRONIC MAIL

January 18, 2022

In the Matter of Public Service Electric and Gas Company
Proposal for a Change in its Monthly Pricing Mechanism
Within its Levelized Gas Adjustment Clause for Residential
Gas Customers Pursuant to
N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1
Docket No. GR00070491

Paul Lupo, Acting Director
Division of Energy
Board of Public Utilities
44 South Clinton Avenue, 9th Floor
Trenton, New Jersey, 08625-0350

RE: PSE&G GAS HEDGING QUARTERLY REPORT – FOURTH QUARTER 2021

Dear Acting Director Lupo:

Enclosed please find Public Service Electric and Gas Company's ("Public Service" or the "Company") quarterly status report which is filed pursuant to the Board's March 30, 2001 Decision and Order in the above-referenced matter. This quarterly report identifies the Company's outstanding hedging positions as of December 31, 2021.

As shown on the attached schedules, hedging for the 2021/2022 winter season is at 88% of plan and 73% of the plan has been completed for 2022 summer. Hedging for the 2022/2023 winter season is at 36% and the 2023 summer season is at 15%. All of these periods are based on a plan of approximately 70bcf with an even split between winter and summer.

The Company will continue to monitor the performance of its hedging program and the criteria it utilizes deciding when to implement hedges, and keep the Board appraised of any changes it anticipates in the program.

Very truly yours,

Matthew M. Weissman

Attachment

C Alice Bator
Felicia Thomas-Friel
Ben Witherell

PSE&G Residential Hedging Report November 2021 - October 2022 As of 12/31/21	Bcf Target*	Bcf Hedged	% Hedged Target		% Hedged Actual	Current Price/ MMBtu
WINTER - Nov 21-Mar 22 Hedge Volume						
(230,000/ day) (151 days)						
Non-Discretionary Volume	17.500	**17.365**	94%	100%	99%	**$2.96**
Dollar Budget Method	17.500	**13.318**	$2.130M/mo.		76%	**$2.72**
Total Winter Hedge Volume	35.000	**30.683**			88%	**$2.85**
			Actual Nymex Prices and 12/30/21 S			**$4.53**
SUMMER - Apr 22-Oct 22 Hedge Volume						
(160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**13.910**	78%	83%	79%	**$2.20**
Dollar Budget Method	17.500	**11.535**	$1.653M/mo.		66%	**$2.11**
Total Summer Hedge Volume	35.000	**25.445**			73%	**$2.16**
			12/30/21 Nymex Settles			**$3.51**
Total Non-Discretionary Method	35.000	**31.275**				**$2.62**
Total Dollar Budget Method	35.000	**24.853**				**$2.44**
					Difference	**($0.19)**
					Percent	**-7.6%**

PSE&G Residential Hedging Report November 2022 - October 2023 As of 12/31/21	Bcf Target*	Bcf Hedged	% Hedged Target		% Hedged Actual	Current Price/ MMBtu
WINTER - Nov 22-Mar 23 Hedge Volume (230,000/ day) (151 days)						
Non-Discretionary Volume	17.500	**7.550**	39%	44%	43%	**$2.98**
Dollar Budget Method	17.500	**5.149**	$1.884M/mo.		29%	**$2.90**
Total Winter Hedge Volume	35.000	**12.699**			36%	**$2.95**
			12/30/21 Nymex Settles			**$3.82**
SUMMER - Apr 23-Oct 23 Hedge Volume (160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**3.210**	11%	17%	18%	**$2.51**
Dollar Budget Method	17.500	**1.883**	$1.593M/mo.		11%	**$2.51**
Total Summer Hedge Volume	35.000	**5.093**			15%	**$2.51**
			12/30/21 Nymex Settles			**$3.09**
Total Non-Discretionary Method	35.000	**10.760**				**$2.84**
Total Dollar Budget Method	35.000	**7.032**				**$2.79**
					Difference	**($0.04)**
					Percent	**-1.6%**

Matthew M. Weissman
Managing Counsel – State Regulatory

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email: matthew.weissman@pseg.com

PSEG
Services Corporation

VIA ELECTRONIC MAIL

October 19, 2021

In the Matter of Public Service Electric and Gas Company
Proposal for a Change in its Monthly Pricing Mechanism
Within its Levelized Gas Adjustment Clause for Residential
Gas Customers Pursuant to
N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1
Docket No. GR00070491

Paul Lupo, Acting Director
Division of Energy
Board of Public Utilities
44 South Clinton Avenue, 9th Floor
Trenton, New Jersey, 08625-0350

RE: PSE&G GAS HEDGING QUARTERLY REPORT – THIRD QUARTER 2021

Dear Acting Director Lupo:

Enclosed please find Public Service Electric and Gas Company's ("Public Service" or the "Company") quarterly status report which is filed pursuant to the Board's March 30, 2001 Decision and Order in the above-referenced matter. This quarterly report identifies the Company's outstanding hedging positions as of September 30, 2021.

As shown on the attached schedules, hedging for the 2021/2022 winter season is at 81% of plan and 62% of the plan has been completed for 2022 summer. Hedging for the 2022/2023 winter season is at 23% and we have not yet begun to hedge for the 2023 summer. All of these periods are based on a plan of approximately 70bcf with an even split between winter and summer.

The Company will continue to monitor the performance of its hedging program and the criteria it utilizes deciding when to implement hedges, and keep the Board appraised of any changes it anticipates in the program.

Very truly yours,

Matthew Weissman

Matthew M. Weissman

Attachment

C Alice Bator
Brian Lipman
Ben Witherell

PSE&G Residential Hedging Report November 2021 - October 2022 As of 9/30/2021	Bcf Target*	Bcf Hedged	% Hedged Target		% Hedged Actual	Current Price/ MMBtu
WINTER - Nov 21-Mar 22 Hedge Volume (230,000/ day) (151 days)						
Non-Discretionary Volume	17.500	**15.478**	89%	94%	88%	**$2.66**
Dollar Budget Method	17.500	**12.941**	$2.130M/mo.		74%	**$2.64**
Total Winter Hedge Volume	35.000	**28.418**			81%	**$2.65**
			Actual 9/30/21 Settles			**$5.88**
SUMMER - Apr 22-Oct 22 Hedge Volume (160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**11.770**	61%	67%	67%	**$2.06**
Dollar Budget Method	17.500	**9.951**	$1.653M/mo.		57%	**$1.96**
Total Summer Hedge Volume	35.000	**21.721**			62%	**$2.01**
			Actual 9/30/21 Settles			**$3.90**
Total Non-Discretionary Method	35.000	**27.248**				**$2.40**
Total Dollar Budget Method	35.000	**22.892**				**$2.35**
					Difference	**($0.05)**
					Percent	**-2.2%**

PSE&G Residential Hedging Report
November 2022 - October 2023
As of 9/30/2021

	Bcf Target*	Bcf Hedged	% Hedged Target		% Hedged Actual	Current Price/ MMBtu
WINTER - Nov 22-Mar 23 Hedge Volume						
(230,000/ day) (151 days)						
Non-Discretionary Volume	17.500	**4.530**	22%	28%	26%	**$2.60**
Dollar Budget Method	17.500	**3.564**	$1.884M/mo.		20%	**$2.61**
Total Winter Hedge Volume	35.000	**8.094**			23%	**$2.61**
			Actual 9/30/21 Settles			**$4.06**
SUMMER - Apr 23-Oct 23 Hedge Volume						
(160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**0.000**	0%	0%	0%	**$0.00**
Dollar Budget Method	17.500	**0.000**			0%	**$0.00**
Total Summer Hedge Volume	35.000	**0.000**			0%	**#DIV/0!**
						$0.00
Total Non-Discretionary Method	35.000	**4.530**				**$2.60**
Total Dollar Budget Method	35.000	**3.564**				**$2.61**
					Difference	**$0.01**
					Percent	**0.3%**

Matthew M. Weissman
Managing Counsel – State Regulatory

Law Department
PSEG Services Corporation
80 Park Plaza – T5, Newark, New Jersey 07102-4194
tel : 973-430-7052 fax: 973-430-5983
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VIA ELECTRONIC MAIL

July 16, 2021

In the Matter of Public Service Electric and Gas Company
Proposal for a Change in its Monthly Pricing Mechanism
Within its Levelized Gas Adjustment Clause for Residential
Gas Customers Pursuant to
N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1
Docket No. GR00070491

Stacy Peterson, Director
Division of Energy
Board of Public Utilities
44 South Clinton Avenue, 9th Floor
Trenton, New Jersey, 08625-0350

RE: PSE&G GAS HEDGING QUARTERLY REPORT – SECOND QUARTER 2021

Dear Director Peterson:

Enclosed please find Public Service Electric and Gas Company's ("Public Service" or the "Company") quarterly status report which is filed pursuant to the Board's March 30, 2001 Decision and Order in the above-referenced matter. This quarterly report identifies the Company's outstanding hedging positions as of June 30, 2021.

As shown on the attached schedules, hedging for the 2021/2022 winter season is at 70% of plan and 47% of the plan has been completed for 2022 summer. Hedging for the 2022/2023 winter season is at 9% and we have not yet begun to hedge for the 2023 summer. All of these periods are based on a plan of approximately 70bcf with an even split between winter and summer.

The Company will continue to monitor the performance of its hedging program and the criteria it utilizes deciding when to implement hedges, and keep the Board appraised of any changes it anticipates in the program.

Very truly yours,

Matthew Weissman

Matthew M. Weissman

Attachment

C Stefanie A. Brand
Alice Bator
Felicia Thomas-Friel
Ben Witherell

PSE&G Residential Hedging Report November 2021 - October 2022	Bcf Target*	Bcf Hedged	% Hedged Target		% Hedged Actual	Current Price/ MMBtu
WINTER - Nov 21-Mar 22 Hedge Volume						
(230,000/ day) (151 days)						
Non-Discretionary Volume	17.500	**13.213**	72%	78%	76%	**$2.46**
Dollar Budget Method	17.500	**11.280**	$2.130M/mo.		64%	**$2.49**
Total Winter Hedge Volume	35.000	**24.492**			70%	**$2.47**
			6/30/21	**Nymex Settles**		**$3.68**
SUMMER - Apr 22-Oct 22 Hedge Volume						
(160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**8.560**	44%	50%	49%	**$1.89**
Dollar Budget Method	17.500	**8.004**	$1.653M/mo.		46%	**$1.83**
Total Summer Hedge Volume	35.000	**16.564**			47%	**$1.86**
			6/30/21 Nymex Settles			**$2.97**
Total Non-Discretionary Method	35.000	**21.773**				**$2.24**
Total Dollar Budget Method	35.000	**19.284**				**$2.22**
					Difference	**($0.02)**
					Percent	**-0.9%**

PSE&G Residential Hedging Report November 2022 - October 2023	Bcf Target*	Bcf Hedged	% Hedged Target		% Hedged Actual	Current Price/ MMBtu
WINTER - Nov 22-Mar 23 Hedge Volume						
(230,000/ day) (151 days)						
Non-Discretionary Volume	17.500	**1.510**	6%	11%	9%	**$2.24**
Dollar Budget Method	17.500	**1.616**	$1.884M/mo.		9%	**$2.31**
Total Winter Hedge Volume	35.000	**3.126**			9%	**$2.28**
			6/30/21 Nymex Settles			**$3.14**
SUMMER - Apr 23-Oct 23 Hedge Volume						
(160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**0.000**	0%	0%	0%	**$0.00**
Dollar Budget Method	17.500	**0.000**			0%	**$0.00**
Total Summer Hedge Volume	35.000	**0.000**			0%	**#DIV/0!**
			Current Nymx			**$0.00**
Total Non-Discretionary Method	35.000	**1.510**				**$2.24**
Total Dollar Budget Method	35.000	**1.616**				**$2.31**
					Difference	**$0.07**
					Percent	**3.0%**

12. Storage Gas Volumes, Prices and Utilization

Ending Storage Inventory by Contract

Mdth

Storage Contract	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22
DTI GSS	16,222.9	14,964.8	12,712.4	8,757.0	4,495.3	1,710.7	2,167.4
ARLINGTON	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TR GSS	15,361.3	14,676.4	13,868.1	9,495.3	6,502.7	2,824.2	2,758.8
TR S-2	5,849.8	5,744.5	4,887.4	2,850.8	1,342.6	883.3	882.7
TR LSS	4,950.9	4,336.5	3,532.1	2,396.6	1,465.6	952.5	1,221.5
TENN FS-MA	7,990.3	6,974.5	5,589.2	3,390.7	2,286.3	1,391.4	454.9
DTI GSS-TE	14,022.8	13,480.9	11,703.7	7,360.7	4,031.9	1,759.9	1,895.4
TE SS-1 / SS	3,674.7	3,540.0	3,044.4	2,073.8	1,175.2	411.4	622.1
TE SS1	1,441.7	1,394.8	1,189.4	811.7	495.3	188.8	246.3
TR ESS	788.6	1,186.5	1,186.5	866.2	712.1	958.3	1,186.5
GULF SOUTH	296.7	636.1	969.4	663.7	748.8	152.6	805.3
TR LNG	1,335.4	1,333.8	1,333.8	1,218.5	1,131.4	992.9	941.7
TR LNG New	15.5	15.5	15.5	15.5	15.5	15.5	15.5
Total	71,950.8	68,284.3	60,031.9	39,900.6	24,402.6	12,241.6	13,198.0
Ending Inventory Cost ($/Dth)	$4.44	$4.65	$4.76	$4.79	$5.13	$5.48	$6.10

NOTE: All volumes shown above represent total storage for all firm customers while the average inventory cost is applicable to residential only.

LPG INVENTORY VOLUMES AND COST BY LOCATION
(000)

	Camden		Central		Harrison		Linden	
Month	Dth	Dollars	Dth	Dollars	Dth	Dollars	Dth	Dollars
Jan-19	43	$495	80	$777	71	$849	62	$577
Feb-19	41	$474	79	$770	68	$822	61	$568
Mar-19	41	$474	79	$770	75	$896	61	$568
Apr-19	40	$455	75	$731	70	$841	61	$568
May-19	40	$455	75	$731	70	$841	61	$568
Jun-19	40	$455	75	$731	70	$841	61	$568
Jul-19	40	$455	75	$731	70	$841	61	$568
Aug-19	40	$455	75	$731	70	$841	61	$568
Sep-19	44	$485	84	$796	77	$893	61	$568
Oct-19	44	$485	84	$795	77	$893	63	$581
Nov-19	44	$485	84	$795	77	$893	63	$581
Dec-19	45	$496	85	$811	79	$910	64	$592
Jan-20	45	$493	85	$804	74	$857	64	$592
Feb-20	45	$493	85	$804	69	$800	64	$592
Mar-20	45	$493	55	$523	55	$631	64	$592
Apr-20	45	$493	55	$523	55	$631	64	$592
May-20	45	$493	55	$523	55	$631	64	$592
Jun-20	45	$493	55	$523	52	$594	64	$592
Jul-20	45	$493	55	$523	52	$594	64	$592
Aug-20	45	$493	55	$523	52	$594	64	$592
Sep-20	45	$493	55	$523	52	$594	64	$592
Oct-20	45	$493	90	$846	82	$887	64	$592
Nov-20	45	$493	99	$928	82	$885	64	$592
Dec-20	44	$482	89	$839	80	$860	64	$592

LPG INVENTORY VOLUMES AND COST BY LOCATION
(000)

Month	Camden Dth	Camden Dollars	Central Dth	Central Dollars	Harrison Dth	Harrison Dollars	Linden Dth	Linden Dollars
Jan-21	43	$477	89	$839	80	$860	64	$592
Feb-21	43	$472	86	$808	59	$639	64	$592
Mar-21	43	$472	63	$592	52	$565	64	$592
Apr-21	43	$472	62	$584	50	$534	64	$592
May-21	43	$472	57	$539	50	$534	64	$592
Jun-21	43	$472	57	$539	50	$534	64	$592
Jul-21	43	$472	57	$539	50	$534	64	$592
Aug-21	43	$472	57	$539	50	$534	64	$592
Sep-21	43	$472	57	$539	69	$896	64	$592
Oct-21	46	$534	82	$1,041	76	$1,041	64	$592
Nov-21	46	$530	82	$1,049	76	$1,036	63	$579
Dec-21	46	$530	82	$1,049	75	$1,039	63	$579
Jan-22	45	$526	79	$1,015	67	$926	63	$579
Feb-22	45	$526	79	$1,015	67	$926	63	$579
Mar-22	45	$526	79	$1,015	29	$398	63	$579
Apr-22 est	45	$526	77	$988	25	$347	63	$579
May-22 est	45	$526	77	$988	25	$347	63	$579
Jun-22 est	45	$526	77	$988	25	$347	63	$579
Jul-22 est	45	$526	77	$988	25	$347	63	$579
Aug-22 est	45	$526	77	$988	25	$347	63	$579
Sep-22 est	45	$526	77	$988	25	$347	63	$579
Oct-22 est	45	$526	77	$988	25	$347	63	$579
Nov-22 est	45	$526	77	$988	25	$347	63	$579
Dec-22 est	45	$526	77	$988	25	$347	63	$579

LNG INVENTORY VOLUMES AND COST
(000)

Month	Dth	Dollars	Month	Dth	Dollars
Jan-19	282	$152	Jan-21	246	$222
Feb-19	262	$141	Feb-21	217	$196
Mar-19	237	$128	Mar-21	209	$188
Apr-19	228	$123	Apr-21	201	$182
May-19	221	$119	May-21	195	$176
Jun-19	263	$115	Jun-21	257	$244
Jul-19	257	$168	Jul-21	276	$265
Aug-19	250	$164	Aug-21	269	$259
Sep-19	244	$159	Sep-21	259	$249
Oct-19	234	$153	Oct-21	298	$291
Nov-19	267	$199	Nov-21	289	$283
Dec-19	303	$242	Dec-21	277	$271
Jan-20	294	$235	Jan-22	227	$222
Feb-20	236	$188	Feb-22	167	$163
Mar-20	228	$182	Mar-22	149	$145
Apr-20	220	$176	Apr-22 est	198	$193
May-20	213	$170	May-22 est	198	$193
Jun-20	206	$165	Jun-22 est	198	$193
Jul-20	199	$159	Jul-22 est	198	$193
Aug-20	285	$250	Aug-22 est	198	$193
Sep-20	299	$269	Sep-22 est	198	$193
Oct-20	292	$263	Oct-22 est	198	$193
Nov-20	284	$256	Nov-22 est	198	$193
Dec-20	271	$245	Dec-22 est	198	$193

13. Affiliate Gas Supply Transactions

Item 13

<u>Principal Terms of the Requirements Contract</u>
<u>between</u>
<u>PSE&G and PSEG Energy Resources & Trade (ER&T)</u>

1. Effective Date: May 1, 2002, as amended March 31, 2007, April 1, 2014, and April 1, 2022.
2. Supply Obligation: In daily consultation with PSE&G, ER&T is obligated to supply Basic Gas Supply Service ("BGSS") to PSE&G
   - BGSS is the retail gas supply service, by which ER&T provides all needed firm and non-firm gas to PSE&G to meet the natural gas requirements of its customers, including:
     - PSE&G's firm obligations
     - PSE&G's balancing services
     - PSE&G's non-firm supply obligations
     - PSE&G's non-tariff service agreements
   - To meet this obligation, ER&T holds all the necessary firm transportation, storage and gas purchase contracts to reliably serve PSE&G, as they may change over time
     - Gas capacity, storage, and transportation contracts were transferred from PSE&G to ER&T

        - Natural gas, LNG, and propane inventories were transferred from PSE&G to ER&T at book value as of April 30, 2002
        - BPU order authorizing the transfer was entered April 17, 2002
    - ER&T provides administrative and management services to PSE&G related to the wholesale delivery of gas, including:
        - Load scheduling
        - Load balancing
        - Mitigation of price volatility
        - When appropriate, input into decisions regarding whether to interrupt service and when to call upon peak shaving
    - PSE&G maintains peak shaving facilities, for which ER&T pays operating and maintenance costs, and also return
    - Deliveries of BGSS services are to be made to PSE&G at pipeline or peak shaving interconnections
        - ER&T is responsible for transportation of gas to the Points of Delivery, and PSE&G is responsible for transportation of gas from the Points of Delivery
    - ER&T is the sole supplier of the BGSS full requirements
3. Term: Through March 31, 2027, and year-to-year thereafter, subject to cancellation by either party with 2 years notice
    - Original term was to March 31, 2004, with option to extend

- Revised term was to March 31, 2007, and year-to-year thereafter
- Further revised term was to March 31, 2012, and year-to-year thereafter
- Further revised term was to March 31, 2019, and year-to-year thereafter

4. Quality: The quality of gas delivered to PSE&G shall conform with the specifications of ER&T's interstate transportation providers, with the exception of refinery, landfill, and peaking gas, which shall be blended
5. Pressure: The pressure of gas delivered to PSE&G shall conform with the specifications of ER&T's interstate transportation providers
6. Default: PSE&G may recall all BGSS assets upon a default by ER&T
7. Warranty: ER&T warrants that:
   - It holds good Title to gas it sells
   - It holds sufficient entitlements to provide the full requirements services
8. Interruptible Loads: PSE&G is responsible for curtailing interruptible loads when appropriate
9. Payment: PSE&G pays ER&T monthly for these services:
   - All gas supply and capacity charges
   - Balancing
10. Non-Tariff Services: Non-tariff service to cogenerators is provided
11. Regulatory: The contract is subject to regulatory oversight, and ER&T shall supply expert witness testimony in any BPU proceeding concerning the gas component of any rate.

14. Supply and Demand Data

FIRM GAS SUPPLY AND DEMAND DATA (October 2019- September 2020)

	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Total
Gas Supplies (MDTh)													
Beginning Inventory	69,819	76,368	74,506	67,496	55,843	43,110	34,606	31,754	37,509	44,566	52,122	59,353	
Natural Gas Receipt	14,427	23,028	25,783	20,785	15,935	12,091	13,214	14,914	11,865	11,485	11,461	13,613	188,601
Total Inventory Available	84,246	99,396	100,289	88,281	71,778	55,201	47,821	46,668	49,374	56,051	63,583	72,966	
Gas Demand (MDTh)													
Firm Sendout	7,878	24,890	32,793	32,438	28,668	20,595	16,066	9,159	4,808	3,929	4,230	4,793	190,248
Ending Inventory MDTh	76,368	74,506	67,496	55,843	43,110	34,606	31,754	37,509	44,566	52,122	59,353	68,172	

FIRM GAS SUPPLY AND DEMAND DATA (October 2020- September 2021)

	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Total
Gas Supplies (MDTh)													
Beginning Inventory	68,172	74,824	74,832	61,298	43,380	28,126	19,857	23,019	30,235	40,237	49,683	58,505	
Natural Gas Receipt	15,716	17,100	18,992	19,917	19,207	15,708	17,248	14,966	14,582	13,465	12,976	13,403	193,280
Total Inventory Available	83,889	91,924	93,824	81,215	62,587	43,834	37,105	37,985	44,817	53,702	62,659	71,908	
Gas Demand (MDTh)													
Firm Sendout	9,064	17,092	32,526	37,835	34,461	23,977	14,087	7,750	4,580	4,019	4,154	4,551	194,096
Ending Inventory MDTh	74,824	74,832	61,298	43,380	28,126	19,857	23,019	30,235	40,237	49,683	58,505	67,357	

FIRM GAS SUPPLY AND DEMAND DATA (October 2021- September 2022)

	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Total
Gas Supplies (MDTh)													
Beginning Inventory	**67,357**	76,466	74,518	65,401	46,612	31,005	18,054	18,605	30,447	39,407	49,726	57,330	
Natural Gas Receipt	15,649	19,717	17,656	23,741	15,537	11,230	15,893	18,985	14,662	14,315	11,374	14,725	193,484
Total Inventory Available	83,006	96,183	92,174	89,142	62,148	42,235	33,947	37,590	45,108	53,722	61,100	72,055	
Gas Demand (MDTh)													
Firm Sendout	6,540	21,664	26,773	42,530	31,143	24,181	15,342	7,144	5,702	3,996	3,771	4,093	192,879
Ending Inventory MDTh	76,466	74,518	65,401	46,612	31,005	18,054	18,605	30,447	39,407	49,726	57,330	67,962	

FIRM GAS SUPPLY AND DEMAND DATA (October 2022- September 2023)

	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Total
Gas Supplies (MDTh)													
Beginning Inventory	**67,962**	73,813	69,161	50,385	28,999	14,199	4,580	7,536	15,067	27,124	40,623	50,478	
Natural Gas Receipt	14,923	16,167	13,922	19,637	18,889	18,558	17,950	15,059	17,651	17,413	13,532	17,687	201,388
Total Inventory Available	82,885	89,980	83,083	70,022	47,888	32,757	22,531	22,595	32,718	44,537	54,154	68,165	
Gas Demand (MDTh)													
Firm Sendout	9,071	20,820	32,698	41,023	33,689	28,176	14,994	7,528	5,594	3,915	3,676	4,002	205,187
Ending Inventory MDTh	73,813	69,161	50,385	28,999	14,199	4,580	7,536	15,067	27,124	40,623	50,478	64,164	

FIRM GAS SUPPLY AND DEMAND DATA (October 2023- September 2024)

	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Total
Gas Supplies (MDTh)													
Beginning Inventory	**64,164**	73,814	69,610	51,174	29,167	12,983	3,156	5,768	12,954	25,404	39,687	49,980	
Natural Gas Receipt	18,797	16,685	14,117	19,422	18,799	18,507	17,704	14,761	18,105	18,195	14,004	18,643	207,738
Total Inventory Available	82,960	90,499	83,727	70,596	47,966	31,490	20,860	20,530	31,058	43,599	53,691	68,622	
Gas Demand (MDTh)													
Firm Sendout	9,146	20,889	32,553	41,429	34,982	28,334	15,091	7,576	5,654	3,912	3,711	4,100	207,379
Ending Inventory MDTh	73,814	69,610	51,174	29,167	12,983	3,156	5,768	12,954	25,404	39,687	49,980	64,522	

15. Actual Peak Day Supply and Demand

Item 15 - Actual Peak Day Supply and Demand

	DATE	NEWARK AVG. TEMP (F)	LOAD (000 DTh) TOTAL	FIRM	INTERR.	SUPPLY SOURCES (000 DTh) NATURAL GAS HLF TRANSP.	STORAGE / LNG	LPA
2021 / 2022 WINTER								
	29-Jan-22	13.7	2466	2277	189	1290	1177	0
	15-Jan-22	13.2	2412	2250	162	1500	912	0
	14-Feb-22	20.7	2373	2070	303	1066	1297	10
	3-Jan-22	23.8	2323	1872	451	1021	1301	0
	11-Jan-22	18.7	2300	2150	150	1274	1026	0
2020 / 2021 WINTER								
	29-Jan-21	20.3	2504	2146	358	1489	1008	7
	28-Jan-21	24.0	2308	1956	352	1405	895	8
	31-Jan-21	24.4	2274	1932	342	1646	628	0
	30-Jan-21	25.5	2151	1845	306	1532	618	0
	16-Dec-20	27.2	2178	1796	382	1270	907	1
2019 / 2020 WINTER								
	19-Dec-19	23.7	2389	1983	406	1768	620	1
	20-Jan-20	25.6	2311	1909	402	1530	780	1
	18-Dec-19	24.8	2251	1852	399	1499	751	0
	17-Jan-20	24.5	2243	1847	396	1523	721	0

16. Capacity Contract Changes

Including Gas Sales Forecast Support

SCHEDULE F

May-22

PEAK DAY GAS REQUIREMENTS AND SUPPLY

	SUPPLY		2022-2023	2023-2024	2024-2025	2025-2026	2026-2027
	Transco FT		432.4	432.4	432.4	432.4	432.4
	Transco FT (DTI)		32.2	32.2	32.2	32.2	32.2
	Transco FT (Cove Point)		20.0	20.0	20.0	20.0	20.0
	Transco FT (Gateway)		54.0	54.0	54.0	54.0	54.0
	Texas Eastern FT		246.6	246.6	246.6	246.6	246.6
	Tennessee FT		36.4	36.4	36.4	36.4	36.4
	FT from Lebanon:						
	Texas Eastern		180.7	180.7	180.7	180.7	180.7
	DTI/Transco		49.7	49.7	49.7	49.7	49.7
	Columbia		12.5	12.5	12.5	12.5	12.5
	Subtotal		242.9	242.9	242.9	242.9	242.9
	Transco/Tetco FT (Leidy)		330.2	330.2	330.2	330.2	330.2
	Columbia (Hanover)		18.8	18.8	18.8	18.8	18.8
	Algonquin		15.0	15.0	15.0	15.0	15.0
	Pipeline Firm Transportation		1,428.5	1,428.5	1,428.5	1,428.5	1,428.5
	Refinery Gas		0.0	0.0	0.0	0.0	0.0
	Total Firm FT Supply		1,428.5	1,428.5	1,428.5	1,428.5	1,428.5
	Storage		894.2	894.2	894.2	894.2	894.2
	Transco Peaking		13.2	13.2	13.2	13.2	13.2
	Transco LGA		275.4	275.4	275.4	275.4	275.4
	PSEG Burlington LNG		81.1	81.1	81.1	81.1	81.1
	LPA		201.2	201.2	201.2	201.2	201.2
	Total Peaking Supply		570.9	570.9	570.9	570.9	570.9
	PSEG Firm Supply Subtotal		2,893.7	2,893.7	2,893.7	2,893.7	2,893.7
	FTS DCQ 1./		308.1	315.6	316.8	317.3	317.9
[a]	Total PSEG Gas Supply		3,201.8	3,209.3	3,210.4	3,210.9	3,211.6
	Peak Day Sendout Forecast 2./		3,026.0	3,052.0	3,068.0	3,081.0	3,093.0
[b]	Total Peak Day Capacity Requirements	3./	3,172.7	3,201.4	3,216.0	3,232.1	3,243.8
[a]-[b]	Surplus / (Deficiency)	3./	29.1	7.8	(5.5)	(21.2)	(32.2)

1./ Forecasted FT-S DCQ (January)

2./ Based on Corporate Energy Forecast, Gas -2022

3./ 3% Loss of Load Probability

Item 16

Natural Gas Sales Forecast - 2022

Public Service Electric & Gas Company

Finance Department

Electric and Gas Sales and Revenue Forecasting Group

November 2021

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Introduction

The natural gas sales forecast has a key role in both the operating and financial planning processes of Public Service Electric & Gas (PSE&G).

The volumetric and maximum day sendout projections are used in the development of strategies for optimal gas procurement by PSE&G's BGSS supplier.

The sales forecast also serves as the basis for the natural gas revenue forecast that is a key parameter in PSE&G's financial planning process. This includes not only the budgeting process but also the regulatory process.

The purpose of this document is to describe the current forecast methodology, forecast assumptions, and the 2022 gas sales forecast. The first section describes the econometric sales models. A discussion of the forecast assumptions used to develop the sales forecast follows. Section III describes the maximum daily send-out projection. An appendix contains more detailed information on the billing period to calendar month conversion, and forecast tables.

I Model Specification and Estimation

Residential Model

Residential gas sales are determined by the number of residential customers and the amount of gas that each of these customers uses. As a result, the modeling of residential sales is disaggregated into two components: the projection of the number of customers and the estimate of what, on average, each of these customers will use. While the projection of the number of residential natural gas customers can be based on historical trends and expected residential construction activity in the service area, the models utilized to develop the average use forecast are more complicated and are described below.

The demand for energy is a derived demand from the demand for the services that the energy provides. In the case of gas in the residential sector, this is a demand for the three main end-uses of gas: space heating, water heating, and cooking. Standard microeconomic theory suggests that the demand for these gas-fueled end-uses is a function of the real, i.e. inflation adjusted, price of gas, and the income of the household. In addition, since space heating and, to a lesser extent, water heating is affected by the weather; weather also needs to be included in the model specification, i.e.

$$\text{THERM/CUST} = f(\text{PRICEGAS, INCOME, WEATHER}) \qquad [1]$$

where:

THERM/CUST	= Average gas sales per customer,
PRICEGAS	= Real price of gas,
INCOME	= Measure of customer income,
WEATHER	= Billing-month weather.

While information on individual appliance ownership and consumption is not available, PSE&G does segregate its Residential customer data into those customers that have gas space heating and those that do not. As a result, separate models estimating the average gas sales for space heating customers and non-space heating customers were developed.

Weather is incorporated into the models using billing-month heating degree days (HDD). To allow for the possibility of month-specific response to weather, the heating degree data was multiplied by monthly binary variables to produce month-specific HDD independent variables.

The real price of gas was defined as the annual average revenue per therm divided by the Consumers' Price Index –All Urban Consumers. However, the extreme seasonality of monthly gas consumption made the utilization of this variable directly in a linear specification impractical because it is unrealistic to expect that a change in price would have the same impact, measured in therms, in January, a high consumption month, as in July where consumption can be only one-tenth the January volume. As a result, this variable was incorporated as an interactive variable with HDD to create the effect that a change in price will affect the magnitude of the response to weather, i.e. a small response in the summer months and a much larger response during the space heating season.

Income is defined as the total real wages and salary disbursements for New Jersey from the U.S. Department of Commerce, Bureau of Economic Analysis. This is a narrower measure than personal income, omitting for example dividends, interest and rental income, and, as a result, is assumed to more accurately reflect the economic well-being of the majority of our customers. The incorporation of this variable directly into a linear specification suffers from the same drawback as that of the price. As a result, this variable was also incorporated into the specification as an interactive variable with HDD. In the models the economic variables were lagged one year to account for the delay in the impact that these variables have on consumer behavior.

As a result, the final functional form of the model that was estimated is:

$$THERM/CUST_t = f(\overline{MONTH} x HDD_t \times PRICEGAS_{a-1}, \overline{MONTH} x HDD_t \times INCOME_{a-1}, \overline{MONTH} x HDD_t) \qquad [2]$$

where:

THERM/CUST	= Average gas sales per customer,
PRICEGAS	= Real price of gas,
INCOME	= Real Wage and Salary Disbursements,
HDD	= Heating degree days,
$\overline{MONTH}$	= Vector of binary variables for each heating month,
t	= Billing-month,
a	= Year associated with billing-month, t.

The models were estimated using monthly data from January 2010 to February 2020 period The results of the OLS estimation procedure are summarized in Table 1 and Figures 1 and 2.

As Figures 1 and 2 illustrate, the high values of the coefficients of determination of both the model for gas space heating customers and the model of those customers without gas heating explain an extremely high proportion of the variation from the mean values. The estimates of the individual coefficients of the RSG model estimations are what one would expect given the characteristics of residential natural gas consumption. The key predictor of gas sales to this sector is weather with the weather having a greater impact on those customers with gas space heating than those without. Price is a factor for residential customers during the winter months but, its impact is relatively small.

Figure 1

RSG Space Heating Model
Actual vs. Fitted Values

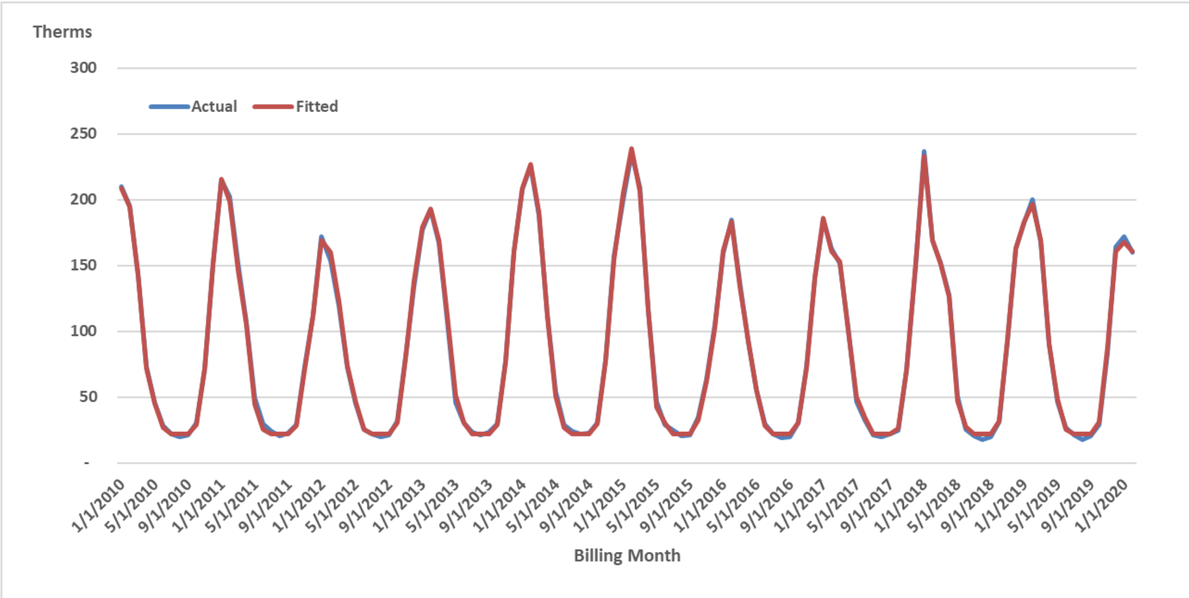
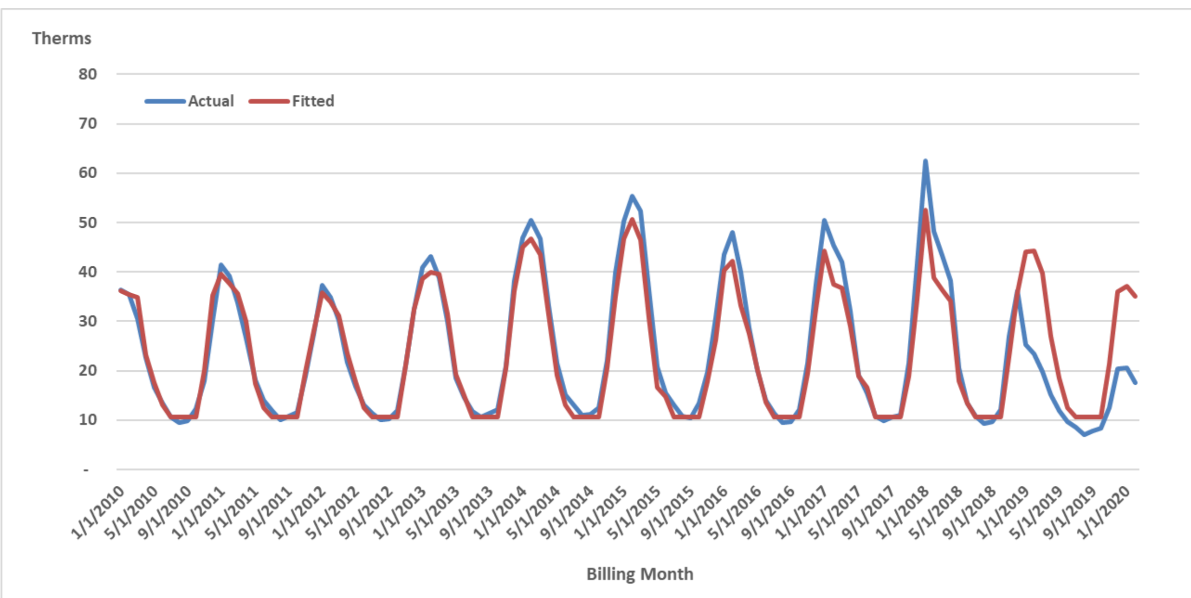


Figure 2
RSG Non-Space Heating Model
Actual vs. Fitted Values



The price elasticity estimates were estimated to be -0.0125 and -0.17 for space heating and non-space heating customers, respectively and consistent with lower gas prices and the lack of a surge in consumption in response to them. The non-space heating elasticity is the result of a similar therm impact of price but, measured over a much smaller base usage. Income was found to have an effect on gas consumption by space heating customers in the fall. This is consistent with income changes resulting affecting when space heating equipment is turned on. The economic downturn appeared to result in a delay in turning on this equipment in the fall reducing use.

Table 1

Estimated Coefficients of the Residential Models

(standard errors in parentheses)

	JAN	FEB	MAR	APR	MAY	JUNE	NOV	DEC	R2	DW	n
HEATING											
HDD	0.20804	0.19978	0.19447	0.19225	0.13848	0.18255	0.057	0.190	0.999	1.554	122
	(0.007)	(0.006)	(0.006)	(0.009)	(0.004)	(0.022)	(0.008)	(0.008)			
		DJF*									
PRICE x HDD		-0.00637									
		(0.002)									
		ON**									
WAGE x HDD		0.00116									
		(0.000)									
*** Dec-Jan-Feb**											
**** Oct-Nov**											

	JAN	FEB	MAR	APR	MAY	JUNE	NOV	DEC	R2	DW	n
NON-HEATING											
HDD	0.04981	0.04465	0.03549	0.03872	0.03975	0.08491	0.02519	0.03102	0.974	0.989	150
	(0.007)	(0.007)	(0.002)	(0.004)	(0.010)	(0.048)	(0.005)	(0.003)			
PRICE x HDD	-0.01366	-0.01019									
	(0.005)	(0.006)									

The second key element of the residential forecast, as noted above, is the projection of the number of residential natural gas customers. This forecast is based on historical trends between customer growth and residential construction activity in the service area and is discussed in the Forecast Assumptions section.

Commercial

The demand for natural gas by the non-residential sector, as with any other factor of production, is a function of the input's price, the price of substitutes (if any) and the level of production. This implies that gas sales to the commercial sector is a function of the real price of gas and the level of "output" of the commercial sector in PSE&G's service territory, i.e. Again, since gas is primarily used for space and/or water heating, weather needs to be included in the specification resulting in the following:

THERMS = *f*(PRICEGAS, OUTPUT, HDD) [3]

where:

THERMS	= Gas Sales,	
PRICEGAS	= Real price of gas,	
OUTPUT	= Commercial sector output,	
HDD	= Heating degree days.	

The problem with this specification is that there is not a good measure of output for the local commercial sector. However, if it is assumed that the demand for local commercial output is a function of the local economic and demographic factors, i.e., how many households there are (HSH) and how much money do they have to spend (INCOME), commercial output can then be defined as:

OUTPUT = *f*(INCOME, HSH) [4]

Substituting [4] into [3] yields:

THERMS = *f*(PRICEGAS, INCOME, HSH, HDD) [5]

LVG model was estimated for customers in the commercial sector using monthly billing data from January 2010 to December 2020 period .The firm delivery customers in this class whose usage does not exceed 300 Dth are served under rate GSG. These customers are further disaggregated into those with gas space heat and those that heat with other fuels. These two groups of customers are modeled separately. Time period for GSG Heating model set from January 2010 to December 2020 period while GSG Non-Heating model set from January 2011 to December 2020 in order to get better estimation results. The larger commercial customers are served under rate LVG. These are also modeled separately.

Historical annual household estimates for New Jersey is available from the U.S. Bureau of the Census. As with the residential models, the strong seasonality associated with commercial gas sales dictates that the economic/demographic variables can be used in the model directly but, need to be used as interactive variables with HDD. In addition, in the models the economic variables were lagged one year to account for the delay in the impact that these variables have on consumer behavior. As a result, the functional form that was estimated for each of the three groups of commercial customers is[1]:

$$
\begin{aligned}
THERMS_t = f(&\overline{MONTH} \times HDD_t \times PRICEGAS_{a-1}, \\
&\overline{MONTH} \times HDD_t \times INCOME_{a-1}, \\
&\overline{MONTH} \times HDD_t \times HSH_{a-1}, HDD_t)
\end{aligned}
\qquad [6]
$$

where:

THERMS	= Gas sales,
PRICEGAS	= Real price of gas,
INCOME	= Real Wage and Salary Disbursements,
HDD	= Heating degree days,
$\overline{MONTH}$	= Vector of binary variables for each heating month,
t	= Billing-month,
a	= Year associated with billing-month, t.

The results of the OLS estimation procedure, summarized in Figures 3-5, show that the commercial models also fit the historical data well.

The estimated coefficients of the three commercial models indicate that while the small commercial space heating are sensitive to price, with an estimated elasticity of -0.23 the non-space heating customers are not, and the large commercial LVG customers are sensitive to price, with an estimated elasticity of -0.012. In addition, while the coefficients on households, the economic indicator in the models, are highly statistically significant, this does not imply large sales increases given the anticipated slow growth in the number of households.

[1] It was not necessary to incorporate month-specific HDD specification since the LVG sales are less sensitive to the weather.

Figure 3
GSG Commercial Space Heating Model
Actual vs. Fitted Values

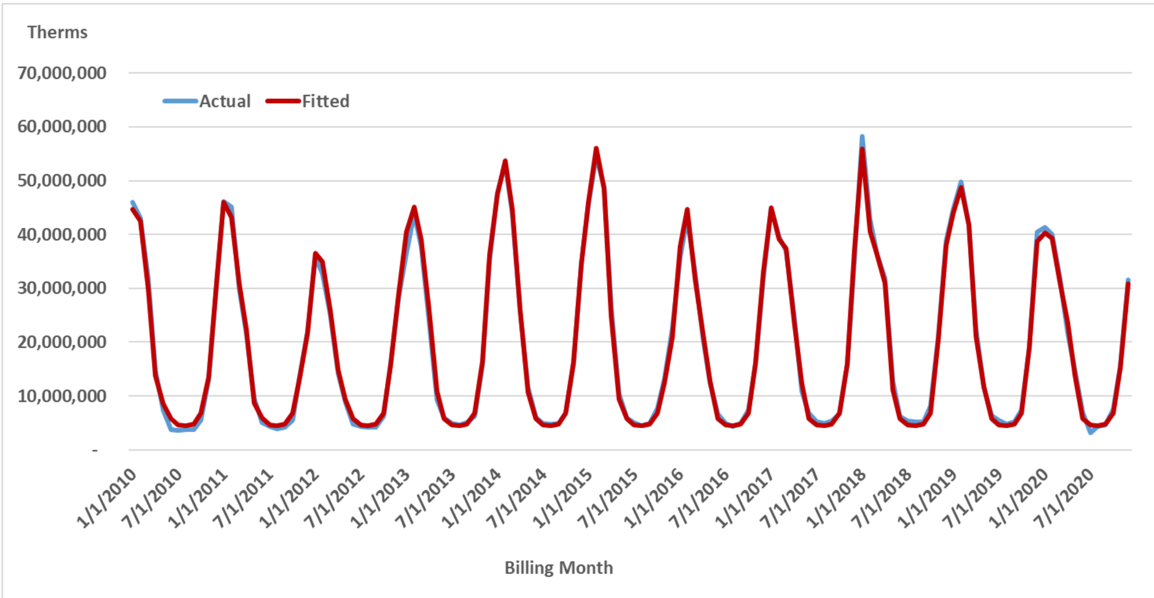


Figure 4
GSG Commercial Non-Space Heating Model
Actual vs. Fitted Values

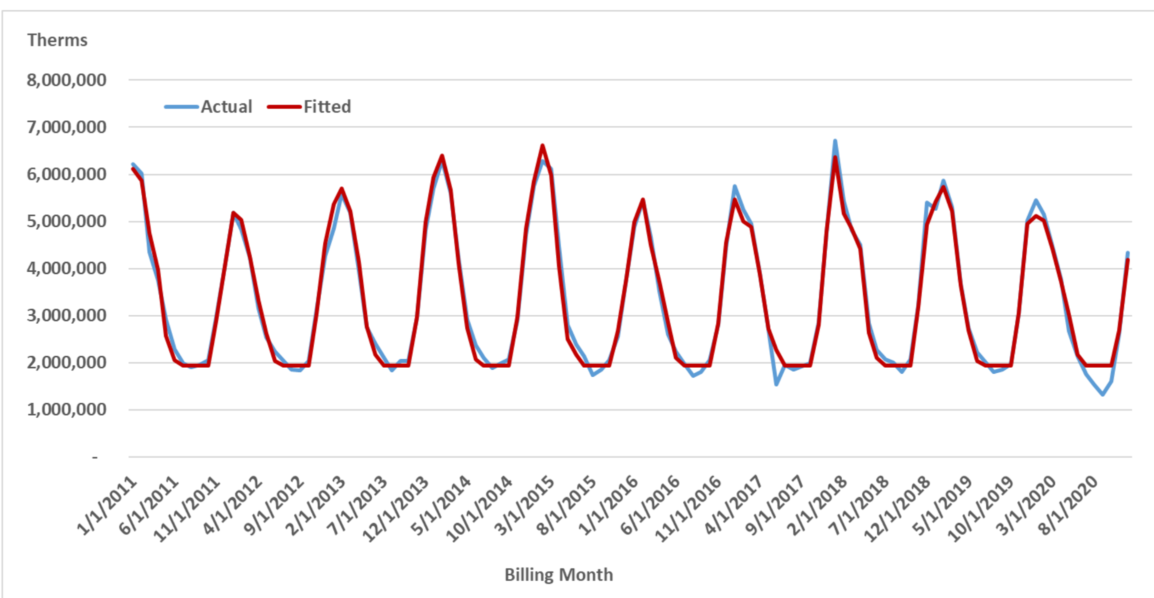


Figure 5
LVG Commercial Model
Actual vs. Fitted Values

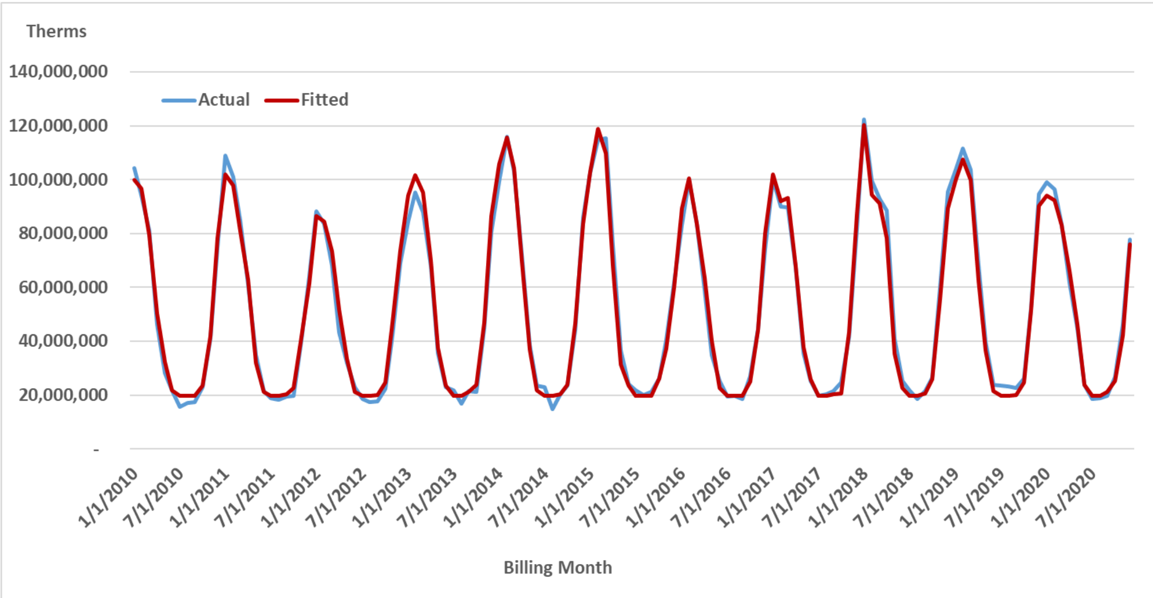


Table 2

Estimated Coefficients of the GSG Commercial Gas Sales Models
(standard errors in parentheses)

	JAN	FEB	MAR	APR	MAY	JUN	NOV	DEC	R2	DW	n
HEATING											
PRICE x HDD	-12668	-14163	-12272	-10012	-38026		-22077	-16575	0.996	1.398	132
	(2,269)	(2,453)	(3,113)	(5,145)	(16,543)		(5,985)	(3,181)			
CUST x HDD	19.03	20.06	19.54	19.38	17.24		16.86	19.77			
	(0.9)	(0.9)	(1.1)	(1.7)	(3.8)		(2.5)	(1.1)			
COVID-HDD	-1208										
	(1,353)										
NON-HEATING											
HDD	3887	3995	4008	4082	3758	4651	2590	3693	0.983	1.333	120
	(75)	(77)	(92)	(147)	(338)	(1,718)	(187)	(100)			
COVID-HDD	-343										
	(228)										

Table 3

Estimated Coefficients of the LVG Commercial Gas Sales Models

(standard errors in parentheses)

HDD x PRICE	HDD x CUST	HDD x COVID	R2	DW	n
-26136	32	-3133	0.989	1.007	132
(4,274)	(1)	(4,067)			

Industrial

While gas sales to the commercial sector are correlated with commercial output because output tends to be correlated with commercial space-heated floor space, sales to the PSE&G rate GSG and rate LVG gas customers in the industrial sector are not correlated with the industrial output because gas, for the most part, is not used for process heat. It is used to heat employee workspaces and the number of employees has been declining while industrial output has been increasing. Therefore, rather than used the traditional function for the demand for a factor of production such as [3], the following specification is used:

$$\text{THERMS} = f(\text{PRICEGAS, EMP, HDD}) \qquad [7]$$

where:

EMP = Manufacturing employment.

Since gas is used primarily for space heating the economic variables need to be used as interactive variables with HDD to account for the extreme seasonality of the data. As a result, the functional forma that was estimated is:

$$\text{THERMS}_t = f(\text{HDD}_t \times \text{PRICEGAS}_{a-1}, \text{HDD}_t \times \text{EMP}_{a-1}, \text{HDD}_t) \qquad [8]$$

where:

THERMS = Gas sales,
PRICEGAS = Real price of gas,
HDD = Heating degree days,
t = Billing-month,
a = Year associated with billing-month, t.

The results of the OLS estimation procedure, summarized in Figures 6-8, show that the industrial models for customers in the two space heating segments fit the historical data well. GSG Heating model is estimated for using monthly billing data from January 2011 to December 2020 period while Non-Heating model is estimated for using monthly billing data from January 2013 to December 2020 in order to get better estimation results. The data for industrial GSG non-heating customers, however, seems to indicate the presence of out of period adjustments in the billing data which the model doesn't, and can't be expected to, account for. These were addressed with binary variables. The larger industrial customers are served under rate LVG. The model was estimated for customers in the industrial sector using monthly billing data from January 2010 to December 2020 period.

Like the small and medium commercial models, the estimated coefficients of the three industrial models indicate that sensitivity to price is small. The small industrial customers, rate GSG did not show any statistically significant response to price while rate LVG sensitive to price, with an estimated elasticity of -0.1 Small response of the industrial sector to gas prices is attributed to the fact that gas, since it is not used for process heat, is a relatively small proportion of the total costs of production.

Figure 6

GSG Industrial Space Heating Model

Actual vs. Fitted Values

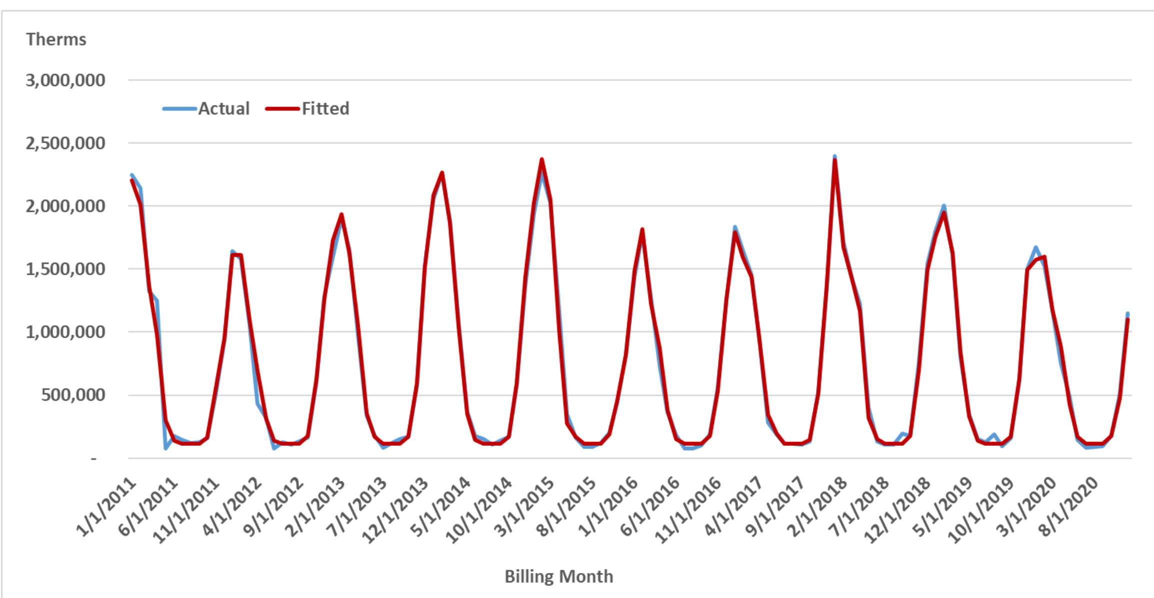


Figure 7
GSG Industrial Non-Space Heating Model
Actual vs. Fitted Values

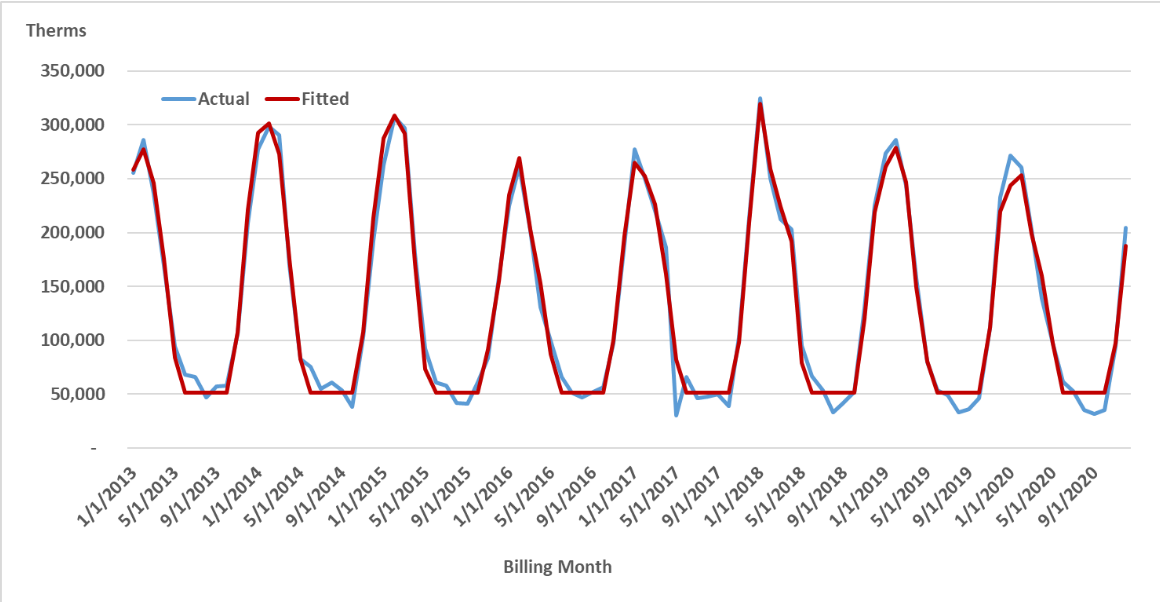


Figure 8
LVG Industrial Heating Model
Actual vs. Fitted Values

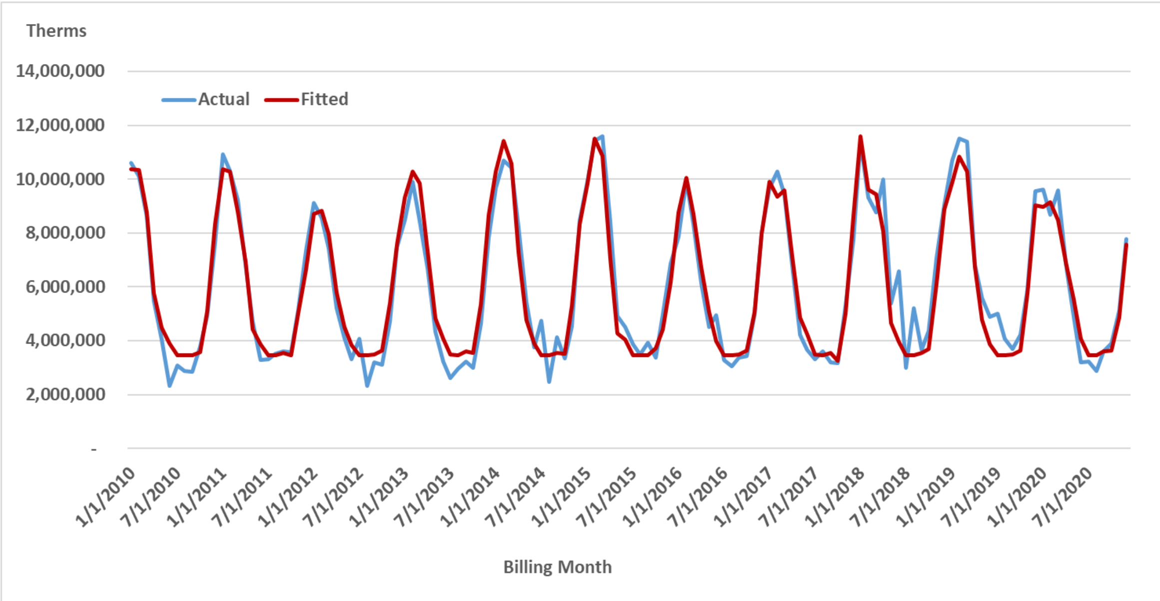


Table 4

Estimated Coefficients of the GSG Industrial Gas Sales Models

(standard errors in parentheses)

	JAN	FEB	MAR	APR	MAY	JUN	OCT	NOV	DEC	R2	DW	n
HEATING												
HDD	2467	1935	2217	1746	1112	1188		1219	2163	0.992	2.203	120
	(182)	(25)	(157)	(48)	(111)	(564)		(187)	(100)			
COVID-HDD	-113											
	(74)											
NON-HEATING												
HDD	235	138	239	232	150			142	207	0.981	1.796	96
	(5)	(33)	(6)	(10)	(23)			(13)	(7)			
COVID-HDD	-2											
	(15)											

Table 5

Estimated Coefficients of the LVG Industrial Gas Sales Models

(standard errors in parentheses)

HDD x PRICE	HDD x EMP	HDD x COVID	R2	DW	n
-2595	39	-110	0.938	1.459	132
(1,057)	(4)	(792)			

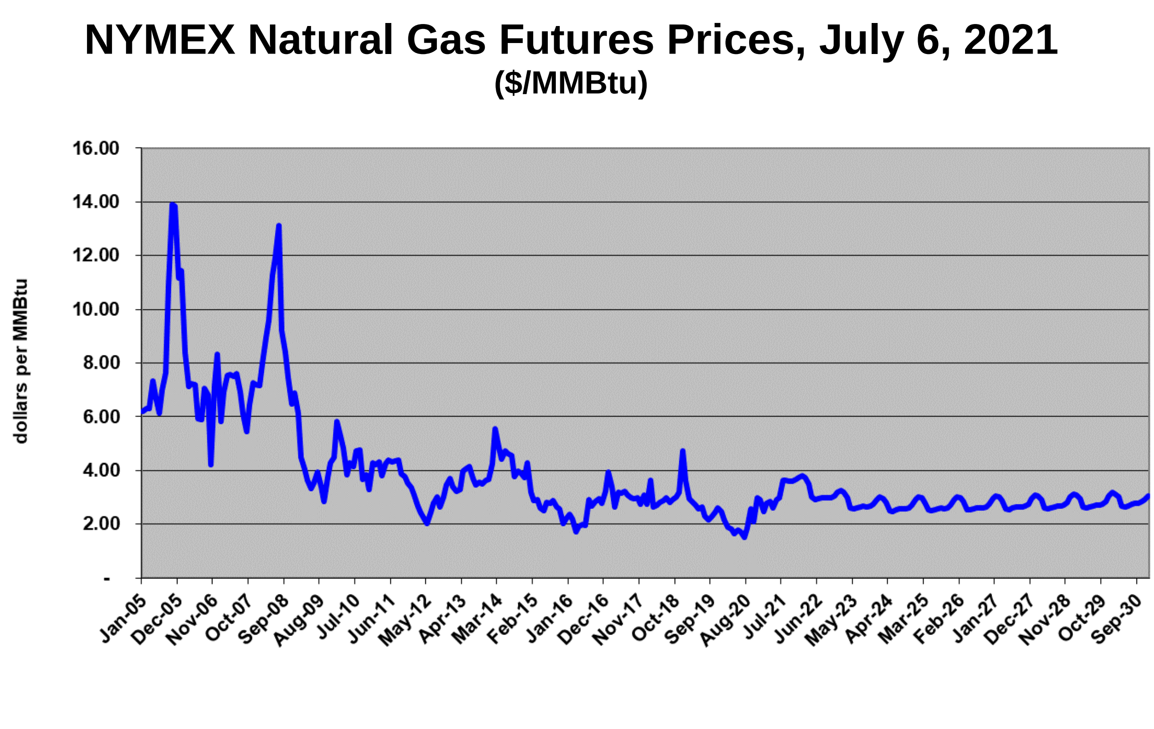
II Forecast Assumptions

The models described above, in concert with assumptions about future prices and local economic and demographic parameters, were utilized to produce a forecast of billed natural gas delivered sales by rate for the residential, commercial, and industrial customer classes. The assumptions and the forecasts are described in more detail below.

Natural Gas Prices

The main driver of retail natural gas prices is the wholesale cost of gas which changes monthly. While these costs are passed through to commercial and industrial customers on monthly basis, the gas cost under- or over-collection of the residential customers is addressed in October where the rate is adjusted to collect or return the imbalance over the following twelve months. For the purpose of the forecast, the wholesale natural gas price was assumed to follow the NYMEX future prices as of July 06, 2021. As figure 9 shows, the wholesale price of gas is projected to stay relatively stable during the 2019-2029 periods.

Figure 9



This price projection was used in the ER&T Gas cost model which generated commodity gas costs by rate. The residential costs, along with the actual imbalance in the residential gas supply cost and the revenue collection to offset this cost was utilized in the Cognos residential model to produce a stream of residential prices assuming that every October the imbalance was trued-up over the following 12 months. These projected commodity costs, combined with delivery tariff assumptions results in projected retail prices that are summarized below.

Table 6

Historic and Projected Retail Gas Prices

(dollars per therm)

			Commercial			Industrial		
	RSG		GSG		LVG	GSG		LVG
Year	Heating	Non-Heating	Heating	Non-Heating		Heating	Non-Heating	
2010	1.24	1.43	1.10	1.07	0.97	1.11	1.06	0.92
2011	1.09	1.26	1.06	1.04	0.92	1.05	1.05	0.87
2012	1.00	1.18	0.95	0.93	0.80	0.95	0.98	0.75
2013	0.94	1.09	1.00	0.99	0.84	1.00	1.01	0.80
2014	0.80	0.94	1.06	1.04	0.91	1.10	1.08	0.90
2015	0.64	0.80	0.86	0.85	0.74	0.86	0.88	0.74
2016	0.71	0.87	0.83	0.83	0.69	0.83	0.86	0.70
2017	0.77	0.91	0.95	0.95	0.79	0.95	0.98	0.80
2018	0.74	0.88	0.93	0.92	0.79	0.94	0.96	0.77
2019	0.81	1.25	0.94	0.92	0.78	0.94	0.97	0.73
2020	0.78	1.31	0.87	0.87	0.71	0.80	0.91	0.66
2021	0.79	1.08	0.95	0.96	0.77	0.93	0.98	0.73
2022	0.83	1.11	1.05	1.03	0.85	1.04	1.08	0.80
2023	0.81	1.09	0.99	0.98	0.81	0.98	1.03	0.75
2024	0.84	1.11	0.99	0.99	0.79	0.98	1.03	0.73
2025	0.83	1.09	0.99	0.98	0.78	0.97	1.02	0.73
2026	0.82	1.09	0.99	0.98	0.78	0.97	1.02	0.73
2027	0.82	1.08	0.99	0.97	0.78	0.96	1.01	0.73
2028	0.81	1.06	0.98	0.96	0.77	0.95	0.99	0.71
2029	0.84	1.09	1.01	0.98	0.78	0.97	1.02	0.68
2030	0.86	1.12	1.06	1.01	0.79	0.99	1.04	0.69
2031	0.86	1.12	1.06	1.01	0.79	0.99	1.04	0.69
2032	0.86	1.12	1.06	1.01	0.79	0.99	1.04	0.69
2033	0.86	1.12	1.06	1.01	0.79	0.99	1.04	0.69
2034	0.86	1.12	1.06	1.01	0.79	0.99	1.04	0.69
2035	0.86	1.12	1.06	1.01	0.79	0.99	1.04	0.69

Energy Efficiency

In recent years, new technologies and state's saving programs have had significant impact on gas consumption to residential, commercial and industrial customer groups. The method of incorporating efficiency changes into the model estimation process when the changes are not driven by any of the economic explanatory variables is a two-step process.

The first step is to eliminate the impact of these programs in the historical series by adding the estimated impacts of these programs to the historical data, estimating the model, and then producing a forecast. This forecast will not have any impacts of the efficiency programs embedded in it.

The second step is to remove the impacts of the efficiency programs from both the history and the forecast. This reverts the historical data back to actual values and produces a forecast with the impacts of the efficiency programs correctly incorporated.

This methodology is used for RSG Heating, Commercial GSG Heating and LVG sales to incorporate the impacts of the current PSE&G efficiency programs and the estimated impacts of the proposed Clean Energy Future filing. These impacts are summarized in Table 7 below.

Table 7
Impacts of
Energy Master Plan – Energy Efficiency – Clean Energy Future
(therms)

	BILLING MONTH ASUMPTIONS		
	EMP	EE	CEF
2010	14,596,331	1,014,482	-
2011	16,831,360	3,286,510	-
2012	12,618,148	4,213,546	-
2013	16,790,499	5,039,977	-
2014	22,116,578	6,586,486	-
2015	24,589,911	6,989,516	-
2016	27,228,971	7,495,738	-
2017	30,109,454	8,348,880	-
2018	33,743,659	9,542,828	-
2019	37,356,813	9,955,587	-
2020	40,245,934	13,762,353	128
2021	40,245,934	13,762,353	4,134,178
2022	40,245,934	13,762,353	14,630,313
2023	40,245,934	13,762,353	29,173,727
2024	40,245,934	13,762,353	38,163,963
2025	40,245,934	13,762,353	51,804,502
2026	40,245,934	13,762,353	64,283,838
2027	40,245,934	13,762,353	76,038,938
2028	40,245,934	13,762,353	87,794,039
2029	40,245,934	13,762,353	99,549,140
2030	40,245,934	13,762,353	111,304,240
2031	40,245,934	13,762,353	123,059,340
2032	40,245,934	13,762,353	134,814,441
2033	40,245,934	13,762,353	146,569,542
2034	40,245,934	13,762,353	158,324,643
2035	40,245,934	13,762,353	170,079,743

Economic Projections

Economic and demographic forecast assumptions for the nation and New Jersey are from Moody's Economy July 2021 forecast. This forecast captures impact of COVID-19 on economy which assumes that, nationally, the economy will recover at a slow rate after pandemic. This national forecast is expected to be reflected in New Jersey's economic outlook that is also expected to be at a slow pace. In addition, an adjustment was made to RSG sales forecast, to capture perceived impacts of pandemic due to the most recent impacts of the government mandated economic restrictions that were not captured in the economic forecast. Commercial GSG and LVG models are estimated through 2020 and derived the COVID impact from estimated COVID coefficient. The forecast is summarized in Table 8.

Weather during the forecast period is assumed to be "normal" as defined by the average daily weather during the twenty-year period ending December 31, 2019.

Table 8

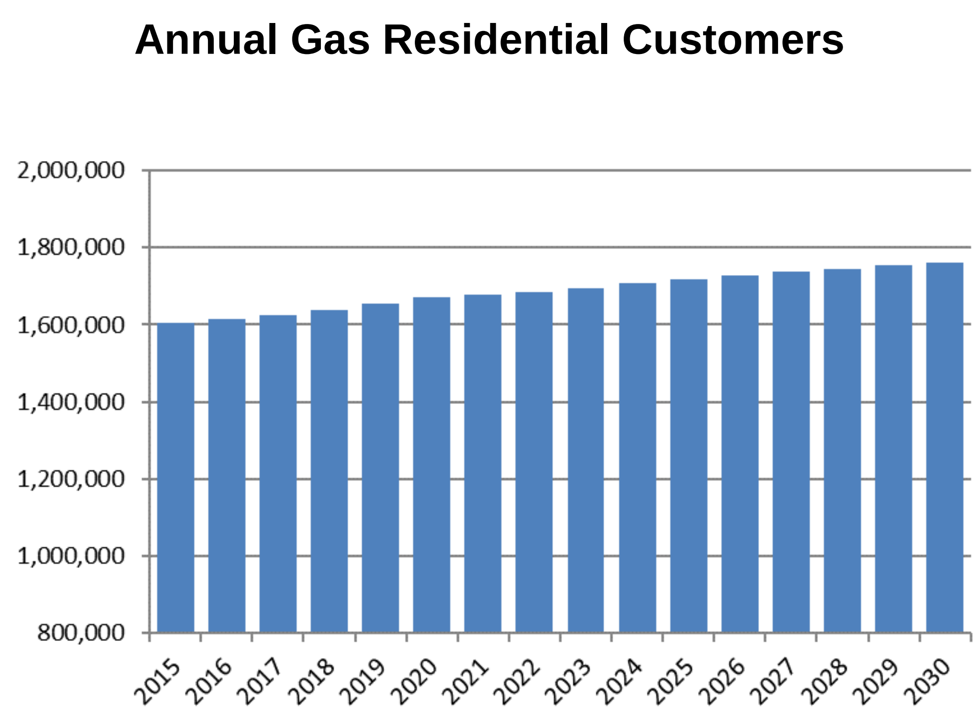
National and New Jersey Economic Forecast Assumptions

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
United States														
Gross Domestic Product, (Bil. USD, SAAR)	19,543	20,612	21,433	20,938	22,577	24,517	25,753	26,983	28,136	29,242	30,383	31,580	32,819	34,106
Industrial Production: Total, (Index 2012=100, SA)	104	109	109	102	110	113	114	116	117	118	119	121	122	124
Income: Personal - Total, (Bil. Ch. 2009 USD, SAAR)	15,992	16,493	16,889	17,714	18,212	17,923	18,391	18,842	19,207	19,610	20,067	20,561	21,070	21,584
Employment: Total Nonagricultural, (Mil. #, SA)	147	149	151	142	145	151	153	155	156	156	157	158	159	159
Household Survey: Unemployment Rate, (%, SA)	4.3	3.9	3.7	8.1	5.7	4.3	4.0	3.9	4.1	4.2	4.2	4.3	4.2	4.3
CPI: Urban Consumer - All Items, (Index 1982-84=100, SA)	245	251	256	259	265	272	279	286	293	300	306	313	320	327
Interest Rates: 3-Month Treasury Bills EBY, (% p.a., NSA)	0.9	2.0	2.1	0.4	0.1	0.2	0.6	1.5	2.4	2.5	2.5	2.5	2.4	2.4
Terms Conventional Mortgages: All Loans Fixed Effective Rate, (%, NSA)	4.1	4.7	4.4	3.8	3.9	4.3	4.8	5.2	5.5	5.8	5.8	5.8	5.8	5.7
New Jersey														
Real Personal Income, (Mil. 09$, SAAR)	544,786	556,962	569,814	604,789	625,424	612,017	624,969	638,812	649,981	662,249	676,134	691,296	706,813	721,889
Employment: Total Nonagricultural, (Ths., SA)	4,121	4,159	4,197	3,851	3,931	4,054	4,114	4,145	4,159	4,172	4,186	4,200	4,215	4,229
Employment: Total Manufacturing, (Ths., SA)	247	250	251	238	242	246	245	241	237	233	229	225	221	218
Employment: Total Non-Manufacturing, (Ths., SA)	3,874	3,909	3,946	3,613	3,689	3,808	3,869	3,904	3,922	3,939	3,957	3,975	3,994	4,011
Labor: Unemployment Rate, (%, SA)	4.5	4.0	3.4	9.8	7.0	5.0	4.3	4.1	4.2	4.3	4.3	4.3	4.3	4.3
Population: Total, (Ths.)	8,886	8,885	8,881	8,888	8,903	8,917	8,934	8,953	8,971	8,986	8,997	9,003	9,006	9,008
Households: Total, (Ths.)	3,343	3,353	3,363	3,346	3,345	3,415	3,437	3,454	3,471	3,484	3,495	3,504	3,514	3,524
Housing Starts: Single-family, (#, SAAR)	11,568	12,255	12,243	12,637	17,278	19,241	19,840	19,957	19,987	18,785	17,265	15,472	14,307	13,646

Customer Forecasts

The number of residential customers with and without natural gas space heat is based on historical trends and expected residential construction activity in the service area. Residential non-heating customers have been steadily declining at an average annual rate of 0.75 percent and this is expected to continue. Furthermore it is assumed that these customers are converting to gas heat. The number of gas heating customers is also expected to increase as new residential construction occurs. The number of gas customers is assumed to reflect the current decline seen in new single family housing construction. As a result, as the figure below shows, the number of residential customers is expected to remain relatively stable.

Figure 10



BGSS Share

The share of delivered sales that are BGSS supplied is assumed to follow recent trends where therm shares have stabilized at their current levels across the broad range of customer classes.

III Maximum Daily Sendout Forecast

Introduction

Distribution facilities are designed to meet the estimated maximum hour demand on a day with a mean temperature of 0°F and with seven weather stations in NJ as the measuring base. Gas supplies are designed to meet the estimated maximum daily as well as maximum hourly demand. The maximum daily sendout forecast process consists of:

- Estimating the relationship between weather and firm daily sendout,
- Extrapolating that relationship to determine the current level of daily sendout at 0 degrees if no day that cold appeared in the model estimation data,
- Forecasting future maximum daily sendout levels based on the current estimated level

The remainder of this section describes each of these steps in turn.

Daily Firm Sendout Model Estimation

There are two major issues in modeling maximum firm daily sendout. First, the diversity of the customer base needs to be controlled for. Second, the model has to be designed to be extrapolated rather than interpolated. Each of these issues is discussed below.

The firm sendout number accounts for gas deliveries to a diverse set of customers ranging from residential homes to large industrial sites. Since sales to different types of customers respond to weather differently, customer mix must be controlled for in any modeling effort. In addition, the behavior of this diverse group of customers will change differently over time as prices and other economic parameters change over time. As a result, these changes also need to be accounted for. Unfortunately, the firm sendout number is not available by rate. As a result, the only way to control for changes in customer mix and changes in the behavior over time by these customers is to limit the time period of data that is used in the model estimation.

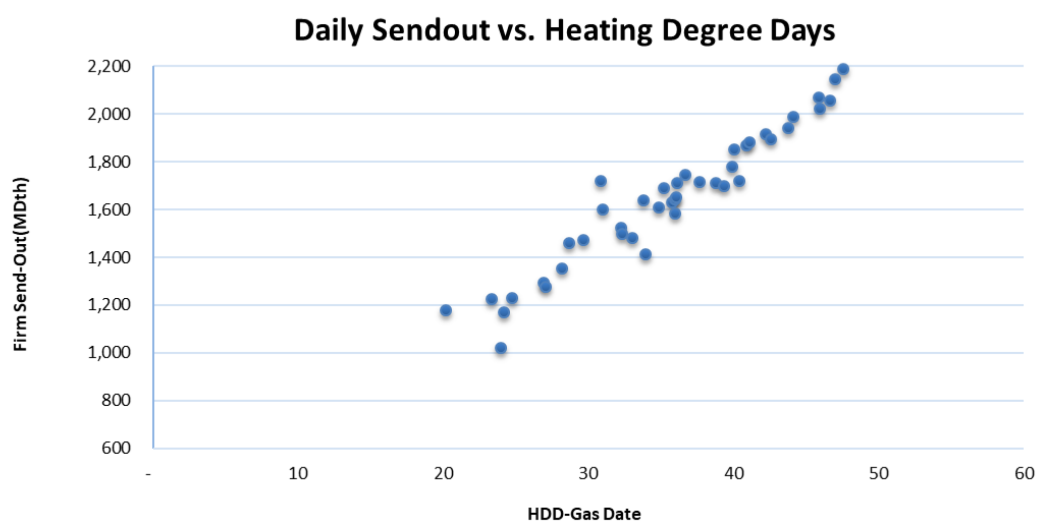
The second issue, of extrapolation, is addressed in a similar way. The relationship between sendout and weather is fairly linear. In reality, it is probably not perfectly linear. This is not an issue when estimating a model and using the results to interpolate values with the range of the estimation data. However, when extrapolating the data outside the range of the estimation data the imprecision increases. The way to minimize this imprecision is to limit the observations to the lower temperature data so as to get a linear estimation of that portion of a non-linear curve that is closest to the ultimate extrapolation value.

To address both of these forecasting issues, the data used in estimating the relationship between daily sendout and weather was limited to January 2022, January to February 18th 2022 during the most recent year available. Customer class mix will not change significantly in this short period and it contains the coldest months when the maximum sendout would most likely occur. Analysis of the data for these months indicates two things.

First, the data confirms the general responsiveness of firm sendout to the weather, as Figure 11 shows. Second, the relationship appears linear

Figure 11

January & February 2022
Daily Firm Sendout vs Heating Degree Days



To refine the impact of the day-type on sendout, the regression model from previous years was enhanced to allow for not only an intercept change from the day-type but, also a HDD response change.

The regression model that modeled daily sendout, SENDOUT, is specified as:

$$SENDOUT_t = f(HDD_t, HDD_{t-1}, \text{ WIND-SPEED, SKY-CONDITIONS } WEEKDAY_t, HOLIDAY_t, SNOW_t) \qquad [9]$$

Where:

HDD_t = Heating degree days on gas day t,

HDD_{t-1} = One day lag basis Heating degree days on gas day t-1,

WIND-SPEED = Daily average wind speed, MPH,

SKY-COND = Report of each cloud layer,

WEEKDAY = Interactive variable that takes the value of HDD on weekdays, otherwise 0,

HOLIDAY = Interactive variable that takes the value of HDD on Sundays or Holidays, otherwise 0,

SNOW = Binary variable that takes the value of 1 when reported snowstorm accumulation in any portion of the service area is 6 inches or more, 0 otherwise.

The estimation results are shown in Table 8 and Figure 12 below.

Table 8

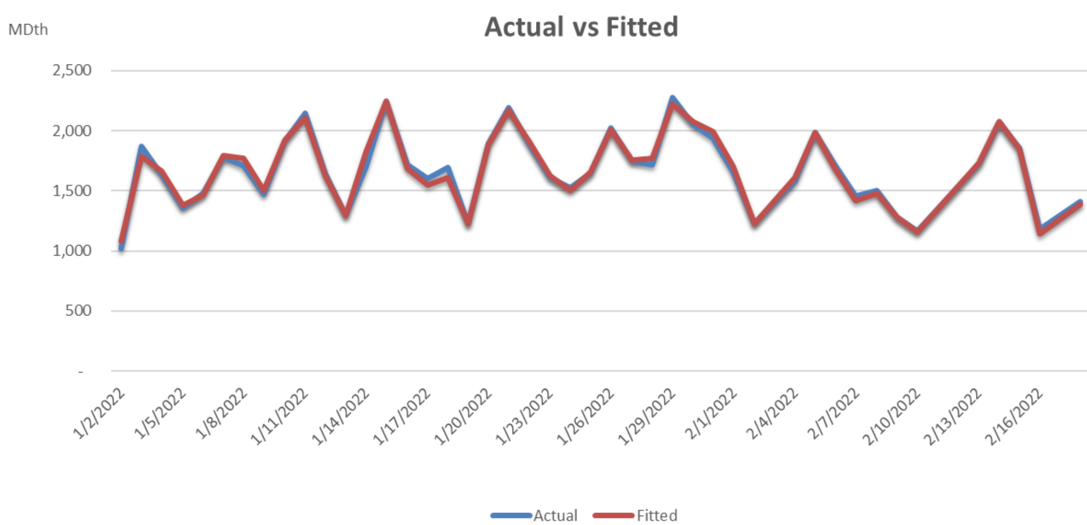
Estimated Coefficients of the Daily Sendout Model

(standard errors in parentheses)

	HDD									
Intercept	HDD	LAG	HOLIDAY	WEEKDAY	WIND-SPEED	SKY COND	SNOW	R2	DW	n
-26.9	36.2	8.0	-1.02	0.16	15.2	6.6	-70.9	0.984	1.814	44
(52.6)	(1.1)	(0.9)	(0.7)	(0.5)	(2.7)	(5.9)	(26.7)			

Figure 12

Daily Sendout Model
Actual vs. Fitted Values



The estimated coefficients of the model suggest that the estimated maximum daily peak would occur on a Friday. The model predicts that the maximum peak daily sendout would be 2221 MDth.

A. Calendar-Month Sales Calculation

Introduction

Utilities have traditionally had a disconnection in the timing of their revenues and their costs. Revenues from retail sales are a revenue stream from meter readings and the resulting bills to their customers that occur on a daily basis throughout the month. The bills issued from meter reads in the current month's meter reading schedule are all recorded as billing-month revenue. Billing-month revenue will include revenue from electricity or gas delivered during the previous month while excluding deliveries of electricity or gas delivered during the current month that occurred after the meters were read. Expenses, on the other hand, such as wages, fuel, depreciation, etc., have been recorded on a calendar-month basis. This inconsistency in the revenue and expense streams can be tolerated if there are no major changes in the revenue and/or expense streams. If major changes are occurring, such as a rapid increase in fossil fuel prices or a high seasonality in sales, a comparison of the billing-month revenue and the calendar-month expenses can give a false view of a utility's financials. To remedy this situation, the sales and revenue accrual calculation, the estimation of calendar-month sales and revenue from billed sales and revenue and the estimation of unbilled sales and revenue was developed.

Section II will discuss how, in theory, the billed sales and the unbilled estimates are used to calculate calendar-month sales using a simple example and introduce the notation that will serve as the basis of the analysis. A description of the theory's specific application to PSE&G's meter reading schedule, that can have a single billing month encompass up to four calendar-months, follows.

Section III will describe the implementation of the estimation of the calendar-month sales and revenue process at PSE&G.

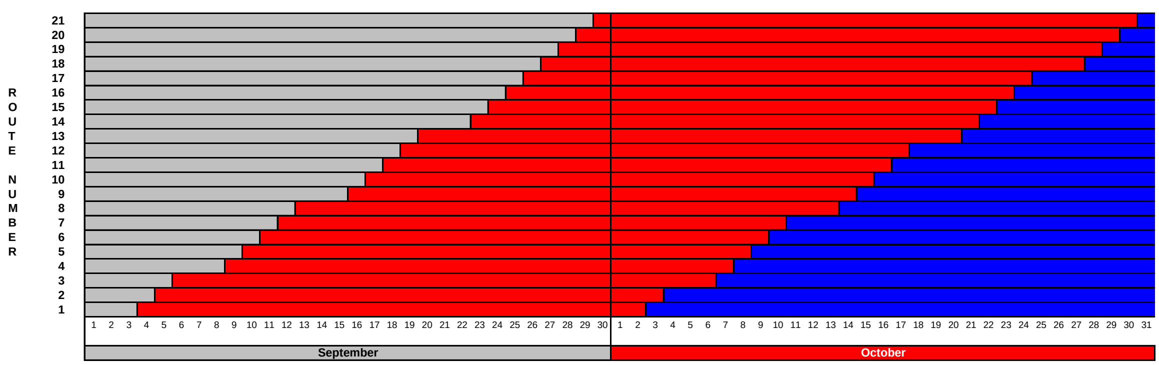
The Unbilled and Calendar-Month Estimation

A Simple Example

Utilities generally read all of their meters every month on 21 workdays. Figure 1, below shows a hypothetical October billing-month (in red) as determined by the September and October meter reading schedules. In the chart, each row represents a Route Number or a group of meters that are always read on the same day (although the day when they are all read may vary from month to month). The bottom row is red on all the days after the September read date, September 3rd until the October read date, October 2nd. If it is assumed that the customers' meters are read at noon, the October bill to these customers will reflect 28.5 days of service in September and only 1.5 days in October[2]. The second row from the bottom represents Route 2 whose customers' meters were read on September 4th and October 3rd. The October bill to these customers will reflect 27.5 days of service in September and only 2.5 days in October. This continues until the top row, Route 21, that had meter reading days of September 29th and October 30th. The October bills to these customers represent only 1.5 days of September service and 29.5 days of October service.

Figure 1

Hypothetical October 2008 Billing-Month



From the red portion of the diagram, it can be seen that the October billing-month consists of September sales that are billed in October that, to facilitate discussion, will be referred to as SEP B> OCT and October sales that are billed in October i.e., OCT B> OCT. The calendar-month sales are defined as the red and blue rectangle defined by the month of October and the 21 read-cycles. This consists of OCT B> OCT sales and the October unbilled sales, OCT B> NOV, the October sales that will be billed in November.

---

[2] Or, more realistically, if the meter reads for all the Route 1 customers are evenly distributed throughout an 8:00 AM to 4:00 PM workday, the reads, on average, would represent a half day's sales on the read day.

The relationship between billed, unbilled, and calendar-month sales can be derived from these identities from the steps below.

$$\text{October Calendar} = \boxed{\text{OCT B> OCT}} + \boxed{\text{OCT B> NOV}} = \boxed{\begin{array}{l}\text{OCT B> OCT}\\ \text{OCT B> NOV}\end{array}} \qquad [1]$$

Adding and subtracting $\boxed{\text{SEP B> OCT}}$ to the r.h.s. of [1] yields:

$$\text{October Calendar} = \boxed{\begin{array}{l}\text{OCT B> OCT}\\ \text{OCT B> NOV}\end{array}} + \boxed{\text{SEP B> OCT}} - \boxed{\text{SEP B> OCT}} \qquad [2]$$

Rearranging the r.h.s. of [2] yields:

$$\text{October Calendar} = \boxed{\begin{array}{l}\text{OCT B> OCT}\\ \text{SEP B> OCT}\end{array}} + \boxed{\text{OCT B> NOV}} - \boxed{\text{SEP B> OCT}} \qquad [3]$$

Substituting [1] into the l.h.s. of [3] yields:

$$\boxed{\begin{array}{l}\text{OCT B> OCT}\\ \text{OCT B> NOV}\end{array}} = \boxed{\begin{array}{l}\text{OCT B> OCT}\\ \text{SEP B> OCT}\end{array}} + \boxed{\text{OCT B> NOV}} - \boxed{\text{SEP B> OCT}} \qquad [4]$$

This is the familiar:

October Calendar = October Billed + October Unbilled – September Unbilled[3] [5]

This formula for the accrual of calendar-month sales and revenues is preferred to any direct estimation of calendar-month sales because any error in the unbilled estimate is "reversed out" in the following month. The advantage of this is that, as the calendar time period extends, the potential error resulting from unbilled estimates is reduced. This can be seen by summing up [5] over the 2008 calendar-year as:

$$\text{Calendar-Year 2008} = \sum_{i=\text{JAN08}}^{\text{DEC08}} \text{Billed}_i + \sum_{i=\text{JAN08}}^{\text{DEC08}} \text{Unbilled}_i - \sum_{i=\text{DEC07}}^{\text{NOV08}} \text{Unbilled}_i \qquad [6]$$

[3] The difference between the current month's unbilled and the previous month's is often referred to as the "net unbilled".

Where:

$Billed_i$ = Billing-month sales in month i,

$Unbilled_i$ = Unbilled sales in month i.

That simplifies to:

$$\text{Calendar-Year 2008} = \sum_{i=JAN08}^{DEC08} Billed_i + Unbilled_{DEC08} - Unbilled_{DEC07} \qquad [7]$$

The key result from [7] is that the annual calendar-year sales are the annual billed sales, a very large real number, and the difference between two monthly unbilled estimates. Since the error that can be expected in the difference between the two monthly unbilled estimates can be assumed to be quite small compared to the annual billed total, the calendar-year estimate, as a result, can be expected to be very accurate.

The same general results described in this simple example apply to PSE&G's more complicated meter reading schedule that is described below.

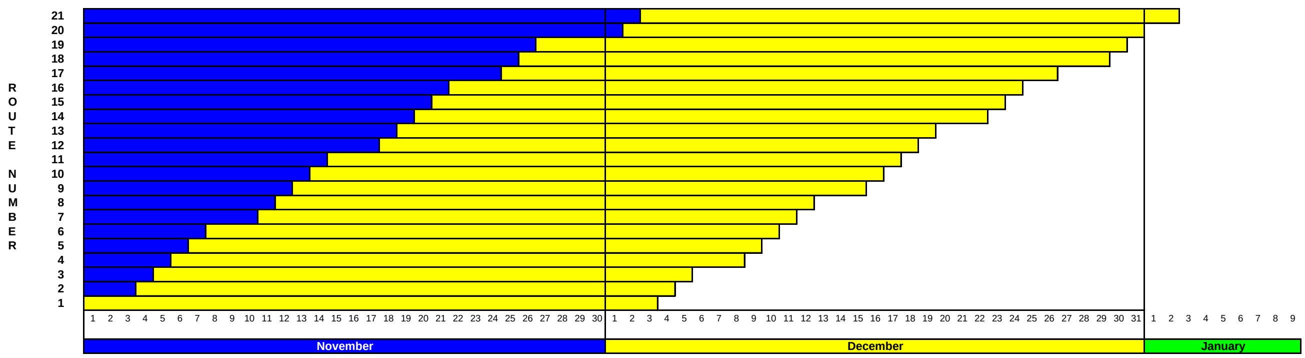
A More General Example

Unlike the hypothetical October billing-month, discussed above, that spanned two months, September and October, the PSE&G billing-month can encompass as many as four months. For example, the December 2008 PSE&G billing month, illustrated in Figure 2. has meter reading dates ranging from October 31st to January 2nd. As a result, it spans four months, October, November, December, and January[4].

[4] This is the original PSE&G December 2008 meter reading schedule. It has since been "compressed" to accommodate the implementation of iPower, the new billing and customer information system.

Figure 2

PSE&G December 2008 Billing-Month



Therefore, to develop a general algorithm applicable to PSE&G, the definition of billed, unbilled, and calendar sales must be expanded to include the potential of having sales from two additional calendar months reflected in a billing-month. December 2008 billing month, for example, is defined as:

December Billed = OCT B> DEC / NOV B> DEC / DEC B> DEC / JAN B> DEC [8]

Given the additional components of the billed, OCT B> DEC, i.e. the "under billed" sales, and JAN B> DEC, the "excess billed" sales, the addition of the current unbilled and subtraction of the previous month's unbilled to the December billed, as defined in the simple example above, will overstate December calendar-month sales by the sum of under billed and excess billed sales. As a result, the December unbilled needs to be redefined as:

December Unbilled = DEC B> JAN / DEC B> FEB + NOV B> JAN - JAN B> DEC [9]

December Unbilled = December Unbilled + January Underbilled – December Excess Billed [10]

December calendar can then be defined as December billed plus the new

December unbilled less the equivalent November unbilled or:

$$
\begin{aligned}
\boxed{\begin{array}{l}\text{DEC B> OCT}\\ \text{DEC B> NOV}\\ \text{DEC B> DEC}\\ \text{DEC B> JAN}\end{array}} \quad = \quad & \boxed{\begin{array}{l}\text{OCT B> DEC}\\ \text{NOV B> DEC}\\ \text{DEC B> DEC}\\ \text{JAN B> DEC}\end{array}} \\
+ \quad & \boxed{\begin{array}{l}\text{DEC B> JAN}\\ \text{DEC B> FEB}\end{array}} + \boxed{\text{NOV B> JAN}} - \boxed{\text{JAN B> DEC}} \\
- \quad & \boxed{\begin{array}{l}\text{NOV B> DEC}\\ \text{NOV B> JAN}\end{array}} - \boxed{\text{OCT B> DEC}} + \boxed{\text{DEC B> NOV}} \qquad [11]
\end{aligned}
$$

or, in words:

December Calendar = December Billed
+ December Unbilled
- November Unbilled [12]

This is the general formula that is used to calculate unbilled sales at PSE&G.

The PSE&G Gas Calendar-Month Estimation

The estimation of calendar-month gas sales at PSE&G is based on the notion that gas sales can be divided into two components: a weather sensitive component and a non-weather sensitive component. The weather sensitive component is affected by the winter weather as measured by heating degree days (HDD). The non-weather component is simply a function of the number of days in the sales period. As a result, sales during the unbilled periods can be estimated based on the HDD and number of days during the unbilled periods and the estimates of the weather-sensitive sales per HDD and non-weather sensitive sales per day.

The estimate of the weather-sensitive sales per HDD for each rate, the HDD coefficient, is the sum of the coefficients associated with its model's independent variables that have a HDD component divided by the number of days in the billing period. In the case of RSG that, unlike the other rates, is modeled on a use per customer basis, this result is multiplied by the number of customers.

The estimate of the non-weather sensitive sales per day for each rate, the base coefficient, is the value of the model equation with all of the coefficients associated with HDD set to zero and divided by the number of days in the billing period. As in the case of the HDD coefficient, the RSG result is multiplied by the number of customers.

Given the structure of the models, these coefficients will vary by month and by year. The current estimates for 2008 and 2009 are shown in Table 1 below.[5]

Table 1

Unbilled Weather and Base Coefficients, 2008-2009

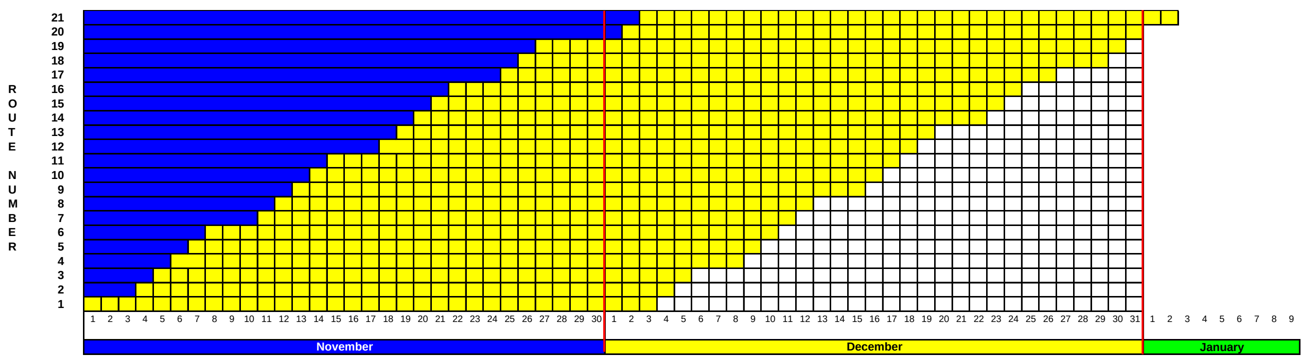
	RSG				GSG-Commercial				GSG-Industrial				LVG - Non Vehicle			
Billing	Heating		Non-heating		Heating		Non-heating		Heating		Non-heating		Commercial		Industrial	
Month	Base	HDD	Base	HDD	Base	HDD	Base	HDD	Base	HDD	Base	HDD	Base	HDD	Base	HDD
Jan-08	1,477,624	246,082	218,393	4,689	56,941	45,607	168,133	3,942	(15,873)	3,333	2,978	501	1,047,971	79,608	145,023	8,767
Feb-08	1,554,914	253,674	234,372	4,811	69,746	45,607	175,674	3,942	(15,256)	3,333	3,786	501	1,172,070	79,608	167,056	8,767
Mar-08	1,343,904	249,936	236,373	4,737	25,553	45,607	158,654	3,942	(16,832)	3,333	2,893	501	1,053,237	79,608	138,433	8,767
Apr-08	1,337,980	248,305	190,526	4,692	13,895	45,607	150,129	3,942	(15,769)	3,333	5,681	501	1,076,058	79,608	159,387	8,767
May-08	1,267,108	251,443	164,912	4,741	146,976	45,607	117,463	3,942	332	3,333	4,166	501	838,647	79,608	137,277	8,767
Jun-08	1,086,639	250,233	135,407	4,714	126,187	45,607	95,849	3,942	2,561	3,333	3,704	501	708,324	79,608	129,981	8,767
Jul-08	984,641	248,954	116,905	4,704	135,270	45,607	94,660	3,942	3,907	3,333	2,680	501	610,707	79,608	119,171	8,767
Aug-08	912,999	249,456	104,709	4,666	103,926	45,607	80,601	3,942	2,045	3,333	2,578	501	613,535	79,608	119,770	8,767
Sep-08	940,487	252,748	111,693	4,746	108,515	45,607	84,252	3,942	2,953	3,333	2,730	501	581,470	79,608	129,852	8,767
Oct-08	809,244	249,439	113,383	4,671	115,541	45,607	90,002	3,942	3,184	3,333	1,932	501	728,815	79,608	116,580	8,767
Nov-08	1,076,293	250,792	138,927	4,687	(9,962)	45,607	107,114	3,942	(7,929)	3,333	5,262	501	769,823	79,608	112,495	8,767
Dec-08	1,191,333	252,604	187,367	4,690	(9,608)	45,607	130,211	3,942	(18,805)	3,333	2,214	501	902,036	79,608	120,543	8,767
Jan-09	1,481,212	248,163	214,955	4,643	56,601	45,745	153,926	3,711	(15,827)	3,259	2,952	490	1,041,705	79,850	144,156	8,190
Feb-09	1,548,542	252,236	228,920	4,692	69,856	45,745	171,980	3,711	(15,254)	3,259	3,796	490	1,173,921	79,850	167,320	8,190
Mar-09	1,393,454	253,517	239,084	4,687	26,121	45,745	168,175	3,711	(17,054)	3,259	2,980	490	1,076,642	79,850	141,509	8,190
Apr-09	1,331,091	250,149	185,138	4,617	13,721	45,745	148,255	3,711	(15,497)	3,259	5,622	490	1,062,628	79,850	157,398	8,190
May-09	1,266,433	253,309	160,992	4,665	145,815	45,745	116,535	3,711	352	3,259	4,136	490	832,022	79,850	136,193	8,190
Jun-09	1,094,707	252,091	133,240	4,638	126,187	45,745	95,849	3,711	2,565	3,259	3,704	490	708,324	79,850	129,981	8,190
Jul-09	987,359	250,802	114,502	4,629	134,644	45,745	94,222	3,711	3,889	3,259	2,668	490	607,880	79,850	118,620	8,190
Aug-09	925,740	251,308	103,701	4,591	104,600	45,745	81,124	3,711	2,058	3,259	2,595	490	617,512	79,850	120,546	8,190
Sep-09	953,382	254,625	110,592	4,670	109,193	45,745	84,778	3,711	2,971	3,259	2,747	490	585,098	79,850	130,662	8,190
Oct-09	808,699	251,291	110,672	4,596	114,612	45,745	89,279	3,711	3,169	3,259	1,918	490	722,957	79,850	115,643	8,190
Nov-09	1,077,388	252,654	135,835	4,612	(9,899)	45,745	106,433	3,711	(7,834)	3,259	5,235	490	764,927	79,850	111,779	8,190
Dec-09	1,203,734	254,479	184,915	4,615	(9,637)	45,745	130,597	3,711	(18,750)	3,259	2,238	490	904,708	79,850	120,900	8,190

[5] While the coefficient is called the "base" coefficient, it really does not measure base use per day. Rather it is the intercept term in a simple regression. As a result, it can be negative reflecting the intercept of a regression that is outside of the relevant range.

The billed, unbilled, excess billed, and underbilled days and heating degree days are derived from the meter reading schedule and daily weather data. The measure used is the Average Route Days (ARD). The ARD are defined as the number of days across all routes for a given period divided by 21, the total number of routes. This concept is illustrated in Figure 3, a slightly different version of the December 2008 billing-month, shown below.

Figure 3

PSE&G December 2008 Billing-Month



Each square represents an ARD.[6] The total yellow blocks in each row represent the number of days in that particular route during the December billing-month. The sum of all the yellow blocks, 677, divided by 21 represent the average number of days in the December billing-month, i.e., the average number of days across the 21 routes or 32.24.

The number of excess billed days, $\boxed{\text{JAN B> DEC}}$, is:

1.5 (January 1st and half of January 2nd) / 21 = 0.07 [13]

HDD for each period are a weighted sum of the daily HDD where the weight is the ARD associated with that day. For example, from the diagram it can be seen that on December 21st, the sales to 8 routes, routes 14-21, will be in the

[6] Well, not exactly. Remember that it is assumed that the meters are read at noon. As a result the last yellow block to the right of each row counts as a half day. On the other hand, the last blue block on the right of each row also counts as a half day in the December billing-month so, the math works for the billing-month but, the half needs to be taken into account when discussing portions of the unbilled and billed periods. For a clearer discussion, however, the half days will be, for the most part, ignored.

December billing-month while sales to the first thirteen routes will be in the January billing-month. As a result , 8/21 or 38 percent of the HDD on December 20th will be assigned to the December billing month and 62 percent will be assigned to the January billing month.

HDD for underbilled and excess billed periods are assigned in a similar manner.

From Table 2 below that shows the normal monthly billed an unbilled HDD and days by type, it can be seen that underbilled days and HDD occur rarely while excess billed days are quite common.

Table 2

Billed and Unbilled Days and Weather
2008-2009

	Heating Degree Days				Days			
Billing Month	Billed	Unbilled	Excess Billed	Under Billed	Billed	Unbilled	Excess Billed	Under Billed
Jan-08	795.06	322.08	0.59	-	31.67	12.76	0.02	0.00
Feb-08	786.44	283.76	5.90	-	30.19	11.83	0.29	0.00
Mar-08	643.82	187.74	2.62	-	30.67	12.10	0.21	0.00
Apr-08	360.41	73.05	0.20	-	30.14	11.83	0.10	0.00
May-08	108.21	13.78	0.05	-	29.90	13.05	0.21	0.00
Jun-08	15.47	0.14	-	-	30.33	12.60	0.10	0.00
Jul-08	0.14	-	-	-	30.71	12.81	0.02	0.00
Aug-08	0.01	0.03	-	-	29.57	14.29	0.07	0.00
Sep-08	1.87	7.02	0.04	-	30.71	13.52	0.02	0.00
Oct-08	60.34	87.80	-	-	29.38	15.12	0.00	0.00
Nov-08	255.88	213.78	1.65	-	29.76	15.43	0.10	0.00
Dec-08	578.34	338.40	1.75	0.17	32.24	14.19	0.07	0.02
Jan-09	797.36	361.02	1.75	-	31.86	13.33	0.07	0.00
Feb-09	786.19	277.80	7.41	-	30.14	11.48	0.36	0.00
Mar-09	634.56	188.08	1.17	-	30.00	12.21	0.10	0.00
Apr-09	361.92	73.58	0.46	-	30.52	11.79	0.19	0.00
May-09	108.91	13.36	0.05	-	30.14	12.67	0.21	0.00
Jun-09	15.07	0.12	-	-	30.33	12.21	0.10	0.00
Jul-09	0.12	-	-	-	30.86	12.38	0.12	0.00
Aug-09	0.01	0.03	-	-	29.38	13.90	0.02	0.00
Sep-09	1.97	6.92	0.04	-	30.52	13.38	0.02	0.00
Oct-09	61.71	86.34	-	-	29.62	14.74	0.00	0.00
Nov-09	261.34	207.03	1.65	-	29.95	14.88	0.10	0.00
Dec-09	582.57	329.38	3.90	-	32.14	13.81	0.17	0.00

On a monthly basis, the necessary coefficient, weather, and day data are transmitted to PSE&G accounting services each month. They are used to calculate the actual current month unbilled sales, UnbilledTherms, using:

$$\text{UnbilledTherms} = \text{UnbilledDays} \times \text{BASECoef} + \text{UnbilledHDD} \times \text{HDDCoef} \qquad [14]$$

Where:

UnbilledDays = the number of route days in the unbilled period as defined by [9],

Unbilled HDD = the number of HDD in the unbilled period as defined by [9],

BASECoef = the Base coefficient,

HDDCoef = the HDD coefficient.

The results of this calculation, with the previous month's unbilled results, are used to calculate calendar-month sales.

Unbilled, and as a consequence, calendar-month revenue is calculated by pricing the unbilled therms at the projected tariff rates. Adding the net unbilled revenue to the billing-month revenues results in the estimate of calendar-month revenue.

B. Summary Tables

Delivered Gas Sales As Billed
2017-2027
(MDth)

Class	Rate	Category	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Residential	RSG	Heating	130,512	147,879	146,246	139,222	151,937	152,180	151,659	153,036	154,322	155,639	156,992
		Non-Heating	8,860	9,314	4,016	3,620	3,995	4,057	3,961	3,956	3,929	3,910	3,889
	Total		139,371	157,193	150,262	142,842	155,932	156,237	155,620	156,992	158,251	159,550	160,881
Commercial	GSG	Heating	22,541	25,864	24,501	20,883	24,011	23,691	23,435	23,606	23,339	23,126	22,862
		Non-Heating	3,939	4,315	4,077	3,682	3,766	3,798	3,913	3,914	3,915	3,913	3,912
		Total	26,480	30,179	28,577	24,565	27,777	27,489	27,348	27,520	27,253	27,039	26,774
	LVG		61,091	70,527	68,443	60,670	66,680	66,563	67,069	67,807	68,197	68,275	68,315
	TSG	Firm	941	1,193	1,060	971	1,010	992	962	922	866	809	754
		Non-Firm	10,062	14,028	14,595	9,534	10,783	10,756	10,710	10,643	10,541	10,434	10,330
		Total	11,003	15,221	15,655	10,505	11,793	11,748	11,672	11,566	11,407	11,242	11,084
	CIG		3,595	5,471	4,746	1,808	1,910	1,910	1,910	1,910	1,910	1,910	1,910
	CSG		16,341	21,300	8,119	5,254	8,297	8,297	8,297	8,297	8,297	8,297	8,297
	Total		118,510	142,697	125,540	102,801	116,458	116,007	116,297	117,100	117,064	116,763	116,379
Industrial	GSG	Heating	871	1,019	940	786	864	874	913	913	913	913	913
		Non-Heating	153	169	160	149	158	158	158	158	158	158	158
		Total	1,025	1,188	1,100	935	1,022	1,032	1,071	1,071	1,071	1,071	1,072
	LVG		7,043	8,383	8,339	6,937	7,823	7,862	7,806	7,801	7,759	7,698	7,643
	TSG	Firm	1,511	1,528	1,444	1,497	1,567	1,540	1,496	1,436	1,351	1,266	1,183
		Non-Firm	17,374	6,115	6,373	5,867	5,815	5,796	5,766	5,721	5,653	5,581	5,512
		Total	18,886	7,643	7,816	7,364	7,381	7,336	7,261	7,157	7,004	6,847	6,695
	CIG		564	1,020	695	613	535	535	535	535	535	535	535
	CSG		83,737	106,647	122,752	71,945	68,134	68,134	68,134	68,134	68,134	68,134	68,134
	Contract		8,822	-	-	-	-	-	-	-	-	-	-
	Total		120,075	124,880	140,702	87,793	84,896	84,899	84,808	84,699	84,503	84,286	84,080
Lighting	SLG		66	76	62	69	64	64	64	64	64	64	64
Total			378,023	424,847	416,566	333,506	357,350	357,207	356,789	358,854	359,882	360,663	361,404

Supplied Gas Sales As Billed
2017-2027
(MDth)

Class	Rate	Category	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Residential	RSG	Heating	124,075	141,470	141,490	135,338	148,004	148,241	147,733	149,075	150,329	151,612	152,929
		Non-Heating	8,362	8,844	3,814	3,472	3,840	3,899	3,807	3,802	3,776	3,758	3,738
	Total		132,437	150,315	145,305	138,811	151,844	152,140	151,540	152,877	154,104	155,370	156,667
Commercial	GSG	Heating	17,387	19,929	19,320	16,454	18,986	18,733	18,539	18,680	18,474	18,308	18,103
		Non-Heating	2,965	3,158	3,044	2,780	2,888	2,913	3,000	3,001	3,001	3,000	2,999
		Total	20,352	23,087	22,364	19,234	21,874	21,646	21,539	21,681	21,475	21,308	21,102
	LVG		24,578	26,300	27,067	22,372	25,169	25,117	25,338	25,658	25,821	25,865	25,893
	TSG	Firm	-	-	-	-	-	-	-	-	-	-	-
		Non-Firm	942	807	840	1,108	788	788	788	788	788	788	788
		Total	942	807	840	1,108	788	788	788	788	788	788	788
	CIG		3,595	5,471	4,746	1,808	1,910	1,910	1,910	1,910	1,910	1,910	1,910
	CSG		-	-	-	-	-	-	-	-	-	-	-
	Total		49,467	55,664	55,017	44,522	49,741	49,461	49,575	50,037	49,994	49,872	49,693
Industrial	GSG	Heating	689	799	774	649	721	729	762	762	762	762	763
		Non-Heating	113	127	126	121	130	130	131	131	131	131	131
		Total	802	927	901	770	851	860	892	892	893	893	893
	LVG		1,864	2,108	2,426	1,854	2,214	2,225	2,207	2,207	2,192	2,173	2,155
	TSG	Firm	-	-	-	-	-	-	-	-	-	-	-
		Non-Firm	108	109	67	39	22	22	22	22	22	22	22
		Total	108	109	67	39	22	22	22	22	22	22	22
	CIG		564	1,020	695	613	535	535	535	535	535	535	535
	CSG		-	-	-	-	-	-	-	-	-	-	-
	Contract		1,301	-	-	-	-	-	-	-	-	-	-
	Total		4,638	4,164	4,089	3,276	3,622	3,641	3,657	3,656	3,642	3,623	3,605
Lighting	SLG		26	26	24	29	25	25	25	25	25	25	25
Total			186,568	210,170	204,435	186,638	205,231	205,267	204,797	206,596	207,765	208,889	209,991

Supplied Share of Delivered Gas Sales As Billed
2017-2027
(percent)

Class	Rate	Category	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Residential	RSG	Heating	95%	96%	97%	97%	97%	97%	97%	97%	97%	97%	97%
		Non-Heating	94%	95%	95%	96%	96%	96%	96%	96%	96%	96%	96%
	Total		95%	96%	97%	97%	97%	97%	97%	97%	97%	97%	97%
Commercial	GSG	Heating	77%	77%	79%	79%	79%	79%	79%	79%	79%	79%	79%
		Non-Heating	75%	73%	75%	76%	77%	77%	77%	77%	77%	77%	77%
		Total	77%	76%	78%	78%	79%	79%	79%	79%	79%	79%	79%
	LVG		40%	37%	40%	37%	38%	38%	38%	38%	38%	38%	38%
	TSG	Firm	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
		Non-Firm	9%	6%	6%	12%	7%	7%	7%	7%	7%	8%	8%
		Total	9%	5%	5%	11%	7%	7%	7%	7%	7%	7%	7%
	CIG		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	CSG		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Total		42%	39%	44%	43%	43%	43%	43%	43%	43%	43%	43%
Industrial	GSG	Heating	79%	78%	82%	83%	83%	83%	83%	83%	83%	83%	83%
		Non-Heating	74%	75%	79%	82%	83%	83%	83%	83%	83%	83%	83%
		Total	78%	78%	82%	82%	83%	83%	83%	83%	83%	83%	83%
	LVG		26%	25%	29%	27%	28%	28%	28%	28%	28%	28%	28%
	TSG	Firm	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
		Non-Firm	1%	2%	1%	1%	0%	0%	0%	0%	0%	0%	0%
		Total	1%	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%
	CIG		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	CSG		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Contract		15%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Total		4%	3%	3%	4%	4%	4%	4%	4%	4%	4%	4%
Lighting	SLG		39%	35%	39%	42%	39%	39%	39%	39%	39%	39%	39%
Total			49%	49%	49%	56%	57%	57%	57%	58%	58%	58%	58%

Delivered Gas Sales Calendar-Year
2017-2027
(MDth)

Class	Rate	Category	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Residential	RSG	Heating	131,801	144,199	146,339	140,696	151,526	152,014	151,316	153,700	153,979	155,321	156,582
		Non-Heating	8,866	9,044	4,065	3,319	3,985	4,051	3,952	3,967	3,920	3,902	3,879
	Total		140,667	153,243	150,404	144,015	155,511	156,065	155,268	157,666	157,899	159,223	160,461
Commercial	GSG	Heating	22,771	25,196	24,676	21,218	23,857	23,706	23,336	23,735	23,277	23,073	22,793
		Non-Heating	4,040	4,256	4,086	3,714	3,720	3,816	3,905	3,926	3,907	3,905	3,902
		Total	26,811	29,453	28,762	24,932	27,577	27,522	27,241	27,661	27,185	26,978	26,695
	LVG		61,513	68,128	67,729	60,455	66,231	66,653	66,888	68,090	68,081	68,142	68,142
	TSG	Firm	951	1,197	924	1,000	1,010	992	962	922	866	809	754
		Non-Firm	9,668	10,972	12,155	9,455	10,783	10,756	10,710	10,643	10,541	10,434	10,330
		Total	10,618	12,169	13,079	10,455	11,793	11,748	11,672	11,566	11,407	11,242	11,084
	CIG		3,408	3,568	3,373	1,376	1,910	1,910	1,910	1,910	1,910	1,910	1,910
	CSG		8,734	18,502	6,131	5,374	10,113	8,297	8,297	8,297	8,297	8,297	8,297
	Total		111,084	131,819	119,074	102,591	117,625	116,129	116,008	117,524	116,880	116,570	116,127
Industrial	GSG	Heating	875	993	943	807	843	880	910	916	910	911	910
		Non-Heating	155	166	161	149	157	158	158	159	158	158	158
		Total	1,030	1,159	1,104	957	1,000	1,037	1,068	1,075	1,068	1,068	1,068
	LVG		7,093	8,258	8,373	6,923	7,816	7,863	7,785	7,823	7,741	7,679	7,622
	TSG	Firm	1,574	1,453	1,499	1,520	1,567	1,540	1,496	1,436	1,351	1,266	1,183
		Non-Firm	15,878	5,486	6,373	5,867	5,815	5,796	5,766	5,721	5,653	5,581	5,512
		Total	17,451	6,939	7,872	7,387	7,381	7,336	7,261	7,157	7,004	6,847	6,695
	CIG		557	657	594	331	535	535	535	535	535	535	535
	CSG		72,331	86,007	99,401	70,866	68,134	68,134	68,134	68,134	68,134	68,134	68,134
	Contract		6,389	-	-	-	-	-	-	-	-	-	-
	Total		104,851	103,020	117,344	86,465	84,867	84,906	84,783	84,725	84,482	84,264	84,055
Lighting	SLG		66	72	62	69	64	64	64	64	64	64	64
Total			356,668	388,153	386,884	333,140	358,067	357,164	356,123	359,979	359,325	360,121	360,707

Supplied Gas Sales Calendar-Year
2017-2027
(MDth)

Class	Rate	Category	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Residential	RSG	Heating	125,315	137,603	141,644	136,807	147,604	148,080	147,399	149,722	149,994	151,302	152,530
		Non-Heating	8,365	8,561	3,859	3,187	3,829	3,893	3,798	3,812	3,767	3,750	3,728
	Total		133,680	146,164	145,502	139,994	151,433	151,973	151,198	153,534	153,761	155,052	156,259
Commercial	GSG	Heating	17,569	19,242	19,479	16,762	18,829	18,745	18,463	18,780	18,427	18,268	18,050
		Non-Heating	2,976	3,083	3,053	2,804	2,856	2,926	2,994	3,010	2,995	2,994	2,991
		Total	20,545	22,325	22,531	19,567	21,685	21,671	21,457	21,790	21,422	21,262	21,041
	LVG		24,708	25,405	26,878	22,105	25,344	25,154	25,264	25,773	25,774	25,811	25,823
	TSG	Firm	-	-	-	-	-	-	-	-	-	-	-
		Non-Firm	892	699	803	1,016	788	788	788	788	788	788	788
		Total	892	699	803	1,016	788	788	788	788	788	788	788
	CIG		3,408	3,568	3,373	1,376	1,910	1,910	1,910	1,910	1,910	1,910	1,910
	CSG		-	-	-	-	-	-	-	-	-	-	-
	Total		49,553	51,997	53,586	44,063	49,727	49,522	49,419	50,261	49,894	49,771	49,562
Industrial	GSG	Heating	692	785	778	663	708	734	759	765	760	760	760
		Non-Heating	115	124	127	122	130	130	130	131	130	130	130
		Total	806	909	905	786	838	864	890	896	890	890	890
	LVG		1,877	2,082	2,428	1,859	2,244	2,225	2,200	2,214	2,187	2,167	2,148
	TSG	Firm	-	-	-	-	-	-	-	-	-	-	-
		Non-Firm	59	82	67	39	22	22	22	22	22	22	22
		Total	59	82	67	39	22	22	22	22	22	22	22
	CIG		557	657	594	331	535	535	535	535	535	535	535
	CSG		-	-	-	-	-	-	-	-	-	-	-
	Contract		805	-	-	-	-	-	-	-	-	-	-
	Total		4,104	3,731	3,994	3,015	3,639	3,646	3,647	3,667	3,634	3,614	3,596
Lighting	SLG		26	26	24	29	25	25	25	25	25	25	25
Total			187,362	201,918	203,107	187,101	204,824	205,166	204,289	207,487	207,314	208,462	209,441

Supplied Share of Delivered Gas Sales Calendar Year 2017-2027 (percent)

Class	Rate	Category	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Residential	RSG	Heating	95%	95%	97%	97%	97%	97%	97%	97%	97%	97%	97%
		Non-Heating	94%	95%	95%	96%	96%	96%	96%	96%	96%	96%	96%
	Total		95%	95%	97%	97%	97%	97%	97%	97%	97%	97%	97%
Commercial	GSG	Heating	77%	76%	79%	79%	79%	79%	79%	79%	79%	79%	79%
		Non-Heating	74%	72%	75%	76%	77%	77%	77%	77%	77%	77%	77%
		Total	77%	76%	78%	78%	79%	79%	79%	79%	79%	79%	79%
	LVG		40%	37%	40%	37%	38%	38%	38%	38%	38%	38%	38%
	TSG	Firm	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
		Non-Firm	9%	6%	7%	11%	7%	7%	7%	7%	7%	8%	8%
		Total	8%	6%	6%	10%	7%	7%	7%	7%	7%	7%	7%
	CIG		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	CSG		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Total		45%	39%	45%	43%	42%	43%	43%	43%	43%	43%	43%
Industrial	GSG	Heating	79%	79%	83%	82%	84%	83%	83%	83%	83%	83%	83%
		Non-Heating	74%	75%	79%	82%	83%	83%	83%	83%	83%	83%	83%
		Total	78%	78%	82%	82%	84%	83%	83%	83%	83%	83%	83%
	LVG		26%	25%	29%	27%	29%	28%	28%	28%	28%	28%	28%
	TSG	Firm	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
		Non-Firm	0%	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%
		Total	0%	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%
	CIG		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	CSG		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Contract		13%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Total		4%	4%	3%	3%	4%	4%	4%	4%	4%	4%	4%
Lighting	SLG		39%	37%	39%	42%	39%	39%	39%	39%	39%	39%	39%
Total			53%	52%	52%	56%	57%	57%	57%	58%	58%	58%	58%

17. FERC Pipeline Activities

Item 17

FERC Pipeline Activities

Pipeline	Docket No.	Description
Transco	RP20-614 & RP20-618 & RP21-24	On February 28, 2020, Transco filed proposed changes to its cash out process. The Company protested this filing and worked as a part of a large customer group to reach a settlement that was approved by FERC on July 30, 2021. As a part of the settlement, Transco engaged an expert consultant to assist in the review of its cash out and accounting processes. The final expert consultant report was received on April 29, 2022 and is currently the subject of further negotiations by all participants.
Tennessee	RP21-552	On March 1, 2021, Tennessee filed to adjust its fuel and loss percentages and electric power cost rates, resulting in a small cost increase to the Company. One party protested the filing, and FERC set the matter for hearing. Settlement conferences held in 2021 led to an impasse, at which point a formal hearing was held. The issues have been briefed, and it is expected that FERC will be issuing its decision in the near future.
Transco	CP21-94	On March 26, 2021, Transco applied for approval of the Regional Energy Access Project, which includes incremental firm transportation of 60,000 dekatherms/day to the Company. Acting to meet increasing market demands from its firm customers, the Company has filed comments in support for the project, which has an updated target in-service date of the fourth quarter of 2024.

Tennessee	RP22-417 & RP22-921	On December 15, 2021 Tennessee filed to implement a producer group certified gas (PCG) pooling service option under rate schedule Supply Aggregation Service in Docket No. RP22-417. This filing was intended to encourage the transportation and trading of responsibly sourced natural gas supply. The Company was a participant in this case and on April 29, 2022 FERC rejected the filing without prejudice, stating that Tennessee failed to demonstrate that incorporating the PCG criteria into its tariff is just and reasonable. On May 11, 2022 Tennessee filed a revised application on this matter in Docket No. RP22-921. The Commission's order rejecting their earlier filing stated that there was no standard for such determinations and stated that it would approve a future filing that moved the particulars of the program from the tariff to Tennessee's website. The Company has intervened and will continue to monitor as it comes to conclusion.
TETCO	RP21-1001 & RP21-1188	On July 30, 2021 Texas Eastern (TETCO) filed a General Section 4 rate case (RP21-1001) seeking a $2.3 billion cost of service that was initially rejected by FERC due to the inclusion of an assumed corporate tax rate increase. On September 30, 2021 TETCO filed another General Section 4 rate case (RP21-1188) seeking a $2.2 billion cost of service with rates effective April 1, 2022 subject to refund. FERC later determined that if TETCO adjusted its assumed tax rate in the initial rate case filing, it could make those rates effective February 1, 2022, subject to refund.

		The Company protested both of these filings and is an active participant in these cases, as well as a member of a group of firm customers jointly seeking to decrease the magnitude of the potential rate increase. The group has retained an expert witness to assist them in their pursuit of cost of service and operational issues. Settlement discussions are currently being pursued.
EGTS	RP21-1187	On September 30, 2021 Eastern Gas Transmission and Storage (EGTS) filed a General Section 4 rate case seeking a $1.2 billion cost of service. The Company protested the application and is an active participant in this case as well as a member of a group of firm customers jointly seeking to decrease the magnitude of the potential rate increase. The group has retained an expert witness to assist them in their pursuit of cost of service and operational issues. Settlement discussions are currently being pursued.

18. Gas Supply Plan

Gas Procurement Objectives

Current & Forecasted Gas Service Requirements

Projected Sources of Capacity

Affiliate Relationship / Asset Management

Hedging Plan & Strategy

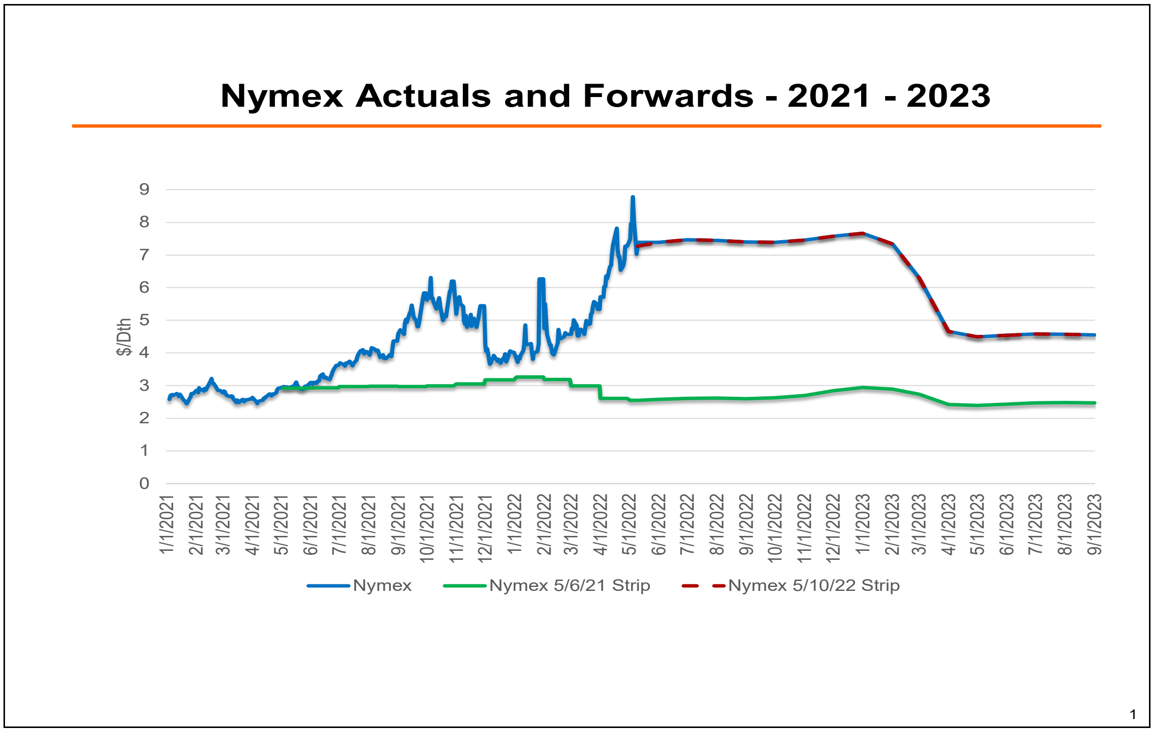
Capacity Releases / Off-System Sales

Gas Supply Plan

1. Gas Procurement Objectives

As discussed in the body of the testimony of David F. Caffery herein, natural gas prices during the most recent period have increased dramatically from the levels experienced at this time last year, trading at highs not seen since 2008. NYMEX prompt month daily prices have traded between approximately $3.50/Dth and $9.00/Dth since the middle of January 2022, with June prices settling at $8.908/Dth. This compares with a NYMEX price of $3.00/Dth at this time last year during the midst of the Covid crisis. The forward (May 10th) NYMEX strip used by the Company in this filing (see Item 8) shows that average prices are 120.5% higher than last year's NYMEX strip. Based upon the forward strip, prices are expected to increase for the rest of 2022, as well as in January and February of 2023, followed by a significant decrease from the $8.00 range to about $5.00/Dth during April 2023 through September 2023, the end of this BGSS period.

This dramatic increase in NYMEX prices, illustrated in the chart below, is the primary driver of the requested increase in the BGSS-RSG rate included in the instant filing. The chart shows the Actual NYMEX (by day) in solid blue for the January 1, 2021 through May 18, 2022 period. The green line represents the NYMEX forward strip as of May 6, 2021 that formed the basis of last year's BGSS Filing. Finally, the dashed red/blue line is the NYMEX forward strip as of May 10, 2022 that is the basis for this year's BGSS Filing. As can be seen on the chart, the increase in prices during the May 2022 through February 2023 period compared to last year's filing is approximately $5.00/Dth or roughly 200%.



The natural gas market has undergone significant changes since last year's BGSS Filing. US dry gas production levels hit a peak of 93.5 Bcf/d during 2019 only to decline dramatically during the summer of 2020 to a level of 85 Bcf/d due to the demand destruction resulting from the Covid restrictions. Over the course of the past year, production volumes have increased to a level of approximately 94 Bcf/d to meet rising demand levels – of which drivers include the lifting of Covid related restrictions (and resultant increase in economic activity) and increase in LNG exports. Regarding the latter, feedgas volumes for the country's seven LNG export facilities have recently achieved a record of 13.5 Bcf/d, representing 14% of US dry gas production during the same timeframe.

Unfortunately, this increase in production volume has not kept pace with the increases in demand, both domestically and internationally (related to the increase in European imports of U.S. LNG to make up for the shortfall of Russian gas supplies). Additionally, the significant increase in pipeline takeaway capacity that occurred during 2017 and 2018, primarily from the Marcellus/Utica region, has all but ended due to state and federal permitting challenges impacting pipeline construction. U.S. natural gas storage levels are currently 16% below the 5-year average and 376 Bcf, or 15%, below this time last year – which will likely add an incremental 1.7 Bcf/d to summer gas demand (associated with increased gas going into storage).

In addition to the dramatic increase in the NYMEX prices, two of the Company's largest pipeline suppliers have filed rate increases at FERC, both of which went into effect earlier this year. Texas Eastern filed a rate case in mid-2021, which increased the Company's rates by approximately 53% or $56 million/year effective February 1, 2022. In addition, Eastern Gas Transmission and Storage (formerly known as Dominion Transmission) filed a FERC rate case in late 2021 that increased the Company's rates by 66% or $26 million/year effective April 1, 2022. These increased costs are reflected in the instant filing. In response to these rate case filings, the Company has formed customer groups on each pipeline consisting of the largest customers on each pipeline system to protest and aggressively seek to reduce these cost impacts through either settlement or litigation. For the purposes of this BGSS Filing, the Company has assumed that in both cases settlements will be achieved in late 2022/early 2023, with lower settlement rates being put into effect by the pipelines in the first half of 2023. As a result, the Company has included an estimate of $38 million in refunds (as a credit to BGSS-RSG customers) in the instant filing related to the anticipated settlement of these two rate cases.

The Company achieves its gas procurement objectives through its management and optimization of many factors. First and foremost, the Company manages a diverse contract portfolio of natural gas transportation and storage capacity on seven different pipelines, in addition to both LNG and LPA (propane) supplies from facilities on the Company's distribution system used for peaking purposes. The Company has optimized its transportation capacity portfolio over the past ten years such that the majority of its gas supply over the course of the year is sourced from the lower priced Marcellus/Utica supply regions. Furthermore, the Company holds over 70 Bcf of storage capacity in the Marcellus/Utica region, which provides the ability to inject low priced gas during the April through October period, and then withdraw this lower priced inventory in winter months in lieu of paying higher winter prices. Also, the Company hedges approximately 50% of the RSG sales volumes during the year, further insulating its customers from potential price spikes throughout the year. In addition, the Company aggressively utilizes any excess capacity that may exist from time to time above its firm customer requirements to make Off System Sales and Capacity Releases, from which the majority of the revenues flow back as a credit to the BGSS-RSG customers. Through the active and effective management of these resources, the Company consistently provides the reliable, low cost supply desired by its firm BGSS-RSG customers.

2. Current and Forecasted Gas Service Requirements

The Company's forecasted natural gas supply requirements are included herein as Item 16. Item 16 consists of two parts. First, Schedule F illustrates the Company's Peak Day Gas Requirements and Supply over the next five winter periods. This schedule illustrates both the forecasted peak day supply by winter period as well as the pipeline transportation, storage and peaking supplies that the Company will rely upon to meet those forecasted requirements. The second part of Item 16 is the Company's 2022 update of the Natural Gas Sales Forecast. This document provides the Company's natural gas sales forecast, as well as the current forecast methodology, the econometric sales models and the forecast assumptions.

3. Projected Sources of Capacity

The Company periodically reviews its pipeline transportation, storage and peaking capacity supplies to ensure that the optimal mix of capacity assets are maintained to meet its forecasted peak day and seasonal requirements at the lowest possible cost. Several changes in the Company's pipeline capacity portfolio have been made which are discussed in the instant BGSS Filing.

As mentioned in prior BGSS Filings, the Company has taken certain steps to ensure that it continues to meet its projected peak day capacity requirements to serve its firm customers. As illustrated on Item 16, based on the Company's latest forecast, it is projected that the Company will have a slight surplus in peak day supply for the upcoming 2022/2023 winter, followed by a shortfall in peak day supply commencing in 2024/2025.

The Company is a participant in Transco's Regional Energy Access Project which provides for an expansion of the Transco system between the Marcellus supply region in northeast Pennsylvania and central and southern New Jersey. The Company has entered into a precedent agreement with Transco providing for 60,000 Dth/d of new firm transportation capacity to help meet the projected shortfall in peak day supply for the 2024/2025 winter and beyond, and to meet increased gas requirements in the Mount Laurel and Camden areas of its distribution system. Transco filed its certificate application for REA at FERC on March 26, 2021. Transco anticipates placing the REA project into service in the fourth quarter of 2024.

On December 31, 2021, the Company also entered into a precedent agreement with Texas Eastern related to their Appalachia to Market II Project providing for 25,000 Dth/d of new firm transportation capacity to help meet incremental system peak day demand and increased gas requirements in the South Plainfield and Jamesburg areas of its gas distribution system. Texas Eastern's Appalachia to Market II Project provides for an expansion of Texas Eastern's system between the Marcellus/Utica supply regions in southwest Pennsylvania and central New Jersey. It is anticipated that Texas Eastern will make their FERC filing seeking approval of the Appalachia to Market II Project during the summer of 2022. The Project's in-service date is projected to be November 1, 2025. Both the Regional Energy Access Project and the Appalachia to Market II Project will further enhance the Company's ability to access low-cost Marcellus/Utica supplies to the benefit of its customers.

Finally, the Company was a shipper in the PennEast project, which was designed to provide increased capacity from the Marcellus shale region, as well as provide a new independent source of pipeline supply, and thereby increase the reliability of the Company's portfolio of firm pipeline transportation capacity. PennEast received its FERC Certificate on January 19, 2018. On January 30, 2020, PennEast filed an Amendment to its FERC Certificate requesting a phasing of the project with Phase I providing for facility construction and transportation service within Pennsylvania and Phase II providing for facilities and service in New Jersey. Following extensive state and federal delays that hindered its ability to receive the necessary permits to allow construction to commence, on November 30, 2021 PennEast notified FERC that it was ceasing development of the project.

As agreed to in the Stipulation between the Parties in the June 2018 BGSS Filing, in addition to the description of the contract changes above, the following table represents a listing of all contracts that have been extended pursuant to their evergreen provisions during the last BGSS Filing period:

Counterparty	Rate Schedule	Contract Number	Top Gas Quantity	Daily Contract Quantity
Texas Eastern	FT-1	911682		25,018
Texas Eastern	FTS	330840		12,315
Texas Eastern	FTS - 5	330915		45,084
Texas Eastern	FTS - 5	330181		10,508
Texas Eastern	FTS - 7	331007		97,915
Texas Eastern	FTS - 8	331017		60,069
Texas Eastern	SS - 1	400260	3,737,160	62,286

Texas Eastern	SS - 1	400259	1,453,340	20,762
Texas Eastern	FT - 1	911677		40,526
Texas Eastern	CDS	911679		120,000
Texas Eastern	FT - 1	911678		26,115
Texas Eastern	FT - 1	911680		110,000
Texas Eastern	FT - 1	911684		15,000
Texas Eastern	FT - 1	911683		30,000
Texas Eastern	FT - 1	911681		40,000
Texas Eastern	FT - 1	911685		50,000
Transco	FT	1006312		72,450
Transco	FT	1044211		50,000
Transco	FT	9009846		73,500
Transco	FT	9146335		9,400
Transco	FT	9146336		9,850
Transco	FT	1002228		6,440
Transco	FT	1003688		425,930
Transco	FT	1003835		198,950
Transco	FT	1005002		13,248
Transco	FT	1033145		48,240
Transco	FT	1041156		50,000
Transco	S - 2	1000823	6,158,589	68,514
Transco	FT	9066768		43,300
Eastern (Formerly Dominion)	GSSTE	600043	14,249,916	162,995
Eastern (Formerly Dominion)	GSS (Combo)	300173	16,363,947	233,555
Gulf South	FSS	661	1,000,000	100,000

4. Affiliate Relationships/Asset Management

The Company obtains its full natural gas requirements for BGSS Service pursuant to the Requirements Contract entered into between the Company and PSEG Energy Resources and Trade (PSEG ERT) effective May 2002. Under this agreement, PSEG ERT manages its portfolio of transportation, storage and peaking supply assets to meet the Company's natural gas requirements on an hourly, daily, weekly, monthly and annual basis. The Company meets with representatives of PSEG ERT as needed to provide oversight of the procurement of supplies pursuant to the Requirements Contract. PSEG ERT provides updates to the Company regarding changes to pipeline capacity under contract, hedging activities, supply and pricing trends, as well as market developments. In addition, the Company and PSEG ERT work together to prepare the information provided in the annual BGSS Filing. Item 13 in this BGSS Filing includes a summary of the principal terms of the Requirements Contract.

As noted in Item 13, the Term of the Requirements Contract has been extended for a five-year period through March 31, 2027. The Company requested the Term extension in its June 1, 2021 Annual BGSS Filing, and the Board approved the same in its Order dated April 6, 2022.

5. Hedging Plan and Strategy

The Company has included as Item 11 in the instant BGSS Filing its PSE&G Quarterly Gas Hedging Reports, which have been filed with the NJBPU over the past year. As discussed in the testimony of David F. Caffery herein, the Company to date has hedged approximately 86 % of its planned volume for the 2022 summer period, approximately 50 % of its planned volume for the 2022-2023 winter period and approximately 35 % of its planned volume for the 2023 summer period. Hedging for the winter 2023-2024 period has just begun.

In addition to its transportation and peaking assets, PSEG ERT maintains approximately 70 Bcf of storage assets under contract with various pipeline suppliers. These storage assets are used to supplement flowing gas supplies when customer demand on the Company's distribution system increases during the winter period. The Company typically injects gas into its storages during the April through October timeframe, targeting a level of approximately 97% full by October 31. Item 12 included herein provides the list of storage services under contract as well as the monthly ending storage inventory by contract for the past winter period. This illustrates the manner in which each storage service was utilized over the 2021-2022 winter. The Company's extensive storage portfolio allows the Company to purchase gas supplies during the April through October timeframe and withdraw this gas for use during the peak winter months, thereby providing a further hedge on behalf of its customers against winter price volatility.

6. Capacity Releases/Off-System Sales

The attached schedule provides a summary of the capacity release and off-system sales by the Company for the prior eight calendar years and for the first four months of 2022. For the upcoming BGSS period that is covered by this filing, the Company has projected $ 39.2 million in credits attributed to capacity release and off-system sales. As can be seen on the attached schedule, off-system sales margins for the 4 months ending April 2022 total $ 68.5 million, vastly exceeding the annual totals for 2019 through 2021, as well as exceeding the annual totals back to 2016. The Company's 2022 off-system sales year to date benefitted from a colder than normal January and February and extreme price volatility during which the Company was able to maximize its off-system sales volumes and margins.

Despite the favorable results so far this year, the Company has continued to experience significantly decreased margins in off-system sales and capacity release transactions during the summer and shoulder months than experienced during the 2010 to 2016 period. A number of significant pipeline expansions from the Marcellus and Utica supply regions, representing over 9 Bcf/d of new capacity, were placed into service during 2017/2018, providing additional outlets for these shale gas supplies. The increased ability of these pipelines to move additional volumes to market has resulted in a large decrease in the basis differentials between the Marcellus and Utica supply region and the Transco Z6 market during most months, where the Company makes the majority of its off-system sales. The Company anticipates this extensive pipeline capacity buildout will continue to put significant downward pressure on capacity release and off-system sales margins throughout the summer and shoulder months during the upcoming BGSS period (and thus the Company does not expect that the large amount of off-system sales margin realized in the first four months of 2022 will be sustained). However, should the current volatility in prices persist into the 2022/2023 winter, the Company would expect additional opportunities to maximize the value of its BGSS Assets through off-system sales and capacity releases.

Off System Sales -- Revenues, Costs and Margins

2014 - 2022

Year	BGSS-RSG OSS Revenue (1)	BGSS-RSG OSS Cost (2)	BGSS-RSG OSS Margins (3)
2014	$327,717,529	$143,452,710	$184,264,819
2015	$197,662,767	$61,941,827	$135,720,940
2016	$145,423,895	$86,729,138	$58,694,758
2017	$156,240,095	$96,425,765	$59,814,330
2018	$194,555,168	$124,011,106	$70,544,017
2019	$79,655,383	$59,067,798	$20,587,585
2020	$95,986,987	$75,386,530	$20,600,457
2021	$162,784,140	$123,967,006	$38,817,133
2022*	$135,121,768	$72,597,406	$62,524,362

*Note: Through April 2022 Estimate

Item 18

Attachment D

Support for Balancing Charge
& Storage Inventory Carrying Charge
(Including Update for A&G Charge)

Balancing Charge - Annual Allocated Cost

Firm Capacity Allocation:	Total (Mdth/day)	Capacity Used for Balancing (Mdth/day)	Percent Allocated to Balancing Use
Base FT	887.2	0.0	0.0%
Storage	894.2	458.1	51.2%
Balancing FT	403.3	403.3	100.0%
Peaking	570.9	570.9	100.0%
	2,755.6	1,432.2	

	Total Cost	Percent Allocated to Balancing Use	Allocated Cost
Fixed Cost Allocation:			
Base FT	$165,597.7	0.0%	$0.0
Storage	$122,428.0	51.2%	$62,715.4
Balancing FT	$65,137.6	100.0%	$65,137.6
Peaking	$20,342.3	100.0%	$20,342.3
	$373,505.7		
Variable Cost Allocation:			
Base FT	$0.0	0.0%	$0.0
Storage	$12,465.8	51.2%	$6,385.7
Balancing FT	$0.0	100.0%	$0.0
Peaking	$2,199.0	100.0%	$2,199.0
	$14,664.8		
Total Annual Allocated Costs ($000)			**$ 156,780.1**

Balancing Use Billing Determinants - Oct - May (MDth)	187,248
Balancing Charge - Annual Allocated Cost ($/Dth)	$ 0.83729
Storage Inventory Carrying Charge ($/Dth) (page 2)	$ 0.04597
Revenue Requirement on Gas Production Plant Charge ($/Dth) (page 3)	$ 0.04220
Total Balancing Charge (excl. losses) ($/Dth)	$ 0.92546
Total Balancing Charge (incl. losses @ 2%) ($/Dth)	$ 0.94435
Total Balancing Charge (incl. SUT) ($/Dth)	**$ 1.00691**
Total Balancing Charge (incl. SUT) ($/Therm)	**$ 0.100691**

Storage Inventory Carrying Charge

	12 Months Oct 2022- Sept 2023 (000)
RSG Inventory Cost	$ 196,098
BGSS-F Inventory Cost	$ 58,589
BGSS-F Fixed Cost Deferred	$ 15,330
LNG + LPA	$ 2,633
Total Inventory Cost	**$ 272,650**
Total Annual Storage Carrying Cost @ 9.02%	**$ 24,593**

Recovery %	**Recovery %**
Balancing	35.00%
Commodity	65.00%

Rate per Dth	MDth	Cost	**$/Dth**
Balancing	187,248	$ 8,608	**$ 0.04597**
Commodity	205,187	$ 15,985	**$ 0.07791**

Revenue Requirement on Gas Production Plants

		12 Months Oct 22 - Sep 23
2022	October	$ 1,009,877.53
	November	$ 458,418.64
	December	$ 468,401.84
2023	January	$ 655,113.37
	February	$ 792,091.57
	March	$ 777,069.77
	April	$ 691,047.97
	May	$ 660,026.17
	June	$ 382,833.29
	July	$ 674,464.41
	August	$ 664,118.39
	September	$ 668,245.31
Total		**$ 7,901,708**
Balancing Use Billing Determinants (MDth)		**187,248**
Revenue Requirement on Gas Production Plant Charge ($/Dth)		**$ 0.04220**

Gas Supply A&G

	12 Months Oct 22 - Sep 23
Direct Labor & Overhead	$ 8,682,070
Firm Sendout - Dth (000)	205,186.8
Gas Supply A&G Rate	$ 0.04231

Attachment B

Redlined Tariff Sheets

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 54**
Superseding
B.P.U.N.J. No. 16 GAS **XXX Revised Sheet No. 54**

BGSS-RSG
BASIC GAS SUPPLY SERVICE-RSG
COMMODITY CHARGES APPLICABLE TO RATE SCHEDULE RSG
(Per Therm)

Estimated Non-Gulf Coast Cost of Gas	$ 0.066421 ~~0.060119~~
Estimated Gulf Coast Cost of Gas	0.505159 ~~0.235911~~
Adjustment to Gulf Coast Cost of Gas	0.000000 ~~0.083056~~
Prior period (over) or under recovery	0.027530 ~~(0.002130)~~
Adjusted Cost of Gas	0.599110 ~~0.376956~~
Commodity Charge after application of losses: (Loss Factor = 2.0%)........................	$ 0.611337 ~~0.384649~~
Commodity Charge including New Jersey Sales and Use Tax (SUT)	$ 0.651838 ~~0.410132~~

The above Commodity Charge will be established on a level annualized basis immediately prior to the winter season of each year for the succeeding twelve-month period. The estimated average Non-Gulf and Gulf Coast Cost of Gas will be adjusted for any under- or over-recovery together with applicable interest thereon which may have occurred during the operation of the Company's previously approved Commodity Charge filing. Further, the Company will be permitted a limited self-implementing increase to the Commodity Charge on December 1 and February 1 of each year. These limited self-implementing increases, if applied, are to be in accordance with a Board of Public Utilities approved methodology. Commodity Charge decreases would be permitted at any time if applicable.

The difference between actual costs and Public Service's recovery of these costs shall be determined monthly. If actual costs exceed the recovery of these costs, an underrecovery or a negative balance will result. If the recovery of these costs exceeds actual costs, an overrecovery or a positive balance will result. Interest shall be applied monthly to the average monthly cumulative deferred balance, positive or negative, from the beginning to the end of the annual period. Monthly interest on negative deferred balances (underrecoveries) shall be netted against monthly interest on positive deferred balances (overrecoveries) for the annual period. A cumulative net positive interest balance at the end of the annual period is owed to customers and shall be returned to customers in the next annual period. A cumulative net negative interest balance shall be zeroed out at the end of the annual period. The sum of the calculated monthly interests shall be added to the overrecovery balance or subtracted from the underrecovery balance at the end of the annual period. The positive interest balance shall be rolled into the beginning under- or over-recovery balance of the subsequent annual period.

Pursuant to the Board's January 6, 2003 Order approving the BGSS price structure under Docket No. GX01050304 and the BGSS Pricing Proposal appended as Attachment A to and approved in that Order, Public Service Electric and Gas Company may issue a bill credit for its BGSS-RSG customers as detailed below.

Effective	BGSS-RSG Credit (per therm)	BGSS-RSG Credit including SUT (per therm)
February 1, 2020 through March 31, 2020	($0.070340)	($0.075000)
April 1, 2020	$0.000000	$0.000000

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 65**
Superseding
B.P.U.N.J. No. 16 GAS **XXX Revised Sheet No. 65**

RATE SCHEDULE RSG
RESIDENTIAL SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Firm delivery service for residential purposes. Customers may either purchase gas supply from a Third Party Supplier (TPS) or from Public Service's Basic Gas Supply Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$8.08 in each month [$8.62 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges:

Charge	Charge Including SUT	
$0.418429	$0.446150	per therm

Balancing Charge:

Charge	Charge Including SUT	
$0.094435 ~~$0.087669~~	$0.100691 ~~$0.093477~~	per Balancing Use Therm

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 60 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Societal Benefits include: 1) Social Programs, 2) Demand Side Management Programs, 3) Manufactured Gas Plant Remediation, 4) Consumer Education, and 5) Universal Service Fund. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Margin Adjustment Charge:

This charge shall credit net revenue associated with Rate Schedule Non-Firm Transportation Gas Service (TSG-NF) to customers on Rate Schedules RSG, GSG, LVG, SLG and TSG-F. Refer to the Margin Adjustment Charge sheet of this Tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs as approved by the Board. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Weather Normalization Charge:

This charge is designed to adjust base rate recoveries to offset the effects of abnormal weather on sales. The weather normalization charge applied in each winter period shall be based on the differences between actual and normal weather during the preceding winter period. Refer to the Weather Normalization Charge sheet of this Tariff for the current charge.

The Weather Normalization Charge will be combined with the Balancing Charge for billing.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 72**
Superseding
B.P.U.N.J. No. 16 GAS **XXX Revised Sheet No. 72**

RATE SCHEDULE GSG
GENERAL SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Firm delivery service for general purposes where: 1) customer does not qualify for RSG and 2) customer's usage does not exceed 3,000 therms in any month. Customers may either purchase gas supply from a Third Party Supplier (TPS) or from Public Service's Basic Gas Supply Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$17.99 in each month [$19.18 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges:

Pre-July 14, 1997 *		All Others		
Charge	Charge Including SUT	Charge	Charge Including SUT	
$0.318585	$0.339691	$0.318585	$0.339691	per therm

* Applicable to customers who have taken TPS supplied commodity service continuously since July 14, 1997.

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 60 for details of these charges.

Balancing Charge:

Charge	Charge Including SUT	
$0.094435 ~~$0.087669~~	$0.100691 ~~$0.093477~~	per Balancing Use Therm

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Societal Benefits include: 1) Social Programs, 2) Demand Side Management Programs, 3) Manufactured Gas Plant Remediation, 4) Consumer Education, and 5) Universal Service Fund. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Margin Adjustment Charge:

This charge shall credit net revenue associated with Rate Schedule Non-Firm Transportation Gas Service (TSG-NF) to customers on Rate Schedules RSG, GSG, LVG, SLG and TSG-F. Refer to the Margin Adjustment Charge sheet of this Tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs as approved by the Board. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY — **XXX Revised Sheet No. 79**
Superseding
B.P.U.N.J. No. 16 GAS — **XXX Revised Sheet No. 79**

RATE SCHEDULE LVG
LARGE VOLUME SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Firm delivery service for general purposes. Customers may either purchase gas supply from a Third Party Supplier (TPS) or from Public Service's Basic Gas Supply Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$159.75 in each month [$170.33 including New Jersey Sales and Use Tax (SUT)].

Demand Charge (Applicable in the months of November through March):

Charge	Charge Including SUT	
$4.2464	$4.5277	per Demand Therm

Distribution Charges:

Per therm for the first 1,000 therms used in each month		Per therm in excess of 1,000 therms used in each month	
Charges	Charges Including SUT	Charges	Charges Including SUT
$0.037727	$0.040226	$0.047127	$0.050249

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 60 for details of these charges.

Balancing Charge:

Charge	Charge Including SUT	
$0.094435	$0.100691	per Balancing Use Therm
~~$0.087669~~	~~$0.093477~~	

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Societal Benefits include: 1) Social Programs, 2) Demand Side Management Programs, 3) Manufactured Gas Plant Remediation, 4) Consumer Education, and 5) Universal Service Fund. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 112A**
Superseding
B.P.U.N.J. No. 16 GAS **XXX Revised Sheet No. 112A**

RATE SCHEDULE CSG
CONTRACT SERVICE
(Continued)

ECONOMICALLY VIABLE BYPASS
DELIVERY CHARGES:

Service Charge:
$855.59 in each month [$912.27 including New Jersey Sales and Use Tax (SUT)]

Distribution Charge:
Net Alternative Delivery Cost multiplied by the applicable Net Alternative Delivery Cost Factor divided by the Contracted Monthly Therms rounded to the nearest $0.000000 per therm.

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 61 for details of these charges.

Maintenance Charges:
Equals the Alternative Delivery Cost multiplied by the applicable Alternative Delivery Cost Factor divided by the Contract Monthly Therms rounded to the nearest $0.000000 per therm.

Plus any customer site-specific ongoing or continuing cost not directly related to the operation, maintenance or inspection of the customer's planned by-pass pipeline. This shall include, but not be limited to, periodic payments for rights-of-way, easements, pipeline cost differentials, permits or other such costs. These charges shall be expressed on a monthly levelized basis over the term of service.

Public Service will also take into consideration any operational or deliverability differences that would be reasonably expected between the pipeline and/or service over Public Service's distribution system in determining Delivery Charges. In no event shall the Delivery Charges be lower than an amount sufficient to generate a return on the capital investments made by Public Service and recovery of marginal and embedded costs, including depreciation, to provide service to the customer over the term of each CSG agreement.

Balancing Charge:
Applicable only if the customer is provided Public Service's Basic Gas Supply Service – Firm (BGSS-F) default service.

Charge	Charge Including SUT	
$0.094435 ~~$0.087669~~	$0.100691 ~~$0.093477~~	per Balancing Use Therm

Societal Benefits Charge:
This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by government. In appropriate circumstances, the Board of Public Utilities may approve a discount from the Societal Benefits Charge. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge and applicable exemptions.

Green Programs Recovery Charge:
This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs as approved by the Board. In appropriate circumstances, the Board of Public Utilities may approve a discount from the Green Programs Recovery Charge. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge and applicable exceptions.

Attachment B

Proposed Tariff Sheets

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 54**
Superseding
B.P.U.N.J. No. 16 GAS **XXX Revised Sheet No. 54**

BGSS-RSG
BASIC GAS SUPPLY SERVICE-RSG
COMMODITY CHARGES APPLICABLE TO RATE SCHEDULE RSG
(Per Therm)

Estimated Non-Gulf Coast Cost of Gas	$ 0.066421
Estimated Gulf Coast Cost of Gas	0.505159
Adjustment to Gulf Coast Cost of Gas	0.000000
Prior period (over) or under recovery	0.027530
Adjusted Cost of Gas	0.599110
Commodity Charge after application of losses: (Loss Factor = 2.0%)..........	$ 0.611337
Commodity Charge including New Jersey Sales and Use Tax (SUT)	$ 0.651838

The above Commodity Charge will be established on a level annualized basis immediately prior to the winter season of each year for the succeeding twelve-month period. The estimated average Non-Gulf and Gulf Coast Cost of Gas will be adjusted for any under- or over-recovery together with applicable interest thereon which may have occurred during the operation of the Company's previously approved Commodity Charge filing. Further, the Company will be permitted a limited self-implementing increase to the Commodity Charge on December 1 and February 1 of each year. These limited self-implementing increases, if applied, are to be in accordance with a Board of Public Utilities approved methodology. Commodity Charge decreases would be permitted at any time if applicable.

The difference between actual costs and Public Service's recovery of these costs shall be determined monthly. If actual costs exceed the recovery of these costs, an underrecovery or a negative balance will result. If the recovery of these costs exceeds actual costs, an overrecovery or a positive balance will result. Interest shall be applied monthly to the average monthly cumulative deferred balance, positive or negative, from the beginning to the end of the annual period. Monthly interest on negative deferred balances (underrecoveries) shall be netted against monthly interest on positive deferred balances (overrecoveries) for the annual period. A cumulative net positive interest balance at the end of the annual period is owed to customers and shall be returned to customers in the next annual period. A cumulative net negative interest balance shall be zeroed out at the end of the annual period. The sum of the calculated monthly interests shall be added to the overrecovery balance or subtracted from the underrecovery balance at the end of the annual period. The positive interest balance shall be rolled into the beginning under- or over-recovery balance of the subsequent annual period.

Pursuant to the Board's January 6, 2003 Order approving the BGSS price structure under Docket No. GX01050304 and the BGSS Pricing Proposal appended as Attachment A to and approved in that Order, Public Service Electric and Gas Company may issue a bill credit for its BGSS-RSG customers as detailed below.

Effective	BGSS-RSG Credit (per therm)	BGSS-RSG Credit including SUT (per therm)
February 1, 2020 through March 31, 2020	($0.070340)	($0.075000)
April 1, 2020	$0.000000	$0.000000

RATE SCHEDULE RSG
RESIDENTIAL SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Firm delivery service for residential purposes. Customers may either purchase gas supply from a Third Party Supplier (TPS) or from Public Service's Basic Gas Supply Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$8.08 in each month [$8.62 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges:

Charge	Charge Including SUT	
$0.418429	$0.446150	per therm

Balancing Charge:

Charge	Charge Including SUT	
$0.094435	$0.100691	per Balancing Use Therm

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 60 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Societal Benefits include: 1) Social Programs, 2) Demand Side Management Programs, 3) Manufactured Gas Plant Remediation, 4) Consumer Education, and 5) Universal Service Fund. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Margin Adjustment Charge:

This charge shall credit net revenue associated with Rate Schedule Non-Firm Transportation Gas Service (TSG-NF) to customers on Rate Schedules RSG, GSG, LVG, SLG and TSG-F. Refer to the Margin Adjustment Charge sheet of this Tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs as approved by the Board. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Weather Normalization Charge:

This charge is designed to adjust base rate recoveries to offset the effects of abnormal weather on sales. The weather normalization charge applied in each winter period shall be based on the differences between actual and normal weather during the preceding winter period. Refer to the Weather Normalization Charge sheet of this Tariff for the current charge.

The Weather Normalization Charge will be combined with the Balancing Charge for billing.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 72**
Superseding
B.P.U.N.J. No. 16 GAS **XXX Revised Sheet No. 72**

RATE SCHEDULE GSG
GENERAL SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Firm delivery service for general purposes where: 1) customer does not qualify for RSG and 2) customer's usage does not exceed 3,000 therms in any month. Customers may either purchase gas supply from a Third Party Supplier (TPS) or from Public Service's Basic Gas Supply Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$17.99 in each month [$19.18 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges:

Pre-July 14, 1997 *		All Others		
Charge	Charge Including SUT	Charge	Charge Including SUT	
$0.318585	$0.339691	$0.318585	$0.339691	per therm

* Applicable to customers who have taken TPS supplied commodity service continuously since July 14, 1997.

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 60 for details of these charges.

Balancing Charge:

Charge	Charge Including SUT	
$0.094435	$0.100691	per Balancing Use Therm

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Societal Benefits include: 1) Social Programs, 2) Demand Side Management Programs, 3) Manufactured Gas Plant Remediation, 4) Consumer Education, and 5) Universal Service Fund. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Margin Adjustment Charge:

This charge shall credit net revenue associated with Rate Schedule Non-Firm Transportation Gas Service (TSG-NF) to customers on Rate Schedules RSG, GSG, LVG, SLG and TSG-F. Refer to the Margin Adjustment Charge sheet of this Tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs as approved by the Board. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 79**
Superseding
B.P.U.N.J. No. 16 GAS **XXX Revised Sheet No. 79**

RATE SCHEDULE LVG
LARGE VOLUME SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Firm delivery service for general purposes. Customers may either purchase gas supply from a Third Party Supplier (TPS) or from Public Service's Basic Gas Supply Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$159.75 in each month [$170.33 including New Jersey Sales and Use Tax (SUT)].

Demand Charge (Applicable in the months of November through March):

Charge	Charge Including SUT	
$4.2464	$4.5277	per Demand Therm

Distribution Charges:

Per therm for the first 1,000 therms used in each month		Per therm in excess of 1,000 therms used in each month	
Charges	Charges Including SUT	Charges	Charges Including SUT
$0.037727	$0.040226	$0.047127	$0.050249

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 60 for details of these charges.

Balancing Charge:

Charge	Charge Including SUT	
$0.094435	$0.100691	per Balancing Use Therm

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Societal Benefits include: 1) Social Programs, 2) Demand Side Management Programs, 3) Manufactured Gas Plant Remediation, 4) Consumer Education, and 5) Universal Service Fund. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY | **XXX Revised Sheet No. 112A**
Superseding
B.P.U.N.J. No. 16 GAS | **XXX Revised Sheet No. 112A**

RATE SCHEDULE CSG
CONTRACT SERVICE
(Continued)

ECONOMICALLY VIABLE BYPASS
DELIVERY CHARGES:

Service Charge:
$855.59 in each month [$912.27 including New Jersey Sales and Use Tax (SUT)]

Distribution Charge:
Net Alternative Delivery Cost multiplied by the applicable Net Alternative Delivery Cost Factor divided by the Contracted Monthly Therms rounded to the nearest $0.000000 per therm.

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 61 for details of these charges.

Maintenance Charges:
Equals the Alternative Delivery Cost multiplied by the applicable Alternative Delivery Cost Factor divided by the Contract Monthly Therms rounded to the nearest $0.000000 per therm.

Plus any customer site-specific ongoing or continuing cost not directly related to the operation, maintenance or inspection of the customer's planned by-pass pipeline. This shall include, but not be limited to, periodic payments for rights-of-way, easements, pipeline cost differentials, permits or other such costs. These charges shall be expressed on a monthly levelized basis over the term of service.

Public Service will also take into consideration any operational or deliverability differences that would be reasonably expected between the pipeline and/or service over Public Service's distribution system in determining Delivery Charges. In no event shall the Delivery Charges be lower than an amount sufficient to generate a return on the capital investments made by Public Service and recovery of marginal and embedded costs, including depreciation, to provide service to the customer over the term of each CSG agreement.

Balancing Charge:
Applicable only if the customer is provided Public Service's Basic Gas Supply Service – Firm (BGSS-F) default service.

Charge	Charge Including SUT	
$0.094435	$0.100691	per Balancing Use Therm

Societal Benefits Charge:
This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by government. In appropriate circumstances, the Board of Public Utilities may approve a discount from the Societal Benefits Charge. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge and applicable exemptions.

Green Programs Recovery Charge:
This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs as approved by the Board. In appropriate circumstances, the Board of Public Utilities may approve a discount from the Green Programs Recovery Charge. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge and applicable exceptions.