BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of City of Sturgeon Bay,
as an Electric Public Utility, Door County, Wisconsin,
for Approval of Revisions to its Parallel Generation Tariff

Docket No. 5780-TE-111

DIRECT TESTIMONY OF ANDREW KELL

ON BEHALF OF RENEW WISCONSIN

I. INTRODUCTION, QUALIFICATIONS, AND PURPOSE

Q. Please state your name and business address

A. My name is Andrew Kell, and my business address is 214 North Hamilton Street, Suite 300, Madison, Wisconsin 53703.

Q. By whom are you employed, and in what capacity?

A. I am a Policy Director for RENEW Wisconsin (RENEW).

Q. On whose behalf are you testifying?

A. I am testifying on behalf of RENEW.

Q. Please describe RENEW.

A. RENEW is a domestic, nonprofit corporation headquartered in Madison that works to advance the renewable energy goals adopted by the State of Wisconsin over the years. Since its founding in 1991, RENEW has worked to increase access to and development of renewable energy sources in Wisconsin to power homes, businesses, and vehicles. To that end, RENEW formulates and advocates for policies and programs to create and expand the use of solar power, wind power, biogas, local hydropower, geothermal energy, and electric vehicles.

Q. Please describe your educational and relevant training background.

A. I graduated from the University of Wisconsin-Oshkosh with a Bachelor of Arts in English, and I later completed a Master of Public Affairs degree at the University of Wisconsin-Madison, Robert M. La Follette School of Public Affairs. During my graduate studies, I also received a certificate in Energy Analysis and Policy from the Nelson Institute for Environmental Studies. During my employment at the Public Service Commission of Wisconsin (Commission), I received training on various topics related to the utility industry and ratemaking. For example, the most pertinent trainings that I completed were the National Association of Regulatory Utility Commissioners' (NARUC) 'Camp NARUC' Regulatory Studies Program and NARUC's Utility Rate School.

Q. Please describe your relevant work experience.

A. I worked at the Commission for 10 years from May of 2010 to March of 2021. During my tenure at the Commission, I was an energy policy analyst on various topics, including renewable energy, energy efficiency, demand-side management technologies and programs, wholesale energy markets, and utility emergency planning. In 2017, I became an energy rates analyst at the Commission, concentrating on utility cost-of-service studies (COSS), revenue allocation, rate design, and tariff program evaluation. My primary work responsibilities as a rates analyst included analysis and case coordination of municipal rate cases, rate analysis of investor-owned utility rate cases, and analysis and case coordination of utility applications for new tariff options for customers, such as innovative programs to purchase renewable energy and charge electric vehicles.

Q. Have you testified in a utility rate case proceeding before the Commission?

A. Yes. As a Commission staff rates analyst, I submitted several Commission staff testimonies and exhibits in electric and natural gas rate cases before the Commission. I also drafted many memoranda that analyzed utility tariff and program applications.

During my employment with RENEW, I have also submitted testimony in several utility cases before the Commission. I have included my curriculum vitae (CV) in Ex.-RENEW-Kell-1, which provides key examples of testimony I have submitted to the Commission.

Q. What is the purpose of your testimony in this proceeding?

A. I concentrate my testimony on analysis of SBU's proposed parallel generation tariff revisions, and I provide analysis and evidence to support my recommended modifications. It is important to note that I provide the Commission with optionality for avoided cost reference points. For example, while SBU has not provided the Commission with any reference points for avoided transmission costs, below I provide the Commission with three methodological options that include a variety of calculation pathways to convert these methods into buyback rates for SBU's parallel generation tariffs.

I conclude that, due to the demonstrated benefits of net energy metering (NEM), low solar adoption rates in SBU's service territory, and an open Commission investigation into NEM policy, no changes to SBU's Pgs-1 NEM tariff are warranted at this time. For SBU's proposed revisions to behind-the-meter (BTM) generator buyback rates, those rates are below their avoided costs, and therefore modifications are required. Finally, while SBU's proposed new option for front-of-the-meter (FTM) generators under Pgs-2 is welcomed, the proposed buyback rates are below SBU's avoided costs and lacking standardized contract terms and ability to lock in all three avoided cost components for the duration of the contract.

Q. Please summarize the results of your calculations and recommendations for the Commission.

A. My calculations and recommendations are summarized in Table 1 below. For Pgs-2 BTM, I include my primary recommendation, as well as alternative recommendations.

Table 1: RENEW Buyback Rate Recommendations

Tariff Name	Avoided Energy	Avoided Capacity	Avoided Transmission
Pgs-1 NEM	No Changes		
Pgs-2 BTM: Primary Recommendation	SBU's Base Cost of Power: $0.0747/kWh		
Pgs-2 BTM: Alternative Recommendation	On-peak: $0.0531/kWh, Off-peak: $0.0386/kWh	On-peak: $0.033/kWh, Off-peak: $0.00/kWh	On-peak: $0.030/kWh, Off-peak: $0.00/kWh
Pgs-2 FTM (Values locked in contract)	On-peak: $0.0531/kWh, Off-peak: $0.0386/kWh	Capacity Accreditation: $8.520/kW-month	Billable Demand: $7.772/kW-month

Q. Which exhibits are you sponsoring?

A. I am sponsoring the following exhibits:

- Ex.-RENEW-Kell-1: Andrew Kell's CV,
- Ex.-RENEW-Kell-2: Vibrant Report,
- Ex.-RENEW-Kell-3: LBNL Context Report,

- Ex.-RENEW-Kell-4: Focus TRM,
- Ex.-RENEW-Kell-5: WEPCO CGS-CU Tariff,
- Ex.-RENEW-Kell-6: WPSC PG-2B Tariff,
- Ex.-RENEW-Kell-7: WPPI Tariff,
- Ex.-RENEW-Kell-8: ATC Rates, and
- Ex.-RENEW-Kell-9: Synapse Recommendations in 6630-TE-107.
- Ex.-RENEW-Kell-10: SBU Response to 2-RENEW-INT-2

II. PGS-1 AND NET ENERGY METERING

Q. Please describe SBU's current Pgs-1 tariff?

A. Like all municipal electric utilities in Wisconsin, SBU has a monthly NEM tariff (also called net energy billing), which is titled Pgs-1. This tariff is available to all SBU retail customers who install a generation facility of 20 kilowatts (kW) or less in parallel operations with SBU's distribution grid. Participating customers can reduce their energy usage directly by serving their own load, and any generation in excess of the customer's load will be metered by SBU. Within a monthly billing cycle, excess generation is credited by SBU at the customer's full retail rate. If there is monthly excess generation, SBU will provide billing credits that roll over to the next month. These monthly rollover credits are worth the customer's full retail rate and are subject to monthly power cost adjustment clause (PCAC) adjustments.

Q. What benefit does SBU's current Pgs-1 NEM tariff provide to participating customers?

A. The Pgs-1 NEM tariff provides economic certainty for customers who invest in and install solar and other distributed energy resources (DER) in SBU's service territory. The ability to reduce one's own load and receive retail rate compensation for excess generation allows the customer to predict the payback period for the investment with a reasonable degree of certainty. Production from customer-sited DER also counts towards customer goals for near or net-zero carbon emissions in homes and businesses. Providing retail credit for excess generation that directly serves neighboring load also provides an economic pathway for SBU's participating customers to collaborate with SBU in a clean energy future.

Q. What benefit does this provide to SBU and customers not participating under the current Pgs-1 NEM tariff?

A. Production from generation facilities under SBU's Pgs-1 NEM tariff help the utility avoid costs both in the short and long run, which I will further discuss below. SBU's non-participating customers in turn receive zero-carbon energy from their neighbors, rather than fossil fuel-based energy from resources many miles away. Local clean energy businesses, such as solar installers, also generate economic stimulus in SBU's community. Although local economic activity is difficult to quantify, it is likewise important to note.

Capacity expansion modelers are just beginning to model and understand the optimization of transmission-level and distribution-level resources to capture more accurately DER benefits for all utility customers. For example, Vibrant Clean Energy has these modeling capabilities. A recent report by Vibrant Clean Energy, titled *Why Local Solar For All Costs Less: A New Roadmap for the Lowest Cost Grid* (Vibrant Report), describes the modeled benefits of DER and distribution planning co-optimization results.[1] I have included the executive summary of the Vibrant Report as Ex.-RENEW-Kell-2.

Q. What benefit does the current Pgs-1 NEM tariff provide to the state of Wisconsin?

A. NEM tariffs allow Wisconsinites to reduce carbon emissions in the utility sector, which better ensures Wisconsin will meet its goal to reach 100 percent carbon-free electricity by 2050[2] while keeping the economic benefits of the clean energy transition within state borders and as close to ratepayers possible.

Q. What impact does the current Pgs-1 NEM tariff have on non-participating customers?

A. To date, SBU's Pgs-1 NEM tariff has not triggered a large amount of customer-sited solar installations, and therefore any cost impact to non-participating customers is negligible. Based on a simple customer count adoption rate analysis, about 0.4 percent of SBU's customers were participating under Pgs-1 by the end of 2022.[3] This is a very small number of customers participating under Pgs-1 compared with the total number who are eligible to participate. With a participation rate this low, there is little cause for concern over high adoption rates and cost impacts within SBU's territory.

[1] The Executive Summary of this report can be downloaded at: https://vibrantcleanenergy.com/wp-content/uploads/2020/12/WhyDERs_ES_Final.pdf Any information contained in this citation, based solely on this citation, is not record evidence (NRE).
[2] See Governor Ever's 2019 Executive Order 38, Relating to Clean Energy in Wisconsin, which can be downloaded at: https://evers.wi.gov/Documents/EO 038 Clean Energy.pdf (NRE).
[3] SBU identified 36 customers participating under Pgs-1 through 2022 in Response-Data Request-PSC-Stevenson-1. (PSC REF# 482230). According to SBU's 2022 Annual Report to the Commission, the utility had 9,282 average number of retail customers. 36 Pgs-1 customers divided by 9,282 total customers equals 0.388 percent.

This assumption is backed by a Lawrence Berkeley National Laboratory (LBNL) report titled *Putting the Potential Rate Impacts of Distributed Solar into Context* (LBNL Context Report). I have included the entire Executive Summary of the LBNL Context Report as Ex.-RENEW-Kell-3.

Q. Please summarize key aspects of the LBNL Context Report with regards to non-participating customer impacts.

A. The LBNL Context Report discusses NEM and DER adoption rates, approaches to Value of Solar in relation to utility average cost of service, and drivers of retail rate increases such as energy efficiency programs, wholesale prices, state and federal policies, and utility capital expenditures. One key statement in the first paragraph of the 'Overview' section adds context to utility and stakeholder concerns over NEM impacts:

> These concerns have, in turn, led to a proliferation of proposals to reform retail rate structures and net metering rules for distributed solar customers, often extending to states that have yet to witness significant solar growth. These proposals have typically been met with a great deal of contention and often absorb substantial time and administrative resources, potentially at the expense of other issues that may ultimately have greater impact on utility ratepayers. (LBNL Context Report, page 1).

A key LBNL conclusion can also be found in the 'Summary and Conclusions' section, which states:

> For the vast majority of states and utilities, the effects of distributed solar on retail electricity prices will likely remain negligible for the foreseeable future. (LBNL Context Report, page 3).

Q. What revisions has SBU proposed to its Pgs-1 tariff?

A. SBU proposes to reduce Pgs-1 monthly bill rollover credits from the retail rates to the wholesale rates. SBU proposes "grandfathering" legacy treatment for Pgs-1 generating facilities currently in-service, but only until 2029. Per SBU's proposal, current Pgs-1 customer would receive legacy treatment until December 31, 2029, which represents 10 years after a prior SBU filing in docket 5780-TE-108. The Commission took no action in 5780-TE-108, and presumably no further action will take place in that docket as the Commission considers an updated SBU application in this case proceeding.

The proposed SBU methodology to calculate average wholesale rate for the Pgs-1 NEM tariff is the same methodology that SBU now proposes for avoided energy costs in proposed Pgs-2 revisions. I will discuss this methodology further below under my discussion of the Pgs-2 tariff revisions.

Q. Do you agree with SBU's proposed revisions to Pgs-1?

A. No. The Commission has recently opened an investigation into NEM policy[4] to collect information and determine next steps towards a statewide approach for this policy. While the NEM investigation is ongoing, utility-by-utility revisions to individual NEM tariffs will undercut the ability of the Commission to assess the impacts of current NEM tariffs. Additionally, individual utility revisions that reduce NEM tariff certainty while the NEM investigation is proceeding will likely cause customer confusion and frustration. NEM tariff revisions also run the risk of reducing the benefits to SBU ratepayers that I described above. I recommend that the Commission not make any changes to SBU's Pgs-1 NEM tariff until the Commission has concluded its investigation in Docket 5-EI-157. This would allow the Commission to implement NEM policy changes in a consistent,

[4] See Cover Letter and Commission Memorandum for Comment, Docket 5-EI-157 (Mar. 3, 2024) (PSC REF# 494461).

statewide manner after the Commission has gathered robust data and information from all stakeholders.

Q. If the Commission accepts SBU's proposed Pgs-1 revisions, do you have any proposed modifications to recommend?

A. Yes. Although I recommend against any changes at this time, there are important factors to consider if the Commission makes any modifications to SBU's Pgs-1 NEM tariff. SBU's proposed legacy treatment is not equitable, as it applies a retroactive start date that references a previous 2019 SBU filing. As I described above, SBU proposes a 10-year legacy treatment, in which the start date is effectively January 1, 2020. While I agree that any legacy treatment should be 10 years or more, SBU's proposal is a 10-year legacy period in name only. By the time actual tariff revisions are presumably made later this year in 2024, almost half of SBU's proposed 10-year legacy period will have already passed.

As per Commission practice, the earliest any legacy treatment should start is at the time tariff revision is implemented. For example, if SBU's Pgs-1 tariff revisions were to take effect on June 1, 2024, then all SBU customers who have DER interconnected under Pgs-1 before that date should have full legacy treatment for a 10-year period starting at that date. In other words, under the tariff effective date example of June 1, a 10-year legacy treatment should end on May 31, 2034 for all SBU customer DER installations that come before that date.

Q. Why is legacy treatment important?

A. Customers who install DER make significant financial investments with an understanding of the value that clean energy production has for the local utility.

As a NEM tariff, SBU's Pgs-1 is just as much a policy as it is a rate schedule. Policy changes must consider direct impacts to those who made significant investments due to the policy, especially policy created to support beneficial clean energy technologies. As such, implementing sudden compensation changes without the appropriate amount of legacy treatment is similar to breaking a contract. Customers have made significant financial investments in large part due to presence of steady policy positions, and sudden changes will be disruptive to the economic underpinnings of these investments.

III. PSGS-2 AND BTM GENERATION

Q. Please describe SBU's Pgs-2 tariff?

A. SBU's Pgs-2 is a parallel generation tariff for customer DER systems that are more than 20 kW but less than 100 kW. There are tariff sections that describe charges, contract requirements, and other requirements for participation. The Pgs-2 tariff does not list actual buyback rates for excess generation, however it states that rates shall reflect "latest rates of the wholesale supplier unless the latest rates of the wholesale supplier do not properly reflect avoided costs."

Q. How many SBU customers currently participate under the Pgs-2 tariff?

A. According to SBU's response to Commission staff's data request, only one customer is currently participating under Pgs-2. Low participation under Pgs-2 is not surprising, as buyback rates are not listed in the tariff. This "you get what you get" practice provides little value certainty for SBU customers interested in installing DER systems above 20 kW.

Q. Do you believe revisions are needed to SBU's Pgs-2 tariff?

A. Yes, however, I disagree with several of SBU's proposed changes, and will therefore recommend modifications below for the Commission's consideration. In general, SBU's Pgs-2 tariff could be revised to either 1) simply reference SBU's base cost of power or 2) reference specific methodologies and calculations for each BTM avoided cost component within the tariff.

Additionally, while SBU is proposing an FTM option in its proposed revisions to Pgs-2, I recommend that an FTM option be created in a new tariff, which would be separate from the existing BTM option within Pgs-2. Creating a separate FTM tariff will reduce confusion for terms not applicable to BTM resources and allow basic contract terms to be clearly outlined for FTM resources as I describe below.

Q. What revisions has SBU proposed to its Pgs-2 tariff?

A. SBU has proposed a different methodological approach for calculating buyback rates for BTM DER above 20 kW but below 5,000 kW. As I described above, SBU's current Pgs-2 tariff simply refers to avoided cost rate per its wholesale provider, but the tariff does not list the actual buyback rates. Presumably, SBU currently only provides average wholesale energy prices to Pgs-2 customers, which reflects what WPPI pays MISO for wholesale energy market participation. This would mean DER under Pgs-2 are only currently compensated for avoided energy costs and not for avoided capacity, transmission, and other avoided costs. SBU has also proposed a new FTM interconnection option under Pgs-2 tariff, which I will discuss below.

Q. Do you agree with SBU's proposed revisions to Pgs-2 for BTM systems?

A. No, I do not agree with SBU's BTM Pgs-2 revisions. While I agree that the cap should be increased to 5,000 kW, and that BTM avoided cost-based methodology and calculated rates should be clearly spelled out in the tariff, breaking down SBU's avoided cost rates into energy, capacity, and transmission components that align with WPPI's avoided cost components is not necessary. For BTM resource compensation, it simpler and more accurate to refer to SBU's base cost of power as a one consolidated avoided cost component. This SBU avoided cost component is updated by the Commission during every rate case and is subject to monthly true-ups per SBU's PCAC-1 tariff schedule.

Base Cost of Power

Q. What is SBU's "Base Cost of Power"?

A. The base cost of power, which is sometimes referred to as the base cost of energy, is listed in SBU's PCAC-1 tariff sheet. The base cost of power is based on all wholesale power costs that municipal utilities must pay, which makes up a large portion of their revenue requirements on a levelized kilowatt-hour (kWh) basis. In the case of SBU, the base cost of power is entirely associated with its contract with WPPI Energy, Inc. (WPPI). These costs reflect WPPI energy, demand, transmission, and administrative charges that are audited by Commission staff during each rate case. In between rate cases, the base cost of power is also the basis of monthly power cost adjustments for retail customers, which account for the difference between the base cost of power and the actual cost of power that occurred during a monthly billing period. SBU's current base cost of power under its PCAC-1 tariff is $0.0747 per kWh, as established by the Commission in SBU's last rate case.

Q. How is SBU's Base Cost of Power determined by the Commission?

A. For each municipal utility rate case, Commission staff perform a revenue requirement audit, a cost-of-service study, and additional analyses to inform appropriate revenue increases and rate design. As part of its cost-of-service study, Commission staff forecast SBU's bill components and apply them to WPPI's tariff charges applicable to the test-year being studied. These billing components primarily include energy and demand forecasts that are applicable to SBU's Schedule for Firm Requirement Service tariff with WPPI (WPPI Tariff). I discuss the WPPI Tariff further below in relation to direct demand and transmission charges that SBU pays WPPI for service.

Q. Why should the Commission adopt the Base Cost of Power for BTM resources in SBU's Pgs-2 tariff?

A. SBU proposes that its own avoided costs are in alignment with its wholesale supplier WPPI. However, WPPI's avoided costs are only partially obtainable, and ostensibly, completely unavailable to SBU. Rather than differentiating between the complexities of SBU, WPPI, and the wholesale market for each avoided cost component, a simpler alternative is available for the Commission. SBU's Base Cost of Power is regulated by the Commission, reflective of SBU's levelized power costs, codified by tariff, updated during rate cases, and adjusted monthly via the PCAC. A simple reference to the Base Cost of Power removes the confusion over SBU costs versus WPPI costs versus constantly changing wholesale prices within various market constructs.

Q. If the Commission does not agree with a Base Cost of Power approach, do you have further recommendations?

A. Yes. If the Commission believes that SBU's avoided costs are the same as WPPI's avoided costs, the Commission should consider modifications to each avoided cost component proposed by SBU, which I describe in each section below.

BTM Avoided Energy Costs

Q. What does SBU propose as WPPI's avoided energy costs?

A. SBU proposes that avoided energy costs be based on wholesale energy prices, known as MISO Locational Marginal Pricing (LMP). WPPI acts as a Load Serving Entity (LSE) in the MISO wholesale market on behalf of its distribution utility members, such as SBU. As an LSE market buyer, WPPI pays Locational Marginal Pricing (LMP) electricity prices that MISO calculates for its respective load node zone.

Q. How does SBU proposed to incorporate WPPI's avoided energy costs into Pgs-2 BTM buyback rates?

A. SBU proposes to incorporate average LMP prices based on the most recent 3-year historical average. In other words, Pgs-2 buyback rates for 2024 would be based on the average of actual prices for 2021, 2022, and 2023.

Q. Do you agree with this approach for BTM avoided energy costs?

A. If the Commission believes each avoided cost component must be calculated separately, then yes, I agree with SBU's approach to calculate avoided energy costs for BTM resources. While investor-owned utilities (IOU) received authorization from the Commission based avoided costs on forward-looking, test-year forecasts as established in either rate cases or fuel cases, municipally-owned utilities do not frequently have rate cases and are not subject to fuel cases. Therefore, a recent historical average is a reasonable approach to approximate actual LMP prices that WPPI is avoiding due to BTM excess generation. SBU proposes a calculation of $0.05314/kWh for on-peak production, and $0.03857/kWh for off-peak production, which are 36-month historical averages. (Direct-SBU-Noeldner-6). I will provide further insight on appropriate avoided energy cost value for FTM production below.

BTM Avoided Capacity Costs

Q. What does SBU propose as WPPI's avoided capacity costs?

A. SBU provides two references to avoided capacity costs. The first is the Cost of New Entry (CONE), which SBU applies to the Pgs-2 FTM option that I will describe below. The second is average of clearing prices in MISO's Planning Resource Auction (PRA), which is also referred to as MISO's capacity auction. SBU proposes that average PRA clearing prices are appropriate for BTM resources under Pgs-2.

Q. Do you agree with SBU's proposed capacity costs?

A. While I agree with SBU's cost reference of MISO CONE for FTM resources, which I will further discuss below, I disagree with SBU's reference to average MISO PRA clearing prices for BTM resources.

Q. Why do you disagree with SBU's proposal to reference MISO PRA clearing prices for BTM resources under Pgs-2?

A. SBU proposes inequitable treatment between BTM and FTM resources within its proposed Pgs-2 revisions. While SBU provides a reasonable monetary reference of CONE for FTM capacity payments, the utility proposes MISO PRA clearing prices for BTM capacity payments. MISO PRA clearing prices are typically much lower than CONE and come with price uncertainty and volatility due the structure of the MISO PRA. As I discuss below, the voluntary MISO PRA is not robust in a vertically-integrated utility regulatory environment and does not provide the proper structure and market signals for new entrants.

Q. What is the structure of the MISO PRA?

A. The MISO PRA is a voluntary capacity auction for market participants. Wisconsin utilities generally self-serve their own capacity needs and are not materially impacted by PRA clearing prices. Instead, Wisconsin utilities procure their capacity needs via combination of generation ownership and Purchase Power Agreements (PPA). Investor-owned utilities generally self-serve their capacity needs with more owned assets than PPAs, and municipally-owned utilities (such as SBU and WPPI) generally self-serve with more PPAs than owned generation. The same is true for many states within MISO's footprint that have regulated, vertically-integrated utilities.

The nature of the voluntary PRA, in combination with self-serving, vertically-integrated utilities throughout MISO, results in low PRA clearing prices that occasionally and unpredictably spike due to variables outside the control of Wisconsin utilities. MISO PRA clearing prices do not provide market signals that incentivize the expansion of generation capacity and additionally have little impact on Wisconsin utility capacity procurement. With or without favorable MISO PRA clearing prices, Wisconsin utilities procure their own capacity requirements and serve their own load.

Q. How does SBU and WPPI procure capacity?

A. WPPI, on behalf of SBU and other members, primarily uses PPAs with generator owners, which provide capacity value that serves all WPPI member load requirements related to MISO's Planning Reserve Margin Requirement (PRMR). If SBU believes that WPPI's avoided costs are the same as their own, then an assessment of WPPI PPA costs would provide important contextual reference points for renewable procurement costs.

RENEW requested WPPI PPA cost and production information from SBU.[5] At this time, RENEW has not received the information. As a result, I cannot perform a robust WPPI PPA until more information is provided. Without this critical information, I assume the WPPI PPA levelized costs are both below and above SBU's base cost of power, which I referenced above as a simple reference for Pgs-2 BTM buyback rates. Given that WPPI cost information is not readily available, and that SBU refuses to provide this information, I believe

[5] See SBU response to 2-RENEW-INT-4. (PSC REF#493335). (NRE).

SBU's base cost of power is a simple, accurate, and Commission-regulated cost reference for Pgs-2 BTM buyback rates.

WPPI also owns generating capacity, such as South Fond du Lac Units 1 and 4, Boswell Unit 4, Elm Road Generating Station, Island Street Peaking Plant, and Worthington Wind Turbines.[6]

By self-serving member capacity requirements through a combination of PPAs and owned generation, WPPI does not rely on the MISO PRA capacity market to serve its members' capacity needs.

Q. How do Wisconsin utilities interface with the MISO capacity construct and PRA?

A. Wisconsin utilities can either 1) opt-out of the voluntary MISO PRA by submitting a Fixed Resource Adequacy Plan (FRAP) to MISO or 2) participate directly in the voluntary MISO PRA on both the supply-side and demand-side of the capacity market. The former option provides little capacity market exposure to utilities, in which they can submit excess generation capacity and receive market payments with no demand-side market exposure. The latter option essentially results in a revenue wash, in which the utility's supply-side participation receives payment based on the MISO PRA clearing price, and the demand-side participation makes payments based on the MISO PRA clearing price. The outcome is virtually the same regardless of whether a Wisconsin utility chooses the former or the latter option, as there is little net capacity market exposure, and utilities remain motivated to continue self-serving their capacity needs.

[6] For a list of owned generation and purchased power, see: https://wppienergy.org/power-supply/. (NRE).

Q. How does WPPI interface with the MISO capacity construct and PRA?

A. Based on an SBU response to a RENEW discovery request, I believe that WPPI does not submit a FRAP but instead participates in the MISO PRA with its supply and demand-side resources.[7]

Q. What do you propose for SBU's avoided capacity costs?

A. I believe that SBU's capacity cost reference to CONE for FTM resources is also appropriate for BTM excess generation. Instead of determining capacity allocations among WPPI's PPA and owned generating capacity costs, CONE provides an approximation of the next generic peaker unit cost. As described by Mr. Noeldner:

> CONE approximates the annualized cost of a new advanced combustion turbine assumed to be available for decades. This methodology allows for a straight-forward capacity credit calculation consistent with the market value of capacity purchases having a 10-year term. (Direct-SBU-Noldner-8).

Q. Why do you believe CONE is also appropriate capacity value for BTM resources?

A. I believe a CONE on-peak performance payment is the most equitable method to measure and pay for BTM capacity. This recognizes that SBU customers who participate under Pgs-2 receive value when reducing their own load, as well as value for excess generation. This is also in line with how the Commission has historically placed value on DER capacity values.

Q. How has the Commission historically placed capacity value on DER?

[7] See Supplemental Responses to 2-RENEW-INT-8, 9, 10. (PSC REF# 495084). (NRE).

A. In order to reference how the Commission recognizes capacity value from DER, I would like to briefly summarize how Focus on Energy (Focus) accounts for capacity savings associated with DER, such as Energy Efficiency (EE) and Distributed Generation (DG) measures. The performance and cost-effectiveness of the Focus program is evaluated by professional third-party consultants, and the methodology and high-level assumptions of the third-party evaluator are regularly reviewed by the Commission. Energy and demand savings are two of the most important components in determining the cost-effectiveness of the program. Focus evaluators measure and verify demand savings based on the ability of DER measures to reduce energy at peak times, and therefore reduce utility investments in peaker units. While the Focus program calls it 'demand savings', on the supply side this is the equivalent of capacity savings. Once these EE and DG measures are installed, there are direct, inherent capacity savings for the lifetime of these measures. Focus evaluators also review persistent savings based on how long these resources are installed, in terms of measure lifetimes and lifecycle savings, and at what rate measure degrade in value.

Q. What is the inherent capacity value of BTM resources?

A. I have included Ex.-RENEW-Kell-4 for the Commission's consideration, which includes a section of the Wisconsin Focus on Energy (Focus) 2022 Technical Reference Manual (Focus TRM). In particular, I include the section that outlines how Focus evaluators measure both energy and demand savings from a solar photovoltaic measure. Page 1064 of the TRM includes an outline of major assumptions per 1 kW-dc of installed solar photovoltaic measure. On page 1066, a table labeled “Installed Capacity by City” outlines summer coincident demand reductions assumed by city and by cardinal direction. For example, Focus evaluators assume that a predominantly west-facing array will achieve about 50 percent of coincident demand savings per nameplate capacity. These are the demand savings that the Focus evaluator assumes for solar photovoltaic measures, which then drives the economic benefits of the Focus on Energy program in terms of avoided peaker capacity value.

I would also note that these DER measures are installed by customers, are not owned by the utility, and are not ‘dispatchable’. Ownership and dispatchability statuses are not variables related to the inherent capacity value that the Focus TRM recognizes and assumes for benefit-cost analysis. For example, when a customer installs a light-emitting diode (LED) in place of an incandescent bulb, the Focus TRM does not assume that the customer could reinstall the incandescent bulb at any moment and therefore the demand savings of the LED should be zero or based on MISO PRA clearing prices. Likewise, the Focus TRM does not assume that a customer could arbitrarily remove or disable a solar system at any moment and therefore the demand savings of a solar system should be zero. Instead, the Focus evaluator uses reasonable assumptions about measure lifetimes and persistence of demand savings, which are also called lifecycle savings. Therefore, DER capacity savings are measurable, verifiable, and inherent in the operation of the measures themselves.

Q. How are DER demand savings realized in WPPI’s capacity construct participation?

A. BTM resources already operating in WPPI's service territory have reduced WPPI's historical peak load, which then provides an inherent value in reducing peak load forecasts. As a result of the existence of BTMs and FTMs alike, WPPI's PRMR within MISO's capacity construct is reduced, which then reduces WPPI's capacity need on an ongoing basis. This then results in a reduction or deferment of WPPI's need to procure additional capacity.

All DER inherently achieve real capacity reductions in the same way via real reduction in peak demand at the wholesale level, which is inherently captured in utility load forecasting. To the extent that the utility pays very little for BTM capacity associated with excess generation, the utility is receiving a capacity value for under avoided costs, which in turns does not equitably value the capacity contributions of BTM resources.

Q. Do other utilities make capacity payments for BTM resources based on CONE?

A. Yes. Both Wisconsin Electric Power Company (WEPCO) and Wisconsin Public Service Corporation (WPSC) provide a CONE reference for their respective BTM tariffs above NEM thresholds. WEPCO's BTM tariff is titled "CGS-CU", which I have included as Ex.-RENEW-Kell-5 (WEPCO CGS-CU Tariff). WPSC's BTM tariff is titled "PG-2B", which I have included as Ex.-RENEW-Kell-6 (WPSC PG-2B Tariff). Both of these utility BTM tariffs contain the following statement under the Avoided Capacity Cost Rate section:

> The Avoided Capacity Cost Rate will be updated each June 1 to reflect the current MISO Cost of New Entry (CONE) value for the applicable Local Resource Zone and Planning Year, and will be adjusted for

distribution and transmission line losses based on the most recently authorized values.

Q. How do you propose to translate avoided CONE capacity costs into BTM buyback rates?

A. I propose to translate CONE costs into BTM capacity payments using the same methodology that WEPCO and WPSC utilize. These utilities make BTM CONE capacity payments for all on-peak kWh excess generation and levelize the payment over all on-peak hours per year. This is done by first referencing the applicable $/kW-year unit. According to Attachment A of SBU's application, the most recent MISO calculated CONE is $102.24/kW-year for the 2023-2024 planning year. (Ex.-SBU-Noeldner-1). This number can then be divided by the number of on-peak hours per year. For WPPI members there are 3,072 on-peak hours in 2024.[8] $102.24/kW-year divided by 3,072 on-peak hours per year equals $0.033/kWh. SBU would only pay this amount for BTM excess generation during on-peak hours and not make a capacity payment for off-peak excess production.

Q. Are there any other avoided capacity cost references for SBU?

A. Yes, for purposes of contextual reference, I would also like to note the Demand Charge within WPPI's Tarff. Applicable to Billable Demand, the Demand Charge is $15.355 per kW for July and August, $11.355 for June and September, and $9.355 for the other eight months of the year. A simple monthly weighted average of these Demand Charges is $10.688 per kW-month. Levelizing this weighted

[8] According to Pricing Period section of WPPI's Tariff, on-peak hours applicable to the Demand Charge and Transmission Demand Charge are all weekday hours 8:00 a.m. to 8:00 p.m., excluding noted holiday. 262 weekdays, minus 6 holidays that occur weekdays, times 12 hours per day equals 3,072 on-peak hours for 2024.

average Demand Charge over all on-peak hours of the year results in $0.042/kWh[9]. Using the on-peak levelization calculation for both methodologies results in the WPPI Demand Charge being about a cent per kWh more than CONE for on-peak hours.

Q. Do you believe this is a reasonable avoided cost reference for SBU's avoided capacity costs?

A. Yes, I believe this is also a reasonable avoided capacity cost for SBU since it reflects SBU's Demand Charge paid to WPPI. The Commission could consider this WPPI Demand Charge as an alternative to a CONE-based payment. I believe CONE is the industry standard for capacity value, however, if the Commission wishes to instead reference WPPI's Tariff and its Demand Charge to SBU this may also be a reasonable option.

BTM Avoided Transmission Costs

Q. What does SBU propose as WPPI's avoided transmission costs?

A. SBU proposes a $0.00/kWh placeholder payment for avoided transmission costs. SBU witness Mr. Tim Noeldner states that 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." (Direct-SBU-Noeldner-8). Furthermore, SBU's application states:

> 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

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[9] $10.688/kW-month * 12 months/year / 3,072 on-peak hours/year = $0.042/kWh.

> 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. (Ex.-SBU-Noeldner-1, page 7).

SBU states that transmission costs for SBU and WPPI can be avoided by DER, however SBU and WPPI provide no estimate of avoided transmission costs and provide no analysis on how utility cost savings would be shifted to other ATC utilities. Based on this rationale, SBU proposes that a $0.00/kWh placeholder value in Pgs-2 is an appropriate reflection of avoided transmission costs.

Q. What analysis, study, or assessment does SBU reference to support the proposed $0 avoided transmission cost?

A. Per SBU's discovery response to 2-RENEW-INT-2, which I have included with my testimony as Ex.-Kell-10, "[t]here are no such assessments."

Q. Do you agree with SBU's proposed avoided transmission costs under Pgs-2?

A. No. While I agree with SBU that DER can avoid transmission costs for SBU and WPPI, I believe that assessments can be made and avoided transmission costs can be reasonably estimated and paid to generators under SBU's Pgs-2 tariff. Below I discuss SBU's direct transmission costs, WPPI's direct transmission costs, and the avoidance of transmission investments for all ratepayers by way of wholesale demand reduction that occurs due to DER production. There are several options for the Commission to determine SBU's avoided transmission costs.

Q. How can SBU's avoided transmission costs be calculated?

A. There are two primary methodologies that I am aware of, each with a variety of ways to calculate avoided transmission cost buyback rates under Pgs-2. The first method is to reference direct transmission charges, either for SBU or WPPI. A simple reference can be made to SBU's current Transmission Demand Charge for SBU within its Schedule for Firm Requirement Service with the WPPI. With that reference, Pgs-2 credits can be calculated. Alternatively, a reference can be made to current WPPI transmission charges as billed by their transmission provider, American Transmission Company (ATC), and Pgs-2 credits can be calculated with that reference.

The second method involves a more forward-looking estimation of the future ATC transmission investment costs of tomorrow that can be avoided by DER generation at the distribution level today. RENEW has provided this recommendation prior Commission dockets. I will summarize this methodology and result below.

Q. What is SBU's Transmission Demand Charge under the WPPI Tariff?

A. SBU provided the WPPI Tariff as a discovery response to 2-RENEW-RDP-5 with reference to Attachment A to 2-RENEW-RDP-5. I have included the WPPI Tariff as RENEW-Kell-7. According to the WPPI Tariff, WPPI's Transmission Demand Charge for 2024 is $7.772 per kW of Billed Demand per month. The Billed Demand is the maximum on-peak demand measured during all on-peak hours[10] within a billable month. As I explain below, WPPI's Transmission Demand Charge is an appropriate avoided cost reference for Pgs-2 buyback rates.

Q. How could WPPI's Transmission Demand Charge be applied as a buyback rate within Pgs-2?

[10] According to Pricing Period section of WPPI's Tariff, on-peak hours applicable to the Demand Charge and Transmission Demand Charge are all weekday hours 8:00 a.m. to 8:00 p.m., excluding noted holidays.

A. I believe two calculations that reference SBU's Transmission Demand Charge could be reasonable. The first approach, which I recommend as it aligns with avoided capacity payments, would involve translating the $/kW-month amount to a $/kWh amount for all on-peak hours. Such a formula would represent $7.772/kW-month times 12 months/year divided by all on-peak hours/year. In 2024, there are 3,072 on-peak hours[11] that occur according to WPPI's Tariff definitions. Using the formula outlined above results in $0.0304/kWh for all excess generation occurring during on-peak hours. This would be a performance-based payment that is paid for all excess generation occurring during on-peak hours when SBU could be exposed to WPPI's Transmission Demand Charge.

The second option would involve a direct application of the $7.772/kW-month to Pgs-2 excess generation metered during SBU's maximum on-peak demand within that month. This would be a performance-based payment applied to all kWh of excess generation that occurred within a single hour each month. The single hour would be WPPI's application of its Transmission Demand Charge coincident to SBU's maximum on-peak demand.

Q. What are WPPI's transmission rates under the ATC Tariff?

A. WPPI receives monthly bills reflecting ATC transmission charges. I have provided ATC's 2024 Transmission Rates Schedules 7 and 8 (ATC Rates) as Ex.-RENEW-Kell-8. Under ATC Rates, all major IOUs in Wisconsin receive the same rates. Based on SBU's market load node being labeled "WEC.WPPI", subject to verification I believe WPPI's ATC rates are the same as those listed

[11] 262 weekdays, minus 6 holidays that occur weekdays, times 12 hours per day equals 3,072 on-peak hours for 2024.

under “Wisconsin Energy Corp”. Among those rates, I believe the most applicable is the “Monthly Charge per MW” under Schedule7 Firm Point to Point Transmission Rates. This ATC rate is $5,940.91/Megawatt (MW)-month, which converts to $5.941/kW-month.

Q. How does this ATC transmission charge compare to WPPI’s Transmission Demand Charge that is applied to SBU’s Billable Demand?

A. The ATC Monthly Charge per MW of $5.941/kW-month is about $1.83/kW-month less than the WPPI’s Transmission Demand Charge of $7.772/kW-month. However, there are other ATC rates under Schedule 7, such as a Weekly Charge, an on-peak daily charge, and an off-peak daily charge. These additional charges are likely factors in why the WPPI Transmission Demand Charge is higher than the ATC Monthly Charge per MW.

Q. How could WPPI’s transmission charge within ATC’s Tariff be applied as a buyback rate within Pgs-2?

A. I believe further investigation and analysis would be needed to determine how to apply ATC Tariff rates to SBU’s buyback rates for purposes of capture avoided transmission costs that WPPI bears. There is a possibility that the ATC Monthly Charge per MW is the most applicable, however the presence of other ATC Tariff charges may require incorporation of other transmission costs that WPPI pays to ATC on behalf of its members. Therefore, WPPI’s Transmission Demand Charge is likely the most directly applicable avoidable transmission cost for SBU, however, other ATC transmission charges should also be considered as avoided transmission costs.

Q. You also referenced an assessment of avoided ATC transmission investments above. Can you further explain the origin of this methodology?

A. Yes. Ms. Divita Bhandari, employed as a consultant at Synapse Energy Economics, Incorporated, filed testimony with the Commission on behalf of RENEW in the prior investor-owned utility parallel generation cases (Synapse Analysis). In her Synapse Analysis, she provided an assessment of ATC avoided transmission costs based on ATC's own peak load growth forecasts and planned transmission investments associated with peak load growth. I submit Ex.-RENEW-Kell-9, which contains Ms. Bhandari's testimony in the Wisconsin Electric Power Company (WEPCO) parallel generation docket 6630-TE-107, where Ms. Bhandari overviews her method. As explained in Ms. Bhandari's testimony, she had previously applied this avoided cost methodology in cases before the jurisdictions of New England states, New York, Hawaii, Puerto Rico, and the District of Columbia.

Q. Can you summarize the rationale behind avoided transmission costs in the Synapse Analysis?

A. According to the Synapse Analysis, "for every kW of peak load growth that is reduced on the transmission system through investments in distributed generation, there is an equivalent transmission-related cost (in $/kW) that can be avoided due to these investments." In short, the rationale of Synapse Analysis is that when DER produce energy in coincidence with peak load, this reduces the utility's peak load growth, which causes a reduced need for future transmission investments.

Q. Can you summarize the avoided transmission cost analytical steps within the Synapse Analysis?

A. Yes. The Synapse Analysis 1) collected and analyzed ATC peak load forecasts over a long-term period, 2) identified ATC plans for transmission development driven by peak load growth over that period, 3) calculated and levelized $/kW avoidable transmission costs, 4) and included line losses associated with peak times to arrive at proposed avoided transmission costs.

Q. Can you summarize the results of the Synapse Analysis?

A. Yes. According to the assessment described above, Ms. Bhandari calculated that $70.82/kW-year in transmission costs can be avoided as a result of DER production during peak times. This number did not include line losses.

Q. How could avoided ATC transmission investments be applied as a buyback rate within Pgs-2?

A. In my testimony within the WEPCO case mentioned above, I converted the $/kW-year value into $5.9017/kW-month by simply dividing the Synapse Testimony results by 12 months/year. Including line losses provide by the Synapse Testimony resulted in $7.0178/kW-month.

Q. How does this result translate to SBU's avoided transmission costs?

A. The Synapse Analysis results were related to avoided ATC transmission investment costs. The result is directly applicable to all distribution utilities served by ATC. The only difference utility-by-utility might be line losses. I would assume that there would be similar line losses (associated with delivery of transmission-connected generation to customer load) between SBU and WEPCO, however, further study may be warranted.

In order to apply this Synapse Analysis result to on-peak production, I would propose taking the $5.9017/kW-month multiplied by 12 months/year and divided by 3,072 on-peak hours/year. This would result in $0.023/kWh for BTM on-peak production. If WEPCO's line losses were applied, then this would result in $0.027/kWh.

Q. Above you describe avoided transmission cost methodological options that included reference to WPPI's Transmission Demand Charge, ATC Tariff's transmission charges, and avoidable transmission investment costs as assessed by Synapse Analysis. What do you propose for SBU's avoided transmission costs?

A. While the Commission should consider all of these avoided transmission cost methodologies, I ultimately propose that a reference to WPPI's Transmission Demand Charge levelized across on-peaks hours is the most straightforward method to apply to BTM resources under Pgs-2. As I calculated above, this is $0.0304/kWh for all excess generation occurring during on-peak hours.

IV. PGS-2 AND FTM GENERATION

FTM Avoided Energy Costs

Q. What does SBU propose as WPPI's avoided energy costs for FTM resources?

A. SBU proposes the same avoided energy costs for FTM resources as BTM resources, which are MISO LMP prices based on the most recent 3-year historical average. SBU proposes to update these energy values annually.

Q. Do you agree with SBU's proposed avoided energy costs for FTM resources?

A. No. While I agree that MISO LMPs are an appropriate reference point, I do not believe that FTM resources under contract should be subject to complete market uncertainty and volatility year-over-year under a 10-year contract. FTM resources serve no load and require financial certainty for developers to acquire financing and make investments. Instead of being subject to market uncertainty, FTM owners should have the option to sign a contract and lock-in long-term, forecasted rates. Contracts with fixed terms benefit both seller and buyer and are a crucial reason why WPPI and other utilities enter into PPA contracts. I will discuss this further below in reference to SBU's proposed Power Sales Agreement (PSA) for FTM resources.

Q. What do you propose for avoided energy costs for FTM resources?

A. The FTM asset owner should have the right to lock-in energy credits throughout the term of the contract. This could be reflective of the most recent 3-year historical average, or some inflation-adjusted forecast if agreeable to both SBU and the FTM owner.

Q. What is the difference between using a historical average LMP and a long-term contract that is fixed to that historical average LMP?

A. The short answer is financial certainty. The FTM owner will likely need to show a revenue model that demonstrates a predictable return on investment to a financial entity. If only capacity values are locked throughout the contract, this may not provide enough certainty to secure financing and green light the project. While it may be possible for LMP prices to increase over the course of the contract, an

FTM owner will likely prefer certainty over potential higher revenues over the long run to secure project financing.

FTM Avoided Capacity Costs

Q. What does SBU propose as WPPI's avoided capacity costs for FTM resources?

A. SBU proposed to pay FTM resources based on the most recent MISO CONE calculation. According to Attachment A of SBU's application, the most recent MISO calculated CONE is $102.24/kW-year for the 2023-2024 planning year. (Ex.-SBU-Noeldner-1). SBU proposes to apply the CONE value to the MISO capacity accreditation of the FTM resource (50 percent of nameplate capacity for solar) and divide by 12 for monthly payments. According to SBU's proposed PSA with FTM resources, the initial CONE price will be effective for a 10-year term. If a 5-year extension is agreed to, the CONE price would be refreshed the month the extension becomes effective.

Q. Do you agree with SBU's proposed capacity costs for FTM resources?

A. Yes. I agree with SBU's approach to create a PSA contract and lock-in the CONE price for a 10-year term. Ideally, contract terms would allow for 15- or 20-year terms, but an initial 10-year term with 5-year extension options would be acceptable if the full CONE value is applied to the whole term. This contract term should be extended to energy and transmission payments as well, which I discuss below.

FTM Avoided Transmission Costs

Q. What does SBU propose as WPPI's avoided transmission costs for FTM resources?

A. As with BTM resources, SBU also proposes that no transmission costs can be avoided and therefore a $0.00/kWh transmission payment placeholder is appropriate.

Q. Do you agree with SBU's proposed avoided transmission costs for FTM resources?

A. No, for the same reasons stated above for BTM resources, I do not agree with SBU's proposal. I believe that both SBU and WPPI have direct avoided transmission costs (via transmission charges), and that avoidance of transmission investment costs for all ratepayers occurs by way of wholesale demand reduction due to DER production. Similar to what I proposed for BTM resources under Pgs-2, I propose that FTM resources help SBU avoid WPPI Tariff Transmission Demand Charges. Rather than levelize the WPPI Tariff Transmission Demand Charge across on-peak hours, I propose that SBU could pay the direct $7.772/kW-month for all FTM production that occurs during the single hour each month that WPPI charges SBU for Billable Demand. As I describe below, the ability for FTM resources to sign a contract and lock-in this rate will benefit both the FTM asset owner as a seller, as well as SBU as a buyer subject to future cost inflation and WPPI rate increases.

FTM Contract Options

Q. What does SBU propose for FTM contract options?

A. SBU proposes a PSA contract, which is essentially a capacity-only contract. As stated above, the PSA contract should be applicable to energy, capacity, and transmission values. Similar to agreements under PPA contracts, asset owners need certainty to invest in generating resources and provide value to buyers under contract. For this reason, I believe a separate FTM tariff is appropriate, perhaps labeled as Pgs-4, which should include standardized contract pricing and terms.

Q. Does SBU already have a negotiation option under Pgs-2, and will SBU likely offer a negation option for FTM resources going forward?

A. Yes, SBU does offer a negotiation option under Pgs-2, however, since contract terms are not defined and standardized any potential negotiations would heavily favor the buyer (SBU) to the determinant of the FTM seller. This is because FTM developer cannot realistically contract with a different distribution utility if the asset will be located within SBU's service territory. Due to Wisconsin utility regulations, the FTM developer also cannot directly sell energy to a retail customer, either within or outside of SBU's territory. The result in most cases would lead to no FTM development in SBU's territory, unless contract terms are standardized and payment values are reasonable and fixed throughout a contract term.

Q. Why is it important to fix values and terms in a contract?

A. I'll answer this question with another question. What would happen if WPPI or SBU told PPA generators in negotiations that prices and terms would change every year based on MISO construct changes and fluctuating wholesale market prices? The answer would be that likely no PPA generator would agree to a long-term contract with WPPI or SBU. WPPI signs contracts with PPA generators using amenable terms under contracts that contain stable prices over the duration. This is the kind of certainty that allows for financing of utility infrastructure projects. For purposes of equitable treatment, the Commission should require SBU to lock-in energy, capacity, and transmission values under standardized terms and conditions.

Beyond providing equitable treatment, offering contract pricing for FTM resources is also in accordance with my understanding of federal law and associated requirements. When the Federal Energy Regulatory Commission (FERC) first implemented the Public Utility Regulatory Policies Act of 1978 (PURPA), it determined that Qualifying Facilities (QFs) must have the right to establish the avoided cost purchase rates that would apply to the entire contract term, even though such rates would necessarily be based on forecasts. By contrast, when the utility simply pays prevailing MISO prices, the FTM asset owner bears all of the risk of changing energy prices, while the utility bears none. In order for any Commission action to effectively support FTM development, developers must be able to establish purchase prices upfront for the entire term of the long-term contract. Moreover, Congress and the FERC have already established the circumstances under which small QFs are only eligible for market-based rates. Utilities may request that FERC exempt them from PURPA's must-buy obligation only with respect to QFs with capacities greater than 5 MW, under the rationale that such QFs have direct and "nondiscriminatory access" to the wholesale markets, into which they can sell energy and capacity at prevailing market prices. Allowing utilities to offer only long-term contracts that provide the same value as participating in the market effectively allows the utilities to terminate the must-buy obligation for all QFs, rather than only for QFs smaller than 5 MW, in contravention of PURPA and the FERC's regulations.

V. CONCLUDING REMARKS

Q. Please summarize your testimony and recommendations.

A. It is important for the Commission to consider the future of municipally-owned utility parallel generation tariffs before coming to conclusions in this SBU case. As stated in the SBU application, WPPI intends to replicate SBU's tariff revisions across its members' parallel generation tariffs. Likewise, the Commission's SBU decisions might set precedent for other municipally-owned parallel generation tariffs.[12] As the Commission stated in a recent IOU rate case decision on the topic of net metering revisions:

> The Commission agrees that further analysis is required. Additional investigation of net metering shall proceed in docket 5 EI-157. The Commission notes that docket 5 EI-157 is a generic docket and that any party or utility may participate. (page 76, *Final Decision in the Application of Wisconsin Power and Light Company for Authority to Adjust Electric and Natural Gas Rates*, docket 6680-UR-124).

As the Commission decided for recent IOU rate cases, I recommend that no NEM tariff revisions are made for SBU and other Wisconsin utilities until the Commission finishes its open and active NEM investigation.

With regards to SBU's proposed Pgs-2 tariff revisions for larger BTM and FTM resources, I recommend that the Commission carefully consider the true

[12] Rice Lake Utilities has also recently applied for parallel generation tariff revisions in docket 5050-TE-105. (PSC REF# 490670). (NRE).

value of the utility's avoided costs and all methodological options presented as evidence in this case. My recommendations are summarized in Table 1 above, which provide just and reasonable modifications to SBU's proposed Pgs-2 tariff revisions.

Q. Does this complete your direct testimony?

A. Yes, it does.