BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of PPL Electric Utilities Corporation for Approval of Tariff Modifications and Waivers of Regulations Necessary to Implement its Distributed Energy Resources Management Plan	: : : : :	Docket No. P-2019-3010128

REBUTTAL TESTIMONY OF SALIM SALET

PPL Electric Statement No. 1-R

March 4, 2020

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Term	Definition
AC	Alternating Current
AEPS	Alternative Energy Portfolio Standards
ANSI	American National Standards Institute
C&I	Commercial & Industrial
ComEd	Commonwealth Edison Company
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management System
DG	Distributed Generation
DMS	Distribution Management System
Duquesne	Duquesne Light Company
EDC	Electric Distribution Company
EE&C	Energy Efficiency and Conservation
EIA	Energy Information Administration
EIS	Energy Independent Solutions, LLC
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
FISR	Fault Isolation and Service Restoration
HECO	Hawaiian Electric Co.
IEEE	Institute of Electrical and Electronics Engineers
IREC	Interstate Renewable Energy Council

kW	Kilowatt
kWh	Kilowatt hours
MW	Megawatt
NARUC	National Association of Regulatory Utility Commissioners
NEM	Net Energy Metering
NERC	North American Electric Reliability Corporation
NH PUC	New Hampshire Public Utilities Commission
NIST	National Institute of Standards and Technology
NOAA	National Oceanic and Atmospheric Association
NRDC	Natural Resources Defense Council
NREL	National Renewable Energy Laboratory
OCA	Office of Consumer Advocate
PASEIA	Pennsylvania Solar Energy Industries Association
PECO	PECO Energy Company
PJM	PJM Interconnection, LLC
PRC	Protection and Control
PPL Electric	PPL Electric Utilities
PV	Photovoltaic
REMSI	Rules for Electric Meter & Service Installations
RF	Radio Frequency
RS	Recommended Standard
SEF	Sustainable Energy Fund

SEIA	Solar Energy Industries Association
SREC	Solar Renewable Energy Credit
SUNWPA	Solar Unified Network of Western Pennsylvania
UL	Underwriters Laboratories
USB	Universal Serial Bus
V	Volt(s)
VAR	Volt Ampere Reactive
VVC	Volt/VAR Control

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Salim Salet, and my business address is 2 North Ninth Street, Allentown, PA 18101.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by PPL Electric Utilities Corporation ("PPL Electric" or the "Company") as Director – Operations.

Q. HAVE YOU PREVIOUSLY SUBMITTED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes. My direct testimony is set forth in PPL Electric Statement No. 1.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I will respond to many of the allegations and recommendations made in NRDC Statement No. 1, the Direct Testimony of Harry Warren submitted on behalf of the Natural Resources Defense Council ("NRDC"); OCA Statement No. 1, the Direct Testimony of Ron Nelson submitted on behalf of the Office of Consumer Advocate ("OCA"); SEF Statement No. 1 (Non-Proprietary and Proprietary Versions), the Direct Testimony of John Costlow submitted on behalf of the Sustainable Energy Fund ("SEF"); and SEF Statement No. 2, the Direct Testimony of Ron Celentano submitted on behalf of SEF.

I have arranged my rebuttal testimony by subject matter. When more than one witness has addressed the same subject matter with testimony that I wish to rebut, I address all of that testimony in the same section. I will address the following issues in the order listed: (1) updates to the Company's Distributed Energy Resource ("DER") Management proposal; (2) details on the grid support functions that the Company will use under its DER Management Plan; (3) allegations that the Company's DER Management proposal is premature; (4) other parties' recommendations for a statewide proceeding; (5) the financial benefits of the Company's DER Management proposal; (6) the benefits of remote monitoring and management versus solely relying on pre-set autonomous functions; (7) allegations that the Company's proposal could negatively affect third-party aggregation of DERs; (8) the length of PPL Electric's requested waivers of regulations; (9) claims that the Company's proposal will affect the design of DERs; (10) questions about how PPL Electric's proposal will affect electric vehicles ("EVs") and battery storage; (11) other parties' assertions about PJM Interconnection LLC's ("PJM") recommended ride-through settings; (12) other issues and alternative recommendations raised by other parties; and (13) a summary of the benefits of the Company's DER Management proposal compared to its costs.

Q. ARE YOU SPONSORING ANY EXHIBITS WITH YOUR REBUTTAL TESTIMONY?

A. Yes. Attached to my rebuttal testimony are the following exhibits:

- PPL Electric Exhibit SS-1R – A comprehensive list of the grid support functions that the Company would use under its DER Management Plan as well as details about when, how much, and how long those functions would be used by the Company.

- PPL Electric Exhibit SS-2R – Supporting calculations showing that PPL Electric's use of the grid support functions under its DER Management Plan would have a negligible impact on customers' net metering compensation.
- PPL Electric Exhibit SS-3R – A document showing an example where the Constant Power Factor function could be used.

I. INTRODUCTION

Q. DO YOU HAVE ANY OVERALL COMMENTS ON THE OTHER PARTIES' DIRECT TESTIMONY?

A. Yes. PPL Electric appreciates the feedback that the other parties have provided on the Company's proposal. From my perspective, the other parties and PPL Electric share a common goal in helping DERs become more prevalent in the Company's service territory. Many, if not all, of the witnesses also recognize the benefits that smart inverters can generally produce.

Nevertheless, the other parties have raised issues regarding the Company's DER Management proposal, such as the timing of PPL Electric's proposal, whether these issues are better addressed in a statewide proceeding, and the financial impact of the Company's proposal on DER owners.

As explained in this rebuttal testimony, the Company continues to maintain that the DER Management proposal will produce substantial benefits and is in the public interest. However, based on other parties' direct testimony, the Company has incorporated updates to its proposal that should better encourage and facilitate the deployment of DERs in the Company's service territory, while enabling PPL Electric and its ratepayers to reap the substantial benefits of the smart inverters' grid support functions.

The fundamental purpose of PPL Electric's DER Management Plan is to provide the Company with the necessary tools to operate its distribution system safely and reliably. As explained in the Company's DER Management Petition, electric transmission and distribution systems in Pennsylvania and the United States are currently undergoing significant changes. In particular, the increasing deployment and use of DERs, such as solar panels and batteries, are upending the traditional electric grid model of large scale generation located at significant distances from customers. By allowing customers to both consume and produce electricity at what were traditionally points of delivery, 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.

However, even as the deployment of DERs in PPL Electric's service territory continues to increase, I have been advised by counsel that the Company still must provide reasonable, safe, and reliable electric service to all of its customers, including those who have not installed DERs. This can be particularly difficult because electricity cannot be readily stored. As a result, PPL Electric and all electric utilities must simultaneously balance distribution system demand and supply to avoid potential safety and reliability issues. At the same time, PPL Electric recognizes the benefits of alternative energy sources in combating climate change and wants to encourage their deployment in the Company's service territory.

Ultimately, these considerations led PPL Electric to develop its DER Management Plan, which will help facilitate the interconnection of more DERs on its distribution system, while also enabling the Company to monitor and manage the DERs so that they do not negatively affect the distribution system needing to provide electric service to approximately 1.4 million customers.

The Company's Petition should not be controversial. Under the traditional central generating station model, the amount of generation and voltage on the transmission system is fully controlled by PJM. All PPL Electric is requesting is for the Company to have some of the same capabilities with respect to generation interconnected with the distribution system. In fact, some of the other parties' witnesses have acknowledged that use of the smart inverters' grid support functions can provide benefits to the distribution system, such as increasing hosting capacity. Yet, the other parties continue to oppose PPL Electric's DER Management Petition, claiming that the Petition is premature, the issues should be addressed in a statewide proceeding, and PPL Electric should not be able to monitor and manage the DERs interconnected with its distribution system because, among other things, doing so would negatively affect the DER market.

As explained in this rebuttal testimony, the other parties' concerns have either been fully addressed by the Company's updates to its DER Management proposal, which are set forth in Section II, *infra*, or are entirely without merit. Thus, PPL Electric's DER Management Petition, as updated by the Company's rebuttal testimony, is reasonable and in the public interest and, therefore, should be approved by the Commission.

Q. COULD YOU PLEASE SUMMARIZE AND GENERALLY ADDRESS THE MAIN ISSUES RAISED IN OTHER PARTIES' DIRECT TESTIMONY?

A. In general, the other parties raised the following principal issues in their direct testimony:

1. **<u>Additional Costs on New DER Customers</u> –** The other parties argued that PPL Electric's DER Management proposal would chill the installations of DERs in the Company's service territory by: (1) imposing additional costs on new DER customers because they would have to pay for the DER Management devices; and (2) reducing the amount of electric power and, therefore, revenue produced by the DERs.
2. **<u>Technical Specifications</u> –** The other parties asserted that not enough information was provided about the technical specifications under the Company's DER Management Plan, including which smart inverters' grid support functions would be used as well as how, when, and how long PPL Electric would use each of those functions.
3. **<u>Premature</u> –** The other parties alleged that the Company's proposal is premature because the IEEE and UL standards at issue have not been finally published yet and that the levels of DERs interconnected with the Company's distribution system are not high enough.
4. **<u>Statewide Proceeding</u> –** The other parties claimed that the Company's implementation of IEEE 1547-2018 and its request to monitor and manage DERs through smart inverters that meet IEEE 1547-2018 should be addressed in a statewide proceeding.
5. **<u>Compensation Mechanism</u> –** The other parties questioned the Company's lack of a proposed mechanism to compensate DER customers for when PPL Electric uses the smart inverters' grid support functions, which may affect the DERs' real power output.

6. <u>Impact Customers' and Third-Party DER Aggregators' Ability to Communicate with DERs</u> – The other parties argued that the Company's DER Management proposal could affect customers' and third-party DER aggregators' ability to monitor and manage the DERs. The other parties' issues and arguments are either without merit or have been fully addressed in this rebuttal testimony.

1. <u>Additional Costs on New DER Customers</u>

PPL Electric's DER Management proposal, as updated by its rebuttal testimony, will actually <u>reduce</u> the costs of DERs for new DER customers. Under the Company's updated proposal, PPL Electric will purchase, install, own, and maintain the DER Management devices at no direct cost to the DER customers. Therefore, DER customers will no longer have to pay the approximately $755[1] to purchase and install the DER Management devices or worry about ongoing maintenance of the devices.

Further, the DER Management devices that the Company will use are made by ConnectDER LLC ("ConnectDER"). PPL Electric searched for simpler and more cost-effective DER Management device. This resulted in a partnership and production of the ConnectDER DER Management device that the Company will purchase, install, own, and maintain on new DER installations in its service territory under the DER Management Plan. This device consists of two components: (1) a meter collar that is installed between the meter and the customer-owned meter base; and (2) a "dongle," which is a small communications device that is plugged into the smart inverter and communicates wirelessly with the meter collar. The radio transmitter in the meter collar then transmits

[1] PPL Electric initially estimated the installation cost would be $150; however, through further cost analysis, the Company has determined that the installation cost would be approximately $55.

information to PPL Electric's system using the Company's Radio Frequency ("RF") Mesh network.

Importantly, the ConnectDER DER Management device will reduce most new DER customers' installation costs by, at least, an estimated $393 to $700. Specifically, for DER installations with nameplate capacity below 15 kilowatts ("kW"), the DER can plug directly into the breaker on the ConnectDER DER Management device. This simple solution saves the customer an estimated $393 to $700 by eliminating the cost to install cable and conduit from the DER to the customer's electrical panel. Further, the ConnectDER DER Management device can often allow a DER under 15 kW to be connected without the customer needing to upgrade the electrical panel, which results in another $1,000 to $1,600 in estimated cost savings. Moreover, by increasing hosting capacity on the Company's distribution circuits, PPL Electric's DER Management proposal can help customers avoid paying for costly distribution system upgrades in order to connect their DERs, such as voltage regulators that cost approximately $60,000. Thus, the Company's updated proposal will produce substantial cost savings for customers as compared to PPL Electric's original proposal.

In addition, the other parties' claims about the Company's DER Management Plan reducing DER customers' revenue are grossly misleading and overstated. None of the other parties performed or presented any quantifiable analysis about these claims. PPL Electric has performed such an analysis. As explained later in my testimony, the Company's use of the grid support functions would reduce the annual net metering compensation for an average 6 kW solar photovoltaic ("PV") system by an estimated $1.04.

For these reasons, the Company's DER Management Plan, as updated by this rebuttal testimony, will actually provide a financial incentive for new DER installations in the Company's service territory. Therefore, the other parties' concerns about the alleged financial impact of PPL Electric's DER Management Plan have been fully addressed.

2. <u>Technical Specifications</u>

In my rebuttal testimony, I will provide explicit details on the technical specifications under the Company's DER Management Plan. Specifically, the Company will use the following grid support functions in autonomous and active modes: (1) Volt/VAR; (2) Constant Power Factor; (3) Remote On/Off; (4) Voltage Ride-through; and (5) Frequency Ride-through. My testimony also answers the questions of when, how, and how long PPL Electric will use each of those functions. Moreover, in response to OCA witness Nelson's testimony, I will clarify that the Company is not requiring the use of the Volt-Watt functionality under its DER Management Plan. Likewise, I will explain that SEF witness Costlow's concerns about the Company's use of the Remote On/Off function are without merit because he fails to recognize that PPL Electric will only use that functionality when: (1) the DER's internal sensor fails to turn off the DER automatically during an outage and the DER is causing an "unintentional island" on the distribution circuit; or (2) there is an emergency situation, such as a gas leak or fire, in the vicinity of the DER.

3. <u>Premature</u>

The other parties erroneously claim that PPL Electric's DER Management Petition is premature. The critical flaw with their reasoning is that PPL Electric should only address the issues presented by DERs when the DER penetration levels rise to a point where the DERs are or are at a substantial risk of causing widespread issues on the distribution system. No prudent operator of an electric distribution system only addresses issues after they actually occur. Indeed, the planning horizon for distribution and transmission are 5 and 10 years, respectively. To improve the safety, reliability, and power quality of its customers' electric service, PPL Electric must get ahead of the issues experienced by utilities in other states due to DERs and implement its DER Management Plan now. In fact, the Company is already experiencing issues with two-way power flows and "hidden load" from DERs on its distribution system. PPL Electric's DER Management Plan can address the current problems and prevent future issues from arising. However, the longer the Company waits, the more DERs with non-smart inverters are installed. Each new installation is an opportunity lost for PPL Electric and its customers to leverage the safety, reliability, and power quality benefits of the smart inverters' grid support functions.

Moreover, the other parties fail to realize that the Company is well-positioned to implement the DER Management Plan because it has a lower number of DERs as compared to utilities in other states, such as California and Hawaii. If an electric utility waits until there are a very high number of DERs on the system to implement a proposal similar to the DER Management Plan, the utility is faced with two unfavorable choices: (1) retrofitting existing installations with DER Management devices, an expensive, time-consuming process that also disrupts customers; or (2) limiting its proposal to the small, incremental benefit of only using the grid support functions on new DER installations.

Therefore, the more cost-effective approach is to implement the DER Management Plan now and maximize the number of DERs that can provide grid support.

Additionally, as explained previously, PPL Electric's updated proposal will actually reduce the costs for most new DER installations. This will encourage customers to install more new DERs in PPL Electric's service territory. As a result, the level of DER growth in the Company's service territory would likely increase due to the Company's proposal. Given the urgent need to promote alternative energy sources to combat climate change, the time to implement the DER Management Plan and substantially reduce the cost of new DERs is now.

Furthermore, by the time this proceeding concludes, the applicable IEEE and UL standards will be in place, and smart inverters that are certified as meeting IEEE 1547-2018 will be commercially available. Also, as explained in the Company's direct testimony, PPL Electric has an interim plan in place in the unlikely event that the standards are not published or compliant smart inverters are not commercially available when this proceeding ends.

Thus, the other parties' claims about the Company's DER Management Plan being premature should be rejected entirely.

4. <u>Statewide Proceeding</u>

The other parties' recommendation for a statewide proceeding also should be disregarded. As explained in Mr. Whitley's rebuttal testimony (PPL Electric Statement No. 4-R), statewide proceedings in other states have done nothing but prevent these issues from being addressed for several years. If the Commission follows the same path as other states, PPL Electric would be unable to address and get ahead of the issues presented by DERs for many years.

The other parties also incorrectly assert that without a statewide proceeding, parties will incur additional time and costs litigating individual proceedings for each electric distribution company ("EDC"). But that claim is totally dependent on their assumption that other EDCs in Pennsylvania want and are ready to implement IEEE 1547-2018 and a proposal similar to the DER Management Plan. Here, PPL Electric has the technology and infrastructure already in place to implement IEEE 1547-2018 and the DER Management Plan right now. Nothing in the other parties' direct testimony, however, demonstrates or even suggests that other EDCs want and are ready to implement IEEE 1547-2018, implement automated grid support functions, or monitor and manage DERs, as PPL Electric is trying to do here. The Company should be able to leverage its prior capital investments and implement its DER Management Plan for the betterment of its ratepayers and the general public, rather than waiting for several years for a statewide proceeding to conclude. Moreover, under PPL Electric's updated proposal, DER installations will be less expensive and less complex. The delay resulting from a statewide proceeding will deny DER customers these benefits and deter the installation of new DERs.

5. <u>Compensation Mechanism</u>

No compensation mechanism for the value of customers' grid support services needs to be established in this proceeding. I want to emphasize that the Company's DER Management Plan would simply establish reasonable terms and conditions for new DERs to interconnect with PPL Electric's distribution system. Although PPL Electric wants to encourage and facilitate the interconnection of DERs, the Company must do so in a reasonable way that does not negatively affect the safety, reliability, and power quality of its distribution system. As a result, DERs should not be permitted to operate in a way that causes the Company to violate voltage and other requirements or that prevents PPL Electric from promptly responding to emergencies and unintentional islanding situations. Therefore, PPL Electric's DER Management Plan is not a demand side management proposal. Rather, it is simply designed to interconnect DERs on a safe and reliable basis. No additional compensation needs to be paid to DER customers for merely allowing their DERs to be managed so that they do not jeopardize safe and reliable service to other customers. DERs should not be compensated for operating their systems in coordination with PPL Electric's facilities to help ensure safe and reliable service.

I also reject the other parties' implication that DER customers should be allowed to operate their DERs continuously and produce as much generation as they want without any ability by the Company to manage those DERs in a way that affects generation output. I have been advised by counsel that PPL Electric has a duty to provide reasonable service, not perfect service. No customers, including DER customers, can reasonably be provided with perfect service. Indeed, the capital investments necessary to provide fully redundant electric service to all customers would be astronomical.

Although the Company works diligently to provide continuous service to all customers, including DER customers, issues and events experienced on the distribution system, such as scheduled maintenance, extended outages, momentary outages, and voltage irregularities, can and do occur. These issues and events require PPL Electric to, in certain circumstances, ramp down or curtail customers' load and generation. For example, even today, the Company has instructed DERs, particularly larger installations, to shut down for hours or even days during scheduled maintenance. As explained by Ms. Johnson in her rebuttal testimony (PPL Electric Statement No. 7-R), during any of these scheduled or non-scheduled periods of service interruption, customers and customer-generators do not receive compensation for the revenue lost while they were ramped down or shut off. Counsel also has advised me that the Company cannot unreasonably discriminate between customers in the same customer classes as to service or rates. Therefore, when there are interruptions to a customer's operations, DER customers should not be treated differently from non-DER customers in the same customer class. Those principles should continue apply for DERs after the Company's DER Management Plan is approved.

In addition, as explained in Ms. Johnson's rebuttal testimony (PPL Electric Statement No. 7-R), the Company's updated proposal eliminates any potential need for such a mechanism because new DER customers will no longer have to pay for the ConnectDER DER Management devices, which cost approximately $755 to purchase and install, and most new DER customers will save an estimated $393 to $700 in installation costs due to the Company's use of those DER Management devices. Further, when the customer needs to upgrade the home's electrical panel and the DER is under 15 kW, the smart inverter can be directly connected to the ConnectDER DER Management device, saving the customer estimated $1,000 to $1,600 on top of the $393 to $700 in reduced installation costs.

Notwithstanding, if the Commission orders PPL Electric to provide compensation for the kilowatt hour ("kWh") output lost due to the Company's use of the grid support functions, a new compensation mechanism does not need to be established. As explained in Ms. Johnson's rebuttal testimony (PPL Electric Statement No. 7-R), PPL Electric would calculate the kWh output the DER system would have produced if not for Company management and adjust the DER customers' kWh bank accordingly. All other net metering compensation regulations, calculations, and process would continue to apply as they do today. The only change to the current net metering process would be the specific customers' kWh would be adjusted due to the Company's occasional management.

6. <u>Impact Customers' and Third-Party DER Aggregators' Ability to Communicate with DERs</u>

Contrary to other parties' assertions, PPL Electric's DER Management Plan will not affect customers' or third-party DER aggregators' ability to communicate with DERs. Under IEEE 1547-2018, compliant smart inverters must have two communications ports. The Company only needs to connect to one of those communications ports under its DER Management Plan. Therefore, the other port remains available for the customer or third-party DER aggregator. Furthermore, PPL Electric will not prevent third-party DER aggregators from communicating with the smart inverters or sending commands to DERs. Such third-party DER aggregators are free to continue operating, even with DER installations that are subject to the Company's proposal. Thus, the other parties' concerns are without merit. Furthermore, as explained in Mr. Bayles's rebuttal testimony (PPL Electric Statement No. 5-R), using customers or third-party DER aggregators to provide smart inverter data to PPL Electric presents substantial cybersecurity risks. Under the DER Management Plan, however, Mr. Bayles states that these risks do not exist. As a result, PPL Electric's proposal is much sounder from a cybersecurity standpoint.

Q. DO YOU HAVE ANY FURTHER COMMENTS ON THE OTHER PARTIES' PRINCIPAL ISSUES?

A. From my perspective, there are three main questions running through the other parties' principal issues. They are: (1) whether PPL Electric should install DER Management devices to monitor IEEE 1547-2018 compliant smart inverters (Issues 1 and 6 above); (2) whether the Company's proposal is premature and should be addressed in a statewide proceeding (Issues 3 and 4 above); and (3) whether PPL Electric should use the DER Management devices to manage the smart inverters' grid support functions and should compensate customers for the use of those functions (Issues 1, 2, 5, and 6 above).

The first main question, in my view, is no longer reasonably in dispute. By adjusting its proposal so that the Company purchases, installs, owns, and maintains the ConnectDER DER Management devices at no direct cost to the DER customers, the Company's DER Management Plan will not impose additional installation or maintenance costs on the customers. Further, the proposal actually will help incent the deployment of DERs in its service territory because the DER Management devices will substantially reduce the DER installation costs for many, largely residential, customers. Moreover, the other parties cannot dispute the reliability benefits due to PPL Electric being able to monitor the DERs' generation output, determine the amount of "masked" or "hidden" load on a distribution circuit, improve its distribution system planning practices, and increase workers' and the public's safety by detecting unintentional islanding.

As for the second question, PPL Electric's DER Management Plan is not premature and should not be addressed in a lengthy, complicated statewide proceeding. Unlike other EDCs, PPL Electric is well-positioned to implement the DER Management Plan now and should be permitted to do so before more DERs without compliant smart inverters interconnect with its distribution system and exacerbate the issues. Also, if the DER Management Plan is deferred to a statewide proceeding, the Company's plan to install the new DER Management devices and substantially reduce customers' DER installation costs would be either completely foreclosed or unnecessarily delayed for several years. Customers should not lose out on this clear financial benefit that will help encourage and facilitate new DER installations.

On the third question, PPL Electric should be able to manage the smart inverters' grid support functions because doing so will provide safety, reliability, and power quality benefits for ratepayers and the general public. DERs also must be safely and reliably interconnected with the distribution system and, therefore, should not receive additional compensation simply for meeting that fundamental requirement. Furthermore, a new compensation mechanism does not need to be established because the impact of the Company's proposal on net metering compensation is negligible, and any such impact is greatly exceeded by the substantial savings in installation costs and potential deferral of distribution system upgrades that will result from the DER Management Plan.

For these reasons, and as I will explain in more detail in the following sections, PPL Electric's DER Management proposal, as updated by the Company's rebuttal testimony, is in the public interest and should be approved.

II. UPDATES TO THE COMPANY'S DER MANAGEMENT PROPOSAL BASED ON OTHER PARTIES' DIRECT TESTIMONY

Q. PLEASE EXPLAIN THE COMPANY'S FIRST UPDATE TO ITS DER MANAGEMENT PROPOSAL.

A. PPL Electric first updates its proposal so that the Company will use the ConnectDER DER Management devices under its DER Management Plan, rather than the existing DER management devices that are used in the Company's pilot Keystone Solar Future Project ("Keystone Solution").[2]

Under the Company's original proposal, new DER customers would have had to purchase and install a DER management device. At that time, the only device that was available was the Keystone Solution. That device is installed in a cabinet located behind the customer's meter, physically interconnects with the customer's smart inverter, and communicates with PPL Electric's system via a mesh network radio or a cellular modem. The total unit cost of the Keystone Solution, regardless of whether it used the mesh network or cellular network, was approximately $1,400. The approximate installation cost of the Keystone Solution was $250. Further, if a cellular modem was needed, the ongoing cost was approximately $90 per year.

However, the Company continued to search for a better and cheaper DER management device that could be used in its DER Management Plan. Ultimately, PPL Electric contracted with ConnectDER to repackage a DER management device into a more affordable and easier-to-install solution. As a result of those efforts, ConnectDER

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[2] Any necessary changes to the Company's *pro forma* tariff supplement submitted as PPL Electric Exhibit SS-1 due to this update will be reflected in the Company's compliance tariff filed after Commission approval of the DER Management Petition.

developed a DER Management device that is much better and less expensive than the Keystone Solution. Also, because the Company's RF Mesh network is now fully deployed and reaches all areas of PPL Electric's service territory, a cellular modem option is no longer necessary.

As explained in Mr. Wallace's rebuttal testimony (PPL Electric Statement No. 6-R), the ConnectDER DER Management device has two major components: (1) the meter collar; and (2) the dongle. The meter collar plugs into the customer's meter base, meaning that it is positioned between the customer-owned meter base and the Company-owned meter. The meter collar has an electrical breaker on it, which enables a DER installation up to 15 kW to plug directly into the meter collar.

The second component, *i.e.*, the dongle, is a very small communications device that physically connects to the customer's smart inverter and transmits information to the meter collar. In turn, the meter collar transmits the information to PPL Electric via the Company's RF Mesh network.

Right now, the total individual cost of the ConnectDER DER management device currently is approximately $700 for the unit and $55 for the installation. Therefore, the ConnectDER DER Management device's estimated all-in cost of $755 (*i.e.*, $700 unit cost + $55 installation cost) is $895 cheaper than the Keystone Solution's estimated all-in cost of $1,650 (*i.e.*, $1,400 unit cost + $250 installation cost).

On top of being cheaper to purchase and install, the ConnectDER DER Management device differs from the Keystone Solution because it can produce substantial savings for new DER customers in two ways.

First, if the DER is under 15 kW, the DER can be plugged directly into the meter collar. Doing so eliminates the need to install cable and conduit from the smart inverter to the customer's own electrical panel, which is typically located in the basement. This saves the customer approximately $393 to $700 in installation costs (see PPL Electric Exhibit MW-1R).

Second, when installing a new DER, the customer may need to upgrade the electrical panel's capacity, such as from 100 amps to 200 amps, to accommodate the increased load from the DER. The estimated cost for that upgrade is $1,000 to $1,600. However, if the DER's nameplate capacity is under 15 kW, the customer does not need to upgrade the electrical panel because the DER plugs directly into the ConnectDER DER Management device instead of the electrical panel. Thus, in that scenario, the device saves the customer an additional estimated $1,000 to $1,600 on top of the $393 to $700 in general installation costs savings.

Moreover, there is another key difference between the Keystone Solution and the ConnectDER DER Management device—the location of the Company-owned property relative to the customer-owned meter base. Whereas the Keystone Solution was a less favorable "behind the meter" solution that was installed in a cabinet located downstream from the meter, the ConnectDER DER Management device's meter collar is a preferable "in front of the meter" solution that is located between the Company-owned meter and the customer-owned meter base. This makes it easier for the Company to access the ConnectDER DER Management device and preserves the point of delivery as the general dividing line of responsibility between the Company and the customer.

Q. PLEASE EXPLAIN THE COMPANY'S SECOND UPDATE TO ITS DER MANAGEMENT PROPOSAL.

A. The second update is that PPL Electric will purchase, own, install, and maintain the ConnectDER DER Management devices at no direct cost to the DER interconnection applicants.

One of the common themes throughout the other parties' direct testimony was their concern that individual DER customers would have to bear the cost of the DER management devices. They felt that this could inhibit the DER market and lead to fewer DERs being installed in PPL Electric's service territory. In fact, according to OCA witness Nelson, "[a] potential outcome of allowing PPL to unilaterally specify smart inverter specifications is that PPL's operational costs are reduced at the cost of DER owners." (OCA St. No. 1, p. 15.) According to him, this "would be an inequitable outcome." (OCA St. No. 1, p. 15.) SEF witness Celentano also alleged that the cost of the DER management device "could increase the total installation cost by 6% to 10% for small residential systems." (SEF St. No. 2, p. 11.)

Although PPL Electric continues to maintain that its original DER Management proposal would produce substantial benefits, the Company certainly wants to promote the deployment of DERs in its service territory. In fact, one of the primary reasons that PPL Electric filed its DER Management Petition was to help facilitate and encourage the increased number of DERs in its service territory.

To eliminate any risk that the Company's proposal will be anything but a net-positive from a cost perspective to most new DER owners, PPL Electric believes it would be appropriate for the Company to purchase, install, own, and maintain the DER management devices.

By making this update, new DER customers will not have to purchase and install the DER Management devices. Therefore, in contrast to the Company's original proposal, a new DER customer will not have to directly pay an additional estimated $755 for the ConnectDER DER Management device in order to interconnect with PPL Electric's distribution system.[3]

Further, the Company's installation of the ConnectDER DER Management devices will reduce the installation costs for DER installations that are less than 15 kW by approximately $393 to $700 (see PPL Electric Exhibit MW-1R). Because those DERs can plug directly into the device's meter collar, rather than the customer's electrical panel. Consequently, PPL Electric's DER Management proposal will reduce the total cost of DER installations under 15 kW by approximately $393 to $700. Also, as noted previously, the customer avoids any necessary upgrade to the electrical panel so long as the DER's nameplate capacity is under 15 kW because the DER can plug directly into the ConnectDER DER Management device rather than the electrical panel. In such a situation, the device also saves the customer an estimated $1,000 to $1,600 on top of the $393 to $700 in general installation costs savings. This is particularly important because, on average, 80% of the DERs interconnected to PPL Electric's distribution system are less than 15 kW.

[3] I note that Consolidated Edison Company ("ConEd"), after a two-year pilot program on Staten Island, will similarly be providing ConnectDER devices throughout its service territory free of charge to residential customers who install solar panels or electric vehicle chargers. Information about ConEd's program is available on its website: https://www.coned.com/en/about-us/media-center/news/20190503/con-edison-helps-customers-save-on-solar.

Moreover, the estimated impact on customer-generators' net metering compensation is negligible. PPL Electric has calculated that an average solar PV installation's net metering compensation would be reduced by $1.04 per year. (*See* PPL Electric Exhibit SS-2R.)

In addition, the DER Management proposal will produce substantial benefits for all of the Company's ratepayers, by providing PPL Electric with new tools to increase service reliability, improve power quality, and defer costly distribution system upgrades. Also, by utilizing the grid support functions of the smart inverters, PPL Electric can increase a distribution circuit's hosting capacity and accommodate more DERs interconnecting with that circuit.

Therefore, the DER Management proposal will provide substantial benefits to PPL Electric's ratepayers, DER owners, the DER market, and the public in general and will facilitate and incent the increased deployment of DERs in the Company's service territory. Thus, the Company believes it is appropriate to recover the capital costs and expenses associated with the ConnectDER DER Management devices from ratepayers.

Q. IS THE COMPANY SEEKING APPROVAL FOR IMMEDIATE COST RECOVERY OF THE CONNECTDER DER MANAGEMENT DEVICES?

A. No. As explained in Ms. Johnson's rebuttal testimony (PPL Electric Statement No. 7-R), the Company is not making a claim to recover the capital costs and expenses associated with the ConnectDER DER Management devices in this proceeding. Any such proposal will be made in a future proceeding, most likely a base rate case.

III. DETAILS ON THE GRID SUPPORT FUNCTIONS THAT PPL ELECTRIC WILL USE UNDER ITS DER MANAGEMENT PLAN

Q. OTHER PARTIES HAVE CLAIMED THAT THE COMPANY HAS NOT PROVIDED ENOUGH DETAILS ABOUT THE GRID SUPPORT FUNCTIONS THAT PPL ELECTRIC WILL USE UNDER ITS DER MANAGEMENT PLAN. WOULD YOU PLEASE RESPOND?

A. In discovery, PPL Electric provided its Draft DER Management Plan White Paper, which outlined the potential grid support functions that the Company could utilize under its DER Management Plan. This draft document described, among other things, the grid support functions that the Company envisioned potentially using under its DER Management proposal. However, NRDC witness Warren and OCA witness Nelson alleged that there was a lack of detail about the functions that would actually be used, including the parameters governing how long and how often those functions could be used. (NRDC St. No. 1, pp. 7-8, 24; OCA St. No. 1, pp. 11-12, 14-15.)

Attached to my rebuttal testimony as PPL Electric Exhibit SS-1R is a comprehensive list of the grid support functions that the Company would use under its DER Management Plan as well as details about when, how much, and how long those functions would be used by the Company. As explained in that exhibit, PPL Electric will use the following grid support functions in both autonomous and active management modes under its proposal[4]:

[4] Although PPL Electric does not require implementation of other grid support functions, such as Volt/WATT and Watt Ramp Rate, the Company reserves its right to offer these settings to customers as potential alternatives when the interconnection impact study concludes that the customer must pay for a distribution system upgrade in order to interconnect with PPL Electric's distribution system. In such a case, the customer would have to voluntarily consent to the use of these other settings.

1. Volt/VAR[5];
2. Constant Power Factor;
3. Remote On/Off;
4. Voltage Ride-through; and
5. Frequency Ride-through.

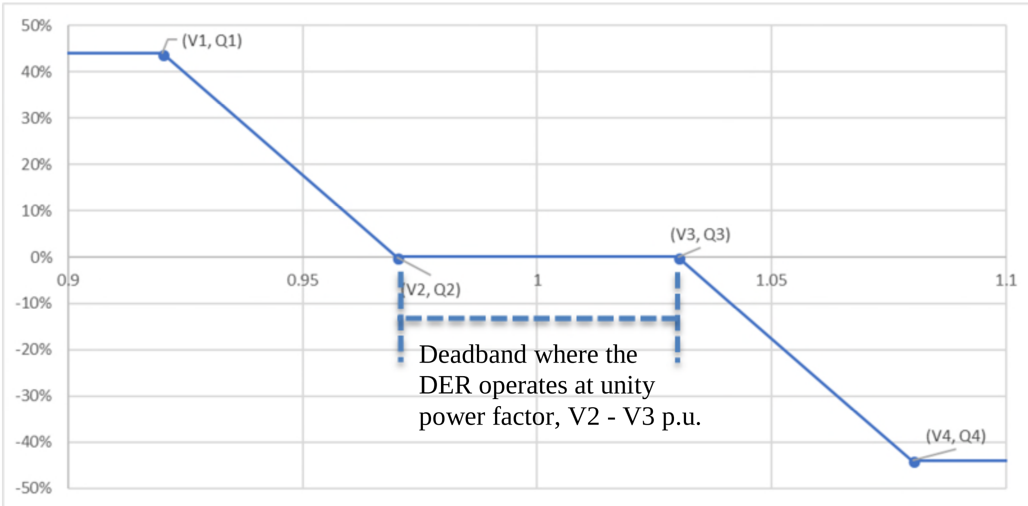
A. VOLT/VAR

Q. COULD YOU PLEASE EXPLAIN WHAT THE "VOLT/VAR" FUNCTION DOES?

A. Volt/VAR, also commonly referred to as "Volt-Var Mode" or "Voltage-reactive power mode," is intended to stabilize grid voltages and enable the DERs to either supply or absorb reactive power in response to local voltage issues. The amount of reactive power that gets injected or absorbed is dictated by a curve defining the percentage of reactive power (Q) versus per-unit voltage (V) at the DER. A typical Volt/VAR curve is set with four pairs of data points (V, Q) as shown in Figure 1. The Volt/VAR mode also includes a dead-band, located between V2 and V3. Reactive power injection or absorption will only occur when voltage is outside of the dead-band, *i.e.*, voltage drops below V2 or rises above V3.

[5] "VAR" stands for "volt-ampere-reactive" and is a unit of measurement for reactive power.

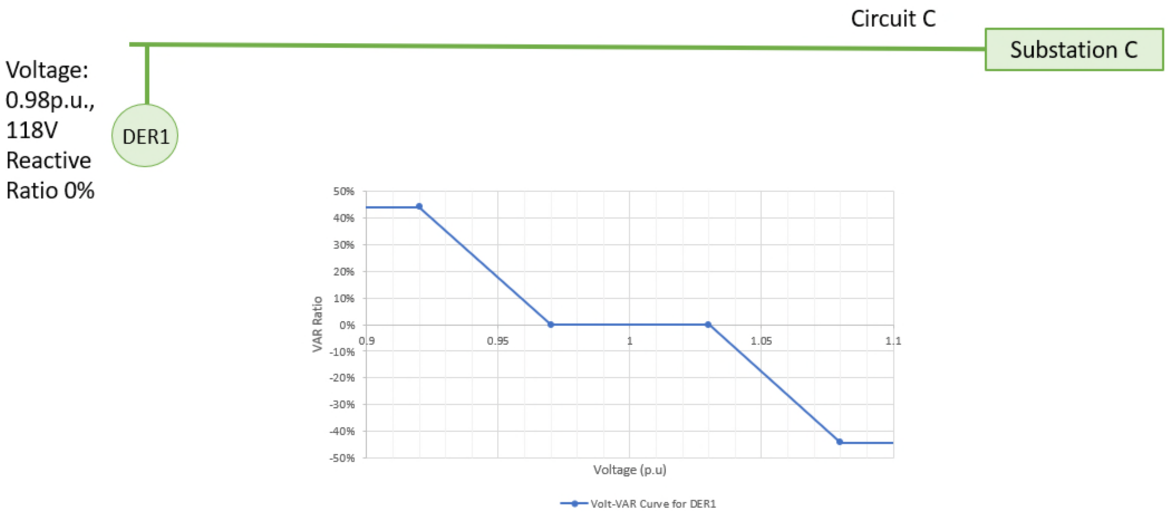
Figure 1 – Default Volt/VAR Curve



Under the Company's DER Management Plan, Volt/VAR will be the default enabled voltage regulating mode for all inverter-based DERs. During interconnection, the Company will specify a default curve as categorized in Table 2 of PPL Electric Exhibit SS-1R. However, depending on the feeder's characteristics and the DER's location, a different curve with a revised voltage dead-band that is still within the range of the IEEE 1547-2018 allowable settings might be issued instead of the default. The Volt/VAR curve selected when the DER is interconnected will only be actively adjusted to a different curve when there is a significant load profile changes on the feeder, such as when the feeder has been reconfigured permanently and when new load(s) or generator(s) connect or disconnect from the distribution system.

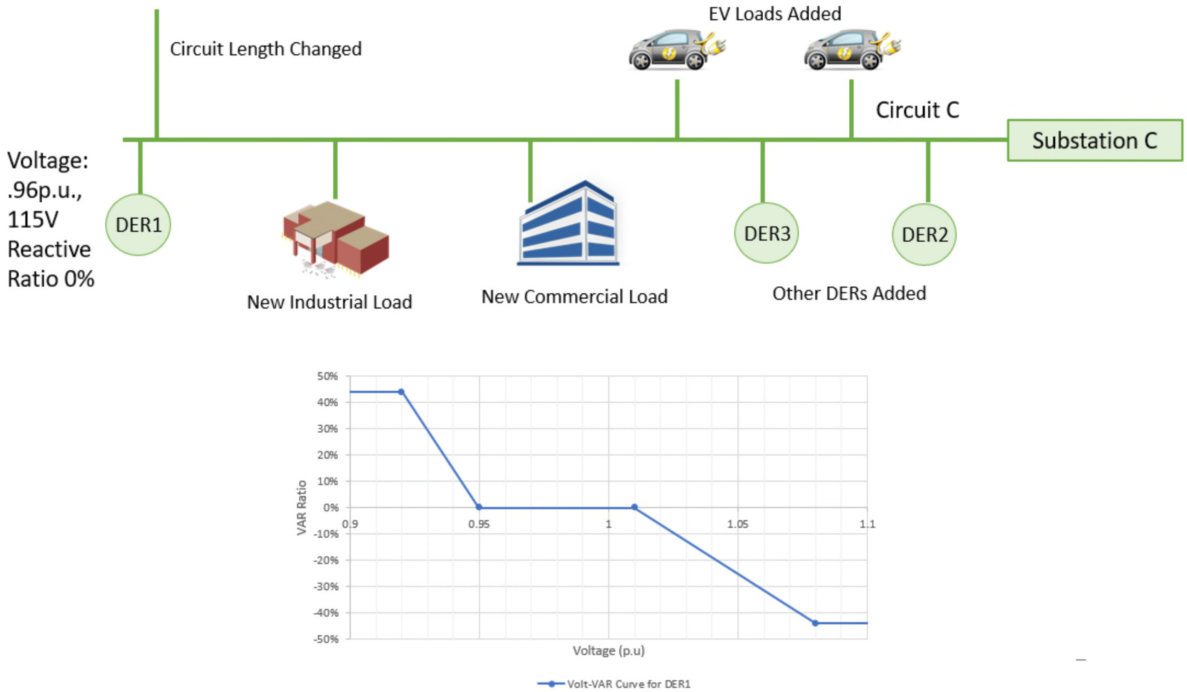
Figures 2-A and 2-B below provide examples of significant load profile changes where PPL Electric would adjust the original Volt/VAR curve.

Figure 2-A – Circuit C at Time of DER1's Interconnection



In Figure 2-A, Circuit C has a single DER (called "DER1") connected to it. At the time of interconnection, a Volt/VAR curve was selected that fit the needs of Circuit C at that time. Specifically, a Volt/VAR curve of 0.97-1.03 per unit was selected, and there are no voltage issues on Feeder B.

<u>Figure 2-B – Circuit C after Dynamic Changes to the Circuit</u>



In Figure 2-B, there have been changes to Circuit C. The feeder now has additional load and DERs added to it, such as more DERs, EVs, and residential and commercial load. In addition, the feeder length has increased. These changes impact the voltage and load characteristics of Circuit C, which requires a new Volt/VAR curve to be selected. Here, the Volt/VAR curve is shifted from the original 0.97-1.03 per unit to 0.95-1.01 per unit. As shown in Figure 2-B, DER1 now experiences an average distribution system voltage of 115 Volts ("V"). If the Volt/VAR curve remains with a dead-band of 0.97 to 1.03 (*i.e.*, 116.4 V to 123.6 V), the DER system would be injecting VARs often. By reissuing the Volt/VAR curve with a dead-band shifted to 0.95 to 1.01 (*i.e.*, 114.0 V to 121.2 V), the DER will not inject or absorb VARs often. Without communication and remote management capabilities, this change would have to be

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performed manually by the customer or by PPL Electric. Therefore, remote management of the Volt/VAR curve is quicker, avoids disrupting the customer, and is less expensive.

Lastly, the Volt/VAR curve might also be temporarily disabled and overwritten with a Constant Power Factor during dynamic system reconfiguration, where circuits are reconfigured temporarily due to an outage, maintenance, or equipment failure. This will be discussed in detail later in my rebuttal testimony.

Q. WHAT BENEFITS WOULD THE "VOLT/VAR" FUNCTION PROVIDE TO PPL ELECTRIC AND ITS RATEPAYERS?

A. Volt/VAR function provides a series of benefits to PPL Electric and its ratepayers:

First, utilizing Volt/VAR function allows DERs to maintain reliable voltage levels on the distribution system without causing adverse impacts to power quality of the grid. Due to DERs' variation in output, they can cause transient voltage swings, flicker, and overvoltage, which might negatively affect customers' equipment or appliances. PPL Electric is required to maintain voltage within American National Standards Institute ("ANSI") C84.1 acceptable limits for all customers, including the DER customers.

Second, implementing Volt/VAR across the distribution system increases the amount of DERs that can be interconnected to the system before making costly system investments. This is known in the industry as increasing "hosting capacity." For each area of a circuit where a DER may interconnect, the Company evaluates specific criteria, including loading, voltage and protection, and their associated limits, for possible negative system impacts. For residential solar systems, the most common criterion typically violated is overvoltage. Typically, this is due to a combination of comparably high solar generation output and low demand (especially during spring and autumn months). DERs equipped with Volt/VAR can absorb reactive power during these times, which effectively lowers the voltage and avoids overvoltage conditions. As a result, more solar systems can be hosted on that distribution circuit without overvoltage violations.

Third, continuing with the previous scenario where even a small DER will cause a localized overvoltage condition, costly system investments in voltage control equipment are required at the time of interconnection without the Volt/VAR function activated. For example, the traditional device used to reduce voltage on a circuit is a voltage regulator, which costs approximately $60,000. The Volt/VAR function allows deferral or avoidance of some of the costly distribution upgrades by allowing for the absorption of reactive power on an as-needed basis.

Q. WOULD THE COMPANY'S USE OF THE "VOLT/VAR" FUNCTION AFFECT THE DER'S REAL POWER OUTPUT, AS ALLEGED BY OCA WITNESS NELSON?

A. Activation of Volt/VAR does have the potential for real power curtailment during periods of high voltage on the specific feeder. However, as shown in PPL Electric Exhibit SS-1R, the inverters do not inject or absorb reactive power when voltage is within the normal, relatively wide range of 0.97 per unit voltage to 1.03 per unit voltage, which is relatively wide (116.4 V and 123.6 V on a 120 V base). It is important to note that a DER's real power output is only impacted when the DER is generating more than 90% of the inverter's kW rating or said another way, is operating at greater than 90% efficiency.

Simulations and field pilot studies have suggested that the risk of DER real power output curtailment is very low, even negligible in most cases.[6] For example, the National Renewable Energy Laboratory's ("NREL") study on HECO circuits showed that enabling Volt/VAR system-wide resulted in real power curtailment of less than 0.5% during high voltage periods.[7]

B. REMOTE ON/OFF

Q. COULD YOU PLEASE EXPLAIN WHAT THE "REMOTE ON/OFF" FUNCTION DOES?

A. Remote On/Off function, also commonly referred to as "Connect/Disconnect function," allows the inverter to be connected or disconnected remotely. When the inverter is disconnected or turned off, the DER's power output will drop to zero.

Under the DER Management Plan, the Company only will utilize this function in two scenarios. The first scenario is during emergency situations, such as a gas leak or fire in the vicinity of the DER. In this scenario, the Company is requested by the gas company or by the local fire department to shut off all power sources at the scene for the safety of the public and emergency personnel. The second scenario is during situations where DERs back-feed a segment of the distribution system that was de-energized due to an outage, also known as "unintentional islanding." During any of these situations, the section of the distribution system that is impacted the gas leak, fire, or unintentional

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[6] Examining Benefits and Impacts of the IEEE1547 Smart Inverter Settings. EPRI, Palo Alto, CA: 2019. 3002015280.

[7] Giraldez Miner, Julieta I., Hoke, Anderson F., Gotseff, Peter, Wunder, Nicholas D., Emmanuel, Michael, Latif, Aadil, Ifuku, Earle, Asano, Marc, Aukai, Thomas, Sasaki, Reid, & Blonsky, Michael. Advanced Inverter Voltage Controls: Simulation and Field Pilot Findings. United States. doi:10.2172/1481102.

islanding must be de-energized along with all DERs connected to it. However, the Company only needs to remotely turn off the DERs when they are not automatically disconnected by their smart inverters as further described below.

Q. WHAT BENEFITS WOULD THE "REMOTE ON/OFF" FUNCTION PROVIDE TO PPL ELECTRIC AND ITS RATEPAYERS?

A. All IEEE 1547 compliant inverters are equipped with anti-islanding protection which is intended to automatically shut off DER systems following the loss of the primary source of electricity. If DERs fail to shut off, however, it may lead to maintaining a segment of the grid energized, which is known as "unintentional islanding." Unintentional islanding poses a safety concern to utility workers and the public because they may believe that a line is deenergized since the upstream protective device is open. However, if the DER fails to shut down, the DER is continuing to feed electricity into the line. In addition, unintentional islanding may cause overvoltage and power quality issues. During an outage, the segment of the distribution system that is impacted by the outage is required to be deenergized, including all DERs connected to it. But if the DER fails to shut off and, as a result, creates an unintentional island, the Company must shut it off to eliminate the risks associated with it. The safest and most efficient way to turn off the DER is by using the Remote On/Off function on the DER's smart inverter.

When there is a gas leak or fire, the safety benefits are even clearer. During a gas leak, any electricity flowing in the vicinity of the leak poses the risk of sparking and igniting a gas explosion. During a fire, electricity needs to be shut off to the facility that is on fire to help ensure the safety of the first responders. In either situation, the standard industry practice is to shut off all electricity sources as a matter of safety. It is also in the DER customers' best interest to shut off their systems in those situations because doing so helps ensure their physical safety and protect their property and facilities.

Q. WOULD THE COMPANY USE THE "REMOTE ON/OFF" FUNCTION IF THERE IS A "GRID FAILURE," AS ALLEGED BY SEF WITNESSES COSTLOW AND CELENTANO (SEF ST. NO. 1 (NON-PROPRIETARY), PP. 10, 12; SEF ST. NO. 2, P. 14)?

A. As previously explained, during an outage, PPL Electric will only use the Remote On/Off function when there is unintentional islanding. The Company will use its DER Management devices to monitor and detect any unintentional islanding that occurs and will use the Remote On/Off function to shut off the DER(s) responsible for the unintentional islanding. Otherwise, so long as the smart inverters shut off the DERs as designed during an emergency situation or outage and there is no unintentional islanding, the Company will not prevent the customer from using a backup power source, such as a battery or a generator. Therefore, SEF's witnesses' concerns about PPL Electric using the Remote On/Off function when there is a "grid failure" are without merit.

Q. SEF WITNESSES COSTLOW AND CELENTANO ALSO CONTEND THAT THERE IS NO NEED FOR THE COMPANY TO USE THE "REMOTE ON/OFF" FUNCTION BECAUSE ALL INVERTERS HAVE TRANSFER SWITCHES THAT DISCONNECT THE DER FROM THE GRID WHEN THERE IS A

POWER FAILURE. (SEF ST. NO. 1 (NON-PROPRIETARY), PP. 10, 12; SEF ST. NO. 2, P. 14.) DO YOU AGREE?

A. Absolutely not. The SEF witnesses' sole reliance on the DERs to automatically shut off on their own is not a safe approach. Even today, emergency personnel still manually check the DERs in PPL Electric's service territory to make sure they are turned off during an emergency. Therefore, as explained previously, the Company needs the Remote On/Off function in case DERs are not automatically turned off during the scenarios described above.

C. <u>CONSTANT POWER FACTOR</u>

Q. COULD YOU PLEASE EXPLAIN WHAT THE "CONSTANT POWER FACTOR" FUNCTION DOES?

A. Constant Power Factor mode, also commonly referred to as "Fixed Power Factor Function" or "Specified Power Factor," allows the inverter to operate at a specific power factor based on a pre-determined or real time system voltage need. Under the DER Management Plan, Volt/VAR is the default voltage regulation mode. Therefore, under normal operating conditions, the Constant Power Factor function will remain deactivated.

However, the Company may need to use Constant Power Factor temporarily in certain situations. One scenario where it may be used is during a distribution system reconfiguration, where the DER is transferred to another feeder because of outages, system maintenance, or equipment failure. When a DER with a certain Volt/VAR curve is transferred to another feeder, the curve that is used in the DER may not be adequate to support the voltage characteristics of the new feeder. If that happens, the DER may cause a voltage issue on the new feeder. Therefore, PPL Electric would use Constant Power Factor to temporarily change the Volt/VAR curve so that the DER no longer causes the voltage issue on that feeder.

I want to emphasize that DER transfers are temporary in nature and, at times, are executed automatically through the Company's Distribution Management System ("DMS"). With Constant Power Factor, DERMS, which is part of DMS, could study the DER's new feeder, calculate a Constant Power Factor that fits the DER's new feeder, and change the configuration of the DER. Specifically, one component of PPL Electric's DERMS is the voltage management application, known as Volt/VAR Control ("VVC"). This application optimizes voltage by coordinating and controlling PPL Electric's distribution system voltage control infrastructure, such as substation transformer tap changers, capacitor banks, and voltage regulators. In the scenario mentioned above where the DER is transferred to another feeder, VVC would monitor and manage power factor and then issue an appropriate power factor setting via the Constant Power Factor function to the DERs. This functionality may bring power factor to unity or the range of the Constant Power Factor would be between 0.9 leading to 0.9 lagging.

Q. WHAT BENEFITS WOULD THE "CONSTANT POWER FACTOR" FUNCTION PROVIDE TO PPL ELECTRIC AND ITS RATEPAYERS?

A. As discussed above, PPL Electric believes Constant Power Factor has the best value when it acts as a supplement to the Volt/VAR function. In PPL Electric Exhibit SS-3R, Figure 1 shows two example circuits, each with one generator (G1 and G2), and examples of Volt/VAR curves to be applied to each generator respectively. Due to voltage drop, most distribution systems are designed to start at the substation with higher voltage, approximately 124 – 125 V. As electricity flows downstream away from the substation, the voltage will drop in relative proportion to the customer loads and impedances on the circuit. Therefore, starting with a higher voltage near the substation accounts for this voltage drop and maintains acceptable voltage at the end of the line.

In Figure 1, a generator connected near the distribution substation on the left, Substation A, would reasonably have a voltage of approximately 124 – 125 V, as shown at location G1 of Circuit A. Towards the end of the line, however, lower voltages, in the range of 115 – 116 V are expected, as shown at location G2 of Circuit B. The Volt/VAR curves for these two generators follow their system location and expected voltage range where unity power factor (0% VAR Ratio) can be maintained. The Volt/VAR curve for G1 maintains its dead-band and a VAR Ratio (power factor) of 0% for voltages on the higher end of the scale, while the Volt/VAR curve for G2 maintains its dead-band and a Reactive Ratio (power factor) of 0% for voltages on the lower end of the scale.

In an event where Circuit A is being fed from Circuit B temporarily, as shown in Figure 2, G1 has moved, electrically speaking, from near Substation A to far away from Substation B. G1 will now experience a much lower voltage, although still within the acceptable range, because it is at the end of the circuit. In this scenario, G1's Volt/VAR curve would have the generator exporting VARs to raise the voltage according to its curve. However, since G1 is now at the end of the circuit temporarily, it actually does not need to export VARs. The Constant Power Factor function could override the Volt/VAR curve and return G1's VAR Ratio to 0%. Without the Constant Power Factor function, the DER would export VARs unnecessarily. It may even need to be shut off to maintain voltage on the circuit, which would prevent the DER from generating. Therefore, this example shows how PPL Electric can use Constant Power Factor to maintain a feeder's voltage quality during the temporary transfer of a DER.

D. VOLTAGE RIDE-THROUGH

Q. COULD YOU PLEASE EXPLAIN WHAT THE "VOLTAGE RIDE-THROUGH" FUNCTION DOES?

A. Voltage Ride-through, if enabled, allows inverters to continue operating or "ride-through" during momentary voltage and frequency deviations.

Under the DER Management Plan, Voltage Ride-through will be enabled during the DER's interconnection. The Company's default settings for the Voltage Ride-through function are shown in Tables 3 and 4 of PPL Electric Exhibit SS-1R. The Voltage Ride-through settings developed by the Company are designed to coordinate with North American Electric Reliability Corporation's ("NERC") standard PRC-024-02: Generator Frequency and Voltage Protective Relay Settings and are within the available range specified in IEEE 1547-2018.

Voltage Ride-through settings are designed for both distribution system support as well as bulk electric system reliability needs. Unique system characteristics such as distribution reclosing times, transmission clearing times and coordination with synchronous machines play into the determination of the Ride-through settings. The Company's settings were chosen so the DERs: (1) ride-through voltage and frequency disturbances on the bulk electric system and distribution system longer than the larger generators; and (2) better support system-wide stability. These settings might need to be updated based on industry stability requirements or planning requirements, as the distribution system or bulk electric system changes. Voltage Ride-through settings might also need to be adjusted after the industry gathers more data about inverter-based DERs and learns more about the settings' impact on anti-islanding schemes of inverters. With active management provided by the DER Management Plan, these settings can be automatically changed if needed in the future, thereby avoiding the costs associated with manual setting changes.

Q. WHAT BENEFITS WOULD THE "VOLTAGE RIDE-THROUGH" FUNCTION PROVIDE TO PPL ELECTRIC AND ITS RATEPAYERS?

A. Voltage Ride-through enables the DER to ride-through transient grid voltage disturbances instead of tripping offline. During a transmission fault, voltage on the distribution system may temporarily sag until the fault is isolated by the transmission protection schemes and breakers. If hundreds or even thousands of DERs trip offline due to that fault, the sudden appearance of this masked load can further destabilize the distribution system and bulk electric system, which decreases the voltage and increases the likelihood of a cascading outage.[8] With Voltage Ride-through capabilities, DERs can help support the distribution system and the bulk electric system rather than exacerbating the problem. Voltage Ride-through allows the DERs to stay connected during the temporary voltage sag instead of

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[8] As noted on pages 19-20 of my direct testimony (PPL Electric Statement No. 1), a black out affecting approximately 1.1 million customers occurred in the United Kingdom on August 9, 2019. During this cascading event that started with a transmission disturbance, a total of approximately 500 MW of DER generation was unexpectedly lost due to protection settings inside the inverters without EDCs even knowing about it and, therefore, further increased the total customers impacted by the event.

tripping off, thereby avoiding the continued load increase and voltage decrease and the potential frequency excursions. Voltage Ride-through also enables DERs to perform momentary cessation, such that inverters can suspend feeding current onto the grid until the voltage and frequency return to within the normal threshold instead of tripping offline completely. Voltage Ride-through, specifically, high Voltage Ride-through, also allows DERs to respond quickly during high voltage excursions without tripping, which minimizes disruptions. Other than the benefits to the distribution system and bulk electric systems, more importantly, Voltage Ride-through also has substantial benefits to individual DER customers because it allows the DER system to continue generating electricity and, therefore, revenue during those events.

E. FREQUENCY RIDE-THROUGH

Q. COULD YOU PLEASE EXPLAIN WHAT THE "FREQUENCY RIDE-THROUGH" FUNCTION DOES?

A. Frequency Ride-through allows inverters to continue operating or "ride-through" during momentary frequency deviations.

Under the DER Management Plan, Frequency Ride-through will be enabled during the DER's interconnection with the default settings shown in Table 5 of PPL Electric Exhibit SS-1R. The Frequency Ride-through settings developed by the Company are designed to coordinate with NERC's standard PRC-006-02: Automatic Under-frequency Load Shedding and are within the available range specified in IEEE 1547-2018.

Frequency Ride-through settings are designed for both distribution system support as well bulk electric system reliability needs. Unique system characteristics such as distribution reclosing times, transmission fault clearing times and coordination with synchronous machines play into the determination of the Frequency Ride-through settings. The Company's settings were chosen so the DERs: (1) ride-through frequency disturbances on the bulk electric system longer than larger generators as specified in PRC-0024-02; and (2) pickup at a lower frequency than under-frequency load-shed requirements specified in PRC-006-02 to support system-wide stability. These settings may need to be updated based on industry stability requirements or planning requirements as the distribution system changes. Frequency Ride-through settings might also need to be adjusted once the industry learns more about the settings' impact on anti-islanding schemes of inverters and gathers more data on inverter-based DERs. With active management provided by the DER Management Plan, these settings can be automatically changed if needed in the future, thereby avoiding the costs associated with manual setting changes.

Q. WHAT BENEFITS WOULD THE "FREQUENCY RIDE-THROUGH" FUNCTION PROVIDE TO PPL ELECTRIC AND ITS RATEPAYERS?

A. Instead of tripping offline during transient transmission or distribution system events resulting in frequency deviations, DERs will ride-through the disturbance according to the specified settings. During an under-frequency or an over-frequency event on the bulk electric system, traditionally, frequency falling outside of the normal operating ranges, even very briefly, will cause DERs to disconnect. Like Voltage Ride-through, Frequency

Ride-through capabilities allow DERs to stay connected and ride-through frequency deviations. This helps stabilize the bulk electric system and the distribution system instead of exacerbating the problem with more frequency deviation caused by the tripping DERs.

This is particularly relevant for coordinating with under-frequency load-shed required by NERC's standard PRC-006-02, which requires the Company to shed 10% of system load in three frequency steps. In a real under-frequency event, system frequency is decreasing because there is more load than generation. In that situation, tripping inverters offline during this event would only accelerate a system-wide blackout because the masked load must suddenly be supplied by the large generators, further decaying system frequency. Keeping the DERs online would allow the DERs to continue offsetting the masked distribution load, which would support recovery of system-wide frequency and potentially prevent a blackout. From the DER customer's perspective, Frequency Ride-through would allow the DERs to continue generating electricity and, therefore, revenue during those events.

F. <u>VOLT/WATT</u>

Q. OCA WITNESS NELSON RAISES A QUESTION ABOUT THE COMPANY POTENTIALLY USING THE "VOLT/WATT" FUNCTION. (OCA ST. NO. 1, PP. 14-15.) WILL PPL ELECTRIC USE THE VOLT/WATT FUNCTION UNDER ITS DER MANAGEMENT PLAN?

A. Under the Company's DER Management Plan, PPL Electric will not require DER systems to have Volt/Watt enabled, however, the Company reserves the right to offer

Volt/Watt function to customers as an alternative to system upgrades at the time of interconnection on a case-by-case basis. Also, in cases where system upgrades are planned for other reasons, the customer could opt to utilize the Volt/Watt setting temporarily until the scheduled upgrades are completed, after which the customer could choose to disable the Volt/Watt setting. Thus, although Volt/Watt is not required under the DER Management Plan, customers should have the option of implementing a Volt/Watt curve in lieu of paying for system upgrades or temporarily until other scheduled system upgrades are finished.

G. OTHER PARTIES' QUESTIONS ABOUT THE DER MANAGEMENT PLAN WHITE PAPER AND THE COMPANY'S TARIFF

Q. OCA WITNESS NELSON AND SEF WITNESS COSTLOW HAVE ALSO RAISED CONCERNS ABOUT THE COMPANY'S SPECIFICATIONS FOR THE GRID SUPPORT FUNCTIONS BEING OUTLINED IN THE COMPANY'S DER MANAGEMENT PLAN WHITE PAPER, RATHER THAN IN THE DER MANAGEMENT PETITION, THE COMPANY'S PRO FORMA TARIFF SUPPLEMENT, OR BOTH. (OCA ST. NO. 1, PP. 11-12, 35-39; SEF ST. NO. 1 (NON-PROPRIETARY), P. 4.) COULD YOU PLEASE RESPOND?

A. I have been advised by counsel that there was no requirement for PPL Electric to include the DER Management Plan White Paper in its DER Management Petition. Moreover, the White Paper was a preliminary draft document that described, among other things, the grid support functions that the Company envisioned potentially using under its DER Management proposal. The Company always intended to either update the draft White Paper or develop a new document based upon the outcome of this proceeding, which could change the actual specifications that would be permissible under the Company's DER Management Plan.

In addition, there is no need for all of these specifications to be set forth word-for-word in the Company's Commission-approved tariff. In fact, it is my understanding there are many regulatory requirements that PPL Electric must follow that are not included in its tariff. For example, the Company's Phase III Energy Efficiency and Conservation ("EE&C") Plan is not a part of the Company's tariff; however, I have been advised by counsel that PPL Electric must still follow that EE&C Plan.

Furthermore, all of these specifications will be set forth in the Company's Rules for Electric Meter & Service Installations ("REMSI"), which is incorporated explicitly into PPL Electric's proposed Rule 12 – Distributed Energy Resource (DER) Interconnection Service. The Company's REMSI is publicly-available on the Company's website.[9] Therefore, customers, DER owners, DER installers, and any other interested persons will be able to access the Company's website and obtain a complete list of the Company's specifications for the grid functions that PPL Electric will use under the DER Management Plan.

IV. PPL ELECTRIC'S DER MANAGEMENT PROPOSAL IS NOT PREMATURE

Q. OCA WITNESS NELSON AND SEF WITNESSES COSTLOW AND CELENTANO GENERALLY ALLEGE THAT THE COMPANY'S DER MANAGEMENT PROPOSAL IS PREMATURE. (OCA ST. NO. 1, PP. 17-35; SEF

[9] *See* "Rules for Electric Meter & Service Installations (REMSI)," *available at* https://www.pplelectric.com/remsi.

ST. NO. 1 (NON-PROPRIETARY), PP. 5-9, 14; SEF ST. NO. 2, PP. 6-8, 10-11, 13, AND 15.) DO YOU AGREE WITH THEIR POSITION?

A. No, I do not agree with the other parties for several reasons. First, as explained in Mr. Whitley's rebuttal testimony (PPL Electric Statement No. 4-R), the fundamental fallacy underpinning the OCA's and SEF's claims is that the Company only needs to take action when DER penetration levels increase to the point where PPL Electric is experiencing wide-spread issues. Such an approach is harmful to PPL Electric and its customers and inconsistent with prudent system planning. In the Company's direct testimony, Mr. Whitley and Ms. Reder outlined several instances where electric utilities experienced many problems due to their failure to prepare for increased levels of DERs. (*See* PPL Electric Statement No. 2, pp. 12-13, 16-17; PPL Electric Statement No. 4, pp. 8.) PPL Electric wants to learn from the mistakes of these other states, not repeat them. By the other parties' logic, PPL Electric cannot address the issues presented by DERs until the number of DERs increases to an unspecified point where the Company is already experiencing or is at substantial risk of experiencing severe problems on its distribution system. The time to address issues is before, not after, they occur.

Second, the other parties fail to recognize that PPL Electric is experiencing issues now with its current level of DERs. Contrary to OCA witness Nelson's characterization, PPL Electric is <u>not</u> only experiencing two-way power flows on a "*de minimus* number of circuits." (OCA St. No. 1, p. 33.) Mr. Nelson misinterpreted the Company's answer in discovery, which he relied on in making this statement. PPL Electric's discovery response provided "examples" of circuits experiencing issues. In actuality, PPL Electric is experiencing two-way power flows on most circuits that have DERs interconnected.

Even though the Company may have lower penetration levels than utilities in other states such as California and Hawaii, PPL Electric's circuits experience two-way power flow on a regular basis.

Indeed, as seen in Figure 3 below, a single-phase line can regularly experience two-way power flow with only a few DERs.

<u>Figure 3 – Example of Two-Way Power Flows</u>

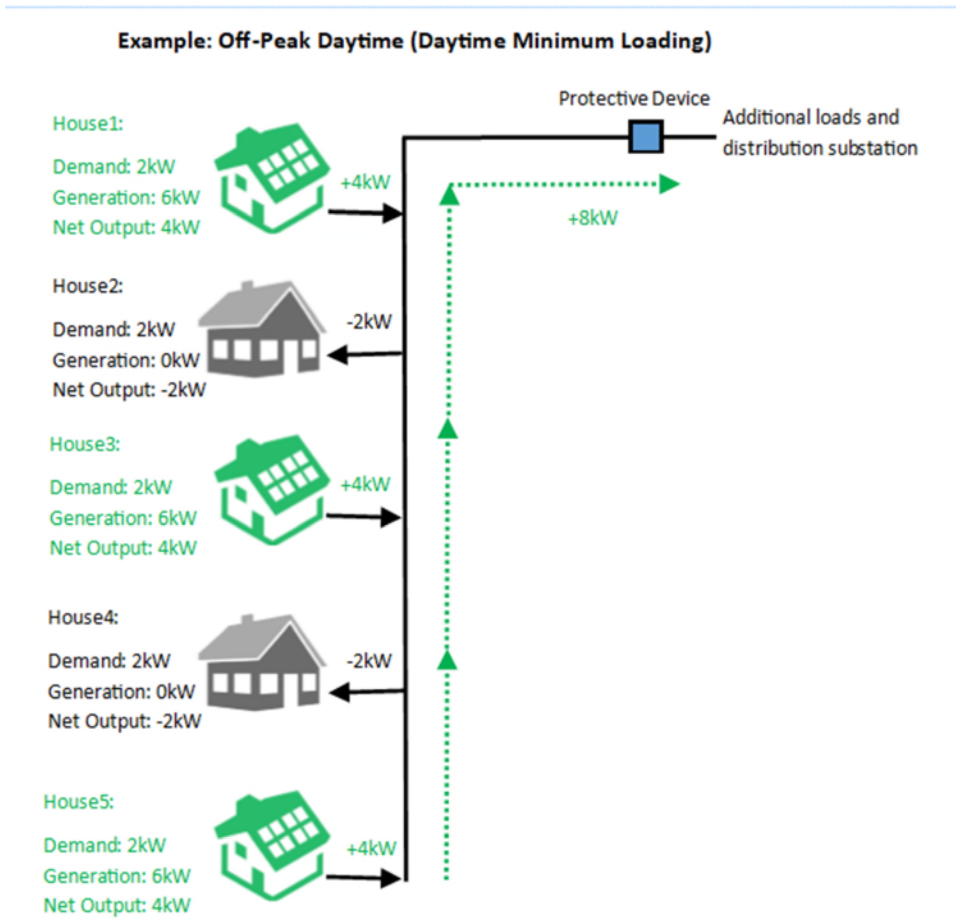


Figure 3 shows five homes connected downstream from the protective device. Three of the homes have solar on their roofs, with a total of 18 kW of generation available. Each home has 2 kW of demand, totaling 10 kW for all homes. When the solar installations are at maximum efficiency and are producing maximum output, a total of 8 kW will be generated back onto the grid, away from the houses, and through the protective device (18 kW generation – 10 kW demand = 8 kW generation). When the sun sets and the solar panels are not generating, the power will be flowing in the opposite direction with a total of 10 kW flowing into the homes (*i.e.*, 2 kW demand from each home). Thus, this example shows how, as a fundamental, indisputable premise, two-way power flows are occurring regularly on PPL Electric's distribution system.

The safety and reliability implications of two-way power flows are very important. A member of the public, a Company employee, or emergency personnel could come in contact with an unknowingly-energized downed wire if the inverters have not shut off and have created an unintentional island.

Yet, it is impossible to know when and where all of these scenarios occur without real-time data about the DER's generation output, such as through the installation and use of DER Management devices. Therefore, with the implementation of the DER Management Plan, PPL Electric will be able to better detect and respond to two-way power flows on its distribution system.

In addition to two-way power flows, the Company is experiencing hidden load issues due to the current levels of DER penetration. When a fault occurs on the distribution system, nearby DERs are designed to trip offline in response. When service is restored, the DERs generally have a reconnect time delay of a few minutes before they resume generating power. During that delay, the load that is normally served by the DERs must now be served by the Company until the DERs resume generation. Without real-time monitoring of DERs, the system cannot know how much hidden load PPL Electric needs to serve until the DERs come back online. As a result, the Company's and the customers' equipment could be potentially damaged by overloading, thereby delaying service restoration.

For this example, in Figure 3 above, the homes' total actual electric demand is 10 kW. However, PPL Electric's DMS is unable to "see" the entire 10 kW of demand because that load is being "masked" or "hidden" since it is being fed from the solar customers nearby, who have 18 kW of generation. During peak generation output, PPL Electric's substation is not directly providing the electricity to feed the loads for the five homes shown in this example, so the DMS system cannot account for needing to do that when it is completing its automatic analysis of the distribution system. Additionally, DMS is unaware of the bi-directional power flow, *i.e.*, a total of 8 kW of generation flowing away from the houses. If an outage occurs on this circuit, PPL Electric's DMS will run calculations and automatically transfer these homes to a different circuit in order to restore their power.

However, because the load of these homes was being fed from the solar generation, the load was "masked" or "hidden" and could not be accounted for in DMS's calculations. Once the houses' power is restored through a different circuit, all 10 kW of the houses' load will be fed from the new circuit during the estimated five minutes that it takes the solar generation to turn back on. This results in an unaccounted for demand of an additional 10 kW that is now flowing from the distribution substation and through the protective device towards the houses. If this scenario occurred on multiple sections of one or more feeders simultaneously, as would happen on PPL Electric's system in real time, the load hidden by the DERs would quickly become a very large problem.

But with the DER Management Plan, PPL Electric would be able to know how much generation output is coming from every DER that is equipped with the DER Management device. Therefore, the Company would be able to detect the "masked" or "hidden" load on its system, and PPL Electric's DMS could properly account for such load when performing its calculations during an outage.

Third, in contrast to other electric utilities that have made proposals to monitor and manage DERs, PPL Electric has all of the necessary infrastructure and equipment in place to implement its DER Management proposal. The Company has been and continues to be an industry leader for implementing grid modernization technologies such as Distribution Automation, DMS, and Fault Isolation and Service Restoration ("FISR"), which provided the Company with the infrastructure needed for centralized monitoring and management of the distribution system. To date, these technologies have eliminated permanent outages for over 900,000 customers since 2015. PPL Electric is also the only utility in the Commonwealth that currently has an operational DERMS platform, which is built and integrated with the Company's existing technologies and would enable the Company to take advantage of the smart inverters' grid support functions. In addition, the Company has a RF Mesh network that is capable of handling all of the communications between PPL Electric and the smart inverters through the Company's service territory. PPL Electric should be permitted to build upon these capital investments and implement its DER Management proposal for the benefit of the Company and its ratepayers, including DER customer-generators.

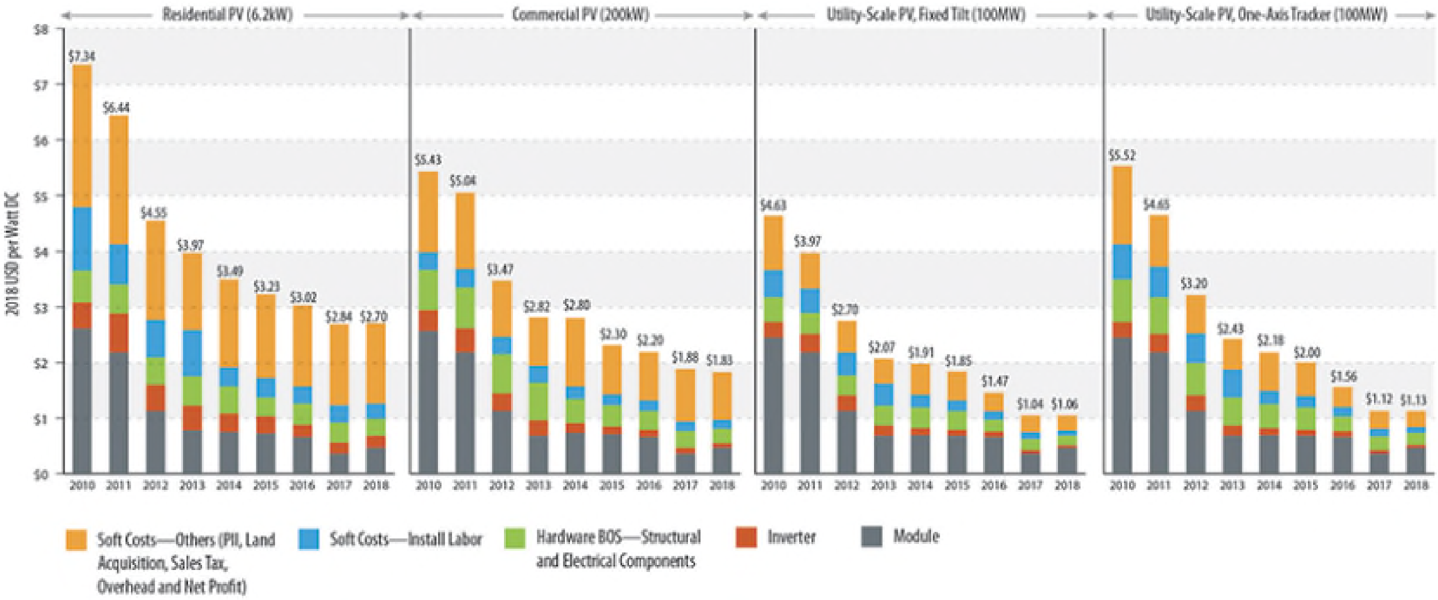
Fourth, PPL Electric thoroughly disagrees with the OCA's and SEF's pessimistic position regarding the potential for DER installations to substantially increase in the

Company's service territory. (*See* OCA St. No. 1, pp. 29-32; SEF St. No. 1 (Non-Proprietary), pp. 5-8; SEF St. No. 2, pp. 6-8.) Indeed, SEF's testimony is replete with references to other states, arguing that Pennsylvania is lagging behind those states in solar penetration and that it is unlikely the Commonwealth will see any substantial increases in the near future. (SEF St. No. 2, pp. 6-8, 13.)

The other parties completely fail to observe the substantial year-over-year decreases in the costs for DERs, and, in particular, solar PV systems. Research completed by NREL in December 2018 shows significant decrease in residential and commercial solar costs, including the solar panel modules, inverters, and labor from 2010 to 2018. Residential installations, for example, dropped 63%, from $7.34 per watt in 2010 to $2.70 per watt in 2018, as seen in Figure 4 below.[10]

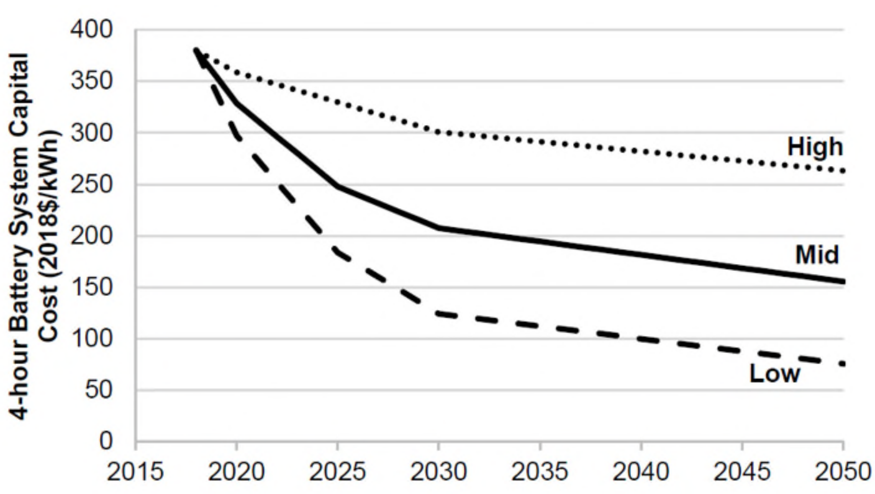
[10] "Costs Continue to Decline for Residential and Commercial Photovoltaics in 2018, *NREL* (Dec. 17, 2018), *available at* https://www.nrel.gov/news/program/2018/costs-continue-to-decline-for-residential-and-commercial-photovoltaics-in-2018.html.

<u>Figure 4 – Residential Solar Installation Costs from 2010 to 2018</u>



Another NREL study shows that utility-scale battery storage costs will continue to decline, with projected decreases by 2025 of 10-52%, as shown in Figure 5 below.[11]

<u>Figure 5 – Projected Utility-Scale Battery Storage Costs (2020-2050)</u>



[11] *See* Cole, W. & Frazier, A, "Costs Projections for Utility-Scale Battery Storage," *NREL* (June 2019), *available at* https://www.nrel.gov/docs/fy19osti/73222.pdf.

In addition, PPL Electric's DER Management proposal will encourage, not discourage, the deployment of DERs in the Company's service territory. When coupling the declining costs of solar PV with the benefits of the Company's proposal, PPL Electric maintains that the amount of solar PV will increase more rapidly in the Company's service territory. Indeed, as noted previously, the Company's proposal will reduce an estimated $393 to $700 in DER installation costs for DERs under 15 kW, which comprise approximately 80% of PPL Electric's existing DERs. Moreover, if the customer's electrical panel needs to be upgraded and the DER is under 15 kW, the ConnectDER DER Management device saves the customer an estimated $1,000 to $1,600 because the DER can be plugged directly into the DER Management device.

Also, a customer's interconnection costs may be further reduced due to an increase in hosting capacity. Today, when an interconnection impact study shows that the circuit does not have enough hosting capacity to accommodate the DER, the customer has to pay for the installation of traditional voltage control equipment, such as a voltage regulator. However, the installed cost of a voltage regulator is approximately $60,000. Under the Company's proposal, PPL Electric can potentially increase a distribution circuit's hosting capacity to the point where the DER can be safely interconnected without the need for any traditional voltage control equipment.

Fifth, as explained by Ms. Reder in her rebuttal testimony (PPL Electric Statement No. 2-R), the other parties' claims about when smart inverters that are compliant with IEEE 1547-2018 will be commercially available do not provide a complete picture. In actuality, compliant inverters are expected to be certified and commercially available as soon as the fourth quarter of 2020. Some inverters also would already have the required functionality due to manufacturers' active participation in standards development and their preparations and proactive efforts to develop compliant inverters before the new standards become final.

Furthermore, the other parties fail to recognize that there may not be any Commission decision on the Company's DER Management Petition until 2021. Right now, briefing in this case will not conclude until May 21, 2020. I have been advised by counsel that there is no established deadline for either the presiding administrative law judge or the Commission to issue their decisions on the Company's DER Management Petition. Moreover, counsel has advised me that parties could seek reconsideration or pursue appeals that would prolong a final adjudication in this matter even further. Therefore, PPL Electric's DER Management Petition was well-timed with the expected availability of smart inverters that are compliant with IEEE 1547-2018.

Sixth, as explained in Mr. Whitley's rebuttal testimony (PPL Electric Statement No. 4-R), the Commission should disregard the other parties' remaining allegations that the Company's DER Management Petition is premature. The critical flaw with their position is their belief that the Company does not need to implement its DER Management proposal because the DER penetration levels in PPL Electric's service territory are not as high as utilities in other states, such as California or Hawaii. However, they only disagree with PPL Electric on the rate of projected growth. No party disputes that DER penetration levels will continue to increase in PPL Electric's service territory. Therefore, it is much better to get ahead of the problem now, especially before too many DERs without compliant smart inverters are installed. In that respect, the lower number of DERs on PPL Electric's system as compared to utilities in other states, such as

California and Hawaii, is all the more reason to implement the DER Management Plan now.

Finally, as a prudent system operator, PPL Electric must be able to know the load and generation that is on its system. Currently, the Company has no ability to know how much load and generation on its distribution circuits are attributable to DERs. This "hidden load" issue can be easily rectified by the Company's DER Management Plan. Through the installation of the ConnectDER DER Management devices, PPL Electric will be able to track, in real-time, the demand and generation of each new DER that is connected to its distribution system. Even today, such information is vitally important for reliability, operating, and system planning purposes and actually will enable the Company to increase the hosting capacity for new DERs.

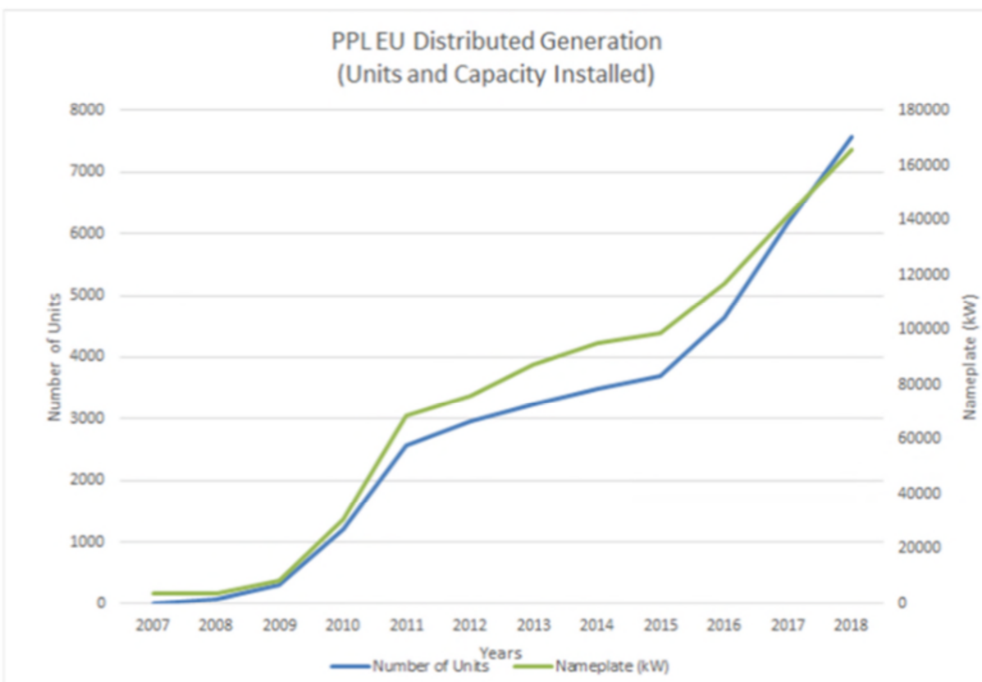
For all of these reasons, PPL Electric can and should take action now to implement IEEE 1547-2018 and the Company's DER Management Plan.

Q. OCA WITNESS NELSON PRESENTS A GRAPH ON THE INCREMENTAL PERCENTAGES OF DER GROWTH IN THE COMPANY'S SERVICE TERRITORY FROM 2010 TO 2018. (OCA ST. NO. 1, P. 32.) IS THIS A SOUND ANALYTICAL APPROACH?

A. No. OCA witness Nelson's graph showing the percentage of incremental solar growth since 2010 is grossly misleading. By using incremental growth percentages, Mr. Nelson makes it appear that the number of DERs being installed year-over-year in PPL Electric's service territory is declining. When you use incremental growth percentages, the initial year or years will show substantial increases because you are starting from zero or a much lower base number of DERs. As the years pass, there generally will be lower percentages of incremental growth because the base number of DERs is increasing. For example, from 2010 to 2011, Mr. Nelson shows that the annual growths in installed units and nameplate capacity dropped from approximately 120% to below 20%. However, the number of installed units and nameplate capacity actually increased from 1,200 and 30.7 MW to 2,571 and 68.5 MW respectively.

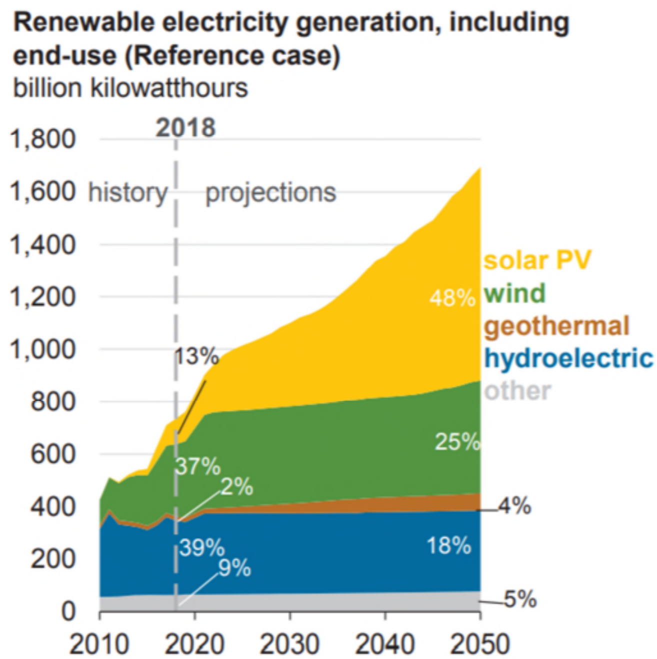
In reality, the correct approach is to rely on the number of DER installations and nameplate capacity shown year-over-year in the Company's service territory. Figure 6 below is a chart that provides a summary of the Company's year-over-year increase in DER installations and nameplate capacity.

<u>Figure 6 – DERs Installed on PPL Electric's Distribution System (2007-2018)</u>



In contrast to Mr. Nelson's Graph 1, this provides a better foundation to project the base level of DERs that will be interconnected in future years. Mr. Nelson also overlooks the U.S. Energy Information Administration's ("EIA") report projecting that national growth for solar generation (including end-use) will increase from 13% in 2018 to 48% in 2050, as shown in Figure 7 below.[12]

<u>Figure 7 – EIA's Projection of National Solar Growth (2018-2050)</u>



Therefore, Mr. Nelson's analysis is critically flawed and should be disregarded.

Q. SEF WITNESS CELENTANO AVERS THAT "THE UL1741 SA STANDARD MAY NOT SYNCHRONIZE WITH THE REVISED IEEE 1547-2018 UNTIL 2021." (SEF ST. NO. 2, P. 6.) WOULD YOU PLEASE RESPOND?

A. Ms. Reder addresses this point in detail in her rebuttal testimony (PPL Electric Statement No. 2-R). However, I want to add how Mr. Celentano fails to recognize that there may

[12] "Annual Energy Outlook 2019 with projections to 2050," *EIA*, p. 21 (Jan. 24, 2019), *available at* https://www.eia.gov/outlooks/aeo/pdf/aeo2019.pdf.

not be any Commission decision on the Company's DER Management Petition until 2021. Right now, briefing in this case will not conclude until May 21, 2020. I have been advised by counsel that there is no established deadline for either the presiding administrative law judge or the Commission to issue their decisions on the Company's DER Management Petition. Moreover, counsel has advised me that parties could seek reconsideration or pursue appeals that would prolong a final adjudication in this matter even further.

V. <u>OTHER PARTIES' RECOMMENDATIONS FOR A STATEWIDE PROCEEDING SHOULD BE REJECTED</u>

Q. THE OTHER PARTIES GENERALLY ARGUE THAT THE COMMISSION SHOULD INITIATE A STATEWIDE PROCEEDING INSTEAD OF GRANTING PPL ELECTRIC'S DER MANAGEMENT PETITION. (NRDC ST. NO. 1, PP. 7-10, 14-18, 32; OCA ST. NO. 1, PP. 4, 46-50, 52; SEF ST. NO. 1 (NON-PROPRIETARY), PP. 9-10, 16; SEF ST. NO. 2, P. 15.) COULD YOU PLEASE SUMMARIZE THEIR POSITIONS?

A. In general, the other parties recommend that the Commission deny the Company's DER Management Petition and initiate a statewide proceeding. However, the parties varied in whether they provided recommendations for the scope of the statewide proceeding, when that proceeding should take place, and the steps (if any) that PPL Electric and other EDCs should be allowed to take in the interim.

Specifically, SEF witnesses Costlow and Celentano contend that the Commission should deny PPL Electric's DER Management Petition and open a statewide stakeholder proceeding. (*See* SEF St. No. 1 (Non-Proprietary), p. 16; SEF St. No. 2, p. 15.) Mr.

Costlow also alleges that there are too few participants in this case and that there is a lack of industry awareness and interest in this proceeding. (*See* SEF St. No. 1 (Non-Proprietary), pp. 9-10.) According to Mr. Costlow, a "statewide stakeholder proceeding" with a wide group of stakeholders would be preferable." (*See* SEF St. No. 1 (Non-Proprietary), pp. 9-10.)

Similarly, OCA witness Nelson recommends that the Commission "[r]equire a state-wide proceeding for implementing IEEE 1547-2018." (OCA St. No. 1, p. 4.) Among other things, Mr. Nelson alleges that a statewide proceeding is "more considered, transparent approach." (OCA St. No. 1, p. 4.) He also avers that changes to interconnection standards should be done on a uniform, statewide basis or else there will be: (1) increased costs for developers and consumers installing DERs within the state; and (2) increased regulatory burden and costs to ratepayers. (OCA St. No. 1, pp. 46-47.) Further, Mr. Nelson claims that a statewide proceeding is needed to address changes to interconnection standards so that PJM Interconnection LLC ("PJM") can participate. (OCA St. No. 1, p. 48.) He also believes that a statewide proceeding would produce "a more fully developed record and additional stakeholder input." (OCA St. No. 1, p. 50.)

Like the OCA and SEF witnesses, NRDC witness Warren recommends that the Commission address these issues in a statewide collaborative proceeding. (*See* NRDC St. No. 1, pp. 7, 32.) According to Mr. Warren, a statewide proceeding would "minimize DER installation costs," would help "assure that inverters are properly configured at the time of installation," and would be more "streamlined and less time-consuming" when "compared to a series of utility-specific proceedings." (NRDC St. No. 1, p. 16.) Mr.

Warren also contends that the Company does not have "unique characteristics that would require utility-specific settings." (NRDC St. No. 1, p. 17.)

However, Mr. Warren differs from the OCA and SEF witnesses by making specific recommendations about the scope and timeline of the statewide proceeding. In fact, Mr. Warren proposes that the statewide proceeding be a "collaborative stakeholder process" that will: (1) "select voltage control modes and settings covering a broad range of applications where autonomous operation based on preset parameters *without* external communication is effective and appropriate"; (2) identify the "applications in which external control and communications would provide advantages commensurate with their costs"; (3) identify the "opportunities to provide additional grid services"; and (4) propose "appropriate compensation mechanisms for DER owners providing those services." (NRDC St. No. 1, pp. 9-10, 32.) He also recommends that the Commission prescribe two outcomes for the stakeholder process: (1) all new inverters installed in Pennsylvania be compliant with IEEE 1547-2018 beginning January 1, 2022; and (2) reductions of solar production be minimized to the extent possible, consistent with safe, reliable, and economic operation of the distribution system. (*See* NRDC St. No. 1, p. 10.)

Furthermore, Mr. Warren suggests "two interim steps" that EDCs should take outside of the stakeholder process and before the statewide process establishes new standards: (1) EDCs should propose under what circumstances the Category II or III requirements for abnormal operation of IEEE 1547-2018 should be applied on their systems, and the Commission should require that compliant inverters be configured in accordance with PJM's ride-through setting recommendations beginning January 1, 2022; and (2) EDCs should be allowed to use UL 1741 SA compliant inverters, DER management devices, and DERMS prior to the completion of the stakeholder process "in order to minimize distribution upgrade costs on a case-by-case basis" and "by mutual agreement of utilities and interconnecting customers." (NRDC St. No. 1, pp. 7, 10-11, 33.)

Like NRDC, PPL Electric supports implementing IEEE 1547-2018 for the Company sooner rather than later. However, unlike NRDC, OCA, and SEF, PPL Electric does not believe that a statewide stakeholder process is the correct approach to address the issues raised by the Company's proposal: (1) PPL Electric has distinct characteristics from its peer EDCs that warrant the Company being able to take action now; (2) the instant proceeding is developing a full and complete record; (3) NRDC's recommendation for pre-determined outcomes of the statewide proceeding raises several issues; and (4) the two "interim steps" that NRDC recommends for EDCs to take outside of the stakeholder process are not enough. Furthermore, I note that the rebuttal testimony of Ms. Reder (PPL Electric Statement No. 2-R) and Mr. Whitley (PPL Electric Statement No. 4-R) respond to other parties' remaining allegations in support of a statewide proceeding.

A. PPL ELECTRIC HAS DISTINCT CHARACTERISTICS FROM ITS PEER EDCS THAT WARRANT THE COMPANY BEING ABLE TO TAKE ACTION NOW

Q. YOU MENTIONED NRDC WITNESS WARREN'S ALLEGATION THAT PPL ELECTRIC DOES NOT HAVE "UNIQUE CHARACTERISTICS THAT WOULD REQUIRE UTILITY-SPECIFIC SETTINGS." (NRDC ST. NO. 1, P. 17.) DO YOU AGREE WITH THAT CHARACTERIZATION?

A. No. Nothing presented by NRDC witness Warren or any of the other parties has established that the other EDCs in Pennsylvania are ready or even willing to: (1) implement IEEE 1547-2018; or (2) develop and implement a DER Management proposal similar to PPL Electric's. Notably, without a DERMS, an EDC cannot implement a proposal similar to PPL Electric's DER Management Plan. Please see Table 1 for a chart breaking down whether other EDCs in Pennsylvania have a DERMS, have DMS, have FISR throughout its entire service territory, and have RF Mesh meters deployed fully and designed to handle communication to inverters.

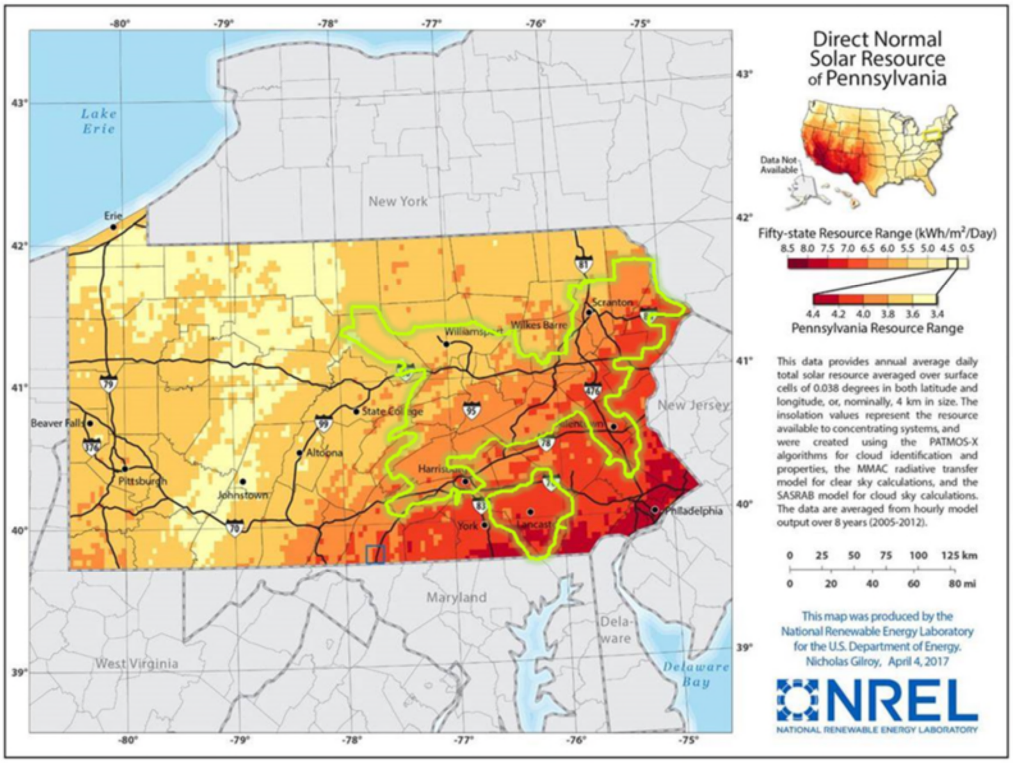
Table 1 – Comparison of EDCs' Technology Infrastructure[13]

EDCs	DMS	Deployed and Fully functional FISR	DERMS	Mesh Network system designed for DER communication
PPL Electric	Y	Y	Y	Y
Duquesne	N*	N	N	N**
PECO	Y***	N****	N	Y

* Duquesne Light Company ("Duquesne") has a Supervisory Control and Data Acquisition ("SCADA") system with more limited visibility and control to its distribution system than PPL Electric's DMS.
** Duquesne has a mesh network deployed, but its network cannot communicate with DERS without further investments
*** PECO Energy Company ("PECO") has a DMS, but its current version of DMS requires further investment in the Geographic Information System ("GIS") modeling
**** FISR algorithm is available in PECO's version of DMS, but it requires investment in the GIS before it is able to be used.

In addition, PPL Electric's service territory and distribution system are different in other ways. First, PPL Electric's territory has some of the highest solar radiation in the state. The map below contains the approximate outline of PPL Electric's service territory overlaid in yellow on top of a solar irradiance map created by NREL.[14]

[13] The FirstEnergy Companies are not listed because information on their technology infrastructure was not readily available.
[14] A copy of this map is public available in at the following URL:



Second, PPL Electric's system is much more rural with much longer circuits compared to other EDCs in the state such as PECO and Duquesne. For example, the average length of PPL Electric's distribution lines is 27 miles, whereas the average length of Duquesne's distribution lines is 5 miles with the longest length at 13 miles. Additionally, 16% of PPL Electric's distribution lines are over 50 miles long, and 7% are over 75 miles long. Long distribution circuits make managing voltage more challenging due to the line losses associated with long distribution lines.

Third, although other EDCs may be experiencing similar challenges as PPL Electric with regards to two-way power flow and hidden load, it is highly impractical and

https://www.heraldmailmedia.com/news/tri_state/pennsylvania/solar-has-potential-in-greencastle-antrim-area/article_4494a04c-b9f5-11e8-83ba-3f7473a8e763.html.

less beneficial for all EDCs to use the same exact Volt/VAR settings to address voltage regulation needs because of the differences in their distribution system characteristics.

Moreover, PPL Electric continues to dispute that having an individual proceeding for every EDC would be more time consuming than a statewide stakeholder process. As explained by Mr. Whitley in his direct testimony (PPL Electric Statement No. 4), statewide proceedings in other states have been extraordinarily lengthy and inefficient. However, even assuming that individual proceedings for every EDC in Pennsylvania would be costlier and more time-consuming, the other parties' argument is predicated on their belief that all of the other EDCs would voluntarily initiate such proceedings. Again, there is no evidence that any of the other EDCs in Pennsylvania are ready or willing to: (1) implement IEEE 1547-2018; or (2) develop and implement a DER Management proposal similar to PPL Electric's DER Management Plan.

B. THE INSTANT PROCEEDING IS DEVELOPING A FULL AND COMPLETE RECORD FROM A DIVERSE SET OF STAKEHOLDERS

Q. DO YOU AGREE WITH THE CLAIMS THAT A STATEWIDE PROCEEDING WOULD BE MORE TRANSPARENT, DEVELOP A MORE COMPLETE RECORD, AND ALLOW FOR A WIDER RANGE OF STAKEHOLDERS TO PARTICIPATE?

A. No. This instant proceeding is developing a full and complete record from a diverse set of stakeholders. The OCA represents the interests of customers in Pennsylvania; SEF is an interconnection applicant, end-user of DER, and environmental advocate; Sunrun, Inc. is a solar installer and DER aggregator; and NRDC is an environmental advocate. Moreover, SEF witness Celentano is a solar consultant and the president of the

Pennsylvania Solar Energy Industries Association ("PA-SEIA"). Moreover, Comments on the Company's DER Management Plan were filed by Trinity Solar, SEF, GridLab, the Solar Unified Network of Western Pennsylvania ("SUNWPA"), Energy Independent Solutions, LLC ("EIS"), the Interstate Renewable Energy Council, Inc. ("IREC"), the Pennsylvania Solar Energy Industries Association ("PASEIA"), and Exact Solar.

Additionally, parties have engaged in substantial discovery, in which over 1,240 pages of documents and approximately 70 Microsoft Excel files have been disclosed by PPL Electric to date. Also, unlike a statewide proceeding, parties are submitting comprehensive written testimony and will have the opportunity to cross-examine each other's witnesses. From the Company's perspective, this fully-litigated proceeding will lead to a more complete and developed record than a statewide collaborative proceeding. Indeed, the parties' direct testimony and exhibits totaled over 330 pages.

I also categorically reject any implication that there was a lack of transparency or deficiency in how the DER Management Petition was publicly noticed. In fact, I have been advised by counsel that PPL Electric voluntarily requested that the DER Management Petition be publicly noticed in the *Pennsylvania Bulletin*. My understanding is that any rulemaking order proposed by the Commission would similarly be published in the *Pennsylvania Bulletin*. Moreover, PPL Electric served Notice of the DER Management Petition on approximately 90 solar entities, in addition to the statutory parties, which provided the deadline for comments and petitions to intervene. It is unclear how a statewide proceeding, which would similarly be initiated by the Commission publishing a proposed rulemaking order in the *Pennsylvania Bulletin*, would garner more interest or comment.

C. ISSUES WITH NRDC'S PROPOSED STATEWIDE PROCEEDING WITH PRE-DETERMINED OUTCOMES

Q. YOU MENTIONED BEFORE THAT ONLY NRDC ACTUALLY PLACES A DEADLINE ON THE STATEWIDE COLLABORATIVE PROCESS THAT IT RECOMMENDS. WOULD YOU PLEASE RESPOND TO NRDC'S RECOMMENDATION?

A. Although PPL Electric agrees with NRDC that IEEE 1547-2018 should be implemented sooner rather than later, there is no guarantee that other stakeholders, including other EDCs, will be supportive. As I explained previously, PPL Electric and its peer EDCs have very different characteristics and are at different stages of implementing the requisite foundational technologies needed to implement and take advantage of IEEE 1547-2018. Therefore, the Commission and other entities may be hesitant to place any deadline on the statewide collaborative process.

D. THE TWO "INTERIM STEPS" THAT NRDC RECOMMENDS FOR EDCS TO TAKE OUTSIDE OF THE PROPOSED STATEWIDE STAKEHOLDER PROCESS ARE NOT ENOUGH

Q. YOU PREVIOUSLY MENTIONED THAT NRDC WITNESS NELSON ALSO RECOMMENDED TWO "INTERIM STEPS" THAT EDCS SHOULD BE ALLOWED TO TAKE OUTSIDE OF HIS PROPOSED STATEWIDE COLLABORATIVE PROCEEDING. WOULD YOU PLEASE RESPOND TO THAT RECOMMENDATION?

A. The two "interim steps" recommended by Mr. Warren are not enough to address the issues being experienced on PPL Electric's distribution system and to prepare for increased levels of DERs in the Company's service territory.

The first interim step suggested by Mr. Warren is that EDCs should propose under what circumstances the Category II or III requirements for abnormal operation of IEEE 1547-2018 should be applied on their systems and the PUC should require that compliant inverters be configured in accordance with PJM's ride-through setting recommendations beginning January 1, 2022. (*See* NRDC St. No. 1, pp. 7, 10-11, 33.) However, IEEE 1547-2018 Category II and Category III settings are only the recommended default ride-through setting for manufacturers. Category II is based on NERC standard PRC-024-02 requirements and Category III is based on California Rule 21. These default inverter settings are only adequate if they meet the PRC-024-02 and California Rule 21 requirements. If these requirements change in the future, it would be beneficial to have remote access to update the inverter ride-through settings to meet the new standard, rather than having to incur the substantial cost and time to manually update each inverter. Also, as discussed in earlier in my testimony, PPL Electric chose the ride-through settings to coordinate with NERC standard PRC-024-02: Generator Frequency and Voltage Protective Relay Settings, and the Company's ride-through settings are within the available range specified in IEEE 1547-2018.

Concerning the remainder of the first interim step, which deals with PJM's ride-through settings, PPL Electric is very supportive of PJM's efforts and leadership in adopting ride-through capabilities for bulk electric system stability and has been an active participant in PJM's ride-through workshop. However, I have been advised by counsel that PJM does not have jurisdiction over DERs connected to the distribution system, unless those DERs are participating in the interstate market. Therefore, PJM's recommended ride-through settings are non-binding for DERs on the distribution system. Further, PPL Electric believes it should implement ride-through settings now to avoid potential cascading impacts of inverters that do not meet the specified ride-through requirements. Indeed, the Company's specifications for Voltage Ride-through and Frequency Ride-through outlined in PPL Electric Exhibit SS-1R are consistent with PJM's recommendations. Moreover, if the Company can remotely manage the ride-through settings on the smart inverters, then PPL Electric can incorporate future changes to the ride-through settings, either due to PJM revising its recommendations or in response to distribution system needs. Therefore, no need exists for the Company to wait until 2022 to implement PJM's recommended ride-through settings. For further discussion, I address PJM's ride-through recommendations and the other parties' assertions related to those recommendations in Section XII, *infra*, of my rebuttal testimony.

As for the second interim step, Mr. Warren recommends that EDCs should be allowed to use UL 1741 SA compliant inverters, DER management devices, and DERMS prior to the completion of the stakeholder process "in order to minimize distribution upgrade costs on a case-by-case basis" and "by mutual agreement of utilities and interconnecting customers." (NRDC St. No. 1, pp. 7, 10-11, 33.) PPL Electric has, in essence, already implemented this recommendation. PPL Electric currently requires DER interconnection applicants to use UL 1741 SA compliant inverters, the Company is already using its DERMS, and PPL Electric has (with customer consent) used DER management devices on certain DER installations on a case-by-case basis. To realize all of the substantial benefits from the DER Management proposal, the Company must be able to monitor and manage DERs on its distribution system. Solely relying on customers agreeing to participate will result in a lot fewer DERs that the Company can monitor and manage. As a result, a large number of DERs would be connected to the Company's distribution system without any ability to monitor and manage them.

Unless PPL Electric implements its DER Management Plan, the Company would be unable to effectively address several issues raised by the Company in this proceeding. First, the Company would not be able to manage the Volt/VAR and Constant Power Factor functions on the interconnected DERs, resulting in power quality issues impacting all customers. As stated earlier in my testimony, a DER's variation in output can cause transient voltage swings, flicker, and overvoltage, which can negatively impact customers.

Second, as more DERs get interconnected to the distribution system without the Company being able to monitor their output, hidden load and the safety and reliability risks posed by hidden load will continue to increase.

Third, the Company would not be able to leverage the voltage and frequency ride-through settings on DERs, which increases the risk of DERs shutting down for voltage or frequency disturbances. This leads to an increased risk of destabilizing the bulk electric system and the distribution system, as stated earlier in my testimony.

Fourth, the lack of visibility and monitoring of DER output will negatively impact the ability to perform planning functions. If PPL Electric cannot monitor DERs, the Company must perform system planning assuming worst case scenarios, rather than the actual condition of the distribution system. This could lead to unnecessary investments and higher costs.

Fifth, the ability to locate faults accurately will be affected. Visibility into the real time production of DER assists in making more accurate fault location calculations, which helps to reduce service restoration time. When a fault occurs, fault location is informed by the magnitude of fault current flowing through the Company's smart grid devices, such as telemetered reclosers. Today, the accuracy of the fault location determination is negatively affected because the Company cannot determine whether DERs are on or off at the time of the fault. This, in turn, can slow restoration efforts because line crews will have a less accurate prediction of where on the system the problem occurred. This is particularly important for lines located underground. Troubleshooting on underground lines is considerably more time consuming (compared to overhead lines) and involves digging into the ground to inspect buried infrastructure to identify and repair failures. If real time monitoring is only available for a smaller percentage of DERs on the grid, fault location will not be accurate.

For these reasons, Mr. Warren's recommended "interim steps" should not be implemented in lieu of the DER Management Plan. Nonetheless, if PPL Electric's DER Management Petition is denied and a statewide stakeholder proceeding is established, PPL Electric would support these two "interim steps" being allowed until the statewide proceeding concludes.

VI. <u>PPL ELECTRIC'S DER MANAGEMENT PROPOSAL WILL BE FINANCIALLY BENEFICIAL TO DER OWNERS</u>

Q. OTHER PARTIES HAVE ARGUED THAT THE COMPANY'S DER MANAGEMENT PROPOSAL WILL NEGATIVELY AFFECT DER OWNERS AND THE DER MARKET BECAUSE IT WILL INCREASE COSTS FOR DER INTERCONNECTION APPLICANTS AND REDUCE REVENUES RECEIVED FROM DERS. DO YOU AGREE?

A. No, I do not, especially now that the Company has updated its proposal such that PPL Electric will purchase, install, own, and maintain the DER management devices at no direct cost to the DER owners. Moreover, the other parties completely failed to quantify the alleged revenue impact that would be created by the Company's use of the grid support functions. In reality, and as explained later in this section of my rebuttal testimony, the revenue impact is miniscule and pales in comparison to the estimated $393 to $700 in reduced installation costs for most DER owners. Therefore, PPL Electric's DER Management proposal will be financially beneficial for DER owners and have no adverse impact on the DER market.

A. <u>THE DER MANAGEMENT DEVICES WILL BE INSTALLED BY PPL ELECTRIC AT NO DIRECT COST TO THE DER OWNERS</u>

Q. OTHER PARTIES HAVE CRITICIZED THE COMPANY'S DER MANAGEMENT PROPOSAL BECAUSE IT WOULD FORCE DER OWNERS TO BEAR THE COSTS OF THE DER MANAGEMENT DEVICES. (NRDC ST. NO. 1, PP. 7-8, 20-23; OCA ST. NO. 1, PP. 15-16; SEF ST. NO. 2, P. 11.) WHAT IS YOUR RESPONSE?

A. As explained previously, PPL Electric maintains that its original proposal was justified by the substantial benefits presented by the Company monitoring and managing the grid support functions of the DERs. Nonetheless, the other parties raised concerns about DER owners bearing the costs of the DER management devices. According to SEF witness Celentano, the DER management device's approximate cost of $850[15] "could increase the total installation cost by 6% to 10% for small residential systems." (SEF St. No. 2, p. 11.)

PPL Electric has updated its proposal so that the Company will purchase, install, own, and maintain the ConnectDER DER Management devices. Therefore, the ConnectDER DER Management devices will no longer need to be purchased by the DER interconnection applicants or their installers. Instead, the Company will install those DER management devices at no direct cost to the DER interconnection applicants. As explained in Ms. Johnson's rebuttal testimony (PPL Electric Statement No. 7-R), the Company is not seeking immediate recovery of the capital costs and expenses associated with the Company purchasing, installing, owning, and maintaining the ConnectDER DER Management devices; rather, those capital costs and expenses will be claimed in a separate proceeding, most likely a base rate case.

Thus, the parties' concerns about the DER interconnection applicants bearing the costs of the DER management devices have been addressed.

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[15] As explained in footnote 1, *supra*, the Company has updated the estimated installation cost for the ConnectDER DER Management device. Therefore, the approximate cost to purchase and install the device is $755, not $850.

B. ANY MINOR REDUCTIONS IN REVENUES FROM THE DERS WILL BE GREATLY EXCEEDED BY THE COST SAVINGS FROM THE DER MANAGEMENT DEVICES

Q. OTHER PARTIES ALSO HAVE RAISED ALLEGATIONS THAT THE COMPANY'S DER MANAGEMENT PLAN WILL REDUCE CUSTOMER-GENERATORS' REAL POWER OUTPUT AND, THEREFORE, REVENUE FROM THEIR DER INSTALLATIONS. (NRDC ST. NO. 1, PP. 7-8, 23; OCA ST. NO. 1, PP. 11-12, 14; SEF ST. NO. 2, PP. 7-8, 13.) WOULD YOU PLEASE RESPOND?

A. The other parties' claims about the reduced revenue under PPL Electric's proposal are grossly overstated and fail to account for the substantial installation cost savings the DER owners will experience from the Company's installation of the DER management devices.

As explained earlier in my rebuttal testimony, PPL Electric will only be using the following grid support functions in autonomous and active management modes under its DER Management Plan: (1) Volt/VAR; (2) Remote On/Off; (3) Constant Power Factor; (4) Voltage Ride-through; and (5) Frequency Ride-through. Out of the 5 grid support functions, real power output reduction could potentially occur from Volt/VAR and Constant Power Factor. [16]

The other parties never quantified how much they believed a DER's revenue would be reduced by the Company's proposal. Accordingly, PPL Electric conducted an analysis of how much a DER's revenue would be affected by the Company's use of the

[16] Obviously, utilizing the Remote Off function would turn off the DER and reduce the DER's real power output to zero. However, as explained earlier, the Company will only be using the Remote Off function when the DER fails to automatically turn off on its own in emergency and unintentional islanding situations. Therefore, Remote Off will not reduce real power output when the DER otherwise should have been permitted to continue generating electricity.

grid support functions outlined above. The analysis, captured in PPL Electric Exhibit SS-2R, shows that even with relatively aggressive assumptions around how often above grid support functions would cause a negative impact on system revenue, the estimated annual revenue reduction for a typical 6 kW solar system is $1.04. (*See* PPL Electric Exhibit SS-2R.) For a large 100 kW installation, PPL Electric Exhibit SS-2R shows that the projected annual revenue reduction is only $9.28. (*See* PPL Electric Exhibit SS-2R.)

As for SREC revenue, PJM calculates the revenue credit based on an estimation of DER's generation output. Given the negligible impact the Company's proposal would have on DERs' real power output, there should be little to no effect on the SREC revenue calculation.

For these reasons, the Company's proposal is a clear financial benefit to most DER interconnection applicants and should incent the deployment of more DERs.

Q. WHAT IS YOUR RESPONSE TO SEF WITNESS COSTLOW'S CLAIM THAT THE COMPANY COULD INCREASE ITS DISTRIBUTION REVENUE BY CURTAILING DERS' PRODUCTION (SEF ST. NO. 1 (NON-PROPRIETARY), P. 13)?

A. PPL Electric is going to use the grid support functions to improve the safety, reliability, and quality of its electric service, not as a means of increasing the Company's distribution revenues. The Company filed the DER Management Petition so that the Company can have increased visibility of the DERs and manage the smart inverters' grid support functions for the benefit of PPL Electric's distribution system operations and its ratepayers. The insinuation that the Company is trying to increase its revenues at the expense of DER owners is flatly wrong. As explained above, any such revenue decrease is miniscule. Lastly, it is my understanding that the revenue derived from the Company's use of the grid support functions, if any, would be reflected in the Company's proposed revenue requirement in a future base rate case.

VII. PPL ELECTRIC'S PROPOSAL FOR REMOTE MONITORING AND MANAGEMENT OF THE DERS IS SUBSTANTIALLY BETTER THAN SOLELY RELYING ON PRE-SET AUTONOMOUS FUNCTIONS

Q. OTHER PARTIES HAVE ARGUED THAT THE SMART INVERTERS' AUTONOMOUS FUNCTIONS PROVIDE BENEFITS AND/OR THAT IT IS UNCLEAR WHY PPL ELECTRIC NEEDS TO REMOTELY MONITOR AND MANAGE THE DERS. (NRDC ST. NO. 1, PP. 7, 18-19; OCA ST. NO. 1, PP. 4, 16-17; SEF ST. NO. 1 (NON-PROPRIETARY), P. 10.) WOULD YOU PLEASE RESPOND?

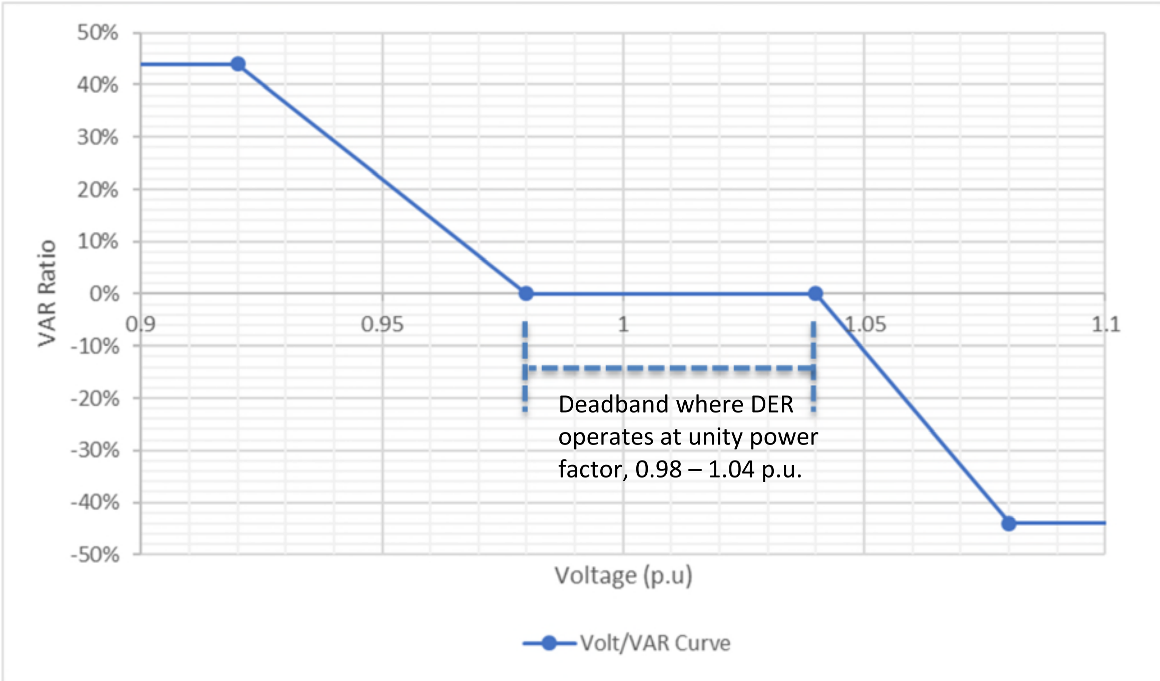
A. Pre-set autonomous functions are precisely calculated and determined based on historical data and system behaviors. They cannot adapt to future changes to the distribution circuit or distribution system, unless those pre-set parameters are manually changed. This would require customers or PPL Electric to physically adjust the autonomous setting(s), locally, on each inverter that needs to be changed. Such a process requires substantial time, effort, and expense. There are many examples where autonomous settings would need to be adjusted.

First, changes to feeder load and voltage profile may impact the autonomous settings, such as Volt/VAR, and require those settings to be actively changed over time. As discussed in Section III.A, all new inverter-based DERs will be issued autonomous

Volt/VAR curves at the interconnection. However, depending on the feeder's characteristics and the exact location of a DER, PPL Electric may require a slightly different Volt/VAR curve in order for inverters to maintain unity power factor for as much of the time as possible. The same concept applies when permanent system reconfiguration or significant load profile changes occur, which would require PPL Electric to issue a new Volt/VAR curve. The Company could remotely adjust this setting so that the DER maintains unity power factor or remains in a dead-band where no VARs are being injected or absorbed, for as much time as possible, while still avoiding negative distribution system voltage impacts. The challenge is that, over time, the most appropriate curve may change.

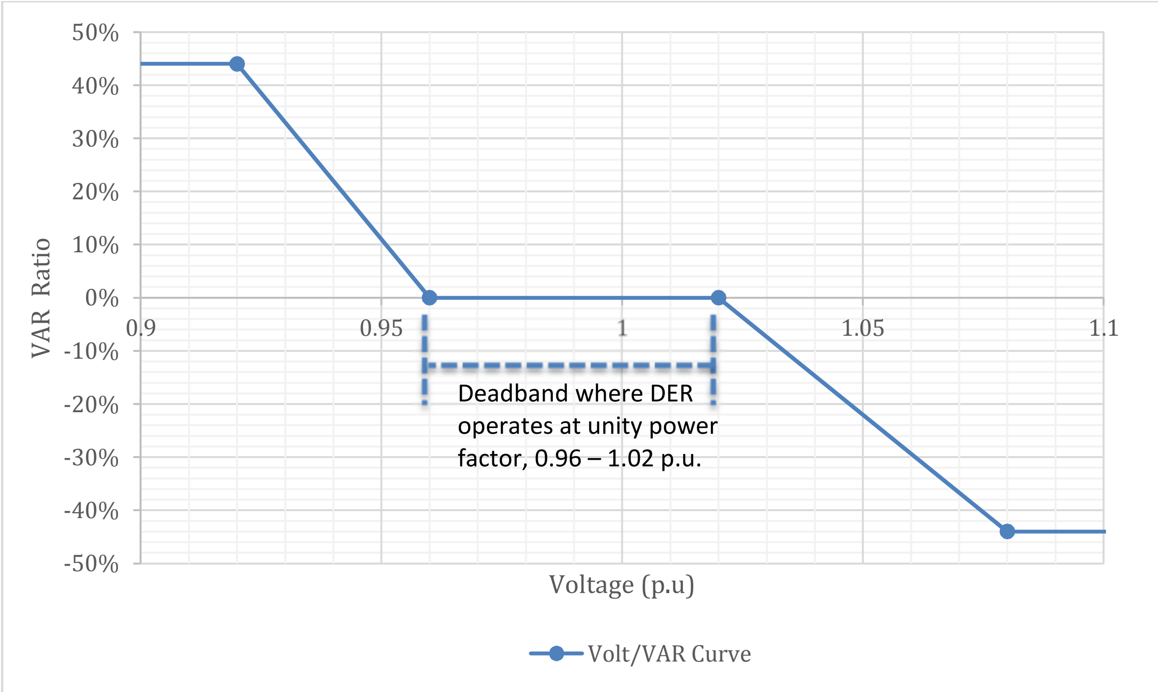
For example, if a 1 MW DER is located very near a distribution substation, where voltages are near 125 V, a Volt/VAR curve would be issued to the inverter in order to shift the dead-band from 0.97-1.03 per unit to 0.98-1.04 per unit, as shown below in Figure 8. By setting the dead-band higher, the DER would not absorb or inject VARs on a regular basis because it is located near a substation where voltage is normally higher than in other areas.

Figure 8 – Volt/VAR Curve Near a Substation



In a similar example, if a 1 MW or larger DER interconnects at the end of a distribution circuit, voltages are typically close to 115 V. In that case, a revised Volt/VAR curve could be issued to shift the dead-band from 0.98-1.04 per unit to 0.96-1.02 per unit, as shown in Figure 9 below. By setting the dead-band lower, the DER will not absorb or inject VARs on a regular basis because the DER is located near the end of a circuit, where voltage is normally lower than in other areas.

Figure 9 – Volt/VAR Curve Near the End of the Circuit



Therefore, Volt/VAR curves may shift to best accommodate the DER at its revised location on the Company's distribution system in the future as new distribution circuits are built, new customers or DERs connect to or disconnect from the system, or new substations are constructed.

A second example highlights the need for pre-set voltage and frequency ride-through settings to change, as discussed in Sections III.D and III.E, *supra*, of my rebuttal testimony. Similar to Volt/VAR, a default ride-through setting will be selected at the time of interconnection. However, changes to the transmission and distribution grid characteristics, such as distribution reclosing times, transmission clearing times, and coordination with behaviors of synchronous machines, may require ride-through settings to be changed. As mentioned in Ms. Reder's rebuttal testimony, this happened in

Germany when ride-through settings were required to be changed over time but had to be done manually. This required significant time, effort, and costs.

A third example is the need to temporarily override a Volt/VAR curve with the Constant Power Factor setting, which happens during temporary transfers of DERs from one distribution circuit to another. For more information, please see Section III.C of my rebuttal testimony, *supra*, and PPL Electric Exhibit SS-3R.

For all of the examples above, the Company's DER Management proposal would enable PPL Electric to remotely adjust these settings with minimal time, effort, and costs and without inconveniencing the customer. Therefore, it is important for PPL Electric to be able to remotely manage these settings.

Moreover, as explained in Ms. Reder's rebuttal testimony (PPL Electric Statement No. 2-R), this type of remote monitoring and management was envisioned by IEEE 1547-2018. IEEE 1547-2018 requires smart inverters to have two communication ports, each of which can be used to monitor and manage DERs. PPL Electric's DER Management proposal would allow the Company to utilize one of the communications ports to monitor and manage the DER in order to maintain power quality and reliability by mitigating the impact DERs have on the distribution system.

In addition, remote monitoring and management is absolutely needed for utilities' "black start" capability. Black start is the process of restoring power without relying on the external electric power transmission system to recover from a complete or partial shutdown. Traditionally, large power stations have been used to restore the system. However, depending on the number of DERs, there may not be enough centralized generation to recover after going black. As a result, approaches are being investigated on how to use distributed generation to bring back the grid should a "black start" event occur. Indeed, several research projects are underway to test and validate whether this approach can work across transmission and distribution systems, potentially supporting the shift to a decentralized low-carbon energy system to meet climate change targets without compromising electric service reliability. One critical piece of this approach is to have monitoring and management of DERs, which will need to be visible and likely adjustable in order for them to be used as the primary source to recover from a "black start" event.

Finally, in addition to the substantial benefits of managing the smart inverters' grid support functions, no parties can dispute the benefits of monitoring the DERs as well. Monitoring would provide PPL Electric with data on the dynamic DER generation output and improve the Company's overall system planning functions. Instead of planning for worst case scenarios, planners could plan for the actual condition of the distribution system. As explained in Figure 3, *supra*, visibility of DER generation output also allows the Company to: (1) mitigate issues such as hidden load; (2) better understand and more accurately plan the distribution system, which avoids unnecessary system upgrades; and (3) improve fault location capability, which enhances the overall reliability of the distribution system. Remote monitoring of DERs also provides visibility of unintentional islanding conditions. As described earlier in my testimony, unintentional islanding is an issue that could happen where DERs fail to shut off during an outage. It is important for PPL Electric to monitor and identify such events to protect for the safety of the public and utility workers.

VIII. PPL ELECTRIC'S DER MANAGEMENT PROPOSAL WILL NOT NEGATIVELY AFFECT THIRD-PARTY AGGREGATION OF DERS

Q. OTHER PARTIES HAVE RAISED SOME CONCERNS ABOUT THE IMPACT PPL ELECTRIC'S PROPOSAL WILL HAVE ON THIRD-PARTY AGGREGATORS OF DERS. (NRDC ST. NO. 1, PP. 8-9; OCA ST. NO. 1, PP. 18-28, 42-44; SEF ST. NO. 1 (NON-PROPRIETARY), P. 4.) WOULD YOU PLEASE RESPOND?

A. To be clear, PPL Electric's proposal would not prevent third-party DER aggregators from operating. PPL Electric is simply seeking Commission approval to leverage smart inverters' capabilities in order to mitigate the impact of DERs on the distribution system and improve safety, reliability, and power quality. Such third-party DER aggregators are free to continue operating, even with DER installations that are subject to the Company's proposal.

As explained by Ms. Reder (PPL Electric Statement No. 2-R), IEEE 1547-2018 requires the smart inverters to have two communications ports, one of which is available for use by the utility. Therefore, both PPL Electric and a third-party aggregator can tap into the smart inverter's capabilities.

IX. PPL ELECTRIC IS NOT REQUESTING "PERMANENT" WAIVERS OF THE COMMISSION'S REGULATIONS

Q. OCA WITNESS NELSON CONTENDS THAT THE COMPANY IS SEEKING A "PERMANENT" WAIVER OF THE COMMISSION'S REGULATIONS AND MAKES AN ALTERNATIVE RECOMMENDATION, IF THE DER MANAGEMENT PETITION IS FULLY OR PARTIALLY APPROVED, FOR

THE COMPANY TO RECEIVE "TEMPORARY" WAIVERS. (OCA ST. NO. 1, PP. 4-5, 10, 40-41, 52-53.) WOULD YOU PLEASE RESPOND?

A. PPL Electric is not seeking "permanent" waivers of the Commission's regulations. For many of the waivers, specifically, 52 Pa. Code 75.22's definition of "Certified" and other regulations using the term "Certified," the waivers are only necessary until the revisions to IEEE 1547 and UL 1741 become final. Indeed, counsel has advised me that "Certified" is defined by Section 75.22 as:

> A designation that the interconnection equipment to be used by a customer-generator complies with the following standards, as applicable:
>
> (i) IEEE Standard 1547, ''Standard for Interconnecting Distributed Resources with Electric Power Systems,'' <u>as amended and supplemented</u>.
>
> (ii) UL Standard 1741, ''Inverters, Converters and Controllers for use in Independent Power Systems'' (January 2001), <u>as amended and supplemented</u>.

52 Pa. Code § 75.22 (emphasis added). Therefore, although I am not a lawyer, I do not believe PPL Electric would need waivers of many of these regulations to implement IEEE 1547-2018 and the revisions to UL 1741 after IEEE 1547 and UL 1741 are "amended and supplemented."

Further, I have been advised by counsel that waivers of regulations are only effective until the regulations at issue are revised. Therefore, if and when the Commission's regulations are revised the Company's waivers would no longer be effective. Under that scenario, if the Company wanted to do anything different from the Commission's regulations, I have been advised by counsel that PPL Electric would have to petition to amend those regulations or request a new set of waivers from those regulations.

X. PPL ELECTRIC'S DER MANAGEMENT PROPOSAL WILL NOT MATERIALLY AFFECT THE DESIGN OF DERS

Q. NRDC WITNESS WARREN CLAIMS THAT THE COMPANY'S PROPOSAL WOULD "AFFECT THE DESIGN OF A SOLAR SYSTEM." (NRDC ST. NO. 1, P. 14.) WOULD YOU PLEASE RESPOND?

A. The DER Management proposal has two system requirements: (1) the use of smart inverters that are either meet the Company's interim testing and approval requirements, or are certified as compliant with IEEE 1547-2018; and (2) the installation of the DER management device. The requirement to use a smart inverter is not new, as the Company currently requires customers to use smart inverters that meet UL 1741 SA. When IEEE 1547-2018 is finalized, the Company does not project that such change from PPL Electric's current requirements will have any material effect on a DER's system design. As for the DER management device, it actually has a positive impact on DER system design. In Mr. Wallace's rebuttal testimony (PPL Electric Statement No. 6-R), he explains that the ConnectDER DER Management device simplifies the installation for most new DERs by eliminating the need to connect the smart inverter to the customer's electrical panel.

XI. PPL ELECTRIC'S DER MANAGEMENT PROPOSAL WILL NOT NEGATIVELY AFFECT ELECTRIC VEHICLES AND BATTERY STORAGE

Q. OTHER PARTIES ALSO HAVE RAISED QUESTIONS ABOUT THE IMPACT THE COMPANY'S PROPOSAL WOULD HAVE ON ELECTRIC VEHICLES AND BATTERY STORAGE. (NRDC ST. NO. 1, PP. 14-15; OCA ST. NO. 1, P. 44;

SEF ST. NO. 1, PP. 9-10, 12; SEF ST. NO. 2, P. 14.) WHAT IS THE COMPANY'S RESPONSE?

A. PPL Electric's DER Management proposal is designed to monitor DERs' output and leverage smart inverters' capabilities to maintain grid reliability and power quality. In the case of battery storage, or solar plus storage, PPL Electric will be managing the smart inverter consistent with the specifications set forth in PPL Electric Exhibit SS-1R and will not be interfering with customers' control of their systems. Customers will continue to manage their systems, including as a back-up source during an outage. An EV is a load installed behind the meter and generally will not be impacted by the Company's proposal. However, if the EV is used as a battery outputting power onto the grid through an inverter, it will fall under the DER Management proposal.

XII. <u>OTHER PARTIES' ASSERTIONS ABOUT PJM'S RECOMMENDED RIDE-THROUGH SETTINGS</u>

Q. BEFORE RESPONDING TO THE OTHER PARTIES' ALLEGATIONS, COULD YOU PROVIDE SOME BACKGROUND ON PJM'S RECOMMENDED RIDE-THROUGH SETTINGS?

A. As explained earlier in my rebuttal testimony, PJM's ride-through settings are a non-binding document for distribution customers in PJM's territory. PPL Electric participated in the discussion and development of these settings. PJM attempted to create standard ride-through settings for all member utilities; however, agreement could not be reached, and many members shared the same concern of letting the regional transmission authority govern distribution setting requirements, which is why the default Categories of II and III were chosen by PJM.

Chief amongst those concerns was the effect of ride-through settings on distribution hot-line work and how the increased interconnection time would affect worker safety during arc flash events, and coordination of ride-through settings with different transmission reclosing standards amongst the participating member utilities.

Q. EARLIER, IN SECTION V.D OF YOUR REBUTTAL TESTIMONY, YOU GENERALLY RESPONDED TO NRDC WITNESS WARREN'S RECOMMENDED "INTERIM STEP" THAT THE COMMISSION "SHOULD REQUIRE THAT COMPLIANT INVERTERS BE CONFIGURED IN ACCORDANCE WITH PJM'S RIDE-THROUGH SETTING RECOMMENDATIONS BEGINNING JANUARY 1, 2022." (NRDC ST. NO. 1, PP. 10-11.) DO YOU HAVE ANYTHING FURTHER TO ADD?

A. As I stated previously, PPL Electric agrees with PJM's overall goal in developing the recommended ride-through settings. To that end, the Company has developed its own ride-through settings to coordinate with NERC standards PRC-024-02 and PRC-006-02, which PPL Electric believes better meet PJM's objectives with the ride-through settings. Compared to the Category II and III requirements that Mr. Warren mentions, PPL Electric's settings are more lenient. In addition, Category II settings have large, undefined areas where the inverter may ride-through or may trip, which creates safety and equipment hazards because operation of the inverter is undefined. Further, although Category III settings are more well-defined, they still may ride-through or may trip areas. Also, the ride-through times are unacceptably long and do not coordinate with the

Company's standard first reclose time. Therefore, the Company prefers its ride-through settings than the Category II and III requirements.

Q. NRDC WITNESS WARREN ALSO CONTENDS THAT EXTERNAL COMMUNICATIONS AND MANAGEMENT OF SMART INVERTERS ARE NOT NECESSARY TO COMPLY WITH PJM'S RIDE-THROUGH SETTING RECOMMENDATION. (NRDC ST. 1, PP. 28-29.) COULD YOU PLEASE RESPOND?

A. Although external communication is not required to comply with PJM's ride-through settings, the Company's ride-through settings better meet PJM's goals by riding through most disturbances for longer periods. Further, the ability to remotely change these settings enables the Company to respond to changes in PJM's ride-through recommendations in a quicker, less expensive manner.

Q. OCA WITNESS NELSON ASSERTS THAT "PPL DID NOT EXPLICITLY ACKNOWLEDGE THAT IT CONSIDERED PJM'S GUIDELINES NOR DID THE COMPANY NOTE WHETHER ITS PROPOSED IMPLEMENTATION PLAN FOR IEEE 1547-2018 CONFORMS TO THE GUIDELINE." (OCA ST. NO. 1, NO. P. 48.) WOULD YOU PLEASE RESPOND?

A. PPL Electric disagrees with this statement. The Company considered PJM's requirements through two years of active participation in PJM's ride-through initiative through phone calls and on-site meetings, as well as reviewing drafts of PJM's ride-through document.

As explained previously, the Company believes its ride-through settings are consistent with PJM's recommendations.

XIII. <u>OCA'S ALTERNATIVE RECOMMENDATIONS IF THE DER MANAGEMENT PLAN IS FULLY OR PARTIALLY APPROVED</u>

Q. OCA WITNESS NELSON MADE A SERIES OF ALTERNATIVE RECOMMENDATIONS IN HIS DIRECT TESTIMONY IN CASE THE COMMISSION FULLY OR PARTIALLY APPROVES THE DER MANAGEMENT PETITION. (OCA ST. NO. 1, PP. 4-6, 52-54.) COULD YOU PLEASE EXPLAIN THE COMPANY'S POSITION ON EACH OF THOSE ALTERNATIVE RECOMMENDATIONS?

A. PPL Electric's positions on those alternative recommendations are as follows.

1. <u>Waivers of Regulations Should Be Temporary, and Any Future Waivers Must Be Proposed and Renewed on a Periodic Basis and Subject to Further Review and Analysis</u>

As explained in Section IX, *supra*, PPL Electric is not requesting "permanent" waivers of the regulations. Therefore, the Company does not believe that this alternative recommendation needs to be adopted.

2. <u>Establish a Process to Develop Guidelines for Tracking and Reporting Any Customer Generation Losses</u>

PPL Electric agrees to track and report the real power reductions experienced by customers under the Company's proposal. Specifically, the Company will use the real time output of the DER, the nameplate of the DER, and the duration of the voltage regulation function to calculate the DER's generation loss. Such information will be presented, in aggregate and without identifiable customer information, in annual reports filed by PPL Electric at this docket. PPL Electric also will send an annual report to each new DER customer, whose grid support functions are used during that annual reporting period. In that annual report, the Company will provide the amount of generation loss experienced by the customer for the past year. Further, there is no need to establish a process to develop the guidelines, given that PPL Electric has already agreed to track and report these details.

3. <u>Establish a Process to Evaluate the Method and Techniques for Estimating Generation Losses and the Extent of Voltage Excursions</u>

PPL Electric will create annual reports describing the method and technique used to estimate generation losses caused by voltage excursions. Thus, there is no need to establish a process to do so.

4. <u>Require PPL Electric to Report When, Where, and How Often Voltage Regulation Functions Are Utilized</u>

PPL Electric agrees to this recommendation. The Company will be tracking all events where voltage regulation functions (*i.e.*, Volt/VAR and Constant Power Factor) are changed for each DER installation. This information will be included in the annual report sent to the DER customer. For the events where a Constant Power Factor is temporarily used to override an existing Volt/VAR curve, the customer's annual report will show the existing Volt/VAR curve, the Volt/VAR curve that was temporarily used, and the duration of the event. For the events where a new Volt/VAR curve is issued, the new curve will be included in the report. In the annual report filed with the Commission, PPL Electric will provide information about how many times voltage regulation functions were utilized in the annual reporting period.

5. <u>Establish a Process for Identifying and Considering Possible Corrective Measures in the Event Losses Are Deemed Excessive or Unwarranted</u>

As explained above, PPL Electric will track and annually report the lost generation for DERs under its DER Management Plan, which potentially could be used to consider and evaluate Mr. Nelson's undefined "corrective measures."

6. <u>Require the Company to Report on the Impact of Using New Versus Conventional Planning Tools</u>

PPL Electric agrees to report on when non-wires alternatives are installed in order to defer distribution system upgrades. This information will be included in the annual report filed with the Commission at this docket. Specifically, the Company will provide the non-wires alternatives installed to improve customer reliability or defer voltage control investment using DER management, in lieu of traditional alternatives, for that annual reporting period.

7. <u>Create Reporting Criteria Related to the Provision of Grid Services from the DERs under PPL Electric's Control (If Applicable)</u>

As stated previously, PPL Electric will file an annual report with the Commission providing information about the Company's use of the grid support functions in the annual reporting period. Further, the Company will provide this information on an individual basis by sending an annual report to each new DER customer whose grid support functions were used in the reporting period.

8. Require the Company to Post Public Hosting Capacity Maps and Post Public Maps that Highlight Areas with Voltage Issues that Have a High Probability of DER Control/Curtailment

PPL Electric disagrees with this recommendation depending on the detail level and public availability of the hosting capacity maps. Although hosting capacity information can be useful to potential investors in DERs, the Company has serious concerns about the sensitivity and security risks associated with posting public hosting capacity maps as well as the costs of maintaining and regularly updating the maps.

XIV. OTHER ISSUES AND ALLEGATIONS RAISED BY SEF

A. PPL ELECTRIC'S DER MANAGEMENT PROPOSAL WOULD NOT "SEVERELY" LIMIT THE ABILITY OF A DER OWNER OR THIRD-PARTY TO COMMUNICATE WITH DERS

Q. SEF WITNESS COSTLOW ASSERTS THAT THE COMPANY'S PROPOSAL WOULD "SEVERELY LIMIT A DER OWNER'S ABILITY TO COMMUNICATE WITH THEIR DERS OR UTILIZE THIRD-PARTY SERVICES TO MONITOR THE HEALTH OF THEIR SYSTEMS." (SEF ST. NO. 1 (NON-PROPRIETARY), P. 4.) DO YOU AGREE?

A. No. As explained previously, there are two communications ports on the smart inverters that meet IEEE 1547-2018, one of which is available for the electric utility's use. Therefore, PPL Electric and a DER customer (or that customer's designated third party) can both connect to and communicate with the smart inverter under the Company's proposal.

Q. SEF WITNESS COSTLOW ALSO CLAIMS THAT THE COMPANY'S PROPOSAL WOULD RESULT IN THE RS485 BUS AT SEF'S NET ZERO BUILDING BEING REMOVED, THEREBY PREVENTING SEF FROM MONITORING, INTERFACING, AND CONTROLLING ITS SOLAR MONITORING AND CONTROL SYSTEM. (SEF ST. NO. 1 (NON-PROPRIETARY), PP. 14-15.) IS THAT CORRECT?

A. No. Again, there are two communications ports on the smart inverter. Therefore, SEF will still be able to connect to one of those communications ports and monitor, interface, and control its solar system.

Q. WOULD THE COMPANY'S PROPOSAL PREVENT A DER OWNER FROM CURTAILING THE DER'S PRODUCTION AND TURNING THE DER OFF, AS ALLEGED BY SEF WITNESS COSTLOW (SEF ST. NO. 1 (NON-PROPRIETARY), P. 11)?

A. No. If a DER owner wants to "curtail production and turn their DERs on or off," they are free to do so under the Company's proposal. PPL Electric will not turn on a system that has been turned off by the customer, or increase the DER's production if the customer voluntarily decided to reduce the DER's production (in the unlikely event that occurs).

B. SEF'S CLAIMS ABOUT FOSSIL FUEL BACK-UP GENERATORS ARE WITHOUT MERIT

Q. SEF WITNESS COSTLOW ALSO TRIES TO CRITICIZE THE COMPANY'S DER MANAGEMENT PETITION BECAUSE, ACCORDING TO HIM, IT WOULD ALLOW PPL ELECTRIC TO SHUT OFF BACK-UP RENEWABLE

GENERATORS BUT DOES NOTHING TO REMOTELY SHUT DOWN BACK-UP FOSSIL FUEL GENERATORS. (SEF ST. NO. 1 (NON-PROPRIETARY), PP. 11-12.) WOULD YOU PLEASE RESPOND?

A. The critical flaw with SEF's distinction is that it fails to recognize that fossil fuel back-up generators do not put excess electricity back onto the distribution system and, therefore, do not affect the distribution system's power quality or reliability. This makes shutting down DERs in the vicinity of emergency situations, such as a gas leak, more of a priority than fossil fuel back-up generators because inverter-based DERs can maintain power to the distribution system during an outage through intentional or unintentional islanding.

From the Company's perspective, it is better to eliminate some potential issues that may arise in emergency situations than none at all. Indeed, if the Company can remotely shut down the DERs in emergency situations, then emergency personnel can focus on manually checking and shutting down any fossil fuel back-up generators in the area.

C. <u>PPL ELECTRIC IS NOT PROPOSING A "DEMAND CONTROL PROGRAM"</u>

Q. SEF WITNESS COSTLOW ALSO CONTENDS THAT PPL ELECTRIC IS PROPOSING A "DEMAND CONTROL PROGRAM" THAT IS INCONSISTENT WITH THE "PARAMETERS OF ESTABLISHED COMMISSION POLICY." (SEF ST. NO. 1 (NON-PROPRIETARY), PP. 13-14.) IS THIS ACCURATE?

A. No. PPL Electric's DER Management Plan is not a demand response program, nor is the Company proposing in this proceeding that another demand response program be added to its current Phase III EE&C Plan. PPL Electric's only demand response program in its

EE&C Plan remains its C&I Demand Response Program, which is a load curtailment program for non-residential customers. Thus, the Company's use of the grid support functions of smart inverters under the DER Management Plan is not a part of the Company's Phase III EE&C Plan.

D. SEF ERRONEOUSLY ASSERTS THAT THE COMPANY'S PROCEDURES FOR TESTING AND APPROVING INVERTERS "COULD LEAD TO SIGNIFICANT DELAYS FOR THE DER OWNER"

Q. SEF WITNESS COSTLOW ALSO CLAIMS THAT THE COMPANY'S PROCEDURES FOR TESTING AND APPROVAL OF INVERTERS "COULD LEAD TO SIGNIFICANT DELAYS FOR THE DER OWNER, FURTHER INCREASING THEIR RISKS." (SEF ST. NO. 1 (NON-PROPRIETARY), P. 15.) IS THIS CORRECT?

A. No. SEF provided no support for this assertion. In actuality, PPL Electric only will test and approve inverters as part of its interim solution until IEEE 1547-2018 is fully effective. From that point onward, the Company would rely on the marketplace's designation of whether smart inverters are compliant with IEEE 1547-2018 or not. Moreover, the Company's testing procedures for the communications requirements under IEEE 1547-2018 are very straightforward. To test and approve an inverter, or series of inverters, PPL Electric connects to the inverter's local communication interface to see if it works with the SunSpec Modbus information model (register map) provided by the inverter manufacturer. The Company then develops communication protocol conversion software to be loaded onto the DER Management device. The entire process takes approximately two weeks. PPL Electric will continue to test and approve inverters consistent with these procedures until IEEE 1547-2018 and the revisions to IEEE 1547.1 and UL 1741 are final and smart inverters that meet these standards are available in the marketplace. To date, PPL Electric has tested and approved the following inverters as meeting the Company's interim requirements under the DER Management Plan: (1) Fronius Galvo, Primo, and Symo; and (2) ABB Uno.

On average, it has taken PPL Electric approximately two weeks to test and approve each of those smart inverters. Thus, the Company's testing and approval of inverters under its interim requirements will not lead to any significant delays for the DER owners.

E. THE DISTRIBUTED GENERATION PORTAL'S INABILITY TO WORK FOR NEW CONSTRUCTION IS COMPLETELY IRRELEVANT

Q. SEF WITNESS COSTLOW FURTHER OBSERVES IN HIS DIRECT TESTIMONY HOW THE COMPANY'S DISTRIBUTED GENERATION ("DG") WEB PORTAL DOES NOT WORK FOR NEW CONSTRUCTION PROJECTS. (SEF ST. NO. 1 (NON-PROPRIETARY), P. 15.) WOULD YOU PLEASE RESPOND?

A. This fact has nothing to do with the merits of PPL Electric's DER Management Petition. Moreover, it is axiomatic that a net metering interconnection applicant must have an electric service account already established before the DER's generation could be used to offset the account's usage. Also, it astounds me that Mr. Costlow is trying to assail the Company's DG Web Portal. PPL Electric worked hard on developing and implementing this software, which has had real and substantial benefits for customers seeking to interconnect DERs. Specifically, the DG Web Portal has reduced the average review and approval time for a residential interconnection applicant from up to three weeks to less than 24 hours for over 90% of applicants. Lastly, I am aware of no other utility in Pennsylvania that allows new construction net metering applications.

F. SEF'S ASSERTION THAT THE COMPANY CAN SIMPLY ACCOMMODATE MORE DERS BY UNDERTAKING TRADITIONAL DISTRIBUTION SYSTEM UPGRADES WHOLLY LACKS MERIT

Q. SEF WITNESS COSTLOW ALSO ARGUES THAT THE COMPANY CAN SIMPLY "ACCOMMODATE MORE DERS" BY UNDERTAKING TRADITIONAL UPGRADES TO ITS DISTRIBUTION SYSTEM. (SEF ST. NO. 1 (NON-PROPRIETARY), P. 16.) WOULD YOU PLEASE RESPOND?

A. This is a very costly approach that will negatively affect potential DER interconnection applicants. The whole purpose of non-wires alternatives and the Company's DER Management Plan is to try to avoid the need for costly distribution system upgrades in order to accommodate more DERs.

DERs naturally raise voltage at the point of the connection to the distribution system. Currently, when a customer applies to interconnect DER to the distribution system, engineers run studies. During these studies, voltage, protection or load violations caused by the DER are identified. From this, any voltage control equipment required to address overvoltage violations must be paid for by the customer installing the DER before interconnection, even if the overvoltage condition occurs only for a small portion of the year during off-peak load periods. Voltage control equipment, such as voltage regulators, cost approximately $60,000, which is obviously cost prohibitive for many customer-generators and will have a negative impact on customers' implementation of DERs.

Moreover, Mr. Costlow appears to overlook that the costs of those distribution system upgrades are borne by the interconnection applicants, PPL Electric's ratepayers, or both. The Company should not be prevented from undertaking alternative approaches that will accommodate more DERs on its distribution system, while avoiding costly distribution system upgrades.

In fact, Mr. Costlow's reasoning conflicts with the positions taken by OCA witness Nelson in the Public Service of New Hampshire d/b/a Eversource Energy ("Eversource Energy") and Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities ("Liberty") rate cases before the New Hampshire Public Utilities Commission ("NH PUC"). In his direct testimony submitted in the Eversource Energy case on December 20, 2019, Mr. Nelson criticized the utility's "base capital plan" and "Grid Transformation Enablement Program" because the utility did not update its interconnection standards and use smart inverters' grid support functionalities to increase hosting capacity. Specifically, on page 33 of that testimony, he stated the following:

> [T]he Company has not upgraded its interconnection standards recently and has not considered current IEEE standards, including 1547-2018 and 2030.5. Updating interconnection and engineering standards are important because they could reduce distribution system investments. For example, the Company has noted that one of its objectives is to increase hosting capacity on the distribution system with its spending plans. However, customer-owned smart inverters or energy storage systems could be used to increase hosting capacity. Through updated interconnection standards, smart inverters can be required to operate under specific configurations to increase hosting capacity. Energy storage can also be operated to increase hosting capacity. Embedding increased hosting capacity into the entire distribution system may be a costly investment. Before upgrading the entire systems[']

hosting capacity, these lower cost alternatives should be explored.[17]

Therefore, PPL Electric's plan to update its interconnection standards to IEEE 1547-2018 and utilize smart inverters' grid support functions to increase hosting capacity, rather than traditional distribution system upgrades, is consistent with Mr. Nelson's testimony in the Eversource Energy rate case.

Similarly, in the Liberty rate case, Mr. Nelson explained how a utility updating its interconnection standards and using the smart inverters' grid support functions can be a more cost-effective solution to increasing distribution circuits' hosting capacity for DERs:

> Currently, New Hampshire's PUC 900 Rules could use updating for multiple reasons. For example, the PUC 900 Rules do not mention energy storage systems, rely on IEEE 1547-2003 when 1547-2018 is the current standard, and do not explicitly integrate components of IEEE 2030.5. Updating the interconnection standards will lower barriers for adopting DERs and may result in more cost-effective integration.
>
> More specifically, updating interconnection standards could lead to decreased distribution system infrastructure spending. There are two ways that reductions in distribution system infrastructure could be realized: at the system level, and during the interconnection process. Regarding the system level, some utilities are currently upgrading their systems to increase hosting capacity in preparation for high penetrations of DERs. However, technologies installed with the DERs, such as smart inverter functionality, could be utilized to increase hosting capacity. Regarding the interconnection process, allowing interconnecting facilities to pair with energy storage systems and, more generally, incorporating the operational characteristics of energy storage systems can mitigate

[17] Direct Testimony of Ron Nelson on behalf of the New Hampshire Office of Consumer Advocate, p. 36, *In re Public Service of New Hampshire d/b/a Eversource Energy*, Docket No. DE 19-057 (Dec. 20, 2019) (emphasis added), *available at* https://www.puc.nh.gov/Regulatory/Docketbk/2019/19-057/TESTIMONY/19-057_2019-12-20_OCA_TESTIMONY_NELSON.PDF.

> the need for interconnection upgrades. Take a residential solar plus storage system, for example, with 8 kW of solar and 8 kW of storage (together, "facility"). Utilities can evaluate this facility as though it will export 16 kW when the grid is the least equipped to handle its export – which may trigger the need for a grid upgrade. However, interconnection standards could be updated to reflect the operational characteristics of this facility more accurately. In fact, one simple solution would be limiting facility exports through its smart inverter (*i.e.*, by configuring the smart inverter to limit exports to no more than 8 kW).[18]

Thus, as Mr. Nelson testified in these NH PUC proceedings, PPL Electric's implementation of IEEE 1547-2018 and using the smart inverters' grid support functionalities are more cost-effective solutions to increasing distribution circuits' hosting capacity when compared to traditional distribution system upgrades.

G. SEF'S CONTENTION THAT PPL ELECTRIC DOES NOT UNDERSTAND RAMP RATES FOR SOLAR PV SYSTEMS IS WRONG

Q. IN HIS DIRECT TESTIMONY, SEF WITNESS CELENTANO CLAIMS THAT PPL ELECTRIC'S DER MANAGEMENT SUPPORT GUIDE SHOWS A LACK OF UNDERSTANDING ABOUT THE RAMP RATE FOR A SOLAR PV SYSTEM. (SEF ST. NO. 2, PP. 12-13.) WOULD YOU PLEASE RESPOND?

A. The Company is not proposing to use Watt Ramp Rate under its DER Management Plan, as seen in PPL Electric Exhibit SS-1R. Therefore, Mr. Celentano's purported issue with the DER Management Support Guide's statements about ramp rate is irrelevant. Nonetheless, PPL Electric is well aware of how ramp rates work for solar PV and agrees

[18] Direct Testimony of Ron Nelson on behalf of the New Hampshire Office of Consumer Advocate, p. 36, *In re Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities*, Docket No. DE 19-064 (Dec. 6, 2019) (emphasis added), *available at* https://www.puc.nh.gov/Regulatory/Docketbk/2019/19-064/TESTIMONY/19-064_2019-12-06_OCA_TESTIMONY_NELSON.PDF.

with Mr. Celentano that solar output does not necessarily drop to zero when it is cloudy. However, even when the output is not at zero, the sudden increase of output, due to a dynamic weather change or the re-energization of service after an outage, can still lead to the inverter ramping up quickly. This can cause power quality issues such as flicker or spikes in voltage.

XV. THE BENEFITS OF THE DER MANAGEMENT PETITION ARE CLEAR AND INDISPUTABLE AND GREATLY OUTWEIGH THE COSTS OF THE COMPANY'S PROPOSAL

Q. NRDC WITNESS WARREN AND OCA WITNESS NELSON ARGUE THAT THE COMPANY'S PROPOSAL IS UNSUPPORTED BECAUSE PPL ELECTRIC HAS NOT PRESENTED A FORMAL COST-BENEFIT ANALYSIS. (NRDC ST. NO. 1, P. 7; OCA ST. NO. 1, P. 51.) WOULD YOU PLEASE RESPOND?

A. As a preliminary matter, I reject the premise that a cost-benefit analysis is needed when the primary purpose of the Company's proposal is to provide safer and more reliable service. Safety and reliability benefits cannot be easily quantified, so a prudent electric utility often must take actions to improve safety and reliability that are unable to be justified by a formal cost-benefit analysis. The bottom line is that PPL Electric evaluates a particular approach and makes a determination as to whether it is in the best interest of the Company and its ratepayers. Here, PPL Electric continues to believe that the DER Management Plan is the best approach to address the DER-related issues that the Company currently experiences on its distribution system and to prevent more severe DER-related issues from happening in the future.

In addition, I have been advised by counsel that there is no requirement for a public utility to present a formal cost-benefit analysis for a petition for waiver of Commission regulations to be approved. Moreover, system planning is performed years in advance before there are any issues experienced. This is a forward-looking process that requires both timely and pro-active approaches, which cannot always specifically quantify the benefits and costs. PPL Electric's distribution system is dynamic, and customers may apply to interconnect DERs with the Company's distribution system at any time and in any location on one of the Company's more than 1,250 distribution circuits. Costs, impacts, and benefits are directly tied to the location and size of DERs, thereby creating a near-infinite number of possibilities and making an accurate cost-benefit analysis prohibitive.

Nonetheless, even assuming *arguendo* that these issues should be viewed from a strict cost-benefit perspective, NRDC witness Warren and OCA witness Nelson overlook the clear benefits of the Company's proposal, including those that were outlined in discovery, which greatly exceed the costs associated with the DER Management Plan:

First, the Company's DER Management Plan increases service reliability, improves power quality, and allows the Company to defer costly distribution system upgrades. Also, by utilizing the grid support functions of the smart inverters, PPL Electric can increase a distribution circuit's hosting capacity and accommodate more DERs interconnecting with that circuit. Further, being able to reduce overvoltage conditions by modification of the inverter's power factor setting will greatly reduce the cost of voltage related interconnection costs paid for by the customer. As explained previously, the traditional device used to reduce voltage on a circuit is a voltage regulator, which costs approximately $60,000. Under the Company's proposal, more DERs will be able to be interconnect with a distribution circuit without the need for expensive capital investments in a voltage regulator.

Second, as explained in Mr. Wallace's rebuttal testimony (PPL Electric Statement No. 6-R), utilizing the ConnectDER DER Management device will reduce the DER installation costs by approximately $393 to $700. The reduced installation costs are due to the DER management device making it no longer necessary to install an electrical cable to the electric panel as well as potentially upgrading the system to include a subpanel or a local disconnect. Further, as explained previously, PPL Electric would install, purchase, own, and maintain the DER management devices. Therefore, the Company's proposal would eliminate any direct cost of the DER management device being borne by the DER customer. Thus, the customer will receive the full benefit of the DER management device's reduction to the DER installation costs.

Thus, PPL Electric's proposal will produce substantial benefits to the Company's distribution system, its electric service to all customers, and customers who install DERs in the Company's service territory and will help incent and facilitate the increased deployment of DERs.

For all of these reasons, PPL Electric's DER Management proposal is reasonable and in the public interest and should be approved.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY AT THIS TIME?

A. Yes, although I reserve the right to supplement my rebuttal testimony.

PPL Electric Exhibit SS-1R

PPL Electric will use following grid support functions or modes under its DER Management plan.

Grid Support Function	Autonomous Management	Remote Management (Y/N)
Volt/VAR	Enabled at Interconnection	Y
Remote On/Off	N/A	Y
Constant Power Factor	N/A	Y
Voltage Ride-through	Enabled at Interconnection	Y
Frequency Ride-through	Enabled at Interconnection	Y
Volt/WATT	N/A[a]	N
Watt Ramp rate	N/A[b]	N

Table 1: DER Management Function Requirement

[a] Although not required under the DER Management Plan, the Company reserves its right to enable Volt-watt upon mutual consent with the DER customer.

[b] Although not required under the DER Management Plan, the Company reserves its right to specify a Watt Ramp Rate Upon mutual consent with the DER customer.

The following sections describe the grid support functions that will be utilized under the DER Management Plan, including their operating modes and default settings.

1. Volt/VAR

Volt/VAR, also commonly referred to as "Volt-Var Mode" or "Voltage-reactive power mode," is intended to stabilize grid voltages and enable the DERs to either supply or absorb reactive power in response to local voltage issues. The amount of reactive power that gets injected or absorbed is dictated by a curve defining the percentage of reactive power (Q) versus per-unit voltage (V) at the DER. A typical Volt/VAR curve is set with four pairs of data points (V, Q) as shown in Figure 1. The Volt/VAR mode also includes a dead-band, located between V2 and V3. Reactive power injection or absorption will only occur when voltage is outside of the dead-band, i.e., voltage drops below V2 or rises above V3.

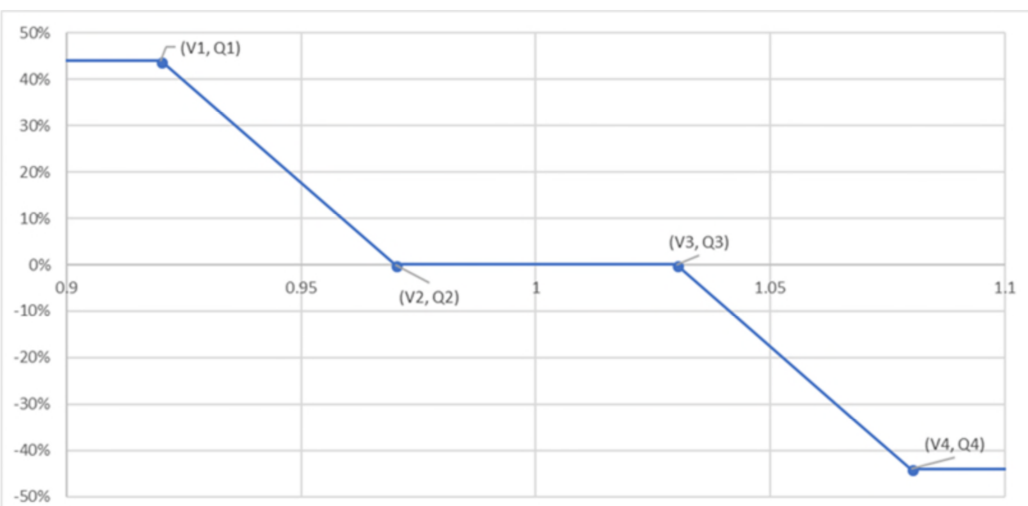


Figure 1: Typical Volt/VAR Curve

Under the Company's DER Management Plan, Volt/VAR will be the default enabled voltage regulating mode for all inverter-based DERs. During interconnection, the Company will specify a default curve as categorized in Table 2 below.

Voltage Setpoint	Voltage (p.u.[1])	Reactive Setpoint	Reactive Ratio	Operation	Adjustable Voltage Range (IEEE 1547-2018 allowable settings)
V1	0.92	Q1	44%	Reactive Power Injection	0.77 - 1.03
V2	0.97	Q2	0	Unity Power Factor	0.92 - 1.05
V3	1.03	Q3	0	Unity Power Factor	0.95 - 1.08
V4	1.08	Q4	44%	Reactive Power Injection	0.98 - 1.23

Table 2: Default volt-var Settings with adjustable range

However, depending on the feeder's characteristics and the DER's location, a different curve with a revised voltage dead-band that is still within the range of the IEEE 1547-2018 allowable settings might be issued instead of the default. The Volt/VAR curve selected when the DER is interconnected will only be actively adjusted to a different curve when there is a significant load profile change on the feeder, such as when the feeder has been reconfigured permanently and when new load(s) or generator(s) connect or disconnect from the distribution system. See Figures 2 and 3 for an example of a significant load profile change occurring after interconnection of the DER.

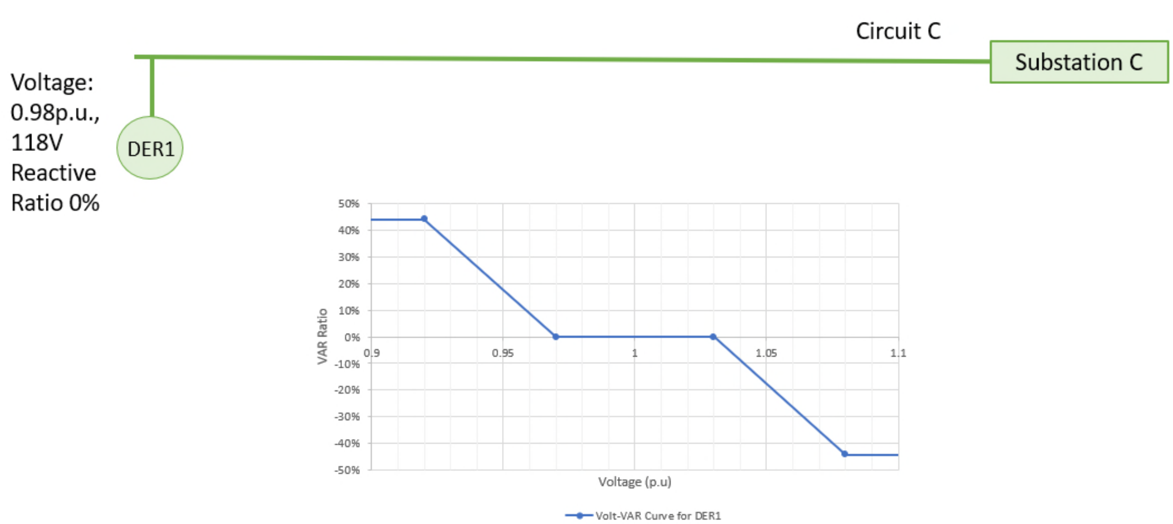


Figure 2: DER1 settings at time of interconnection

[1] "p.u." stands for per unit.

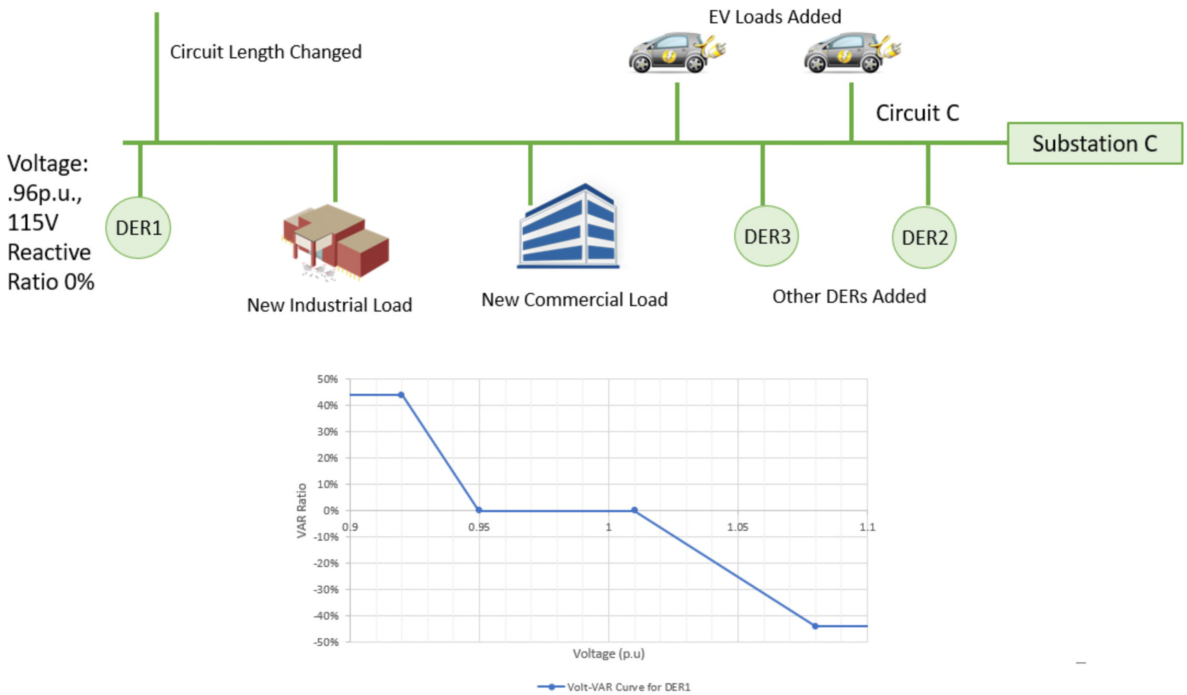


Figure 3: DER1 settings requiring an active change due to feeder dynamic changes

The Volt/VAR curve might also be temporarily disabled and overwritten with a constant power factor during dynamic system reconfiguration, where circuits are reconfigured temporarily due to an outage, maintenance, or equipment failure.

2. Remote On/Off

Remote On/Off function, also commonly referred to as “Connect/Disconnect function,” allows the inverter to be connected or disconnected remotely. When the inverter is disconnected or turned off, the DER’s power output will drop to zero.

Under the DER Management Plan, the Company only will utilize this function in two scenarios. The first scenario is during emergency situations, such as a gas leak or fire in the vicinity of the DER. In this scenario, the Company is requested by the gas company or by the local fire department to shut off all power sources at the scene for the safety of the public and emergency personnel. The second scenario is during situations where DERs back-feed a segment of the distribution system that was de-energized due to an outage, also known as “unintentional islanding.” During any of these situations, the section of the distribution system that is impacted by the gas leak, fire, or unintentional islanding be de-energized along with all DERs connected to it. However, the Company only needs to remotely turn off the DERs they are not automatically disconnected as they are supposed to do.

3. Constant Power Factor

Constant Power Factor mode, also commonly referred to as "Fixed Power Factor Function" or "Specified Power Factor," allows the inverter to operate at a specific power factor based on a pre-determined or real time system voltage need. Under the DER Management Plan, Volt/VAR is the default voltage regulation mode. Therefore, under normal operating conditions, the Constant Power Factor function will remain deactivated.

However, the Company may need to use Constant Power Factor temporarily in certain situations. One scenario where it may be used is during a distribution system reconfiguration, where the DER is transferred to another feeder because of outages, system maintenance, or equipment failure. When a DER with a certain Volt/VAR curve is transferred to another feeder, the curve that is used in the DER may not be adequate to support the voltage characteristics of the new feeder. If that happens, the DER may cause a voltage issue on the feeder. Therefore, PPL Electric would use Constant Power Factor to temporarily change the Volt/VAR curve so that the DER no longer causes the voltage issue on that feeder.

DER transfers are temporary in nature and, at times, are executed automatically through the Company's DMS. With Constant Power Factor, DERMS, which is part of DMS, could study the DER's new feeder, calculate a Constant Power factor that fits the DER's new feeder, and change the configuration of the DER. Specifically, one component of PPL Electric's DERMS is the voltage management application, known as Volt/VAR Control ("VVC"). This application optimizes voltage by coordinating and controlling PPL Electric's distribution system voltage control infrastructure, such as substation transformer tap changers, capacitor banks, and voltage regulators. In the scenario mentioned above where the DER is transferred to another feeder, VVC would monitor and manage power factor and then issue an appropriate power factor setting via the Constant Power Factor function to the DERs. This functionality may bring power factor to unity or the range of the Constant Power Factor would be between 0.9 leading to 0.9 lagging.

4. Voltage Ride-through

Voltage Ride-through, if enabled, allows inverters to continue operating or "ride-through" during momentary voltage and frequency deviations.

Under the DER Management Plan, Voltage Ride-through will be enabled during the DER's interconnection. The Company's default settings for the Voltage Ride-through function are shown in Tables 3 and 4 below. The Voltage Ride-through settings developed by the Company are designed to coordinate with North American Electric Reliability Corporation's ("NERC") standard PRC-024-02: Generator Frequency and Voltage Protective Relay Settings and are within the available range specified in IEEE 1547-2018.

Voltage Ride-through settings are designed for both distribution system support as well as bulk electric system reliability needs. Unique system characteristics such as distribution reclosing times, transmission clearing times and coordination with synchronous machines play into the determination of the Ride-through settings. The Company's settings were chosen so the DERs: (1) ride-through voltage and frequency disturbances on the bulk electric system and distribution system longer than the larger generators; and (2) better support system-wide stability. These settings might need to be updated based on industry stability requirements or planning requirements, as the distribution system or bulk electric system changes. Voltage Ride-through settings might also need to be adjusted after the industry gathers more data about inverter-based DERs and learns more about the settings' impact on anti-islanding schemes of inverters. With active management provided by the DER Management Plan, these settings can be automatically changed if needed in the future, thereby avoiding the costs associated with manual setting changes.

Under Voltage Requirements		
Shall Trip Function	Voltage (p.u. of nominal voltage)	Clearing Time (sec)
UV1	0.9	> 4
UV2	0.6	> 4
UV3	0.6	> 2.5
UV4	0.5	> 2.5
UV5	0.5	> 0.5
UV6	0	> 0.5

Table 3: Default Under Voltage Ride-Through Settings
(based on variation of IEEE 1547-2018 Voltage Ride-Through Category 2)

Over Voltage Requirements			
Shall Trip Function	Voltage (p.u. of nominal voltage)	Time (sec)	Operation Mode
OV1	1.0 – 1.1	0 – 1	Permissive Operation
OV2	1.0 – 1.1	1 – 5	Momentary Cessation
OV3	> 1.2	> 0	Momentary Cessation

Table 4: Default Over Voltage Ride-Through Settings
(based on variation of IEEE 1547-2018 Voltage Ride-Through Category 2)

5. Frequency Ride-through

Frequency Ride-through, if enabled, allows inverters to continue operating or "ride-through" during momentary frequency deviations.

Under the DER Management Plan, Frequency Ride-through will be enabled during the DER's interconnection with the default settings shown in Table 5 below. The Frequency Ride-through settings developed by the Company are designed to coordinate with NERC standard PRC-006-02: Automatic Under-frequency Load Shedding and are within the available range specified in IEEE 1547-2018.

Frequency Ride-through settings are designed for both distribution system support as well bulk electric system reliability needs. Unique system characteristics such as distribution reclosing times, transmission fault clearing times and coordination with synchronous machines play into the determination of the frequency Ride-through settings. The Company's settings were chosen so the DERs: (1) ride-through frequency disturbances on the bulk electric system longer than larger generators as specified in PRC-0024-02; and (2) pickup at a lower frequency than under-frequency load-shed requirements specified in PRC-006-02 to support system-wide stability. These settings may need to be updated based on industry stability requirements or planning requirements as the distribution system changes. Frequency Ride-through settings might also need to be adjusted once the industry learn more about the settings' impact on anti-islanding schemes of inverters and gathers more data on inverter-based DERs. With active management provided by the DER Management Plan, these settings can be automatically changed if needed in the future, thereby avoiding the costs associated with manual setting changes.

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Shall Trip – Under Frequency Requirements		
Shall Trip Function	Frequency (Hz)	Clearing Time (sec)
UF1	59.5	> 700
UF2	58	> 700
UF3	58	> 10
UF4	57	> 10
UF5	57	0

Table 5: Default Frequency Ride-Through Settings
(based on variation of IEEE 1547-2018 Frequency Ride-Through)

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	Autnomous Volt-VAR Curve	Power Factor Override	Ride-Through
Assumptions	1. An inverter will only have real power curtailment if the inverter's output is >90% of its full capacity, which is approximated to occur for a maximum of 4 hours (two hours on either side of solar noon) on clear, sunny days, when the sun has the highest Global Horizontal Irradiance (GHI) as shown by NREL's GHI Maps. In eastern Pennsylvania, this is between the months of May and August.[1] 2. Based on actual voltages for 2/1/2019 to 1/31/2020 at a sampling of existing DER customers with generators sized at 6kW and 100kW, these customers experienced voltages outside of what would be their set Volt/VAR curve's unity power factor deadband for 50 hours/year. **For this analysis, assume 25% of those 50 hours occur during peak output hours between May and August, or 12.5 hours/year.** 3. A power factor reduction to 0.9 will cause a real power curtailment of at most 10%. 4. Price per kWh generated **$0.1175 cent/kWh** and **$0.0663 cent/kWh** (based on 1/1/2020 pricing) for 6kW Residential and 100kW Small Commerical & Industrial respectively	1. An inverter will only have real power curtailment if the inverter's output is >90% of its full capacity, which is only likely to occur for a **maximum of 4 hours** (two hours on either side of solar noon) on clear, sunny days, when the sun has the highest Global Horizontal Irradiance (GHI) as shown by NREL's GHI Maps. In eastern Pennsylvania, this is between the months of May and August.[1] 2. Power Factor Override will be used when circuits are transferred to another circuit due to outages, maintenance, equipment failures, etc. PPL Electric approximates that the average feeder is reconfiugred temporarily on average once a year, for less than 24 hours, due to the above stated conditions. **For this analysis, assume the one transfer referenced above occurs during the peak 4 output hours between May and August or 4 hours per year.** 3. A power factor reduction to 0.9 will cause a real power curtailment of at most 10%. 4. Price per kWh generated **$0.1175 cent/kWh and $0.0663 cent/kWh** (based on 1/1/2020 pricing) for 6kW Residential and 100kW Small Commerical & Industrial respectively	1. An inverter will only have real power curtailment if the inverter's output is >90% of its full capacity, which is only likely to occur for a **maximum of 4 hours** (two hours on either side of solar noon) on clear, sunny days, when the sun has the highest Global Horizontal Irradiance (GHI) as shown by NREL's GHI Maps. In eastern Pennsylvania, this is between the months of May and August.[1] 2. PPL Electric approximates Ride-Through activated **2 times per year** due to transmission disturbances or distribution events. 3. Inverters remain connected during ride-through instead of shutting off for 5 minutes before reconnecting to the grid (**5 min/event, 2/year = 10 min/year, or ~17% of one hou**r) 4. Ride Through is activated during peak generation output and **results in 100% gain of revenue** for electricity output during the time the generator would have shut off without ride-through. 5. Price per kWh generated **$0.1175 cent/kWh and $0.0663 cent/kWh** (based on 1/1/2020 pricing) for 6kW Residential and 100kW Small Commerical & Industrial respectively
Revenue Reduction Calculation (6kW Solar)	6kW x 12.5 hr/year = 75kWh (Assumptions 1 and 2) 75kWh x 10% = 7.5kWh (Assumption 3) 7.5kWh x $0.1175 cent/kWh = **$0.88 revenue reduction/year** (Assumption 4)	6kW x 4 hr/year = 24kWh (Assumptions 1 and 2) 24kWh x 10% = 2.4kWh (Assumption 3) 2.4kWh x $0.1175 cent/kWh = **$0.28 revenue reduction/year** (Assumption 4)	6kW x 17% hr/year = 1.0kWh (Assumptions 1, 2 and 3) 1.0kWh x $0.1175 cent/kWh = **$0.12 revenue increase/year** (Assumption 4)
Revenue Reduction Calculation (100kW Solar)	100kW x 12.5 hr/year = 1250kWh (Assumptions 1 and 2) 1250kWh x 10% = 125kWh (Assumption 3) 125kWh x $0.0663 cent/kWh = **$8.29 revenue reduction/year** (Assumption 4)	100kW x 4 hr/year = 400kWh (Assumptions 1 and 2) 400kWh x 10% = 40kWh (Assumption 3) 40kWh x $0.0663 cent/kWh = **$2.65 revenue reduction/year** (Assumption 4)	100kW x 17% hr/year = 25kWh (Assumptions 1, 2 and 3) 25kWh x $0.0663 cent/kWh = **$1.66 revenue increase/year** (Assumption 4)

[1] https://www.nrel.gov/gis/solar.html

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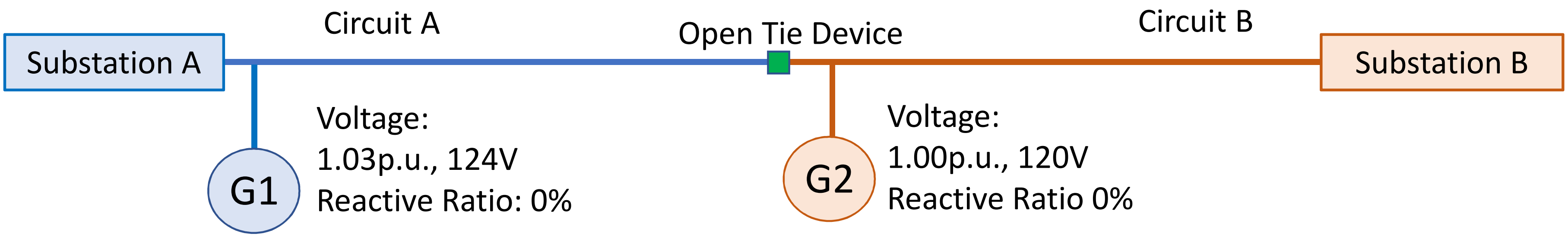
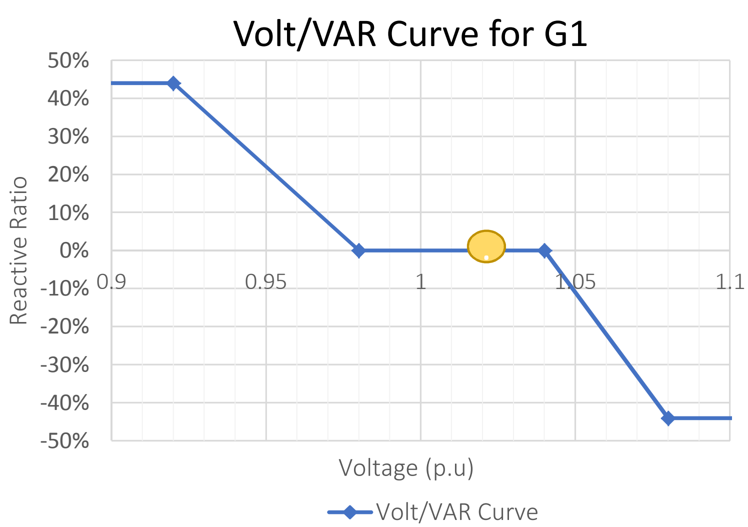
Figure 1: G1 Fed From Substation A





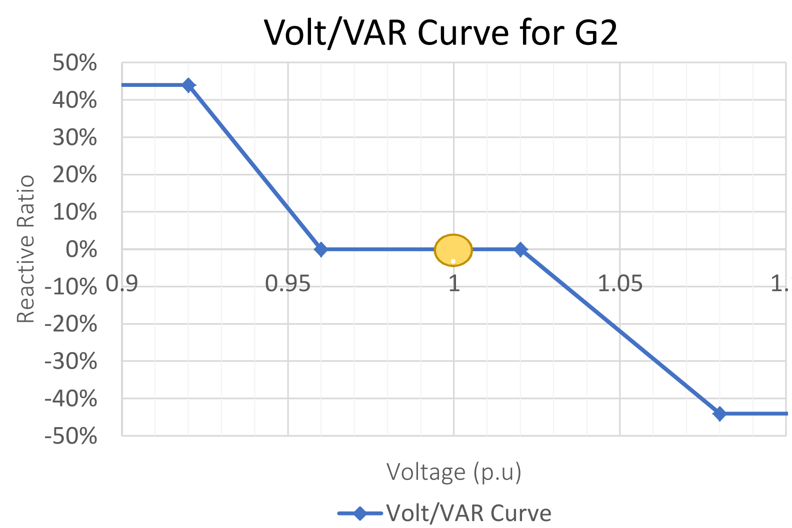
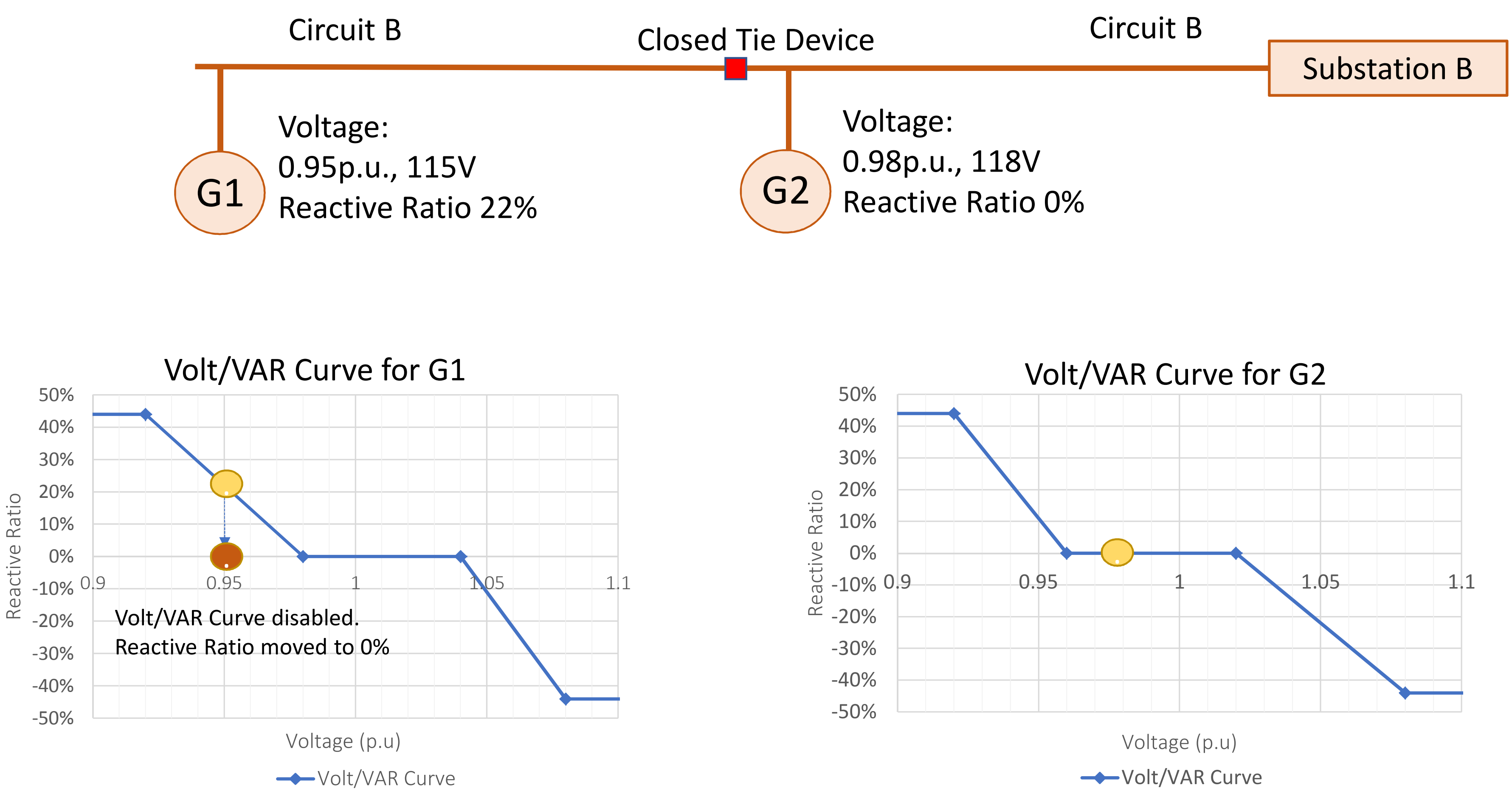


Figure 2: G1 Fed From Substation B



VERIFICATION

I, SALIM SALET, being the Director-Operations at PPL Electric Utilities Corporation, hereby state that the facts above set forth are true and correct to the best of my knowledge, information and belief and that I expect PPL Electric Utilities Corporation to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 relating to unsworn falsification to authorities.

Date: 3/4/2020

Salim Salet