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File #: 205510

March 25, 2025

VIA ELECTRONIC FILING

Rosemary Chiavetta, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street, 2nd Floor North
Harrisburg, PA 17105-3265

Re: Petition of PPL Electric Utilities Corporation for Approval of its Second Distribution Energy Resources Management Plan
Docket No. P-2024-3049223

Dear Secretary Chiavetta:

Attached for filing on behalf of PPL Electric Utilities Corporation ("PPL" or the "Company") is the Main Brief and associated Appendices A through C for the above-referenced proceeding.

PPL notes that Proprietary and Non-Proprietary copies of the Main Brief are being submitted. The Proprietary version will only be provided to parties subject to the terms of a Stipulated Protective Agreement or the Protective Order entered in this proceeding.

Copies are being provided as indicated on the Certificate of Service.

Respectfully submitted,

Devin Ryan

DR/dmc
Attachments

cc: The Honorable John M. Coogan (*via email; w/attachments*)
Certificate of Service

CERTIFICATE OF SERVICE

(Docket No. P-2024-3049223)

I hereby certify that a true and correct copy of this filing has been served upon the following persons, in the manner indicated, in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant).

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of PPL Electric Utilities Corporation for Approval of its Second Distributed Energy Resources Management Plan	:	Docket No. P-2024-3049223

MAIN BRIEF OF
PPL ELECTRIC UTILITIES CORPORATION

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Dated: March 25, 2025

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I. INTRODUCTION

Pending before the Pennsylvania Public Utility Commission ("Commission") is PPL Electric's Petition for Approval of its Second Distributed Energy Resources ("DER") Management Plan ("Second DER Management Plan" or the "Plan"), which was filed on May 20, 2024. Under the Company's proposal, PPL Electric would continue actively managing and monitoring DERs in its service territory, as the Company has done for the past 3 years under its First DER Management Plan that the Commission approved at Docket No. P-2019-3010128. Specifically, pursuant to the Joint Petition for Settlement of All Issues in that proceeding, PPL Electric has operated a pilot program ("DER Management Pilot Program" or "Pilot Program") where the Company installs DER Management devices and uses them to actively manage and monitor the DERs to which they are connected. When the Settlement in that proceeding was unanimously approved, former Chairman Brown Dutrieuille issued a Statement in which she "commend[ed] PPL for being in the vanguard of distributed energy advancement" and declared that "[t]aking this next step in managing distributed energy has the potential to permit PPL to better control power quality, reliability, and safety throughout the grid while further fostering investment in resources such as rooftop solar and combined heat and power."[1]

PPL Electric now seeks approval of its Second DER Management Plan, so that it can continue actively managing and monitoring DERs and build upon the DER Management Pilot Program's successes. Doing so will enable the Company to improve the safety, reliability, adequacy, and resiliency of its electric service, while simultaneously: (1) encouraging and facilitating the increased deployment of DERs to address climate change and sustainability objectives through increases in clean energy; and (2) bolstering PPL Electric's ability to address

[1] Statement of Chairman Brown Dutrieuille, Docket No. P-2019-3010128 (Dec. 17, 2020).

the significant resource adequacy issues facing the Commonwealth. Further, PPL Electric's Second DER Management Plan is projected to produce net benefits of approximately $65.5 million over the 2025-2030 period, which will put downward pressure on distribution rates and reduce costs for DER and non-DER customers alike. Accordingly, the Commission should approve PPL Electric's Second DER Management Plan without modification.

II. STATEMENT OF THE CASE

On May 20, 2024, PPL Electric filed a Petition requesting the Pennsylvania Public Utility Commission's ("Commission") approval of tariff modifications and other authorizations that are needed to implement PPL Electric's Second Distributed Energy Resources ("DER") Management Plan ("Second DER Management Plan" or the "Plan"), pursuant to Paragraph 62 of the Joint Petition for Settlement of All Issues approved by the Commission at Docket No. P-2019-3010128.

On June 7, 2024, the Office of Small Business Advocate ("OSBA") filed a Notice of Intervention, Public Statement, and Verification at the above-captioned docket.

On July 1, 2024, the Office of Consumer Advocate ("OCA") filed an Answer to the Petition.

On July 8, 2024, American Home Contractors, Inc., Enphase Energy, Inc., the Solar Energy Industries Association, SolarEdge Technologies, Inc., Sun Directed, Sunnova, Inc., Tesla, Inc., and Trinity Solar, LLC (collectively, the "Joint Solar Parties" or "JSPs") filed an Answer, Petition to Intervene, and Protest at the above-captioned docket.

On July 10, 2024, the PP&L Industrial Customer Alliance ("PPLICA") filed a Petition to Intervene.

On July 12, 2024, the Sustainable Energy Fund of Central Eastern Pennsylvania ("SEF") filed a Petition to Intervene.

On July 24, 2024, a Call-In Telephone Prehearing Conference Notice was issued, scheduling a telephonic prehearing conference for August 6, 2024, at 10:00 AM before Administrative Law Judge John M. Coogan (the "ALJ").

On July 25, 2024, the ALJ issued a Prehearing Order, which, among other things, directed the parties to file Prehearing Conference Memoranda on or before August 2, 2024.

On August 2, 2024, PPL Electric, JSPs, OCA, OSBA, SEF, and PPLICA filed their Prehearing Conference Memoranda.

The prehearing conference was held as scheduled on August 6, 2024. At the prehearing conference, a procedural schedule was set and certain modifications to the Commission's discovery rules were established.

On August 7, 2024, the ALJ issued a Scheduling Order.

On August 12, 2024, PPL Electric, OCA, OSBA, SEF, and JSPs filed a Joint Petition for an Extension of PPL Electric's DER Management Pilot Program Period at Docket No. P-2019-3010128, the docket for the Company's First DER Management Plan. The Joint Petition requested an extension of the Company's currently effective Pilot Program period until 30 days after the Commission's Final Order is entered in the instant proceeding.

On September 12, 2024, the Commission granted the Joint Petition filed at Docket No. P-2019-3010128 and extended the Pilot Program period as requested.

On September 24, 2024, JSPs, SEF, OCA, and OSBA submitted their direct testimony. No other party submitted direct testimony.

On October 17, 2024, counsel for PPL Electric emailed the ALJ stating that the parties had developed a proposed mutually agreeable revised litigation schedule for the proceeding.

On October 21, 2024, the ALJ issued an Order Modifying Scheduling Order adopting the parties' proposed revised litigation schedule. On October 22, 2024, the ALJ issued a Corrected Modified Scheduling Order.

On December 5, 2024, PPL Electric, JSPs, and SEF submitted rebuttal testimony. No other party submitted rebuttal testimony.

On January 8, 2025, a Corrected Hearing Notice was issued, scheduling the telephonic evidentiary hearing for this proceeding for February 11 through 13, 2025.

On January 22, 2025, PPL Electric, JSPs, OCA, and OSBA submitted surrebuttal testimony. No other party submitted surrebuttal testimony.

On February 4, 2025, PPL Electric served its rejoinder testimony and exhibits.

On February 8, 2025, the Joint Solar Parties filed a Protective Motion to File Surrejoinder Testimony and simultaneously submitted their surrejoinder testimony.

On February 10, 2025, PPL Electric served its supplemental rejoinder testimony and exhibit.

On February 11 and 12, 2025, the first and second days of evidentiary hearings were held as scheduled.

On February 13, 2025, a Cancellation Notice was issued, which canceled the third day of hearings scheduled for February 13, 2025.

Also on February 13, 2025, the ALJ issued a Briefing Order setting forth requirements for the briefs to be submitted in this proceeding.

III. <u>LEGAL STANDARDS</u>

Under Section 332(a) of the Public Utility Code, the proponent of a Commission rule or order bears the burden of proof. *See* 66 Pa. C.S. § 332(a). The "burden of proof before administrative tribunals as well as before most civil proceedings is satisfied by establishing a preponderance of the evidence."[2] A preponderance of evidence is demonstrated where the evidence presented is more convincing, even by the smallest degree, than the evidence presented by the opposing party.[3] Moreover, the Commission's findings and conclusions must be supported by substantial evidence, which has been defined as "that quantum of evidence which reasonable minds might accept as adequate to support a conclusion."[4] However, mere bald assertions, personal opinions or perceptions, when not substantiated by facts, do not constitute evidence.[5]

In addition, Section 5.41 of the Commission's regulations states, in part, that "[p]etitions for relief under the act or other statute that the Commission administers, must be in writing, state clearly and concisely the interest of the petitioner in the subject matter, the facts and law relied upon, and the relief sought." 52 Pa. Code § 5.41(a). Copies of any petition under Section 5.41 must be served on the statutory parties and "on all persons directly affected and on other parties whom petitioner believes will be affected by the petition," as well as further directed by the Commission. *Id.* §§ 5.41(b)-(c).

Further, "[u]nless the Commission otherwise orders, a public utility . . . may not change an existing and duly established tariff, except after notice of 60 days to the public." *Id.* § 53.31. Electric distribution companies ("EDCs") are required to "file a tariff with the Commission that provides for net metering consistent with" Chapter 75 of the Commission's regulations. *Id.* § 75.13(c). Also, an EDC and default service provider ("DSP") "may not require additional equipment or insurance or impose any other requirement" on a net metering customer-generator

[2] *Lansberry v. Pa. PUC*, 578 A.2d 600, 602 (Pa. Cmwlth. 1990).

[3] *See Brown v. Commonwealth*, 940 A.2d 610, 614 n.14 (Pa. Cmwlth. 2008); *Pa. PUC v. HIKO Energy, LLC*, 2015 Pa. PUC LEXIS 364 (I.D. entered Aug. 21, 2015) (citing *Lansberry*, 578 A.2d at 602).

[4] *Nat'l Fuel Gas Distrib. Corp. v. Pa. PUC*, 677 A.2d 861, 863-64 (Pa. Cmwlth. 1996) (quoting *Norfolk & Western Ry. Co. v. Pa. PUC*, 413 A.2d 1037, 1046 (Pa. 1980)); *see Pa. PUC v. Dep't of Transp.*, 346 A.2d 376, 378 (Pa. Cmwlth. 1975) (quotation omitted).

[5] *Pa. Bureau of Corrections v. City of Pittsburgh*, 532 A.2d 12 (Pa. 1987).

"unless the additional equipment, insurance or other requirement is specifically authorized under this chapter or by order of the Commission." *Id.* § 75.13(k).

IV. SUMMARY OF ARGUMENT

PPL Electric faces substantial challenges to its continued provision of safe, reliable, adequacy, and reasonable electric service. Within the next decade, Pennsylvania is projected to rank sixth amongst all states in DER capacity. Although DERs can provide benefits to the distribution system, they cause issues on the system as well, such as voltage violations, even at low levels of penetration and even when equipped with smart inverters that meet the applicable IEEE and UL requirements. Meanwhile, the Commonwealth and other states in the PJM footprint are confronting significant resource adequacy issues, due to surging growth in electric demand that is fueled principally by data centers, electric vehicles, and electrification. These challenges are not far off in the future. They are here now, and PPL Electric must take action to confront them.

The Second DER Management Plan is a well-designed solution that will help address these issues. Under the Plan, the Company can continue actively managing and monitoring DERs that are interconnected with its distribution system. Through active management and monitoring of DERs, PPL Electric can resolve the issues caused by DERs on the distribution system while maintaining and improving the safety, reliability, adequacy, and resiliency of the Company's electric service. Indeed, through its DER Management Pilot Program, PPL Electric has mitigated over 600,000 voltage violations. Also, PPL Electric can eliminate safety and reliability issues presented by DERs' "hidden load," where the DER output inherently masks, or cancels, actual load demand. Such "hidden load" can cause serious problems, such as leading to faulty switching decisions when a distribution system is reconfigured following an outage and making the determination of minimum load conditions difficult. The Company also can ensure that every actively managed and monitored DER successfully islands when necessary, thereby providing increased safety to PPL Electric's workers and the public alike.

In addition, PPL Electric's proposal will help address climate change and sustainability objectives and respond to the significant resource adequacy issues. The Second DER Management Plan can increase the hosting capacity on distribution circuits, which enables customers to interconnect more DERs and larger-sized DERs on distribution circuits without requiring distribution system upgrades. By bringing those additional and larger DERs online, PPL Electric can support zero-carbon emitting resources while also reducing the demand on its distribution circuits and, by extension, the demand they are pulling from the transmission system. Furthermore, the situational awareness and system-wide connectivity provided by the Second DER Management Plan would help de-stress the transmission system and better focus and enhance investments in transmission and generation infrastructure to meet the increased electric demand. Without active DER management and monitoring, however, the Commonwealth, Commission, and PPL Electric all will lose a vital tool in addressing climate change and sustainability objectives and these resource adequacy challenges.

These benefits, on their own, would be enough to justify the Commission's approval of the Second DER Management Plan. However, PPL Electric further demonstrated that its proposal would be cost-effective. In fact, the conservative cost-benefit analysis prepared by PPL Electric's outside expert projects that the Second DER Management Plan will produce net benefits of approximately $65.5 million over the 2025-2030 period. Such net benefits will put downward pressure on PPL Electric's distribution rates, thereby benefitting DER and non-DER customers. Even assuming *arguendo* that none of those quantifiable benefits come to pass, the absolute costs of the Second DER Management Plan are modest (*e.g.*, an increase of approximately $4.13 per year based on an average residential bill). Such costs are more than justified compared to the safety, reliability, adequacy, and resiliency benefits that would result from the Plan as well as the quantifiable benefits that would be produced and more than offset those costs.

At the same time, opposing parties have argued that PPL Electric's proposal should be modified or denied entirely. For example, some parties' witnesses have criticized the Company's cost-benefit analyses, while the JSPs have made unfounded and uncredible allegations that PPL Electric's DER Management device installations have caused or contributed to thermal events in 5 out of the 7,956 SolarEdge inverters with DER Management devices installed. PPL Electric has presented extensive evidence fully rebutting these claims. The Company also has identified several flaws and credibility issues with the JSPs' testimony, which undercut their safety-related allegations.

For these reasons, and as explained in more detail herein, the Commission should approve PPL Electric's Second DER Management Plan without modification because it is reasonable and in the public interest.

V. ARGUMENT

A. OVERVIEW OF THE DER MANAGEMENT SETTLEMENT AND PILOT PROGRAM

In 2019, the Company took a proactive step requesting Commission approval to implement its First DER Management Plan, which was designed to produce cost-effective benefits for customers with and without DERs, the DER market, and the Commonwealth as a whole. (PPL Electric Exh. 1 at 2.) Under that proposal, customers applying to interconnect new DERs to PPL Electric's distribution system would be required to: (1) use Company-approved smart inverters that are compliant with IEEE 1547-2018 and then-forthcoming revisions to UL Standard 1741;

and (2) install DER Management devices that enable PPL Electric to monitor and actively manage DERs. (*Id.*) These proposals would enable PPL Electric to:

- Facilitate and encourage the increased deployment of DERs in its service territory by reducing interconnection costs for customers installing DERs and increasing hosting capacity on distribution circuits[6];

- Improve the safety, reliability, adequacy, and resiliency of its distribution service by gaining visibility into the DERs' impacts on the distribution system and actively leveraging the grid support functions of the DERs' smart inverters;

- Improve distribution system operation and planning by eliminating "hidden load"[7] at DER points of interconnection; and

- Reduce the Company's capital costs and operation and maintenance expenses that are passed onto ratepayers by, among other things, remotely managing the DERs' voltage support functions to mitigate voltage violations on distribution circuits, which decreases system upgrades as well as costs to manually address voltage violations (*e.g.*, reduction in the number of truck rolls).

(*Id.*)

Ultimately, on December 17, 2020, the Commission approved a settlement reached by all the active parties in the First DER Management Plan proceeding. The Settlement set forth, among other things: (1) requirements for the use of smart inverters in PPL Electric's service territory effective January 1, 2021; (2) the terms and conditions for PPL Electric's Pilot Program, including the submission of a detailed Pilot Implementation Plan; (3) a provision addressing cost recovery of PPL Electric's DER Management devices; (4) a provision concerning the Company's agreement

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[6] "Hosting capacity is the amount of [distributed photovoltaic systems ('DPV')] that can be added to distribution system before control changes or system upgrades are required to safely and reliably integrate additional DPV." (PPL Electric Exh. 1 at 2) (citing Advanced Hosting Capacity Analysis, NREL, *available at* https://www.nrel.gov/solar/market-research-analysis/advanced-hosting-capacity-analysis.html).

[7] "Hidden load" is the amount of load that is present on a circuit but not measured at telemetry points (e.g., the feeder circuit breaker) because the energy is being provided by local downstream DERs. (PPL Electric Exh. 1 at 2.) The amount of load measured by distribution equipment is often referred to as the "net" load, and the total amount of load operating on the feeder (including the amount offset by DER production) is the "native" load, with "hidden" load in a given interval as the difference between the two. (PPL Electric Exh. 1 at 2.)

to participate in any statewide proceeding initiated by the Commission that focuses on smart inverters, DER management devices, IEEE 1547-2018, IEEE 1547.1, and/or UL 1741; (5) several reporting requirements, including annual reports to the Commission and to customers participating in the Pilot Program; (6) the Company's compliance tariff supplement; (7) an exemption for electric vehicles ("EVs") from the Pilot Program; and (8) a provision addressing certain data on program performance to be sent to SEF. (*Id*. at 12.)

Effective January 1, 2021, new DERs interconnecting with the Company's distribution system were required to have smart inverters installed that meet: (1) UL 1741 SA; and (2) the Company's testing for the communications requirements under IEEE 1547-2018. (*Id*.) These interim requirements were used by PPL Electric until January 1, 2023, at which point, the Company transitioned to requiring new DERs to have smart inverters installed that meet IEEE 1547-2018 and have been certified with IEEE 1547.1 / UL 1741 SB. (*Id*. at 12-13.)

The Pilot Program was designed to test and evaluate: (1) the costs and benefits to distribution system operation and design of monitoring DERs through devices connected to inverters as compared to maintaining distribution system status visibility through other means (e.g., automated meter reading equipment, ADMS systems, modeling); and (2) the costs and benefits to distribution system operation of active management of DERs as compared to the benefits available through the use of inverter autonomous grid support functions. (*Id*. at 13.)

During the Pilot Program, the Company is authorized to purchase and install DER Management devices on all new DERs with inverters up to an annual limit of 3,000 DER Management devices. (*Id*.) DERs installed above the annual limit are not part of the Pilot Program. (*Id*.) All DER Management devices are owned, operated, and maintained by the Company at no direct cost to interconnecting customers. (*Id*.) Moreover, the annual cap on the number of DER Management devices is not an annual cap on the number of new DERs that can be interconnected with the Company's distribution system. (*Id*.)

The Pilot Program began on January 1, 2021, and was set to end on March 21, 2025. (*Id*.) On August 12, 2024, PPL Electric, OCA, OSBA, SEF, and the Joint Solar Parties filed a Joint Petition for an Extension of PPL Electric's DER Management Pilot Program Period, in light of the ongoing Second DER Management Plan proceeding. The Joint Petition requested an extension of the Company's currently effective Pilot Program period until 30 days after the Commission's Final Order is entered in the instant proceeding. On September 12, 2024, the Commission granted the Joint Petition and extended the Pilot Program period as requested.

B. OVERVIEW OF THE SECOND DER MANAGEMENT PLAN

The Company's proposed Second DER Management Plan is built upon the successes achieved through its Commission-approved First DER Management Plan and Pilot Program. PPL Electric's Second DER Management Plan will enable the Company to continue to integrate, monitor, and manage DER resources throughout PPL Electric's service territory. (PPL Electric St. No. 1 at 22.)

As proposed, PPL Electric's Second DER Management Plan will require that all customer-owned and third party-owned, inverter-based DER system installations be equipped with DER Management devices so that the Company can monitor and manage the DERs. (*Id*.) In addition, the Second DER Management Plan would expand on the Pilot Program by authorizing PPL Electric to: (1) actively monitor and manage the smart inverter settings on all DERs that are in the Pilot Program's control groups; (2) utilize the Volt/Watt functionality, with customer consent, when the interconnecting DER could create a localized high voltage issue on the distribution system at the time of interconnection, which would not be resolved by the Volt/VAR or Constant

Power Factor grid support functions[8]; and (3) make the Pilot Program permanent. As such, provisions in the Settlement that limit the scope of the Pilot Program's requirements, such as the annual cap of 3,000 DER Management devices, would be eliminated. (*Id.*) Moreover, the Company proposes to install DER Management devices on: (1) solar photovoltaic systems interconnected before the Pilot Program started on January 1, 2021; and (2) inverter-based DERs interconnected after the Pilot Program started without DER Management devices installed on them.[9] (*Id.* at 23.)

These proposals are necessary and appropriate because they will help PPL Electric fully realize the benefits of actively monitoring and managing DERs. As demonstrated by the Pilot Program, the Company can leverage the smart inverters' grid support functions to improve safety, reliability and resiliency, reduce interconnection costs for DER interconnection applicants (*e.g.*, avoidance of paying for distribution system upgrades), mitigate the impact of DERs on the distribution system, and increase the distribution circuits' hosting capacity by monitoring and managing DERs in the service territory. (*Id.*)

C. PPL ELECTRIC'S SECOND DER MANAGEMENT PLAN SHOULD BE APPROVED BECAUSE IT IS REASONABLE AND IN THE PUBLIC INTEREST

1. ACTIVE MANAGEMENT AND MONITORING OF DERS IS NEEDED NOW TO IMPROVE ELECTRIC SAFETY, RELIABILITY, AND ADEQUACY, ADDRESS CLIMATE CHANGE AND SUSTAINABILITY OBJECTIVES, AND RESPOND TO SIGNIFICANT RESOURCE ADEQUACY ISSUES

[8] Such customer consent will be required because the Volt/Watt functionality will affect the generating facility's production.

[9] As proposed in PPL Electric Exhibit SS-2, customer-generators with these systems must submit a new interconnection application when they upgrade their system, install a new inverter on their system, or by March 22, 2040, whichever is earlier. The DER Management devices will be installed on those systems after their new interconnection applications are approved as compliant with the Company's current requirements for DERs and inverters and after their systems are installed and inspected.

a. The Second DER Management Plan Will Help Improve the Safety, Reliability, Adequacy, and Resiliency of the Company's Electric Service

The Commission should approve the Second DER Management Plan because it will help improve the safety, reliability, adequacy, and resiliency of the Company's electric service. As a regulated EDC, PPL Electric must provide safe, reliable, adequate, and reasonable service as required under the Public Utility Code. *See* 66 Pa. C.S. § 1501. However, the deployment of DERs continues to present challenges to the Company complying with that statutory duty. (PPL Electric St. No. 1 at 8-10.)

As PPL Electric witness Salet explained, the "electric transmission and distribution systems in Pennsylvania and the United States continue to undergo significant changes." (*Id*. at 8.) "In particular, the increasing deployment and use of DERs, such as solar panels and batteries, have upended the traditional electric grid[10] model of large-scale generation located at significant distances from customers." (*Id*. at 8-9.) By allowing customers to both consume and produce electricity at what were traditionally points of delivery (*i.e.*, at the distribution system's "edge"), DERs force the electric distribution system to perform in a way for which it was not originally designed and, as a result, place an increasing stress on the grid. (*Id*. at 9.)

As a result, "DERs pose numerous challenges to safe and reliable operation of electric distribution systems and to the electrical grid at large." (PPL Electric St. No. 4 at 15.) These challenges include: (1) "creating voltage changes that can result in voltage exceeding regulatory limits" (i.e., voltage violations); (2) "excessively low voltage provided to some customers, as well as high voltage to other customers"; (3) "disrupt[ed] conservation voltage reduction schemes,"

[10] The terms "grid," "electric grid," or "power grid," mean an interconnected network for delivering electricity from producers to consumers. (PPL Electric St. No. 1 at 9.) The network includes both the transmission system and distribution system. (PPL Electric St. No. 1 at 9.)

which "lead[s] to excess energy consumption by consumers"; and (4) "increasing wear-and-tear of" the "mechanical devices intended for voltage management (e.g., regulators and switched capacitor banks)," thereby "leading to premature failure or increased maintenance requirements"; (5) "overload[ing] circuits and equipment, leading to failure or accelerated loss of life"; (6) the potential for "[c]ontinued energization of an 'islanded' distribution feeder or system by DERs," which can "pose a significant risk to utility workers and to the public"; (7) damaging "other customers' equipment" when "transient and temporary overvoltages" reach certain "magnitudes"; and (8) issues due to "load masking," where the "DER output inherently masks, or cancels, actual load demand," which can cause problems, such as "lead[in]g to faulty switching decisions when a distribution system is reconfigured following an outage" and making the "determination of minimum load conditions difficult." (*Id*. at 15-18.)

Crucially, while the deployment of DERs in Pennsylvania continues to increase (with a recent analysis by Deloitte even showing that Pennsylvania will rank sixth out of all states in DER capacity by 2035), the Company still must provide reasonable, safe, and reliable electric service to all of its customers, including those who have not installed DERs. (PPL Electric St. No. 1 at 9; PPL Electric St. No. 6-R at 19.) Without active management and monitoring of DERs, however, distribution system operators are severely limited in their ability to respond to these changing dynamics and the issues created by DERs. (*See* PPL Electric St. No. 4 at 19-22.)

These kinds of limitations do not exist on the transmission system. Transmission operators, such as PJM Interconnection LLC ("PJM"), manage the transmission grid by maintaining a balance between demand and generation through monitoring and managing generation assets near instantaneously. (PPL Electric St. No. 1 at 9.) Traditionally, distribution operators did not have to worry about balancing demand and generation because the distribution grid had very little generation connected to it. (*Id.*) However, as the penetration level of DERs increased, the classic model of distribution systems was not well-equipped to handle the simultaneous balancing of demand and generation on the distribution system. (*Id.*) Therefore, as distribution systems have become increasingly similar to transmission, *i.e.*, a mix of demand and generation, the need to balance generation and demand becomes vitally important. (PPL Electric St. No. 1 at 9.) Such balancing cannot be accomplished without the ability to monitor and manage generation assets on the grid. (*Id.*)

Moreover, by negatively affecting the voltage on the electric distribution system, solar and other intermittent resources can result in delayed interconnection or the need for potentially costly distribution system reinforcements before additional DERs can be installed. (*Id.* at 10.) Without the ability to directly communicate with and manage customer DERs to leverage grid support functionality, the amount of intermittent generation that can be interconnected on the distribution circuits must be limited to maintain system stability and reliability. (*Id.*) Also, without such ability to monitor and manage the DERs, the reliability, safety, and efficiency of electric service would be placed at increased risk with each new DER interconnected to the distribution system. (*Id.*)

These issues are not dependent on significant increases in the number of DER deployments. (*See, e.g.*, PPL Electric St. No. 4 at 18; PPL Electric St. No. 8 at 16-18.) Even with existing levels of DER penetration, PPL Electric's distribution system can experience safety, reliability, adequacy, and resiliency issues due to DERs. (*See* PPL Electric St. Nos. 8 at 11, 16-18; 8-R at 2-3, 7-8, 11, 18; and 8-RJ at 2-5.) Dr. Karen Miu, a Professor of Electric and Computer Engineering at Drexel University,[11] conducted multiple studies of PPL Electric's distribution circuits to

[11] Dr. Karen Miu's educational background is in the field of electrical engineering. (PPL Electric St. No. 8 at 1.) Her MS thesis and Ph.D. dissertation focused on electric power distribution systems. (PPL Electric St. No. 8 at 1.) Her degrees received include: B.S. in Electrical Engineering from Cornell University, Ithaca NY, 1992; M.S.

evaluate the impacts of DERs on the Company's distribution system. (*See* PPL Electric St. Nos. 8, 8-R, and 8-RJ.) Specifically, as the principal investigator of the Drexel University team for two Department of Energy projects led by PPL Electric, Dr. Miu performed detailed simulations of several actual PPL Electric distribution circuits. (PPL Electric St. No. 8 at 7.) "Throughout all of this research," Dr. Miu "found that even the then-existing DER levels measurably impacted voltage power quality at various individual nodes throughout the distribution system itself" and that "DER injections are non-uniform across electrical phases." (*Id*. at 11.) Consequently, "core assumptions on balanced behavior of injections made in bulk power transmission systems and their energy management systems cannot capture the physical reality of DER installations at the distribution level." (*Id*.) "Yet, especially as DER adoption is expected to increase, capturing this physical reality is fundamental to determining safe control actions, especially in the case of electric service restoration in emergency circumstances to the public and to distribution personnel." (*Id*.) Also, "under normal operating conditions, voltage power quality with respect to voltage levels and voltage balance are critical to energy efficiency of the power distribution system and to equipment safety controls of both utility-owned and customer owned devices.[12] (*Id*.)

Building on those prior studies, Dr. Miu performed detailed simulations with revised system conditions in 2024 and presented her findings in her direct and rebuttal testimony. (PPL Electric St. No. 8 at 12; PPL Electric St. No. 8-R at 4.) In her direct testimony, Dr. Miu presented details about "[t]he additional simulations" and explained how they "consistently demonstrate[d] that DER impacts on a distribution system change with the type of DER installations, their

in Electrical Engineering from Cornell University, Ithaca NY, 1995; and Ph.D. in Electrical Engineering from Cornell University, Ithaca NY, 1998. (PPL Electric St. No. 8 at 1.)

[12] See note 6, *supra*, Z. Minter, J. Hill, J. de Oliveira, S. Hughes, K. Miu, "A Study of Imbalance Levels Attributed to Photovoltaic Penetration in Distribution Systems."

locations, and the system operating conditions." (PPL Electric St. No. 8 at 12-14.) In fact, her analyses performed at "summer peak and winter peak loading" consistently showed that "DERs increased the number of overvoltage violations on the distribution system as compared to the same system at the same loading without DER." (*Id*. at 13.) Then, in her rebuttal testimony, Dr. Miu presented the findings of "additional studies focused on a distribution circuit that was not previously investigated." (PPL Electric St. No. 8-R at 4-7.) Those studies showed that "the 42 photovoltaic installations" connected to the distribution circuit "reduced the substation output real power by 8.67% and 8.45% of the summer and winter peak, respectively." (*Id*. at 5.) "Compared to the circuit without DERs, the circuit with DER installations has an approximately 1% increase in power system losses in both cases and, for winter peak loading, 353 overvoltage violations compared to 0 overvoltage violations with no DERs." (*Id*. at 5-6.) Critically, these voltage impacts are not limited to the locations of the DERs on the distribution circuit. As Dr. Miu testified, "A consistent observation is the increase in voltages at nodes (electrical points where customers and other devices, such as capacitors, interconnect to the circuit) both at and remote to the DERs." (*Id*. at 11.) As such, "[t]he installation of individually owned and operated DERs directly impacts voltages at other customer locations." (*Id*.)

Active management and monitoring of DERs is necessary to address these issues in a prudent, efficient, and effective way. To date, PPL Electric's DER Management Pilot Program, under which the Company is capped at installing 3,000 DER Management devices annually, has <u>mitigated over 600,000 voltage violations through active management of DERs</u>. (PPL Electric St. No. 1 at 13; Tr. 316.) This reality aligns with Dr. Miu's analyses, where she found that active management effectively resolved voltage violations on the circuits she studied. In her direct testimony, Dr. Miu explained how actively managing the power factor setpoint on the inverters for the 12 DERs on "phase A" of the distribution circuit "consistently removed the overvoltage violations, up to 46 locations" and that "[s]imilar observations were made for the winter peak loading conditions." (PPL Electric St. No. 8 at 14.) Then, in rebuttal, Dr. Miu presented the results of additional studies she conducted on a PPL Electric distribution circuit, that "at peak loading conditions," all of the "system overvoltages can be removed through active management of DERs—something autonomous settings could not accomplish." (PPL Electric St. No. 8-R at 8.)

Collectively, these studies demonstrate the limitations of relying on autonomous settings to resolve voltage violations, as other parties in this proceeding have suggested. (*See* PPL Electric St. No. 8-R at 2, 7-8; PPL Electric St. No. 8-RJ at 4-6.) These parties fail to recognize that "[a]utonomous power factor control stops when its local voltage is satisfied." (PPL Electric St. No. 8-R at 13.) However, "utility active management can enact a potentially larger amount of power management than autonomous functions." (*Id.*) As a result, active management removed a much larger number of overvoltages than autonomous settings (e.g., last rows in Table 6 and 7 of PPL Electric Exhibit KM-4 (HIGHLY CONFIDENTIAL)) and, in fact, removed all system overvoltage violations in the scenario presented in the last row of Table 7 of PPL Electric Exhibit KM-1R (HIGHLY CONFIDENTIAL)." (*Id.*) Thus, Dr. Miu's studies have shown that "active management of the DERs allows for targeted actions, such as appropriate phase and location selection, to fix the problems that the DERs themselves have created." (*Id.* at 11.)

Apart from fully resolving voltage violations, PPL Electric's ability to actively manage DER power factors can significantly reduce the frequency, duration, and severity of customer voltage violations. (PPL Electric St. No. 3 at 65.) PPL Electric witness Davis described how "DER power factor setpoint adjustments performed by system operators and the ADMS/DERMS . . . can reduce the number, frequency, and duration of voltage violations." (*Id.* at 48.) Those reductions, in turn, decrease the number of customers who contact PPL Electric about voltage violations and, subsequently, decrease the number of investigations performed by the reliability engineering team and the number of visits to customer locations by PPL Electric (commonly referred to as "truck rolls"). (*Id.*) Within the Program Year 2 Annual Report, PPL Electric identified 23,272 customers that had a voltage violation resolved during the same time interval as a DER power factor control event through the end of Program Year 2 in March 2024 and could have resulted in a truck roll. (*Id.*) Even under conservative assumptions, PPL Electric can significantly reduce its O&M expenditures by resolving those voltage violations without performing truck rolls. (*See* PPL Electric St. No. 10-RJ at 4.) Moreover, reducing the frequency, duration, and severity of voltage violations can help reduce the need to make system modifications or investments in voltage support equipment, further demonstrating how active management and monitoring of DERs can help maintain and improve the safety, reliability, adequacy, and resiliency of the Company's electric service in an effective and efficient manner. (PPL Electric St. No. 3 at 48.)

In addition, the Company's proposed Second DER Management Plan will provide other benefits to safety, reliability, and resiliency. (*See, e.g.*, PPL Electric St. No. 4 at 15-18.) PPL Electric witness Walling identified "15 types of DER impacts" in his direct testimony and testified that "11 can potentially be completely eliminated or substantially mitigated by application of DER monitoring and management by the utility." (*Id.* at 15-19.) As one example, PPL Electric witness Walling noted that "there is a substantial uncertainty regarding the reliability of many DER island detection schemes when applied in practical circumstances," despite DERs being "required by IEEE 1547 to cease energization of disconnected distribution circuits (islanding)." (*Id.* at 16.) Such "[c]ontinued energization of an 'islanded' distribution feeder or system by DER can pose a significant risk to utility workers and the public." (*Id.*) Mr. Walling even highlighted "an incident in Ontario, Canada where certified DERs continued to undesirably energize a utility island for eight minutes after a switching operation isolated the distribution system from the transmission system." (PPL Electric St. No. 4-R at 12.) Although "[i]n that particular case, the utility had other means to disrupt the DER-energized island," those "means are infrequently available to utilities." (*Id.*) Therefore, "this incident does serve as an example where the on/off functionality" provided by the Second DER Management Plan "could be an important safety feature," as "utility management of DER operating status can be applied as a backup to DER island detection capabilities, increasing worker and public safety." (PPL Electric St. No. 4 at 21; PPL Electric St. No. 4-R at 12.)

Furthermore, the "continuous monitoring and archiving of DER output data avoids load masking." (PPL Electric St. No. 4 at 21.) "This leads to more reliable circuit reconfiguration to restore service following outages and to more accurate forecasting of both DER output and customer load demand." (*Id.*) With more accurate forecasts, PPL Electric can better plan and reliably operate its distribution system. (*Id.*) Additionally, PPL Electric can improve "[u]tility worker safety . . . if DERs' protective trip functions are made more sensitive during planned live-line work on a circuit." (*Id.*) Even though "[s]uch sensitive settings conflict with the voltage ride-through requirements of IEEE 1547-2018," PPL Electric witness Walling explained that "the standard also allows temporary implementation of sensitive settings on specific circuits for the time live-line work is to be performed." (*Id.*) Temporary changes of fixed trip settings on DERs not incorporated into a management system are infeasible due to the typically large number of individual DER units involved. (*Id.* at 21-22.) However, "DER management systems, such as

PPL Electric's Second DER Management Plan, allow for the relatively easy implementation of temporary settings as necessary." (*Id*. at 22.)[13]

Based on the foregoing, "PPL Electric's ability to continue monitoring and actively managing DER deployments is necessary and critical to delivering power at acceptable operating ranges for all customers." (PPL Electric St. No. 8-R at 8.) A "[f]ailure to implement effective DER monitoring and management will either result in markedly decreased utility system efficiency, reliability, and quality of service or severely limited implementation of DER[s] in conflict with public policy promoting DERs." (PPL Electric St. No. 4 at 23.) Accordingly, the Commission should approve the Second DER Management Plan so that the Company can continue actively managing and monitoring DERs and providing safe, reliable, adequate, and resilient electric service.

b. The Second DER Management Plan Will Help Address Climate Change and Sustainability Objectives by Facilitating and Encouraging Increased Deployments of DERs

The Commission also should approve the Second DER Management Plan because it will help address climate change and sustainability objectives. (PPL Electric St. No. 7 at 5-12, 7-R at 12-13.) As PPL Electric witness Krevat testified, electric power generation emits approximately 25% of total greenhouse gases ("GHG") and combined with the transportation sector, accounts for over 50%. (PPL Electric St. No. 7 at 6.) Given the imperative to reduce GHG, the carbon intensity of electric power generation and the availability of reasonably priced renewable energy make power production a low hanging fruit that also has the potential to make an impact in the

[13] PPL Electric also has on numerous occasions alerted customers that their systems were either turned off or not generating. (PPL Electric St. No. 2 at 15.) When on site, the Company also has supported customers by informing them that their backup battery was not connected properly and instructed them to reach out to their installers to have the situation fixed. (PPL Electric St. No. 2 at 15.) In other instances, the Company has alerted customers that their inverters were faulty and needed replacement due to hardware issues. (PPL Electric St. No. 2 at 15.)

transportation sector as the electric vehicle movement gains momentum. (*Id*.) While rooftop and utility solar photovoltaics ("PV") are not the least carbon intensive generation technologies – for example wind and nuclear can be less carbon intensive – they are significantly less carbon intensive than natural gas and coal (70+% reduction). (*Id*.) Also, increased customer investment in solar and energy storage solutions "has the potential to significantly reduce the evening peak, further extending the benefits of solar." (*Id*. at 7.)

PPL Electric's First DER Management Plan has helped encourage and facilitate renewable energy development, which helps address climate change and sustainability objectives. (*Id*. at 8.) Over the course of the DER Management Pilot Program, PPL Electric has seen large increases in the number of DERs deployed, growing from 3,493 in 2021 to 6,799 in 2023. (PPL Electric St. No. 2-R at 65.) As noted previously, "[r]ooftop solar is significantly less carbon intensive than natural gas and coal" and "enables customers to be prosumers of energy, inspiring a feeling of energy independence and likely to motivate them to take additional actions to help mitigate climate change." (PPL Electric St. No. 7 at 8; PPL Electric Exh. LK-5.) Relatedly, by deferring capital investments, generating and non-generating customers will see lower bill increases, and by avoiding DER blamed bill increases, financial-driven pushbacks against solar are kept at bay. (PPL Electric St. No. 7 at 8.) Further, these deferred capital improvement projects would take time to complete and also generate carbon emissions. (*Id*. at 9.) As customers wait for these projects to be completed, they are not helping the planet by generating renewable energy. (*Id*.) In contrast, by deferring capital projects, customers wanting to invest in solar are able to act on that decision as soon as they are ready. (*Id*.) Large financial decisions take a lot of research and time; if customers are forced to wait until a capital project is completed, it may discourage them from investing in solar. (*Id*.) PPL Electric's First DER Management Plan has ensured that the grid is ready when customers are. (*Id*.)

The Second DER Management Plan will further address climate change and sustainability objectives by building upon these foundations and continuing to encourage and facilitate the development of DERs in multiple ways. First, the Second DER Management Plan makes the plan permanent. (*Id*. at 10.) Tremendous benefits have been achieved for all customers through the First DER Management Plan, and those benefits will continue to grow as more customers install DERs. (*Id*.)

Second, under the Second DER Management Plan, the 3,000 DER system cap per year is removed. (*Id*.) In 2023, the cap was exceeded in September, and if the cap is not removed soon, more than half the DERs each year and soon after that, throughout the system, will not be monitored or manageable. (*Id*.) The success of the Second DER Management Plan will be diminished; customers will have higher bills due to investment in capital projects that will be necessary to mitigate DER issues and suffer increased emissions and costs due to truck rolls responding to power quality issues. (*Id*.) Moreover, the installation cost for DER customers will increase because customers will need to wait for capital projects to be completed before moving forward with solar investments, and some may not be able to proceed due to system limitations because of a lack of system visibility and hosting capacity. (PPL Electric St. No. 7 at 10-11.)

Third, the Second DER Management Plan introduces the capability to manage real power output with customer consent. (PPL Electric St. No. 7 at 11; PPL Electric St. No. 1 at 11.) Because grid planners must plan for the worst case when evaluating a proposed DER interconnection, many EDCs plan the system to be able to handle all the solar systems on a feeder at nameplate capacity and capital investments to improve the system are made accordingly. (PPL Electric St. No. 7 at

11.) PPL Electric already leverages the technologies deployed as part of the First DER Management Plan to use actual generation data in planning. (*Id*.) This has enabled an additional 29 MW of rooftop solar distribution grid availability as of March 21, 2024. (*Id*.) PPL Electric's Second DER Management Plan would increase the potential MW even more significantly by managing real power output, enabling more people to invest in solar. (*Id*.) Indeed, by reducing customers' upfront interconnection costs in exchange for the ability to curtail a few hours each year, PPL Electric is further encouraging new solar installations. (*Id*. at 12.) Even with curtailment, the overall amount of solar energy is increased because additional MWs of DERs can reliably connect to the system with confidence, reliability can be maintained, and capital investment by PPL Electric can be avoided. (*Id*.) Since the increased DERs will be generating all but a small percentage of the time each year, climate change will be further mitigated the great majority of the time. (*Id*.)

Based on the foregoing, PPL Electric's Second DER Management Plan should be approved because it will help address climate change and sustainability objectives by encouraging and facilitating renewable energy development.

c. The Second DER Management Plan Will Help Address the Significant Resource Adequacy Challenges Facing the Commonwealth

The Second DER Management Plan should be approved because it will help address the significant resource adequacy issues facing the Commonwealth due to significant increases in electric demand. (PPL Electric St. No. 6-R at 6-10.) After over two decades of declining or stagnant growth in electric demand, electric utilities across the country, including PPL Electric, are now dealing with surging growth in electric demand, fueled principally by data centers, electric vehicles, and electrification. (*Id*. at 6-7.) As noted by the U.S. Department of Energy ("DOE"), "in response to transformations in technologies like artificial intelligence ("AI"), data center expansion, new domestic manufacturing, and electrification in different sectors, the United States is returning to a period of rising electricity demand, with total energy demand potentially growing ~15-20% in the next decade."[14] (*Id*. at 7.) Regulators, electric generators, electric transmission companies, and electric distribution utilities all face serious challenges due to this significant growth in electric demand. (*Id*. at 8.) Chief among those challenges is ensuring that there is enough transmission and generation capacity to meet that demand now and in the future. (*Id*.)

As the agency tasked with regulating EDCs' electric service and facilities, the Commission has rightly recognized the role it must play in responding to these issues. (*See* PPL Electric St. No. 6-R at 8.) Although Pennsylvania deregulated the electric generation markets in 1996, shifting generation planning to market forces operated by PJM Interconnection, LLC ("PJM"), the Commission still must ensure the continuation of safe and reliable electric service at a just and reasonable rate to all consumers in the Commonwealth, including maintaining adequate reserve margins by electric suppliers.[15] In fact, the Competition Act was designed to achieve lower electricity rates while maintaining system reliability.[16] The General Assembly even prioritized electric service reliability, finding that competition is only in the customers' best interest as long as safe and affordable transmission and distribution service is available at levels of reliability currently enjoyed by the Commonwealth's citizens and businesses.[17] Moreover, Section 524 of the Public Utility Code requires the Commission to submit an annual report to the General Assembly about electric utilities' future plans to meet customer demand, including, but not limited to: (1) "[a] year-by-year projection of electrical energy use and electrical energy demand for each

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[14] "Clean Energy Resources to Meet Data Center Electricity Demand," U.S. Department of Energy (Aug. 12, 2024), *available at* https://www.energy.gov/policy/articles/clean-energy-resources-meet-data-center-electricity-demand#op3.

[15] *See* 66 Pa. C.S. § 2804(1)(i).

[16] *See* 66 Pa. C.S. § 2802(4)-(7), (9), (11)-(12), (20).

[17] *See* 66 Pa. C.S. § 2802(11)-(12), (20).

of the next 20 years"; (2) "[a] year-by-year projection of all available sources of supply for each of the next 20 years, including, but not limited to . . . [t]he projected utilization, and the potential for additional utilization, of cogeneration and nonconventional technologies relying on renewable energy resources, including, but not limited to, solar, wind, biomass and geothermal and other small power technologies . . ."; and (3) "[a]n explanation of how the utility has integrated all demand-side and supply-side options to derive a resource mix to meet customer demand"; and (4) "[a] comparison of the total annual cost to customers and to the company of the utility's plan to meet new demand compared with alternative plans for the next 20 years." 66 Pa. C.S. § 524(a)(1)-(2), (a)(4)-(5), (b). Consistent with these charges, the Commission hosted a technical conference regarding resource adequacy on November 25, 2024, where presenters stressed the importance of pursuing many options to increase the transmission and generation capacity in Pennsylvania. (PPL Electric St. No. 6-R at 8.)

PPL Electric's Second DER Management Plan stands ready to help address these resource adequacy issues facing the Commonwealth. As PPL Electric witness Cook explained, "[a]t the distribution level, PPL Electric's Second DER Management Plan can increase the hosting capacity on distribution circuits," which "enables customers to interconnect more DERs and larger-sized DERs on distribution circuits without requiring distribution system upgrades." (*Id.*) By bringing those additional and larger DERs online, PPL Electric can reduce the demand on its distribution circuits and, by extension, the demand they are pulling from the transmission system. (*Id.*) Furthermore, "the situational awareness and system-wide connectivity provided by the Second DER Management Plan would help de-stress the transmission system and better focus and enhance investments in transmission and generation infrastructure to meet the increased electric demand." (*Id.*)

Without active DER management and monitoring, however, the Commonwealth, Commission, and PPL Electric all will lose a vital tool in combatting these resource adequacy challenges. Although other parties have suggested various forms of data collection instead of the Company's proposal,[18] such data collection alone cannot provide the situational awareness and system-wide connectivity needed to meet these resource adequacy challenges and help de-stress the transmission system. (PPL Electric St. No. 6-R at 9.) Achieving the level of situational awareness and system-wide connectivity that is necessary requires "a robust data strategy and a cohesive framework that integrates, and responds to, insights from across the utility's operations." (*Id.*) "The process of developing this framework begins at the edge of the grid"[19] and then "flows through every layer of the distribution system." (PPL Electric St. No. 6-R at 9.)

As such, EDCs must "have visibility of, and the ability to manage, the devices that are connected to their systems, for "[a] fully connected platform for system planning and operations would incorporate a broad range of utility insights: customer engagement data, insights for customer programs, non-wires alternatives, capital investment strategies, asset health metrics, reliability indicators, geographical variables, and operational parameters, such as age, usage, capacity, and voltage of grid components." (*Id.*) Additionally, by linking edge data to central systems, utilities can see beyond isolated metrics and into the broader context that influences grid health. (*Id.*) For example, a customer's individual energy usage data could inform broader load forecasts and reliability metrics, while real-time voltage data at the edge could highlight where additional capacity may be needed before issues arise. (*Id.*)

[18] *See, e.g.*, OCA St. 1SR at 36-44; SEF St. No. 1 at 21; JSP St. No. 1-SR at 15-19.)

[19] The "edge of the grid" is "where DERs, smart meters, and other customer-side technologies reside" and "can provide real-time, granular insights that enable better distribution grid performance." (PPL Electric St. No. 6-R at 5.) "When connected and coordinated, these edge resources become not just isolated energy assets but part of a larger intelligence network that strengthens both operational planning and real-time management." (PPL Electric St. No. 6-R at 5.)

Accordingly, the Company's Second DER Management Plan is a part of a larger strategy that must be executed. (*Id.*) The Company's capital and O&M planning can become far more strategic with data from the edge because knowing where non-wires alternatives (such as energy storage or demand response) can defer infrastructure upgrades in certain locations will give the Company the flexibility to allocate resources more efficiently and effectively. (*Id.*) The ultimate goal is to prioritize investments and allocate resources to areas of highest need, not to defer capital investments merely for the sake of deferral. (*Id.*) PPL Electric and other utilities can achieve that goal by using interconnectivity and a strong data strategy to glean added knowledge and insight from what, in the past, were disparate and unconnected datasets. (*Id.*)

For these reasons, the Commission should approve PPL Electric's Second DER Management Plan, so that the Company and the Commission can more effectively tackle the resource adequacy challenges facing the Commonwealth.

2. ACTIVE MANAGEMENT AND MONITORING OF DERS WILL PRODUCE SIGNIFICANT BENEFITS IN EXCESS OF THE PLAN'S COSTS

PPL Electric has fully demonstrated that the active management and monitoring of DERs will produce significant benefits in excess of the Plan's costs. The Company has produced a robust, reasonable, and transparent cost-benefit analysis that forecasts that over the 2025-2030 period, the Plan is projected to produce $65.5 million in net benefits. (PPL Electric St. No. 10-R at 8, Table SSW-2.) These projected net benefits are supported by the experience and benefits achieved during the period of the Pilot Program. (*See* PPL Electric St. No. 3 at 13-56.) While the other parties criticize the projected costs and benefits, these arguments have no merit considering the conservative methodology used to generate the analysis. (PPL Electric St. No. 10-RJ at 4.) Further, the Company has demonstrated that even if the Plan's benefits were removed completely, the Plan's absolute costs would not significantly impact customers' bills. (PPL Electric St. No.

11-R at 10-11; PPL Electric Exhibit BLJ-1R.) Finally, the Company has indicated its willingness to explore cloud-based communications in lieu of its DER Management devices, which would significantly reduce the largest driver of costs in the cost-benefit analysis and only increase the benefit-cost ratio projected by the Company in this proceeding. (*See* PPL Electric St. No. 1-RJ at 4-5, 14-15; PPL Electric St. No. 10-R at 9, Table SWW-2.) As more fully explained below, the well-supported cost-benefit analysis demonstrates that the Commission should approve the Plan without modification.

a. Over the 2025-2030 Period, the Second DER Management Plan Is Projected to Produce $65.5 Million in Net Benefits

The Company has thoroughly demonstrated that the proposed Plan will produce significant benefits for PPL Electric's ratepayers, interconnecting customer-generators, and electric distribution system. PPL Electric retained Concentric Energy Advisors, Inc. ("Concentric") to conduct a complete and detailed cost-benefit analysis of the costs and benefits of the Second DER Management Plan. (PPL Electric St. No. 1-R at 10.) The cost-benefit model developed by Concentric offers a transparent analysis that demonstrates that the benefits of PPL Electric's Second DER Management Plan will exceed its cost. (PPL Electric St. No. 10-R at 4.) Specifically, the model found that due to the relatively low cost of the DER Management devices, the Plan will provide a net benefit to all customers, will lower overall system costs, and will provide critical system management tools at a time when DERs will experience rapid growth in the Company's service territory. (PPL Electric St. No. 10-R at 4.)

Concentric included three categories of costs in its analysis: (1) the cost of the DER Management devices; (2) the ongoing maintenance of those devices; and (3) other costs that may be associated with the program. (PPL Electric St. No. 10-R at 5.) Concentric's analysis considered three categories of benefits solely related to the active management of DERs. The first category of benefits is incremental hosting capacity, which will allow a greater number of customers to install DERs in the future, and includes: (1) avoided capital investments in the distribution system that would have been needed to create an equivalent amount of hosting capacity on the system; and (2) future avoided wholesale energy purchases. (PPL Electric St. No. 10-R at 5-6.) The second category of benefits stems from improved distribution voltage that results from the Company's active management program. The largest of these benefits is associated with avoided O&M expenses that result from reduced voltage violations on the system. The model also includes an estimate of improved line losses that are expected to result from the Company's ability to actively manage smart inverters. (PPL Electric St. No. 10-R at 6.) Lastly, the model includes an estimate of the potential benefits of conservation voltage reduction. Although the Commission has not approved the use of DER Management devices for conservation voltage reduction, Concentric determined that it should still be considered a potential benefit of the program because it is a function enabled through the active management of DERs. (PPL Electric St. No. 10-R at 6.)

Based solely on the active management of DERs under the proposed Plan, Concentric determined that between 2025 and 2030, active management would produce $21.4 in net benefits, achieving a cost-benefit ratio of 1.8. (PPL Electric St. No. 10-R at 7, Table SSW-1.) Specifically, Concentric projected that the total costs related to active management in that period will total $26.5 million, with active management producing more than $48 million in benefits, including approximately $7.9 million in reduced O&M expense, $13.4 million in avoided distribution infrastructure investments, $18.7 million in energy reduction, and $7.8 million in conservation voltage reduction. (PPL Electric St. No. 10-R at 7, Table SWW-1.)

In addition to examining the benefits associated exclusively with active management, Concentric's modeling further projected the benefits attributable to the detailed monitoring of the

Company's distribution system enabled by DER Management devices. (PPL Electric St. No. 10-R at 8-10.) Accounting for the monitoring capabilities created by the installation of DER Management devices results in net benefits that are even greater, growing to approximately $65.5 million on a net present value basis, with the monitoring capabilities alone producing an additional $98.6 million in total benefits. (PPL Electric St. No. 10-R at 8, Table SSW-2.)

The findings of the model accounting for both active management and monitoring are summarized in Table SSW-2 of the Rebuttal Testimony of Stephen Wishart, as reproduced below.

Table SSW-2

Summary of Costs and Benefits							
				NPV (2025 Dollars)			
Line No.	Description		Total		Active Management		Monitoring
(A)	(B)		(C)		(D)		(E)
1	**Costs**						
2	DER Management Device Capital Cost	$	62,525,013	$	20,471,027	$	42,053,986
3	DER Management Device Maintenance	$	7,342,016	$	2,403,816	$	4,938,200
4	Other Program Costs	$	11,223,501	$	3,674,635	$	7,548,866
5	**Total Costs**	**$**	**81,090,530**	**$**	**26,549,478**	**$**	**54,541,052**
6	**Benefits**						
7	Reduced O&M Expense						
8	Total Avoided Costs Responding to Voltage Violations	$	7,488,261	$	7,488,261	$	-
9	Avoided Manual Capacitor Bank Switching for VAR Support	$	372,523	$	372,523	$	-
10	Troubleshoot Stuck Voltage Regulator	$	79,063	$	79,063	$	-
11	Total Reduced O&M Expense	$	7,939,848	$	7,939,848	$	-
12	Avoided Distribution Infrastructure Investments						
13	Avoided Installation of Switched Capacitor Banks	$	134,527	$	134,527	$	-
14	Avoided Distribution Infrastructure Investments - Hosting Capacity	$	61,348,156	$	13,336,556	$	48,011,600
15	Total Avoided Distribution Infrastructure Investments	$	61,482,683	$	13,471,083	$	48,011,600
16	Energy Reduction						
17	Avoided Cost from Reduced Electricity Losses	$	4,686,210	$	4,686,210	$	-
18	Avoided Energy From Incremental Hosting Capacity	$	64,660,328	$	14,056,593	$	50,603,735
19	Total Energy Reduction	$	69,346,538	$	18,742,803	$	50,603,735
20	Reduced Customer Electricity Costs						
21	Conservation Voltage Reduction	$	7,850,212	$	7,850,212	$	-
22	**Total Benefits**	**$**	**146,619,280**	**$**	**48,003,945**	**$**	**98,615,335**
23	**Net Benefits**	**$**	**65,528,750**	**$**	**21,454,467**	**$**	**44,074,283**
24	**Ratio of Benefits to Costs**		**1.8**		**1.8**		**1.8**

(PPL Electric St. No. 10-R at 8, Table SSW-2.)

Importantly, the Company also produced a sensitivity analysis that stress-tested the findings of the cost-benefit analysis under various scenarios, including eliminating all benefits except incremental hosting capacity, eliminating half of the incremental hosting capacity, increasing the costs associated with DER Management devices, their maintenance, and the administration of the Plan, as well as lower DER interconnection forecast. (PPL Electric St. No. 10-R at 24, Table SWW-7.) Crucially, none of the sensitivities conducted resulted in overall negative net benefits for the Second DER Management Plan, demonstrating that even under unfavorable conditions, the Plan is still projected to achieve benefits in excess of its cost. (PPL Electric St. No. 10-R at 23.)

In sum, the results of the cost-benefit analysis show that the financial benefits associated with installing DER Management devices to be used for detailed system monitoring and active management significantly outweigh the associated costs. (PPL Electric St. No. 10-R at 24.)

b. The Second DER Management Plan's Projected Net Benefits Are Supported by the Cost-Benefit Evaluations of the DER Management Pilot Program

The findings of the cost-benefit analysis produced for the Second DER Management Plan are further supported by the data collected by the Company during the Pilot Program. Importantly, unlike the forward-looking cost-benefit analysis performed for the Second DER Management Plan, the Company's evaluations of the costs and benefits of the Pilot Program were retroactive and, therefore, did not account for the ongoing benefits that will continue to be provided by the DER Management devices already installed. (PPL Electric St. No. 10-R at 29.) Notwithstanding, through the course of the Pilot Program the Company identified many tangible benefits achieved through active management and monitoring of DERs. (*See* PPL Electric St. No. 3 at 13-56.)

In line with the Settlement reached in the First DER Management Plan proceeding, the costs and benefits of the Pilot Program were analyzed in the context of specific use cases designed to capture the benefits realized using the new capabilities enabled by the Pilot Program. (PPL Electric St. No. 3 at 11.) Identifying, tracking, and analyzing use case opportunities allowed the Company to evaluate the efficacy and efficiency of the Pilot Program while ensuring that the overall value of the new capabilities are maximized. (PPL Electric St. No. 3 at 11.)

Notably, the Pilot Program demonstrated that the real power monitoring enabled by DER Management devices improves the accuracy of load and capacity calculations and produces substantial benefits. (PPL Electric St. No. 3 at 17.) The use of data from real power monitoring during the Pilot Program improved the accuracy of distribution system planning models and increased the system-wide hosting capacity by approximately 18 MW when compared to using the DER nameplate data instead. (*Id*. at 19.) The Pilot Program also demonstrated that monitoring real power production can be used to detect hidden load,[20] which helps ensure that switching operations do not result in equipment overloads or any potential equipment damage and enable operators and the ADMS to make informed decisions to avoid overload conditions during restoration efforts. (*Id*. at 21.) Real power monitoring can also defer upgrades on circuits with relatively high penetrations of DER that are forecasted to experience load growth and subsequent capacity constraints. (*Id*. at 13, 17; HIGHLY CONFIDENTIAL PPL Electric Exhibit CD-5.) The data gathered improves the accuracy of load and capacity calculations, resulting in more timely investments in capacity where it is needed. Absent this data, such investments would be more likely to occur sooner than necessary. (PPL Electric St. No. 3 at 17.)

The Company also demonstrated that DER power factor setpoint adjustments performed by system operators and the ADMS/DERMS can reduce the number, frequency, and duration of voltage violations. (*Id*. at 48.) This reduces the number of customers who contact PPL Electric about voltage violations and, subsequently, reduces the number of investigations performed by the reliability engineering team and the number of visits to customer locations by PPL Electric (commonly referred to as "truck rolls"). (*Id*.) Within the Program Year 2 Annual Report, PPL Electric identified 23,272 customers that had a voltage violation resolved during the same time interval as a DER power factor control event through the end of Program Year 2 in March 2024

[20] "Hidden load" is the amount of load that is present on a circuit but not measured at telemetry points (e.g., the circuit breaker) because the energy is being provided by local downstream DERs. The amount of load measured by distribution equipment is often referred to as the "net" load, and the total amount of load operating on the circuit (including the amount offset by DER production) is the "native" load, with "hidden" load in a given interval as the difference between the two. (PPL Electric St. No. 3 at 15.)

and could have resulted in a truck roll. If each such customer had contacted PPL Electric about their voltage issue, it would have resulted in approximately $13,666,306 of operation and maintenance expense for truck rolls. (*Id*.)

Additionally, the Pilot Program identified opportunities for lower interconnection costs on the Company's distribution system, including a case study that found that the management of the real power limit function would enable a proposed 10 MW solar facility to avoid approximately $1.48 million in system upgrades that would otherwise be necessary as a result of a conductor overload. (PPL Electric St. No. 3 at 61.) Also within the Program Year 2 Annual Report, PPL Electric identified two studies related to planned switching that indicate that active management of DER power factor setpoints would have been able to avoid $38,000 of investment in capacitor banks to support planned switching. (*Id*.; HIGHLY CONFIDENTIAL PPL Electric Exhibits CD-9 and Exhibit CD-10.)

Through the course of the Pilot Program, the Company identified that DER management and monitoring can achieve system-wide benefits by improving:(1) the accuracy of planning models, which improves the accuracy of the studies that utilize those models, including load interconnection studies and DER interconnection studies (PPL Electric St. No. 3 at 15); (2) the accuracy of load and capacity calculations, resulting in more timely investments in capacity where it is needed (*Id*. at 17); (3) the accuracy of operational models to increase the accuracy of voltage calculation, which helps PPL Electric more effectively identify and respond to voltage violations through both traditional means (e.g., using capacitor banks) and using the DER power factor control capabilities established by the Pilot Program (*Id*. at 21); (3) outcomes during planned an unplanned switching events to ensure that switching operations do not result in equipment overloads or any potential equipment damage (*Id.*); and (4) communications with customer-generators by identifying systems that are not operational (*Id.* at 23).

Considering the far-reaching benefits achieved in the Company's Pilot Program, the projected benefits of the Second DER Management Plan are well founded.

c. The DER Management Pilot Program and Second DER Management Plan Will Help Decrease the Company's Revenue Requirement in Base Rate Proceedings

The net benefits of the Company's DER Management Pilot Program and Second DER Management Plan will directly benefit ratepayers by decreasing PPL Electric's revenue requirement in base rate proceedings. Specifically, after accounting for the reduced capital costs and expenses from the Company's DER Management Pilot Program and Second DER Management Plan, the estimated revenue requirement impact in a hypothetical 2025 base rate case would be approximately $4,497,918 lower than without them, which would put a downward pressure on the base rates ultimately adopted in that proceeding. (PPL Electric St. No. 11-R at 11.) In fact, all else being equal, the amount of that decrease in the revenue requirement would equal a decrease in the estimated average residential bill of $2.62 per year. (*Id.* at 11.)

In addition, even if you set aside completely the Plan's projected benefits that will put a downward pressure on distribution rates, the Plan's absolute costs would not significantly impact customers' bills. PPL Electric witness Bethany Johnson prepared an estimate of the Company's capital cost and expense claims for those devices in a hypothetical 2025 base rate case, along with the projected average bill impact for PPL Electric's customers due to these costs and expenses, for illustration purposes. (*Id.* at 10.) After setting aside the reduced capital costs and expenses from the Company's DER Management Pilot Program and Second DER Management Plan, the estimated revenue requirement impact is approximately $7,089,896, resulting in an estimated average residential bill increase of $4.13 per year. (*Id.* at 10-11; PPL Electric Exhibit BLJ-1R.)

This bill impact analysis demonstrates that even without realizing any of the projected benefits from the proposed Plan, the Plan would not significantly impact customers' bills. Also, given the significant benefits to safety, reliability, adequacy, and resiliency detailed in Section V.C.1, *supra*, such an impact on customers' bills would be more than justified.

d. The Second DER Management Plan's Benefit-Cost Ratio Will Only Increase if the Company Shifts to Incorporating Cloud-Based Communications (as the Company Has Stated It Is Willing to Do) Because the Plan's Largest Cost Component Is the DER Management Devices

The largest cost component in the cost-benefit analysis was the cost of the DER Management devices themselves, so if the Company shifts to incorporating cloud-based communications that eliminate the need to install DER Management devices at customer locations, the benefit-cost ratio will only increase.

Specifically, the capital cost and maintenance of DER Management devices account for $69.8 million of the $81 million in projected total costs under the cost-benefit analysis of active management and monitoring. (*See* PPL Electric St. No. 10-R at 9, Table SWW-2.) However, the Company indicated in its Rejoinder testimony that it is willing to investigate cloud-based communications as an alternative to the DER Management devices. (PPL Electric St. No. 1-RJ at 4-5, 14-15.) The Company believes that based on its prior work setting up servers with JSP member Enphase, it could seamlessly incorporate cloud-based communications through the Enphase modems into its ADMS/DERMS. (*Id*. at 14-15.) Because cloud-based communications would not require the procurement, installation, and maintenance of a DER Management device, the largest driver of cost identified in the cost-benefit analysis could be reduced. It is reasonable to assume that the adoption of cloud-based communications would only increase the cost-benefit ratio of the Plan.

e. Other Parties' Criticisms of the Company's Cost-Benefit Analyses Lack Merit and Should Be Rejected

The Commission should reject other parties' criticisms of the cost-benefit analyses because, among other reasons, the forward-looking cost-benefit analysis for the Second DER Management Plan was overly conservative. The other parties' arguments are largely based on contentions that the Plan's projected benefits are overstated or speculative, that the Company failed to fully capture or consider costs associated with the Plan, and that the Company should have evaluated alternative DER management strategies in its analysis. (*See, e.g.*, OCA St. 1SR at 18; OSBA St. No. 1-SR at 1; JSP St. No. 1-SR at 16-17.) These arguments are flawed for several reasons.

Contrary to the other parties' characterizations, the Company did not exaggerate the benefits that can be expected to be generated by the Second DER Management Plan or include overly speculative benefits. JSP witness White, for example, claims that "the cost-benefit analysis provided by PPL relies largely on avoided energy and O&M costs that are unlikely to materialize." (JSP St. No. 1-SR at 17.) However, Ms. White provides no evidence or reasoning as to why energy and O&M savings would not materialize as a result of the Second DER Management Plan. (PPL Electric St. No. 10-RJ at 19.) In contrast, PPL Electric has demonstrated through its Pilot Program how hosting capacity could be increased through monitoring and active management, which then leads to energy savings, and that active management of DER devices can address voltage violations and reduce O&M associated with truck rolls. (*Id.*)

Similarly, OSBA witness Farr claims that the results of the cost-benefit analysis are "highly dependent on an assumption that is difficult to quantify and that was not directly included in the sensitivity analysis," referring to the per-device creation of incremental hosting capacity in the cost-benefit analysis. (OSBA St. No. 1-SR at 4, 6-8.) However, the amount of incremental hosting capacity created per DER installation as used in the CBA was based on the Company's experienced incremental hosting capacity created by the Pilot Program. (PPL Electric St. No. 10-RJ at 13.) Moreover, contrary to OSBA's claims, the Company did perform a sensitivity analysis of incremental hosting capacity in the scenario in which 50% of the incremental hosting capacity benefits were removed from the base case. While this resulted in a significant decrease in the projected net benefits, notably, this still resulted in a cost-benefit ratio of 1.03, demonstrating that even using conservative assumptions surrounding one of the largest drivers of projected benefits, the Company's Plan continues to be cost effective. (PPL Electric St. No. 10-R at 24; PPL Electric St. No. 10-RJ at 13-14.)

Finally, the OSBA's claim that the cost benefit analysis inappropriately included benefits from conservation voltage reduction because implementation would require Commission approval is similarly without merit. (OSBA St. No. 1-SR at 4-5.) The intent of the cost benefit analysis was to quantify the net benefits that could reasonably be expected to result from the installation of DER Management devices and the monitoring and active management of DERs through those devices. Because those actions will enable conservation voltage reduction, it is appropriate to include those benefits for consideration. Furthermore, of the $147 million in total benefits estimated, conservation voltage reduction accounted for only $7.9 million and was clearly shown as a separate line item, so that the Commission or other stakeholders could assess the magnitude and the role it plays in the overall cost effectiveness of the Company's proposal. (PPL Electric St. No. 10-RJ at 12.)

In fact, the Company intentionally used conservative assumptions regarding future benefits. Specifically, the analysis used moderated assumptions related to the number of truck rolls related to voltage violations and capacitor bank switching, the cost of distribution investments, and the cost of wholesale energy that can be saved through the Plan. (*Id*. at 4.) The analysis conservatively specified that the cost of DER Management devices would only increase over time and did not allow for the possibility that technological advancements could reduce device costs in the future. Finally, the cost-benefit analysis included approximately $1 million per year in "other costs" to account for costs that may not have been otherwise recognized. (*Id*.)

The Company also rebutted the other parties' claims that the cost-benefit analysis failed to fully capture or consider costs associated with the Plan. For example, OCA's objection to the exclusion of capital costs associated with DERs interconnected between 2030 and 2034 was reasonable considering the cost-benefit analysis includes capital investments forecasted from 2025 to 2030. (OCA St. 1SR at 35.) Similarly, OCA's criticism that the CBA does not account for costs related to projected EV adoption is meritless because EVs were exempt from the Pilot Program and are not included in the proposed Second DER Management Plan. (OCA St. 1SR at 35; PPL Electric St. No. 10-RJ at 9-10.) The JSPs took issue that the CBA did not account for the impact of reduced energy sales and increased net metering credits attributable to increased DER penetration, a critique that unexpectedly suggests that the JSPs believe that net-metering policies overcompensate DER owners and put upward pressure on rates for other customers. (JSP St. No. 10-RJ at 23.) However, the Company reasonably chose not to include these costs in the analysis because Pennsylvania law requires PPL Electric to offer net metering and compensate customer-generators for the full retail value of their electric generation. (*Id*.)

Finally, the Company reasonably limited the scope of the cost-benefit analysis to the proposals contained in the Second DER Management Plan and the other parties' arguments that the analysis was too limited should be rejected. To this point, OCA, OSBA, and the JSPs argue that the cost-benefit analysis is flawed because it does not include a separate analysis for autonomous inverter settings. (*See, e.g.*, OCA St. 1SR at 18; OSBA St. No. 1-SR at 13; JSP St. No. 4-SR at 31-32.) However, the IEEE Standard 1547-2018 has been incorporated into the Commission's regulations for DERs. *See* 52 Pa. Code § 75.22 (defining "certified"). This means that smart inverters with their voltage regulations, frequency support, and ride-through capabilities are required for all new DER interconnections. (PPL Electric St. No. 10-RJ at 4.) Commission approval of the Plan would not eliminate or diminish the benefits of autonomous operation but would add to the total net benefits that can be realized through IEEE 1547-2018. (*Id*. at 4-5.) As such, Concentric concluded that it was unnecessary to conduct a separate analysis to account for autonomous functions are already required by regulation.

Similarly, the parties argue that the Company failed to evaluate the costs and benefits associated with alternative program structures or other solutions that do not require the installation of DER management devices. (*See, e.g.*, OCA St. 1SR at 31-33; OSBA St. No. 1-SR at 13; JSP St. No. 1-SR at 16.) However, the Company reasonably limited the scope of its cost-benefit analysis to consider the Plan as designed and proposed in the instant proceeding. The CBA focuses on Company-specific data obtained as a result of the DER Management Pilot Program in order to evaluate the costs and benefits of the Second DER Management Plan. While intervenors may make recommendations on alternative strategies to adopt, these recommendations do not necessarily lend themselves to inclusion in the cost-benefit analysis during this proceeding. (PPL Electric St. No. 10-RJ at 16.) Thus, the other parties' criticisms of the cost-benefit analysis performed have no merit and should be rejected.

For all of these reasons, the Commission should approve the Second DER Management Plan because PPL Electric has fully demonstrated that its active management and monitoring of DERs will produce significant benefits in excess of the Plan's costs.

3. PPL ELECTRIC HAS FULLY REBUTTED THE JOINT SOLAR PARTIES' ALLEGATIONS CONCERNING THE ADVERSE EFFECTS OF THE DER MANAGEMENT PILOT PROGRAM AND SECOND DER MANAGEMENT PLAN

As part of their effort to oppose PPL Electric's Second DER Management Plan, the JSPs make a series of allegations about the impact of the DER Management Pilot Program and Second DER Management Plan on solar and inverter companies' projects and communications with DERs. (*See generally* JSP St. No. 2 at 3-6; JSP St. No. 3 at 3-6; JSP St. No. 4 at 5-24; JSP St. No. 5 at 3-6; JSP St. No. 6 at 4-10; JSP St. No. 7 at 15-22; JSP St. No. 10 at 3-6.) They also contend that the Company's installation of DER Management devices on SolarEdge inverters have caused or contributed to alleged safety incidents. (*See* JSP St. No. 7 at 8-15; JSP St. No. 7-SR at 3-17; JSP St. No. 14-SR at 5-16.) As set forth in the following sections, PPL Electric has fully rebutted these allegations concerning the adverse effects of the DER Management Pilot Program and Second DER Management Plan and has demonstrated that Second DER Management Plan should be approved as filed.

a. The JSPs' Allegations Concerning the Impact on Solar and Inverter Companies' Projects and Communications Should Be Denied

The Commission should deny the JSPs' allegations about the DER Management Pilot Program's and Second DER Management Plan's impact on solar and inverter companies' projects and communications. (*See generally* JSP St. No. 2 at 3-6; JSP St. No. 3 at 3-6; JSP St. No. 4 at 5-24; JSP St. No. 5 at 3-6; JSP St. No. 6 at 4-10; JSP St. No. 7 at 15-22; JSP St. No. 10 at 3-6.) In their testimony, the JSPs made several claims on these fronts, including allegations that the Company has placed restrictions on inverters and projects, caused customers, solar installers, and inverter manufacturers to experience increased costs, affected customers' and inverter manufacturers' systems and communications, caused lost sales and delayed projects, and affected inverters' warranties. (*See id.*) PPL Electric fully rebutted these allegations in testimony.

First, PPL Electric does not restrict options for DERs. (PPL Electric St. No. 2 at 15-24.) "As of December 2, 2024, the Company's Approved Inverter List has a total of 315 different inverters from 18 different manufacturers (see PPL Electric Exhibit AD-1R), with 21 inverters and one more manufacturer being added in the near future." (PPL Electric St. No. 2-R at 15.) To the extent that options for DERs are being limited by the lack of Tesla inverters on the Approved Inverter List, PPL Electric would be happy to review Tesla's inverters and place them on the Approved Inverter List. (*Id*. at 17.) However, despite the Company's multiple requests, Tesla continues to refuse PPL Electric to test their inverters and make sure they are compatible and safe to use with the Company's DER Management devices. (*Id*.) Further, although there are six manufacturers that are limited to single-inverter installs on the Approved Inverter List as of January 12, 2025, there is a clear reason why—as these manufacturers have publicly stated that these inverters cannot be networked, which would cause these inverters to be noncompliant with SunSpec Modbus Communication protocols.[21] (PPL Electric St. No. 2-RJ at 37.)

Second, the JSPs' allegations about increased costs due to the DER Management Pilot Program are unsupported. (*See* PPL Electric St. No. 2-R at 25-36.) Their contentions about how the inverters on PPL Electric's Approved Inverter List are not cost-effective were based on flawed and misleading analyses and were directly refuted by publicly-available information about inverter costs. (PPL Electric St. No. 2-R at 25-31; PPL Electric St. No. 2-RJ at 11-13, 22-24.) Also, nothing supports the argument that the DER Management Pilot Program prevented Tesla from

[21] For all inverters held to the IEEE 1547-2018 standard, they need to follow one of three communication protocols: IEEE Std 2030.5 (SEP2), IEEE Std 1815 (DNP3), or SunSpec Modbus, all of which have specifications related to the communication protocol. (PPL Electric St. No. 2-RJ at 37.)

monetizing approximately $38,064 in Solar Renewable Energy Credits ("SRECs") because "Tesla still could have gathered the data that was needed for these SRECs by contacting the customer or manufacturer or by visiting the site to gather the necessary revenue-grade production information." (PPL Electric St. No. 2-R at 26.) Likewise, there is no merit to the JSPs' claim that PPL Electric excluded Enphase from the solar market in the Company's service territory for four months in early 2021. (*Id*. at 31-32.) Enphase failed to provide all of the required documentation when it originally submitted its inverters for review on January 5, 2021. (*Id*. at 31.) After Enphase provided the outstanding documentation on February 23, 2021, PPL Electric approved the inverters and added them to the Approved Inverter List only two days later on February 25, 2021. (*Id*. at 31-32.) Contrary to the JSPs' claims, PPL Electric's DER Management devices also did not interfere with any systems' power production. (*Id*. at 32-33, 36.)

Third, the JSPs' allegations concerning lost sales and delayed projects should be rejected. (*Id*. at 48-53.) JSP witness Zavala alleged that AHC lost 52 sales in PPL Electric's service territory. (JSP St. No. 2-SR at 11.) However, 6 of those addresses do not have electric service accounts with PPL Electric, so they would be unable to interconnect DERs with the Company's distribution system and would not be subject to the requirements of the DER Management Pilot Program. (PPL Electric St. No. 2-RJ at 9-10.) Thus, approximately 12% of the alleged lost sales cannot be considered as lost sales due to the DER Management Pilot Program. (*Id*. at 10.) Moreover, "this calls into question the reliability of the information Mr. Zavala obtained from the prospective customers, how far along in the process the customers decided not to go forward with the sales, and the role in which PPL Electric's DER Management Pilot Program played in the sales being purportedly 'lost.'" (*Id*.) Additionally, PPL Electric attempts to install the DER Management device within 14 calendar days, assuming there is not any inclement weather or discrepancies found when field visiting the customer's system, so that DER projects are not delayed. (PPL Electric St. No. 2-R at 53.) For at least 3 of Mr. Stahlman's installations where he asserts that the timeline took longer than the 14 calendar days, those installations were delayed because there were missing signatures from the customer on the certificate of electrical inspection ("CEI"). (*Id*. at 53; *see* PPL Electric St. No. 2-RJ at 40-41.) Such a CEI is required before installing the DER Management device. (PPL Electric St. No. 2-RJ at 40.)

Fourth, PPL Electric witnesses Dombrowski-Diamond and Floyd testified about how it would be inappropriate to void any customer warranties due to the Company's installation of the DER Management devices. (PPL Electric St. No. 2-R at 59-60.) Indeed, as explained in the following section, no credible evidence supports the JSPs' allegations that the DER Management devices have caused or contributed to alleged thermal events. PPL Electric also provided information to SolarEdge on multiple occasions about how the Company installs its DER Management device on SolarEdge inverters, including in response to inquiries directly from SolarEdge about that topic.[22] For SolarEdge to turn around now and argue that the installation of the DER Management devices voids the customers' warranties would not be fair to customers. (PPL Electric St. No. 2-R at 59; PPL Electric St. No. 12-R at 11.)

b. The JSPs' Safety-Related Allegations Have No Merit and Should Be Disregarded

The Commission should likewise disregard the JSPs' safety-related allegations concerning PPL Electric's DER Management devices. (*See, e.g.*, JSP St. No. 7 at 8-15; JSP St. No. 7-SR at 3-17; JSP St. No. 14-SR at 5-16.) Safety is a cornerstone of the Second DER Management Plan. Not only will the Company's proposal produce significant safety-related benefits,[23] but PPL

[22] *See* Section V.C.1.b, *infra*.
[23] *See* Section V.C.1.a, *supra*.

Electric has taken several steps to ensure the safety of its DER Management devices and their installation. (*See, e.g.*, PPL Electric St. No. 2 at 13-14.)

As outlined in PPL Electric Exhibits AD-3 and AD-4, the Company's DER Management devices undergo a series of internal and manufacturer tests to confirm they are safe for use. (*Id*. at 11.) Some of these tests include tampering, voltage checks, amperage checks, and weatherproof checks. (*Id*.) All of PPL Electric's DER Management devices have passed these tests. (*Id*.) Additionally, the Company's "DER Lab team performs a series of steps to confirm the DER Management device properly connects and communicates with the DER system." (*Id*.) As part of that review process, "the DER Lab works closely with the DER system manufacturer." (PPL Electric St. No. 2 at 11; *see* PPL Electric Exh. AD-2.)

In addition, all of the Company's DER Management device installations are performed by PPL Electric meter technicians. (PPL Electric St. No. 2 at 13.) When installing a DER Management device, the technicians first verify that they are installing the correct device at the correct location. (*Id*.) Once the verification is complete, then the technicians follow a Distribution Device Instruction ("DDI"), which gives step by step instructions to install the DER Management device based on the type of inverter. (*Id*.) Relevant here, the DDI for the device's installation on a SolarEdge inverter was provided as part of the Company's initial filing. (*Id*.; PPL Electric Exh. AD-6.) The meter technicians undergo an extensive two-week training on installing DER Management devices, which includes practicing installations in the Company's DER Lab as well as demonstrating successful side-by-side installations in the field with the trainer. (PPL Electric St. No. 2 at 14.) Also, during this training, all technicians are required to pass a written and physical test before they can install DER Management devices alone. (*Id*.) These processes are designed to ensure that only qualified and trained personnel are installing DER Management devices in the field. (*See id*. at 13-14.)

Nevertheless, the JSPs raised, for the first time in their direct testimony, allegations that PPL Electric's DER Management device installations were causing or contributing to safety incidents involving SolarEdge inverters. (*See* JSP St. No. 7 at 8-15.) Specifically, the JSPs originally claimed that the Company's DER Management device installations caused or contribute to alleged thermal events at 8 inverter locations. (JSP St. No. 7 at 14.) Then, in their surrebuttal testimony, JSP witness Geller conceded that there was no conclusive evidence to determine PPL Electric's DER Management device caused or contributed to 3 of those alleged thermal events. (JSP ST. No. 13-SR at 8.) Thus, out of 7,956 DER Management device installations on SolarEdge inverters, the JSPs have pointed to 5 alleged thermal events (*i.e.*, 0.06% of the locations where the DER Management devices were installed on SolarEdge inverters). (PPL Electric St. No. 2-RJ at 32.) The JSPs' claims are meritless and should be rejected for several reasons.

First, the JSPs' direct case was founded on the unreliable and uncredible testimony of JSP witness Bobruk. (*See generally* JSP St. No. 7.) Mr. Bobruk's testimony about the 8 alleged incidents hinged on SolarEdge's "PPL Case Review," a PowerPoint presentation where each of the purported incidents was listed on a slide and accompanied by photographs and information about the site. (*See* JSP St. No. 7 at 8-15.) Despite agreeing that it is important to establish a timeline when investigating potential claims in order to determine the potential causes for alleged damage, Mr. Bobruk admitted that he did not know who took the photographs or when those photographs were taken. (Tr. 396-97.) According to Mr. Bobruk, "I suppose anybody could have taken the photograph." (Tr. 396.) In fact, in his role with SolarEdge, he is "simply looking for code compliance," so he does not "have the knowledge of necessarily the timeline of the case."

(Tr. 397.) He also does not handle SolarEdge's "return merchant authorization" or "RMA" process, where a SolarEdge employee actually reviews the damaged inverter (along with any photographs provided) and determines whether the damaged inverter is covered by the warranty. (Tr. 392-93.)

Mr. Bobruk further claimed that SolarEdge first became aware of PPL Electric's method for installing its DER Management devices on SolarEdge inverters in August 2024. (Tr. 399.) However, there were numerous instances before that time when PPL Electric provided actual or constructive notice to SolarEdge about its installation method.

1. May 20, 2024 – PPL Electric filed its Petition for Approval of its Second DER Management Plan, attached to which was PPL Electric Exhibit AD-6, a copy of the DDI that sets forth the Company's detailed instructions, accompanied by photographs, for installing the DER Management devices on SolarEdge inverters.

2. August 31, 2023 – In response to an August 29, 2023 email from Brett Hallgren (SolarEdge) for a copy of PPL Electric's installation manual for its DER Management devices, Aliesha Dombrowski-Diamond (PPL Electric) sent an email to Mr. Hallgren and Alex Dinh (SolarEdge), copying Mr. Wallace (PPL Electric), that contained a copy of PPL Electric's installation manual for installing DER Management devices on SolarEdge inverters, including the procedure for PPL Electric's method of powering the DER Management device. (PPL Electric St. No. 13-RJ at 4; HIGHLY CONFIDENTIAL PPL Electric Exh. AD-1RJ.) Mr. Hallgren responded by sending an email later on August 31, 2023, in which he acknowledged receipt of the manual and saying that he performed a quick review. (PPL Electric St. No. 13-RJ at 4; HIGHLY CONFIDENTIAL PPL Electric Exh. AD-1RJ.)

3. January 26, 2022 – Matthew Wallace (PPL Electric) and Alex Dinh (SolarEdge) had a Zoom call, where the Company "screenshared photographs of a PPL Electric DER Management device installation on a SolarEdge inverter." (PPL Electric St. No. 13-RJ at 2.) Mr. Wallace also reviewed how PPL Electric: (a) "[i]nstalls the PPL Electric DER Management device next to the inverter"; (b) "[i]nstalls weatherproof conduit between [the] PPL Electric DER Management device and the inverter"; (c) "[r]uns data & power cables through this conduit to connect the PPL Electric DER Management device to the inverter"; (d) "[c]onnects the data cable to the inverter's RS485 terminals"; (e) "[c]onnects the AC Line (power cable, using a fork connector, to the AC Line terminal of the inverter"; (f) "[c]onnects the AC Neutral cable, using a fork connector, to the AC Neutral terminal of the inverter"; and (g) "[c]onnects the AC Ground cable to the inverter's ground bus bar." (PPL Electric St. No. 13-RJ at 2-3.) Mr. Wallace then asked Mr. Dinh if he saw any issues with this approach, and Mr. Dinh responded that he did not see any issues. (PPL Electric St. No. 13-RJ at 3, 5.) Shortly after that Zoom call, per Mr. Dinh's request, Mr. Wallace

> emailed him the photographs that they reviewed together. (PPL Electric St. No. 13-RJ at 3, 5.)

Mr. Bobruk tried to sidestep this clear evidence by asserting that the Company's manual "describes the connection to some screw terminals inside the inverter, but those are not identified or listed as the hot and neutral terminals of the inverter." (Tr. 403.) He also claimed that photograph in the manual did not "show the neutral or the hot terminal." (Tr. 405-06.) When pressed on cross-examination, however, Mr. Bobruk conceded that the manual "does describe the connections of the device to the neutral and hot line terminal to the inverters" and that the area circled in yellow in the photograph depicts the connections to the neutral (white) terminal and the hot line (black) terminal. (Tr. 405-07.)

Furthermore, Mr. Bobruk admitted that he did not review JSP witness Geller's surrebuttal testimony before asserting in his own surrebuttal testimony that PPL Electric's "method of installing its device on the circuit board not only causes a shock risk, it has in fact caused at least eight thermal events." (Tr. 423.) Mr. Bobruk even underlined "at least eight thermal events" in his surrebuttal testimony. (Tr. 423.) However, had he reviewed Mr. Geller's surrebuttal testimony before making that statement in his own surrebuttal testimony, Mr. Bobruk would have seen that his fellow employee at SolarEdge conceded that there was no clear evidence to connect PPL Electric's DER Management device to 3 of those 8 alleged events. (JSP ST. No. 13-SR at 8.)

In addition, in his surrebuttal testimony, Mr. Bobruk responded to PPL Electric witness Dombrowski-Diamond's rebuttal testimony concerning the failure rates of SolarEdge inverters with PPL Electric DER Management devices installed and without those devices installed. (JSP St. No. 7-SR at 15.) According to Mr. Bobruk:

> SolarEdge is a large manufacturer, which like any company, can experience equipment failures. That fact has no bearing on the unusually high incidences of thermal events we have observed in PPL territory, combined with consistent evidence of PPL's

> tampering with the AC screws in our inverters, along with installations of DER devices. We have seen no such pattern in any other territory.

Yet, on cross-examination, Mr. Bobruk stated that he did not know what is an "acceptable failure rate for inverters" because that is "not [his] department." (Tr. 422.) Further, Mr. Bobruk said, "I don't believe I'm making a judgment on the importance of failure rates here." (Tr. 425.)

More importantly, Mr. Bobruk submitted a verified discovery response about any root cause analyses performed by SolarEdge that directly contradicted JSP witness Geller's surrebuttal testimony. (*See* HIGHLY CONFIDENTIAL PPL Electric Exh. AD-9RJ; JSP St. No. 13-SR at 4-11.) In his surrebuttal testimony, Mr. Geller, who is a "Failure Analysis Engineer," claimed that the "PPL Case Review" is a "root cause" analysis, the contents of which he was "consulted." (JSP St. No. 13-SR at 4.) He then stated that he "formed [his] opinions based on [his] review of digital evidence reflected therein, and field service tech reports." (*Id*. at 4.) Therefore, he analyzed the root causes of the alleged thermal damage and developed opinions as to the root causes, which he sets forth in detail in his surrebuttal testimony. (*See id*. at 5-11.)

Yet, the Joint Solar Parties did not present any of Mr. Geller's analyses in support of their direct case, nor did they provide any of this information in discovery, despite PPL Electric specifically requesting that the Joint Solar Parties **[BEGIN HIGHLY CONFIDENTIAL]** [redacted]

[redacted] **[END HIGHLY CONFIDENTIAL]**. Thus, Mr. Bobruk failed to answer PPL Electric's discovery request accurately and fully and, as a result, unduly prejudiced the Company by forcing PPL Electric to respond to Mr. Geller's analyses in the 13 days between the receipt of his surrebuttal testimony and the due date for the Company's rejoinder testimony. (PPL Electric St. No. 2-RJ at 46.)

Second, other JSP witnesses who testified about these alleged safety incidents lack credibility as well. JSP witness Dinh testified that "if PPL had asked for [his] opinion as to its method of installing its device for purposes of powering it," then he "would have referred PPL to the correct persons in SolarEdge who are authorized to review such request." (JSP St. No. 11-SR at 6.) However, in his own email sent on January 19, 2022, Mr. Dinh specifically asked for details about the DER Management device installation, including its power source. (PPL Electric St. No. 13-RJ at 5-6; HIGHLY CONFIDENTIAL PPL Electric Exh. AD-27R.) Notably, while Mr. Dinh claims to not remember this particular Zoom call with Mr. Wallace on January 26, 2022, where the device's power source was specifically discussed, as he has "had several zoom calls with PPL," Mr. Dinh does not deny that such a call occurred. (Tr. 432.) Shortcomings can be seen with JSP witness Stahlman's credibility, too. In his direct testimony, Mr. Stahlman claimed that the way PPL Electric installs its devices "is not compliant with the UL listing of the device." (JSP St. No. 10 at 7.) In discovery, however, Mr. Stahlman admitted that he did not review the UL listings at issue before submitting his direct testimony and stated that he is "not aware how PPL Electric's installation of a DER Management device violates any UL requirements or listings." (PPL Electric St. No. 12-R at 18; PPL Electric Exhs. LF-2R and LF-3R.)

Third, the Company presented detailed evidence refuting the JSPs' claims that the Company's DER Management device installations caused or contributed to the alleged thermal events. (*See* PPL Electric St. Nos. 2-R at 55-60; 2-RJ at 44-63; 12-R at 4-20; 12-RJ at 7-17.) In particular, after the JSPs raised these allegations for the first time in their direct testimony, PPL Electric engaged H. Landis Floyd, PE as an outside expert to investigate and address the JSPs' allegations. Mr. Floyd holds a Bachelor of Science degree in Electrical Engineering from Virginia Polytechnique Institute and State University, and his professional experience in the area of electrical safety is extensive. (PPL Electric St. No. 12-R at 1-2.)[24]

Mr. Floyd reviewed all of the JSPs' testimony and exhibits regarding their electric safety-related claims. In his expert opinion, "PPL Electric's devices, including the way in which they are installed, are well-designed and well-engineered and are consistent with electric industry best practices." (*Id*. at 13.) Furthermore, "there is no credible evidence to support that PPL Electric's DER Management devices are creating an electric arc within the inverters." (*Id*. at 15.) "Based on [his] review of Mr. Bobruk's and Mr. Stahlman's allegations, PPL Electric is, in actuality, maintaining consistent spacing when it installs its DER Management device." (*Id*. at 17.) Also, "when a component has caused or contributed to a thermal event, the thermal damage should

[24] Mr. Floyd worked for the DuPont Company for over 45 years, with assignments in the design, construction, commissioning, operation, maintenance, and safety of industrial electrical systems. (PPL Electric St. No. 12-R at 1.) He also provided technical and leadership contributions in the technical activities of the Institute of Electrical and Electronics Engineers ("IEEE") since 1984. (PPL Electric St. No. 12-R at 1.) Mr. Floyd was elected to IEEE Fellow in 2000 and served on the National Fire Protection Association ("NFPA") and the National Electrical Code ("NEC") technical committee from 1990 to 2014. (PPL Electric St. No. 12-R at 1.) Since 2014, he has been an adjunct faculty member of the Advanced Safety Engineering and Management graduate engineering program at the University of Alabama at Birmingham. (PPL Electric St. No. 12-R at 1-2.) In this capacity, he has developed and taught the course Electrical Systems Safety. (PPL Electric St. No. 12-R at 2.) Mr. Floyd also has provided consulting and expert witness services with Electrical Safety Group Inc. since 2005. (PPL Electric St. No. 12-R at 2.) Mr. Floyd also is a professional engineer in several states, including the Commonwealth of Pennsylvania. (PPL Electric St. No. 12-R at 2.)

appear at the component, not near it." (*Id.*) Therefore, Mr. Bobruk's claim that "the 'burnt components' were 'very close' to the connectors is not persuasive." (*Id.* at 16.)

In addition, in their rejoinder testimony, Mr. Floyd and Ms. Dombrowski-Diamond went through, in detail, the allegations in SolarEdge's "PPL Case Review" that formed the basis for Mssrs. Bobruk and Geller's testimony. (*See* PPL Electric St. Nos. 2-RJ at 49-56 and 12-RJ at 8-11.) Both witnesses identified critical flaws with that document and the allegations based thereon. (*See* PPL Electric St. Nos. 2-RJ at 49-56 and 12-RJ at 8-11.) As a threshold matter, Mr. Floyd testified how the "PPL Case Review" is not a properly conducted root cause analysis. (PPL Electric St. No. 12-RJ at 7-8.) Mr. Floyd has performed "[m]ore than 100" root cause analyses in his career. (*Id.* at 7.) As Mr. Floyd explained, "A properly conducted root cause analysis identifies all possible causes of failure and, using scientific and engineering methods, rules out possible caused that could not have caused the failure being investigated." (*Id.* at 7-8.) "The root cause analysis, as described by Mr. Geller, did not follow this protocol." (*Id.* at 8.)

Moreover, Mr. Floyd and Ms. Dombrowski-Diamond went through each of the "cases" listed in the "PPL Case Review," refuted the JSPs' allegations, and noted several omissions and errors. For example, Ms. Dombrowski-Diamond explained how the inverter involved with Case 3456467 "did not have the DER Management device connected, so any failure could not be caused by the DER Management device." (PPL Electric St. No. 2-RJ at 55.) Mr. Floyd and Ms. Dombrowski-Diamond also testified about how PPL Electric's connections cannot reduce the space between the AC terminals and the board, as alleged by Mr. Geller, with Ms. Dombrowski-Diamond explaining:

> PPL Electric uses specific fork connectors to make sure the 5 mm of clearance is not affected by the Company's installation. Moreover, SolarEdge's inverters use ring terminals for the yellow AC capacitor leads. Therefore, it is impossible to reduce the spacing because the

> location for the AC capacitor leads is a permanent fixture on the circuit board. Thus, the Company's use of fork connectors cannot reduce the spacing between the AC terminals and the board.

(*Id*. at 57; *see* PPL Electric St. No. 12-RJ at 12.)

Based on the foregoing, the JSPs' safety-related allegations have no merit. These flawed claims were presented by witnesses lacking credibility and were fully rebutted and refuted by PPL Electric's expert testimony. Accordingly, these allegations should be disregarded entirely.

4. OTHER PARTIES' RECOMMENDATIONS EITHER HAVE BEEN ADOPTED OR SHOULD BE REJECTED

a. OCA'S Recommendations

Originally, in its direct testimony, the OCA recommended that the Commission approve the Second DER Management Plan with certain modifications, namely that the Commission exempt all DERs with a capacity of 200 kW or less from mandatory participation in active management and provide those DERs with the option to participate in active management. (OCA St. 1 at 6.) The OCA also made recommendations for the Company to file a DER Orchestration Plan and provide an evaluation of three different flexible interconnection approaches within 12 months of the Commission's Order in this proceeding.[25] (*Id.* at 6-7.) However, despite PPL Electric making no programmatic changes to its proposal in its rebuttal testimony, the OCA changed its recommendation at the surrebuttal stage and recommended that the Second DER Management Plan be denied. (OCA St. 1SR at 2-3.) The Commission should reject the OCA's recommendation. As explained previously, PPL Electric's Second DER Management Plan will produce significant benefits in excess of its costs, while enabling the Company to improve and

[25] PPL Electric stated in testimony that it is willing to file the DER Orchestration Plan. (PPL Electric St. No. 1-R at 20.) As for the three flexible interconnection approaches noted in OCA's recommendation, the Company already has proposed actively managed interconnections as a flexible interconnection approach, and "PPL Electric's DER Management Pilot Program and the Second DER Management Plan do not prevent either" of the other two approaches "from being implemented." (PPL Electric St. No. 3-R at 2-3.)

maintain the safety, reliability, adequacy, and resiliency of its electric service. PPL Electric also can use its Second DER Management Plan to respond to the significant resource adequacy issues facing the Commonwealth.

Moreover, to the extent that the OCA's initial recommendation of a 200-kW threshold is considered, PPL Electric demonstrated that such a threshold is unwarranted. Specifically, PPL Electric witness Walling explained that a 200-kW threshold raises issues that OCA witness Nelson has not considered or has given insufficient weight, such as the fact that the problems created by DERs are location and circuit-specific and, therefore, the cumulative impact of multiple small DERs on the same circuit can be greater than that of one or a few larger DERs. (PPL Electric St. No. 1-R at 22; PPL Electric St. No. 4-R at 10-11.) PPL Electric witness Wishart also testified that 99% of the DERs representing 51% of the DER capacity on the Company's system are below the OCA's proposed threshold. (PPL Electric St. No. 1-R at 22; PPL Electric St. No. 10-R at 10.) More importantly, if that recommendation were adopted, the majority of the benefits Mr. Wishart calculated for the Second DER Management Plan would be eliminated, including $126,008,484 of benefits for incremental DER hosting capacity. (PPL Electric St. No. 1-R at 22-23; PPL Electric St. No. 10-R at 10.)

In addition, as explained by PPL Electric witness Davis, Mr. Nelson's description of an alleged 200-kW threshold on active DER management in Australia is not correct. (PPL Electric St. No. 1-R at 23; PPL Electric St. No. 3-R at 6-7.) Similarly, his attribution to Mr. Davis of statements regarding size limits on DER management imposed by Ameren Illinois Company ("Ameren Illinois") are also incorrect because Ameren Illinois's experience is simply not comparable to PPL Electric's. (PPL Electric St. No. 1-R at 23; PPL Electric St. No. 3-R at 8-9.) Finally, active management of DERs at or below 200 kW provides substantial value across all the use cases that Mr. Davis analyzed in both his direct and rebuttal testimony. (PPL Electric St. No. 1-R at 23; PPL Electric St. No. 3-R at 9-10.)

Notwithstanding, if the Commission were to give any credence to the OCA's claims, PPL Electric's Second DER Management Plan should not be denied outright. Rather, the Commission should approve the Second DER Management Plan and direct the Company to modify the Plan such that an appropriate threshold for determining when DERs must participate in active management or have the option to participate in active management.[26]

b. OSBA's Recommendations

The Commission should deny the OSBA's recommendations regarding the Second DER Management Plan. As explained more thoroughly in Section V.B, above, the Plan should be approved without modification. The OSBA recommends that the Pilot Program be extended or paused until a cost benefit framework to analyze the costs and benefits of the Second DER Management Plan is established and approved by the Commission. Alternatively, OSBA recommends that the term of the DER Management Plan be limited to three years and for PPL Electric to be required to file reports on the costs and benefits of the Second DER Management Plan annually with the Commission. (OSBA St. No. 1-SR at 15.)

None of these recommendations should be granted and PPL Electric's Second DER Management Plan should be approved as proposed. As explained more fully in Section V.C, above, the Company's cost-benefit analysis is reliable, robust, and transparent, and clearly demonstrates that PPL Electric's proposal will be cost-effective. Accordingly, there is no need to

[26] Even JSP witness White stated that "DER management and flexible interconnection only become necessary when the distribution grid is highly saturated with DER." (JSP St. No. 1 at 10.) At the hearing, she explained that the circuit would be highly saturated with solar DERs if they equaled 100% of the "minimum daytime load." (Tr. 470-72.)

extend or freeze the DER Management Pilot Program to develop a cost benefit framework, as recommended by OSBA. (*Id*. at 14-15.)

Additionally, Commission should not limit the Second DER Management Plan's term to three years. (*Id*. at 15.) PPL Electric has established that its Second DER Management Plan is reasonable and in the public interest, and if modifications to the Plan are required in the future, the Company can file a petition with the Commission and propose those modifications. (*See* Section V.B.) Limiting the Second DER Management Plan to three years would force PPL Electric to expend significant time and resources in the next couple years to develop and litigate a Third DER Management Plan. Also, the Company has already expressed its willingness to, as recommended by OCA witness Nelson, develop and file a DER Orchestration Plan within 12 months of the Commission's final order in this proceeding. (*See* PPL Electric St. No. 1-R at 20.) Thus, a three-year term for the Second DER Management Plan would likely result in the overlap of a Third DER Management Plan proceeding and DER Orchestration Plan proceeding, which would constrain the available time and resources of the Company and other parties. (PPL Electric Exhibit No. 1-RJ at 7-8.)

Therefore, the Commission should reject the OSBA's recommendations.

c. SEF's Recommendations

The Commission should deny the SEF's recommendations regarding the Second DER Management Plan. For the reasons explained in Section V.B, above, the Plan should be approved without modification. SEF recommends that the Commission deny the Second DER Management Plan and instead continue the Pilot Program "with the goal of gathering and analyzing more data" related to the costs and benefits of DER management. (SEF St. No. 1-R at 1, 5.) As explained in Section V.C, above, the Company's cost-benefit analysis is reliable and clearly demonstrates that PPL Electric's proposal will be cost-effective. Accordingly, there is no need to extend or freeze the DER Management Pilot Program to develop a cost benefit framework. As such, the Commission should deny SEF's recommendations.

d. JSPs' Recommendations

The Commission also should reject the JSPs' recommendation to deny the Second DER Management Plan. (*See, e.g.*, JSP St. No. 1-SR at 23; JSP St. No. 2-SR at 11; JSP St. No. 4-SR at 33.) PPL Electric's proposal is well-designed to tackle the safety, reliability, adequacy, and resiliency challenges presented by DERs now and into the future, address climate change and sustainability objectives by facilitating and encouraging the increase development of DERs, and respond to the significant resource adequacy issues facing PPL Electric and the Commonwealth at large.

Furthermore, completing making participation in the Plan voluntary, as some JSP witnesses recommend,[27] would severely inhibit the Plan's benefits. "The problems created by DER penetration on the PPL Electric distribution system cannot be addressed by relying solely on voluntary compliance with an opt-in arrangement, whether or not pricing incentives are available to try to change DER behavior." (PPL Electric St. No. 1-R at 27.) To explain that point further, should there be a feeder where extensive DER penetration causes a system problem, and none of the DER customers on that feeder have opted-in to a management program, the Company cannot rely solely on an opt-in arrangement to solve system issues created by DERs. (PPL Electric St. No. 11-RJ at 2.) In that instance, absent any other alternative, the Company would need to continue investing to serve the single maximum peak, whether due to load or generation, whether that peak occurs once for 15 minutes a year or 60 times. (*Id*. at 2.)

The Commission also should reject the JSPs' recommendation to initiate a statewide

[27] JSP St. No. 1 at 9. 30-32.

proceeding on flexible interconnections.[28] PPL Electric believes there could be value in initiating a Pennsylvania-wide proceeding focused on generic issues, which could provide guidance to other electric utilities contemplating following PPL Electric's lead to proactively address issues of DER integration. (PPL Electric St. No. 1-R at 44.) However, PPL Electric is now much farther down the road than the other electric utilities in the Commonwealth, and approval of the Second DER Management Plan, therefore, should not be contingent on the Commission's opening or completing a statewide proceeding. (*Id*.) Adding that contingency here would only: (1) delay the substantial benefits that the Second DER Management Plan can produce; and (2) prevent PPL Electric from addressing the issues and risks posed by existing and future DER interconnections, which the DER Management Pilot Program and Second DER Management Plan were designed to remedy. (*Id*. at 44-45.) Also, generic statewide proceedings have been used as justifications to delay making important decisions about matters that need to be addressed in a far more timely fashion. (*Id*. at 45.)

Moreover, the Company's active management and monitoring of DERs should not be contingent on the provision of additional compensation to participating DERs. PPL Electric's Second DER Management Plan, like the DER Management Pilot Program, is designed primarily to manage the reactive power output of the DERs. (*Id*. at 25.) Active (real) power generation by DERs is not materially affected by the Company's active management and, while active DER management can affect the production or absorption of reactive power, there is no active market that can or would compensate DER for reactive power regulation. (*Id*.) Any active management of a DER's active (real) power generation would only be with customer consent. (*Id*. at 25-26.) DERs also share in the benefits of the Second DER Management Plan because the investments

[28] JSP St. No. 1 at 9, 11.

and other costs avoided by active DER management reduce the revenue requirement for distribution service that otherwise would be borne by all customers – DER and non-DER alike. (*Id*. at 26.) Additionally, the JSPs failed to offer any workable proposal for a compensation mechanism, and when pressed on their preferred compensation schemes, their witnesses' responses did not align and, in fact, were inconsistent. (*Id*.)

Finally, the Commission should reject certain JSP witnesses' recommendations that PPL Electric cease its installation of DER Management devices on SolarEdge inverters and/or remove its DER Management devices from SolarEdge inverters in the field. (JSP St. No. 7-SR at 24; JSP St. No. 13-SR at 15.) These recommendations were based on the JSPs' allegations that PPL Electric's DER Management devices have caused or contributed to alleged thermal events in 5 SolarEdge inverters. As explained in this Brief, these allegations have no merit. Also, the removal of PPL Electric's DER Management devices would force the Company to incur approximately $887,000 in expenses. (JSP Exhibit JSP-JB-22SR.) To the extent the Commission gives any credence to the JSPs' allegations, the remedy is not to deny the Second DER Management Plan or cease the installation of DER Management devices on SolarEdge inverters. Rather, it is to direct PPL Electric to use a different device, method of installation, or mode of communication (such as cloud-based communications), similar to how PECO Energy Company changed the type of smart meters it was deploying under its Commission-approved Smart Meter Plan after certain issues arose with the ones it was using.[29]

Based on the foregoing, the Commission should deny the JSPs' recommendations and approve the Company's Second DER Management Plan as filed.

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[29] *See Frompovich v. PECO Energy Co.*, Docket No. C-2015-2474602 (Order entered May 3, 2018) (citing *Petition of PECO Energy Company for Approval of its Smart Meter Technology Procurement and Installation Plan*, Docket No. M-2009-2123944 (Recommended Decision issued July 12, 2013)).

VI. CONCLUSION

WHEREFORE, PPL Electric Utilities Corporation respectfully requests that the Pennsylvania Public Utility Commission issue an Order approving the Company's Second DER Management Plan, the Company's proposed tariff modifications, and related authorizations and grant any other approvals or authorizations that are necessary to implement PPL Electric's Second DER Management Plan.

Respectfully submitted,

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Dated: March 25, 2025

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Appendix A – Proposed Findings of Fact

1. In 2019, the Company requested Commission approval to implement its First DER Management Plan, which was designed to produce cost-effective benefits for customers with and without DERs, the DER market, and the Commonwealth as a whole. (PPL Electric Exh. 1 at 2.)

2. Under that proposal, customers applying to interconnect new DERs to PPL Electric's distribution system would be required to: (1) use Company-approved smart inverters that are compliant with IEEE 1547-2018 and then-forthcoming revisions to UL Standard 1741; and (2) install DER Management devices that enable PPL Electric to monitor and actively manage DERs. (PPL Electric Exh. 1 at 2.)

3. On December 17, 2020, the Commission approved a settlement reached by all the active parties in the First DER Management Plan proceeding. (PPL Electric Exh. 1 at 12.)

4. Effective January 1, 2021, new DERs interconnecting with the Company's distribution system were required to have smart inverters installed that meet: (1) UL 1741 SA; and (2) the Company's testing for the communications requirements under IEEE 1547-2018. (PPL Electric Exh. 1 at 12.)

5. These interim requirements were used by PPL Electric until January 1, 2023, at which point, the Company transitioned to requiring new DERs to have smart inverters installed that meet IEEE 1547-2018 and have been certified with IEEE 1547.1 / UL 1741 SB. (PPL Electric Exh. 1 at 12-13.)

6. The Pilot Program was designed to test and evaluate: (1) the costs and benefits to distribution system operation and design of monitoring DERs through devices connected to inverters as compared to maintaining distribution system status visibility through other means (e.g., automated meter reading equipment, ADMS systems, modeling); and (2) the costs and

benefits to distribution system operation of active management of DERs as compared to the benefits available through the use of inverter autonomous grid support functions. (PPL Electric Exh. 1 at 13.)

7. During the Pilot Program, the Company is authorized to purchase and install DER Management devices on all new DERs with inverters up to an annual limit of 3,000 DER Management devices. (PPL Electric Exh. 1 at 13.)

8. DERs installed above the annual limit are not part of the Pilot Program. (PPL Electric Exh. 1 at 13.)

9. All DER Management devices are owned, operated, and maintained by the Company at no direct cost to interconnecting customers. (PPL Electric Exh. 1 at 13.)

10. The annual cap on the number of DER Management devices is not an annual cap on the number of new DERs that can be interconnected with the Company's distribution system. (PPL Electric Exh. 1 at 13.)

11. The Pilot Program began on January 1, 2021, and was set to end on March 21, 2025. (PPL Electric Exh. 1 at 13.)

12. PPL Electric's Second DER Management Plan will enable the Company to continue to integrate, monitor, and manage DER resources throughout PPL Electric's service territory. (PPL Electric St. No. 1 at 22.)

13. As proposed, PPL Electric's Second DER Management Plan will require that all customer-owned and third party-owned, inverter-based DER system installations be equipped with DER Management devices so that the Company can monitor and manage the DERs. (PPL Electric St. No. 1 at 22.)

14. The Second DER Management Plan would expand on the Pilot Program by authorizing PPL Electric to: (1) actively monitor and manage the smart inverter settings on all DERs that are in the Pilot Program's control groups; (2) utilize the Volt/Watt functionality, with customer consent, when the interconnecting DER could create a localized high voltage issue on the distribution system at the time of interconnection, which would not be resolved by the Volt/VAR or Constant Power Factor grid support functions; and (3) make the Pilot Program permanent. (PPL Electric St. No. 1 at 22.)

15. The Company proposes to install DER Management devices on: (1) solar photovoltaic systems interconnected before the Pilot Program started on January 1, 2021; and (2) inverter-based DERs interconnected after the Pilot Program started without DER Management devices installed on them. (PPL Electric St. No. 1 at 23.)

16. As a regulated EDC, PPL Electric must provide safe, reliable, adequate, and reasonable service as required under the Public Utility Code. *See* 66 Pa. C.S. § 1501.

17. The deployment of DERs continue to present challenges to the Company complying with its statutory duty to provide safe, reliable, adequate, and reasonable service. (PPL Electric St. No. 1 at 8-10.)

18. Electric transmission and distribution systems in Pennsylvania and the United States continue to undergo significant changes. (PPL Electric St. No. 1 at 8.)

19. The increasing deployment and use of DERs, such as solar panels and batteries, have upended the traditional electric grid model of large-scale generation located at significant distances from customers. (PPL Electric St. No. 1 at 8-9.)

20. By allowing customers to both consume and produce electricity at what were traditionally points of delivery (*i.e.*, at the distribution system's "edge"), DERs force the electric

distribution system to perform in a way for which it was not originally designed and, as a result, place an increasing stress on the grid. (PPL Electric St. No. 1 at 9.)

21. DERs pose numerous challenges to safe and reliable operation of electric distribution systems and to the electrical grid at large. (PPL Electric St. No. 4 at 15.)

22. Without active management and monitoring of DERs, distribution system operators are limited in their ability to respond to these changing dynamics and the issues created by DERs. (*See* PPL Electric St. No. 4 at 19-22.)

23. Traditionally, distribution operators did not have to worry about balancing demand and generation because the distribution grid had very little generation connected to it. (PPL Electric St. No. 1 at 9.)

24. As the penetration level of DERs increased, the classic model of distribution systems was not well-equipped to handle the simultaneous balancing of demand and generation on the distribution system. (PPL Electric St. No. 1 at 9.)

25. As distribution systems have become increasingly similar to transmission, *i.e.*, a mix of demand and generation, the need to balance generation and demand becomes vitally important. (PPL Electric St. No. 1 at 9.)

26. Such balancing cannot be accomplished without the ability to monitor and manage generation assets on the grid. (PPL Electric St. No. 1 at 9.)

27. By negatively affecting the voltage on the electric distribution system, solar and other intermittent resources can result in delayed interconnection or the need for potentially costly distribution system reinforcements before additional DERs can be installed. (PPL Electric St. No. 1 at 10.)

28. Without the ability to directly communicate with and manage customer DERs to leverage grid support functionality, the amount of intermittent generation that can be interconnected on the distribution circuits must be limited to maintain system stability and reliability. (PPL Electric St. No. 1 at 10.)

29. Without ability to monitor and manage the DERs, the reliability, safety, and efficiency of electric service would be placed at increased risk with each new DER interconnected to the distribution system. (PPL Electric St. No. 1 at 10.)

30. Even with existing levels of DER penetration, PPL Electric's distribution system can experience safety, reliability, adequacy, and resiliency issues due to DERs. (*See* PPL Electric St. Nos. 8 at 11, 16-18; 8-R at 2-3, 7-8, 11, 18; and 8-RJ at 2-5.)

31. Dr. Karen Miu, a Professor of Electric and Computer Engineering at Drexel University, conducted multiple studies of PPL Electric's distribution circuits to evaluate the impacts of DERs on the Company's distribution system. (*See* PPL Electric St. Nos. 8, 8-R, and 8-RJ.)

32. Specifically, as the principal investigator of the Drexel University team for two Department of Energy projects led by PPL Electric, Dr. Miu performed detailed simulations of several actual PPL Electric distribution circuits. (PPL Electric St. No. 8 at 7.)

33. Dr. Miu found that even the then-existing DER levels measurably impacted voltage power quality at various individual nodes throughout the distribution system itself" and that "DER injections are non-uniform across electrical phases. (PPL Electric St. No. 8 at 11.) C

34. Core assumptions on balanced behavior of injections made in bulk power transmission systems and their energy management systems cannot capture the physical reality of DER installations at the distribution level." (PPL Electric St. No. 8 at 11.)

35. As DER adoption is expected to increase, capturing the physical reality of DER installations at the distribution level is fundamental to determining safe control actions, especially in the case of electric service restoration in emergency circumstances to the public and to distribution personnel. (PPL Electric St. No. 8 at 11.)

36. Under normal operating conditions, voltage power quality with respect to voltage levels and voltage balance are critical to energy efficiency of the power distribution system and to equipment safety controls of both utility-owned and customer owned devices. (PPL Electric St. No. 8 at 11.)

37. Dr. Miu performed detailed simulations with revised system conditions in 2024 and presented her findings in her direct and rebuttal testimony. (PPL Electric St. No. 8 at 12; PPL Electric St. No. 8-R at 4.)

38. Dr. Miu explained how additional simulations consistently demonstrated that DER impacts on a distribution system change with the type of DER installations, their locations, and the system operating conditions. (PPL Electric St. No. 8 at 12-14.)

39. The analyses performed at summer peak and winter peak loading consistently showed that DERs increased the number of overvoltage violations on the distribution system as compared to the same system at the same loading without DER. (PPL Electric St. No. 8at 13.)

40. Additional studies showed that 42 photovoltaic installations connected to the distribution circuit reduced the substation output real power by 8.67% and 8.45% of the summer and winter peak, respectively. (PPL Electric St. No. 8-R at 5.)

41. Compared to the circuit without DERs, the circuit with DER installations has an approximately 1% increase in power system losses in both cases and, for winter peak loading, 353

overvoltage violations compared to 0 overvoltage violations with no DERs. (PPL Electric St. No. 8-R at 5-6.)

42. Voltage impacts are not limited to the locations of the DERs on the distribution circuit. PPL Electric St. No. 8-R at 11.)

43. A consistent observation is the increase in voltages at nodes (electrical points where customers and other devices, such as capacitors, interconnect to the circuit) both at and remote to the DERs. (PPL Electric St. No. 8-R at 11.)

44. The installation of individually owned and operated DERs directly impacts voltages at other customer locations. (PPL Electric St. No. 8-R at 11.)

45. To date, PPL Electric's DER Management Pilot Program has mitigated over 600,000 voltage violations through active management of DERs. (PPL Electric St. No. 1 at 13; Tr. 316.)

46. Actively managing the power factor setpoint on the inverters for the 12 DERs on phase A of the distribution circuit consistently removed the overvoltage violations, up to 46 locations, with similar observations were made for the winter peak loading conditions. (PPL Electric St. No. 8 at 14.)

47. Additional studies conducted by Dr. Miu on a PPL Electric distribution circuit, showed that at peak loading conditions, all of the system overvoltages can be removed through active management of DERs, which autonomous settings could not accomplish. (PPL Electric St. No. 8-R at 8.)

48. The studies run by Dr. Miu demonstrate the limitations of relying on autonomous settings to resolve voltage violations, as other parties in this proceeding have suggested. (*See* PPL Electric St. No. 8-R at 2, 7-8; PPL Electric St. No. 8-RJ at 4-6.)

49. Autonomous power factor control stops when its local voltage is satisfied." (PPL Electric St. No. 8-R at 13.)

50. Utility active management can enact a potentially larger amount of power management than autonomous functions. (PPL Electric St. No. 8-R at 13.)

51. Active management removed a much larger number of overvoltages than autonomous settings and, in fact, removed all system overvoltage violations in the scenario presented in the last row of Table 7 of PPL Electric Exhibit KM-1R (HIGHLY CONFIDENTIAL). (PPL Electric St. No. 8-R at 13; *see also* PPL Electric Exhibit KM-4 (HIGHLY CONFIDENTIAL)).

52. Dr. Miu's studies have shown that active management of the DERs allows for targeted actions, such as appropriate phase and location selection, to fix the problems that the DERs themselves have created. (PPL Electric St. No. 8-R at 11.)

53. PPL Electric's ability to actively manage DER power factors can significantly reduce the frequency, duration, and severity of customer voltage violations. (PPL Electric St. No. 3 at 65.)

54. DER power factor setpoint adjustments performed by system operators and the ADMS/DERMS can reduce the number, frequency, and duration of voltage violations. (PPL Electric St. No. 3 at 48.)

55. Those reductions decrease the number of customers who contact PPL Electric about voltage violations and decrease the number of investigations performed by the reliability engineering team and the number of visits to customer locations by PPL Electric (commonly referred to as "truck rolls"). (PPL Electric St. No. 3 at 48.)

56. Within the Program Year 2 Annual Report, PPL Electric identified 23,272 customers that had a voltage violation resolved during the same time interval as a DER power factor control event through the end of Program Year 2 in March 2024 and could have resulted in a truck roll. (PPL Electric St. No. 3 at 48.)

57. Even under conservative assumptions, PPL Electric can significantly reduce its O&M expenditures by resolving those voltage violations without performing truck rolls. (PPL Electric St. No. 10-RJ at 4.)

58. Reducing the frequency, duration, and severity of voltage violations can help reduce the need to make system modifications or investments in voltage support equipment. (PPL Electric St. No. 3 at 48.)

59. The Company's proposed Second DER Management Plan will provide other benefits to safety, reliability, and resiliency. (*See, e.g.*, PPL Electric St. No. 4 at 15-18.)

60. PPL Electric witness Walling identified 15 types of DER impacts in his direct testimony and testified that 11 can potentially be completely eliminated or substantially mitigated by application of DER monitoring and management by the utility. (PPL Electric St. No. 4 at 15-19.)

61. There is a substantial uncertainty regarding the reliability of many DER island detection schemes when applied in practical circumstances, despite DERs being required by IEEE 1547 to cease energization of disconnected distribution circuits (islanding). (PPL Electric St. No. 4 at 16.)

62. Continued energization of an 'islanded' distribution feeder or system by DER can pose a significant risk to utility workers and the public. (PPL Electric St. No. 4 at 16.)

63. The the on/off functionality provided by the Second DER Management Plan could be an important safety feature, as utility management of DER operating status can be applied as a backup to DER island detection capabilities, increasing worker and public safety." (PPL Electric St. No. 4 at 21; PPL Electric St. No. 4-R at 12.)

64. The continuous monitoring and archiving of DER output data avoids load masking. (PPL Electric St. No. 4 at 21.)

65. This leads to more reliable circuit reconfiguration to restore service following outages and to more accurate forecasting of both DER output and customer load demand. (PPL Electric St. No. 4 at 21.)

66. With more accurate forecasts, PPL Electric can better plan and reliably operate its distribution system. (PPL Electric St. No. 4 at 21.)

67. Additionally, PPL Electric can improve utility worker safety if DERs' protective trip functions are made more sensitive during planned live-line work on a circuit. (PPL Electric St. No. 4 at 21.)

68. Temporary changes of fixed trip settings on DERs not incorporated into a management system are infeasible due to the typically large number of individual DER units involved. (PPL Electric St. No. 4 at 21-22.)

69. DER management systems, such as PPL Electric's Second DER Management Plan, allow for the relatively easy implementation of temporary settings as necessary. (PPL Electric St. No. 4 at 22.)

70. PPL Electric also has on numerous occasions alerted customers that their systems were either turned off or not generating. (PPL Electric St. No. 2 at 15.)

71. When on site, the Company also has supported customers by informing them that their backup battery was not connected properly and instructed them to reach out to their installers to have the situation fixed. (PPL Electric St. No. 2 at 15.)

72. In other instances, the Company has alerted customers that their inverters were faulty and needed replacement due to hardware issues. (PPL Electric St. No. 2 at 15.)

73. Electric power generation emits approximately 25% of total greenhouse gases ("GHG") and combined with the transportation sector, accounts for over 50%. (PPL Electric St. No. 7 at 6.)

74. Rooftop and utility solar photovoltaics ("PV") are significantly less carbon intensive than natural gas and coal. (PPL Electric St. No. 7 at 6.)

75. Increased customer investment in solar and energy storage solutions has the potential to significantly reduce the evening peak, further extending the benefits of solar. (PPL Electric St. No. 7 at 7.)

76. PPL Electric's First DER Management Plan has helped encourage and facilitate renewable energy development and combat climate change. (PPL Electric St. No. 7 at 8.)

77. Over the course of the DER Management Pilot Program, PPL Electric has seen large increases in the number of DERs deployed, growing from 3,493 in 2021 to 6,799 in 2023. (PPL Electric St. No. 2-R at 65.)

78. By deferring capital investments, generating and non-generating customers will see lower bill increases, and by avoiding DER blamed bill increases, financial-driven pushbacks against solar are kept at bay. (PPL Electric St. No. 7 at 8.)

79. These deferred capital improvement projects would take time to complete and also generate carbon emissions. (PPL Electric St. No. 7 at 9.)

80. As customers wait for these projects to complete, they are not helping the planet by generating renewable energy. (PPL Electric St. No. 7 at 9.)

81. Large financial decisions take a lot of research and time; if customers are forced to wait until a capital project is completed, it may discourage them from investing in solar. (PPL Electric St. No. 7 at 9.)

82. Under the Second DER Management Plan, the 3,000 DER system cap per year is removed. (PPL Electric St. No. 7 at 9.)

83. In 2023, the 3,000 DER system cap was exceeded in September. (PPL Electric St. No. 7 at 9.)

84. If the cap is not removed soon, more than half the DERs each year and soon after that, throughout the system, will not be monitored or manageable. (PPL Electric St. No. 7 at 9.)

85. The success of the Second DER Management Plan will be diminished; customers will have higher bills due to investment in capital projects that will be necessary to mitigate DER issues and suffer increased emissions and costs due to truck rolls responding to power quality issues. (PPL Electric St. No. 7 at 9.)

86. The installation cost for DER customers will increase because customers will need to wait for capital projects to complete before moving forward with solar investments, and some may not be able to proceed due to system limitations because of a lack of system visibility and hosting capacity. (PPL Electric St. No. 7 at 10-11.)

87. The Second DER Management Plan introduces the capability to manage real power output with customer consent. (PPL Electric St. No. 7 at 11; PPL Electric St. No. 1 at 11.)

88. Because grid planners must plan for the worst case when evaluating a proposed DER interconnection, many EDCs plan the system to be able to handle all the solar systems on a

feeder at nameplate capacity and capital investments to improve the system are made accordingly. (PPL Electric St. No. 7 at 11.)

89. PPL Electric already leverages the technologies deployed as part of the First DER Management Plan to use actual generation data in planning. (PPL Electric St. No. 7 at 11.)

90. This has enabled an additional 29 MW of rooftop solar distribution grid availability as of March 21, 2024. (PPL Electric St. No. 7 at 11.)

91. PPL Electric's Second DER Management Plan would increase the potential MW even more significantly by managing real power output, enabling more people to invest in solar. (PPL Electric St. No. 7 at 11.)

92. By reducing customers' upfront interconnection costs in exchange for the ability to curtail a few hours each year, PPL Electric is further encouraging new solar installations. (PPL Electric St. No. 7 at 12.)

93. Even with curtailment, the overall amount of solar energy is increased because additional MWs of DERs can reliably connect to the system with confidence, reliability can be maintained, and capital investment by PPL Electric can be avoided. (PPL Electric St. No. 7 at 12.)

94. Since the increased DERs will be generating all but a small percentage of the time each year, climate change will be further mitigated the great majority of the time. (PPL Electric St. No. 7 at 12.)

95. After over two decades of declining or stagnant growth in electric demand, electric utilities across the country, including PPL Electric, are now dealing with surging growth in electric demand, fueled principally by data centers, electric vehicles, and electrification. (PPL Electric St. No. 6-R at 6-7.)

96. The United States is returning to a period of rising electricity demand, with total energy demand potentially growing ~15-20% in the next decade. (PPL Electric St. No. 6-R at 7.)

97. Regulators, electric generators, electric transmission companies, and electric distribution utilities all face serious challenges due to this significant growth in electric demand. (PPL Electric St. No. 6-R at 8.)

98. Chief among those challenges is ensuring that there is enough transmission and generation capacity to meet that demand now and in the future. (PPL Electric St. No. 6-R at 8.)

99. As the agency tasked with regulating EDCs' electric service and facilities, the Commission has rightly recognized the role it must play in responding to these issues. (*See* PPL Electric St. No. 6-R at 8.)

100. Consistent with these charges, the Commission hosted a technical conference regarding resource adequacy on November 25, 2024, where presenters stressed the importance of pursuing many options to increase the transmission and generation capacity in Pennsylvania. (PPL Electric St. No. 6-R at 8.)

101. At the distribution level, PPL Electric's Second DER Management Plan can increase the hosting capacity on distribution circuits, which enables customers to interconnect more DERs and larger-sized DERs on distribution circuits without requiring distribution system upgrades. (PPL Electric St. No. 6-R at 8.)

102. By bringing additional and larger DERs online, PPL Electric can reduce the demand on its distribution circuits and, by extension, the demand they are pulling from the transmission system. (PPL Electric St. No. 6-R at 8.)

103. The situational awareness and system-wide connectivity provided by the Second DER Management Plan would help de-stress the transmission system and better focus and enhance

investments in transmission and generation infrastructure to meet the increased electric demand. (PPL Electric St. No. 6-R at 8.)

104. Without active DER management and monitoring, the Commonwealth, Commission, and PPL Electric all will lose a vital tool in combatting these resource adequacy challenges. (PPL Electric St. No. 6-R at 8.)

105. Data collection alone cannot provide the situational awareness and system-wide connectivity needed to meet these resource adequacy challenges and help de-stress the transmission system. (PPL Electric St. No. 6-R at 9.)

106. Achieving the level of situational awareness and system-wide connectivity that is necessary requires a robust data strategy and a cohesive framework that integrates, and responds to, insights from across the utility's operations. (PPL Electric St. No. 6-R at 9.)

107. EDCs must have visibility of, and the ability to manage, the devices that are connected to their systems, for a fully connected platform for system planning and operations would incorporate a broad range of utility insights: customer engagement data, insights for customer programs, non-wires alternatives, capital investment strategies, asset health metrics, reliability indicators, geographical variables, and operational parameters, such as age, usage, capacity, and voltage of grid components. (PPL Electric St. No. 6-R at 9.)

108. By linking edge data to central systems, utilities can see beyond isolated metrics and into the broader context that influences grid health. (PPL Electric St. No. 6-R at 9.)

109. For example, a customer's individual energy usage data could inform broader load forecasts and reliability metrics, while real-time voltage data at the edge could highlight where additional capacity may be needed before issues arise. (PPL Electric St. No. 6-R at 9.)

110. The Company's capital and O&M planning can become far more strategic with data from the edge because knowing where non-wires alternatives (such as energy storage or demand response) can defer infrastructure upgrades in certain locations will give the Company the flexibility to allocate resources more efficiently and effectively. (PPL Electric St. No. 6-R at 9.)

111. PPL Electric retained Concentric Energy Advisors, Inc. ("Concentric") to conduct a complete and detailed cost-benefit analysis of the costs and benefits of the Second DER Management Plan. (PPL Electric St. No. 1-R at 10.)

112. The cost-benefit model developed by Concentric offers a transparent analysis that demonstrates that the benefits of PPL Electric's Second DER Management Plan will exceed its cost. (PPL Electric St. No. 10-R at 4.)

113. The model found that due to the relatively low cost of the DER Management devices, the Plan will provide a net benefit to all customers, will lower overall system costs, and will provide critical system management tools at a time when DERs will experience rapid growth in the Company's service territory. (PPL Electric St. No. 10-R at 4.)

114. Concentric included three categories of costs in its analysis: (1) the cost of the DER Management devices; (2) the ongoing maintenance of those devices; and (3) other costs that may be associated with the program. (PPL Electric St. No. 10-R at 5.)

115. Concentric's analysis considered three categories of benefits solely related to the active management of DERs. (PPL Electric St. No. 10-R at 5-6.)

116. The first category of benefits is incremental hosting capacity, which will allow a greater number of customers to install DERs in the future, and includes: (1) avoided capital investments in the distribution system that would have been needed to create an equivalent amount

of hosting capacity on the system; and (2) future avoided wholesale energy purchases. (PPL Electric St. No. 10-R at 5-6.)

117. The second category of benefits stems from improved distribution voltage that results from the Company's active management program. (PPL Electric St. No. 10-R at 6.)

118. The largest of these benefits is associated with avoided O&M expenses that result from reduced voltage violations on the system. (PPL Electric St. No. 10-R at 6.)

119. The model also includes an estimate of improved line losses that are expected to result from the Company's ability to actively manage smart inverters. (PPL Electric St. No. 10-R at 6.)

120. The model includes an estimate of the potential benefits of conservation voltage reduction. (PPL Electric St. No. 10-R at 6.)

121. Although the Commission has not approved the use of DER Management devices for conservation voltage reduction, Concentric determined that it should still be considered a potential benefit of the program because it is a function enabled through the active management of DERs. (PPL Electric St. No. 10-R at 6.)

122. Of the $147 million in total benefits estimated, conservation voltage reduction accounted for only $7.9 million and was clearly shown as a separate line item, so that the Commission or other stakeholders could assess the magnitude and the role it plays in the overall cost effectiveness of the Company's proposal. (PPL Electric St. No. 10-RJ at 12.)

123. Based solely on the active management of DERs under the proposed Plan, Concentric determined that between 2025 and 2030, active management would produce $21.4 in net benefits, achieving a cost-benefit ratio of 1.8. (PPL Electric St. No. 10-R at 7, Table SSW-1.)

124. Concentric projected that the total costs related to active management in that period will total $26.5 million, with active management producing more than $48 million in benefits, including approximately $7.9 million in reduced O&M expense, $13.4 million in avoided distribution infrastructure investments, $18.7 million in energy reduction, and $7.8 million in conservation voltage reduction. (PPL Electric St. No. 10-R at 7, Table SWW-1.)

125. Concentric's modeling further projected the benefits attributable to the detailed monitoring of the Company's distribution system enabled by DER Management devices. (PPL Electric St. No. 10-R at 8-10.)

126. Accounting for the monitoring capabilities created by the installation of DER Management devices results in net benefits that are even greater, growing to approximately $65.5 million on a net present value basis, with the monitoring capabilities alone producing an additional $98.6 million in total benefits. (PPL Electric St. No. 10-R at 8, Table SSW-2.)

127. Company also produced a sensitivity analysis that stress-tested the findings of the cost-benefit analysis under various scenarios, including eliminating all benefits except incremental hosting capacity, eliminating half of the incremental hosting capacity, increasing the costs associated with DER Management devices, their maintenance, and the administration of the Plan, as well as lower DER interconnection forecast. (PPL Electric St. No. 10-R at 24, Table SWW-7.)

128. None of the sensitivities conducted resulted in overall negative net benefits for the Second DER Management Plan, demonstrating that even under unfavorable conditions, the Plan is still projected to achieve benefits in excess of its cost. (PPL Electric St. No. 10-R at 23.)

129. The results of the cost-benefit analysis show that the financial benefits associated with installing DER Management devices to be used for detailed system monitoring and active management significantly outweigh the associated costs. (PPL Electric St. No. 10-R at 24.)

130. Unlike the forward looking cost-benefit analysis performed for the Second DER Management Plan, the Company's evaluations of the costs and benefits of the Pilot Program were retroactive and, therefore, did not account for the ongoing benefits that will continue to be provided by the DER Management devices already installed. (PPL Electric St. No. 10-R at 29.)

131. Through the course of the Pilot Program the Company identified many tangible benefits achieved through active management and monitoring of DERs. (*See* PPL Electric St. No. 3 at 13-56.)

132. In line with the Settlement reached in the First DER Management Plan proceeding, the costs and benefits of the Pilot Program were analyzed in the context of specific use cases designed to capture the benefits realized using the new capabilities enabled by the Pilot Program. (PPL Electric St. No. 3 at 11.)

133. Identifying, tracking, and analyzing use case opportunities allowed the Company to evaluate the efficacy and efficiency of the Pilot Program while ensuring that the overall value of the new capabilities are maximized. (PPL Electric St. No. 3 at 11.)

134. The Pilot Program demonstrated that the real power monitoring enabled by DER Management devices improves the accuracy of load and capacity calculations and produces substantial benefits. (PPL Electric St. No. 3 at 17.)

135. The use of data from real power monitoring during the Pilot Program improved the accuracy of distribution system planning models and increased the system-wide hosting capacity by approximately 18 MW when compared to using the DER nameplate data instead. (PPL Electric St. No. 3 at 19.)

136. The Pilot Program also demonstrated that monitoring real power production can be used to detect hidden load, which helps ensure that switching operations do not result in equipment

overloads or any potential equipment damage and enable operators and the ADMS to make informed decisions to avoid overload conditions during restoration efforts. (PPL Electric St. No. 3 at 21.)

137. Real power monitoring can also defer upgrades on circuits with relatively high penetrations of DER that are forecasted to experience load growth and subsequent capacity constraints. (PPL Electric St. No. 3 at 13, 17; HIGHLY CONFIDENTIAL PPL Electric Exhibit CD-5.)

138. The data gathered improves the accuracy of load and capacity calculations, resulting in more timely investments in capacity where it is needed. Absent this data, such investments would be more likely to occur sooner than necessary. (PPL Electric St. No. 3 at 17.)

139. DER power factor setpoint adjustments performed by system operators and the ADMS/DERMS can reduce the number, frequency, and duration of voltage violations. (PPL Electric St. No. 3 at 48.)

140. This reduces the number of customers who contact PPL Electric about voltage violations and, subsequently, reduces the number of investigations performed by the reliability engineering team and the number of visits to customer locations by PPL Electric (commonly referred to as “truck rolls”). (PPL Electric St. No. 3 at 48.)

141. Within the Program Year 2 Annual Report, PPL Electric identified 23,272 customers that had a voltage violation resolved during the same time interval as a DER power factor control event through the end of Program Year 2 in March 2024 and could have resulted in a truck roll. (PPL Electric St. No. 3 at 48.)

142. If each such customer had contacted PPL Electric about their voltage issue, it would have resulted in approximately $13,666,306 of operation and maintenance expense for truck rolls. (PPL Electric St. No. 3 at 48.)

143. The Pilot Program identified opportunities for lower interconnection costs on the Company's distribution system, including a case study that found that the management of the real power limit function would enable a proposed 10 MW solar facility to avoid approximately $1.48 million in system upgrades that would otherwise be necessary as a result of a conductor overload. (PPL Electric St. No. 3 at 61.)

144. Also within the Program Year 2 Annual Report, PPL Electric identified two studies related to planned switching that indicate that active management of DER power factor setpoints would have been able to avoid $38,000 of investment in capacitor banks to support planned switching. (*Id*.; HIGHLY CONFIDENTIAL PPL Electric Exhibits CD-9 and Exhibit CD-10.)

145. DER management and monitoring can improve the accuracy of planning models, which improves the accuracy of the studies that utilize those models, including load interconnection studies and DER interconnection studies (PPL Electric St. No. 3 at 15).

146. DER management and monitoring can improve the accuracy of load and capacity calculations, resulting in more timely investments in capacity where it is needed (PPL Electric St. No. 3 at 17).

147. DER management and monitoring can improve the accuracy of operational models to increase the accuracy of voltage calculation, which helps PPL Electric more effectively identify and respond to voltage violations through both traditional means (e.g., using capacitor banks) and using the DER power factor control capabilities established by the Pilot Program (PPL Electric St. No. 3 at 21).

148. DER management and monitoring can improve outcomes during planned an unplanned switching events to ensure that switching operations do not result in equipment overloads or any potential equipment damage (PPL Electric St. No. 3 at 21.)

149. DER management and monitoring can improve communications with customer-generators by identifying systems that are not operational (PPL Electric St. No. 3 at 23).

150. After accounting for the reduced capital costs and expenses from the Company's DER Management Pilot Program and Second DER Management Plan, the estimated revenue requirement impact in a hypothetical 2025 base rate case would be approximately $4,497,918 lower than without them, which would put a downward pressure on the base rates ultimately adopted in that proceeding. (PPL Electric St. No. 11-R at 11.)

151. All else being equal, the amount of that decrease in the revenue requirement would equal a decrease in the estimated average residential bill of $2.62 per year. (PPL Electric St. No. 11-R at 11.)

152. Even if the Plan's projected benefits are completely set aside, the Plan's absolute costs would not significantly impact customers' bills. (PPL Electric St. No. 11-R at 10-11.)

153. PPL Electric witness Bethany Johnson prepared an estimate of the Company's capital cost and expense claims for those devices in a hypothetical 2025 base rate case, along with the projected average bill impact for PPL Electric's customers due to these costs and expenses, for illustration purposes. (PPL Electric St. No. 11-R at 10.)

154. After setting aside the reduced capital costs and expenses from the Company's DER Management Pilot Program and Second DER Management Plan, the estimated revenue requirement impact is approximately $7,089,896, resulting in an estimated average residential bill increase of $4.13 per year. (PPL Electric St. No. 11-R at 10-11; PPL Electric Exhibit BLJ-1R.)

155. This bill impact analysis demonstrates that even without realizing any of the projected benefits from the proposed Plan, the Plan would not significantly impact customers' bills. (PPL Electric St. No. 11-R at 10-11; PPL Electric Exhibit BLJ-1R.)

156. The largest cost component in the cost-benefit analysis was the cost of the DER Management devices themselves. (*See* PPL Electric St. No. 10-R at 9, Table SWW-2.)

157. Specifically, the capital cost and maintenance of DER Management devices account for $69.8 million of the $81 million in projected total costs under the cost-benefit analysis of active management and monitoring. (*See* PPL Electric St. No. 10-R at 9, Table SWW-2.)

158. The Company indicated in its Rejoinder testimony that it is willing to investigate cloud-based communications as an alternative to the DER Management devices. (PPL Electric St. No. 1-RJ at 4-5, 14-15.)

159. PPL Electric has demonstrated through its Pilot Program how hosting capacity could be increased through monitoring and active management, which then leads to energy savings, and that active management of DER devices can address voltage violations and reduce O&M associated with truck rolls. (PPL Electric St. No. 10-RJ at 19.)

160. The amount of incremental hosting capacity created per DER installation as used in the CBA was based on the Company's experienced incremental hosting capacity created by the Pilot Program. (PPL Electric St. No. 10-RJ at 13.)

161. The Company intentionally used conservative assumptions regarding future benefits in its cost benefit analyses. (PPL Electric St. No. 10-RJ at 4.)

162. Specifically, the analysis used moderated assumptions related to the number of truck rolls related to voltage violations and capacitor bank switching, the cost of distribution

investments, and the cost of wholesale energy that can be saved through the Plan. (PPL Electric St. No. 10-RJ at 4.)

163. The analysis conservatively specified that the cost of DER Management devices would only increase over time and did not allow for the possibility that technological advancements could reduce device costs in the future. (PPL Electric St. No. 10-RJ at 4.)

164. The cost-benefit analysis included approximately $1 million per year in "other costs" to account for costs that may not have been otherwise recognized. (PPL Electric St. No. 10-RJ at 4.)

165. EVs were exempt from the Pilot Program and are not included in the proposed Second DER Management Plan. (PPL Electric St. No. 10-RJ at 9-10.)

166. However, the IEEE Standard 1547-2018 has been incorporated into the Commission's regulations for DERs. *See* 52 Pa. Code § 75.22 (defining "certified").

167. Smart inverters with their voltage regulations, frequency support, and ride-through capabilities are required for all new DER interconnections. (PPL Electric St. No. 10-RJ at 4.)

168. Commission approval of the Plan would not eliminate or diminish the benefits of autonomous operation but would add to the total net benefits that can be realized through IEEE 1547-2018. (PPL Electric St. No. 10-RJ at 4-5.)

169. PPL Electric does not restrict options for DERs. (PPL Electric St. No. 2 at 15-24.)

170. As of December 2, 2024, the Company's Approved Inverter List has a total of 315 different inverters from 18 different manufacturers (see PPL Electric Exhibit AD-1R), with 21 inverters and one more manufacturer being added in the near future." (PPL Electric St. No. 2-R at 15.)

171. Despite the Company's multiple requests, Tesla continues to refuse PPL Electric to test their inverters and make sure they are compatible and safe to use with the Company's DER Management devices. (PPL Electric St. No. 2-R at 17.)

172. The six manufacturers limited to single-inverter installs on the Approved Inverter List as of January 12, 2025, cannot be networked, which would cause these inverters to be noncompliant with SunSpec Modbus Communication protocols. (PPL Electric St. No. 2-RJ at 37.)

173. Enphase failed to provide all of the required documentation when it originally submitted its inverters for review on January 5, 2021. (PPL Electric St. No. 2-R at 31.)

174. After Enphase provided the outstanding documentation on February 23, 2021, PPL Electric approved the inverters and added them to the Approved Inverter List only two days later on February 25, 2021. (PPL Electric St. No. 2-R at 31-32.)

175. PPL Electric's DER Management devices did not interfere with any systems' power production. (PPL Electric St. No. 2-R at 32-33, 36.)

176. PPL Electric attempts to install the DER Management device within 14 calendar days, assuming there is not any inclement weather or discrepancies found when field visiting the customer's system, so that DER projects are not delayed. (PPL Electric St. No. 2-R at 53.)

177. For at least 3 of Mr. Stahlman's installations where he asserts that the timeline took longer than the 14 calendar days, those installations were delayed because there were missing signatures from the customer on the certificate of electrical inspection ("CEI"). (PPL Electric St. No. 2-R at 53; *see* PPL Electric St. No. 2-RJ at 40-41.)

178. A CEI is required before installing the DER Management device. (PPL Electric St. No. 2-RJ at 40.)

179. PPL Electric also provided information to SolarEdge on multiple occasions about how the Company installs its DER Management device on SolarEdge inverters, including in response to inquiries directly from SolarEdge about that topic. (PPL Electric St. No. 2-R at 59; PPL Electric St. No. 12-R at 11.)

180. PPL Electric has taken several steps to ensure the safety of its DER Management devices and their installation. (*See, e.g.*, PPL Electric St. No. 2 at 13-14.)

181. Company's DER Management devices undergo a series of internal and manufacturer tests to confirm they are safe for use. (PPL Electric St. No. 2 at 11.)

182. Some of these tests include tampering, voltage checks, amperage checks, and weatherproof checks. (PPL Electric St. No. 2 at 11.)

183. All of PPL Electric's DER Management devices have passed these tests. (PPL Electric St. No. 2 at 11.)

184. The Company's DER Lab team performs a series of steps to confirm the DER Management device properly connects and communicates with the DER system. (PPL Electric St. No. 2 at 11.)

185. As part of that review process, the DER Lab works closely with the DER system manufacturer. (PPL Electric St. No. 2 at 11; *see* PPL Electric Exh. AD-2.)

186. All of the Company's DER Management device installations are performed by PPL Electric meter technicians. (PPL Electric St. No. 2 at 13.)

187. When installing a DER Management device, the technicians first verify that they are installing the correct device at the correct location. (PPL Electric St. No. 2 at 13.)

188. Once the verification is complete, then the technicians follow a Distribution Device Instruction ("DDI"), which gives step by step instructions to install the DER Management device based on the type of inverter. (PPL Electric St. No. 2 at 13.)

189. The meter technicians undergo an extensive two-week training on installing DER Management devices, which includes practicing installations in the Company's DER Lab as well as demonstrating successful side-by-side installations in the field with the trainer. (PPL Electric St. No. 2 at 14.)

190. During this training, all technicians are required to pass a written and physical test before they can install DER Management devices alone. (*Id.*) These processes are designed to ensure that only qualified and trained personnel are installing DER Management devices in the field. (PPL Electric St. No. 2 at 13-14.)

191. PPL Electric engaged H. Landis Floyd, PE as an outside expert to investigate and address the JSPs' safety allegations.

192. Mr. Floyd worked for the DuPont Company for over 45 years, with assignments in the design, construction, commissioning, operation, maintenance, and safety of industrial electrical systems. (PPL Electric St. No. 12-R at 1.)

193. He also provided technical and leadership contributions in the technical activities of the Institute of Electrical and Electronics Engineers ("IEEE") since 1984. (PPL Electric St. No. 12-R at 1.)

194. Mr. Floyd was elected to IEEE Fellow in 2000 and served on the National Fire Protection Association ("NFPA") and the National Electrical Code ("NEC") technical committee from 1990 to 2014. (PPL Electric St. No. 12-R at 1.)

195. Since 2014, he has been an adjunct faculty member of the Advanced Safety Engineering and Management graduate engineering program at the University of Alabama at Birmingham. (PPL Electric St. No. 12-R at 1-2.)

196. In this capacity, he has developed and taught the course Electrical Systems Safety. (PPL Electric St. No. 12-R at 2.)

197. Mr. Floyd also has provided consulting and expert witness services with Electrical Safety Group Inc. since 2005. (PPL Electric St. No. 12-R at 2.)

198. Mr. Floyd also is a professional engineer in several states, including the Commonwealth of Pennsylvania. (PPL Electric St. No. 12-R at 2.)

199. In Mr. Floyd's expert opinion, PPL Electric's devices, including the way in which they are installed, are well-designed and well-engineered and are consistent with electric industry best practices. (PPL Electric St. No. 12-R at 13.)

200. PPL Electric witnesses Mr. Floyd and Ms. Dombrowski-Diamond went through, in detail, the allegations in SolarEdge's "PPL Case Review" that formed the basis for Mssrs. Bobruk and Geller's testimony. (*See* PPL Electric St. Nos. 2-RJ at 49-56 and 12-RJ at 8-11.)

201. Both witnesses identified critical flaws with that document and the allegations based thereon. (*See* PPL Electric St. Nos. 2-RJ at 49-56 and 12-RJ at 8-11.)

202. The "PPL Case Review" is not a properly conducted root cause analysis. (PPL Electric St. No. 12-RJ at 7-8.)

203. Mr. Floyd has performed more than 100 root cause analyses in his career. (PPL Electric St. No. 12-RJ at 7.)

204. A properly conducted root cause analysis identifies all possible causes of failure and, using scientific and engineering methods, rules out possible caused that could not have caused the failure being investigated. (PPL Electric St. No. 12-RJ at 7-8.)

205. The root cause analysis, as described by Mr. Geller, did not follow this protocol. (PPL Electric St. No. 12-RJ at 8.)

206. Mr. Floyd and Ms. Dombrowski-Diamond also went through each of the "cases" listed in the JSPs' "PPL Case Review," refuted the JSPs' allegations, and noted several omissions and errors. (PPL Electric St. No. 2-RJ at 55.)

207. For example, Ms. Dombrowski-Diamond explained how the inverter involved with Case 3456467 "did not have the DER Management device connected, so any failure could not be caused by the DER Management device." (PPL Electric St. No. 2-RJ at 55.)

208. Mr. Floyd and Ms. Dombrowski-Diamond also testified about how PPL Electric's connections cannot reduce the space between the AC terminals and the board, as alleged by Mr. Geller. (PPL Electric St. No. 2-RJ at 57; *see* PPL Electric St. No. 12-RJ at 12.)

209. PPL Electric uses specific fork connectors to make sure the 5 mm of clearance is not affected by the Company's installation and SolarEdge's inverters use ring terminals for the yellow AC capacitor leads. (PPL Electric St. No. 2-RJ at 57; *see* PPL Electric St. No. 12-RJ at 12.)

210. It is impossible to reduce the spacing because the location for the AC capacitor leads is a permanent fixture on the circuit board. (*Id*. at 57; *see* PPL Electric St. No. 12-RJ at 12.)

211. The Company's use of fork connectors cannot reduce the spacing between the AC terminals and the board. (*Id*. at 57; *see* PPL Electric St. No. 12-RJ at 12.)

212. There is no credible evidence to support the allegation that PPL Electric's DER Management devices are creating an electric arc within the inverters. (PPL Electric St. No. 12-R at 15.)

Appendix B – Proposed Conclusions of Law

1. Under Section 332(a) of the Public Utility Code, the proponent of a Commission rule or order bears the burden of proof. *See* 66 Pa. C.S. § 332(a).

2. The "burden of proof before administrative tribunals as well as before most civil proceedings is satisfied by establishing a preponderance of the evidence." *Lansberry v. Pa. PUC*, 578 A.2d 600, 602 (Pa. Cmwlth. 1990).

3. A preponderance of evidence is demonstrated where the evidence presented is more convincing, even by the smallest degree, than the evidence presented by the opposing party. *See Brown v. Commonwealth*, 940 A.2d 610, 614 n.14 (Pa. Cmwlth. 2008); *Pa. PUC v. HIKO Energy, LLC*, 2015 Pa. PUC LEXIS 364 (I.D. entered Aug. 21, 2015) (citing *Lansberry*, 578 A.2d at 602).

4. Moreover, the Commission's findings and conclusions must be supported by substantial evidence, which has been defined as "that quantum of evidence which reasonable minds might accept as adequate to support a conclusion." *Nat'l Fuel Gas Distrib. Corp. v. Pa. PUC*, 677 A.2d 861, 863-64 (Pa. Cmwlth. 1996) (quoting *Norfolk & Western Ry. Co. v. Pa. PUC*, 413 A.2d 1037, 1046 (Pa. 1980)); *see Pa. PUC v. Dep't of Transp.*, 346 A.2d 376, 378 (Pa. Cmwlth. 1975) (quotation omitted).

5. However, mere bald assertions, personal opinions or perceptions, when not substantiated by facts, do not constitute evidence. *Pa. Bureau of Corrections v. City of Pittsburgh*, 532 A.2d 12 (Pa. 1987).

6. In addition, Section 5.41 of the Commission's regulations states, in part, that "[p]etitions for relief under the act or other statute that the Commission administers, must be in writing, state clearly and concisely the interest of the petitioner in the subject matter, the facts and law relied upon, and the relief sought." 52 Pa. Code § 5.41(a).

7. Copies of any petition under Section 5.41 must be served on the statutory parties and "on all persons directly affected and on other parties whom petitioner believes will be affected by the petition," as well as further directed by the Commission. *Id.* §§ 5.41(b)-(c).

8. Further, "[u]nless the Commission otherwise orders, a public utility . . . may not change an existing and duly established tariff, except after notice of 60 days to the public." *Id.* § 53.31.

9. Electric distribution companies ("EDCs") are required to "file a tariff with the Commission that provides for net metering consistent with" Chapter 75 of the Commission's regulations. *Id.* § 75.13(c).

10. Also, an EDC and default service provider ("DSP") "may not require additional equipment or insurance or impose any other requirement" on a net metering customer-generator "unless the additional equipment, insurance or other requirement is specifically authorized under this chapter or by order of the Commission." *Id.* § 75.13(k).

11. The Commission is the authority that has jurisdiction over PPL Electric's DER Management devices and their installation. *See* 66 Pa.C.S. §§ 102, 1501.

12. PPL Electric's DER Management devices do not need to comply with the National Electric Code because they are authorized by the Commission.

13. PPL Electric met its burden of proof in this proceeding and demonstrated that its Petition for Approval of the Second DER Management Plan should be approved.

Appendix C – Proposed Ordering Paragraphs

1. That the Commission hereby grants PPL Electric's Petition for Approval of its Second DER Management Plan as filed on May 20, 2025, as well as the Company's proposed tariff modifications and any other approvals or authorizations that are necessary to implement PPL Electric's Second DER Management Plan.

2. That PPL Electric Utilities Corporation shall file a tariff supplement to become effective on one day's notice that is consistent with the *pro forma* tariff supplement attached as PPL Electric Exhibit SS-2 to the Direct Testimony of Salim Salet (PPL Electric St. No. 1).

3. That PPL Electric's DER Management devices, including the method of installation, are approved by this Commission.