PECO Energy Company

Electric Service Tariff

COMPANY OFFICE LOCATION

2301 Market Street

Philadelphia, Pennsylvania 19103

For List of Communities Served, See Page 4.

Issued March 13, 2020 **Effective June 1, 2021**

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NOTICE

LIST OF CHANGES MADE BY THIS SUPPLEMENT

GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASSES 1 AND 2 LOADS UP TO 100KW – X REVISED PAGE NO. 34, X REVISED PAGE NO. 35, ORIGINAL PAGE NO. 35A,
Updated to reflect effective date of June 1, 2021 (DSP V). Expanded to describe new optional Time-Of-Use (TOU) Pricing Option, including customer eligibility requirements, pricing provisions, and switching rules. Labeled pre-existing non-TOU pricing as "Standard" GSA.

GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASS 3/4 LOADS GREATER THAN 100KW REVISED PAGE NO. 36 - Updated to reflect effective date of June 1, 2021 (DSP V).

RECONCILIATION - X REVISED PAGE NO. 37 AND X REVISED PAGE NO. 38
Updated to reflect effective date of June 1, 2021 (DSP V). Modified "Applicability" section to clarify that Standard and TOU default service rate over/undercollections will be calculated in total for both Procurement Classes 1 and 2 (each "reconciled in one group"). Removed obsolete language on Procurement Class 3/4 transition.

RATE RS-2 NET METERING - X REVISED PAGE NO. 51, X REVISED PAGE NO. 52, X REVISED PAGE NO. 53
Updated "Metering Provisions" to exclude virtual net metering customers from default service TOU. Supplemented "Billing Provisions" with description of excess generation accounting and cashout processes for customer-generators enrolled in default service TOU. Pages 52 and 53 are repaginated.

CUSTOMER ASSISTANCE PROGRAM (CAP) RIDER – X REVISED PAGE NO. 77
Eliminated restriction of "Availability" to customers who obtain competitive energy supply. Also added restriction of "Availability" excluding CAP customers from selecting default service TOU.

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GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASSES 1 AND 2 LOADS UP TO 100KW

Applicability: June 1, 2021 this adjustment shall apply to all customers taking default service from the Company with demands up to 100 kW. The rate contained herein shall be calculated to the nearest one thousandth of a cent. The GSA shall contain the cost of generation supply for each tariff rate. The Company will apply Standard Pricing unless customers voluntarily request and are eligible to participate in the Time-Of-Use Pricing Option as detailed below. **(C)** **(C)**

Standard Pricing: Standard Pricing provides default service to customers who have not selected or are not eligible for PECO's Time-Of-Use Pricing Option. The rates below shall include the cost of procuring power to serve the default service customers including the cost of complying with the Alternative Energy Portfolio Standards Act ("AEPS" or the "Act") plus associated administrative expenses incurred in acquiring power and gaining regulatory approval of any procurement strategy and plan. The standard pricing for default service will represent the estimate of the cost to serve the specific tariff rate for the next quarterly period beginning with the three months ended August 31, 2021. The rates in this tariff shall be updated quarterly on June 1, September 1, December 1 and March 1 commencing June 1, 2021 and are not prorated. If the balance of over/(under) recovery gets too large, the Company can file a reconciliation that will mitigate the subsequent impact. The standard generation service charge shall be calculated using the following formula: **(C)** **(C)** **(C)** **(C)** **(C)**

Standard GSA(n) = (C-E+A)/S*1/(1-T)* (1-ALL)/(1-LL) +AEPS/S*1/(1 - T) + WC where; **(C)**

C= The sum of the amounts paid to the full requirements suppliers providing the power for the quarterly period, the spot market purchases for the quarterly period, plus the cost of any other energy acquired for the quarterly period. Cost shall include energy, capacity and ancillary services, distribution line losses, cost of complying with the Alternative Energy Portfolio Standards, and any other load serving entity charges other than network transmission service and costs assigned under the Regional Transmission Expansion Plan. Ancillary services shall include any allocation by PJM to PECO default service associated with the failure of a PJM member to pay its bill from PJM as well as the load serving entity charges listed in the Supply Master Agreement Exhibit D as the responsibility of the supplier. This component shall include the proceeds and costs from the exercise of Auction Revenue Rights granted to PECO by PJM.

AEPS = The projected total cost of complying with the Alternative Energy Portfolio Standards Act ("AEPS" or the "Act") not included in the C component above for the quarterly period for each procurement class. Costs include the amount paid for Alternative Energy and/or Alternative Energy Credits ("AEC's") purchased for compliance with the Act, the cost of administering and conducting any procurement of Alternative Energy and/or AEC's, payments to the AEC program administrator for its costs of administering an alternative energy credits program, payments to a third party for its costs in operating an AEC registry, any charge levied by PECO's regional transmission operator to ensure that alternative energy sources are reliable, a credit for the sale of any AEC's sold during the calculation period, and the cost of Alternative Compliance Payments that are deemed recoverable by the Commission, plus any other direct or indirect cost of acquiring Alternative Energy and/or AEC's and complying with the AEPS statute.

E = Experienced over or under-collection calculated under the reconciliation provision of the tariff to be effective semiannually with recovery during the periods March 1 through August 31 of the current year and September 1 of the current year through February 28 (29) of the following year.

A = Administrative Cost - This includes the cost of the Independent Evaluator, consultants providing guidance on the development of the procurement plan, legal fees incurred gaining approval of the plan and any other costs associated with designing and implementing a procurement plan including the cost of the pricing forecast necessary for estimating cost recoverable under this tariff. Also included in this component shall be the cost to implement real time pricing or other time sensitive pricing such as dynamic pricing that is required of the Company or is approved in its Act 129 filing. Administrative Costs also includes any other costs incurred to implement retail market enhancements directed by the Commission in its Retail Market Investigation at Docket No. I-2011-2237952 or any other applicable docket that are not recovered from EGSs or through another rate.

S = Estimated sales for the period the rate is in effect for the classes to which the rate is applicable. Six month sales are used for the E factor with effective periods March 1 through August 31 of the current year and September 1 of the current year through February 28 (29) of the following year.

T = The currently effective gross receipts tax rate.

n = The procurement class for which the GSA is being calculated.

ALL = Average line losses for the procurement class.

LL = Line losses for the specific rate class provided in the Company's Electric Generation Supplier Coordination Tariff rule 6.6.

WC = $0.00019/kWh to represent the cash working capital for power purchases.

Auction Revenue Rights (ARR) = Allocated annually by PJM to Firm transmission customers, the ARR's allow a Company to select rights to specific transmission paths in order to avoid congestion charges. In general, the line loss adjustment is applicable to Procurement Class 2 only as those classes contain rate classes with three different line loss factors: Current Charges:

Standard Rate		Standard GSA Price
R	GSA (1)	$0.XXXXX
RH	GSA (1)	$0.XXXXX
GS	GSA (2)	$0.XXXXX

(C)

(C) Denotes Change

GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASSES 1 AND 2 LOADS UP TO 100KW (CONTINUED)

(C)

PD	GSA (2)	$0.XXXXX
HT	GSA (2)	$0.XXXXX
POL*	GSA (2)	$0.XXXXX
SL-S*	GSA (2)	$0.XXXXX
TLCL	GSA (2)	$0.XXXXX
SL-E*	GSA (2)	$0.XXXXX
AL*	GSA (2)	$0.XXXXX
SL-C* **	GSA (2)	$0.XXXXX

* Prices shall exclude capacity from the Procurement Class 2 RFP results.
** Rate SL-C was effective July 1, 2019 pursuant to the Order at Docket No. R-2018-3000164

Procedure: For Procurement Classes 1 and 2 the GSA shall be filed 45 days before the effective dates of June 1, September 1, December 1 and March 1 in conjunction with the Reconciliation Schedule.

Time-Of-Use (TOU) Pricing Option: The TOU Pricing Option provides eligible customers with an opportunity to shift energy usage away from peak periods, when wholesale electricity demand and prices are high, to off-peak periods, when demands and prices are lower. Customers may voluntarily request this option in lieu of Standard Pricing described above and must meet the TOU Eligibility Requirements below. TOU Pricing Option rates will be updated quarterly in concurrence with the Standard GSA on June 1, September 1, December 1 and March 1 commencing XXX and are not prorated. (C)

The year-round TOU Pricing Periods, TOU Period Allocators ["PA-GSA(n)"], and TOU Pricing Multipliers ["PM-GSA(n)"] as approved in the Company's most recent DSP proceeding at Docket No. XXX are as follows:

TOU Pricing Period	Days/Hours Included	TOU Period Allocator PA-GSA(1)	TOU Period Allocator PA-GSA(2)	TOU Pricing Multiplier PM-GSA(1) (Ratio to Super Off-Peak)	TOU Pricing Multiplier PM-GSA(2) (Ratio to Super Off-Peak)
Peak ("PP")	2:00 – 6:00 p.m. Monday through Friday, excluding PJM holidays	12%	14%	6.5-to-1	5.1-to-1
Super Off-Peak ("SOPP")	Midnight (12 a.m.) – 6 a.m. Every day	20%	20%	1-to-1	1-to-1
Off-Peak ("OPP")	All other hours	68%	66%	1.5-to-1	1.7-to-1

To calculate the quarterly TOU Pricing Option rates, the Company will first calculate the quarterly TOU Super Off-Peak Price ("SOPP") in accordance with the formula set forth below:

TOU SOPP GSA(n) = Standard GSA(n) * [1 / SOPP-F(n)] where;

Standard GSA(n) = Defined as above for Standard Pricing.

SOPP-F(n) = Super Off-Peak Price Factor representing the ratio of the Standard GSA(n) to the Super Off-Peak Price, calculated as follows:

TOU SOPP PA-GSA(n) + [(TOU OPP PM-GSA(n) * TOU OPP PA-GSA(n)] + [(TOU PP PM-GSA(n) * TOU PP PA-GSA(n)]

The Company will then calculate the quarterly TOU Peak ("PP") and Off-Peak ("OPP") prices as follows:

TOU PP GSA(n) = TOU SOPP GSA(n) * TOU PP PM-GSA and;

TOU OPP GSA(n) = TOU SOPP (GSA(n) * TOU OPP PM-GSA.

Current TOU Pricing Option Charges (Year-Round):

TOU Rate	Peak Hours (2-6 PM Monday-Friday, excluding holidays)	Super Off-Peak Hours (12-6 AM all days)	Off-Peak Hours (All other times)
R (GSA 1)	$0.XXXXX	$0.XXXXX	$0.XXXXX
RH (GSA 1)	$0.XXXXX	$0.XXXXX	$0.XXXXX
GS (GSA 2)	$0.XXXXX	$0.XXXXX	$0.XXXXX
PD (GSA 2)	$0.XXXXX	$0.XXXXX	$0.XXXXX
HT (GSA 2)	$0.XXXXX	$0.XXXXX	$0.XXXXX

(C)

(C) Denotes Change

GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASSES 1 AND 2
LOADS UP TO 100KW (CONTINUED)

TOU Eligibility Requirements and Switching Rules: **(C)**

The TOU Pricing Option is available to new and existing Customers in Procurement Classes 1 or 2 with a smart meter configured to measure energy consumption in watt-hours. This includes Customers in the above referenced Procurement Classes taking default service from the Company and who also participate in the Company's RS-2 (Net Metering) tariff, except for virtual net metered Customers. Residential Customers enrolled in the Company's Customer Assistance Program (CAP) are not eligible for the TOU Pricing Option.

As a prerequisite for enrollment, the Customer must have a valid e-mail address to ensure the Company is able to provide the enrolled TOU Pricing Option Customer with timely and meaningful communications regarding their bill savings performance.

Participating Customers will remain on the TOU Pricing Option rate until they affirmatively elect to return to PECO's Standard GSA rate, switch to an EGS, or otherwise become ineligible.

Customers who select the TOU Pricing Option may leave at any time without incurring related penalties or fees. However, Customers who select and subsequently leave the TOU Pricing Option for any reason may not re-enroll on the TOU Pricing Option rate for twelve billing months after switching off the TOU Pricing Option rate.

(C) Denotes Change

GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASS 3/4 LOADS GREATER THAN 100KW

Applicability: June 1, 2021 this adjustment shall apply to all customers taking default service from the Company with demands greater than 100 kw. **(C)**

Hourly Pricing Service
Pricing: The rates below shall include the cost of procuring power to serve the default service customers plus associated administrative expenses incurred in acquiring power and gaining regulatory approval of any procurement strategy and plan. The rates for the GSA 3/4 Hourly Pricing Adder* shall be updated quarterly on June 1, September 1, December 1 and March 1 commencing June 1, 2021 and are not prorated. **(C)**
If the balance of over/(under) recovery gets too large due to billing lag, the Company can file a reconciliation that will mitigate the subsequent impact. The cost for this hourly service rate shall be as follows:

Generation Supply Cost (GSC) = (C+R+AS+AC-E)/(1-T)+WCA where;

C = The PJM day ahead hourly price multiplied by the customers usage in the hour summed up for all hours in the month

ΣPJM_{DA} x usage / (1-LL)
PJM_{DA} – PJM on day ahead hourly price.
Usage - Electricity used by an end use customer.
R = The PJM reliability pricing model (RPM) charge for month for the customer. The RPM charge shall be the customers peak load contribution as established for PJM purposes multiplied by the current RPM monthly charge and the PJM established reserve margin adjustment.
PLC x (1+ RM) x P_{RPM} x Bill Days
PLC = Peak load contribution
RM = Reserve margin adjustment per PJM
P_{RPM} = Capacity price per MW-day
AC = Administrative Cost - This includes an allocation of the cost of the Independent Evaluator, consultants providing guidance on the development of the procurement strategy, legal fees incurred gaining approval of the plan, and any other costs associated with designing and implementing a procurement plan divided by the total default service sales and then multiplied by the customers usage for the month. Administrative Costs also includes any other costs incurred to implement retail market enhancements directed by the Commission in its Retail Market Investigation at Docket No. I-2011-2237952 or any other applicable docket that are not recovered from EGSs or through another rate.
A / S x Usage
A = Administrative cost
S = Default service sales
AS = The cost, on a $/MWH basis, of acquiring ancillary services from PJM and of complying with the Alternative Energy Portfolio Standard, multiplied by the customers usage for the month and divided by (1-LL). Congestion charges including the proceeds and costs from the exercise of
Auction Revenue Rights shall be included in this component. Ancillary services shall be those included in the Supply Master Agreement as being the responsibility of the supplier.

((PJM_{AS} x Usage*1/(1-LL) + AEPS/S_{AEPS} x Usage)

PJM_{AS} = $/MWH charged by PJM for ancillary services
AEPS = Cost of complying with the alternative energy portfolio standard
S_{AEPS} = Sales for which AEPS cost is incurred
If the supplier provides the ancillary services and AEPS cost then the customer shall be charged the supplier's rate for these services times usage and divided by (1-LL).

Auction Revenue Rights (ARR) = Allocated annually by PJM to Firm transmission customers, the ARR's allow a Company to select rights to specific transmission paths in order to avoid congestion charges
LL = Line loss factor as provided in the Company's Electric Generation Supplier Coordination Tariff Rule 6.6 based upon the customers distribution rate class adjusted to remove losses included in the PJM LMP
T = The currently effective gross receipts tax rate
E = $\Sigma O/(U)/S_{3/4}$ x usage where
E (Purchased Generation Adj.) = Over/under recovery as calculated in the reconciliation
$S_{3/4}$ = Procurement class 3/4 sales
WC = $0.00019 kWh for working capital associated with power purchases
WCA = Individual customer sales x WC
Procedure: The "E" factor shall be updated semiannually in conjunction with the Reconciliation. The applicable above items are converted to the rates listed below.

Tariff Rate	GS	PD	HT	EP
Hourly Pricing Adder* (dollars/kWh)	$0.XXXXX	$0.XXXXX	$0.XXXXX	$0.XXXXX

(C)

* Includes administrative cost (AC), ancillary service charge (AS), E factor (E) and working capital (WC).

(C) Denotes Change

RECONCILIATION

Applicability: June 1, 2021 this adjustment shall apply to all customers who received default service during the period the cost of which is being reconciled. Customers taking default service during the reconciliation period that leave default service prior to the assessment of the collection of the over/(under) adjustment shall still pay or receive credit for the over/(under) adjustment through the migration provision. The Company shall notify the Commission and parties to the Default Service Settlement 15 days in advance of the quarterly or monthly filing if the Migration Provision will be implemented in the filing. **(C)**

This adjustment shall be calculated on a semiannual basis for Procurement Classes 1, 2 and 3/4 Hourly. The reconciliation period will include the six month period beginning January 1 and July 1 commencing with the July 1, 2020 through December 31, 2020 reconciliation **(C)** period. The reconciliation shall be separate for each procurement class. Any resulting over or under recovery shall be assessed on an equal cents per kilowatt hour basis to all customers in the relevant procurement group. Any over/(under) recovery shall be collected after the Occurrence of two months from the end of the reconciliation period. Recovery shall be over a six month period commencing September 1 and March 1. The initial six month period is March 1, 2021 through August 31, 2021. For purposes of this rider the reconciliation shall be **(C)** calculated 45 days before the effective date of recovery. The over or under recovery shall be calculated using the formula below. The calculation of the over/(under) recovery shall be done separately for the following procurement classes – Class 1 – Residential Class 2 – Small C&I up to and including 100 kW, and Class 3/4 – Large C&I greater than 100 kW. For Procurement Classes 1 and 2, Standard **(C)** Pricing and TOU Pricing Option revenue and cost of supply will be included for the entire Procurement Class.

Reconciliation Formula

$E_N = \Sigma O/(U) + I$

Migration Provision $E_M = [\Sigma O/(U) + I]/S/(1\text{-}GRT)*(1\text{-}ALL)/(1\text{-}LL)$

Where:

E = Experienced over or under collection plus associated interest
N = Procurement class
M = Migration Rider
O/(U) = The monthly difference between revenue billed to the procurement class and the cost of supply as described below in Cost, AEPS Cost and Administrative Cost.

Revenue = Amount billed to the tariff rates applicable to the procurement class including approved Real Time Price or other time sensitive rates for the period being reconciled through the GSA.

Cost = The sum of the amounts paid to all of the full requirements suppliers providing the power for the period being reconciled, the spot market purchases for the period being reconciled, plus the cost of any other energy acquired for the period being reconciled. Cost shall include energy, capacity and ancillary services as well as the proceeds and costs of auction revenue rights for Procurement Classes 1 and 2. Ancillary services shall include any allocation by PJM to PECO default service associated with the failure of a PJM member to pay its bill from PJM as well as those costs listed in the Supply Master Agreement as the responsibility of the seller.

AEPS = The total cost of complying with the Alternative Energy Portfolio Standards Act ("AEPS" or the "Act") not included in the Cost component above for the reconciliation period for Procurement Classes 1 and 2 and not included in the ancillary services component for Procurement Class 3/4 Hourly Service. Costs include the amount paid for Alternative Energy and/or Alternative Energy Credits ("AEC's") purchased for compliance with the Act, the cost of administering and conducting any procurement of Alternative Energy and/or AEC's, payments to the AEC program administrator for its costs of administering an alternative energy credits program, payments to a third party for its costs in operating an AEC registry, any charge levied by PECO's regional transmission operator to ensure that alternative energy sources are reliable, a credit for the sale of any AEC's sold during the calculation period, and the cost of Alternative Compliance Payments that are deemed recoverable by the Commission, plus any other direct or indirect cost of acquiring Alternative Energy and/or AEC's and complying with the AEPS statute.

Administrative Cost = This includes the cost of the Independent Evaluator, consultants providing guidance on the development of the procurement strategy, legal fees incurred gaining approval of the strategy, and any other costs associated with designing and implementing a procurement plan including the cost of the pricing forecast necessary for estimating cost recoverable under this tariff. Also included in this component shall be the cost to implement real time pricing or other time sensitive pricing such as dynamic pricing that is required of the Company or approved in its Act 129 filing. Administrative Costs also includes other costs incurred to implement retail market enhancements directed by the Commission in its Retail Market Investigation at Docket No. I-2011-2237952 or any other applicable docket that are not recovered from EGS's or through another rate.

Full Requirements Supply = A product purchased by the Company that includes a fixed price for all energy consumed. The only cost added by the Company to the full requirements price is for gross receipts tax, distribution line losses, and administrative cost.

Ancillary Services = The following services in the PJM OATT- reactive support, frequency control, operating reserves, supplemental reserves, imbalance charges, PJM annual charges, any PJM assessment associated with non-payment by members, and any other load serving entity charges not listed here but contained in Exhibit D of the Supply Master Agreement. Also included shall be the proceeds and costs from the exercise of auction revenue rights for Procurement Class 3/4 Hourly Service.

(C) Denotes Change

RECONCILIATION
(CONTINUED)

Auction Revenue Rights (ARR) = Allocated annually by PJM to Firm transmission customers, the ARR's allow a Company to select rights to specific transmission paths in order to avoid congestion charges.

Capacity = The amount charged to PECO by PJM for capacity for its default service load under the reliability pricing model (RPM).

I = interest on the over or under collection at the prime rate of interest for commercial banking, not to exceed the legal rate of interest, in effect on the last day of the month the over collection or under collection occurs, as reported in the Wall Street Journal in accordance with the Order at Docket No. L-2014-2421001.

S= Estimated default service retail sales in kWh for the period the cost of which is being reconciled.

ALL = The average line losses in a procurement class as a percent of generation.

LL = The average line losses for a particular rate (e.g. HT, PD, GS) as provided in the Electric Generation Supplier Coordination Tariff rule 6.6.

GRT = The current gross receipts tax rate.

Procurement Class - Set of customers for which the company has a common procurement plan.

Procedural Schedule
The Company shall file the calculation of the over/under collection for the period being reconciled and the proposed adjustment to the GSA 45 days before the effective date as described below. The over/under collection adjustment, shall be effective no earlier than the first day of the month such that the commencement of recovery shall lag by two months. The GSA will be effective June 1, September 1, December 1 and March 1 commencing June 1, 2021 with over/under collection recovery occurring over the six month period beginning September 1 and March 1. **(C)**
The data provided in the reconciliation shall be audited on an annual basis by the PaPUC Bureau of Audits.

(C) Denotes Change

RATE RS-2 NET METERING

PURPOSE.

This Rate sets forth the eligibility, terms and conditions applicable to Customers with installed qualifying renewable customer-owned generation using a net metering system.

APPLICABILITY.

This Rate applies to renewable customer-generators served under Rates R, RH, CAP, GS, HT, PD and EP who install a device or devices which are, in the Company's judgment, subject to Commission review, a bona fide technology for use in generating electricity from qualifying Tier I or Tier II alternative energy sources pursuant to Alternative Energy Portfolio Standards Act No. 2004-213 (Act 213) or Commission regulations and which will be operated in parallel with the Company's system. This Rate is limited to installations where the renewable energy generating system is intended primarily to offset part or all of the customer-generator's requirements for electricity. A renewable customer-generator is a non-utility owner or operator of a net metered generation system with a nameplate capacity of not greater than 50 kilowatts if installed at a residential service (Rate R, RH, or CAP) or not larger than 3,000 kilowatts at other customer service locations (Rate GS, HT, PD and EP), except for Customers whose systems are above 3 megawatts and up to 5 megawatts who make their systems available to operate in parallel with the Company during grid emergencies as defined by the regional transmission organization or where a microgrid is in place for the purpose of maintaining critical infrastructure such as homeland security assignments, emergency services facilities, hospitals, traffic signals, wastewater treatment plants or telecommunications facilities provided that technical rules for operating generators interconnected with facilities of the Company have been promulgated by the Institute of Electrical and Electronic Engineers "IEEE" and the Commission.

Qualifying renewable energy installations are limited to Tier I and Tier II alternative energy sources as defined by Act 213 and Commission Regulations. The Customer's equipment must conform to the Commission's Interconnection Standards and Regulations pursuant to Act 213. This Rate is not applicable when the source of supply is service purchased from a neighboring electric utility under Borderline Service.

Service under this Rate is available upon request to renewable customer-generators on a first come, first served basis so long as the total rated generating capacity installed by renewable customer-generator facilities does not adversely impact service to other Customers and does not compromise the protection scheme(s) employed on the Company's electric distribution system.

METERING PROVISIONS.

A Customer may select one of the following metering options in conjunction with service under applicable Rate Schedule R, RH, CAP, GS, HT, PD or EP.

1. A customer-generator facility used for net metering shall be equipped with a single bi-directional meter that can measure and record the flow of electricity in both directions at the same rate. A dual meter arrangement may be substituted for a single bi-directional meter at the Company's expense.

2. If the customer-generator's existing electric metering equipment does not meet the requirements under option (1) above, the Company shall install new metering equipment for the customer-generator at the Company's expense. Any subsequent metering equipment change necessitated by the customer-generator shall be paid for by the customer-generator. The customer-generator has the option of utilizing a qualified meter service provider to install metering equipment for the measurement of generation at the customer-generator's expense.

   Additional metering equipment for the purpose of qualifying alternative energy credits owned by the customer-generator shall be paid for by the customer-generator. The Company shall take title to the alternative energy credits produced by a customer-generator where the customer-generator has expressly rejected title to the credits. In the event that the Company takes title to the alternative energy credits, the Company will pay for and install the necessary metering equipment to qualify the alternative energy credits. The Company shall, prior to taking title to any alternative energy credits, fully inform the customer-generator of the potential value of those credits and options available to the customer-generator for their disposition.

3. Meter aggregation on properties owned or leased and operated by a customer-generator shall be allowed for purposes of net metering. Meter aggregation shall be limited to meters located on properties within two (2) miles of the boundaries of the customer-generator's property. Meter aggregation shall only be available for properties located within the Company's service territory. Physical meter aggregation shall be at the customer-generator's expense. The Company shall provide the necessary equipment to complete physical aggregation. If the customer-generator requests virtual meter aggregation, it shall be provided by the Company at the customer-generator's expense. The customer-generator shall be responsible only for any incremental expense entailed in processing his account on a virtual meter aggregation basis. Customer generators involved in virtual metering programs are not eligible for the company's default service TOU Pricing Option. **(C)**

(C) Denotes Change

RATE RS-2 NET METERING (continued)

BILLING PROVISIONS.

The following billing provisions apply to default service customer-generators in conjunction with service under applicable Rates R, RH, CAP, GS, HT, PD, EP. **(C)**

1. The customer-generator will receive a credit for each kilowatt-hour received by the Company up to the total amount of electricity delivered to the Customer during the billing period at the full retail rate consistent with Commission regulations. If a customer-generator supplies more electricity to the Company than the Company delivers to the customer-generator in a given billing period, the excess kilowatt hours shall be carried forward and credited against the customer-generator's usage in subsequent billing periods at the full retail rate. Any excess kilowatt hours will continue to accumulate until the end of the PJM planning period ending May 31 of each year. On an annual basis, the Company will compensate the customer-generator for kilowatt-hours received from the customer-generator in excess of the kilowatt hours delivered by Company to the customer-generator during the preceding year at the "full retail value for all energy produced" consistent with Commission regulations. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

   For default service Time-Of-Use ("TOU") customer-generators only: The Company will record excess generation supplied by TOU Pricing Period, maintaining an active record of kilowatt hours produced and consumed at the customer-generator's premise. If, in a subsequent default service TOU billing period, a customer consumes more electricity than produced within a given TOU Pricing Period, The Company will pull kilowatt hours for the excess generation from the customer's banked kilowatt-hours for that TOU Pricing Period. Any excess kilowatt hours remaining in that TOU Pricing Period will continue to accumulate until the end of the PJM planning period ending May 31 of each year. On an annual basis, the Company will compensate the TOU customer generator for accumulated excess generation at the full retail value based on the applicable TOU Pricing Option rate and TSC rate in effect at the time the excess electricity was generated. **(C)**

2. If the Company supplies more kilowatt-hours of electricity than the customer-generator facility feeds back to the Company's system during the billing period, all charges of the appropriate rate schedule shall be applied to the net kilowatt-hours of electricity that the Company supplied. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

3. For customer-generators involved in virtual meter aggregation programs, any excess credit shall be applied first to the account containing the meter through which the generating facility supplies electricity to the distribution system, also known as the "host account". If the host account's usage has been fully offset by this credit and additional excess credit still remains, PECO will divide that remaining credit into equal parts based on the number of additional virtually metered accounts under the customer-generator's name, also known as "satellite accounts", and apply one part to each satellite account in a "waterfall"-like fashion at each account's designated rate. This process continues as PECO bills each subsequent satellite account, with any additional excess credits from each divided equally among the remaining satellite accounts. Virtual meter aggregation is the combination of readings and billing for all meters regardless of rate class on properties owned or leased and operated by a customer-generator by means of the Company's billing process, rather than through physical rewiring of the customer-generator's property for a physical, single point of contact. The customer-generators are responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

4. Procurement Class 3/4 customer-generators will receive a generation credit, at the PJM Day Ahead hourly energy rate, for each kilowatt hour received by the Company during each hour of the billing period up to the total amount of electricity delivered to the customer during each hour of the billing period.

   If a Procurement Class 3/4 customer-generator supplies more electricity to the Company than the Company delivers to the customer-generator during any hour in the billing period, the excess kilowatt hours shall not be carried forward to a subsequent billing period but will be credited in the current month toward generation charges based on the PJM Day Ahead hourly rate. Any excess kilowatt hours at the end of the PJM planning period will not carry over to the next year.

5 Procurement Class 3/4 customer-generators will also receive a variable distribution credit for each kilowatt hour received by the Company during the monthly billing period up to the total amount of electricity delivered to the Customer during the monthly billing period at the applicable distribution rate.

   If a Procurement Class 3/4 customer-generator supplies more electricity to the Company than the Company delivers to the customer-generator, the variable distribution charges will be reduced by the excess kilowatt hours, which will be carried forward and credited against the customer-generator's distribution kilowatt hours in subsequent billing periods until the end of the PJM planning period, ending May 31 of each year.

   Procurement Class 3/4 customer-generators are responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

   Any excess kilowatt hours at the end of the PJM planning period will not carry over to the next year and reduce distribution charges.

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RATE RS-2 NET METERING (continued)

NET METERING FOR SHOPPING CUSTOMERS

1. Customer-generators may take net metering services from EGSs that offer such services.

2. If a net-metering customer takes service from an EGS, the Company will credit the customer for distribution charges for each kilowatt hour produced by a Tier I or Tier II resource installed on the customer-generator's side of the electric revenue meter, up to the total amount of kilowatt hours delivered to the customer by the Company during the billing period. If a customer-generator supplies more electricity to the electric distribution system than the EDC delivers to the customer-generator in a given billing period, the excess kilowatt hours shall be carried forward and credited against the customer-generator's usage in subsequent billing periods at the Company's distribution rates. Any excess kilowatt hours at the end of the PJM planning period will not carry over to the next year and reduce distribution charges. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rates Schedule.

3. If the Company delivers more kilowatt hours of electricity than the customer-generator facility feeds back to the Company's system during the billing period, all charges of the applicable rate schedule shall be applied to the net kilowatt hours of electricity that the Company delivered. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

4. Pursuant to Commission regulations, the credit or compensation terms for excess electricity produced by customer-generators who are customers of EGSs shall be stated in the service agreement between the customer-generator and the EGS.

5. If a customer-generator switches electricity suppliers, the Company shall treat the end of the service as if it were the end of the PJM planning period.

APPLICATION.

Customer-generators seeking to receive service under the provisions of this Rate must submit a written application to the Company demonstrating compliance with the Net Metering Rate provisions and quantifying the total rated generating capacity of the customer-generator facility. The installation cannot be directly connected to the Company's distribution system ("stand alone"). Instead, the installation must be connected to a facility (residence or business) that is connected to the Company's distribution system.

INTERCONNECTION EXPIRATION.

Interconnection applications will be reviewed and processed in accordance with the timeframes designated by PECO in Act 213 and Title 52 of the Pa Code Chapter 75. A customer-generator (or authorized designee) must submit a completed certificate of completion ("COC") for residential level 1 and 2 interconnection applications to PECO within 180 calendar days from the date that PECO approves the interconnection application. If a COC is not received within 180 calendar days from the date that PECO approves the interconnection application then the residential level 1 and level 2 interconnection applications shall expire. A customer-generator may request an extension of a residential level 1 or level 2 application expiration date for good cause shown (i.e., that significant progress in construction of the interconnection has been or will be made). Upon a showing of good cause, the application expiration date will be extended. The length of the extension may be extended up to but no more than 180 calendar days. A customer-generator must make such extension requests in writing or via e-mail no less than 30 calendar days prior to an application's original expiration date. PECO will provide notice to developers of distributed generation at least 45 calendar days ahead of the original expiration date.

MINIMUM CHARGE.

The Minimum Charges under Rate Schedule R, RH, CAP, GS, PD, HT and EP apply for installations under this Rate.

RIDERS.

Bills rendered by the Company under this Rate shall be subject to charges stated in any other applicable Rate.

CUSTOMER ASSISTANCE PROGRAM (CAP) RIDER

AVAILABILITY.
To payment-troubled customers who are currently served under or otherwise qualify for Rate R, or RH (excluding multiple dwelling unit buildings consisting of two to five dwelling units). Customers must apply for the rates contained in this rider and must demonstrate annual household gross income at or below 150% of the Federal Poverty guidelines. In addition, these customers are not eligible to select the Time-Of-Use default service pricing option. (C)

Based on the applicable level of income, number of household members, and their historical usage CAP customers will receive a Fixed Credit Option ("FCO") based upon that individual household's need. The details of the FCO calculation can be found in the PECO Universal Service and Energy Conservation Plan at Docket No. M-2015-2507139.

DISCOUNT LEVELS: The Company will modify the level of discounts every quarter to adjust for changes in Customer usage as well as any Rate changes which may have occurred.

CERTIFICATION/VERIFICATION Prior to enrollment in the CAP Rider, and then again every two years, customers must verify, to PECO's satisfaction, that their household income level meets the "Availability" standards set forth in this Rider. Customers being considered for the CAP Rider will be required to:

- Provide information sufficient to demonstrate to PECO their household income level.
- Waive certain privacy rights to enable PECO to effectively conduct the above certification process.
- Apply for and assign to PECO at least one energy assistance grant from the Commonwealth.
- Participate in various energy education and conservation programs facilitated by PECO.

PECO may, at its sole discretion, supplement this verification process by using data from Commonwealth or federal government programs which demonstrate the income eligibility of its customers. Such data may come from a customer's participation in, or receipt of benefits from, the Low Income Home Energy Assistance Program, Temporary Assistance for Needy Families, Food Stamps, Supplemental Security Income, and Medicaid. Information available from the Pennsylvania Department of Revenue may also be used where appropriate to expedite the process.

MINIMUM CHARGE. The minimum charge per month will be the $12 for Residential customers or $30 for Residential Heating customers.

ARREARAGE.
Customers who qualify and are enrolled in CAP will have their pre-program arrearage ("PPA") forgiven if the Customer pays his / her new, discounted CAP bill on time and in full each month. With every full and on-time monthly payment, one-twelfth of the PPA will be forgiven. If the customer develops any in-program arrearage while on the CAP Rate-- that is, if the customer does not pay the entire outstanding balance -- then preprogram arrearage forgiveness will not resume until the first month in which the full outstanding balance is paid.

(C) Denotes Change