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PUBLIC SERVICE COMMISSION
District of Columbia

Your Energy. Your Voice.

RM40-2020-01, IN THE MATTER OF 15 DCMR CHAPTER 40 – DISTRICT OF COLUMBIA SMALL GENERATOR INTERCONNECTION RULES,

and

FORMAL CASE NO. 1050, IN THE MATTER OF THE INVESTIGATION OF IMPLEMENTATION OF INTERCONNECTION STANDARDS IN THE DISTRICT OF COLUMBIA

***Formal Case No. 1050* and *Rulemaking 40* Working Group Meeting Minutes November 18, 2021**

Meeting Commencement:

The RM40 Working Group (WG) meeting started at 1:04 pm and ended at 3:05 pm.

Issues Discussed:

The meeting begins with introductions, followed by a presentation on Level 2 Interconnection Procedures by DOEE. DOEE highlights the 10% solar carveout requirement from the CleanEnergy DC Act. The presentation notes deviations from the regulations in terms of business days for steps in the interconnection process. Data on areas of delay is mostly anecdotal, from DOEE's working with Solar-for-All to discussions with developers. Delays are seen in the queue position assignment, Approval to Install (ATI), Conditional ATI (including invoice), executed Interconnection Agreement, construction, and especially between receiving ATI and Authorization to Operate (ATO). DOEE also notes the construction schedule is frequently missing when receiving ATI. DOEE would like to see more oversight and enforcement by the Commission and a change in regulations for improved cost transparency and timelines. DOEE does not want an increase in the timelines for CREF interconnections.

Staff asks which level the 20-business day ATO request is for. DOEE answers preferably for Levels 2, 3, and 4. Staff asks for regulations for the Ombudsperson. DOEE agrees to provide the relevant orders. Staff asks about Conditional ATO not being in the regulation. DOEE does not want Conditional ATO to continue and would prefer the EDC to conform to the regulations. NCS notes the chaotic graphic of the timeline speaks to the nature of the current interconnection process. DC has reached 2.5% of the solar carveout now, with the goal to reach 10% by 2040. NCS asks how the process and smart grid investments impacts the deployment of additional solar given some developers are not expanding where the costs of system upgrades are required. DOEE states that it is still in Stage 1, low DER adoption, and there are several steps needed to be taken to reach Stage 2 of moderate to high DER adoption. Staff notes the four pilot programs structured to promote DER in the District in the GD2020 Governance Board discussions. NCS believes a steeper curve of solar deployment is needed to meet the legislative mandate. NCS echoes their experience of long delays between DCRA inspection and reaching final ATO.

Staff states the achievements of Solar-for-All and CREF deployment in terms of achieving equity while deploying DER has gained national recognition. The NEM facilities' size has been increased from 100%, currently at 140%, with the plan to continue towards 200% size based off annual customer usage. Staff notes NEM is constrained by legislation to 1 MW, whereas we note that Maryland has a limit of 2 MW. While we need to follow the legislative mandate, we have tried to maximize the additional NEM size through increased limit from 100% of annual consumption to 200% annual consumption in 5 years. Staff's Consultant asks about the provision for a scoping study to determine the need for a system upgrade, noting it may be an additional source of delay. DOEE notes that it is optional and was not a source of delay in their experience. DCCA comments on the success of Solar-for-All, but notes there are some problems, which need to be acknowledged. A lot was accomplished in Phase 1, and there are new challenges in scaling phase 2. DOEE notes the delays in the chart are being experienced by the Solar-for-All program and that has implications for customers. Staff notes those issues are being discussed in other jurisdictions such as New Jersey. Staff also checked with a few states and NRRI/NREL to see whether other states can or have provided total time spent on community solar interconnection, but no information was provided through such a survey or inquiry with some selected states and NRRI etc. Such information is not readily available from other states.

Staff asks Pepco about the previous meeting's presentation by CHESSA, regarding the delays of issuance of ATO. Pepco could not verify which projects were included in the case study and is unable to respond without the data from 20 case studies. CleanGrid Advisors states its position about the customer data used in the case study. The members were concerned about confronting Pepco on a case-specific basis, which could impact the relationship between the developers and Pepco. The process needs to be reviewed holistically, and not through arguing the experience of the 20 case studies. Pepco attempted to match the system sizes but was unable to do so. Staff is interested in the distribution of the cases if they are typical interconnections. Without that customer specific data, there are still trends that can be identified by the overall data reported by Pepco. Pepco notes the importance of the Solar for All program and its commitment to the program. Given the importance, Pepco, DOEE, DCSEU and some developers meet weekly to discuss the Solar For All Projects. Pepco discusses providing Conditional ATO to Solar-for-All projects due to the funding deadlines of the Solar-for-All program and the fact that projects can be added or changed close to the funding deadlines and late in the interconnection process. Pepco is taking steps to help make the Solar-for-All program successful. Pepco discusses the fact that in the meetings DOEE, DC SEU and the developers are all aware of and in agreement with the steps taken to make Solar For All successful, including such steps as providing a Conditional ATO when necessary. Solar For All is a partnership among Pepco, DOEE, DCSEU and the developers, and they work together to make it a success. DOEE's presentation highlighted the more general basis of delays in interconnection in contrast to the 20 case studies previously presented by CHESSA. DOEE believes the group can get to a place where Conditional ATO is not needed.

Pepco presents next. Pepco states the CREF interconnection process is an interactive process between Pepco and the developer. Interaction between Pepco and developers/customer starts from initial application through to ATO. Pepco has set up weekly and biweekly check ins with developers to address any and all project concerns. With an understanding that there is an influx of DER in the District, Pepco has taken the proactive steps to increase resources (FTE and Contractors) and move to automating the application process by launching the Connect the Grid tool (CTG). This has improved the CREF application and interconnection process significantly. Pepco is still pushing to improve the process, addressing the short-term gaps while achieving an overall better process using developer/customer feedback as guidance. Pepco is also doing internal benchmarking in other jurisdictions—MD, DE and NJ—to compare processes and leveraging best practices in the District as well as looking for opportunities to benchmark against other utilities nationally regarding their process and procedures. Staff asks about the increased resources and whether there are additional staff members. Pepco responds that there are several additional resources: technology improvements, additional engineering staff to addressing NEM and CREF projects, and additional program managers. NCS asks about the New Business team dedicated to DER interconnection and whether is it already established and working and whether developers interact with this team. Pepco's presenter is the manager of the team and states there are engineers on board. The team will add project managers in the future.

Pepco's presentation details the key actions of both the customer and the utility. Pepco states it is Level 2, and that it can show a side-by-side comparison of Level 2 and CREF projects in a future presentation. DOEE notes there are differences between projects that do and do not require additional construction. Staff notes that some details are in Staff DR 13-8 but that additional information is needed. Staff's Consultant asks whether the complexities of scheduling the addition of telemetry goes beyond the current process and whether it needs its own process. Pepco states it is within the current process scheduling, but that it does get a separate cost letter. Telemetry and construction are done side-by-side. Staff's Consultant asks about the construction schedule being included with the estimate and how it will be communicated to the customer. The construction schedule is provided shortly after the cost estimate is furnished. Even after the construction timeline is provided to the customer, customers have revised project scope, and this will cause further delays. Customers providing an incorrect TPF will hold up projects moving through construction and other delays may occur when developer/customer wants to use spare conduit that belongs to a building for new CREF service, and Pepco requires a load limiting letter to be signed by the premise owner and returned to the utility.[1] Complexities can arise if an outage is required, such as when the interconnection customer and the other customer(s) are served by a shared line, they must be notified of the required outage but the non-interconnection customer on that service cannot take the outage within the timeline needed by the CREF project.

[1] This letter outlines to the premise owner the potential liabilities associated with allowing the CREFs to use their spare duct should a cable fault occur.

Staff's Consultant asks about installing new service being unique to CREFs: is that typical for NEM installs? Pepco states that it's not unique to CREFs; sometimes NEM installs require reconductoring/service upgrade, and that process is essentially the same as establishing new service. If it is a CREF, they will try to make it work as a VCREF, but if that is infeasible then new service would be required. New service requires a new meter, but with VCREF there are two Pepco meters. DOEE notes that they have a different interpretation of the regulations about the meter ownership in the case of CREFs. Pepco explained that the meter for CREFs is the same as those used to meter SRECs.

Pepco continues its presentation on telemetry. NCS asks if Pepco could present further on the loss of service and islanding impacts showed in the presentation. Pepco cited IEEE-1547 -2018 Clause 9, which calls for instantaneous monitoring of power conditions at the point of common coupling (PCC), and explained this requirement is one key driver of the need for telemetry. Staff's Consultant asks about the customer's inverter: is it located at the PCC? Pepco only showed a high-level diagram, and the specific example is not that detailed. In a typical connection, the telemetry does allow them to interact with the customer equipment provided the site employs DNP3 protocol to communicate with the utility equipment. While the inverter may measure power generated at the PCC, an external meter would still be required to measure the net flow of power.

Staff asks whether there are any active advanced inverters and where they have been tested? Pepco is not doing anything in the field yet but are engaged with EPRI on modeling the smart inverter settings. Pepco is working in Maryland on testing smart inverter settings and control as well. The telemetry process takes place in parallel with the interconnection process and are addressed in the Pepco Technical Interconnection Requirements (TIR). There were challenges to initial telemetry requirements: technical, invoicing and material adequacy, and Pepco has revised its TIR to be more flexible regarding telemetry, including being one of the few utilities allowing any export on networks (Con Edison is another example). Pepco is also looking at potentially implementing a pilot of third-party telemetry.

Meeting Adjournment and Next Steps:

Staff notes that an issue that needs to be discussed is reporting requirements from its annual and quarterly reports. Stakeholders have requested additional items for reporting. Staff will compile a list of current reporting items prior to the next meeting. Stakeholders will be able to suggest additional items after the list is circulated. And, the Working Group will discuss this in the next meeting. All the stakeholders agreed to such a suggestion. The next meeting is scheduled for December 16 at 10am.

Formal Case No. 1050 and RM40 Working Group
1325 G Street, N.W., 8th Floor
Washington, D.C. 20005

Virtual Meeting – November 18, 2021
1 - 3 pm (2 Hours)

AGENDA

I. Introduction

- **A. Participant Identification**

II. Discussion

- **A. DOEE Presentation on Interconnection Issues (15 minutes)**
- **B. Pepco Presentation**
- **C. Overall Timelines and Reporting for Level 2 (Staff and Staff Consultant, 15 minutes)**
  - **Current Rules vs. Proposed Rules**
  - **Review of Level 2 Applications in 2020**
- **D. Modifications: Timelines and Procedures for Interconnection Facilities and System Upgrades (Section 4005.6)**
  - **Cost Matrix**
  - **Cost Letter Approach**
- **E. VCREF Definition and Requirements for Interconnection**
- **F. Requirements for Communications with EDC, including Telemetry and Associated Cost Burden (Section 4005.2)**
- **G. Proposed Revisions to Small Generator Capacity Limits by Feeder Capacity (Section 4005.2(a))**
- **H. Streamlining Assignment and Transfer of CREF Ownership**

III. General Q&A, Additional Issues

IV. Next Steps

- **A. Follow-up Items**
- **B. Objectives for next meeting**
- **C. Meeting minutes**
  - **Draft distributed by November 22, 2021**
  - **Comments due by November 29, 2021**

- **File minutes with Commission by December 1, 2021**

ADJOURNMENT

Formal Case No. 1050 **and** *Rulemaking 40*

RM40 Working Group

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LEVEL 2 INTERCONNECTION PROCEDURES

DCMR Title 15, Chapter 40

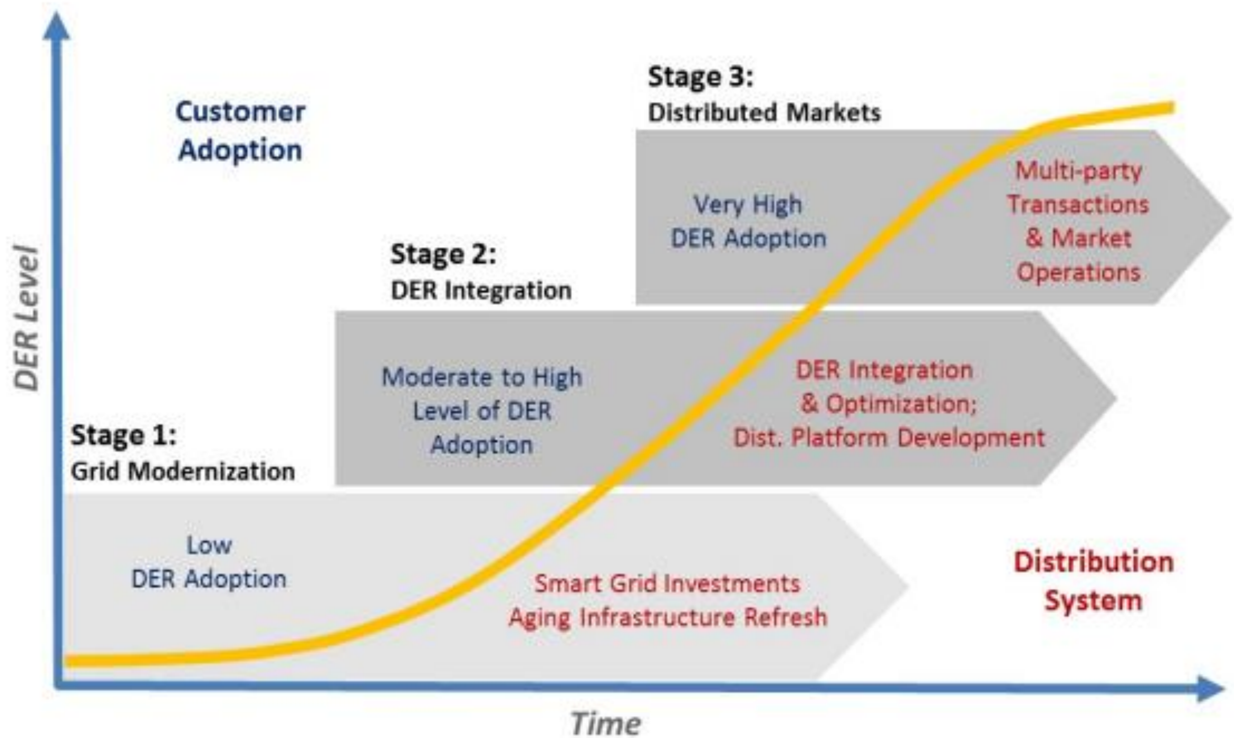
DEPARTMENT OF ENERGY AND ENVIRONMENT
ENERGY ADMINISTRATION

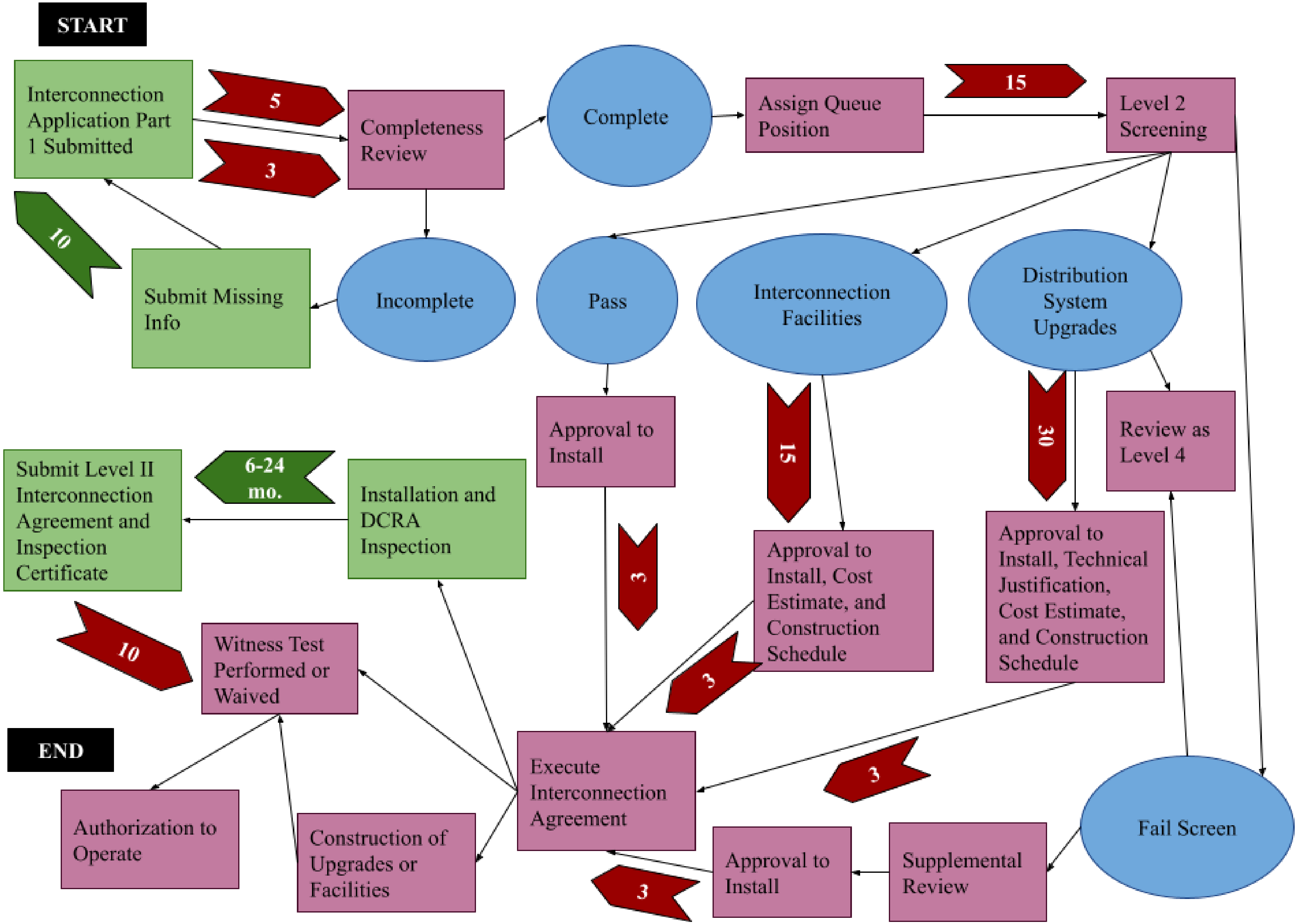
DEPARTMENT OF ENERGY & ENVIRONMENT

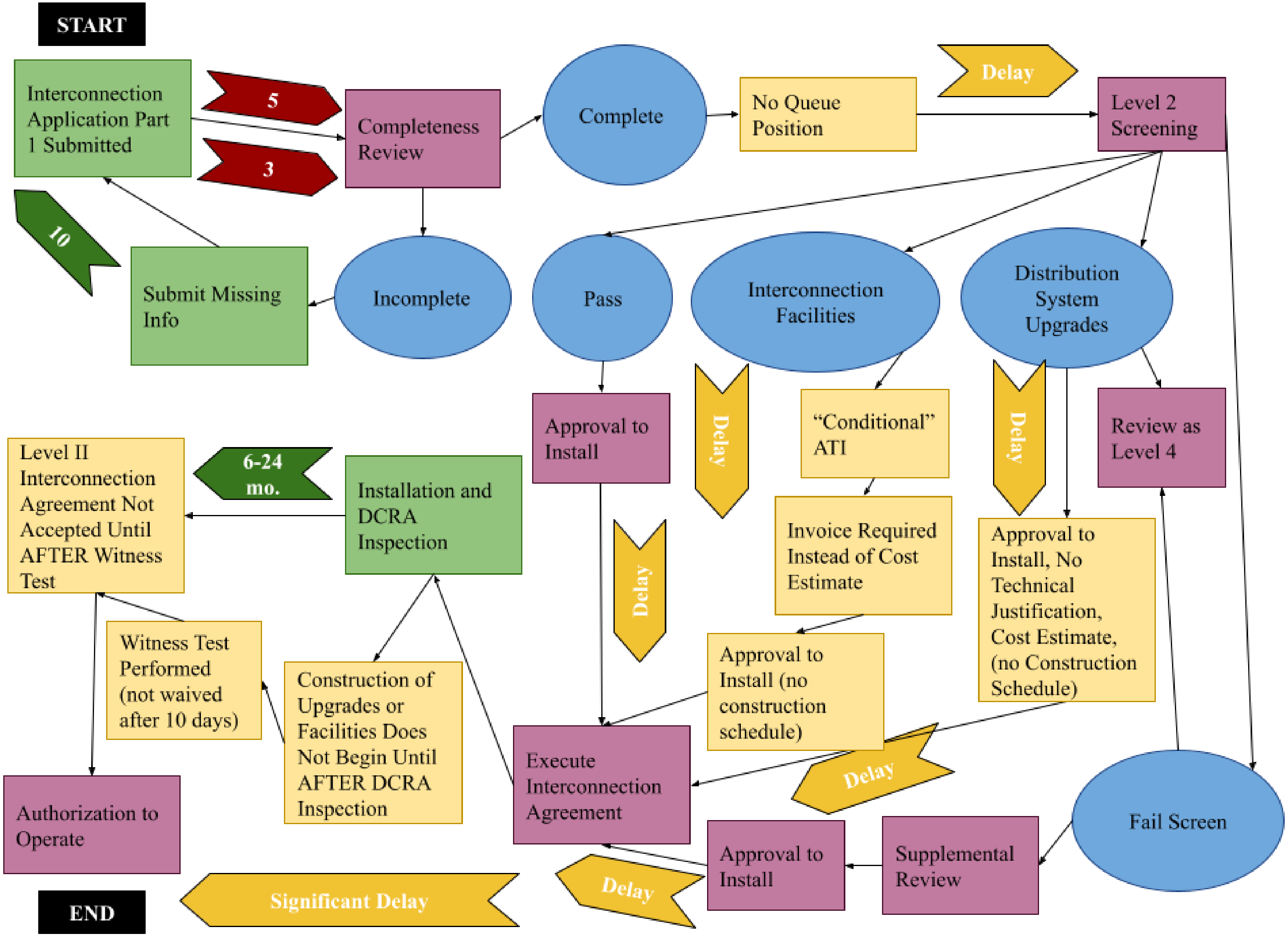
WE ARE WASHINGTON DC

GOVERNMENT OF THE DISTRICT OF COLUMBIA
MURIEL BOWSER, MAYOR

INTERCONNECTION AND GRID MODERNIZATION




START
Interconnection Application Part 1 Submitted
5
3
Completeness Review
Complete
Assign Queue Position
15
Level 2 Screening
10
Submit Missing Info
Incomplete
Pass
Interconnection Facilities
Distribution System Upgrades
Approval to Install
15
30
Review as Level 4
Submit Level II Interconnection Agreement and Inspection Certificate
6-24 mo.
Installation and DCRA Inspection
3
Approval to Install, Cost Estimate, and Construction Schedule
Approval to Install, Technical Justification, Cost Estimate, and Construction Schedule
10
Witness Test Performed or Waived
3
END
Execute Interconnection Agreement
3
Fail Screen
Authorization to Operate
Construction of Upgrades or Facilities
Approval to Install
Supplemental Review
3



START
Interconnection Application Part 1 Submitted
5
3
Completeness Review
Complete
No Queue Position
Delay
Level 2 Screening
10
Submit Missing Info
Incomplete
Pass
Interconnection Facilities
Distribution System Upgrades
Delay
"Conditional" ATI
Delay
Review as Level 4
Approval to Install
Invoice Required Instead of Cost Estimate
Approval to Install, No Technical Justification, Cost Estimate, (no Construction Schedule)
Level II Interconnection Agreement Not Accepted Until AFTER Witness Test
6-24 mo.
Installation and DCRA Inspection
Delay
Witness Test Performed (not waived after 10 days)
Construction of Upgrades or Facilities Does Not Begin Until AFTER DCRA Inspection
Approval to Install (no construction schedule)
Delay
Execute Interconnection Agreement
Fail Screen
Authorization to Operate
Approval to Install
Supplemental Review
Delay
END
Significant Delay

DOEE POSITIONS ON INTERCONNECTION IMPROVEMENTS

- More oversight and enforcement by the Commission is required (i.e. potential for role of the "ombudsperson")
- DOEE supports changes to the SGIR that improve the cost transparency and timeliness of interconnection (i.e. itemized cost letters, a clear ATO deadline of 20 business days)
- DOEE does not support the proposed changes under consideration that would increase timelines for CREF in a targeted manner or artificially reduce hosting capacity
- Technical Interconnection Requirements

RM40 Interconnection Working Group

November 18, 2021

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Agenda

1. The CREF Interconnection Process
2. Telemetry
3. The Process from Temporary Pending Final (TPF) to Authorization to Operate (ATO)

The CREF Interconnection Process

CREF Interconnection Is an Interactive Process

- CREF interconnection is a process that involves extensive interaction between the customer/developer and Pepco
- Pepco is constantly learning and improving the CREF interconnection process and has made progress in recent years
  - Launched Connect the Grid tool
  - Established dedicated project managers to walk projects through the process
  - Increased resources
- There is still room for improvement
  - Created a New Business team dedicated to DER interconnection in the District
  - Analyzing internal processes to identify gaps and opportunities to streamline the process
  - Continues to seek feedback from external stake holders, quarterly meetings
- Many actions and interactions are involved as a part of the process and sometimes the various steps are perceived as delays
  - Working to ensure awareness and understanding of the process, including opportunities to improve
- Actual delays in the process have varying points of origination

CREF INTERCONNECTION PROCESS

Key Actions

Customer Actions
Company Actions

APPLY	APPROVAL	DESIGN & CONSTRUCTION	INSTALL	INSPECT	CERT. OF COMPLETION	AUTHORIZE	OPERATE
▪ Customer submits application ▪ Company reviews application for completeness ▪ Company performs sizing validation ▪ Company issues completeness notification ▪ Company assigns Project Manager	▪ Company performs Technical Screening – Capacity Planning & Analytics – Distribution Engineering – System Protection – Company and Customer perform site visits ▪ Company creates preliminary design ▪ Company develops and issues distribution system upgrade (DSU) and interconnection facilities (IF) cost estimate ▪ Company issues Approval to Install ▪ Company issues telemetry cost letter if applicable	▪ Company provides final design ▪ Company issues final invoice ▪ Customer pays invoice ▪ Customer submits Temporary Pending Final (TPF) ▪ Company schedules Company construction ▪ Customer builds conduit and other infrastructure ▪ Company inspects customer-built conduit and other infrastructure ▪ Company constructs DSU/IF ▪ Company installs meter	▪ Customer installs interconnection point ▪ Company installs new service ▪ Customer installs system	▪ Customer has system inspected by DCRA ▪ Customer submits to Company Part 2 from application and inspection from DCRA	▪ Company reviews Part 2 Submission ▪ Company issues notification of complete Part 2 ▪ Company confirms minimum subscribers in CSP portal ▪ Company confirms DSU construction completed ▪ Company confirms New Service construction complete ▪ Company conducts Witness Testing, if applicable ▪ Company confirms new account	▪ Company confirms meter installed ▪ Company issues Authorization to Operate	▪ Customer energizes system

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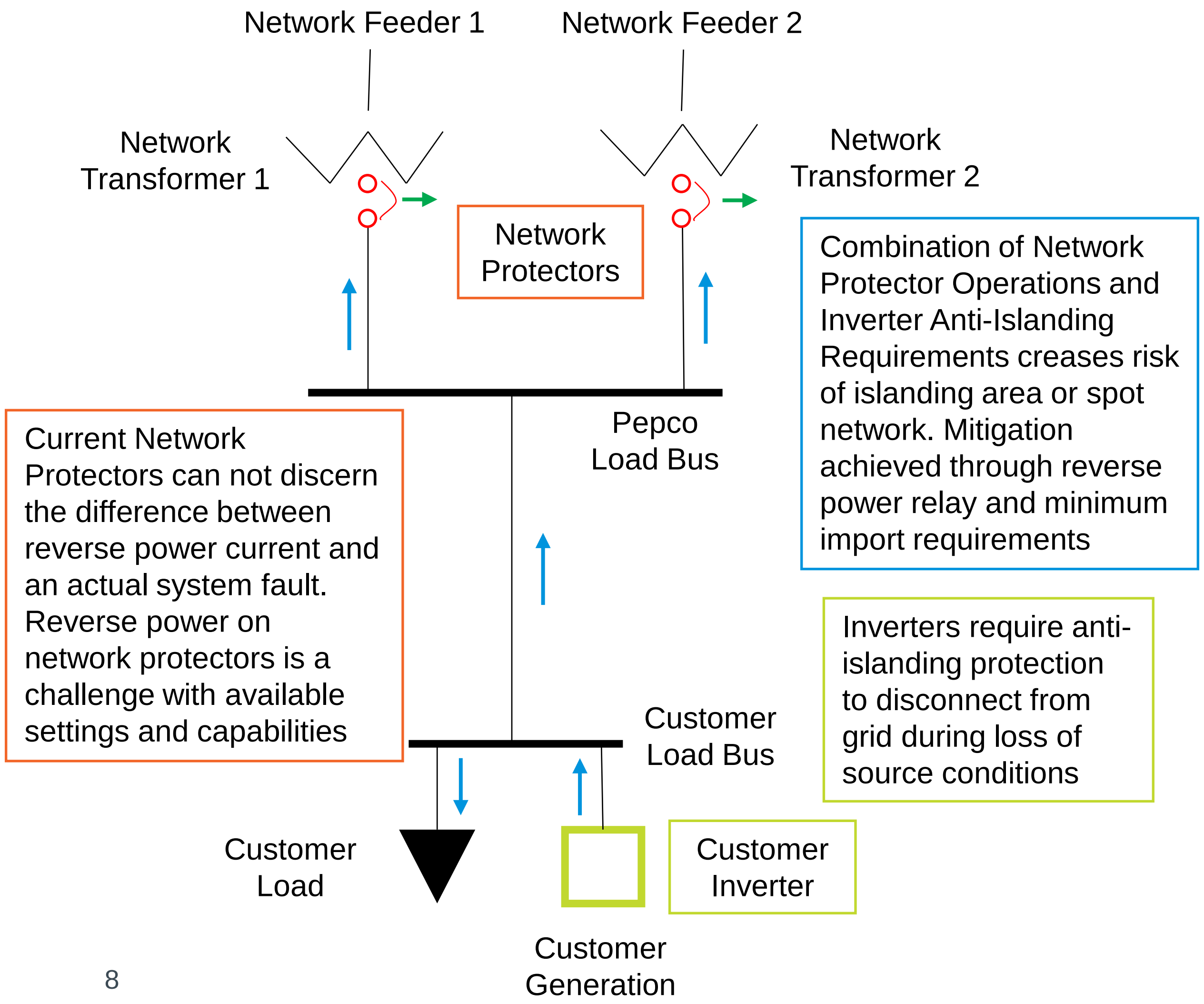
Telemetry

Spot and Area Low Voltage AC (LVAC) Network Telemetry Requirements

- Telemetry, monitoring and control is required for visibility into the operation of interconnections to prevent unintentional islanding from network protector operations
  - Spot LVAC Network Telemetry requirements for interconnections greater than 150 kW or where an interconnection will operate in conditions within 30% of Minimum Daytime Load (MDL)
  - Spot LVAC Network Minimum Import Limit: 20% of spot network minimum daytime load or 20kW (the greater of the two) is assigned to each project using a reverse power or directional current relay
  - Spot and Area LVAC Network monitoring and control requirements where aggregate DER capacity of spot or area is greater than 5% of peak load
- Ensures a robust and sustainable implementation of the operational DER interconnection for reliability of the spot and area LVAC networks
- Supports IEEE 1547-2018 Clause 9 requirements that DER shall not cause reverse power or cycling of network protectors and shall have instantaneous monitoring at the PCC
- Result of lessons learned in operating experience where telemetry would have supported Pepco troubleshooting and identification of unintended islanding and loss of service

LVAC Network Protector Operations with DER Interconnections



IEEE Std 1547-2018
IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces

Power flow during this transition shall be positive from the Area EPS to the load and the DER unless approved by and coordinated with the Area EPS operator.

DER on grid or spot networks shall have provisions to

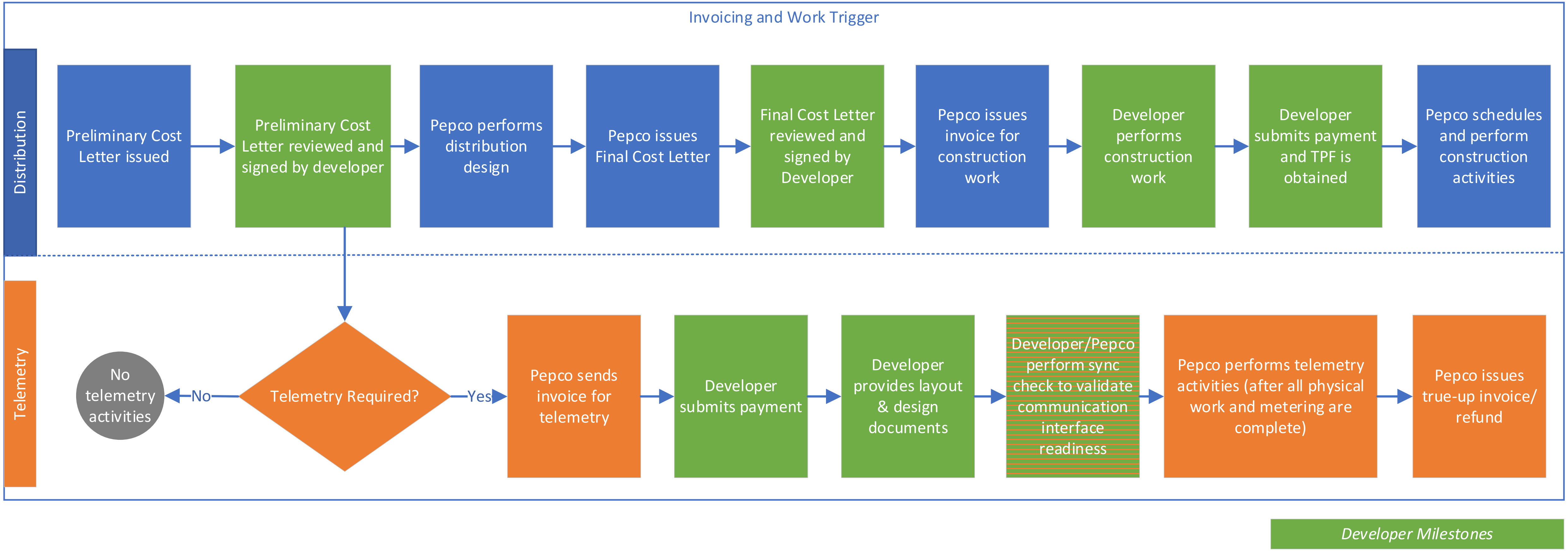
— Monitor instantaneous power flow at the PCC of the DER interconnected to the secondary grid or spot network for reverse power relaying, minimum import relaying, dynamically controlled inverter functions and similar applications to prevent reverse power flow through network protectors.
— Maintain a minimum import level at the PCC as determined by the Area EPS operator.
— Control DER operation or disconnect the DER from the Area EPS based on an autonomous setting at the PCC and/or a signal sent by the Area EPS operator.

DER on grid or spot networks shall not

— Cause any NP to exceed its loading or fault-interrupting capability.
— Cause any NP to separate dynamic sources.
— Cause any NP to connect two dynamic systems together.
— Cause any NP to operate more frequently than prior to DER operation.
— Prevent or delay the NP from opening for faults on the Area EPS.
— Delay or prevent NP closure.
— Energize any portion of an Area EPS when the Area EPS is de-energized.
— Require the NP settings to be adjusted except by consent of the Area EPS operator.
— Prevent reclosing of any network protectors installed on the network. This coordination shall be accomplished without requiring any changes to prevailing network protector *clearing time* practices of the Area EPS.

Citation: IEEE 1547-2018

The Telemetry Process



The 2019 PHI DER Technical Interconnection Requirements (TIR)

- New TIR introduced in 2019—telemetry standard revised to ensure system safety and reliability
- Increase in demand from Solar for All combined with cabinet revisions and inadequate forecasting, led to shortages of cabinets in 2019 (leading to delays)
- Cabinet delay has been rectified
  - All components tracked in the Pepco supply system, enabling forecasting and purchasing of materials in advance
  - Streamlining to a common telemetry standard, utilizing the same components for all outdoor installations (indoor may require additional engineering)

Comparisons of 2018 to 2020

- 2018 Prior to Technical Interconnection Requirements Introduced
  - Customer can use either reverse power relay or a combination of controller and inverter to monitor net power flow at POI and control generation to curtail or trip
  - Customer required to send an email every time generation tripped or was out of service. Maintained on an internet dashboard
  - 2018 event on 2 transformer spot LVAC network for a large customer service was interrupted during low load period after activating a large solar PV interconnection prompting investigation and corrective actions
- 2020 After Technical Interconnection Requirements Introduced
  - Pepco added protection relay with specified trip timing
  - Proactive measures to modulate power flows to meet limits remains at the customer’s discretion
  - Telemetry requirements were introduced to ensure timely and accurate information to Pepco required to troubleshoot grid reliability and power quality events
  - Other utilities similarly apply monitoring requirements by size and location

Initial Telemetry Challenges (& Pepco's Efforts to Address)

- **Formal introduction of requirements in 2019**
  - Growing pains internal & external from new requirement
  - Initial hurdles – technical challenges, invoicing process, material adequacy

- **Technical Challenges**
  - Not receiving necessary information from developers early enough (Pepco coordinates telemetry with developer earlier in process)
  - Internal coordination not streamlined (Pepco created dedicated Project Management team to own overall coordination)
  - Telemetry cabinet details not yet provided upfront externally (Pepco now provides cabinet details upfront)
  - Detailed communications requirements not yet included upfront in cost letters (Pepco now provides communication requirements in cost letters)

- **Technical Opportunities:**
  - Publishing a list of developer-side equipment that have successfully interfaced with Pepco's system

Initial Telemetry Challenges (& Pepco's Efforts to Address)

- <u>Invoicing Process Challenges</u>
  - Not yet streamlined leading to potential delays (Pepco has defined a controlled invoicing process)
  - Setting up invoicing mechanisms project-by-project took time (Pepco established programmatic financial structures to accelerate process)

- <u>Material Adequacy</u>
  - Updated cabinet standards & inadequate forecasting resulted in gap in supply (Pepco proactively ensures supply needs match solar expectations)
  - Surge in demand from Solar For All (SFA) added to supply gap (Pepco batch orders telemetry boxes ahead of SFA start)

Labor Costs for Telemetry

- 13 Telemetry Units were installed in 2020 & 2021
- Often estimated between $30,000 and $40,000
  - Costs are trued up after the project is closed in the system
  - Looking at ways to reduce the initial estimate
- Labor cost is dependent upon duration and iteration of work performed
  - Paying for integration into complex telecommunication system including appropriate level of cybersecurity
  - The labor is typically in the following areas
    - Capacity Planning – analyzes need
    - System Protection & Control – design, commissioning
    - Telecom Engineering – design, signal testing
    - Radio Shop – IP addresses, Sim Cards, programming, testing
    - System Operations – control center setup and testing
    - Witness Testing – on-site with Customer
    - Project Management
- Difference is reimbursed at the completion of work

Telemetry Cost Reductions

- Cabinet
  - Collaborated with multiple utilities in Exelon to get bulk savings on cabinets
  - Reduced unnecessary components leftover from non-DER use
  - Eliminated separate security device and obtained the same level of encryption within the radio

- Labor
  - Standardized components and carry in Pepco stock, eliminating time to order non-stock materials
  - Standardized cabinet setup, reducing time to install radio into cabinet (i.e., a repeatable process for technicians)

- Pepco continues to look for opportunities to reduce cost

Third-Party Telemetry

- Some Pepco-owned telemetry is directly connected through Pepco-owned networks to the SCADA system for the purpose of automated system restoration (ASR)
- Allows a continuous flow of real-time information that permits the Control Center to monitor and operate for safety and reliability of the system
- Currently not capable of relying on third-party telemetry because the data flows over public internet
  - Cannot guarantee the continuous flow of real-time information that allows the Control Center to monitor for safety and reliability of the system
  - Cybersecurity concerns regarding protecting real-time control systems
- Some Pepco-owned telemetry is located on parts of the system for monitoring purposes to ensure minimum import limits are maintained for system reliability
  - Looking into implementing a pilot third-party telemetry project that can safely and reliably operate on the distribution system

Process from Temporary Pending Final (TPF) to Authorization to Operate (ATO)

Process TPF to ATO

	DESIGN & CONSTRUCTION	INSTALL	INSPECT	CERT. OF COMPLETION	AUTHORIZE	OPERATE
Key Actions Customer Actions Company Actions	▪ Company provides final design ▪ Company issues final invoice ▪ Customer pays invoice ▪ Customer submits TPF ▪ Company schedules Company construction ▪ Customer builds conduit and other infrastructure ▪ Company inspects customer-built conduit and other infrastructure ▪ Company constructs DSU/IF ▪ Company installs meter	▪ Customer installs interconnection point ▪ Company installs new service ▪ Customer installs system	▪ Customer has system inspected by DCRA ▪ Customer submits Part 2 from application and inspection from DCRA to Company	▪ Company reviews Part 2 Submission ▪ Company issues notification of complete Part 2 ▪ Company confirms minimum subscribers in CSP portal ▪ Company confirms DSU construction completed ▪ Company confirms New Service construction complete ▪ Company conducts Witness Testing, if applicable ▪ Company confirms new account	▪ Company confirms meter installed ▪ Company issues Authorization to Operate	▪ Customer energizes system

Reverse Power Relay Witness Test

- What is it?
  - Due to the potential negative impact DER has on customers located on the network, witness testing by a utility representative is required once systems are installed to ensure full functionality
  - This process requires customers to provide personnel and test plans to demonstrate the simulation of site conditions, using specified testing equipment
  - The current witness testing criteria aligns Pepco practices for the acceptance of other customer protection schemes for load customer interconnections

- Why is it important?
  - To ensure safe and reliable operation for customers and Pepco's system

- When is it implemented?
  - Systems greater than 50 kw on a spot or low voltage (LV) network where solar back feed is must be limited
  - If the customer generation is larger than 1 MW, a Pepco representative is required for point-to-point testing of customer telemetry

- What are the drivers in the delays?
  - Limited resources given the volume of applications requiring witness testing
  - Complexity and engagement of a commissioning review necessitates additional time
  - Customer/developer misinterpretation of the requirements necessary for completion

- What have we done to mitigate delays?
  - Hired additional resources to assist with witness test process
  - Creating FAQs and posting to the website
  - Updating requirements documents to make clearer what is required upfront

Project–Specific Illustration

Telemetry cost letter sent

4/12/21

Customer submitted TPF

6/7/21

- Customer DSU Payment
- Job released to construction
- Billing account created

6/18/21

Company Construction completed

8/17/21

Customer received telemetry box

8/27/21

Customer notified Pepco it would be ready for testing on 9/19

9/17/21

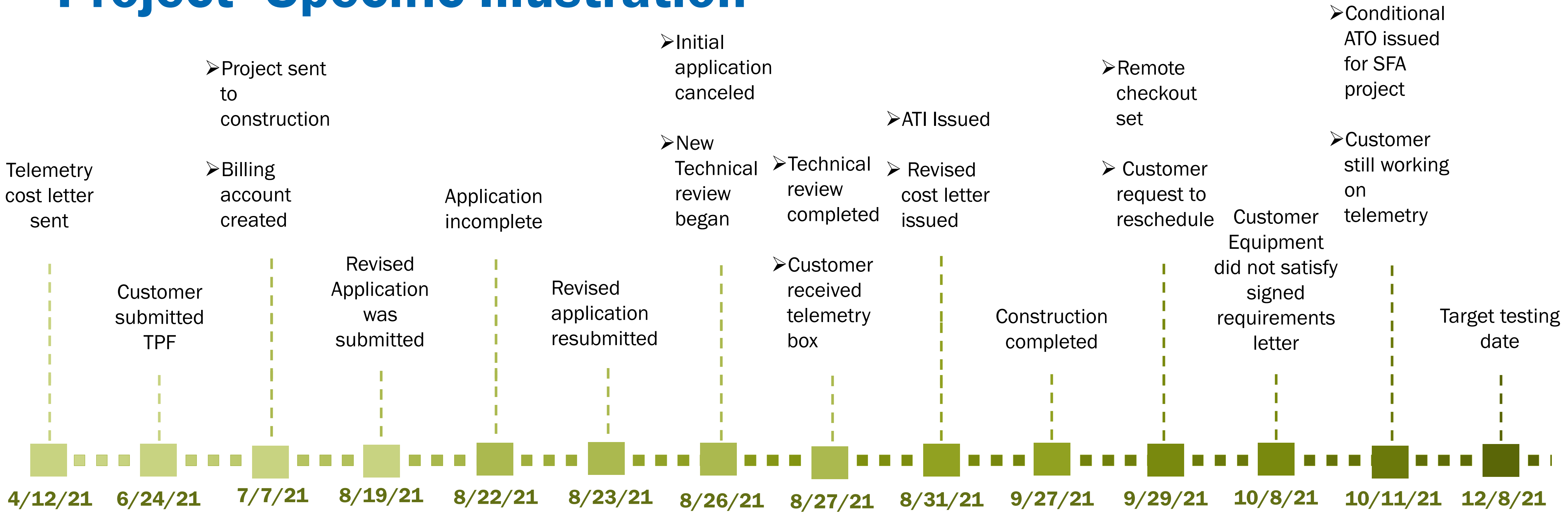
- Conditional ATO issued for SFA project
- Telemetry testing scheduled

9/21/21

Telemetry testing was completed

9/24/21

Project–Specific Illustration



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