Matthew M. Weissman
General State Regulatory Counsel

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

VIA BPU PORTAL & ELECTRONIC MAIL

June 1, 2023

In the Matter of Public Service Electric and Gas Company's 2023/2024
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_____________

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

Dear Secretary Golden:

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 decrease the current BGSS default commodity charge applicable to residential customers for service rendered on and after October 1, 2023. The Company is also requesting a decrease in its Balancing Charge rate. The average monthly impact of the proposed RSG Commodity Rate and Balancing Charge change is a decrease of approximately 6.70% for a typical residential gas heating customer using 172 therms in a winter month and 86.7 average monthly therms (1,040 annually).

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 M. Weissman

C Attached Service List (electronic)

BPU
Sherri Golden
Board of Public Utilities
44 South Clinton Avenue
Trenton NJ 08625-0350
Board.Secretary@bpu.nj.gov

BPU
Malike Cummings
Board of Public Utilities
44 S. Clinton Avenue
Trenton NJ 08625
malike.cummings@bpu.nj.gov

BPU
Michael Kammer
Board of Public Utilities
44 South Clinton Avenue
Trenton NJ 08625-0350
mike.kammer@bpu.nj.gov

BPU
Stacy Peterson
Board of Public Utilities
44 South Clinton Avenue
Trenton NJ 08625-0350
stacy.peterson@bpu.nj.gov

BPU
Heather Weisband
Board of Public Utilities
44 South Clinton Avenue
Trenton NJ 08625-0350
Heather.Weisband@bpu.nj.gov

DAG
Daren Eppley
NJ Division of Law & Public Safety
25 Market Street, P.O. Box 112
Trenton NJ 08625
daren.eppley@law.njoag.gov

DAG
Matko Ilic
NJ Dept. of Law and Public Safety
Richard J. Hughes Justice Complex
Public Utilities Section
25 Market Street, P.O. Box 112
Trenton NJ 08625
matko.ilic@law.njoag.gov

DAG
Pamela Owen
NJ Dept of Law & Public Safety
Division of Law, Public Utilities Section
R.J. Hughes Justice Complex
25 Market Street, P.O. Box 112
Trenton NJ 08625
Pamela.Owen@law.njoag.gov

PSE&G
Stephen Irons
80 Park Plaza, T18
Newark NJ 07101
stephen.irons@pseg.com

PSE&G
Deborah Marks
Public Service Electric & Gas Co.
80 Park Plaza, T18
Newark NJ 07102
deborah.marks@pseg.com

PSE&G
Terrence J. Moran
Public Service Electric & Gas Co.
80 Park Plaza, T18
Newark NJ 07102
terrence.moran@pseg.com

PSE&G
Katherine E. Smith
PSEG Services Corporation
80 Park Plaza, T5
Newark NJ 07102
katherine.smith@pseg.com

PSE&G
Matthew M. Weissman Esq.
PSEG Services Corporation
80 Park Plaza, T5
Newark NJ 07102
matthew.weissman@pseg.com

Rate Counsel
Maura Caroselli Esq.
Division of Rate Counsel
140 East Front Street
Trenton NJ 08625
mcaroselli@rpa.nj.gov

Rate Counsel
Brian O. Lipman
Division of Rate Counsel
140 East Front Street, 4th Flr.
Trenton NJ 08625
blipman@rpa.nj.gov

Rate Counsel
Megan Lupo
New Jersey Division of Rate Counsel
140 East Front Street, 4th Floor
Trenton New Jersey 08625
mlupo@rpa.nj.gov

Rate Counsel
Carlena Morrison
New Jersey Division of Rate Counsel
140 East Front Street, 4th Floor
Trenton New Jersey 08625
cmorrison@rpa.nj.gov

Rate Counsel
Sarah Steindel
Division of Rate Counsel
140 East Front Street, 4th Flr.
Trenton NJ 08625
ssteinde@rpa.nj.gov

Rate Counsel Consultant
Dante Mugrace
PCMG and Associates
90 Moonlight Court
Toms River NJ 08753
dmugrace@pcmgregcon.com

Rate Counsel Consultant
Karl Pavlovic
PCMG and Associates, LLC
22 Brooks Avenue
Gaithersburg MD 20877
kpavlovic@pcgmgregcon.com

1. Motion, Supporting Testimony & Tariff Modifications

Motion – dated June 1, 2023

Testimony of David F. Caffery – Attachment A

Tariff Sheets – Attachment B

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY'S 2023/2024 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.

<u>GENERIC PROCEEDING ON BGSS PRICE STRUCTURE</u>

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 or before 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 was 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.

2022/2023 ANNUAL BGSS COMMODITY CHARGE FILING

4) On June 1, 2022, the Company made its 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. The filing was also made in accordance with the above-referenced Minimum Filing Requirements.

5) In the 2022/2023 BGSS filing the Company requested to increase the then current BGSS Commodity Charge rate of $0.410132 per therm (including losses and SUT) to $0.651838 per

therm (including losses and SUT) through September 30, 2023. 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 $0.093477 per balancing therm (including losses and SUT) to the current charge of $0.100691 per balancing use therm (including losses and SUT). The increase in the balancing charge was supported by Mr. Caffery.

7) The 2022/2023 filing by the Company estimated a BGSS revenue increase of $339M (excluding losses and SUT) would be required for the period of October 1, 2022 through September 30, 2023.

8) Residential annual bills comparing the then current and proposed Balancing Charge, pursuant to the 2022/2023 filing were included in the form of public notice attached as Attachment C to that motion.

9) Notices setting forth the Company's June 1, 2022 request to increase 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.

10) Public hearings were scheduled and conducted telephonically on August 31, 2022, at 4:30 p.m. and 5:30 p.m. No member of the public appeared or spoke at the 4:30 public hearing.

Four (4) members of the public attended the 5:30 p.m. public hearing and spoke in opposition to the proposed rate increase. The Board did not receive any written comments.

11) PSE&G, Board Staff, and Rate Counsel agreed, on a provisional basis, to increase the BGSS-RSG Commodity Charge and increase the Balancing Charge as of October 1, 2022, 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 September 7, 2022. As a result, 1) the Company's BGSS Commodity rate, tariff rate BGSS-RSG, was provisionally increased to $0.651838 per therm (including losses and SUT) and 2) the BGSS Balancing Charge was provisionally increased to $0.100691 per balancing use therm (including losses and SUT) for service rendered on and after October 1, 2022.[1]

12) On September 21, 2022, the Board transmitted this matter to the Office of Administrative Law as a contested case, where it was subsequently assigned to the Honorable Irene Jones, Administrative Law Judge ("ALJ"). ALJ Jones held telephonic prehearing conferences on October 26, 2022 and December 15, 2022.

13) By Order dated November 9, 2022, the Board approved a 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.[2] Pursuant to that approval, the BGSS-RSG Commodity Charge was decreased

[1] In re the Petition 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, BPU Docket No. GR22060363, Order dated September 7, 2022.

[2] In re 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") (June 2022 GSMP II Rate Filing), BPU Docket No. GR22060409, Order dated November 9, 2022.

from \$0.651838 per therm (including losses and SUT) to \$0.651764 per therm (including losses and SUT) effective December 1, 2022.

14) On January 24, 2023, the Company filed a notice ("January 2023 Notice") of a BGSS-RSG rate reduction of 15 cents per therm effective February 1, 2023. This rate reduction decreased the BGSS-RSG Commodity Charge from the rate of \$0.651764 per therm to \$0.501764 per therm (including losses and SUT). As a result of the January 2023 Notice, a typical residential gas heating customer using 172 therms per month during the winter months and 1,040 therms on an annual basis would see a decrease of \$156.00 or 11.49% on an annual basis.

15) On February 22, 2023, the Company filed a notice ("February 2023 Notice") of a BGSS-RSG rate reduction of three (3) cents per therm effective March 1, 2023. This rate reduction decreased the BGSS-RSG Commodity Charge from the rate of \$0.501764 per therm to \$0.471764 per therm (including losses and SUT). As a result of the February 2023 Notice, a typical residential gas heating customer using 172 therms per month during the winter months and 1,040 therms on an annual basis would see a decrease of \$31.20 or 2.60% on an annual basis.

16) PSE&G, Board Staff, and Rate Counsel subsequently completed their review of the Company's 2022/2023 BGSS filing, and agreed that: (a) the Company's BGSS Commodity Service, tariff rate for BGSS-RSG of \$0.651838 per therm (including losses and SUT) in effect from October 1, 2022 through November 30, 2022 would be deemed final for that period; (b) the Company's BGSS Commodity Service, tariff rate for BGSS-RSG of \$0.651764 per therm (including losses and SUT) in effect from December 1, 2022 through January 31, 2023 would be deemed final for that period; (c) the Company's BGSS Commodity Service, tariff rate for BGSS-RSG of

$0.501764 per therm (including losses and SUT) in effect from February 1, 2023 through February 28, 2023 would be deemed final for that period; (d) the Company's BGSS Commodity Service, tariff rate for BGSS-RSG of $0.471764 per therm (including losses and SUT) in effect beginning March 1, 2023 would be deemed final; and (e) the Balancing Charge of $0.100691 per balancing use therm would remain in effect and also be deemed final. The Board approved this stipulation for final rates on April 12, 2023.

17) Subsequent to the April Order, on April 27, 2023 the Company made a compliance filing in response to the Board's Order *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. ER22110669 and GR22110670. In that matter, the BGSS-RSG Commodity Charge was decreased from $0.471764 per therm (including losses and SUT) to $0.471752 per therm (including losses and SUT) effective May 1, 2023.

18) Also, on May 25, 2023 the Company made a compliance filing in response to the Board's Order *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 2022 GSMP II Rate Filing)* in BPU Docket No. GR22120749. In that matter, the BGSS-RSG Commodity Charge was decreased from $0.471752 per therm (including losses and SUT) to $0.471718 per therm (including losses and SUT) effective June 1, 2023.

<u>2023/2024 ANNUAL BGSS COMMODITY CHARGE FILING</u>

19) The Company is making this 2023/2024 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.

20) In this Motion the Company is requesting to decrease the current Board approved BGSS rate of $0.471718 per therm (including losses and SUT) to $0.397497 per therm (including losses and SUT) through September 30, 2024. 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 decrease the current BGSS-RSG rate.

21) The Company is also requesting a decrease 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 $0.100691 per balancing use therm (including losses and SUT) to $0.097914 per balancing use therm (including losses and SUT). The decrease in the balancing charge is supported by Mr. Caffery (Attachment A).

22) Natural gas prices were extremely volatile during the most recent BGSS period, having increased dramatically from the levels experienced in early 2022, trading at highs not seen since 2008, followed by a dramatic decline through the 2022/2023 winter. NYMEX prompt month daily prices have traded between approximately $3.75/Dth in the middle of January 2022, to as high as $9.65 in August 2022, followed by a dramatic decline to about $2.00 in March 2023. Current prices for June trading are at approximately $2.50/Dth. The forward (May 10th) NYMEX strip used by the Company in this filing (see Item 8) shows that average prices are 54% lower than last year's NYMEX strip. Based upon the forward strip,

prices are expected to increase above current levels by $1.00 to $1.35/Dth through the rest of 2023, as well as an additional $0.30/Dth in January and February of 2024, followed by a modest decrease from $3.70/Dth to about $3.30/Dth during April 2024 through September 2024, the end of this BGSS period.

23) The natural gas market has undergone significant changes since last year's BGSS Filing. U.S. gas production has leveled off at a peak of about 101 Bcf/d in response to increased demand over the past year and price levels up to $9/Dth, both factors providing producers with a strong incentive to maximize production. Prices responded strongly following Russia's invasion of Ukraine and the potential shortfall of gas supply to Europe to meet the 2022/2023 winter demand following the cutback of supplies from Russia to the continent. Feedgas volumes for the U.S.'s seven LNG export facilities have recently achieved a record of 14 Bcf/d, representing 14% of U.S. dry gas production during the same timeframe, due in part to the increase in European imports of U.S. LNG to make up for the shortfall of Russian gas supplies. In response to Russia's cutback in supply to Europe, many European countries filled storages to maximum levels and increased their capability to receive LNG to displace the Russian cutbacks. Those measures, coupled with the warmest winter on record both in the U.S. and Europe, resulted in an oversupply of gas in both markets causing prices to decline dramatically. Despite this decline in prices, however, U.S. gas production remains above 101 Bcf/d, continuing to cause a general moderation of market pricing. Additionally, the warm winter here in the US has resulted in natural gas storage levels that are currently 18 % above the 5-year average and 340 Bcf, or 30 %, above this time last year, decreasing

summer demand by approximately 1.6 Bcf/d as storages are refilled in preparation for the 2023/2024 winter season.

24) The Company estimates that a decrease in BGSS revenue of approximately $101 million (excluding losses and SUT) is required for the period of October 1, 2023 through September 30, 2024. As stated in the testimony of Mr. Caffery and shown in Item 7, the Company is requesting a decrease in the current Board approved rate of $0.471718 per therm (including losses and SUT) to $0.397497 per therm (including losses and SUT) to eliminate the projected over-recovery.

25) Residential average monthly winter 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 in a winter month and 86.7 average monthly therms (1,040 annually) is a decrease in the winter monthly bill of approximately 6.94%. 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, 2023 and February 1, 2024. The impact of such potential self-implementing increases on an average residential bill (1,200 therms annually) would be an increase of approximately $10.52 per winter month on December 1, 2023 and an additional approximate increase of $10.52 per winter month on February 1, 2024.

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

27) 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[3] 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, 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.

[3] 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.

CONCLUSION

WHEREFORE, Public Service hereby requests that the Board issue a written Order by October 1, 2023 approving:

(1) the Company's proposal to change its current Board approved BGSS-RSG Commodity Charge to $0.397497 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, 2023 through September 30, 2024 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 $0.097914 per balancing use therm (including losses and SUT) effective with the billing of month of October 2023;

(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, 2023
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

Sworn to and subscribed to
before me this 1st day of
June, 2023

DEBORAH S. MARKS
Notary Public
State of New Jersey
My Commission Expires June 3, 2028
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 decrease the current Basic Gas Supply Service (BGSS) default Commodity Charge applicable to residential customers. The requested decrease for the BGSS-RSG Commodity rate is from the current charge of $0.471718 per therm (including losses and New Jersey Sales and Use Tax, SUT) to a charge of $0.397497 per therm (including losses and SUT). This charge is requested to remain in effect from October 1, 2023 through September 30, 2024 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 a decrease in its Balancing Charge, which recovers the cost of providing storage, peaking services, and a share of its Storage Inventory Carrying Charge. The decreased charge reflects a projected decrease in the costs of interstate pipeline transportation services that make up the Company's gas supply portfolio. In addition, peaking costs are expected to decrease, and the Carrying Charge component of the Balancing Charge is projected to decrease due to the decrease in the cost of the Company's storage inventory due to the decrease in gas prices. As a result, the Company requests a decrease in the Balancing Charge from $0.100691 per balancing use therm (including losses and SUT) to $0.097914 per balancing use therm (including losses and SUT). The average monthly impact of the proposed RSG Commodity

Rate and Balancing Charge change is a decrease of approximately 6.70% for a typical residential gas heating customer using 172 therms in a winter month and 86.7 average monthly therms (1,040 annually).

The RSG customer class is expected to be over-recovered by $72.9M by September 30, 2023 (see Item 7). This period began in October of 2022 with an under-recovery of $8.3M (including interest rollover). As directed by BPU Staff, the Company utilized May 10, 2023 NYMEX forward prices for the computations included in this filing, resulting in a projected over-recovery at the end of September 2024 of $101M (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 $0.397497 per therm (including losses and SUT), would be required to reduce the projected over-collection of $101M (excluding losses and SUT) to zero by September 30, 2024, 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 $3.1M of interest has been included.

Natural gas prices were extremely volatile during the most recent BGSS period, having increased dramatically from the levels experienced in early 2022, trading at highs not seen since 2008, followed by a dramatic decline through the 2022/2023 winter. NYMEX prompt month daily prices have traded between approximately $3.75/Dth in the middle of January 2022, to as high as $9.65 in August 2022, followed by a dramatic decline to about $2.00 in March 2023. Current prices for June trading are at approximately $2.50/Dth. The forward (May 10th) NYMEX strip used by the Company in this filing (see Item 8) shows that average prices are 54% lower than last year's NYMEX strip. Based upon the forward strip, prices are expected to increase above current levels by $1.00 to $1.35/Dth through the rest of 2023, as well as an additional $0.30/Dth in January and February of 2024, followed by a modest decrease from $3.70/Dth to about $3.30/Dth during April 2024 through September 2024, the end of this BGSS period.

The natural gas market has undergone significant changes since last year's BGSS Filing. U.S. gas production has leveled off at a peak of about 101 Bcf/d in response to increased demand over the past year and price levels up to $9/Dth, both factors providing producers with a strong incentive to maximize production. Prices responded strongly following Russia's invasion of Ukraine and the potential shortfall of gas supply to Europe to meet the 2022/2023 winter demand following the cutback of supplies from Russia to the continent. Feedgas volumes for the U.S.'s seven LNG export facilities have recently achieved a record of 14 Bcf/d, representing 14% of US dry gas production during the same timeframe, due in part to the increase in European imports of US LNG to make up for the shortfall of Russian gas supplies. In response to Russia's cutback in supply to Europe, many European countries filled storages to maximum levels and increased their capability to receive LNG to displace the Russian cutbacks. Those measures, coupled with the warmest winter on record both in the US and Europe, resulted in an oversupply of gas in both markets causing prices to decline dramatically. Despite this decline in prices, however, US gas production remains above 101 Bcf/d, continuing to cause a general moderation of market pricing. Additionally, the warm winter here in the US has resulted in natural gas storage levels that are currently 18 % above the 5-year average and 340 Bcf, or 30 %, above this time last year, decreasing summer demand by approximately 1.6 Bcf/d as storages are refilled in preparation for the 2023/2024 winter season.

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, 2023 and February 1, 2024, respectively, with the impact of those possible increases.

4. <u>Actual and Forecasted Refund Amounts</u>

The first schedule of Item 4 shows actual supplier refunds, totaling approximately $28.2M, that were credited to BGSS-RSG recovery costs from May 2022 through April 2023. The Company does not currently expect to receive any supplier refunds in excess of $1M during the upcoming BGSS period.

5. <u>Cost of Gas Sendout by Component</u>

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. <u>BGSS Contribution and Credit Offsets</u>

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. The BPU approved the elimination of the BGSS Asset

Charge 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 2022 to September 2023 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 2024 based on the May 10, 2023 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 2023 and the projected period through September 2024 along with a comparison of these prices with the prices included in the current BGSS rate (from last year's BGSS filing) which indicates a decrease of approximately 54%. These estimates reflect the future NYMEX prices on May 10, 2023, 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. <u>Historic Service Interruptions</u>

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 76% of its planned volume for the 2023 summer period, approximately 57% of its planned volume for the 2023-2024 winter period and approximately 41% of its planned volume for the 2024 summer period. Hedging for the winter 2024-2025 period has just begun in May 2023. 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 a decrease 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 \$0.100691 per balancing therm (including losses and SUT) to a Balancing Charge of \$0.097914 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 \$0.082946 per balancing therm (excluding losses and SUT), which is a decrease from the previous charge of \$0.083729 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 \$0.003154 per balancing therm (excluding losses & SUT) for the balancing portion and \$0.005371 per therm (excluding losses & SUT) for the commodity portion (included in Item 2) using the applicable billing determinants for each. The current charges are \$0.004597 per balancing therm (excluding losses & SUT) for the balancing portion and \$.007791 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 \$0.003893 per balancing use therm (excluding losses & SUT), which is a decrease from the previous charge of \$0.00422 per balancing use therm (excluding losses and SUT).

Also included in Attachment D is a decrease in the A&G charge. This change is reflected in Item 2. The current rate is \$0.004231 per therm (excluding losses & SUT) and the updated rate is \$0.003757 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.

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, 2023 or earlier, should the Board deem it appropriate, approving: (1) the Company's proposal to decrease the current BGSS Commodity Charge of $0.471718 per therm (including losses and SUT) to $0.397497 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) a decrease in the Balancing Charge to $0.097914 per balancing use therm (including losses and SUT).

PROFESSIONAL QUALIFICATIONS
OF
DAVID F. CAFFERY
<u>VICE PRESIDENT – GAS SUPPLY</u>

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 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, 2023

COMPUTATION OF
BGSS COMMODITY CHARGE FOR RSG
OCTOBER 2023 - SEPTEMBER 2024

($-000)

	$000	$/DTh
FIXED COSTS:		
FT DEMAND COST	$ 179,011	$1.1643
STORAGE DEMAND/CAPACITY COSTS	95,608	$0.6218
STORAGE INJ & W/D COSTS	5,613	$0.0365
PEAKING COSTS	15,881	$0.1033
	296,113	**$1.9260**
CONTRIBUTIONS	(31,470)	($0.2047)
PIPELINE REFUNDS	0	$0.0000
OFF-SYSTEM SALES MARGIN	(62,892)	($0.4091)
LEGACY ELECTRIC CONTIBUTION - CSG	(3,695)	($0.0240)
NET TOTAL FIXED COST	**$ 198,056**	**$1.28820**
FIRM RSG SENDOUT (MDTh) 10/23 - 9/24	**153,748**	
TOTAL NON-GULF COAST COST ($/DTh)		**$1.28820**
Removal of Balancing Cost (incl. above)		(0.63135)
Inventory Carrying Charge Allocation		0.05371
Gas Supply A&G		0.03757
Total Adjustments		**($0.54007)**
ADJUSTED NON-GULF COAST COST ($/DTh)		**$0.74813**
(OVER)/UNDER RECOVERY @ 9/30/23 - INCL. INT.	**($75,940)**	**($0.49390)**
GULF COAST COST OF GAS ($/DTh)		
FT COMMODITY AND FUEL		0.00000
COST OF GAS		**3.39920**
TOTAL GULF COAST COST		**$3.39920**

SUMMARY OF CHARGE COMPONENTS

	(cents/therm) BGSS-RSG	(dollars/therm) BGSS-RSG
Estimated Non-Gulf Coast Cost of Gas	7.4813	$ 0.074813
Estimated Gulf Coast Cost of Gas	33.9920	$ 0.339920
Adjustment to Gulf Coast Cost of Gas	-	$ -
Prior Period (Over)/Under Recovery	(4.9390)	$ (0.049390)
Adjusted Cost of Gas	36.5343	$ 0.365343
COMMODITY CHARGE (after application of losses 2.0%)	**37.2799**	**$ 0.372799**
COMMODITY CHARGE (including SUT)	**39.7497**	**$ 0.397497**

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

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 2023/2024 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.

TAKE NOTICE that, on June 1, 2023, 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 decrease its Basic Gas Supply Service ("BGSS-RSG") Commodity Charge applicable to its Residential Service ("RSG") customers and to decrease 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, 2023, or earlier should the Board deem it appropriate ("Petition"). Approval of the Company's request would result in a decrease in annual BGSS-RSG revenues of approximately $101 million (excluding losses and New Jersey Sales and Use Tax or "SUT"). The requested decrease in the BGSS-RSG Commodity Charge is from $0.471718 per therm (including losses and SUT) to $0.397497 per therm (including losses and SUT), and the requested decrease in the Balancing Charge is from $0.100691 per balancing use therm (including losses and SUT) to $0.097914 per balancing use therm (including losses and SUT).

Based upon rates effective June 1, 2023, the combined effects of the requested decrease in the BGSS-RSG and Balancing Charges on typical residential gas winter monthly bills, if approved by the Board, are shown in Table #1.

Based on the filing, the average monthly impact of the proposed rates to the typical residential gas customer using 172 therms in a winter month and 86.7 average monthly therms (1,040 annually) would be a decrease in the average monthly bill from $98.45 to $91.85, or $6.59 or approximately 6.70%.

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, 2023, and/or February 1st of next year, 2024, 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, 2023 and/or January 1, 2024 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, 2023 self-implementing 5% increase, the bill impact would be an increase as illustrated in Table #2. Further, if a February 1, 2024 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.

Any rate adjustments with resulting changes in bill impacts found by the Board to be just and reasonable as the result of the Company's Petition may be modified and/or allocated by the Board in accordance with the provisions of N.J.S.A. 48:2-21 and for other good and legally sufficient reasons to any class or classes of customers of the Company. Therefore, the described charges may increase or decrease based upon the Board's decision.

A copy of this Notice of Filing and Public Hearings on the Petition is being served upon the clerk, executive or administrator of each municipality and county within the Company's service territory. The Petition is available for review online at the PSEG website at http://www.pseg.com/pseandgfilings and has been sent to the New Jersey Division of Rate Counsel ("Rate Counsel"), who will represent the interests of all PSE&G customers in this proceeding. The Petition is also available to review online through the Board's website, https://publicaccess.bpu.state.nj.us, where you can search by the above-captioned docket number. The Petition and Board file may also be reviewed at the Board located at 44 South Clinton Avenue, 1st Floor, Trenton, NJ, with an appointment. To make an appointment, please call (609) 913-6298.

PLEASE TAKE FURTHER NOTICE that due to the COVID-19 Pandemic, virtual public hearings are scheduled on the following date and times so that members of the public may present their views on the Petition:

DATE: TBD
TIMES: 4:30 p.m. and 5:30 p.m.
Join: Join Zoom Meeting
https://pseg.zoom.us/j/92846158128?pwd=czBtZHE5ZTh1Z1FveGlmSVg0R1NuQT09#success

Go to www.zoom.com and choose "Join a Meeting" at the top of the web page. When prompted, use Meeting number 928 4615 8128 to access the meeting. -or-
Join by phone (toll-free):
Dial In: (888) 475-4499
Meeting ID: 928 4615 8128

When prompted, enter the Meeting ID number to access the meeting.

Representatives from the Company, Board Staff and the New Jersey Division of Rate Counsel will participate in the virtual 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 Petition. All comments will be made a 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 and/or listening assistance, 48 hours prior to the above hearings to the Board Secretary at board.secretary@bpu.nj.gov.

Comments may be submitted directly to the specific docket listed above using the "Post Comments" button on the Board's https://publicaccess.bpu.state.nj.us. Comments are considered public documents for purposes of the State's Open Public Records Act. Only public documents should be submitted using the "Post Comments" button on the Board's Public Document Search tool. Any confidential information should be submitted in accordance with the procedures set forth in N.J.A.C. 14:1-12.3. Due to the COVID-19 pandemic, certain rules requiring paper submissions have been temporarily waived. In addition to hard copy submissions, confidential information may also be filed electronically via the Board's e-filing system or by email to the Secretary of the Board. Please include "Confidential Information" in the subject line of any email. Instructions for confidential e-filing are found on the Board's webpage.
https://www.nj.gov/bpu/agenda/efiling/.

Emailed and/or written comments may also be submitted to:
Sherri L. Golden, Secretary of the Board
44 South Clinton Ave., 1st Floor
PO Box 350
Trenton, NJ 08625-0350
Phone: 609-913-6241
Email: board.secretary@bpu.nj.gov

Table # 1
Residential Gas Service – Monthly Winter Bill

If 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:
25	$34.65	$32.75	($1.90)	(5.48)%
50	60.71	56.89	(3.82)	(6.29)
100	113.92	106.27	(7.65)	(6.72)
172	189.76	176.59	(13.17)	(6.94)
201	220.38	204.99	(15.39)	(6.98)
300	324.50	301.54	(22.96)	(7.08)

(1) Based upon Delivery Rates and Basic Gas Supply Service (BGSS-RSG) in effect June 1, 2023, 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 Monthly Winter Therm Use Is:	Self-Implementing 5% Increases		
	December 1, 2023 Monthly Winter Change Would Be:	February 1, 2024 Monthly Winter Change Would Be:	Total If both 5% Self-Implementing Increases Are Put Into Effect:
25	$1.31	$1.30	$2.61
50	2.62	2.62	5.24
100	5.23	5.24	10.47
172	9.00	9.01	18.01
201	10.52	10.52	21.04
300	15.70	15.71	31.41

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

Katherine E. Smith
Managing Counsel – State Regulatory

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

4. <u>Actual and Forecasted Refund Amounts</u>

Item 4

NATURAL GAS PIPELINE REFUNDS RECEIVED MAY 2022 - APRIL 2023

(000)

MONTH	SUPPLIER	AMOUNT	TOTAL
May 2022	Algonquin	$ 0.2	
	Algonquin	$ (0.03)	**$ 0.1**
June 2022			
	Algonquin	$ 6.9	
	Algonquin	$ 0.02	
	Texas Eastern	$ 228.7	
	Texas Eastern	$ 55.0	
	Transco	$ 20.0	
	Algonquin	$ (0.002)	
	Columbia	$ (0.1)	**$ 310.5**
July 2022			
	Dominion	$ 26.6	
	Algonquin	$ (0.1)	**$ 26.5**
August 2022			
	Transco	$ 6.2	**$ 6.2**
September 2022			
	Algonquin	$ 0.1	**$ 0.1**
October 2022			
	Algonquin	$ 0.1	
	Texas Eastern	$ 82.5	
	Texas Eastern	$ 17.4	
	Transco	$ 13.1	**$ 113.1**
November 2022			
	Algonquin	$ 3.7	
	Algonquin	$ 0.02	
	Tennessee	$ 1.4	
	Transco	$ 7.0	**$ 12.1**
December 2022			
	Texas Eastern	$ 6.5	
	Texas Eastern	$ 1.0	**$ 7.5**
January 2023			
	Algonquin	$ 0.1	
	Transco	$ 0.7	**$ 0.9**
February 2023			
	Algonquin	$ 0.7	
	Eastern Gas	$ 3,412.7	
	Columbia	$ 36.1	**$ 3,449.5**
March 2023			
	Algonquin	$ 0.2	**$ 0.2**
April 2023			
	Algonquin	$ 0.3	
	Texas Eastern	$ 108.9	
	Texas Eastern	$ 22.3	
	Transco	$ 7.6	
	Texas Eastern	$ 19,643.9	
	Texas Eastern	$ 3,346.5	
	Transco	$ 1,131.4	**$ 24,260.9**
Total		28,188	**$ 28,188**

Item 4

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

DOCKET	SUPPLIER	STATUS

No refunds in excess of $1M are currently expected.

5. <u>Cost of Gas Sendout by Component</u>

ACTUAL COST OF BGSS-RSG GAS SENDOUT BY COMPONENT

	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	Total
Beginning Inventory Price $000	$367,536	$403,320	$388,831	$339,526	$260,726	$182,810	$119,186	
Fixed Pipeline Charge $000	$25,171	$26,214	$26,660	$25,250	$24,152	$22,893	$21,372	
Gas Purchases and Hedges $000	$68,191	$60,439	$95,760	$42,216	$34,080	$34,486	$29,817	
Receipt Value $000	$93,362	$86,653	$122,420	$67,466	$58,232	$57,378	$51,189	$536,700
Total Inventory Value $000	$460,898	$489,973	$511,251	$406,991	$318,958	$240,188	$170,374	
Total $/dth	$6.92	$6.84	$6.82	$6.75	$6.63	$6.41	$5.20	
Beginning Inventory Volume MDth	50,540	58,260	56,841	49,808	38,564	27,478	18,488	
Receipt Volume MDth	16,090	13,364	18,150	10,501	9,530	9,989	14,296	91,919
Total Inventory Volume MDth	66,630	71,624	74,992	60,309	48,094	37,467	32,784	
RSG Sendout MDth	8,167	14,804	25,228	21,546	20,388	18,688	8,446	117,268
Total RSG Sendout Cost $000	$56,492	$101,271	$171,993	$145,399	$135,215	$119,805	$43,896	$774,071
Ending Inventory Rebalance								
Volume	(203)	21	45	(200)	(228)	(291)	(146)	
Amount	($1,085)	$129	$268	($867)	($933)	($1,197)	($541)	

FORECASTED COST OF BGSS-RSG GAS SENDOUT BY COMPONENT

	May-23	Jun-23	Jul-23	Aug-23	Sep-23	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 Oct - Sept
Beginning Inventory Cost $000	$125,938	$151,189	$172,774	$192,941	$211,749	$243,017	$277,608	$259,735	$193,822	$120,882	$56,484	$16,937	$19,904	$47,261	$97,307	$146,790	$189,457	
Receipt Value $000	$51,671	$38,886	$35,484	$33,351	$47,874	$71,869	$64,973	$65,229	$84,724	$77,410	$73,387	$59,740	$59,557	$67,977	$64,142	$56,467	$65,421	$810,894
Total Inventory Value $000	$177,609	$190,074	$208,258	$226,293	$259,623	$314,886	$342,581	$324,963	$278,546	$198,293	$129,870	$76,677	$79,461	$115,237	$161,449	$203,257	$254,879	
Total $/dth	$4.50	$4.82	$5.16	$5.47	$5.38	$5.03	$5.12	$5.31	$5.40	$5.48	$5.48	$5.06	$5.02	$4.95	$5.18	$5.37	$5.40	
Beginning Inventory Volume MDth	24,191	33,585	35,862	37,366	38,746	45,209	55,204	50,737	36,519	22,374	10,315	3,092	3,937	9,412	19,668	28,322	35,290	
Receipt Volume MDth	15,263	5,867	4,470	4,042	9,552	17,407	11,717	10,490	15,038	13,837	13,397	12,073	11,888	13,880	11,483	9,538	11,948	152,695
Total Inventory Volume MDth	39,454	39,453	40,332	41,407	48,298	62,616	66,920	61,227	51,557	36,211	23,711	15,165	15,824	23,292	31,151	37,860	47,238	
RSG Sendout MDth	5,869	3,591	2,966	2,661	3,089	7,413	16,183	24,709	29,182	25,896	20,619	11,228	6,412	3,624	2,828	2,570	3,082	153,748
Total RSG Sendout Cost $000	$26,421	$17,300	$15,317	$14,544	$16,606	$37,278	$82,847	$131,141	$157,664	$141,809	$112,933	$56,773	$32,200	$17,930	$14,659	$13,799	$16,630	$815,663

6. BGSS Contribution and Credit Offsets

Actual BGSS Contribution and Credit Offsets

($000)

			Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	Total
(1)	**BGSS-I Contribution**		$161	$100	$334	$314	$725	$61	$349	$2,045
(2)	**Cogeneration Contribution**		$366	$973	$2,622	$439	$240	$134	$1,314	$6,088
(3)	**TSG-F Contribution**		$159	$504	$340	$297	$266	$301	($80)	$1,787
(4)	**"Contribution"**	Sum of (1) through (4)	$686	$1,577	$3,296	$1,050	$1,231	$496	$1,583	$9,920
(5)	**Off-System Contribution**		$1,035	$5,465	$50,301	$12,658	$18,425	$2,885	$2,732	$93,501
(6)	**Electric Contribution**		$270	$259	$273	$185	$72	$140	$306	$1,505
(7)	**FT-S Balancing Credit**		$945	$2,197	$4,015	$3,258	$3,296	$2,984	$1,384	$18,080
(8)	**Pipeline Refunds**		$113	$12	$8	$1	$3,450	$0	$24,261	$27,844

Forecasted BGSS Contribution and Credit Offsets

		May-23	Jun-23	Jul-23	Aug-23	Sep-23	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 Oct - Sept
(1)	**BGSS-RSG Sendout, Mdth**	5,869	3,591	2,966	2,661	3,089	7,413	16,183	24,709	29,182	25,896	20,619	11,228	6,412	3,624	2,828	2,570	3,082	153,748
(2)	**BGSS-F Sendout, Mdth**	2,124	1,130	1,109	1,190	1,124	1,826	5,029	8,303	9,557	9,217	7,580	3,983	2,310	1,118	1,055	1,154	1,105	52,236
(3)	**Total Firm Sendout, Mdth**	7,993	4,721	4,075	3,852	4,213	9,238	21,212	33,011	38,740	35,114	28,199	15,211	8,722	4,742	3,883	3,724	4,187	205,985
(4)	**Annual % BGSS-RSG of Firm Sendout**	74.6%	74.6%	74.6%	74.6%	74.6%	74.6%	74.6%	74.6%	74.6%	74.6%	74.6%	74.6%	74.6%	74.6%	74.6%	74.6%	74.6%	74.6%
(5)	**BGSS-I Contribution**	$613.8	$22.2	$22.1	$1.2	($14.9)	$149.6	$98.2	$333.3	$310.9	$734.2	$62.1	$353.2	$613.0	$22.1	$22.1	$1.3	($14.8)	$2,685.1
(6)	**Cogeneration Contribution, $000**	$805.3	($97.5)	$1,018.0	($520.5)	($1,172.2)	($151.9)	$742.8	$2,237.8	$78.6	($254.5)	($228.9)	($22.4)	$804.3	($97.1)	$1,017.2	($521.0)	($1,167.5)	$2,437.4
(7)	**TSG-F Contribution**	($107.2)	$118.4	($705.5)	$78.4	$85.7	$147.6	$493.5	$339.1	$294.1	$269.3	$307.6	($80.8)	($107.0)	$117.9	($705.0)	$78.4	$85.4	$1,240.1
(8)	**CSG**	$339.5	$414.7	$456.4	$203.0	$454.8	$395.5	$159.4	$281.9	$268.6	$366.6	$267.5	$997.1	$339.5	$414.7	$456.4	$203.0	$454.8	$4,605.0
(9)	**"Contribution"**	$1,651.4	$457.9	$791.0	($237.8)	($646.6)	$540.7	$1,493.8	$3,192.1	$952.2	$1,115.6	$408.4	$1,247.1	$1,649.8	$457.7	$790.7	($238.3)	($642.2)	$10,967.6
(10)	**Off-System Contribution, $000**	$3,094.6	$2,415.6	$2,765.1	$2,895.2	$2,407.2	$2,400.6	$10,674.0	$10,674.0	$10,674.0	$10,674.0	$10,674.0	$1,024.4	$963.1	$1,100.0	$1,449.1	$1,509.8	$1,074.8	$62,891.9
(11)	**Legacy Electric Contribution, $000**	$199.7	$372.6	$725.6	$681.5	$211.3	$269.2	$258.7	$272.9	$184.7	$72.5	$140.5	$306.2	$199.7	$372.6	$725.6	$681.5	$211.3	$3,695.2
(12)	**Pipeline Refund, $000**	$1,971.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
(13)	**FT-S Balancing Use, Mdth**	568.7	0.0	0.0	0.0	0.0	1,721.7	3,322.2	5,424.0	7,152.2	6,263.2	5,538.5	2,638.8	1,055.1	0.0	0.0	0.0	0.0	
(14)	**Balancing Charge, $/dth**	$0.8373	$0.0000	$0.0000	$0.0000	$0.0000	$0.8295	$0.8295	$0.8295	$0.8295	$0.8295	$0.8295	$0.8295	$0.8295	$0.0000	$0.0000	$0.0000	$0.0000	
(15)	**FT-S Balancing Credit, $000**	$568.7	$0.0	$0.0	$0.0	$0.0	$1,065.9	$2,056.8	$3,358.1	$4,428.1	$3,877.7	$3,429.0	$1,633.7	$653.2	$0.0	$0.0	$0.0	$0.0	$20,502.4
(16)	**BGSS-RSG Balancing Use, Mdth**	2,607	0	0	0	0	4,285	13,157	21,581	26,055	22,971	17,492	8,202	3,285	0	0	0	0	
(17)	**Balancing Charge, $/dth**	$0.8373	$0.0000	$0.0000	$0.0000	$0.0000	$0.8295	$0.8295	$0.8295	$0.8295	$0.8295	$0.8295	$0.8295	$0.8295	$0.0000	$0.0000	$0.0000	$0.0000	
(18)	**BGSS-RSG Balancing Rev., $000**	$2,182.5	$0.0	$0.0	$0.0	$0.0	$3,554.6	$10,913.1	$17,900.7	$21,611.5	$19,053.3	$14,508.7	$6,803.2	$2,724.9	$0.0	$0.0	$0.0	$0.0	$97,070.1

BGSS-RSG MARGIN FROM GAS TRANSPORTATION FOR ELECTRIC GENERATION

	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	Total
BGSS Asset Charge ($000)	$0	$0	$0	$0	$0	$0	$0	$0
CSG Transportation Revenues ($000)	$269	$259	$273	$185	$72	$140	$306	$1,505
Total BGSS-RSG Margin ($000)	$269	$259	$273	$185	$72	$140	$306	$1,505

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 2022 - SEPTEMBER 2023

(000)

		TOTAL RECOVERY	LESS: TOTAL EXPENSE	MONTHLY OVER/(UNDER RECOVERY
Balance September 30, 2022				**($9,062)**
Interest Adjustment				**731**
October 1, 2022 Adjusted Balance				**($8,331)**
October 2022		$ 50,627	$ 56,532	(5,905)
November		98,793	98,611	182
December		177,094	126,883	50,211
January 2023		149,331	141,025	8,306
February		121,858	115,901	5,956
March		103,611	118,315	(14,704)
April		48,207	20,022	28,185
May	**(Est.)**	26,929	18,935	7,994
June	**(Est.)**	15,141	14,054	1,087
July	**(Est.)**	12,507	11,035	1,472
August	**(Est.)**	11,221	11,205	16
September	**(Est.)**	13,025	14,633	(1,608)
Total				**$72,862**

INTEREST
COMPUTED AT 6.99% ROR FOR October 2022 - SEPTEMBER 2023

(000)

		OVER/(UNDER) RECOVERIES			
		Monthly	Cumulative	Average Balance	INTEREST
Balance September 30, 2022			**($9,062)**		
Interest Adjustment			**731**		
October 1, 2022 Adjusted Balance			**($8,331)**		
October 2022		$ (5,905)	(14,237)	$ (11,284)	$ (66)
November		182	(14,054)	$ (14,145)	$ (82)
December		50,211	36,157	11,051	$ 64
January 2023		8,306	44,463	40,310	$ 235
February		5,956	50,419	47,441	$ 276
March		(14,704)	35,715	43,067	$ 251
April		28,185	63,901	49,808	$ 290
May	**(Est.)**	7,994	71,895	67,898	$ 396
June	**(Est.)**	1,087	72,982	72,438	$ 422
July	**(Est.)**	1,472	74,454	73,718	$ 429
August	**(Est.)**	16	74,470	74,462	$ 434
September	**(Est.)**	(1,608)	72,862	73,666	$ 429
Total					**$ 3,078**

BGSS-RSG 2023-2024
NYMEX====>>> May 10, 2023

NO CHANGE IN RATES

	BGSS-RSG MDTh	COST	REFUNDS	CONTRIB	OFF-SYS Margin	Electric Contribution	FT Balancing Credit	ADJ COST	RSG Bal. Revenue	BGSS RECOVERY	EXCESS COST	OVER/(UNDER) RECOVERY Month	OVER/(UNDER) RECOVERY Cumulative	RSG Rate $/dth
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(2).+.(7)	(9)	(10)=(1)*(14)+(9)	(11)=(10)-(8)	(12)=-(11)	(13)	(14)
Apr-23 Act													**$63,901**	$4.2165
May-23 Est.	5,869	$26,421	($1,971)	($1,651)	($3,095)	($200)	($569)	$18,935	$2,183	$26,929.49	($7,994)	$7,994	$71,895	$4.2165
Jun-23 Est.	3,591	$17,300	$0	($458)	($2,416)	($373)	$0	$14,054	$0	$15,141.08	($1,087)	$1,087	$72,982	$4.2165
Jul-23 Est.	2,966	$15,317	$0	($791)	($2,765)	($726)	$0	$11,035	$0	$12,507.30	($1,472)	$1,472	$74,454	$4.2165
Aug-23 Est.	2,661	$14,544	$0	$238	($2,895)	($681)	$0	$11,205	$0	$11,221.38	($16)	$16	$74,470	$4.2165
Sep-23 Est.	**3,089**	**$16,606**	**$0**	**$647**	**($2,407)**	**($211)**	**$0**	**$14,634**	**$0**	**$13,025.44**	**$1,608**	**($1,608)**	**$72,862**	$4.2165
Oct-23 Est.	7,413	$37,278	$0	($541)	($2,401)	($269)	($1,066)	$33,001	$3,555	$34,810.80	($1,809)	$1,809	$74,671	$4.2165
Nov-23 Est.	16,183	$82,847	$0	($1,494)	($10,674)	($259)	($2,057)	$68,363	$10,913	$79,150.36	($10,787)	$10,787	$85,458	$4.2165
Dec-23 Est.	24,709	$131,141	$0	($3,192)	($10,674)	($273)	($3,358)	$113,644	$17,901	$122,084.33	($8,441)	$8,441	$93,899	$4.2165
Jan-24 Est.	29,182	$157,664	$0	($952)	($10,674)	($185)	($4,428)	$141,425	$21,612	$144,658.58	($3,234)	$3,234	$97,133	$4.2165
Feb-24 Est.	25,896	$141,809	$0	($1,116)	($10,674)	($72)	($3,878)	$126,069	$19,053	$128,245.07	($2,176)	$2,176	$99,309	$4.2165
Mar-24 Est.	20,619	$112,933	$0	($408)	($10,674)	($140)	($3,429)	$98,281	$14,509	$101,448.82	($3,168)	$3,168	$102,476	$4.2165
Apr-24 Est.	11,228	$56,773	$0	($1,247)	($1,024)	($306)	($1,634)	$52,562	$6,803	$54,148.11	($1,586)	$1,586	$104,063	$4.2165
May-24 Est.	6,412	$32,200	$0	($1,650)	($963)	($200)	($653)	$28,734	$2,725	$29,763.19	($1,029)	$1,029	$105,091	$4.2165
Jun-24 Est.	3,624	$17,930	$0	($458)	($1,100)	($373)	$0	$16,000	$0	$15,280.46	$719	($719)	$104,372	$4.2165
Jul-24 Est.	2,828	$14,659	$0	($791)	($1,449)	($726)	$0	$11,694	$0	$11,926.06	($232)	$232	$104,604	$4.2165
Aug-24 Est.	2,570	$13,799	$0	$238	($1,510)	($681)	$0	$11,846	$0	$10,838.07	$1,008	($1,008)	$103,596	$4.2165
Sep-24 Est.	**3,082**	**$16,630**	**$0**	**$642**	**($1,075)**	**($211)**	**$0**	$15,986	**$0**	$12,995.82	$2,991	($2,991)	$100,605	$4.2165
Oct-23 to Sept-24	**153,748**	**$815,663**	**$0**	**($10,968)**	**($62,892)**	**($3,695)**	**($20,502)**	**$717,606**	**$97,070**	**$745,350**	**($27,744)**			

BGSS-RSG 2023-2024
NYMEX====>>> May 10, 2023

ZERO BALANCE

	BGSS-RSG MDTh	COST	REFUNDS	CONTRIB	OFF-SYS Margin	Electric Contribution	FT Balancing Credit	ADJ COST	RSG Bal. Revenue	BGSS RECOVERY	EXCESS COST	OVER/(UNDER) RECOVERY Month	OVER/(UNDER) RECOVERY Cumulative	RSG Rate $/dth
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(2).+.(7)	(9)	(10)=(1)*(14)+(9)	(11)=(10)-(8)	(12)=-(11)	(13)	(14)
Apr-23 Act.													**$63,901**	$4.2165
May-23 Est.	5,869	$26,421	($1,971)	($1,651)	($3,095)	($200)	($569)	$18,935	$2,183	$26,929	($7,994)	$7,994	$71,895	$4.2165
Jun-23 Est.	3,591	$17,300	$0	($458)	($2,416)	($373)	$0	$14,054	$0	$15,141	($1,087)	$1,087	$72,982	$4.2165
Jul-23 Est.	2,966	$15,317	$0	($791)	($2,765)	($726)	$0	$11,035	$0	$12,507	($1,472)	$1,472	$74,454	$4.2165
Aug-23 Est.	2,661	$14,544	$0	$238	($2,895)	($681)	$0	$11,205	$0	$11,221	($16)	$16	$74,470	$4.2165
Sep-23 Est.	**3,089**	**$16,606**	**$0**	**$647**	**($2,407)**	**($211)**	**$0**	**$14,634**	**$0**	**$13,025**	**$1,608**	**($1,608)**	**$72,862**	$4.2165
Oct-23 Est.	7,413	$37,278	$0	($541)	($2,401)	($269)	($1,066)	$33,001	$3,555	$29,960	$3,041	($3,041)	$69,821	$3.5621
Nov-23 Est.	16,183	$82,847	$0	($1,494)	($10,674)	($259)	($2,057)	$68,363	$10,913	$68,561	($198)	$198	$70,018	$3.5621
Dec-23 Est.	24,709	$131,141	$0	($3,192)	($10,674)	($273)	($3,358)	$113,644	$17,901	$105,916	$7,727	($7,727)	$62,291	$3.5621
Jan-24 Est.	29,182	$157,664	$0	($952)	($10,674)	($185)	($4,428)	$141,425	$21,612	$125,563	$15,862	($15,862)	$46,429	$3.5621
Feb-24 Est.	25,896	$141,809	$0	($1,116)	($10,674)	($72)	($3,878)	$126,069	$19,053	$111,300	$14,769	($14,769)	$31,660	$3.5621
Mar-24 Est.	20,619	$112,933	$0	($408)	($10,674)	($140)	($3,429)	$98,281	$14,509	$87,957	$10,324	($10,324)	$21,335	$3.5621
Apr-24 Est.	11,228	$56,773	$0	($1,247)	($1,024)	($306)	($1,634)	$52,562	$6,803	$46,801	$5,761	($5,761)	$15,574	$3.5621
May-24 Est.	6,412	$32,200	$0	($1,650)	($963)	($200)	($653)	$28,734	$2,725	$25,567	$3,167	($3,167)	$12,407	$3.5621
Jun-24 Est.	3,624	$17,930	$0	($458)	($1,100)	($373)	$0	$16,000	$0	$12,909	$3,091	($3,091)	$9,316	$3.5621
Jul-24 Est.	2,828	$14,659	$0	($791)	($1,449)	($726)	$0	$11,694	$0	$10,075	$1,619	($1,619)	$7,698	$3.5621
Aug-24 Est.	2,570	$13,799	$0	$238	($1,510)	($681)	$0	$11,846	$0	$9,156	$2,690	($2,690)	$5,007	$3.5621
Sep-24 Est.	**3,082**	**$16,630**	**$0**	**$642**	**($1,075)**	**($211)**	**$0**	**$15,986**	**$0**	**$10,979**	**$5,007**	**($5,007)**	**$0**	$3.5621
Oct-23 to Sept-24	**153,748**	**$815,663**	**$0**	**($10,968)**	**($62,892)**	**($3,695)**	**($20,502)**	**$717,606**	**$97,070**	**$644,744**	**$72,862**			

PSE&G
FOR PERIOD OCT22 TO SEP23

	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23
Beginning Balance	(8,331,490)	(14,236,651)	(14,054,257)	36,156,733	44,462,804	50,419,300	35,715,452
FUEL REVENUES							
Fuel Revenues	49,672,127	96,956,732	173,553,926	148,096,596	120,553,936	102,974,365	46,317,547
Interruptible Contribution	955,088	1,836,198	3,540,507	1,234,494	1,303,716	636,912	1,889,292
PSEG Holding's Affiliation Fee							
Total Fuel Revenues	50,627,216	98,792,931	177,094,434	149,331,090	121,857,651	103,611,276	48,206,839
FUEL EXPENSE							
Gas Purchases	56,645,428	98,622,604	126,890,992	141,025,912	119,350,677	118,315,288	44,282,658
Refunds	(113,052)	(12,067)	(7,548)	(892)	(3,449,522)	(163)	(24,260,926)
Total Fuel Expense	56,532,377	98,610,537	126,883,444	141,025,020	115,901,155	118,315,124	20,021,732
OVER / (UNDER) RECOVERY	(5,905,161)	182,394	50,210,990	8,306,071	5,956,496	(14,703,848)	28,185,107
Cumulative Recovery	(14,236,651)	(14,054,257)	36,156,733	44,462,804	50,419,300	35,715,452	63,900,559

BGSSR
CALCULATION OF FUEL REVENUES
FOR PERIOD OCT22 TO SEP23

	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23
RSG Fuel Revenues	$43,967,943	$83,325,323	$146,288,558	$125,089,945	$98,177,693	$83,029,118	$38,228,582
RSGM Fuel Revenues	$847,522	$1,664,191	$2,960,128	$2,598,081	$2,057,779	$1,760,998	$856,794
Subtotal	$44,815,465	$84,989,514	$149,248,686	$127,688,026	$100,235,473	$84,790,116	$39,085,376
FT Balancing Revenues	3,169,284	7,946,905	20,307,183	22,925,913	21,251,839	$19,000,451	$10,383,903
FT Balancing Revenues (Unbilled Calc)	1,687,378	5,707,691	9,705,748	7,188,405	6,255,029	5,438,828	2,287,096
FT Balancing Revenues (Prior Unbilled Calc)	0	-1,687,378	-5,707,691	-9,705,748	-7,188,405	-6,255,029	-5,438,828
Manual Rev Accrual not part of BGSSR							
Total BGSSR Fuel Recovery	$49,672,127	$96,956,732	$173,553,926	$148,096,596	$120,553,936	$102,974,365	$46,317,547
Bill Credits							
Billed Revenues							
Current Unbilled Usage							
Prior Unbilled Usage							
Net Unbilled Usage							
Rate							
Subtotal Unbilled Revenues							
Total Bill Credits							

	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23
Interruptible Contributions:							
ISG (BGSS-I):							
ISG (BGSS-I) Sales Therms	324,574	727,151	1,408,894	729,652	1,667,259	1,324,429	456,227
ISG BGSS-I) Gross Revenues	$ 312,646	$ 552,180	$ 1,277,283	$ 1,165,181	$ 1,174,800	$ 373,377	$ 446,622
ISG (BGSS-I) Cost	$ 130,076	$ 394,610	$ 807,172	$ 780,838	$ 342,081	$ 259,468	$ 71,642
PSEG Power's share of Contribution	$ 21,796	$ 57,221	$ 135,902	$ 70,584	$ 107,277	$ 53,039	$ 25,715
ISG Interuptible Contribution to BGSSR	$ 160,774	$ 100,349	$ 334,209	$ 313,759	$ 725,442	$ 60,871	$ 349,265
CIG:							
CIG SBC Rate adjustment (line 84)							
CIG Sales Therms	687,830.20	3,485,546.88	5,057,901.86	2,833,723.39	1,906,987.69	1,556,983.16	438,721.83
CIG Gross Revenues	$ 346,295	$ 2,169,387	$ 4,476,874	$ 1,556,074	$ 487,663	$ 467,997	$ 333,845
CIG SBC/GPRC Revenues	$ 35,094	$ 177,836	$ 258,059	$ 144,579	$ 97,296	$ 79,439	$ 22,384
CIG Cost	$ 424,537	$ 1,161,247	$ 1,810,674	$ 1,323,880	$ 554,097	$ 568,642	$ 283,472
CIG TAC revenues	$ (8,668)	$ (43,925)	$ (63,740)	$ (35,711)	$ (24,032)	$ (19,621)	$ (7,139)
PSEG Power's share of Contribution	$ 58,659	$ 115,027	$ 227,828	$ 44,022	$ 111,733	$ 63,724	$ 57,254
CIG Interuptible Contribution to BGSSR	$ (163,327)	$ 759,201	$ 2,244,052	$ 79,303	$ (251,432)	$ (224,186)	$ (22,125)
TSG-F:							
TSG-F SBC Rate adjustment (line 84)							
TSG-F Sales Therms	2,236,775.78	2,146,608.61	2,415,888.29	2,385,139.50	2,102,189.33	2,546,765.78	1,231,174.89
TSG-F Gross Revenues	$ 269,026	$ 661,022	$ 510,131	$ 471,417	$ 440,193	$ 495,453	$ 10,592
TSG-F SBC/GPRC Revenues	$ 114,123	$ 109,522	$ 123,261	$ 121,692	$ 107,256	$ 129,939	$ 62,816
TSG-F TAC Revenues	$ (34,339)	$ (32,955)	$ (37,089)	$ (36,617)	$ (32,273)	$ (39,098)	$ (18,901)
TSG-F MAC Revenues	$ (13,020)	$ (12,495)	$ (14,063)	$ (13,884)	$ (12,237)	$ (14,825)	$ (7,167)
TSG-F PSEG Power's share of Contribution	$ 43,607	$ 92,567	$ 97,964	$ 103,416	$ 111,333	$ 118,110	$ 53,750
TSG-F Interuptible Contribution to BGSSR	$ 158,655	$ 504,383	$ 340,057	$ 296,810	$ 266,114	$ 301,327	$ (79,907)
CSG NON-Power:							
CSG Non-Power Therms	83,493,352.51	71,618,137.13	5,155,202.35	43,312,232.50	26,502,967.26	30,398,868.34	75,656,883.31
CSG Non-Power Revenues	$ 736,166	$ 438,475	$ 682,888	$ 541,863	$ 572,679	$ 523,143	$ 1,633,853
CSG Non Power SBC Revenues	$ 10,642	$ 302	$ 19,927	$ 8,511	$ 4,467	$ 11,337	$ 8,943
CSG TAC Revenues Power and NON-Power	$ (83,478)	$ (71,614)	$ (5,131)	$ (43,303)	$ (26,482)	$ (30,405)	$ (75,645)
CSG Non-Power ER&T's share of Contribution	$ 10,016	$ 37,522	$ 17,506	$ 32,033	$ 31,103	$ 43,311	$ 58,498
CSG Non-Power Contribution to BGSSR	$ 798,986	$ 472,265	$ 650,586	$ 544,623	$ 563,592	$ 498,900	$ 1,642,058
Total Interruptible Contributions	$ 955,088	$ 1,836,198	$ 3,568,904	$ 1,234,494	$ 1,303,716	$ 636,912	$ 1,889,292
SBC & GPRC rate-CIG & TSG-F	**0.051021**	**0.051021**	**0.051021**	**0.051021**	**0.051021**	**0.051021**	**0.051021**
TEFA rate-TSG-F							
Cogen Contract RAC rate							
MAC rate-TSG-F	**(0.005821)**	**(0.005821)**	**(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	$ 57,186,148	$ 98,837,782	$ 126,804,352	$ 140,320,469	$ 118,449,889	$ 119,094,533	$ 42,716,058
Prior Month Actual - Gas Purchases (1) See below row 105	$ 20,562,504	$ 56,958,902	$ 98,916,874	$ 127,508,903	$ 137,771,735	$ 117,670,481	$ 96,400,207
Prior Month Estimate - Gas Purchases See below row 115	$ 21,216,275	$ 57,186,148	$ 98,837,782	$ 126,804,352	$ 140,320,469	$ 118,449,889	$ 119,094,533
Gas Purchases	$ 56,532,377	$ 98,610,537	$ 126,883,444	$ 141,025,020	$ 115,901,155	$ 118,315,124	$ 20,021,732
Gas Refunds							
ISG (BGSS-I) Cost Est. (2)	$ 129,315	$ 386,451	$ 807,338	$ 698,468	$ 338,285	$ 242,175	$ 67,986
PSEG Power's share of Contribution CMnth Est. (2)	$ 20,621	$ 53,141	$ 136,976	$ 86,039	$ 95,357	$ 59,910	$ 23,854
ISG (BGSS-I) Cost Pr Mnth Act. (2)	$ 129,990	$ 137,473	$ 386,286	$ 889,708	$ 702,264	$ 355,578	$ 245,831
PSEG Power's share of Contribution Pr Mnth Act. (2)	$ 18,007	$ 24,702	$ 52,066	$ 121,521	$ 97,959	$ 88,486	$ 61,770
ISG (BGSS-I) Cost PrMnth Est.	$ 129,228	$ 129,315	$ 386,451	$ 807,338	$ 698,468	$ 338,285	$ 242,175
PSEG Power's share of Contribution PrMnth Est.	$ 16,833	$ 20,621	$ 53,141	$ 136,976	$ 86,039	$ 95,357	$ 59,910

	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23
CIG Cost (3) - CMnth Est. (3)	$ 420,332	$ 1,115,631	$ 1,812,091	$ 1,172,589	$ 568,205	$ 518,279	$ 278,999
PSEG Power's share of Contribution - CMnth Est. (3)	$ 53,528	$ 101,779	$ 229,960	$ 82,860	$ 100,154	$ 72,037	$ 56,051
CIG Cost (3) - PrMnth Act. (3)	$ 717,670	$ 465,949	$ 1,114,213	$ 1,963,382	$ 1,158,482	$ 618,567	$ 522,751
PSEG Power's share of Contribution - PrMnth Act. (3)	$ 81,380	$ 66,776	$ 99,648	$ 191,121	$ 94,439	$ 91,841	$ 73,240
CIG Cost - PrMnth Est.	$ 713,465	$ 420,332	$ 1,115,631	$ 1,812,091	$ 1,172,589	$ 568,205	$ 518,279
PSEG Power's share of Contribution - PrMnth Est.	$ 76,249	$ 53,528	$ 101,779	$ 229,960	$ 82,860	$ 100,154	$ 72,037
TSG-F PSEG Power's share of Contribution CMth Est. (4)	$ 40,581	$ 87,063	$ 100,188	$ 103,713	$ 101,912	$ 114,940	$ 49,650
TSG-F PSEG Power's share of Contribution PrMth Actual (4)	$ 40,333	$ 46,084	$ 84,839	$ 99,891	$ 113,134	$ 105,082	$ 119,040
TSG-F PSEG Power's share of Contribution PrMth Est.	$ 37,306	$ 40,581	$ 87,063	$ 100,188	$ 103,713	$ 101,912	$ 114,940
CSC Non-Power Cost & PSEG Power's share of Contribution CMth Est. (6)	$ 36,282	$ 32,551	$ 18,260	$ 32,138	$ 28,185	$ 41,638	$ 56,120
CSC Non-Power Cost & PSEG Power's share of Contribution PMth Act. (6)	$ -	$ 41,252	$ 31,797	$ 18,154	$ 35,056	$ 29,858	$ 44,017
CSC Non-Power Cost & PSEG Power's share of Contribution PMth Est.	$ 26,266	$ 36,282	$ 32,551	$ 18,260	$ 32,138	$ 28,185	$ 41,638
BGSS-RSG Prior Month Actual	$ 21,509,551	$ 57,653,803	$ 100,569,087	$ 130,674,635	$ 139,824,880	$ 118,824,953	$ 97,303,800
FTS Balancing/BGSS-RSG Cogen Contracts Prior Month Actual (6)	$ -	$ 404,389	$ 699,435	$ 1,251,161	$ 1,022,439	$ 1,069,811	$ 977,463
BGSS-RSG TSG Cashouts Prior Mnth Actuals	$ (75,835)	$ 332,086	$ 502,989	$ 646,806	$ 125,284	$ (192,613)	$ 147,771
Subtotal	$ 22,345,462	$ 58,390,277	$ 101,771,512	$ 132,572,602	$ 2,170,162	$ 1,947,010	$ 2,102,697
Total BGSS-RSG Actual Bill	**$ 22,345,462**	**$ 57,985,888**	**$ 101,072,077**	**$ 131,321,441**	**$ 139,950,163**	**$ 118,632,340**	**$ 97,451,571**
Difference							
BGSS-RSG Current Month Estimate	$ 57,809,944	$ 100,494,784	$ 129,790,717	$ 142,360,425	$ 119,551,890	$ 119,986,933	$ 43,142,948
BGSS-RSG Cogen Contracts Prior Month Estimate (6)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal	$ 57,809,944	$ 100,494,784	$ 129,790,717	$ 142,360,425	$ 119,551,890	$ 119,986,933	$ 43,142,948
Total BGSS-RSG Estimate Bill	**$ 57,809,944**	**$ 100,494,784**	**$ 129,790,717**	**$ 142,360,425**	**$ 122,964,587**	**$ 119,986,933**	**$ 43,142,948**
Difference							
Gas Purchases Details:							
Current Month Estimate							
BGSS-RSG GAS COMMODITY VOLUMES MDTh	8,212,303	14,810,539	25,460,208	21,943,061	20,628,087	18,468,581	8,452,237
BGSS-RSG GAS COMMODITY COST	$ 56,711,453	$ 101,323,274	$ 171,724,653	$ 148,287,428	$ 136,273,262	$ 118,288,730	$ 43,902,305
BGSS-RSG Balancing	$ 1,598,706	$ 3,019,630	$ 5,394,750	$ 4,606,765	$ 4,346,938	$ 3,873,654	$ 1,583,972
BGSS-RSG Off System Sales	$ (1,124,011)	$ (5,505,122)	$ (50,315,051)	$ (12,573,724)	$ (18,793,228)	$ (3,067,851)	$ (2,770,219)
Electric Reservation Charge							
Non Compliance Penalty	$ -	$ -	$ -	$ -	$ 35,614	$ -	$ -
CSG Revenues	**$** -	**$** -	**$** -	**$** -	**$** -	**$** -	**$** -
Credit for Pipeline Refunds	$ -	$ -	$ -	$ -	$ (3,412,697)	$ -	$ -
Total	$ 57,186,148	$ 98,837,782	$ 126,804,352	$ 140,320,469	$ 118,449,889	$ 119,094,533	$ 42,716,058
Prior Actual							
BGSS-RSG GAS COMMODITY VOLUMES MDTh	3,422,390	8,173,170	14,811,351	25,265,298	21,553,193	20,433,587	18,695,592
BGSS-RSG GAS COMMODITY COST	$ 24,849,988	$ 56,499,445	$ 101,375,421	$ 172,283,331	$ 145,407,944	$ 135,351,482	$ 119,813,521
BGSS-RSG Balancing	$ 293,607	$ 1,555,686	$ 3,039,656	$ 5,377,140	$ 4,500,991	$ 4,305,992	$ 3,877,171
BGSS-RSG Off System Sales	$ (3,556,294)	$ (1,084,161)	$ (5,490,654)	$ (50,399,695)	$ (12,205,747)	$ (18,610,726)	$ (3,029,559)
Electric Reservation Charge	$ (911,745)	$ -	$ -	$ -	$ -	$ -	$ -
CSG Revenues	**$** -	**$** -	**$** -	**$** -	**$** -	**$** -	**$** -
Non Compliance Penalty	$ -	$ -	$ -	$ 249,020	$ -	$ 36,593	$ -
Credit for Pipeline Refunds	$ (113,052)	$ (12,067)	$ (7,548)	$ (892)	$ (36,825)	$ (3,412,860)	$ (24,260,926)
Residential Share of Propane Contract Deficiency Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Residential Share of Property Taxes Paid	$ -	$ -	$ -	$ -	$ 105,372	$ -	$ -
Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ 20,562,504	$ 56,958,902	$ 98,916,874	$ 127,508,903	$ 137,771,735	$ 117,670,481	$ 96,400,207

	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23
Prior Estimate							
BGSS-RSG GAS COMMODITY VOLUMES MDTh	3,505,192	8,212,303	14,810,539	25,460,208	21,943,061	20,628,087	18,468,581
BGSS-RSG GAS COMMODITY COST	$ 25,473,639	$ 56,711,453	$ 101,323,274	$ 171,724,653	$ 148,287,428	$ 136,273,262	$ 118,288,730
BGSS-RSG Balancing	$ 300,710	$ 1,598,706	$ 3,019,630	$ 5,394,750	$ 4,606,765	$ 4,346,938	$ 3,873,654
BGSS-RSG Off System Sales	$ (3,645,655)	$ (1,124,011)	$ (5,505,122)	$ (50,315,051)	$ (12,573,724)	$ (18,793,228)	$ (3,067,851)
Electric Reservation Charge	$ (912,419)	$ -	$ -	$ -	$ -	$ -	$ -
Other	$ -	$ -	$ -	$ -	$ -	$ 35,614	$ -
Prior CSG Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Credit for Pipeline Refunds	$ -	$ -	$ -	$ -	$ -	$ (3,412,697)	$ -
Total	$ 21,216,275	$ 57,186,148	$ 98,837,782	$ 126,804,352	$ 140,320,469	$ 118,449,889	$ 119,094,533
<u>Net</u>							
BGSS-RSG GAS COMMODITY VOLUMES MDTh	8,129,501	14,771,406	25,461,020	21,748,151	20,238,219	18,274,081	8,679,248
BGSS-RSG GAS COMMODITY COST	$ 56,087,802	$ 101,111,267	$ 171,776,799	$ 148,846,106	$ 133,393,779	$ 117,366,950	$ 45,427,096
BGSS-RSG Balancing	$ 1,591,602	$ 2,976,610	$ 5,414,776	$ 4,589,154	$ 4,241,163	$ 3,832,709	$ 1,587,490
BGSS-RSG Off System Sales	$ (1,034,650)	$ (5,465,272)	$ (50,300,583)	$ (12,658,368)	$ (18,425,251)	$ (2,885,349)	$ (2,731,928)
Electric Reservation Charge	$ 674	$ -	$ -	$ -	$ -	$ -	$ -
Other	$ -	$ -	$ -	$ 249,020	$ 140,986	$ 979	$ -
CSG Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Credit for Pipeline Refunds	$ (113,052)	$ (12,067)	$ (7,548)	$ (892)	$ (3,449,522)	$ (163)	$ (24,260,926)
Total	$ 56,532,377	$ 98,610,537	$ 126,883,444	$ 141,025,020	$ 115,901,155	$ 118,315,124	$ 20,021,732
BGSS-RSG GAS COMMODITY VOLUMES MDTh	8,129,501	14,771,406	25,461,020	21,748,151	20,238,219	18,274,081	8,679,248
NET SALES VOLUMES RESIDENTIAL	7,523,115	13,859,342	24,398,800	20,904,731	20,892,426	19,111,431	8,840,036
Diff	606,386	912,064	1,062,220	843,420	(654,207)	(837,350)	(160,788)

INTEREST CALCULATION
FOR PERIOD OCT22 TO SEP23

	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23
CUMULATIVE OVER/(UNDER) RECOVERY PRIOR MONTH	($8,331,490)	($14,236,651)	($14,054,257)	$36,156,733	$44,462,804	$50,419,300	$35,715,452
CUMULATIVE OVER/(UNDER) RECOVERY CURRENT MONTH	($14,236,651)	($14,054,257)	$36,156,733	$44,462,804	$50,419,300	$35,715,452	$63,900,559
AVERAGE BALANCE	($11,284,070)	($14,145,454)	$11,051,238	$40,309,768	$47,441,052	$43,067,376	$49,808,006
MONTHLY INTEREST (Income)/Expense allowed rate of return of 6.99%	**($65,730)**	**($82,397)**	**$64,291**	**$234,804**	**$276,344**	**$250,867**	**$290,132**
INTEREST ACCUMULATED, (Income)/Expense	($65,730)	($148,127)	($83,836)	$150,968	$427,312	$678,180	$968,311

8. Wholesale Gas Pricing Assumptions

A Comparison of the Forecasted Cost of Gas as represented by the NYMEX
June 2023 Filing versus June 2022 Filing

($/Mbtu)

		June '23 Filing Nymex - 5/10/2023	June '22 Filing Nymex - 5/10/2022	Difference	Percentage Difference
2023	**May**	$2.117	$7.267	($5.150)	-70.9%
	June	$2.191	$7.385	($5.194)	-70.3%
	July	$2.336	$7.467	($5.131)	-68.7%
	August	$2.419	$7.446	($5.027)	-67.5%
	September	$2.415	$7.400	($4.985)	-67.4%
	October	$2.520	$7.391	($4.871)	-65.9%
	November	$2.974	$7.457	($4.483)	-60.1%
	December	$3.470	$7.571	($4.101)	-54.2%
2024	**January**	$3.719	$7.663	($3.944)	-51.5%
	February	$3.635	$7.342	($3.707)	-50.5%
	March	$3.323	$6.302	($2.979)	-47.3%
	April	$3.004	$4.659	($1.655)	-35.5%
	May	$2.998	$4.496	($1.498)	-33.3%
	June	$3.147	$4.539	($1.392)	-30.7%
	July	$3.288	$4.581	($1.293)	-28.2%
	August	$3.329	$4.574	($1.245)	-27.2%
	September	$3.293	$4.550	($1.257)	-27.6%
	Average	$2.952	$6.358	($3.407)	-53.6%

9. <u>GCUA Recoveries and Balances</u>

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 2022-2023.

Rate Schedule CIG:
Number of Customers: 9 (including 4 CEGs)

- Event #1: 12/23/2022 12AM (Midnight) – 12/24/2022 10AM
- Event #2: 02/04/2023 10AM – 02/05/2023 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: 27

- Event #1: 12/23/2022 12AM (Midnight)– 12/25/2022 10AM
- Event #2: 02/03/2023 10AM – 02/05/2023 10AM

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

- Event #1: 12/23/2022 12AM (Midnight)– 12/24/2022 10AM
- Event #2: 02/03/2023 10AM – 02/04/2023 10AM

Rate Schedule CSG-I (Third Party Suppliers):
Number of Customers: 4

- Event #1: 12/23/2022 12AM (Midnight)– 12/24/2022 10AM
- Event #2: 02/03/2023 10AM – 02/04/2023 10AM

Rate Schedule CSG-I (Power Generation Stations):
Number of Customers: 4

- Event #1: 12/23/2022 12AM (Midnight)– 12/24/2022 10AM
- Event #2: 02/03/2023 10AM – 02/05/2023 10AM

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

Reports Dated:

April 18, 2023

January 17, 2023

October 13, 2022

July 20, 2022

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 18, 2023

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

Michael Kammer, Director
Division of Water and 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 2023

Dear Mr. Kammer:

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, 2023.

As shown on the attached schedules, hedging for the 2022/2023 winter season was 74% of plan and 76% of the plan has been completed for 2023 summer. Hedging for the 2023/2024 winter season is at 48% and the 2024 summer season is currently 30%. 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
Brian Lipman
Malike Cummings
Ben Witherell

PSE&G Residential Hedging Report
November 2022 - October 2023
As of March 31, 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	**17.365**	94%	100%	99%	**$4.21**
Dollar Budget Method	17.500	**8.486**	$1.884M/mo.		48%	**$3.93**
Total Winter Hedge Volume	35.000	**25.851**			74%	**$4.12**
SUMMER - Apr 23-Oct 23 Hedge Volume						
(160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**17.120**	94%	100%	98%	**$3.12**
Dollar Budget Method	17.500	**9.395**	$1.593M/mo.		54%	**$2.97**
Total Summer Hedge Volume	35.000	**26.515**			76%	**$3.06**
			3/31/23 Nymex Settles			**$2.54**

PSE&G Residential Hedging Report November 2023 - October 2024 As of March 31, 2023	Bcf Target*	Bcf Hedged	% Hedged Target		% Hedged Actual	Current Price/ MMBtu
WINTER - Nov 23-Mar 24 Hedge Volume						
(230,000/ day) (152 days)						
Non-Discretionary Volume	17.500	**10.640**	56%	61%	61%	**$4.40**
Dollar Budget Method	17.500	**6.004**	$2.389M/mo.		34%	**$4.33**
Total Winter Hedge Volume	35.000	**16.644**			48%	**$4.37**
			3/31/23 Nymex Settles			**$3.64**
SUMMER - Apr 24-Oct 24 Hedge Volume						
(160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**5.350**	28%	33%	31%	**$2.92**
Dollar Budget Method	17.500	**5.050**	$2.405M/mo.		29%	**$2.81**
Total Summer Hedge Volume	35.000	**10.400**			30%	**$2.87**
			3/31/23 Nymex Settles			**$3.43**

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

January 17, 2023

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

Michael Kammer, Director
Division of Water and 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 2022

Dear Mr. Kammer:

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, 2022.

As shown on the attached schedules, hedging for the 2022/2023 winter season is 74% of plan and 61% of the plan has been completed for 2023 summer. Hedging for the 2023/2024 winter season is at 33% and the 2024 summer season is currently 16%. 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
Brian Lipman
Malike Cummings
Ben Witherell

PSE&G Residential Hedging Report November 2022 - October 2023 As of December 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	**17.365**	94%	100%	99%	**$4.21**
Dollar Budget Method	17.500	**8.486**	$1.884M/mo.		48%	**$3.93**
Total Winter Hedge Volume	35.000	**25.851**			74%	**$4.12**
			12/30/22 Nymex Settles			**$5.04**
SUMMER - Apr 23-Oct 23 Hedge Volume						
(160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**13.910**	78%	83%	79%	**$3.31**
Dollar Budget Method	17.500	**7.362**	$1.593M/mo.		42%	**$3.16**
Total Summer Hedge Volume	35.000	**21.272**			61%	**$3.26**
			12/30/22 Nymex Settles			**$4.07**

PSE&G Residential Hedging Report November 2023 - October 2024 As of December 31, 2022	Bcf Target*	Bcf Hedged	% Hedged Target		% Hedged Actual	Current Price/ MMBtu
WINTER - Nov 23-Mar 24 Hedge Volume						
(230,000/ day) (152 days)						
Non-Discretionary Volume	17.500	**7.600**	39%	44%	43%	**$4.84**
Dollar Budget Method	17.500	**3.891**	$2.389M/mo.		22%	**$4.85**
Total Winter Hedge Volume	35.000	**11.491**			33%	**$4.84**
			12/30/22 Nymex Settles			**$4.76**
SUMMER - Apr 24-Oct 24 Hedge Volume						
(160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**3.210**	11%	17%	18%	**$3.18**
Dollar Budget Method	17.500	**2.247**	$2.405M/mo.		13%	**$3.18**
Total Summer Hedge Volume	35.000	**5.457**			16%	**$3.18**
			12/30/22 Nymex Settles			**$3.94**

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

VIA ELECTRONIC MAIL

October 13, 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, Bureau Chief
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 2022

Dear Bureau Chief 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, 2022.

As shown on the attached schedules, hedging for the 2022/2023 winter season is 69% of plan and 51% of the plan has been completed for 2023 summer. Hedging for the 2023/2024 winter season is at 20% and the 2024 summer season has not yet begun. 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
Brian Lipman
Mike Kammer
Ben Witherell

PSE&G Residential Hedging Report November 2022 - October 2023 As of 9/30/2022	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	**15.855**	89%	94%	91%	**$4.61**
Dollar Budget Method	17.500	**8.124**	$1.884M/mo.		46%	**$3.88**
Total Winter Hedge Volume	35.000	**23.979**			69%	**$4.36**
			09/30/22 Settles			**$6.81**
SUMMER - Apr 23-Oct 23 Hedge Volume						
(160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**11.770**	61%	67%	67%	**$3.23**
Dollar Budget Method	17.500	**6.142**	$1.593M/mo.		35%	**$3.03**
Total Summer Hedge Volume	35.000	**17.912**			51%	**$3.16**
			09/30/22 Settles			**$4.89**
Total Non-Discretionary Method	35.000	**27.625**				**$4.02**
Total Dollar Budget Method	35.000	**14.266**				**$3.51**
					Difference	**($0.51)**
					Percent	**-14.5%**

PSE&G Residential Hedging Report
November 2023 - October 2024
As of 9/30/2022

	Bcf Target*	Bcf Hedged	% Hedged Target		% Hedged Actual	Current Price/ MMBtu
WINTER - Nov 23-Mar 24 Hedge Volume						
(230,000/ day) (152 days)						
Non-Discretionary Volume	17.500	**4.560**	22%	28%	26%	**$4.79**
Dollar Budget Method	17.500	**2.447**	$2.389M/mo.		14%	**$4.80**
Total Winter Hedge Volume	35.000	**7.007**			20%	**$4.79**
			09/30/22 Settles			**$5.40**
SUMMER - Apr 24-Oct 24 Hedge Volume						
(160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**0.000**	0%	0%	0%	
Dollar Budget Method	17.500	**0.000**	$2.405M/mo.		0%	
Total Summer Hedge Volume	35.000	**0.000**			0%	**#DIV/0!**
			Current Nymex			

Total Non-Discretionary Method	35.000	**4.560**				**$0.00**
Total Dollar Budget Method	35.000	**2.447**				**$0.00**
					Difference	**$0.00**
					Percent	**#DIV/0!**

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

July 20, 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, Bureau Chief
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 2022

Dear Bureau Chief 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 June 30, 2022.

As shown on the attached schedules, hedging for the 2022/2023 winter season is 55% of plan and 39% of the plan has been completed for 2023 summer. Hedging for the 2023/2024 winter season is at 10% and the 2024 summer season has not yet begun. 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
Mike Kammer
Ben Witherell

PSE&G Residential Hedging Report November 2022 - October 2023 As of June 30, 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	**12.080**	72%	78%	69%	**$3.91**
Dollar Budget Method	17.500	**7.308**	$1.884M/mo.		42%	**$3.56**
Total Winter Hedge Volume	35.000	**19.388**			55%	**$3.78**
			6/30/22 Nymex Settles			**$5.50**
SUMMER - Apr 23-Oct 23 Hedge Volume						
(160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**8.560**	44%	50%	49%	**$2.94**
Dollar Budget Method	17.500	**4.965**	$1.593M/mo.		28%	**$2.82**
Total Summer Hedge Volume	35.000	**13.525**			39%	**$2.89**
			6/30/22 Nymex Settles			**$4.36**
Total Non-Discretionary Method	35.000	**20.640**				**$3.51**
Total Dollar Budget Method	35.000	**12.273**				**$3.26**
					Difference	**($0.25)**
					Percent	**-7.6%**

PSE&G Residential Hedging Report November 2023 - October 2024 As of June 30, 2022	Bcf Target*	Bcf Hedged	% Hedged Target		% Hedged Actual	Current Price/ MMBtu
WINTER - Nov 23-Mar 24 Hedge Volume						
(230,000/ day) (151 days)						
Non-Discretionary Volume	17.500	**2.280**	6%	11%	13%	**$4.51**
Dollar Budget Method	17.500	**1.049**	$2.389M/mo.		6%	**$4.47**
Total Winter Hedge Volume	35.000	**3.329**			10%	**$4.50**
			6/30/22 Nymex Settles			**$4.79**
SUMMER - Apr 24-Oct 24 Hedge Volume						
(160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**0.000**	0%	0%	0%	
Dollar Budget Method	17.500	**0.000**			0%	
Total Summer Hedge Volume	35.000	**0.000**			0%	**#DIV/0!**
			Current Nymex			
Total Non-Discretionary Method	35.000	**2.280**				**$4.51**
Total Dollar Budget Method	35.000	**1.049**				**$4.47**
					Difference	**($0.05)**
					Percent	**-1.0%**

12. Storage Gas Volumes, Prices and Utilization

Ending Storage Inventory by Contract

Mdth

Storage Contract	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23 * Est
DTI GSS	15,929.1	14,621.7	13,249.9	9,117.0	5,819.2	3,222.1	5,617.9
ARLINGTON	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TR GSS	15,125.4	15,247.4	13,974.1	11,316.8	8,642.2	4,707.3	5,447.7
TR S-2	5,636.5	5,663.6	4,525.9	3,190.2	1,991.1	1,617.4	1,739.7
TR LSS	4,950.9	4,517.9	3,356.7	2,249.2	1,394.6	1,210.6	1,727.0
TENN FS-MA	8,045.7	7,537.0	6,428.6	5,458.4	4,314.4	2,413.7	4,106.4
DTI GSS-TE	13,862.9	13,105.8	11,151.0	8,719.1	5,468.8	2,640.4	4,780.4
TE SS-1 / SS	3,669.6	3,586.2	2,953.8	2,021.6	1,173.7	651.3	1,092.6
TE SS1	1,423.2	1,395.3	1,163.9	797.7	494.0	294.9	462.8
TR ESS	1,186.5	1,186.5	953.4	1,184.3	903.4	1,186.5	1,186.5
GULF SOUTH	291.2	1,000.0	881.1	942.9	919.9	985.0	954.6
TR LNG	1,325.8	1,337.0	1,063.0	1,244.8	1,157.2	1,327.1	1,333.8
TR LNG New	15.5	15.5	15.5	15.5	15.5	15.5	15.5
Total	71,462.5	69,213.9	59,717.0	46,257.5	32,294.1	20,271.8	28,464.9
Ending Inventory Cost ($/Dth)	$6.92	$6.84	$6.82	$6.76	$6.65	$6.45	$5.21

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-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
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

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-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	45	$526	77	$988	25	$347	63	$579
May-22	45	$526	77	$988	25	$347	63	$579
Jun-22	45	$526	77	$988	25	$347	63	$579
Jul-22	45	$526	77	$988	25	$347	63	$579
Aug-22	45	$526	77	$988	25	$347	63	$579
Sep-22	45	$526	77	$988	25	$347	63	$579
Oct-22	48	$563	103	$1,366	55	$814	63	$579
Nov-22	48	$563	103	$1,366	65	$973	63	$579
Dec-22	46	$534	82	$1,091	78	$1,179	62	$574
Jan-23	45	$529	80	$1,065	57	$852	62	$574
Feb-23	45	$527	80	$1,065	57	$852	62	$574
Mar-23	42	$493	73	$971	57	$852	62	$574
Apr-23 est	42	$493	73	$971	57	$852	62	$574
May-23 est	42	$493	73	$971	57	$852	62	$574
Jun-23 est	42	$493	73	$971	57	$852	62	$574
Jul-23 est	42	$493	73	$971	57	$852	62	$574
Aug-23 est	42	$493	73	$971	57	$852	62	$574
Sep-23 est	42	$493	73	$971	57	$852	62	$574
Oct-23 est	42	$493	73	$971	57	$852	62	$574
Nov-23 est	42	$493	73	$971	57	$852	62	$574
Dec-23 est	42	$493	73	$971	57	$852	62	$574

LNG INVENTORY VOLUMES AND COST
(000)

Month	Dth	Dollars	Month	Dth	Dollars
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	198	$193
May-20	213	$170	May-22	234	$245
Jun-20	206	$165	Jun-22	227	$238
Jul-20	199	$159	Jul-22	219	$230
Aug-20	285	$250	Aug-22	211	$222
Sep-20	299	$269	Sep-22	203	$213
Oct-20	292	$263	Oct-22	224	$205
Nov-20	284	$256	Nov-22	254	$197
Dec-20	271	$245	Dec-22	229	$249
Jan-21	246	$222	Jan-23	244	$239
Feb-21	217	$196	Feb-23	190	$209
Mar-21	209	$188	Mar-23	180	$197
Apr-21	201	$182	Apr-23 est	172	$188
May-21	195	$176	May-23 est	172	$188
Jun-21	257	$244	Jun-23 est	172	$188
Jul-21	276	$265	Jul-23 est	172	$188
Aug-21	269	$259	Aug-23 est	172	$188
Sep-21	259	$249	Sep-23 est	172	$188
Oct-21	298	$291	Oct-23 est	172	$188
Nov-21	289	$283	Nov-23 est	172	$188
Dec-21	277	$271	Dec-23 est	172	$188

13. Affiliate Gas Supply Transactions

Item 13

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

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 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	68,175	74,827	74,836	61,301	43,383	28,129	19,860	23,022	30,238	40,240	49,686	58,508	
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	83,892	91,927	93,827	81,218	62,590	43,837	37,108	37,988	44,820	53,705	62,662	71,911	
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	74,827	74,836	61,301	43,383	28,129	19,860	23,022	30,238	40,240	49,686	58,508	67,360	

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	**67,360**	76,469	74,521	65,404	46,615	31,008	18,057	18,728	29,504	39,222	49,446	57,430	
Natural Gas Receipt	15,649	19,717	17,656	23,741	15,537	11,230	15,747	17,928	14,461	13,905	11,895	14,763	192,229
Total Inventory Available	83,009	96,186	92,177	89,145	62,152	42,238	33,804	36,657	43,964	53,127	61,341	72,193	
Gas Demand (MDTh)													
Firm Sendout	6,540	21,664	26,773	42,530	31,143	24,181	15,076	7,153	4,742	3,681	3,911	4,561	191,956
Ending Inventory MDTh	76,469	74,521	65,404	46,615	31,008	18,057	18,728	29,504	39,222	49,446	57,430	67,632	

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	**67,632**	77,963	76,065	66,653	51,607	36,772	24,742	32,658	45,601	48,687	50,899	53,071	
Natural Gas Receipt	20,979	17,616	24,132	14,306	13,019	13,813	19,346	20,936	7,807	6,288	6,023	13,169	177,433
Total Inventory Available	88,611	95,578	100,196	80,959	64,627	50,586	44,088	53,594	53,408	54,975	56,923	66,240	
Gas Demand (MDTh)													
Firm Sendout	10,649	19,514	33,543	29,352	27,854	25,843	11,430	7,993	4,721	4,075	3,852	4,213	183,039
Ending Inventory MDTh	77,963	76,065	66,653	51,607	36,772	24,742	32,658	45,601	48,687	50,899	53,071	62,027	

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	**62,027**	74,594	68,740	49,743	30,967	14,615	4,738	5,888	13,342	26,769	38,658	48,761	
Natural Gas Receipt	21,806	15,358	14,015	19,963	18,762	18,322	16,362	16,177	18,169	15,772	13,827	16,237	204,768
Total Inventory Available	83,833	89,952	82,755	69,707	49,729	32,937	21,099	22,065	31,511	42,541	52,485	64,997	
Gas Demand (MDTh)													
Firm Sendout	9,238	21,212	33,011	38,740	35,114	28,199	15,211	8,722	4,742	3,883	3,724	4,187	205,985
Ending Inventory MDTh	74,594	68,740	49,743	30,967	14,615	4,738	5,888	13,342	26,769	38,658	48,761	60,811	

FIRM GAS SUPPLY AND DEMAND DATA (October 2024- September 2025)

	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Total
Gas Supplies (MDTh)													
Beginning Inventory	**60,811**	73,599	67,509	48,425	29,389	13,882	3,861	4,806	12,369	25,875	37,846	47,993	
Natural Gas Receipt	22,057	15,421	13,946	20,013	18,787	18,290	16,222	16,127	18,218	15,736	13,771	16,320	204,907
Total Inventory Available	82,867	89,020	81,455	68,438	48,176	32,173	20,082	20,934	30,588	41,610	51,617	64,314	
Gas Demand (MDTh)													
Firm Sendout	9,268	21,511	33,030	39,049	34,294	28,312	15,276	8,564	4,713	3,764	3,623	4,119	205,523
Ending Inventory MDTh	73,599	67,509	48,425	29,389	13,882	3,861	4,806	12,369	25,875	37,846	47,993	60,195	

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
2022 / 2023 WINTER								
	3-Feb-23	15.0	2551	2315	236	1196	1350	5
	24-Dec-22	15.5	2456	2326	130	1238	1204	14
	23-Dec-22	17.6	2272	2111	161	1336	936	0
	25-Dec-22	23.1	2131	2010	121	1198	933	0
	4-Feb-23	25.1	2102	1993	108	808	1292	1
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. Capacity Contract Changes

Including Gas Sales Forecast Support

Item 16

Schedule F

May-23

PEAK DAY GAS REQUIREMENTS AND SUPPLY

	SUPPLY		2023-2024	2024-2025	2025-2026	2026-2027	2027-2028
	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		212.4	212.4	212.4	212.4	212.4
	Total Peaking Supply		582.1	582.1	582.1	582.1	582.1
	PSEG Firm Supply Subtotal		2,904.9	2,904.9	2,904.9	2,904.9	2,904.9
	FTS DCQ 1./		301.1	300.7	299.6	302.3	300.3
[a]	Total PSEG Gas Supply		3,205.9	3,205.6	3,204.4	3,207.2	3,205.1
	Peak Day Sendout Forecast 2./		3,058.0	3,071.0	3,069.0	3,076.0	3,061.0
[b]	Total Peak Day Capacity Requirements	3./	3,194.8	3,205.4	3,203.2	3,210.6	3,197.3
[a]-[b]	Surplus / (Deficiency)	3./	11.1	0.1	1.3	(3.5)	7.8

1./ Forecasted FT-S DCQ (January)

2./ Based on Corporate Energy Forecast, Gas-2023

3./ 3% Loss of Load Probability

Natural Gas Sales Forecast - 2023

Public Service Electric & Gas Company

Finance Department

Electric and Gas Sales and Revenue Forecasting Group

September 2022

Contents

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 2023 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:

$$\text{THERM/CUST}_t = f(\overline{\text{MONTH}}\text{x}\text{HDD}_t \times \text{PRICEGAS}_{a-1}, \overline{\text{MONTH}}\text{x}\text{HDD}_t \times \text{INCOME}_{a-1}, \overline{\text{MONTH}}\text{x}\text{HDD}_t) \qquad [2]$$

where:

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

RSG Heating model was estimated using monthly data from January 2010 to December 2021 period while RSG No-Heating model was estimated using monthly data from January 2019 to December 2021. 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

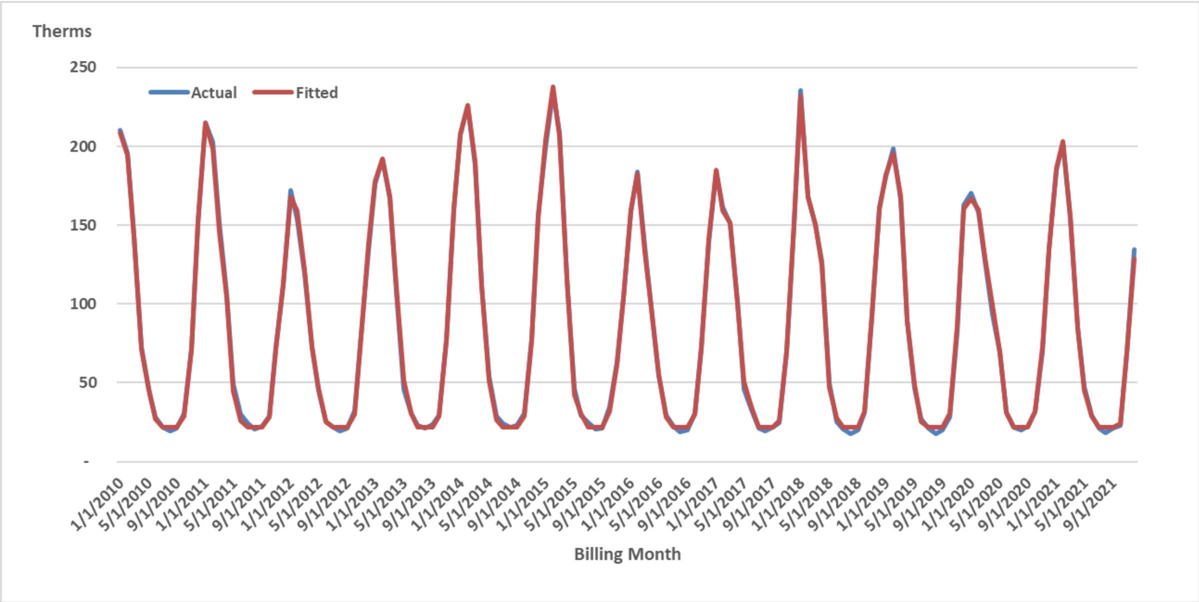
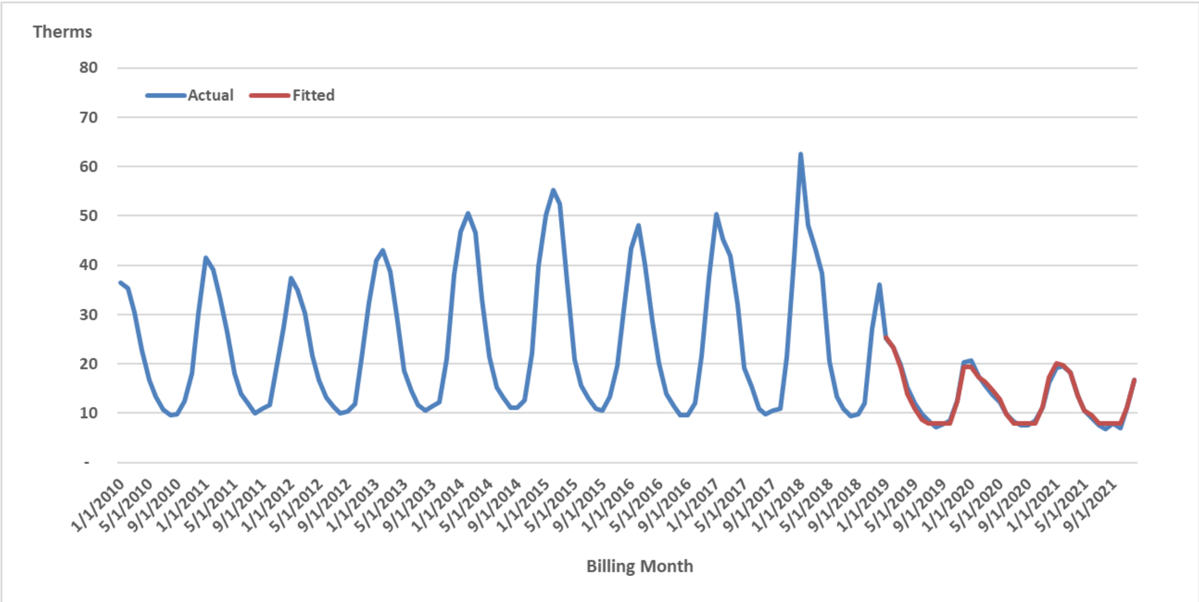


Figure 2
RSG Non-Space Heating Model
Actual vs. Fitted Values



The price elasticity estimates were estimated to be -0.0103 and -0.2101 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	0.20747	0.19926	0.19586	0.19037	0.13935	0.18614	0.05772	0.18472	0.999	1.588	144
	(0.007)	(0.006)	(0.006)	(0.009)	(0.004)	(0.019)	(0.008)	(0.007)			
		DJF*				**A**	**C**				
PRICE x HDD		-0.00507		**COVID x HDD**		0.0137	0.0009				
		(0.002)				(0.008)	(0.001)				
		ON**									
WAGE x HDD		0.00114									
		(0.000)									

* Dec-Jan-Feb
** Oct-Nov

	JAN	FEB	MAR	APR	MAY	JUNE	NOV	DEC	R2	DW	n
NON-HEATING											
HDD	0.03325	0.02620	0.01389	0.01454	0.01602	0.04181	0.01080	0.01416	0.984	1.027	36
	(0.003)	(0.003)	(0.001)	(0.001)	(0.002)	(0.013)	(0.001)	(0.001)			
PRICE x HDD	-0.01459	-0.01052									
	(0.003)	(0.003)									

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:

$$\text{THERMS} = f(\text{PRICEGAS, OUTPUT, HDD}) \qquad [3]$$

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:

$$\text{OUTPUT} = f(\text{INCOME, HSH}) \qquad [4]$$

Substituting [4] into [3] yields:

$$\text{THERMS} = f(\text{PRICEGAS, INCOME, HSH, HDD}) \qquad [5]$$

LVG model was estimated for customers in the commercial sector using monthly billing data from January 2010 to December 2021 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 and GSG Non-Heating model set from January 2010 to December 2021 period for the model estimations. 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 -0.2085 the non-space heating customers are not, and the large commercial LVG customers are sensitive to price, with an estimated elasticity of -0.1193. 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

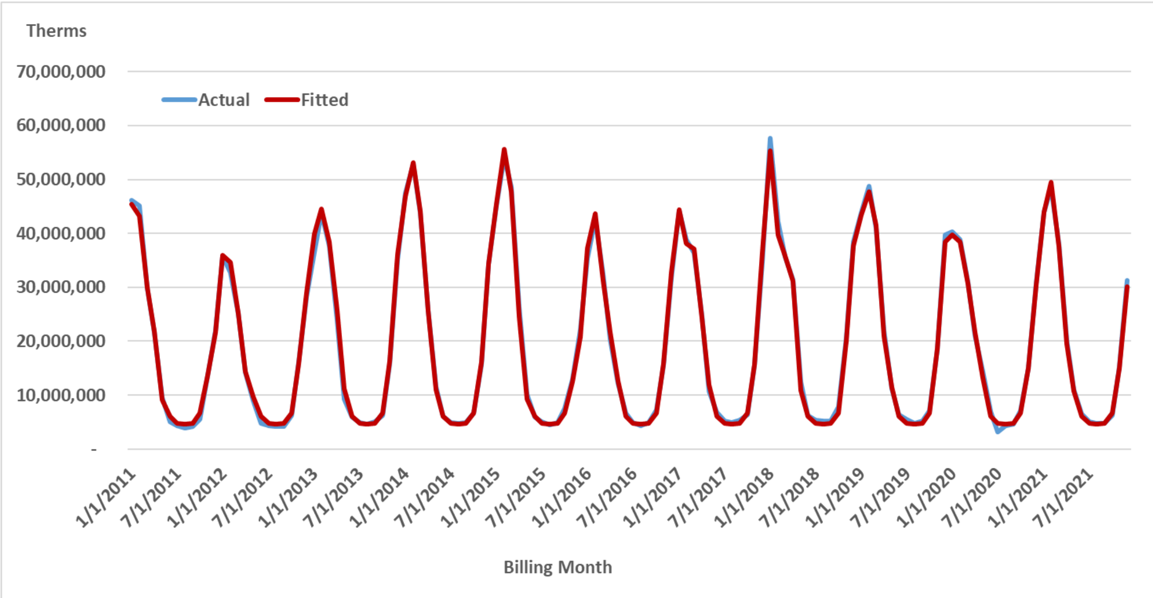


Figure 4
GSG Commercial Non-Space Heating Model
Actual vs. Fitted Values

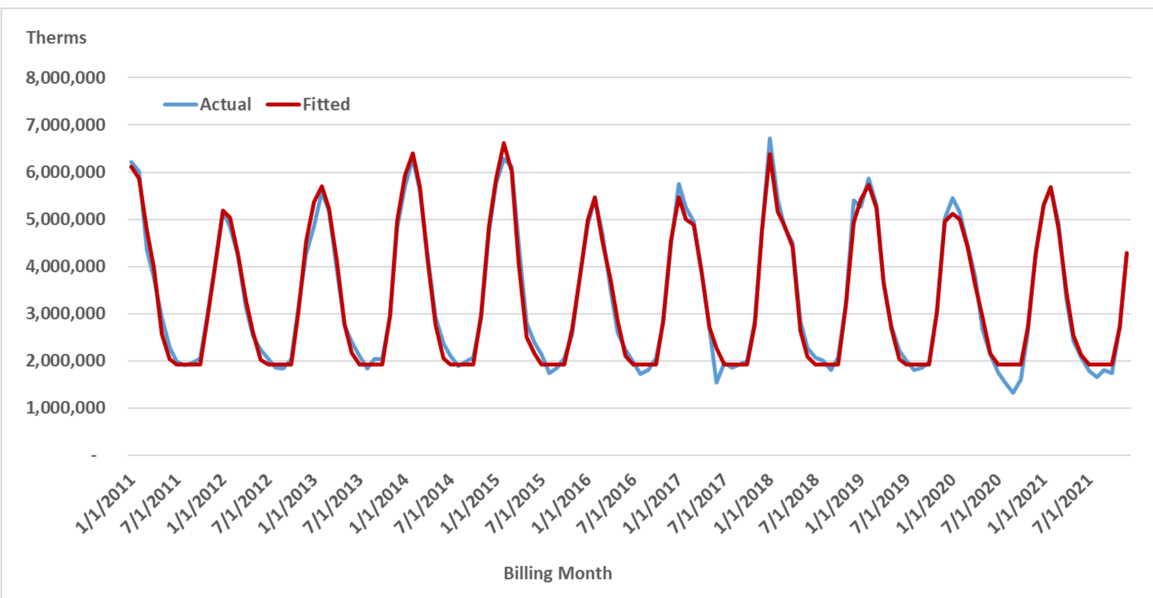


Figure 5

LVG Commercial Model

Actual vs. Fitted Values

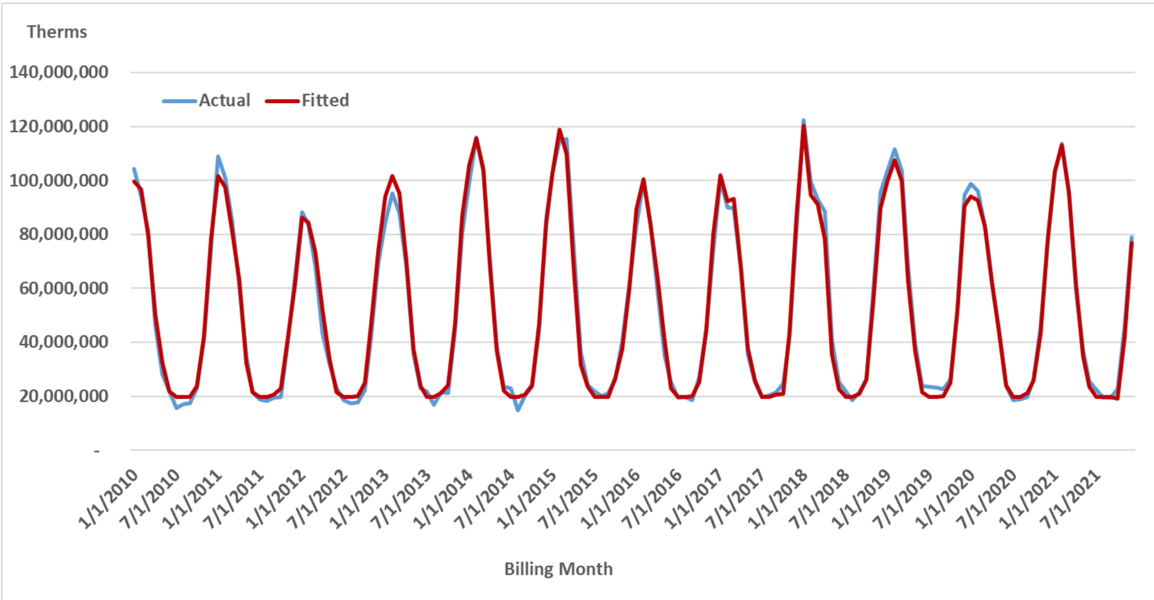


Table 2

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	-12340	-11197	-13840	-12741	-20477		-17475	-13906	0.997	1.576	132
	(2,064)	(2,169)	(2,726)	(4,346)	(12,206)		(5,345)	(3,033)			
CUST x HDD	19.03	19.18	20.19	20.61	14.51		15.40	19.20			
	(0.8)	(0.8)	(1.0)	(1.6)	(3.4)		(2.4)	(1.0)			
	A	B									
COVID x HDD	-5053	-1334									
	(2,017)	(614)									
NON-HEATING											
HDD	3907	4014	4047	4118	3863	4938	2625	3709	0.984	1.333	132
	(71)	(72)	(86)	(141)	(326)	(1,597)	(176)	(92)			
	A	B									
COVID x HDD	-618	-200									
	(371)	(117)									

Table 3

Estimated Coefficients of the LVG Commercial Gas Sales Models

(standard errors in parentheses)

HDD x PRICE	HDD x CUST	COVID x HDD A	COVID x HDD B	R2	DW	n
-26003	32	-11745	-531	0.990	1.011	144
(3,909)	(1)	(6,344)	(2,241)			

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:

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

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:

$$THERMS_t = f(HDD_t \times PRICEGAS_{a-1}, HDD_t \times EMP_{a-1}, HDD_t) \qquad [8]$$

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 2021 period while Non-Heating model is estimated for using monthly billing data from January 2013 to December 2021 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 2021 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

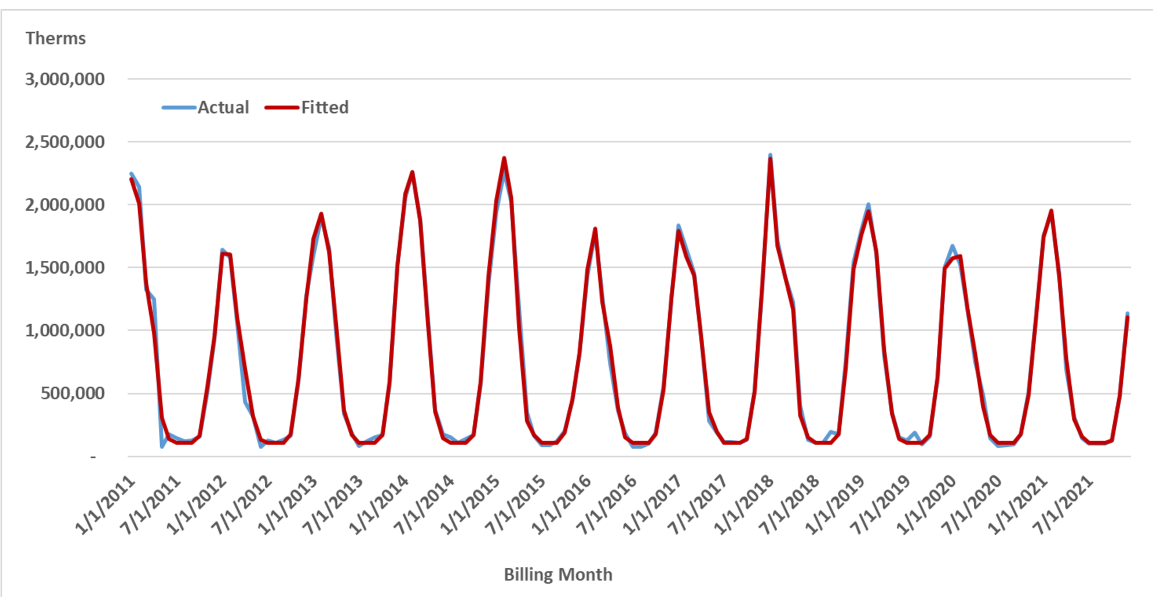


Figure 7
GSG Industrial Non-Space Heating Model
Actual vs. Fitted Values

Figure 8
LVG Industrial Heating Model
Actual vs. Fitted Values

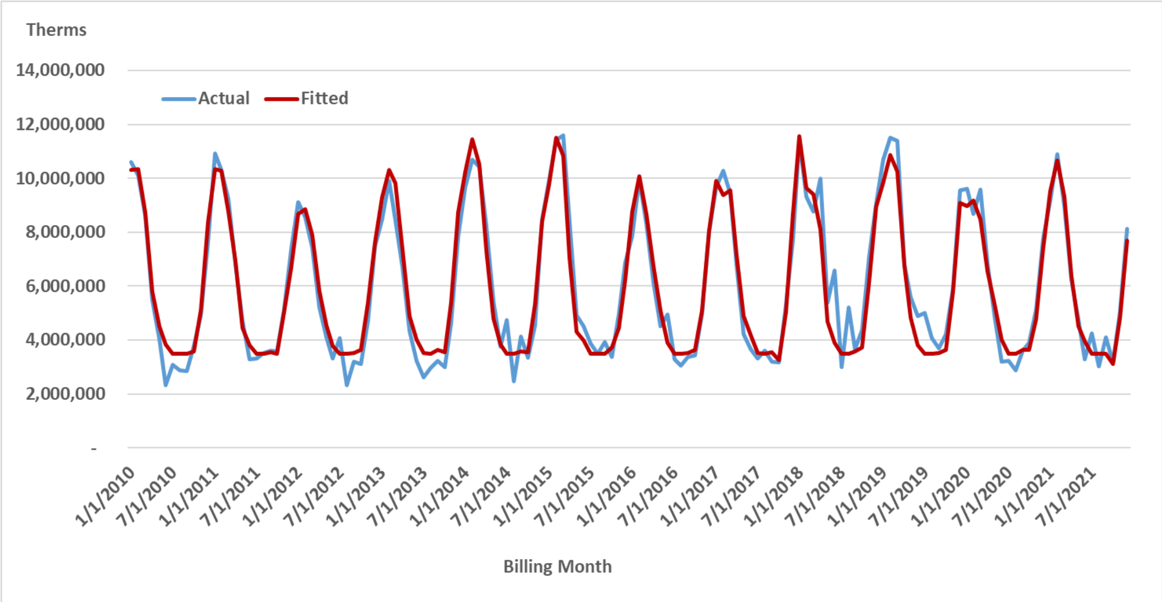


Table 4

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	2463	1934	2215	1748	1160	1195	633	1220	2154	0.993	2.228	132
	(174)	(23)	(150)	(46)	(105)	(515)	(226)	(57)	(183)			
	A	B										
COVID x HDD	-257	-66										
	(117)	(37)										
NON-HEATING												
HDD	234	138	243	229	163			139	259	0.874	2.039	120
	(14)	(84)	(16)	(27)	(61)			(33)	(17)			
	A	B										
COVID x HDD	-34	-1										
	(69)	(22)										

Table 5

Estimated Coefficients of the
LVG Industrial Gas Sales Models
(standard errors in parentheses)

HDD x PRICE	HDD x EMP	COVID x HDD		R2	DW	n
		A	B			
-2597	39	-914	-459	0.941	1.516	144
(968)	(4)	(1,242)	(455)			

II Forecast Assumptions

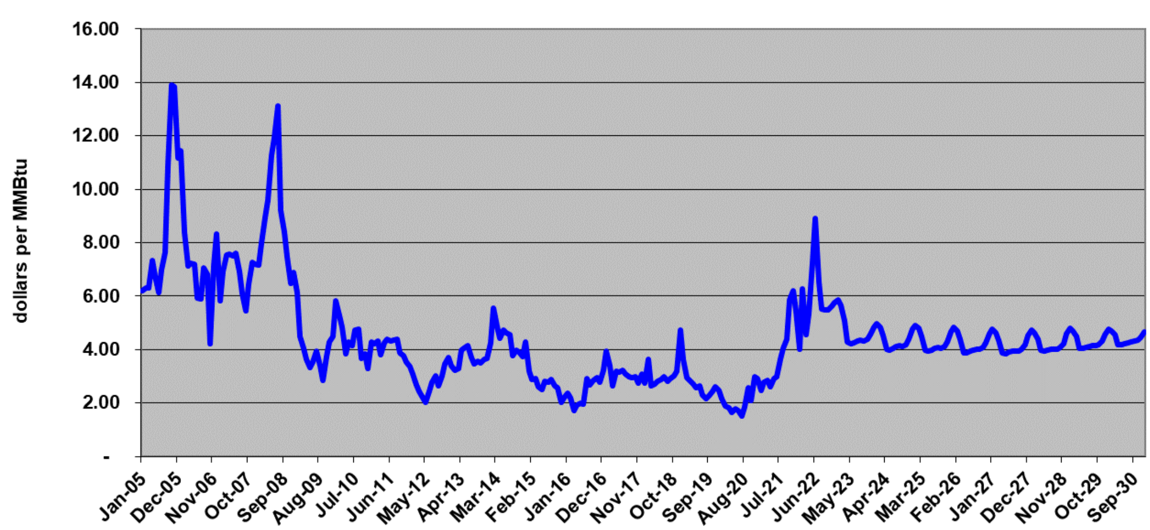
The models described above, in concert with assumptions about future prices and local economic and demographic parameters, were utilized to produce a forecast of billed natural gas delivered sales by rate for the residential, commercial, and industrial customer classes. The assumptions and the forecasts 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, 2022. As figure 9 shows, the wholesale price of gas is projected to stay relatively stable during the 2022-2029 periods.

Figure 9

NYMEX Natural Gas Futures Prices, July 6, 2022
($/MMBtu)



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	0.82	1.36	1.02	1.04	0.84	1.01	1.07	0.77
2022	0.97	1.37	1.10	1.33	0.91	1.29	1.35	1.07
2023	1.09	1.51	1.09	1.28	0.87	1.29	1.33	1.04
2024	1.03	1.44	1.01	1.21	0.90	1.21	1.25	0.97
2025	1.10	1.51	1.08	1.27	0.93	1.27	1.31	0.99
2026	1.07	1.48	1.06	1.25	0.91	1.25	1.29	0.98
2027	1.15	1.56	1.13	1.32	0.94	1.32	1.36	1.01
2028	1.22	1.63	1.18	1.38	0.97	1.36	1.41	1.03
2029	1.31	1.72	1.24	1.43	1.00	1.41	1.46	1.06
2030	1.40	1.81	1.33	1.52	1.04	1.50	1.55	1.09
2031	1.42	1.83	1.33	1.52	1.04	1.50	1.55	1.10
2032	1.09	1.50	1.09	1.27	0.91	1.25	1.30	0.97
2033	1.09	1.50	1.09	1.27	0.91	1.25	1.30	0.97
2034	1.09	1.50	1.09	1.27	0.91	1.25	1.30	0.97
2035	1.09	1.50	1.09	1.27	0.91	1.25	1.30	0.97

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	14,596,330	1,014,482	-
2011	16,831,360	3,286,510	-
2012	12,618,148	4,213,546	-
2013	14,974,182	5,039,977	-
2014	17,382,618	6,586,486	-
2015	17,361,247	6,989,516	-
2016	18,497,175	7,495,738	-
2017	19,852,982	8,348,880	-
2018	22,055,381	9,278,342	-
2019	22,760,483	8,941,105	-
2020	23,414,574	10,475,843	1,214,524
2021	29,100,748	9,957,697	6,978,195
2022	26,222,532	9,608,747	21,136,341
2023	22,509,898	8,137,942	39,588,634
2024	21,650,010	8,420,245	59,629,458
2025	20,624,395	9,239,028	82,689,574
2026	19,357,357	8,385,886	106,477,515
2027	17,336,599	7,191,938	132,972,229
2028	15,336,888	6,779,179	158,913,247
2029	14,061,212	2,972,413	179,354,570
2030	12,588,250	2,563,522	191,297,509
2031	11,294,115	2,086,041	198,946,301
2032	9,680,670	2,010,338	205,006,562
2033	8,067,225	1,325,004	205,171,618
2034	6,453,780	-	205,171,618
2035	4,840,335	-	205,171,618

Economic Projections

Economic and demographic forecast assumptions for the nation and New Jersey are from Moody's Economy July 2022 forecast. This forecast captures impact of COVID-19 on economy which assumes that, nationally, the economy will recover at a slow rate after pandemic. Tighter monetary and financial conditions to reduce stubbornly high inflation will slow economic growth. This national forecast is expected to be reflected in New Jersey's economic outlook that is also expected to be at a slow pace. 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, 2021.

Table 8

National and New Jersey Economic Forecast Assumptions

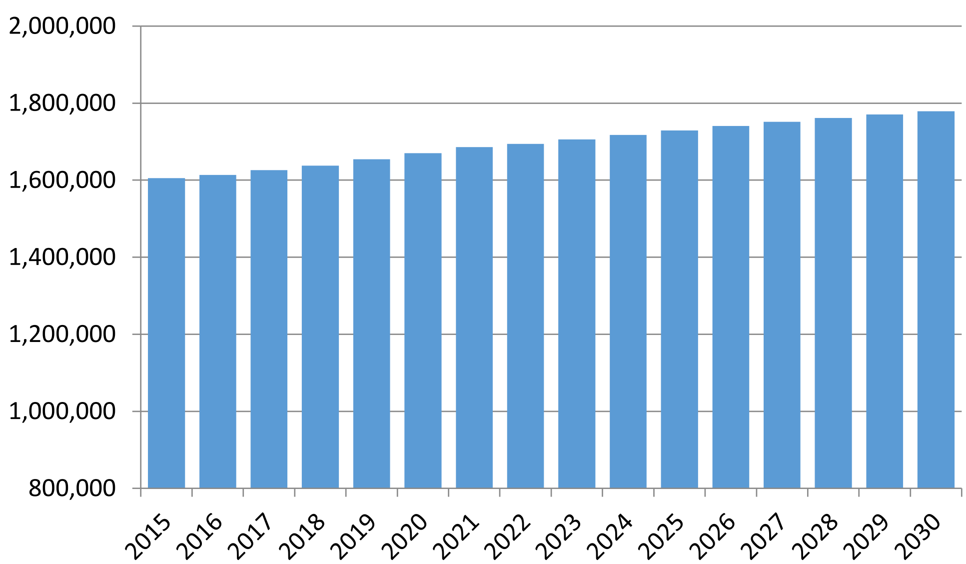
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
United States														
Gross Domestic Product, (Bil. USD, SAAR)	19,480	20,527	21,372	20,897	22,997	24,962	26,271	27,589	28,896	30,238	31,571	32,930	34,333	35,729
Industrial Production: Total, (Index 2012=100, SA)	100	103	102	95	100	106	108	110	112	113	114	116	118	119
Income: Personal - Total, (Bil. Ch. 2009 USD, SAAR)	15,889	16,346	16,762	17,647	18,272	17,763	18,218	18,767	19,214	19,676	20,138	20,606	21,075	21,536
Employment: Total Nonagricultural, (Mil. #, SA)	147	149	151	142	146	152	154	155	156	157	157	158	159	160
Household Survey: Unemployment Rate, (%, SA)	4.4	3.9	3.7	8.1	5.4	3.6	3.7	3.7	3.8	4.1	4.1	4.1	4.1	4.1
CPI: Urban Consumer - All Items, (Index 1982-84=100, SA)	245	251	256	259	271	291	300	307	314	321	328	335	342	350
Interest Rates: 3-Month Treasury Bills EBY, (% p.a., NSA)	0.9	2.0	2.1	0.4	0.0	1.6	3.5	3.0	2.5	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	3.8	4.9	5.7	5.7	5.9	6.2	6.2	6.2	6.2	6.1
New Jersey														
Real Personal Income, (Mil. 09$, SAAR)	539,796	551,146	563,195	586,604	600,681	580,203	592,487	608,647	621,807	634,912	647,534	660,082	672,561	684,156
Employment: Total Nonagricultural, (Ths., SA)	4,124	4,161	4,198	3,857	4,021	4,200	4,253	4,286	4,301	4,304	4,308	4,313	4,319	4,322
Employment: Total Manufacturing, (Ths., SA)	247	250	251	238	240	246	248	248	248	246	243	241	238	235
Employment: Total Non-Manufacturing, (Ths., SA)	3,877	3,911	3,947	3,619	3,780	3,954	4,005	4,038	4,053	4,059	4,065	4,073	4,081	4,086
Labor: Unemployment Rate, (%, SA)	4.5	4.0	3.4	9.5	6.4	4.0	4.0	3.9	4.0	4.2	4.3	4.3	4.3	4.3
Population: Total, (Ths.)	8,886	8,885	8,878	8,865	8,863	8,884	8,909	8,920	8,921	8,920	8,916	8,911	8,905	8,898
Households: Total, (Ths.)	3,343	3,353	3,362	3,354	3,364	3,379	3,394	3,403	3,409	3,413	3,415	3,417	3,420	3,424
Housing Starts: Single-family, (#, SAAR)	11,707	12,291	12,288	13,333	14,573	15,490	18,485	18,826	18,286	17,578	16,352	14,860	13,839	12,874

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 1.5 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

Annual Gas Residential Customers



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.

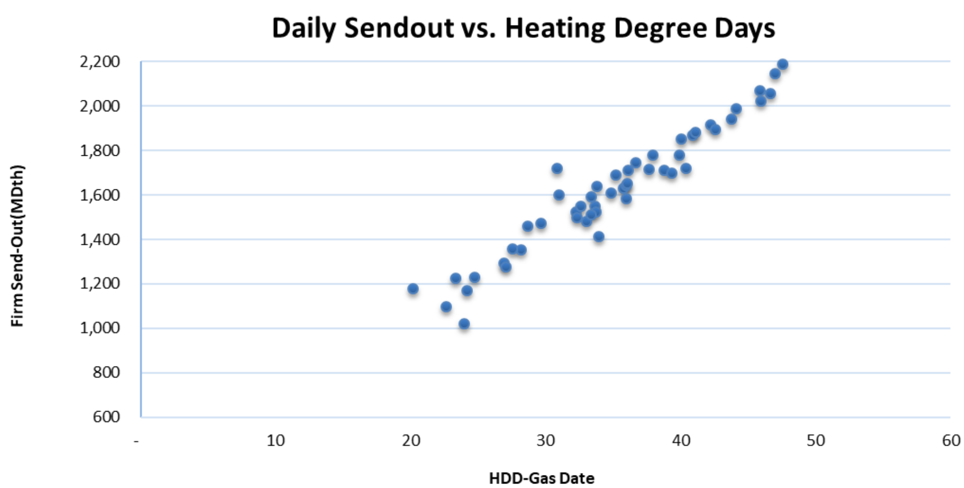
The second issue, of extrapolation, is addressed in a similar way. The relationship between sendout and weather is fairly linear. In reality, it is probably not perfectly linear. This is not an issue when estimating a model and using the results to interpolate values with the range of the estimation 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 - February 2022 due to 2023 weather being one of the warmest winter on records in NJ. 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:

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

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

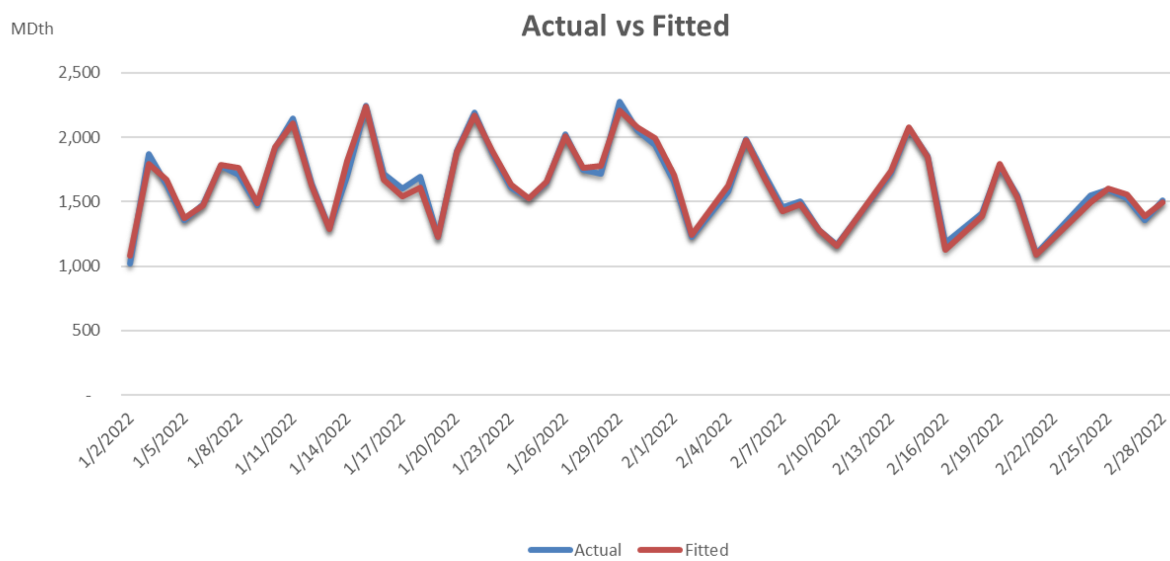
Estimated Coefficients of the Daily Sendout Model

(standard errors in parentheses)

	HDD									
Intercept	**HDD**	**LAG**	**HOLIDAY**	**WEEKDAY**	**WIND-SPEED**	**SKY COND**	**SNOW**	**R2**	**DW**	**n**
-34.1	36.9	7.4	-0.91	0.38	13.1	11.8	-72.8	0.9841	1.793	59
(43.9)	(0.9)	(0.8)	(0.6)	(0.4)	(2.2)	(4.4)	(24.1)			

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 2220 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.

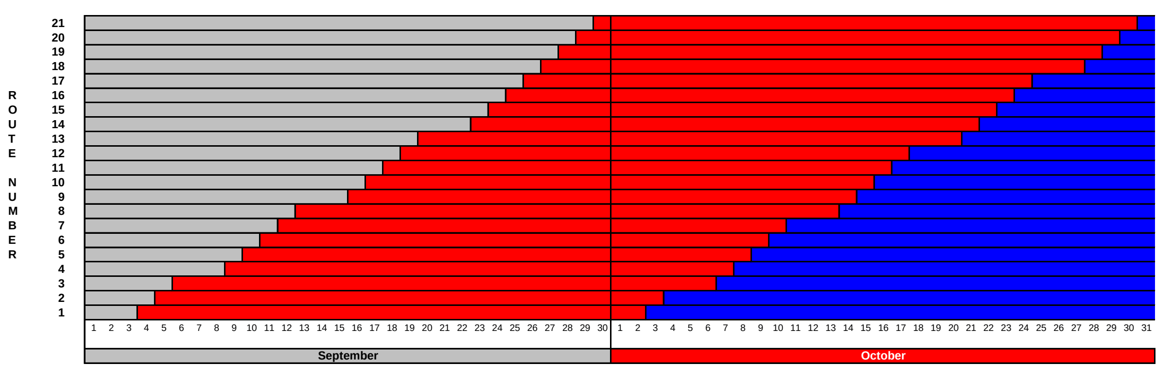
The Unbilled and Calendar-Month Estimation

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.

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

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

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

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

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

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

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

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.

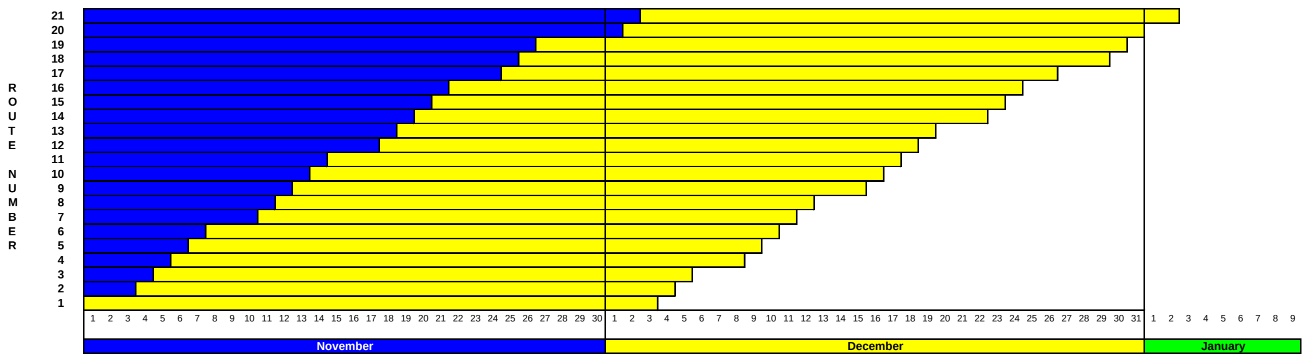
A More General Example

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 = $\boxed{\begin{array}{l}\text{OCT B> DEC}\\ \text{NOV B> DEC}\\ \text{DEC B> DEC}\\ \text{JAN B> DEC}\end{array}}$ [8]

Given the additional components of the billed, $\boxed{\text{OCT B> DEC}}$, i.e. the "under billed" sales, and $\boxed{\text{JAN B> DEC}}$, 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 = $\boxed{\begin{array}{l}\text{DEC B> JAN}\\ \text{DEC B> FEB}\end{array}}$ + $\boxed{\text{NOV B> JAN}}$ - $\boxed{\text{JAN B> DEC}}$ [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:

$$\boxed{\begin{array}{l}\text{DEC B> OCT}\\ \text{DEC B> NOV}\\ \text{DEC B> DEC}\\ \text{DEC B> JAN}\end{array}} = \boxed{\begin{array}{l}\text{OCT B> DEC}\\ \text{NOV B> DEC}\\ \text{DEC B> DEC}\\ \text{JAN B> DEC}\end{array}}$$

$$+ \boxed{\begin{array}{l}\text{DEC B> JAN}\\ \text{DEC B> FEB}\end{array}} + \boxed{\text{NOV B> JAN}} - \boxed{\text{JAN B> DEC}}$$

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

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

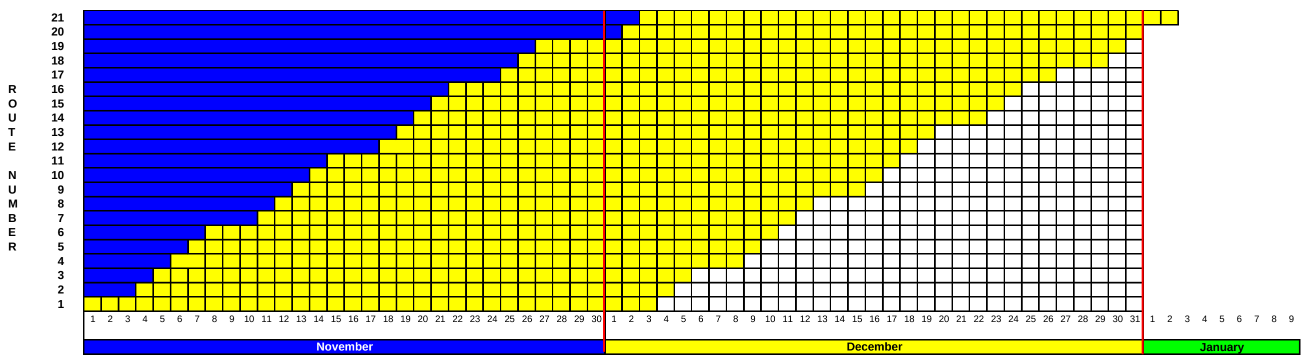
	RSG				GSG-Commercial				GSG-Industrial				LVG - Non Vehicle			
Billing	Heating		Non-heating		Heating		Non-heating		Heating		Non-heating		Commercial		Industrial	
Month	Base	HDD	Base	HDD	Base	HDD	Base	HDD	Base	HDD	Base	HDD	Base	HDD	Base	HDD
Jan-08	1,477,624	246,082	218,393	4,689	56,941	45,607	168,133	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, 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:

UnbilledTherms = UnbilledDays x BASECoef + UnbilledHDD x HDDCoef [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. All parties have agreed to a one-year extension of the settlement and pro forma filing deadlines.
Transco	CP21-94	On March 26, 2021, Transco applied for approval of the Regional Energy Access Project that includes incremental firm transportation of 60,000 dekatherms/day to the Company. FERC recently issued this project's certificate and notice to proceed. Court appeals remain pending. The current timeline is projected to have this project go into service in the fourth quarter of 2024.
TETCO	RP21-1001 & RP21-1188	On July 30, 2021 Texas Eastern filed a General Section 4 rate case in RP21-1001, which was then supplemented by a second rate case filing in RP21-1188. The Company protested both of these filings and was 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 retained an expert witness that assisted in the pursuit of cost of service and operational issues. FERC approved an uncontested settlement on November 30, 2022 for rates effective February 1, 2023, and refunds were received in April 2023.
EGTS	RP21-1187	On September 30, 2021 Eastern Gas Transmission and Storage filed a General Section 4 rate case in RP21-1187. The Company protested the application and was 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 retained an expert witness that assisted them in the pursuit of cost of service and operational issues. FERC approved an uncontested settlement on November 30, 2022 for rates effective January 1, 2023 and refunds were received in February 2023.
Florida Gas Transmission Company, LLC	RP23-466	Florida Gas proposes certain RNG tariff principles that are the subject of this proceeding. FERC issued an order stating that actions in this case could have precedential effect elsewhere, leading to the Company's decision to submit an intervention, even though it is not a customer, because of the Company's efforts to develop its own RNG capabilities. FERC established hearing procedures in this matter, but placed those actions in abeyance pending the outcome of a technical conference

		scheduled for May 23, 2023. The Company plans to participate.
TETCO	CP22-486	The Appalachia to Market II project has a total project capacity of 55,000 Dth/d from the Appalachia supply basin. The Company has executed a binding 15-year 25,000/day precedent agreement calling for delivery of 19,810 dth/day at South Plainfield and 5,190/day at Jamesburg. The current timeline is projected to have this project go into service in the fourth quarter of 2025.
Tennessee	Potential Section 4 rate case initiative	Tennessee has announced its intent to initiate settlement discussions with its stakeholders to implement unspecified rate changes outside of FERC's typical formal Section 4 rate case procedures. The pipeline has organized an in-person conference scheduled for June 5. The Company plans to attend and actively participate in any proceeding that then follows.

18. <u>Gas Supply Plan</u>

Gas Procurement Objectives

Current & Forecasted Gas Service Requirements

Projected Sources of Capacity

Affiliate Relationship / Asset Management

Hedging Plan & Strategy

Capacity Releases / Off-System Sales

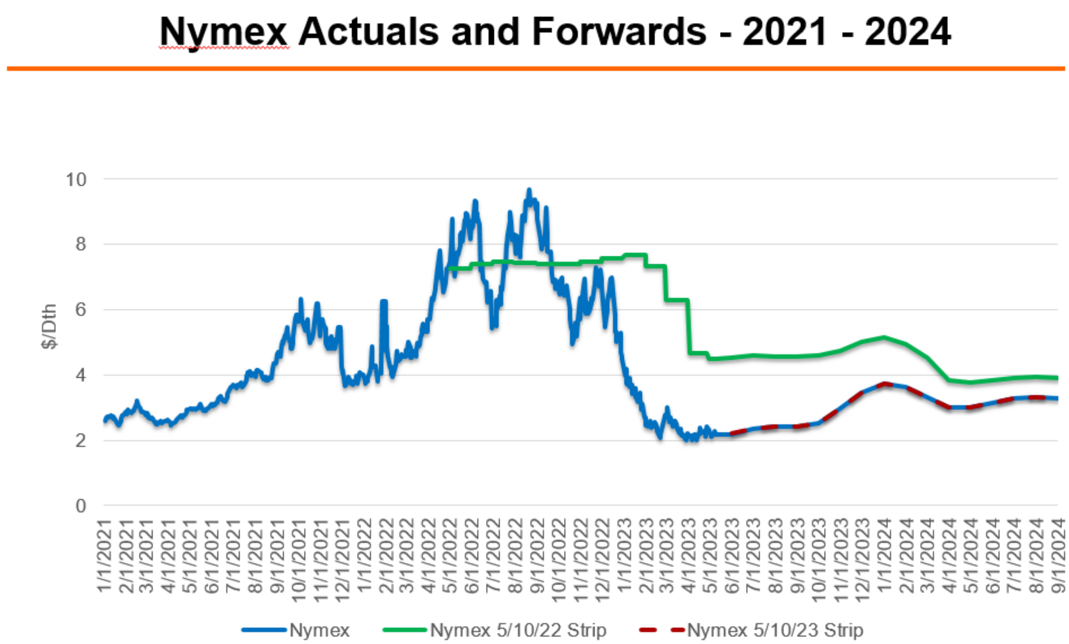
Item 18

Gas Supply Plan

1. Gas Procurement Objectives

As discussed in the body of the testimony of David F. Caffery herein, natural gas prices were extremely volatile during the most recent BGSS period, having increased dramatically from the levels experienced in early 2022, trading at highs not seen since 2008, followed by a dramatic decline through the 2022/2023 winter. NYMEX prompt month daily prices have traded between approximately \$3.75/Dth in the middle of January 2022, to as high as \$9.65 in August 2022, followed by a dramatic decline to about \$2.00 in March 2023. Current prices for June trading are at approximately \$2.50/Dth. The forward (May 10th) NYMEX strip used by the Company in this filing (see Item 8) shows that average prices are 54% lower than last year's NYMEX strip. Based upon the forward strip, prices are expected to increase above current levels by \$1.00 to \$1.35/Dth through the rest of 2023, as well as an additional \$0.30/Dth in January and February of 2024, followed by a modest decrease from \$3.70/Dth to about \$3.30/Dth during April 2024 through September 2024, the end of this BGSS period.

This dramatic decrease in NYMEX prices during late 2022 and into Q1 2023, illustrated in the chart below, is the primary driver of the requested decrease 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, 2023 period. The green line represents the NYMEX forward strip as of May 10, 2022 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, 2023 that is the basis for this year's BGSS Filing. As can be seen on the chart, the projected decrease in prices during the upcoming BGSS period compared to last year's filing is significant, particularly during the first six months of the BGSS period.



The natural gas market has undergone significant changes since last year's BGSS Filing. US gas production has leveled off at a peak of about 101 Bcf/d in response to increased demand over the past year and price levels up to $9/Dth, both factors providing producers with a strong incentive to maximize production. Prices responded strongly following Russia's invasion of Ukraine and the potential shortfall of gas supply to Europe to meet the 2022/2023 winter demand following the cutback of supplies from Russia to the continent. Feedgas volumes for the US' seven LNG export facilities have recently achieved a record of 14 Bcf/d, representing 14% of US dry gas production during the same timeframe, due in part to the increase in European imports of US LNG to make up for the shortfall of Russian gas supplies. In response to Russia's cutback in supply to Europe, many European countries filled storages to maximum levels and increased their capability to receive LNG to displace the Russian cutbacks. Those measures, coupled with the warmest winter on record both in the US and Europe, resulted in an oversupply of gas in both markets causing prices to decline dramatically. Despite this decline in prices, however, US gas production remains above 101 Bcf/d, continuing to cause a general moderation of market pricing. Additionally, the warm winter here in the US has resulted in natural gas storage levels that are currently 18 % above the 5-year average and 340 Bcf, or 30 %, above this time last year, decreasing summer demand by approximately 1.6 Bcf/d as storages are refilled in preparation for the 2023/2024 winter season.

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, storage, and peaking 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 (greater than 95%) 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 lower 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 2023 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. 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 adequate supply to meet its projected peak day requirements over the next several years. Over the longer term, however, the Company expects a shortfall in peak day supply that increases year over year.

To address the projected shortfall in peak day supply over the longer term, 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 binding precedent agreement with Transco providing for 60,000 Dth/d of new firm transportation capacity to supplement its peak day supplies 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 and received its FERC certificate authorizing the REA project on January 11, 2023. Transco anticipates placing the REA project into service in the fourth quarter of 2024.

On December 31, 2021, the Company entered into a binding 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. Texas Eastern filed their FERC certificate application seeking approval of the Appalachia to Market II Project on July 6, 2022. The Project received its Environmental Assessment from FERC on February 10, 2023 and the in-service date of the Project 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 efficiently access low-cost Marcellus/Utica supplies to the benefit of its customers.

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 (DTH)
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

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.

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 76 % of its planned volume for the 2023 summer period, approximately 57 % of its planned volume for the 2023-2024 winter period and approximately 41 % of its planned volume for the 2024 summer period. Hedging for the winter 2024-2025 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 2022-2023 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 2023. For the upcoming BGSS period that is covered by this filing, the Company has projected $63 million in credits to its residential customers attributed to capacity release and off-system sales. As can be seen on the attached schedule, off-system sales credits for the 4 months ending April 2023 total $36.6 million, representing a significant decline from the corresponding period last year. The Company's 2023 off-system sales suffered during the January through April period due to the significantly warmer than normal weather, resulting in significant declines in prices and margins. However, should price volatility return to the gas market during the 2023/2024 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

2016 - 2023

Year	BGSS-RSG OSS Revenue (1)	BGSS-RSG OSS Cost (2)	BGSS-RSG OSS Margins (3)
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	$448,755,709	$299,602,376	$149,153,332
2023*	$77,675,884	$41,086,029	$36,589,855

*Note: Through April 2023 Estimate

Item 18

<u>Attachment D</u>

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	777.3	0.0	0.0%
Storage	894.2	421.8	47.2%
Balancing FT	421.3	421.3	100.0%
Peaking	570.9	570.9	100.0%
	2,663.6	1,414.0	

	Total Cost	Percent Allocated to Balancing Use	Allocated Cost
Fixed Cost Allocation:			
Base FT	$169,876.1	0.0%	$0.0
Storage	$128,685.1	47.2%	$60,701.1
Balancing FT	$71,050.0	100.0%	$71,050.0
Peaking	$20,342.0	100.0%	$20,342.0
	$389,953.2		
Variable Cost Allocation:			
Base FT	$0.0	0.0%	$0.0
Storage	$7,520.6	47.2%	$3,547.5
Balancing FT	$0.0	100.0%	$0.0
Peaking	$996.0	100.0%	$996.0
	$8,516.6		

Total Annual Allocated Costs ($000)	**$ 156,636.6**
Balancing Use Billing Determinants - Oct - May (MDth)	188,843
Balancing Charge - Annual Allocated Cost ($/Dth)	$ 0.82946
Storage Inventory Carrying Charge ($/Dth) (page 2)	$ 0.03154
Revenue Requirement on Gas Production Plant Charge ($/Dth) (page 3)	$ 0.03893
Total Balancing Charge (excl. losses) ($/Dth)	$ 0.89993
Total Balancing Charge (incl. losses @ 2%) ($/Dth)	$ 0.91830
Total Balancing Charge (incl. SUT) ($/Dth)	**$ 0.97914**
Total Balancing Charge (incl. SUT) ($/Therm)	**$ 0.097914**

Storage Inventory Carrying Charge

	12 Months Oct 2023- Sept 2024 (000)
RSG Inventory Cost	$ 138,703
BGSS-F Inventory Cost	$ 31,234
BGSS-F Fixed Cost Deferred	$ 15,658
LNG + LPA	$ 3,087
Total Inventory Cost	**$ 188,682**
Total Annual Storage Carrying Cost @ 9.02%	**$ 17,019**

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

Rate per Dth	MDth	Cost	**$/Dth**
Balancing	188,843	$ 5,957	**$ 0.03154**
Commodity	205,985	$ 11,062	**$ 0.05371**

Revenue Requirement on Gas Production Plants

		12 Months Oct 23 - Sep 24
2023	October	$589,783
	November	$594,502
	December	$596,623
2024	January	$447,238
	February	$448,063
	March	$448,888
	April	$948,865
	May	$948,842
	June	$948,819
	July	$449,926
	August	$457,248
	September	$472,104
Total		**$ 7,350,901**
Balancing Use Billing Determinants (MDth)		**188,843**
Revenue Requirement on Gas Production Plant Charge ($/Dth)		**$ 0.03893**

Gas Supply A&G

	12 Months Oct 23 - Sep 24
Direct Labor & Overhead	$ 7,738,550
Firm Sendout - Dth (000)	205,984.5
Gas Supply A&G Rate	$ 0.03757

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..	$0.074813 ~~0.066310~~
Estimated Gulf Coast Cost of Gas..	0.339920 ~~0.339720~~
Adjustment to Gulf Coast Cost of Gas..	0.000000
Prior period (over) or under recovery	(0.049390) ~~0.027530~~
Adjusted Cost of Gas..	0.365343 ~~0.433560~~
Commodity Charge after application of losses: (Loss Factor = 2.0%)	$0.372799 ~~0.442408~~
Commodity Charge including New Jersey Sales and Use Tax (SUT)	$0.397497 ~~0.471718~~

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

Date of Issue: Effective:
Issued by SCOTT S. JENNINGS, SVP – Finance, Planning & Strategy – PSE&G
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 60**
Superseding
B.P.U.N.J. No. 16 GAS **XXX Revised Sheet No. 60**

INFRASTRUCTURE IMPROVEMENT PROGRAM CHARGES

Rate Schedule		Base Distribution Charges Including SUT*	Energy Strong II Charges	Energy Strong II Charges Including SUT	Total Charges Including SUT
RSG					
Service Charge	per Month	$8.62	$0.00	$0.00	$8.62
Distribution Charges	per therm	0.046399	0.002603	0.002775	0.466475
Balancing Charge	per Balancing therm	0.097914 ~~0.100691~~	0.000000	0.000000	0.097914 ~~0.100691~~
Off-Peak Use	per therm	0.231851	0.001301	0.001388	0.233238
GSG					
Service Charge	per Month	20.09	0.13	0.14	20.23
Distribution Charge - Pre July 14, 1997	per therm	0.348581	0.001341	0.001430	0.350010
Distribution Charge - All Others	per therm	0.348581	0.001341	0.001430	0.350010
Balancing Charge	per Balancing therm	0.097914 ~~0.100691~~	0.000000	0.000000	0.097914 ~~0.100691~~
Off-Peak Use Dist Charge - Pre July 14, 1997	per therm	0.174290	0.000670	0.000715	0.175005
Off-Peak Use Dist Charge - All Others	per therm	0.174290	0.000670	0.000715	0.175005
LVG					
Service Charge	per Month	178.38	1.20	1.28	179.66
Demand Charge	per Demand therm	4.6464	0.0177	0.0188	4.6653
Distribution Charge 0-1,000 pre July 14, 1997	per therm	0.035914	(0.000629)	(0.000671)	0.035244
Distribution Charge over 1,000 pre July 14, 1997	per therm	0.052989	0.000404	0.000431	0.053420
Distribution Charge 0-1,000 post July 14, 1997	per therm	0.035914	(0.000629)	(0.000671)	0.035244
Distribution Charge over 1,000 post July 14, 1997	per therm	0.052989	0.000404	0.000431	0.053420
Balancing Charge	per Balancing therm	0.097914 ~~0.100691~~	0.000000	0.000000	0.097914 ~~0.100691~~
SLG					
Single-Mantle Lamp	per Unit per Month	14.1119	0.0000	0.0000	14.1119
Double-Mantle Lamp, inverted	per Unit per Month	14.1119	0.0000	0.0000	14.1119
Double Mantle Lamp, upright	per Unit per Month	14.1119	0.0000	0.0000	14.1119
Triple-Mantle Lamp, prior to January 1, 1993	per Unit per Month	14.1119	0.0000	0.0000	14.1119
Triple-Mantle Lamp, on and after January 1, 1993	per Unit per Month	71.9465	0.0000	0.0000	71.9465
Distribution Therm Charge	per therm	0.056854	0.000210	0.000224	0.057077

*Base Distribution Charges include GSMPII changes pursuant to Docket Nos. GR21121256, GR22060409 & GR22120749.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 61**
Superseding
B.P.U.N.J. No. 16 GAS **XXX Revised Sheet No. 61**

INFRASTRUCTURE IMPROVEMENT PROGRAM CHARGES (Continued)

Rate Schedule		Base Distribution Charges Including SUT*	Energy Strong II Charges	Energy Strong II Charges Including SUT	Total Charges Including SUT
TSG-F					
Service Charge	per Month	$955.37	$6.41	$6.84	$962.21
Demand Charge	per Demand therm	2.3306	0.0038	0.0040	2.3347
Distribution Charges	per therm	0.089084	0.000147	0.000157	0.089241
TSG-NF					
Service Charge	per Month	955.37	6.41	6.84	962.21
Distribution Charge 0-50,000	per therm	0.104741	0.000447	0.000476	0.105218
Distribution Charge over 50,000	per therm	0.104741	0.000447	0.000476	0.105218
CIG					
Service Charge	per Month	211.29	0.95	1.01	212.30
Distribution Charge 0-600,000	per therm	0.094412	0.000414	0.000441	0.094854
Distribution Charge over 600,000	per therm	0.083750	0.000414	0.000442	0.084191
BGSS-RSG					
Commodity Charge including Losses	per therm	0.397512 ~~0.471734~~	(0.000015)	(0.000015)	0.397497 ~~0.471718~~
CSG					
Service Charge	per Month	955.37	6.41	6.84	962.21
Distribution Charge - Non-Firm	per therm	0.104741	0.000447	0.000476	0.105218

*Base Distribution Charges include GSMPII changes pursuant to Docket Nos. GR21121256, GR22060409 & GR22120749.

INFRASTRUCTURE IMPROVEMENT PROGRAM CHARGE

These charges are designed to recover the revenue requirements associated with the Company's Infrastructure Improvement Programs (IIPs) in accordance with the New Jersey Board of Public Utilities' rules on IIPs, N.J.A.C. 14:3-2A.

For detail concerning individual rate class base distribution charges, see individual rate class tariff sheets.

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	
$0.437491	$0.466475	per therm

Balancing Charge:

Charge	Charge Including SUT	
$0.091830~~0.094435~~	$0.097914~~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.

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:

$18.97 in each month [$20.23 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges:

Pre-July 14, 1997 *		All Others		
Charge	Charge Including SUT	Charge	Charge Including SUT	
$0.328263	$0.350010	$0.328263	$0.350010	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	
$0.091830~~0.094435~~	$~~0.100691~~0.097914	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:

$168.50 in each month [$179.66 including New Jersey Sales and Use Tax (SUT)].

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

Charge	Charge Including SUT	
$4.3754	$4.6653	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
$0.033054	$0.035244	$0.050101	$0.053420

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

Balancing Charge:

Charge	Charge Including SUT	
$0.091830~~0.094435~~	$0.097914~~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.

Date of Issue: Effective:

Issued by SCOTT S. JENNINGS, SVP – Finance, Planning & Strategy – PSE&G
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

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:

$902.42 in each month [$962.21 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	
$0.091830~~0.094435~~	$0.097914~~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.

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	$0.074813
Estimated Gulf Coast Cost of Gas	0.339920
Adjustment to Gulf Coast Cost of Gas	0.000000
Prior period (over) or under recovery	(0.049390)
Adjusted Cost of Gas	0.365343
Commodity Charge after application of losses: (Loss Factor = 2.0%)	$0.372799
Commodity Charge including New Jersey Sales and Use Tax (SUT)	$0.397497

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

Date of Issue: Effective:
Issued by SCOTT S. JENNINGS, SVP – Finance, Planning & Strategy – PSE&G
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 60**
Superseding
B.P.U.N.J. No. 16 GAS **XXX Revised Sheet No. 60**

INFRASTRUCTURE IMPROVEMENT PROGRAM CHARGES

Rate Schedule		Base Distribution Charges Including SUT*	Energy Strong II Charges	Energy Strong II Charges Including SUT	Total Charges Including SUT
RSG					
Service Charge	per Month	$8.62	$0.00	$0.00	$8.62
Distribution Charges	per therm	0.046399	0.002603	0.002775	0.466475
Balancing Charge	per Balancing therm	0.097914	0.000000	0.000000	0.097914
Off-Peak Use	per therm	0.231851	0.001301	0.001388	0.233238
GSG					
Service Charge	per Month	20.09	0.13	0.14	20.23
Distribution Charge - Pre July 14, 1997	per therm	0.348581	0.001341	0.001430	0.350010
Distribution Charge - All Others	per therm	0.348581	0.001341	0.001430	0.350010
Balancing Charge	per Balancing therm	0.097914	0.000000	0.000000	0.097914
Off-Peak Use Dist Charge - Pre July 14, 1997	per therm	0.174290	0.000670	0.000715	0.175005
Off-Peak Use Dist Charge - All Others	per therm	0.174290	0.000670	0.000715	0.175005
LVG					
Service Charge	per Month	178.38	1.20	1.28	179.66
Demand Charge	per Demand therm	4.6464	0.0177	0.0188	4.6653
Distribution Charge 0-1,000 pre July 14, 1997	per therm	0.035914	(0.000629)	(0.000671)	0.035244
Distribution Charge over 1,000 pre July 14, 1997	per therm	0.052989	0.000404	0.000431	0.053420
Distribution Charge 0-1,000 post July 14, 1997	per therm	0.035914	(0.000629)	(0.000671)	0.035244
Distribution Charge over 1,000 post July 14, 1997	per therm	0.052989	0.000404	0.000431	0.053420
Balancing Charge	per Balancing therm	0.097914	0.000000	0.000000	0.097914
SLG					
Single-Mantle Lamp	per Unit per Month	14.1119	0.0000	0.0000	14.1119
Double-Mantle Lamp, inverted	per Unit per Month	14.1119	0.0000	0.0000	14.1119
Double Mantle Lamp, upright	per Unit per Month	14.1119	0.0000	0.0000	14.1119
Triple-Mantle Lamp, prior to January 1, 1993	per Unit per Month	14.1119	0.0000	0.0000	14.1119
Triple-Mantle Lamp, on and after January 1, 1993	per Unit per Month	71.9465	0.0000	0.0000	71.9465
Distribution Therm Charge	per therm	0.056854	0.000210	0.000224	0.057077

*Base Distribution Charges include GSMPII changes pursuant to Docket Nos. GR21121256, GR22060409 & GR22120749.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 61**
Superseding
B.P.U.N.J. No. 16 GAS **XXX Revised Sheet No. 61**

INFRASTRUCTURE IMPROVEMENT PROGRAM CHARGES (Continued)

Rate Schedule		Base Distribution Charges Including SUT*	Energy Strong II Charges	Energy Strong II Charges Including SUT	Total Charges Including SUT
TSG-F					
Service Charge	per Month	$955.37	$6.41	$6.84	$962.21
Demand Charge	per Demand therm	2.3306	0.0038	0.0040	2.3347
Distribution Charges	per therm	0.089084	0.000147	0.000157	0.089241
TSG-NF					
Service Charge	per Month	955.37	6.41	6.84	962.21
Distribution Charge 0-50,000	per therm	0.104741	0.000447	0.000476	0.105218
Distribution Charge over 50,000	per therm	0.104741	0.000447	0.000476	0.105218
CIG					
Service Charge	per Month	211.29	0.95	1.01	212.30
Distribution Charge 0-600,000	per therm	0.094412	0.000414	0.000441	0.094854
Distribution Charge over 600,000	per therm	0.083750	0.000414	0.000442	0.084191
BGSS-RSG					
Commodity Charge including Losses	per therm	0.397512	(0.000015)	(0.000015)	0.397497
CSG					
Service Charge	per Month	955.37	6.41	6.84	962.21
Distribution Charge - Non-Firm	per therm	0.104741	0.000447	0.000476	0.105218

*Base Distribution Charges include GSMPII changes pursuant to Docket Nos. GR21121256, GR22060409 & GR22120749.

INFRASTRUCTURE IMPROVEMENT PROGRAM CHARGE

These charges are designed to recover the revenue requirements associated with the Company's Infrastructure Improvement Programs (IIPs) in accordance with the New Jersey Board of Public Utilities' rules on IIPs, N.J.A.C. 14:3-2A.

For detail concerning individual rate class base distribution charges, see individual rate class tariff sheets.

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	
$0.437491	$0.466475	per therm

Balancing Charge:

Charge	Charge Including SUT	
$0.091830	$0.097914	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.

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:

$18.97 in each month [$20.23 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges:

Pre-July 14, 1997 *		All Others		
Charge	Charge Including SUT	Charge	Charge Including SUT	
$0.328263	$0.350010	$0.328263	$0.350010	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	
$0.091830	$0.097914	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.

Date of Issue: Effective:
Issued by SCOTT S. JENNINGS, SVP – Finance, Planning & Strategy – PSE&G
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

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:

$168.50 in each month [$179.66 including New Jersey Sales and Use Tax (SUT)].

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

Charge	Charge Including SUT	
$4.3754	$4.6653	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
$0.033054	$0.035244	$0.050101	$0.053420

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

Balancing Charge:

Charge	Charge Including SUT	
$0.091830	$0.097914	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:
$902.42 in each month [$962.21 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	
$0.091830	$0.097914	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.