

Danielle Lopez
Associate Counsel - Regulatory

Public Service Electric and Gas Company
80 Park Plaza, T20, Newark, New Jersey 07102-4194
Tel: 973.430.6479
Email: Danielle.Lopez@pseg.com



July 1, 2026

In the Matter of the Provision of Basic Generation Service (BGS)
for the Period Beginning June 1, 2027

BPU Docket No. ER26040105

VIA ELECTRONIC MAIL AND E-FILING

Sherri L. Lewis, Secretary
New Jersey Board of Public Utilities
44 South Clinton Avenue
P.O. Box 350
Trenton, New Jersey 08625-0350

Dear Secretary Lewis:

This letter provides notice that Public Service Electric and Gas Company (PSE&G) has filed its Company Specific Addendum (CSA) in the above-referenced docket via the BPU's e-filing system. This filing is made in compliance with the procedural schedule in the Board Order dated April 22, 2026 in this docket. PSE&G's CSA is electronically attached herein and can be accessed on the BGS Auction website at:

<http://bgs-auction.com/bgs.auction.regproc.asp>

In accordance with I/M/O the New Jersey Board of Public Utilities' Response to the COVID-19 Pandemic for a Temporary Waiver of Requirements for Certain Non-Essential Obligations, BPU Docket No. EO20030254, Order dated March 19, 2020, this document is being electronically filed with the Secretary of the Board and the New Jersey Division of Rate Counsel. Paper copies will not be filed.

Thank you for your attention to this matter. Feel free to contact me with any questions or if I can be of further assistance.

Very truly yours,

A handwritten signature in blue ink that reads "Danielle Lopez".

Danielle Lopez

Electronic Attachment

C Service List (Electronic)

IN THE MATTER OF THE PROVISION OF BASIC GENERATION SERVICE ("BGS")
FOR THE PERIOD BEGINNING JUNE 1, 2027

DOCKET NO. ER26040105

Service List

BPU

44 South Clinton Avenue
Post Office Box 350
Trenton, NJ 08625-0350

Sherri L. Lewis, Secretary
board.secretary@bpu.nj.gov

Robert Brabston, Executive Director
robert.brabston@bpu.nj.gov

Stacy Peterson, Deputy Executive Director
stacy.peterson@bpu.nj.gov

Counsel's Office

Ava-Marie Madeam, General Counsel
avamarie.madeam@bpu.nj.gov

Gary Colin Emerle
Deputy General Counsel
colin.emerle@bpu.nj.gov

Elsbeth Faiman Hans
Deputy General Counsel
elsbeth.hans@bpu.nj.gov

Heather Weisband, Senior Counsel
heather.weisband@bpu.nj.gov

Division of Law

25 Market Street
Post Office Box 112
Trenton, NJ 08625-0112

Pamela Owen, DAG
pamela.owen@law.njoag.gov

Matko Ilic, DAG
matko.ilic@law.njoag.gov

Terel Klein, DAG
terel.klein@law.njoag.gov

BPU's BGS CONSULTANTS

Frank Mossburg, Managing Director
Bates White, LLC
2001 K Street, NW
North Building, Suite 500
Washington DC, 20006
frank.mossburg@bateswhite.com

DIVISION OF RATE COUNSEL

140 East Front Street, 4th Floor
Post Office Box 003
Trenton, New Jersey 08625

Brian Lipman, Esq., Director
blipman@rpa.nj.gov

David Wand, Esq., Managing Attorney
dwand@rpa.nj.gov

Lisa Littman, Esq.
llittman@rpa.nj.gov

Debra Layugan, Paralegal
dlayugan@rpa.nj.gov

Rate Counsel Consultant

Max Chang, President
Zoooid Energy
11 S. Angell St., #411
Providence, RI 02906
mchang@zoooid-energy.com

ACE

Kenneth Wan, Esq.
Pepco Holdings, LLC – 92DC42
500 N. Wakefield Drive
PO Box 6066
Newark, DE 19714-6066

Susan DeVito
susan.devito@pepcoholdings.com

kenneth.wan@exeloncorp.com

Peter Samuel
peter.samuel@pepcoholdings.com

Ashley Fitzgerald
ashley.fitzgerald@pepcoholdings.com

Deborah Sears
deborah.sears2@exeloncorp.com

ROCKLAND

4 Irving Place
New York, NY 10003

John L. Carley, Esq.
carleyj@coned.com

William A. Atzl, Jr.
atzlw@coned.com

Margaret Comes, Esq.,
comesm@coned.com

PSE&G

80 Park Plaza, T-18
Newark, NJ 07102-4194

Terrance J. Moran
terrance.moran@pseg.com

Dnielle Lopez, Esq.
danielle.lopez@pseg.com

Myron Filewicz, BGS
myron.filewicz@pseg.com

maria.barling@pseg.com
caitlyn.white@pseg.com

JCP&L

300 Madison Avenue
Morristown, NJ 07962-1911

Jennifer Spricigo
jspricigo@firstenergycorp.com

Yongmei Peng
ypeng@firstenergycorp.com

James Meehan, Esq.
jameehan@firstenergycorp.com

341 White Pond Drive
A-WAC-C2
Akron, OH 44320

Randy Feucht
rfeucht@firstenergycorp.com

Courtney Luff
caluff@firstenergycorp.com

NERA

1255 23rd Street NW, Suite 600
Washington, DC 20037

Chantale LaCasse
chantale.lacasse@nera.com

Rachel Northcutt
rachel.northcutt@nera.com

NERA Economic Consulting
777 S. Figueroa, Suite 1950
Los Angeles, CA 90017

Kathleen Orlandi
kathleen.orlandi@nera.com

Paul Cardona
paul.cardona@nera.com

IN THE MATTER OF THE PROVISION OF BASIC GENERATION SERVICE ("BGS")
FOR THE PERIOD BEGINNING JUNE 1, 2027

DOCKET NO. ER26040105

Service List

BGS Suppliers

Steven Gabel - IEPNJ
Gabel Associates
417 Denison Street
Highland Park, NJ 08904
steven@gabelassociates.com

Holly Reed
Gabel Associates
417 Denison Street
Highland Park, NJ 08904
holly.reed@gabelassociates.com

Raymond Depillo
PSEG Power
80 Park Plaza, T-19
P.O. Box 570
Newark, NJ 07101
raymond.depillo@pseg.com

David K Richter, Esq.
PSEG Services
80 Park Plaza, T-2
P. O. Box 570 Newark, NJ 07101
david.richter@pseg.com

Kathleen Maher
Constellation New Energy
810 Seventh Avenue, Suite 400 New
York, NY 10019-5818
kathleen.maher@constellation.com

David B. Applebaum
Director, Regulatory Affairs
NextEra Energy Resources, LLC
21 Pardee Place
Ewing, New Jersey 08628
david.applebaum@nexteraenergy.com

David Gil
Manager, Regulatory Affairs
NextEra Energy Resources, LLC
700 Universe Boulevard
Juno Beach, Florida 33408
david.gil@nexteraenergy.com

Murray E. Bevan, Esq.
Bevan, Mosca & Giuditta, P.C.
163 Madison Avenue, Suite 220-8
Morrisotwn, NJ 07960
mbevan@bmgclaw.com

Sharon Weber
PPL Energy Plus
2 North 9th Street TW 20
Allentown, PA 18101
sjweber@pplweb.com

Craig S. Blume
Director, Power Marketing
UGI Energy Services / UGI Development
Company
One Meridian Boulevard, Suite 2C01
Wyomissing, PA 19610
cblume@ugies.com

Cynthia Klots, General Counsel
DTE Energy Trading, Inc.
414 South Main Street
Suite 200
Ann Arbor, MI 48104
cynthia.klots@dteenergy.com

Don Hubschman
American Electric Power
155 W. Nationwide Blvd.
Columbus, OH 43215
dmhubschman@aepes.com

Christine McGarvey
AEP Energy Partners, Inc.
Energy Trader
155 W Nationwide Blvd
Suite 500
Columbus, OH 43215
clmcgarvey@aepes.com

Matthew Davies
TransCanada Power Marketing Ltd.
110 Turnpike Road, Suite300
Westborough, MA 01581
matthew_daview@transcanada.com

Becky Merola
Noble Americas Energy Solutions, LLC
5325 Sheffield Avenue
Powell, OH 43065
bmerola@noblesolutions.com

Glenn Riepl
AEP Energy Services
1 Riverside Plaza
14th Floor
Columbus, OH 43215-2373
gfriep1@aep.com

Howard O. Thompson
Russo Tumulty Nester Thompson
Kelly, LLP
240 Cedar Knolls Road
Suite 306
Cedar Knolls, NJ 07927
htompson@rusсотumulty.com

Tom Hoatson
LS Power Development, LLC
2 Tower Center
East Brunswick, NJ 08816
thoatson@lspower.com

Glen Thomas
The P³ Group; GT Power Group LLC
1060 First Avenue
Suite 400
King of Prussia, PA 19406
gthomas@gtpowergroup.com

Adam Kaufman, Executive Director
Independent Energy Producers of NJ
Five Vaughn Drive, Suite 101
Princeton, NJ 08540
akaufman@kzgrp.com

Anthony Pietranico
ConEdison Solutions Inc.
Electricity Supply Specialist
pietranicoa@conedsolutions.com

Christi L. Nicolay, Division Director
Macquarie Energy LLC
500 Dallas St., Level 31
Houston, TX 77002
Christi.Nicolay@macquarie.com

Dinkar Bhatia
Hartree Partners LP
8 Market Place, Suite 500 A
Baltimore, MD 21202
dbhatia@hartreepartners.com

Other Parties

Ray Cantor
NJBIA
10 West Lafayette Street
Trenton, NJ 08608-2002
rcantor@njbja.org

John Holub
NJ Retail Merchants Assoc.
332 West State Street
Trenton, NJ 08618
john@njirma.org

Steven S. Goldenberg, Esq.
Giordano, Halleran & Ciesla, P.A.
125 Half Mile Road, Suite 300
Red Bank, NJ 07701
sgoldenberg@ghclaw.com

Angela Schorr
NRG Energy, Inc.
804 Carnegie Center
Princeton, NJ 08540
angela.schorr@nrg.com

IN THE MATTER OF THE PROVISION OF :
BASIC GENERATION SERVICE FOR BASIC :
GENERATION SERVICE REQUIREMENTS : Docket No. ER26040105
EFFECTIVE JUNE 1, 2027 :

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

PROPOSAL FOR

BASIC GENERATION SERVICE REQUIREMENTS

TO BE PROCURED EFFECTIVE JUNE 1, 2027

COMPANY SPECIFIC ADDENDUM

July 1, 2026

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I. USE OF COMMITTED SUPPLY AND CONTINGENCY PLANS

COMMITTED SUPPLY

“Committed Supply,” means non-utility generation power supplies to which Public Service Electric and Gas (“PSE&G” or “Public Service” or “Company”) has an existing physical or financial entitlement. In prior auctions, PSE&G provided renewable attributes from non-utility generation contracts on a pro-rata basis to BGS-RSCP Suppliers. Since PSE&G’s last non-utility generation contract was terminated in 2014, no renewable attributes will be available going forward. PSE&G has no committed supply.

CONTINGENCY PLANS

While not every contingency can be anticipated, we can differentiate three time periods of concern:

- (a) There are an insufficient number of bids to provide for a fully subscribed Auction Volume either for the BGS-RSCP auction or the BGS-CIEP auction;
- (b) A default by one of the winning bidders prior to June 1, 2027;
- (c) A default during the June 1, 2027 – May 31, 2030 supply period.

(a) Insufficient Number of Bids in Auction

In order to ensure that the Auction Process achieves the best price for customers, the degree of competition in the auction must be sufficient. To ensure a sufficient degree of competition, the target volume of BGS-RSCP and BGS-CIEP Load purchased at each auction will be decided after the first-round bids are received. Provided that there are sufficient bids at the starting prices, the auctions will be held for 100 percent of BGS-RSCP and BGS-CIEP Load.

It is possible that the amount of initial bids will not result in a competitive auction for 100 percent of the BGS-RSCP or BGS-CIEP Load. This determination will be made by the Auction Manager in consultation with the EDCs and the Board Advisor.

In the event that the auction volume is reduced to less than 100 percent of BGS-RSCP or BGS- CIEP Load, PSE&G will implement a contingency plan for the remaining tranches. Under that plan, PSE&G, at its option, will purchase necessary services for the remaining tranches through PJM-administered markets until May 31, 2028. After May 31, 2028, any unfilled tranches may be included in a subsequent auction or treated as in Contingency Plans Part (c) below. This Contingency Plan will alert bidders that in order to secure BGS-RSCP or BGS-CIEP prices from New Jersey BGS customers for their supply, it will be necessary to bid in the auctions. Failure to bid will mean that the BGS market faced by suppliers will be a spot market with volatility and related risks.

Since the contingency plan calls for the purchase of BGS supply in PJM-administered markets, it is considered a strong feature of the auction proposal because it provides bidders a strong incentive to participate in the Auction Process. If bidders were to believe that a less than fully subscribed auction would lead to a negotiation or a secondary market in which PSE&G, on behalf of its customers, would seek to acquire fixed priced supplies, the incentive to participate in the auction and the incentive to offer the best prices in the auction would be diminished.

(b) Defaults prior to June 1st, 2027.

If a winning bidder defaults prior to the beginning of the BGS service, then, at the option of the EDC, the open tranches may be offered to the other winning bidders or these tranches may be bid out or procured in PJM-administered markets. Additional costs incurred by PSE&G in implementing this Contingency Plan will be assessed against the defaulting supplier's credit security.

(c) Defaults during the Supply Period

If a default occurs during the June 1, 2027 through May 31, 2030 period, at the option of PSE&G, the

available tranches may be offered to other winning bidders, bid out, or procured in PJM administered markets. Additional costs incurred by PSE&G in implementing this Contingency Plan will be assessed against the defaulting supplier's credit security.

II. ACCOUNTING AND COST RECOVERY

The accounting and cost recovery that PSE&G proposes for its BGS service is summarized in this section. These provisions are intended to be applicable to PSE&G only. Each EDC will provide individual BGS cost recovery proposals.

BGS-RSCP AND BGS-CIEP RECONCILIATION CHARGES

PSE&G's BGS accounting will account for BGS-RSCP revenues and BGS-CIEP revenues individually as follows:

1. BGS-RSCP and BGS-CIEP revenues will be tracked using established accounting procedures and recorded separately as BGS-RSCP revenue and BGS-CIEP revenue;
2. As previously established for PSE&G, uncollectible revenues are recovered through a component of PSE&G's Societal Benefits Charge.

PSE&G will account for BGS-RSCP and BGS-CIEP costs individually as the sum of the following:

1. Payments made for the provision of BGS-RSCP or BGS-CIEP service;
2. Any administrative costs associated with the provision of BGS-RSCP and BGS-CIEP service;

Administrative costs are defined as commonly-incurred or directly-incurred. *Commonly-incurred costs* are costs shared among all of the New Jersey Electric Distribution Companies (the "EDCs"). *Directly-incurred costs* are costs specifically incurred by each EDC, individually.

- a. Commonly-incurred costs include, but are not limited to, the following:
- preparing and conducting the annual auction, which include all pre-auction development work, developing and printing materials, developing and maintaining the BGS auction website, conducting information sessions for prospective bidders, as well as other consulting services provided by the Auction Manager;
 - oversight of the auction process on behalf of the New Jersey Board of Public Utilities (the “Board or “BPU”), as performed by the Board’s consultant;
 - rent and maintenance of office space in New Jersey for the Auction Manager;
 - outside counsel legal costs associated with the prosecution and/or defense of BGS patent claims; and
 - costs associated with viewing the annual auction in real time, which may include, but are not limited to, costs for physical space and equipment/media connections.
- b. Directly-incurred costs (for PSE&G) include, but are not limited to, the costs noted below. In addition to the fees related to GATS administration and the Environmental Label insert (if necessary), these costs also include directly-incurred labor costs associated with several functions that are common across the EDCs (consistent with the Order of Implementation related to the BGS Administrative Expense audit with the effective date specified in the final Board Order in the Company’s most recent base rate case¹ (“Rate Case Order”).
- Direct labor costs for RPS Compliance
 - Direct labor costs for BGS Steering Committee
 - Direct labor costs for BGS Data Room
 - Direct labor costs for BGS Payments
 - GATS Administrative Fee
 - Printing Costs of Environmental Label inserts, if necessary

The commonly-incurred cost estimates for each BGS Auction cycle are paid for by the

¹ *In re the Petition of Public Service Electric and Gas Company For Approval of an Increase in Electric and Gas Rates for Changes in the Tariffs for Electric and Gas Service, B.P.U.N.J. No. 17 Electric and B.P.U.N.J. No. 17 Gas, and for Changes in Depreciation Rates, Pursuant to N.J.S.A. 48:2-18, N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, and for Other Appropriate Relief, BPU Docket Nos. ER23120924 & GR23120925, Order dated October 9, 2024 (“Base Rate Case Order”).*

winning bidders of the auction at the start of each Energy Year through the Tranche Fee. The difference between the estimated commonly-incurred costs and the actual commonly-incurred costs and all the directly-incurred costs are paid through the BGS Reconciliation Charges.

3. The cost of any procurement of necessary services including capacity, energy, ancillary services, transmission, RPS compliance, and other expenses related to the Contingency Plan less any payments recovered from defaulting suppliers.

Adjustment type (i.e., reconciliation) charges are necessary in order to balance out the difference between (1) the amounts paid to the BGS-RSCP and BGS-CIEP supplier(s) for BGS-RSCP and BGS-CIEP supply and (2) the total revenue from customers for BGS-RSCP and BGS-CIEP services , respectively.

Prior to 2021, the Company calculated and applied the reconciliation charge on a monthly basis. However, in Company Specific Addendum filed on July 1, 2020² the Company proposed a change to a quarterly reconciliation charge construct with the aim of reducing BGS rate volatility related to monthly changes in the reconciliation charge. This proposed change was ultimately approved in the Board's November 18, 2020 Decision and Order in this matter. Since this change to a quarterly reconciliation charge construct, though the month-to-month volatility has been mitigated, seasonal volatility still persists. By example, the reconciliation charge has consistently been a positive charge to BGS-RSCP customers for charges based on the winter revenue vs cost, transitioning to a large credit for BGS-RSCP customers for charges based on summer revenue vs cost. The Company believes that this

² Filed I/M/O the Provision of Basic Generation Service for Basic Generation Service Requirements Effective June 1, 2021, Docket No. ER20030190.

winter/summer seasonal variability and resultant BGS rate volatility can be further muted by changing from a quarterly reconciliation charge construct to one that is set and applied annually. To that end, the Company is proposing to migrate to an annual reconciliation charge beginning March 1, 2027 (based on revenue and cost data for the calendar year of 2026). Implementing the new annual charge methodology in March further promotes BGS rate stability by lessening compounding rate impacts when BGS-RSCP and BGS-CIEP rates become effective June 1.

With this process, these reconciliation charges are calculated separately each year for BGS-RSCP and BGS- CIEP and applied for the upcoming year on a dollars per kWh basis and the respective charges are applied to all BGS-RSCP and BGS-CIEP kWh billed. These charges are combined with BGS-RSCP and hourly BGS-CIEP charges for billing although they are published in separate BGS-RSCP reconciliation charge and BGS-CIEP reconciliation charge tariff sheets that are revised annually to reflect actual revenues and costs. These tariff sheets are filed with the Board approximately each February 15th.

The BGS-RSCP reconciliation charge and BGS-CIEP reconciliation charge are subject to deferred accounting with interest at the NGC rate previously set by the Board and are determined individually as set forth below:

The reconciliation charges are used in both BGS-RSCP and BGS-CIEP to true up the differences between BGS payments to suppliers and BGS revenues from customers for the year. Differences in BGS costs and BGS revenues for a calendar year are computed following that year and applied to BGS rates for the upcoming year beginning in March. Two of these differences are shown below:

1. The difference between BGS Costs (as defined above) paid to suppliers in the prior calendar year and the BGS revenue in the year. This difference is calculated after the calendar year to become effective in the upcoming March.
2. The difference between the total adjustment charge revenue intended to be recovered in the

year and the actual adjustment charge revenue recovered in the year. This difference is driven by differences between actual kWh in the quarter and the kWh used to calculate the charge.

The reconciliation charges to be applied in the upcoming year are calculated as the net of the two differences described above for the calendar year (plus or minus any cumulative under or over recovery from the prior year) divided by the forecast of BGS kWh in the upcoming year.

III. A. DESCRIPTION OF BGS TARIFF SHEETS AND OTHER TARIFF ITEMS

GENERAL

As described in the generic section of this filing, two different methods will continue to be utilized for the pricing of BGS default supply service to customers: Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) for residential and small commercial customers and Basic Generation Service – Commercial and Industrial Energy Pricing (BGS-CIEP), a variable hourly energy pricing for large commercial and industrial customers.

The Company is not proposing any modification of the criteria for BGS-CIEP eligibility from the current peak load share of 500kW. Thus BGS-CIEP is proposed to continue to be the default service for all customers served under delivery rate schedules HTS-High Voltage, HTS-Subtransmission, and LPL-Primary and for LPL-Secondary customers with a peak load share (PLS) of 500 kW or higher.

As in prior years, all other non-residential customers also have the option of electing BGS-CIEP as their default supply service. All non-residential customers with BGS-CIEP as their optional default service will be notified of their option to switch to BGS-CIEP through PSE&G's website and tariffs. Annually, customers eligible for this option must notify PSE&G no later than the second business day of January of any given year to have BGS-CIEP as their default supply service option for the annual period beginning June 1st of that year. The BGS-RSCP default service will be available to residential and small

and medium sized non-residential customers, specifically those served on Rate Schedules RS, RS TOU-3P, RHS, RLM, WH, WHS, HS, BPL, BPL-POF, PSAL, GLP and LPL-Secondary (PLS less than 500 kW).

The following sections describe the tariff sheets that would implement Public Service's BGS service effective June 1, 2027.

BGS-RSCP

While Public Service is not proposing any change in the structure of the BGS-RSCP default supply service, the BGS Transmission Charges continue to be shown separately. The form of the BGS-RSCP tariff sheets is included in Attachment 1 and are indicated as Sheet Nos. 75, 76, and 79. Once the results of the BGS-RSCP Bid are finalized, the values on these tariff sheets will be updated reflecting the results of the bid.

As indicated on these tariff sheets, the BGS-RSCP default service is made up of several components: BGS Energy Charges, BGS Capacity Charges, BGS Transmission Charges, and the BGS Reconciliation Charges. These charges will apply for usage in the calendar months of June through September, or October through May, as applicable.

BGS Energy Charges

The values of the BGS Energy charges applicable to Rate Schedules RS, RS TOU-3P, RHS, RLM, WH, WHS, HS, BPL, BPL-POF and PSAL include the costs related to energy, ancillary services and generation capacity costs. This overall approach is a continuation of the current approved methodology of recovering all electric supply service costs in the kilowatt-hour charges for these rate schedules.

Typically, the generation capacity costs used in the development of the BGS-RSCP rates are the relevant current wholesale market prices for capacity based on the average, 2027/2028, 2028/2029 and

2029/2030 Base Residual Auction (“BRA”) results under the Reliability Pricing Model (“RPM”) applicable to load served in the PSEG zone

This process has been impacted in recent years by delays in conducting the BRAs – resulting in the need for contract supplements with Capacity Proxy Prices for delivery years with delayed BRAs. Due to the delays of the BRAs, contracts from the 2025 and 2026 BGS auctions contained supplements with Capacity Proxy Prices. With the delays of the BRAs for the 2027/2028 Delivery Year and the 2028/2029 Delivery Year, a Capacity Proxy Price of \$270.35 per MW-Day was used in place of the 2027/2028 BRA value in the 2025 contracts, while a Capacity Proxy Price of \$333.69 per MW-Day was used in place of the 2028/2029 BRA value in the 2026 contracts.

At this time the results of the BRAs for the 2028/2029 and 2029/2030 Delivery Years are not yet available but the BRAs are scheduled to be held in June 2026 (results posted in July 2026), and December 2026, respectively. Given the continued delay in the schedule of these BRAs a Capacity Proxy price of \$333.69 per MW-Day has been used for the 2028/2029 Delivery Year and a Capacity Proxy Price of \$333.69 per MW-Day has been used in place of the prices paid for capacity for the 2029/2030 Delivery Year. The details of the EDCs’ Proxy Price proposal for BGS-RSCP is included in the EDCs’ Proposal for Generation Service Requirements to be Procured Effective June 1, 2027 (Docket No. ER26040105).

For Energy Year (EY) 2029, if Supplement A to the BGS-RSCP Supplier Master Agreement is approved by the BPU and the BRA for the 2028/2029 Delivery Year has not occurred at least 5 business days prior to the BGS-RSCP Auction, payments to BGS-RSCP Suppliers will be adjusted for the difference between the “Zonal Capacity Price”, which is the price paid by BGS-RSCP Suppliers for Capacity in the Company’s PJM Zone, as may be determined under the Reliability Pricing Model or its successor or otherwise, and the Capacity Proxy Price for the 2028/2029 Delivery Year.

For Energy Year (EY) 2030, if Supplement B to the BGS-RSCP Supplier Master Agreement is approved by the BPU and the BRA for the 2029/2030 Delivery Year has not occurred at least 5 business days prior to the BGS-RSCP Auction, payments to BGS-RSCP Suppliers will be adjusted for the difference between the “Zonal Capacity Price”, which is the price paid by BGS-RSCP Suppliers for Capacity in the Company’s PJM Zone, as may be determined under the Reliability Pricing Model or its successor or otherwise, and the Capacity Proxy Price for the 2029/2030 Delivery Year.

PSE&G will file new tariff sheets for EY 2028 reflecting the impact of this price adjustment, in a manner similar to Attachment 4, Page 1 (“Attach 4 P1”)– Development of Capacity Proxy Price True Up - \$/MWh. The rate design spreadsheets include the formulas that will be used to reflect the impact of payments made pursuant to the Supplements. Attachment 4, Pages 2 and 3 (“Attach 4 P2”, “Attach 4 P3”) are illustrative examples of how of how the Capacity Proxy Price True Up will be calculated for EY 2029 and EY 2030 respectively and prospectively.

The Supplement to the SMAs signed by BGS-RSCP Suppliers in February 2025 is still in effect for approximately one-third of the load for Energy Year 2028 (the year beginning June 1, 2027). Payments to BGS-RSCP Suppliers that executed the Supplement to the SMA approved by the BPU on November 21, 2024 will be adjusted for the price difference between the price paid by BGS-RSCP Suppliers for Capacity in the Company’s PJM Zone and the Capacity Proxy Price for the 2027/2028 Delivery Year. Upon the conclusion of the Third Incremental RPM Auction, or the RPM’s successor or otherwise, the price paid by BGS-RSCP Suppliers for Capacity in the Company’s PJM Zone will be known. At that time, PSE&G will file new tariff sheets reflecting the impact of the Supplement. The rate design spreadsheets include the formulas that will be used to reflect the impact of payments made pursuant to the Supplement executed by BGS-RSCP Suppliers in February 2025. The value of (\$333.69 per MW-day) is used as an approximation for the price paid by BGS-RSCP Suppliers for Capacity in the

Company's PJM Zone for the 2027/2028 Delivery Year.

The generation capacity and transmission related costs will continue to be recovered through separate charges for customers on Rates GLP and LPL-Secondary (less than 500 kW) based on the customer specific assigned generation capacity and transmission obligation values. The resulting BGS Energy Charges applicable to this latter set of customers thus do not include the costs related to generation capacity and transmission service.

In order to more accurately reflect the costs of providing energy and other electric services when relying on the day-ahead PJM versus the real-time markets, the Company will apply two ancillary services costs, one applied to BGS-RSCP service and the other applied to BGS-CIEP service. A \$2.00 per MWh ancillary services rate is used in the calculation of the BGS-RSCP rates since it is more reflective of costs borne in the day-ahead market. Additionally, Renewable Portfolio Standard costs estimated to be \$16.04 per MWh are included in the calculation of the BGS-RSCP rates to reflect compliance costs. A BGS-CIEP ancillary services cost of \$6.00 per MWh is applied since it is more reflective of costs borne in the real-time market.

The specific values that will be utilized for the BGS Energy Charges will be calculated from the winning BGS-RSCP bid prices for the Public Service zone. It is the intent of the EDCs that the factors in the tables will be applied to the tranche-weighted average winning bid prices adjusted for seasonal payment factors resulting from the auctions for BGS-RSCP with terms covering the period from June 1, 2027 to May 31, 2028. For example, for Public Service, for the period beginning June 1, 2027 the weighting will be based on the load (i.e., successfully bid tranches) at the 36-month prices from the 2025, 2026, and 2027 BGS-RSCP auctions, and the seasonal payment factors calculated in Attachment 2.

The tables will be updated annually, prior to future BGS auctions and utilized to develop customer charges for a related annual period in a similar manner as discussed above. The updates will reflect then

current factors such as updated futures prices, factors based on 12- month data, and any changes in the customer groups and loads eligible for the BGS-RSCP class.

BGS Capacity Charges

These charges are the separate charges previously mentioned that are designed to recover the costs associated with generation capacity for customers served on Rate Schedules GLP and LPL-Secondary (less than 500 kW). These charges are expressed on a per-kW of generation capacity obligation basis.

Typically, the generation capacity costs designed to be used in the development of the BGS-RSCP rates are the relevant current wholesale market prices for capacity based on the average, 2027/2028, 2028/2029 and 2029/2030 BRA for RPM results applicable to load served in the PSEG zone. This process has been impacted in recent years by delays in conducting the BRAs – resulting in the need for contract supplements with Capacity Proxy Prices for delivery years with delayed BRAs. Due to the delays of the BRAs, contracts from the 2025 and 2026 BGS auctions contained supplements with Capacity Proxy Prices. With the prior delays of the BRAs for the 2027/2028 Delivery Year and 2028/2029 Delivery Year, a Capacity Proxy Price of \$270.35 per MW-Day was used in place of the 2027/2028 BRA value in the 2025 contracts, while a Capacity Proxy Price of \$333.69 per MW-Day was used in place of the 2028/2029 BRA value in the 2026 contracts.

At this time the results of the BRAs for the 2028/2029 and 2029/2030 Delivery Years are not yet available but the BRAs are scheduled to be held in June 2026 (results posted in July 2026), and December 2026, respectively. Given the continued delay in the schedule of these BRAs a Capacity Proxy Price of \$333.69 per MW-Day has been used for the 2028/2029 Delivery Year and a Capacity Proxy Price of \$333.69 per MW-Day has been used in place of the prices paid for capacity for the 2029/2030 Delivery Year. The details of the EDCs' Proxy Price proposal for BGS-RSCP is included in the EDCs' Proposal for Generation Service Requirements to be Procured Effective June 1, 2027 (Docket

No. ER26040105).

For Energy Year (EY) 2029, if Supplement A to the BGS-RSCP Supplier Master Agreement is approved by the BPU and the BRA for the 2028/2029 Delivery Year has not occurred at least 5 business days prior to the BGS-RSCP Auction, payments to BGS-RSCP Suppliers will be adjusted for the difference between the “Zonal Capacity Price”, which is the price paid by BGS-RSCP Suppliers for Capacity in the Company’s PJM Zone, as may be determined under the Reliability Pricing Model or its successor or otherwise, and the Capacity Proxy Price for the 2028/2029 Delivery Year.

For Energy Year (EY) 2030, if Supplement B to the BGS-RSCP Supplier Master Agreement is approved by the BPU and the BRA for the 2029/2030 Delivery Year has not occurred at least 5 business days prior to the BGS-RSCP Auction, payments to BGS-RSCP Suppliers will be adjusted for the difference between the “Zonal Capacity Price”, which is the price paid by BGS-RSCP Suppliers for Capacity in the Company’s PJM Zone, as may be determined under the Reliability Pricing Model or its successor or otherwise, and the Capacity Proxy Price for the 2029/2030 Delivery Year.

PSE&G will file new tariff sheets for EY 2029 and EY 2030, reflecting the impact of this price adjustment. The rate design spreadsheets include the formulas that will be used to reflect the impact of payments made pursuant to the Supplements.

The Supplement to the SMAs signed by BGS-RSCP Suppliers in February 2025 is still in effect for approximately one-third of the load for Energy Year 2028 (the year beginning June 1, 2027). Payments to BGS-RSCP Suppliers that executed the Supplement to the SMA approved by the BPU on November 21, 2024 will be adjusted for the price difference between the price paid by BGS-RSCP Suppliers for Capacity in the Company’s PJM Zone and the Capacity Proxy Price for the 2027/2028 Delivery Year. Upon the conclusion of the Third Incremental RPM Auction, or the RPM’s successor or otherwise, the price paid by BGS-RSCP Suppliers for Capacity in the Company’s PJM Zone will be known. At that

time, PSE&G will file new tariff sheets reflecting the impact of the Supplement. The rate design spreadsheets include the formulas that will be used to reflect the impact of payments made pursuant to the Supplement executed by BGS-RSCP Suppliers in February 2025. The value of (\$333.69 per MW-Day) is used as an approximation for the price paid by BGS-RSCP Suppliers for Capacity in the Company's PJM Zone for the 2027/2028 Delivery Year.

BGS Transmission Charges

Similar to the BGS Capacity Charges, the BGS Transmission Charges recover the customer specific costs associated with network transmission service for customers on Rates GLP and LPL-Secondary (less than 500 kW). The charge is based on the annual transmission rate for network service for the PSE&G zone, as stated in PJM's Open Access Transmission Tariff (OATT), and as approved by the BPU for inclusion in the BGS Transmission Charge. The bids will exclude BGS Transmission Charges. PSE&G will file with the BPU to change the transmission cost components of the BGS charges to customers as FERC approves changes in the Network Integration Transmission Service rates for the PSE&G zone in the PJM OATT, or the FERC approves other network transmission-related charges in the PJM OATT at a minimum of twice per year for rates based on transmission-related costs that are to be effective January 1 and June 1 of each year. To the extent that there is a change to the payments required by PJM for transmission, either as a result of a change in the firm transmission rate or as a result of cost reallocation, PSE&G will present an additional filing to the Board to change the transmission charge paid by BGS customers. PSE&G will review and verify the basis for any BGS transmission charge adjustment and will file supporting documentation from the OATT, as well as any rate translation spreadsheets used. For the BGS-RSCP energy only rates (Rate Schedules RS, RS TOU-3P, RHS, RLM, WH, WHS, HS, BPL, BPL-POF and PSAL), upon BPU approval, changes in the OATT rate (per kW of transmission obligation) will be implemented by multiplying such change in the OATT rate by each rate class's ratio of the kW of transmission load of that class divided by

the expected annual kWh of that class. The results, in dollars per kWh, will then be added to all BGS-RSCP Energy charges for each class. In the event that PJM institutes a charge for transmission network service on an energy basis (per kWh), this charge will be added to the BGS-RSCP Energy charges for all kWhs for all rate schedules.

BGS Reconciliation Charge

The BGS Reconciliation Charge for the BGS-RSCP default service is explained in the prior Section II - Accounting and Cost Recovery and will be combined with the BGS-RSCP energy charge for billing.

BGS-CIEP

The bid product in the 2027 BGS-CIEP auction will continue to be the Generation Capacity Cost, as it was in last year's BGS-CIEP auction. Public Service will continue the use of a value for the CIEP Standby Fee equal to 0.000150 dollars per kWh. The form of tariff sheets for the Basic Generation Service – Commercial and Industrial Energy - Pricing (BGS-CIEP) are included in Attachment 1 and are indicated as Sheet Nos. 73, 82, and 83. Similar to the BGS-RSCP, the charges for BGS-CIEP are comprised of several components: BGS Energy Charges, BGS Capacity Charges, BGS Transmission Charges, and the BGS Reconciliation Charges.

BGS Energy Charges

The primary component of this charge will be the actual PJM load-weighted average Residual Metered Load Aggregate Locational Marginal Price (LMP) of energy for the Public Service Transmission Zone. Added to this is an ancillary service cost (including PJM Administrative Costs) for the Public Service zone of \$6.00 dollars per MWh that was estimated as being reflective of ancillary service costs in the PSEG zone for energy purchased in the real time market. This sum is then adjusted for losses. Because the LMPs are calculated to include a marginal loss component for the transmission system, a loss correction is performed. This is done by removing the mean hourly marginal transmission loss factor for the PSE&G transmission zone (equal to 0.92504%) from the BPU-approved PSE&G delivery tariff loss

factors. The result is reflective of losses from the customer meter to the transmission nodes (at which the LMPs are calculated).

BGS Capacity Charges

These charges will recover the costs associated with generation capacity. The BGS Capacity Charge component of the BGS-CIEP bid is set equal to the BGS-CIEP auction clearing price. These charges are expressed on a per-kW of generation capacity obligation basis.

BGS Transmission Charges

BGS-CIEP Transmission Charges recover the customer specific costs associated with Transmission service for customers on BGS-CIEP. The charges are based on the annual transmission rate for network transmission service for the PSE&G zone, in PJM's Open Access Transmission Tariff (OATT), and as approved by the BPU for inclusion in the BGS-CIEP Transmission Charges. This charge is expressed as a monthly charge on a per-kW of transmission obligation basis. PSE&G will file with the BPU to change the transmission cost components of the BGS charges to customers as FERC approves changes in the Network Integration Transmission Service rates for the PSE&G zone in the PJM OATT, or the FERC approves other network transmission- related charges in the PJM OATT at a minimum of twice per year for rates based on transmission-related costs that are to become effective January 1 and June 1 or each year. To the extent that there is a change to the payments required by PJM for transmission, either as a result of a change in the firm transmission rate or as a result of cost reallocation, PSE&G will present an additional filing to the Board to change the transmission charge paid by BGS customers.

PSE&G will review and verify the basis for any BGS transmission charge adjustment and will file supporting documentation from the OATT, as well as any rate translation spreadsheets used.

BGS Reconciliation Charge

The BGS Reconciliation Charge for the BGS-CIEP default service is explained in the prior Section II - Accounting and Cost Recovery and will be combined with the BGS-CIEP energy charge for billing.

OTHER ITEMS

CIEP STANDBY FEE

PSE&G will continue to pay each BGS-CIEP supplier a CIEP Standby Fee, which is set at 0.000150 dollars per kWh times their pro-rata share of the total energy usage measured at the meters of all PSE&G's customers whose default service option is limited to BGS-CIEP and those customers who have elected BGS-CIEP as their default supply.

A tariff sheet, included in Attachment 1 and indicated as Sheet No. 73, shows the CIEP Standby Fee as a Delivery Charge that is applicable to all customers having BGS-CIEP as their sole default supply service option and those customers who have elected BGS-CIEP as their default supply. This includes all customers served on Rate Schedules LPL-Secondary (peak load share of 500 kW or greater), LPL-Primary, HTS-Subtransmission, HTS-High Voltage, and all customers on Rate Schedules HS, GLP, and LPL-Secondary (less than 500 kW) that have elected the BGS-CIEP default supply option.

DESCRIPTION OF BGS PRICING SPREADSHEETS

As described in the generic write-up, the resulting charge for each BGS rate element (i.e. Rate RS summer charge, winter charge, etc.) for the non-hourly BGS supply service will generally be based on factors applied to the tranche-weighted average winning bid prices adjusted for seasonal payments.

These factors have been developed based on the ratios of the estimated underlying market costs of each

rate element (for each rate class) to the overall all-in BGS cost. The tables included in Attachments 2, 3 and 5 present all of the input data, intermediate calculations, and the final results in the calculation of these factors.

The following is a description of the calculations shown in the spreadsheet titled “Development of BGS-RSCP Cost and Bid Factors for the 2027/2028 BGS Filing” and included as Attachment 2.

Table #1 (% Usage during PJM On-Peak Period) contains the percentage of on-peak load, inputted by month, for each rate schedule. The on-peak period as used in this table (referred to as PJM periods) is defined as the 16-hour period from 7 AM to 11 PM, Monday through Friday. All remaining weekday hours and all hours on weekends and holidays recognized by the National Electric Reliability Council (NERC) are considered the off-peak period. This is consistent with the time periods used in the forwards market for trading of bulk power. The values in this table for each month are the average on-peak percentages from the years 2023 and 2024 and 2025, as calculated from the same load research data used for retail settlement for current customers that have chosen to be supplied by a Third-Party Supplier (TPS). The average for a three-year period was used to reduce the variability of weather effects on the percentage from any single year.

Table #2 (% Usage During PSE&G On-Peak Billing Period) contains the percentage of on-peak load, by month, for each applicable rate schedule based on the definitions of time periods as contained in Public Service’s delivery rate schedules. Since, excluding the hourly price BGS rates, only Rate Schedule RLM and LPL-Sec are billed on a time-of-day basis utilizing time periods, these are the only two columns in this table where data has been inputted. These are the percentage of actual on-peak kWh usage for the years, 2023, 2024, and 2025. As was done with Table #1, the three-year average was used to reduce the effects of weather in a particular year.

Table #3 (Class Usage @ customer) contains the total calendar month sales forecasted for the calendar

year 2026 without a migration adjustment (e.g. 100% migration). In past auctions, 50% migration was used to develop Class Usage @ customer. Given the historic stability of migration, developing prices without a migration adjustment will result in lower BGS rates and move the annual average reconciliation charge closer to zero. The Company reserves the right to modify the migration adjustment based upon market conditions. The values in Table #3 will be updated in January 2027 to better reflect the amount by rate schedule that could be in effect starting on June 1, 2027. For Rate LPL-Secondary, these values have been reduced for the percentage of customers having a Peak Load Share of 500 kW or greater, and thus having BGS- CIEP as their default service. These monthly percentages were based on the 2025 monthly percentages of total actual sales for customers meeting this Peak Load Share threshold.

Table #4 (Forwards Prices – Energy Only @ Bulk System) contains the forward prices for energy, by time period and month for the BGS analysis period. These values are an average of the most recent energy on-peak forwards values available for the PJM West trading hub for the period of June 2027 to May 2030 and the historical ratio of actual off-peak to on-peak PJM LMPs from June 2023 through September 2025 and March 2023 through February 2026, for summer and winter periods, respectively.

An adjustment of the forwards prices contained in Table #4 is then made to correct for the effects of transmission congestion in the PJM system between the PJM West trading hub and the Public Service zone where the BGS supply will be utilized.

Table #5 (Congestion Factors) contains an estimate of the average congestion factors, by month and time period, which when multiplied by the prices at the PJM West trading hub will result in costs for power delivered into the Public Service zone. These Hub-to-Zone differentials are based on the average percent differences from June 2023 through September 2025 and March 2023 through February 2026, for summer and winter periods, respectively.

Table #6 (Losses) The factors utilized for total average losses, including PJM losses, are inputted in the upper portion of Table #6 (Losses) by rate schedule. Delivery loss factors used are those in the Company's tariff. PJM losses are the average percentage PJM EHV losses plus inadvertent energy for the three-year period June 2013 through May 2016, a value equal to 0.456%.

The lower portion of this table shows the derivation of the effective losses from the customer meter to the transmission nodes at which the LMPs are calculated. The loss factors shown are the Delivery loss factors from the Company's filed tariff less the mean hourly marginal loss factors for the PSE&G transmission zone as calculated by PJM. The resulting loss factor is reflective of losses from the customer meter to the transmission nodes (at which the LMPs are calculated) and at which payments to the winning bidders are based. The marginal loss factors used above are actual marginal loss de-rating factors based May 2023 to April 2026 data adjusted for the portion of marginal losses attributed to PJM extra-high voltage.

Since the service for all of the rates indicated is at secondary voltages, the applicable loss factors are identical for all rates.

Table #7 (Summary of Average BGS Energy Only Unit Costs @ Customer – PJM Time Periods) is the calculation of the energy only costs by rate, time period and season. These values are the seasonal and time period average costs per MWh as measured at the customer billing meter (from Table #3), based on the forwards prices (from Table #4) corrected for congestion (from Table #5), losses (from Table #6), and monthly time period weights (from Table #1). These average costs do not include the costs associated with Ancillary Services, Renewable Portfolio Standard compliance, Generation Obligation or Transmission costs, which will be considered in subsequent calculations.

Table #8 (Summary of Average BGS Energy Only Costs @ Customer – PJM Time Periods) indicates the total value, in thousands of dollars, of the average BGS energy only costs. These are the results of

the multiplication of the unit costs from Table #7, the monthly time period weights from Table #1 and the total sales to customers from Table #3.

Since these calculations will be utilized in the development of retail BGS rates, the rates utilizing time-of-day pricing must be developed based upon the time periods as described in the applicable tariff.

Table #9 (Summary of Average BGS Energy Only Unit Costs @ Customer – PSE&G Time Periods) shows the result of the corrections for the two rates billed on a time-of-day basis, Rates RLM and LPL-Secondary (less than 500 kW). These values are calculated based on the assumption that the MWhs included in the PJM on-peak time period and not included in the PSE&G on-peak time periods are at the average of the on and off-peak PJM prices.

Table #10 (Generation Obligation and Costs and Other Adjustments) The next steps set up the values necessary for the inclusion of the costs of the Generation Capacity obligation. The top portion of Table #10 shows the total obligations without migration adjustment (e.g. 100% migration. Please see migration explanation in Table #3 description above), by rate schedule, that are currently being utilized in the year 2026. The values in the top portion of Table #10 will be updated in January 2027 to better reflect the aggregate amount by rate schedule that could be in effect on June 1, 2027. Similar to the methodology used in Table #3, the obligations for Rate LPL-Secondary have been reduced for the percentage of customers having a Peak Load Share of 500 kW or greater. The middle portion of this table shows the number of summer and winter days and months that are used in this analysis. The bottom portion of this table shows the annual cost for transmission service now to be zero and the average price of generation capacity, using the BRA Capacity Price for Delivery Year 2027/2028, the Capacity Proxy Price for Delivery Year 2028/2029, and the Capacity Proxy Price for Delivery Year 2029/2030. The Capacity Proxy Prices will be replaced with the Zonal Capacity Prices, which are the prices paid by BGS-RSCP Suppliers for Capacity for the 2028/2029 and the 2029/2030 delivery years,

when available as may be determined through the Reliability Pricing Model or its successor or otherwise.

The BGS Transmission Charge is set through separate filings as discussed in the BGS Transmission Charge sections. This table also shows the level of blocking in current BGS charges for Rates RS and RHS, which will be utilized in the later calculations of the blocking of the new BGS charges for these rates. The Company has previously objected to the blocking of these charges since there is no compelling cost basis for any such blocking. The Company proposes to keep blocking in this year's filing but wishes to note that it does not believe that there is a cost basis for doing so.

Table #11 (Ancillary Services and Renewable Portfolio Standard) An estimate of the effects of the costs of ancillary services and Renewable Portfolio Standard is included in the development of the final BGS rates. The values of \$2.00 per MWh and \$16.04 per MWh are used, respectively. Since the actual costs are a complex combination of many factors, this Board-approved estimate of the overall annual average value, expressed on a dollar per MWh basis, is used as a reasonable and practical alternative.

Table #12 (Summary of Obligation Costs Expressed as \$/MWh @ Customer – For Non- Demand Rates Only) shows the result of the allocation of both the transmission and generation costs on a per kWh basis to those rates whose BGS service will only be recovered through energy charges, Rates RS through BPL. The obligation costs for the rates not indicated in this table, Rates GLP and LPL-Sec, will be recovered directly through a distinct obligation charge based on a separate charge times each customer's assigned transmission and generation capacity obligation. The annual values are calculated as the total obligations (upper part of Table #10) times their costs (lower part of Table #10) divided by the appropriate total rate schedule MWh (from Table #3).

Table #13 (Summary of BGS Unit Costs @ Customer) is the result of the inclusion of the Generation Capacity, Ancillary Services, and Renewable Portfolio Standard costs to the energy only costs shown in

Table #9. The top portion of this table shows the total estimated all-in BGS costs for the non-demand rates (Rates RS, RHS, RLM, WH, WHS, HS, PSAL and BPL), whose BGS costs are proposed to be recovered on an energy only basis through kWh charges. The all-in costs for the residential non-time of day rates, Rates RS and RHS, are currently blocked in the summer based on the current level of BGS blocking inputted in Table #10 so as to maintain the same BGS rate differential that currently exists. The middle section shows the results for the demand rates (Rates GLP and LPL-Sec) whose BGS costs will be recovered through both energy charges on a per kWh basis and obligation charges on a per kW of obligation basis. The left-hand columns indicate the unit energy costs, while the right-hand columns indicate the obligation costs. The bottom portion of this table shows the total estimated costs for BGS, based on the assumptions utilized in the above tables, and the average per unit cost, as measured at the customer meters or the transmission nodes.

Table #14 (Ratio of BGS Unit Costs @ Customer to All-In Average Cost @ Transmission Nodes)

indicates the ratio of the individual rate element costs from Table #13 to the overall all- in cost as measured at the transmission nodes, plus constants, where applicable. These bid factor ratios are a key element in the calculation of the actual BGS-RSCP charges and will be used in later tables to convert the winning bids into actual BGS rates charged to customers.

The top portion of this table indicates these ratios for the non-demand rates while the ratios for the demand rates are shown on the bottom portion of the table. Since the unit rates charged for generation and transmission obligation (as shown in the right-hand columns) for Rates GLP and LPL-Sec are not unitized but kept at the estimated market value, it is necessary to modify the energy ratios for these two rate classes to assure that the resulting overall revenue from charges to the customers equals the payment to suppliers. The first of the values indicated, the “multiplier” is utilized as a ratio, with the “constant” term an additive adjustment to the resulting value. For example, if the tranche weighted average winning

bid prices adjusted for seasonal payment factors is \$111.57 per MWh and the GLP multiplier for summer is 0.949 and the constant is (\$25.687), the summer BGS rate charged customers would equal $(\$111.57 * 0.949) - \25.687 , or \$80.193 per MWh.

Assumptions: This unnumbered table summarizes some of the most important assumptions utilized in the above calculations.

Table #15 (Summary of Total BGS Costs by Season) shows the calculation of the total BGS Costs, utilizing the total customer usage from Table #3 and the all-in unit costs from Table #13. The lower left portion of this table indicates the relative percentage of total costs by season for all rate schedules, while the center shows the calculation of the overall average all-in seasonal unit costs on a dollar per MWh basis. The ratio of these overall average seasonal costs to the overall total cost, shown in the lower right-hand portion of this table, are the seasonal payment ratios upon which payments to the winning bidders are based. Since the normal calculation would produce an atypical result of a summer payment ratio (factor) that is lower than the winter payment ratio (factor) for the 2027/2028 BGS Supply Period, a factor of 1.0 will be used for both the summer and winter payment factors.

Table #16 (Spreadsheet Error Checking) shows the reconciliation between the customer revenue calculation to the BGS supplier payments, utilizing an assumed winning bid price (as indicated) and the calculated summer-winter payment ratios, the customer usage from Table #3 and the all-in unit costs from Table #13.

Table #17 (Total Supplier Energy @ transmission nodes) shows the calculation of the total supplier energy by season, utilizing the total customer usage from Table #3 and the meter to transmission node loss factors from the lower portion of Table #6.

The second spreadsheet used in the calculation of the final BGS-RSCP rates is included as Attachment

#3 and is titled “Calculation of June 2027 to May 2028 BGS-RSCP Rates”. The tables in this spreadsheet calculate the weighted average winning bid price and convert it into the final BGS-RSCP rates that are charged to customers. An explanation of each of the six tables, labeled as Table A through F, is as follows.

Table A (Auction Results) contains the results of the prior two BGS auctions as well as the results (shown with illustrative values) of the current auction. The Capacity Proxy Price True Up cost in \$ per MWh will be used to reflect the impact of payments made pursuant to the Supplement executed by BGS Suppliers in February 2025. Upon conclusion of the Third Incremental RPM Auction through the Reliability Pricing Model or its successor or otherwise, the price paid by BGS-RSCP Suppliers for Capacity in the Company’s PJM Zone will be known. The Capacity Proxy Price True-Up will then be determined by the price difference between the price paid by BGS-RSCP Suppliers for Capacity in the Company’s PJM Zone and the Capacity Proxy Price for the 2027/2028 Delivery Year. The value of (\$333.69 per MW-Day) is used as an approximation for the price paid by BGS-RSCP Suppliers for Capacity in the Company’s PJM Zone for the 2027/2028 Delivery Year.

Table B (Ratio of BGS Unit Costs @ Customer to All-In Average Cost @ transmission nodes) is a repeat of the values shown in Table #14 from Attachment 2, the bid factors calculated based on current market conditions.

Table C (Preliminary Resulting BGS Rates) contains the preliminary customer BGS-RSCP rates as the product of the weighted average bid price (from Table A) and the Bid Factors from Table B.

Table D (Revenue Recovery Calculations) contains a comparison of the total anticipated rate revenue billed to customers based on the preliminary BGS-RSCP rates developed in Table C and the anticipated total season payments to BGS suppliers, based on the data in Table A. The calculation of the kWh Rate Adjustment Factors are also done in this table, which are equal to the seasonal dollar differences

between the anticipated billed revenue and supplier payments, divided by the total anticipated seasonal billed BGS-RSCP energy related charges.

Table E (Final Resulting BGS Rates) contains the final adjusted BGS-RSCP rates, which are equal to the preliminary BGS–RSCP rates shown in Table C times the seasonal kWh Rate Adjustment Factors that were developed in Table D.

Table F (Spreadsheet Error Checking) contains a comparison of the total anticipated rate revenue billed to customers based on the final BGS-RSCP rates developed in Table E and the anticipated total season payments to BGS suppliers, based on the data in Table A.

Attachment 5 contains the rate design and proposed BGS rates for the Residential Time of Use three period rate structure (“RS TOU-3P”)³. rate class.

Background: In the Company’s most recent Rate Case Order, the Board approved the implementation and rate design of the RS TOU 3P rate class. Further, in its Company Specific Addendum filed on July 1, 2025⁴, the Company proposed revisions to the 2025 BGS RS TOU 3P rates and proposed 2026 RS TOU 3P rate design effective June 1, 2026. In its November 21, 2025 Decision and Order in this matter, the Board approved the Company’s proposal. The Company began to make RS TOU-3P rates available in late 2025.

Customers that opt into the RS TOU-3P program during the first 24 months for which it is available will

³ The RS TOU-3P rate structure will replace the existing residential BGS EV credit program currently in effect since June of 2023. In compliance with a Board Order dated November 9, 2022 I/M/O the Provision of Basic Generation Service for the Period Beginning June 1, 2023 (Docket No. ER22030127), PSE&G filed a petition with the Board to implement a BGS EV credit program effective June 1, 2023 (Docket No. ER23030131). On May 24, 2023 the Board issued an Order in response to the Company’s Petition approving the Company’s proposed tariff modifications (subject to specific changes) and directed the Company to file a petition to recover the deferred costs (which may include a proposal to recovery the costs through the BGS Reconciliation Charge Filings. Thought this matter is still outstanding, PSE&G is not including a proposal to recover these costs in this proceeding.

⁴ I/M/O The Provision of Basic Generation Service (BGS) for the Period Beginning June 1, 2026. BPU Docket No. ER 25040190.

receive a report at the end of their initial 12-month period on the rate showing the difference between their 12-month bill-history on the RS TOU-3P rate versus what the bill-history would have been on the RS Rate Schedule. If the RS TOU-3P 12-month total bill is higher, the customer will be provided a one-time bill credit of the difference. For customers served on BGS, the supply portion of the refund will be recorded as a reduction to BGS revenue in the month it is credited to the customer and be recovered through the BGS-RSCP reconciliation charge.

Rate Design: The RS TOU-3P rates for service beginning June 1, 2027 continue to be designed to be revenue neutral to the RS rate class. The RS revenue proposed in this BGS Pricing Spreadsheet was allocated to capacity and energy components based upon the underlying cost components in this model. Capacity costs are designed to be collected during on-peak and mid-peak periods. Energy costs are designed to be collected over the three corresponding time periods. RPS and ancillary costs are designed to be collected over all time periods. In order to make RS TOU-3P easily comparable for customers considering the service compared to the RS rate, and to encourage movement to the class, the mid peak energy costs were adjusted slightly between summer and winter to have the total RS-TOU 3P mid-peak rates set to at least \$0.001/kWh lower than the corresponding total RS rates.

The RS TOU-3P rates have been derived utilizing the RS rate class load profile. In the future, once there is a significant number of customers receiving BGS under the RS TOU-3P rate, the actual load profile of the class will be used and corresponding rate design will be integrated into Attachment 2 and 3 of BGS Pricing Spreadsheet. The detailed rate design for the RS TOU-3P rate for service after June 1, 2027, can be found in Attachment 5.

B. ELECTRIC VEHICLE (“EV”) REPORTING AND TOU RATE PROGRAM

In paragraph 14 of the Company’s June 22, 2026 Letter Petition in accordance with the Board’s May 21, 2026 Board Order (“CEF-EV Extension Order”)⁵, PSE&G noted that it reports residential and DCFC charging data in its semi-annual program reports – and such reports include specific EV-related information in accordance with the Board’s November 9, 2022 BGS Decision and Order (“2023 BGS Auction Order”)⁶. Further, because DCFC sites typically use a separate meter, PSE&G can collect and report DCFC data utilizing its own data without incurring additional data collection costs. However, to report residential EV charging data the Company utilizes a paid service to collect data and incurs costs of more than \$2M annually. In an effort to save these third-party data collection costs for customers, PSE&G requested that it be permitted to eliminate the requirement to continue to collect and report residential EV charging data – noting that the Company will rely on the vast amount of data already collected for ongoing analysis of charging behavior, EV load growth, and any other relevant analysis.

The 2023 BGS Auction Order also required the Company to create a “residential supply side” TOU rate (i.e. off-peak credit) similar to the “residential EV charging” that was “addressed in some of the EDCs’ EV proceedings”. The Company subsequently implemented this rate (and utilized the above-referenced third-party data collection entity to enable the process), but due to the implementation of the Company’s approved RS TOU-3P rate, the Company is in the process of terminating this residential supply side program – and as a result will no longer require the use of the third party vendor for this EV rate option (i.e. further support for the request to eliminate the collection and reporting of EV data noted above).

⁵ I/M/O Straw Proposal of Electric Vehicle Infrastructure Build Out, BPU Docket No. QO20050357, Order on Extension of Programs, Dated May 21, 2026.

⁶ I/M/O the Provision of Basic Generation Service for the Period Beginning June 1, 2023. BPU Docket No. ER22030127.

IV. CONCLUSION

In connection with the approval of this filing, the Company requests that the Board determine:

1. It is necessary and in the public interest for the electric public utilities to secure service for the BGS-RSCP and BGS-CIEP customers, as approved herein, for the period June 1, 2027 to May 31, 2030.
2. The Company's proposed accounting for BGS is approved for purposes of accounting and BGS cost recovery.
3. The proposed BGS Contingency Plan is approved, and there will exist a presumption of prudence with respect to the BGS Auction Plan method and the costs incurred for BGS service under the Auction Plan and the related Contingency Plan.
4. The Company's Rate Design Methodology and Tariff Sheets, including the change to an annual BGS Reconciliation Charge methodology, are approved.
5. The Company's request to eliminate the collection and reporting of EV data.

V. ATTACHMENT 1 - TARIFF SHEETS

"Form Of" CIEP Standby Fee, BGS-RSCP and BGS-CIEP tariff sheets

(Pages 1 through 7)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

First Revised Sheet No. 73

B.P.U.N.J. No. 17 ELECTRIC

**Superseding
Original Sheet No. 73**

COMMERCIAL AND INDUSTRIAL ENERGY PRICING (CIEP) STANDBY FEE

APPLICABLE TO:

All kilowatt-hour usage under Rate Schedules LPL-Secondary (500 kilowatts or greater), LPL-Primary, HTS-Subtransmission, HTS-Transmission, HTS-High Voltage and all kilowatt-hour usage for customers under Rate Schedules HS, GLP and LPL-Secondary (less than 500 kilowatts) who have elected hourly energy pricing service from either BGS-CIEP or a Third Party Supplier.

**Charge
(per kilowatt-hour)**

Commercial and Industrial Energy Pricing (CIEP) Standby Fee\$ 0.000150

Charge including New Jersey Sales and Use Tax (SUT)\$ 0.000160

The above charges shall recover costs associated with the administration, maintenance and availability of the Basic Generation Service default electric supply service for applicable rate schedules. These charges shall be combined with the Distribution Kilowatt-hour Charges for billing.

Kilowatt threshold noted above is based upon the customer's Peak Load Share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM). See Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions of this Tariff.

Date of Issue: May 23, 2025

Effective: June 1, 2025

Issued by RICARDO G. FONSECA – VP Finance – PSEG Services Corp.

80 Park Plaza, Newark, New Jersey 07102

Filed pursuant to Order of Board of Public Utilities dated May 21, 2025
in Docket No. ER24030191

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

XXX Revised Sheet No. 75

B.P.U.N.J. No. 17 ELECTRIC

**Superseding
XXX Revised Sheet No. 75**

**BASIC GENERATION SERVICE – RESIDENTIAL SMALL COMMERCIAL PRICING (BGS-RSCP)
ELECTRIC SUPPLY CHARGES**

APPLICABLE TO:

Default electric supply service for Rate Schedules RS, RHS, RLM, WH, WHS, HS, BPL, BPL-POF, PSAL, GLP and LPL-Secondary (less than 500 kilowatts).

BGS ENERGY & CAPACITY CHARGES:

**Applicable to Rate Schedules RS, RHS, RLM, WH, WHS, HS, BPL, BPL-POF and PSAL
Charges per kilowatt-hour:**

Rate Schedule	For usage in each of the months of October through May		For usage in each of the months of June through September	
	Energy & Capacity Charges	Charges Including SUT	Energy & Capacity Charges	Charges Including SUT
RS – first 600 kWh	\$ x.xxxxxx	\$ x.xxxxxx	\$ x.xxxxxx	\$ x.xxxxxx
RS – in excess of 600 kWh	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
RS-TOU 3P On-Peak	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
RS-TOU 3P Mid-Peak	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
RS-TOU 3P Off-Peak	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
RHS – first 600 kWh	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
RHS – in excess of 600 kWh	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
RLM On-Peak	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
RLM Off-Peak	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
WH	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
WHS	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
HS	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
BPL	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
BPL-POF	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
PSAL	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx

The above Basic Generation Service Energy Charges reflect costs for Energy, Generation Capacity, and Ancillary Services (including PJM Interconnection, L.L.C. (PJM) Administrative Charges).

Kilowatt threshold noted above is based upon the customer's Peak Load Share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM). See Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions of this Tariff.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY

XXX Revised Sheet No. 76

B.P.U.N.J. No. 17 ELECTRIC

Superseding

XXX Revised Sheet No. 76

**BASIC GENERATION SERVICE – RESIDENTIAL SMALL COMMERCIAL PRICING (BGS-RSCP)
ELECTRIC SUPPLY CHARGES**

(Continued)

BGS TRANSMISSION CHARGES:

Applicable to Rate Schedules RS, RHS, RLM, WH, WHS, HS, BPL, BPL-POF and PSAL

Charges per kilowatt-hour:

Rate Schedule	For usage in each of the months of <u>October through May</u>		For usage in each of the months of <u>June through September</u>	
	Transmission Charges	Charges Including SUT	Transmission Charges	Charges Including SUT
RS	\$ x.xxxxxx	\$ x.xxxxxx	\$ x.xxxxxx	\$ x.xxxxxx
RS-TOU 3P On-Peak	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
RS-TOU 3P Mid-Peak	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
RS-TOU 3P Off-Peak	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
RHS	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
RLM On-Peak	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
RLM Off-Peak	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
WH	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
WHS	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
HS	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
BPL	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
BPL-POF	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
PSAL	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx

The above charges shall recover all costs related to the overall summer peak transmission load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned transmission capacity related factors and allocated to the above Rate Schedules. These charges will be changed from time to time on the effective date of such change to the PJM rate for charges for Network Integration Transmission Service, including the PJM Seams Elimination Cost Assignment Charges, the PJM Reliability Must Run Charge and PJM Transmission Enhancement Charges as approved by Federal Energy Regulatory Commission (FERC).

BGS ENERGY CHARGES:

Applicable to Rate Schedules GLP and LPL-Sec.

Charges per kilowatt-hour:

Rate <u>Schedule</u>	For usage in each of the months of <u>October through May</u>		For usage in each of the months of <u>June through September</u>	
	<u>Charges</u>	<u>Charges Including SUT</u>	<u>Charges</u>	<u>Charges Including SUT</u>
GLP	\$x.xxxxxx	\$x.xxxxxx	\$x.xxxxxx	\$x.xxxxxx
GLP Night Use	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
LPL-Sec. under 500 kW				
On-Peak	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
Off-Peak	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx

The above Basic Generation Service Energy Charges reflect costs for Energy and Ancillary Services (including PJM Administrative Charges).

Kilowatt thresholds noted above are based upon the customer's Peak Load Share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM). See Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions of this Tariff.

Date of Issue:

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY

XXX Revised Sheet No. 79

B.P.U.N.J. No. 17 ELECTRIC

Superseding

XXX Revised Sheet No. 79

BASIC GENERATION SERVICE – RESIDENTIAL SMALL COMMERCIAL PRICING (BGS-RSCP)

ELECTRIC SUPPLY CHARGES

(Continued)

BGS CAPACITY CHARGES:

Applicable to Rate Schedules GLP and LPL-Sec.

Charges per kilowatt of Generation Obligation:

Charge applicable in the months of June through September.....	\$x.xxxx
Charge including New Jersey Sales and Use Tax (SUT)	<u>\$x.xxxx</u>
Charge applicable in the months of October through May	\$xx.xxxx
Charge including New Jersey Sales and Use Tax (SUT)	<u>\$xx.xxxx</u>

The above charges shall recover each customer's share of the overall summer peak load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions.

BGS TRANSMISSION CHARGES

Applicable to Rate Schedules GLP and LPL-Sec.

Charges per kilowatt of Transmission Obligation:

Currently effective Annual Transmission Rate for

Network Integration Transmission Service for the Public
Service Transmission Zone as derived from the
FERC Electric Tariff of the PJM Interconnection, LLC

EL05-121	\$ xxx,xxx.xx per MW per year
FERC 680 & 715 Reallocation.....	\$ xx.xx per MW per month
PJM Seams Elimination Cost Assignment Charges	\$ x.xx per MW per month
PJM Reliability Must Run Charge	\$ x.xx per MW per month
PJM Transmission Enhancements	
Trans-Allegheny Interstate Line Company	\$ xx.xx per MW per month
Virginia Electric and Power Company	\$ xx.xx per MW per month
Midcontinent Independent System Operator	\$ x.xx per MW per month
PPL Electric Utilities Corporation.....	\$ xxx.xx per MW per month
American Electric Power Service Corporation.....	\$ xx.xx per MW per month
Atlantic City Electric Company	\$ x.xx per MW per month
Delmarva Power and Light Company.....	\$ x.xx per MW per month
Potomac Electric Power Company	\$ x.xx per MW per month
Baltimore Gas and Electric Company.....	\$ x.xx per MW per month
Jersey Central Power and Light	\$ xx.xx per MW per month
Mid Atlantic Interstate Transmission.....	\$ xx.xx per MW per month
PECO Energy Company.....	\$ xx.xx per MW per month
Silver Run Electric, Inc	\$ xx.xx per MW per month
Northern Indiana Public Service Company.....	\$ x.xx per MW per month
Commonwealth Edison Company	\$ x.xx per MW per month
South First Energy Operating Company.....	\$ x.xx per MW per month
Duquesne Light Company	\$ x.xx per MW per month
Transource Pennsylvania LLC	\$ x.xx per MW per month
NextEra Energy	\$ x.xx per MW per month

Above rates converted to a charge per kW of Transmission

Obligation, applicable in all months	\$ xx.xxxx
Charge including New Jersey Sales and Use Tax (SUT)	<u>\$ xx.xxxx</u>

The above charges shall recover each customer's share of the overall summer peak transmission load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned transmission capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. These charges will be changed from time to time on the effective date of such change to the PJM rate for charges for Network Integration Transmission Service, including the PJM Seams Elimination Cost Assignment Charges, the PJM Reliability Must Run Charge and PJM Transmission Enhancement Charges as approved by Federal Energy Regulatory Commission (FERC).

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY

XXX Revised Sheet No. 80

B.P.U.N.J. No. 17 ELECTRIC

**Superseding
XXX Revised Sheet No. 80**

**BASIC GENERATION SERVICE – RESIDENTIAL SMALL COMMERCIAL PRICING (BGS-RSCP)
ELECTRIC SUPPLY CHARGES
(Continued)**

**DCFC RSCP RATE PROGRAM – CAPACITY AND TRANSMISSION CHARGE
Applicable to Rate Schedules GLP and LPL-Sec.
Charges per kilowatt-hour:**

<u>Charge</u>	<u>Charge</u>
\$x.xxxxxx	<u>Including SUT</u> \$x.xxxxxx

The above charge is for customers who operate DCFC Stations to serve electric vehicles only and who elect to be included in the DCFC BGS Rate Program. BGS energy charges still apply.

The above charges shall recover each customer's share of the overall summer peak transmission load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned transmission capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. These charges will be changed from time to time on the effective date of such change to the PJM rate for charges for Network Integration Transmission Service, including the PJM Seams Elimination Cost Assignment Charges, the PJM Reliability Must Run Charge and PJM Transmission Enhancement Charges as approved by Federal Energy Regulatory Commission (FERC).

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY

XXX Revised Sheet No. 82

Superseding

B.P.U.N.J. No. 17 ELECTRIC

XXX Revised Sheet No. 82

**BASIC GENERATION SERVICE – COMMERCIAL AND INDUSTRIAL ENERGY PRICING (CIEP)
ELECTRIC SUPPLY CHARGES**

APPLICABLE TO:

Default electric supply service for Rate Schedules LPL-Secondary (500 kilowatts or greater), LPL-Primary, HTS-Subtransmission, HTS-Transmission, HTS-High Voltage and to customers served under Rate Schedules HS, GLP and LPL-Secondary (less than 500 kilowatts) who have elected BGS-CIEP as their default supply service.

BGS ENERGY CHARGES:

Charges per kilowatt-hour:

BGS Energy Charges are hourly and include PJM Locational Marginal Prices, and PJM Ancillary Services. The total BGS Energy Charges are based on the sum of the following:

- The real time PJM Load Weighted Average Residual Metered Load Aggregate Locational Marginal Prices for the Public Service Transmission Zone, adjusted for losses (tariff losses, as defined in Standard Terms and Conditions Section 4.3, adjusted to remove the mean hourly PJM marginal losses of 0.92504%), and adjusted for SUT, plus
- Ancillary Services (including PJM Administrative Charges) at the rate of \$0.006000 per kilowatt-hour, adjusted for losses (tariff losses, as defined in Standard Terms and Conditions Section 4.3, adjusted to remove the mean hourly PJM marginal losses of 0.92504%), and adjusted for SUT, plus

BGS CAPACITY CHARGES:

Charges per kilowatt of Generation Obligation:

Charge applicable in the months of June through September	\$ xx.xxxx
Charge including New Jersey Sales and Use Tax (SUT)	<u>\$ xx.xxxx</u>
Charges applicable in the months of October through May	\$ xx.xxxx
Charges including New Jersey Sales and Use Tax (SUT).....	<u>\$ xx.xxxx</u>

The above charges shall recover each customer's share of the overall summer peak load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions.

Date of Issue:

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY

XXX Revised Sheet No. 83

Superseding

B.P.U.N.J. No. 17 ELECTRIC

XXX Revised Sheet No. 83

BASIC GENERATION SERVICE – COMMERCIAL AND INDUSTRIAL ENERGY PRICING (CIEP)

ELECTRIC SUPPLY CHARGES

(Continued)

BGS TRANSMISSION CHARGES

Charges per kilowatt of Transmission Obligation:

Currently effective Annual Transmission Rate for

Network Integration Transmission Service for the
Public Service Transmission Zone as derived from the
FERC Electric Tariff of the PJM Interconnection, LLC

\$ xxx,xxx.xx per MW per year

EL05-121

\$ xx.xx per MW per month

FERC 680 & 715 Reallocation.....

\$ x.xx per MW per month

PJM Seams Elimination Cost Assignment Charges.....

\$ x.xx per MW per month

PJM Reliability Must Run Charge.....

\$ x.xx per MW per month

PJM Transmission Enhancements

Trans-Allegheny Interstate Line Company

\$ xx.xx per MW per month

Virginia Electric and Power Company

\$ xx.xx per MW per month

Midcontinent Independent System Operator

\$ x.xx per MW per month

PPL Electric Utilities Corporation.....

\$ xxx.xx per MW per month

American Electric Power Service Corporation.....

\$ xx.xx per MW per month

Atlantic City Electric Company.....

\$ x.xx per MW per month

Delmarva Power and Light Company.....

\$ x.xx per MW per month

Potomac Electric Power Company

\$ x.xx per MW per month

Baltimore Gas and Electric Company.....

\$ x.xx per MW per month

Jersey Central Power and Light.....

\$ xx.xx per MW per month

Mid Atlantic Interstate Transmission.....

\$ xx.xx per MW per month

PECO Energy Company.....

\$ xx.xx per MW per month

Silver Run Electric, Inc.....

\$ xx.xx per MW per month

Northern Indiana Public Service Company.....

\$ x.xx per MW per month

Commonwealth Edison Company

\$ x.xx per MW per month

South First Energy Operating Company.....

\$ x.xx per MW per month

Duquesne Light Company

\$ x.xx per MW per month

Transource Pennsylvania LLC.....

\$ x.xx per MW per month

NextEra Energy

\$ x.xx per MW per month

Above rates converted to a charge per kW of Transmission

Obligation, applicable in all months

\$ xx.xxxx

Charge including New Jersey Sales and Use Tax (SUT)

\$ xx.xxxx

DCFC CIEP RATE PROGRAM – CAPACITY AND TRANSMISSION CHARGE

Charges per kilowatt-hour:

	Charge
<u>Charge</u>	<u>Including SUT</u>
\$x.xxxxxx	\$x.xxxxxx

The above charge is for customers who operate DCFC Stations to serve electric vehicles only and who elect to be included in the DCFC BGS Rate Program. BGS energy charges still apply.

The above charges shall recover each customer's share of the overall summer peak transmission load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned transmission capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. These charges will be changed from time to time on the effective date of such charge to the PJM rate for charges for Network Integration Transmission Service, including the PJM Seams Elimination Cost Assignment Charges, the PJM Reliability Must Run Charge and PJM Transmission Enhancement Charges as approved by Federal Energy Regulatory Commission (FERC).

Kilowatt threshold noted above is based upon the customer's Peak Load Share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM). See Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions of this Tariff.

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80 Park Plaza, Newark, New Jersey 07102
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VI. ATTACHMENT 2 - SPREADSHEETS FOR THE DEVELOPMENT OF BGS COST BID FACTORS

(Pages 1 through 7)

**Public Service Electric and Gas Company Specific Addendum
Attachment 2**

**Development of BGS-RSCP Cost and Bid Factors for 2027/2028 BGS Filing
Adjusted to Billing Time Periods**

Table #1 % Usage During PJM On-Peak Period

*Based on average of year 2023, 2024 & 2025 Load Profile Information
On-Peak periods defined as the 16 hr PJM Trading period, adj for NERC holidays*

	<i>Profile Meter</i>	<i>Profile Meter</i>	<i>Profile Meter</i>	<i>Profile Meter</i>	<i>Profile Meter</i>	<i>Profile Meter</i>	<i>--- Other Analysis ---</i>		<i>Profile Meter</i>	<i>Profile Meter</i>
	<i>Data</i> RS	<i>Data</i> RHS	<i>Data</i> RLM	<i>Data</i> WH	<i>Data</i> WHS	<i>Data</i> HS	PSAL	BPL	<i>Data</i> GLP	<i>Data</i> LPL-S
<i>(data rounded to nearest .01%)</i>										
January	48.14%	47.36%	47.73%	48.14%	48.14%	47.39%	30.63%	30.63%	52.14%	50.32%
February	49.01%	47.60%	47.93%	49.01%	49.01%	47.69%	29.45%	29.45%	53.43%	51.49%
March	49.82%	48.93%	47.76%	49.82%	49.82%	49.07%	25.51%	25.51%	54.43%	52.40%
April	48.46%	48.14%	46.67%	48.46%	48.46%	49.56%	22.35%	22.35%	52.82%	50.76%
May	48.64%	49.90%	48.21%	48.64%	48.64%	53.01%	20.89%	20.89%	53.67%	51.18%
June	53.22%	53.82%	53.07%	53.22%	53.22%	57.97%	20.13%	20.13%	56.78%	53.68%
July	50.26%	50.56%	50.09%	50.26%	50.26%	54.35%	19.02%	19.02%	52.76%	49.60%
August	52.77%	53.69%	52.91%	52.77%	52.77%	58.13%	21.49%	21.49%	56.54%	53.11%
September	48.95%	50.37%	48.93%	48.95%	48.95%	54.54%	23.33%	23.33%	53.63%	50.79%
October	50.03%	50.46%	49.05%	50.03%	50.03%	53.58%	27.21%	27.21%	54.98%	52.46%
November	47.66%	47.07%	47.00%	47.66%	47.66%	47.72%	30.56%	30.56%	52.28%	50.26%
December	46.41%	45.99%	46.12%	46.41%	46.41%	45.78%	30.54%	30.54%	50.56%	48.72%

Table #2 % Usage During PSE&G On-Peak Billing Period

*Based on average of year 2023, 2024 & 2025 Load Profile Information
On-Peak periods as defined in specified rate schedule (average of %s for 2023, 2024 & 2025)*

	<i>N/A</i>	<i>N/A</i>	<i>Profile Meter</i>	<i>N/A</i>	<i>N/A</i>	<i>N/A</i>	<i>N/A</i>	<i>N/A</i>	<i>N/A</i>	<i>Profile Meter</i>
	RS	RHS	<i>Data</i> RLM	WH	WHS	HS	PSAL	BPL	GLP	<i>Data</i> LPL-S
<i>(data rounded to nearest .01%)</i>										
January	0%	0%	42%	0%	0%	0%	0%	0%	0%	46%
February	0%	0%	41%	0%	0%	0%	0%	0%	0%	46%
March	0%	0%	41%	0%	0%	0%	0%	0%	0%	46%
April	0%	0%	42%	0%	0%	0%	0%	0%	0%	47%
May	0%	0%	44%	0%	0%	0%	0%	0%	0%	48%
June	0%	0%	47%	0%	0%	0%	0%	0%	0%	49%
July	0%	0%	48%	0%	0%	0%	0%	0%	0%	49%
August	0%	0%	49%	0%	0%	0%	0%	0%	0%	48%
September	0%	0%	47%	0%	0%	0%	0%	0%	0%	48%
October	0%	0%	45%	0%	0%	0%	0%	0%	0%	49%
November	0%	0%	42%	0%	0%	0%	0%	0%	0%	48%
December	0%	0%	41%	0%	0%	0%	0%	0%	0%	47%

**Public Service Electric and Gas Company Specific Addendum
Attachment 2**

Table #3 Class Usage @ customer
Calendar month sales forecasted for 2026, less % for LPL-Sec > 500 kW Peak Load Share in MWh

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	< 500 kW LPL-S
January	1,259,579	11,242	14,007	22	1	1,185	16,031	33,689	435,441	259,563
February	1,010,668	8,514	11,481	18	1	1,074	11,344	27,773	395,009	230,493
March	987,350	7,040	11,124	19	1	881	11,979	31,037	422,269	251,859
April	807,598	3,688	9,562	19	1	495	9,867	23,847	360,498	212,892
May	910,245	2,821	11,748	17	1	363	9,146	22,335	378,551	245,733
June	1,271,301	3,359	17,042	16	1	416	8,319	19,512	419,122	252,445
July	1,650,928	4,435	20,696	13	0	388	8,472	18,630	475,985	283,630
August	1,568,771	4,092	18,883	13	0	459	9,673	19,365	480,205	292,747
September	1,085,346	2,862	14,248	17	0	478	10,729	22,518	416,016	249,043
October	854,467	3,988	9,680	17	0	360	11,841	24,926	373,645	240,351
November	895,632	6,283	9,515	20	1	512	12,952	25,965	359,459	227,684
December	1,154,678	8,864	12,127	20	1	900	14,352	31,117	426,137	250,153
Total	13,456,564	67,188	160,112	211	8	7,512	134,705	300,714	4,942,336	2,996,592

Table #4 Forwards Prices - Energy Only @ bulk system
in \$/MWh, not including PJM losses

	On-Peak	Off/On Pk LMP ratio	Resulting Off-Peak
January	101.42	0.8003	81.163
February	92.20	0.8003	73.787
March	60.13	0.8003	48.124
April	59.68	0.8003	47.764
May	61.00	0.8003	48.818
June	67.20	0.5490	36.892
July	99.15	0.5490	54.432
August	84.77	0.5490	46.536
September	67.43	0.5490	37.020
October	64.58	0.8003	51.686
November	66.85	0.8003	53.500
December	78.55	0.8003	62.863

Table #5 Zone to Western Hub Basis Differential

	On-Peak	Off-Peak
January	83%	86% ICE Forwards - 6/1/2026 from NERA
February	83%	86%
March	83%	86% Congestion Factors & On/Off Peak Ratios
April	83%	86% Summer Avg's from June 2023 through Sep 2025
May	83%	86% Winter Avg's from Mar 2023 through Feb 2026
June	77%	82%
July	77%	82%
August	77%	82%
September	77%	82%
October	83%	86%
November	83%	86%
December	83%	86%

Table #6 Losses

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	LPL-S
<i>from meter to bulk system (includes Delivery & PJM EHV losses)</i>										
Loss Factors =	6.2621%	6.2621%	6.2621%	6.2621%	6.2621%	6.2621%	6.2621%	6.2621%	6.2621%	6.2621%
Expansion Factor =	1.066804	1.066804	1.066804	1.066804	1.066804	1.066804	1.066804	1.066804	1.066804	1.066804
1 / Expansion Factor =	0.937379	0.937379	0.937379	0.937379	0.937379	0.937379	0.937379	0.937379	0.937379	0.937379
<i>from meter to transmission node (includes Delivery less mean hourly PJM marginal losses)</i>										
Loss Factors =	4.9322%	4.9322%	4.9322%	4.9322%	4.9322%	4.9322%	4.9322%	4.9322%	4.9322%	4.9322%
Expansion Factor =	1.051881	1.051881	1.051881	1.051881	1.051881	1.051881	1.051881	1.051881	1.051881	1.051881
1 / Expansion Factor =	0.950678	0.950678	0.950678	0.950678	0.950678	0.950678	0.950678	0.950678	0.950678	0.950678

Loss Type	Percentage	Source
Delivery Losses	5.8327%	Tariff (Result of 2018 Loss Study)
EHV Losses	0.4560%	PJM
Marginal Loss Deration Factor	1.3989%	NERA
Marginal Loss Factor	0.94719%	

**Public Service Electric and Gas Company Specific Addendum
Attachment 2**

Table #7 **Summary of Average BGS Energy Only Unit Costs @ customer - PJM Time Periods**
based on Forwards prices corrected for congestion & all losses - PJM time periods
in \$/MWh

		RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	LPL-S
Summer - all hrs	\$	53.47	\$ 53.72	\$ 53.20	\$ 51.17	\$ 44.44	\$ 53.05	\$ 43.66	\$ 43.55	\$ 53.63	\$ 52.76
	PJM on pk	\$ 66.90	\$ 66.91	\$ 66.58	\$ 64.10	\$ 55.11	\$ 64.73	\$ 64.35	\$ 64.22	\$ 65.82	\$ 65.78
	PJM off pk	\$ 39.27	\$ 39.35	\$ 39.09	\$ 37.58	\$ 32.29	\$ 38.03	\$ 38.10	\$ 38.03	\$ 38.78	\$ 38.77
Winter - all hrs	\$	60.44	\$ 63.27	\$ 60.07	\$ 59.56	\$ 59.96	\$ 63.24	\$ 58.01	\$ 57.66	\$ 60.05	\$ 59.56
	PJM on pk	\$ 66.52	\$ 69.65	\$ 66.30	\$ 65.55	\$ 66.04	\$ 69.37	\$ 67.77	\$ 67.44	\$ 65.44	\$ 65.21
	PJM off pk	\$ 54.73	\$ 57.43	\$ 54.42	\$ 53.93	\$ 54.28	\$ 57.48	\$ 54.28	\$ 53.95	\$ 53.96	\$ 53.69
Annual	\$	57.55	\$ 61.17	\$ 57.03	\$ 57.22	\$ 58.02	\$ 60.88	\$ 54.05	\$ 53.91	\$ 57.72	\$ 57.11
System Total	\$	57.47									

Table #8 **Summary of Average BGS Energy Only Costs @ customer - PJM Time Periods**
based on Forwards prices corrected for congestion & all losses
in \$1000

		RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	LPL-S
Summer - all hrs	\$	298,169	\$ 792	\$ 3,770	\$ 3	\$ 0	\$ 92	\$ 1,624	\$ 3,485	\$ 96,068	\$ 56,864
	PJM on pk	\$ 191,699	\$ 514	\$ 2,422	\$ 2	\$ 0	\$ 63	\$ 506	\$ 1,084	\$ 64,752	\$ 36,713
	PJM off pk	\$ 106,470	\$ 278	\$ 1,348	\$ 1	\$ 0	\$ 29	\$ 1,117	\$ 2,401	\$ 31,316	\$ 20,151
Winter - all hrs	\$	476,295	\$ 3,318	\$ 5,361	\$ 9	\$ 0	\$ 365	\$ 5,657	\$ 12,725	\$ 189,204	\$ 114,271
	PJM on pk	\$ 253,973	\$ 1,745	\$ 2,814	\$ 5	\$ 0	\$ 194	\$ 1,829	\$ 4,089	\$ 109,314	\$ 63,738
	PJM off pk	\$ 222,322	\$ 1,573	\$ 2,547	\$ 4	\$ 0	\$ 171	\$ 3,828	\$ 8,635	\$ 79,890	\$ 50,533
Annual	\$	774,464	\$ 4,110	\$ 9,131	\$ 12	\$ 0	\$ 457	\$ 7,281	\$ 16,210	\$ 285,273	\$ 171,135
System Total	\$	1,268,073									

Table #9 **Summary of Average BGS Energy Only Unit Costs @ customer - PSE&G Time Periods**
based on Forwards prices corrected for congestion & all losses - PSE&G billing time periods
in \$/MWh

		RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	LPL-S
Summer - all hrs	\$	53.47	\$ 53.72	\$ 53.20	\$ 51.17	\$ 44.44	\$ 53.05	\$ 43.66	\$ 43.55	\$ 53.63	\$ 52.76
	PSE&G On pk			\$ 67.57						\$	\$ 66.67
	PSE&G Off pk			\$ 40.00						\$	\$ 39.62
Winter - all hrs	\$	60.44	\$ 63.27	\$ 60.07	\$ 59.56	\$ 59.96	\$ 63.24	\$ 58.01	\$ 57.66	\$ 60.05	\$ 59.56
	PSE&G On pk			\$ 67.07						\$	\$ 65.67
	PSE&G Off pk			\$ 54.97						\$	\$ 54.10
Annual Average	\$	57.55	\$ 61.17	\$ 57.03	\$ 57.22	\$ 58.02	\$ 60.88	\$ 54.05	\$ 53.91	\$ 57.72	\$ 57.11
System Average	\$	57.47									

**Public Service Electric and Gas Company Specific Addendum
Attachment 2**

Table #10 Generation & Transmission Obligations and Costs and Other Adjustments
Obligations - Peak Load shares eff 6/1/26, scaling factors eff 6/8/2026, Transmission Loads eff 6/8/26; costs are market estimates in MW

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	Adj for PLS > 500 kW LPL-S
Gen Obl - MW	4,133.0	10.7	57.2	0.0	0.0	1.1	0.0	0.0	1,130.3	551.8
	4209	11	58.5	0	0	1.3	0	0	1333.4	890.6
Trans Obl - MW	5,112.9	13.1	68.7	0.0	0.0	1.2	0.0	0.0	1,202.3	611.2
# of Months and Days used in this analysis										
		# of summer days =	122		# of summer months =	4				
		# of winter days =	244		# of winter months =	8				
					total # months =	12				
Transmission Cost	year round =	\$0.00 per MW-yr								
Generation Capacity cost		Base Capacity	Capacity Proxy True Up	Total Capacity						
	summer =	\$ 333.69	\$ -	\$ 333.69 \$/MW/day						
	winter =	\$ 333.69	\$ -	\$ 333.69 \$/MW/day						
<u>% usage in Summer Blocks</u>										
		RS	RHS							
	Block 1 (0-600 kWh/m)	64.3%	67.8%							
	Block 2 (>600 kWh/m)	35.7%	32.2%							
	Required summer inversion =	0.8652	1.1569 ¢/kWh	(same as 2003/2004 BGS blocking inversion)						

Table #11 Ancillary Services & Renewable Power Cost

Ancillary Services	\$ 2.00
Renewable Power Cost	\$16.04
Total Ancillary Services & Renewable Power Costs	\$ 18.04 per MWh @ bulk system

Table #12 Summary of Obligation Costs Expressed as \$/MWh @ customer (for non-demand rates only)

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Transmission Obl - all months	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Generation Obl -								
per annual MWh	\$ 37.51	\$ 19.45	\$ 97.68	\$ -	\$ -	\$ 17.88	\$ -	\$ -
recovery per summer MWh	\$ 30.17	\$ 29.54	\$ 68.65	\$ -	\$ -	\$ 25.71	\$ -	\$ -
recovery per winter MWh	\$ 42.70	\$ 16.61	\$ 123.87	\$ -	\$ -	\$ 15.52	\$ -	\$ -
			For RLM, per on-peak kWh only					

**Public Service Electric and Gas Company Specific Addendum
Attachment 2**

Table #13 Summary of BGS Unit Costs @ customer

NON-DEMAND RATES

includes energy, Generation obligations, Ancillary Services and Renewable Power Costs- adjusted to billing time periods in \$/MWh

		RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Summer - all hrs	\$	110.23	\$ 92.42		\$ 70.42	\$ 63.69	\$ 90.18	\$ 62.90	\$ 62.80
	PSE&G On pk			\$ 184.50					
	PSE&G Off pk			\$ 59.25					
	Block 1 (0-600 kWh/m)	\$ 107.14	\$ 88.69						
	Block 2 (>600 kWh/m)	\$ 115.79	\$ 100.26						
Winter - all hrs	\$	117.20	\$ 101.97		\$ 78.81	\$ 79.21	\$ 100.37	\$ 77.26	\$ 76.91
	PSE&G On pk			\$ 184.00					
	PSE&G Off pk			\$ 74.22					
Annual -all hrs	\$	114.31	\$ 99.87	\$ 119.91	\$ 76.46	\$ 77.27	\$ 98.01	\$ 73.30	\$ 73.15

DEMAND RATES

includes energy and Ancillary Services, G&T obligations charged separately - adjusted to billing time periods in \$/MWh

		GLP	LPL-S	PLUS:	GLP	LPL-S
Summer - all hrs	\$	72.88	\$ 72.00	<u>Gen Cost</u>		
	PSE&G On pk		\$ 85.92	summer	\$ 10.1775	\$ 10.1775 per kW of G obl /month
	PSE&G Off pk		\$ 58.87	winter	\$ 10.1775	\$ 10.1775 per kW of G obl /month
				annual	\$ 10.1775	\$ 10.1775 per kW of G obl /month
Winter - all hrs	\$	79.29	\$ 78.80	<u>Trans cost</u>		
	PSE&G On pk		\$ 84.92	all months	\$ -	\$ - per kW of T obl /month
	PSE&G Off pk		\$ 73.35			
Annual - all hrs per MWh only	\$	76.97	\$ 76.36			

Including Generation Obligation \$

Summer - all hrs	\$	98.57	\$ 92.85	Note: Obligation \$ included in On pk costs
	PSE&G On pk		\$ 128.83	
	PSE&G Off pk		\$ 58.87	
Winter - all hrs	\$	108.50	\$ 102.22	
	PSE&G On pk		\$ 134.57	
	PSE&G Off pk		\$ 73.35	
Annual - including Gen Obl \$	\$	104.90	\$ 98.85	

ALL RATES

Grand Total Cost in \$1000 = \$ 2,411,442
 All-In Average cost @ customer = \$ 109.28 per MWh at customer (per customer metered MWh)
 All-In Average costs @ transmission nodes = \$ 103.89 per MWh at transmission nodes (per metered MWh at transmission node)

**Public Service Electric and Gas Company Specific Addendum
Attachment 2**

Table #14 Ratio of BGS Unit Costs @ customer to All-In Average Cost @ transmission nodes - rounded to 3 decimal places, unit obligation \$ rounded to 4 decimal places

NON-DEMAND RATES

includes energy, Generation obligations, Ancillary Services and Renewable Power Costs- adjusted to billing time periods

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Summer - all hrs				0.678	0.613	0.868	0.605	0.604
PSE&G On pk			1.776				Use weighted average	
PSE&G Off pk			0.570				for all streetlighting =	
								0.604
All usage Multiplier	1.061	0.890						
Constant (in \$/MWh) \$	(3.089) \$	(3.725) \$	for Block 1 (0-600 kWh/m) usage					
Constant (in \$/MWh) \$	5.563 \$	7.844 \$	for Block 2 (>600 kWh/m) usage					
Winter - all hrs	1.128	0.981		0.759	0.762	0.966	0.744	0.740
PSE&G On pk			1.771				Use weighted average	
PSE&G Off pk			0.714				for all streetlighting =	
								0.741
Annual - all hrs	1.100	0.961	1.154	0.736	0.744	0.943	0.706	0.704

DEMAND RATES

includes energy and Ancillary Services, G&T obligations charged separately - adjusted to billing time periods

	GLP Multiplier	GLP Constant (in \$/MWh)	LPL-S Multiplier	LPL-S Constant (in \$/MWh)	PLUS:
Summer - all hrs	0.949	(25.687)			<u>Gen Cost</u>
PSE&G On pk			1.240	(42.911)	summer \$ 10.1775 \$ 10.1775 per kW of G obl /month
PSE&G Off pk			0.567	-	winter \$ 10.1775 \$ 10.1775 per kW of G obl /month
					annual \$ 10.1775 \$ 10.1775 per kW of G obl /month
Winter - all hrs	1.044	(29.206)			<u>Trans cost</u>
PSE&G On pk			1.295	(49.651)	all months \$ - \$ - per kW of T obl /month
PSE&G Off pk			0.706	-	
Annual - including Gen Obl \$	1.010		0.951		

Assumptions:

Gen Cost = \$ 333.69 /MW day summer
 \$ 333.69 /MW day winter

Trans cost = \$ - per MW-yr

Analysis time period = 4 summer months
 8 winter months

Ancillary Services & RPS = \$ 18.04 per MWh

Energy Costs = based on Forwards @ PJM West - corrected for congestion

Usage patterns = forecasted 2026 energy use by class, PJM and PSE&G on/off % from 2023, 2024 & 2025 class load profiles

Obligations = class totals in effect as of filing date

Losses = Delivery losses from tariff, PJM losses based on 3 year average %

PJM Time Periods = PJM trading time periods - 7 AM to 11 PM weekdays, local time, x NERC
 holidays - New Year's, Memorial, 4th of July, Labor Day, Thanksgiving & Christmas

PSE&G Billing time periods = as per specific rate schedule

NJ SUT (Sales & Use Tax) = SUT excluded from all rates

**Public Service Electric and Gas Company Specific Addendum
Attachment 2**

Table #15 Summary of Total BGS Costs by Season

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	LPL-S
Total Costs by Rate - in \$1000										
Summer	\$ 614,679	\$ 1,363	\$ 8,447	\$ 4	\$ 0	\$ 157	\$ 2,340	\$ 5,026	\$ 176,564	\$ 100,075
Winter	\$ 923,571	\$ 5,347	\$ 10,751	\$ 12	\$ 1	\$ 579	\$ 7,534	\$ 16,973	\$ 341,886	\$ 196,132
Total	\$ 1,538,250	\$ 6,710	\$ 19,199	\$ 16	\$ 1	\$ 736	\$ 9,874	\$ 21,998	\$ 518,450	\$ 296,207
% of Annual Total \$ by Rate										
Summer	40%	20%	44%	26%	10%	21%	24%	23%	34%	34%
Winter	60%	80%	56%	74%	90%	79%	76%	77%	66%	66%
Total Costs - in \$1000										
Summer	\$ 908,655									
Winter	\$ 1,502,787									
Total	\$ 2,411,442									
If total \$ were split on a per MWh basis (on transmission node MWhs):										
Summer	38%		\$ 99.86	per MWh @ trans nodes			Ratio to All-In Cost >>>		Summer	1.0000
Winter	62%		\$ 106.49	per MWh @ trans nodes					Winter	1.0000

rounded to 4 decimal places

Table #16 Spreadsheet Error Checking - Reconciliation of Customer Revenue and Supplier Payments, based on above data only

Assumed Winning Bid Price = \$ 103.89 *(bid includes payments for all losses)*
 Payment Ratio - Summer = 1.0000
 Payment Ratio - Winter = 1.0000

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	LPL-S
Total Rate Revenue - in \$1000										
Summer	\$ 614,684	\$ 1,364	\$ 8,447	\$ 4	\$ 0	\$ 157	\$ 2,334	\$ 5,022	\$ 176,616	\$ 100,097
Winter	\$ 923,496	\$ 5,345	\$ 10,749	\$ 12	\$ 1	\$ 579	\$ 7,507	\$ 16,990	\$ 341,774	\$ 196,108
Total	\$ 1,538,180	\$ 6,708	\$ 19,196	\$ 16	\$ 1	\$ 736	\$ 9,841	\$ 22,011	\$ 518,390	\$ 296,205
Total Summer	\$ 908,725									
Total Winter	\$ 1,502,560									
Grand Total	\$ 2,411,285									
Total Supplier Payment - in \$1000										
Summer	\$ 609,402	\$ 1,612	\$ 7,745	\$ 6	\$ 0	\$ 190	\$ 4,065	\$ 8,745	\$ 195,762	\$ 117,793
Winter	\$ 861,177	\$ 5,731	\$ 9,753	\$ 17	\$ 1	\$ 631	\$ 10,656	\$ 24,118	\$ 344,353	\$ 209,685
Total	\$ 1,470,580	\$ 7,343	\$ 17,498	\$ 23	\$ 1	\$ 821	\$ 14,721	\$ 32,863	\$ 540,115	\$ 327,478
Total Summer	\$ 945,321									
Total Winter	\$ 1,466,121									
Grand Total	\$ 2,411,442									

Difference (in \$1000) = \$ (157)

Note: Minor differences in totals are due to rounding of Bid Factors and Payment Factors

**Table #17 Total Supplier Energy @ transmission nodes
in MWh**

Summer	9,098,957
Winter	<u>14,111,789</u>
Total	23,210,746

VII. ATTACHMENT 3 - SPREADSHEETS FOR THE CALCULATION OF BGS RATES

(Pages 1 through 6)

Calculation of June 2027 to May 2028 BGS-RSCP Rates

Illustrative Purposes Only

NJ Sales & Use Tax (SUT) excluded

Table A Auction Results

line #	Specific BGS-RSCP Auction >>	remaining portion of 36 month bid - 2025 auction	remaining portion of 36 month bid - 2026 auction	2027 Auction Winning Bid	Notes:
1	Winning Bid - in \$/MWh	\$ 107.36	\$ 109.38	\$ 109.38	Winning Bids
1A	Capacity Proxy Price True-Up - in \$/MWh	\$5.88			entered after 2027 Auction
1B					
1C	Total - in \$/MWh	\$ 113.24	\$ 109.38	\$ 109.38	= line 1 + line 1A - line 1B
<i>(includes all payments, including impact of PJM marginal losses)</i>					
2	# of Tranches for Bid	28	28	29	from current Attach2 - BidFactors
3	Total # of Tranches	85	85	85	from current Attach2 - BidFactors
Payment Factors					
4	Summer	1.0000	1.0000	1.0000	
5	Winter	1.0000	1.0000	1.0000	
Applicable Customer Usage @ transmission nodes - in MWh					
6	Summer MWh	9,098,957			from Table #17 of the current Attach2 - BidFactors
7	Winter MWh	14,111,789			
Total Payment to Suppliers - in \$1000					
8	Summer	\$ 339,415	\$ 327,845	\$ 339,554	= ((1C * (2)/(3) * (4) * (6)) / 1000
9	Winter	\$ 526,406	\$ 508,463	\$ 526,622	= ((1C * (2)/(3) * (5) * (7)) / 1000
10	Total	\$ 865,821	\$ 836,308	\$ 866,176	Note: \$ reflect total payment
Average Payment to Suppliers - in \$/MWh					
11	Summer	\$ 110.652			= sum(line 8) / (6) - rounded to 3 decimal places
12	Winter	\$ 110.652			= sum(line 9) / (7) - rounded to 3 decimal places
13	Total weighted average	\$ 110.652	<<< used in calculation of Customer Rates		= sum(line 10) / [(6) + (7)] rounded to 3 decimal places
Reconciliation of amounts - in \$1000					
14	Weighted Average * Total MWh =	\$ 2,568,315			= (13) * [(6)+(7)] / 1000
15	Total Payment to Suppliers =	\$ 2,568,304			= sum (line 10)
16	Difference =	\$ 11			= line (14) - line (15)

Calculation of June 2027 to May 2028 BGS-RSCP Rates

Illustrative Purposes Only

NJ Sales & Use Tax (SUT) excluded

Table B Ratio of BGS Unit Costs @ customer to All-In Average Cost @ transmission nodes

*from Table #14 of the bid factor spreadsheet (Attach2 - BidFactors)
rounded to 3 decimal places, unit obligation \$ rounded to 4 decimal places*

NON-DEMAND RATES

includes energy, G&T obligations, and Ancillary Services - adjusted to billing time periods

		RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	
Summer - all hrs					0.678	0.613	0.868	0.605	0.604	
	PSE&G On pk			1.776				Use weighted average		
	PSE&G Off pk			0.570				for all streetlighting =		0.604
	All usage Multiplier	1.061	0.890							
	Constant (in \$/MWh) \$	(3.089) \$	(3.725) \$							
	Constant (in \$/MWh) \$	5.563 \$	7.844 \$							
Winter - all hrs		1.128	0.981		0.759	0.762	0.966	0.744	0.740	
	PSE&G On pk			1.771				Use weighted average		
	PSE&G Off pk			0.714				for all streetlighting =		0.741
Annual - all hrs		1.100	0.961	1.154	0.736	0.744	0.943	0.706	0.704	

DEMAND RATES

includes energy and Ancillary Services, G&T obligations charged separately - adjusted to billing time periods

		GLP Multiplier	GLP Constant (in \$/MWh)	LPL-S Multiplier	LPL-S Constant (in \$/MWh)	PLUS:	GLP	LPL-S	
Summer - all hrs		0.949	(25.687)			<u>Gen Cost</u>			
	PSE&G On pk			1.240	(42.911)	summer \$	10.1775 \$	10.1775	per kW of G obl /month
	PSE&G Off pk			0.567	-	winter \$	10.1775 \$	10.1775	per kW of G obl /month
Winter - all hrs		1.044	(29.206)			<u>Trans cost</u>			
	PSE&G On pk			1.295	(49.651)	all months \$	- \$	-	per kW of T obl /month
	PSE&G Off pk			0.706	-				
Annual - including T&G Obl \$		1.010		0.951					

Calculation of June 2027 to May 2028 BGS-RSCP Rates

Illustrative Purposes Only

NJ Sales & Use Tax (SUT) excluded

Table C Preliminary Resulting BGS Rates (in cents per kWh) - equal to bid factors times weighted average bid price rounded to 4 decimal places

NON-DEMAND RATES -----
includes energy, G&T obligations, and Ancillary Services - adjusted to billing time periods

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Summer - all hrs				7.5022	6.7830	9.6046	6.6834	6.6834
			19.6518					
			6.3072					
for Block 1 (0-600 kWh/m) usage	11.4313	9.4755						
for Block 2 (>600 kWh/m) usage	12.2965	10.6324						
Winter - all hrs	12.4815	10.8550		8.3985	8.4317	10.6890	8.1993	8.1993
			19.5965					
			7.9006					

DEMAND RATES -----
includes energy and Ancillary Services, G&T obligations charged separately - adjusted to billing time periods

	GLP	LPL-S	PLUS:	GLP	LPL-S
Summer - all hrs	7.9322		Gen Cost		
		9.4297	summer \$	10.1775	\$ 10.1775 per kW of G obl /month
		6.2740	winter \$	10.1775	\$ 10.1775 per kW of G obl /month
Winter - all hrs	8.6315		Trans cost		
		9.3643	all months \$	-	\$ - per kW of T obl /month
		7.8120			

Calculation of June 2027 to May 2028 BGS-RSCP Rates

Illustrative Purposes Only

NJ Sales & Use Tax (SUT) excluded

Table D Revenue Recovery Calculations - Reconciliation of seasonal Customer Revenue and Supplier Payments, based on actual anticipated revenues and payments

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Total Preliminary Rate Revenue - in \$1000								
Summer	\$ 654,673	\$ 1,452	\$ 8,996	\$ 4	\$ 0	\$ 167	\$ 2,486	\$ 5,348
Winter	\$ 983,569	\$ 5,692	\$ 11,448	\$ 13	\$ 1	\$ 617	\$ 7,995	\$ 18,095
Total	\$ 1,638,242	\$ 7,145	\$ 20,444	\$ 17	\$ 1	\$ 784	\$ 10,481	\$ 23,443
	GLP	GLP		LPL-S	LPL-S			
	Energy \$	Obligation \$		Energy \$	Obligation \$			
Summer	\$ 142,092	\$ 46,015		\$ 84,145	\$ 22,464			
Winter	\$ 271,979	\$ 92,029		\$ 163,937	\$ 44,928			
Total	\$ 414,071	\$ 138,044		\$ 248,083	\$ 67,391			
	Energy \$	Obligation \$	Total \$					
Total Summer	\$ 899,365	\$ 68,478	\$ 967,843					
Total Winter	\$ 1,463,347	\$ 136,957	\$ 1,600,303					
Grand Total	\$ 2,362,711	\$ 205,435	\$ 2,568,146					
Total Supplier Payment - in \$1000								
Summer	\$ 1,006,813							
Winter	\$ 1,561,491							
Total	\$ 2,568,304							
Differences - in \$1000								
Summer	\$ 38,971							
Winter	\$ (38,812)							
Total	\$ 158							

kWh Rate Adjustment Factors	<i>rounded to 5 decimal places</i>
1.04333	
0.97348	

Note: These differences are due to rounding and seasonal differences in Bidder Payments (which are based on prior winning bids and Seasonal Payment Factors) and current Rates (based on current seasonal market differentials)

Calculation of June 2027 to May 2028 BGS-RSCP Rates

Illustrative Purposes Only

NJ Sales & Use Tax (SUT) excluded

Table E Final Resulting BGS Rates from Auctions (in cents per kWh) - with preliminary kWh rates adjusted by the kWh Rate Adjustment Factor rounded to 4 decimal places

NON-DEMAND RATES -----

includes energy, G&T obligations, and Ancillary Services - adjusted to billing time periods & adjustment to energy price

		RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Summer - all hrs					7.8273	7.0769	10.0208	6.9730	6.9730
	PSE&G On pk			20.5033					
	PSE&G Off pk			6.5805					
for Block 1 (0-600 kWh/m) usage		11.9266	9.8861						
for Block 2 (>600 kWh/m) usage		12.8293	11.0931						
Winter - all hrs		12.1505	10.5671		8.1758	8.2081	10.4055	7.9819	7.9819
	PSE&G On pk			19.0768					
	PSE&G Off pk			7.6911					

DEMAND RATES -----

includes energy and Ancillary Services, G&T obligations charged separately - adjusted to billing time periods & adjustment to energy price

		GLP	LPL-S	PLUS:	GLP	LPL-S
Summer - all hrs		8.2759		<u>Gen Cost</u>		
	PSE&G On pk		9.8383	summer	\$10.1775	\$10.1775
	PSE&G Off pk		6.5459	winter	\$10.1775	\$10.1775
Winter - all hrs		8.4026		<u>Trans cost</u>		
	PSE&G On pk		9.1160	all months	\$0.0000	\$0.0000
	PSE&G Off pk		7.6048			

Calculation of June 2027 to May 2028 BGS-RSCP Rates

Illustrative Purposes Only

NJ Sales & Use Tax (SUT) excluded

Table F Spreadsheet Error Checking - Checking of seasonal Customer Revenue and Supplier Payments, based on final actual anticipated revenues and payments

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	LPL-S
Total Rate Revenue - in \$1000										
Summer	\$ 683,039	\$ 1,515	\$ 9,386	\$ 5	\$ 0	\$ 175	\$ 2,593	\$ 5,580	\$ 194,263	\$ 110,255
Winter	\$ 957,486	\$ 5,541	\$ 11,145	\$ 12	\$ 1	\$ 600	\$ 7,783	\$ 17,615	\$ 356,796	\$ 204,517
Total	\$ 1,640,525	\$ 7,057	\$ 20,531	\$ 17	\$ 1	\$ 775	\$ 10,377	\$ 23,195	\$ 551,059	\$ 314,773
Total Summer	\$ 1,006,812									
Total Winter	\$ 1,561,497									
Grand Total	\$ 2,568,309									
Total Supplier Payment - in \$1000										
Summer	\$ 1,006,813									
Winter	\$ 1,561,491									
Total	\$ 2,568,304									
Differences - in \$1000										
Summer	\$ (2)									<u>% difference</u> -0.0002%
Winter	\$ 6									0.0004%
Total	\$ 4									0.0002%

**VIII. ATTACHMENT 4 – DEVELOPMENT OF CAPACITY PROXY PRICE
TRUE UP - \$/MWh**

(Pages 1 through 5)

Development of Capacity Proxy Price True-Up - \$/MWh

2027/2028 Delivery Year - Illustrative Data

Capacity Proxy Price True-Up
Development for Winning Suppliers
from 2025 BGS-RSCP Auction

	2027/28 Delivery Year	Notes:
1 Zonal Capacity Price (\$/MW-day)	\$333.69	as may be determined by the RPM or its successor or otherwise per Board Orders dated 11/21/2024
2 Capacity Proxy Price (\$/MW-day)	\$270.35	
3 Capacity Proxy Price True-Up - \$/MW-day	\$63.34	= line 1 - line 2
4 BGS-RSCP Gen Obl - MW	5,884.1	
5 Days in Year	366	
6 Capacity Proxy Price True-Up Annual Cost	\$136,407,795	= line 3 * line 4 * line 5
7 Eligible Tranches	28	from Table A
8 Total Tranches	85	from Table A
9 % of tranches eligible for payment	32.94%	= line 7 / line 8
10 Capacity Proxy Price True-Up Cost	\$44,934,333	= line 6 * line 9
11 Total Applicable Customer Usage @ bulk system - in MWh	23,210,746	
12 Eligible Customer Usage @ bulk system - in MWh	7,645,893	= line 9 * line 11
13 Capacity Proxy Price True-Up - \$/MWh	\$5.88	= line 10/ line 12 - rounded to 2 decimal places

Development of Capacity Proxy Price True-Up - \$/MWh

	Capacity Proxy Price True-Up Development for Winning Suppliers from 2026 BGS-RSCP Auction	Capacity Proxy Price True-Up Development for Winning Suppliers from 2027 BGS-RSCP Auction (if needed)	
	2028/29 Delivery Year	2028/29 Delivery Year	
2028/2029 Delivery Year - Illustrative Data			
1 Zonal Capacity Price (\$/MW-day)	\$335.00	\$335.00	Notes: as may be determined by the RPM or its successor or otherwise per Board Orders dated 11/21/2025 and XX/XX/2026
2 Capacity Proxy Price (\$/MW-day)	\$333.69	\$333.69	
3 Capacity Proxy Price True-Up - \$/MW-day	\$1.31	\$1.31	= line 1 - line 2
4 BGS-RSCP Gen Obl - MW	5,884.1	5,884.1	
5 Days in Year	365	365	
6 Capacity Proxy Price True-Up Annual Cost	\$2,813,482	\$2,813,482	= line 3 * line 4 * line 5
7 Eligible Tranches	28	29	from Table A
8 Total Tranches	85	85	from Table A
9 % of tranches eligible for payment	32.94%	34.12%	= line 7 / line 8
10 Capacity Proxy Price True-Up Cost	\$926,794	\$959,894	= line 6 * line 9
11 Total Applicable Customer Usage @ bulk system - in MWh	23,210,746	23,210,746	
12 Eligible Customer Usage @ bulk system - in MWh	7,645,893	7,918,960	= line 9 * line 11
13 Capacity Proxy Price True-Up - \$/MWh	\$0.12	\$0.12	= line 10/ line 12 - rounded to 2 decimal places

Public Service Electric and Gas Company Specific
Addendum Attachment 4 P3

Development of Capacity Proxy Price True-Up - \$/MWh

	Capacity Proxy Price True-Up Development for Winning Suppliers from 2027 BGS-RSCP Auction (if needed) 2029/30 Delivery Year	
2029/2030 Delivery Year - Illustrative Data		
1 Zonal Capacity Price (\$/MW-day)	\$335.00	<i>Notes:</i> as may be determined by the RPM or its successor or otherwise per Board Orders dated XX/XX/2026
2 Capacity Proxy Price (\$/MW-day)	\$333.69	
3 Capacity Proxy Price True-Up - \$/MW-day	\$1.31	= line 1 - line 2
4 BGS-RSCP Gen Obl - MW	5,884.1	
5 Days in Year	365	
6 Capacity Proxy Price True-Up Annual Cost	\$2,813,482	= line 3 * line 4 * line 5
7 Eligible Tranches	29	from Table A
8 Total Tranches	85	from Table A
9 % of tranches eligible for payment	34.12%	= line 7 / line 8
10 Capacity Proxy Price True-Up Cost	\$959,894	= line 6 * line 9
11 Total Applicable Customer Usage @ bulk system - in MWh	23,210,746	
12 Eligible Customer Usage @ bulk system - in MWh	7,918,960	= line 9 * line 11
13 Capacity Proxy Price True-Up - \$/MWh	\$0.12	= line 10/ line 12 - rounded to 2 decimal places

**Public Service Electric and Gas Company Specific Addendum
Attachment 4 P4**

Table A With Additional Line Item
Calculation of June 2028 to May 2029 BGS-RSCP Rates
Illustrative Purposes Only

Table A Auction Results

line #	Specific BGS-RSCP Auction >>	remaining portion of 36 month bid - 2026 auction	remaining portion of 36 month bid - 2027 auction	36 month bid - 2028 auction	Notes:
1	Winning Bid - in \$/MWh	\$ 109.38	\$ 109.38	\$ 109.50	<i>Winning Bids</i> entered after 2028 BGS Auction = line 1 + line 1A
1A	28/29 Capacity Proxy Price True-up - in \$/MWh	\$ 0.12	\$ 0.12		
1B	Total - in \$/MWh	\$ 109.50	\$ 109.50	\$ 109.50	
2	# of Tranches for Bid	28	29	28	from current Attach2 - BidFactors
3	Total # of Tranches	85	85	85	from current Attach2 - BidFactors
Payment Factors					
4	Summer	1.0000	1.0000	1.0000	from current Attach2 - BidFactors
5	Winter	1.0000	1.0000	1.0000	from current Attach2 - BidFactors
Applicable Customer Usage @ bulk system - in MWh					
6	Summer MWh	9,098,957			from current Attach2 - BidFactors
7	Winter MWh	14,111,789			
Total Payment to Suppliers - in \$1000					
8	Summer	\$ 328,205	\$ 339,926	\$ 328,205	= (1B * (2)/(3) * (4) * (6)) / 1000
9	Winter	\$ 509,021	\$ 527,200	\$ 509,021	= (1B * (2)/(3) * (5) * (7)) / 1000
10	Total	\$ 837,225	\$ 867,126	\$ 837,225	
Average Payment to Suppliers - in \$/MWh					
11	Summer	\$ 109.50			= sum(line 8) / (6) - rounded to 2 decimal places
12	Winter	\$ 109.50			= sum(line 9) / (7) - rounded to 2 decimal places
13	Total weighted average	\$ 109.50	<<< used in calculation of Customer Rates		= sum(line 10) / [(6) + (7)] rounded to 2 decimal places

Table A With Additional Line Item
Calculation of June 2029 to May 2030 BGS-RSCP Rates
Illustrative Purposes Only

Table A Auction Results

line #	Specific BGS-RSCP Auction >>	remaining portion of 36 month bid - 2027 auction	remaining portion of 36 month bid - 2028 auction	36 month bid - 2029 auction	Notes:
1	Winning Bid - in \$/MWh	\$ 109.38	\$ 109.50	\$ 109.50	<i>Winning Bids</i> entered after 2029 BGS Auction = line 1 + line 1A
1A	29/30 Capacity Proxy Price True-up - in \$/MWh	\$ 0.12			
1B	Total - in \$/MWh	\$ 109.50	\$ 109.50	\$ 109.50	
2	# of Tranches for Bid	29	28	28	from current Attach2 - BidFactors
3	Total # of Tranches	85	85	85	from current Attach2 - BidFactors
Payment Factors					
4	Summer	1.0000	1.0000	1.0000	from current Attach2 - BidFactors
5	Winter	1.0000	1.0000	1.0000	from current Attach2 - BidFactors
Applicable Customer Usage @ bulk system - in MWh					
6	Summer MWh	9,098,957			from current Attach2 - BidFactors
7	Winter MWh	14,111,789			
Total Payment to Suppliers - in \$1000					
8	Summer	\$ 339,926	\$ 328,205	\$ 328,205	= (1B * (2)/(3) * (4) * (6)) / 1000
9	Winter	\$ 527,200	\$ 509,021	\$ 509,021	= (1B * (2)/(3) * (5) * (7)) / 1000
10	Total	\$ 867,126	\$ 837,225	\$ 837,225	
Average Payment to Suppliers - in \$/MWh					
11	Summer	\$ 109.50			= sum(line 8) / (6) - rounded to 2 decimal places
12	Winter	\$ 109.50			= sum(line 9) / (7) - rounded to 2 decimal places
13	Total weighted average	\$ 109.50	<<< used in calculation of Customer Rates		= sum(line 10) / [(6) + (7)] rounded to 2 decimal places

IX. ATTACHMENT 5 – DEVELOPMENT OF RS TOU-3P CHARGES - \$/KWH

