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

REJOINDER TESTIMONY OF SALIM SALET

PPL Electric Statement No. 1-RJ

August 26, 2020

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 TESTIMONY IN THIS PROCEEDING?

A. Yes. My direct testimony is set forth in PPL Electric Statement No. 1, and my rebuttal testimony is set forth in PPL Electric Statement No. 1-R.

Q. WHAT IS THE PURPOSE OF YOUR REJOINDER TESTIMONY?

A. I will respond to many of the allegations and recommendations made in NRDC Statement No. 1-SR, the Surrebuttal Testimony of Harry Warren submitted on behalf of the Natural Resources Defense Council ("NRDC"); OCA Statement No. 1-SR, the Surrebuttal Testimony of Ron Nelson submitted on behalf of the Office of Consumer Advocate ("OCA"); SEF Statement No. 1-SR, the Surrebuttal Testimony of John Costlow submitted on behalf of the Sustainable Energy Fund ("SEF"); and SEF Statement No. 2-SR, the Surrebuttal Testimony of Ron Celentano submitted on behalf of SEF. In this rejoinder testimony, I will address the witnesses' surrebuttal testimony in that order.

Furthermore, some parties recommended in their surrebuttal testimony that PPL Electric undertake a pilot program to test and evaluate the Company's remote management of distributed energy resources ("DERs") interconnected with its distribution system through the use of the ConnectDER LLC ("ConnectDER") DER management devices. PPL Electric continues to maintain that its DER Management proposal should be granted in full as set forth in its rebuttal testimony. However, if the Commission concludes that the Company should undertake a pilot program, the Commission should direct PPL Electric to implement the DER Management Plan as set forth at the conclusion of my rejoinder testimony, which includes a program to test and evaluate the remote active management of DERs. Moreover, such direction from the Commission should not prohibit the Company's ability to seek recovery of the costs and expenses associated with the DER Management Plan in a future proceeding.

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

A. Yes. Attached to my rejoinder testimony is PPL Electric Exhibit SS-1RJ, which is a more in-depth analysis of the costs and benefits of the Company being able to remotely manage the smart inverters' grid support functions, along with a detailed list of the assumption used in that analysis.

I. <u>NRDC STATEMENT NO. 1-SR – SURREBUTTAL TESTIMONY OF HARRY WARREN</u>

Q. DO YOU HAVE ANY OVERALL COMMENTS ON NRDC WITNESS WARREN'S SURREBUTTAL TESTIMONY?

A. Yes. I would like to note that Mr. Warren does agree with the Company, at least in part, on the need for PPL Electric's proposal. Specifically, Mr. Warren recommends that PPL

Electric be permitted to begin requiring Institute of Electrical and Electronics Engineers ("IEEE") 1547-2018 compliant smart inverters and establishing the autonomous settings on the DERs' smart inverters beginning January 1, 2022. (NRDC Statement No. 1-SR, pp. 2-3.) He then recommends a pilot program that is "designed to demonstrate the incremental costs vs. the incremental benefits of communication with and control of newly installed der inverters." (NRDC Statement No. 1-SR, pp. 2, 16, 22.) Although I disagree with certain points in Mr. Warren's testimony, such as the January 1, 2022 start date for requiring IEEE 1547-2018 compliant smart inverters and autonomous settings as well as his pilot program recommendation, his surrebuttal testimony, at the very least, establishes that PPL Electric's DER Management Petition should be granted in part.

Q. YOU MENTIONED THAT YOU DISAGREE WITH NRDC WITNESS WARREN'S PILOT PROGRAM PROPOSAL. COULD YOU PLEASE EXPLAIN WHY?

A. NRDC witness Warren makes the pilot program recommendation for three primary reasons: (1) remote management is "not necessary to assure the safe and reliable operation of the distribution system or the bulk power system," but if PPL Electric wants to do that, it "should demonstrate that incremental advantages warrant incremental costs"; (2) the Company's analysis of cost savings for DER customers "is inaccurate in some respects, not universal in other respects, and does not address systems larger than 15 kW"; and (3) it is uncertain whether ConnectDER can "furnish the needed supplies of ConnectDER devices to cover all PPL DER systems." (NRDC Statement No. 1-SR, p. 4.)

However, none of these reasons have merit. First, PPL Electric has demonstrated that remote management of DERs has substantial safety and reliability benefits and that the incremental benefits of remote management outweigh the reduced benefits of solely relying on autonomous functions. One of the principal benefits is increasing the amount of DERs that can be safely and reliably interconnected with the distribution system, which can be accomplished by managing DERs' settings remotely, such as Volt/VAR and Constant Power Factor. Doing so across the distribution system increases the amount of DERs that can be interconnected to the system before making costly system upgrades. This is known in the industry as increasing "hosting capacity." Although autonomous functions can help increase hosting capacity in some circumstances, remote management will result in far fewer disruptions and reductions to service. For example, if the Volt/VAR curve on a customer's DER needs to be changed to accommodate a temporary or permanent overvoltage condition, remote management would enable PPL Electric to adjust the DER's Volt/VAR curve in a very quick and inexpensive manner. Without remote management, PPL Electric would have to dispatch personnel to adjust the settings on the inverter manually.

As a result, Mr. Warren continues to overlook how initial autonomous settings on smart inverters cannot be relied upon prospectively. Subsequent changes on the distribution system, such as the addition of more DERs or customers to a feeder, will require new autonomous settings. In other words, the autonomous settings will be established to address the conditions of the system existing today, not tomorrow. While Mr. Warren wants PPL Electric to solely rely on the autonomous settings, he fails to account for the obvious benefits of PPL Electric remotely adjusting those settings as needed in a quick, inexpensive manner, rather than having to dispatch personnel to manually adjust the settings on the inverter.

Second, PPL Electric's estimates of cost savings for customers under its proposal are accurate, as explained by Mr. Wallace (PPL Electric Statement No. 6-RJ) and shown by PPL Electric Exhibit MW-1RJ.

Third, NRDC witness Warren's concerns about whether ConnectDER can supply a sufficient quantity of ConnectDER DER Management devices should be rejected. The Company will maintain a running inventory for minimum of three months' worth of system demand, starting at 400 units, which will be replenished monthly. ConnectDER will maintain minimum of three months' worth of inventory, which will be available for immediate delivery. ConnectDER's manufacturer, Allen Integrated Assemblies ("AIA"), will maintain an allocated inventory for PPL Electric of the necessary parts and components to assemble an additional three months' worth of units, which can all be delivered within one month's time. For additional materials beyond the nine-month supply, the longest lead time is three months. AIA can hire and train additional labor in two weeks' time. In addition, based on the Company's experience with DER installations in its service area, it takes customers a minimum of approximately six weeks to install their DER systems after they receive the PPL Electric's approval. Therefore, the Company will be able to foresee the demand coming. ConnectDER also has provided PPL Electric with a letter of prioritization, showing that demand by other utilities should not affect the Company's demand for the DER Management devices.

Further, despite recognizing that any pilot program would need "a significant number of DER management devices to be deployed," NRDC witness Warren proposes an unsound “opt-in” approach for participation in the pilot, thereby significantly reducing the number of participants and unduly hindering the benefits and evaluation of any such pilot. Indeed, for the past couple years, PPL Electric has been operating a pilot program in coordination with the U.S. Department of Energy (“DOE”) called the Keystone Solar Future Project, which has been trying to evaluate the benefits of remote active management of DERs. Participation in this pilot program has been entirely voluntary. While the Company believes that the Keystone Solar Future Project has provided valuable insights and information, participation in the pilot has been far below the Company’s expectations due to the limited geographic scope of the pilot, the Company’s inability to control where DERs will be interconnected, and, most critically, the voluntary nature of the pilot. Thus, if Mr. Warren truly wants the Company to evaluate “a significant number of DER management devices,” an opt-in approach is not the correct strategy.

Notwithstanding, although PPL Electric disagrees with NRDC’s pilot program recommendation, it appears that the NRDC recognizes the benefits of PPL Electric requiring IEEE 1547-2018 compliant smart inverters and using automated grid support functions.

Q. NRDC WITNESS WARREN ALSO RECOMMENDS THAT THE COMPANY “BE AUTHORIZED TO REQUIRE THAT INVERTERS CERTIFIED TO IEEE-1547-2018 BE USED IN ALL NEW DER INSTALLATIONS AFTER JANUARY 1, 2022” (NRDC STATEMENT NO. 1-SR, P. 3.) WOULD YOU PLEASE RESPOND?

A. There is no need to wait until January 1, 2022, to launch PPL Electric’s DER Management proposal. The basis for Mr. Warren’s recommendation is his estimation that IEEE 1547-

2018 compliant smart inverters will not be readily available on the market by January 1, 2022. (NRDC Statement No. 1-SR, p. 18.) However, as explained in my prior testimony, PPL Electric has a robust and detailed interim solution for using certified smart inverters until the IEEE 1547-2018 and UL 1741 standards are finalized and published. Therefore, PPL Electric should be permitted to begin implementing its DER Management proposal as soon as the Commission enters its Order approving the Company's Petition.

Q. NRDC WITNESS WARREN ALSO RAISES A QUESTION AS TO WHETHER THE COMPANY'S DER MANAGEMENT PROPOSAL WOULD APPLY TO DER SYSTEMS WITH NAMEPLATE CAPACITIES LARGER THAN 15 KW. (NRDC STATEMENT NO. 1-SR, PP. 8-9.) CAN YOU PLEASE CLARIFY?

A. PPL Electric would purchase, install, own, and maintain DER Management devices for larger DER installations in the same manner as the Company would for smaller installations. However, for systems larger than 15 kW, the customers may not be able to enjoy the benefits of the reduced installation costs stemming from the use of the ConnectDER DER Management Device, as seen in PPL Electric Exhibit MW-1RJ attached to Mr. Wallace's rejoinder testimony (PPL Electric Statement No. 6-RJ).

Q. NRDC WITNESS WARREN ALSO ASSERTS THAT EVEN IF THE COMMISSION APPROVES PPL ELECTRIC'S DER MANAGEMENT PLAN OR HIS PROPOSED PILOT PROGRAM, A STATEWIDE PROCEEDING SHOULD STILL BE INITIATED TO ADDRESS OTHER UTILITIES' PLANS TO

IMPLEMENT IEEE 1547-2018. (NRDC STATEMENT NO. 1-SR, P. 19.) WHAT IS YOUR RESPONSE?

A. If such a proceeding is initiated after PPL Electric's DER Management Petition is approved, the Company would be willing to share its experiences obtained through DER Management Plan with other utilities in Pennsylvania and the Commission. In that respect, PPL Electric's DER Management proposal should provide valuable data and information for interested parties and the Commission to consider in that statewide proceeding. Therefore, other utilities, stakeholders, customers, and the Commission would benefit from PPL Electric implementing its DER Management proposal before any such statewide proceeding.

II. <u>OCA STATEMENT NO. 1-SR – SURREBUTTAL TESTIMONY OF RON NELSON</u>

Q. OCA WITNESS NESLON CLAIMS THAT PPL ELECTRIC'S DECISION TO MAKE ITS UPDATED DER MANAGEMENT PROPOSAL IN ITS REBUTTAL TESTIMONY REFLECTS A LACK OF PLANNING AND CALLS INTO QUESTION THE COMPANY'S ANALYSIS OF THE DER MANAGEMENT DEVICES. (OCA STATEMENT NO. 1-SR, PP. 3-5.) DO YOU AGREE?

A. Absolutely not. PPL Electric made its updated proposal after careful analysis and in an effort to respond to the other parties' issues raised in their direct testimony, including the impact of the Company's proposal on customers' costs to install new DERs. Moreover, OCA was provided with details about the ConnectDER DER Management device in discovery as early as December 3, 2019, when the Company served its response to Interrogatory 42 in SEF's first set of discovery. In fact, Mr. Nelson attached that discovery response to his direct testimony as an exhibit, which has a picture of the ConnectDER DER Management device and has multiple paragraphs explaining the development, installation, and operation of the device. (*See* OCA Schedule REN-2, Answer to Interrogatory SEF-I-42, Attachment 1, p. 16.) Therefore, the OCA was provided with information about this device and its potential use by the Company over two months before the OCA served its direct testimony on February 5, 2020. Thus, the OCA had more than enough time to engage in discovery about this device before serving its direct testimony.

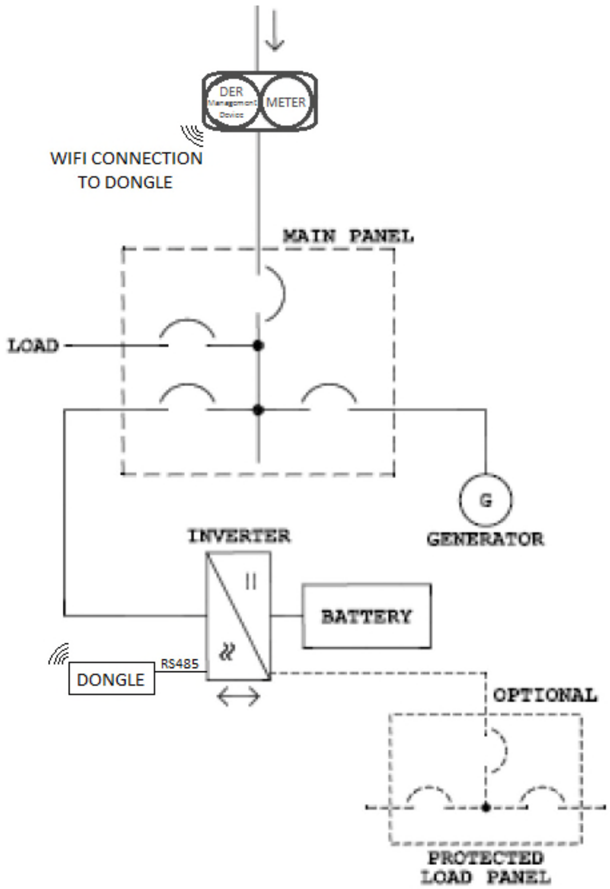
Q. MR. NELSON ALSO CLAIMS THAT THE ESTIMATED COST OF THE CONNECTDER DER MANAGEMENT DEVICE IS $400, NOT THE COMPANY'S ESTIMATE OF $700. (OCA STATEMENT NO. 1-SR, P. 5.) IS MR. NELSON CORRECT?

A. No. It appears Mr. Nelson was looking at the Simple ConnectDER device, not the ConnectDER DER Management device that PPL Electric plans on utilizing. The Simple ConnectDER device allows for a straightforward connection of the electrical output of the DER system, in lieu of connection to a customer's electrical panel. The Simple ConnectDER device consists of the meter collar only and lacks the radio that can communicate with the smart inverter and manage the smart inverter's grid support functions.

In contrast, the ConnectDER DER Management device, which PPL Electric is proposing to use, does contain the radio and can communicate with the smart inverter and manage the smart inverters' settings. Such capabilities are necessary to realize the safety and reliability benefits of the DER Management Plan. Therefore, OCA witness Nelson's analysis on the estimate cost of the DER Management device is based on the wrong ConnectDER device.

Q. OCA WITNESS NELSON CONTENDS THAT PPL ELECTRIC DID NOT ADDRESS THE INSTALLATION COSTS OR EXPLAIN HOW THE DER MANAGEMENT DEVICES WOULD INTERCONNECT TO STANDALONE BATTERY STORAGE OR ELECTRIC VEHICLES ("EVs"). (OCA STATEMENT NO. 1-SR, PP. 8-9.) PLEASE RESPOND.

A. To clarify, the Company no longer is proposing to include EVs under its present DER Management Plan. In the future, as standards develop and mature, as well as EV technology, PPL Electric will continue to evaluate impact to safety and reliability on the distribution system. As for standalone battery storage, IEEE 1547-2018, the "Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces," applies to all DERs, including fuel cells, photovoltaics, dispersed generation, and energy storage. The Standard specifies standardized communication interfaces for DERs, including generators (like solar photovoltaic generators) and energy storage (like lithium ion batteries). Just as PPL Electric would connect the dongle of the DER Management device to the interface on a solar photovoltaic smart inverter certified to IEEE 1547-2018, the Company would connect the dongle of the DER Management device to the interface on a standalone battery inverter certified to IEEE 1547-2018. A one-line diagram of how the device would be interconnected with a standalone battery storage unit's inverter is provided below.



I further note that PPL Electric will only connect a DER Management device to a standalone battery that acts as a DER, *i.e.*, exports power onto the electric distribution system. PPL Electric will not connect a DER Management device to standalone batteries that are intended exclusively for backup generation, rather than exporting electric power onto the distribution system.

Q. MR. NELSON ALSO ASSERTS THAT PPL ELECTRIC FAILED TO ADDRESS THE CUSTOMER PROTECTION CONCERNS RAISED BY THE OCA. (OCA STATEMENT NO. 1-SR, PP. 10-11.) DO YOU AGREE?

A. No. PPL Electric's updated proposal substantially addressed the customer protection concerns raised by the OCA, including the submission of annual reports to the Commission and individual customers that would provide the Commission, stakeholders, and customers with significant oversight of the DER Management Plan. Moreover, as set forth in the Company's pilot program alternative, PPL Electric would provide extensive annual reports to the Commission, stakeholders, and individual customers about the progress of the DER Management Plan and the impact, if any, on participating customer-generators' production.

Q. OCA WITNESS NELSON TAKES THE POSITION THAT OTHER ELECTRIC DISTRIBUTION COMPANIES ("EDCs") CAN SIMPLY IMPLEMENT IEEE-1547 2018 WITHOUT FURTHER INVESTMENTS. (OCA STATEMENT NO. 1-SR, PP. 20-21.) DO YOU BELIEVE THIS IS A SOUND APPROACH?

A. No. Although other EDCs could just require all DERs to use IEEE 1547-2018 compliant inverters, this would not produce any substantial benefits. Indeed, to get any substantial benefit out of those smart inverters, EDCs have to study their distribution systems and come up with EDC-specific default settings that fit their distribution circuits. The other EDCs would have to devote the necessary time and expense to conduct this analysis and implement their default settings, which they may not be willing to do. In addition, without the investments made in Distributed Energy Resource Management System ("DERMS"), Distribution Management System ("DMS"), and the communication system, EDCs cannot achieve the significant safety and reliability benefits highlighted by PPL Electric's DER Management Plan, such as managing voltage issues, increasing hosting capacity, improving safety and reliability, addressing issues with masked load, and mitigating fault location concerns. Therefore, Mr. Nelson's claim that other EDCs can implement IEEE 1547-2018 without further investments should be rejected.

Q. MR. NELSON ALSO CRITICIZES THE COMPANY'S COST-BENEFIT ANALYSIS OF ITS PROPOSAL. (OCA STATEMENT NO. 1-SR, PP. 7-9.) PLEASE RESPOND.

A. As Ms. Johnson will explain in her rejoinder testimony, OCA witness Nelson's allegations related to the Company's cost-benefit analysis are without merit. Nonetheless, attached as PPL Electric Exhibit SS-1RJ is a more in-depth analysis of the costs and benefits of the Company being able to remotely manage the smart inverters' grid support functions, along with a detailed list of the assumption used in that analysis.

III. <u>SEF STATEMENT NO. 1-SR – SURREBUTTAL TESTIMONY OF JOHN COSTLOW</u>

Q. SEF WITNESS COSTLOW RAISES ISSUES CONCERNING THE USE OF THE SMART INVERTERS' REMOTE ON/OFF FUNCTION FOR SOLAR PLUS STORAGE DER INSTALLATIONS. (SEF STATEMENT NO. 1-SR, PP. 2-3, 8.) WOULD YOU PLEASE RESPOND?

A. Mr. Costlow's arguments lack merit and show that he fundamentally misunderstands unintentional islanding. Mr. Costlow claims that unintentional islanding will not happen since solar and battery inverters will shut off automatically. Although inverters are designed to shut off during an grid outage, unintentional islanding could still happen when: (1) inverters malfunction and fail to shut off; (2) inverters on the same feeder use different algorithms that may cause each other to stay online during a loss-of-source; or (3) combined generation is approximately equal to load on the line and cause reference voltage at the DER to appear sufficiently similar to grid voltage.

Further, PPL Electric has no intention to remotely turn off solar plus storage after it has automatically disconnected from the distribution system in case of an outage. In the case of an outage, and assuming there is no emergency situation such as a gas leak, PPL Electric will not remotely turn off solar plus storage after that system has automatically disconnected from the distribution system. After the customer's solar plus storage disconnects from the distribution system, the customer can continue to operate the DER system to supply their native load. Therefore, the customer's solar plus storage system can provide power behind the customer disconnect.

Q. MR. COSTLOW ALSO RECOMMENDS THAT ANY MODIFICATIONS TO PPL ELECTRIC'S DER MANAGEMENT PLAN SHOULD HAVE TO BE APPROVED BY THE COMMISSION AFTER THE SUBMISSION OF COMMENTS AND REPLY COMMENTS ON THE PROPOSED MODIFICATIONS, LIKE IN THE ENERGY EFFICIENCY AND CONSERVATION ("EE&C") PLAN PROCEEDINGS. (SEF STATEMENT NO. 1-SR, P. 3.) DO YOU AGREE?

A. No. Mr. Costlow's recommendation lacks merit. In the EE&C Plan proceedings, different review processes are set up for "minor" and "major" plan changes, as defined by the Commission's *Minor Plan Change Order*.[1] However, I have been advised by counsel that not every change or adjustment to an EE&C Plan is subject to Commission review and

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[1] *See Energy Efficiency and Conservation Program*, Docket No. M-2008-2069887 (Order entered June 10, 2011) ("*Minor Plan Change Order*").

approval, as suggested by Mr. Costlow. Indeed, PPL Electric's currently-effective Phase III EE&C Plan has various provisions that give the Company flexibility in operating its EE&C Plan without the need for formal Plan changes to be approved. For example, many of the incentives offered for EE&C measures have incentive ranges, allowing the Company to change the incentive offered to customers to any dollar figure within those ranges. Moreover, the EE&C Plan has language allowing PPL Electric to adjust the available measures offered under certain programs, so that the Company can efficiently operate its programs while still achieving the requisite level of savings and remaining under the established budget. Therefore, Mr. Costlow's reliance on the Company's EE&C Plan as support for his recommendation that "PPL Electric should not be given the authority to modify, in any way, its DER Management Plan at Company discretion" is misplaced. (SEF Statement No. 1-SR, p. 3.)

Furthermore, Mr. Costlow fails to recognize that there are already established procedures for modifications to tariffs and Commission orders. I have been advised by counsel that if the Company wanted to change any terms in the proposed Tariff Rule 12, PPL Electric would have to follow the Commission's established procedures for proposal and approval of tariff modifications. Similarly, counsel has advised me that PPL Electric would have to adhere to the terms of the Commission's order approving the DER Management Plan. If a party wishes to propose amendments or modifications to a Commission order, both the Public Utility Code and the Commission's regulations set forth the procedures for a party to file a petition to amend or modify that Order. *See* 66 Pa. C.S. § 703(g); 52 Pa. Code § 5.41.

Q. WILL PPL ELECTRIC'S DER MANAGEMENT PLAN LIMIT THE ABILITY OF DER OWNERS TO MONITOR AND CONTROL THEIR SMART INVERTERS, AS ALLEGED BY SEF WITNESS COSTLOW? (SEF STATEMENT NO. 1-SR, P. 5.)

A. No. PPL Electric's DER Management Plan will not limit the ability of DER owners to monitor and control their smart inverters. PPL Electric has evaluated inverters with three ports that would allow the Company to connect its DER Management device without impacting the ability for the customer to manage their energy infrastructure. In cases where three communications ports are needed, such as in a solar plus storage situation, PPL Electric will provide a multi-port solution at no direct cost to that customer. Therefore, Mr. Costlow's concern is moot.

In addition, in SEF witness Costlow's surrebuttal testimony, he references SEF's system that will be used in its "Net Zero Energy Office Building." (SEF Statement No. 1-SR, p. 5.) The SolarEdge SE43.2KUS inverters used in this system feature two RS485 ports, where one port is used to network the inverters together and the other port is used to connect to the customer's energy management system. Out-of-the-box, this model of inverter may not be capable of simultaneously connecting to: (a) other inverters; (b) the customer's energy management system; and (c) PPL Electric's DER Management device. However, a mini Remote Terminal Unit ("RTU") could be utilized to connect multiple devices (such as the customer's energy management system and PPL Electric's DER Management device) to a single RS485 port.

Further, other commercially available inverters feature enough RS485 interfaces to accommodate such a configuration out-of-the-box. For example, the CanadianSolar CSI

Series inverters (available in 40KVA, 50KVA, and 60KVA capacities) feature three ports and are comparable to the inverters used in SEF's Net Zero Energy Office Building. And once the IEEE 1547-2018 Standard is fully adopted by the inverter manufacturing industry, inverters will feature a standardized interface that can be used by the EDC, per Section 10.7 of the Standard.

Lastly, SEF's interconnection application for the system it is installing at its Net Zero Energy Office Building has already been approved to move forward. Given that the Company's DER Management Plan will only apply to new DERs that are installed in its service territory, SEF's currently-designed system will not be affected by the Company's proposal. Thus, SEF's concerns about its own system being negatively affected by the DER Management Plan are invalid.

Q. SEF WITNESS COSTLOW ALSO RAISES A CONCERN ABOUT THE NUMBER OF INVERTERS CERTIFIED AS MEETING THE COMPANY'S INTERIM REQUIREMENTS. (SEF STATEMENT NO. 1-SR, PP. 3-4.) PLEASE RESPOND.

A. SEF witness Costow's concerns should be rejected. PPL Electric's DER Management Plan is ready to be implemented upon the Commission's approval and does not need to be delayed until, as SEF witness Costlow alleges, "significantly more smart inverters . . . become commercially available." (SEF Statement No. 1-SR, p. 4.) PPL Electric has already approved inverters from six major inverter brands (*i.e.*, Fronius, Delta, ABB, Sol-Ark, Canadian Solar, and Chint) as meeting its interim criteria (*i.e.*, inverters that are certified to Underwriters Laboratories ("UL") 1741 Supplement A and also satisfy the communication requirements described IEEE 1547-2018, Section 10.7) and is rapidly evaluating additional major brands that it expects will also satisfy these requirements, such as SolarEdge, Ginlong Solis, Sungrow, and Yaskawa. By the time the Commission approves the DER Management Petition, customers will have many choices of smart inverters that meet the Company's interim requirements.

Q. SEF WITNESS COSTLOW ASSERTS THAT PPL ELECTRIC'S UPDATED DER MANAGEMENT PROPOSAL ONLY REDUCES COSTS TO CUSTOMERS WHEN COMPARED TO THE COMPANY'S ORIGINAL PROPOSAL. (SEF STATEMENT NO. 1-SR, P. 7.) DO YOU AGREE?

A. No. Mr. Costlow completely overlooks how the updated proposal will substantially reduce installation costs for most new DER customers. Without PPL Electric's DER Management Plan being approved, those customers will lose out on the opportunity to save on those installation costs. Thus, PPL Electric's updated proposal will reduce costs to customers versus the status quo.

Q. MR. COSTLOW ALSO CLAIMS THAT PPL ELECTRIC'S DISTRIBUTION GENERATION ("DG") WEB PORTAL'S CURRENT INABILITY TO ACCEPT NEW CONSTRUCTION APPLICATIONS INDICATES A "LACK OF UNDERSTANDING OF THE DER MARKET WHICH WILL CERTAINLY IMPACT THE COMPANY'S ABILITY TO SUCCESSFULLY MANAGE DERS," AS ALLEGED BY SEF WITNESS COSTLOW. (SEF STATEMENT NO. 1-SR, PP. 8-9.) DO YOU AGREE?

A. Absolutely not. As noted in my rebuttal testimony, PPL Electric has all of the necessary infrastructure and equipment in place to implement its DER Management proposal, and continues to be an industry leader for implementing grid modernization technologies such as Distribution Automation, DMS, and Fault Isolation and Service Restoration ("FISR"). PPL Electric also is the only utility in the Commonwealth that currently has an operational DERMS platform. The Company also 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. Thus, PPL Electric is well-equipped to leverage these investments, its stellar customer service record, and its in-house knowledge and resources to implement its DER Management proposal. Those facts are what matter when evaluating whether PPL Electric can successfully implement the DER Management Plan, not the lack of a minor functionality in the Company's DG Web Portal. Additionally, although the DG Web Portal cannot currently process new construction applications until an account and meter number are assigned, PPL Electric can process those applications manually through the Company's customer service department.

Q. WOULD YOU PLEASE RESPOND TO SEF WITNESS COSTLOW'S ARGUMENTS ABOUT THE ALLEGED DISTANCE OF THE CONNECTDER DER MANAGEMENT DEVICE'S WI-FI COMMUNICATIONS AFFECTING THE "MOST EFFICIENT" PLACEMENT OF INVERTERS? (SEF STATEMENT NO. 1-SR, P. 9.)

A. The most efficient place to have the inverter is close to the connection point of the distribution system. The closer the inverter is to the distribution system, the lower the losses are.

Likewise, SEF witness Costlow inaccurately claims that inverters may need to be placed more than 100 feet away in order to avoid "significant losses associated with the transmission of DC power." (SEF Statement No. 1-SR, p. 9.) While there are many design considerations that come into play with inverter placement, the general rule is to keep the inverter as close to the Area EPS interconnection (*i.e.*, the meter) as possible to help maximize power output and, by extension, the customer's return on investment. However, if the smart inverter must be located outside of the Wi-Fi communication distance of the DER Management device, the Company will install necessary additional equipment to extend the range of connection.

Q. MR. COSTLOW ALSO OUTLINES A PILOT PROGRAM RECOMMENDATION IN CASE THE COMMISSION DOES NOT DENY PPL ELECTRIC'S DER MANAGEMENT PLAN. (SEF STATEMENT NO. 1-SR, PP. 10-14.) DO YOU AGREE WITH THIS RECOMMENDATION?

A. No. Like NRDC's proposal, it is a poorly designed "opt-in" proposal. Moreover, SEF's proposal contains several unnecessary and burdensome requirements that would severely limit participation in the pilot, impose additional costs on the Company, and significantly hinder the benefits and evaluation of any such pilot. For example, Mr. Costlow recommends that PPL Electric be directed to "create a text alert system that will notify customers when PPL Electric modifies an inverter setting as well as a text alert when the system is restored to its previous settings." (SEF Statement No. 1-SR, p. 13.) This would require substantial IT work, be expensive, and provide little benefit to customers.

Mr. Costlow also proposes that PPL Electric be prevented from commencing the pilot until it "certifies 80% of the inverters in the market," which "should include, at minimum, five (5) inverter manufacture[rs] as well as micro inverters." (SEF Statement No. 1-SR, p. 11.) As in any competitive market, the market for inverters is continually changing, with new products coming to market and old products being removed from the market in a fairly unpredictable manner. Therefore, it is highly questionable as to when PPL Electric could certify 80% of the inverters in the market, when more inverters are being added to the market and older inverters are being removed. Such certifications would also be rendered moot once IEEE 1547-2018 and UL 1741 are fully implemented. Thus, this requirement would only serve to unduly delay the implementation of any such pilot. Nevertheless, I note that PPL Electric has approved six major inverter brands' inverters as meeting the Company's interim criteria and will approve more by the time the Commission approves the DER Management Petition.

Finally, as mentioned previously, PPL Electric no longer will include EVs under its DER Management Plan, so SEF's recommendation for EVs to be excluded from the pilot program is now moot.

IV. <u>SEF STATEMENT NO. 2-SR – SURREBUTTAL TESTIMONY OF RON CELENTANO</u>

Q. CONCERNING THE COMPANY'S PROPOSED USE OF THE REMOTE ON/OFF FUNCTION DURING POWER OUTAGES, SEF WITNESS CELENTANO ARGUES THAT UNINTENTIONAL ISLANDING IS NOT A CONCERN AND

THAT IT IS UNCLEAR HOW THE COMPANY'S USE OF THE REMOTE ON/OFF FUNCTION WOULD AFFECT SOLAR PLUS STORAGE SYSTEMS. (SEF STATEMENT NO. 2-SR, PP. 2-3.) DO YOU AGREE?

A. No. Unintentional islanding could still occur when inverters on the same distribution feeder use different algorithms that may cause each other to stay online during a loss-of-source, or when combined generation is approximately equal to load on the line and causes reference voltage at the DERs to appear sufficiently similar to grid voltage. Line loading is dynamic during a fault, so a lower generation-to-load ratio is used to assess islanding in these scenarios.

Moreover, for solar plus storage, the Company has no intention of shutting down a battery storage system or the solar system during outage situation. With either a DC coupled or an AC coupled solar plus storage, the Company would only remotely turn off the inverter connected to the distribution system in the case where its grid side failed to disconnect and is back-feeding into a de-energized and faulted line section, or if there is an emergency situation such as a gas leak.

Q. SEF WITNESS CELENTANO ALSO MAKES CERTAIN CRITICISMS ABOUT YOUR TWO-WAY POWER FLOW EXAMPLE. (SEF STATEMENT NO. 2-SR, PP. 3-4.) DO THOSE CRITICISMS HAVE MERIT?

A. No. Mr. Celentano's criticisms of the Company's two-way power flow example should be rejected. PPL Electric included a simple example of a small two-way power flow that can happen anywhere in Company's distribution system for illustration purposes. This simple example was intended to show how two-way power flows work and create issues on the distribution system. Further, the example helped show that, contrary to OCA witness Nelson's characterization in his direct testimony, PPL Electric is not only experiencing two-way power flows on a "de minimus number of circuits." (OCA St. No. 1, p. 33.) In fact, PPL Electric experiences two-way power flows on a regular basis. In discovery, the Company listed several locations where two-way power flow known to the Company because the two-way power flow is high enough to back-feed circuit breaker level or 3 phase circuit device. Thus, depending on the circuit, the amount of generation and load on a circuit could create a much more dire two-way power flow situation than the illustrative example set forth in my rebuttal testimony.

Q. MR. CELENTANO ALSO CONTENDS THAT YOU REFERENCE TO THE NATIONAL AVERAGE RESIDENTIAL SOLAR INSTALLATION COST DOES NOT COMPARE TO AVERAGE COST IN PENNSYLVANIA. (SEF STATEMENT NO. 2-SR, PP. 5-6.) PLEASE RESPOND.

A. Mr. Celentano misunderstands the purpose of my reference to the national solar installation cost. In my rebuttal testimony, I referenced national data compiled by National Renewable Energy Laboratory ("NREL"), which indicated that the residential solar installation cost has dropped 63%, from $7.34 per watt in 2010 to $2.70 per watt in 2018. While Mr. Celentano asserts that the residential solar installation cost in Pennsylvania is $2.94 per watt, he does not dispute that the costs have been dropping substantially. No reason exists to believe that this trend will stop or reverse course in Pennsylvania. In fact, even Mr. Celentano's $2.94 per watt figure is a substantial 60% drop from the national average cost in 2010.

Q. MR. CELENTANO ALSO AVERS THAT THE COMPANY'S USE OF THE CONNECTDER DER MANAGEMENT DEVICE MAY BE INCONSISTENT WITH 52 PA. CODE § 75.36(9)'S REQUIREMENTS FOR A LOCKABLE, VISIBLE BREAK ISOLATION DEVICE OR A DRAW-OUT TYPE CIRCUIT BREAKER. (SEF STATEMENT NO. 2-SR, PP. 6-7.) WOULD YOU PLEASE RESPOND?

A. PPL Electric maintains that the new ConnectDER DER Management device should be allowed to be used and, to the extent necessary, a waiver of this regulation should be granted. I have been advised by counsel that Section 75.36(9) of the Commission's regulations is intended to provide the EDCs with the ability to, if necessary, isolate interconnected DERs from the distribution system. Although the ConnectDER DER Management device is not a physical switch like an AC Disconnect, it is a device that provides a lockable, visible-break isolation point. If PPL Electric were required to isolate the customer's inverter system, PPL Electric would simply remove the ConnectDER DER Management device's meter collar and reinstall the customer's meter with a meter lock. Thus, even if the ConnectDER DER Management device were used, the Company could use the device as a visible break isolation point for the customer's inverter system and install the meter lock to prevent any re-energization without PPL Electric's permission.

Moreover, my understanding is that Section 75.36 is founded upon the principle that the "lockable, visible-break isolation device" must be "accessible by the EDC." 52 Pa. Code § 75.36(9). The requirement for accessibility is a moot concern when the EDC owns the isolation device instead of the customer. As proposed by the Company in its rebuttal testimony, PPL Electric would purchase, own, install, and maintain the ConnectDER DER Management device. Importantly, PPL Electric's Tariff Rule 2(F) grants the Company "access at all reasonable hours to customer's premises, without charge, for the purpose of inspecting installations, installing meters, reading, testing, removing, replacing or otherwise maintaining or disposing of any of Company's property." Supp. No. 59 to Electric Pa. P.U.C. No. 201, Fifth Revised Page No. 6B. As a result, there would be no issues with the Company's ability to access this equipment. Therefore, I do not believe that Section 75.36(9) should be used to restrict the Company's ability to implement the DER Management Plan.

Finally, PPL Electric requested in its DER Management Petition that "the Commission grant any additional waivers of the Commission's regulations it deems are necessary to implement the DER Management Plan." (DER Management Petition ¶ 81.) Therefore, to the extent that the Commission believes that a waiver of Section 75.36(9) is necessary, the Commission should grant such waiver so that the Company can implement the DER Management Plan and reap the substantial benefits of the proposal.

Q. DO YOU AGREE WITH SEF WITNESS CELENTANO'S ASSERTION THAT "THE VAST MAJORITY OF INVERTERS ARE CURRENTLY NOT TEMPORARILY SHUTTING DOWN TOO OFTEN WITHOUT ENGAGING VOLTAGE AND FREQUENCY RIDE-THROUGH"? (SEF STATEMENT NO. 2-SR, P. 8.)

A. No. Mr. Celentano's claim should be rejected because: (1) it is based on his "belief" and not any cited support; and (2) incorrectly discounts the benefits of ride-through settings.

(SEF Statement No. 2-SR, p. 8.) Further, while the Electric Power Research Institute ("EPRI") study shows that the impact of five different solar systems on flicker is not significant, the impact of hundreds or thousands of systems ramping up or ramping down would likely be much more significant.

V. <u>AMENDED DER MANAGEMENT PLAN THAT SHOULD BE IMPLEMENTED IF THE COMMISSION DIRECTS THE COMPANY TO UNDERTAKE A PILOT PROGRAM</u>

Q. YOU PREVIOUSLY ADDRESSED THE PILOT PROGRAMS RECOMMENDED BY NRDC WITNESS HARRY WARREN AND SEF WITNESS JOHN COSTLOW. ALTHOUGH THE COMPANY DISAGREES WITH THOSE RECOMMENDATIONS, DOES PPL ELECTRIC HAVE A COUNTER-PROPOSAL ON WHAT PILOT PROGRAM, IF ANY, SHOULD BE IMPLEMENTED BY THE COMPANY?

A. Yes. Again, based on the evidence presented in this proceeding, PPL Electric should be permitted to implement its DER Management proposal as currently proposed. The benefits of the Company's proposal are well-documented and cannot reasonably be disputed. At a bare minimum, as the operator of its distribution system, PPL Electric needs the ability to monitor and manage the generation from DERs that is flowing onto its system so that the Company can safely and reliably provide electric service to its customers.

However, in the event that the Commission decides that it would be more prudent to test and evaluate some of these technologies, PPL Electric recommends that the pilot program be focused on the remote active management aspect of its DER Management Plan.

Thus, to the extent the Commission believes a pilot program is appropriate here, the DER Management Plan should be implemented as follows:

A. <u>SMART INVERTERS</u>

1. Effective January 1, 2021, new DERs interconnecting with the Company's distribution system must have smart inverters installed that meet: (1) Underwriters Laboratories ("UL") Standard 1741 Supplement A ("UL 1741 SA"); and (2) the Company's testing for the communications requirements under the 2018 revisions to the Institute of Electrical and Electronics Engineers ("IEEE") Standard 1547, "Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces" ("IEEE Standard 1547" or "IEEE 1547-2018"). These requirements shall be known as the "Interim Requirements." The list of smart inverters that meet the Interim Requirements will be publicly available and regularly updated on the Company's website.

2. The Interim Requirements shall be used by PPL Electric until January 1, 2022. At that point, the Company will transition to requiring new DERs to have smart inverters installed that meet IEEE 1547-2018 and have been certified with IEEE 1547.1 / UL 1741 Supplement B ("UL 1741 SB").

3. The smart inverters that are installed consistent with Paragraphs 2 and 3, *supra*, must have one of their communications ports dedicated to use by PPL Electric. In the event that the customer's DER requires two communications ports to operate (such as in a solar plus battery storage set-up), PPL Electric will provide a multi-port solution at no direct cost to that customer.

4. PPL Electric shall not be responsible for purchasing, owning, installing, or maintaining the customers' smart inverters.

B. DER MANAGEMENT PLAN

i. Automated Grid Support Functions

5. Effective January 1, 2021, PPL Electric shall be authorized to set the automated Volt/VAR curve, Voltage Ride-through settings, and Frequency Ride-through settings on every new DER installation in its service territory pursuant to the terms and conditions set forth in PPL Electric Exhibit SS-1R. If the DERs are equipped with the Company's DER management devices installed pursuant to Paragraph 7, *infra*, PPL Electric shall be permitted to monitor the DERs and their autonomous settings. Such monitoring will be conducted remotely through the use of the smart inverters, the DER management devices, and the Company's DERMS.

6. Although not required under the DER Management Plan, PPL Electric can enable the Volt-Watt function or specify a Watt Ramp Rate upon voluntary consent of the DER customer.

ii. DER Management Devices

7. Effective January 1, 2021, new DERs interconnecting with the Company's distribution system must have DER management devices that are purchased, installed, owned, and maintained by the Company.

iii. Remote Active Management of Grid Support Functions

8. The first 1,000 new DERs installed in the Company's service territory on or after January 1, 2021, shall function as a control group for the remote active management program. The customers in the control group will be required to have DER

management devices installed on their DERs. Pursuant to Paragraph 5, *supra*, the Company will monitor the control group's DERs and smart inverters and will set the automated grid support functions on the control group's smart inverters. During the term of the remote active management program, the Company will not actively manage the control group's smart inverter grid support functions as described in Paragraph 9, *infra*.

9. After the control group is established pursuant to Paragraph 9, PPL Electric shall be authorized to conduct a 5-year program, under which the Company would be permitted to actively manage the grid support functions of new DERs installed in its service territory through the use of the smart inverters, the DER management devices, and the Company's DERMS, provided that the Company only actively manages the following grid support functions of the smart inverters pursuant to the terms and conditions set forth in PPL Electric Exhibit SS-1R: (a) Volt/VAR; (b) Constant Power Factor; (c) Remote On/Off; (d) Voltage Ride-through; and (e) Frequency Ride-through.

10. The program's purpose will be to test and evaluate the benefits of remote active management of DERs, as compared to the use of the smart inverters' automated grid support functions.

11. Participation in the program will be required for all new DERs installed in the Company's service territory during the 5-year program period.

12. Within 60 days after the end of the program's fourth year, PPL Electric will be permitted to file a petition with the Commission to: (a) extend the program and, in the Company's discretion, make other changes to the program; and/or (b) authorize

the Company to remotely and actively manage (i) the DERs that were in the control group described in Paragraph 8, *supra*, (ii) the DERs that have enrolled and will enroll in the program, and (iii) any new DERs that will interconnect with the Company's distribution system after the program concludes. PPL Electric reserves the right to request that the Commission continue the existing remote active management program until litigation over a petition filed pursuant to Paragraph 12 concludes. If no such petition is filed within 60 days after the end of the program's fourth year, the remote active management program will end after the fifth program year.

13. Regardless of whether this remote active management program is continued or not, the Company will be authorized to continue: (a) requiring new DERs to have IEEE 1547-2018 compliant smart inverters per Paragraph 3, *supra*; (b) requiring new DERs to have DER management devices installed on them per Paragraph 4, *supra*; (c) utilizing the smart inverters' automated grid support functions per Paragraph 5, *supra*; and (d) monitoring the DERs that have the Company's DER management devices installed per Paragraph 5, *supra*.

iv. Grandfathering of Current DER Installations and Interconnection Applications

14. DER installations whose interconnection applications are submitted to PPL Electric before January 1, 2021, shall not be required to install smart inverters and DER management devices. However, the Company reserves the right to propose the application of its DER Management Plan to existing DERs in a future proceeding.

C. REPORTING REQUIREMENTS

i. Annual Reports Submitted to the Commission

15. PPL Electric will track and report the real power reductions experienced by customers under the Company's DER Management Plan, including the 5-year program for remote active management. 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.

16. PPL Electric shall file annual reports that provide the following information for the annual reporting period: (a) the aggregate amount of DERs' net generation loss due to the use of the automated grid support functions set forth in Paragraph 5, *supra*; (b) the aggregate amount of DERs' net generation loss due to the Company's active management of the grid support functions set forth in Paragraph 9, *supra*; (c) the method and technique used to calculate the DERs' net generation loss; (d) the number of times each grid support function was used on an automated basis and the average duration of that function's automated use; (e) the number of times that PPL Electric actively managed each grid support function and the average duration that the function was actively managed; and (f) the non-wires alternatives installed to improve customer reliability or defer voltage control investments using DER management, in lieu of traditional alternatives, for that annual reporting period.

17. In addition, the annual report will set forth the number of DERs installed, the number of DER management devices installed, and the capital costs and expenses associated with the purchase, installation, ownership, and maintenance of the DER management devices.

18. The annual reports filed with the Commission shall not contain any identifying customer information. The annual reports shall be filed within 30 days following the end of each calendar year.

ii. Annual Reports to Individual DER Customers

19. PPL Electric shall send an individualized annual report to each new DER customer, whose smart inverter's grid support functions are used by the Company during the annual reporting period. The customer's annual report shall provide the following information for the annual reporting period: (a) the amount of the DER's net generation loss due to the use of the automated grid support functions set forth in Paragraph 5, *supra*; (b) the aggregate amount of DERs' net generation loss due to the Company's active management of the grid support functions set forth in Paragraph 9, *supra*; (c) the method and technique used to calculate the DER's net generation loss; (d) the number of times each grid support function was used on an automated basis and the average duration of that function's automated use; and (e) the number of times that PPL Electric actively managed each grid support function and the average duration that the function was actively managed. In addition, 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. The customer's annual report will be sent to the customer within 30 days following the cash-out of the customer's banked excess

generation, which typically occurs at the end of each PJM Interconnection LLC ("PJM") Planning Year.

D. <u>COMPLIANCE TARIFF SUPPLEMENT</u>

20. Upon Commission approval of the DER Management Petition, PPL Electric shall file a compliance tariff supplement consistent with PPL Electric Exhibit SS-1 and the terms outlined above. The compliance tariff supplement will be effective on one day's notice.

E. <u>ELECTRIC VEHICLES</u>

21. Electric vehicles ("EVs") shall be exempt from the requirements of Section B, *supra*.

Again, the Company disagrees that a pilot program is necessary. However, if the Commission decides that such a pilot would be appropriate here, the Commission should direct PPL Electric to implement the program outlined above. It will enable PPL Electric to gather valuable data on the benefits of remote active management and present that data to the Commission, the other parties, and the Company's customers. Such data can then be used to evaluate whether the Company should continue remotely managing the grid support functions beyond the 5-year program.

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

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

Economic Analysis of DER for Voltage Management

- The objective of this analysis was to develop various scenarios and their cost benefits of PPL's DER Management proposal's active management of DERs

Establishing Context for Distribution Cost For Voltage Control

- Distribution system voltage control costs vary significantly depending on locational factors, loads, the status of the rest of the power system, and DER penetration.
- Distribution system costs are higher when DERs are clustered together and located further from the substation.
- Distribution costs are higher in rural areas, which are currently more likely to be lightly loaded, have a lower rated capacity, and host larger PV systems located further from the substation
- PPL feeders require voltage management, especially as DER is added, because feeders are generally long, rural, and typically do not have Transformer Load Tap Changers (LTCs)
- Increased DER hosting capacity and voltage management can be achieved through communications and management of DERs enabled by the DER Management proposal

Methodology

- One actual PPL feeder is used throughout this analysis to review various scenarios. The feeder characteristics
  - 1800 customers, mix of residential, commercial and industrial
  - Currently 100 kW of connected DER
  - Located in a geographic pocket that has been realizing DER growth
- Assumptions used for DER growth, capital costs and models are included in the Appendix.
- Some scenario are shown with both conservative and aggressive rates to show impact at an adoption level near the current rate as well as with the potential for future accelerated growth.
- With assumed DER growth, multiple scenarios are evaluated to demonstrate the overall cost benefit of voltage management enabled by DER Management Petition.

Hypothetical Ranges of DER Integration Costs

- Figure 1 is an illustration of three regions of PV integration costs:
    1. (near) zero cost when within the hosting capacity range
    2. increasing, quantifiable cost
    3. fuzzy cost domain
- Curve illustrates potential cost drivers
- The shape and magnitude of the curve is scenario dependent

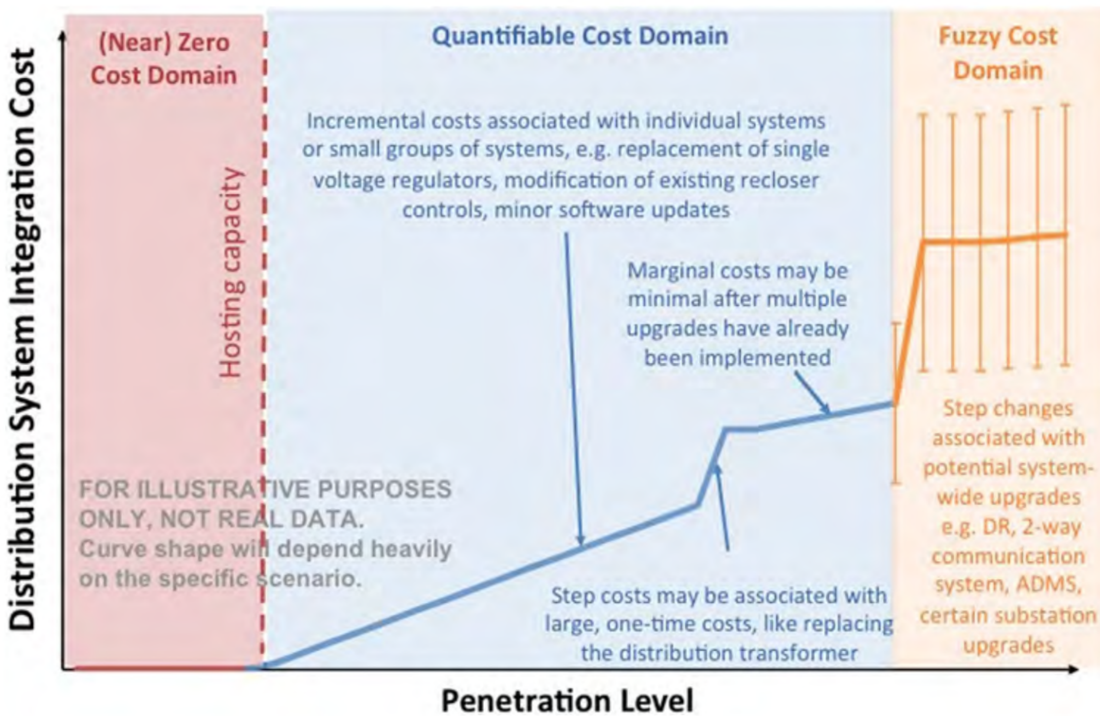


Figure 1: Distribution System Costs Associated with Solar PV Adoption

Source: Distribution system costs associated with the deployment of photovoltaic systems by Kelsey A.W. Horowitz , Bryan Palmintier, Barry Mather, Paul Denholm National Renewable Energy Laboratory (NREL), 15013 Denver West Parkway, Golden, CO 80401, USA, Elsevier Renewable and Sustainable Energy Reviews

Summary of Cost Benefits

Multiple Scenarios are evaluated in this study to show the overall costs benefits of the DER Management Petition.

		Scenario/Situation	Traditional Costs	Costs with DER Management	Conservative DER Growth Cost Savings	Aggressive DER Growth Cost Savings
Quantifiable Cost Domain	**Scenario 1**	Areas of aggressive small & large DER growth	$48.6M over 10 years	$25.2M over 10 years	**$23.4M over 10 years**	**$58.3M over 10 years**
	Scenario 2	Permanent Configuration Changes Yields Settings Modification Manual or Automated	$4.5M over 20 years	$0 over 20 years	**$8.5M over 20 years**	**$30.4M over 20 years**
	Scenario 3	Impact to DER Inverter Settings During Temporary Configurations and N-1 Emergencies	Customer's DER may be required to shut off during temporary configurations to maintain reliable grid	Customer's DER may lose revenue of $2.65/year	**Customer's DER may be required to shut off during temporary configurations**	
Fuzzy Cost Domain	**Situation 1**	Unexpected System Fluctuations Due to Unforeseen Events	**Utilize the DER Management Plan to build flexibility into the distribution system to maintain safe and reliable service during unforeseen system instabilities or variations**			
	Situation 2	Large Scale Voltage and VAR Control Without Substation Transformer LTCs	**The transmission and distribution systems may see negative voltage or VAR impacts because most station transformers on PPL Electric's systems are not equipped with LTCs. Defer or avoid LTC additions with the DER Management Plan**			

Scenario 1: *Impact to Voltage in Areas of Aggressive Small & Large DER growth*

- **Base Case Scenario, see Table 1**
  - No DER Management
  - Increasing small DER, 10 kW each, at a rate of 30% per year
  - Increasing medium DER, 250 kW installation every year
  - Increasing large DER, 1 MW installation every 3rd year

Voltage remediation requirements:

- Added Regulators in Years 3, 6, and 9
- $60,000 in Year 3; $60,000[1] in Year 6; $60,000 in Year 9,
- **Total cost for voltage support over 10 years: $180,000 (using traditional means to fix voltage)**

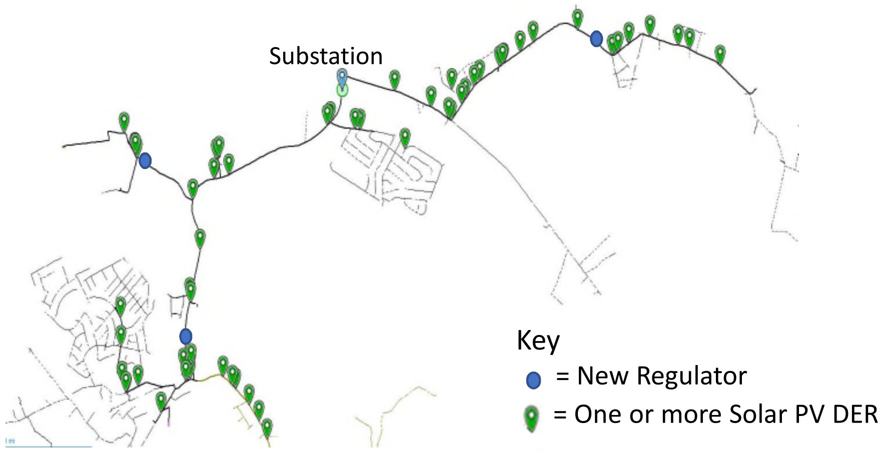
- **Alternative Scenario, see Table 1**
  - DER Management
  - Increasing small DER installations at a rate of 30% per year for residential systems (typical growth rate in Lancaster region)
  - Increasing medium DER, 250 kW installation every year
  - Increasing large DER, 1 MW installation every 3rd year

Voltage remediation requirements:

- $0 in voltage support equipment in any year for at least 10 years
- **Cost of DER management devices over 10 years: $112,000**

Scenario 1 continued on the next page.

Scenario 1: *Impact to Voltage in Areas of Aggressive Small & Large DER growth*



--- Cost/Benefit Impact ---

Voltage regulators to address for overvoltage in Years 3, 6, and 9, **without DER management:**

1. Total cost for voltage support over 10 years: $180k
2. **Extrapolated to 20% of PPL feeders: (1,350 x 20%) x $180k = $48.6M**
3. **Extrapolated to 50% of PPL feeders: (1,350 x 50%) x $180k = $121.5M**

With Remote DER Management:

1. $0 in voltage support equipment in any year for at least 10 years
2. Cost of DER management devices over 10 years: $93.6k
3. DER Management savings on just one feeder: $86.4k or 48%
4. **Extrapolated to 20% of PPL feeders: (1,350 x 20%) x $93.6k = $25.2M**
5. **Extrapolated to 50% of PPL feeders: (1,350 x 50%) x $93.6k = $63.2M**

Conservative Total Savings to customers: $48.6M – $25.2M = $23.4M
Aggressive Total Cost Savings to customer: $121.5M - $63.2M = $58.3M

Table 1: DER Growth – Base Case Scenario vs Alternative Scenario

Year	kW @ 30% residental growth rate	Adding 250kW C&I growth/year	Adding 1MW DER every 3 years	Total DER installed (kW)	Quantity @ 30% residential, plus C&I and 1MW growth rate	Per year DER Management devices @$755/device	Total spent on DER Management Devices	Total Spent on Voltage Reinforcements required	% Savings : DER Mangement vs Voltage Reinforcements
Year 0	100.0			100	10	0			
Year 1	130.0	250.0	0	380	14	$3,020			
Year 2	169.0	250.0	0	669	19	$3,926			
Year 3	219.7	250.0	1000	1970	26	$5,104	$12,050	$60,000	80%
Year 4	285.6	250.0	0	2286	35	$6,635			
Year 5	371.3	250.0	0	2621	46	$8,625			
Year 6	482.7	250.0	1000	3983	61	$11,213	$35,503	$120,000	70%
Year 7	627.5	250.0	0	4377	80	$14,577			
Year 8	815.7	250.0	0	4816	105	$18,950			
Year 9	1060.4	250.0	1000	6310	138	$24,635	$93,665	$180,000	48%
Year 10	1378.6	250.0	0	6879	180	$32,026			

Optimal Voltage Management from Centralized and Distributed Control

- The benefits in Scenario 1, can not be fully realized with autonomous settings that are set initially and remained unmanaged throughout the life-cycle.
- As shown in the Drexel University studies summarized in PPL Electric Exhibit SS-1RJ, DER injections can lead to voltage issues at other distribution locations, which can not be mitigated with pre-set Volt/Var curves contribution at the DER location.
- This highlights the importance of centralized system to manage voltage remotely, like PPL Electric's DERMS, as well as localized voltage management capabilities that can be provided by DERs to maintain distribution voltage within operational tolerances.

Scenario 2: Permanent *Feeder Configuration Changes Yields Volt/VAR Modification Manual vs. Automated*

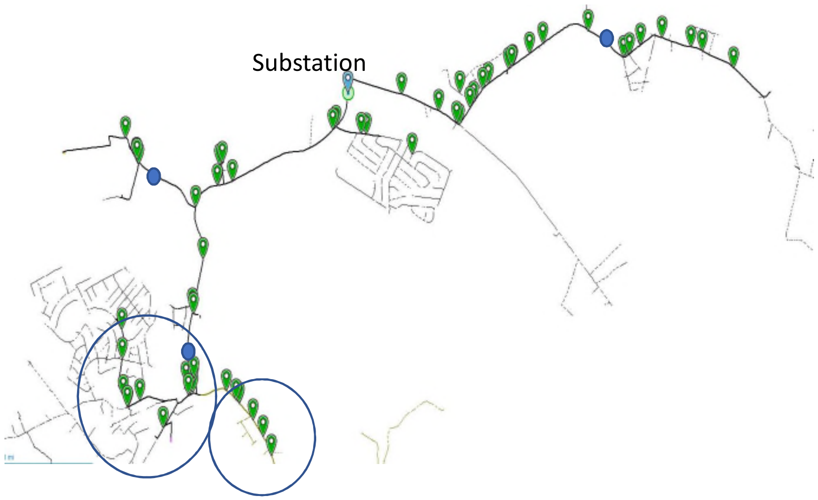


Figure 2: Feeder with high DER penetration

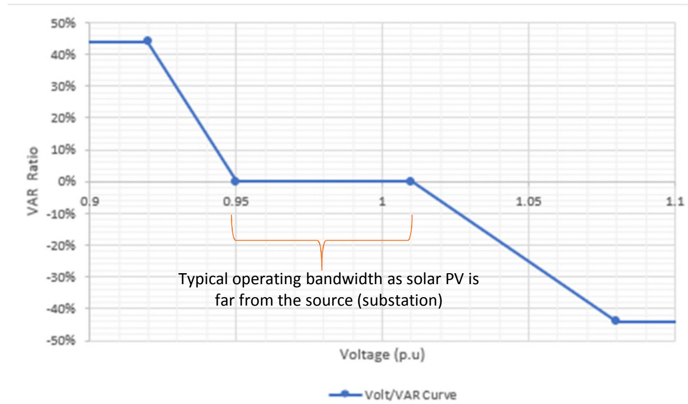


Figure 3: Scenario 2 Base Case Volt/VAR curve

- **Scenario 2 Base Case**
  - Feeder shown in Figure 2 is has approximately 1,800 customers, mix of residential, commercial, and industrial.
  - Volt/VAR curves issued at interconnection for customers in the circles have lower dead bands as they are between 8 and 12 miles from the substation where voltage is typically lower, as shown in Figure 3, where voltage is typically 0.96 p.u. (115.2V).

Scenario 2: *Permanent Feeder Configuration Changes Yields Volt/VAR Modification Manual vs. Automated*

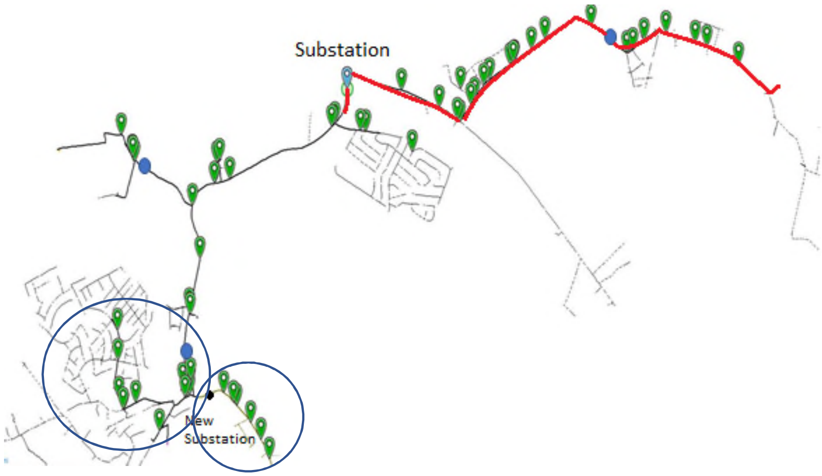


Figure 4: A New substation is built, splitting the feeder in two, with high DER Penetration

- **Scenario 2 Future State – A split of the Feeder**
  - Feeder shown in red is served by the upper substation as it is in the base case.
  - Feeder in black is now served by the lower "new substation".
  - The red feeder length, shown in Figure 4, is reduced to 40% of its original length, now with 800 customers. The black feeder is approximately 60% of the original feeder with 1000 customers. Both have a mix of residential, commercial and industrial customers.
  - Volt/VAR curves issued for customers in the circles have higher dead bands, as shown in Figure 5, as they are within 0 – 3 miles of the new substation where voltage is typically near 1.03 p.u. (123.6V)
  - DER default settings issued at interconnection are no longer adequate and are required to be changed.
  - **Modification of Volt/VAR provides benefit to the customer and PPL as the curve should fit the customer's location and typical voltage on the system in order to maintain unity power factor as much as possible.**

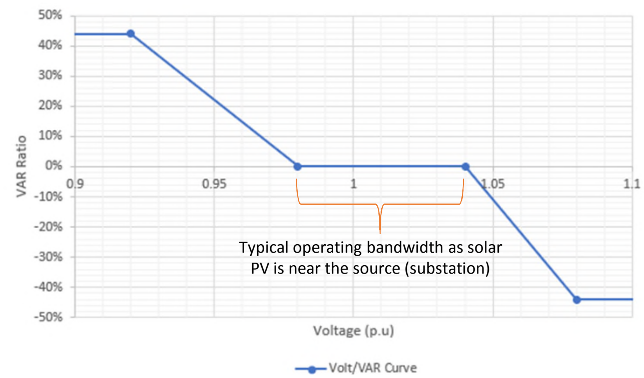


Figure 5: Scenario 2 Future State Volt/VAR curve

--- Cost/Benefit Impact ---

1. Manual Volt/VAR modification by visiting each DER site and adjusting inverter settings: ~$225 per solar PV
2. Feeder in Figure 4 includes 35 inverters requiring Volt/VAR modification
3. Due to the dynamic nature of PPL's system, 4 or more Volt/VAR modifications may occur over the 20-year life of a system on 20% of PPL's feeders (~1350 total)

Conservative:
$225 x 35 inverters x 4 changes over life of systems = **$31.5k**

If this level of change occurs on 20% of PPL feeders:
$31.5k x (1350 feeders x 20%) = **$8.5M over 20 years**

Aggressive:
$225 x 50 inverters x 4 changes over life of systems = **$45k**

If this level of change occurs on 50% of PPL feeders:
$45k x (1350 feeders x 50%) = **$30.4M over 20 years**

Modification of Volt/VAR settings using DERMs through PPL's DER management costs **$0 over 20 years**

Scenario 3: *Impact to Voltage and Volt/VAR Settings During Temporary Configurations and N-1 Emergencies*

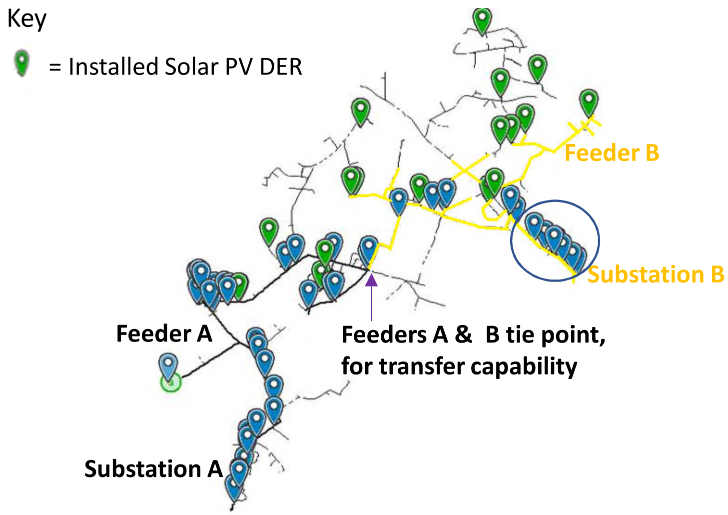


Figure 6: Two Feeders both with high DER penetrations

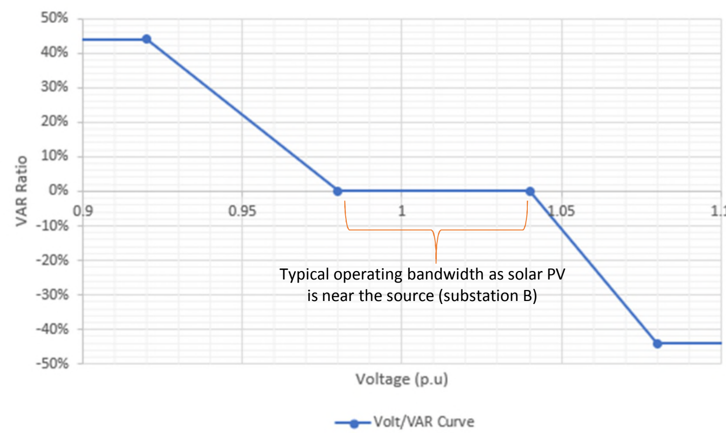


Figure 7: Volt/VAR Scenario 2 Base Case

Scenario 3 Base Case:

- Substation A serves Feeder A (shown in black)
- Substation B serves Feeder B (shown in yellow)
- Multiple feeders with high penetration (>5000kW) in the same geographic area
- Upon interconnection, the solar PV DER within the circle shown in Figure 6 are provided the autonomous Volt/VAR curve shown in Figure 7 due to the proximity of the source (substation B with an average voltage p.u. of 1.03 or 123.6V)
- N-1 is defined a form of resilience which ensures distribution system availability in the event of one component failure. A temporary transfer occurs as part of an N-1 reliability driven plan

Scenario 3: *Impact to Voltage and Volt/VAR Settings* During *Temporary Configurations and N-1 Emergencies*

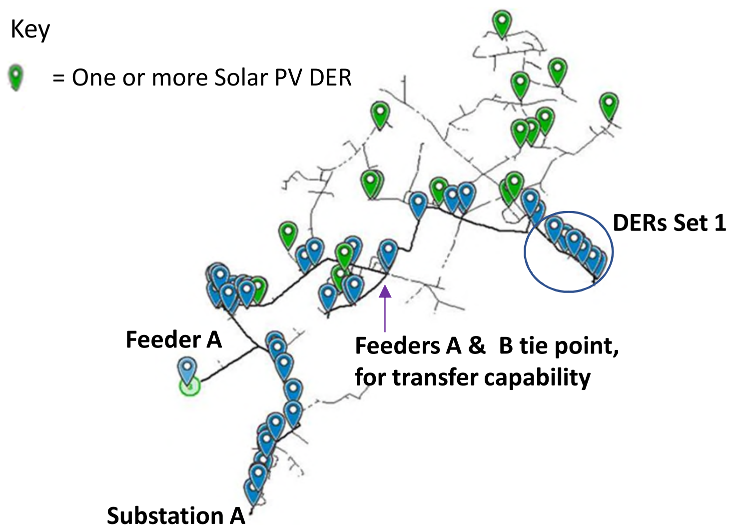


Figure 8: Two Feeders both with high DER penetrations

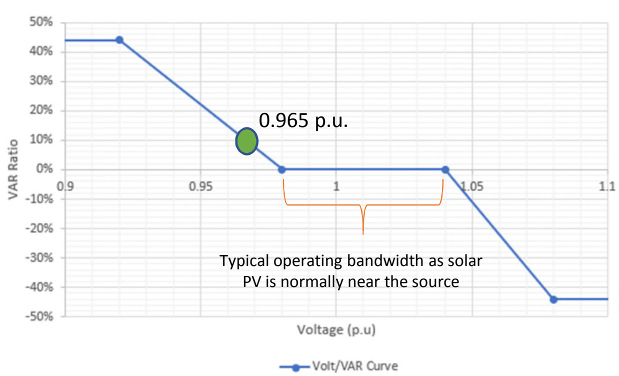


Figure 9: Volt/VAR Scenario 2 Base Case

Scenario 3 Event (alternative 1)

- Autonomous Volt/VAR settings are in use on all DERs.
- Feeder B is transferred to Feeder A due to maintenance.
- Autonomous Volt/VAR settings are in use on all DERs.
- The solar PV installations shown in DER Set 1, continue operating on their autonomous Volt/VAR curves during the temporary transfer.
- As DER Set 1 is no longer in close proximity to the source, those DERs' typical operating voltage is 0.965 p.u. (115.8V). Therefore, the Volt/Var settings for DER Set 1 needs to be changed.

--- Cost/Benefit Impact ---

1. Assume:
   - All generators in DER Set 1 are 100kW.
   - See all assumptions in Salet Rebuttal Exhibit SS-2R

100kW x 4 hr/year = 400kWh (Assumptions 1 and 2 from Exhibit SS-2R)
400kWh x 10% = 40kWh (Assumption 3 from Exhibit SS-2R)
40kWh x $0.0663 cent/kWh = $2.65 revenue reduction/year (Assumption 4 from Exhibit SS-2R)

Without active DER management, DERs may be asked to shut off and remain off during abnormal configurations and N-1 Emergencies because the DERs may operate at an inappropriate power factor due to the applied Volt/VAR curve. With active management, DERMS will send new settings to these DER to maintain reliability and keep the DERs operational.

Situation 1: *Unexpected System Fluctuations Due to Unforeseen Events*

When studying and planning for the impacts of DERs, the Company's Distribution Planning and Engineering team delineates system upgrades, protection requirements, and voltage settings and reinforcements based on historic and projected peak and daytime minimum loads and voltage as well as known system changes (including new loads, DER, reconfigurations, system upgrades, etc.) Without visibility of DERs, performing planning functions is extremely difficult due to issues such as hidden load. However, not all system fluctuations can be predicted. Unprecedented events, such as the recent coronavirus pandemic, have unquestionably altered electric demand as cities are locked down, shops close, and industry significantly slows or halts.

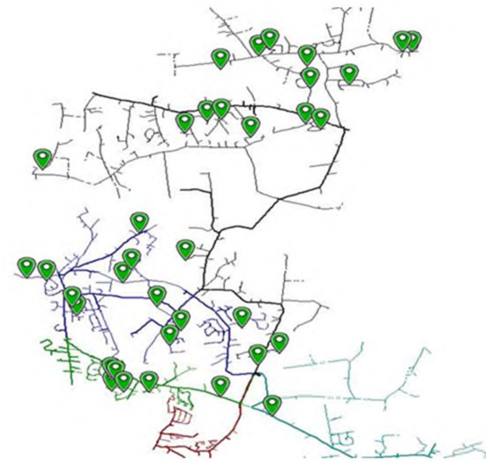
A preliminary coronavirus electric demand impact study for Italy in March 2020 shows a peak and daily energy use reduction of 18 – 21% compared to the same weeks of the prior year. At the time of this writing, worldwide electric system impacts are not yet fully experienced or appreciated. However, PPL Electric has preliminary load data that mimic Italy's experience.

System upgrades, protection requirements, and voltage settings and reinforcements are based on daytime minimum loads. When those loads are further reduced by 20%, especially during spring or autumn months, the system is operating in a way in which is was not planned, engineered, or designed. Without real time visibility and management of DERs, a system with higher DER penetration will certainly face real-time operating challenges that could cause overvoltage, overloads, equipment damage, and outages.

During an unexpected event like the coronavirus pandemic that impacts load dramatically, PPL Electric could change inverter settings as needed to operate within voltage tolerances. The DER Management Plan would provide operating flexibility to continue to provide reliable service, even if life-sustaining supply shortages change future customer behavior and drive consumer demand for more DERs that provide a capability for self-sufficient existence. By proceeding with the DER Management Plan, PPL can be more adaptable to meet customers' needs for a flexible, reliable, and fully integrated distribution system.

Source: "COVID-19 Impacts and Actions: Preliminary Analysis of Italy Load Trends Summary of Industry Response, by Aidan Tuohy, Adrian Kelly, Brian Deaver, Eamonn Lannoye, Daniel Brooks, Electric Power Research Institute (EPRI), 19 March 2020.

Situation 2: *Large Scale Voltage and VAR Control Without Substation Transformer LTCs*



PPL Electric is mandated to maintain voltage at + / - 5% , per ANSI C84.1 and PUC requirements.

System conditions at PPL Electric make voltage management a challenge

- Average feeder length is 27 miles long
    - Other Pennsylvania EDCs have average feeder lengths which are significantly shorter
- Past practice design includes few Load Tap Changers (LTCs) on station transformers
    - Inability to actively manage voltage at the head of a circuit
    - Heavily reliant on capacitors to control voltage
    - Dependent on transmission voltage

Managing voltage

- Limited options to manage the voltage
- Overvoltage conditions can only be effectively managed with overhead line regulators ($60,000 per regulator)
- Leverage automated capacitor banks and regulators for voltage control
- Voltage profiles can swing widely, especially on the end of a feeder
    - *Due to the nature and seasonality of loads on the distribution system, voltages may swing significantly between seasons*
    - *Example: One feeder may see loads exceeding 10.5MW in the winter and less than 1MW in the spring/fall.*

In the event of high DER penetration on multiple feeders out of the same substation, the transmission and distribution systems may see negative voltage or VAR impacts as most station transformers on PPL Electric's systems are not equipped with LTCs. Along with some wide and significant swings between peak and daytime minimum load, an LTC transformer may be required to be installed to maintain acceptable voltage year-round without autonomous Volt/VAR. **Cost of $1.1M**

- With remote DER management, this cost could be deferred for up to 10 years as DERMS will be able to manage voltage and VAR flow on the system in real time.
- Extrapolated to 5% of PPL substations (~350 Substations) **= $19.3M**, **showing significant financial value is possible from a 10-year deferral**

Appendix

Assumptions

- DER growth rate
  - Over the last 5 years, PPL has seen an average DER growth rate of 25% per year. This study assumes 30% DER growth for residential customers, as some of PPL see growth rates higher than average. The DER growth rate in 2019 was 28% over 2018 suggesting that these are reasonable DER growth rates.
- Installed capital cost
  - **ConnectDER**: The cost of an installed ConnectDER is $755. In this study it is assumed the ConnectDER cost will remain constant for the next ten years.
  - **Regulator**: The cost of an installed regulator is $60,000. In this study it is assumed this cost will remain constant for the next ten years.
  - **LTC**: The cost of an installed LTC transformer $1.1M
- Models
  - The models in these studies were built to determine at what level randomly placed DER will cause overvoltage and require system upgrades.
  - System upgrades are heavily dependent on the location and size of the DER, which is impossible to accurately predict. This methodology, with DER randomly placed on the feeder, yields the need for system upgrades at a slower rate than if DER were they were clustered together. In industry and economic research strongly suggests a strong relationship between solarPV adoption and the number of nearby previously installed system (as well as other factors)
  - The models in this study were built to reflect conservative projections of DER growth and penetration. Pockets of the Company’s system will experience aggressive DER growth over time. To reflect this, aggressive DER growth is extrapolated.

Source: Marcello Graziano, Kenneth Gilligham, “Spatial Patters of Solar Photovoltaic System Adoption: The Influence of Neighbors and the Built Environment”, Journal of Economic Geography, 2015, pp 815-839.