



VIA ELECTRONIC MAIL & REGULAR MAIL

May 29, 2009

In the Matter of Public Service Electric and
Gas Company's 2009/2010 Annual BGSS Commodity
Charge Filing for its Residential Gas Customers
Under its Periodic Pricing Mechanism and for
Changes in the Tariff for Gas Service
B.P.U.N.J. No. 14 Gas Pursuant to
N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1

Kristi Izzo, Secretary
Board of Public Utilities
Two Gateway Center
Newark, New Jersey 07102

Dear Secretary Izzo:

Enclosed for filing please find the original and ten copies of Public Service Electric and Gas Company's (Public Service, the Company) Motion, Testimony of David F. Caffery and supporting attachments in the above-referenced matter. In this filing, Public Service is requesting a decrease in Annual BGSS gas revenues of approximately \$132.9 million (excluding losses & New Jersey Sales and Use Tax, SUT) or approximately a 7.0% decrease to be implemented for service rendered on and after October 1, 2009 or earlier, should the Board deem it appropriate. The attached filing represents an overall 18% decrease compared with BGSS rates implemented in October 2008, which Public Service subsequently reduced on January 1 and March 1, 2009.

This filing and the proposed implementation date for the new 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 included in an April 22, 2003 Settlement under Docket No. GR02090702 approved by the Board on June 20, 2003.

Very truly yours,

*Original Signed by
Frances I. Sundheim, Esq.*

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**1. Motion, Supporting Testimony
& Tariff Modifications**

Motion – dated May 28, 2009

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) MOTION
2009/2010 ANNUAL BGSS COMMODITY)
CHARGE FILING FOR ITS RESIDENTIAL)
GAS CUSTOMERS UNDER ITS PERIODIC) DOCKET NO. GR_____)
PRICING MECHANISM AND FOR)
CHANGES IN THE TARIFF FOR GAS)
SERVICE B.P.U.N.J. NO. 14 GAS PURSUANT)
TO N.J.S.A. 48:2-21 AND N.J.S.A. 48:2-21.1)

Public Service Electric and Gas Company (Public Service, 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:

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

GENERIC PROCEEDING ON BGSS PRICE STRUCTURE

1. On January 6, 2003 as the result of a generic proceeding, the Board issued its Order Approving the BGSS Price Structure under Docket No. GX01050304 (BGSS Pricing Structure Order) under which the Board approved procedures providing for annual Basic Gas Supply Service (BGSS) Commodity Charge filings by the Company and all the New Jersey gas distribution companies by June 1st of 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 Division of Rate Counsel (Rate Counsel)¹ on November 1st and January 1st of the estimated change to take effect on December 1st and February 1st, respectively.

MINIMUM FILING REQUIREMENTS

2. In addition, the Board in its January 16, 2003 Order Adopting Provisional Rates under 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 agreed on a list of 17 Annual BGSS Minimum Filing Requirements that shall be applicable to the Company's June 1st Annual BGSS proceedings. The Parties included those in a Settlement on Annual BGSS Minimum Filing Requirements which was approved by the Board on June 20, 2003.

2007/2008 BGSS ANNUAL COMMODITY CHARGE FILING

4. On June 1, 2007, Public Service filed a motion requesting an increase in its annual revenues from its BGSS Commodity Charge (BGSS-RSG) of approximately \$38.8 million (excluding Sales and Use Tax, or "SUT") or approximately a 2% increase

¹ Previously known as the Division of the Ratepayer Advocate.

for the period October 1, 2007 through September 30, 2008. In the June 1, 2007 filing, the Company proposed an increase in the BGSS-RSG rate from 98.0852 cents per therm (including SUT) to 101.0008 cents per therm (including SUT). The impact of this change for a typical residential heating customer using 606 therms on an annual basis would be an increase in the customer's annual bill from \$909.34 to \$927.02, or, \$17.68, or approximately 2%.

5. Notice setting forth the Company's June 1, 2007 request for an increase in its BGSS Commodity Charge, including the date, time, and place of the public hearings, was placed in newspapers having a circulation within the Company's gas service territory and was served on the county executives and clerks of all municipalities within the Company's gas service territory.

6. Public hearings were scheduled and conducted in Hackensack, New Brunswick and Mt. Holly on September 17, 19 and 20, 2007 respectively.

7. Thereafter, the Parties engaged in settlement conferences and, as the result of negotiations, the Parties entered into a settlement and agreed as follows:

- Considering the reduction in the current NYMEX forward gas prices since the June 1, 2007 filing, the requested increase in the BGSS-RSG Commodity Charge was not necessary at that time.
- The Company's BGSS default Commodity Service, Tariff rate, BGSS-RSG of 98.0852 cents per therm (including SUT) will remain in effect at this

time. The Parties agree that the aforementioned BGSS-RSG rate shall be deemed final upon the effective date of the Board's written Order approving this Settlement.

- The Parties agreed that, for this proceeding, they take no issue with the Company's method of allocating gas costs and associated credits between its residential and C&I customers through September 30, 2007 and recommend that it should be approved. They also agreed that the allocation method beginning on October 1, 2007 will be subject to review for appropriateness in future annual BGSS proceedings. The Parties reserved their rights to challenge this allocation methodology in future proceedings. The Company will file, when available, actual gas cost and revenue recovery data for the 2007-2008 BGSS annual period in the same format used in the Company's initial 2007-2008 BGSS filing.

8. The Stipulation described above was approved by the Board on March 4, 2008.

2008/2009 BGSS ANNUAL COMMODITY CHARGE FILING

9. On May 30, 2008, Public Service made a filing in the above-referenced matter, requesting an increase of approximately \$402.1 million (including Losses & SUT). (approximately 20%) in its BGSS revenues (including SUT), due primarily to

projected increases in natural gas costs during the 2008-2009 BGSS year (October 1, 2008 through September 30, 2009).

10. Residential annual bills comparing the current BGSS Commodity Charge with the as-requested provisional BGSS Commodity Charge reflected an increase of approximately 19.2% for a residential heating customer using 100 therms per winter month and 606 therms annually. As filed, the BGSS-RGS Commodity charge would increase from 98.0852 cents per therm, including SUT, to 126.6889 cents per therm including SUT or an increase of 28.6037 cents per therm.

11. Notice setting forth the Company's May 30, 2008 request for an increase in its BGSS Commodity Charge, including the date, time and place of the public hearings, was placed in newspapers having a circulation within the Company's gas service territory and was served on the county executives and clerks of all municipalities within the Company's gas service territory.

12. Public hearings were scheduled and conducted in Hackensack, New Brunswick, and Mt. Holly on August 18, 19, and 21, 2008, respectively. Collectively, three members of the public appeared and commented on the filing.

13. After the significant reduction in the NYMEX forward gas prices since the May 30, 2008 filing, Public Service reduced the amount of the requested increase, and the Parties entered into a Stipulation for Provisional BGSS Rates on September 24, 2008. On October 3, 2008, the Board issued an Order approving the Stipulation for Provisional

BGSS Rates, and the Company implemented the new rates effective that date. Pursuant to the Order, the Company's BGSS default Commodity Service, Tariff rate BGSS-RSG, was provisionally increased to 118.5628 cents per therm (including SUT) from the then current 98.0852 cents per therm (including SUT) subject to refund with interest on any net over-recovery. The residential customer impact of the increase was as follows: MONTHLY – a residential customer using 100 therms per month during the winter months and 606 therms on an annual basis would see an increase in the monthly bill from \$145.46 to \$165.93 (an increase of \$20.47 or approximately 14.1%). ANNUAL – a residential customer using 200 therms per month during the winter months and 1,210 therms on an annual basis would see an increase in the annual bill from \$1,733.54 to \$1,981.32 (an increase of \$247.78 or approximately 14.3%). The agreed-upon provisional rate resulted in an annual increase in revenues during the 2008-2009 BGSS year of approximately \$285.4 million including SUT.

14. As a result of the continued reduction in the NYMEX forward gas prices, on December 19, 2008 the Company filed a notice with the Board of a decrease in its BGSS-RSG Commodity Charge to be effective January 1, 2009. The self-implementing rate decrease reduced the Company's BGSS-RSG Commodity Charge from 118.5628 cents per therm (including SUT) to 110.3449 cents per therm (including SUT). The residential customer impact of this decrease was as follows: MONTHLY – a residential customer using 100 therms per month during the winter months and 606 therms on an

annual basis would see a decrease in the monthly bill from \$166.96 to \$158.74 (a decrease of \$8.22 or approximately 4.9%). ANNUAL – a residential customer using 200 therms per month during the winter months and 1,210 therms on an annual basis would see a decrease in the annual bill from \$1,993.68 to \$1,894.26 (a decrease of \$99.42 or approximately 5.0%).

15. Additionally, as a result of the continued reduction in the NYMEX forward gas prices since the January 1, 2009 self-implementing decrease, on February 19, 2009 the Company filed a notice with the Board of an additional decrease in its BGSS-RSG Commodity Charge to be effective March 1, 2009. The self-implementing rate decrease reduced the Company's BGSS-RSG Commodity Charge from 110.3449 cents per therm (including SUT) to 99.0753 cents per therm (including SUT). The residential customer impact of this decrease was as follows: MONTHLY – a residential customer using 100 therms per month during the winter months and 606 therms on an annual basis would see a decrease in the monthly bill from \$158.78 to \$147.52 (a decrease of \$11.26 or approximately 7.1%). ANNUAL – a residential customer using 200 therms per month during the winter months and 1,210 therms on an annual basis would see a decrease in the annual bill from \$1,894.722 to \$1,758.36 (a decrease of \$136.36 or approximately 7.2%).

² PSE&G notes that the monthly and annual bill amounts listed herein were impacted by changes in other components of the PSE&G gas rate (new SBC rates effective 12/9/08 and the RGGI Recovery Charge rate effective 1/1/09).

16. Public Service, Board Staff, and Rate Counsel (collectively, the “Parties”) engaged in settlement negotiations and discussions. As a result of those discussions, the Parties HEREBY AGREE as follows:

17. The Company’s BGSS default Commodity Service, Tariff rate BGSS-RSG of 99.0753 cents per therm (including SUT) will remain in effect at this time. The Parties agree that the aforementioned BGSS-RSG rate shall be deemed final upon the effective date of the Board’s written Order approving this Settlement.

18. The Parties agree that, for this proceeding, they take no issue with the Company’s method of allocating gas costs and associated credits between its residential and C&I customers through September 30, 2008 and recommend that it should be approved. They also agree that the allocation method beginning on October 1, 2008 will be subject to review for appropriateness in future annual BGSS proceedings. The Parties reserve their rights to challenge this allocation methodology in future proceedings. The Company will file, when available, actual gas cost and revenue recovery data for the 2008-2009 BGSS annual period in the same format used in the Company’s initial 2008-2009 BGSS filing.

2009/2010 BGSS ANNUAL COMMODITY CHARGE FILING

19. The Company is making this 2009/2010 Annual BGSS Commodity Charge filing for its Periodic Pricing Mechanism applicable to its residential gas customers pursuant to the Board’s above-referenced January 6, 2003 Order Approving the BGSS

Price Structure under Docket No. GX01050304. This filing is also made in accordance with the above-referenced Settlement on Minimum Filing Requirements.

20. This Motion is supported by the direct testimony of David F. Caffery (Attachment A) in which he addresses all of the minimum filing requirements which have been met and demonstrates why the new BGSS rate should become effective through a written Board Order issued no later than October 1, 2009, or earlier, should the Board deem it appropriate.

21. The natural gas markets continue to be characterized by increased volatility making reliance upon the NYMEX forward price curve as an indicator of future price levels over an extended period of 12 to 18 months exceptionally difficult. This is particularly true given the price levels experienced during the current BGSS Filing period wherein NYMEX prices rose to a level of \$13 in July, 2008, only to fall to the \$3 level in March of 2009. The May 6, 2009 NYMEX strip which is used in this filing illustrates a gradual increase in prices through the 2009-2010 winter period, followed by a softening in the spring of 2010, and then a resumption of a gradual increase in the summer of 2010. While the market has always imputed a premium for the winter period, due to the possibility of colder than normal temperatures, it has recently begun imputing a summer premium as well for the likelihood of a severe hurricane season. Following the dramatic run-up in prices experienced in the first half of 2008, and the steep decline in the second half of 2008 through the first quarter of 2009, it is expected that the market will reach a

more balanced condition for the remainder of this year. The substantial amount of natural gas currently in storage should serve to temper price increases during the summer while the dramatic cutback in drilling should act to support prices from decreasing much further during the period.

22. The current NYMEX futures prices that the Company utilized to develop its filing, as shown on Item 8, are based on the NYMEX of May 6, 2009. A comparison of these prices with the prices included in our current BGSS rate (from the self-implementing reduction implemented on March 1, 2009) indicates a decrease of approximately 13%.

23. In this filing the Company includes the following:

- a. The Company estimates that a decrease in BGSS revenue of approximately \$132.9 million (excluding losses & SUT) would be required for the period of October 1, 2009 through September 30, 2010;
- b. The requested decrease for BGSS-RSG Commodity Service is from the current charge of 99.0660 cents per therm (including SUT) to a charge of 88.7950 cents per therm (including SUT).

24. Residential annual bills comparing the current and proposed BGSS charge pursuant to this filing are included in the attached Notice (Attachment C). The impact of the change for the class average residential heating customer on an annual basis is a decrease of approximately 7.0%. Moreover, pursuant to paragraph 10 of the above-

referenced January 6, 2003 Order Approving Price Structure, the attached Notice also indicates that such proposed rates may be subject to self-implementing rate increases of up to 5% on the ensuing December 1st and February 1st. The impact of such potential self-implementing increases on an average residential bill (1200 therms annually) is an increase of approximately \$13.51 for a winter month on December 1, 2009 and an additional approximate increase of \$13.51 per winter month on February 1, 2010.

25. The proposed BGSS-RSG Tariff Sheet (redlined and non-redlined) to implement the above request have been annexed as Attachment B.

26. A form of notice and public hearing dates setting forth the request for an increase in BGSS-RSG Commodity Charge will be placed in newspapers having a circulation within the Company's gas service territory, and notice of this filing will be served on the County Executives and Clerks of all municipalities within the Company's gas territory upon the receipt, scheduling and publication of hearing dates. A copy of the form of newspaper notice of this request is attached hereto as Attachment C.

27. As was done in the Company's 2008/2009 Annual BGSS Commodity Charge filing, the Company requests pursuant to paragraph 13 of Attachment A to the Settlement approved in the above-referenced BGSS Pricing Structure Order that the pricing mechanism approved in that Order be extended unless and until the Board in writing decides to address that pricing mechanism.

28. For the period beginning on October 1, 2008 to the filing of this proceeding, the Company has not experienced any main breaks caused by third parties involving losses of natural gas valued at \$50,000 or more.

CONCLUSION

WHEREFORE, Public Service hereby requests that the Board issue a written Order by October 1, 2009 decreasing the Company's BGSS-RSG Commodity Charge from the current charge of 99.0660 cents per therm (including SUT) to a charge of 88.7950 cents per therm (including SUT), as explained above, and extending the pricing mechanism approved in the BGSS Pricing Structure Order as requested herein.

Respectfully submitted,

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

*Original Signed by
Frances I. Sundheim, Esq.*

BY: _____

Frances I. Sundheim, Esq.
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Newark, New Jersey 07101

DATED: May 29, 2009
Newark, New Jersey

1 The filing herein complies with the provisions of the Annual BGSS
2 Minimum Filing Requirements (comprised of 17 items) in Docket No. GR02090702,
3 dated April 22, 2003 (Minimum Filing Requirements Settlement). Since Item 1 is the
4 Company's Motion, Testimony and Tariff Sheets, Items 2 through 17 are discussed
5 below:

6 **Item 2 Computation of Proposed BGSS Rates**

7 This summary schedule shows the forecasted BGSS cost components
8 and applicable credits that comprise the basis for the proposed BGSS rate that is to
9 become effective October 1, 2009. Additional details on the cost components and
10 applicable credits are provided in several of the other items, as specified in the
11 Minimum Filing Requirements Settlement. This schedule computes the BGSS
12 Commodity Charge to residential gas customers based on all the forecasted gas cost
13 components and applicable credits using forecasted sendout. Also included is an
14 adjustment for the prior period over recovery, with interest, which is the result of a
15 comparison of actual revenues recovered to actual cost (including applicable credits).
16 The intent of this calculation is to develop a charge that would produce a zero balance
17 at the end of the clause period, which is September 30, 2010.

18 The natural gas markets continue to be characterized by increased
19 volatility making reliance upon the NYMEX forward price curve as an indicator of
20 future price levels over an extended period of 12 to 18 months exceptionally difficult.

1 This is particularly true given the price levels experienced during the current BGSS
2 Filing period wherein NYMEX prices rose to a level of \$13 in July, 2008, only to fall
3 to the \$3 level in March of 2009. The May 6, 2009 NYMEX strip which is used in
4 this filing illustrates a gradual increase in prices through the 2009-2010 winter period,
5 followed by a softening in the spring of 2010, and then a resumption of a gradual
6 increase in the summer of 2010. While the market has always imputed a premium for
7 the winter period, due to the possibility of colder than normal temperatures, it has
8 recently begun imputing a summer premium as well for the likelihood of a severe
9 hurricane season. Following the dramatic run-up in prices experienced in the first
10 half of 2008, and the steep decline in the second half of 2008 through the first quarter
11 of 2009, it is expected that the market will reach a more balanced condition for the
12 remainder of this year. The substantial amount of natural gas currently in storage
13 should serve to temper price increases during the summer while the substantial
14 cutback in drilling should act to support prices from decreasing much further during
15 the period.

16 The current NYMEX futures prices that the Company utilized to
17 develop its filing are shown on Item 8. A comparison of the simple average of these
18 NYMEX prices with the prices included in our current BGSS rate (from the self-
19 implementing reduction implemented on March 1, 2009) indicates a decrease of
20 approximately 13%.

1 **Item 3 Public Notice with Proposed Impact on Bills**

2 Included is a copy of the Company's Public Notice with details
3 concerning the impact of the proposed BGSS rate on typical residential gas bills at
4 various winter therm utilization levels. The Notice (Attachment C) includes a table
5 showing the impacts at various levels and also a reference to the possibility of self-
6 implementing BGSS Commodity increases of 5% on December 1, 2009 and February
7 1, 2010, respectively, with the impact of those possible increases.

8 **Item 4 Actual and Forecasted Refund Amounts**

9 The first schedule of Item 4 shows several supplier refunds, totaling
10 approximately \$15.9 million, that were credited to BGSS-RSG recovery costs from
11 May 2008 through the date of this filing and the second schedule shows that there are
12 no estimated supplier refunds (in excess of \$1 million) through September 2010.
13 These two schedules are intended to show the actual and forecasted refunds that are
14 received by the Company as the result of various FERC proceedings and returned to
15 the residential customers through the BGSS Commodity Charge. Currently, there are
16 no on-going supplier rate cases which would result in a refund during the next BGSS
17 period.

18 **Item 5 Cost of Gas Sendout by Component**

19 This schedule includes monthly data showing the derivation of all cost
20 components used to calculate the BGSS residential sendout for the projected period.

1 The individual components are utilized to derive inventory values, which form the
2 basis of the over/ under collection for the period.

3 All of the fixed and variable charges are allocated proportionately to the
4 residential and commercial and industrial (C & I) customer groups monthly based on
5 the estimated firm sendout and are trued up when the actual firm sendout is available.
6 Each class of customers also shares equitably in any credits or contributions that serve
7 to lower gas costs. The gas costs are similarly allocated to the respective customer
8 classes following the direct allocation of any volumes hedged exclusively for the
9 residential categories.

10 **Item 6 BGSS Contribution and Credit Offsets**

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

1 An additional page has been added to this item which provides details
2 on gas volumes used for electric generation. This data was agreed to by the Parties in
3 the settlement of the 2006/07 BGSS proceeding. The schedule shows the volumes of
4 gas burned and the Gas Reservation Charge revenue which is credited to the
5 residential customers. In the settlement of the 2006/2007 BGSS proceeding the rate
6 applicable to these gas volumes was increased from 27.4 cents per DTh to to 42.5
7 cents per DTh.

8 **Item 7 Over/Under Recovery Comparisons**

9 The schedules under this item provide the derivation of the monthly
10 over or under recoveries plus cumulative balances for the reconciliation and projected
11 period. For the reconciliation period, one schedule also shows the calculation of the
12 monthly actual or estimated accrued interest. The net interest calculated during the
13 October 2008 to September 2009 period is positive and therefore has been included in
14 the calculation of the BGSS charge on Item 2. Additional schedules include
15 prospective data shown for the projected period based on the prevailing BGSS rate
16 and, alternatively, based on the requested BGSS rate. Also included are supporting
17 workpapers.

18 **Item 8 Wholesale Gas Pricing Assumptions**

19 This schedule details the monthly gas prices for the end of the
20 reconciliation period through September 2009 and the projected period through

1 September 2010 along with a comparison of the prices used in this filing to the prices
2 used as the basis for our current BGSS rate. This comparison depicts the price
3 decreases that have occurred in the NYMEX since the 2008/2009 BGSS Filing and
4 our two subsequent self-implementing reductions, which results in the Company's
5 request for an additional reduction in the BGSS rate. These estimates reflect the
6 future NYMEX prices on May 6, 2009, when this analysis was done. The NYMEX
7 has proven to be the best indicator of future prices, although from time to time short-
8 term prices may be modified to reflect certain market conditions.

9 **Item 9 GCUA Recoveries and Balances**

10 This schedule is no longer necessary since the Gas Cost Underrecovery
11 Adjustment (GCUA) recovery has been completed.

12 **Item 10 Historical Service Interruptions**

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

17 **Item 11 Gas Price Hedging Activities**

18 Included are the Company's last four quarterly hedging reports as filed
19 with the Board. The reports provide gas purchase volume requirements and price-
20 hedged volumes broken down into discretionary and non-discretionary components,

1 which allow evaluation of compliance with the Company's established hedging
2 objectives. The Company continues to utilize hedging as a means to stabilize the
3 price of gas to the residential customer. The consistent goal of the program is to
4 assure a reasonable level of price stability, not necessarily achieving the lowest
5 possible price. The Company, to date, has locked in prices for approximately 100%
6 of its planned volume for the 2009 summer period and approximately 86% of its
7 planned volume for the 2009-2010 winter period.

8 The BPU initiated a process to obtain a consultant to analyze the gas
9 purchasing practices of all four Gas Distribution Companies and provide a report and
10 recommendations on these practices. As a result of this process, the BPU selected
11 Vantage Consulting, Inc. (Vantage) and its subcontractor Pace Global Energy
12 Services, LLC, to perform a comprehensive review of the Company's hedging
13 activities covering the period 2001 to 2007. On January 15, 2009, Vantage submitted
14 a Final Report to the BPU. The BPU accepted the Final Report in its Order of
15 February 24, 2009.

16 In the April 8, 2009 Settlement for Final BGSS Rates in BPU Docket
17 No. GR08050368, the Company agreed to meet with Board Staff and Rate Counsel to
18 review the Company's current hedging program and to discuss hedging guidelines for
19 the future. The initial meeting to discuss these matters took place at the Company's
20 offices on May 15, 2009. The Company anticipates that additional meetings will take

1 place over the next several months and any changes to the Company's hedging
2 program will be made at a future time.

3 The Company's experience has been that the increased volatility in the
4 natural gas market makes it increasingly difficult to accurately estimate future price
5 movements. Whereas, in the past, the winter price has always been strong entering
6 the season each November due to the anticipated colder weather, it now seems that
7 pricing for the summer season has a built in premium for the potential of hurricanes
8 and the potential supply disruptions which may result. As a result, prices have the
9 potential to increase significantly in either the winter or the summer seasons. The
10 Company continues to believe that a program that attempts to capture a stable price
11 through a disciplined planned hedging program will, in the long run, result in the most
12 competitive price for the customer.

13 **Item 12 Storage Gas Volumes, Prices and Utilization**

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

20

1 **Item 13 Affiliate Gas Supply Transactions**

2 During these periods, there has not been, nor are there expected to be,
3 any such transactions.

4 **Item 14 Supply and Demand Data**

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

8 **Item 15 Actual Peak Day Supply and Demand**

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

13 **Item 16 Capacity Contract Changes**

14 Included in this schedule is the most recent peak day forecast and the
15 supplies to be utilized to meet these requirements. Included are the details for the last
16 two (2) winter seasons concerning any changes to interstate pipeline contracts
17 (entitlements, storage capacities, daily deliverability, or transportation) and the
18 forecast for the next two (2) winter seasons.

19

20

SCHEDULE DFC-1

PROFESSIONAL QUALIFICATIONS OF DAVID F. CAFFERY DIRECTOR – PORTFOLIO MANAGEMENT & REGULATORY

My name is David F. Caffery and my business address is 80 Park Plaza, Newark, New Jersey 07101-0570. I am the Director – Portfolio Management & Regulatory for PSEG Energy Resources and Trade LLC (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. I was promoted to my present position in March, 2007. In June 2002, as a result of the transfer of the gas supply contracts, I became an employee of PSEG ER&T. In my present position I am responsible for the management of the BGSS portfolio of gas transportation and storage contracts and the FERC regulatory activities associated with those contracts.

I am currently a member of the American Gas Association, the National Energy Services Association, and the Energy Bar Association. I have provided testimony before the Federal Energy Regulatory Commission and the New Jersey Board of Public Utilities.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

XXX Revised Sheet No. 48

B.P.U.N.J. No. 14 GAS

Superseding

XXX Revised Sheet No. 48

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

Estimated Non-Gulf Coast Cost of Gas	<u>8.58519.1024</u> ¢
Estimated Gulf Coast Cost of Gas	<u>78.473099.3314</u> ¢
Adjustment to Gulf Coast Cost of Gas	<u>0.0000(18.1224)</u> ¢
Prior period (over) or under recovery.....	<u>(4.4850)1.8130</u> ¢
Adjusted Cost of Gas	<u>82.573192.1244</u> ¢
Commodity Charge after application of losses: (Loss Factor = 0.5%).....	<u>82.986092.5850</u> ¢
Commodity Charge including New Jersey Sales and Use Tax (SUT)	<u>88.795099.0660</u> ¢

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.

Date of Issue:

Issued by FRANCES I. SUNDHEIM, Vice President and Corporate Rate Counsel
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Orders of Board of Public Utilities dated
in Docket No.

Effective:

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

XXX Revised Sheet No. 48

B.P.U.N.J. No. 14 GAS

Superseding

XXX Revised Sheet No. 48

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

Estimated Non-Gulf Coast Cost of Gas	8.5851 ¢
Estimated Gulf Coast Cost of Gas	78.4730 ¢
Adjustment to Gulf Coast Cost of Gas	0.0000 ¢
Prior period (over) or under recovery	(4.4850) ¢
Adjusted Cost of Gas	82.5731 ¢
Commodity Charge after application of losses: (Loss Factor = 0.5%)	82.9860 ¢
Commodity Charge including New Jersey Sales and Use Tax (SUT)	88.7950 ¢

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.

Date of Issue:

Issued by FRANCES I. SUNDHEIM, Vice President and Corporate Rate Counsel
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Orders of Board of Public Utilities dated
in Docket No.

Effective:

2. Computation of Proposed BGSS Rate

**COMPUTATION OF
BGSS COMMODITY CHARGE FOR RSG
OCTOBER 2009 - SEPTEMBER 2010**

(\$-000)

	12-MONTH LEVELIZED	
	\$000	\$/DTh
FIXED COSTS:		
FT DEMAND COST	\$ 156,520	\$1.1252
STORAGE DEMAND/CAPACITY COSTS	77,073	0.5541
STORAGE W/D+INJ. COSTS	14,033	0.1009
PEAKING COSTS	10,860	0.0781
	258,485	\$1.8583
CONTRIBUTIONS	(38,789)	(0.2789)
REFUNDS	0	0.0000
OFF-SYSTEM SALES MARGIN	(48,786)	(0.3507)
GAS RESERVATION CHARGE	(18,568)	(0.1335)
NET TOTAL FIXED COST	\$ 152,342	\$1.09520
FIRM RSG SENDOUT (MDTh) 10/09 - 9/10	139,101	
TOTAL NON-GULF COAST COST (\$/DTh)		\$1.09520
Removal of Balancing Cost (incl. above)		(0.4859)
Inventory Carrying Charge Allocation		0.2131
Gas Supply A&G		0.0370
Total Adjustments		(\$0.23583)
ADJUSTED NON-GULF COAST COST (\$/DTh)		\$0.85937
(OVER)/UNDER RECOVERY @ 9/30/09 - INCL. INTEREST	\$ (62,383)	(\$0.44850)
GULF COAST COST OF GAS (\$/DTh)		
FT COMMODITY AND FUEL		0.75500
COST OF GAS		7.09230
TOTAL GULF COAST COST		\$7.84730

SUMMARY OF CHARGE COMPONENTS (cents per therm)

	BGSS-RSG
Estimated Non-Gulf Coast Cost of Gas	8.5937
PSE&G Capital Adjustment Charge (CAC) (as of 5/1/09)	(0.0086)
Adjusted Non Gulf Coast Cost of Gas	8.5851
Estimated Gulf Coast Cost of Gas	78.4730
Adjustment to Gulf Coast Cost of Gas	-
Prior Period (Over)/Under Recovery	(4.4850)
Adjusted Cost of Gas	82.5731
COMMODITY CHARGE after application of losses (0.5%)	82.9860
Shopping Incentives	-
COMMODITY CHARGE excluding SUT	82.9860
COMMODITY CHARGE including SUT	88.7950

3. Public Notice with Proposed Impact on Bills

Notice (including Typical Bills) – Attachment C

NOTICE TO PUBLIC SERVICE ELECTRIC AND GAS COMPANY GAS CUSTOMERS

IN THE MATTER OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY'S 2009/2010 ANNUAL BGSS COMMODITY CHARGE FILING FOR ITS RESIDENTIAL GAS CUSTOMERS UNDER ITS PERIODIC PRICING MECHANISM AND FOR CHANGES IN THE TARIFF FOR GAS SERVICE B.P.U.N.J. NO. 14 GAS PURSUANT TO N.J.S.A. 48:2-21 AND N.J.S.A. 48:2-21.1

Notice of Filing And Notice of Public Hearings

Docket No. XXXXXXXXXX

TAKE NOTICE that, on May 28, 2009, Public Service Electric and Gas Company ("Public Service", "the Company") filed a Motion and supporting testimony (Annual BGSS Commodity Charge filing) with the New Jersey Board of Public Utilities ("Board", "BPU") requesting that the Board permit Public Service to decrease its Basic Gas Supply Service (BGSS-RSG) Commodity Charge to Residential Service (RSG) customers effective October 1, 2009 or earlier, should the Board deem it appropriate. Approval of the Company's request would result in a decrease in annual BGSS-RSG revenues of approximately \$132.9 million (excluding losses and New Jersey Sales and Use Tax, SUT). The requested average BGSS commodity decrease is approximately 7.04% on an annual basis for the class average residential heating customer. The requested decrease in the BGSS-RSG Commodity Charge is from \$0.990660 per therm (including losses and SUT) to \$0.887950 per therm (including losses and SUT).

The effect of the Company's Annual BGSS Commodity Charge filing on typical residential gas bills, if approved by the Board, is show in Table # 1.

Under the Company's proposal, a residential heating customer using 100 therms per month during the winter months and 606 therms on an annual basis would see a decrease in the annual bill from \$919.98 to \$857.78, or \$62.20 or approximately 6.76%. Moreover, under the Company's proposal, a typical residential heating customer using 200 therms per month during the winter months and 1,210 therms on an annual basis would see a decrease in the annual bill from \$1,765.54 to \$1,641.28 or \$124.26 or approximately 7.04%.

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 and/or February 1st of next year on a self-implementing basis, with each such increase being subject to a maximum rate increase of 5% of the average rate based on a typical 100 therms per month average

(1,200 therms annual usage) residential customer's total bill. Such rate increases shall be preconditioned upon written notice by Public Service to the BPU Staff and to the Division of Rate Counsel no later than November 1st of this year and/or January 1st of next year 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 1st self-implementing 5% increase, the bill impact would be an increase as illustrated in Table #2. Further, if a February 1st 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 Public Service Electric and Gas Company.

Any final rate adjustments with resulting changes in bill impacts found by the Board to be just and reasonable as the result of this Annual BGSS Commodity Charge filing 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 above described charges may increase or decrease based upon the Board's decision.

Copies of the Company's Motion and its supporting documents can be reviewed at the Company's Customer Service Centers or at the Board of Public Utilities at Two Gateway Center, Newark, New Jersey 07102 or online at the PSEG Web site at <http://www.pseg.com>.

The following dates, times and locations for public hearings have been scheduled on the Company's

filing so that members of the public may present their views.

Date 1, 2009	Date 2, 2009	Date 3, 2009
Location 1	Location 2	Location 3
Time 1	Time 2	Time 3
Location 1 Overflow	Location 2 Overflow	Location 3 Overflow
Room 1	Room 2	Room 3
Room 1 Overflow	Room 2 Overflow	Room 3 Overflow
Address 1	Address 2	Address 3
City 1, N.J. Zip 1	City 2, N.J. Zip 2	City 3, N.J. Zip 3

In order to encourage full participation in this opportunity for public comment, please submit any requests for needed accommodations, including interpreters, listening devices or mobility assistance, 48 hours prior to the above hearings. Customers may file written comments with the Secretary of the Board

of Public Utilities at Two Gateway Center, Newark, New Jersey 07102 ATTN: Secretary Kristi Izzo whether or not they attend the public hearings.

Table # 1
Residential Gas Service

If Your Annual Therm Use Is:	And Your Monthly Winter Therm Use Is:	Then Your Present Monthly Winter Bill (1) Would Be:	And Your Proposed Monthly Winter Bill (2) Would Be:	Your Monthly Winter Bill Change Would Be:	And Your Monthly Percent Change Would Be:
222	25	\$40.57	\$38.00	(\$2.57)	(6.33%)
444	50	75.16	70.03	(5.13)	(6.83)
606	100	148.12	137.85	(10.27)	(6.93)
1,210	200	290.27	269.73	(20.54)	(7.08)
1,816	300	432.44	401.63	(30.81)	(7.12)

- (1) Based upon Delivery Rates and Basic Gas Supply Service (BGSS-RSG) in effect May 1, 2009 and assumes that the customer receives commodity service from Public Service.
 (2) Same as (1) except includes the proposed change in BGSS-RSG.

Table # 2
Residential Gas Service

If Your Annual Therm Use Is:	And Your Monthly Winter Therm Use Is:	Self-Implementing 5% Increases	
		December 1, 2009 Monthly Winter Change Would Be:	February 1, 2010 Monthly Winter Change Would Be:
222	25	\$1.70	\$1.69
444	50	3.39	3.39
606	100	6.78	6.79
1,200	199	13.51	13.51
1,210	200	13.57	13.58
1,816	300	20.36	20.36

Andrew Dembia, Esq.
Assistant Corporate Rate Counsel

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

4. Actual and Forecasted Refund Amounts

Item 4

NATURAL GAS PIPELINE REFUNDS RECEIVED

(000)

<u>MONTH</u>	<u>SUPPLIER</u>	<u>AMOUNT</u>	<u>TOTAL</u>
May 2008	Transcontinental	873	873
June	Transcontinental	39	39
July	Transcontinental	13,445	
	Old Dominion	34	13,479
August	Transcontinental	69	
	Trunkline	74	143
September	Transcontinental	1,185	1,185
October	Transcontinental	96	
	Transcontinental	12	108
November	Transcontinental	2	
	Columbia	10	12
December		-	-
January 2009	Tennessee	19	19
February		-	-
March		-	-
April		-	-
TOTAL			<u>\$ 15,858</u>

Item 4

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

(000)

DOCKET

SUPPLIER

STATUS

(none anticipated)

5. Cost of Gas Sendout by Component

ACTUAL COST OF BGSS-RSG GAS SENDOUT BY COMPONENT

	<u>Oct-08</u>	<u>Nov-08</u>	<u>Dec-08</u>	<u>Jan-09</u>	<u>Feb-09</u>	<u>Mar-09</u>	<u>Apr-09</u>	<u>Total</u>
Beginning Inventory Price \$000	\$633,908	\$649,785	\$617,826	\$512,215	\$339,348	\$246,928	\$204,852	
Fixed Pipeline Charge \$000	\$17,559	\$19,596	\$19,459	\$19,456	\$18,482	\$19,582	\$17,639	
Gas Purchases and Hedges \$000	<u>\$89,744</u>	<u>\$123,966</u>	<u>\$130,252</u>	<u>\$132,732</u>	<u>\$112,510</u>	<u>\$118,535</u>	<u>\$89,893</u>	
Receipt Value \$000	\$107,303	\$143,561	\$149,712	\$152,188	\$130,992	\$138,117	\$107,532	\$929,405
Total Inventory Value \$000	\$741,211	\$793,346	\$767,538	\$664,403	\$470,340	\$385,045	\$312,384	
Total \$/dth	\$11.28	\$11.17	\$11.06	\$10.82	\$10.47	\$10.12	\$9.00	
Beginning Inventory Volume MDth	54,415	57,622	55,323	46,346	31,406	23,598	20,260	
Receipt Volume MDth	11,316	13,405	14,099	15,069	13,516	14,441	14,466	96,311
Total Inventory Volume MDth	65,731	71,027	69,422	61,415	44,922	38,039	34,726	
RSG Sendout MDth	8,101	15,788	23,191	30,204	21,375	17,842	9,143	125,644
Total RSG Sendout Cost \$000	\$91,350.76	\$176,346.10	\$256,407.81	\$326,751.33	\$223,796.07	\$180,601.30	\$82,247.27	\$1,337,501
Ending Inventory Rebalance								
Volume	(8)	84	116	195	50	63	400	
Amount	(\$75)	\$826	\$1,085	\$1,696	\$385	\$408	\$2,150	

FORECASTED COST OF BGSS-RSG GAS SENDOUT BY COMPONENT

	<u>May-09</u>	<u>Jun-09</u>	<u>Jul-09</u>	<u>Aug-09</u>	<u>Sep-09</u>	<u>Oct-09</u>	<u>Nov-09</u>	<u>Dec-09</u>	<u>Jan-10</u>	<u>Feb-10</u>	<u>Mar-10</u>	<u>Apr-10</u>	<u>May-10</u>	<u>Jun-10</u>	<u>Jul-10</u>	<u>Aug-10</u>	<u>Sep-10</u>	Total Oct - Sept
Beginning Inventory Price \$000	\$232,286	\$275,934	\$334,492	\$400,534	\$469,168	\$532,041	\$563,920	\$540,174	\$440,474	\$294,960	\$171,161	\$92,448	\$106,211	\$167,030	\$232,469	\$305,800	\$380,078	
Receipt Value \$000	\$91,057	\$94,704	\$96,286	\$98,690	\$96,074	\$99,405	\$111,249	\$117,598	\$113,631	\$100,497	\$110,956	\$99,844	\$105,897	\$97,467	\$100,492	\$100,954	\$101,430	\$1,259,420
Total Inventory Value \$000	\$323,343	\$370,638	\$430,778	\$499,224	\$565,243	\$631,446	\$675,169	\$657,771	\$554,106	\$395,457	\$282,117	\$192,292	\$212,108	\$264,497	\$332,961	\$406,754	\$481,508	
Total \$/dth	\$9.45	\$9.54	\$9.62	\$9.63	\$9.66	\$9.70	\$9.70	\$9.71	\$9.79	\$9.97	\$10.08	\$9.06	\$8.70	\$8.64	\$8.60	\$8.60	\$8.60	
Beginning Inventory Volume MDth	25,983	29,198	35,044	41,635	48,726	55,052	58,147	55,709	45,349	30,117	17,161	9,170	11,725	19,189	26,908	35,546	44,214	
Receipt Volume MDth	8,232	9,633	9,735	10,212	9,762	10,057	11,484	12,012	11,228	9,533	10,823	12,058	12,642	11,427	11,794	11,772	11,776	136,607
Total Inventory Volume MDth	34,215	38,831	44,779	51,847	58,487	65,109	69,631	67,721	56,577	39,650	27,984	21,229	24,367	30,616	38,703	47,317	55,990	
RSG Sendout MDth	5,017	3,787	3,144	3,121	3,435	6,963	13,922	22,372	26,460	22,489	18,814	9,503	5,179	3,707	3,157	3,103	3,432	139,101
Total RSG Sendout Cost \$000	\$47,409	\$36,146	\$30,244	\$30,056	\$33,202	\$67,526	\$134,996	\$217,297	\$259,146	\$224,296	\$189,668	\$86,081	\$45,078	\$32,027	\$27,161	\$26,676	\$29,518	\$1,339,470

6. BGSS Contribution and Credit Offsets

Actual BGSS Contribution and Credit Offsets

		<u>Oct-08</u>	<u>Nov-08</u>	<u>Dec-08</u>	<u>Jan-09</u>	<u>Feb-09</u>	<u>Mar-09</u>	<u>Apr-09</u>	<u>Total</u>	
(1)	BGSS-I - Contribution	\$288	\$405	\$343	\$621	(\$644)	\$93	(\$350)	\$756	
(2)	CIG - Contribution	(\$125)	(\$322)	\$33	\$64	(\$206)	(\$470)	\$516	(\$509)	
(3)	Cogen Contract - Contribution	\$2,346	\$2,063	\$1,752	\$2,137	\$2,477	\$2,214	\$2,120	\$15,109	
(4)	TSG-F - Contribution	<u>\$181</u>	<u>\$608</u>	<u>\$307</u>	<u>\$409</u>	<u>\$700</u>	<u>\$424</u>	<u>\$398</u>	<u>\$3,026</u>	
(5)	"Contribution"	Sum of (1) through (5)	\$2,691	\$2,754	\$2,434	\$3,230	\$2,327	\$2,261	\$2,684	\$18,381
(6)	Off-System Contribution	\$796	\$5,547	\$9,800	\$15,094	\$9,150	\$6,764	\$1,087	\$48,239	
(7)	Electric Contribution	\$1,503	\$1,811	\$1,525	\$2,052	\$1,466	\$993	\$1,345	\$10,695	
(8)	FT-S Balancing Credit	\$5	\$1,311	\$2,447	\$2,786	\$3,303	\$2,709	\$94	\$12,655	
(9)	Pipeline Refunds	\$108	\$12	\$0	\$19	\$0	\$0	\$0	\$140	

Forecasted BGSS Contribution and Credit Offsets

	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Total Oct - Sept
(1) BGSS-RSG Sendout, Mdth	5,017	3,787	3,144	3,121	3,435	6,963	13,922	22,372	26,460	22,489	18,814	9,503	5,179	3,707	3,157	3,103	3,432	139,101
(2) BGSS-F Sendout, Mdth	1,422	1,510	1,338	1,341	1,404	2,609	4,988	8,132	9,655	8,539	6,930	4,051	1,551	1,449	1,336	1,311	1,382	51,931
(3) Total Firm Sendout, Mdth	6,439	5,297	4,482	4,463	4,839	9,572	18,910	30,504	36,115	31,028	25,744	13,554	6,729	5,156	4,493	4,414	4,814	191,033
(4) Annual % BGSS-RSG of Firm Sendout	72.8%	72.8%	72.8%	72.8%	72.8%	72.8%	72.8%	72.8%	72.8%	72.8%	72.8%	72.8%	72.8%	72.8%	72.8%	72.8%	72.8%	72.8%
(5) BGSS-I Sendout, Mdth	325	207	218	267	158	248	314	320	483	499	433	259	325	207	218	267	158	
(6) BGSS-I Margin, \$/Dth	\$0.4743	\$0.4743	\$0.4743	\$0.4743	\$0.4743	\$0.4743	\$0.4743	\$0.4743	\$0.4743	\$0.4743	\$0.4743	\$0.4743	\$0.4743	\$0.4743	\$0.4743	\$0.4743	\$0.4743	
(7) BGSS-I Contribution	\$112.2	\$71.5	\$75.4	\$92.4	\$54.5	\$85.6	\$108.3	\$110.5	\$167.0	\$172.2	\$149.4	\$89.5	\$112.2	\$71.5	\$75.4	\$92.4	\$54.5	\$1,288.4
(8) CIG Sendout, Mdth	352	388	435	411	404	385	489	575	599	504	481	357	352	388	435	411	404	
(9) CIG Margin, \$/Dth	\$0.3662	\$0.3662	\$0.3662	\$0.3662	\$0.3662	\$0.3662	\$0.3662	\$0.3662	\$0.3662	\$0.3662	\$0.3662	\$0.3662	\$0.3662	\$0.3662	\$0.3662	\$0.3662	\$0.3662	
(10) CIG Contribution	\$93.8	\$103.4	\$116.0	\$109.6	\$107.8	\$102.7	\$130.5	\$153.3	\$159.7	\$134.3	\$128.1	\$95.2	\$93.8	\$103.4	\$116.0	\$109.6	\$107.8	\$1,434.3
(11) Cogen Contract Contribution, \$000	\$1,871.4	\$1,871.4	\$1,871.4	\$1,871.4	\$1,871.4	\$1,871.4	\$1,871.4	\$1,871.4	\$1,871.4	\$1,871.4	\$1,871.4	\$1,871.4	\$1,871.4	\$1,871.4	\$1,871.4	\$1,871.4	\$1,871.4	\$22,456.3
(12) TSG-F Sendout, Mdth	267	248	241	233	136	373	340	317	488	399	358	280	267	248	241	233	136	
(13) TSG-F Avg Distribution Charge, \$/Dth	\$0.7000	\$0.7000	\$0.7000	\$0.7000	\$0.7000	\$0.7000	\$1.4000	\$1.4000	\$1.4000	\$1.4000	\$1.4000	\$0.7000	\$0.7000	\$0.7000	\$0.7000	\$0.7000	\$0.7000	
(14) TSG-F Contribution	\$136.2	\$126.6	\$122.7	\$118.7	\$69.4	\$189.9	\$346.3	\$323.0	\$497.2	\$407.1	\$364.7	\$142.9	\$136.2	\$126.6	\$122.7	\$118.7	\$69.4	\$2,844.8
(15) "Contribution"	\$2,213.4	\$2,172.9	\$2,185.5	\$2,192.0	\$2,103.2	\$2,249.6	\$2,456.5	\$2,458.1	\$2,695.3	\$2,584.9	\$2,513.6	\$2,198.9	\$2,213.4	\$2,172.9	\$2,185.5	\$2,192.0	\$2,103.2	\$28,023.8
(16) Off-System Contribution, \$000	\$1,559.4	\$1,559.4	\$1,559.4	\$1,559.4	\$1,559.4	\$1,559.4	\$5,569.2	\$7,796.9	\$11,138.4	\$7,796.9	\$5,569.2	\$1,559.4	\$1,559.4	\$1,559.4	\$1,559.4	\$1,559.4	\$1,559.4	\$48,786.4
(17) Electric Contribution, \$000	\$1,293.7	\$1,750.3	\$2,435.1	\$2,663.4	\$1,902.5	\$1,522.0	\$1,522.0	\$1,522.0	\$761.0	\$761.0	\$1,217.6	\$1,217.6	\$1,293.7	\$1,750.3	\$2,435.1	\$2,663.4	\$1,902.5	\$18,568.0
(18) Pipeline Refund, \$000	\$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	\$0.0
(19) FT-S Balancing Use, Mdth	0.0	0.0	0.0	0.0	0.0	0.0	2,157.9	4,393.0	5,727.6	5,088.6	4,034.6	0.0	0.0	0.0	0.0	0.0	0.0	
(20) Balancing Charge, \$/dth	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.6908	\$0.6908	\$0.6908	\$0.6908	\$0.6908	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	
(21) FT-S Balancing Credit, \$000	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$1,085.4	\$2,209.7	\$2,881.0	\$2,559.6	\$2,029.5	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$10,765.3
(22) BGSS-RSG Balancing Use, Mdth	0	0	0	0	0	0	10,271	18,599	22,687	19,081	15,041	0	0	0	0	0	0	
(23) Balancing Charge, \$/dth	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.6908	\$0.6908	\$0.6908	\$0.6908	\$0.6908	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	
(24) BGSS-RSG Balancing Rev., \$000	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$7,095.0	\$12,847.9	\$15,672.1	\$13,180.9	\$10,390.2	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$59,186.0

BGSS-RSG MARGIN FROM GAS SALES FOR ELECTRIC GENERATION

	<u>Gas Sales For Electric Use</u>		<u>Gas Reservation Charge</u>		<u>BGSS-RSG % of Sales</u>		<u>BGSS-RSG Gas Reservation Charge</u>		
	<u>Estimate</u>	<u>Actual</u>	<u>Estimate</u>	<u>Actual</u>	<u>Estimate</u>	<u>Actual</u>	<u>Estimate</u>	<u>Actual</u>	<u>Booked</u>
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	(dth)	(dth)	(1)*\$.425	(2)*\$.425			(3)*(5)	(4)*(6)	*
2008 September	8,445,290	8,478,846	\$3,589,248	\$3,603,510	70.49%	71.20%	\$2,530,061	\$2,565,699	
October	4,921,873	4,945,695	\$2,091,796	\$2,101,920	70.16%	71.74%	\$1,467,604	\$1,507,918	\$1,503,242
November	5,845,771	5,871,606	\$2,484,453	\$2,495,433	71.28%	74.18%	\$1,770,918	\$1,851,112	\$1,811,231
December	4,678,874	4,699,903	\$1,988,521	\$1,997,459	72.65%	72.49%	\$1,444,661	\$1,447,958	\$1,524,855
2009 January	6,724,164	6,777,719	\$2,857,770	\$2,880,531	71.70%	72.50%	\$2,049,021	\$2,088,385	\$2,052,318
February	4,691,334	4,706,520	\$1,993,817	\$2,000,271	71.55%	72.02%	\$1,426,576	\$1,440,595	\$1,465,940
March	3,186,678	3,219,323	\$1,354,338	\$1,368,212	72.27%	72.90%	\$978,780	\$997,427	\$992,799
April	4,441,375		\$1,887,584		70.26%		\$1,326,217		\$1,344,863

* Column 9 is derived by accrual accounting. The difference between actual and estimate from the prior month is added to the estimate of the current month.

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 2008 - SEPTEMBER 2009**

(000)

	<u>TOTAL RECOVERY</u>	<u>LESS: TOTAL EXPENSE</u>	<u>MONTHLY OVER/(UNDER) RECOVERY</u>
Balance September 30, 2008			(\$25,734)
Interest Adjustment			<u>0</u>
October 1, 2008 Adjusted Balance			(\$25,734)
October 2008	\$ 89,504	\$ 87,330	2,174
November	189,475	174,642	14,833
December	269,380	262,304	7,076
January 2009	344,462	318,321	26,141
February	235,591	224,988	10,603
March	184,733	181,799	2,934
April	87,321	82,650	4,671
May (Est.)	-	(2,623)	2,623
June (Est.)	-	(3,280)	3,280
July (Est.)	-	(4,115)	4,115
August (Est.)	-	(4,337)	4,337
September (Est.)	-	(3,156)	3,156
Total			<u><u>\$60,209</u></u>

**INTEREST
COMPUTED AT 7.96% ROR
OCTOBER 2008 - SEPTEMBER 2009**

(000)

		<u>OVER/(UNDER) RECOVERIES</u>			
		<u>Monthly</u>	<u>Cumulative</u>	<u>Average Balance</u>	<u>INTEREST</u>
Balance September 30, 2008			(\$25,734)		
Interest Adjustment			0		
October 1, 2008 Adjusted Balance			(\$25,734)		
October 2008		\$ 2,174	(23,560)	\$(24,647)	\$ (163)
November		14,833	(8,727)	\$(16,144)	(107)
December		7,076	(1,651)	(5,189)	(34)
January 2009		26,141	24,490	11,420	76
February		10,603	35,093	29,792	198
March		2,934	38,027	36,560	243
April		4,671	42,698	40,363	268
May	(Est.)	2,623	45,321	44,010	292
June	(Est.)	3,280	48,601	46,961	312
July	(Est.)	4,115	52,716	50,659	336
August	(Est.)	4,337	57,053	54,885	364
September	(Est.)	3,156	60,209	58,631	389
Total					<u><u>\$ 2,174</u></u>

BGSS-RSG 2008-2009

NYMEX====>>: 5/6/09

NO CHANGE IN RATES

	BGSS-RSG			OFF-SYS	Electric	FT Balancing		RSG Bal.	BGSS	EXCESS	OVER/(UNDER)	RECOVERY	RSG Rate	
	MDTh	COST	REFUNDS	CONTRIB	Margin	Contribution	Credit	ADJ COST	Revenue	RECOVERY	COST	Month	Cumulative	\$/dth
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(2)+.(7)	(9)	(10)=(1)*(14)+(9)	(11)=(10)-(8)	(12)=(11)	(13)	(14)
Apr-09 Act.													\$42,698	\$8.9632
May-09 Est.	5,017	\$47,409	\$0	(\$2,213)	(\$1,559)	(\$1,294)	\$0	\$42,342	\$0	\$44,965	(\$2,623)	\$2,623	\$45,321	\$8.9632
Jun-09 Est.	3,787	\$36,146	\$0	(\$2,173)	(\$1,559)	(\$1,750)	\$0	\$30,664	\$0	\$33,943	(\$3,280)	\$3,280	\$48,600	\$8.9632
Jul-09 Est.	3,144	\$30,244	\$0	(\$2,185)	(\$1,559)	(\$2,435)	\$0	\$24,064	\$0	\$28,179	(\$4,115)	\$4,115	\$52,715	\$8.9632
Aug-09 Est.	3,121	\$30,056	\$0	(\$2,192)	(\$1,559)	(\$2,663)	\$0	\$23,641	\$0	\$27,978	(\$4,337)	\$4,337	\$57,053	\$8.9632
Sep-09 Est.	3,435	\$33,202	\$0	(\$2,103)	(\$1,559)	(\$1,902)	\$0	\$27,637	\$0	\$30,793	(\$3,156)	\$3,156	\$60,209	\$8.9632
Oct-09 Est.	6,963	\$67,526	\$0	(\$2,250)	(\$1,559)	(\$1,522)	\$0	\$62,195	\$0	\$62,408	(\$213)	\$213	\$60,422	\$8.9632
Nov-09 Est.	13,922	\$134,996	\$0	(\$2,456)	(\$5,569)	(\$1,522)	(\$1,085)	\$124,362	\$7,095	\$131,883	(\$7,521)	\$7,521	\$67,943	\$8.9632
Dec-09 Est.	22,372	\$217,297	\$0	(\$2,458)	(\$7,797)	(\$1,522)	(\$2,210)	\$203,310	\$12,848	\$213,372	(\$10,061)	\$10,061	\$78,005	\$8.9632
Jan-10 Est.	26,460	\$259,146	\$0	(\$2,695)	(\$11,138)	(\$761)	(\$2,881)	\$241,670	\$15,672	\$252,840	(\$11,170)	\$11,170	\$89,175	\$8.9632
Feb-10 Est.	22,489	\$224,296	\$0	(\$2,585)	(\$7,797)	(\$761)	(\$2,560)	\$210,593	\$13,181	\$214,753	(\$4,160)	\$4,160	\$93,335	\$8.9632
Mar-10 Est.	18,814	\$189,668	\$0	(\$2,514)	(\$5,569)	(\$1,218)	(\$2,029)	\$178,338	\$10,390	\$179,025	(\$687)	\$687	\$94,022	\$8.9632
Apr-10 Est.	9,503	\$86,081	\$0	(\$2,199)	(\$1,559)	(\$1,218)	\$0	\$81,105	\$0	\$85,179	(\$4,073)	\$4,073	\$98,095	\$8.9632
May-10 Est.	5,179	\$45,078	\$0	(\$2,213)	(\$1,559)	(\$1,294)	\$0	\$40,012	\$0	\$46,417	(\$6,405)	\$6,405	\$104,500	\$8.9632
Jun-10 Est.	3,707	\$32,027	\$0	(\$2,173)	(\$1,559)	(\$1,750)	\$0	\$26,545	\$0	\$33,228	(\$6,684)	\$6,684	\$111,184	\$8.9632
Jul-10 Est.	3,157	\$27,161	\$0	(\$2,185)	(\$1,559)	(\$2,435)	\$0	\$20,981	\$0	\$28,298	(\$7,317)	\$7,317	\$118,501	\$8.9632
Aug-10 Est.	3,103	\$26,676	\$0	(\$2,192)	(\$1,559)	(\$2,663)	\$0	\$20,262	\$0	\$27,815	(\$7,553)	\$7,553	\$126,055	\$8.9632
Sep-10 Est.	3,432	\$29,518	\$0	(\$2,103)	(\$1,559)	(\$1,902)	\$0	\$23,953	\$0	\$30,765	(\$6,812)	\$6,812	\$132,867	\$8.9632

BGSS-RSG 2008-2009
 NYMEX====>>: 5/6/09

ZERO BALANCE

	BGSS-RSG			OFF-SYS	Electric	FT Balancing		RSG Bal.	BGSS	EXCESS	OVER/(UNDER)	RECOVERY	RSG Rate	
	MDTh	COST	REFUNDS	CONTRIB	Margin	Contribution	Credit	ADJ COST	Revenue	RECOVERY	COST	Month	Cumulative	\$/dth
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(2)+.(7)	(9)	(10)=(1)*(14)+(9)	(11)=(10)-(8)	(12)=(11)	(13)	(14)
Apr-09 Act.													\$42,698	\$8.9632
May-09 Est.	5,017	47,409	0	(2,213)	(1,559)	(1,294)	0	\$42,342	\$0	\$44,965	(\$2,623)	\$2,623	\$45,321	\$8.9632
Jun-09 Est.	3,787	36,146	0	(2,173)	(1,559)	(1,750)	0	\$30,664	\$0	\$33,943	(\$3,280)	\$3,280	\$48,600	\$8.9632
Jul-09 Est.	3,144	30,244	0	(2,185)	(1,559)	(2,435)	0	\$24,064	\$0	\$28,179	(\$4,115)	\$4,115	\$52,715	\$8.9632
Aug-09 Est.	3,121	30,056	0	(2,192)	(1,559)	(2,663)	0	\$23,641	\$0	\$27,978	(\$4,337)	\$4,337	\$57,053	\$8.9632
Sep-09 Est.	3,435	33,202	0	(2,103)	(1,559)	(1,902)	0	\$27,637	\$0	\$30,793	(\$3,156)	\$3,156	\$60,209	\$8.9632
Oct-09 Est.	6,963	67,526	0	(2,250)	(1,559)	(1,522)	0	\$62,195	\$0	\$55,758	\$6,437	(\$6,437)	\$53,772	\$8.0081
Nov-09 Est.	13,922	134,996	0	(2,456)	(5,569)	(1,522)	(1,085)	\$124,362	\$7,095	\$118,585	\$5,777	(\$5,777)	\$47,994	\$8.0081
Dec-09 Est.	22,372	217,297	0	(2,458)	(7,797)	(1,522)	(2,210)	\$203,310	\$12,848	\$192,003	\$11,308	(\$11,308)	\$36,687	\$8.0081
Jan-10 Est.	26,460	259,146	0	(2,695)	(11,138)	(761)	(2,881)	\$241,670	\$15,672	\$227,566	\$14,104	(\$14,104)	\$22,583	\$8.0081
Feb-10 Est.	22,489	224,296	0	(2,585)	(7,797)	(761)	(2,560)	\$210,593	\$13,181	\$193,273	\$17,321	(\$17,321)	\$5,262	\$8.0081
Mar-10 Est.	18,814	189,668	0	(2,514)	(5,569)	(1,218)	(2,029)	\$178,338	\$10,390	\$161,054	\$17,284	(\$17,284)	(\$12,022)	\$8.0081
Apr-10 Est.	9,503	86,081	0	(2,199)	(1,559)	(1,218)	0	\$81,105	\$0	\$76,102	\$5,004	(\$5,004)	(\$17,026)	\$8.0081
May-10 Est.	5,179	45,078	0	(2,213)	(1,559)	(1,294)	0	\$40,012	\$0	\$41,471	(\$1,459)	\$1,459	(\$15,567)	\$8.0081
Jun-10 Est.	3,707	32,027	0	(2,173)	(1,559)	(1,750)	0	\$26,545	\$0	\$29,687	(\$3,143)	\$3,143	(\$12,424)	\$8.0081
Jul-10 Est.	3,157	27,161	0	(2,185)	(1,559)	(2,435)	0	\$20,981	\$0	\$25,282	(\$4,302)	\$4,302	(\$8,123)	\$8.0081
Aug-10 Est.	3,103	26,676	0	(2,192)	(1,559)	(2,663)	0	\$20,262	\$0	\$24,851	(\$4,589)	\$4,589	(\$3,533)	\$8.0081
Sep-10 Est.	3,432	29,518	0	(2,103)	(1,559)	(1,902)	0	\$23,953	\$0	\$27,486	(\$3,534)	\$3,534	\$0	\$8.0081

PSE&G							
BGSS OVER / (UNDER) RECOVERY CALCULATION							
FOR THE LGAC PERIOD OCT. 2008 TO APR. 2009							
	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09
<u>Beginning Balance</u>	(25,734,474)	(23,560,299)	(8,726,940)	(1,650,784)	24,490,604	35,093,503	38,027,405
<u>FUEL REVENUES</u>							
Fuel Revenues	86,813,746	186,720,436	266,945,494	341,231,269	233,263,765	182,472,127	84,406,837
Interruptible Contribution	2,690,627	2,754,442	2,434,421	3,230,398	2,326,772	2,260,764	2,683,853
PSEG Holding's Affiliation Fee	0	0	0	0	0	0	0
Total Fuel Revenues	89,504,373	189,474,879	269,379,915	344,461,666	235,590,537	184,732,890	87,090,690
<u>FUEL EXPENSE</u>							
Gas Purchases	87,438,374	174,653,712	262,304,167	318,339,334	224,987,638	181,798,988	82,419,866
Refunds	(108,175)	(12,193)	(408)	(19,056)	0	0	0
Total Fuel Expense	87,330,199	174,641,519	262,303,759	318,320,279	224,987,638	181,798,988	82,419,866
OVER / (UNDER) RECOVERY	2,174,175	14,833,360	7,076,156	26,141,388	10,602,898	2,933,902	4,670,823

**BGSS
Calculation of Fuel Revenues**

	Oct 08	Nov 08	Dec 08	Jan 09	Feb 09	Mar 09	Apr 09
RSG Fuel Revenues	\$85,102,162	\$167,981,613	\$241,255,270	\$307,000,788	\$209,294,235	\$173,682,963	\$82,406,903
RSGM Fuel Revenues	<u>\$1,719,340</u>	<u>\$3,608,484</u>	<u>\$5,429,963</u>	<u>\$6,534,853</u>	<u>\$4,636,591</u>	<u>\$4,095,830</u>	<u>\$2,043,275</u>
Subtotal	\$86,821,502	\$171,590,096	\$246,685,233	\$313,535,641	\$213,930,826	\$177,778,793	\$84,450,178
FT Balancing Revenues	-7,756	8,388,261	17,396,132	19,859,661	23,420,410	18,048,038	-43,341
FT Balancing Revenues (Unbilled Calc)	0	6,742,079	9,606,209	17,442,176	13,354,704	0	0
FT Balancing Revenues (Prior Unbilled Calc)	0	0	-6,742,079	-9,606,209	-17,442,176	-13,354,704	0
Total BGSS Fuel Recovery	\$86,813,746	\$186,720,436	\$266,945,494	\$341,231,269	\$233,263,765	\$182,472,127	\$84,406,837

Input Page							
Interruptible Contributions	Oct 08	Nov 08	Dec 08	Jan 09	Feb 09	Mar 09	Apr 09
<i>ISG (BGSS-I):</i>							
ISG (BGSS-I) Sales Therms	2,466,931	3,142,798	3,243,730	4,024,280	2,564,629	2,547,691	845,400
ISG BGSS-I) Gross Revenues	\$2,243,259.68	\$2,629,240.05	\$2,797,350.71	\$3,196,644.42	\$1,365,842.69	\$1,450,646.67	\$376,405.65
ISG (BGSS-I) Cost	\$1,861,881.72	\$2,169,987.95	\$2,348,675.64	\$2,382,513.50	\$1,980,603.74	\$1,300,991.15	\$672,717.10
PSEG Power's share of Contribution	<u>\$93,281.09</u>	<u>\$54,058.29</u>	<u>\$105,877.55</u>	<u>\$193,356.21</u>	<u>\$28,915.92</u>	<u>\$56,294.02</u>	<u>\$53,974.95</u>
ISG Interruptible Contribution to LGAC	\$288,096.87	\$405,193.81	\$342,797.52	\$620,774.71	(\$643,676.97)	\$93,361.50	(\$350,286.40)
<i>CIG:</i>							
CIG SBC Rate adjustment (line 76)							
CIG Sales Therms	3,831,728	4,869,029	5,721,042	5,224,949	5,612,203	4,262,848	5,416,138
CIG Gross Revenues	\$3,515,512.75	\$3,922,859.58	\$4,980,047.97	\$4,146,740.63	\$3,467,772.72	\$2,432,428.51	\$2,894,493.06
CIG SBC Revenues	\$171,541.53	\$235,320.16	\$297,042.02	\$279,686.32	\$300,415.62	\$228,186.00	\$289,920.47
CIG Cost	\$3,335,579.94	\$3,964,116.90	\$4,501,888.00	\$3,560,393.50	\$3,380,580.01	\$2,617,915.20	\$1,975,488.68
PSEG Power's share of Contribution	<u>\$132,993.16</u>	<u>\$45,149.18</u>	<u>\$148,218.20</u>	<u>\$242,483.06</u>	<u>(\$6,948.20)</u>	<u>\$56,307.03</u>	<u>\$112,926.16</u>
CIG Interruptible Contribution to LGAC	(\$124,601.88)	(\$321,726.65)	\$32,899.75	\$64,177.75	(\$206,274.70)	(\$469,979.72)	\$516,157.75
<i>TSG-F:</i>							
TSG-F Sales Therms	3,708,115	3,408,745	3,222,324	4,068,687	10,100,135	3,380,510	3,705,327
TSG-F Gross Revenues	\$385,831.70	\$886,270.33	\$575,214.00	\$770,964.70	\$1,319,783.74	\$717,901.71	\$620,791.79
TSG-F SBC Revenues	\$166,007.51	\$164,744.63	\$167,306.17	\$217,792.74	\$540,650.15	\$180,955.31	\$198,342.46
TSG-F TEFA Revenues	\$7,119.58	\$6,544.79	\$6,186.86	\$7,811.88	\$19,392.26	\$6,490.58	\$7,114.23
TSG-F MAC Revenues	(\$27,221.27)	(\$25,023.59)	(\$23,655.08)	(\$29,868.23)	(\$74,145.09)	(\$24,816.32)	(\$27,200.81)
TSG-F PSEG Power's share of Contribution	<u>\$58,733.02</u>	<u>\$132,243.87</u>	<u>\$118,695.64</u>	<u>\$166,486.87</u>	<u>\$134,138.49</u>	<u>\$131,727.21</u>	<u>\$44,442.44</u>
TSG-F Interruptible Contribution to LGAC	\$181,192.85	\$607,760.63	\$306,680.41	\$408,741.43	\$699,747.94	\$423,544.93	\$398,093.47
<i>Cogen Contracts :</i>							
NewMarket Settlement Incl. in Cogen Rev. row 35 (add back C&I Portion)			\$145,995.45				
Cogen Contract Therms	20,316,190	23,540,680	21,200,170	29,024,120	33,790,850	28,047,290	30,071,850
Cogen Contract Gross Revenues	\$530,376.00	\$9,351,769.00	\$1,320,283.51	\$5,162,407.00	\$9,250,627.00	\$5,112,818.00	\$5,824,929.00
Cogen Contract RAC Revenues	\$75,926.59	\$37,642.44	\$37,815.70	\$40,375.17	\$37,542.45	\$40,359.06	\$36,953.29
Linden Cogen Resale	\$0.00	\$5,722,940.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
JCPL (NJ Natural Deliveries) reduction to expense	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Cogen Contract Cost & PSEG Power's share of Contribution	<u>-\$1,891,490.00</u>	<u>\$1,527,972.00</u>	<u>-\$323,580.00</u>	<u>\$2,985,328.00</u>	<u>\$6,736,109.00</u>	<u>\$2,858,622.00</u>	<u>\$3,668,088.00</u>
Cogen Contract Contribution	\$2,345,939.41	\$2,063,214.56	\$1,752,043.26	\$2,136,703.83	\$2,476,975.55	\$2,213,836.94	\$2,119,887.71
Total Interruptible Contributions	\$2,690,627.24	\$2,754,442.35	\$2,434,420.94	\$3,230,397.72	\$2,326,771.81	\$2,260,763.65	\$2,683,852.53
Current Month Estimate - Gas Purchases (1) See below row 96	\$88,304,109.47	\$171,957,679.68	\$258,652,864.10	\$320,496,314.89	\$222,197,213.20	\$180,530,227.27	\$82,189,657.39
Prior Month Actual - Gas Purchases (1) See below row 105	\$35,153,077.63	\$90,987,948.77	\$175,608,574.59	\$256,476,827.77	\$323,286,739.91	\$223,465,974.04	\$180,760,435.96
Prior Month Estimate - Gas Purchases See below row 115	<u>\$36,126,988.33</u>	<u>\$88,304,109.47</u>	<u>\$171,957,679.68</u>	<u>\$258,652,864.10</u>	<u>\$320,496,314.89</u>	<u>\$222,197,213.20</u>	<u>\$180,530,227.27</u>
Gas Purchases	\$87,330,198.77	\$174,641,518.99	\$262,303,759.01	\$318,320,278.56	\$224,987,638.22	\$181,798,988.10	\$82,419,866.08
Gas Refunds	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
ISG (BGSS-I) Cost Est. (2)	\$1,852,984.34	\$2,214,320.72	\$2,414,406.97	\$2,434,259.41	\$1,806,275.57	\$1,259,984.32	\$664,867.02

PSEG Power's share of Contribution CMnth Est. (2)	\$98,716.54	\$46,568.03	\$93,607.93	\$178,573.29	\$81,353.17	\$67,975.11	\$57,012.62
ISG (BGSS-I) Cost Pr Mnth Act. (2)	\$1,620,446.67	\$1,808,651.57	\$2,148,589.39	\$2,362,661.06	\$2,608,587.58	\$1,847,282.40	\$1,267,834.40
PSEG Power's share of Contribution Pr Mnth Act. (2)	\$110,386.40	\$106,206.80	\$58,837.66	\$108,390.84	\$126,136.05	\$69,672.08	\$64,937.45
ISG (BGSS-I) Cost PrMnth Est.	\$1,611,549.29	\$1,852,984.34	\$2,214,320.72	\$2,414,406.97	\$2,434,259.41	\$1,806,275.57	\$1,259,984.32
PSEG Power's share of Contribution PrMnth Est.	\$115,821.85	\$98,716.54	\$46,568.03	\$93,607.93	\$178,573.29	\$81,353.17	\$67,975.11
CIG Cost (3) - CMnth Est. (3)	\$3,318,301.46	\$4,044,497.84	\$4,621,947.50	\$3,643,963.54	\$3,122,170.40	\$2,553,221.83	\$1,963,568.73
PSEG Power's share of Contribution - CMnth Est. (3)	\$144,540.92	\$30,086.83	\$120,256.85	\$214,021.09	\$70,164.51	\$75,567.37	\$117,873.28
CIG Cost (3) - PrMnth Act. (3)	\$3,636,873.17	\$3,237,920.52	\$3,924,438.34	\$4,538,377.46	\$3,902,373.15	\$3,186,863.77	\$2,565,141.78
PSEG Power's share of Contribution - PrMnth Act. (3)	\$214,708.64	\$159,603.26	\$58,048.18	\$148,718.82	\$136,908.38	\$50,904.17	\$70,620.24
CIG Cost - PrMnth Est.	\$3,619,594.69	\$3,318,301.46	\$4,044,497.84	\$4,621,947.50	\$3,643,963.54	\$3,122,170.40	\$2,553,221.83
PSEG Power's share of Contribution - PrMnth Est.	\$226,256.39	\$144,540.92	\$30,086.83	\$120,256.85	\$214,021.09	\$70,164.51	\$75,567.37
TSG-F PSEG Power's share of Contribution CMth Est. (4)	\$57,535.16	\$133,921.59	\$132,107.39	\$163,541.46	\$138,906.33	\$132,644.29	\$55,780.79
TSG-F PSEG Power's share of Contribution PrMth Actual (4)	\$45,911.17	\$55,857.44	\$120,509.84	\$135,052.81	\$158,773.62	\$137,989.25	\$121,305.94
TSG-F PSEG Power's share of Contribution PrMth Est.	\$44,713.32	\$57,535.16	\$133,921.59	\$132,107.39	\$163,541.46	\$138,906.33	\$132,644.29
Cogen Contracts Linden Cogen Resale CMth Est.							
Cogen Contracts Linden Cogen Resale Prior Mth Actual							
Cogen Contracts Linden Cogen Resale Prior Mth Est.							
JCPL (NJ Natural Deliveries) reduction to expense CMnth Est.							
JCPL (NJ Natural Deliveries) reduction to expense Prior Mnth Act.							
JCPL (NJ Natural Deliveries) reduction to expense Prior Mnth Est.							
Cogen Contract Cost & PSEG Power's share of Contribution CMth Est. (5)	-\$1,864,223.00	\$1,316,353.00	-\$264,080.00	\$2,937,958.00	\$6,745,788.00	\$2,845,849.00	\$3,664,108.00
Cogen Contract Cost & PSEG Power's share of Contribution PMth Act. (5)	\$12,247,121.00	-\$1,652,604.00	\$1,256,853.00	-\$216,710.00	\$2,928,279.00	\$6,758,561.00	\$2,849,829.00
Cogen Contract Cost & PSEG Power's share of Contribution PMth Est.	\$12,274,388.00	-\$1,864,223.00	\$1,316,353.00	-\$264,080.00	\$2,937,958.00	\$6,745,788.00	\$2,845,849.00
CIG & TSG-F SBC & RGGI rate (CHECK tariff pages for rate changes)	0.044769	0.048330	0.051921	0.053529	0.053529	0.053529	0.053529
TSG-F TEFA rate	0.00192	0.00192	0.00192	0.00192	0.00192	0.00192	0.00192
Cogen Contract RAC rate (separate schedule beginning 12/02)	n/a	n/a	n/a	n/a	n/a	n/a	n/a
TSG-F MAC rate (Per GCUA MAC CALC Worksheet)	-0.007341	-0.007341	-0.007341	-0.007341	-0.007341	-0.007341	-0.007341
BGSS-RSG Prior Month Actual	\$40,735,492.51	\$96,300,330.93	\$181,798,488.15	\$263,634,975.96	\$330,060,745.07	\$228,620,696.46	\$184,728,969.83
BGSS-RSG Cogen Contracts Prior Month Actual (6)	\$12,660,999.00	\$4,408,820.00	\$2,074,089.00	\$1,100,923.00	\$3,543,367.00	\$6,500,419.00	\$2,607,269.00
BGSS-RSG TSG Cashouts Prior Mnth Actuals	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Subtotal	\$53,396,491.51	\$100,709,150.93	\$183,872,577.15	\$264,735,898.96	\$333,604,112.07	\$235,121,115.46	\$187,336,238.83
Total BGSS-RSG Actual Bill	\$53,396,491.51	\$100,709,150.93	\$183,872,577.15	\$264,735,898.96	\$333,604,112.07	\$235,121,115.46	\$187,336,238.83
Difference	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
BGSS-RSG Prior Month Estimate	\$93,718,652.73	\$178,293,153.10	\$265,903,083.35	\$326,967,132.23	\$227,277,176.85	\$184,486,975.90	\$84,992,979.03
BGSS-RSG Cogen Contracts Prior Month Estimate (6)	\$4,390,403.00	\$2,068,295.00	\$1,067,953.00	\$3,538,563.00	\$6,479,670.00	\$2,595,450.00	\$3,587,950.00
Subtotal	\$98,109,055.73	\$180,361,448.10	\$266,971,036.35	\$330,505,695.23	\$233,756,846.85	\$187,082,425.90	\$88,580,929.03
Total BGSS-RSG Estimate Bill	\$98,109,055.73	\$180,361,448.10	\$266,971,036.35	\$330,505,695.23	\$233,756,846.85	\$187,082,425.90	\$88,580,929.03
Difference	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Gas Purchases Details:							
Current Month Estimate							
BGSS-RSG GAS COMMODITY VOLUMES MDth	7,852,246	15,428,027	23,431,976	30,184,758	21,356,723	17,862,797	9,147,223
BGSS-RSG GAS COMMODITY COST	\$ 88,707,316.05	\$ 172,657,093.95	\$ 259,227,433.79	\$324,292,384.36	\$222,997,135.12	\$180,375,406.41	\$82,258,888.31

BGSS-RSG Balancing	\$1,963,611.16	\$6,611,519.36	\$10,449,366.90	\$13,824,735.73	\$9,605,733.87	\$7,842,409.85	\$2,287,446.06
BGSS-RSG Off System Sales	(\$802,978.14)	(\$5,529,988.80)	(\$9,579,275.76)	(\$15,571,784.33)	(\$8,979,079.76)	(\$6,708,808.81)	(\$1,030,460.20)
Electric Reservation Charge	(\$1,467,604.09)	(\$1,770,917.87)	(\$1,444,660.83)	(\$2,049,020.87)	(\$1,426,576.03)	(\$978,780.18)	(\$1,326,216.78)
Credit for Pipeline Refunds	(\$96,235.51)	(\$10,026.96)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Total	\$88,304,109.47	\$171,957,679.68	\$258,652,864.10	\$320,496,314.89	\$222,197,213.20	\$180,530,227.27	\$82,189,657.39
Prior Actual							
BGSS-RSG GAS COMMODITY VOLUMES MDTh	3,381,202	8,110,718	15,794,132	23,200,137	30,318,734	21,437,289	17,861,318
BGSS-RSG GAS COMMODITY COST	\$39,358,407.70	\$91,376,889.29	\$176,360,052.86	\$256,469,334.55	\$327,148,614.91	\$224,175,408.26	\$180,660,524.46
BGSS-RSG Balancing	\$845,537.18	\$2,028,247.25	\$6,861,278.17	\$10,375,095.61	\$13,869,150.82	\$9,633,310.45	\$7,857,379.90
BGSS-RSG Off System Sales	(\$1,072,322.03)	(\$820,190.92)	(\$5,751,209.67)	(\$9,101,878.90)	(\$15,742,831.05)	(\$9,033,783.54)	(\$6,765,353.54)
Electric Reservation Charge	(\$2,565,698.80)	(\$1,507,917.68)	(\$1,851,111.87)	(\$1,447,957.87)	(\$2,088,384.67)	(\$1,440,595.17)	(\$997,426.75)
Non Compliance Penalty	\$0.00	\$0.00	\$0.00	\$0.00	\$6,228.32	\$0.00	\$0.00
Credit for Pipeline Refunds	(\$1,197,324.02)	(\$98,401.71)	(\$10,434.90)	(\$19,055.51)	\$0.00	\$0.00	\$0.00
Adjustment for Send Out Volumes	\$0.00	\$0.00	\$0.00	\$66,279.22	\$0.00	\$0.00	\$0.00
Residential Share of Propane Contract Deficiency Charges	\$0.00	\$9,322.54	\$0.00	\$11,993.48	\$93,961.59	\$2,919.53	\$5,311.89
Residential Share of Property Taxes Paid	\$0.00	\$0.00	\$0.00	\$123,017.19	\$0.00	\$284,142.25	\$0.00
Prior Period Adjustments	(\$215,522.40)	\$0.00	\$0.00	\$0.00	\$0.00	(\$155,427.74)	\$0.00
Residential Share of Hattisburg Tax Payment	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Credit for IMD Accounting error	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Total	\$35,153,077.63	\$90,987,948.77	\$175,608,574.59	\$256,476,827.77	\$323,286,739.91	\$223,465,974.04	\$180,760,435.96
Prior Estimate							
BGSS-RSG GAS COMMODITY VOLUMES MDTh	3,443,068	7,852,246	15,428,027	23,431,976	30,184,758	21,356,723	17,862,797
BGSS-RSG GAS COMMODITY COST	\$40,060,714.23	\$88,707,316.05	\$172,657,093.95	\$259,227,433.79	\$324,292,384.36	\$222,997,135.12	\$180,375,406.41
BGSS-RSG Balancing	\$861,008.01	\$1,963,611.16	\$6,611,519.36	\$10,449,366.90	\$13,824,735.73	\$9,605,733.87	\$7,842,409.85
BGSS-RSG Off System Sales	(\$1,079,288.41)	(\$802,978.14)	(\$5,529,988.80)	(\$9,579,275.76)	(\$15,571,784.33)	(\$8,979,079.76)	(\$6,708,808.81)
Electric Reservation Charge	(\$2,530,061.09)	(\$1,467,604.09)	(\$1,770,917.87)	(\$1,444,660.83)	(\$2,049,020.87)	(\$1,426,576.03)	(\$978,780.18)
Credit for Pipeline Refunds	(\$1,185,384.41)	(\$96,235.51)	(\$10,026.96)	\$0.00	\$0.00	\$0.00	\$0.00
Total	\$36,126,988.33	\$88,304,109.47	\$171,957,679.68	\$258,652,864.10	\$320,496,314.89	\$222,197,213.20	\$180,530,227.27
Net							
BGSS-RSG GAS COMMODITY VOLUMES MDTh	7,790,380	15,686,499	23,798,081	29,952,919	21,490,699	17,943,363	9,145,744
BGSS-RSG GAS COMMODITY COST	\$88,005,009.52	\$175,326,667.19	\$262,930,392.70	\$321,534,285.12	\$225,853,365.67	\$181,553,679.55	\$82,544,006.36
BGSS-RSG Balancing	\$1,948,140.33	\$6,676,155.45	\$10,699,125.71	\$13,750,464.44	\$9,650,148.95	\$7,869,986.42	\$2,302,416.11
BGSS-RSG Off System Sales	(\$796,011.76)	(\$5,547,201.58)	(\$9,800,496.63)	(\$15,094,387.47)	(\$9,150,126.48)	(\$6,763,512.59)	(\$1,087,004.93)
Electric Reservation Charge	(\$1,503,241.80)	(\$1,811,231.45)	(\$1,524,854.83)	(\$2,052,317.91)	(\$1,465,939.83)	(\$992,799.32)	(\$1,344,863.35)
Other	(\$215,522.40)	\$9,322.54	\$0.00	\$201,289.89	\$100,189.91	\$131,634.04	\$5,311.89
Credit for Pipeline Refunds	(\$108,175.12)	(\$12,193.16)	(\$407.94)	(\$19,055.51)	\$0.00	\$0.00	\$0.00
Total	\$87,330,198.77	\$174,641,518.99	\$262,303,759.01	\$318,320,278.56	\$224,987,638.22	\$181,798,988.10	\$82,419,866.08
BGSS-RSG GAS COMMODITY VOLUMES MDTh	7,790,380	15,686,499	23,798,081	29,952,919	21,490,699	17,943,363	9,145,744
NET SALES VOLUMES RESIDENTIAL	7,948,836	15,479,950	22,262,943	30,360,497	20,755,145	19,257,237	9,095,127
Diff	(158,456)	206,549	1,535,138	(407,578)	735,554	(1,313,874)	50,617

BGSS Interest Calculation
Continuing from 11/1/2001

	(1) Oct-08	(1) Nov-08	(1) Dec-08	(1) Jan-09	(1) Feb-09	(1) Mar-09	(1) Apr-09
CUMULATIVE OVER/(UNDER) RECOVERY PRIOR MONTH	(\$25,734,473.88)	(\$23,560,299.30)	(\$8,726,939.53)	(\$1,650,783.54)	\$24,490,604.36	\$35,093,502.73	\$38,027,404.99
CUMULATIVE OVER/(UNDER) RECOVERY CURRENT MONTH	(\$23,560,299.30)	(\$8,726,939.53)	(\$1,650,783.54)	\$24,490,604.36	\$35,093,502.73	\$38,027,404.99	\$42,698,228.45
AVERAGE BALANCE	(\$24,647,386.59)	(\$16,143,619.42)	(\$5,188,861.54)	\$11,419,910.41	\$29,792,053.54	\$36,560,453.86	\$40,362,816.72
MONTHLY INTEREST @ 0.006892, (Income)/Expense	(\$163,486.12)	(\$107,080.63)	(\$34,417.72)	\$75,748.27	\$197,610.69	\$242,505.49	\$267,726.56
@ 0.006633, (Income)/Expense - 11/06							
INTEREST ACCUMULATED, (Income)/Expense *	(\$163,486.12)	(\$270,566.74)	(\$304,984.46)	(\$229,236.20)	(\$31,625.50)	\$210,879.99	\$478,606.55

8. Wholesale Gas Pricing Assumptions

Item 8

A Comparison of the Forecasted Cost of Gas as represented by the NYMEX June 2009 Filing versus March 1, 2009 Self-Implementing Reduction

(\$/Mbtu)

	<u>June '09 Filing</u> <u>Nymex - 5/06/09</u>	<u>March 1, 2009</u> <u>Self-Implementing</u> <u>Reduction</u> <u>Nymex - 2/6/09</u>	<u>Difference</u>	<u>Percentage</u> <u>Difference</u>
2009				
May	\$3.321	\$4.901	(\$1.580)	-32.2%
June	\$3.887	\$5.030	(\$1.143)	-22.7%
July	\$4.012	\$5.161	(\$1.149)	-22.3%
August	\$4.131	\$5.243	(\$1.112)	-21.2%
September	\$4.204	\$5.281	(\$1.077)	-20.4%
October	\$4.341	\$5.394	(\$1.053)	-19.5%
November	\$4.991	\$5.872	(\$0.881)	-15.0%
December	\$5.691	\$6.399	(\$0.708)	-11.1%
2010				
January	\$5.986	\$6.659	(\$0.673)	-10.1%
February	\$6.027	\$6.674	(\$0.647)	-9.7%
March	\$5.976	\$6.549	(\$0.573)	-8.7%
April	\$5.801	\$6.229	(\$0.428)	-6.9%
May	\$5.849	\$6.249	(\$0.400)	-6.4%
June	\$5.957	\$6.344	(\$0.387)	-6.1%
July	\$6.090	\$6.464	(\$0.374)	-5.8%
August	\$6.175	\$6.549	(\$0.374)	-5.7%
September	\$6.218	\$6.584	(\$0.366)	-5.6%

9. GCUA Recoveries and Balances

N/A

10. Historical Service Interruptions

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 2008-2009.

Rate Schedule CIG:

Number of Customers: 23

10:00 AM January 15 through 10:00 AM January 17

10:00 AM January 25 through 10:00 AM January 26

Rate Schedule TSG-NF (BGSS-I):

Number of Customers: 47

10:00 AM January 15 through 10:00 AM January 17

10:00 AM January 25 through 10:00 AM January 26

Rate Schedule TSG-NF (Third Party Suppliers):

Number of Customers: 198

10:00 AM January 15 through 10:00 AM January 17

All of the above interruptions were done for operational reasons.

In addition, the Company interrupted its contract cogeneration customers pursuant to the provisions of those contracts.

11. Gas Price Hedging Activities

Reports Dated:

April 30, 2009

January 6, 2009

October 2, 2008

July 10, 2008



April 30, 2009

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

Jerome May
Director of Energy
Board of Public Utilities
Two Gateway Center
Newark, New Jersey 07102

Enclosed please find Public Service Electric and Gas Company's (Public Service, 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, 2009.

As shown on the attached schedules, approximately 100% of the planned residential volume was completed for the current summer season and 81% of the plan for next winter. Approximately 67% of the planned residential volume has been completed for the next summer season.

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 apprised of any changes it anticipates in the program.

Very truly yours,
Original Signed by
Frances I. Sundheim

Attachment

C Stefanie A. Brand
 Alice Bator
 Mark Beyer

PSE&G Residential Hedging Report
November 2008 - October 2009
3/31/09

	<u>Bcf</u> <u>Target*</u>	<u>Bcf</u> <u>Hedged</u>	<u>%</u> <u>Hedged</u> <u>Time Trigger</u> <u>Target</u>	<u>%</u> <u>Hedged</u> <u>Actual</u>	<u>Current</u> <u>Price/</u> <u>MMBtu</u>
Nov 08-Mar 09 Hedge Volume (325,000/ day)					
Non-discretionary volume	24.550	24.538	100%	100%	\$9.70
Discretionary volume	<u>24.550</u>	<u>24.538</u>	100%	100%	\$9.48
Total Winter Hedge Volume	49.100	49.076		100%	\$9.59
Apr 09-Oct 09 Hedge Volume (230,000/ day)					
Non-discretionary volume	24.600	24.610	94-100%	100%	\$8.22
Discretionary volume	<u>24.600</u>	<u>24.610</u>	67-100%	100%	\$9.12
Total Summer Hedge Volume	49.200	49.220		100%	\$8.67
Annual Hedge Volume	98.300	98.296		100%	\$9.13

PSE&G Residential Hedging Report
November 2009 - October 2010
3/31/09

	<u>Bcf</u> <u>Target*</u>	<u>Bcf</u> <u>Hedged</u>	<u>%</u> <u>Hedged</u> <u>Time Trigger</u> <u>Target</u>	<u>%</u> <u>Hedged</u> <u>Actual</u>	<u>Current</u> <u>Price/</u> <u>MMBtu</u>
Nov 09-Mar 10 Hedge Volume (325,000/ day)					
Non-discretionary volume	24.550	15.478	61-67%	63%	\$8.73
Discretionary volume	<u>24.550</u>	<u>24.538</u>	33-100%	100%	\$8.35
Total Winter Hedge Volume	49.100	40.016		81%	\$8.50
Apr 10-Oct 10 Hedge Volume (230,000/ day)					
Non-discretionary volume	24.600	8.560	33-39%	35%	\$6.70
Discretionary volume	<u>24.600</u>	<u>24.610</u>	0-100%	100%	\$7.07
Total Summer Hedge Volume	49.200	33.170		67%	\$6.98
Annual Hedge Volume	98.300	73.186		74%	\$7.81

* Total annual Bcf allowed = 115.0



January 6, 2009

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

Director of Energy
Board of Public Utilities
Two Gateway Center
Newark, New Jersey 07102

Enclosed please find Public Service Electric and Gas Company's (Public Service, 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, 2008.

As shown on the attached schedules, approximately 100% of the planned residential volume was completed for the current winter season and 92% of the plan for next summer. Approximately 72% of the planned residential volume has been completed for the next winter season and 43% for the 2010 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 apprised of any changes it anticipates in the program.

Very truly yours,
Original Signed by
Frances I. Sundheim

Attachment

C Stefanie A. Brand
Alice Bator
Mark Beyer

PSE&G Residential Hedging Report
November 2008 - October 2009
12/31/08

	<u>Bcf Target*</u>	<u>Bcf Hedged</u>	<u>% Hedged Actual</u>	<u>Current Price/ MMBtu</u>
Nov 08-Mar 09 Hedge Volume (325,000/ day)				
Non-discretionary volume	24.550	24.538	100%	\$9.70
Discretionary volume	<u>24.550</u>	<u>24.538</u>	100%	\$9.48
Total Winter Hedge Volume	49.100	49.076	100%	\$9.59
Apr 09-Oct 09 Hedge Volume (230,000/ day)				
Non-discretionary volume	24.600	20.865	85%	\$8.79
Discretionary volume	<u>24.600</u>	<u>24.610</u>	100%	\$9.12
Total Summer Hedge Volume	49.200	45.475	92%	\$8.97
Annual Hedge Volume	98.300	94.551	96%	\$9.29

* Total annual Bcf allowed = 115.0

PSE&G Residential Hedging Report
November 2009 - October 2010
12/31/08

	<u>Bcf</u> <u>Target*</u>	<u>Bcf</u> <u>Hedged</u>	<u>%</u> <u>Hedged</u> <u>Actual</u>	<u>Current</u> <u>Price/</u> <u>MMBtu</u>
Nov 09-Mar 10 Hedge Volume (325,000/ day)				
Non-discretionary volume	24.550	10.948	45%	\$9.78
Discretionary volume	<u>24.550</u>	<u>24.538</u>	100%	\$8.35
Total Winter Hedge Volume	49.100	35.486	72%	\$8.80
Apr 10-Oct 10 Hedge Volume (230,000/ day)				
Non-discretionary volume	24.600	3.210	13%	\$7.35
Discretionary volume	<u>24.600</u>	<u>18.190</u>	74%	\$7.27
Total Summer Hedge Volume	49.200	21.400	43%	\$7.28
Annual Hedge Volume	98.300	56.886	58%	\$8.23

* Total annual Bcf allowed = 115.0



October 2, 2008

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

Nusha Wyner, Director
Board of Public Utilities
Two Gateway Center
Newark, New Jersey 07102

Dear Ms. Wyner:

Enclosed please find Public Service Electric and Gas Company's (Public Service, 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, 2008.

As shown on the attached schedules, approximately 97% of the planned residential volume had been completed for the upcoming winter season and 67% of the plan for next summer. Approximately 28% of the planned residential volume has been completed for the next winter season and hedging for the 2010 summer has not begun.

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 apprised of any changes it anticipates in the program.

Very truly yours,
Original Signed by
Frances I. Sundheim

Attachment

C Stefanie A. Brand
 Alice Bator
 Mark Beyer

PSE&G Residential Hedging Report
November 2008 - October 2009
9/30/2008

	<u>Bcf Target*</u>	<u>Bcf Hedged</u>	<u>% Hedged Actual</u>	<u>Current Price/ MMBtu</u>
Nov 08-Mar 09 Hedge Volume (325,000/ day)				
Non-discretionary volume	24.550	23.028	94%	\$9.85
Discretionary volume (10/31) To Go: 0	<u>24.550</u>	<u>24.538</u>	100%	\$9.48
Total Winter Hedge Volume	49.100	47.566	97%	\$9.66
Apr 09-Oct 09 Hedge Volume (230,000/ day)				
Non-discretionary volume	24.600	16.585	67%	\$9.28
Discretionary volume (3/31) To Go: 37.5	<u>24.600</u>	<u>16.585</u>	67%	\$10.00
Total Summer Hedge Volume	49.200	33.170	67%	\$9.64
Annual Hedge Volume	98.300	80.736	82%	\$9.65

* Total annual Bcf allowed = 115.0

PSE&G Residential Hedging Report
November 2009 - October 2010
9/30/2008

	<u>Bcf</u> <u>Target*</u>	<u>Bcf</u> <u>Hedged</u>	<u>%</u> <u>Hedged</u> <u>Actual</u>	<u>Current</u> <u>Price/</u> <u>MMBtu</u>
Nov 09-Mar 10 Hedge Volume (325,000/ day)				
Non-discretionary volume	24.550	7.173	29%	\$10.72
Discretionary volume (10/31) To Go: 10	<u>24.550</u>	<u>6.795</u>	28%	\$9.45
Total Winter Hedge Volume	49.100	13.968	28%	\$10.10
Apr 10-Oct 10 Hedge Volume (230,000/ day)				
Non-discretionary volume	24.600	0.000	0%	\$0.00
Discretionary volume (3/31) To Go: 38	<u>24.600</u>	<u>0.000</u>	0%	\$0.00
Total Summer Hedge Volume	49.200	0.000	0%	#DIV/0!
Annual Hedge Volume	98.300	13.968	14%	#DIV/0!

* Total annual Bcf allowed = 115.0

Frances I. Sundheim
Vice President and Corporate Rate Counsel

Public Service Electric and Gas Company
80 Park Plaza, T8C, Newark, NJ 07102-4194
mailing address: P.O. Box 570, Newark, NJ 07101
tel: 973.430.6928 fax: 973.648.0838
email: frances.sundheim@pseg.com



July 10, 2008

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

Nusha Wyner, Director
Board of Public Utilities
Two Gateway Center
Newark, New Jersey 07102

Dear Ms. Wyner:

Enclosed please find Public Service Electric and Gas Company's (Public Service, 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, 2008.

As shown on the attached schedules, approximately 83% of the planned residential volume had been completed for the current summer season and 59% of the plan for this winter. Approximately 24% of the planned residential volume has been completed for the next summer season and hedging for the 2009/10 winter is at 7% of planned.

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 apprised of any changes it anticipates in the program.

Very truly yours,

A handwritten signature in black ink, appearing to read "James P. Sundheim", is written over the typed name "James P. Sundheim". The signature is fluid and cursive.

Attachment

C Stefanie A. Brand
Alice Bator
Mark Beyer

PSE&G Residential Hedging Report
 November 2007 - October 2008
 06/30/08

	<u>Bcf</u> <u>Target*</u>	<u>Bcf</u> <u>Hedged</u>	<u>%</u> <u>Hedged</u>	<u>Current</u> <u>Price/</u> <u>MMBtu</u>
Nov 07-Mar 08 Hedge Volume (325,000/ day)				
Non-discretionary volume	35.720	35.720	100%	\$9.62
Discretionary volume	<u>13.380</u>	<u>12.458</u>	93%	\$8.74
Total Winter Hedge Volume	49.100	48.178	98%	\$9.39
Apr 08-Oct 08 Hedge Volume (230,000/ day)				
Non-discretionary volume	24.600	23.540	96%	\$8.13
Discretionary volume	<u>24.600</u>	<u>17.120</u>	70%	\$7.59
Total Summer Hedge Volume	49.200	40.660	83%	\$7.90
Annual Hedge Volume	98.300	88.838	90%	\$8.71

* Total annual Bcf allowed = 115.0

PSE&G Residential Hedging Report
 November 2008 - October 2009
 06/30/08

	<u>Bcf Target*</u>	<u>Bcf Hedged</u>	<u>% Hedged Actual</u>	<u>Current Price/ MMBtu</u>
Nov 08-Mar 09 Hedge Volume (325,000/ day)				
Non-discretionary volume	24.550	18.498	75%	\$9.85
Discretionary volume	<u>24.550</u>	<u>10.570</u>	43%	\$8.98
Total Winter Hedge Volume	49.100	29.068	59%	\$9.53
Apr 09-Oct 09 Hedge Volume (230,000/ day)				
Non-discretionary volume	24.600	11.770	48%	\$9.15
Discretionary volume	<u>24.600</u>	<u>0.000</u>	0%	\$0.00
Total Summer Hedge Volume	49.200	11.770	24%	\$9.15
Annual Hedge Volume	98.300	40.838	42%	\$9.42

* Total annual Bcf allowed = 115.0

PSE&G Residential Hedging Report
 November 2009 - October 2010
 06/30/08

	<u>Bcf</u> <u>Target*</u>	<u>Bcf</u> <u>Hedged</u>	<u>%</u> <u>Hedged</u> <u>Actual</u>	<u>Current</u> <u>Price/</u> <u>MMBtu</u>
Nov/09-Mar 10 Hedge Volume (325,000/ day)				
Non-discretionary volume	24.550	3.398	14%	\$11.27
Discretionary volume	<u>24.550</u>	<u>0.000</u>	0%	\$0.00
Total Winter Hedge Volume	49.100	3.398	7%	\$11.27
Apr 10-Oct 10 Hedge Volume (230,000/ day)				
Non-discretionary volume	24.600	0.000	0%	\$0.00
Discretionary volume	<u>24.600</u>	<u>0.000</u>	0%	\$0.00
Total Summer Hedge Volume	49.200	0.000	0%	\$0.00
Annual Hedge Volume	98.300	3.398	3%	\$11.27

* Total annual Bcf allowed = 115.0

12. Storage Gas Volumes, Prices and Utilization

Storage Volumes and Month End by Contract

<u>Storage Contract</u>	Mnth						
	<u>Oct-08</u>	<u>Nov-08</u>	<u>Dec-08</u>	<u>Jan-09</u>	<u>Feb-09</u>	<u>Mar-09</u>	<u>Apr-09</u>
TR S-2	6,088.563	5,554.624	4,324.974	2,772.853	2,425.039	2,089.540	2,377.860
TR GSS	15,606.161	15,234.286	13,009.883	10,402.813	8,053.824	6,453.513	7,576.613
TR LGA-Old	1,333.807	1,333.807	1,286.680	1,286.680	1,183.655	1,057.939	1,084.615
TRLG-S	(25.845)	0.000	0.000	0.000	0.000	0.000	0.000
TR LSS	4,951.566	4,453.283	3,556.175	2,650.611	1,673.043	1,371.168	1,909.952
TR-SS-1	3,361.163	3,231.263	2,625.063	1,282.763	629.635	515.969	876.809
SS-1 / SS	1,452.468	1,359.797	1,187.550	842.477	569.692	571.946	616.308
CNG GSS-TE	13,687.259	12,812.996	10,244.606	5,988.498	3,937.303	3,464.904	5,281.765
GSS combined	13,452.888	13,154.519	11,408.354	6,592.364	4,701.045	0.000	0.000
Hattisburgh	355.507	514.235	527.000	527.000	629.308	686.667	548.149
TENN-SSE	8,449.006	7,749.845	5,971.815	3,412.262	2,796.094	2,439.264	3,570.555
STEUBEN	4,405.000	3,760.525	3,215.356	1,958.833	1,280.251	1,093.676	1,496.572
ESS	1,122.804	1,378.058	1,448.942	1,448.942	1,472.570	1,568.544	1,580.358
Dominion DTI	1,800.000	1,800.000	1,501.151	978.568	728.568	4,962.686	6,404.547
TE MBA	0.000	0.000	0.000	0.000	0.000	0.000	8.458
TE S1	3,686.831	3,472.063	3,111.353	2,205.558	1,964.962	1,942.695	2,056.379
Total	79,727.18	75,809.30	63,418.90	42,350.22	32,044.99	28,218.51	35,388.94
Ending Inventory Cost (\$/Dth)	\$11.16	\$11.00	\$10.79	\$10.63	\$9.99	\$9.14	\$8.07

**LPG INVENTORY VOLUMES AND COST BY LOCATION
(000)**

<u>Month</u>	<u>Camden</u>		<u>Central</u>		<u>Harrison</u>		<u>Linden</u>	
	<u>Dth</u>	<u>Dollars</u>	<u>Dth</u>	<u>Dollars</u>	<u>Dth</u>	<u>Dollars</u>	<u>Dth</u>	<u>Dollars</u>
Jan-06	48	\$422	88	\$881	83	\$818	65	\$852
Feb-06	48	\$422	88	\$881	83	\$818	65	\$852
Mar-06	48	\$422	88	\$881	83	\$818	65	\$852
Apr-06	46	\$403	74	\$745	82	\$806	65	\$852
May-06	46	\$403	74	\$745	82	\$806	65	\$852
Jun-06	46	\$403	74	\$745	82	\$806	65	\$852
Jul-06	46	\$403	74	\$745	82	\$806	65	\$852
Aug-06	46	\$403	74	\$745	82	\$806	65	\$852
Sep-06	46	\$403	74	\$745	82	\$806	65	\$852
Oct-06	46	\$403	83	\$845	82	\$806	65	\$852
Nov-06	46	\$403	83	\$845	90	\$897	65	\$852
Dec-06	48	\$436	90	\$940	85	\$848	70	\$915
Jan-07	48	\$431	89	\$927	81	\$806	70	\$915
Feb-07	48	\$431	89	\$927	81	\$806	70	\$915
Mar-07	39	\$357	72	\$755	58	\$581	70	\$915
Apr-07	39	\$352	70	\$724	53	\$528	70	\$915
May-07	39	\$352	69	\$724	53	\$528	70	\$915
Jun-07	45	\$443	82	\$907	82	\$962	70	\$915
Jul-07	45	\$443	82	\$907	82	\$962	70	\$915
Aug-07	45	\$443	82	\$907	82	\$962	70	\$915
Sep-07	45	\$443	82	\$907	82	\$962	70	\$915
Oct-07	45	\$443	82	\$907	82	\$962	70	\$915
Nov-07	45	\$443	82	\$907	82	\$962	70	\$915
Dec-07	50	\$549	92	\$1,102	87	\$1,057	70	\$915

**LPG INVENTORY VOLUMES AND COST BY LOCATION
(000)**

<u>Month</u>	<u>Camden</u>		<u>Central</u>		<u>Harrison</u>		<u>Linden</u>	
	<u>Dth</u>	<u>Dollars</u>	<u>Dth</u>	<u>Dollars</u>	<u>Dth</u>	<u>Dollars</u>	<u>Dth</u>	<u>Dollars</u>
Jan-08	50	\$546	89	\$1,059	81	\$977	70	\$915
Feb-08	50	\$546	89	\$1,059	81	\$977	70	\$915
Mar-08	46	\$503	78	\$930	75	\$912	70	\$915
Apr-08	46	\$562	78	\$930	75	\$912	70	\$915
May-08	46	\$562	73	\$876	75	\$912	70	\$915
Jun-08	46	\$562	72	\$860	75	\$912	70	\$915
Jul-08	46	\$562	72	\$860	75	\$912	70	\$915
Aug-08	46	\$562	72	\$860	75	\$912	70	\$915
Sep-08	46	\$562	72	\$860	75	\$912	70	\$915
Oct-08	47	\$596	81	\$1,037	80	\$997	70	\$915
Nov-08	47	\$596	81	\$1,037	80	\$997	70	\$915
Dec-08	50	\$625	93	\$1,147	88	\$1,081	70	\$915
Jan-09	49	\$618	92	\$1,132	85	\$1,035	70	\$915
Feb-09	45	\$560	89	\$1,095	76	\$927	70	\$915
Mar-09	45	\$560	74	\$911	62	\$754	70	\$915
Apr-09 Est	45	\$560	73	\$894	62	\$754	70	\$915
May-09 Est	45	\$560	73	\$894	62	\$754	70	\$915
Jun-09 Est	45	\$560	73	\$894	62	\$754	70	\$915
Jul-09 Est	45	\$560	73	\$894	62	\$754	70	\$915
Aug-09 Est	45	\$560	73	\$894	62	\$754	70	\$915
Sep-09 Est	45	\$560	73	\$894	62	\$754	70	\$915
Oct-09 Est	45	\$560	73	\$894	62	\$754	70	\$915
Nov-09 Est	45	\$560	73	\$894	62	\$754	70	\$915
Dec-09 Est	45	\$560	73	\$894	62	\$754	70	\$915

**LNG INVENTORY VOLUMES AND COST
(000)**

<u>Month</u>	<u>Dth</u>	<u>Dollars</u>	<u>Month</u>	<u>Dth</u>	<u>Dollars</u>
Jan-06	361	\$1,399	Jan-08	344	\$780
Feb-06	259	\$1,004	Feb-08	292	\$664
Mar-06	143	\$554	Mar-08	286	\$650
Apr-06	137	\$532	Apr-08	278	\$632
May-06	131	\$507	May-08	268	\$608
Jun-06	125	\$522	Jun-08	323	\$659
Jul-06	284	\$705	Jul-08	316	\$884
Aug-06	360	\$960	Aug-08	308	\$864
Sep-06	356	\$948	Sep-08	303	\$849
Oct-06	351	\$932	Oct-08	314	\$813
Nov-06	345	\$918	Nov-08	369	\$794
Dec-06	365	\$949	Dec-08	363	\$940
Jan-07	326	\$847	Jan-09	212	\$551
Feb-07	189	\$492	Feb-09	172	\$445
Mar-07	173	\$451	Mar-09 Est	147	\$381
Apr-07	168	\$435	Apr-09 Est	141	\$365
May-07	162	\$420	May-09 Est	141	\$365
Jun-07	202	\$402	Jun-09 Est	141	\$365
Jul-07	236	\$534	Jul-09 Est	141	\$365
Aug-07	237	\$658	Aug-09 Est	141	\$365
Sep-07	291	\$642	Sep-09 Est	141	\$365
Oct-07	380	\$746	Oct-09 Est	141	\$365
Nov-07	373	\$829	Nov-09 Est	141	\$365
Dec-07	362	\$803	Dec-09 Est	141	\$365

**LPG INVENTORY VOLUMES AND COST BY LOCATION
(000)**

<u>Month</u>	<u>Camden</u>		<u>Central</u>		<u>Harrison</u>		<u>Linden</u>	
	<u>Dth</u>	<u>Dollars</u>	<u>Dth</u>	<u>Dollars</u>	<u>Dth</u>	<u>Dollars</u>	<u>Dth</u>	<u>Dollars</u>
Jan-08	50	\$546	89	\$1,059	81	\$977	70	\$915
Feb-08	50	\$546	89	\$1,059	81	\$977	70	\$915
Mar-08	46	\$503	78	\$930	75	\$912	70	\$915
Apr-08	46	\$562	78	\$930	75	\$912	70	\$915
May-08	46	\$562	73	\$876	75	\$912	70	\$915
Jun-08	46	\$562	72	\$860	75	\$912	70	\$915
Jul-08	46	\$562	72	\$860	75	\$912	70	\$915
Aug-08	46	\$562	72	\$860	75	\$912	70	\$915
Sep-08	46	\$562	72	\$860	75	\$912	70	\$915
Oct-08	47	\$596	81	\$1,037	80	\$997	70	\$915
Nov-08	47	\$596	81	\$1,037	80	\$997	70	\$915
Dec-08	50	\$625	93	\$1,147	88	\$1,081	70	\$915
Jan-09	49	\$618	92	\$1,132	85	\$1,035	70	\$915
Feb-09	45	\$560	89	\$1,095	76	\$927	70	\$915
Mar-09	45	\$560	74	\$911	62	\$754	70	\$915
Apr-09 Est	45	\$560	73	\$894	62	\$754	70	\$915
May-09 Est	45	\$560	73	\$894	62	\$754	70	\$915
Jun-09 Est	45	\$560	73	\$894	62	\$754	70	\$915
Jul-09 Est	45	\$560	73	\$894	62	\$754	70	\$915
Aug-09 Est	45	\$560	73	\$894	62	\$754	70	\$915
Sep-09 Est	45	\$560	73	\$894	62	\$754	70	\$915
Oct-09 Est	45	\$560	73	\$894	62	\$754	70	\$915
Nov-09 Est	45	\$560	73	\$894	62	\$754	70	\$915
Dec-09 Est	45	\$560	73	\$894	62	\$754	70	\$915

**LNG INVENTORY VOLUMES AND COST
(000)**

<u>Month</u>	<u>Dth</u>	<u>Dollars</u>	<u>Month</u>	<u>Dth</u>	<u>Dollars</u>
Jan-06	361	\$1,399	Jan-08	344	\$780
Feb-06	259	\$1,004	Feb-08	292	\$664
Mar-06	143	\$554	Mar-08	286	\$650
Apr-06	137	\$532	Apr-08	278	\$632
May-06	131	\$507	May-08	268	\$608
Jun-06	125	\$522	Jun-08	323	\$659
Jul-06	284	\$705	Jul-08	316	\$884
Aug-06	360	\$960	Aug-08	308	\$864
Sep-06	356	\$948	Sep-08	303	\$849
Oct-06	351	\$932	Oct-08	314	\$813
Nov-06	345	\$918	Nov-08	369	\$794
Dec-06	365	\$949	Dec-08	363	\$940
Jan-07	326	\$847	Jan-09	212	\$551
Feb-07	189	\$492	Feb-09	172	\$445
Mar-07	173	\$451	Mar-09 Est	147	\$381
Apr-07	168	\$435	Apr-09 Est	141	\$365
May-07	162	\$420	May-09 Est	141	\$365
Jun-07	202	\$402	Jun-09 Est	141	\$365
Jul-07	236	\$534	Jul-09 Est	141	\$365
Aug-07	237	\$658	Aug-09 Est	141	\$365
Sep-07	291	\$642	Sep-09 Est	141	\$365
Oct-07	380	\$746	Oct-09 Est	141	\$365
Nov-07	373	\$829	Nov-09 Est	141	\$365
Dec-07	362	\$803	Dec-09 Est	141	\$365

13. Affiliate Gas Supply Transactions

N/A

14. Supply and Demand Data

GAS SUPPLY AND DEMAND DATA (October 2006 - September 2007)

	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Total
Gas Supplies (MDTh)													
Beginning Inventory	89,824	78,917	80,109	69,799	51,919	31,552	24,431	29,240	42,074	54,480	64,679	72,431	
Natural Gas Receipt	15,626	16,392	14,502	14,367	18,385	19,403	21,983	19,027	16,782	14,543	11,902	10,463	193,375
Refinery Gas & Landfill	537	504	463	180	289	463	445	519	495	468	512	494	5,370
Peaking Supplies													

Total Inventory Available	105,988	95,813	95,074	84,346	70,593	51,418	46,859	48,787	59,351	69,491	77,092	83,388	
Gas Demand (MDTh)													
Firm Sendout	11,900	15,704	25,275	32,427	39,040	26,807	17,169	6,713	4,871	4,812	4,661	4,965	194,346
Interruptible Sales Sendout	697	707	804	922	617	729	794	611	567	636	605	527	

Ending Inventory MDTh	93,390	79,402	68,995	50,997	30,935	23,882	28,896	41,463	53,913	64,043	71,826	77,896	

GAS SUPPLY AND DEMAND DATA (October 2007 - September 2008)

	Oct-07	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Total
Gas Supplies (MDTh)													
Beginning Inventory	77,896	82,730	78,716	66,627	50,342	31,070	20,979	27,581	39,833	51,490	62,062	69,528	
Natural Gas Receipt	11,983	18,254	20,982	17,921	12,602	15,411	18,613	20,540	16,806	15,307	12,146	9,624	190,189
Refinery Gas & Landfill	633	626	572	581	534	383	383	475	437	438	478	452	5,992
Peaking Supplies													

Total Inventory Available	90,511	101,609	100,271	85,129	63,478	46,865	39,975	48,595	57,076	67,235	74,686	79,603	
Gas Demand (MDTh)													
Firm Sendout	7,214	22,147	32,749	33,733	31,417	25,004	11,771	8,124	4,948	4,483	4,480	4,744	190,814
Interruptible Sales Sendout	568	746	895	1054	991	882	623	638	638	690	678	650	

Ending Inventory MDTh	82,730	78,716	66,627	50,342	31,070	20,979	27,581	39,833	51,490	62,062	69,528	74,209	

GAS SUPPLY AND DEMAND DATA (October 2008 - September 2009)

	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Total
Gas Supplies (MDTh)													
Beginning Inventory	76,038	79,561	75,466	61,830	39,674	26,650	20,792	34,057	42,015	50,116	58,823	68,025	
Natural Gas Receipt	15,311	17,613	18,954	20,328	18,339	19,317	22,070	13,624	14,398	14,274	14,731	14,069	203,029
Refinery Gas & Landfill	462	458	496	457	427	492	518	519	495	468	512	494	5,797
Peaking Supplies													
Total Inventory Available	91,810	97,632	94,917	82,615	58,441	46,460	43,381	48,200	56,908	64,858	74,066	82,587	
Gas Demand (MDTh)													
Firm Sendout	11,292	21,284	31,993	41,662	29,677	24,473	13,012	6,439	5,297	4,482	4,463	4,839	198,913
Interruptible Sales Sendout	958	881	1093	1278	2113	1194	1389	1576	1495	1553	1579	1462	
Ending Inventory MDTh	79,561	75,466	61,830	39,674	26,650	20,792	28,979	42,015	50,116	58,823	68,025	76,286	

GAS SUPPLY AND DEMAND DATA (October 2009 - September 2010)

	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Total
Gas Supplies (MDTh)													
Beginning Inventory	76,286	80,136	76,955	62,618	41,832	24,424	13,639	16,751	27,310	38,154	49,823	61,546	
Natural Gas Receipt	13,997	16,551	16,869	16,033	13,409	15,578	16,793	17,289	16,000	16,162	16,137	16,053	190,869
Refinery Gas & Landfill	958	881	1,093	1,278	2,113	1,194	1,389	1,576	1,495	1,553	1,579	1,462	16,573
Peaking Supplies													
Total Inventory Available	91,241	97,568	94,917	79,929	57,354	41,196	31,821	35,616	44,805	55,870	67,538	79,061	
Gas Demand (MDTh)													
Firm Sendout	9,572	18,910	30,504	36,115	31,028	25,744	13,554	6,729	5,156	4,493	4,414	4,814	191,033
Interruptible Sales Sendout	1533	1703	1795	1982	1902	1813	1516	1576	1495	1553	1579	1462	
Ending Inventory MDTh	80,136	76,955	62,618	41,832	24,424	13,639	16,751	27,310	38,154	49,823	61,546	72,784	

GAS SUPPLY AND DEMAND DATA (October 2009 - September 2010)

	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Total
Gas Supplies (MDTh)													
Beginning Inventory	72,784	79,676	74,744	60,204	40,489	23,234	13,761	16,543	27,367	38,064	49,777	61,475	
Natural Gas Receipt	17,007	14,759	16,572	17,087	13,577	16,716	16,694	17,240	15,911	16,163	16,137	16,054	193,915
Refinery Gas & Landfill	958	881	1,093	1,278	2,113	1,194	1,389	1,576	1,495	1,553	1,579	1,462	16,573
Peaking Supplies													

Total Inventory Available	90,749	95,316	92,409	78,569	56,179	41,144	31,844	35,359	44,773	55,780	67,493	78,991	
Gas Demand (MDTh)													
Firm Sendout	9,540	18,870	30,409	36,098	31,043	25,570	13,785	6,416	5,214	4,449	4,439	4,777	190,610
Interruptible Sales Sendout	1533	1703	1795	1982	1902	1813	1516	1576	1495	1553	1579	1462	

Ending Inventory MDTh	79,676	74,744	60,204	40,489	23,234	13,761	16,543	27,367	38,064	49,777	61,475	72,752	

15. Actual Peak Day Supply and Demand

Actual Peak Day Supply and Demand
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	NEWARK AVG. DATE	TEMP (F)	LOAD (000 DTh)			SUPPLY SOURCES (000 DTh)		
			TOTAL	FIRM	INTERR.	NATURAL GAS		LPA / REFINERY /
						HLF TRANSP.	STORAGE / LNG	LANDFILL
2008 / 2009 WINTER								
	5-Feb-09	18.8	2580	1990	589	1479	1065	36
	16-Jan-09	11.0	2522	2251	271	1588	924	10
	21-Jan-09	21.8	2502	1841	661	1592	893	17
	20-Jan-09	22.6	2491	1803	688	1516	960	15
	22-Dec-08	20.8	2482	1914	568	1468	1001	13
2007 / 2008 WINTER								
	28-Feb-08	22.8	2458	1808	650	1607	819	32
	11-Feb-08	20.4	2449	1972	477	1391	1027	31
	2-Jan-08	21.5	2433	1863	571	1474	941	18
	3-Jan-08	18.8	2403	2026	377	1454	932	18
	24-Jan-08	27.2	2399	1669	730	1469	908	21
2006 / 2007 WINTER								
	5-Feb-07	13.7	2431	2261	170	1357	1056	18
	6-Mar-07	16.0	2418	2072	346	1542	862	14
	14-Feb-07	20.1	2404	2032	372	1513	878	13
	7-Mar-07	19.9	2341	1951	390	1478	848	15
	15-Feb-07	18.3	2340	2060	280	1454	869	17

16. Capacity Contract Changes

PEAK DAY GAS REQUIREMENTS AND SUPPLY

(MDTh)

<u>SUPPLY</u>	<u>2008-09</u>	<u>2009-10</u>	<u>2010-11</u>	<u>2011-12</u>	<u>2012-13</u>
Transco FT	432.4	432.4	432.4	432.4	432.4
Transco FTNT	95.7	95.7	95.7	95.7	95.7
Transco Niagara	119.9	119.9	119.9	119.9	119.9
Transco/ Tetco Leidy (DTI)	106.5	106.5	106.5	106.5	106.5
Transco Sentinel	-	50.0	50.0	50.0	50.0
Texas Eastern FT	231.6	231.6	231.6	231.6	231.6
Texas Eastern ITP	110.0	110.0	110.0	110.0	110.0
Texas Eastern Time II	50.0	50.0	50.0	50.0	50.0
Tennessee FT	36.4	36.4	36.4	36.4	36.4
Columbia FTS	<u>25.0</u>	<u>25.0</u>	<u>25.0</u>	<u>25.0</u>	<u>25.0</u>
Pipeline Firm Transportation	1207.5	1257.5	1257.5	1257.5	1257.5
Landfill Gas	2.3	2.3	2.3	2.3	2.3
Refinery Gas	<u>10.0</u>	<u>10.0</u>	<u>10.0</u>	<u>10.0</u>	<u>10.0</u>
Total Firm FT Supply	1219.8	1269.8	1269.8	1269.8	1269.8
Storage	959.4	959.4	959.4	959.4	959.4
Coastal/Eagle Point	55.0	55.0	55.0	0.0	0.0
Newark Bay	0.0	0.0	0.0	0.0	0.0
Virginia Power Peaking	25.0	25.0	0.0	0.0	0.0
Transco Peaking	13.2	13.2	13.2	13.2	13.2
Transco LGA	273.3	273.3	273.3	273.3	273.3
PSEG Burlington LNG	67.5	67.5	67.5	67.5	67.5
LPA	212.0	212.0	212.0	212.0	212.0
Total Peaking Supply	646.1	646.1	621.1	566.1	566.1
PSEG Firm Supply Subtotal	2825.3	2875.3	2850.3	2795.3	2795.3
FTS ADCQ 1./	232.7	232.7	232.7	232.7	232.7
Total PSEG Gas Supply	3058.0	3108.0	3083.0	3028.0	3028.0
Peak Day Sendout Forecast 2./	2730.4	2743.8	2760.9	2794.6	2807.6
Total Peak Day Capacity Requirements	2995.5	3010.2	3029.0	3065.9	3080.2
Surplus / (Deficiency)	62.5	97.8	54.0	(37.9)	(52.1)

1./ Current January FT-S ADCQ (02/23/09)

2./ Based on Corporate Energy Forecast, Gas -2009

17. FERC Pipeline Activities

FERC Pipeline Activities

Pipeline	Docket No.	Description
Algonquin	RP07-504	<p>Northeast Gateway Deepwater Port</p> <p>A contested settlement, which had been supported by PSEG, has now been approved by the Commission, but is still pending rehearing requests. PSEG actively participated in an earlier informal collaborative investigation of the impact that re-gasified LNG will have upon the quality and interchangeability characteristics of natural gas delivered by interstate pipelines. The earlier collaborative effort directly led to the approved settlement.</p>
Texas Eastern	Pending	<p>Gas Quality Proceedings</p> <p>While not yet a formal Commission docket, the ongoing discussions among the parties are expected to lead to a broadly supported offer of settlement. PSEG is a participant in those discussions, which focus not only upon the accommodation of LNG supplies, but also the more-recent advent of shale gas as a viable gas supply.</p>
Texas Gas	RP09-556	<p>Pressure agreements between pipeline and its customers</p> <p>PSEG submitted comments seeking more clarity regarding pressure agreements and how they could affect other customers operationally and financially.</p>

Algonquin	RP07-139, et al	<p>Creditworthiness</p> <p>Actively participated in technical conference and settlement discussions with Spectra pipeline affiliates. Caused settlement, which has since been approved subject to unrelated required changes, to not include a provision which would have increased the likelihood that PSEG would be required to post additional funds in order to be deemed creditworthy.</p>
Texas Gas	RP09-7	<p>Fuel Incentive Ratemaking</p> <p>PSEG was perhaps the principal supporter of an initiative to align pipeline financial incentives with its efforts to reduce the use of system fuel. Because of the objections of one participant, and in spite of the acquiescence of all other parties, the Commission has rejected the proposal, at least for the time being.</p>
Texas Gas	RP09-317	<p>Pipeline funding of customer-specific projects</p> <p>In response to PSEG Protest, Texas Gas confirmed that such facilities would be non-jurisdictional. The facilities should therefore not be subject to Commission actions that would allocate costs to other customers.</p>
Tennessee	RP09-194	<p>Enhance flexibility of production area pools</p> <p>PSEG submitted technical conference comments to ensure that special pooling treatment sought by one party would not cause a deterioration of services to other customers.</p>

Texas Eastern	RP09-66	<p>Establish evergreen rights in existing agreements</p> <p>PSEG identified an omission from certain current certificated agreements regarding evergreen renewal rights. The pipeline filed its pleading to address the discrepancy.</p>
Transco	RP09-558	<p>Rate Schedule FDLS</p> <p>Establish new rate schedule FDLS, Firm Delivery Lateral Service, to provide service to customers on laterals constructed between Transco's mainline and the customers' facilities.</p>
Transco	RP09-402	<p>Annual Fuel Tracker Filing</p> <p>Transco's annual filing to adjust its fuel retention.</p>
DTI	CP09-44	<p>Facility Refunctionalization and Replacement</p> <p>Refunctionalization of certain pipe segments and replacement of certain pipe segments.</p>
DTI	RP09-461	<p>Form of Service Agreement</p> <p>Filing to modify certain service agreements to conform to DTI's Form of Service Agreement.</p>