
Devin Ryan

dryan@postschell.com
717-612-6052 Direct
717-731-1985 Direct Fax
File #: 175564

January 19, 2021

VIA ELECTRONIC FILING

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

**Re: 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**

Dear Secretary Chiavetta:

Pursuant to Paragraph 61 of the Joint Petition for Settlement of All Issues that was approved by the Pennsylvania Public Utility Commission (“Commission”) on December 17, 2020, in the above-captioned proceeding, PPL Electric Utilities Corporation hereby files the enclosed DER Management Pilot Implementation Plan.

Copies of this filing are being provided as indicated on the Certificated of Service.

Respectfully submitted,


Devin Ryan

DR/jl
Enclosures

cc: Certificate of Service

CERTIFICATE OF SERVICE

(Docket No. P-2019-3010128)

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

VIA E-MAIL ONLY

Darryl A. Lawrence, Esquire
Phillip D. Demanchick, Esquire
David T. Evrard, Esquire
Office of Consumer Advocate
555 Walnut Street
Forum Place, 5th Floor
Harrisburg, PA 17101-1923

Mark C. Szybist, Esquire
1152 15th Street, NW, Suite 300
Washington, DC 20005
Natural Resources Defense Council

Andrew J. Karas, Esquire
Emily A. Collins, Esquire
Fair Shake Environmental Legal Services
647 E. Market Street
Akron, OH 44302
Natural Resources Defense Council

James M. Van Nostrand, Esquire
Keyes & Fox LLP
275 Orchard Drive
Pittsburgh, PA 15228
Sunrun Inc.

Beren Argetsinger, Esquire
Keyes & Fox LLP
PO Box 166
Burdett, NY 14818
Sunrun Inc.

Kenneth L. Mickens, Esquire
316 Yorkshire Drive
Harrisburg, PA 17111
Sustainable Energy Fund

Date: January 19, 2021



Devin Ryan

DER Management Pilot Implementation Plan

Dated: January 19, 2021

TABLE OF CONTENTS

	Page
I. INTRODUCTION	1
II. DER MANAGEMENT PILOT	2
A. OBJECTIVES	2
B. TIMELINE AND MILESTONES	3
C. DER CUSTOMER GROUPS	3
D. COMPONENTS AND ARCHITECTURE	5
E. DER INVERTERS.....	8
1. Inverter Requirements.....	8
2. Approved List of Smart Inverters	8
3. Customer Enrollment	9
4. DER Settings.....	10
F. PILOT PROGRAM ANALYSIS.....	11
1. Anticipated Benefits.....	12
2. Data Collection and Verification	12
3. Use Cases	14
G. PILOT PROGRAM REPORTING.....	15
1. Annual Reports Submitted to the Commission.....	15
2. Annual Reports to Individual DER Customers.....	17
3. Data on Program Performance.....	18
H. CUSTOMER AND INSTALLER INFORMATION	19
Attachment A – Excluded Circuits	
Attachment B – Pilot Milestones with Program Year 1 Commencing July 2021	
Attachment C – Use Cases	

I. INTRODUCTION

This Implementation Plan describes PPL Electric Utilities Corporation's ("PPL Electric" or the "Company") Distributed Energy Resource ("DER") Management Pilot ("Pilot") that commenced on January 1, 2021. This Implementation Plan has been prepared and submitted pursuant to the Joint Petition for Settlement of All Issues ("Settlement") approved by the Pennsylvania Public Utility Commission ("Commission") at Docket No. P-2019-3010128. As required, this Implementation Plan explains how the Company will implement and conduct the Pilot, including the goals of the Pilot, the use cases the Company plans to test and evaluate, the specific methods and approaches for testing each use case, the methods by which PPL Electric will communicate the Pilot's requirements to customers and DER installers, and any additional information PPL Electric believes is necessary to be included in the annual reports submitted pursuant to the Settlement.

By way of background, many utilities have experienced operations and planning challenges as DER penetration becomes increasingly significant. These challenges include, but are not limited to, voltage swings, masked or hidden load, limited hosting capacity, planning uncertainties, and protection/operational challenges with two-way power flow. As a response to these challenges, the Institute of Electrical and Electronics Engineers ("IEEE") made revisions to Standard 1547 in 2018 ("IEEE 1547-2018"), which set forth requirements for smart inverters that can help support the distribution system. When these smart inverters are coupled with DER management devices, electric utilities can monitor and manage DERs interconnected with their distribution systems.

On May 24, 2019, PPL Electric filed a Petition with the Commission for permission to require smart inverters that meet the new IEEE and Underwriters Laboratories ("UL") standards, to install DER management devices on new DERs interconnected with its distribution system, and

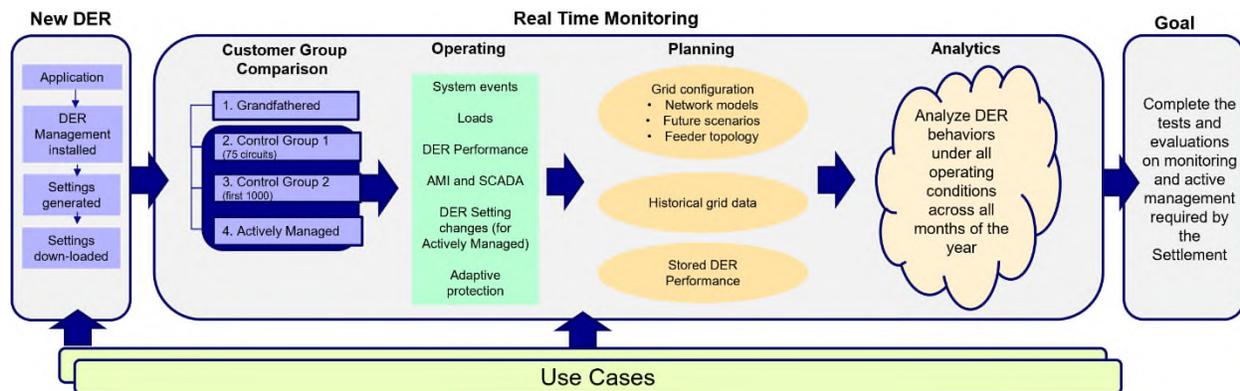
to monitor and manage those new DERs. Ultimately, the parties agreed to the Settlement, which, as approved by the Commission, permits the Company to conduct a Pilot to test and evaluate the costs and benefits of monitoring and managing DERs.

II. DER MANAGEMENT PILOT

A. OBJECTIVES

Under the Settlement, the Pilot is designed to test and evaluate: (1) the costs and benefits to distribution system operation and design of monitoring DERs through devices connected to inverters as compared to maintaining distribution system status visibility through other means; and (2) the costs and benefits to distribution system operation of active management of DERs as compared to the benefits available through the use of inverter autonomous grid support functions. Figure 1 is a graphic overview of the Pilot, beginning with a PPL Electric customer filing an application to interconnect a DER to the Company’s distribution system. Approved DER interconnection applications will receive a DER management device and be assigned to a customer group pursuant to the Settlement.

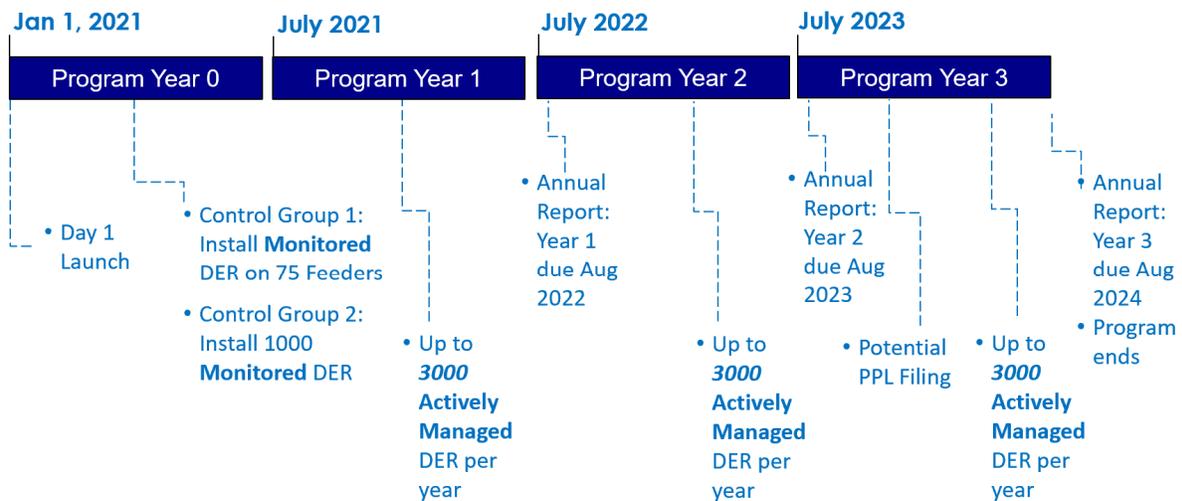
Figure 1- Pilot Overview



B. TIMELINE AND MILESTONES

The three-year Pilot timeline will commence after Control Groups 1 and 2, described below in Section C, have been fully established. The time leading up to the Pilot commencement will be referred to as Program Year 0. After the end of Program Year 0, the subsequent three years of the Pilot will be referenced as Program Year 1, Program Year 2, and Program Year 3, respectively. Assuming Control Groups 1 and 2 have reached 75 circuits and 1,000 participants by July 2021, Pilot milestones are described below in Figure 2. A more detailed list is provided in Attachment B.

Figure 2- Pilot Implementation Milestones



C. DER CUSTOMER GROUPS

As of December 31, 2020, PPL Electric has 11,614 DERs interconnected with its electric distribution system. Some of these DERs are participating in the Company's Keystone Solar Future Project, which are interconnected with 12 specific distribution circuits on PPL Electric's system.

For purposes of this Pilot, PPL Electric has identified four different DER customer groups. The groups are defined below, including their relationship to this Pilot. These definitions are critical to understanding the comparisons that will be made across the different customer groups, to establishing reporting requirements, and to calculating the costs and benefits attributed to monitoring and management of the DERs. Control Groups 1 and 2 and the Actively Managed Group are created and defined as part of the Pilot. Conversely, information from the Grandfathered Group will be used in the final analysis of the Pilot Program as a basis for comparison. Pursuant to the Commission-approved Settlement, some DER customers will not be able to participate in the Pilot because they are grandfathered or because PPL Electric exhausted the cap of 3,000 DER management devices installed in the calendar year that they interconnected the DERs.

- 1) **Grandfathered Group.** DER customers who applied for interconnection on or before December 31, 2020, are “grandfathered” and, therefore, are not required to comply with the new interconnection requirements in the operations and maintenance of their DER installation. PPL Electric collects information continuously on the distribution system, including the circuits that host these DER customers, but there is no direct monitoring or active management of DER installations in this group.
- 2) **Control Group 1.** This group will contain all DER customers, who apply on or after January 1, 2021 and are located on 75 specific circuits. These circuits will be selected based on the circuits which serve the first 75 DER customers who apply to interconnect and are served by unique circuits. Once those circuits are identified, all new DER customers who are served by one of these 75 circuits will be interconnected in monitoring mode and will operate with autonomous grid support functions only. The DERs on these 75 circuits will remain in “monitor-only” mode for the duration of the Pilot. DER customers in Control Group 1 will receive DER management devices. Pursuant to the Settlement, Control Group 1 will not include any of the excluded circuits set forth in Attachment A.
- 3) **Control Group 2.** This group will contain the first DER customers to complete their installation, up to 1,000 participants, who also applied to interconnect on or after January 1, 2021, regardless of where they are located on the system. These customers will be interconnected in monitoring mode and will operate with autonomous grid support functions only. DER customers in Control Group 2 will receive DER management devices. DER customers in Control Group 1 will count toward the 1,000 DERs in Control Group 2.

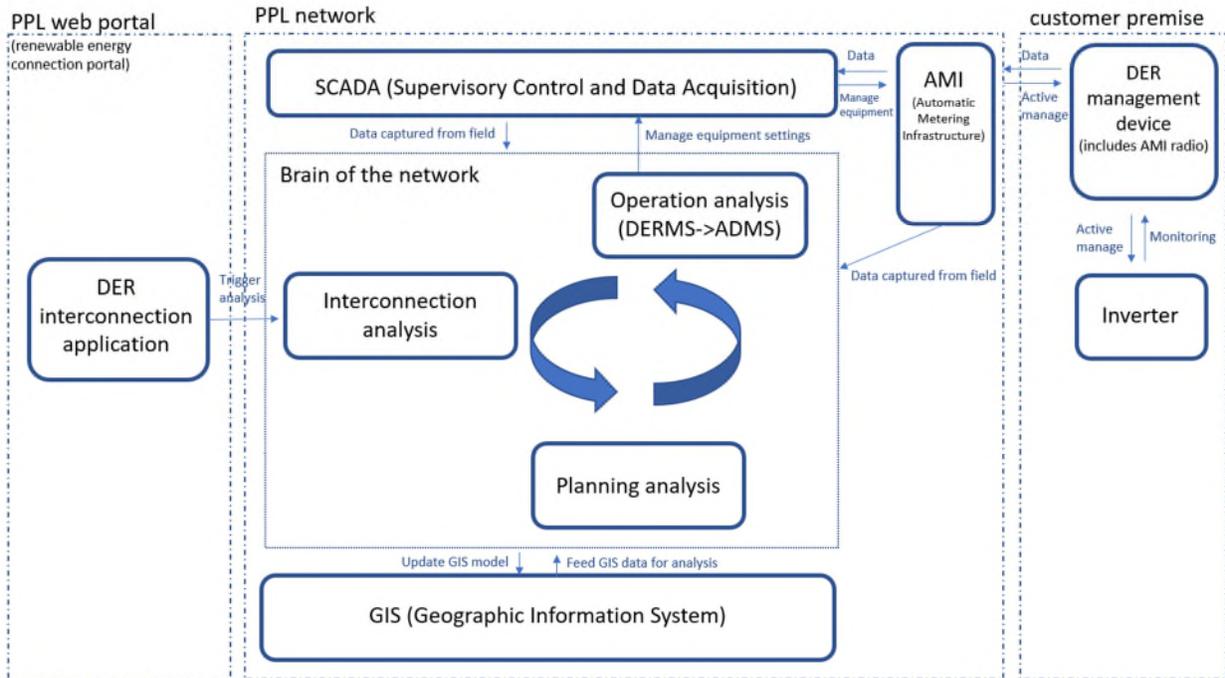
- 4) **Actively Managed Group.** All DER customers who submit applications and interconnect with the distribution system on or after January 1, 2021, excluding the customers outlined in Control Groups 1 and 2 as well as any customers interconnecting after the cap of 3,000 DER management devices installed in the calendar year has been reached. The Company can actively manage the grid support functions of the DER inverters in this Actively Managed Group using the DER management devices and the Company's Distributed Energy Resources Management System ("DERMS"). The following grid support functions can be utilized in the smart inverters: (1) Volt/VAR; (2) Constant Power Factor; (3) Remote On/Off; (4) Voltage Ride-through; (5) Frequency Ride-through; and (6) Volt/Watt. Volt/Watt may only be enabled and managed with the consent of the interconnecting customer. PPL Electric will only use the Remote On/Off function on battery storage or solar systems that have not safely isolated or "islanded" from the distribution system: (1) in emergency situations, such as a gas leak or fire in the vicinity of the DER; or (2) during restoration efforts following a power outage.

Control Group 1, Control Group 2, and the Actively Managed Group are included in the Pilot scope and reporting. The analysis will compare these groups to each other and to the Grandfathered Group to understand the costs and benefits of monitoring and actively managing DERs.

D. COMPONENTS AND ARCHITECTURE

Several components will be used as part of the Pilot to process the DER interconnections and monitor and manage the DERs under the Pilot. The Company's DER Management Architecture is set forth in Figure 3 below and outlines how the Company will interconnect the DER to the system, communicate to DER management devices, receive and integrate operational feedback from DERs for system analysis, calculate dynamic operation settings for DERs, and manage settings changes as needed.

Figure 3- DER Management Architecture



The components in the architecture are:

- **DER Interconnection Application:** Interconnection applications are submitted through a customer facing portal on PPL Electric’s website. The portal allows for work orders to be generated and for customer and inverter data to pass automatically to the Company’s Geographic Information System (“GIS”).
- **Interconnection Analysis:** The technical analysis process by which PPL Electric reviews the proposed interconnection against its requirements, determines if upgrades are required to the PPL Electric system, and, when satisfied, provides approval for installation.
- **Planning Analysis:** The routine technical analysis PPL Electric uses to determine whether additional system upgrades are required to address capacity, voltage, or reliability needs on the distribution system. The planning process uses data from the

Supervisory Control and Data Acquisition (“SCADA”) system and GIS, among other systems.

- Distributed Energy Resource Management System (“DERMS”): A centralized system responsible for DER management; DERMS is being migrated to an Advanced Distribution Management System (“ADMS”) in the first quarter of 2021. First DERMS, then ADMS, will be used for DER monitoring and management during the Pilot.
- Geographic Information System: A database providing the equipment, asset data, and locations of the equipment on the distribution system.
- Supervisory Control and Data Acquisition: In addition to the data that is already collected by PPL Electric’s SCADA system, this system captures the data from the inverters through the automated metering infrastructure (“AMI”) mesh network and provides it to DERMS. Additionally, SCADA data is stored and available historically.
- AMI Mesh Network: The communication pathway that was originally created for the Company’s AMI meters that is now being used for DER communication as well. It facilitates data exchange with SCADA via the AMI Headend and with the individual DERs via the AMI radios located within the DER management devices.
- DER Management Device: Featuring an AMI radio, this device connects to the DER’s local communication interface, enabling monitoring and management of the DER through the existing AMI Mesh Network. This device allows PPL Electric to remotely monitor the attributes and performance of the DER and manage its grid support settings as needed.

E. DER INVERTERS

1. Inverter Requirements

Effective January 1, 2021, new DERs interconnecting with the Company's distribution system must feature smart inverters that meet: (1) UL Standard 1741 Supplement A ("UL 1741 SA"); and (2) the Company's testing for the communications requirements under IEEE 1547-2018. The Company shall perform its testing expeditiously so DER interconnections are not delayed. These requirements shall be known as the "Interim Requirements" and will be used until January 1, 2022. Thereafter, the Company will transition to requiring new DERs to have smart inverters that meet IEEE 1547-2018 and have been certified with IEEE 1547.1 / UL 1741 Supplement B ("UL 1741 SB"). Inverter manufacturers will be required to follow PPL Electric's certification process to be eligible for Pilot participation.

If a customer installs a new inverter on an existing DER installation or upgrades an existing DER installation after January 1, 2021, the customer may install a replacement inverter of similar make and model as the existing inverter; provided, however, that any such inverter must meet the Commission's applicable standards and requirements set forth in its regulations. These inverter requirements also do not apply to DER installations whose interconnection applications are submitted to PPL Electric before January 1, 2021.

2. Approved List of Smart Inverters

The list of smart inverters that meet the Interim Requirements are publicly available and will be regularly updated on the Company's website. An initial list was published on December 1, 2020. On January 1, 2021, the Company's Renewable Energy Connection web portal was updated to reflect the list of smart inverters that have been certified to meet the Interim Requirements. If a customer or installer would like to use an inverter not on the approved inverter list, they must follow PPL Electric's certification process.

3. Customer Enrollment

The DER interconnection application process will utilize the Company’s Renewable Energy Connection web portal for the approval and the creation of interconnection work orders. The portal also is used to obtain the Certificate of Completion (“COC”) for the DER interconnection.

During the Pilot, the Company will purchase and install DER management devices on all new DERs with inverters installed for DER customers in Control Groups 1 and 2 and DER customers in the Actively Managed Group, up to an annual limit of 3,000 DER management devices. DERs installed above the annual limit shall not be part of the Pilot. All DER management devices shall be owned, operated, and maintained by the Company at no direct cost to interconnecting customers. The smart inverters that are installed as part of the Pilot 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 three-communications port solution at no direct cost to that customer.

When a complete DER interconnection application is received, a unique and internal DER management identification category is assigned to the application based on: (1) the order it was received relative to other applications; and (2) the customer group to which that specific application was assigned, as shown in Table 1 below.

Table 1: DER Management Designation

DER Management Designation	Description
Designation Category 0	This DER management designation will include interconnections that belong to the Grandfathered Group that are not required to comply with the new interconnection requirements in the operations and maintenance of their installation.
Designation Category 1	This DER management designation will be assigned to those DER customers in Control Group 1, those on the first 75 circuits for which DERs are installed.

Designation Category 2	This DER management designation will include the first 1,000 DERs which apply and complete their interconnection on or after January 1, 2021 and may include DER customers who are also assigned to Control Group 1 (Designation Category 1).*
Designation Category 3	A DER system that is enrolled in the Actively Managed Group will be assigned this DER management designation.

* Customers included in the first 1,000 DERs interconnected and are on one of the first 75 circuits will have a designation noting inclusion in both control groups.

4. DER Settings

Volt/VAR will be used as the default voltage management mode for all inverters. The Company will establish and maintain default Volt/VAR settings based on the location and impact of each DER, as well as voltage ride-through and frequency ride-through functions which meet or exceed PJM Interconnection LLC's ("PJM") guidelines. Alternative voltage management modes and settings may be used to reduce or eliminate distribution system upgrade costs to interconnecting customers with their agreement.

Prior to the customer completing the DER installation and submitting the COC, a Volt/VAR curve will be calculated and stored in a database to be sent to the inverter following its installation. Each Volt/VAR curve will be calculated using the DER's location on the distribution system, kW nameplate, calculated voltage rise, and other pertinent data.

DERs in Control Group 1 and Control Group 2 will be monitored using DERMS/ADMS and the AMI Mesh Network to understand the actual state of the distribution system and the DERs' performance. The Company shall not make operational decisions regarding the distribution system based on that information. Control Group inverters will exclusively use autonomous grid support functions, which will dictate the inverter's operational behaviors, using the local conditions as input. Each Control Group inverter will be tagged in DERMS/ADMS to prevent any active management by either DERMS/ADMS or PPL Electric's operations personnel.

In the Actively Managed Group, the developed Volt/VAR curve will be used until field conditions deem a power factor override or a change of power factor is necessary to maintain acceptable system conditions. In operating scenarios where the distribution system is configured abnormally due to maintenance or an outage, DERMS/ADMS may manage these inverter settings by “overriding” the autonomous Volt/VAR curve and using a specific Constant Power Factor until system conditions return to acceptable levels. PPL Electric will only use the Remote On/Off function on battery storage or solar systems that have not safely isolated or “islanded” from the distribution system. The Company will only use Volt/Watt when mutually agreed upon by the DER customer and the Company. Aside from Volt/VAR curves, default Voltage Ride-through and Frequency Ride-through will also be provided and programmed by the Company at interconnection. PPL Electric will track and report yearly on each instance when active management is used.

F. PILOT PROGRAM ANALYSIS

During the Pilot, PPL Electric will gather and store data from participating DERs in three of the customer groups: Control Group 1, Control Group 2, and the Actively Managed Group. The data will be used in comparison among the four customer groups (*i.e.*, Control Group 1, Control Group 2, Actively Managed Group, and Grandfathered Group) to determine the impact and benefits of DER monitoring and active management. The analysis will occur in both an operating (real-time) environment and in planning (long-term) scenarios.

Operational analysis will be done in near real-time so that operators and DERMS/ADMS can identify the impact of each DER on voltage and load on the circuit. The Company shall not make operational decisions regarding the distribution system based on the information gathered from Control Group 1 and Control Group 2. DERMS/ADMS will determine if adjustments need to be made to traditional voltage management devices, the settings on inverters in the Actively

Managed Group, or both to mitigate violations and make work conditions safer. The operators can then change the inverter settings and determine if the potential violation is ameliorated. The information from all these events, for both monitored and actively managed customers, will be tracked and made available for further analysis.

Planning analysis will include post-event analysis of voltage and load information from the circuits with Grandfathered Group DERs (no monitoring) compared to circuits with monitored DERs and those with actively managed DERs. Comparisons will determine whether monitoring and/or actively managing the DERs results in fewer voltage violations, fewer capital expenditures, or other system challenges being avoided.

1. Anticipated Benefits

The anticipated benefits are expected to provide a value proposition for Reliability, Power Quality, and Safety as shown in Table 2, below.

Table 2- Value Proposition and Anticipated Benefits

Reliability	a. Enhance operational flexibility
	b. Improved excursion ride-through
	c. Improved hidden load visibility
Power Quality	d. System upgrades deferred / avoided
	e. Increased hosting capacity
	f. Improved long-term forecasting
	g. Improved voltage management
Safety	h. Safer work environment

2. Data Collection and Verification

DER information, such as grid number, premise number, user group, circuit ID, nameplate generation size (kW), and distance from substation, will be captured from the GIS and Customer

Service System (“CSS”) databases for all DER customer groups. Voltage data will be taken across PPL Electric’s network at all the available measuring points, such as SCADA and AMI meters, to monitor the network voltage level. System load data will be captured at Company-owned devices at all the available measuring points in the network, such as circuit breakers, recloser devices, smart switching devices, and AMI meters. Voltage and load data will be captured at all DER inverters within Control Groups 1 and 2 and the Actively Managed Group.

Inverter baseline data to be collected and archived includes amps, voltage, watts, VARs, Power Factor, Power Factor setpoint value, Power Factor setpoint enabled, Volt/VAR enabled, and system status (On/Off). This data will be captured for all DER customer groups and used for comparative analysis. This comparative analysis includes, but is not limited to:

- a. Peak load and associated voltage;
- b. Minimum load and associated voltage;
- c. Minimum daytime load and associated voltage;
- d. Number of voltage violations;
- e. Standard deviation of voltage violations;
- f. Peak load at customer meter for all DER customers on the circuit;
- g. Minimum load at customer meter for all DER customers on the circuit;
- h. Standard deviation of loads for all DER customers on the circuit;
- i. Number of hours without DER production; and
- j. 8760 load levels and voltage levels on circuits.

With DER monitoring and management, PPL Electric will have a significant increase in data to help manage and plan the distribution system, with sources from the grid (before the meter) as well as AMI meter data and DER inverter data (behind the meter). Collecting data both before

and behind the meter will bring critical information to understand the full impact of two-way power flow on the safe and reliable operation of the distribution system.

Using this, PPL Electric will be able to conduct comparisons among the four DER customer groups, show use cases, track multiple metrics, and analyze the differences in performance and grid-supporting behaviors of DERs with active management, monitoring, and without visibility on the Distribution system.

3. Use Cases

These use cases cover relevant scenarios under which DERs would interact with the electric distribution system. By leveraging the DER management devices' ability to monitor and/or manage the DERs, several beneficial objectives can be achieved in each use case. Throughout the Pilot's implementation, as PPL Electric gains more experience, the Company may revise and refine the details of these use cases, adjust the methodology and approaches, use more advanced tools, and adopt industry best practices. The use cases include:

1. Voltage violation at DER Point of Interconnection (“POC”)
2. Voltage violation mitigated by DERs on the circuit
3. Voltage violation during planned switching
4. System restoration
5. Hidden load impact on load forecasting
6. DER management impact on voltage management
7. DER active management impact on hosting capacity increase and deferral of capital upgrade
8. DER operation in emergency conditions and in active work zones

Use cases are further described in Attachment C.

G. PILOT PROGRAM REPORTING

1. Annual Reports Submitted to the Commission

The annual reports will be filed with the Commission at Docket No. P-2019-3010128, providing detailed quantitative information relevant to the evaluation of the results of the Pilot. Annual reports to the Commission will be published at the end of each program year, starting with the end of Program Year 1. The reports will also be made publicly available. Care will be taken to protect customer privacy, so reporting shall not contain any sensitive customer information. The annual reports shall be filed within 30 days following the end of each program year (first report is estimated to be filed in the second quarter of 2022). Reports shall include data in electronic formats that support analysis (i.e., Excel or other machine-readable data where appropriate). Annual reports shall include the information listed below.

- (1) The number of DERs installed and the number of DER management devices installed**
- (2) Capital costs and expenses associated with the purchase, installation, ownership, and maintenance of the DER management devices**
- (3) Number of times, locations, and duration for active management**

The number of times and the locations at which the Company actively managed each grid support function and the average duration that the function was actively managed.

This would be a summary showing aggregated counts among all customers of:

- Volt/VAR Curve Overrides
- Power Factor Setting Changes
- Ride-through Setting Changes
- Remote On/Off
- Volt/Watt Curve Overrides (where applicable)

- (4) Grid benefits achieved for each instance of active management**

The grid benefits achieved in each instance of active management, include, but are not limited to, real-time grid constraint mitigation. The Company shall develop the definition and parameters of the grid benefits.

(5) Net generation loss or gain due to active management

The net generation loss or gain due to the Company's active management of grid support functions (defined above) in each instance.

(6) Distribution system upgrades avoided due to increased hosting capacity attributed to monitoring

This report will be a comparison of the computed circuit hosting capacity when all DERs are evaluated at nameplate kW only, versus the hosting capacity of each circuit with actual kW output, gained via monitoring (while keeping Grandfathered DERs at nameplate kW).

(7) Distribution system upgrades avoided due to increased hosting capacity attributed to autonomous grid support functions

This report will be a comparison of the computed circuit hosting capacity of each circuit with actual kW gained via monitoring only versus the scenario where those DERs are equipped with autonomous grid support functions (while keeping Grandfathered DERs at nameplate kW).

(8) Distribution system upgrades avoided due to increased hosting capacity attributed to active management

This report will be a comparison of the computed circuit hosting capacity when all DERs are evaluated at nameplate kW only, the scenario without any monitoring or active management, versus the hosting capacity of each circuit with actual kW output gained via active management (while keeping Grandfathered DER at nameplate kW).

(9) System operation comparisons of circuits under autonomous inverter grid support functions versus active management

The comparison will involve DERs on the 75 circuits in Control Group 1, circuits with DERs in Control Group 2, and the circuits with actively managed DERs. This report will be in the form of a voltage metric depicting the performance characteristics between the two groups. Depending on the mix of Grandfathered Group, Control Group, and Actively Managed Group DERs on the remaining circuits, those circuits may need to be segmented to provide an accurate statistical comparison. This reporting will be tracked and maintained manually.

(10) Operational descriptions of how active management was executed and implemented

This report will use data captured in DERMS/ADMS, which identifies any operational issues faced, what kind of active management action was taken, and the resulting system impact(s) and benefit(s) of the action. Additional manually noted information will be provided in this report, as available (e.g., day-ahead and real-time remote setting alterations to DERs).

(11) Performance measures related to active management

This report will address all performance measures related to active management and, where applicable, monitoring, including, but not limited to, communication reliability (e.g., communication uptime) and data quality.

2. Annual Reports to Individual DER Customers

Within 30 days following the cash-out of the customers' banked excess generation, which typically occurs at the end of each PJM Planning Year, each DER customer whose smart inverter's grid support functions are used by the Company during the annual reporting period will be sent an individualized annual report. The annual report will provide:

(1) The amount of the DER's net generation loss or gain due to the use of the autonomous grid support functions:

- Default Volt/VAR Settings

- Default Voltage Ride-through Settings
- Default Frequency Ride-through Settings

(2) The aggregate amount of all DERs’ net generation loss or gain due to the Company’s active management of the grid support functions outlined below:

- Volt/VAR Curve Overrides
- Power Factor Setting Changes
- Ride-through Setting Changes
- Remote On/Off
- Volt/Watt Curve Overrides (where applicable)

(3) The method and technique used to calculate the DER’s net generation loss or gain

The Company will provide a description of the method and technique used to calculate the net generation loss or gain for customer reporting.

(4) The number of times each grid support function was used on an automated basis, and the average duration of that function’s automated use

(5) The number of times that PPL Electric actively managed each grid support function, and the average duration that the function was actively managed

(6) Volt/VAR Curve Override Table

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 Power Factor 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.

3. Data on Program Performance

Within 30 days after the end of each program year, PPL Electric will provide the following data on an anonymous basis to the Sustainable Energy Fund (“SEF”):

(1) Raw DER Data – 15-minute interval data for participants (delivered kWh, received kWh, RMS voltage).

(2) DER Management Data – 15-minute inverter data for participants (kW and voltage).

PPL Electric will use generic but unique identifiers for each customer to anonymize the customers' names and account numbers when providing the data to SEF.

H. CUSTOMER AND INSTALLER INFORMATION

Customers and installers who are pursuing or are interested in learning more about installing DERs on the PPL Electric distribution system are able to find information and instructions about the updated interconnection process on PPL Electric's external Rules for Electric Meter and Service Installations ("REMSI") website and also on the PPL Electric's Renewable Energy Connection Portal. The frequently asked questions ("FAQs") section on the REMSI website has been updated to include impacts and details for the Pilot and appropriate PPL Electric contact information.

On an annual basis during the Pilot, customers whose inverters' settings are actively managed during the Pilot will receive the individualized annual reports outlined in Section II.G.2, *supra*. Customers, or the installers who are installing the DERs, will be notified by the Company, via a phone call, regarding coordination of a PPL Electric representative installing the DER management device.

Attachment A

Excluded Distribution Circuits

To preserve the integrity of the 75 distribution circuit control group, the Pilot will not include any of the following 12 distribution circuits, due to the presence of remotely managed DERs (e.g., participants in PPL Electric's Keystone Solar Future Project) and/or similar Company-owned facilities (e.g., batteries) on these distribution circuits during the term of the Pilot:

- (1) Leola No. 3 Distribution Circuit
- (2) Leola No. 5 Distribution Circuit
- (3) Prince No. 2 Distribution Circuit
- (4) South Akron No. 4 Distribution Circuit
- (5) Cocalico No. 1 Distribution Circuit
- (6) Letort No. 1 Distribution Circuit
- (7) Letort No. 2 Distribution Circuit
- (8) Buck No. 3 Distribution Circuit
- (9) East Petersburg No. 1 Distribution Circuit
- (10) Newport No. 1 Distribution Circuit
- (11) Crackersport No. 2 Distribution Circuit
- (12) Renovo No. 2 Distribution Circuit.

Attachment B

Pilot Milestones with Program Year 1 Commencing July 2021

Key timeline and milestones of the Pilot implementation is provided below. This includes an assumption that Program Year 1 will start in the third quarter of 2021. In the event that DER adoption is slower or faster, the three-year schedule will be adjusted accordingly.

1. December 1, 2020 – Inverter List Published on REMSI
2. December 17, 2020 – Commission Order Approving the Settlement
3. January 1, 2021 – Day 1 of Pilot
4. January 19, 2021 – File the Pilot Implementation Plan
5. January 29, 2021 – Technical Collaborative
6. February 8, 2021 – Other Parties’ Comments Due
7. March 1, 2021 – File the Revised Pilot Implementation Plan (if necessary)
8. June 30, 2021 – 30 days after PJM Calendar Year, First Annual Reports to Customers
9. July 2021 – Estimated start date of Program Year 1
 - Control Group 1 Established with Circuits 1 to 75
 - Control Group 2 Established with DERs 1 to 1,000 Installed
10. January 1, 2022 – New DERs have inverters certified with IEEE 1547.1 / UL 1741 SB
11. June 30, 2022 – Second Annual Reports to Customers
12. End of Program Year 1, 2022 – First Annual Report to Commission
13. June 30, 2023 – Third Annual Reports to Customers
14. End of Program Year 2, 2023 – Second Annual Report to Commission

15. Simultaneously with End of Program Year 2, 2023 – Potential Petition Filing
16. June 30, 2024 – Fourth Annual Reports to Customers
17. End of Program Year 3, 2024 – Third Annual Report to Commission

Attachment C

Use Cases

1. Voltage Violation at DER Point of Interconnection

DERs can sometimes exacerbate voltage violations on the network. Currently, there is no real time visibility for the grid operator of the voltage level at the physical location of all DERs. As a result, often the grid operator might not be aware of a voltage violation caused or exacerbated by a DER in a timely fashion, and, if they do notice a voltage violation on the network, there is no way to identify which DER is the cause of the issue. Monitoring capability and an alarm system at a DER location can certainly provide visibility that is needed but missing.

If a violation is identified on a particular DER, currently the only way to act on the issue is to contact the DER operator and request action from them. In some cases, PPL Electric staff will need to be sent on-site, which is time consuming and resource intensive. Active management capability will enable speedy response to the issue and save cost and resources by avoiding sending field personnel to be physically present at the location.

For Monitored DER customers, the Company will be able to identify voltage violations at particular DER locations remotely and will be able to come up with mitigation strategies. For Actively Managed DER customers, the Company will be able to identify the voltage violation and actively manage the DER to attempt to eliminate the voltage violation.

For the Grandfathered Group, the Company will record voltage violations (counts and violation level) using non real-time AMI voltage data. For Control Groups 1 and 2, the Company will record voltage violations using the DER information available from monitoring these customers. For the Actively Managed group, the Company will capture any event where DER settings are adjusted to mitigate voltage issues at the DER point of interconnection.

The Company will analyze the impacts and interaction in voltage management among DERs across the defined customer groups. The Company will also record all field trips needed and those avoided to resolve voltage violations and will calculate the cost savings resulting from fewer trips.

2. Voltage Violation Mitigated by DERs on the Circuit

DER interconnections can exacerbate voltage fluctuations particularly if there are numerous DERs on a single circuit. With additional DERs coming on the system, the voltage violations could be extreme, and, without visibility, PPL Electric's operators and planners will be challenged to manage the system reliably and safely.

For the Actively Managed DER customers, PPL Electric will identify and capture scenarios where DERs may be utilized to alleviate the voltage violations via active management of the DER settings. For the Monitored DER customers, PPL Electric will capture and review events where DERs are using autonomous grid support functions to mitigate voltage issues and will study their overall impact on circuit voltage.

3. Voltage Violation During Planned Switching

During planned switching, when loading and/or network topology changes, DERs can cause network violations. Although some violations can be addressed by changing settings at voltage regulation equipment, sometimes violations would require changes at the customer level, such as requiring DERs to stay offline during the switching. With DER monitoring, the Company has more accurate data to predict the impact of DERs during the switching. With active management, DERMS/ADMS and operators can respond to and mitigate the violation by changing the DERs' settings.

The analysis will be performed prior to execution of the planned switching. The analysis will utilize historically collected data at both the monitored and actively managed DERs on the

circuit(s) to design mitigation strategies if violations would exist during the planned switching period. The Company will decide and document if DERs need to switch from the default Volt/VAR mode to Constant Power Factor during the planned switching, or if a revised default Volt/VAR curve shall be temporarily issued.

During the switching period, the Company will also utilize its Load/Voltage Management program within the DERMS/ADMS to manage the actively managed DERs that are in Constant Power Factor mode.

4. System Restoration

When an outage occurs, all the DERs on the circuit shall automatically switch off to avoid unintentional islanding. When the restoration is complete, the load that will need to be brought back online is larger than the load level under normal operating conditions because the load normally served by the DER will now need to be sourced by the Company's network ("hidden load"). By being aware of the actual amount of hidden load, restoration can be planned to accommodate the total load (apparent + hidden) and dramatically reduce the risk of conductor overload and equipment damage during restoration. Monitoring capability at the DER will provide the critical information on the actual amount of hidden load on the circuit and guide the grid restoration with more visibility. Analysis will be based on the voltage level and circuit loading level recorded in the log after the restoration of circuits with different DER customer groups (Grandfathered Group, Control Groups 1 and 2, and Actively Managed Group). If the information is not clearly portrayed in the log, the Company will perform simulation studies as needed without taking the hidden load into consideration and compare the difference between loading levels with or without the hidden load.

5. Hidden Load Impact on Load Forecasting

Distribution planning reviews the load data for all distribution circuits routinely (during customer load and generation application analysis). During this planning review, the circuit/substation overload risks are evaluated with hidden load considered. Hidden load is the amount of load on a circuit that is masked by distributed generation making the perceived kilovolt-ampere (“kVA”) value appear to be lower than it is. System investments are developed based on the outcome of the load forecasting. To compensate for the hidden load, the system may be studied with all DER off-line, as it depicts a scenario where the distribution system must carry the full load without DERs. This makes the analysis less accurate, which may result in unnecessary or less timely system investments. DERs in the Pilot with monitoring and active management capabilities will improve the load model accuracy and decrease circuit/substation overload risk, which could defer the need for system investment.

6. DER Management Impact on Voltage Management

With DER monitoring, the accuracy of voltage profile studies will improve. Having more voltage data points will eliminate assumptions made today and will provide a more accurate voltage profile and allow for timelier and more prudent system upgrades with DER active management through DERMS/ADMS. Also, more voltage support functions will be available, and system investments for upgrading voltage management equipment, such as voltage regulators and capacitor banks, can be avoided. DER management and Volt/VAR curve will also be implemented in the power flow modeling process when applications are reviewed by the Planning team and will directly save the cost of reinforcements to the customer by being able to alleviate voltage violations through the use of smart inverters.

The DER data generated will be utilized by the Planning team to conduct studies and compile a list of voltage violations alleviated through DER monitoring, autonomous grid support

functions, and active management. Planning will use this information and perform power flow and voltage studies to determine reinforcements that would have been required to prevent these voltage violations. A cost-saving estimation will be compiled for each DER management category.

7. DER Active Management Impact on Hosting Capacity Increase and Deferral of Capital Upgrade

Hosting Capacity is the amount of Distributed Generation that can be added to the distribution system before load or voltage violations occur or system upgrades are required for safe and reliable DER integration. With DER monitoring enabled, the actual DER generation information will be used to identify the available hosting capacity, rather than using DER kW nameplate ratings. Knowing that DER actual generation is always smaller or equal to its nameplate rating, the hosting capacity of the distribution system will increase if the actual generation information is used.

The impact analysis will consist of conducting two hosting capacity studies (also known as integration capacity studies) on PPL Electric's network in power flow simulation platform using: (1) DERs' nameplate rating (kW, kilovolt-ampere reactive ("kVAR"), kVA); and (2) DERs' actual generation info (kW, kVAR, kVA) obtained from smart inverters. The hosting capacity at node level, circuit level, and system level will be obtained in both studies and compared together to investigate hosting capacity improvement attributed to the following comparison scenarios:

- i. Monitored DERs versus Grandfathered DERs
- ii. Autonomous DERs versus Grandfathered DERs
- iii. Actively Managed DERs versus Grandfathered DERs

In addition, capital upgrades may be required for new DER interconnection applications, due to limited hosting capacity calculated based on existing DERs' nameplate ratings. The hosting

capacity obtained from actual DER generation info of monitored DERs is used to investigate avoided/deferred capital investments attributed to the comparison scenarios mentioned above.

8. DER Operation in Emergency Conditions and in Active Work Zones

When there is a reported fire, gas leak, or down conductor, field personnel may be needed to clear the issue. The network in the affected part of the distribution system will be de-energized for the safety of the Company's employees and the general public. Through monitoring of DERs, the team can identify all DERs in the active work zone and verify their status (on or off), and through active management, the Company can turn off the DERs remotely, if needed. As a result, safety risks during field work will be greatly mitigated.

In addition, in a fire situation in which the fire chief requests a house to be de-energized, the house can be disconnected from the grid at the meter point by the Company remotely. If there is a behind-the-meter DER on site, the Company can monitor whether the DER turns off as required. With monitored DERs, the Fire Department can be notified if the DER is still in operation. The actively managed DERs can be turned off remotely if the DER does not safely isolate from the distribution system on its own. This will increase the certainty of de-energizing and as a result, increase the overall safety level.

The Company will record the number of DERs in active work zones and the number of DERs that require remote management, as the data and time permit. The Company will also record the costs and benefits to the safety measurements through monitoring and/or actively managed DERs.