Post & Schell P.C.
ATTORNEYS AT LAW

17 North Second Street
12th Floor
Harrisburg, PA 17101-1601
215-587-1000 Main
717-731-1985 Main Fax
www.postschell.com

Devin Ryan

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

March 1, 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 Revised DER Management Pilot Implementation Plan. Clean and compare versions of the Revised DER Management Pilot Implementation Plan are enclosed. The compare version shows, in redline, the changes made to the original Plan filed on January 19, 2021.

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: March 1, 2021

Devin Ryan

18769526v1

DER Management Pilot Implementation Plan

Dated: March 1, 2021 (Revised)

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. Inverter Testing and Certification Process 9

4. Customer Enrollment 10

5. DER Settings 11

F. PILOT PROGRAM ANALYSIS 13

1. Anticipated Benefits 14

2. Data Collection and Verification 14

3. Use Cases 15

G. PILOT PROGRAM REPORTING 16

1. Annual Reports Submitted to the Commission 16

2. Annual Reports to Individual DER Customers 19

3. Data on Program Performance 20

H. CUSTOMER AND INSTALLER INFORMATION 21

Attachment A – Excluded Circuits
Attachment B – Pilot Milestones with Program Year 1 Commencing July 2021
Attachment C – Use Cases
Attachment D – Due Consideration of Other Parties' Comments

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.

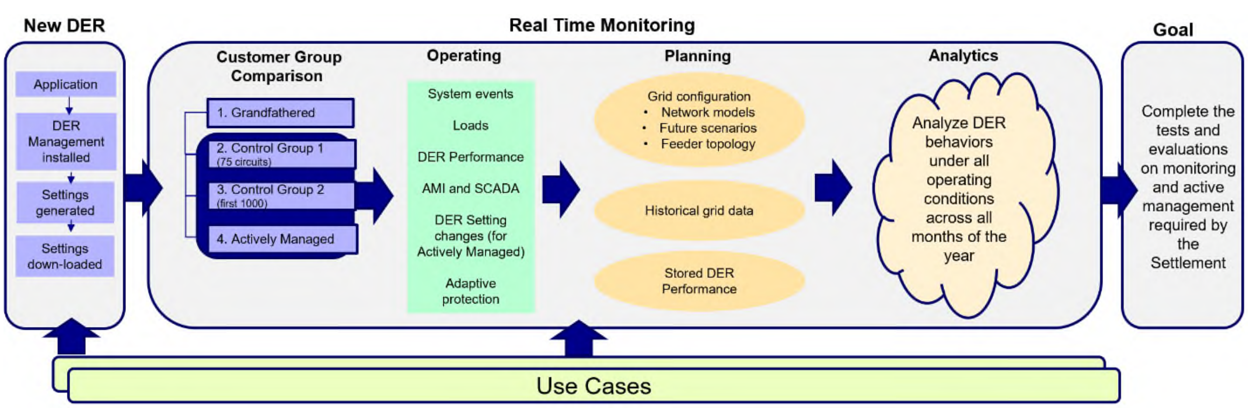
On May 24, 2019, PPL Electric filed a Petition with the Commission for permission to require smart inverters that meet the new IEEE and Underwriters Laboratories ("UL") standards, to install DER management devices on new DERs interconnected with its distribution system, and to monitor and manage those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

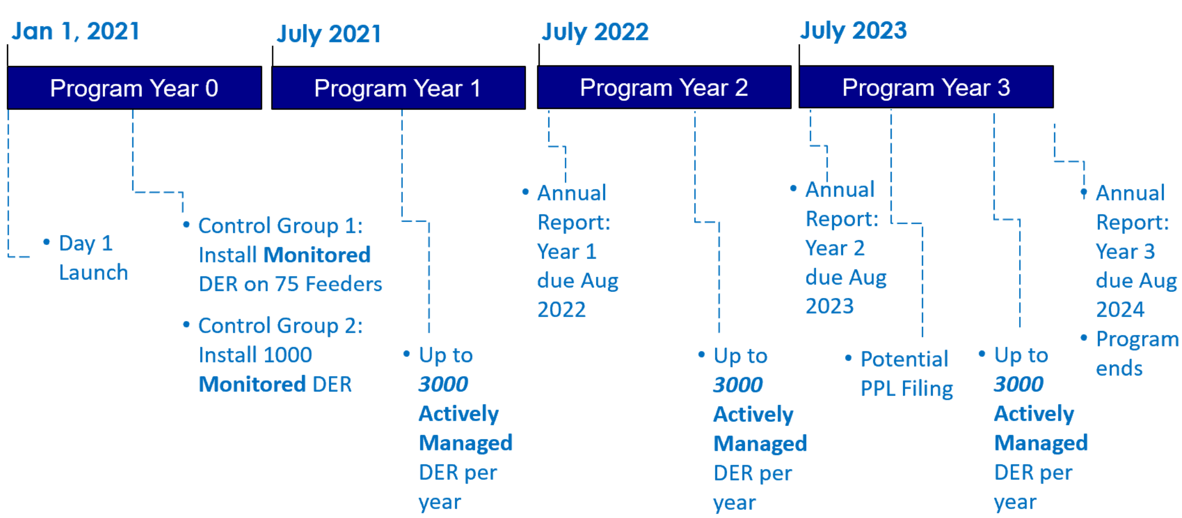


21621804v1

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.

21621804v1

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.

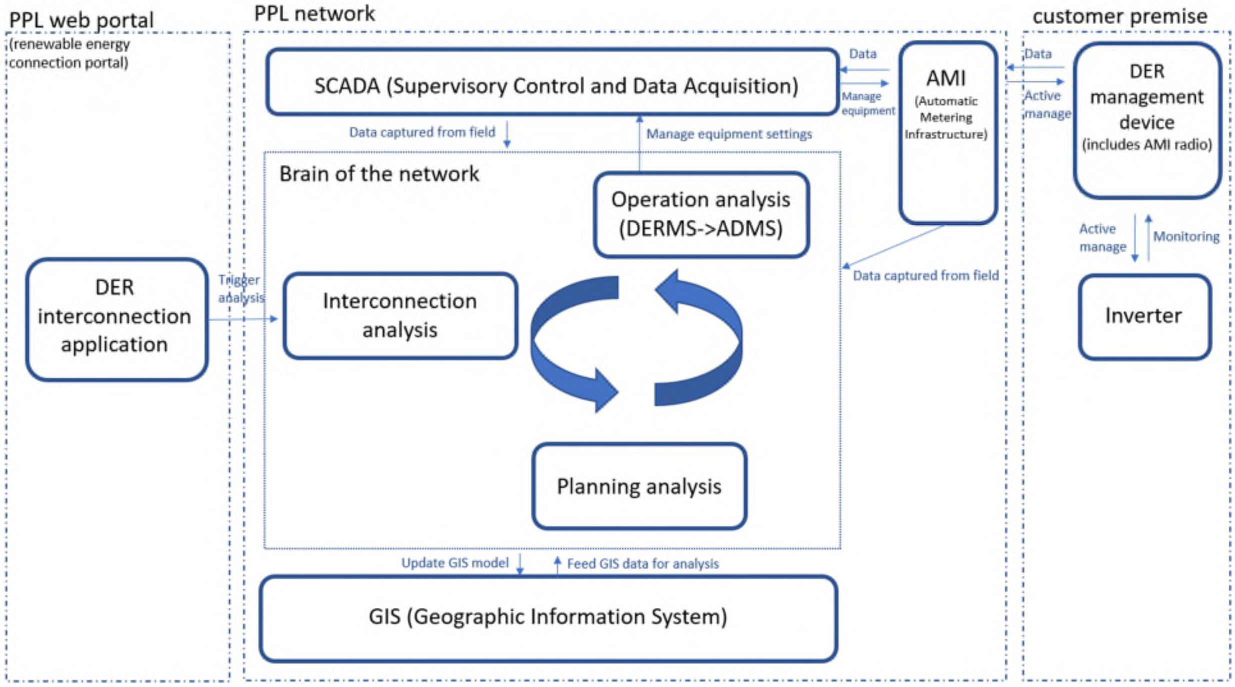
4) **Actively Managed Group.** All DER customers who submit applications and interconnect with the distribution system on or after January 1, 2021, excluding the customers outlined in Control Groups 1 and 2 as well as any customers interconnecting after the cap of 3,000 DER management devices installed 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. Inverter Testing and Certification Process

PPL Electric follows a streamlined process for testing new inverters requesting approval. The steps are laid out as follows:

First, the inverter manufacturer needs to provide proof that the inverter is UL 1741-SA certified and has a dedicated local communication interface available for testing, which are both pre-requisites for being able to be certified under the Interim Requirements. The inverter manufacturer also must provide technical information on its inverter model, including, but not limited to, the inverter's communication protocol, data models, and configuration profiles. The Company also works with the inverter manufacturer to obtain a test model for PPL Electric's testing lab.

Second, after the Company receives all of the requested information and has set up a test model in the lab, the inverter testing proceeds in the following sequence:

1. DER Communication Protocol Testing

   PPL Electric validates that one of the three approved protocols (IEEE 2030.5, IEEE 1815(DNP3) or SunSpec Modbus) is supported as a local communication interface.

2. Profile Configuration including Data Point Mapping

   PPL Electric develops and loads the proper server profile configuration to allow data points to flow correctly between the server and client.

3. Read Points Testing

   PPL Electric tests and validates the capability to receive the following via the inverters' local communication interface.

   - Real Power
   - Apparent Power
   - Reactive Power
   - Power Factor
   - Current (Total, Phase A, Phase B, and Phase C)

- o Voltage (Phase A-to-neutral, B-to-neutral, C-to-neutral)

4. Write Points Testing

   PPL Electric tests and validates the capability to monitor and manage grid support functions of the inverters via their local communication interface.

5. DER Management Device Testing

   PPL Electric tests and validates end-to-end testing between the DER and the Company's DERMS/ADMS via the DER Management devices.[1]

Smart inverters that pass the Company's testing requirements are added to PPL Electric's Approved List of Smart Inverters.

4. 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

[1] The Company's current DER Management device is not compatible with IEEE 2030.5 inverters. PPL Electric is actively working on a solution that will resolve the incompatibility issue. However, until a IEEE 2030.5-compatiable DER Management device is available, PPL Electric will permit DERs using IEEE 2030.5 inverters that pass the Company's other testing requirements to interconnect and not be subject to the pilot program. Subsequently, once the IEEE 2030.5-compatible DER Management device becomes available, any new DER interconnection applications that will use an IEEE 2030.5 inverter would be included in the pilot program. This practice is consistent with Paragraph 56 of the Settlement, which states that "the Company shall not deny or delay the permission to connect and operate a DER due to unavailability of DER management devices" and that "[a]ny DER not equipped with a DER management device for this reason shall not be part of the pilot program." (Settlement ¶ 56.)

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.

5. 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. The Company will provide its findings and information on these use cases in its annual reports filed with the Commission.

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) A list of the participating DERs that includes for each DER: (a) a unique customer identifier; (b) the nameplate capacity; (c) the initial settings established for that DER's smart inverter; and (d) the type of DER (e.g., solar, solar plus storage)

(3) Capital costs and expenses associated with the purchase, installation, ownership, and maintenance of the DER management devices

(4) 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)

(5) 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.

(6) 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.

(7) 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).

(8) 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).

(9) 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).

(10) 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.

(11) 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).

(12) 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.

(13) Findings and information on the Company's use cases

This report will provide findings and information on the pilot program's use cases to date, in addition to the data being presented in the annual report.

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.

Also, in March or April 2021, PPL Electric will be launching a new webpage specifically for DER Management. This new webpage will act as the main "hub" with easily located information or hyperlinks to pertinent information on DER Management, including, but not limited to, material pertaining to DER management as a whole, Volt/VAR and Ride-through setting guidelines, approved installation sketches, frequently asked questions, the Pilot Implantation Plan, and the approved inverter list.

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 28, 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 when they do not safely isolate from the distribution system. 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.

As previously stated, in accordance with Paragraph 59 of the Settlement, 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 a power outage.

Attachment D

Due Consideration of Other Parties' Comments

Under Paragraph 61 of the Settlement, PPL Electric agreed to give due consideration to the Joint Petitioners' written Comments. However, the Company retained the ultimate discretion to accept or reject the Joint Petitioners' feedback in its Pilot Implementation Plan. If any changes were made to the Pilot Implementation Plan based on the Joint Petitioners' feedback, PPL Electric would file a revised Pilot Implementation Plan at this docket within 20 days after the deadline for the Joint Petitioners' Comments.

In compliance with Paragraph 61 of the Settlement, PPL Electric reviewed and gave due consideration to the Joint Petitioners' Comments. Sunrun, who was not a Joint Petitioner, also filed Comments on the Pilot Implementation Plan. Although not obligated to consider Sunrun's Comments under the Settlement, PPL Electric nevertheless reviewed and gave due consideration to those Comments as well.

PPL Electric appreciates the other parties' feedback on the Pilot Implementation Plan. As seen in the revised Pilot Implementation Plan, and as explained further in this Attachment D, the Company incorporated some of the recommendations proposed by the parties. As a result, PPL Electric determined that it needed to file a revised Pilot Implementation Plan. In the following sections, PPL Electric summarizes and responds to certain of the parties' Comments.

I. <u>OTHER PARTIES' COMMENTS</u>

A. SEF'S COMMENTS

SEF contends in its Comments that PPL Electric "misrepresents the objective of the DER Management Pilot Program," believing that the purpose is to determine the cost and benefits to ratepayers, not PPL Electric. (SEF Comments, pp. 1-2.)

The Company disagrees with SEF's characterization. The pilot program's objectives are clearly outlined in Paragraph 54 of the Settlement, which states that the pilot program will "test and evaluate: (1) the costs and benefits to distribution system operation and design of *monitoring* DERs through devices connected to inverters as compared to maintaining distribution system status visibility through other means (e.g., automated meter reading equipment, ADMS systems, modeling); and (2) the costs and benefits to distribution system operation of *active management* of DERs as compared to the benefits available through the use of inverter autonomous grid support functions." (Settlement ¶ 54.) Nothing in the Pilot Implementation Plan alters those fundamental objectives. Moreover, costs and expenses incurred by PPL Electric are sought for recovery from the Company's ratepayers, and benefits to PPL Electric's electric distribution service are experienced by its ratepayers, who ultimately receive that service. Therefore, PPL Electric views SEF's characterization as a distinction without a difference.

In addition, SEF argues that the pilot should be delayed "until PPL Electric approves more inverters representing a more significant market share." (SEF Comments, p. 3.) SEF states that "[a]s of the recent conference call among the parties in this proceeding, PPL Electric has yet to solve the technical issues in communicating with Enphase inverters." (SEF Comments, p. 2.) As for SolarEdge, according to SEF, "the Solar Edge inverters approved by PPL Electric are incomplete," as the Company "only approved the H-US series of inverters designed for residential systems and the KUS inverters designed for 3-phase systems." (SEF Comments, p. 2.) SEF states that "[f]or residential customers alone, the approval does not include the H-RW, M-RW, and K-RW series inverters." (SEF Comments, p. 2.) SEF raises concerns about the inverters' approved for use in the Company's service territory and the potential impact on solar developments. (SEF Comments, pp. 2-3.)

PPL Electric has resolved the concerns regarding the IEEE 2030.5 inverters, such as the microinverters used by Enphase. With the agreement of the other parties, until the IEEE 2030.5-compatiable DER Management device is available, PPL Electric will permit DERs using Company-tested and validated IEEE 2030.5 inverters to interconnect and not be subject to the pilot program. Subsequently, once the IEEE 2030.5-compatible DER Management device becomes available, any new DER interconnection applications that will use an IEEE 2030.5 inverter would be included in the pilot program. This practice is consistent with Paragraph 56 of the Settlement, which states that "the Company shall not deny or delay the permission to connect and operate a DER due to unavailability of DER management devices" and that "[a]ny DER not equipped with a DER management device for this reason shall not be part of the pilot program." (Settlement ¶ 56.) Nevertheless, effective January 1, 2021, the Settlement requires new DERs interconnecting with the Company's distribution system to have smart inverters installed that meet: (1) UL 1741 SA; and (2) the Company's testing for the communications requirements under IEEE 1547-2018. (Settlement ¶ 48.) Therefore, PPL Electric must still test those inverters and validate that they meet those requirements before they can be installed in the Company's service territory.

SEF's concerns about the inverter approvals have either been addressed or lack merit. PPL Electric completed the testing and validation of Enphase's IEEE 2030.5 inverters on February 25, 2021. Thus, interconnection applications using those inverters can now be submitted on PPL Electric's web portal. As a result, SEF's concerns about the testing of Enphase's IEEE 2030.5 inverters are moot. Moreover, PPL Electric confirmed with SolarEdge that the Company tested and validated all of the inverter models currently offered by SolarEdge. The inverter models listed by SEF in its Comments are not SolarEdge models. Consequently, SEF's allegations about the testing and validation of SolarEdge's inverters lack merit.

SEF also raised concerns about the Remote On/Off function regarding solar plus storage installations. (SEF Comments, p. 3.) SEF believes that modifications to "the use cases for system restoration and DER operation in emergency conditions and in active work zones" should "be reviewed with the parties in this proceeding prior to implementation." (SEF Comments, p. 3.) SEF continues to believe that under the DER Management Plan, "PPL Electric could modify its approach to shut-down inverters appropriately disconnected from the distribution system," which "could endanger the life of ratepayers that utilize energy storage systems to provide uninterrupted service in the event of the failure of PPL Electric's distribution system." (SEF Comments, p. 3.) Although "SEF fully understands PPL Electric's concern for the safety of its workers," SEF asserts that "these workers can still be provided safe access to the distribution circuits without unnecessarily endangering the lives of ratepayers who may be using solar plus storage to power durable medical equipment." (SEF Comments, p. 3.)

To be clear, PPL Electric will adhere to Paragraph 59 of the Settlement, which states that the Company "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 a power outage." (Settlement ¶ 59.) Therefore, SEF's concern that PPL Electric may "shut-down inverters appropriately disconnected from the distribution system" is without merit. Remote On/Off will only be used for systems that "have not safely isolated or 'islanded' from the distribution system" and only in the circumstances set forth in Paragraph 59 of the Settlement. Nonetheless, PPL Electric has added language to the Pilot Implementation Plan's eighth use case to make this well-established point clearer. (*See* Pilot Implementation Plan, Attachment C, pp. 6-7.)

B. OCA'S COMMENTS

In its Comments, the OCA asserted that "[m]itigation or deferral of DER-related system upgrades can be achieved through numerous smart inverter related use cases that require various technological capabilities. Therefore, it is critical that the Company collect sufficient information to further inform these possibilities and potential solutions." (OCA Comments, p. 3.)

PPL Electric agrees and has designed its use cases not only to "further inform these possibilities and potential solutions" but potentially achieve system upgrade deferrals during the pilot program.

The OCA also commented on the data collection of energy storage systems, stating that "it is unclear as to whether, or what, energy storage related data the Company will collect through the Pilot Program." (OCA Comments, p. 3.) The OCA claims that "it is unclear whether the Company will be able to capture the existence of energy storage systems on PPL's system and separately evaluate the characteristics of these devices." (OCA Comments, p. 3.) Further, the OCA notes that "energy storage charging tariffs have been proposed in different districts throughout the country." (OCA Comments, pp. 3-4.) "While it is unclear whether PPL has grid connected storage or whether the Commission would consider a charging tariff reasonable at this time," the OCA believes that "collecting data on energy storage systems for the purpose of understanding cost causation is reasonable." (OCA Comments, p. 4.) Therefore, the OCA recommends that PPL "collect energy storage related data and specify how it will collect and share this information within the Pilot Program" and that, "[a]t a minimum, PPL should track and provide energy storage data as a separate load profile." (p. 4.)

PPL Electric will collect the same data from all DERs that are participating in the pilot program. Energy storage data will not be treated any differently. Therefore, for solar plus storage DERs, PPL Electric will collect the same data that the Company collects from any other DER participating in the pilot program. As for the OCA's Comments about charging tariffs and developing a separate load profile for storage, PPL Electric views these issues as outside the scope of the pilot program. As stated previously, PPL Electric is committed to test and evaluate: (1) the costs and benefits to distribution system operation and design of *monitoring* DERs through devices connected to inverters as compared to maintaining distribution system status visibility through other means (e.g., automated meter reading equipment, ADMS systems, modeling); and (2) the costs and benefits to distribution system operation of *active management* of DERs as compared to the benefits available through the use of inverter autonomous grid support functions. (Settlement ¶ 54.) However, in its annual reports, PPL Electric will be indicating the type of DER installation for each of the participating systems (e.g., solar plus storage). Thus, the OCA will be able to analyze data about solar plus storage systems participating in the pilot program.

Further, the OCA "strongly supports the evaluation of" the active network management ("ANM") use case and "appreciates PPL clearly articulating the use [case] in the Pilot" because it can "be an exceptionally cost-effective approach to increasing hosting capacity and deferring system upgrades related to DERs." (OCA Comments, pp. 4-5.) The OCA recommends that PPL Electric "consider tracking cost causative characteristics of DER export, which will provide interested stakeholders information concerning the qualities of DERs that can cause costs to be incurred by the Company, that may otherwise be avoided through the use of PPL's Distributed Energy Resource Management System (DERMS)." (OCA Comments, p. 5.)

PPL Electric will be reporting the distribution system upgrades that were avoided with DER monitoring and remote active management. Although not intended for evaluation of ANM cases, PPL Electric believes that this reporting will provide a good foundation for the stakeholders to conduct such an evaluation.

The OCA also argues that the "cost-effectiveness of PPL's DER Management Device could be highly dependent on the size of DER that the Company monitors and controls." (OCA Comments, p. 6.) As a result, the OCA recommends that "PPL, to the extent possible, attempt to collect data and conduct analysis to investigate this issue." (OCA Comments, p. 6.)

PPL Electric will collect and report on the nameplate capacities of the DERs participating in the pilot program. In its annual reports, PPL Electric will provide the nameplate capacity of each participating DER. This will enable the stakeholders, including the OCA, to analyze the data based on specific nameplate capacities of the DERs. However, PPL Electric does not believe that a specific use case needs to be developed to analyze the impact of the DER's size on the cost-effectiveness of the DER Management device. The stakeholders will be able to disaggregate and analyze the annual reports' data by system size, thereby enabling them to perform their own evaluation. Nevertheless, PPL Electric's planned use cases are subject to change, and the Company may ultimately analyze the impact of the DER's size on cost-effectiveness, either as a separate use case or within the currently planned use cases.

C. NRDC'S COMMENTS

In NRDC's Comments, NRDC raises a series of concerns about inverter testing and compatibility issues, namely SolarEdge's inverters and the IEEE 2030.5 inverters, such as the microinverters manufactured by Enphase. (NRDC Comments, pp. 2-6.) NRDC agrees with PPL Electric's plan to address the incompatibility of IEEE 2030.5 inverters with the Company's DER Management device, under which: (1) until the IEEE 2030.5-compatiable DER Management device is available, PPL Electric will permit DERs using Company-tested and validated IEEE 2030.5 inverters to interconnect and not be subject to the pilot program; and (2) once the IEEE 2030.5-compatible DER Management device becomes available, any new DER interconnection applications that will use an IEEE 2030.5 inverter would be included in the pilot program. (NRDC

Comments, p. 5.) NRDC states, however, that "the Company should clarify the reasons for the incompatibility between a smart inverter that appears to clearly meet the interim standards and the ConnectDER device, and explain what actions it is taking to ensure that similar issues do not arise with other smart inverters that meet the interim standards." (NRDC Comments, p. 5.) NRDC also suggests providing more detail on whether the delays with the Enphase inverters is manufacturer-specific or a broader issue. (NRDC Comments, p. 5.) Furthermore, NRDC recommends that PPL "undertake efforts to ensure that other inverter manufacturers are aware of the issue of ConnectDER compatibility with IEEE 2030.5 and the temporary exemption to install affected inverters outside the pilot program." (NRDC Comments, pp. 5-6.)

As noted by NRDC, the concerns raised specifically to SolarEdge are moot because the list of approved smart inverters now includes SolarEdge's inverters. (NRDC Comments, p. 3.) Moreover, as explained in Section II.A., *supra*, PPL Electric completed testing and validating Enphase's IEEE 2030.5 inverters on February 25, 2021, and interconnection applications using those inverters can now be submitted. Therefore, the inverter testing issues raised by NRDC have been addressed.

Regarding the IEEE 2030.5 inverters' incompatibility with PPL Electric's DER Management device, PPL Electric clarifies that the incompatibility issue is only limited to inverters that use IEEE 2030.5 as the sole communication protocol. Per IEEE 1547-2018, inverters should be able to support one of the three communication protocols: DNP 3, SunSpec Modbus, or IEEE 2030.5, as specified by the electric distribution company. Before filing the DER Management Petition, PPL Electric surveyed and researched the inverter industry and determined that the majority of the inverter manufacturers use SunSpec Modbus and DNP 3. Thus, PPL Electric's current DER Management device was designed, tested, and implemented to support these two protocols. IEEE 2030.5 is the newest of the three communications protocols, and PPL Electric is actively working on a DER Management device solution that will resolve the incompatibility issue. Although PPL Electric believes that many of the issues encountered with testing and validating Enphase's IEEE 2030.5 inverters were manufacturer-specific, the incompatibility with the current DER Management device applies to all IEEE 2030.5 inverters. As such, PPL Electric will update its solar inverter and other PPL Electric webpages to help make manufacturers, solar installers, customers, and other stakeholders aware of the incompatibility issue and how customers using tested and validated IEEE 2030.5 inverters will not be a part of the pilot program until PPL Electric has a compatible DER Management device available and ready to be used.

Next, NRDC states that PPL Electric should limit the use of "bespoke inverter settings" in the Control Groups' DER installations. (NRDC Comments, pp. 7-8.) According to NRDC, "the spirit of the pilot would be better served by using utility default inverter settings in as widespread a fashion as practicable." (NRDC Comments, p. 7.) "While it may be the case that locational and other factors may favor departing from default settings in particular circumstances (e.g., larger DER systems)," NRDC believes that "even then the establishment of default settings will provide valuable lessons about the extent of any limitations with a default setting-centered approach." (NRDC Comments, p. 8.)

PPL Electric generally disagrees with NRDC's suggestion. PPL Electric already will be tracking and reporting the initial settings of each DER participating in the pilot. Moreover, PPL Electric developed its Volt/VAR settings in a manner consistent with IEEE standards, i.e., maintaining power factor no lower than +/- 90%. Leveraging Volt/VAR curves which are calculated based on the DER's specific location and size provides the required granularity for distribution system stability. Due to the varied nature of PPL Electric's distribution system, which goes from very urban, short distribution feeders with a high short circuit duty to very rural, long, distribution feeders with a low short circuit duty, the use of a default curve would result in some DERs absorbing or injecting VARs unnecessarily. DERs close to a substation should expect to see a voltage on the higher side of the acceptable range due to its proximity to the source just as DERs that are far from the substation should expect to see a voltage lower in the acceptable range. Use of strict, uniform default settings would necessitate more active management for DERs not in one of the Control Groups and would potentially lead to voltage issues on feeders within the control groups.

Also, PPL Electric has a statutory duty to all of its customers to provide safe, reliable, and adequate electric distribution service. *See* 66 Pa. C.S. § 1501. PPL Electric will not turn a blind eye and allow a DER to interconnect with suboptimal default settings, which, as described previously, could negatively affect the Company's electric distribution service.

Regarding the annual reports, NRDC recommends that the annual reports include information on PPL Electric's review of use cases, specifically "narrative interim assessments," not just data, and that the Company clarify this point in its Pilot Implementation Plan. (NRDC Comments, pp. 8-9.) NRDC also recommends that the annual reports include: (1) all initial inverter settings, including data allowing for regional comparative analysis; (2) the customer's feeder line; and (3) an actual analysis of DER system size, not only the details of the DERs' nameplate capacities. (NRDC Comments, pp. 9-11.)

As stated on pages 16 and 19 of the revised Pilot Implementation Plan, PPL Electric's annual reports will provide findings and information of these use cases. Moreover, PPL Electric will include each participating DER's initial inverter settings and nameplate capacity. However, PPL Electric will not provide each DER's feeder line in a publicly-available annual report. In the

Company's experience, customers are very concerned about their privacy, especially when it comes to details about their electric usage, generation, and DER systems. If PPL Electric provides the feeder line for each participating DER along with all of the other information being presented in the annual reports, the Company cannot guarantee that the customer's identity will be shielded from public view.

Lastly, NRDC makes a series of recommendations about making program documents available to the public. Specifically, NRDC recommends that "all pilot documentation . . . be made available on a dedicated webpage accessible through the . . . Company's Renewable Energy webpage." (NRDC Comments, p. 11.) NRDC believes that the REMSI website was designed with installers in mind, so it may not be an easily navigable resource for some stakeholders. (NRDC Comments, pp. 12-13.) NRDC also appreciates the Company's willingness to put the default setting ranges from PPL Electric Exhibit SS-1R on its REMSI website. (NRDC Comments, p. 12.) Additionally, NRDC seeks clarification on where the "frequently asked questions" appears on PPL Electric's website. (NRDC Comments, p. 13.)

PPL Electric will be launching a new webpage specifically for DER Management, including the pilot program. This new webpage will go live in March or April 2021 and will serve as the main "hub" with easily located information or hyperlinks to pertinent information on DER Management, including, but not limited to, material pertaining to DER management as a whole, Volt/VAR and Ride-through setting guidelines, approved installation sketches, frequently asked questions, the Pilot Implementation Plan, and the approved inverter list. PPL Electric intends for this new webpage to address many, if not all, of NRDC's recommended changes to the Company's website.

D. SUNRUN'S COMMENTS

In its Comments, Sunrun raises issues concerning the Company's testing of inverters, particularly IEEE 2030.5 inverters, and recommends that either: (1) "interconnection should not be delayed for inverters that meet UL 1741 SA and IEEE 1547-2018 standards but are pending PPL testing; or (2) "Pilot Program implementation as a whole should be delayed until PPL demonstrates that its DER management device is compatible with a larger number of smart inverters, including smart inverters with IEEE 2030.5 communication protocols." (Sunrun Comments, pp. 2-4.)

Sunrun's recommendations are unnecessary. As explained previously, PPL Electric has finished testing and validating SolarEdge's inverters and Enphase's IEEE 2030.5 inverters. Therefore, many inverters have been tested and validated by PPL Electric and are now available to be used in the Company's service territory, including the inverter brands that are the most popular in PPL Electric's service territory. Moreover, after consulting with the other parties, including Sunrun, PPL Electric will allow DER installations using tested and validated IEEE 2030.5 inverters to be used in the Company's service territory. Since the Company currently does not have a DER Management device that is compatible with IEEE 2030.5 inverters, such installations will not be part of the pilot program until such a DER Management device is available. PPL Electric believes this is a reasonable approach that will enable the pilot program to continue, while providing the Company more time to develop a solution that will enable DERs using IEEE 2030.5 inverters to participate in the pilot program.

In addition, Sunrun supports revising the Pilot Implementation Plan to include clarifying language about PPL Electric's use of the Remote On/Off function. (Sunrun Comments, p. 4.) Sunrun also states that PPL Electric "should be able to differentiate DERs which have storage from those which do not, as to more effectively utilize remote on/off technology only when it should be used per the Settlement." (Sunrun Comments, p. 4.)

As stated previously and in the revised Pilot Implementation Plan, PPL Electric only will use the Remote On/Off function in compliance with Paragraph 59 of the Settlement. That is, the Company "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 a power outage." (Settlement ¶ 59.) Language to that effect has been added to the revised Pilot Implementation Plan. (*See* Pilot Implementation Plan, Attachment C, pp. 6-7.)

DER Management Pilot Implementation Plan

Formatted: Tab stops: 3.97", Left

Dated: ~~January 19~~March 1, 2021 (Revised)

21621878v1

TABLE OF CONTENTS

Formatted: Space After: 0 pt

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 .... 10~~

~~4. DER Settings .... 11~~

~~F. PILOT PROGRAM ANALYSIS .... 13~~

~~1. Anticipated Benefits .... 14~~

~~2. Data Collection and Verification .... 14~~

~~3. Use Cases .... 15~~

~~G. PILOT PROGRAM REPORTING .... 16~~

~~1. Annual Reports Submitted to the Commission .... 16~~

~~2. Annual Reports to Individual DER Customers .... 19~~

~~3. Data on Program Performance .... 20~~

~~H. CUSTOMER AND INSTALLER INFORMATION .... 21~~

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. Inverter Testing and Certification Process 9
4. Customer Enrollment 10
5. DER Settings 11
F. PILOT PROGRAM ANALYSIS 13
1. Anticipated Benefits 14
2. Data Collection and Verification 14
3. Use Cases 15
G. PILOT PROGRAM REPORTING 16
1. Annual Reports Submitted to the Commission 16
2. Annual Reports to Individual DER Customers 19
3. Data on Program Performance 20
H. CUSTOMER AND INSTALLER INFORMATION 21
Attachment A – Excluded Circuits
Attachment B – Pilot Milestones with Program Year 1 Commencing July 2021
Attachment C – Use Cases
Attachment D – Due Consideration of Other Parties' Comments

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.

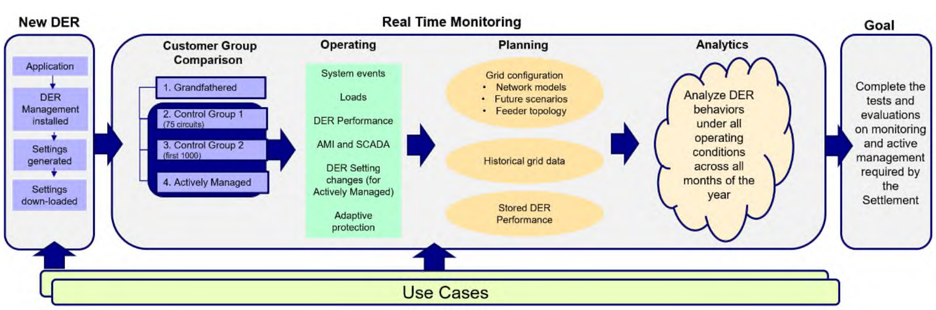
On May 24, 2019, PPL Electric filed a Petition with the Commission for permission to require smart inverters that meet the new IEEE and Underwriters Laboratories ("UL") standards, to install DER management devices on new DERs interconnected with its distribution system, and to monitor and manage those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

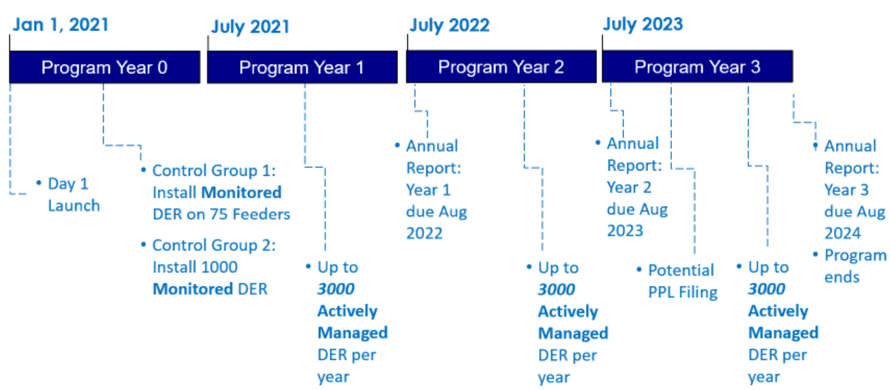
Figure 1- Pilot Overview



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.

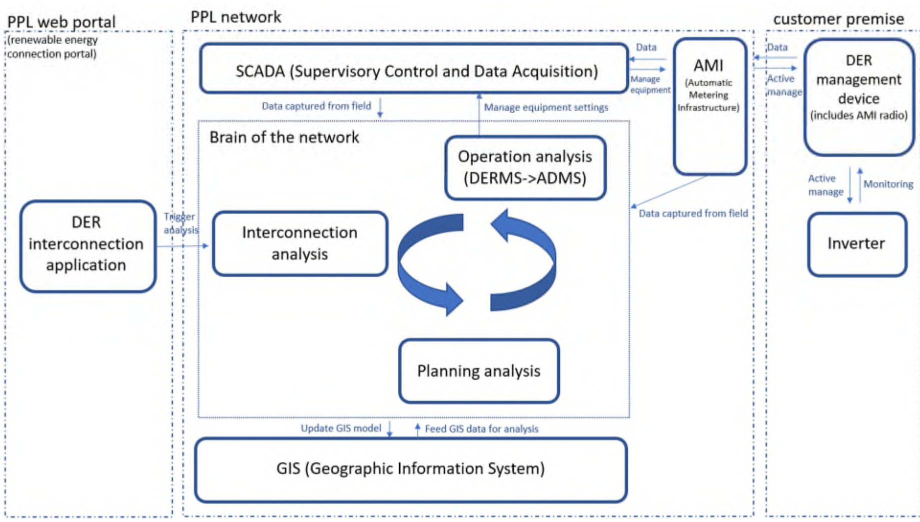
4) **Actively Managed Group.** All DER customers who submit applications and interconnect with the distribution system on or after January 1, 2021, excluding the customers outlined in Control Groups 1 and 2 as well as any customers interconnecting after the cap of 3,000 DER management devices installed 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. Inverter Testing and Certification Process

PPL Electric follows a streamlined process for testing new inverters requesting approval. The steps are laid out as follows:

First, the inverter manufacturer needs to provide proof that the inverter is UL 1741-SA certified and has a dedicated local communication interface available for testing, which are both pre-requisites for being able to be certified under the Interim Requirements. The inverter manufacturer also must provide technical information on its inverter model, including, but not limited to, the inverter's communication protocol, data models, and configuration profiles. The Company also works with the inverter manufacturer to obtain a test model for PPL Electric's testing lab.

Second, after the Company receives all of the requested information and has set up a test model in the lab, the inverter testing proceeds in the following sequence:

1. DER Communication Protocol Testing

   PPL Electric validates that one of the three approved protocols (IEEE 2030.5, IEEE 1815(DNP3) or SunSpec Modbus) is supported as a local communication interface.

2. Profile Configuration including Data Point Mapping

   PPL Electric develops and loads the proper server profile configuration to allow data points to flow correctly between the server and client.

3. Read Points Testing

   PPL Electric tests and validates the capability to receive the following via the inverters' local communication interface.

   - Real Power
   - Apparent Power
   - Reactive Power
   - Power Factor
   - Current (Total, Phase A, Phase B, and Phase C)

o Voltage (Phase A-to-neutral, B-to-neutral, C-to-neutral)

4. Write Points Testing

PPL Electric tests and validates the capability to monitor and manage grid support functions of the inverters via their local communication interface.

5. DER Management Device Testing

PPL Electric tests and validates end-to-end testing between the DER and the Company's DERMS/ADMS via the DER Management devices.[1]

Smart inverters that pass the Company's testing requirements are added to PPL Electric's Approved List of Smart Inverters.

~~3.~~4. 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

[1] The Company's current DER Management device is not compatible with IEEE 2030.5 inverters. PPL Electric is actively working on a solution that will resolve the incompatibility issue. However, until a IEEE 2030.5-compatiable DER Management device is available, PPL Electric will permit DERs using IEEE 2030.5 inverters that pass the Company's other testing requirements to interconnect and not be subject to the pilot program. Subsequently, once the IEEE 2030.5-compatible DER Management device becomes available, any new DER interconnection applications that will use an IEEE 2030.5 inverter would be included in the pilot program. This practice is consistent with Paragraph 56 of the Settlement, which states that "the Company shall not deny or delay the permission to connect and operate a DER due to unavailability of DER management devices" and that "[a]ny DER not equipped with a DER management device for this reason shall not be part of the pilot program." (Settlement ¶ 56.)

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.~~5. 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

Formatted: Keep with next

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. The Company will provide its findings and information on these use cases in its annual reports filed with the Commission.

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) A list of the participating DERs that includes for each DER: (a) a unique customer identifier; (b) the nameplate capacity; (c) the initial settings established for that DER's smart inverter; and (d) the type of DER (e.g., solar, solar plus storage)

~~(2)~~(3) Capital costs and expenses associated with the purchase, installation, ownership, and maintenance of the DER management devices

~~(3)~~(4) 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)~~(5) 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)~~(6) 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)~~(7) 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)~~(8) 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)~~(9) 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)~~(10) System operation comparisons of circuits under autonomous inverter grid support functions versus active management

Formatted: Tab stops: 0.56", Left + Not at 2"

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)~~(11) **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)~~(12) **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.

(13) Findings and information on the Company's use cases

This report will provide findings and information on the pilot program's use cases to date, in addition to the data being presented in the annual report.

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.

Also, in March or April 2021, PPL Electric will be launching a new webpage specifically for DER Management. This new webpage will act as the main "hub" with easily located information or hyperlinks to pertinent information on DER Management, including, but not limited to, material pertaining to DER management as a whole, Volt/VAR and Ride-through setting guidelines, approved installation sketches, frequently asked questions, the Pilot Implantation Plan, and the approved inverter list.

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~~28, 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.~~ when they do not safely isolate from the distribution system. 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.

As previously stated, in accordance with Paragraph 59 of the Settlement, 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 a power outage.

Attachment D

Due Consideration of Other Parties' Comments

Under Paragraph 61 of the Settlement, PPL Electric agreed to give due consideration to the Joint Petitioners' written Comments. However, the Company retained the ultimate discretion to accept or reject the Joint Petitioners' feedback in its Pilot Implementation Plan. If any changes were made to the Pilot Implementation Plan based on the Joint Petitioners' feedback, PPL Electric would file a revised Pilot Implementation Plan at this docket within 20 days after the deadline for the Joint Petitioners' Comments.

In compliance with Paragraph 61 of the Settlement, PPL Electric reviewed and gave due consideration to the Joint Petitioners' Comments. Sunrun, who was not a Joint Petitioner, also filed Comments on the Pilot Implementation Plan. Although not obligated to consider Sunrun's Comments under the Settlement, PPL Electric nevertheless reviewed and gave due consideration to those Comments as well.

PPL Electric appreciates the other parties' feedback on the Pilot Implementation Plan. As seen in the revised Pilot Implementation Plan, and as explained further in this Attachment D, the Company incorporated some of the recommendations proposed by the parties. As a result, PPL Electric determined that it needed to file a revised Pilot Implementation Plan. In the following sections, PPL Electric summarizes and responds to certain of the parties' Comments.

I. OTHER PARTIES' COMMENTS

A. SEF'S COMMENTS

SEF contends in its Comments that PPL Electric "misrepresents the objective of the DER Management Pilot Program," believing that the purpose is to determine the cost and benefits to ratepayers, not PPL Electric. (SEF Comments, pp. 1-2.)

The Company disagrees with SEF's characterization. The pilot program's objectives are clearly outlined in Paragraph 54 of the Settlement, which states that the pilot program will "test and evaluate: (1) the costs and benefits to distribution system operation and design of *monitoring* DERs through devices connected to inverters as compared to maintaining distribution system status visibility through other means (e.g., automated meter reading equipment, ADMS systems, modeling); and (2) the costs and benefits to distribution system operation of *active management* of DERs as compared to the benefits available through the use of inverter autonomous grid support functions." (Settlement ¶ 54.) Nothing in the Pilot Implementation Plan alters those fundamental objectives. Moreover, costs and expenses incurred by PPL Electric are sought for recovery from the Company's ratepayers, and benefits to PPL Electric's electric distribution service are experienced by its ratepayers, who ultimately receive that service. Therefore, PPL Electric views SEF's characterization as a distinction without a difference.

In addition, SEF argues that the pilot should be delayed "until PPL Electric approves more inverters representing a more significant market share." (SEF Comments, p. 3.) SEF states that "[a]s of the recent conference call among the parties in this proceeding, PPL Electric has yet to solve the technical issues in communicating with Enphase inverters." (SEF Comments, p. 2.) As for SolarEdge, according to SEF, "the Solar Edge inverters approved by PPL Electric are incomplete," as the Company "only approved the H-US series of inverters designed for residential systems and the KUS inverters designed for 3-phase systems." (SEF Comments, p. 2.) SEF states that "[f]or residential customers alone, the approval does not include the H-RW, M-RW, and K-RW series inverters." (SEF Comments, p. 2.) SEF raises concerns about the inverters' approved for use in the Company's service territory and the potential impact on solar developments. (SEF Comments, pp. 2-3.)

PPL Electric has resolved the concerns regarding the IEEE 2030.5 inverters, such as the microinverters used by Enphase. With the agreement of the other parties, until the IEEE 2030.5-compatiable DER Management device is available, PPL Electric will permit DERs using Company-tested and validated IEEE 2030.5 inverters to interconnect and not be subject to the pilot program. Subsequently, once the IEEE 2030.5-compatible DER Management device becomes available, any new DER interconnection applications that will use an IEEE 2030.5 inverter would be included in the pilot program. This practice is consistent with Paragraph 56 of the Settlement, which states that "the Company shall not deny or delay the permission to connect and operate a DER due to unavailability of DER management devices" and that "[a]ny DER not equipped with a DER management device for this reason shall not be part of the pilot program." (Settlement ¶ 56.) Nevertheless, effective January 1, 2021, the Settlement requires new DERs interconnecting with the Company's distribution system to have smart inverters installed that meet: (1) UL 1741 SA; and (2) the Company's testing for the communications requirements under IEEE 1547-2018. (Settlement ¶ 48.) Therefore, PPL Electric must still test those inverters and validate that they meet those requirements before they can be installed in the Company's service territory.

SEF's concerns about the inverter approvals have either been addressed or lack merit. PPL Electric completed the testing and validation of Enphase's IEEE 2030.5 inverters on February 25, 2021. Thus, interconnection applications using those inverters can now be submitted on PPL Electric's web portal. As a result, SEF's concerns about the testing of Enphase's IEEE 2030.5 inverters are moot. Moreover, PPL Electric confirmed with SolarEdge that the Company tested and validated all of the inverter models currently offered by SolarEdge. The inverter models listed by SEF in its Comments are not SolarEdge models. Consequently, SEF's allegations about the testing and validation of SolarEdge's inverters lack merit.

SEF also raised concerns about the Remote On/Off function regarding solar plus storage installations. (SEF Comments, p. 3.) SEF believes that modifications to "the use cases for system restoration and DER operation in emergency conditions and in active work zones" should "be reviewed with the parties in this proceeding prior to implementation." (SEF Comments, p. 3.) SEF continues to believe that under the DER Management Plan, "PPL Electric could modify its approach to shut-down inverters appropriately disconnected from the distribution system," which "could endanger the life of ratepayers that utilize energy storage systems to provide uninterrupted service in the event of the failure of PPL Electric's distribution system." (SEF Comments, p. 3.) Although "SEF fully understands PPL Electric's concern for the safety of its workers," SEF asserts that "these workers can still be provided safe access to the distribution circuits without unnecessarily endangering the lives of ratepayers who may be using solar plus storage to power durable medical equipment." (SEF Comments, p. 3.)

To be clear, PPL Electric will adhere to Paragraph 59 of the Settlement, which states that the Company "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 a power outage." (Settlement ¶ 59.) Therefore, SEF's concern that PPL Electric may "shut-down inverters appropriately disconnected from the distribution system" is without merit. Remote On/Off will only be used for systems that "have not safely isolated or 'islanded' from the distribution system" and only in the circumstances set forth in Paragraph 59 of the Settlement. Nonetheless, PPL Electric has added language to the Pilot Implementation Plan's eighth use case to make this well-established point clearer. (*See* Pilot Implementation Plan, Attachment C, pp. 6-7.)

B. OCA'S COMMENTS

In its Comments, the OCA asserted that "[m]itigation or deferral of DER-related system upgrades can be achieved through numerous smart inverter related use cases that require various technological capabilities. Therefore, it is critical that the Company collect sufficient information to further inform these possibilities and potential solutions." (OCA Comments, p. 3.)

PPL Electric agrees and has designed its use cases not only to "further inform these possibilities and potential solutions" but potentially achieve system upgrade deferrals during the pilot program.

The OCA also commented on the data collection of energy storage systems, stating that "it is unclear as to whether, or what, energy storage related data the Company will collect through the Pilot Program." (OCA Comments, p. 3.) The OCA claims that "it is unclear whether the Company will be able to capture the existence of energy storage systems on PPL's system and separately evaluate the characteristics of these devices." (OCA Comments, p. 3.) Further, the OCA notes that "energy storage charging tariffs have been proposed in different districts throughout the country." (OCA Comments, pp. 3-4.) "While it is unclear whether PPL has grid connected storage or whether the Commission would consider a charging tariff reasonable at this time," the OCA believes that "collecting data on energy storage systems for the purpose of understanding cost causation is reasonable." (OCA Comments, p. 4.) Therefore, the OCA recommends that PPL "collect energy storage related data and specify how it will collect and share this information within the Pilot Program" and that, "[a]t a minimum, PPL should track and provide energy storage data as a separate load profile." (p. 4.)

PPL Electric will collect the same data from all DERs that are participating in the pilot program. Energy storage data will not be treated any differently. Therefore, for solar plus storage DERs, PPL Electric will collect the same data that the Company collects from any other DER participating in the pilot program. As for the OCA's Comments about charging tariffs and developing a separate load profile for storage, PPL Electric views these issues as outside the scope of the pilot program. As stated previously, PPL Electric is committed to test and evaluate: (1) the costs and benefits to distribution system operation and design of *monitoring* DERs through devices connected to inverters as compared to maintaining distribution system status visibility through other means (e.g., automated meter reading equipment, ADMS systems, modeling); and (2) the costs and benefits to distribution system operation of *active management* of DERs as compared to the benefits available through the use of inverter autonomous grid support functions. (Settlement ¶ 54.) However, in its annual reports, PPL Electric will be indicating the type of DER installation for each of the participating systems (e.g., solar plus storage). Thus, the OCA will be able to analyze data about solar plus storage systems participating in the pilot program.

Further, the OCA "strongly supports the evaluation of" the active network management ("ANM") use case and "appreciates PPL clearly articulating the use [case] in the Pilot" because it can "be an exceptionally cost-effective approach to increasing hosting capacity and deferring system upgrades related to DERs." (OCA Comments, pp. 4-5.) The OCA recommends that PPL Electric "consider tracking cost causative characteristics of DER export, which will provide interested stakeholders information concerning the qualities of DERs that can cause costs to be incurred by the Company, that may otherwise be avoided through the use of PPL's Distributed Energy Resource Management System (DERMS)." (OCA Comments, p. 5.)

PPL Electric will be reporting the distribution system upgrades that were avoided with DER monitoring and remote active management. Although not intended for evaluation of ANM cases, PPL Electric believes that this reporting will provide a good foundation for the stakeholders to conduct such an evaluation.

The OCA also argues that the "cost-effectiveness of PPL's DER Management Device could be highly dependent on the size of DER that the Company monitors and controls." (OCA Comments, p. 6.) As a result, the OCA recommends that "PPL, to the extent possible, attempt to collect data and conduct analysis to investigate this issue." (OCA Comments, p. 6.)

PPL Electric will collect and report on the nameplate capacities of the DERs participating in the pilot program. In its annual reports, PPL Electric will provide the nameplate capacity of each participating DER. This will enable the stakeholders, including the OCA, to analyze the data based on specific nameplate capacities of the DERs. However, PPL Electric does not believe that a specific use case needs to be developed to analyze the impact of the DER's size on the cost-effectiveness of the DER Management device. The stakeholders will be able to disaggregate and analyze the annual reports' data by system size, thereby enabling them to perform their own evaluation. Nevertheless, PPL Electric's planned use cases are subject to change, and the Company may ultimately analyze the impact of the DER's size on cost-effectiveness, either as a separate use case or within the currently planned use cases.

C. NRDC'S COMMENTS

In NRDC's Comments, NRDC raises a series of concerns about inverter testing and compatibility issues, namely SolarEdge's inverters and the IEEE 2030.5 inverters, such as the microinverters manufactured by Enphase. (NRDC Comments, pp. 2-6.) NRDC agrees with PPL Electric's plan to address the incompatibility of IEEE 2030.5 inverters with the Company's DER Management device, under which: (1) until the IEEE 2030.5-compatiable DER Management device is available, PPL Electric will permit DERs using Company-tested and validated IEEE 2030.5 inverters to interconnect and not be subject to the pilot program; and (2) once the IEEE 2030.5-compatible DER Management device becomes available, any new DER interconnection applications that will use an IEEE 2030.5 inverter would be included in the pilot program. (NRDC

Comments, p. 5.) NRDC states, however, that "the Company should clarify the reasons for the incompatibility between a smart inverter that appears to clearly meet the interim standards and the ConnectDER device, and explain what actions it is taking to ensure that similar issues do not arise with other smart inverters that meet the interim standards." (NRDC Comments, p. 5.) NRDC also suggests providing more detail on whether the delays with the Enphase inverters is manufacturer-specific or a broader issue. (NRDC Comments, p. 5.) Furthermore, NRDC recommends that PPL "undertake efforts to ensure that other inverter manufacturers are aware of the issue of ConnectDER compatibility with IEEE 2030.5 and the temporary exemption to install affected inverters outside the pilot program." (NRDC Comments, pp. 5-6.)

As noted by NRDC, the concerns raised specifically to SolarEdge are moot because the list of approved smart inverters now includes SolarEdge's inverters. (NRDC Comments, p. 3.) Moreover, as explained in Section II.A., *supra*, PPL Electric completed testing and validating Enphase's IEEE 2030.5 inverters on February 25, 2021, and interconnection applications using those inverters can now be submitted. Therefore, the inverter testing issues raised by NRDC have been addressed.

Regarding the IEEE 2030.5 inverters' incompatibility with PPL Electric's DER Management device, PPL Electric clarifies that the incompatibility issue is only limited to inverters that use IEEE 2030.5 as the sole communication protocol. Per IEEE 1547-2018, inverters should be able to support one of the three communication protocols: DNP 3, SunSpec Modbus, or IEEE 2030.5, as specified by the electric distribution company. Before filing the DER Management Petition, PPL Electric surveyed and researched the inverter industry and determined that the majority of the inverter manufacturers use SunSpec Modbus and DNP 3. Thus, PPL Electric's current DER Management device was designed, tested, and implemented to support these two protocols. IEEE 2030.5 is the newest of the three communications protocols, and PPL Electric is actively working on a DER Management device solution that will resolve the incompatibility issue. Although PPL Electric believes that many of the issues encountered with testing and validating Enphase's IEEE 2030.5 inverters were manufacturer-specific, the incompatibility with the current DER Management device applies to all IEEE 2030.5 inverters. As such, PPL Electric will update its solar inverter and other PPL Electric webpages to help make manufacturers, solar installers, customers, and other stakeholders aware of the incompatibility issue and how customers using tested and validated IEEE 2030.5 inverters will not be a part of the pilot program until PPL Electric has a compatible DER Management device available and ready to be used.

Next, NRDC states that PPL Electric should limit the use of "bespoke inverter settings" in the Control Groups' DER installations. (NRDC Comments, pp. 7-8.) According to NRDC, "the spirit of the pilot would be better served by using utility default inverter settings in as widespread a fashion as practicable." (NRDC Comments, p. 7.) "While it may be the case that locational and other factors may favor departing from default settings in particular circumstances (e.g., larger DER systems)," NRDC believes that "even then the establishment of default settings will provide valuable lessons about the extent of any limitations with a default setting-centered approach." (NRDC Comments, p. 8.)

PPL Electric generally disagrees with NRDC's suggestion. PPL Electric already will be tracking and reporting the initial settings of each DER participating in the pilot. Moreover, PPL Electric developed its Volt/VAR settings in a manner consistent with IEEE standards, i.e., maintaining power factor no lower than +/- 90%. Leveraging Volt/VAR curves which are calculated based on the DER's specific location and size provides the required granularity for distribution system stability. Due to the varied nature of PPL Electric's distribution system, which goes from very urban, short distribution feeders with a high short circuit duty to very rural, long, distribution feeders with a low short circuit duty, the use of a default curve would result in some DERs absorbing or injecting VARs unnecessarily. DERs close to a substation should expect to see a voltage on the higher side of the acceptable range due to its proximity to the source just as DERs that are far from the substation should expect to see a voltage lower in the acceptable range. Use of strict, uniform default settings would necessitate more active management for DERs not in one of the Control Groups and would potentially lead to voltage issues on feeders within the control groups.

Also, PPL Electric has a statutory duty to all of its customers to provide safe, reliable, and adequate electric distribution service. *See* 66 Pa. C.S. § 1501. PPL Electric will not turn a blind eye and allow a DER to interconnect with suboptimal default settings, which, as described previously, could negatively affect the Company's electric distribution service.

Regarding the annual reports, NRDC recommends that the annual reports include information on PPL Electric's review of use cases, specifically "narrative interim assessments," not just data, and that the Company clarify this point in its Pilot Implementation Plan. (NRDC Comments, pp. 8-9.) NRDC also recommends that the annual reports include: (1) all initial inverter settings, including data allowing for regional comparative analysis; (2) the customer's feeder line; and (3) an actual analysis of DER system size, not only the details of the DERs' nameplate capacities. (NRDC Comments, pp. 9-11.)

As stated on pages 16 and 19 of the revised Pilot Implementation Plan, PPL Electric's annual reports will provide findings and information of these use cases. Moreover, PPL Electric will include each participating DER's initial inverter settings and nameplate capacity. However, PPL Electric will not provide each DER's feeder line in a publicly-available annual report. In the

Company's experience, customers are very concerned about their privacy, especially when it comes to details about their electric usage, generation, and DER systems. If PPL Electric provides the feeder line for each participating DER along with all of the other information being presented in the annual reports, the Company cannot guarantee that the customer's identity will be shielded from public view.

Lastly, NRDC makes a series of recommendations about making program documents available to the public. Specifically, NRDC recommends that "all pilot documentation . . . be made available on a dedicated webpage accessible through the . . . Company's Renewable Energy webpage." (NRDC Comments, p. 11.) NRDC believes that the REMSI website was designed with installers in mind, so it may not be an easily navigable resource for some stakeholders. (NRDC Comments, pp. 12-13.) NRDC also appreciates the Company's willingness to put the default setting ranges from PPL Electric Exhibit SS-1R on its REMSI website. (NRDC Comments, p. 12.) Additionally, NRDC seeks clarification on where the "frequently asked questions" appears on PPL Electric's website. (NRDC Comments, p. 13.)

PPL Electric will be launching a new webpage specifically for DER Management, including the pilot program. This new webpage will go live in March or April 2021 and will serve as the main "hub" with easily located information or hyperlinks to pertinent information on DER Management, including, but not limited to, material pertaining to DER management as a whole, Volt/VAR and Ride-through setting guidelines, approved installation sketches, frequently asked questions, the Pilot Implementation Plan, and the approved inverter list. PPL Electric intends for this new webpage to address many, if not all, of NRDC's recommended changes to the Company's website.

D. SUNRUN'S COMMENTS

In its Comments, Sunrun raises issues concerning the Company's testing of inverters, particularly IEEE 2030.5 inverters, and recommends that either: (1) "interconnection should not be delayed for inverters that meet UL 1741 SA and IEEE 1547-2018 standards but are pending PPL testing; or (2) "Pilot Program implementation as a whole should be delayed until PPL demonstrates that its DER management device is compatible with a larger number of smart inverters, including smart inverters with IEEE 2030.5 communication protocols." (Sunrun Comments, pp. 2-4.)

Sunrun's recommendations are unnecessary. As explained previously, PPL Electric has finished testing and validating SolarEdge's inverters and Enphase's IEEE 2030.5 inverters. Therefore, many inverters have been tested and validated by PPL Electric and are now available to be used in the Company's service territory, including the inverter brands that are the most popular in PPL Electric's service territory. Moreover, after consulting with the other parties, including Sunrun, PPL Electric will allow DER installations using tested and validated IEEE 2030.5 inverters to be used in the Company's service territory. Since the Company currently does not have a DER Management device that is compatible with IEEE 2030.5 inverters, such installations will not be part of the pilot program until such a DER Management device is available. PPL Electric believes this is a reasonable approach that will enable the pilot program to continue, while providing the Company more time to develop a solution that will enable DERs using IEEE 2030.5 inverters to participate in the pilot program.

In addition, Sunrun supports revising the Pilot Implementation Plan to include clarifying language about PPL Electric's use of the Remote On/Off function. (Sunrun Comments, p. 4.) Sunrun also states that PPL Electric "should be able to differentiate DERs which have storage from those which do not, as to more effectively utilize remote on/off technology only when it should be used per the Settlement." (Sunrun Comments, p. 4.)

As stated previously and in the revised Pilot Implementation Plan, PPL Electric only will use the Remote On/Off function in compliance with Paragraph 59 of the Settlement. That is, the Company "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 a power outage." (Settlement ¶ 59.) Language to that effect has been added to the revised Pilot Implementation Plan. (*See* Pilot Implementation Plan, Attachment C, pp. 6-7.)