OFFICIAL FILING
BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Northern States Power Company-Wisconsin
for Approval of Parallel Generation
Tariff Modifications and Avoided Costs — Docket No. 4220-TE-109

AFFIDAVIT OF ANDREW KELL

The undersigned, Andrew Kell, swears or affirms the following:

1. My name is Andrew Kell.
2. My business address is 214 N. Hamilton St., Suite 300, Madison WI 53703.
3. I am a Policy Analyst for RENEW Wisconsin, Inc.
4. In response to RENEW Wisconsin's First Data Request to Northern States Power Company (PSC ERF# 424283), request RENEW-IR-4, NSPW provided confidential cost information in RENEW-IR-1 Attachment 3 CONFIDENTIAL. (PSC ERF# 426188). My testimony includes a reference to information in that confidential attachment.
5. This testimony satisfies the criteria specified in Wis. Admin. Code PSC § 2.12(3)(a) for the same reasons that the original data response filed by NSPW satisfies those criteria.

Dated this 2nd day of March, 2022,

<u>/s/ Andrew Kell</u>

Andrew Kell
RENEW Wisconsin, Inc.
214 N. Hamilton St., Ste. 300
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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 N. Hamilton St., Suite 300, Madison, WI 53703.

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

A. I am a Policy Analyst for RENEW Wisconsin, Inc. (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 in 2002. In 2010, I completed a Master of Public Affairs degree at the University of Wisconsin-Madison, Robert M. La Follette School of Public

Affairs, and received a graduate 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 National Association of Regulatory Utility Commissioners' (NARUC) "Camp NARUC" Regulatory Studies Program, in August of 2010, and NARUC's Utility Rate School, in May of 2018, were the most pertinent training that I completed.

Q. Please describe your relevant work experience.

A. I worked at the Commission from May of 2010 to March of 2021. During my decade of work experience 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, 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 and other proceedings before the Commission?

A. Yes. As a Commission staff rates analyst, I submitted testimony and exhibits in several electric and natural gas rate cases before the Commission. As case coordinator for many cases before the Commission, I also led the drafting of Commission staff memoranda that analyzed utility tariff and program applications, and ultimately presented Commission alternatives to support Commission decision making.

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

A. I focus my testimony on portions of Northern States Power Company-Wisconsin's (NSPW) application proposing avoided costs and buyback rates for their parallel generation tariffs. Below I present my analysis of NSPW's proposal and RENEW's proposal for just and reasonable tariffs and buyback rates.

Q. Please summarize your recommendations?

A. I recommend that the Commission adopt RENEW's proposal for avoided costs and parallel generation buyback rates. Specifically, I recommend that the Commission:

- Adopt the following avoided energy payments for Pg-2A (front-of-the-meter generators):

5-Year Contract Option		
NSPW Time Period	**Without Losses**	**With Secondary Losses**
Summer On-peak	$0.03219	$0.03675
Winter On-peak	$0.02787	$0.03182
Off-peak	$0.02278	$0.02601
10-Year Contract Option		
NSPW Time Period	**Without Losses**	**With Secondary Losses**
Summer On-peak	$0.03284	$0.03749
Winter On-peak	$0.02726	$0.03112
Off-peak	$0.02322	$0.02651
20-Year Contract Option		
NSPW Time Period	**Without Losses**	**With Secondary Losses**
Summer On-peak	$0.03348	$0.03822
Winter On-peak	$0.02658	$0.03035
Off-peak	$0.02342	$0.02674

- Adopt the following avoided capacity payments for Pg-2A:

Capacity Reference	Without Losses	With Losses
MISO LRZ 1 CONE	$7.6058/kW-month	$9.0442/kW-month

- Adopt the following avoided transmission payments for Pg-2A:

Transmission Cost Reference	Without Losses	With Losses
Synapse-Calculated Avoided Cost	$2.9942/kW-month	$3.5604/kW-month

- Direct NSPW to offer contract terms of 5, 10 and 20 years for the Pg-2A tariff;
- Direct NSPW to allow contracted resources under the Pg-2A tariff to receive the most recently established MISO CONE value in place when the contract is entered, for the duration of the contract;
- Direct NSPW to allow contracted resources under the Pg-2A tariff to lock into the MISO accreditation methodology in effect upon contract signing;

- Adopt the following avoided energy payments for Pg-2B (behind-the-meter generators):

NSPW Time Period	Without Losses	With Losses
Summer On-peak	$0.02506/kWh	$0.02861/kWh
Winter On-peak	$0.02298/kWh	$0.02624/kWh
Off-peak	$0.01420/kWh	$0.01621/kWh

- Adopt the following avoided capacity payments for Pg-2B:

NSPW Time Period	Without Losses	With Losses
Summer On-peak	$0.0298/kWh	$0.0355/kWh
Winter On-peak	$0.0298/kWh	$0.0355/kWh

- Adopt the following avoided transmission payments for Pg-2B:

NSPW Time Period	Without Losses	With Losses
Summer On-peak	$0.0117/kWh	$0.0140/kWh
Winter On-peak	$0.0117/kWh	$0.0140/kWh

The tables above are repeated as Tables 2-8 in Section V of my testimony below. RENEW's proposal is based on economic and engineering modeling of avoided costs per the Commission's directive in its May 4, 2021 Order in 5-EI-157. As I describe below, RENEW provides a comprehensive framework of parallel generation buyback rates that are just and reasonable for all NSPW's retail customers. This framework balances the interests of all NSPW ratepayers, and will lead to a more diverse clean energy portfolio with lower total system costs in the long-run. RENEW's framework will spur the development of renewable distributed customer-owned generating facilities and qualifying facilities (QF) in NSPW's service territory—a market that experienced low levels of penetration under NSPW's current avoided-cost rates. It will also provide greater assurance that NSPW and Wisconsin will achieve their zero carbon goals by 2050 or earlier.

Q. Which exhibits are you sponsoring?

A. I am sponsoring the following exhibits:

- Ex.-RENEW-Kell-1: portions of the report *A "Consumers Plan" for Clean Energy Across NSPM by 2035*,
- Ex.-RENEW-Kell-2: portions of Northern States Power Company - Minnesota's (NSPM) 2022 Value of Solar filing with the Minnesota Public Utilities Commission (MPUC),
- Ex.-RENEW-Kell-3: portions of a Kentucky Public Service Commission Order to revise buyback rates for Kentucky Utilities Company and Louisville Gas and Electric,
- Ex.-RENEW-Kell-4: portions of NSPM's June 2021 Integrated Resource Planning filing with the MPUC,
- Ex.-RENEW-Kell-5: portions of the Focus on Energy 2022 Evaluation Report – Volume III, and
- Ex.-RENEW-Kell-6: Summary of RENEW Avoided Costs and Buyback Rates.
- Ex.-RENEW-Kell-7: portions of NSPW's Application for Approval to Acquire Ownership of the Western Mustang Solar Electric Generating Facility (REDACTED COPY). (PSC Ref# 401687).

II. OVERVIEW OF NSPW'S APPLICATION AND AVOIDED COSTS

Q. What are the parallel generation tariffs that NSPW proposes to modify, and which of these will you focus on?

A. NSPW proposes modifications to the five parallel generation tariffs listed below:

- Pg-1: Net Energy Billing Service,
- Pg-2A: Sale to Company,
- Pg-2B: Sale to Company After Customer Self-supply,
- Pg-2C: Energy Purchase Service-Negotiated, and
- Pg-2D: Self Supply Service.

NSPW proposes minor language and citation changes for Pg-1 (Net Energy Billing Service), and I expect that the Commission will consider net energy billing tariffs via the Commission's Investigation of Parallel Generation Purchase Rates in docket 5-EI-157. As such, I do not have substantive comments on

NSPW's Pg-1 tariff at this time, and instead plan to submit my comments on net energy billing at the appropriate time.

In addition, NSPW made minor changes to Pg-2C to reflect a recent decision by the Federal Energy Regulatory Commission (FERC) in Order 872 that reduced the mandatory purchase obligation of Qualified Facilities (QF) threshold from 20,000 kilowatts (kW) to 5,000 kW. NSPW also made minor modifications to Pg-2D to reflect new NSPW-proposed metering charges.

At this time, I will focus my direct testimony on the most substantive changes proposed for NSPW's Pg-2A and Pg-2B parallel generation tariffs. As proposed, NSPW's Pg-2A tariff would offer service for Front-of-the-Meter Generators (FTMG) with a 5,000 kW Alternating Current (AC) rated nameplate capacity or less, which would interconnect with NSPW's system and sell 100 percent of the metered generation to NSPW. These FTMGs could be either Customer Owned Generating Systems (COGS) or third-party owned Qualifying Facilities (QF) as defined by FERC. NSPW states in its application that FTMGs would have contract length options of 1, 5, 10, or 15 years under Pg-2A service. NSPW has essentially proposed capacity contracts. While the underlying assumptions and references for capacity would be fixed under their proposed contracts, the energy values would be updated each year even if the resource is under contract. It is not clear from NSPW's testimony how frequently it proposes to update transmission values, but I assume these values would also float for resources under contract per NSPW's proposal.

NSPW's proposed Pg-2B tariff offers service for Behind-the-Meter Generators (BTMG), in which generation in excess of the customer's load is sold to NSPW. For any generation that is not in excess of the customer's load, the customer's load is reduced so that the customer avoids the applicable retail rate per the customer's retail classification. NSPW proposes to limit service to maximum-sized 1,000 kW-AC systems. According to NSPW witness Mr. Tyrel Zich, the Pg-2B tariff would provide for "instantaneous net metering," in which at any instant where generation exceeds load the meter would measure the excess generation. (Direct-NSPW-Zich-18). Excess generation, occurring at any point in time, would be sold by the BTMG to NSPW at buyback rates under NSPW's proposed Pg-2B. NSPW does not propose to offer BTMG the option to enter into long-term contracts for energy, capacity or transmission payments with the Company.

Q. What is NPSW's basis for proposed buyback rates under Pg-2A and Pg-2B?

A. NSPW bases Pg-2A buyback rates for FTMGs on its own assumptions and calculations for avoided energy costs, avoided generator capacity costs, and avoided transmission costs. While NSPW bases Pg-2B buyback rates for BTMGs on the same avoided energy costs as Pg-2A, NSPW does not propose any capacity or transmission cost component values for Pg-2B. According to NSPW witness Mr. Zich, "Excess generation from COGS [Customer Owned Generating Systems] is not reliable for capacity purposes" and additionally "is not certifiable with MISO [the Midcontinent Independent System Operator]". (Direct-NSPW-Zich-19). Essentially, by way of proposing Pg-2B buyback rates with only low avoided energy cost-based buyback rates, NSPW believes that these BTMGs provide little or no value to the utility and its retail customers.

Q. Do you agree with NSPW's avoided cost calculations and proposed buyback rates for the Pg-2A and Pg-2B tariffs?

A. No. I do not believe the methodology underlying NSPW's avoided costs calculations reasonably reflects the value provided by renewable energy generators at the distribution level, both for FTMGs and BTMGs. I believe that the NSPW-proposed buyback rates do not reflect true avoided costs and are therefore not just and reasonable. Below, I will provide detail on each avoided cost component and support my analysis with important context from several Wisconsin and other state proceedings.

I summarize avoided cost calculations presented by RENEW's expert witnesses Ms. Divita Bhandari and Ms. Rachel Wilson, as well as additional avoided costs as calculated and referenced by NSPW's parent company (Xcel Energy) and sister company Northern States Power Company-Minnesota (NSPM) in other proceedings. I will also provide economic and policy analysis on how true avoided cost calculations can be translated into just and reasonable rates in the form of RENEW's proposed buyback rates.

III. DISCUSSION OF AVOIDED COSTS

A. Avoided Energy Costs

Q. How does NSPW approach avoided energy costs?

A. NSPW proposes to use a single year forecast of MISO Locational Marginal Prices (LMP), which are updated annually in the Company's fuel plan year docket.

(Direct-NSPW-Zich-8). NSPW proposes to use the test year (TY) LMP forecast for both contracted and non-contracted resources. TY forecasted LMPs are essentially short-term avoided energy costs. RENEW witness Wilson describes the difference between short- and long-term avoided energy costs in her testimony.

Q. Do you agree with NSPW's approach for avoided energy costs?

A. No, not for FTMG resources under contract in NSPW's Pg-2A tariff. I agree that it is appropriate to use forecasted LMPs to determine avoided energy costs, however I disagree with NSPW's application of a single-year forecast of LMPs to both contracted and non-contracted resources. While short-term TY forecasts for LMPs may be appropriate for non-contracted resources, only long-term forecasts appropriately capture the avoided energy value of long-term resources under contract. In my opinion, resources under multi-year contracts should receive avoided energy credits based on equivalent multi-year forecasts of LMPs. RENEW witness Wilson further explains the limitations of relying on short-term LMP forecasts to determine avoided energy costs in her testimony.

Q. What are the avoided energy costs that RENEW witness Wilson calculated?

A. RENEW witness Ms. Wilson provides an in-depth description of the modeling and forecasting calculations that she describes in her direct testimony, and in the technical report provided as Ex.-RENEW-Wilson-2 (Synapse report). In summary, Ms. Wilson provides long-term LMP forecasts for the MISO ND-MN Hub, also referred to in the Synapse report as "LRZ 1", which is the modeled market hub most closely aligned with NSPW's service territory. These forecasts include both “Reference” and “High-Gas” scenarios that provide a range of results over a multi-decade outlook. I have also summarized how these forecasts translate into energy buyback rates in Ex.-RENEW-Kell-6.

Ms. Wilson’s long-term LMP forecasts are the appropriate basis for determining avoided energy costs for long-term resources under contract in NSPW’s Pg-2A tariff. I propose contract length options of 5, 10, and 20 years for Pg-2A, which I will describe below. As a result, 5, 10, and 20-year LMP forecasts are appropriate references for these contract options under Pg-2A. This approach ensures that forecast length matches contract length and the value that the long-term resource provides. NSPW’s proposed reference of TY forecasts is appropriate for short-term resources not under contract. Since BTMG resources under NSPW’s proposed Pg-2B do not have contract options, I agree that the TY forecast is an appropriate basis of avoided energy costs for the Pg-2B tariff.

Q. Why is it important that a long-term resource under contract receive a long-term energy cost value?

A. When a utility and a generation resource owner enter a contact there is an acknowledged sharing of risk. The generation owner entirely takes on the financial risk associated with capital and on-going costs of the generator and its operations. The utility, in hedging against future energy costs, enters a contract not just based on the prices of today, but on the uncertain prices of the future as well. The generation owner can leverage the risk it has taken in developing and operating a project and provide price stabilization for the utility over the course of the contract. This price stability also provides revenue stream certainty for the generation owner, which may be a requirement of its financial lender. In an uncertain future, actual energy costs may be higher or lower than the stable price established in the contract. In the face of this risk, the price stability of a contract provides a market hedge for the utility and a predicable revenue stream for the generator owner—without which it would be challenging for the owner to secure financing at reasonable rates. Within the context of a regulated utility environment filled with risk management plans, fuel cost forecasts, and fuel cost reconciliation processes, stable prices under contracts also provide benefits to the utility's retail customers.

B. Avoided Generation Capacity Costs

Q. How does NSPW approach avoided capacity costs?

A. For resources under contract, NSPW references a calculation described as a "Surplus Capacity Credit", which is applied as a $/kW-month payment when the utility self-identifies a need for capacity. NSPW chooses a generic brownfield H-Class Natural Gas Combustion Turbine as the resource of reference for avoided capacity costs. NSPW identified the avoided capacity costs for this resource within the NSP Integrated Resource Plan (IRP) based methodology established in filings before its Minnesota regulator. The result of NSPW's reference is $6.89/kW-month if a resource signs a 15-year contract under NSPW's proposed Pg-2A tariff; although this amount varies based on contract length option. As stated in NSPW's application, this approach uses a "peaker unit methodology." However, NSPW chooses the lowest possible reference for a peaker plant, which is the "brownfield H-class combustion turbine" option from its IRP report.

Based on its own assessment, NSPW states that it only has a capacity need starting in 2026, and therefore only proposes to pay for capacity starting in 2026. I will further discuss NSPW's assessment of need below. For resources that are not under contract, such as those under NSPW's proposed Pg-2B, NSPW asserts that there are no avoided capacity costs, and therefore proposes to make no capacity payment for these resources.

Q. Do you agree with NSPW's approach for avoided capacity costs?

A. No. NSPW's peaker unit method is on the right track, however NSPW has chosen the lowest possible value of options available. It is more appropriate to use an independent, industry method and metric for purposes of determining avoided capacity costs, which I will describe below.

Additionally, I do not agree with NSPW's proposal to provide zero capacity and transmission value to BTMG resources, and pay nothing for the capacity and transmission value provided by BTMGs under its Pg-2B tariff. I understand that predicting when a BTMG will have generation in excess of load may be uncertain, but this does not mean that the resource does not exist or provide any capacity or transmission value. In fact, from a wholesale market perspective, and from a transmission system perspective, there is no difference between a BTMG serving load and an FTMG placing all of its generation on the distribution grid. Once a solar photovoltaic (PV) system is installed on a customer's property, it could be interconnected as either a BTMG or an FTMG, and the timing and volume of the generation would be the same regardless. Both resources reduce the amount the utility must purchase through the wholesale energy market in the same way. Both resources reduce the utility's peak demand, which drives capacity and transmission costs, in the same way as well. In short, if properly incorporated into the utility's planning processes and forecasting calculations, both resources would reduce forecasts of energy and demand in the same way.

The only difference between these resource types is that when BTMG is serving load, it directly reduces the owner's use of energy from the transmission grid and avoids retail rates. When excess generation from a BTMG is placed on the distribution grid, it reduces the neighboring customers' use of transmission grid energy in the that same way as an FTMG interconnect at the distribution level. In summary, a BTMG resource has the same energy, capacity, and transmission value as an FTMG resource. Due to its dynamic parallel interconnection, serving either load or the distribution grid, the BTMG resource should simply be paid for the same capacity and transmission value in a different way. I believe that an appropriate approach to value the avoided capacity and transmission costs of BTMG is to develop volumetric performance-based payments, namely $/kWh payments for excess generation during on-peak hours. I will describe this approach below when I present RENEW's proposed buyback rates for Pg-2B. I would note that RENEW witness Bhandari further describes the deficiencies in NSPW's approach to determining avoided transmission and capacity costs for FTMG and BTMG resources in her testimony.

Q. What are the avoided capacity costs that RENEW witness Bhandari calculated?

A. In her direct testimony, RENEW witness Ms. Bhandari explains that the Cost of New Entry (CONE) reference is most appropriate reference for avoided capacity costs, particularly for NSPW as a utility within MISO's Local Resource Zone (LRZ) 1. This calculation is completed by MISO staff on an annual basis, and is used in official MISO capacity market references. Since MISO CONE references capital and other costs associated with generators that can be constructed quickly and serve a peak capacity need, the MISO CONE calculation is somewhat similar to a peaker unit methodology. As a third-party, industry-accepted capacity cost reference specific to MISO regions, the MISO CONE reference is a more equitable reference than NSPW's peaker unit reference, for which the utility simply selected the lowest possible cost reference calculated in its Minnesota IRP process.

Ms. Bhandari more thoroughly explains the calculation for CONE in her direct testimony. The MISO calculation of CONE for the most recent 2022/2023 planning year is $91,270/MW-year, exclusive of losses, which I reference in Ex.-RENEW-Kell-6. I will describe how this can be translated into $/kW-month buyback rates for Pg-2A, and $/kWh on-peak buyback rates for Pg-2B, in Section V below. In particular, $/kW-month payments provide price stability for long-term resources under contract, such as FTMG under Pg-2A. Additionally, $/kWh payments to BTMG under Pg-2B for on-peak production creates a performance-based payment that reflects avoidance of transmission costs during periods of peak load if BTMG resources are providing excess generation during on-peak hours.

Q. How does NSPW propose to determine avoided capacity costs based on a determination of need?

A. NSPW proposes to determine a capacity need by referencing their forecasted Planning Resource Margin Requirement (PRMR), which is determined in their IRP modeling. According to NSPW, based on PRMR forecasting the utility presently does not have an immediate need for capacity, and will not have a need for capacity until 2026.

Q. Do you have any concerns with NPSW's approach for determining capacity need?

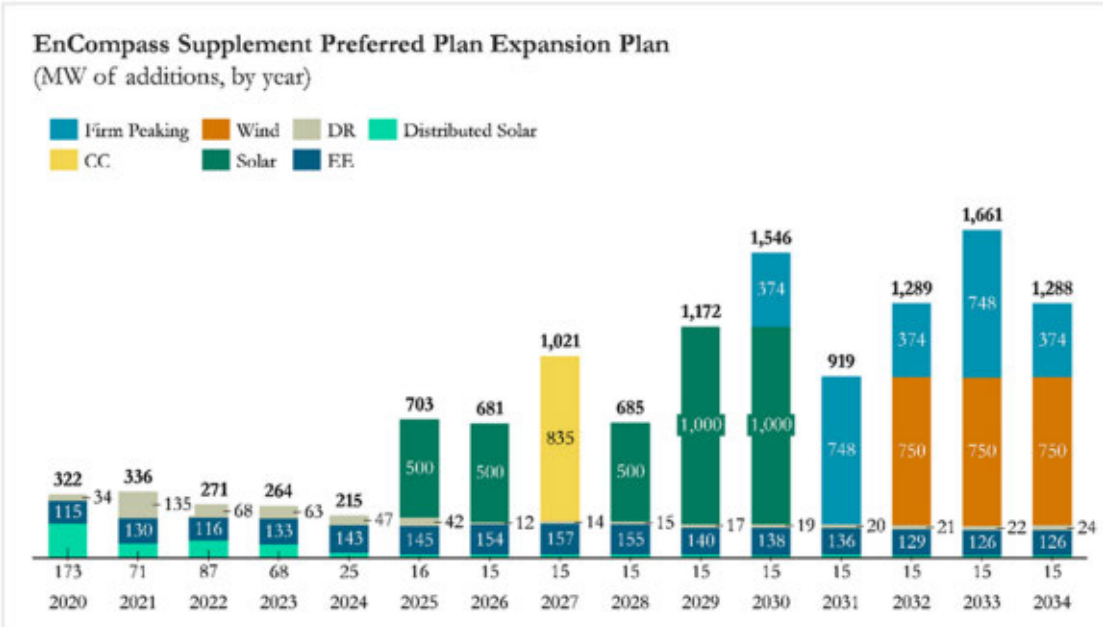
A. Yes. The PRMR is an incomplete assessment of NSPW's capacity needs. Utilities have to plan capacity additions to meet several needs. Beyond PRMR, this includes a need to diversify its generating capacity portfolio and hedge against risks, such as fuel prices, market prices, and environmental regulations. Another continual need for NSPW is the achievement of its carbon reduction goals, which comes with a need to replace fossil fuel generating capacity with zero-carbon generating capacity. In fact, NSPW provided a snapshot of its needs when it filed an application to acquire the Western Mustang Solar Electric Generating Facility (Western Mustang) with the Commission. On page 10, under the section labeled Public Convenience and Necessity Justification, NSPW stated:

> The NSP Companies' IRP was filed with the Minnesota Public Utilities Commission (MPUC) in July 2019 and supplemented on June 30, 2020. Under all planning scenarios considered, the NSP Companies' analysis determined that a substantial amount of solar

> is part of a cost-effective plan to meet the NSP System's needs by 2030, with additions of between 500-1,500 MW of solar needed by 2025 in all scenarios. Therefore, in both the short and long-term, and regardless whether the specifics of the NSP Companies' preferred resource plan (the Preferred Plan) are approved by the MPUC, **it is clear the Company has solar needs far in excess of the 74 MW acquisition proposed in this Application**. If approved by the Commission, this project will be the first utility-scale solar project owned by NSPW or any regulated utility of Xcel Energy, and would be the first step in **the NSP Companies' plan to add at least 3,000 MW of utility-scale solar generation to its system by 2030**.
>
> (Ex.-RENEW-Kell-7) Application for Approval to Acquire Ownership of the Western Mustang Solar Electric Generating Facility (REDACTED COPY). (PSC Ref# 401687) (emphasis added).

NSPW's application to acquire Western Mustang clearly states that the utility has both a short-term and a long-term need far in excess of the 74 MW Western Mustang project. NSPW also states that it plans to add at least 3,000 MW of solar by 2030. Further, on page 11 of its application to acquire Western Mustang, NSPW presents a figure illustrating its preferred plan resource additions. I reproduce that figure below (the title, figure, and footnote are verbatim from NSPW's Western Mustang application document).

Figure 1: Supplement Preferred Plan Resource Additions[1]



This figure shows that NSPW plans to add resources every year, between 2020 through 2034. When presenting this figure, NSPW mentions that this plan will help the "NSP Companies to achieve their ambitious carbon reduction goals while both maintain a reliable system and keeping customers' bill low." (Application for Approval to Acquire Ownership of the Western Mustang Solar Electric Generating Facility at 11 (REDACTED COPY). (PSC Ref# 401687)) While the PRMR is obviously part of NSPW's planning processes, it is not mentioned once in this application document. Instead the need and justification for Western Mustang that NSPW emphasized is based on "ambitious carbon reduction goals" which I wholeheartedly support.

[1] In Figure 1, DR stands for demand response; CC stands for a combined cycle facility; and EE stands for energy efficiency.

Q. Do you believe that NSPW has a present and on-going need to replace fossil fuel generating capacity with carbon-free generating capacity?

A. Yes, based on the Company's own submissions to the Commission and the Commission's approval of those submissions. NSPW claims in this case that based on its present PRMR alone the utility does not need capacity until 2026. However, this perspective does not square with the information that NSPW provided to the Commission in its Western Mustang application. I believe that the information provided in the Western Mustang application clearly demonstrates that NSPW has an on-going need to diversify its resource mix and replace fossil fuel capacity with zero-carbon capacity in the present term, the short-term, and the long-term.

NSPW has a goal to achieve zero carbon emissions by 2050, and Governor Evers signed Executive Order 38 to achieve zero carbon emissions from the electric sector statewide by 2050 as well. If NSPW were to base its resource planning solely upon meeting the minimum PRMR, NSPW would not make investments in clean energy resources at its current pace, and Wisconsin would not meet its carbon reduction goals. Based on NSPW's statements in the Western Mustang application, and the goals established by the utility and state of Wisconsin, it is clear to me that NSPW has an immediate and foreseeable need to continually replace fossil fuel capacity with carbon-free generating capacity. The need for additional clean energy capacity is now, and this need will not decrease until a zero-carbon future is achieved.

Q. Did the Commission recognize NSPW's need to replace fossil generation with clean energy resources in its decision in the Western Mustang proceeding?

A. Yes. In the Commission's Final Decision that authorized NSPW to acquire Western Mustang, the Commission writes on the second page of the introduction "The applicant's stated purpose of this project notes that it is part of an effort to reshape its generator fleet by moving away from some of the coal plants it is retiring, and towards a total of 3,000 MW of solar generation." (PSC REF#415866). Nowhere in the Commission's Final Decision is NSPW's PRMR mentioned. If the Commission believed that there was no need to replace NSPW fossil fuel generating capacity with zero-carbon generating capacity, the Commission might have assessed that NSPW did not need Western Mustang. However, after carefully assessing the utility's plans and resource needs, the Commission agreed that NSPW had a need to retire fossil fuel generation and invest ratepayer dollars in Western Mustang as a carbon-free resource to replace old capacity.

To be clear, I believe this was a correct assessment by the Commission. I also believe that the Commission will and should view applications for the next 3,000 MW of solar facilities to be filed by NSPW before 2030 through the same lens. I further believe that the Commission should view applications that come in after 2030 in order to meet 2050 zero-carbon goals through the same lens. It stands to reason, therefore, that from a fairness and equity perspective, the Commission should use that same lens to determine NSPW's capacity need within this parallel generation case as well. I recommend that the Commission consider all of NSPW's planning information and conclude that NSPW has a present and on-going need for zero-carbon capacity resources. I further recommend that the Commission reject the Company's narrow presentation of its capacity needs in this proceeding—focused entirely on its PRMR—which simply do not square with the Company's far more expansive presentation of its capacity needs when it comes to application for its own solar resources.

Q. What are NSPW's preferences for satisfying its ongoing need to reduce carbon emissions and replace its fossil fuel capacity with carbon-free generating capacity?

A. When assessing need, NSPW is careful to consistently use the term "utility-scale" to make clear its preference for a particular size of carbon-free resources. However, I would also note NSPW's language in the third paragraph of its "Introduction" section of its Western Mustang's application states the following:

> In addition to satisfying the NSP System need for utility-scale solar generation,
>
> NSPW's acquisition of the Facility is the Company's first utility-scale step in *meeting its customers' increasing desire to obtain their power from local renewable resources in or near NSPW electric service territory.* Application for Approval to Acquire Ownership of the Western Mustang Solar Electric Generating Facility at 1 (REDACTED COPY). (PSC Ref# 401687) (emphasis added).

My main comment on this NSPW statement is that distributed renewable resources within NSPW's service territory are much more local (closer to load) than transmission-interconnected resources. In order to meet customers' increasing desire for local renewable resources, a policy approach to purposefully balance carbon-free utility-scale and DG resources would help meet multiple goals at the same time. This will reduce risk and save NSPW's ratepayers money.

Q. How can distributed renewable resources help NPSW meet its diverse capacity and carbon reduction needs?

A. Both financial planners and utility planners often cite building a "diverse portfolio" of assets in order to hedge against risks and weather literal and figurative storms of all sorts. In order to exemplify how distributed renewable resources can better diversify NPSW's generation portfolio, I submit for the Commission's consideration the cover page and executive summary from the report *A "Consumers Plan" for Clean Energy Across NSPM By 2035*, which I have included as Ex.-RENEW-Kell-1. The Citizens Utility Board of Minnesota and Gridlab commissioned this report, with modeling and analysis provided by Vibrant Clean Energy. The report describes a "Consumers Plan" scenario as an alternative to NSPM's proposed IRP approach as filed in Minnesota. On page 3 the report discusses a vision to "co-optimize" NSPM's distribution system with utility-scale generation:

> The "Consumers Plan" scenario unlocks greater efficiencies in the electricity system operation through co-optimizing the distribution system with the utility-scale generation. As a result of this co-optimization, by 2035 2.5 GW [Gigawatts] of distributed solar is added to the NSPM grid along with 1.3 GW of distributed storage. Through optimal deployment and use of the distributed energy resources, the NSPM region is able to defer distribution system upgrades even as the load increases due to electrification.

(Ex.-RENEW-Kell-1). The Minnesota consumer advocates also discuss the benefits to ratepayers that will lead to lower total system costs with this co-optimization approach. I believe that RENEW's proposed avoided costs and parallel generation buyback rates, as described below, will lead to more robust clean energy investments on NSPW's distribution grid. Coupled with a co-optimization vision, and carefully utility planning that incorporates distribution planning, I believe this will lead to lower risk and lower system costs for all ratepayers in the long run. Now is not the time to say “we do not need these distributed resources.” On the contrary, now is the time to fully embrace the desires of customers and harness the capital investment prowess of clean energy developers.

C. Avoided Transmission Costs

Q. How does NSPW approach avoided transmission costs?

A. For resources under contract, NSPW references an existing calculation for avoided transmission costs within an embedded cost approach. This calculation was previously performed by NSPW and implemented for reference in its Solar*Connect Community tariff. NSPW identified the historical embedded costs of transmission within its revenue requirement, and awarded 50 percent of the embedded cost for subscriber credit in this solar program. Similarly, NSPW proposes for Pg-2A that transmission payments be made at 50 percent of embedded transmission costs. NSPW proposes that DG not under contract, such as those taking service under its proposed Pg-2B tariff, provide no avoided transmission cost value, and therefore NSPW proposes to make no transmission payment to these resources.

Q. Do you agree with NSPW’s approach avoided transmission costs?

A. No. NSPW’s approach to using the embedded cost of transmission is an assessment of historical transmission costs, and does not accurately capture estimations of upcoming transmission costs associated with peak load growth that

DG installed today can avoid. RENEW witness Ms. Bhandari further explains the shortcomings of using historical embedded transmission costs in her direct testimony. With regards to BTMG under Pg-2B, I do not agree with NSPW's assessment that excess generation from BTMG avoids no transmission costs. Using avoided transmission costs identified by Ms. Bhandari, I will propose equitable calculations to pay both FTMG and BTMG below.

Q. What are the avoided transmission costs as calculated by Ms. Bhandari?

A. RENEW witness Ms. Bhandari provides a full description of her NSPW avoided cost calculation in her direct testimony. In summary, rather than use an embedded cost approach Ms. Bhandari uses a forecasted marginal cost approach. This is more appropriate as it reflects that DG installed today can avoid the transmission costs of tomorrow. This approach also reflects analysis of NSPW's data, including transmission costs of planned transmission investments directly related to peak load growth, as well as forecasted peak load growth. The result is a $/kW-year number that is an annualization of these future costs and growth forecasts, which DG can reduce by generating at peak times. Using NSPW-specific data, Ms. Bhandari's calculations result in $35.93/kW-year, exclusive of losses.

In section V below, I provide a description of how these $/kW-year avoided transmission costs can be converted into 1) $/kW-month payments for FTMG under Pg-2A, and 2) $/on-peak kWh performance-based payments for excess generation of BTMG under Pg-2B.

Q. Beyond avoided energy, capacity, and transmission costs, can distributed generation help the utility avoid other categories of costs?

A. Yes. Several other avoided costs can be identified and captured within buyback rates. Below I will concentrate on avoided distribution costs and avoided environmental costs.

D. Avoided Distribution Costs

Q. How can DG help avoid distribution costs?

A. In its order requiring NSPW and other utilities to model the avoided costs of parallel generation, the Commission did not require utilities to model the avoided cost of distribution. However, after surveying avoided distribution costs identified in other states it is my assessment that DG does have the potential to avoid distribution costs, including distribution capacity costs, voltage support related costs, line losses, reliability, and other distribution cost categories.

Q. How have other state jurisdictions examined avoided distribution costs?

A. The Minnesota Public Utilities Commission (MPUC) requires NSP-Minnesota (NSPM) to calculate several avoided costs associated with distributed generation per a Value of Solar (VOS) methodology. NSPM provided its 2022 VOS calculations in a filing to the MPUC in September of 2021, portions of which I have included as Ex.-RENEW-Kell-2. NSPM provides the details of calculated avoided distribution capacity costs in Attachment B of its filing, and the results are summarized in Figure ES-1 (page number listed as "Attachment A - Fig. ES-1"). The "Distributed PV Value" for Avoided Distribution Capacity Cost is $0.0028/kWh.

Additionally, the Kentucky Public Service Commission (KPSC) followed the Minnesota VOS approach in order identify avoided distribution capacity costs for the purpose of valuing net metering systems. In its September 24, 2021, Order, the KPSC established new buyback rates for Kentucky Utilities Company (KU) and Louisville Gas and Electric (LG&E). On page 53 or the KPSC Order, the KPSC states: "To calculate an appropriate avoided distribution capacity cost, the Commission will modify the Minnesota VOS approach, based on intervenors' testimony." On the next page, the KPSC concludes: "Based on the approach described above, the Commission finds the fair, just and reasonable avoided distribution capacity cost to be $0.00129 for LG&E and $0.00185 for KU." I provide relevant portions of the KPSC Order as Ex.-RENEW-Kell-3.

Q. How should the Commission assess avoided distribution costs?

A. NSPW has not provided any analysis on avoided distribution capacity costs. I recommend that the Commission order NSPW to work with parties in this case and conduct a study for the Commission's consideration. A placeholder can be inserted into NPSW's revised parallel generation tariffs for avoided distribution capacity after the conclusion of this proceeding. The Commission can determine the appropriate value of avoided distribution capacity at a future date and update NSPW's buyback rates accordingly. For example, the Commission can order that NSPW file analysis and a proposal for avoided distribution costs with its Test-year 2024 rate case application (or fuel case for that test-year).

E. Avoided Environmental Costs

Q. How can DG help avoid environmental costs?

A. Like the identification of avoided distribution costs, NSPW can identify, analyze, and propose avoided environmental costs for the Commission's consideration for future incorporation into buyback rates.

Q. How have other state jurisdictions examined avoided environmental costs?

A. The Minnesota VOS methodology, as well as the KPSC order referenced above, both include avoided environmental costs. Within NPSM's 2022 VOS filing, environmental costs are identified in Attachment A – Table 4 (Ex.-RENEW-Kell-2. CO_2 has the highest avoided value within the table (making up just over 90 percent of avoided emissions costs), which also includes Particulate Matter and other fossil fuel emission types. These values are listed in terms of dollars per Million Metric British Thermal Units (MMBtu). However, these costs are translated into $0.0417/kWh in Figure ES-1 within NSPM's VOS filing.

Likewise, NSPM contains avoided emissions information within their IRP process in Minnesota. Of note, in Table 25 of Appendix A: Modeling Assumptions & Inputs, NSPM assumes market purchase rates for CO_2. Initially the emissions rate is over 1,300 pounds of CO2 per MWh, which decreases to under 1,000 pounds per MWh by 2031. I include this table from NSP's IRP filing as Ex.-RENEW-Kell-4.

Q. Has the Commission considered avoided environmental costs in other proceedings?

A. Yes, the Commission considers avoided environmental costs in several proceeding types. In utility construction applications, economic analysis provided by the utility, and/or parties to the proceedings, often incorporate avoided environmental costs within economic analyses. For example, modeling inputs are included within future scenarios in which the cost of carbon influences the price of commodities and market prices, and therefore the economic viability of proposed construction projects.

The Commission also considers the value of avoided environmental costs in terms of "emissions benefits" for the evaluation of the Focus on Energy program (Focus). In the most recent 2020 Evaluation Report – Volume III, Focus evaluators use emission factor assumptions of $15 per ton of CO2, $7.50 per ton of Nitrogen Oxide, and $2 per ton of Sulfur Dioxide (I have included pertinent pages from the 2020 Evaluation Report – Volume III as Ex.-RENEW-Kell-5). These emissions factors are listed in Table H-7 within Volume III. In the paragraph just below Table H-7, the evaluation authors state: "The team used the carbon dioxide emissions price in the PSC's Order, docket 5-FE-101, PSC REF#: 343909, which states, "The Commission finds it reasonable for Focus cost-effectiveness tests to continue valuing avoided carbon dioxide emissions using a market-based value of $15.00 per ton."

These emission factors are then incorporated into the calculations of emissions benefits of Focus based on energy savings. The emission benefits are then incorporated into the Total Resource Cost evaluation of Focus, which produces a large value that determines the cost-effectiveness of Focus. Focus delivers both energy efficiency and renewable DG measures, and from an emissions avoidance perspective both energy efficiency and renewable DG measures avoid emissions from transmission-interconnected fossil fuel generation.

Q. How should the Commission assess avoided environmental costs?

A. NSPW has not provided any analysis of avoided emissions costs in this case. Similar to my recommendation regarding avoided distribution costs, I recommend that the Commission order NSPW to work with parties in this case and conduct a study of avoided environmental costs for the Commission's consideration. NSP has already produced avoided emission costs analysis for their IRP and VOS requirements in Minnesota, which can be leveraged to produce numbers for Wisconsin. Until an avoided emissions cost number is produced, the Commission could order that a placeholder can be inserted into NPSW's revised parallel generation tariffs. The Commission can later determine the appropriate value of avoided environmental costs and update NSPW's buyback rates accordingly.

IV. AVOIDING FUTURE NSPW GENERATOR INVESTMENTS

Q. Besides consideration of individual avoided cost components, what additional cost references should the Commission consider when assessing the reasonableness of NSPW's proposed buyback rates?

A. The Commission should also consider the costs associated with projects that the Commission has recently authorized NSPW to construct or acquire, because consideration of those costs may assist in the assessment of the value of avoiding future generator investments. The individual avoided energy, capacity and transmission cost components described above may seem intangible and abstract on their own, however I believe a real-world example of authorized generation investment costs would put these avoided cost components into context.

Q. What is a recent example of an NSPW generation asset authorized by the Commission?

A. As I mentioned above, NSPW recently received Commission authorization to acquire ownership of the Western Mustang in docket 4220-BS-100, by way of Commission Order on July 13, 2021. (PSC ERF# 415866). As described in the first paragraph of the Commission's Order, Western Mustang is a 74-megawatt (MW) solar photovoltaic (PV) facility that will be located in Pierce County, Wisconsin when complete. The Commission expects the acquisition to cost NSPW $95.1 million. The Commission Order also notes that the Western Mustang facility is part of the combined NSP system of utilities' IRP as presented in Minnesota and Michigan, which envisions the addition of 3,000 MW of solar generation to reshape the Company's generation fleet and replace coal units.

NSP's IRP, which the Commission's Order acknowledges, essentially states that NSPW needs to continually replace fossil fuel capacity with renewable generating capacity, which I have addressed above in my discussion regarding NSPW's assessment of its needs. In this section I focus on the levelized cost of energy (LCOE) for Western Mustang and how these levelized costs relate to future costs that DG helps avoid.

Q. What are the costs associated with Western Mustang?

A. In response to RENEW Wisconsin's First Data Request to NSPW (PSC ERF# 424283), request RENEW-IR-4, NSPW provided cost information for Western Mustang in RENEW-IR-1 Attachment 3 CONFIDENTIAL. (PSC ERF# 426188). The "Summary" tab of the spreadsheet attached therein contains Schedule 1: Summary Revenue Requirement, which was included in NSPW's application materials for the Western Mustang acquisition docket. NSPW calculates that the LCOE of Western Mustang is $[redacted][2] per Megawatthour (MWh), which converts to $[redacted]/kWh.

Q. How do Western Mustang costs relate to costs of generation assets at the distribution level?

A. The Western Mustang facility will be interconnected at the transmission level, and in order to calculate the avoided cost equivalent for distributed resources, adjustments for transmission losses and transmission costs must be made. This is because Western Mustang requires transmission investments in order to be delivered and serve load of retail customers. Additionally, generation at the transmission level incurs energy losses as it is delivered to distribution-interconnected retail customers many miles away. Distributed generation assets do not require transmission, nor do they incur the same energy losses as a transmission-interconnected asset, which is why avoided transmission costs and

[2] I disagree with the LCOE for Western Mustang being treated as confidential, as members of the public are also ratepayers whom I believe are entitled to know the levelized costs of assets that they are paying for. However, Commission staff allowed the LCOE information to be treated as confidential in NSPW's case to acquire Western Mustang, and as a result I also provide the confidential treatment of the same information in this case.

energy loss factors must be applied to transmission-interconnected resources for a comparable value to DG resources.

If the loss factor that Ms. Bhandari calculated for marginal energy losses at the secondary service level (1.14184) is applied to the LCOE of Western Mustang, the LCOE with marginal energy losses would be about $[redacted]/kWh. If the same calculated loss factor is applied to Ms. Bhandari's proposed avoided transmission costs ($35.93/kW-year), the result is a $41.026/kW-year transmission cost adder. When levelized across all hours of the year (8760), the avoided transmission cost with losses proposed by Ms. Bhandari is $0.00468/kWh.

Adding together the energy loss-adjusted LCOE of Western Mustang with the energy loss-adjusted transmission cost adder results in a comparative number presented in Table 1 below. I assess that these are Western Mustang levelized costs as they compare to renewable generators at the distribution level.

Table 1: Comparison of Western Mustang LCOE
With and Without Transmission Costs and Losses

NSPW Project	LCOE without Transmission Costs and Losses Considered	LCOE with Transmission Costs and Losses Included
Western Mustang	$[redacted]/kWh	$[redacted]/kWh

Q. Are you suggesting that renewable generators at the distribution level are avoiding Western Mustang costs?

A. No. Western Mustang will be acquired by NSPW, and NSPW's retail customers must pay for its costs. However, the costs associated with Western Mustang are indicative of future utility-scale solar costs to come, and therefore the levelized costs of the authorized project serve as a good proxy for future NSPW utility-scale solar costs at the time being. As I noted above, according to its IRP NSPW plans on constructing or acquiring about 3,000 MW of solar and other generating assets by 2030. Based on NSPW's zero-carbon by 2050 goal, it is reasonable to assume that NSPW will propose to acquire additional utility-scale renewable resources past 2030 as well. In other words, renewable generation assets developed at the distribution level now will avoid a portion of NSPW's planned generation investments in all future outlooks.

The costs associated with future solar generators at the transmission level could be higher or lower than those associated with Western Mustang. Ultimately, whether those costs are higher or lower depends upon whether the cost of solar facilities will continue to drop, inflation rates, and other variables. However, the Commission need not forecast the cost of future solar investments at the transmission level to recognize that the levelized cost of planned solar investments will likely be similar to the costs of Western Mustang. I recommend that the Commission consider the LCOE of Western Mustang with transmission costs and losses included when comparing to DG costs. This will provide useful contextual information as the Commission considers appropriate avoided costs that inform parallel generation buyback rates.

Q. Are there any other intangible benefits that DG has over a transmission-interconnected asset like Western Mustang?

A. Yes. Most noteworthy are the benefits of not having to "rate base" DG owned by customers and developers. After lengthy proceedings, utility-owned assets are authorized by the Commission, incorporated into the utility's rate base, and earn a return for the utility's shareholders. All the risk, capital costs, and maintenance costs are paid for by the utility's retail customers. Alternatively, none of the risk, capital costs, or maintenance costs associated with DG are borne by the utility's retail customers. The only costs borne by retail customers are services provided by the non-utility owned DG assets as determined by the Commission after an assessment of avoided costs. In short, if utility-owned assets fail or are more expensive than projected, utility retail customers are on the hook; however, if non-utility owned DG assets fail or are more expensive than projected, retail customers are not on the hook.

A more robust contribution of renewable DG assets enable a more diverse, balanced portfolio of clean energy assets that serve retail customers. As utility capital costs increase with fewer fossil fuel costs in the future, along with the 'steel-for-fuel' transition, I believe the Commission should consider services provided by DG as low risk "fuel costs" that should fit squarely within utility planning as zero carbon transition. These clean energy "fuel costs" will help avoid portions of future utility generating capacity and transmission investments. As a result, I recommend that the Commission consider the costs of Western Mustang and future investments planned by NSPW in order to contextualize avoided cost components and set just and reasonable buyback rates.

V. ESTABLISHING JUST AND REASONABLE TARIFFS AND RATES

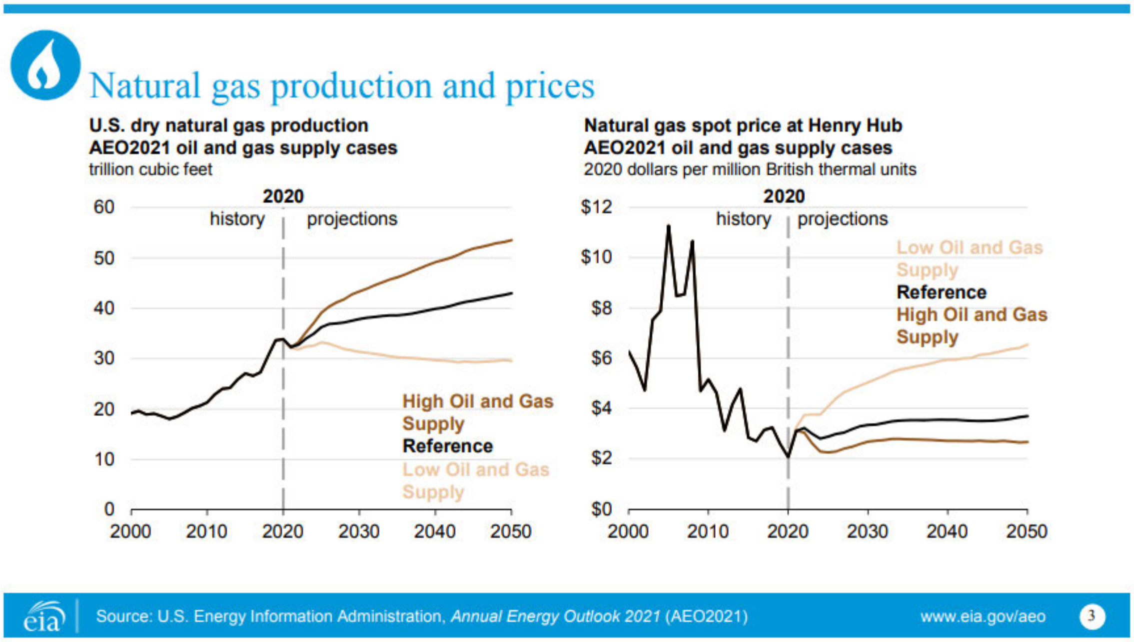
A. Pg-2A (Sale to Company)

Q. Based on your assessment of avoided costs discussed above, what does RENEW propose as energy buyback rates for NSPW's Pg-2A tariff?

A. NSPW's proposed Pg-2A tariff is designed for FTMGs under long-term contracts. As I discussed above in the avoided energy cost section, these long-term contracts must reflect long-term values in order to be just and reasonable. NSPW did not provide long-term forecasts of MISO LMPs with their application, however RENEW witness Ms. Wilson provides long-term forecasts for NSPW using Reference and High-Gas future scenarios. Ms. Wilson also converted nominal forecasted into real values. Based on my discussions with Ms. Wilson, I annualized these values so that forecast windows reflected RENEW's proposal for fixed energy prices under 5, 10, and 20-year contract length options. These annualized energy rates under RENEW's proposed contract length options are provided in Ex.-RENEW-Kell-6.

In order to capture uncertain future LMP values, I recommend that the Commission consider both the Reference and High-Gas future scenarios as modeled by Ms. Wilson. For RENEW's proposed energy credits, I propose that a two-thirds weight be given to the Reference scenario, and that a one-third weight be given to the High-Gas scenario. I base this weighting proposal on the principle that low, reference, and high price scenarios be given approximately equal weight. In order to put this into context, Figure 2 below is a figure taken from EIA's AEO 2021 report on forecasted natural gas prices.

Figure 2: EIA AEO Natural Gas Forecasted Supply Curves and Prices[3]



As described by Ms. Wilson, the EIA AEO "Reference" scenario for natural gas prices informed her "Reference" scenario for an LMP forecast. In order to forecast a "High-Gas" price scenario for LMPs, Ms. Wilson describes using the EIA AEO "Low Oil and Gas Supply" scenario, which causes higher gas prices than the Reference case. Although Ms. Wilson does not forecast for a "Low-Gas" price scenario, this would have likely reflected EIA AEO's "High Oil and Gas Supply" scenario, which causes lower gas prices than the Reference case. As one can see in Figure 2 above, there is not much difference in gas prices between the "Reference" and lower price "High Oil and Gas Supply" scenarios. This is likely due to the Reference case already including relatively low gas prices as an assumption base. As a result, I propose to use a two-thirds weight for Ms.

[3] *See* https://www.eia.gov/outlooks/aeo/pdf/03%20AEO2021%20Natural%20gas.pdf.

Wilson's Reference scenario for LMPs, and a one-third weight to the High-Gas scenario for LMPs. This weighted scenario blend is reflected in Ex.-RENEW-Kell-6.

Finally, energy loss factors must be utilized to reflect line losses, which NSPW proposes to vary by secondary, primary, and transmission levels of interconnection. I use Ms. Bhandari's proposed secondary loss factor for energy value adjustment "WITH LOSSES" as reflected in my calculations of proposed energy rates in Ex.-RENEW-Kell-6.

Table 2 below presents RENEW's proposed energy rates by contract year. The table example presents the values "Without Losses" and "With Losses" examples using the same Synapse secondary loss factor. I provide further details on these calculations in Ex.-RENEW-Kell-6.

Table 2: RENEW Proposed Energy Rates for Pg-2A

5-Year Contract Option		
NSPW Time Period	**Without Losses**	**With Secondary Losses**
Summer On-peak	$0.03219	$0.03675
Winter On-peak	$0.02787	$0.03182
Off-peak	$0.02278	$0.02601
10-Year Contract Option		
NSPW Time Period	**Without Losses**	**With Secondary Losses**
Summer On-peak	$0.03284	$0.03749
Winter On-peak	$0.02726	$0.03112
Off-peak	$0.02322	$0.02651
20-Year Contract Option		
NSPW Time Period	**Without Losses**	**With Secondary Losses**
Summer On-peak	$0.03348	$0.03822
Winter On-peak	$0.02658	$0.03035
Off-peak	$0.02342	$0.02674

Q. What does RENEW propose as just and reasonable capacity buyback rates for NSPW's Pg-2A tariff?

A. RENEW proposes the use of MISO CONE for LRZ 1 to determine capacity payments for Pg-2A. The most recent MISO CONE value for LRZ 1 is $254.27/MW-day. This amount reflects long-term avoided capacity costs, and for FTMGs under contract RENEW proposes $/kW-month flat payments. Based on this unit, the MISO CONE amount is $7.6058/kW-month, exclusive of losses. Additionally, as explained by Ms. Bhandari in her direct testimony, since MISO calculates CONE on an annual basis, resources under multi-year contracts should receive an annual inflation escalation rate in order to capture the inflation rate at the moment the contract is signed. Using MISO accredited $/kW-month as a capacity payment is a just and reasonable unit for long-term contracts that provides price stability. I will address contract terms related to the MISO accreditation process further below. Table 3 below presents RENEW's capacity payments for Pg-2A, which converts the MISO CONE refence to a $/kW-month basis. As with the table above, Table 3 also contains the proposed number "Without Losses" and a "With Losses" example of a resource interconnected at the secondary level, which would receive the 1.14184 Synapse-calculated loss factor adjustment.

Table 3: RENEW Proposed Capacity Payments for Pg-2A

Capacity Reference	Without Losses	With Losses
MISO LRZ 1 CONE	$7.6058/kW-month	$9.0442/kW-month

Q. What does RENEW propose as just and reasonable transmission buyback rates for NSPW's Pg-2A tariff?

A. RENEW's proposed transmission payment for Pg-2A is based on Ms. Bhandari's avoided transmission cost calculations. Unlike NSPW's historical embedded transmission cost approach, Ms. Bhandari's calculations are based on the costs NSPW-forecasted transmission investments that are related to peak load growth, as well as NSPW-forecasted peak load growth. Ms. Bhandari also annualized these forecast numbers to propose a $/kW-year value, which can be easily converted to $/kW-month by dividing by 12 months per year. In other words, the $35.93/kW-year avoided transmission cost, exclusive of losses, calculated by Ms. Bhandari can be converted to a $2.9942/kW-month payment.

RENEW proposes that flat $/kW-month transmission payments are made to FTMGs that sign contracts, and that the MISO capacity accreditation process is appropriate for determining applicable kW-month credits for FTMGs. Using a $/kW-month unit as a transmission payment is just and reasonable for long-term contracts, which provides price stability and revenue stream certainty for financing projects. Table 4 below presents RENEW's capacity payments for Pg-2A.

Table 4: RENEW Proposed Transmission Payments for Pg-2A

Transmission Cost Reference	Without Losses	With Losses
Synapse-Calculated Avoided Cost	$2.9942/kW-month	$3.5604/kW-month

Q. What does RENEW propose as just and reasonable contract terms for NSPW's Pg-2A tariff?

A. Long-term contracts on fair terms are critically important to distributed generation projects because they provide the certainty necessary to secure financing at reasonable rates. I am aware that the Commission is further investigating Legally Enforceable Obligations and standard contract issues in its current 5-EI-157 investigation, and urge the Commission to direct the development of a standard offer contract for QF resources greater than 100 kW. RENEW, along with Clean Energy Advocates, commented on a Commission staff memorandum in that docket this past summer, and submitted high-level policy considerations for Commission in relation to consistency, certainty, and long-term value for long-term resources. (PSC REF# 418909). I look forward to working with stakeholders to develop more detailed comments during future Commission opportunities in that investigation. In the meantime, I have a few important proposed terms for NSPW's Pg-2A tariff revisions in this case. These terms relate to 1) contract length options, 2) the establishment of the avoided capacity payment, and 3) the establishment of the MISO capacity accreditation methodology, which in RENEW's proposal is relevant to both capacity and transmission payments.

Q. Please explain your proposal with respect to contract length.

A. As I described above, I propose contract options of 5, 10, and 20 years for the Pg-2A tariff. This will allow for a long-term 20-year contract for new resources, and shorter long-term contract options for resources currently in the middle of their expected useful lives and those seeking an extension to initial contract. This is an equitable way to provide long-term price certainty for long-term resources, and ensure financing for these clean energy resources.

Q. Please explain your proposal with respect to the establishment of the avoided capacity payment.

A. I propose that contracted resources receive the most recently established MISO CONE value in place when the contract is entered, for the duration of the contract. My interpretation of NPSW's proposed draft tariff, under "Accredited Capacity Credit" issue #4, mirrors this principle in stating, "The contracted capacity credit rate will remain unchanged." If my interpretation of this capacity credit is correct, then I agree with NSPW's condition as stated.

Q. Please explain your proposal with respect to the establishment of the MISO capacity accreditation methodology relevant to both capacity and transmission payments.

A. In NSPW's proposed Pg-2A tariff it states, "MISO's capacity accreditation rules are subject to change", which implies that the resource under contract may be subject to accreditation changes in the middle of the contract. Uncertain changes pending within the accreditation methodology may jeopardize financing of clean energy projects.

As the MISO accredited capacity value is integral to calculating both the capacity and transmission payments (under RENEW's proposal), resources entering into contracts will need some level of certainty regarding the capacity and transmission payments they will receive over the duration of their contract. I propose that when resources sign a contract they will lock in to the MISO accreditation methodology in effect upon signing. Currently, MISO accreditation focuses on summer peak hours and provides an industry average for year one (50 percent of nameplate capacity for resources with no historical production). For future years, there are adjustments to the accredited capacity value based on historical performance during those summer peak hours. So, under my proposal, if a resource were to sign a contract today, the current MISO methodology would be the accreditation process that is locked into the contract for the duration of the contract.

I am aware that at some point MISO will be implementing a seasonal approach to capacity accreditation. When the MISO seasonal approach is finalized and in-effect that methodology should be the capacity accreditation process that is established for contracts signed that day and going forward. However, that new seasonal accreditation process should not alter the locked-in methodology of contracts signed prior to the effective date of MISO's new capacity accreditation methodology.

B. Pg-2B (Sale to Company After Customer Self-Supply)

Q. Based on your assessment of avoided costs discussed above, what do you propose as just and reasonable energy buyback rates for NSPW's Pg-2B tariff?

A. NSPW's proposed Pg-2B tariff is designed for BTMGs that are not under long-term contracts. NSPW proposes to use short-term TY forecasts for energy rates under Pg-2B, which are updated annually under either fuel case or rate case processes under the Commission's authorization. I agree with this approach for energy payments to BTMGs without long-term contracts. Table 5 below presents RENEW's proposed energy rates for Pg-2B, which uses the same methodology proposed by NSPW, if losses are not considered. However, rather than use NSPW's proposed loss factor, I use the loss factor that Ms. Bhandari calculated for secondary service in the "With Losses" column below.

Table 5: RENEW Proposed Energy Rates for Pg-2B

NSPW Time Period	Without Losses	With Losses
Summer On-peak	$0.02506/kWh	$0.02861/kWh
Winter On-peak	$0.02298/kWh	$0.02624/kWh
Off-peak	$0.01420/kWh	$0.01621/kWh

Q. What do you propose as just and reasonable capacity and transmission buyback rates for NSPW's Pg-2B tariff?

A. NSPW does not propose to make capacity or transmission payments for BTMGs under Pg-2B. I believe this not a just and reasonable approach, as it ignores capacity and transmission values provided by these resources.

RENEW proposes that capacity and transmission payments can be made to BTMG resources based on performance. Using the same $/kW-year avoided costs identified above, I have converted these values to $/kWh by levelizing across all NSPW's 3060 on-peak hours of the year. The $/kWh price can then be paid out based on hourly on-peak production. This performance-based payment is created to compensate BTMG resources based on the actual value that they provide to the system. During peak hours, BTMG would not receive any payment from the utility when it is only serving load. However, if the BTMG is providing excess generation then the resource would receive a payment based on actual excess generation during those peak hours. This performance-based payment is an equitable solution that ensures an appropriate fraction of the possible $/kW-year value is paid to excess generation from BTMGs. Table 6 and Table 7 below present RENEW's proposed capacity and transmission rates for Pg-2B. I provide additional details on these calculations in Ex.-RENEW-Kell-6.

Table 6: RENEW Proposed Capacity Rates for Pg-2B

NSPW Time Period	Without Losses	With Losses
Summer On-peak	$0.0298/kWh	$0.0355/kWh
Winter On-peak	$0.0298/kWh	$0.0355/kWh

Table 7: RENEW Proposed Transmission Rates for Pg-2B

NSPW Time Period	Without Losses	With Losses
Summer On-peak	$0.0117/kWh	$0.0140/kWh
Winter On-peak	$0.0117/kWh	$0.0140/kWh

Finally, in order to present the stacked energy, capacity, and transmission values the RENEW proposes for Pg-2B, Table 8 below provides the "all-in" $/kWh values for each of the NSPW time periods. The on-peak periods provide a stack of avoided on-peak energy values specific to those time periods, as well as avoided capacity and transmission values. The off-peak period only reflects avoided off-peak energy values.

Table 8: RENEW Proposed All-in Rates for Pg-2B

NSPW Time Period	Without Losses	With Losses
Summer On-peak	$0.06656/kWh	$0.07804/kWh
Winter On-peak	$0.06448/kWh	$0.07567/kWh
Off-peak	$0.01420/kWh	$0.01621/kWh

Q. How should the Commission address updates to NSPW's buyback rates under RENEW's proposal?

A. For updates to energy rates, the Commission could direct NSPW to complete annual updates under the utility's regular rate case or fuel case proceedings. This annual process is already established for TY forecasts of LMPs. For long-term forecasts of LMPs, the Commission could direct NSPW to perform long-term forecasts of LMPs while the utility provides TY forecasts. Per RENEW's recommendations, these should include Reference and High-Gas scenarios to inform the blended average that the Commission chooses.

For updates to capacity rates, since MISO updates CONE values on an annual basis, the utility could submit the most recent MISO CONE value during its annual rate case or fuel case as well.

For updates to transmission rates, I would defer to the Commission's judgement as to the frequency of updates. One possibility would be to direct utility updates to occur during rate case proceedings when a full Commission audit of revenue requirement will take place. This may be every 2-to-3 years, depending on the utility's rate case cycle, or perhaps longer if the multi-year schedules of rates are authorized by the Commission.

Q. What is your assessment of rate impacts to non-participating customers under both NSPW-proposed and RENEW-proposed parallel generation buyback rates?

A. Ultimately, the rate impact to non-participating customers is based on the Commission's valuation of avoided costs. Under current buyback rates, and those proposed by NSPW, my assessment is that FTMGs and BTMGs exporting renewable generation on the distribution grid are subsidizing non-participating customers. I base this assessment on RENEW's avoided cost analysis, as well as my comparative LCOE analysis for Western Mustang above. On a levelized basis, NSPW ratepayers will be paying for rate-based Western Mustang energy at a higher cost than NSPW is proposing to pay for FTMG energy, and much more than NSPW is proposing to pay for BTMG energy. When considering added transmission costs and energy losses of Western Mustang, this rate-based asset has additional higher costs than NSPW is proposing to pay for customer-owned solar at the distribution level. Because the NSPW proposed buyback rates are based on their interpretation of avoided costs that does not truly value renewable generation at the distribution level, non-participating customers are currently paying for local, clean energy at very low risk and very low rates.

Per NSPW's proposal, FTMGs under long-term contracts are paid based on short-term energy rates and embedded transmission costs that do not fully capture the long-term value of these resources. Additionally, FTMGs are only paid for capacity when NSPW declares that it is needed from the narrow perspective of its PRMR. As stated above, the PRMR is only one aspect of a utility's need set, and it is an aspect that totally ignores NSPW's persistent need to replace fossil fuel capacity with non-fossil fuel capacity for the foreseeable future—a need that NSPW asserts when it comes to its own solar resources. If not under contract, BTMGs are only paid based on short-term energy rates for excess generation under NSPW's proposal, with no additional value.

RENEW's proposal, in contrast, accurately values distributed renewable resources, and keeps non-participating customers economically indifferent between utility-scale renewable resources and distributed renewable resources. RENEW proposes to "right the ship" and get NSPW's buyback rates in alignment with value to non-participating customers. As I describe below, RENEW's proposal will also better support the business case for distributed renewable resources, which better meets NSPW customers' desire for more local clean energy.

Q. What is your assessment of rate impacts to participating customers, who own or wish to develop solar resources, under both NSPW-proposed and RENEW-proposed parallel generation buyback rates?

A. In order to assess the rate impact to customers who choose to install PV systems and participate under NSPW's Pg-2A and Pg-2B tariffs, I examined the financial feasibility, or business case, for PV systems under these buyback rate proposals. To accomplish this task, I utilized the National Renewable Energy Laboratory (NREL) System Advisor Model (SAM). According to NREL's website[4], the SAM tool is a "free techno-economic software model that facilitates decision-making for people in the renewable energy industry." The SAM tool is relatively easy to use and assists analysts in simulating the performance of several renewable energy projects.

Q. How did you assess the impacts to the business-case for PV systems under both NSPW-proposed and RENEW-proposed parallel generation buyback rates using the SAM tool?

A. I used SAM to simulate the performance of a PV project at a generic commercial customer's location[5]. The goal of the simulated customer under the BTMG

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[4] The NREL SAM tool can be downloaded here: https://sam nrel.gov/.

[5] Based on weather and load data availability and ease of comparison across utilities, I utilized Madison, Wisconsin as a location for all NREL SAM analysis. I do not expect locational differences within Wisconsin to dramatically impact the financial results of the modeling. Weather data was downloaded from

scenario, at Pg-2B rates, is to reflect a commercial customer with strong sustainability and carbon reduction goals. While I did not attempt to simulate a "net zero" scenario, I assumed the commercial customer would desire to generate approximately 80 percent of annual load from an on-site PV project as part of its strategies. The simulated commercial customer's summer peak load was about 275 kW, with an annual energy load of about 725,000 kWh. To simulate the generation of approximately 80 percent of the annual kWh load, I sized the PV system at 465 kW-dc (that converts to 419 kW-ac), which is interconnected at the secondary service level, generated about 604,000 kWh in the first year. With a default SAM input of 0.5 percent annual degradation of generation from the system, the PV system generated about 80 percent of load in year 10, and less thereafter. I also simulated the same 419 kW-ac system as a FTMG scenario to assess the NSWP-proposed and RENEW-proposed buyback rates for 'buy-all, sell-all' generation under a Pg-2A, 20-year contract.

Q. Which assumptions did you use to set up the SAM simulations?

A. I used default SAM assumptions for almost all the available inputs, which automatically populate the SAM tool after the Commercial PV simulation option is chosen. For possible modifications to these default values, I concentrated on the selection of finance and insurance assumptions that are key drivers of payback period estimation. The SAM insurance rate input is an important assumption in relation to annual operating costs of a project. For example, when I changed the default input from 0.0 to a 1 percent annual rate (of installed costs), this had a

energyplus net/weather-location/, and load data was downloaded from https://www.energy.gov/eere/buildings/commercial-reference-buildings.

significant impact on the simple payback period results. After referencing an NREL document[6] on the subject, I selected a midpoint insurance rate of 0.3 percent of annual installed costs for all scenarios. For other important financial inputs, I assumed that the commercial customer has fully financed the project with 100 percent debt, and that the financing comes with a 20-year loan term at a rate of 3.5 percent per year. I also used the default 2.5 percent inflation rate within the SAM tool.

Based on PV incentives available to commercial customers under the Focus program, I allowed a Focus incentive of $47,025[7] for all scenarios, which I inserted as an Investment Based Incentive under "Other". All other assumptions relating to finance, installation and maintenance costs, and technical aspects of the system were left at the SAM default inputs. Finally, I used NSWP's Cg-9 customer class rates[8] for the BTMG scenarios. NSPW's proposed metering charge for generators 250 kW-ac and up of $71.80/month, for both Pg-2a and Pg-2B, is captured as a fixed annual cost of $861.60 to the customer within SAM in both the FTMG and BTMG scenarios.

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[6] The NREL document *Insuring Solar Photovoltaics: Challenges and Possible Solutions*, a suggested nationwide range for annual insurance rates was between 0.25 and 0.5 percent: https://www.nrel.gov/docs/fy10osti/46932.pdf.

[7] Focus assumption for systems between 300-500 kW-dc: $33,000 + $85 per kW above 300 kW-dc. Equation 465 kW-dc system for Focus incentive: $33,000 + ($85 * 165 kW) = $47,025. *See* https://www focusonenergy.com/residential#program-renewable-energy.

[8] The NSPW Cg-9 class is for commercial customers with greater than 200 kW of measured demand. While I was able to include the On-peak Demand charge, from my assessment the SAM tool does not accurately capture the structure of NSPW's Distribution Demand charge, and I left this charge out of the simulation. Due to the "ratchet" structure of this charge it is difficult to accurately capture how a PV system may reduce the customer's exposure to Distribution Demand charges in general. If a customer with a BTMG is able to reduce Distribution Demand charge amounts, those would be additional benefits not captured with the SAM analysis that I performed.

Based on SAM's input setup, I was not able to accurately capture \$/kW-month payments based on MISO accreditation. All \$/kW payments within SAM are based on the nameplate kW-dc rating of the project without the ability to make adjustments for a MISO capacity rating. Rather than use existing SAM inputs, I was able to capture MISO accredited \$/kW payments with post-simulation analysis. After downloading the cashflow results from SAM in spreadsheet format, I was able to create annual capacity payments by manually inserting into annual cashflows in the spreadsheet. For example, based on NSPW's proposed Pg-2A capacity payment I was able to insert an annual payment of \$17,321[9] starting in the fourth year, based on NSPW's proposal, into the cashflow row for "Utility Performance-based Incentive". For RENEW's proposed Pg-2A capacity payment for the first year, I was able to insert \$22,737[10] into the cashflow row for "Utility Performance-based Incentive". For subsequent years, I escalated the CONE-based capacity payment in the cashflow analysis by 2.0 percent each year to reflect RENEW's proposal to incorporate inflation for multi-year contracts. For RENEW's proposed Pg-2A transmission payment, I was able to insert \$8,951[11] for all years of the cashflow row for "Other Performance-based Incentive".

Q. What are the results of the SAM simulations for NSPW-proposed buyback rates?

A. There are several results that one can focus upon in order to assess the business case for PV systems under proposed buyback rates; however, I focused on the

[9] 419 kW-ac * 50% MISO accreditation * \$6.89/kW-month *12 months/year = \$17,321.
[10] 419 kW-ac * 0.5 capacity accreditation *9.0442/kW-month *12 months/year = \$22,737.
[11] 419 kW-ac * 0.5 capacity accreditation *3.5604/kW-month *12 months/year = \$8,951.

simple payback period from SAM's cashflow results. The simple payback period is one way looking at how many years that it will take for the project owner to break even, considering the project costs and revenues. More specifically, it is the cost of the investments divided by average annual cash flow. For the BTMG scenario, under NSPW's proposed Pg-2B rates, the simple payback period is 17.42 years. Of note for the BTMG scenario, about 60 percent of the project's production served load, and about 40 percent was exported to the grid and sold to the utility. For the FTMG scenario, in which 100 percent of the production was exported and sold to the utility, under NSPW's Pg-2A rates the simple payback period is 22.12 years.

Q. What are the results of the SAM simulations for RENEW-proposed buyback rates?

A. I used the same project setup and assumptions for RENEW's proposed buyback rates as I did for NSPW's proposed buyback rates. The only difference is that I changed the buyback rate structures to reflect RENEW's proposal. For the BTMG scenario, under RENEW's proposed Pg-2B buyback rates, the simple payback period is 13.60 years. For the FTMG scenario, under RENEW's proposed Pg-2A rates, the simple payback period is 11.82 years. Table 9 below presents the payback period lengths per scenario.

Table 9: Comparison of NREL SAM Analysis of Simple Payback Periods

Tariff Proposal	Pg-2A Payback (Years)	Pg-2B Payback (Years)
NSPW's Proposal	22.12	17.42
RENEW's Proposal	11.82	13.60

Q. How do you assess the SAM simple payback period results?

A. I assume that many corporate finance officers would look at all the listed payback periods above and determine that these numbers exceed normal expectations for financing projects, which they may establish at 5-year or 10-year payback threshold requirements. However, since the simulated commercial customer has strong sustainability goals there may be an appetite for a system that has a slightly longer payback period than other corporate projects are subject to. For example, if a 15-year payback were the threshold for a customer under the BTMG and FTMG scenarios, the RENEW-proposed buyback rates would put the project slightly under that threshold. However, the NSPW-proposed buyback rates would be outside of that threshold for both the BTMG and FTMG scenarios under their proposal.

I would also like to note that these simulated scenarios were based upon one generic customer and project type, and that the inputs would need to vary for every real-world situation to reflect unique corporate strategies, load profiles, costs, and financing available. That said, I do believe that this generic commercial customer example using SAM analysis provides useful, contextual information to the Commission.

Q. Based on this assessment, what are your conclusions SAM results and proposed rates?

A. I believe that my SAM analysis demonstrates that RENEW's proposed buyback rates do not create radically different PV business-case results compared to the buyback rates proposed by NSPW. Instead, the SAM results show that RENEW's proposal would create incrementally improved business-case PV scenarios for NSPW's retail customers and the developers that they work with, consistent with NSPW's call for gradualism. The delta between these proposals may the mean difference between a customer installing a PV system or not installing one at all. Alternatively, for some customers the difference in proposals may mean utilization of private investments and financing to install a slightly larger PV system, rather than constraining the PV system to export as little generation as possible. Based on my understanding of zero-carbon goals, we need to establish price signals that adhere to avoided costs but also encourage clean energy development. RENEW's proposed buyback rates provide both utility system benefits as well as societal benefits. RENEW's proposal also avoids an approach that would limit and downsize investments, which serve only parochial benefits to the detriment of societal carbon reduction goals.

Q. Do you have anything additional to add?

A. I would like to conclude that RENEW's proposed buyback rates are based on thorough engineering modeling and economic assessments as requested by the Commission by Order in docket 5-EI-157. Based on this quantitative analysis, RENEW proposes a comprehensive framework of parallel generation buyback rates that are just and reasonable for all NSPW's retail customers. RENEW's proposed buyback rates reflect NSPW's avoided energy, capacity, and transmission costs, and dynamically represent value of services provided by FTMGs under long-term contracts, as well as BTMGs that are not under contract. As stated above, I further recommend that the Commission order NSPW to further collaborate with parties and utilize existing methodologies to assess avoided distribution and environmental costs, which the Commission can authorize for inclusion in parallel generation buyback rate updates in the future.

Furthermore, I believe that RENEW's proposed buyback rates will "move the needle forward" for renewable DG development within NSPW's territory. I demonstrate this with the SAM tool analysis provided above. NSPW's assessment of avoided costs is incomplete, and for reasons described by RENEW witness Mr. Michael Vickerman in his direct testimony, NSPW's proposal falls short of providing adequate price signals that will lead to any significant develop of renewable resources on their distribution system. In comparison to the utility's proposal, RENEW's proposed buyback rates will create clear price signals that will enable a more balanced generation portfolio approach, and will provide a greater level of assurance that Wisconsin's carbon reduction goals can be met.

Q. Does this complete your direct testimony?

A. Yes, it does.