PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Wisconsin Public Service Corporation for Approval of Proposed Changes to its Parallel Generation Tariffs — 6690-TE-114

FINAL DECISION

This is the Final Decision in the application of Wisconsin Public Service Corporation (applicant) for approval of proposed updates to its parallel generation tariffs and avoided cost rates. The applicant's request for tariff modifications and updated avoided cost rates is APPROVED, subject to the modifications and conditions outlined in this Final Decision.

Introduction

On September 1, 2021, the applicant filed an application for approval of parallel generation tariff modifications and avoided costs. (PSC REF#: 419885.) The application included proposals to update and modify its parallel generation schedules. This proceeding considered whether the applicant's proposed parallel generation tariff modifications and avoided costs are reasonable.

The Public Service Commission of Wisconsin (Commission) issued a Notice of Proceeding in this docket on October 7, 2021. (PSC REF#: 422305.) Citizens Utility Board of Wisconsin (CUB), Tomahawk Power and Pulp Company, RENEW Wisconsin (RENEW), and the Wisconsin Industrial Energy Group (WIEG) were granted party status. On May 25, 2022, the Commission issued a Notice of Hearing for the parties and members of the public. (PSC REF#: 438682.) In total, 18 public comments were received in this docket. (PSC REF#: 443364.)

The Commission considered this matter at its open meetings of September 8, 2022 and December 8, 2022.

Findings of Fact

1. The applicant is a public utility as defined in Wis. Stat. § 196.01(5)(a) and provides electric service in Wisconsin.

2. It is reasonable to approve the revised tariff availability language as filed including the addition of a generation design capacity threshold of 15 megawatt (MW) in Parallel Generation Non-Purchase (PG-1), the expansion of the maximum capacity limit from 2 MW up to 5 MW in Parallel Generation-Purchase by WPSC (PG-2A), and the conversion of Parallel Generation-Purchase by WPSC (PG-2B) tariff into a behind the meter (BTM) offering that would include a maximum capacity limit of 1 MW.

3. It is reasonable to approve the applicant's request to convert its PG-2B tariff to a BTM tariff that would compensate customers with generating systems up to 1 MW for avoided capacity and avoided energy.

4. It is reasonable to approve the proposed metering requirement for the applicant's PG-2A and PG-2B tariffs as filed.

5. It is reasonable to approve the telemetry charge and tariff language as reflected in Ex.-WPSC-Nelson-10 for the PG-2A and PG-2B tariffs.

6. It is reasonable to approve the avoided energy cost rates as proposed by the applicant which will use forecasted LMPs for its Parallel Generation-Net Energy Billing (PG-4), PG-2A, and PG-2B tariffs.

7. It is reasonable to modify and approve the applicant's proposed use of the Midcontinent Independent System Operator, Inc. (MISO) Zone 2 CONE value as the basis for avoided capacity payments for both front of the meter (FTM) and BTM resources and directed that avoided capacity credits should be calculated for FTM resources based on the resource's accredited capacity consistent with MISO's capacity accreditation methodology, and for BTM resources calculated in the manner proposed by RENEW.

8. It is reasonable to approve the applicant's proposal to set the avoided transmission cost rate at $0, but to include, as a placeholder in the tariff sheets, a billing determinant for which a rate can be established if and when customer-owned generation enables the utility to avoid transmission costs.

9. It is reasonable to direct the applicant to file with the Commission, by August 1, 2023, further analysis on a calculation for avoided transmission costs.

10. It is reasonable to approve the use of average line losses as proposed by the applicant.

11. It is reasonable for the applicant to submit additional parallel generation tariff revisions in response to future MISO and/or Federal Energy Regulatory Commission (FERC) proposals.

12. It is reasonable to direct that applicant to expand the applicability of FTM tariffs to include QF developers.

13. It is reasonable to direct the applicant to propose 5-, 10-, and 15-year contracts for FTM resources the next time the applicant comes before the Commission to propose changes to its parallel generation tariffs.

Conclusions of Law

1. The Commission has authority under Wis. Stat. §§ 1.12, 196.03, 196.20, and 196.37 to issue an order requiring the applicant to file tariffs with the Commission which update the applicant's parallel generation tariffs and determine utility avoided energy and capacity costs.

2. The Commission has authority under Wis. Stat. §§ 196.03, 196.20, 196.37, and 196.395 to authorize the applicant to establish electric rates and rules in accordance with this Final Decision and to determine that the rates and rules approved herein are reasonable and just.

Background

On June 11, 2020, the Commission issued a Notice of Investigation in docket 5-EI-157 to consider parallel generation purchase rates. (PSC REF#: 391581.) As part of the investigation, the Commission instructed all electric utilities in the state to file with the Commission information identifying all active distributed generation rates, and specifying how the rates take into account each of the factors for determining avoided costs outlined in 18 CFR § 292.304(e)(2)-(4). (PSC REF#: 393351.)

In docket 5-EI-157, the Commission adopted, as a starting point for further review, that avoided energy, capacity, and transmission costs shall be calculated under a conceptual framework outlined by Commission staff in the Commission's memorandum dated February 22, 2021. (PSC REF#: 406268 at 8-9.) Under the framework, each utility would provide total system economic and engineering modeling of the incremental and decremental costs for that utility's resource mix and load shape.

The avoided energy, capacity, and transmission costs identified through the aforementioned modeling procedures were recognized as a starting point for avoided cost values, which could then be reviewed by utilities and the Commission for adaptations to utility-specific circumstances. On May 4, 2021, the Commission issued an Order in docket 5-EI-157 directing each large investor-owned utility (IOU) to file electric tariff (TE) dockets by September 1, 2021, detailing how it would conform, respond, or make changes to its tariffs to implement the conceptual framework. (PSC REF#: 410850.)

Opinion

As ordered by the Commission's May 4, 2021 Order in docket 5-EI-157, the applicant proposed modifications to its parallel generation tariffs and avoided cost rates. The applicant initially focused its proposed revisions upon energy and capacity rates. Additionally, the applicant proposed tariff revisions relating to avoided transmission costs, telemetry charges, and certain administrative and clerical matters, including tariff participation parameters.

In response to the Commission's Order and Final Decision in docket 5-EI-157, the applicant engaged in an exercise to enact reforms restructuring its parallel generation tariffs, as referenced in the above list of tariff modifications. A rigorous dialogue between the applicant, the parties, and Commission staff facilitated the development of questions, proposals, counter-proposals, compromises, and disagreement to the applicant's proposals. The Commission considered each proposal as part of its review of the record in the proceeding, which are further described in the following sections of this Final Decision.

Availability Criteria

The applicant proposed three availability revisions to its presently offered PG tariffs. Under the PG-1 tariff, the applicant proposed to include the addition of a generation design capacity threshold of 15 MW. Under its PG-2A tariff, the applicant proposed to expand the maximum capacity limit from 2 MW up to 5 MW.

The applicant initially did not propose a change to the 5 MW maximum capacity limit of its PG-2B tariff. The applicant later proposed to convert its PG-2B tariff into a BTM offering that would include a maximum capacity limit of 1 MW.

FERC Order 872 amended the Public Utilities Regulatory Policies Act (PURPA) by lowering the Mandatory Purchase Obligation for Small Power Production Facilities from 20,000 kilowatt (kW) to 5,000 kW when non-discriminatory access to markets exist for Qualifying Facilities (QF) greater than 5,000 kW.

The applicant commented that its proposed revisions are reasonable, comply with PURPA, reflect its avoided costs, represent a fair approach to compensating customer-owned generation without cross-subsidies, and are consistent with FERC Order 872.

Tomahawk commented that the language of the as-filed PG-2A and PG-2B tariffs could wrongly be read to exclude current customers from receiving capacity payments, but that it had no issue with the tariffs' terms of availability. Similarly, Commission staff testified that it did not identify issues with the applicant's proposal.

In light of the evidence presented in this proceeding, and in consideration of the entirety of the record, the Commission finds it reasonable to approve the revised tariff availability language as filed including the addition of a generation design capacity threshold of 15 MW in PG-1, the expansion of the maximum capacity limit from 2 MW up to 5 MW in PG-2A, and the conversion of PG-2B tariff into a BTM offering that would include a maximum capacity limit of 1 MW.

Commissioner Huebner concurs with the decision to approve the tariff availability language as proposed, but dissents as he would also require the applicant to modify its tariffs to specify that the availability thresholds are measured in AC.

Metering Requirements

The applicant's current PG-2A and PG-2B customers have one bidirectional meter that allows instantaneous netting of electrical energy consumption. In this proceeding, the applicant proposed to add a requirement that PG-2A and PG-2B customers have two meters: a generation meter that will measure the generator's total outflows of energy, and a production retail consumption meter that will measure the total inflows of energy. Customers that have a single bidirectional meter today may keep using it in the future, and the proposed metering would only apply to new PG-2A and PG-2B customer-owned generation installations.

The applicant maintained that its proposal would allow it to more reliably measure and plan for each distributed generation resource's output to the grid and provide a Cost of New Entry (CONE) based capacity credit to the distributed generation resources taking service under the PG-2A and PG-2B tariffs. No parties to the proceeding objected to the applicant's proposal.

Ultimately, upon its review of the record, the Commission finds it reasonable to approve the metering requirements as proposed.

Telemetry

The applicant's initial application included a proposed telemetry charge of $0.73071 per day, which would be assessed to customers at the applicant's discretion. The applicant maintained that the telemetry and telecommunications equipment will provide the framework to transfer power flow data from the customer meter to the applicant's energy management system, which will support the real-time planning and reliability of the distribution system.

In the course of the proceeding the applicant offered a modified telemetry proposal. Specifically, the applicant proposed to modify its existing PG-2A tariff, and in the newly proposed PG-2B tariff, to include a $0.73071 per day telemetry charge. After a preliminary review of the proposed generation facility installation, the applicant would advise the customer of any communication equipment requirements. Telemetry equipment would be installed when the aggregate nameplate generation capacity is greater than or equal to 300 kW and it is anticipated that excess energy will be delivered to the applicant. Ex.-WEPCO-Nelson-10. The modified telemetry proposal would only be applicable to new customers, and when telemetry equipment is installed for measuring real-time power flows.

The applicant stated its proposed telemetry charge is reasonable because it needs the option of installing telemetry equipment at customer-owned generation facilities to maintain a reliable distribution system and support instantaneous planning. Such equipment will allow the applicant to assess whether a particular customer-owned generator is producing electricity in real time and to monitor real-time voltage and the status of distribution interconnection breakers. Ultimately, the applicant's revised telemetry proposal was supported by CUB and RENEW, and no parties offered objections.

In light of the evidence in this proceeding, and because the parties ultimately agreed upon the terms of the proposal, the Commission finds it reasonable to approve the applicant's proposal to implement a telemetry charge and tariff language as reflected in Ex.-WEPCO-Nelson-10 for the PG-2A and PG-2B tariffs.

Commissioner Huebner dissents.

Tariff Conversion

The applicant proposed converting its PG-2B tariff, which presently offers an instantaneous netting service in which buy-back energy rates vary by day based on the day-ahead LMP at the WPS. WPSM pricing load zone, to a BTM tariff that would compensate customers with generating systems up to 1 MW for avoided capacity and avoided energy. The avoided energy rate will be set to the yearly forecasted day-ahead LMP for the WPS.WPSM pricing load zone. The avoided capacity cost rate will be based on the CONE. The avoided transmission cost rate will be set at $0. Table 1 below offers a comparison the present PG-2B tariff and the newly proposed PG-2B tariff.

Table 1 Tariff Comparison

	PG-2B (Present)	PG-2B (Proposed)
Eligibility Threshold	2MW to 5 MW	Up to 1 MW
Applicability	Behind the Meter	Behind the Meter
Energy Buyback Rate	Average Day-Ahead LMP	Forecasted LMP
Capacity Buyback Rate	$0	Based on CONE
Transmission Buyback Rate	NA	$0

The reasonableness of the applicant's proposed avoided energy cost rate, avoided capacity cost rate, and avoided transmission cost rate will be reviewed in latter sections of this Final Decision. Overall, however, the applicant commented that its proposal was developed in response to RENEW's request for a tariff that would allow BTM resources to be eligible for capacity payments.

RENEW commented that it supported the approval of a tariff available to behind-the-meter generating systems up to 1 MW and does not object to the applicant's proposal to convert its existing PG-2B tariff to such a tariff. RENEW did not agree with the proposed avoided capacity cost rate and avoided transmission cost rates in the proposed BTM tariff, which will be addressed in latter sections of this Final Decision.

Due to the responsive nature of the applicant's proposal, and in consideration of the evidence in this proceeding, the Commission finds it reasonable to approve the applicant's request to convert its PG-2B tariff to a new tariff that would be available to behind the meter BTM customers with a generating system of up to 1 MW.

Avoided Energy

In the Commission's May 4, 2021 Order in docket 5-EI-157, the Commission adopted a conceptual framework for the calculation of avoided electric energy, capacity, and transmission costs under which total economic and engineering modeling of the incremental and decremental costs for a utility's resource mix and load shape shall serve as a starting point for determining appropriate rates. Specifically, the Commission reviewed using forecasted LMPs to calculate energy rates.

The applicant's current avoided energy cost rates for PG-4 and PG-2A are updated January 1 of each year based on the actual hourly average day-ahead LMP at the WPS.WPSM pricing load zone for the most recently completed November 1 through October 31 period. The rates are differentiated by TOU (on-peak versus off-peak). The PG-2B rates vary based on day-ahead LMPs at the WPS.WPSM pricing load zone.

The applicant has proposed to use forecasted LMPs for its PG-4 and PG-2A tariffs; the avoided energy costs would be updated annually beginning January 1 of each year. The applicant also proposed to transition away from the average day-ahead LMP method used in its existing PG-2B tariff. In the applicant's proposal to convert to a new PG-2B tariff, the applicant proposed to use the same forecasted LMP approach as was proposed for the PG-2A tariff. The forecasted LMPs will continue to be differentiated by season and time-of-use (TOU) based on the size and class of customer taking service – the avoided energy cost rates are either flat (the same for all hours), or differentiated by season (summer vs non-summer) and TOU (on-peak vs off-peak).

The applicant maintained that its PG-4, PG-2A, and PG-2B tariffs use of forecasted LMPs is consistent with the Commission's May 4, 2021 Order and public comments in docket 5-EI-157. According to the applicant, LMPs represent its actual avoided energy costs because, if it did not receive energy produced by customer-owned generation, the applicant would pay the LMP to buy energy in the wholesale market.

CUB commented that because the market value of energy within MISO is tied to LMP, the applicant's proposed energy credit rate structure places customer-owned generation on generally equal footing with applicant-owned generation, which it found to be reasonable. However, CUB also commented that if the Commission were to require long-term contracts, a more analytically rigorous approach could help ensure that energy credit rates under standard-offer contracts balance future risk between the applicant and customers (both generation owners and non-generation owners).

RENEW testified that, although it does not object to using single-year LMP forecasts to determine avoided energy payments for non-contracted, behind-the-meter resources, for front-of-the-meter resources, avoided energy costs should be calculated based on a long-run forecast of LMPs. A single year forecast does not reflect the applicant's costs "but-for" the parallel generation resource. Front-of-the-meter resources should receive a fixed avoided energy payment reflecting long-run forecasted LMPs over the term of a contract.

Commission staff commented that the applicant's proposed avoided energy credits appear to follow the principles set forth by the Commission's May 4, 2021 Order in docket 5-EI-157, and that it did not object to the applicant's use of forecasted LMPs differentiated by season and TOU periods Commission staff did, however, comment that the Commission could consider requiring the applicant to implement a true-up mechanism to account for variations in forecasted and actual LMPs.

The Commission, upon its review of the record in this proceeding, finds the forecasted LMP approach proposed by the applicant is a reasonable method for establishing avoided energy cost rates. This approach adequately addresses the conceptual framework described in the Commission's 5-EI-157 Order for determining appropriate rates for excess generation. Furthermore, the Commission does not find it reasonable to order the applicant to offer fixed energy rates for parallel generation customers that enter into longer-term contracts, nor was it persuaded to direct the applicant to implement a true-up mechanism.

Avoided Capacity

The applicant's current avoided capacity cost rates for its PG-4, PG-2A, and PG-2B service offerings are based on the clearing price of MISO annual Planning Resource Auction (PRA). The PRA is then divided by the number of on-peak hours to derive an on-peak per kWh capacity credit rate. In this proceeding, the applicant has proposed to use the CONE, at the applicable Local Resource Zone and Planning Year, to reflect avoided capacity costs. The CONE value will apply to the PG-2A and PG-2B service offerings, but not to PG-4; in its revised

PG-4 tariff, the applicant has included an avoided capacity cost rate of $0. The applicant's proposal would also base the monthly credit on an individual generation facility's actual energy delivery to the grid during the applicant's monthly net peak load hour, determined by subtracting the applicant's owned renewable generation from its hourly load.

It is the applicant's position that, for PG-2A and PG-2B, CONE is reasonable because it serves as a proxy for the long-term value of capacity; is used in its own generation planning; is informed by economic and engineering modeling; and represents a significant increase in avoided capacity cost payments. Moreover, the applicant maintained that subtracting its owned renewable generation from its hourly load is reasonable because it ties payments to actual performance of customer-owned generation to meet the applicant's needs during peak demand.

CUB testified that the applicant's proposed capacity accreditation methodology is not unreasonable overall but that the Commission may wish to consider whether other methodologies, such as MISO's, are more appropriate. CUB commented that, should the Commission approve the applicant's proposed capacity credit, it could require that the applicant collect and report data on the impact its new renewable facilities have on the timing of net peak load and thus capacity credits to PG customers.

Similarly, RENEW questioned the applicant's proposed accreditation methodology. Although RENEW supported the use of MISO Zone 2 CONE as the pricing input for an avoided capacity credit, it testified that the avoided capacity credits should be calculated based on a resource's accredited capacity consistent with MISO's currently effective capacity accreditation methodology.

Tomahawk commented that capacity credits should be priced as proposed by applicant; and that existing PG-2A and PG-2B customers, including Tomahawk, may receive capacity credit by electing to be treated as new customers under either of the proposed PG-2A or PG-2B tariffs if they conform to the tariff metering requirements.

Commission staff testified that it did not object to the capacity credit calculation proposed by the applicant, but commented that the Commission could consider whether or not it may be reasonable to assume a customer with a generation facility is in a position, or has information readily available to them, to determine when a monthly peak may occur.

Ultimately, the Commission finds it reasonable to modify and approve the applicant's proposed use of the MISO Zone 2 CONE value as the basis for avoided capacity payments for both FTM and BTM resources. However, in light of the record, the Commission directs that avoided capacity credits should be calculated for FTM resources based on the resource's accredited capacity consistent with MISO's capacity accreditation methodology, and for BTM resources calculated in the manner proposed by RENEW.

Commissioner Nowak dissents.

Avoided Transmission

In the Commission's May 4, 2021 Order in docket 5-EI-157, which directed the filing of the tariffs under review in this docket, the Commission adopted a conceptual framework for the calculation of avoided electric energy, capacity, and transmission costs under which total economic and engineering modeling of the incremental and decremental costs for the utility's resource mix and load shape shall serve as a starting point for determining appropriate rates.

For its PG-2A and PG-2B tariffs, the applicant did not include an avoided transmission cost component, and thus do not compensate customers for avoided transmission costs through any credit.

In this proceeding, the applicant's proposal for all of its parallel generation tariffs is to set the avoided transmission cost rate at $0, but to include as a placeholder in the tariff sheets a billing determinant for which a rate can be established if and when customer-owned generation enables the utility to avoid transmission costs.

The applicant maintained that PURPA does not require utilities to pay avoided transmission costs. Furthermore, the applicant stated that because distributed generation does not offset any of its transmission costs in the short-term, and could do so only theoretically, it would be inappropriate and inequitable to compensate distributed generation customers for these costs.

CUB testified that parallel generation provides short- and long-term transmission benefits to the grid, and the applicant's avoided transmission credit of $0 does not reasonably value grid benefits of parallel generation and is not in the public interest.

RENEW testified that avoided transmission costs should be calculated based on an analysis of avoidable marginal load growth-related transmission investments. Avoided transmission costs should be credited on a dollar per kW-month basis for FTM resources, and a dollar per kWh basis during peak hours for behind-the-meter resources. In the alternative, RENEW suggested that the Commission could approve a transmission credit based on the applicant's embedded transmission costs until the applicant completes a marginal transmission cost analysis.

Tomahawk commented that the applicant pays American Transmission Company LLC (ATC) for transmission service based on its load-ratio share of ATC costs, and if a parallel generation customer reduces the applicant's load-ratio share, its transmission costs will be reduced. Even if that reduction is shifted to other utilities, the applicant will realize avoided transmission costs.

Commission staff commented that although it may be correct that transmission costs cannot be avoided in the short and medium term, it is not clear the applicant based its conclusion on any particular analysis as requested by the Commission in its conceptual framework and Final Decision in docket 5-EI-157.

Upon its review of avoided transmission costs, as presented in the record of this proceeding, the Commission finds it reasonable to approve the applicant's proposal to omit avoided transmission costs from its PG tariffs.

Commissioner Huebner dissents.

The Commission does, however, remain interested in the topic of avoided transmission costs. Although the record at this time does not persuade the Commission to include an avoided transmission costs in the applicant's PG tariffs, the Commission directs the applicant to conduct further analysis on the calculation for avoided transmission costs, which the applicant shall file with the Commission by August 1, 2023.

Commissioner Nowak dissents and would not have required further analysis of avoided transmission costs.

Loss Factors

The applicant proposed to use average distribution line losses for the purposes of computing avoided costs. The distribution losses would vary by voltage level of interconnection. The proposed loss factors would apply to its proposed avoided energy payments and avoided capacity payments. Line losses would not apply to the computation of avoided transmission costs.

The applicant maintained that average loss factors are widely understood and consistent with how distribution losses are applied to energy sales for the applicant's other retail customers. The applicant further commented that its proposal results in avoided cost rates that accurately reflect the distribution losses and therefore treat both participating and non-participating customers fairly. Alternatively, both Clean Wisconsin and RENEW commented that the Commission should apply marginal loss factors to avoided energy, capacity, and transmission values.

Upon its review of the record in this proceeding, the Commission finds it reasonable to approve the use of average line losses as proposed by the applicant.

Future Updates

As identified in the record of this proceeding, future MISO and/or FERC proposals and actions may impact the applicant's parallel generation tariffs. For example, MISO recently responded to a compliance filing that is intended establish a framework with supporting tariff language to implement FERC Order 2222. FERC Order 2222 requires MISO to make wholesale markets accessible to individual distributed energy resources (DER), or aggregations of multiple DERs with a minimum combined capacity of 100 kW.

The applicant commented that it does not object to any requirement that it submit additional parallel generation tariff revisions in response to future MISO and/or FERC proposals, but conditioned its position on it not having to submit any tariff revisions before MISO's implementation of FERC Order 2222 takes effect.

CUB supported a recommendation that the Commission's final order require the applicant to timely file updated tariffs that respond to relevant actions by MISO or FERC, including anticipated changes in MISO's seasonal construct and in MISO implementation of FERC Order 2222.

Commission staff commented that the Commission may consider requiring the applicant to develop an Order 2222 implementation plan that incorporates methods for determining the value of long-term avoided transmission costs associated with collaborative planning efforts.

In light of the record and in recognition of the changing landscape as it relates to MISO and FERC regulatory directives, the Commission finds it reasonable to direct the applicant to submit additional parallel generation tariff revisions in response to future MISO and/or FERC proposals.

Additional Modifications

In the Commission's May 4, 2021 Order in docket 5-EI-157, the Commission adopted a conceptual framework for the calculation of avoided electric energy, capacity, and transmission costs under which total economic and engineering modeling of the incremental and decremental costs for the utility's resource mix and load shape shall serve as a starting point for determining appropriate rates. Beyond the issues addressed in the above sections of this Final Decision, the Commission was asked to consider additional actions or investigate any additional issues related to the applicant's parallel generation tariffs.

CUB recommended that the Commission consider whether the applicant's tariffs should be modified to include standard-offer long-term contracts, consistent with cost allocation and ratemaking principles and with the public interest. RENEW recommended that the applicant should make FTM tariffs available to third-party-owned QFs, offer contract lengths of 5-, 10-, and 20-years to FTM resources, develop a standard offer contract for FTM resources greater than 100 kW, and study avoided distribution and environmental costs and insert a placeholder in its tariffs for those costs.

The applicant commented that RENEW's policy preferences to expand the applicability of FTM tariffs to include QF developers and implement long-term contracts for FTM tariffs are not at issue in this docket and not required by PURPA. Additionally, the applicant stated that long-term contracts would be inconsistent with PURPA because they would not base compensation on actual avoided costs, but rather on fixed payments, thereby benefitting participating customers at non-participating customers' expense, resulting in cross-subsidization and a discriminatory approach.

The Commission finds that the record supports further modifications beyond the issued addressed in earlier sections of this Final Decision. Specifically, the Commission finds it reasonable to expand the applicability of FTM tariffs to include QF developers. Furthermore, the Commission finds it reasonable to direct the applicant to offer a proposal that includes 5-, 10-, and 15-year contracts for FTM resources the next time the applicant comes before the Commission to propose changes to its parallel generation tariffs.

Commissioner Nowak dissents.

Implementation of Rates

The tariff changes discussed in the Final Decision may necessitate allowing for the applicant sufficient time to clearly define new tariff parameters to move forward with, and plan accordingly to test new bill coding, metering configurations, and other implementation steps.

Additionally, the applicant clarified that its preferred plan to update its avoided energy cost rates each year not as part of each fuel plan docket but using the forecasted LMPs that are approved in each fuel plan docket. At that point, the applicant will file a request to update its avoided energy cost rates in this TE docket prior to January 1 of each year using the forecasted LMPs approved in its annual fuel plan. (PSC REF#: 442205 at 16.) As such, the final rates and tariff sheet may not become effective no earlier than January 1, 2023 but shall be implemented within a reasonable timeframe.

The Commission finds it reasonable for the applicant to annually update its parallel generation tariffs with updated avoided energy rates consistent with its proposed forecasted LMP method (and consistent with its annual fuel plan filing) and avoided capacity rates consistent with the method outlined in is application, and as modified by this Final Decision. The applicant shall submit an annual compliance filing to update its parallel generation tariffs consistent with the Commission's decision under a tariff electric (TE) docket.[1] The Commission, as it does in any proceeding, encourages the applicant to work with Commission staff and keep them informed of any developments or delays related to the applicant's request for implementation of new rates.

Order

1. The authorized rate adjustments and tariff provisions that restrict the terms of service may take effect no sooner than January 1, 2023, provided that the applicant file these rates and tariff provisions with the Commission and makes them available to the public pursuant to Wis. Stat. § 196.19 and Wis. Admin. Code § PSC 113.0406(1)(a) by that date. If these rate

[1] The applicant's compliance filing for rates effective in 2023 shall be filed in docket 6690-TE-114. Subsequent annual compliance filing shall be made in separate TE dockets.

adjustments and tariff provisions are not filed with the Commission and made available to the public by that date, they take effect one day after the date they are filed with the Commission and made available to the public.

2. The applicant shall implement the revised tariff availability language as filed including the addition of a generation design capacity threshold of 15 MW in PG-1, the expansion of the maximum capacity limit from 2 MW up to 5 MW in PG-2A, and the conversion of PG-2B tariff into a BTM offering that would include a maximum capacity limit of 1 MW.

3. The applicant shall implement a PG-2B tariff to a BTM tariff that would compensate customers with generating systems up to 1 MW for avoided capacity and avoided energy.

4. The applicant shall implement the proposed metering requirement for the applicant's PG-2B and PG-2B tariffs as filed.

5. The applicant shall implement a telemetry charge and tariff language as modified by the applicant for the CGS-DS-FP and CGS-CU tariffs.

6. The applicant shall implement the avoided energy cost rates as proposed by the applicant which will use forecasted LMPs for its PG-4, PG-2A, and PG-2B tariffs.

7. The applicant shall implement its proposed use of the MISO Zone 2 CONE value as the basis for avoided capacity payments for both FTM and BTM resources. The avoided capacity credits shall be calculated for FTM resources based on the resource's accredited capacity consistent with MISO's capacity accreditation methodology, and for BTM resources calculated in the manner proposed by RENEW.

8. The applicant shall set the avoided transmission cost rate at $0, but to include, as a placeholder in the tariff sheets, a billing determinant for which a rate can be established if and when customer-owned generation enables the utility to avoid transmission costs.

9. The applicant shall file with the Commission, by August 1, 2023, further analysis on a calculation for avoided transmission costs.

10. The applicant shall implement the use of average line losses as proposed.

11. The applicant shall submit additional parallel generation tariff revisions in response to future MISO and/or FERC proposals.

12. The applicant shall expand the applicability of its FTM tariffs to include QF developers.

13. The applicant shall propose 5-, 10-, and 15-year contracts for FTM resources the next time the applicant comes before the Commission to propose changes to its parallel generation tariffs.

14. The applicant shall, on an annual basis, file parallel generation tariff sheets with updated avoided energy and capacity costs. The updated tariff sheets shall be filed in a TE docket.

15. The applicant shall file final form tariffs with the Commission consistent with this Final Decision.

16. The Final Decision takes effect one day after the date of service.

17. Jurisdiction is retained.

Concurrence and Dissent

Commissioner Huebner concurs in part, dissents in part, and writes separately (see attached).

Dated at Madison, Wisconsin, the 8th day of December, 2022.

By the Commission:

Cru Stubley
Secretary to the Commission

CS:TB:dsa:DL:01915229

Attachment

See attached Notice of Rights

PUBLIC SERVICE COMMISSION OF WISCONSIN
4822 Madison Yards Way
P.O. Box 7854
Madison, Wisconsin 53707-7854

NOTICE OF RIGHTS FOR REHEARING OR JUDICIAL REVIEW, THE TIMES ALLOWED FOR EACH, AND THE IDENTIFICATION OF THE PARTY TO BE NAMED AS RESPONDENT

The following notice is served on you as part of the Commission's written decision. This general notice is for the purpose of ensuring compliance with Wis. Stat. § 227.48(2), and does not constitute a conclusion or admission that any particular party or person is necessarily aggrieved or that any particular decision or order is final or judicially reviewable.

PETITION FOR REHEARING

If this decision is an order following a contested case proceeding as defined in Wis. Stat. § 227.01(3), a person aggrieved by the decision has a right to petition the Commission for rehearing within 20 days of the date of service of this decision, as provided in Wis. Stat. § 227.49. The date of service is shown on the first page. If there is no date on the first page, the date of service is shown immediately above the signature line. The petition for rehearing must be filed with the Public Service Commission of Wisconsin and served on the parties. An appeal of this decision may also be taken directly to circuit court through the filing of a petition for judicial review. It is not necessary to first petition for rehearing.

PETITION FOR JUDICIAL REVIEW

A person aggrieved by this decision has a right to petition for judicial review as provided in Wis. Stat. § 227.53. In a contested case, the petition must be filed in circuit court and served upon the Public Service Commission of Wisconsin within 30 days of the date of service of this decision if there has been no petition for rehearing. If a timely petition for rehearing has been filed, the petition for judicial review must be filed within 30 days of the date of service of the order finally disposing of the petition for rehearing, or within 30 days after the final disposition of the petition for rehearing by operation of law pursuant to Wis. Stat. § 227.49(5), whichever is sooner. If an *untimely* petition for rehearing is filed, the 30-day period to petition for judicial review commences the date the Commission serves its original decision.[2] The Public Service Commission of Wisconsin must be named as respondent in the petition for judicial review.

If this decision is an order denying rehearing, a person aggrieved who wishes to appeal must seek judicial review rather than rehearing. A second petition for rehearing is not permitted.

Revised: March 27, 2013

[2] *See Currier v. Wisconsin Dep't of Revenue,* 2006 WI App 12, 288 Wis. 2d 693, 709 N.W.2d 520.

APPENDIX A

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Docket 6690-TE-114

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Docket 6690-TE-114

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Docket 6690-TE-114

PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Wisconsin Public Service Corporation for Approval of Proposed Changes to its Parallel Generation Tariffs — 6690-TE-114

CONCURRENCE AND DISSENT OF COMMISSIONER TYLER HUEBNER

I write to concur with many of the Public Service Commission of Wisconsin's (Commission) decisions in this docket. The approved tariffs improve upon Wisconsin Public Service Corporation (applicant) tariffs, moving them towards providing just and reasonable avoided costs to parallel generation resources. In particular, the addition of a generation capacity credit based on the Cost-of-New-Entry (CONE) value is an important step forward.

However, the Commission's approved avoided costs omit an avoided transmission capacity cost, leaving work unfinished. The applicant has previously included transmission credits in at least one of its parallel generation tariffs, and the strength of the record on this issue leads me to find the lack of a transmission credit in this docket unreasonable. I dissent on this item.

I also discuss areas where I found multiple alternatives could have been found just and reasonable based on the record and deserve further consideration in future proceedings, and include a summary table of the key decisions in this docket.

Tariff Availability

I concur with the applicant's final proposed tariff options[1] and the Commission's decision to approve a distinct Front-of-the-Meter (FTM) tariff with availability up to 5

[1] Ex.-WPSC-Nelson-10

megawatts (MW) (Pg-2A) and a Behind-the-Meter (BTM) tariff with availability up to 1 MW (Pg-2B). I also concur with the Commission's decision to order the applicant to explicitly make these tariffs available to Qualified Facilities, as defined in the Public Utility Regulatory Policies Act of 1978 (PURPA). The genesis of these IOU parallel generation dockets was a consumer complaint from a hydropower qualified facility,[2] and it is important and reasonable to ensure QFs are eligible for these tariffs.

In contrast to some other tariffs, the applicant's tariffs do not specify whether the availability criteria is measured in alternating current (AC) or not. Unfortunately, witness testimony did not tackle this issue. However, I would have had the applicant affirmatively update its tariff to specify capacity measurements in kW-AC or MW-AC instead of kW or MW. Such an inclusion increases clarity for the utility, customers, and stakeholders.

However, I want to highlight my understanding of PG-2B's availability to "total customer owned generating capacity of 1,000 kW or less."[3] My understanding is that "customer" is generally designated by the receipt of service at a specific location and/or contiguous property. For example, two Walmart starts in two different communities would be two different "customers" under this definition, and each could install a generating system of up to 1 MW under this tariff. If that is not correct, I encourage the applicant to clarify this phrasing in a future revision.

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[2] *Request for Formal Review of Complaint Filed by Tomahawk Power and Pulp Company Against Wisconsin Public Service Corporation,* Docket No. 6690-CC-223720.
[3] Ex.-WPSC-Nelson-10, Page 6 of 15, Availability Section

In the red-lined tariffs filed October 20, 2022, applicant changed PG-2B to be eligible only to customers under time-of-use tariffs.[4] I encourage discussion of what impact that change has, and whether PG-2B should be available to customers who aren't under time-of-use tariffs in the future.

Finally, in its Order No. 872-A, the Federal Energy Regulatory Commission (FERC) reduced from 20 megawatts down to 5 megawatts the capacity limitation for which small power production facilities are presumed to not have nondiscriminatory access to electricity markets.[5] Thus, the applicant's request to reduce eligibility for its PG-2A tariff to 5 megawatts is reasonable at this time. However, should FERC revisit that decision, the applicant's tariffs should also be updated accordingly.

Avoided Energy Costs

The Commission approved a one-year forecast of locational marginal prices (LMP), updated annually, as the avoided energy value. While I support that finding, I also believe that if the applicant offers long-term contracts in the future, RENEW's proposal to provide contracted energy rates for the life of a contract would be just and reasonable. I also found RENEW's methodology for determining contracted rates sound.[6]

In addition, since this docket began, there has become a dramatic price separation between forecast LMPs and actual LMPs, driven in large part by the Russian invasion of Ukraine and subsequent change in global dynamics of natural gas supply and demand. If this situation

[4] These were superseded by a corrected filing on November 29, 2022: PSC REF#: 453934, See Appendix A, 11th Rev Sheet No. E4.19. This may be due to the Commission's approval of an on-peak capacity credit. However, applicant includes a capacity credit in its current tariff without requiring customers be on a time-of-use tariff.
[5] *Qualifying Facility Rates and Requirements Implementation Issues Under the Public Utility Regulatory Policies Act of 1978*, 173 FERC ¶ 61,158, at pp. 312-3 (2020).
[6] Direct-RENEW-Wilson-r

persists, the Commission should in the future consider approaches that minimize price separation between forecasts and actual values. Examples of such approaches could be true-ups (as proposed by Commission Staff)[7] or an alternative LMP (such as actual day-ahead LMPs as pointed out by applicant witness Nelson)[8] that more closely represents actual costs than an annual forecast.

Avoided Generation Capacity Costs

I concur with the applicant, RENEW, and the Commission's decision to use MISO CONE as a just and reasonable basis for avoided capacity values for FTM resources as well as BTM resources. The applicant uses CONE in its Generation Reshaping Plan as the long-term value of capacity. The use of CONE appropriately puts customer-owned and QF distributed generation on a level playing field with utility-owned and utility-scale generation resources.

For BTM resources, I support the applicant's proposal to "make PG-2B customers eligible for capacity payments for excess generation, as RENEW proposes."[9] RENEW witness Kell describes at length how BTM resources reduce applicant's planning reserve margin requirement "on an ongoing basis" and "achieve real capacity reductions. . . .which is inherently captured in utility load forecasting," and how applicant satisfies its resource adequacy needs through a Fixed Resource Adequacy Plan based on such load forecasts.[10] I also support RENEW's fractional CONE, on-peak performance-based generation capacity payment for such BTM resources.[11]

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[7] Direct-PSC-Blair-7-8
[8] Rebuttal-WPSC-Nelson-r-11
[9] Sur-Surrebuttal-WPSC-Nelson-3
[10] Surrebuttal-RENEW-Kell-9-14
[11] Surrebuttal-RENEW-Kell-14-15

In addition, I concur with the Commission's decision to order the applicant to update their tariffs to use the MISO-approved capacity accreditation appropriate for that resource.

Avoided Transmission Capacity Credit Value

While I concur with the Commission's decision to order the applicant to file further analysis on avoided transmission costs, I would have implemented a transmission credit value in this proceeding, rather than assigning no value. The record contained two options for setting a transmission capacity value:

a) RENEW witness Bhandari's analysis asserting that "the avoided transmission cost associated with projects that are explicitly classified as load growth projects is $42.14/kW-year, which should serve as the floor value for avoided transmission costs."[12]

b) Bhandari's full analysis which pegs total avoided transmission costs at $70.82/kW-year without line losses and $84.22/kW-year with line losses.[13]

RENEW's marginal cost approach has merit. Avoided energy will be based on marginal prices, and avoided transmission capacity costs can be as well. Marginal avoided transmission capacity costs should be reviewed alongside an average or embedded cost approach in future dockets. Based on this record, I believe the Commission should have assigned an avoided transmission capacity cost, and I would use Bhandari's floor estimate of $42.14/kW-year as the most just and reasonable value to appropriately compensate this avoided cost.

[12] Direct-RENEW-Bhandari-22-23
[13] Direct-RENEW-Bhandari-37

I also must note that the applicant *did* include a marginal transmission credit in at least one of its parallel generation tariffs before this docket. The applicant had a transmission credit of $0.00831 per kilowatt-hour which was stricken from their Pg-4 schedule in this docket.[14] As the applicant continues studying avoided transmission capacity costs, it must reconcile the fact that an existing parallel generation tariff includes a transmission credit, found by this Commission to be just and reasonable, despite applicant's repeated argument against the inclusion of such a credit in this proceeding.

Line Losses

The record in this proceeding persuaded me that parallel generation resources will avoid line losses by generating energy closer to load. I believe that either the use of average line losses, as adopted by the Commission in this docket, or the use of marginal line losses could be found just and reasonable based on this record. In particular, I found the Regulatory Assistance Project's 2011 study to be informative on this issue.[15] This issue should be investigated further in future proceedings.

Of note, in this proceeding the Commission approved average line losses to apply to both energy and capacity. I would have also applied line losses to the avoided transmission capacity credit. The values of avoided energy, capacity, and transmission service purchases are *all* increased through local generation within the utility's footprint.

[14] Ex.-WPSC-Nelson-10, Page 2 of 15, Sheet E4.01
[15] Ex.-RENEW-Bhandari-10r

Contract Length

The applicant did not propose any contracts under these tariffs. While I am intrigued by, and supportive of, the applicants' choice to offer capacity values without dedicated contracts in this proceeding, I also believe contracts may support long-term investments into parallel generation resources, especially for FTM resources. Therefore, I concur with the Commission's decision to require the applicant to develop terms and conditions for resources with 5-, 10-, and 15-year contracts the next time the applicant updates these tariffs. However, it will be up to a future Commission to decide whether those revisions are just and reasonable.

Telemetry

I dissent as to the Commission's decision to include a telemetry charge and tariff language. While the applicant and RENEW ultimately agreed to certain terms (the major components of which were that the telemetry equipment would only be installed on new parallel generation resources sized 300 kilowatts and larger), such agreement can only be accepted if the Commission finds it just and reasonable based on the record. From the testimony filed, I did not find this charge just and reasonable. RENEW witness Keeling testified that such telemetry is being installed on resources sized at one megawatt (1,000 kilowatts) and larger for utilities with far more distributed generation than the applicant has.[16] Furthermore, Keeling convincingly stated that "the operational needs and data requirements that WPSC outlines can all be met with the equipment installed in modern inverters and duplicative infrastructure should be avoided if possible."[17]

[16] Citing San Diego Gas & Electric, Southern California Edison, and Alliant Energy at Direct-RENEW-Keeling-21-23 and Hawaiian Electric at Surrebuttal-RENEW-Keeling-7
[17] Surrebuttal-RENEW-Keeling-6

In my view, the record supported the applicant conducting further investigation on smart inverter capabilities before being authorized to install potentially duplicative infrastructure and charge the parallel generation resource for that equipment. This applicant and its sister utility, Wisconsin Electric Power Corporation, are the only two utilities the Commission has authorized to install such telemetry equipment in their parallel generation tariffs.

Summary and Next Steps

In addition to this docket, the Commission separately considered parallel generation tariffs for the four other major investor-owned utilities.[18] While specific costs and some specific issues are different from one utility to the next, I believe the theory and principles underlying just and reasonable avoided costs should be consistent wherever possible across Wisconsin's utilities.[19] With that goal in mind, and as outlined above, I believe numerous issues that arose in this case would benefit from further investigation and a comprehensive approach from the Commission that best reflects avoided cost principles. From there, a future Commission should consistently apply that approach across each utility's parallel generation rates.

Finally, below I summarize what I found to be the key decision points in this docket:

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[18] The following proceedings address parallel generation tariffs for the four other investor-owned utilities pursuant to the Commission's May 4, 2021, order in Docket No. 5-EI-157: 3270-TE-114 (Madison Gas & Electric), 4220-TE-109 (Northern States Power Wisconsin), 6680-TE-107 (Wisconsin Power and Light Company), and 6630-TE-107 (Wisconsin Electric Power Company).

[19] Also note that one of the goals of the Commission's generic proceeding on parallel generation rates in docket 5-EI-157 is "Consistent Parallel Generation Terminology and Terms of Service." *See Investigation of Parallel Generation Purchase Rates*, Docket No. 5-EI-157, Final Order at 9 (PSCW May 4, 2021) (PSC REF# 410850)

Topic	Commission Decision for WPS (6690-TE-114)	Commissioner Huebner Note
FTM Tariff and Size Threshold	PG-2A Up to 5 MW	
BTM Tariff and Size Threshold	PG-2B Up to 1 MW	
Avoided Energy Costs	1-year forecasted LMP	
Avoided Generation Capacity Value – FTM Resources	CONE	
Avoided Capacity Start Year	2023	
Avoided Generation Capacity Value – BTM Resources	Yes: on-peak, per kWh credit based on MISO's CONE	
Avoided Transmission Capacity Value	Not included. Conduct a Study by August 1, 2023	Dissent: would have included marginal Tx credit
Contract Length	None; Ordered to file 5-, 10-, and 15-year contracts upon tariff change	
Contract Early Termination Fee	N/A	
Line Losses	Yes, average line losses for energy and capacity	Would have included Tx losses. Continued analysis re: average or marginal
Telemetry Fee	New resources ≥ 300 kW	Dissent
Generation Capacity Measurement	Not specified	Would make kW-AC explicit

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