**BEFORE THE
PUBLIC SERVICE COMMISSION
OF WISCONSIN**

Application of Wisconsin Power and Light Company for Authority to Adjust Electric and Natural Gas Rates For 2024 and 2025 Test Years	Docket No. 6680-UR-124

PRE-FILED DIRECT TESTIMONY OF

TYSON COOK

FOR

WISCONSIN POWER AND LIGHT COMPANY

April 28, 2023

Q. Please state your name, employer, business title, and business address.

A. My name is Tyson Cook. I am employed by Alliant Energy Corporate Services, Inc. ("AECS"), a service company subsidiary of Alliant Energy Corporation ("Alliant Energy"), as Manager Distributed Generation Services. My business address is 4902 N. Biltmore Lane, Madison, Wisconsin, 53718.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of Wisconsin Power and Light Company ("WPL" or "Company").

Q. Please describe your educational and professional background as it relates to this proceeding.

A. I received a Master of Science degree in Civil and Environmental Engineering through the Atmosphere/Energy Group at Stanford University. I also received a Bachelor of Arts degree majoring in Physics from Kalamazoo College and completed post-graduate coursework in the Environmental Health Sciences program at the University of Michigan School of Public Health. I have been employed by Alliant Energy for around five years. Prior to my current position, I also held roles including Lead Resource Planning Consultant and a Regulatory Strategy and Innovation Manager for Alliant Energy, with responsibilities including overseeing the development of the WPL Clean Energy Blueprint resource plan. Before joining Alliant Energy, I was employed by Clean Wisconsin for approximately seven years as a Staff Scientist, Director of Science and Research, and finally, as Senior Director – Energy, Air and Science. Prior to my time with Clean Wisconsin, I was employed by Energy Solutions in Oakland, California as a Project Manager on energy efficiency, emerging technology, and renewable energy programs.

Q. What are your responsibilities in your current position?

A. I am responsible for managing all activity related to interconnection of distributed energy resources ("DERs"), such as distributed generation ("DG"), to the distribution system, including independent power producers and behind the meter residential and commercial customers, for WPL. This also includes oversight of distributed energy resource programs, distribution level and Public Utility

Regulatory Policies Act ("PURPA") power purchase agreements ("PPAs"), distributed generation tariffs, and associated products and services.

Q. Have you testified in prior cases before the Public Service Commission of Wisconsin ("PSCW" or "Commission")?

A. Yes, I have previously testified before the Commission on behalf of WPL in Docket No. 6680-CE-182, which was WPL's first application for a certificate of authority to construct six solar projects ("Solar CA I"), Docket No. 6680-UR-123, which was WPL's last rate review docket, and Docket No. 6680-TE-107, which was WPL's recent application for approval of updates to its PgS-1 Parallel Generation Tariff. I have also previously testified in several cases before the Commission in my former role with Clean Wisconsin.

Q. What is the purpose of your direct testimony?

A. I will describe WPL's proposal to transition from a net energy metering ("NEM") tariff for Parallel Generation Renewable Resources (PgS-3) to a Power Partnership tariff (PgS-2). I will also discuss the way in which WPL manages distribution upgrades for interconnected DERs.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring eight exhibits:

- Ex.-WPL-Cook-1 is the proposed tariff for parallel generation facilities with a capacity of 20 kilowatts ("kW") or less;

- Ex.-WPL-Cook-2 is *Re Cogeneration and Small Power Production,* Wisconsin Public Service Commission Docket No. 05-ER-11, Order Implementing Rules and Buy-Back Rates for Customer-Owned Generating Systems (June 21, 1983);
- Ex.-WPL-Cook-3 provides modeling results for a hypothetical distributed generation system in 2024, installed by an average residential customer;
- Ex.-WPL-Cook-4 demonstrates the calculation of the proposed System Asset Value Credit rate;
- Ex.-WPL-Cook-5c shows hypothetical financial impacts that could arise from 5,000 residential customers installing distributed generation systems;
- Ex.-WPL-Cook-6 provides example billing components for hypothetical distributed generation systems in 2024, installed by a single average residential customer;
- Ex.-WPL-Cook-7 Michigan Public Service Commission April 18, 2018, Order issued in Case No. U-18383;
- Ex.-WPL-Cook-8 provides example simple payback period calculations for hypothetical distributed generation systems in 2024, installed by an average residential customer; and
- Ex.-WPL-Cook-9 demonstrates the potential reduction in effective cost per kilowatt-hour ("kWh") for residential customers in 2024 with implementation of Power

Partnership for 5,000 hypothetical distributed generation systems as compared to Net Metering.

I. TRANSITION FROM NET METERING TO POWER PARTNERSHIP

Q. Please provide an overview of how the current NEM structure works under PgS-3 tariff.

A. In Wisconsin, WPL and other utilities offer monthly net metering to customers with small renewable resource generators. Under this structure, energy production exceeding a customer's energy consumption at a given time is allowed to "offset," from a billing perspective, that customer's energy consumption from other times. If the excess production amount is greater than the customer's total monthly consumption, the difference between the total production and the total consumption is calculated, and the customer is credited for the net remaining production at an avoided energy cost rate, which is generally based on forecasted locational marginal prices ("LMPs").

Q. Does NEM accurately reflect the values of customer-owned generation?

A. No, the current net metering framework does not create or ensure alignment between the actual power and financial flows. Net energy metering was a simple solution to the policy problem of encouraging customer-owned generation, as contemplated by PURPA when it was passed in 1978. The Commission then provided an interpretation and general model for net metering in a Letter order dated January 1982, that could be cost-effectively, if crudely, implemented with the technology at the time – allowing mechanical electric meters to spin backwards for generators producing surplus energy. That model was adopted to eliminate what would have been a costly requirement at the time to install a separate meter for measuring exported power, with costs in some cases exceeding the payment provided to generators for power produced. (Ex.-WPL-Cook-2)

The appropriateness of the simplified transaction facilitated by net metering, however, is predicated on the proposition that all power has the same value regardless of when and how it is produced or consumed. This does not adequately reflect the true complexities of providing power at varying times of the day or year, in varying amounts per customer, while maintaining critical standards and simultaneously enabling many customers to export power back onto a distribution system. Indeed, after netting a customer's monthly use, neither the utility nor the customer may know quite how much power was consumed from the utility or exported to the grid for the eventual use of others. For example, as modeled in Ex.-WPL-Cook-3, in a situation where an average residential customer installs a solar system, monthly netting could result in customer bills that only reflect approximately 179 kilowatt-hours ("kWh") of electrical load usage on an annual basis. However, that same customer uses approximately 4,847 kWh onsite when considered on a net hourly basis. As a result, the utility's sales to a generating customer under net metering are no longer tied to the degree of service that was provided.

Similarly, the Commission reasoned at the time of developing net metering that the small facilities – producing little surplus energy – would have very small, if not zero, revenue effects on the utility and non-generating customers. This reasoning may have been true, and the net metering arrangement manageable, when the number of generating customers was low. For example, through the end of 2001, approximately twenty years from the time of that order, WPL had a total of 42 NEM customers. Even another ten years on in 2011, while that number had increased substantially, WPL's 189 wind and solar NEM customers had a sum total capacity of less than 2 MW. However, the rapid recent increase of DERs puts a spotlight on the differences between sales under NEM and the actual value of those DERs. For example, as shown in Table 1, over the last two years WPL has received an average of more than 1,000 new applications for the interconnection of distributed solar systems. This is more than four times the annual number even just in 2018, resulting in the addition of more than 20 MW of distributed solar generation capacity in the past two years alone. As a result of NEM reducing the volume of kWh accounted for as consumption through a billing construct, these systems raise rates for other customers by artificially shrinking the denominator (kWh sales) in rate calculations. Today, four decades after that simplified net metering framework was introduced, we can much better track the actual production and use of energy by generating customers and more accurately reflect the corresponding values.

Table 1: WPL Annual Distributed Solar Interconnections and Applications, 2018-2022

Year	2018	2019	2020	2021	2022
New applications (count)	260	411	826	1,198	1,171
Total entering service (count)	252	324	733	919	934
Total entering service (MW)	2.2	4.6	5.2	7.6	15.0

Q. Utilities face lower sales from energy efficiency and other customer behavior changes. How is NEM different from these situations?

A. Unlike other scenarios where customers may actually consume less electricity, NEM results in sales that only appear low from a metering and billing perspective. To be sure, some of the generated electricity will be consumed immediately on-site, thus lowering the amount supplied by the utility. However, allowing a meter to "spin backwards" and simply net out production versus consumption over the course of an entire billing month reduces the sales volumes in a way that does not reflect the actual amount consumed by the customer. For example, NEM would show no electricity use or sales for a customer who in fact consumes a substantial amount of energy from the grid in the morning and evening (e.g., for heating ventilation and air conditioning or electric vehicle charging) that is later "offset" by substantial energy production (e.g., from rooftop solar) sent out through the distribution system mostly during midday. Despite the high levels of grid utilization and electrical consumption by such a customer, and corresponding costs of service provided, NEM could represent them as the same as a customer who temporarily suspended electric service (e.g., at a vacation home).

Q. What are you proposing to replace the current net metering structure?

A. We are proposing to shift NEM Pgs-3 customers from monthly netting to a new Power Partnership model. The new model will more accurately reflect the true values of customer generation and consumption, accounting for customer-owned parallel generation as system assets, incorporating time of day ("TOD") rates for energy use, maintaining avoided energy cost rates for energy production coupled with an added system value credit, and incorporating an Excess Distribution Use charge for large outflows. Changing to Power Partnership would charge or credit the customer on an hourly basis depending on the kWh actually consumed or exported in that hour, capturing whether the customer is in fact drawing power from the utility or providing power back through the distribution network. The Power Partnership framework more effectively accounts for all transactions with distributed generation and enables more discrete transactions for other types of DERs. The new tariff will allow WPL and its customers to be financially agnostic in terms of selecting DERs or another generation source to supply needed power.

Q. Are you proposing to create a separate class of customers?

A. No. Referring to customers as either consuming or generating is simply a shorthand to aid in discussion. In any given hour, a customer can be described as a consuming customer that pulls power from the distribution system, or a generating customer that exports power back through the system. However, these two types of energy transactions (consuming and generating) are simply different aspects of the service that we provide and enable for all customers.

Q. Please describe the energy use component of the Power Partnership structure.

A. The energy use component reflects the energy that is consumed by a customer at a given time. To reflect the time-varying nature of costs to provide that energy, WPL proposes to move residential and general service customers on the Power Partnership tariff to the relevant TOD rate, either Rg-5 or Gs-3. Customers taking service under PgS-3 may optionally take service under the relevant demand rates, Rd-1 or Gd-1. During any hour in which power is drawn through the grid from the utility, a customer with a distributed generation facility will be charged the appropriate retail price for that hour, just like all other consuming customers. This reflects the principle that a customer should pay for the costs of the power they consume.

Q. Why are you proposing to have mandatory TOD for generating customers?

A. Time of day rates more accurately reflect the cost of power across a day, weekday, weekend, or season. The use of TOD rates also allows for time-based avoided energy cost pricing for exported generation, as discussed below. Between these two TOD functions, the proposed move will give customers accurate and transparent information as to the price and cost of power coming in and going out of their property.

Q. The energy production component contains multiple parts. Please describe the first part, the energy cost credit.

A. The energy cost credit is priced the same as the current NEM structure for excess generation. However, it now applies to all power exported to the distribution network in a given hour. This rate reflects the cost of electricity that WPL would have had to purchase through the MISO market for each kWh used by consuming customers at a given time. By crediting generating customers that same energy cost, consuming customers pay the same amount for distributed generation as for other power sources.

Q. How is the System Asset Value Credit different from the energy cost credit?

A. The energy cost credit compensates for power based on MISO market prices, which reflect the marginal cost of electricity at a given time and location through LMPs. However, those LMPs do not necessarily capture the full value, or costs, of a generating asset. The System Asset Value Credit recognizes that, when a generating customer exports power through the distribution network, that power is ultimately received by another customer elsewhere on the network. That ultimate customer then pays for the electricity and services provided via retail rates, which do not vary based on the source from which delivered energy originates. To maintain this neutrality, wherein consuming customers are financially indifferent as to the source of their power, the System Asset Value Credit is set at a level that makes the cost paid by consuming customers equivalent to the embedded capital cost rate for the marginal generator in WPL's most recent resource plan.

Q. How is WPL proposing to calculate the System Asset Value?

A. Again, the System Asset Value Credit is set at a level that makes the cost paid by consuming customers equivalent to the embedded capital cost rate for the marginal generator in WPL's most recent resource plan. That amount is the levelized net revenue requirement per kWh for the marginal generator less power production costs, adjusted to account for the base earnings mechanism described below, as shown in Ex.-WPL-Cook-4.

Q. Is WPL proposing any limits on the level of credits provided to distributed generation customers, for example on a monthly or annual basis?

A. No, WPL is not proposing limits or caps on the total credit amount provided back to distributed generation customers. However, we are capping the total generation credit rate – the sum total of the energy cost credit rate and the System Asset Value credit rate – to be no more than the applicable volumetric retail rate for a given time of day billing period. This limit would be applied by first adjusting the energy credit rate then the System Asset Value rate.

Q. How is WPL proposing to reflect this from an accounting perspective?

A. As described in more detail by WPL witness Harvey Dorn, both the energy cost payment and the System Asset Value Credit will be booked as a purchased power expense. WPL also proposes to establish a regulatory asset with corresponding earnings for the System Asset Value Credit component, the accounting of which WPL witness Neil Michek describes in his direct testimony.

Q. What is the rationale for WPL earning a return on the System Asset Value Credit?

A. In the same way that energy is provided to consuming customers as needed through WPL's operation of its distribution network, the ability of generating customers to provide power and value to the grid – receiving compensation in return – is enabled by WPL managing complex power flows through that network. In so doing, the distribution system acts as a platform for energy transactions. Earning a return on the System Asset Value Credit is a reasonable way for WPL to receive compensation for the additional value provided to DG customers who benefit from having the distribution system available and managed to allow these energy transactions. The benefits provided to DG customers include managing the system to allow interconnection (sometimes called "hosting capacity") of DG, management of interconnection to avoid potential adverse impacts, provision of back-up grid services to account for intermittency of DG, and the added grid planning, investment, operations and maintenance required to allow for cost-effective integration of DG.

Q. What level of return does WPL propose?

A. As described by WPL witness Ann Bulkley in her testimony, the company proposes to maintain its rate of return at 10.0 percent. Likewise, WPL proposes to earn that same base return on the annual amount of the System Asset Value regulatory asset, plus the potential to earn an additional 2 percent in return on the System Asset Value regulatory asset based on the number of Eligible Generation Facilities interconnected to the distribution system in a given year, relative to the recent historical trend. Specifically, WPL proposes additional return at the following rate relative to the baseline of the linearly forecasted increase in interconnected facilities over the three most recent years with full data available (e.g., 2020, 2021, 2022):

<u>Additional return potential for 2023:</u>
105% of forecast (1,079 – 1,129 interconnected systems): 0.5%
110% of forecast (1,130 – 1,180 interconnected systems): 1.0%
115% of forecast (1,181 – 1,232 interconnected systems): 1.5%
120% of forecast (1,233 or more interconnected systems): 2.0%

<u>Additional return potential for 2024:</u>
105% of forecast (1,174 – 1,229 interconnected systems): 0.5%
110% of forecast (1,230 – 1,285 interconnected systems): 1.0%
115% of forecast (1,286 – 1,341 interconnected systems): 1.5%
120% of forecast (1,342 or more interconnected systems): 2.0%

<u>Additional return potential for 2025:</u>
105% of forecast (1,270 – 1,329 interconnected systems): 0.5%
110% of forecast (1,330 – 1,390 interconnected systems): 1.0%
115% of forecast (1,391 – 1,450 interconnected systems): 1.5%

120% of forecast (1,451 or more interconnected systems): 2.0%

This additional 2 percent of return potential further aligns incentives among the utility, customers, and Wisconsin's State energy policy. It does this by providing an incentive for WPL to facilitate the interconnection of new, renewable, customer-owned generation. More broadly, as shown in Ex.-WPL-Cook-5c, it provides an opportunity for WPL to earn a level of return on the System Asset Value Credit that will hold WPL more neutral from a financial perspective to customer-owned generation.

Q. Which customers would ultimately pay for the System Asset Value Credit, and WPL's proposed earnings mechanism?

A. As discussed, WPL would account for the System Asset Value credits as a purchased power expense. The earnings on the System Asset Value would be accounted for as part of that expense, and, therefore, be appropriately recovered from all customers.

Q. Please describe the Excess Distribution Use Charge.

A. The Excess Distribution Use Charge is part of the Power Partnership production component. The Excess Distribution Use Charge is applied to customers who export high amounts of power through the distribution system, to account for the higher investment required to operate and maintain the network. WPL's distribution system has been built based on certain assumptions of average customer load. When customers with DERs export energy back to the grid, the distribution system can handle that up to a point. When a customer exports large amounts of power, however, it can cause operational challenges, such as increased wear-and-tear on existing system components. Further, to enable those large exports, WPL may have to upgrade the distribution network to accommodate the generation. The Excess Distribution Use Charge is designed to recover some of those costs from customers who export large amounts of power to lessen the impact on other customers.

Q. How does the Excess Distribution Use Charge work?

A. The Excess Distribution Use Charge applies to any hour in which a customer exports more than 90 percent of the average peak load in the residential class of approximately 5.8 kW. Thus, if a customer has hours in which the exported kilowatt-hours exceed 5.2 kWh, then the Excess Distribution Use Charge will apply to all kWh exported in those hours.

Q. Other utilities have proposed capacity fees or limits for customer-owned generators. How does the Excess Distribution Use Charge compare to similar charges?

A. By more accurately reflecting the costs of service to customers with DERs, the Power Partnership model allows WPL and its customers to be agnostic to some customers installing generation on the distribution system. A blanket capacity charge or size limit does not target the behavior that results in WPL having to expand the distribution network. For example, a customer with a large house and electric appliances may have a peak load of seven or eight kW.

If that customer installs a generator equal to their peak load, the amount exported in any hour is less likely to exceed the average residential load compared to a customer who installs the same generator for a house with a peak load of three kilowatts. At the same time, while a customer who installs a smaller, three- or four-kW, generation system may result in increased costs to operate and manage the distribution system due to the addition of bi-directional electricity flow, that smaller system is much less likely to cause power flows that exceed the distribution system design and should, therefore, not be held responsible to the same degree for funding distribution system upgrades.

The Excess Distribution Use Charge is designed to provide an appropriate price signal to customer-owned generators, proportional to their distribution grid use and impact. Ex.-WPL-Cook-6 shows a sample bill calculation to illustrate how the Excess Distribution Use Charge works.

Q. How did you derive the amount of the Excess Distribution Use Charge?

A. The Excess Distribution Use Charge is intended for cost-sharing of distribution system costs between customers with large generators and other customers. To derive the amount of the charge to be assessed, we considered a somewhat simpler mechanism to recover distribution system costs from distributed generation, which would be to apply the same level of distribution system costs to any flow of electricity regardless of direction. While we are not proposing that type of mechanism for the reasons discussed above, it does provide an instructive example for the magnitude of distribution system costs that ought to be collected from DG customers.

In a situation in which an average residential customer installs a 7.07 kW solar system (which is in the average size that had been installed through the Net Metering tariff as of the end of 2022), if we were to assign distribution system charges to all net generation at the same level as charged to load ($[redacted] per kWh), we estimate that $[redacted] would be recovered to fund the distribution system annually. This would be equivalent to $[redacted] per kWh collected through the Excess Distribution Use charge applied to kWh exported in hours where the total exceeds 5.2 kWh. For a larger, 12 kW solar system, these respective values would be $[redacted] to be recovered annually, equivalent to $[redacted] per kWh collected through the Excess Distribution Use charge.

We believe a $0.05 charge is a reasonable level that strikes a balance among the level of revenue collected, a price that would not overly disincentivize customers installing generators of their choice, and a fair representation of the proportion of distribution capex and O&M spending attributable to customers who export large amounts of power. Had that $0.05 per kWh Excess Distribution Use Charge been applied to all PgS-3 customers in 2021, the latest year for which full data is available, it would have generated approximately $84,000 of revenue in that year to cover distribution system costs.

Q. Does WPL currently track how much money is spent on the distribution system explicitly to accommodate generators that export large amounts of power?

A. No. As described below, WPL considers this spending as a core part of its business. Since the distribution system equally enables power consumption and power export, it is difficult to attribute a specific portion of a capital project to either function.

Q. Please describe any precedents similar to Power Partnership from other utilities.

A. Interstate Power and Light Company ("IPL") provides an Inflow-Outflow DG Billing tariff for its customers. Customers receive a credit per kWh of energy for all net power flows provided by the customer to IPL during each 15-minute period at an Outflow Purchase Rate. For customers with an eligible distributed generation facility design capacity that exceeds 110 percent of their estimated annual usage, the credit is a prorated amount. This credit is calculated by applying the total energy outflow for all net power flows to a ratio of 110 percent of the customer's annual energy usage to the aggregate nameplate capacity's expected annual energy output at the location. One difference between this and the proposed Power Partnership model is that IPL's Inflow-Outflow tariff does not provide direct compensation for Outflow at the end of a given billing month. Instead, Outflow credits are carried forward to offset future billing periods, with any balance of excess credits remaining at the end of an annual period or upon termination of service forfeited by the customer. Another difference is in the way that the Inflow-Outflow tariff handles the addition of distribution system costs resulting from DG. While Inflow-Outflow does maintain some retail sales volume and associated distribution funding compared to a NEM as a result of moving away from monthly netting, there is no consideration of increased impacts that can occur based on system size or design that Power Partnership recovers through the Excess Distribution Use Charge. The Power Partnership model of the distribution system as a platform to enable energy transactions in all directions also includes a different treatment of distribution upgrades for DG that is described in more detail later.

Michigan has also had inflow/outflow since 2019, resulting from legislation that directed the Michigan Public Service Commission (MPSC) to approve alternative compensation mechanisms to NEM. The MPSC approved a standard Inflow/Outflow tariff for Michigan utilities in its April 18, 2018 Order issued in Case No. U-18383. On page 11 of the Order (Ex.-WPL-Cook-7), the MPSC agreed that an Inflow/Outflow tariff is preferable to a NEM tariff for several reasons:

> As the Staff explained in the DG Report, the Inflow/Outflow tariff is an adaptable framework that will allow the Commission to collect the data and information necessary to accurately capture the costs and benefits

> attributable to DG customers in a way that could not be done under traditional net metering.

And

> The Inflow/Outflow tariff assigns a rate to the DG customer's total inflow and total outflow which is then measured via AMI meters. These simultaneous measurements create a complete picture of the customer's energy usage and excess generation, unlike traditional net metering that only captures the customer's net usage. This improved data collection will allow the Commission to continuously evaluate DG program costs and benefits and provide accurate price signals to DG customers.

DTE Energy's Rider 18 is an inflow/outflow tariff in which the outflow rate is set at power supply cost less transmission. This, and similar tariffs at other Michigan utilities, functionally operate similar to WPL's proposal here. However, it is important to note that the Michigan utilities' tariffs are designed with a focus on the "cost" of customer-made power. Under this system, the Michigan utilities buy power from customers at a relatively low price and sell it at a higher price to other customers. WPL's Power Partnership proposal instead sets the price of customer-made power at a level so that consuming customers are held financially indifferent to the source of power, generating customers are compensated fairly for their power, and the utility receives compensation for shareholders based on the value provided by managing and enabling energy transactions across the distribution system.

Q. How does the proposed Power Partnership structure impact non-generating customers?

A. As previously discussed, this new rate structure will better reflect the values of power at varying times of the day or year and varying amounts. It will thus create efficiencies by, for example, maintaining sales volumes to reflect actual usage and by avoiding the netting of usage during high-cost time periods to usage at low-cost time periods. The costs of inefficiencies in the existing Net Metering framework are borne by non-participating customers, who end up paying costs avoided by monthly netting usage. Power Partnership will instead encourage parallel generation customers to maximize production and minimize energy use during peak hours, which will benefit all customers. Additionally, the inclusion of the Excess Distribution Use Charge will help ensure that parallel generation customers pay a share for the upkeep and operation of the distribution system. By providing better insight into the actual power produced and used by parallel generation customers, the shift to Power Partnership will also allow WPL to manage the distribution system more efficiently and ultimately offset the need to invest in new utility-owned facilities.

Q. How are you proposing to handle any environmental attributes, such as Renewable Energy Credits ("RECs"), that may be associated with generation from DG facilities on the Power Partnership rate?

A. We propose that when WPL purchases power exported from an Eligible Generation Facility, WPL would assume title to all associated renewable attributes. This is consistent with the embedded cost methodology proposed for developing the System Asset Value credit, which is based on the cost of energy from new renewable facilities. With that methodology, all customers are ultimately paying for the exported energy and the associated RECS should therefore be appropriately tracked and retired or sold on their behalf.

Q. Have you quantified the potential impact of the Power Partnership structure on retail rates?

A. The Power Partnership model was designed to be forward-looking, improving the compensation model for DG as adoption continues to increase in the future by allowing for more accurate accounting of value flows to reduce the potential for cross-subsidies in the near-term, while increasing efficiencies and reducing costs over the long-term. As many of those impacts will play out only in the coming years, it is difficult to quantify their exact impact. The impacts will also vary based on individual DG design and performance, as well as individual customer behavior. However, to provide some directional indication of impacts to both participating and non-participating customers, we tested the Power Partnership model by modeling a situation in which an average residential customer installs a 7.07 kW solar system (the average size installed under Net Metering). As shown in Ex.-WPL-Cook-6, such a customer would see little change in DG compensation. For example, in the 2024 test year, the DG compensation under Power Partnership would be largely unchanged – e.g. decreasing by 2.1 percent for

DG that is not on a TOD rate. However, it is notable that DG compensation under Power Partnership would actually increase by roughly 3.6 percent for DG that is on a TOD rate, because it sends price signals that more accurately reflect costs.

Ex.-WPL-Cook-8 shows this impact in terms of a simple payback period based on a hypothetical system cost of $3.50 per watt, taking into account existing federal tax incentives and rebate programs for residential solar customers in Wisconsin. Again, the impact on DG compensation is small (ranging from an increase in payback of 3 months over 12 years, to a decrease of 5 months, depending on use of a TOD rate). It also shows the effect of WPL's proposal to conduct interconnection upgrades at no cost to the customer, as described below. The impact of hypothetical interconnection upgrade requirements at 10 percent of the total system cost, for example, would be an increase to the simple payback period by 15-16 months.

Modeling a situation in which 5,000 residential customers install these 7.07 kW solar systems, we find that compared to the current net metering regime, Power Partnership would reduce the effective price of electricity for residential customers by 0.13 cents per kWh compared to Net Metering by maintaining higher kWh sales as shown in Ex.-WPL-Cook-9.

Q. How long does WPL propose for the transition from Net Metering to the new Power Partnership rates?

A. While it will take some time for our billing system to be updated to accommodate the new rates, we would propose that all new DG and eligible customers are placed on the Power Partnership rate starting as soon as that work is done. For existing PgS-3 customers, it is important to note that the overall net changes in DG compensation are projected to be small compared to Net Metering, resulting in little overall cost to existing customers from a shift to Power Partnership. At the same time, there is a significant benefit that will begin to accrue to all customers as a result of the ability to better track and manage the electrical and value flows associated with DG systems, as well as the new price incentives that will be put into place to drive behavior (e.g., toward reduced net on-peak energy usage). However, based on feedback received from stakeholders, and recognizing that there is the potential for the economic impacts to vary based on individual customer load and DG performance, we propose to provide current PgS-3 customers the option to stay on that rate until January 1, 2028, if desired, while closing PgS-3 to any new customers as of January 1, 2024. Customers who are on the PgS-3 tariff on or before December 31, 2023 would have the opportunity to transfer from PgS-3 to PgS-2 at an earlier date if desired. Under this proposal, the existing PgS-3 rate would become unavailable to any customers as of January 1, 2028.

II. DISTRIBUTION UPGRADES FOR INTERCONNECTED DERS

Q. How are distribution upgrades resulting from interconnected DERs currently treated in Wisconsin?

A. Under Wis. Admin. Code § PSC 119.08(2), utilities may recover the actual cost of distribution upgrades from an interconnecting customer. Those costs are often required to be paid by interconnecting customers upfront in full, prior to making any required upgrades or modifications. However, as WPL expects the pace of interconnected DERs to increase in the coming years, that treatment does not align with WPL's goals for how we operate the distribution system.

Q. What is WPL proposing in this case?

A. We propose to include language in the tariff implementing the Power Partnership model, affirmatively stating that WPL will conduct distribution system upgrades or modifications necessary for the interconnection of an Eligible Generation Facility at no cost to the customer. Instead, the cost of upgrading the distribution system to accommodate DER interconnections will be part of WPL's regular capex and O&M spending for the distribution system.

Q. How will this change be fairer to customers?

A. Currently, a marginal interconnecting customer is charged for the entire cost of the upgrades, not any customer who happened to interconnect before. The payment for the upgrades is received as contributed plant, meaning that the marginal interconnecting customer pays for upgrades to the distribution system, even those which are ultimately used for serving other customers' load and export capabilities. By treating distribution upgrades as part of standard utility service in the Power Partnership tariff, WPL will no longer penalize the marginal interconnecting customer for the distribution system upgrade.

Q. Shouldn't customers who cause the utility to incur additional costs be responsible for paying those costs?

A. Generally speaking, yes. However, WPL does not consider these costs to be "additional." Again, it is WPL's belief that consuming and generating power are different aspects of the service that we provide and enable for all customers. As a result, when considering the distribution network, the costs to accommodate the interconnection of DERs are part of the core business of a utility; they are not extra. To the extent that oversized generators may cause excessive costs due to disproportionately large impacts on the distribution system, those generators would be subject to the Excess Distribution Use Charge previously discussed. As a result, this change does not violate the principle of the cost-causer paying for those costs.

Q. Please explain how this spending is part of a utility's core business.

A. The growth of DERs is changing how the distribution system is built and operated. The distribution network continues to serve the fundamental purpose of providing load to consuming customers, but it is now also the platform that enables the presence and use of

DERs. As customers increasingly want to take advantage of new technologies, the utility must be responsive to that customer demand. Put another way, the distribution system is no longer just a one-way conduit for electrons to move from central power stations to customer appliances. Rather, DERs are creating a dynamic network with multiple power flows. Therefore, the distribution system performs multiple functions, including the delivery of utility-made power to customers and the enablement of DERs. For the first function, the utility base tariffs reflect the cost to perform that function. Charges like the Excess Distribution Use Charge, the customer charge, and other fees reflect the cost of the second function. Naturally, there is some overlap between the two functions, which is why the revenues from one area can be used to offset the revenue requirement in another area.

Q. Do you have any additional comments regarding the Power Partnership model or distribution upgrades for interconnected DERs?

A. At Alliant Energy, our purpose is to serve customers and build strong communities. While attending to the market challenges of today, we are working to power what's next in energy. We believe that this model will enable us to do that, representing a strong step forward in better meeting the current and future needs of our customers. That said, we also recognize that the energy industry is undergoing rapid change, and it is impossible to predict what the future will bring. To the extent that new technologies or energy transactions emerge that require us to modify this structure to better serve our customers, we will remain open to doing so.

Q. Does this conclude your testimony?

A. Yes, it does.