WPPI ENERGY

1425 Corporate Center Drive Sun Prairie, WI 53590-9109 608.834.4500 wppienergy.org

Delivered via ERF

July 14, 2023

Mr. Cru Stubley
Electric Division – Secretary to the Commission
Public Service Commission of Wisconsin
4822 Madison Yards Way
Madison, Wisconsin 53705-9100

RE: Sturgeon Bay Utilities (PSC Utility No. 5780)
Application of Sturgeon Bay Utilities for Parallel Generation Tariff Revisions

Dear Secretary Stubley:

On behalf of Sturgeon Bay Utilities ("SBU"), WPPI Energy ("WPPI") submits this request to revise and update SBU's Pgs-1 and Pgs-2 tariff schedules ("Revised Pgs Schedules") pursuant to Wis. Stats. §§ 196.19 and 196.20. The purpose of the Revised Pgs Schedules is to more appropriately reflect avoided cost in credits/payments by SBU to behind-the-meter ("BTM") distributed generation-owning customers for net excess generation, and to provide stated rates for front-of-the-meter ("FTM") distributed generators that purchase all of their energy requirements from SBU.

This application follows SBU's earlier request to revise its Pgs-1 and Pgs-2 schedules, submitted to the Public Service Commission of Wisconsin ("Commission") on July 26, 2019, in Docket 5780-TE-108.[1] It has been SBU's understanding from discussions with Commission staff that activity in that docket ceased given the Commission's subsequent Investigation of Parallel Generation Purchase Rates in Docket 5-EI-157 ("PG Rates Investigation"), and that it is

[1] PSC REF# 372911

the Commission's preference to return to SBU's earlier request in a new docket. Hence, this application is being filed contemporaneously with a request to close Docket 5780-TE-108.

The revisions also reflect changes to bring SBU's parallel generation schedules more in line with the parallel generation schedules of other Wisconsin utilities[2] and to provide just and reasonable compensation for excess generation delivered to SBU by customer-owned generation systems (COGS). SBU recognizes that with earlier changes to parallel generation schedules by other utilities, existing net metering customers have received grandfathering treatment. As discussed below, SBU's Revised Pgs Schedules provide for similar grandfathering.

SBU's utility commission unanimously approved revision of its Pgs Schedules at its June 11, 2019 meeting and has reviewed and unanimously supports the updates proposed here.

Description of Revised Pgs Schedules:

Background

When evaluating the basis for the Revised Pgs Schedules, it is important to first consider how the purchase of excess generation from a COGS by SBU under its Pgs schedules works with respect to SBU's all-requirements wholesale contract ("Supply Contract") with WPPI Energy ("WPPI").[3] The Federal Energy Regulatory Commission ("FERC") has consistently held that the avoided cost to be paid the customer of an all-requirements utility is the avoided cost of the utility's wholesale supplier. FERC first made this determination in Order No. 69 which implemented section 210 of PURPA.[4] The Commission has agreed, approving this same structure in the existing parallel generation tariffs of Wisconsin municipal utilities, including SBU's current Pgs-2 schedule. SBU's current Pgs-2 schedule provides that the rate paid to a COGS for excess generation is as specified in the latest customer-owned generation system rates of their wholesale supplier.

[2] SBU believes that the substantive provisions of the Revised Pgs Schedules are materially consistent with provisions of other utilities' parallel generation tariffs that have been approved by the Commission since its Order in Docket 5-EI-157 (PSC REF# 410850), and thus also in keeping with the conceptual framework discussed therein.

[3] SBU purchases power from WPPI under a long-term all-requirements wholesale supply agreement. This Supply Contract requires WPPI to provide to SBU, and SBU to purchase from WPPI, all of its power supply requirements. The agreement correspondingly gives WPPI the right to purchase from SBU any customer excess generation.

[4] Order No. 69, FERC Stats. & Regs. ¶ 30,128 at 30,871, *order on reh'g,* Order No. 69-A, FERC Stats. & Regs. ¶30,160 (1980), *aff'd in part and vacated in part, American Electric Power Service Corp. v. FERC, 675 F.2d 1226 (D.C. Cir. 1982), rev'd in part*, *American Paper Institute, Inc. v. American Electric Power Service Corp.,* 461 U.S. 402 (1983).

As an all-requirements member of WPPI, SBU is generally obligated under its Supply Contract to purchase all of its power supply requirements from WPPI. And in the case of purchases by SBU from COGS customers pursuant to its Pgs-2 schedule, SBU passes through that energy as WPPI requires.[5] Under this structure SBU's wholesale power purchases from WPPI are not reduced by the excess generation of a COGS on its system. SBU purchases the same amount of power from WPPI that it would have in the absence of excess COGS output, and remains in the same financial position it would have been in had it not purchased such COGS output in the first place. Thus, to the extent there is avoided cost, it occurs at the wholesale (WPPI) level, not the retail (SBU) level. SBU's proposed amendments to its parallel generation tariffs continue this structure. With respect to avoided costs, the proposed amendments to the Pgs tariffs simply take WPPI's avoided costs and specifically identify them in SBU's retail tariff (with the addition of a distribution loss factor).

Pgs-1 **– <u>BTM COGS 20 kW or less</u>**

SBU's current Pgs-1 schedule provides that customers whose generation systems have a total generating capacity of 20 kW or less will be billed monthly on a net energy basis. With net energy billing, if the COGS produces more energy than the customer's load uses in an hour, the excess amount is used to offset the customer's load in other hours of the month when the COGS does not generate enough energy to fully offset the customer's load. Effectively, the utility's system is used as a battery to absorb excess energy produced by the COGS in one hour and return it to the customer in another hour to serve that customer's load. The customer saves the retail rate for all of its load that is served by the COGS within each month. If the COGS does not generate enough energy to fully offset the customer's load in a given month, the customer buys the shortfall from the utility at the retail rate. Under SBU's current Pgs-1 schedule, if the COGS produces more energy than is needed to meet the customer's load for the month, the customer receives a payment from the utility at the retail rate. Using the retail rate for purchase of excess

[5] Pgs-1 excess energy, if any, is not currently passed directly through to WPPI because it is net energy billed on a monthly basis (effectively providing the Pgs-1 COGS with the full retail rate for any hourly excess energy that can be "stored and used" by the customer in other hours of the same month). Because Pgs-1 is limited to the COGS that are no larger than 20 kW, the anticipated amount of excess energy for any month as a whole is small, and the expected administrative cost to pass through any residual monthly excess energy, if any, to WPPI would generally exceed the benefit available from the additional precision. SBU currently has a single Pgs-2 customer (a local school) with an approximately 43kW COGS. SBU has not been asked by WPPI at this time to pass through the excess energy from this COGS, which is credited to the customer at average annual LMP.

generation results in a credit significantly above avoided cost, and thus does not send the proper price signal to customers who own, or are contemplating purchasing, COGS (and results in non-participating customers subsidizing COGS). SBU proposes to continue this rate treatment for existing ("grandfathered") COGS served under the Pgs-1 schedule through December 31, 2029, which equates to over 10 years since the Commission issued its Notice of Proceeding in 5780-TE-108 (and over 9.5 years since the Commission issued its Notice of Proceeding in the PG Rates Investigation). At that time, SBU had about a dozen customers that would qualify as grandfathered generation systems, and currently it has about 40 customers that would qualify.

As more fully described in the Revised Pgs Schedules, for new generation systems (those not grandfathered), monthly payments for excess generation will be based on the average of hourly Midcontinent Independent System Operator Inc. ("MISO") day-ahead locational marginal price ("LMP") for the previous three years, calculated on an on-peak and off-peak basis.[6] These excess generation rates will be updated annually. A loss factor will also be applied to reflect avoided distribution system losses. See Attachment A to this letter for additional detail on the calculation of this credit.

With the proposed buy-back rate, customers receive a more accurate price signal for the value of their excess generation that equates to WPPI's avoided cost. SBU notes that the current parallel generation schedules of Wisconsin's major investor-owned utilities (IOUs) compensate COGS for excess generation using forecasted LMPs from the utilities' annual fuel cost plans approved by the Commission. While a similar benchmark for projected LMPs is not used by SBU or WPPI, basing the excess generation energy buy-back on the three-year average of actual hourly LMPs is rational and transparent. It provides a beneficial smoothing effect to buy-back rates and appropriately reflects avoided cost over time.

***Pgs*-2 – <u>Behind-the-Meter (BTM) COGS greater than 20 kW and equal to or less than 5 MW</u>**

The current Pgs-2 schedule provides that for BTM COGS greater than 20 kW and less than or equal to 100 kW, monthly payments for all excess generation delivered to the utility will

[6] BTM COGS taking service under SBU's current and proposed Pgs-1 schedule realize significant value for capacity, given that through net metering their retail load is substantially offset with self-generation. These customers effectively receive the full retail rate for offsetting BTM energy usage. The full retail rate necessarily reflects embedded capacity costs, meaning that Pgs-1 customers are compensated for capacity even in the absence of an additional capacity credit.

be made as specified in the latest rates of the wholesale supplier, unless the latest rates of the wholesale supplier do not properly reflect avoided costs. For BTM COGS greater than 100 kW, the current Pgs-2 schedule provides that customers will have the right to negotiate a buy-back rate. The buy-back rate must not exceed avoided cost. There is currently no cap on the size of the COGS eligible for the Pgs-2 schedule.

SBU proposes to combine these two categories of BTM COGS (20kW – 100kW and >100kW) into one category; greater than 20 kW and up to 5 MW. The 5 MW size limit reflects the Federal Energy Regulatory Commission's ("FERC") Order No. 872 presumptive cap of 5 MW for qualified facilities with nondiscriminatory access to competitive markets like MISO's.[7] Additionally, SBU proposes to replace the current compensation components for these BTM COGS categories with the components described below (and more fully in Attachment A). Alternatively, these customers will continue to have the right to negotiate a buy-back rate, provided the buy-back rate is not greater than the full avoided cost.

A. Excess BTM COGS Energy Compensation

The revised Pgs-2 schedule provides that for BTM COGS greater than 20 kW and less than or equal to 5 MW, all excess generation delivered to the utility is cumulated on an hourly basis, and receives the same energy buy-back rate described above for new generation systems under the Pgs-1 schedule. Such BTM COGS will also receive avoided capacity payments as described below. To the extent the utility determines a separate meter is necessary, there will be a monthly meter charge of $8. SBU expects that for most customers a separate meter will be unnecessary.

B. BTM COGS Capacity Compensation

In BTM configurations, the generation output from a COGS goes first to serve the customer's own electrical demand. If the generation output is greater than the customer's demand, the COGS sells the excess energy to the utility (SBU in this case). With BTM COGS the level of excess in any interval depends not only on the generation in that interval, but also on

[7] In FERC Docket No. QM23-5-000, SBU and WPPI (and its other members) have a pending application for relief from the PURPA requirement to enter into new contracts or obligations to purchase power from qualifying facilities that have capacities greater than 5 MW.

the customer's electrical demand. Because there is no obligation for the customer to make a specific amount of generating capacity or energy available to the utility, the utility cannot rely upon the resource to meet its capacity obligations. Excess energy is supplied by the COGS to the utility "as-available". FERC has noted with respect to BTM resources that "[b]ecause the [COGS] has no obligation to deliver any energy in the future, the utility is unable to avoid constructing or contracting for capacity to meet its future needs as a consequence of the delivery of energy by the QF." Order 872 p.118.[8]

As WPPI and its members noted in comments in the Commission's PG Rates Investigation, to the extent excess energy produced by BTM COGS on member systems reduces WPPI's demand in the peak hours on which MISO bases the PRMR, and to the extent WPPI can timely and reliably identify, measure and count on that reduction in demand, the capacity needed to meet its PRMR may be reduced.[9] SBU and WPPI believe it would be practically impossible to determine with precision the value of individual BTM COGS in reducing system capacity requirements given their excess production is highly variable, and depends on the size of the COGS, its energy production profile, and the underlying load profile of the customer that owns the COGS. However, SBU and WPPI believe it would be reasonable to provide a capacity credit to each individual BTM COGS based upon the typical energy production profile of solar photovoltaic generation. SBU is proposing to provide such a capacity credit to Pgs-2 customers based upon a three-year average of auction clearing prices in MISO's annual PRA, applied to the accredited value of solar generation[10], and converted to a kilowatt-hour credit based upon a reasonable approximation of BTM COGS contributions to reducing aggregate WPPI member load during on-peak hours. These capacity credit rates will be updated annually. See Attachment A for additional detail.

[8] Under the MISO capacity construct, regardless of whether a utility satisfies its Planning Reserve Margin Requirement ("PRMR") utilizing a Fixed Resource Adequacy plan (as some Wisconsin utilities do), participates fully in the Planning Resource Auction ("PRA") as WPPI does, or utilizes a combination of both, the criteria for resources to qualify as capacity resources is the same, whether a utility "opts out" of the of the capacity auction or not. An as-available COGS will not meet the requirements of MISO's capacity construct, and will not directly count towards meeting a utility's PRMR.

[9] See PSC REF# 402990.

[10] Nearly 99% of COGS on WPPI member systems are solar photovoltaic. The existing Pgs-2 (greater than 20 kW) COGS on SBU's system is solar photovoltaic.

SBU believes this proposed methodology reasonably balances the inherent difficulty in capturing the aggregate on-peak load-reducing benefits of as-available generation and compensating COGS at a rate that is fair and avoids cross-subsidization by non-participating customers. And similar to the proposed methodology for calculating the credit for excess energy production, use of a a three-year average of annual PRA clearing prices provides a beneficial smoothing effect to buy-back rates.

C. BTM COGS Transmission Service Credit

As noted in SBU's 2019 application in Docket 5780-TE-108, WPPI's demand (load) during the hour in which the transmission system peaks each month of the year determines WPPI's cost of transmission, which is passed on to WPPI's member municipals, including SBU, through WPPI's wholesale rate. So to the extent that a COGS produces excess generation at the time of transmission system peak, WPPI's cost of transmission can be reduced. But that doesn't necessarily translate to a reduction in transmission system needs; it could just shift costs to other transmission customers. SBU and WPPI note that at the time of this application most of Wisconsin's major IOUs do not provide an avoided transmission capacity value and, like SBU and WPPI, do not have direct control over transmission system investment and therefore cannot attribute avoided transmission costs to parallel generation capacity installed within their service territories. SBU and WPPI agree that more thought and analysis is needed, and that any transmission value should be developed from a holistic view with the collaboration of Wisconsin's transmission owners. At this time, SBU includes a proposed transmission credit of $0.00/kWh as a placeholder.

<u>Pgs-2 – FTM COGS less than or equal to 5 MW</u>

SBU proposes the compensation components described below (and more fully in Attachment A), available to a FTM COGS up to 5 MW that executes a 10-year contract, subject to renewal in 5-year increments. Given the inherent risk of separation from actual avoided cost that locking in a power supply resource creates, particularly with a non-regulated seller in a dynamic energy environment, SBU and WPPI believe that the 10 year initial term (i) provides some protection to non-participating SBU customers from the risk of purchasing power from a non-regulated seller in a dynamic energy environment; and (ii) appropriately balances the risk between the COGS owner and non-participating customers.[11] Alternatively, FTM COGS will have the right to negotiate a buy-back rate, provided the buy-back rate is not greater than the full avoided cost. Currently, there is no FTM COGS taking service from SBU or from any other WPPI members.

A. FTM COGS Energy Compensation

For FTM COGS, SBU proposes to pay the same energy rate as credited to BTM COGS taking service under Pgs-2 for all output from the COGS. There will be a monthly meter charge of $8.

B. FTM COGS Capacity Compensation

SBU proposes to pay capacity compensation to FTM COGS based upon their accredited capacity determined pursuant to MISO's accreditation policies and practices based upon the COGS resource type. It is appropriate to pay more than the average annual MISO PRA price for FTM COGS, given they sell all of their generation output to the utility under a 10-year contract. However, the commensurate value for this power is less than the full MISO-determined cost of new entry ("CONE"), which approximates the annualized cost of a new advanced combustion turbine assumed to be available for decades. The appropriate value for a shorter-term 10 year resource is 50 percent of CONE calculated by MISO for the current planning year in which the resource is added, and held constant for each year of the initial term of the contract.[12] The use of this methodology allows for a straight-forward calculation of capacity credit that is consistent with an approximate value of ten-year capacity purchases.

C. FTM COGS Transmission Service Credit

For the same reasons discussed above with respect to BTM COGS, SBU includes a proposed transmission credit of $0.00/kWh as a placeholder.

[11] The Commission reached a similar conclusion in its Final Decision in Docket 3270-TE_114. ("The Commission, therefore, finds it reasonable to approve the applicant's proposal to offer a 10-year contract, with the opportunity to renew in 5-year increments.") PSC REF# 454581.

[12] The Commission reached a similar conclusion in its Final Decision in Docket 6680-TE-107. ("The Commission finds that the applicant's proposal follows cost causation principles and, therefore, authorizes the applicant to develop avoided capacity rates consistent with methods proposed by the applicant.") PSC REF# 454564.

Conclusion

SBU believes that the adjustments to its Pgs-1 and Pgs-2 schedules and the new FTM compensation components as described above are just and reasonable, and appropriately support customer-owned generation while balancing the interests of non-participating customers. The adjustments are materially consistent with provisions of other utilities' parallel generation tariffs approved by the Commission since its Order in Docket 5-EI-157, and are thus also in keeping with the conceptual framework adopted by the Commission in that docket as a starting point for parallel generation rates. SBU respectfully requests that the Commission approve the Revised Pgs Schedules.

Additionally, as has been the case with other first-time rate offerings by a member of WPPI, we anticipate that should the Commission approve this application, other WPPI municipal members will seek approval for a substantially similar changes to their parallel generation schedules. We thus respectfully request that the Commission consider delegating to staff the authority to approve such future applications.

Best Regards,

Anne Rodriguez

Anne Rodriguez
Assistant Vice President – Communications and Rates
Phone: 608-834-4569
Email: arodriguez@wppienergy.org

cc: Jim Stawicki – General Manager, Sturgeon Bay Utilities

RATE FILE

Sheet No. 1 of 2
Schedule No. Pgs-1
Amendment No. EXH

Public Service Commission of Wisconsin

STURGEON BAY ELECTRIC UTILITY

Parallel Generation (20 kW or less) -- Net Energy Billing

1. Effective In

   All territories served by the utility.

2. Availability

   Available for single-phase and three-phase customers generating power using renewable resource generators that satisfy the requirements of "qualifying facility" status under Part 292 of the Federal Energy Regulatory Commission's regulations under the Public Utility Regulatory Policies Act of 1978 where a part or all of the electrical requirements of the customer are supplied by the customer's generating facilities located behind-the-meter (BTM) on the customer's premises, where such facilities have a total generating capability of 20 kW alternating current (AC) or less, where such facilities are connected in parallel with the utility and where such facilities are approved by the utility.

3. Rate

   The customer shall be billed monthly on a net energy basis and shall pay the customer charge and energy charge(s) specified in the rate schedule under which the customer is served. When the energy produced exceeds energy consumed for the billing month, the customer shall be credited for the excess energy volumes at the energy credit component (multiplied by the loss factor) specified for BTM COGS in the utility's Pgs-2 rate schedule, unless the customer qualifies for the rate described in the next paragraph. The buy-back energy rates will be reset annually on January 1 of each year based on the most recent three-year average locational marginal price of energy in MISO at the WEC.WPPI commercial pricing node.

   The following customers will continue to be credited for net monthly excess generation at the energy rate specified in the rate schedule under which the customer purchases energy, including the monthly power cost adjustment clause (PCAC), until December 31, 2029: a) customers taking service under this rate schedule prior to <Effective Date of this Pgs-1 Schedule>; or b) customers who have submitted a complete parallel generation interconnection application to the utility by <Order Date>. A customer that makes changes to the capacity or type of its generation facilities after <Effective Date of this Pgs-1 Schedule> will be treated as a new customer and shall be subject to the standard avoided cost rate.

   If, in any month, the customer's bill has a credit balance of $100 or less, the amount shall be credited to subsequent bills until a debit balance is reestablished. If the credit balance is more than $100, the utility shall reimburse the customer by check upon request. Monthly credits shall be computed by taking the net excess kilowatt-hours produced times the applicable energy charge.

Parallel Generation (20 kW or less) -- Net Energy Billing

4. Metering and Services Facilities

   A customer who is served under a regular rate schedule shall have any ratchet and/or other device removed from the meter to allow reverse power flow and measurement of net energy used. Customers eligible for net energy billing but with existing metering facilities equipped with ratchets or other devices preventing reverse registration (i.e. time-of-use metering facilities) may request that the utility install the necessary metering to permit such billing.

   Non-Standard Meter Service, if any, is not available for customers electing the Pgs-1 Schedule.

5. Customer Obligation

   See Wis. Admin. Code ch. PSC 119; Rules for Interconnecting Distributed Generation Facilities.

6. Renewable Energy Credits and Benefits
   All renewable energy credits and benefits, emissions allowances, or other renewable energy, air emissions, or environmental benefits for which the customer's generation system qualifies under any existing or future applicable law shall remain the property of the customer.

Customer-Owned Generation Systems (Greater than 20 kW)

1. Effective In

   All territories served by the utility.

2. Availability

   Available for single-phase and three-phase customers generating power using renewable resource generators that satisfy the requirements of "qualifying facility" status under Part 292 of the Federal Energy Regulatory Commission's regulations under the Public Utility Regulatory Policies Act of 1978 who desire to sell excess generation to the utility from behind-the-meter (BTM) customer-owned generation systems (COGS), or who sell all generation to the utility from front-of-the-meter (FTM) COGS. For BTM COGS, a part or all of the electrical requirements of the customer are supplied by the COGS located on the customer's premises. For FTM COGS, all of the generation is sold to the utility under an executed service agreement between the COGS and the utility, and all of the customer's electricity usage is supplied separately by the utility under applicable retail service schedules. In either case, BTM or FTM, such facilities shall have a total generating capability of greater than 20 kW and less than or equal to 5 MW alternating current (AC), with such facilities connected in parallel with the utility, and where such facilities are approved by the utility.

   Customers not desiring to sell energy under this rate have the right to negotiate a buy-back rate. If, in lieu of taking service under this rate schedule, a customer elects to sell their excess generation to another utility or into the market administered by the Midcontinent Independent System Operator, Inc. (MISO) the utility shall transport the customer's excess generation across the utility's distribution system and shall recover actual costs of such transportation from the generating customer.

3. Rate

   Unless separately negotiated in accordance with paragraph 7 of this rate schedule, the utility shall, for all energy sold to the utility, credit the COGS at the applicable avoided cost rate specified below. The avoided cost rates will be reset annually on January 1 of each year to reflect the then current value of each component shown in the table below:

   a. For BTM COGS:

      Customers shall receive monthly payments equal to the sum of the excess energy volume (in kWh) in each On-Peak Hour of the month multiplied by **$.06627/kWh** plus the sum of the excess energy volume (in kWh) in each Off-Peak Hour of the month multiplied by **$.03613/kWh**. The following table shows the components of these rates.

Customer-Owned Generation Systems (Greater than 20 kW)

Component	On-Peak	Off-Peak
Energy Credit	$.04804/kWh	$.03508/kWh
Capacity Credit	$.01630/kWh	$.00/kWh
Transmission Credit	$.00/kWh	$.00/kWh
Sub-Total	$.06434/kWh	$.03508/kWh
x Loss Factor	1.03	1.03
Total Buy-Back Rate	**$.06627/kWh**	**$.03613/kWh**

The Energy Credit will be reset annually based on the most recent three-year average locational marginal price of energy in MISO at the WEC.WPPI commercial pricing node. The Capacity Credit will likewise be reset based on the most recent three-year average annual capacity clearing price in the MISO Planning Resource Auction.

b. For FTM COGS:
Customers shall receive monthly payments equal to:

[FTM Energy Credit + FTM Capacity Credit + FTM Trans Credit] x DLF

Where:

FTM Energy Credit = the sum of the energy produced by the FTM COGS (in kWh) in each On-Peak Hour of the month multiplied by **$.04804/kWh**, plus the sum of the energy produced by the FTM COGS in each Off-Peak Hour of the month multiplied by **$.03508/kWh**. The FTM Energy Credit is equal to the Energy Credit component specified in the table for BTM COGS and will be updated annually as described there.

FTM Capacity Credit = (1/12) x (50% x Applicable CONE) x (Cap of FTM COGS)

Applicable CONE = MISO's Cost of New Entry (specified in $/kW-year) effective when the FTM COGS and utility enter into a 10-year service agreement, subject to extension in 5 year increments at the end of the initial term and each subsequent term.

Cap of FTM COGS = MISO's accredited capacity amount (in kW) then effective for the FTM COGS.

Customer-Owned Generation Systems (Greater than 20 kW)

FTM Trans Credit = $0

DLF (Distribution Loss Factor) = 1.03

4. On-Peak and Off-Peak Hours and Holidays

On-Peak Hours:	8:00 a.m. – 8:00 p.m., Central Prevailing Time, Monday through Friday, excluding Holidays.
Off-Peak Hours:	All hours that are not On-Peak Hours.
Holidays:	New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day, or the date celebrated as such.

5. Minimum Charge
   The monthly minimum charge paid by the customer shall be the customer charge.

6. Power Factor
   The customer shall maintain a minimum power factor as specified in Wis. Stats. Chapter PSC 119.20 (7).

7. Negotiated Rates

   Customers with generation systems greater than 20 kW have the right to negotiate a buy-back rate. The buy-back rate cannot be greater than the full avoided cost.

   The following are the required procedure guidelines:

   a. The utility must respond to the customer-owned generating system within 30 days of the initial written receipt of the customer-owned generating system proposal and within 30 days of receipt of a subsequent customer-owned generating system proposal,

   b. The utility's rejection of the customer-owned generating system proposal must be accompanied by a counter-offer relating to the specific subject matter of the customer-owned generating system proposal, and

   c. If the utility is unable to respond to the customer-owned generating system proposal within 30 days it shall inform the customer-owned generating system of:

      1) Specific information needed to evaluate the customer-owned generating system proposal.

Customer-Owned Generation Systems (Greater than 20 kW)

2) The precise difficulty encountered in evaluating the customer-owned generating system proposal.

3) The estimated date that it will respond to the customer-owned generating system proposal.

d. The Commission may become involved in the utility negotiations upon showing by either the utility or the COGS that a reasonable conclusion cannot be reached under the above guidelines. The Commission may provide a waiver to the guidelines and order new negotiation requirements so that a reasonable conclusion can be reached.

e. A copy of all negotiated buy-back rates shall be sent to the Commission. These rates shall not be effective until the contract is placed on file at the Commission.

8. Charges for Energy Supplied by the Utility

Energy supplied by the utility to the customer shall be billed in accordance with the rate schedules of the utility under which the customer is served.

9. Maintenance Rate

A customer-owned generation facility may be billed lower demand charges for energy purchased during scheduled maintenance provided written approval is obtained in advance from the utility. Demand charges other than “Distribution Demand” shall be prorated if maintenance is scheduled such that the utility does not incur additional capacity costs. Such prorated demand charges shall be calculated as the demand charge rate times (the number of days in the billing period minus the number of authorized days of scheduled maintenance), divided by the number of days in the billing period.

10. Application Process and Customer Obligation

See Wis. Admin. Code ch. PSC 119, Rules for Interconnecting Distributed Generation Facilities.

11. Utility Obligation

a. Metering Facilities

The utility shall install appropriate metering facilities to record all flows of energy necessary to bill in accordance with the charges and credits of the rate schedule. To the

Customer-Owned Generation Systems (Greater than 20 kW)

extent that the utility determines a separate meter is required for the generator, the utility will charge a monthly meter charge of $8.00 for such meter. Non-Standard Metering service is not available for customer metering under this schedule.

b. Notice to Communication Firms

Each electric utility shall notify telephone utility and cable television firms in the area when it knows that a customer-owned generating facility is to be interconnected with its system. This notification shall be as early as practicable to permit coordinated analysis and testing in advance of interconnection, if considered necessary by the electric or telephone utility or cable television firm.

12. Right to Appeal

The owner of the generating facility interconnected or proposed to be interconnected with a utility system may appeal to the Commission should any requirement of the utility service rules filed in accordance with the provisions of Wis. Admin. Code § PSC 119.40, or the required contract be considered to be excessive or unreasonable. Such appeal will be reviewed and the customer notified of the Commission's determination.

13. Renewable Energy Credits and Benefits

All renewable energy credits and benefits, emissions allowances, or other renewable energy, air emissions, or environmental benefits for which the customer's generation system qualifies under any existing or future applicable law shall remain the property of the customer.

Attachment A

Summary of the Proposed Avoided Costs of Energy and Capacity, adjusted for Distribution System Loss Factor – As applied in the Parallel Generation Rates of Sturgeon Bay Utilities for Calendar Year 2023

Behind the Meter (BTM) Projects

A BTM project is a Customer-Owned Generation System (COGS) that is interconnected in parallel with the Utility's distribution system and offsets all or a portion of that customer's electricity usage.

BTM Energy Credit

Unless the COGS is net metered and qualifies under the grandfathering provisions described in the Pgs-1 service schedule[1], the energy credit for surplus energy produced by a COGS served under the Pgs-1 or Pgs-2 schedule and purchased by the Utility shall be the most recent 3-year average of the MISO Day-Ahead Locational Marginal Price (DA LMP) of electricity expressed in $/kWh at the applicable WPPI commercial pricing node (e.g., at WEC.WPPI[2] for Sturgeon Bay Utilities). This credit is calculated annually, both in terms of an average DA LMP for all hours and as a time-differentiated average DA LMP for the on-peak and off-peak periods specified in the Utility's retail electric tariffs.

Derivation of the Energy Credit applicable for January 1 – December 31, 2023

Historical Year	On-Peak[3] LMP	Off-Peak[4] LMP
Nov 1, 2019 – Oct 31, 2020	$.02628/kWh	$.01953/kWh
Nov 1, 2020 – Oct 31, 2021	$.04458/kWh	$.03213/kWh
Nov 1, 2021 – Oct 31, 2022	$.07326/kWh	$.05358/kWh
Simple Average for 2023	**$.04804/kWh**	**$.03508/kWh**

The updated 36-month average MISO DA LMP will be the price paid for excess energy purchased under the Utility's Pgs-1 and Pgs-2 rates starting each January 1 and continuing through December 31 of that year.

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[1] Grandfathered Pgs-1 customers effectively receive a payment equal to the Utility's retail rate for the surplus electricity their COGS produces, until the end of the grandfathering period. The maximum size of a COGS is limited to 20 kW (AC) under the Pgs-1 service schedule.
[2] The WPPI commercial pricing nodes are ALTW.WPPI, MIUP.WPPI, NSP.WPPI, UPPC.WPPI, and WEC.WPPI.
[3] On-Peak Hours are defined as 8:00 a.m. – 8:00 p.m. Central Prevailing Time, Monday through Friday except on the holidays nationally celebrated as New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.
[4] Off-Peak Hours are defined as all hours of the year not defined as On-Peak Hours.

Attachment A

BTM Capacity Credit

The capacity credit for BTM COGS served under the Pgs-2 schedule shall be based on the historical clearing prices from MISO's annual Planning Resource Auction (MISO PRA), applied to the typical accreditation MISO provides for solar photovoltaic generation, and converted to an equivalent energy credit.

Step 1 – Determination of the value of capacity ($/kW-year)

The capacity credit shall be calculated by averaging the annual[5] capacity clearing prices in the applicable MISO Local Resource Zone (LRZ 2 in the case of Sturgeon Bay Utilities) from the three most recent MISO PRAs. The capacity credit shall be determined prior to the current calendar year to enable the result to be included in WPPI's annual budget and wholesale rate schedules.

Historical Planning Year	Auction Results	Annual Clearing Price in Zone 2 ($/kW-Year)
June 1, 2020 – May 31, 2021	April 2020	$1.8 / kW-year
June 1, 2021 – May 31, 2022	April 2021	$1.8 / kW-year
June 1, 2022 – May 31, 2023	April 2022	$86.4 / kW-year
Simple Average for 2023[6]		**$30.0 / kW-year**

Step 2 – Determine the accredited value of solar photovoltaic generation in MISO

Although BTM generation is not accredited by MISO, the approach used by MISO in determining the accreditation level of solar generation is instructive here. MISO presently accredits solar generation at 50 percent of nameplate capacity. Thus, the annual clearing price of capacity must be multiplied by 50 percent to obtain the credit per kW of nameplate capacity for COGS consisting of solar panels.[7] The resulting capacity credit related to the nameplate capacity of the COGS is therefore $30.0 / kW-year x 50% **= $15.0/kW-year for calendar year 2023**.

[5] MISO implemented a seasonal Planning Resource Auction in May 2023 for the June 1, 2023 – May 31, 2024 Planning Year. There are four seasons in the planning year. The annual clearing price used in the determination of the annual value of capacity will be the sum of the capacity values for the four seasons beginning for the 2023/2024 Planning Year.

[6] Of interest, the MISO PRA result for the June 1, 2023 – May 31, 2024 planning year is $3.36/kW-year (sum of the four seasons).

[7] The capacity credit method described here for parallel generation schedules of SBU recognizes that the COGS will consist largely of solar photovoltaic arrays. As of December 2022, 98.6% of the 1211 BTM COGS projects located on WPPI Member Utility distribution systems were solar photovoltaic, as is SBU's single Pgs-2 customer. We believe this methodology is reasonable to apply to other non-solar BTM COGS, and note that customers have the right under the Pgs-2 tariff to negotiate a buy-back rate that could reflect the specific characteristics of their COGS.

Step 3 – Convert the Capacity Credit to an Energy Credit

The MISO PRA clearing price (expressed in $/kW-year) and adjusted to apply to nameplate capacity of solar resources under MISO's construct for resource accreditation shall be converted to an energy credit as follows:

- The amount of energy produced in a year by a fixed panel solar photovoltaic resource located in Wisconsin is expected to be at about a 15% capacity factor as indicated from NREL's[8] PVWatts calculator.[9] Thus, for each kW of nameplate capacity, a solar COGS is expected to produce approximately:
  - 15% x 1.0 kW x 8760 hours/year = **1,314 kWh/year**

- Solar energy is produced during daylight hours, typically during the 8:00 a.m. to 8:00 p.m. on-peak window for retail electric rate schedules – so a reasonable approximation is that there would be 104 weekend days plus 6 holidays per year of off-peak production and the rest would be on-peak. Thus, for each kW of nameplate capacity, a solar COGS would produce about ((365 days per year -110 off-peak days per year)/365 days per year) x 1,314 kWh/year = .7 x 1314 kWh/year = **920 kWh/year of on-peak energy**.

- Thus, the capacity credit for 1 kW of nameplate solar capacity in 2023 would convert to an energy credit of:
  - (1 kW x $15 per kW-year)/920 kwh on-peak per year = **$.01630/kWh (on-peak hours)**

  This credit will be applied to Pgs-2 BTM COGS excess generation occurring during the on-peak hours as defined in SBU's Pgs-2 rate schedule.

As described in the SBU application letter, the current Transmission Credit is zero.

<u>BTM Distribution Loss Factor</u>

Based on typical average distribution losses on WPPI member systems, the assumed distribution loss factor is **1.03**. This is consistent with the distribution loss factor approved by the Public Service Commission in the New Load Market Pricing tariff[10] for SBU.

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[8] NREL is the National Renewable Energy Laboratory

[9] The assumptions used in the PVWatts calculator are: standard module type, fixed panels, 14.08% system losses, array tilt of 20 degrees, array azimuth of 180 degrees, DC to AC size ratio of 1.2, inverter efficiency of 96%, and ground coverage ratio of 0.4. PVWatts' specific projection for Sturgeon Bay Utilities is 14.7% annual capacity factor. After examining a variety of WPPI member municipal locations in Wisconsin, WPPI determined that an annual capacity factor of 15.0 percent would be representative on average for WPPI Member Utilities in Wisconsin. This capacity factor may be applied for WPPI members located in Michigan and Iowa for the sake of consistency in implementation of WPPI's buy-back rates.

[10] The New Load Market Pricing (NLMP) tariff for Sturgeon Bay Utilities is Docket 5780-TE-106. [PSC REF # 294595]

Attachment A

Pgs-1 BTM COGS Total Buy-Back Rate for 2023

The resulting buy-back rate for surplus generation from Pgs-1 BTM COGS in calendar year 2023 is shown by component and in total in the following table:

Component	**On-Peak**	**Off-Peak**
Energy Credit	$.04804/kWh	$.03508/kWh
Sub-Total	$.04804/kWh	$.03508/kWh
x Loss Factor	1.03	1.03
Total Buy-Back Rate	**$.04948/kWh**	**$.03613/kWh**

Pgs-2 BTM COGS Total Buy-Back Rate for 2023

The resulting buy-back rate for surplus generation from Pgs-2 BTM COGS in calendar year 2023 is shown by component and in total in the following table:

Component	**On-Peak**	**Off-Peak**
Energy Credit	$.04804/kWh	$.03508/kWh
Capacity Credit	$.01630/kWh	$.00/kWh
Transmission Credit	$.00/kWh	$.00/kWh
Sub-Total	$.06434/kWh	$.03508/kWh
x Loss Factor	1.03	1.03
Total Buy-Back Rate	**$.06627/kWh**	**$.03613/kWh**

Front-of-the-Meter (FTM) Projects

A FTM project is a COGS that is interconnected to the Utility's distribution system and sells all the electricity produced from its generation to the Utility under the terms of a power sales agreement ("PSA") with an initial term of 10 years, with an option for a customer to extend the term by 5 years upon 24 month written notice to the Utility.

FTM Energy Credit

The payment for all energy produced by a FTM COGS and purchased by the Utility shall be the most recent 3-year average of the MISO Day-Ahead Locational Marginal Price (DA LMP) of electricity expressed in $/kWh at the applicable WPPI commercial pricing node (e.g., at

WEC.WPPI[11] for Sturgeon Bay Utilities). This credit is calculated annually, both in terms of an average DA LMP for all hours and as a time-differentiated average DA LMP for the on-peak and off-peak periods specified in the Utility's retail electric tariffs.

Derivation of the Energy Credit applicable for January 1 – December 31, 2023

Historical Year	On-Peak[12] LMP	Off-Peak[13] LMP
Nov 1, 2019 – Oct 31, 2020	$.02628/kWh	$.01953/kWh
Nov 1, 2020 – Oct 31, 2021	$.04458/kWh	$.03213/kWh
Nov 1, 2021 – Oct 31, 2022	$.07326/kWh	$.05358/kWh
Simple Average for 2023	**$.04804/kWh**	**$.03508/kWh**

The updated 36-month average MISO DA LMP will be the price paid for all energy purchased under the Utility's FTM Pgs-2 rates starting each January 1 and continuing through December 31 of that year.

FTM Capacity Credit

The monthly payment for capacity provided by a FTM COGS shall be equal to:

1/12 x 50% x Applicable CONE x Accredited Capacity of COGS

Where:

Applicable CONE is equal to MISO's Cost of New Entry (expressed in $/kW-year) at the time the PSA becomes effective. The Applicable CONE for PSAs effective between June 1, 2023, and May 31, 2024, is **$102.24/kW-year** throughout the initial 10-year term. If the PSA is extended, the Applicable CONE is refreshed in the month that the 5-year extension becomes effective, continuing through the extension period.

Accredited Capacity of COGS is equal to the capacity value (in kW) of the COGS as certified by MISO. The Accredited Capacity of COGS is updated annually in accordance with the MISO Tariff and associated Business Practices.

[11] The WPPI commercial pricing nodes are ALTW.WPPI, MIUP.WPPI, NSP.WPPI, UPPC.WPPI, and WEC.WPPI.
[12] On-Peak Hours are defined as 8:00 a.m. – 8:00 p.m. Central Prevailing Time, Monday through Friday except on the holidays nationally celebrated as New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.
[13] Off-Peak Hours are defined as all hours of the year not defined as On-Peak Hours.

Attachment A

Example Calculation of FTM Capacity Credit

The monthly payment for capacity from a 1,000 kW (nameplate rating) solar FTM COGS with a PSA effective on June 1, 2023, would be:

1 year/12 months x [50% x $102.24/kW-year] x [50% x 1,000 kW] = $2,130/month

As described in SBU's application letter, the current Transmission Credit is zero.

<u>FTM Distribution Loss Factor</u>

Based on typical average distribution losses on WPPI member systems, the assumed distribution loss factor is **1.03**.

<u>Total Buy-Back Rate for FTM COGS effective in 2023</u>

Total = **[FTM Energy Credit + FTM Capacity Payment + FTM Transmission Credit] x FTM Distribution Loss Factor**