Interconnection of Distributed Energy Resources

PEPCO HOLDINGS LLC

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Pepco Holdings.

An Exelon Company

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Background

Requests for distributed energy resource ("DER")[1] interconnections with Pepco Holdings' ("PHI" or "the Company") power delivery system have greatly increased in all jurisdictions in recent years, largely due to customer preferences, decreasing technology costs, and public policy objectives and incentives intended to incorporate greater amounts of renewable energy. The growth of DERs is a trend not only being observed within the Company's service territories but also within the service territories of electric utilities across the United States. The increasing quantity of DERs is creating a myriad of new challenges for electric utilities in planning, designing, constructing, and operating the power delivery system while maintaining reliable, safe, and affordable electric service. In addition, customers prefer ever-increasing amounts of control over the way they produce and consume energy. Meeting these evolving customer needs is a challenge for the entire industry that will only be met through increasing levels of transparency and collaboration between utilities, regulators, developers and other stakeholders.

[1] PHI broadly defines DERs to include the following six categories: 1) Backup generators, 2) NEM facilities, 3) Community Renewable Energy Facilities, 4) Qualifying Facilities, 5) Generators selling into the PJM wholesale market, 6) Behind-the-meter generators that partially offset the customer's load but are precluded from exporting electricity to the grid.

Procedural History

On April 30, 2014 Exelon Corporation ("Exelon") announced its intent to merge with Pepco Holdings, Inc., now Pepco Holdings LLC ("PHI" or "the Company"). On March 23, 2016 the merger of Exelon and PHI was completed on the terms and conditions that were agreed to by Exelon and PHI and approved by the relevant Federal and State regulatory bodies. Settlement agreements were also reached with external stakeholders such as the Delaware Sustainable Energy Utility ("DESEU") and The Alliance for Solar Choice ("TASC"). As a result of the completion of the merger, these conditions are now in effect and compliance with the requirements is the responsibility of Exelon and PHI.

This report discusses a subset of the merger commitments, those which pertain to the transparency, efficiency, and clarity of the PHI utilities[2] processes and treatment of DERs. A summary of the relevant merger commitments for each of the jurisdictions that are addressed by this report are presented as Figure 1. These commitments were not all required by each of the regulatory bodies governing PHI's utilities. However, since the policies and procedures that are discussed in this report apply to all three utilities (Potomac Electric Power Company, Delmarva Power & Light Company and Atlantic City Electric Company) and all four jurisdictions (Delaware, Maryland, New Jersey and the District of Columbia), one report is being prepared and filed with each of the regulatory bodies that oversee each of the PHI utilities.

[2] Where appropriate, reference to the PHI utilities means individually and collectively Potomac Electric Power Company (Pepco), Atlantic City Electric Company (Atlantic City Electric or ACE), and Delmarva Power & Light Company (Delmarva Power).

Introduction

This report was developed to address PHI's commitments related to improvement and enhanced facilitation of the interconnection of DERs with the power delivery system. Many of the sections discussed in this report pertain to specific terms and conditions of the merger between Exelon and PHI, while several of the improvements discussed herein were implemented as part of PHI's ongoing efforts to improve the interconnection process for its customers.

The information in this report should be considered a supplement to the webinar that PHI presented on May 3, 2016.[3] Following the filing of this report, PHI's intention is to initiate a separate dialogue in each of its jurisdictions in order to facilitate a more detailed stakeholder engagement process to review this report. Upon conclusion of this stakeholder engagement process, PHI will take into consideration all comments and recommendations made during the workgroup process and make any additional changes to its plans, policies, or criteria as appropriate.

Figure 1: Summary of Merger Commitments Pertaining to Distributed Energy Resources

Commission/Board Case or Settlement Agreement	Commitment/ Condition Number	Description of Commitment/Condition	Sections of this Report Addressing this Commitment/ Condition
MD 9361 Order 86990	Condition 15	Exelon is committed to maintaining PHI's existing interconnection and net metering programs.	Introduction
DC FC 1119 Order 18148	Commitment 122		
DC FC 1119 Order 18148	Commitment 119	PHI shall reflect in distribution system planning, actual and anticipated renewable generation penetration. Beginning not later than six months after closing of the merger, Distribution System Planning will include an analysis of the long term effects/benefits of the addition of behind-the-meter distributed generation attached to the distribution system within its service territory, including any impacts on reliability and efficiency. PHI will also work with PJM to evaluate any impacts that the growth in these resources may have on the stability of the distribution system in its service territory.	5.1 - 5.6; 6.1
TASC Amended Settlement Agreement	Commitment I (1)		
DE PSC DOCKET NO. 14-193 Amended Settlement Agreement	Commitment 101 (b)	Provide a report within ninety (90) days after merger closing that provides PHI's criteria limits for distributed energy resources that apply for connection to its distribution system (including but not limited to determining when a circuit is "closed"). This report shall include supporting studies and information that substantiate those limits. The report will describe and discuss how PHI utilities consider the generation profile of renewable energy relative to load, as well as discuss the approaches utilized in other jurisdictions that have addressed the issue of the impact of on-site renewable resources on the local grid and circuits. PHI utilities shall make themselves available for discussions with stakeholders on the report and demonstrate the modeling tools used by PHI utilities to perform their analysis to	2.1 - 2.6; 2.8; 5.7
DC FC 1119 Order 18148	Commitment 120 (b)(i)		
MD 9361 Order 86990	Condition 16 (B)(i)		
TASC Amended Settlement Agreement	Commitment I (2) (b) (i)		

[3] A copy of the presentation can be found at the following links, under "Presentations":
http://www.pepco.com/nemeducation/
http://www.delmarva.com/nemeducation/
http://www.atlanticcityelectric.com/nemeducation/

		accommodate additional distributed energy resources.	
DC FC 1119 Order 18148	Commitment 120 (b)(ii)	PHI is currently working with the United States Department of Energy in research designed to show how voltage regulation strategy, phase balancing, optimal capacitor placement, smart inverters and energy storage may impact hosting capacity. PHI shall share this research with upon completion of the project.	5.8
MD 9361 Order 86990	Condition 16 (B)(ii)		
TASC Amended Settlement Agreement	Commitment 1 (2) (b) (ii)		
DC FC 1119 Order 18148	Commitment 120 (b)(iii)	PHI has provided data to the National Renewable Energy Laboratory ("NREL") as part of its in-depth work to review utility interconnection criteria. A report is expected to be issued by the end of 2015. PHI shall evaluate its criteria with the criteria outlined in the NREL report to identify any improvements that may be made including treatment of behind-the-meter storage equipment. PHI and interested stakeholders shall consult NREL during this evaluation to gain any input from NREL that it is willing to provide including research on the inverters under controlled conditions. PHI and other interested stakeholders shall collaborate on the activities in this paragraph, including sharing information, discussing approaches, evaluating interconnection criteria, working with NREL, and providing an opportunity for interested stakeholders to comment on PHI's proposed recommendations on interconnection criteria prior to public release. PHI shall collaborate with interested stakeholders in good faith, but nothing in this agreement obligates PHI to accept or be bound by stakeholder recommendations. This collaborative effort shall be completed within one year following merger closing.	2.9; 4.4
MD 9361 Order 86990	Condition 16 (B)(iii)		
TASC Amended Settlement Agreement	Commitment 1 (2) (b) (iii)		
DC FC 1119 Order 18148	Commitment 120 (b)(iv)	PHI shall consider the hourly load shape and the hourly generation of interconnected small generators as a factor to determine the hosting capacity for any given location of a circuit. PHI's hosting capacity determinations shall adopt the minimum daytime load ("MDL") supplemental review screen established in FERC Order 792 as well as findings from the collaborative research referenced above that allow for interconnection of distributed generation systems without additional need for study or upgrade investments (e.g., "Fast Track Capacity") as long as aggregate installed nameplate capacity on the circuit, including the proposed system, would not exceed 100% of MDL on the circuit and the proposed system passes a voltage and power quality screen and a safety and reliability screen.	2.4 - 2.5; 2.7
MD 9361 Order 86990	Condition 16 (B)(iv)		
TASC Amended Settlement Agreement	Commitment 1 (2) (b) (iv)		
DE PSC DOCKET NO. 14-193 Amended Settlement Agreement	Commitment 101 (c)	PHI utilities shall maintain, within ninety (90) days after merger closing, an accepted equipment list for small generation projects where once an inverter is reviewed and found to be acceptable for use, it is deemed acceptable for future development. This list shall be easily accessible on the utility (and also DE PSC/SEU) websites and updated quarterly. PHI utilities shall review its policy for requiring the equipment list to be submitted for panels and switchgear with each application and post on its website any changes in its policy.	3.1 - 3.3
DC FC 1119 Order 18148	Commitment 121		

MD 9361 Order 86990	Condition 16 (C)		
TASC Amended Settlement Agreement	Commitment I (3)		
DE PSC DOCKET NO. 14-193 Amended Settlement Agreement	Commitment 101 (g)	In behind-the-meter applications where the battery never exports while in parallel with the grid and both the battery and the solar system share one inverter, no additional metering or monitoring equipment shall be required for a solar plus storage facility than would be required for a solar facility without storage technology. Additionally, the utilities, through a stakeholder/committee process, shall undertake appropriate further study of the issues regarding the coupling of solar and storage. As a result of such studies, stakeholders/committee may recommend changes to this protocol to the regulatory bodies. The utilities, in consultation with Board or Commission Staff and interested stakeholders, shall determine an appropriate target completion date for this review within one (1) year after merger closing.	4.1 - 4.4
DC FC 1119 Order 18148	Commitment 124		
MD 9361 Order 86990	Condition 16 (F)		
TASC Amended Settlement Agreement	Commitment I (6)		
DE PSC DOCKET NO. 14-193 Amended Settlement Agreement	Commitment 101 (f)	With respect to the interconnection process and metering and monitoring requirements, in behind-the-meter applications where the battery and the solar - system share one inverter, the maximum bandwidth of charge to discharge will be used as the capacity for determining the requirement of a Level 1 - Level 4 interconnection study. Where the system will be used for frequency regulation, there may be cases where it will result in a higher-level interconnection study based on the aggregate capacity-following frequency-regulation signals on the respective feeder and/or power transformer. Delmarva Power and the SEU, in conjunction with other stakeholders identified by Delmarva Power and the SEU, through a committee process, may elect to further study the issues regarding the coupling of solar and storage. As a result of such studies, the committee may recommend changes to this protocol to the Commission.	4.1 - 4.4
DE PSC DOCKET NO. 14-193 Amended Settlement Agreement	Commitment 101 (a)	Service territory maps of circuits, within ninety (90) days after merger closing, will be uploaded to the each utilities' website, to be updated at least quarterly, that have the following information included: the area where circuits are restricted, and to what size systems the restrictions apply. Three different maps will depict different restriction sizes. Each map will have the circuit areas on the particular map highlighted in a different color. One map will show circuits that are restricted to all sizes. One map will show circuits restricted to systems less than 50kW. One map will show circuits restricted to less than 250kW. The maps will also serve to identify areas that are approaching their operating limits and could become restricted to larger systems in future years. Although there are very limited secondary networks within the distribution systems, a secondary network circuit may become restricted if the active and pending generation would cause utility system operating violations. If this situation were to occur, a new map or method of depiction may be necessary and the appropriate information would be posted. The categories of size restrictions depicted on the circuit maps will be made available for informational purposes only, and will neither yield automatic cost allocation assumptions for resulting upgrades nor supplant the determination of the level of utility review afforded to the interconnection	2.6
MD 9361 Order 86990	Condition 16 (A)		
TASC Amended Settlement Agreement	Commitment I (2) (a)		
DC FC 1119 Order 18148	Commitment 120 (a)		

		request.	
DE PSC DOCKET NO. 14-193 Amended Settlement Agreement	Commitment 101 (d)	Delmarva Power will provide timely information and action to applicants seeking to interconnect behind-the-meter renewable energy projects to the Delmarva Power distribution system with respect to preliminary interconnection approval, replacement of existing meters with bi-directional meters, and permission to operate ("PTO").	1.4
MD 9361 Order 86990	Condition 16 (D) (iii)	PHI will revise and implement within ninety days after merger closing its interconnection agreement to applicants seeking to interconnect behind-the-meter small distributed generation resources to provide permission to operate ("PTO") to the interconnection customer, in the form of an email, within 20 business days from customer satisfying the following requirements based on jurisdiction: Maryland - applicant's receipt of acceptable final documents (signed Interconnection Agreement, certificate of completion and the inspection certificate) New Jersey - N.J.A.C. 14:8-5.4 (submission of documentation approval by appropriate construction official). Delaware - 26 Del. Admin. C.3001 §8.0 (submission of documentation approval by appropriate construction official). District of Columbia - 15 D.C.M.R. § 4004.4 (signed Interconnection Agreement, certificate of completion and the inspection certificate).	
TASC Amended Settlement Agreement	Commitment I (4) (a)		
TASC Amended Settlement Agreement	Commitment I (5) (a)		
DC FC 1119 Order 18148	Commitment 123 (a)		
MD 9361 Order 86990	Condition 16 (D) (i)	PHI shall revise and implement within ninety days after merger closing its interconnection agreement to applicants seeking to interconnect behind-the-meter small distributed generation resources to schedule interconnection construction to be complete within the timeline established by the Commission (currently in Code of Maryland Regulations 20.50.09, but also as that timeline may be changed by the Commission in the future) for notification of acceptance of application and for approval to construct.	1.4
MD 9361 Order 86990	Condition 16 (D) (ii)	PHI shall revise and implement within ninety days after merger closing its interconnection agreement to applicants seeking to interconnect behind-the-meter small distributed generation resources to provide a procedure for email or other electronic submission of all applications (including payments if required).	1.4
MD 9361 Order 86990	Condition 16 (D) (iv)	PHI will revise and implement within ninety days after merger closing its interconnection agreement to applicants seeking to interconnect behind-the-meter renewable-energy projects to provide electronic data interface ("EDI") access to historical electric usage (through Pepco and Delmarva's Green Button capability, and ACE's MyAccount) to its customers and to customer representatives (distributed energy companies and others who a customer designates to receive such information).	1.4
TASC Amended Settlement Agreement	Commitment I (2) (b) (v)		
DC FC 1119 Order 18148	Commitment 120 (b) (v)		
DC FC 1119 Order 18148	Commitment 125	Within six months after Merger closing, Pepco will implement an automated online interconnection application process. This process will enable customers to securely complete interconnection applications online and to track online the status of the customer application, including resolution of customer inquiries, issues and	1.4

		complaints.	
DC FC 1119 Order 18148	Commitment 123 (b)	In Delaware, New Jersey and the District of Columbia, with respect to Level 1 interconnections, the utility shall report its performance with respect to issuance of permission to operate. If more than 10% of the permissions to operate requested are not issued by the utility within twenty (20) business days after satisfaction of the applicable requirements, the report will also include specific remedial action to be taken by the utility to resolve the shortfall and the time frame to perform the remedial action.	6.1
TASC Amended Settlement Agreement	Commitment I (4) (b)		
TASC Amended Settlement Agreement	Commitment I (5) (b)		
DE PSC DOCKET NO. 14-193 Amended Settlement Agreement	Commitment 101 (e) (i) & (ii)	In Delaware and Maryland, the utilities will report on the timeliness of responses to interconnection requests. Reports will include: i. The total number of and the nameplate capacity of the interconnection requests received and approved and denied under level 1, level 2, level 3 and level 4 reviews. ii. The number of and an explanation of the interconnection requests that were not processed within the established timelines. Should delays impact more than 10% of the interconnection requests in a reporting year, the utilities will include plans to address and eliminate the delays.	6.1
MD 9361 Order 86990	Condition 16 (E) (i) & (ii)		
MD 9361 Order 86990	Condition 16 (D) (v)	Within 90 days after the closing of the merger, PHI shall work with Maryland Commission Staff and other interested stakeholders such as TASC to review the existing application process (and timelines) and determine where an application should restart (if at all) if the application is revised (e.g., for spelling, grammatical, or clerical error). PHI shall file a report with the Commission annually showing the number of interconnection requests and performance relative to the timelines. For any metric where 10% or more of the requests are greater than the suggested timeframe the annual report shall also include action to be taken to improve the process to meet the stated timeframes.	1.4
DC FC 1119 Order 18148	Commitment 123 (c)	Within 180 days after the closing of the merger, Pepco shall file a request for proposed rulemaking to add the requirement with respect to issuance of permission to 15 D.C.M.R. Chapter 40, and to make adherence to the deadlines contained in 15 D.C.M.R. Chapter 40 at not less than a 90% compliance level subject to the EQSS standards in 15 D.C.M.R. Chapter 36.	6.1
MD 9361 Order 86990	Condition 7 (iv)	Pepco shall coordinate with Montgomery County and Prince George's County to facilitate planning for and interconnection of renewable generation to be developed by the Counties for governmental buildings or public facilities.	1.4
DC FC 1119 Order 18148	Commitment 118	Pepco shall coordinate with the District Government to facilitate planning for and interconnection of renewable generation to be developed by the District Government for governmental buildings or public facilities.	1.4

DC FC 1119 Order 18148	Commitment 125	PHI shall develop an enhanced communication plan to proactively promote installation of behind-the-meter solar generation in its service territories. Included in the plan will be measures to utilize the utilities' web sites and bill inserts to provide public service information useful to businesses and individuals that may be interested in installing solar generation as well as informing customers as to the capabilities of the utilities' net energy metering programs and advanced metering infrastructure. PHI will share its enhanced communication plan within six (6) months after Merger closing. PHI will implement an automated online interconnection application process. This process will enable customers to securely complete interconnection applications online and to track online the status of the customer application, including resolution of customer inquiries, issues and complaints.	6.1
TASC Amended Settlement Agreement	Commitment I (7)		
DC FC 1119 Order 18148	Commitment 123 (d)	Within 180 days after closing of the Merger, Pepco shall file a request with the Commission to eliminate the $100 fee currently charged for a Level 1 interconnection application.	2.9

1 PHI's Interconnection Application Review and Approval Process

1.1 Purpose of this Section

The purpose of this section is to address PHI's commitment to provide a transparent, efficient, and clear process for review and approval of interconnection of proposed renewable-energy projects to the utilities' distribution systems. In this section, PHI will describe its processes for the review and approval of applications, specifically highlighting changes that it has made recently in order to streamline these processes and improve the customer experience. This document focuses primarily on PHI's role during the interconnection review, which requires evaluation from both an administrative/procedural perspective as well as a technical/engineering perspective. Improvements have been made to both aspects of the process.

1.2 Background

As interconnection applications continue to accelerate in both volume and total capacity (MW) across Pepco, Delmarva Power, and Atlantic City Electric, there is an increasing need to streamline the interconnection application review process to minimize delays, decrease operating issues, and improve the overall customer interconnection experience (see Figure 2 and Figure 3). The review process also ensures safe and reliable operation of the distribution system and that no customers are detrimentally impacted by the introduction of DERs operating in parallel with the distribution system.

Figure 2: PHI-Wide NEM Interconnection Applications by Month and Aggregate Capacity Jan 2013 – May 2016

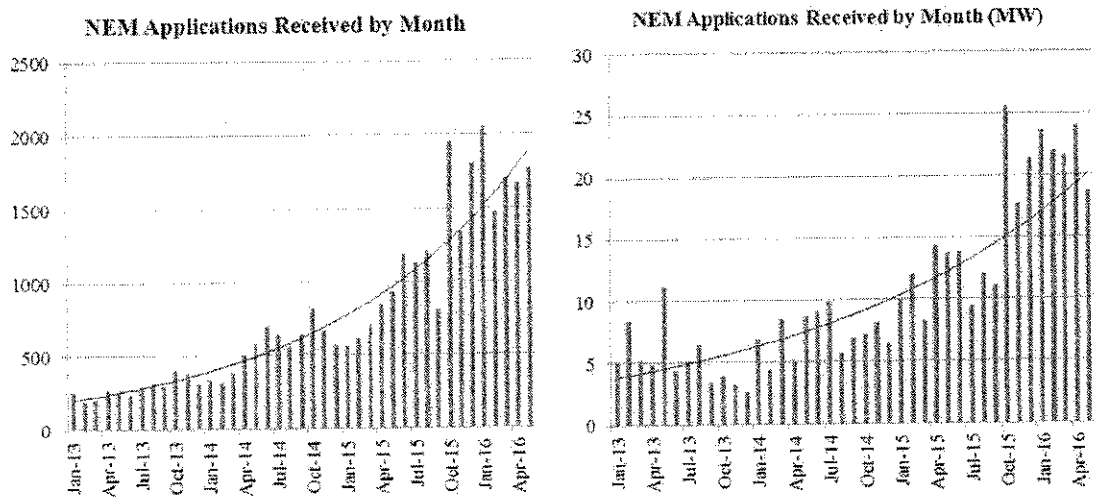
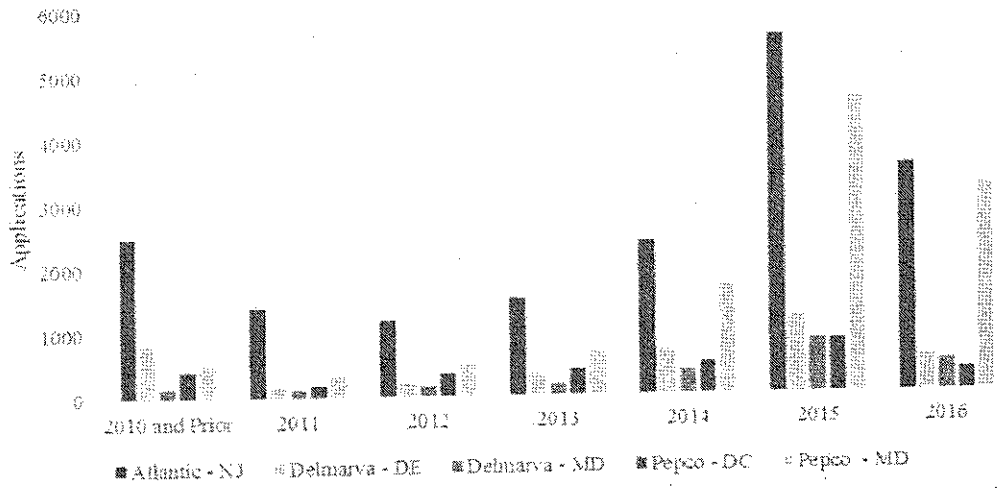


Figure 3: NEM Interconnection Applications – Active and Pending – 2010 and Prior to May 2016



1.3 Criteria for the Evaluation of Interconnection Requests

Interconnection requests submitted by customers and/or developers may be pursuant to either federal or state regulation or statute, placing requests into one of two categories:

1. Interconnection applications subject to state regulations which undergo a review by PHI's Green Power Connection ("GPC") and engineering teams.
2. Interconnection requests being made under federal jurisdiction which undergo a review by PJM Interconnection, LLC, with the Company's engineering teams supporting PJM.

Regardless of whether an interconnection request falls under state or federal jurisdiction, engineering reviews must be conducted to ensure that the parallel operation of the DER with the power delivery system does not introduce detrimental effects to the power delivery system or other customers.

1.4 Recent Improvements to the Interconnection Application Process

PHI has made several improvements to its interconnection application process – both procedural and technical – which are in alignment with the facilitation of a transparent, efficient, and clear process for review and approval of interconnection requests. The combination of these various initiatives has led to an overall streamlining of the application process, leading to shorter overall review and approval times across all PHI companies. Key initiatives which PHI has undertaken in recent months are detailed below.

Streamlined Procedures

A series of more efficient procedures have been recently implemented. The most noteworthy of these improvements is a new online application website, which has significantly decreased the percent of incomplete applications (which would have otherwise been returned or delayed), leading to an overall shorter review process and faster approval times. Other changes include a new application fee process, increased internal cross-jurisdiction facilitation and coordination, and reduction in processing time down to one business day for customer calls, voicemail returns, and Green Power Connection Mailbox messages.

As discussed above, PHI utilities have recently transitioned to an online application portal that allows customers and contractors to enter application information online for direct submission. This streamlining

of the application process is resulting in shorter overall review processes and approval times across all PHI operating companies. Benefits to customers and contractors include:

- Customer usage data enables *MyAccount* download functionality for customers and contractors,
- Reduced application errors and missing information through automated data validation,
- Near real-time monitoring of application status through a personalized dashboard,
- Ability to see aggregated reports for all pending applications submitted online by contractors,
- Ability to designate access to multiple users through new online contractor account,
- Ability to access online application portal from any internet connection, including tablets in the field,
- More intuitive and interactive process guiding the user step-by-step,
- Online signature feature eliminates the need for physical signatures, and
- Reduction in printing, handling, and postage costs.

Where applicable, a new application fee process has also been implemented. The system automatically determines if an application fee is required and calculates the required fee based on jurisdiction, system size, and application level. The system automatically generates an invoice and emails it to the contractor or customer, and contractors can quickly and easily pay their invoice through Speedpay. The system will allow the final Authorization to Operate ("ATO") to be issued only after any applicable application fee is paid.

Benefits of the new application fee invoice process include:

1. Net Energy Metering ("NEM") applications are being processed more quickly, without requiring upfront application fee payment,
2. NEM applications no longer are returned to contractors or customers as incomplete due to an incorrect or missing application fee,
3. The new online application process will automatically generate an invoice and email it to the contractor or customer, and
4. Contractors will have the option to pay invoices via Speedpay or by mailing a check attached to the invoice.

Figure 4: Incremental Interconnection Process Timelines for Level 1 Applications by Region

Interconnection Metrics	Completion Commitment (Business Days)				
	Pepco - DC	Pepco - MD	DPL - MD	DPL - DE	ACE
Acknowledgement	10	5	5	5	3
Authorization to Install	15	15	15	15	10
Authorization to Operate[4,5]	20	20	20	20	20

Figure 4 outlines the maximum number of days within which each PHI utility will issue a decision for the three interconnection metrics for Level 1 applications. PHI will comply with all jurisdictional requirements[6] in a timely manner in the processes leading up to a potential "authorization to operate" status.

[4] Also referred to as "Permission to Operate"

[5] PHI completes its interconnection-related construction prior to issuing "Authorization to Operate" in accordance with jurisdictional requirements and timelines

[6] Maryland 9361 Order 86990 Condition 16 (D)(i) specifies PHI will schedule interconnection construction to be complete within the timeline established by the Commission (currently in COMAR 20.50.09)

Increased Customer Education and Outreach

In 2015 and 2016, all PHI companies initiated a customer and contractor education campaign to improve customer understanding of and satisfaction with the net energy metering and small generation interconnection processes. The key message of this campaign is "Pepco Holdings supports renewable energy and partners with its customers to ensure safe and reliable interconnection of renewable energy in the electric grid." Target audiences included current and future NEM customers; renewables contractors (mostly solar installers), builders, and developers; local government groups, regulators, and stakeholders; PHI employees; and renewable industry associations.

The NEM-related websites have been significantly revised to include:

- Easy-to-remember vanity URLs of AtlanticCityElectric.com/GreenPowerConnection, Delmarva.com/GreenPowerConnection, and Pepco.com/GreenPowerConnection,
- Simplified, intuitive site navigation,
- Hyperlinks and instructions on how to use the online interconnection application portal,
- Easy-to-read tables with links to printable interconnection application forms and riders,
- Lists of application fees,
- Links to PHI's electric rate tariffs, and
- An interactive, searchable Restricted Circuit Map that enables customers and contractors to check whether their local circuit is restricted (see Figure 12).

The websites also include extensive FAQs, educational presentations, and tools to estimate solar costs before investing in a system; links to useful resources from federal, state, and local renewable energy organizations; and consumer information on solar installation provided by the U.S. Department of Energy ("DOE"), Federal Trade Commission ("FTC"), and state offices of consumer protection. PHI will continue to actively update the website to add NEM-related information as it develops.

Each PHI utility developed and provided interconnection customers, contractors, and installers with printed educational materials including:

- The Net Energy Metering and Small Generator Interconnection Brochure,
- The Net Energy Metering and Small Generator Interconnection Application Checklist,
- Frequently Asked Questions,
- Unauthorized Small Generator Interconnections (developed to specifically address the safety risks and hazards associated with unauthorized interconnections), and
- Acceptable Inverters List.

These materials are available as printable PDF documents on the NEM-related web pages, and the Companies integrate them into various outreach activities. These materials will be maintained with current information, and additional materials will be developed, as information gaps are identified.

The PHI utilities implemented live webcasts delivering detailed education on the application process. Webcast topics included "Details of the Application Process,"[7] "Preview the Soon-to-Come Online Application System," "The NEM Engineering Review Process and Speeding Up the Application Fee Process," and "Online NEM Application Training." The companies will continue to host webcasts and educate customers and stakeholders with NEM-related information.

Emails were sent to educate stakeholders about New NEM Application Forms Online and the New

[7] For applications that are revised because of spelling, grammar, or other clerical errors, a review of the existing application process and timelines and a determination of whether the application should restart will be conducted.

Application Fee Invoice Process. Invitational emails also were sent prior to each webcast series.

PHI began holding face-to-face meetings with solar contractors with high numbers of applications returned as incomplete, to educate them on the application process. Examples of returned applications were reviewed with the contractors as teaching aids.

PHI employees attended numerous community outreach events and distributed NEM educational materials, gave presentations at the Solar Energy Industries Association (SEIA) Solar Conference in Washington, D.C. and the Smart Electric Power Alliance (SEPA) conference in Atlanta, and held informational meetings with stakeholders including staff from the Maryland Public Service Commission Office of External Relations, the Public Service Commission of the District of Columbia, the Delaware Public Service Commission Staff, the New Jersey Board of Public Utilities Staff, the District Department of Energy and the Environment, and the District of Columbia Sustainable Energy Utility Staff.

The PHI utilities anticipate that proactive education and outreach similar to the activities listed above will continue for the foreseeable future.

Expedited Technical Review

In an effort to respond to an increased number of applications and customer requests for faster approvals of applications, the review and approval process has been streamlined for small systems (< 10 kW) and contains more clearly defined criteria for larger systems that include a pre-screen, screen, and advanced screen. PHI has implemented a hierarchal screening process – that is an application will require more thorough and comprehensive analysis if it fails to pass a simpler screen first. This process is consistent with the process that FERC enacted to standardize the interconnection process for projects up to 20 MW and to fast track the approval for certain size units– *i.e.*, the Small Generator Interconnection Procedures (SGIP). PHI has adopted the principles outlined by FERC with its changes to the NEM application process, which includes the following provisions:

- A simplified review for certified inverter-based systems of less than 10 kW,
- A "Fast Track Process" for eligible generators, and
- A "Study Process" for all other systems that do not pass the initial screening process.

The expedited Level 1 approval process has significantly enhanced the approval time. Approximately 80% of all Level 1 applications received by PHI utilities were granted "Approvals to Install" in 5 days or less from the date the applications were filed during the period from February 1, 2016 to April 25, 2016.

Electronic Data Interchange

PHI developed an electronic data interchange ("EDI") for its customers and customer representatives to access historical electric usage through the Company's Green Button capability. The Request Customer Usage module within the Net Energy Metering Online Application Portal provides a secure process for distributed energy contractors to obtain a customer's authorization to access the customer's energy usage data, which the module calculates from settlement system data and provides to the contractor for downloading. Customers can authorize access online through My Account or sign a paper release form which the contractor uploads into the Request Customer Usage module. Contractors use the energy usage data to size customers' proposed solar generating systems.

The tool went live on the utilities' NEM-related websites on April 29, 2016 and has been shared with the solar community through news releases, emails to solar contractors and regulators, and in face-to-face training meetings with contractors and stakeholders. The information and tool can be accessed at atlanticcityelectric.com/gpc, delmarva.com/gpc, and pepco.com/gpc, then select Request Customer Usage

from the left navigation column.

2 Technical Evaluation of DERs Applying for Interconnection with PHI's Distribution System

2.1 Purpose of this Section

The purpose of this section is to address PHI's commitment to provide a report to the regulatory bodies and other stakeholders on the technical criteria limits for distributed energy resources (DER) that apply for interconnection with PHI's power delivery system.

This section addresses:

- PHI's general process for conducting a technical evaluation of a request to interconnect with PHI's power delivery system,
- Criteria limits for DERs, as well as the rationale substantiating them,
- Consideration of the generation profile of renewable energy relative to load,
- Criteria for determining that a circuit is restricted,
- Reference to the FERC Order No. 792 Supplemental Screen,
- Modeling methodology and tools for evaluating circuit hosting capacity and DERs, and
- PHI's technical evaluation processes relative to its peers as per the National Renewable Energy Laboratory ("NREL") work to review utility interconnection criteria across the United States.

2.2 PHI's Process for Conducting Technical Evaluations of Interconnection Requests

General Review Process

A review of each interconnection application is made to ensure that operation of the proposed DER system is in accordance with the technical requirements of the power delivery system and does not adversely impact other customers. Requests to interconnect with the distribution system are reviewed for compliance with the technical operating parameters of the utility system, as specified in PHI's internal technical distribution system planning documents. These parameters are specified in Section 2.3 of this document, entitled "Technical Criteria Limits for DERs Applying for Connection to the PHI Distribution System."

Customer/contractor equipment that is used to interconnect with the distribution system is reviewed for compliance with the following documents, based on system size and the location of the proposed system:

- Technical Considerations Covering Parallel Operations of Customer Owned Generation of One (1) Megawatt or Greater Interconnected with the PHI Power Delivery System
- Technical Considerations Covering Parallel Operations of Customer Owned Generation of Less than (1) Megawatt Interconnected with the Delmarva Power System
- Technical Considerations Covering Parallel Operations of Customer Owned Generation of Less than One (1) Megawatt Interconnected with the Atlantic City Electric Power System

To minimize undue burden on applicants, PHI uses a tiered evaluation methodology based on the *Guide for Conducting Distribution Impact Studies for Distributed Resource Interconnection IEEE Std. 1547.7, 2013*. This approach is used to categorize interconnection applications based upon the complexity of review and analysis required, in order to simplify and expedite the overall interconnection process. Please see the section in this report, entitled "Evaluation of Generation Relative to Load in the Interconnection Process" for additional information on this process.

The following are potential outcomes for an interconnection application after it has gone through the technical review process (whether by simple screen or detailed engineering analysis):

- Approved – "Approval to Install" is granted
- Approved – "Approval to Install" is granted, but "Authorization to Operate" is awaiting a utility-sponsored system upgrade[8]
- Conditionally approved – "Approval to Install" is pending, contingent on developer/customer amendment of proposed DER system design, and/or agreement to implement modified operations of equipment, and/or agreement to pay for a utility system upgrade to facilitate the interconnection request
- On hold (NEM Only) – "Approval to Install" is pending, contingent on a planned utility infrastructure enhancement (one not paid for by the applicant but which will coincidentally facilitate DER interconnection for the applicant)
- Denied – "Approval to Install" is not granted
- Complete – "Authorization to Operate" is granted

PHI ensures that the outcome(s) of the technical review process are clearly communicated to the customer at each appropriate stage in the process.

2.3 Technical Criteria Limits for DERs Applying for Interconnection to the PHI Distribution System

Overview

PHI employs technical criteria limits to facilitate the interconnection of DERs with its power delivery system while maintaining its ability to provide safe, reliable, and cost-effective electricity to all of its customers.

A primary driver for maintaining technical criteria limits is the fact that the majority of DERs interconnected with PHI's distribution system are operated in a manner which is not coordinated with PHI's operational decisions of the Company's own assets. Given that PHI does not have visibility or control into the majority of behind-the-meter DERs, the interconnection review process is designed to identify and mitigate any potential issues proactively. However, should a DER introduce detrimental operational and reliability impacts to the system after interconnection, PHI reserves the right to disconnect the DER system. Therefore, PHI must review each interconnection request carefully. Because PHI seeks to assess each interconnection request uniformly and equitably, it employs standardized technical criteria for doing so. These criteria ensure that the type and size of DER being proposed will not create adverse impacts under normal or contingency configurations and corresponding utility system facility ratings (*e.g.* normal ratings vs. emergency ratings). These criteria limits are used in conjunction with a consideration of the generation profile of DERs relative to load, when applicable.

PHI's criteria limits are based on minimization or avoidance of the following detrimental technical conditions that impact the power quality at the customer level and/or the reliability of the distribution system:

- High- and low-voltage conditions
- Voltage fluctuations
- Frequency deviations
- Harmonic distortions

[8] Generally, it is the responsibility of the DER owner/operator to pay for any necessary system upgrades, except when PHI already has a program or project in-place that includes within its scope the necessary upgrades(s).

- Overcurrent
- Excessive impacts on the reliable service life of regulating equipment
- Reactive power issues – power factor variations
- Reverse power flow on equipment not designed for it
- Protection and coordination issues
- Impacts on the transmission system
- Impacts on other customers

The following industry standards and studies underpin PHI's criteria limits:

- Series of Interconnection Standards IEEE 1547
- EPRI Engineering Guide for Integration of Distributed Storage and Generation[9]
- NREL High-Penetration PV Integration Handbook for Distribution Engineers[10]

The following are the technical criteria limits for DERs seeking interconnection with the PHI system, and the rationale underpinning them:

High- and Low-Voltage Conditions

PHI does not permit a DER to cause the delivery voltage levels on the Company's distribution system to deviate outside of the range of voltages described by American National Standard For Electric Power Systems and Equipment – Voltage Ratings (60 Hertz) ANSI C84.1, 2011, or state regulation if it is more restrictive than ANSI C84.1. The highest allowable steady state delivery voltages for each jurisdiction (on a 120 V base) [11] are:

- District of Columbia – 126 V
- Delaware – 126 V
- Maryland – 126 V
- New Jersey – 126 V

Voltage Fluctuations

A DER is not permitted to cause fluctuations in voltage for adjacent customers. Therefore, a 2% maximum allowable fluctuation limit is imposed at the point of interconnection ("POI").

In addition, PHI does not permit a DER to cause excessive voltage flicker on the Company's distribution system. Voltage flicker is not permitted to exceed the "Borderline of Irritation" curve as defined in IEEE Std. 519-1992, *Recommended Practices and Requirements for Harmonic Control in Electric Power Systems.*

Voltage changes due to power output fluctuations shall be kept in compliance with the Institute of Electrical and Electronics Engineers (IEEE) 519, the Computer Business Equipment Manufacturers Association (CBEMA), and Information Technology Industry Council (ITIC) requirements.

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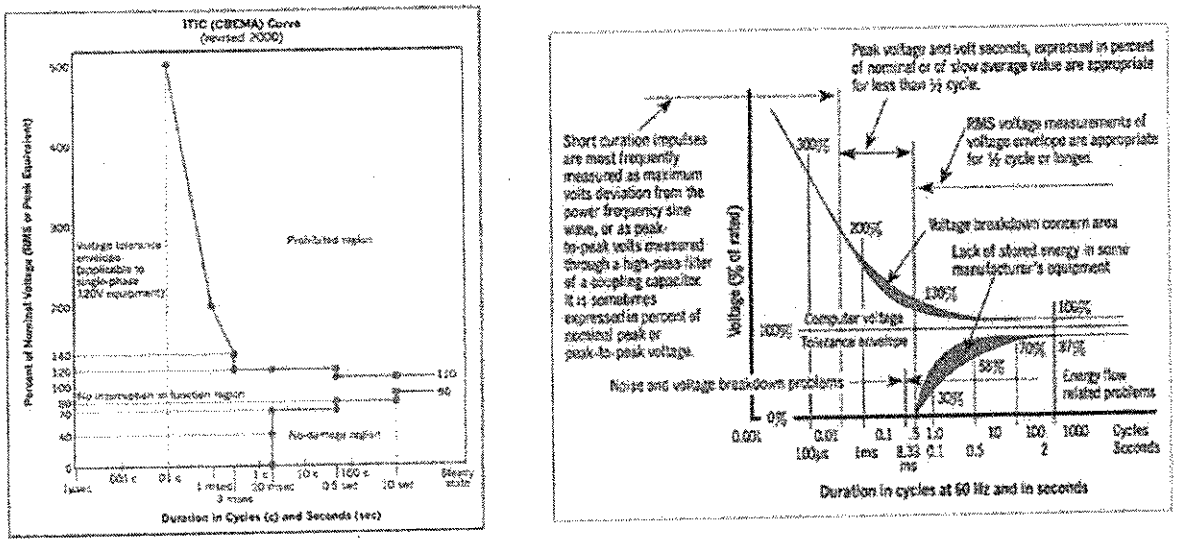
[9] *Engineering Guide for Integration of Distributed Storage and Generation*. EPRI, Palo Alto, CA: 2015. 3002005774. http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002005774

[10] *High-Penetration PV Integration Handbook for Distribution Engineers*. NREL. Golden, CO. 2016. http://www.nrel.gov/docs/fy16osti/63114.pdf

[11] PHI designs the distribution system to comply with ANSI C84.1 standards for voltage levels.

Figure 5: Computer Business Equipment Manufacturers Association (CBEMA) and Information Technology Industry Council (ITIC) Voltage Requirements



Harmonic Distortions

PHI does not permit a DER to introduce unacceptable distortions to the alternating current (AC) sine wave. Per IEEE Std. 519 *Recommended Practices and Requirements for Harmonic Control in Electric Power Systems,* the total harmonic distortion (THD) voltage shall not exceed 5% of the fundamental 60 Hz frequency nor 3% of the fundamental for any individual harmonic as measured at the point of common coupling (the location where the customer interfaces with the Company's system).

In addition, the level of harmonic current that the customer is allowed to inject into the Company's distribution system is not permitted to exceed that specified in Table 10.3 in IEEE Std. 519.
Finally, any commutation notch is to be limited as defined by Table 10.2 in IEEE Std. 519.

Overcurrent

PHI does not permit a DER to generate current flow in excess of the component rating for utility equipment. This is inclusive of normal, emergency, and fault duty system ratings.

Excessive Impact on the Reliable Service Life of Regulating or Protective Equipment

PHI does not permit a DER to cause excessive operation of utility-owned, regulating equipment. Therefore, the following criteria are applied to minimize excessive operation:

- **Voltage Regulators** – DERs are permitted to cause voltage fluctuation of only one-half the band width of any voltage regulator measured at the regulating device
- **Capacitors** - DERs are permitted to cause voltage fluctuation of one-half the net dead band of a capacitor bank measured at the device

Reverse Power Flow

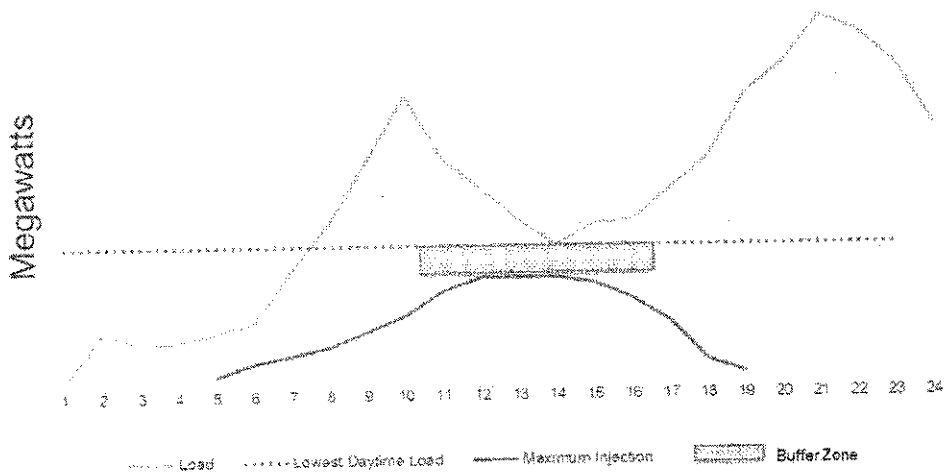
PHI does not allow reverse power flow through any electric system component that is not designed to accommodate it or has the required controls or protection systems to allow reverse power flow. For such system components, appropriate operating buffers are maintained to ensure that periods of low load as well as short-duration decreases in circuit loading that coincide with periods of maximum injection of

power by DERs into the circuit do not result in reverse power flow through a system component not designed to accommodate it. Common elements of the PHI distribution system, which may not be designed to accommodate reverse power flow[12] are:

- Voltage regulators[13]
- Distribution power transformers
- Network protectors[14]
- Feeder terminals

To prevent reverse power flow, the sum total of the full output capacity of all DERs downstream from the relevant device (i.e. one of the devices listed above) is kept to a maximum cumulative injection of 80% of the lowest annual daytime (9am - 3pm) load going through the lowest loaded phase[15] of the distribution system element that is not designed to accommodate reverse power flow.

Figure 6: Illustrative Depiction of Buffer Utilized to Limit Impacts of Reverse Power Flow on Electric System Components not Designed to Accommodate it



Note that Figure 6 is illustrative and that every feeder on the PHI system will have a different composition of customer load and generation. Generally, however, most feeders experience periods of low customer load and high customer generation, as depicted in this chart, on the weekends in the spring and fall seasons.

This buffer zone is required because neither load nor DER output are within PHI's continual control. Without this buffer zone, reverse power flow could arise as the result of:

- Year-to-year variations in weather
- Variations on industrial load
- Unexpected outages of large industrial or commercial load

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[12] Some of these common electric system components have already been upgraded on the PHI system to accommodate reverse power flow. In such instances, these operating buffers do not apply.

[13] In addition to being designed to accommodate reverse power flow, a voltage regulator must be properly calibrated to do so. Generally, PHI will conduct such field calibration work to accommodate an interconnection request.

[14] DERs are not permitted to cause reverse power flow through network protectors, which are devices located on the secondary side of network distribution service transformers and that protect specifically against backfeed from the LVAC secondary network through the service transformer onto higher-voltage feeders.

[15] A "phase" is one of the three conductors that comprises a utility circuit.

- Economic changes causing lower year-to-year load
- Phase imbalances in the system caused by the configuration of customer load and generation

In addition, PHI maintains a minimum size for each buffer zone. This is to prevent a circumstance where the loss of one or a few large customers' loads would have the ability to create a reverse power flow condition.

Figure 7: Minimum Size of Buffer Zone to Prevent Reverse Power Flow on Electric System Components not Designed to Accommodate it

Circuit Voltage Level	Minimum Size of Buffer Zone		
	Voltage Regulators	Distribution Power Transformers	Circuit Terminals
4 kV	100 kW	200 kW	150 kW
12 – 13.8 kV	200 kW	500 kW	250 kW
23 – 25 kV	200 kW	500 kW	250 kW
33.26 – 34.5 kV	300 kW	1 MW	500 kW

Upper Bounds on Concentrations[16] of DERs

PHI's technical criteria are designed to allow for high penetration levels of DER injection on the distribution system, however the criteria do place upper bounds on the concentrations of DER injection that will be allowed. This is specifically because large concentrations of DERs (as opposed to large amounts of DER capacity spread evenly and diffusely across a part or the whole of the distribution system) can have adverse impacts on other surrounding customers and also on the transmission system.

Concentrations of DERs that are too high can potentially have the following effects on the electric transmission system:

- Reverse power flow through a substation transformer can be especially detrimental to the transmission system. Because PHI substation transformers are of a delta-wye type, reverse power flow can result in voltages of up to 173% of nominal on the transmission system[17] during fault conditions on the primary supply line to the transformer. In addition, large blocks of DER injection can also create unacceptable voltage variations on the distribution system and sometimes even the transmission system as when a large block of DER injection trips off.

Concentrations of DERs that are too high can potentially have the following impacts on other customers on the same distribution circuits:

- Unacceptable voltage variations – high- or low-voltage can cause damage to customer equipment and create operating problems on the utility systems. Each of PHI's utilities must maintain operating voltage within specified limits so that the customers are not exposed to voltage levels that could damage common customer equipment.
- Decreased reliability – during outage events, the loss of distributed generation can cause the utility systems to experience higher loads upon restoration of service than existed prior to the outage. As PHI's distribution automation ("DA") schemes automatically reconfigure the distribution system to restore customers, these higher post-outage loads must be accommodated

[16] PHI uses the term "Concentrations" to denote DERs that may either be in close geographic proximity or in close proximity by way of their location within the configuration of the power delivery system. For, example, there may be many DERs that interconnect across the length of a distribution feeder, and while these resources may not be in close geographic proximity, they are electrically interconnected at the same point when viewed from the substation.

[17] Please see EPRI Guide for Integration of Distributed Storage and Generation, section 2-4 for additional information on ground-fault overvoltages

and be able to be transferred to adjacent feeders without causing local utility system overloads. After a period of time, the generation will automatically restore and the loads will be reduced to the pre-outage levels and in the reconfigured state could possibly cause high voltages. This loss and subsequent re-energizing of generation can be a significant reliability concern in areas with advanced distribution automation schemes where the restoration activities occur faster than the automatic restoration time for the generators and the tripping and restoration of a generator facility can cause significant voltage variations and possible overloads. At a minimum it adds significant planning work to make sure the schemes can operate as more and more DERs come on line. In addition, PV and/or wind which are intermittent are very hard to plan for because output can vary significantly from one moment to another.

To prevent potential impacts on the transmission system and to allow multiple customers with different size systems to connect to any individual circuit, PHI limits large (250 kW and over) generator injection to a single distribution power transformer to 10 MWs for systems rated up to 25 kV and 15 MWs for systems rated up to 34 kV, depending on the size of the transformer. In addition, the aggregate limit of large (250 kW and over) generators interconnected on circuits with other customers is:[18]

Figure 8: Aggregate Limit for Large (>250 kW) Generators Interconnected on Circuits

Circuit Voltage	Max Gen Size
4 kV	0.5 MW
12 – 13.8 kV	3 MWs
23 – 25 kV	6 MWs
33.26 – 34.5 kV	10 MWs

After these limits are reached, customers and developers can generally continue to request interconnection of systems less than 250 kW[19] or interconnect on an "express" feeder directly from the DER to the nearest appropriate substation.[20]

Express Circuits (At Customer's Cost)

Maximum generator size for express circuits is as follows, and is dependent on the ratings of approved conductors:

Figure 9: Maximum Generator Size for Express Circuits

Circuit Voltage	Max Gen Size
4 kV	0.5 MW
12 – 13.8 kV	10 MWs
23 – 25 kV	10 MWs
33.26 – 34.5 kV	15 MWs

[18] This limit has the additional benefit of retaining capacity on PHI's circuits for the interconnection of many customer DERs, as opposed to the circumstances where a few or potentially one large commercial DER can take up all circuit capacity.

[19] PHI recommends that customers first check their applicable restricted circuit map to ensure that they are not applying for interconnection on a circuit that is restricted to applications less than 250 kW. Please see Section 2.6 for additional information.

[20] An express feeder is paid for by the customer.

Examples of the Application of PHI's Technical Criteria Limits

The following are examples of the application of PHI's technical criteria limits:

Example 1

An application is received requesting the interconnection of a 3 MW photovoltaic facility on a 25 kV circuit with existing customers. PHI evaluates the application and finds that:

- The circuit already has 4 MW of large (>250 kW) generators already interconnected on this circuit, which has an aggregate limit of 6 MW for such generators (as per Figure 8).
- If the requested interconnection were to be reduced to 2 MW, and no other technical violations (voltage fluctuations, overcurrent, reverse power flow, etc.) are encountered then allowing this interconnection to proceed can be approved.
- If the requested interconnection were to be made on a new express feeder connected directly to the substation, and no other technical violations are encountered then the full 3 MW facility can be connected.
- An alternative could be installing the full amount on an express feeder which would also be screened for violations.

Thus, the customer is given the option of reducing their requested interconnection to 2 MW to interconnect to the feeder with other existing customers or the option of paying for an express feeder to the substation and interconnecting with this new feeder at 3 MW.

Example 2

An application is received requesting the interconnection of a 3 MW photovoltaic facility on a 25 kV circuit with existing customers. PHI evaluates the application and finds that:

- The circuit has no large (>250 kW) generators already interconnected on this circuit.
- Screening finds no technical violations (voltage fluctuations, overcurrent, reverse power flow, etc.) are encountered in allowing this interconnection to proceed.

Thus, the customer's interconnection request is approved.

Example 3

An application is received requesting the interconnection of a 10 kW photovoltaic facility on a 25 kV circuit with existing customers. PHI evaluates the application and finds that:

- The circuit already has 6 MW of large (>250 kW) generators already interconnected on this circuit, which has a limit of 6 MW for such generators (as per Figure 8).
- No technical violations (voltage fluctuations, overcurrent, reverse power flow, etc.) are encountered in allowing this interconnection to proceed.

Thus, the customer's request is approved, because the limits specified in Figure 8 are only for large (>250 kW) generators.

Example 4

An application is received requesting the interconnection of a 100 kW photovoltaic facility on a 13.8V circuit with existing customers. PHI evaluates the application and finds that:

- A nearby voltage regulator is of an older-type that is not designed to accommodate reverse power flow
- Allowing the interconnection of this DER would violate the buffer zone specified in Figure 6.
- No other technical violations (voltage fluctuations, overcurrent, etc.) are encountered in allowing this interconnection to proceed.

Thus, PHI would seek to upgrade the voltage regulator as it already has an existing program to modernize such system components. If the upgrades can be made at this time, then PHI will do so at its own cost and approve the application. If the upgrades cannot be made at this time, then PHI will give the customer the option of reducing the size of their proposed system (to a level such that the buffer zone is not violated) to

be approved. Although the approval to install is given, for system safety, the regulator upgrade should be completed before the new DER can begin to operate.

Example 5

An application is received requesting the interconnection of a 15 MW photovoltaic facility on a new 34.5 kV express circuit[21] to the substation. PHI evaluates the application and finds that:

- No technical violations (voltage fluctuations, overcurrent, etc.) would be encountered in allowing this interconnection to proceed.
- PHI will also evaluate the size of the transformer and will allow 15 MWs on larger transformers, which is more common on the 34 kV system. If the transformer is not large enough, the application may need to be reduced to 10 MW.

Thus, the application is approved.

Example 6

An application is received requesting the interconnection of a 15 MW photovoltaic facility on a new 34.5 kV express circuit[22] to the substation. PHI evaluates the application and finds that:

- The circuit-terminal protective relaying is of an older-type that is not designed to accommodate reverse power flow
- Allowing for the interconnection of this DER would violate the buffer zone specified in Figure 6.
- No other technical violations are identified (voltage fluctuations, overcurrent, etc.) in allowing this interconnection to proceed.

Contingent on the customer paying for the necessary upgrades to the circuit-terminal protective relaying, the application will be approved.

For Synchronous Generation

Although synchronous generation must not cause high voltage or adverse impact on automatic line equipment, there are several other criteria reviewed by Protection and Controls:

- Total short circuit current in relation to duty ratings of equipment
- The ratio of generation to minimum load in a protected section must be less than one-third
- Coordination of fuses and reclosers must still function properly which includes overall reach of the protecting devices.

2.4 Consideration of the Generation Profile of DERs Relative to Load

The hourly production values and generation profiles of renewable energy and interconnected small generators relative to load are considered in both PHI's interconnection application technical evaluation process and PHI's modeling and estimation of circuit hosting capacity.

Evaluation of Generation Relative to Load in the Interconnection Process

PHI uses a tiered evaluation approach for its technical screening and evaluation of DERs seeking interconnection with the distribution systems beginning with an expedited review process. This process is consistent with IEEE Std. 1547.7, 2013 and categorizes interconnection applications based upon the complexity of review and analysis required, in order to simplify and expedite the overall interconnection process. As indicated in Figure 10, the generation profile of the DERs relative to load is only considered when an application fails the expedited review, standard review, pre-screen, and the screen process. If at any stage of the review process it does not fail a review tier, the application will be approved.

[21] At customer cost

[22] At customer cost

Figure 10: Consideration of Hourly Generation Profile Relative to Load in the Tiered Evaluation Process

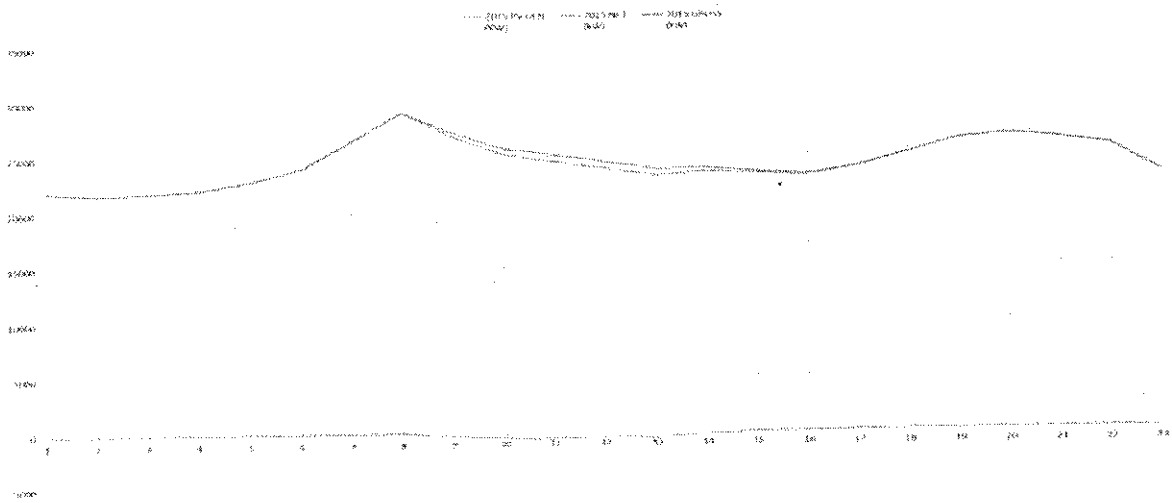
Tier	Valid for Applications	Process Description	Outcomes	Generation profile of the DER considered relative to load?
Expedited review	Less than 10 kW	Quick review to ensure customer is not on a restricted and/or network circuit, inverters are certified, and no additional PV systems exist on the same line transformer	Approved -or- Referred for Standard Review	No
Standard review	10 kW-50 kW -or- Applications that have not been approved through the expedited review	High level engineering review to ensure customer is not on a restricted and/or network circuit, inverters are certified, and no loading or voltage issues at the line transformer	Approved -or- Referred for Pre-screening	No
Pre-screen	50 kW-250 kW -or- Applications that have not been approved through the expedited or standard review	High level engineering analysis to determine feasibility through the examination of circuit voltage, distance from the substation and/or impedance at POI	Approved -or- Referred for Screening	No
Screen	250 kW or greater -or- Applications that have not been approved through the pre-screen	Deeper engineering analysis involving load flow simulation conducted at two points in time (peak load and low load)	Approved -or- Referred for Advanced Study	No
Advanced study	Applications that have not been approved through the screen	Deepest level of engineering analysis involving time-series modeling of load and generation resulting in an impact analysis study	Approved -or- Upgrades Required	Yes

As noted above, PHI considers the generation profile of DERs relative to load when it conducts its advanced studies. In these studies, PHI considers the time series generation profile of the DER throughout the year, as simulated in the Company's planning software.

It is important to note the following:

- Peak solar generation occurs during the mid-day and decreases while the system peak load increases and occurs late-day during the summer months.
- Some of the areas within each of PHI's utilities experience peak loads during winter months in the early morning hours when there is little to no solar generation output. Under these conditions solar generation has no impact on winter peaks and the distribution system must supply 100% of system load (see Figure 11).
- Where available, Advanced Metering Infrastructure ("AMI") and Supervisory Control and Data Acquisition ("SCADA") data is used in system models.

Figure 11: Comparison of Gross Load to PV Generation on a Pepco Feeder (Hour of Day vs. kW) for a Winter Peaking Feeder



2.5 Generation Relative to Load in Hosting Capacity Analysis

PHI performs hosting capacity analysis on feeders to determine how much additional DER capacity a feeder can support in its current configuration, without incurring utility system operational violations. This analysis takes into consideration the characteristics and construction of the circuit, its load profile, and a simulation of random placement of DERs along the circuit. Please see Section 5.8, entitled *Lessons learned from PHI's work with the DOE in the SUNRISE*[23] *effort*, for additional explanations of hosting capacity.

2.6 Criteria for Determining that a Circuit is Restricted

A circuit is referred to as being "restricted" because a major distribution infrastructure investment would be required to allow the DER to interconnect without creating a violation of utility system operational parameters. Circuits that are restricted are identified according to the following categories:

- Restricted to all sizes (*i.e.* closed)
- Restricted to systems below 250kW
- Restricted to systems below 50kW

PHI applies these restrictions on circuits, upon recognizing that a circuit cannot accommodate a DER sized above these levels without violating one or more of the criteria outlined in the section of this report entitled "Criteria Limits for DERs Applying for Connection to PHI's Distribution System."

PHI may on occasion conduct work that would remove a circuit restriction (such as when PHI already has a program or project in-place that includes within its scope the necessary upgrade to remove the restriction). However, generally it would be the responsibility of the DER developer or customer to pay for any necessary system upgrade.[24] If a customer offers to pay for such an upgrade and their application is approved, the project can move forward on an otherwise restricted circuit.

[23] SUNRISE is an acronym for the U.S. DOE program "Solar Utility Networks: Replicable Innovations in Solar Energy"

[24] PHI understands that any such upgrade may be cost prohibitive for the DER customer to reasonably undertake.

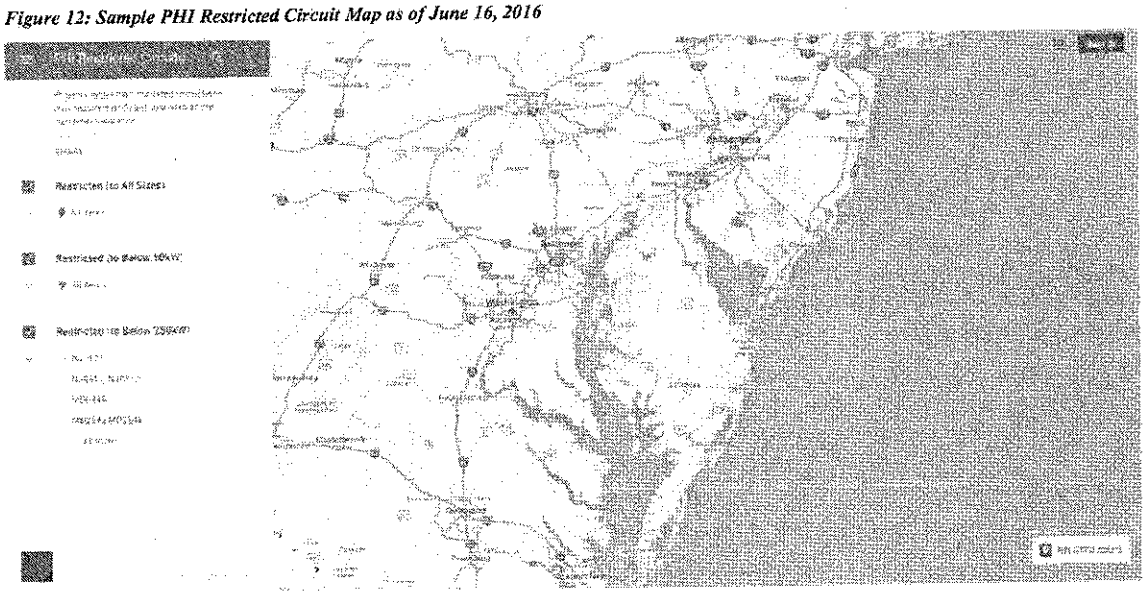
On occasion, PHI may conduct planned system work which will coincidentally increase hosting capacity. Work of this nature has led to lifting the "all size restriction" on four feeders to date. Additionally when certain large DER projects are cancelled or withdrawn, these outcomes may also lift restrictions on some circuits that may have been restricted to 250 kW or below sizes.

PHI's restricted circuits, and additional information about them, can be found on the following sites:

- Pepco - Maryland – http://www.pepco.com/Restricted-Circuit-Map.aspx
- Pepco - District of Columbia – http://www.pepco.com/Restricted-Circuit-Map.aspx
- Delmarva - Maryland – http://www.delmarva.com/DPL-Interactive-Map.aspx
- Delmarva - Delaware – http://www.delmarva.com/DPL-Interactive-Map.aspx
- Atlantic City Electric - New Jersey - http://www.atlnticcityelectric.com/Restricted-Circuit-Map.aspx

From these sites, PHI's customers can view a searchable map (color-coded to show the level of restriction) that is updated at least quarterly.

Figure 12: Sample PHI Restricted Circuit Map as of June 16, 2016



If a customer finds that his/her particular address falls within an area subject to restrictions, the customer can contact PHI's Green Power Connection team for a restriction confirmation or for additional information at:

- Pepco, Maryland – http://www.pepco.com/greenpowerconnection
- Pepco, District of Columbia – http://www.pepco.com/greenpowerconnection
- Delmarva, Maryland – http://www.delmarva.com/green-power-connection
- Delmarva, Delaware –http://www.delmarva.com/green-power-connection
- ACE, New Jersey - http://www.atlanticcityelectric.com/green-power-connection

2.7 FERC Order No. 792 Supplemental Screen

Background

The Federal Energy Regulatory Commission ("FERC") adopted new "small generator" interconnection procedure ("SGIP") procedures for distributed energy resources up to 20 megawatts in Orders 792 and 792-A (November 2013 and September 2014, respectively). The "minimum daytime load" ("MDL") screen and "fast track process" mentioned above are a part of these orders. These new provisions were a departure from the previous, more restrictive screening process that required that a project's generation output not exceed 15% of the peak load of the circuit with which it is seeking interconnection.

While the FERC's procedures apply only to facilities subject to the FERC jurisdiction (*i.e.* those participating in wholesale markets), they tend to serve as a guidepost for a number of state-level procedures. PHI has adopted MDL as a key screening criterion, which it believes is consistent with the spirit and intent of the FERC.

2.8 Modeling Methodology and Tools for Evaluating Hosting Capacity and DERs

PHI employs industry leading planning and analytical tools to model the production of renewable energy relative to load for interconnection applications which require advanced studies. Conducting this type of analysis requires advanced power flow modeling capabilities that are able to model the specific production characteristics of DERs relative to both load and the individual characteristics and configurations of feeders.

PHI currently utilizes a software product known as the Distribution Engineering Workstation ("DEW") to conduct this analysis. The unique capabilities are outlined briefly below and were discussed in detail during PHI's May 3, 2016 webinar:[25]

- For solar generators, DEW maps all DERs into the geospatial model and then determines output based on historical solar irradiance from a "Sky Data" web interface.
- DEW runs multiple time-series load flows to analyze the impact of intermittent generation at a new NEM customer while modeling existing and other pending NEM customers.
- For special studies, DEW can model the impact of increasing generation against the entire transmission and distribution ("T&D") grid as well as a single circuit. As the penetration of DERs increases, more studies will need to include both transmission and distribution impact analyses.

Conducting hosting capacity analysis is an industry-leading capability which has been required and recommended by various regulatory commissions in other states, including California and New York. PHI has taken steps to proactively stay ahead of the industry to help further integrate DERs while ensuring the safe, reliable, and affordable operation of the power delivery system.

PHI is also using this capability to develop estimates of the hosting capacity of its circuits. Once these models are completed, a plan will be developed to release the model results on PHI's interconnection website.

[25] A copy of the presentation can be found at the following links, under "Presentations":
http://www.pepco.com/nemeducation/
http://www.delmarva.com/nemeducation/
http://www.atlanticcityelectric.com/nemeducation/

2.9 PHI's Technical Evaluation of Interconnections Relative to Peers as Per NREL Study

PHI is committed to improving the interconnection process for its customers. Many improvements to this process have already been made as discussed in Section 1. In addition, PHI has worked collaboratively with the National Renewable Energy Laboratory ("NREL") to provide data on its interconnection process in order to ensure that PHI's practices are in alignment with industry leading practices. An analysis of these findings was published by the Electric Power Research Institute ("EPRI") and NREL in December 2014[26] in the *Current Utility Screening Practices, Technical Tools, Impact Studies, and Mitigation Strategies for Interconnecting PV on the Electric Distribution Systems* report.[27] Additionally, the findings of this study were summarized in PHI's May 3, 2016 webinar.[28] The report and presentation discussed leading practices across four areas:

- Application Process
- Interconnection Procedures and Screening Processes
- Detailed Impact Studies of Proposed System Installations
- Mitigation Strategies

The aforementioned EPRI/NREL report does not discuss treatment of behind-the-meter energy storage equipment in the interconnection process. However, the combination of solar plus storage is discussed in Section 4 of this report, including potential modifications which may be required to the interconnection process under various configurations of behind-the-meter storage and solar. It is PHI's expectation that these requirements will be discussed further in the collaborative stakeholder meetings following the filing of this report.

No direct peer comparison of interconnection practices is perfect due to the fact that each utility has characteristics which makes it unique in terms of both operations and topology (*e.g.* feeder design, type, and configuration) and operational philosophy (*e.g.* system protection schemes, distribution automation). Moreover, the volume of interconnection applications varied significantly between regions and utilities surveyed by NREL. Despite these differences, PHI's procedures and processes for interconnection of DERs are generally consistent with or surpass common industry practices identified below.

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[26] This industry report was issued in December of 2014 as referenced herein. Please note that the same report has been incorrectly referred to as being issued by the end of 2015 in the merger terms and conditions.

[27] *Current Utility Screening Practices, Technical Tools, Impact Studies, and Mitigation Strategies for Interconnecting PV on the Electric Distribution Systems*. EPRI, Palo Alto, CA: 2014. 3002003277. http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002003277

[28] A copy of the presentation can be found at the following links under "Presentations"
http://www.pepco.com/nemeducation/
http://www.delmarva.com/nemeducation/
http://www.atlanticcityelectric.com/nemeducation/

Application Process

PHI makes the interconnection application form available online and allows for online submission. However paper application submissions continue to be supported.

Figure 13: NREL Identified Practices vs. PHI Processes – Applications

NREL Identified Practice	PHI Process
Online application information available on customer-facing website	Information is available on the GPC website for each respective jurisdiction including an application checklist, FAQs, pre-approved inverters and manufacturers.
Online application submission	Online submission is available and the preferred application method. PHI has also added automated data validation for application fields to reduce application errors and missing information.
Integration with billing process	Not integrated currently. However, MyAccount information on usage data can be obtained by developers for sizing projects.
Waive application fees for smaller systems	Fees for smaller systems are only required in the District of Columbia. Pepco submitted a request on June 17, 2016 that the DC PSC remove this fee requirement.
Publication of online maps showing preferred locations for PV interconnection	PHI publishes restricted circuit maps for each jurisdiction online. A map of preferred locations is currently not available.
Published list of criteria limits	A summary of the criteria limits are attached herein as Appendix 1. This summary is regularly given out to developers as well.
Interconnection application tracking	24/7 online tracking in near-real time. Additionally, PHI allows customers/developers who have submitted multiple applications the ability to see aggregated reports for all pending applications. This information is accessible via computer or mobile device.

Interconnection Procedure and Screening Process

As discussed in Sections 1 and 2, PHI uses a tiered evaluation methodology, based on IEEE Std. 1547.7, 2013, to minimize undue burden on applicants. Applications only advance to a more rigorous screening process if they fail a lower-level evaluation.

Figure 14: NREL Identified Practices vs. PHI Processes – Interconnection Procedure and Screening Process

NREL Identified Practice	PHI Process
Simplified or expedited applications for systems up to 10 kW in capacity	For systems <10 kW, an expedited review process is used, typically requiring 3-5 days between application submission and approval to install issued.
Consideration of aggregate PV on a feeder	PHI considers aggregate and individual PV against technical criteria to ensure the safe, reliable operation of the distribution system.
Consideration of applications on the same feeder, and joint mitigation strategies if needed	Where possible, PHI considers joint mitigation strategies.
Administrative approval for systems which leads to a penetration level >15% on a feeder	N/A – PHI does not limit the aggregate penetration to 15% of the feeder peak as a criterion for interconnection.
Bypass expedited review and go directly to a more detailed impact study	A standard screen procedure is typically the first step in the impact study. However, if a customer/developer wishes to bypass the screen and go directly into the study, PHI allows this.
Standardized, regional approach	PHI uses the same standardized evaluation approach, except

	where jurisdictional requirements necessitate a difference.

Detailed Impact Studies of Proposed System Installations

Figure 15: NREL Identified Practices vs. PHI Processes – Detailed Impact Studies of Proposed System Installations

NREL Identified Practice	PHI Process
Pre-application reports	PHI customers can request a pre-application study.
Detailed impact studies on large PV system	Engineering Screens are required for systems > 250 kW, which include high-level power flow analysis.
Option of having customer hire outside consultant for feasibility study	PHI allows for this option. However, PHI has found that it is typically more expedient and cost effective to conduct feasibility studies in-house.
Feasibility studies to examine power flow and short circuit current	Power flow and short circuit current studies are conducted when an advanced study of an interconnection request is made.
Update system models as new PV systems are added	System models are updated at either the point when an advanced study of an interconnection request is made, or when a hosting capacity estimate of a circuit is made.
"Cluster studies" – allow for upgrade fee to be shared among developers	PHI is open to this and has implemented on certain interconnection applications. However, PHI cannot guarantee this due to the inability to predict the number, complexity, and concurrence of interconnection applications.
Map all DG with the distribution system OR a separate database to be extracted into modeling software	PHI maps large systems into GIS and maintains a DER database which is used as an input in its power flow modeling.

Mitigation Strategies

There is considerable variability in the mitigation strategies employed by other utilities.

Figure 16: NREL Identified Practices vs. PHI Processes – Mitigation Strategies

NREL Identified Practice	PHI Process
Establish cost limit for mitigation measures for small systems	Cost limitations are set in accordance with state regulation and legislation. PHI will conduct upgrades where coincident with planned system upgrades.
The utility will work collaboratively with the Developer/Customer to identify opportunities for application approval, including mitigation measures and alternative configurations	Where alternatives exist, PHI will consider any alternatives that meet mitigation criteria and resolve impacts.

3 Acceptable Equipment Lists for Small Generation Projects

3.1 Purpose of this Section

The purpose of this section is to address PHI's commitment to maintain an accepted equipment list for small generation projects where once an inverter is reviewed and found to be acceptable for use, it is deemed acceptable for future interconnections. In addition, this section addresses PHI's commitment to review its policy for requiring that equipment lists be submitted for panels and switchgear with each application.

3.2 Acceptable Inverter Equipment Lists

PHI has developed and posted acceptable inverter lists as required. These can be found at:

- Pepco, Maryland - http://www.pepco.com/greenpowerconnection
- Pepco, District of Columbia - http://www.pepco.com/greenpowerconnection
- Delmarva Power, Maryland - http://www.delmarva.com/green-power-connection
- Delmarva Power, Delaware - http://www.delmarva.com/green-power-connection
- ACE, New Jersey - http://www.atlanticcityelectric.com/green-power-connection

PHI's accepted equipment list is comprised of inverters meeting UL1741 Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources and Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems IEEE Std. 1547.1 - 2005 & Std. 1547.1a - 2015 standards that have been reviewed with prior applications and found to be acceptable for interconnection with the PHI systems in the past. Customers can still request the interconnection of inverters not on this list by specifying their preferred inverter on their interconnection applications. The accepted equipment list, however, provides customers with the opportunity to select and utilize inverters that have been previously approved and, thus, allows for their interconnection applications to be reviewed more expediently.

3.3 Policy on Panel and Switchgear Lists

PHI requires that the manufacturer and model number of solar panels being installed at the customer site be submitted with each interconnection request. This information is requested for two reasons, both of which are specific to the particular panels used:

1. To understand the direct current (DC) capacity of energy production
2. To understand the energy output and degradation rates over time

Both of these pieces of information are necessary so that PHI can model and track the impacts of DERs on the system.

For requested DER interconnection applications rated below 2 MWs in size, PHI does not require any additional information or specifications relating to switchgear. For DER interconnection applications rated above 2 MWs, a mutually agreeable disconnect or switchgear will need to be installed to allow for safe and reliable interconnection. Mutually agreeable equipment is to be determined on a project-by-project basis by PHI's Engineering department.

4 Interconnection of Behind-the-Meter Solar and Storage

4.1 Purpose of this Section

The purpose of this section is to provide information to stakeholders on the challenges of incorporating behind-the-meter solar and storage into the electric distribution system and to address PHI's commitments to:

- Not require additional metering or monitoring equipment for behind-the-meter applications where the battery and solar system share one inverter.
- Evaluate and consider its criteria for the evaluation of interconnection applications for behind-the-meter storage with the criteria of other utilities as outlined in the report *Current Utility Screening Practices, Technical Tools, Impact Studies, and Mitigation Strategies for Interconnecting PV on the Electric Distribution Systems*, prepared by NREL and EPRI, published by EPRI.[29]
- File with the relevant state regulating authority, within 12-months, a request to undertake a stakeholder process to study issues regarding the coupling of solar and storage and to specify in its filings an appropriate target date for the completion of this stakeholder process and the recommendation of any changes in protocol.
- For net energy metered ("NEM") customers, PHI's evaluation of interconnection applications for behind-the-meter solar and storage applications that share one inverter, to consider only the maximum bandwidth of charge to discharge in determining the requirement of a Level 1 – Level 4 interconnection study.

4.2 Challenges of Incorporating Energy Storage

The price of energy storage technologies has been dropping rapidly, and the Company expects increased use of energy storage by our customers and other parties and by the Company itself. Energy storage systems can be installed in a variety of configurations, each of which will have different impacts and implications on the distribution grid. Various technical and regulatory issues should be addressed to assure safe and reliable integration of energy storage systems into the distribution grid in an efficient manner so as to not inhibit growth in energy storage development.

Configuration of Energy Storage

One of the challenges of interconnecting energy storage is the variety of possible system installation configurations. Variation in energy storage system configurations can include:

- Connection directly to the power delivery system or behind a customer meter;
- Installed with its own inverter or with an inverter that is shared with another generator (*i.e.* solar);
- Two-way flow capability, enabling storage-system charging;
- Program of the inverter, allowing for variable states of operation;
- Participation in the PJM Regulation Market, either as a generator or as demand response; and
- For behind-the-meter energy storage systems, the system may be designed to prevent discharge when the customer is a net exporter of power.

Interconnection to the Distribution Grid

Energy storage technologies present unique challenges to the distribution grid, many of which can be

[29] *Current Utility Screening Practices, Technical Tools, Impact Studies, and Mitigation Strategies for Interconnecting PV on the Electric Distribution Systems*. EPRI, Palo Alto, CA: 2014. 3002003277. http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002003277

discussed and explored in upcoming stakeholder meetings. For example, when discharging, an energy storage system can impact the grid in a similar way that a generator would. Conversely, if an energy storage system is charging from the grid, the distribution infrastructure must be capable of supporting the increased demand and load. In addition, many energy storage systems are choosing to participate in PJM's Regulation Market. The impact on the distribution system of an energy storage system is amplified when participating in this market because participating systems are asked to follow a dispatch signal that would likely result in reversing modes of operation from charge to discharge quickly, causing the simultaneous change on many systems at the same time. Therefore, pending the outcomes of the stakeholder meetings, the interconnection application and evaluation process in each jurisdiction may need to be reviewed and updated to better assess applications for the interconnection of energy storage.

Net Energy Metering

Net energy metering regulations need to be updated to clarify the role of energy storage. Because energy is lost in the process of storing energy in the form of heat, friction, etc., energy storage is a net consumer of energy and since the overall efficiency is less than 100%. For this reason, energy storage should not be viewed as a form of renewable generation and needs to be evaluated to determine if it meets the requirements for net energy metering.

Measurement of Renewable Energy Certificates

When energy storage systems are installed behind the same meter as a renewable energy generator, care must be taken to assure that the installation does not receive Renewable Energy Certificates ("RECs") for energy storage discharges that are a result of a charge that was originally sourced from the grid. If the energy storage system is configured in such a way that this issue might arise, use of a two-way (net) meter may result in incorrect creation of RECs based on non-renewable generation.

Technical and Operational Challenges

The technical and operational challenges of solar and storage coupled behind-the-meter are also numerous and predominantly relate to the lack of integration and communication between customer and utility systems. Challenges include:

- Battery technical and operating characteristics – customers across the system may ultimately install a variety of types of batteries with different energy and power ratings. The operating characteristics of these different battery types may have different impacts on the utility electrical system. Investments in added monitoring, new modeling and analytical techniques will be required to continue to assure system reliability and safety while providing for the interconnection of behind-the-meter systems with batteries.
- Battery degradation over time – every battery technology degrades in performance over time. If, in the future, the customer is able to provide value to the utility distribution system or other customers on the distribution system, the utility must be assured that the value provided by the battery storage system is delivered as expected, especially if the utility is in a position of deferring projects that would otherwise require a long lead time. Battery degradation over time will need to be much better understood by all stakeholders.
- The customer's planned use of their system – the impact to the utility distribution system from a solar and storage system coupled behind-the-meter can vary widely, depending on how a customer uses that system. At one extreme, a battery system might be fully charging during a period of high customer electricity usage on premises and no solar PV output. At the other extreme, a battery system might be fully exporting during a period of low customer energy usage on premises and high PV solar output. These operating conditions can exacerbate DER impact. In addition, the swing from high energy import to high energy export can be significant, and that impact must be properly evaluated during the screening process to ensure safety and reliability.

Procedural and Administrative Challenges

Customer adoption of battery systems will require an evolution of regulatory and utility interconnection

protocols, and PHI will undertake required changes in concert with regulators and stakeholders.

4.3 No Additional Metering and Monitoring for Solar and Storage Coupled Behind- the-Meter

PHI will not require additional metering or monitoring equipment for behind-the-meter applications where the battery and solar system share one inverter and the battery never exports to the grid. PHI will propose appropriate protocols in the upcoming jurisdictional stakeholder engagement on this topic.

4.4 PHI's Criteria for the Evaluation of Solar and Storage

PHI has evaluated and considered its criteria for the evaluation of interconnection applications for behind-the-meter storage with the criteria of other utilities as outlined in the *Current Utility Screening Practices, Technical Tools, Impact Studies, and Mitigation Strategies for Interconnecting PV on the Electric Distribution Systems* report.[30] Because this document does not contain any references to criteria for the evaluation of behind-the-meter storage in use at any other utilities. PHI's intention is to propose additional or revised criteria in the upcoming jurisdictional stakeholder engagement on this topic. Please see Section 6, "Other Activities and Next Steps" for more information.

[30] *Current Utility Screening Practices, Technical Tools, Impact Studies, and Mitigation Strategies for Interconnecting PV on the Electric Distribution Systems*. EPRI, Palo Alto, CA: 2014. 3002003277. http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002003277

5 Incorporation of Existing, Pending, and Future Anticipated Renewable Generation into PHI's Distribution Planning Process to Facilitate Future Interconnections

5.1 Purpose of this Section

The purpose of this section is to address PHI's commitment to reflect in its distribution system planning actual and anticipated renewable generation penetration. An analysis of the long term effect/benefits of the addition of behind-the-meter distributed generation is not presented herein but will be discussed at length in a supplemental report, which will be filed with each commission no later than six months following the closing of the merger.

5.2 PHI's Existing Distribution Planning Process

The mission of Distribution System Planning is to provide for the modification and expansion of the PHI electric distribution system to meet existing and future customer demands in a reliable manner. This may include adding equipment and facilities to increase capacity, shifting or reconfiguring load among circuits, or reconductoring circuits.

5.3 Distribution Planning Criteria

PHI utilities maintain distribution system planning and design criteria and procedures used in the design of new and modified portions of the distribution system. These criteria delineate:

- Determination of load carrying capacity of distribution system facilities
- Distribution system and service voltage levels and distribution system power factor to be maintained
- Required distribution system reliability contingency (n-1) is maintained

The planning process considers new sources of electric demand as well as load-modifying resources such as energy efficiency resources and DERs against the substation and circuit capabilities of the current system. From there, PHI planners develop and evaluate alternative solutions to identified problems and ultimately formulate construction recommendations which are included in the five-year capital budget. Additionally, PHI must be able to plan for the safe and reliable operation on the power delivery system under both normal and contingency scenarios (*e.g.* sudden loss of behind-the-meter generation).

5.4 Peak Load Projections and the Ten-Year Load Forecast

Fundamental to planning for the orderly and economic modification and expansion of the distribution system is the balancing of peak load and the capability to supply that load. The lead time required to purchase equipment and to plan and execute construction and field work necessitates the projection of future facility load and system adequacy to supply load. To this end, Distribution System Planning develops feeder, distribution substation transformer, and total distribution substation peak load projections over a ten-year period – taking into account the impact of existing and pending DERs. At this point in time, PHI is working to develop a method to forecast future anticipated DERs (*i.e.* those neither in operation currently nor those known to be pending) and appropriate criteria to incorporate such resources into its planning process.

5.5 Reflecting Forecasted DERs in the Distribution Planning Process

In response to the operational challenges presented by DERs, and in particular the intermittent production characteristics of solar photovoltaics ("PV"), PHI is in the process of developing four key modifications to its planning process that addresses the commitment for incorporating the impact of distributed renewable energy.

1. The creation of a five-year NEM PV forecast based upon historical interconnection applications

by PHI utility.

2. Incorporation of the forecasted PV capacity and corresponding load reductions into the short-term load forecast and the Ten-Year Load Forecast (which are the key inputs in the Distribution System Planning process and the initiation of the construction recommendation process).
3. Reconciliation of historical peaks with solar capacity additions – in instances where PHI relies upon historical feeder peaks for planning purposes, the peak values will be adjusted to account for solar capacity additions.
4. Incorporation of criteria to account for active and planned DERs under different operating conditions and system restoration efforts that ensure reliable operations under multiple system configurations.

5.6 Discussion of Modifications to the Planning Process to Account for Anticipated DERs

In accordance with the merger commitment, once these changes are fully developed and rolled out, PHI's distribution planning process will consider the impacts of all "active," "pending" and "anticipated"[31] interconnection applications during the planning process.

It is anticipated that these changes will be developed and a timeline for implementation will be included in the final report.

5.7 Approaches Utilized in Other Jurisdictions to Address the Impacts of On-site Renewable Resources on the Local Grid and Circuits

Several approaches have been taken by utilities to address the impacts of on-site renewable resources. Solutions for addressing the impact of these resources can range from being able to better forecast production of generation relative to load all the way to controlling output – both at the meter and in front of the meter. This section briefly discusses some of the enabling technologies implemented by other utilities that allow for the mitigation of impacts created by the uncoordinated interconnection of intermittent DERs. However, it is important to note that as utilities have better visibility, and potentially control of on-site renewable resources, any potential detrimental effects of high penetrations of DERs can be mitigated more easily as detailed below.

Figure 17: PHI Strategies to Address Impact of On-Site Renewable Resources on the Local Grid

Mitigation Strategy	PHI Initiative
Centralized Capacitor Bank Controls	PHI is developing communications and central control to capacitor banks across its territory as Distribution Automation schemes are put in. The centralized capacitor control works by monitoring the VAR flow at the feeder terminal and turning capacitors on or off to maintain unity power factor.
Increase Hosting Capacity	PHI completed a DOE "SUNRISE" grant study with other collaborators, investigating cost-effective ways to increase hosting capacity and developed a tool that analyzes secondary voltage rise.
Distribution Control and Communications	PHI is collaborating with Chesapeake College and

[31] Anticipated DERs are the five-year forecasted values

	others to conduct a demonstration project that will control smart inverters, battery storage, and flexible load, along with substation and feeder equipment in an integrated system. This along with the development of low-cost, secure communications will prepare PHI to maintain a robust, reliable grid of the future.
Monitoring and Control of Smart Inverters	PHI is collaborating with the University of Hawaii and others to develop this functionality, which will allow for more DERs to be deployed. Additional testing and demonstration of PV and other new technology is taking place at the Water Shed in Rockville, MD.

Hawaii Electric Companies

Hawaii represents an ideal testing ground for groundbreaking DER system management technologies, given the growing amounts of customer-sited PV on its island grids. Hawaii already has approximately 500 MW of solar PV capacity, of which 90% is residential rooftop solar panels. Hawaiian Electric ("HECO") has some distribution circuits that generate more solar power at midday than is being used by customers on those lines, leading to back-feeding problems.[32] HECO is also seeing load-curve disruptions that are more pronounced than the "duck curve"[33] conditions that California is facing and generally needs to ensure stable voltage levels. HECO has undertaken a number of DER adaptation initiatives – collecting and reacting to more detailed data in real-time and automated voltage controls – that allow for higher levels of solar PV to be successfully integrated with the distribution grid. These insights can be valuable to PHI as PHI's levels of distributed generation continue to increase in the near future.

Smart Inverters

HECO collaborated with NREL and SolarCity in early 2015 to test whether inverters can successfully mitigate transient load rejection overvoltage concerns on the distribution grid.[34] These inverters can be programmed and controlled to trip on and off in response to grid voltage fluctuations, inject or absorb reactive power, provide frequency support, and perform other essential grid-balancing tasks. In early 2015, HECO announced plans to increase circuit thresholds from 120% of MDL to 250% of MDL, more than doubling the hosting capacity of circuits to integrate rooftop solar PV.[35] This allowed for a "cleared queue" of more than 2,500 customers waiting to interconnect their solar systems to the grid.

HECO also collaborated with Enphase in 2015 to collect and analyze detailed voltage and frequency data from its microinverter fleet in five-minute increments, data that is significantly more detailed than the substation-level data that HECO collects.[36] This inverter-level data was calibrated and correlated to past HECO system-wide voltage out-of-range readings. The data suggested that the age and quality of power-conducting cables and transformers was the primary indicator of potential voltage concerns for solar-

[32] Greentech Media. "Varentec's Power Electronics to Tame Hawaii's Solar-Rich Distribution Grid". Accessed June 12, 2016. http://www.greentechmedia.com/articles/read/varentecs-power-electronics-to-tame-hawaiis-solar-rich-distribution-gr

[33] CAISO. "What the duck curve tells us about managing a green grid". Accessed June 12, 2016. https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf

[34] SolarCity. "Hawaiian Electric Announces Intent to Increase Circuit Limits for Rooftop Solar as a Result of Laboratory Testing". Accessed June 12, 2016. http://investors.solarcity.com/releasedetail.cfm?releaseid=896100

[35] *Ibid.*

[36] Greentech Media. "How HECO is Using Enphase's Data to Open its Grid to More Solar". Accessed June 12, 2016. http://www.greentechmedia.com/articles/read/how-heco-is-using-enphase-data-to-open-its-grid-to-more-solar

heavy circuits.[37] The circuit-level analysis was overlaid with the large queue of interconnection requests to understand which interconnections would and would not cause a potential issue for the distribution grid.

Power Electronics Devices

In early 2016, HECO announced a partnership with Varentec, deploying Varentec's Edge of Network Grid Optimizer ("ENGO") devices and Grid Edge Management System ("GEMS") software to test their ability to stabilize voltage fluctuations on a HECO circuit with high levels of solar PV penetration.[38] These tools are capable of injecting reactive power to lower or raise voltages – autonomously or by following instructions from GEMS.

HECO also announced in early 2016 a partnership with Gridco Systems, through which HECO has deployed Gridco's In-Line Power Regulator ("IPR").[39] These pole-mounted IPRs allow for real-time visibility at the edge of the grid and enable additional controls, seeking to maintain reliability within required voltage limits, manage harmonics, and limit back-feed conditions.

Production Forecasting

HECO's Distributed Resource Energy Analysis and Management System ("DREAMS") ties together real-time data with forecasting and grid operations.[40] This initiative integrates renewable forecasts (solar irradiance, wind speeds) with ramp statistics and DG impacts into an energy management system. This allows for a complete accounting of renewables and behind-the-meter generation in real-time operations and for planning purposes. It enables dynamic dispatch, improves load forecasting, reduces reserves, and reduces operational costs. This real-time forecasting is another element of data and analytics that develops new forecasting standards and integration procedures for high-penetration levels of renewables.

Secure Communications

Arizona Public Services ("APS") is developing a communications platform to connect distributed pilot systems with the utility control center.[41] This integrated communications network (inverter hardware with utility SCADA or other control software such as a Distribution Management System ("DMS") or Distributed Energy Resource Management System ("DERMS") would allow for a better optimized distribution grid.

Access to inverter data is challenging, as is the capability to analyze, process, and respond to real-time data. Sufficient communications bandwidth will also be required to connect and manage these distributed energy resources. For a select number of installations in the APS service territory, a Schweitzer Engineering Laboratories ("SEL") 734P advanced metering system was installed to collect power quality

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[37] *Ibid.*

[38] PR Newswire. "Hawaiian Electric and Varentec to test technology for enabling more rooftop solar on island grids". Accessed June 12, 2016. http://www.prnewswire.com/news-releases/hawaiian-electric-and-varentec-to-test-technology-for-enabling-more-rooftop-solar-on-island-grids-300246549.html

[39] Hawaiian Electric Company. "Hawaiian Electric Company Deploys Gridco Systems Technology to Help Increase PV Hosting Capacity of Distribution Grid Leverage Installed Asset Base". Accessed June 12, 2016. https://www.hawaiianelectric.com/hawaiian-electric-company-deploys-gridco-systems-technology-to-help-increase-pv-hosting-capacity-of-distribution-grid-leverage-installed-asset-base

[40] U.S. Department of Energy. "Distributed Resource Energy Analysis and Management System (DREAMS) Development for Real-Tme Grid Operations". Accessed June 12, 2016. http://energy.gov/eere/sunshot/distributed-resource-energy-analysis-and-management-system-dreams-development-real-time

[41] Solar Electric Power Association. "Rolling out Smart Inverters". Accessed June 12, 2016. https://www.solarelectricpower.org/media/416463/SEPA-Smart-Inverter-Executive-Summary.pdf

information.[42] A wireless radio network is used to create an Ethernet network for communication to the SEL-734P, and data is transferred to the APS network using Distributed Network Protocol ("DNP3") over Transmission Control Protocol / Internet Protocol ("TCP/IP"). The SEL-734P time is synchronized to the APS network using the DNP3 protocol. APS chose the SEL-734P because of its ability to interface with the utility's specific communications network and infrastructure, ability to capture information at the desired speed and granularity, and ability to be integrated into the utility process for deployment and maintenance.

Battery Storage

San Diego Gas & Electric has deployed numerous larger, substation-level energy storage projects as well as smaller, community energy-level projects.[43] The larger projects are primarily designed to provide peak shave, time shift, Volt-ampere reactive (VAR) Dispatch, Island Support, or PV smoothing services. The smaller projects tend to focus on a subset of the services that the larger projects provide, in addition to EV charging support. The successful implementation of battery storage units involves numerous non-trivial issues related to procurement, design and engineering, construction and installation, and operations. Operational issues – likely most relevant to PHI – may include a lack of integration between network management systems and battery control systems, sporadic communications between systems, scaling of solutions, and failure modes. Other issues may include: limited market availability, long lead times, lack of full "turnkey" projects, lack of extended warranties, and exaggerated capabilities by vendors (procurement); physical space requirements, cooling requirements, noise issues, and a lack of utility construction standards (design and engineering); and environmental restrictions, physical barriers, SCADA switches, non-standard transformers and cables, and communication requirements (construction and installation). All of these issues may be important in PHI's considerations when successfully integrating battery storage systems with the local distribution grid.

5.8 Lessons Learned from PHI's Work with the DOE in the "SUNRISE" Effort

This section presents a synopsis of PHI's recent work with the Department of Energy on the subject of hosting capacity, and also presents the keys lessons learned from this work.

Background

The US DOE's *Sunshot* initiative is a nation-wide collaborative effort aimed at making solar cost-competitive with other forms of electricity by the end of the decade. As a part of the Sunshot initiative, the US DOE announced in October, 2013 nearly $7.8 million in funding for eight projects under the Solar Utility Networks: Replicable Innovations in Solar Energy ("SUNRISE") opportunity. These SUNRISE projects are helping utilities develop adaptable and replicable practices, long-term strategic plans, and technical solutions to sustain reliable operations with large proportions of solar power on the grid. PHI was awarded funding under this competitive solicitation.

In the fall of 2015, PHI concluded an industry-leading study meant to inform utilities as to the levels of distributed generation (*i.e.* "hosting capacity") that can be accommodated by local utility distribution circuits, and to develop insight into methods for increasing feeder hosting capacity in a cost-effective manner.

This work was sponsored by the U.S. DOE as part of its Sunshot initiative (Award Number No. DE-EE0006328) and was completed with the participation of PHI, Electrical Distribution Design, Inc., Clean

[42] *High-Penetration PV Deployment in the Arizona Public Service System, Phase 1 Update.* NREL. Golden, CO. 2012. http://www.nrel.gov/docs/fy12osti/54110.pdf

[43] San Diego Gas & Electric. "SDG&E's Energy Storage Implementation". Accessed June 12, 2016. http://energy.gov/sites/prod/files/2014/06/f17/EACJune2014-4Bialek.pdf

Power Research, the Center for Energy, Economic & Environmental Policy ("CEEEP") at Rutgers University, and the New Jersey Board of Public Utilities. The release of the final report for this work, entitled "Model-Based Integrated High Penetration Renewables Planning and Control Analysis," is subject to the approval and timeline of the US DOE.

Methodology

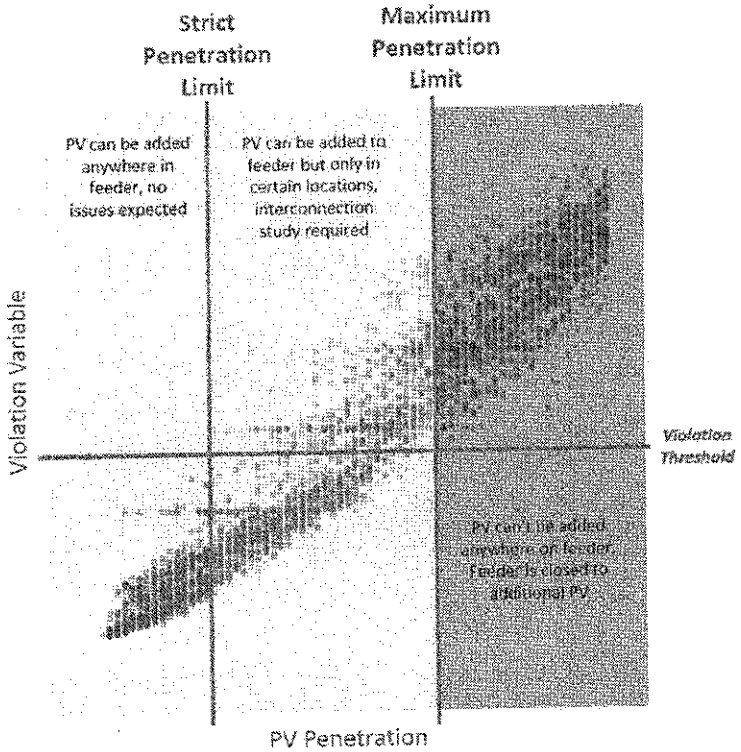
The study focused on a sample of 20 overhead distribution feeders across PHI's service territories in Delaware, Maryland, and New Jersey. The selection of these particular feeders was made with diversity of circuit configuration, customer count, technology, and various other factors in mind. It was anticipated that this particular sample set of feeders would be representative enough for many utilities across the US to be able to draw appropriate lessons from this study in planning and operating their own individual local area distribution systems.

A circuit model was developed for each of the 20 selected feeders and was tested in an analysis that would reveal the capacity (MW) of distributed generation that could interconnect with each circuit without causing operational issues.

The analysis of each circuit was conducted iteratively, in each step adding PV to random sites across the feeder in increasing quantities while conducting a load flow analysis to check for operational violations, such as voltage excursions, overloading, phase imbalances, and other violations. The load flow analysis at each iterative step was a dynamic load flow analysis that considered the generation profile of PV with the circuit load shape over a 12-month period. The result at the end of this stage in the analysis was an estimate for each circuit of:

- **The Strict Penetration Limit** – The amount of capacity known with certainty to be available to host interconnecting PV, which can be added anywhere in the feeder up to this level without creating an adverse impact on the system or other customers.
- **The Maximum Penetration Limit** – The amount of additional capacity that may be available to host interconnecting PV, above and beyond the Strict Penetration Limit, but is dependent on specific locations and circumstances on the circuit and thus cannot be guaranteed with certainty unless a detailed study is made to analyze each proposed interconnection request received after the Strict Penetration Limit has been reached.

Figure 18: Penetration Limits for Adding PV to Distribution Circuits



Once the baseline Strict and Maximum penetration limits of each circuit were determined, a new analysis was conducted to identify what impact various circuit improvements might have on the Strict and Maximum penetration limits of each circuit. This new analysis was also iterative in nature, and evaluated improvements, such as phase balancing, capacitor redesign, reducing the voltage regulator set points, implementation of fixed power factor operation on PV inverters, and the installation of battery storage.

Finally, cost estimates for each of these feeder improvements were developed, from which it can be understood which circuit improvements increasing the hosting capacity of these 20 feeders were most cost effective.

Results

While the official report is not yet available from the U.S. DOE, PHI has begun sharing the results to socialize this valuable information. The results presented in the report were broad and extensive, and thus any interested party should review the full U.S. DOE report when released. There are key results, however, that were shared with stakeholders during the May 3, 2016 webinar.[44] Discussed below are the results of the analysis for one individual feeder and the aggregate results for each of the 20 feeders.

[44] Please see Appendix 2 for list of attendees to the May 3rd webinar

An Individual Feeder Case Study

The following case study is representative of the case studies available in the final report. This particular feeder consists mostly of 34.5 kV primary conductor but also has several areas of older 4.15 kV primary conductors connected through step-down transformers. It is one of the longer feeders in the study, with three voltage regulation zones, four voltage controlled switched capacitor banks and one fixed capacitor bank. Currently, the feeder can experience poor voltage regulation on the 4.15 kV sections, and phase imbalances limit the PV penetration of the base circuit to about 6% (limited by customer steady-state high voltages). The following table and graphic depict this feeder case study:

Figure 19: SUNRISE Feeder Case Study Information

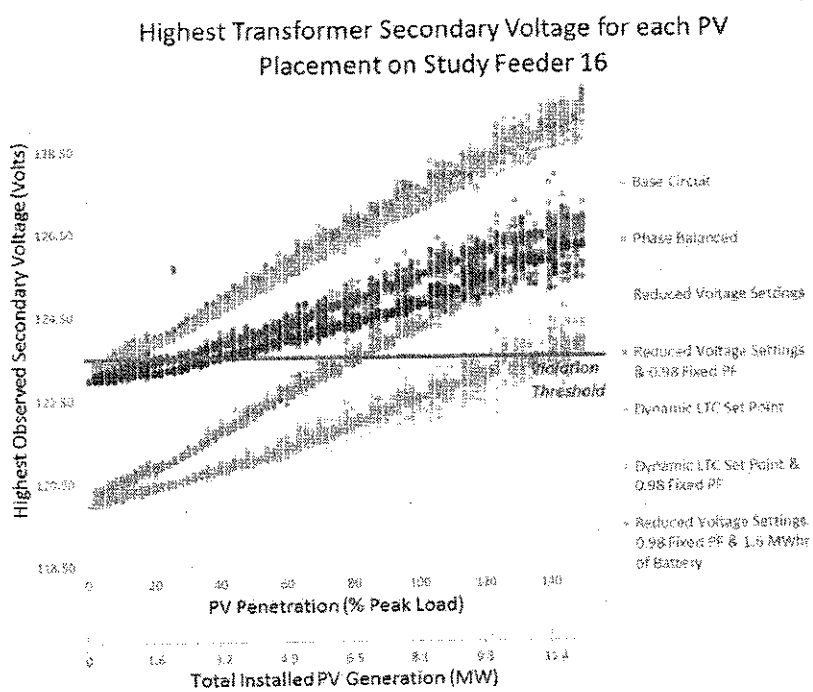
Study Feeder 16 Summary	
Feeder Type	Res
Primary Voltage	34.5 kV Y-G and 4.15 kV Y-G
Feeder Length (total circuit miles)	64 mi
Distance from Sub to Furthest Load	12.8 mi
Peak Load (SCADA)	8.1 MW
Minimum Daytime Load (SCADA)	2.4 MW
Number of Distribution Transformers	331
Connected KVA (total xfrmr rating)	65 MVA
Number of Capacitor Banks	5
Total Capacitor Bank Rating	7.8 MVAR
Number of Voltage Regulation Zones	3
Number of Existing PV Sites	2
Total Existing PV Generation	15 kW
Existing PV Penetration	< 1%

In the second phase of PHI's analysis, several mitigation options were analyzed to identify which mitigation strategy could most effectively mitigate high voltage issues. These solutions are described below and illustrated graphically in Figure 20 and include:

- **Phase Balancing** – Phase balancing attempts to ensure the same amount of power is consumed evenly across all 3 phases of the distribution system. A lightly loaded phase will typically have higher voltages than the others which would limit PV deployment as that phase would run into high voltage issues sooner. By balancing the three phases, all of the voltage profiles would be brought to the lowest possible point, allowing for the maximum amount of voltage headroom and the highest PV penetration limits.
- **Reducing Voltage Settings** – Reducing the voltage set point on the load tap changers at the substation and voltage regulators along the feeder creates more headroom, as explained above. The settings are reduced enough to sustain acceptable voltage levels during peak load.
- **Reducing Voltage Settings and Fixing .98 Power Factor** – In conjunction with lowering voltage set points, a fixed, absorbing power factor on inverters can help mitigate high voltage during low-load periods. The absorbing power factor curtails the real power output to 98% and allows the inverter to absorb VARs from the grid. While running hosting capacity, all PV inverters on the feeder have an adjusted power factor.
- **Dynamically Modifying LTC Set Points** – Dynamically modifying load tap changer (LTC) set points is an extension of reducing voltage settings. This feeder improvement would involve implementing a control scheme which would update voltage regulator settings over time in order to best match circuit conditions. The set point would be reduced as low as possible during light load, high PV output times and re-adjust voltage set points to support lower voltage levels at peak load.

- **Dynamically Modifying LTC Set Points and Fixing .98 Power Factor** – This feeder improvement incorporates a dynamic voltage control scheme while all systems operate at .98 fixed, absorbing power factor, as previously described.
- **Reducing Voltage Settings, Fixing .98 Power Factor, and Implementing a 1.6 MWh Battery** This improvement incorporates a reduced voltage setting, a .98 power factor and a 1.6 MWh battery. The battery can dynamically control voltage levels, charging and discharging as needed. The battery can also charge or discharge in order to offset sudden changes in load or PV generation, specifically during rapid cloud cover causing intermittent generation. Lastly, as an inverter-based generator, the power factor and other advanced inverter functions can be utilized.

Figure 20: Mitigation Options for Feeders with High Voltage due to Presence of PV



As can be seen in Figure 20, the circuit in its current configuration without any improvements (see "base circuit") can accommodate very little distributed PV (see "PV Penetration" on the x-axis) before violating circuit voltage standards. Each circuit improvement tested in the analysis, however, has an effect of increasing the level of allowable PV penetration, with dynamically adjusting substation transformer load tap changers (see "Dynamic LTC Set Point") and at the same time implementing a leading customer inverter fixed power factor of .98 (see "Dynamic LTC Set Point & 0.98 Fixed PF") providing the greatest level of improvement.

Aggregate Results of all 20 Case Studies

The aggregate results of all twenty case studies, presented in Figure 21, highlight the fact that each distribution feeder is unique in its ability to host distributed energy resources. Many factors that influence circuit hosting capacity are location-dependent and can range from field conditions to local permitting requirements:

Figure 21: Penetration Limits of Studied Feeders Before and After Upgrades and Upgrade Costs

Strict Penetration Limit (Before and After)						
Feeder	Base Case			Max. Penetration w/ Upgrades		
	PV (%)	PV (MW)	Cost (k$)	PV(%)	PV(MW)	Cost(k$)
1	29.7	1.0	0.0	167.9	5.9	60.2
2	29.7	1.5	0.0	197.1	10.4	32.5
3	53.6	2.2	67.9	264.7	10.9	149.3
4	34.9	1.2	0.0	134.5	4.8	22.0
5	43.7	2.0	67.3	193.7	8.7	96.8
6	38.9	2.6	0.0	219.6	14.5	78.5
7	36.9	1.9	0.0	92.7	4.7	131.4
8	23.8	1.4	0.0	129.2	7.6	2.0
9	1.9	0.1	0.0	161.3	8.1	21.0
10	12.8	0.3	0.0	62.9	1.6	27.5
11	39.0	2.0	37.2	61.0	3.1	178.3
12	8.0	0.7	37.2	11.9	1.0	118.7
13	2.9	0.2	0.0	104.9	5.8	150.2
14	15.9	1.5	0.0	18.0	1.7	33.0
15	20.0	1.6	0.0	76.0	6.2	21.5
16	5.9	0.5	59.7	63.9	5.2	167.1
17	17.0	2.0	0.0	104.9	12.1	31.0
18	42.9	2.8	0.0	336.7	22.2	25.0
19	25.9	1.6	74.0	67.8	4.1	80.0
20	44.9	2.7	0.0	184.6	11.0	2.5
AVERAGE	**26.4**	**1.5**	**17.2**	**132.7**	**7.5**	**71.4**

Notes:

- "PV (%)" represents the aggregate inverter nameplate output (AC) as a percentage of feeder peak load
- The above does not include battery deployment
- The above feeders represent different voltage levels

The rows highlighted in the table above show the range of hosting capacity improvement that was demonstrated to be possible. The magenta row is illustrative of the low end, with the case study on feeder no. 14 demonstrating the potential for a 200 kW increase in the Maximum Penetration Limit after $33,000 in upgrades. The green row is illustrative of the high end, with the case study on feeder no. 18 demonstrating the potential for a 19.4 MW increase in the Maximum Penetration Limit after only $25,000 in upgrades.

The average improvement in Maximum Penetration Limit across all 20 case study feeders was 7.5 MW at an average cost of $71,400.[45] It should be noted that there are other factors that must be evaluated such as distribution automation schemes and the impact on the transmission system which means that not all of the hosting capacity increases may be fully realized. However, the study does show that some techniques can be quite effective on certain circuits.

[45] The results of the 20 feeders studied by PHI are illustrative. The cost of increasing hosting capacity can vary significantly when considering factors such as field conditions and local permitting requirements.

Relevance of the Study to Distribution System Planning

This study has demonstrated many different lessons applicable to Distribution System Planning. Among them are:

1. **No circuit is the same in its innate ability to host distributed energy resources** – each circuit is an amalgamation of different utility assets and technologies installed and reconfigured over many decades to meet changing customer needs. These variations in technology type, circuit usage, and configuration under normal and backup conditions create a great deal of variation in the hosting capacity of one circuit relative to the next.
2. **Distributed energy investment can be guided onto circuits that can better accommodate it** – hosting capacity analysis is a valuable tool that can be used as a signal to customers and developers to focus efforts on parts of the system that have a greater ability to accommodate interconnection. While such a tool takes time and investment to develop, refine, and formalize the processes for, it is a worthwhile investment.
3. **Additional headroom for hosting distributed energy can be made on circuits at a reasonable cost** – utilities can make potentially[46] modestly priced upgrades to create additional headroom in circuits to accommodate interconnections. While this kind of utility investment would undoubtedly be subject to regulatory review and approval because of its monetary impacts on ratepayers and customers seeking interconnection, there may be justification for conducting such work programmatically on areas of the system experiencing high demand for interconnection.[47]
4. **Advanced communication and control allow for the greatest gains in hosting capacity** – today, hosting capacity is inhibited by the lack of communication and control between the utility and certain line equipment such as voltage regulators and capacitors and also customer systems. Even modest measures to improve communication and control can have material impacts on circuit hosting capacity. In addition to the communication systems and the ability for equipment to receive and implement control commands, is the development of the logic for the centralized or centralized/distributed control systems.

[46] Every circuit configuration and field installation is unique, and many factors may drive the price of improvements upward.

[47] The results of the 20 feeders studied by PHI are illustrative. The cost of increasing hosting capacity can vary significantly when considering factors such as field conditions and local permitting requirements.

6 Other Activities and Next Steps

It is important to note that the sections discussed in this report pertain to PHI's operation of the power delivery system at a time when interconnection applications continue to increase, and PHI is required to maintain the safe, reliable and affordable operation of the system despite having limited visibility into the actual operations of customer-sited equipment. PHI also has existing interconnection and net metering programs, which Exelon is committed to maintaining. PHI's intention is that the collaborative stakeholder process will lead to discussion and proposed solutions as to how PHI and other stakeholders can help better account for and integrate the operations of DERs. This will allow for an improved planning process for the orderly expansion and modification of a reliable power delivery system as well as meet the policy goal of increasing the amounts of distributed, renewable energy.

6.1 Ongoing Activities

In addition to the commitments described herein, the PHI utilities will also be undertaking the following related activities:

- Filing an enhanced communication plan within six months of merger closing,[48]
- Filing an issuance of permission related to 15 D.C.M.R. Chapter 40 within 180 days of merger closing,[49]
- Filing an analysis of the long term effects/benefits of the addition of behind-the-meter distributed generation attached to the distribution system within its service territory, including any impacts on reliability and efficiency within six months of merger closing,[50]
- Further investigation through a stakeholder/committee review process related to the coupling of solar and storage,
- Continued compliance with annual and semi-annual regulatory and stakeholder reporting requirements as well as adherence to any new reporting requirements outlined in Figure 1 which include:
    - Atlantic City Electric Company Net Metering Reports and Interconnection Reports Pursuant to N.J.A.C 14:8-4.5 and 14.8-5.9
    - Delmarva Power & Light Company Annual Report Filed Pursuant to Interconnection Standards for Delmarva Power (Delaware) Annual Small Generator Interconnection Report - Docket No. 49
    - Delmarva Power & Light Company Annual Report Filed Pursuant to Code of Maryland Regulation ("COMAR") 20.50.09.14 - Small Generator Interconnection Standards Annual Small Generator Interconnection Report
    - Potomac Electric Power Company Annual Report Filed Pursuant to Code of Maryland Regulation ("COMAR") 20.50.09.14 - Small Generator Interconnection Standards Annual Small Generator Interconnection Report
    - Potomac Electric Power Company - District of Columbia Formal Case No. 1050 Compliance Report for Pepco

6.2 Next Steps

PHI will notify stakeholders upon filing of this report and begin the working group process across the

[48] In accordance with DC FC 1119, Order 18148, Commitment 125 and TASC Amended Settlement Agreement, Commitment I (7)

[49] In accordance with DC FC 1119, Order 18148, Commitment 123 (b) and TASC Amended Settlement Agreement Commitment I (4) (b) and I (5) (b)

[50] In accordance with DC FC 1119, Order 18148 Commitment 119 and TASC Amended Settlement Agreement Commitment I (1)

four jurisdictions. PHI will summarize and respond to the questions and issues raised through this process

APPENDICES

Appendix 1 – Summary of Criteria Limits for Distributed Energy Resource Connections to the ACE, DPL and Pepco Distribution Systems (less than 69kV)

Note: PHI typically provides this summary document to contractors and developers.

1. Single Phase Limit
The largest capacity single phase generator or DER (battery) operating in parallel with the grid is 100 kW. Above that size, a balanced 3 phase system is required.

2. Voltage Limits
DERs are permitted to cause up to 2% voltage fluctuation at the Point of Interconnection and ½ the band width of any voltage regulator or ½ the net dead band of a capacitor bank. DERs in maximum output, are permitted to raise feeder voltage to the ANSI or state limit whichever is more conservative.

3. Existing Distribution Circuit Capacity Limits
The aggregate limit of large (250 kW and over) generators running in parallel with a single, existing distribution circuit is 0.5 MWs on the 4 kV, 3 MWs on the 12 kV, 6 MWs on the 25 kV, and 10 MWs on the 34 kV.

4. Express Circuit Capacity Limits
Distributed generation installations which exceed the limit for an existing circuit require an express circuit.

The maximum generator size for express circuits shall be:

- 4 kV 0.5 MW
- 12 – 13.8 kV 10 MWs
- 23 – 25 kV 10 MWs
- 33.26 – 34.5 kV 15 MWs

5. Distribution Power Transformer Limit
The aggregate limit of large (250 kW and over) generator injection to a single distribution transformer of 22.5 MVA nameplate or larger is 10 MWs. Transformers with nameplate ratings lower than 22.5 MVA will be given lower ratings on an individual basis. If the transformer rating is significantly greater than 40 MVA (such as on a 34 kV circuit) it may be possible to interconnect a generation capacity of up to 15 MW.

Adding a new transformer will be considered if there is no availability on any of the existing transformers and space is available in an existing substation. Any proposed transformers would be PHI's standard distribution transformer (37 MVA nameplate rating.)

6. Express Circuit Length Limit
If there is no more injection capacity or space for an additional transformer at the closest substation, the next closest substation will be considered. The length of an express circuit is limited to 5 miles, or for the sake of the feasibility study, 3.8 straight line miles to the substation. This simplification is used because the feasibility study phase does not allow for the time and resources to examine routes in detail (including existing pole lines, easements, ROW, and environmental issues etc.)

7. When a New Substation is Required
If a distribution express circuit can't be built from an existing substation for a project, it will be necessary

to construct a new distribution substation with a standard ring bus design. It will be supplied by extending existing transmission lines. In NJ, it is the developer's responsibility to verify eligibility of this configuration for solar renewable energy certificates with New Jersey's Clean Energy Program if desired.

All limits, given above in MWs, are subject to more detailed study to ensure feasibility.

8. Secondary and Spot Networks

For the Pepco DC area

Secondary Area Network

- No reverse power is allowed thru the network protector, and system shall cause no network protector cycling
- Aggregate maximum injection into an area network is 5% of the area network maximum load or 500 kW, whichever is less
- Individual DER system maximum output is 50 kW
- Aggregate maximum on a single phase line is 20 kW
- Aggregate maximum on any transformer in the secondary area network is 5% of the transformers peak load. This shall be determined by mapping the closest PV systems to the network transformer and summing their output. (This will insure that a problematic concentration doesn't occur in one part of the area network).

Spot Network

- Systems will be limited to 5% of the spot network peak load or less.
- No reverse power is allowed thru the Network Protector, and system shall cause no Network Protector cycling

For the New Jersey (Atlantic City) Area Network

- Aggregate PV generation on the network shall not exceed 10% of minimum load or 500 kW, whichever is less. For Atlantic City, the limit shall be 1,500 kW (approximate minimum) x 10% = 150 kW. This network will continue to be downsized, so this aggregate amount should not be exceeded.
- No reverse power allowed to Network Protector
- No conditions where Network Protector is adversely affected are allowed
- Aggregate maximum on any transformer in the secondary area network is 5% of the transformers peak load. This shall be determined by mapping the closest PV systems to the network transformer and summing their output. (This will insure that a problematic concentration doesn't occur in one part of the area network).

For the Delaware (Wilmington) area:

- Same as DC

- For the Wilmington Network the aggregate maximum shall be the smaller of 5% or 50 kW.

For the Maryland area:

- Same as DC

Explanation of the Reviewed Impacts

Voltage Fluctuation – This is a metric used to represent the DER's impact on distribution feeder voltage. It quantifies the difference in feeder voltage between when the system is running at full output and then after the generation has been suddenly lost. Larger systems and systems connected further from a substation tend to have a higher voltage fluctuation value. If this criterion can't be met with power factor mitigation, an impact study will be required to ensure that voltage can be maintained within applicable

standards.

Steady State High Voltage – A simulation is performed which predicts how high the voltage will rise at a point in time when energy consumption is lowest on the feeder and the DER is injecting power. The system is simulated in a normal, steady state and abnormalities are not accounted for. In some cases, steady state high voltage can be mitigated by changing settings on voltage regulation equipment.

Reverse Power Flow – Some devices may require setting changes, a re-evaluation of their control scheme, or replacement. The lowest daytime (9am - 3pm) load going thru the lowest loaded phase of a voltage regulator or distribution power transformer must be 20% greater than the aggregate solar output downstream of the respective equipment or mitigation is required.

Explanation of Restricted Circuits

Restricted Circuits – any size – Given current technology, each distribution circuit will have a limit to the amount of distributed generation that can be accommodated. When the installed generation on a circuit has reached its maximum, (generally just before the point of voltage violations), no further applications can be accepted for DER's, regardless of size, unless the customer is willing to pay for the needed upgrades. Potential DER owners may request, at their expense, to pay for upgrades that would allow them to install their system. In many cases, the required upgrade costs may make an installation cost prohibitive.

Restricted Circuits – over 250kW – Circuits which have active and/or pending generation that exceeds the amount that can be accommodated may be restricted to generators with AC ratings of 250 kW or less. Typically, this is done in the case where distributed generation requests exceed set criteria limits in order to avoid closing the circuit entirely. (See: 3. Existing Distribution Circuit Capacity Limits)

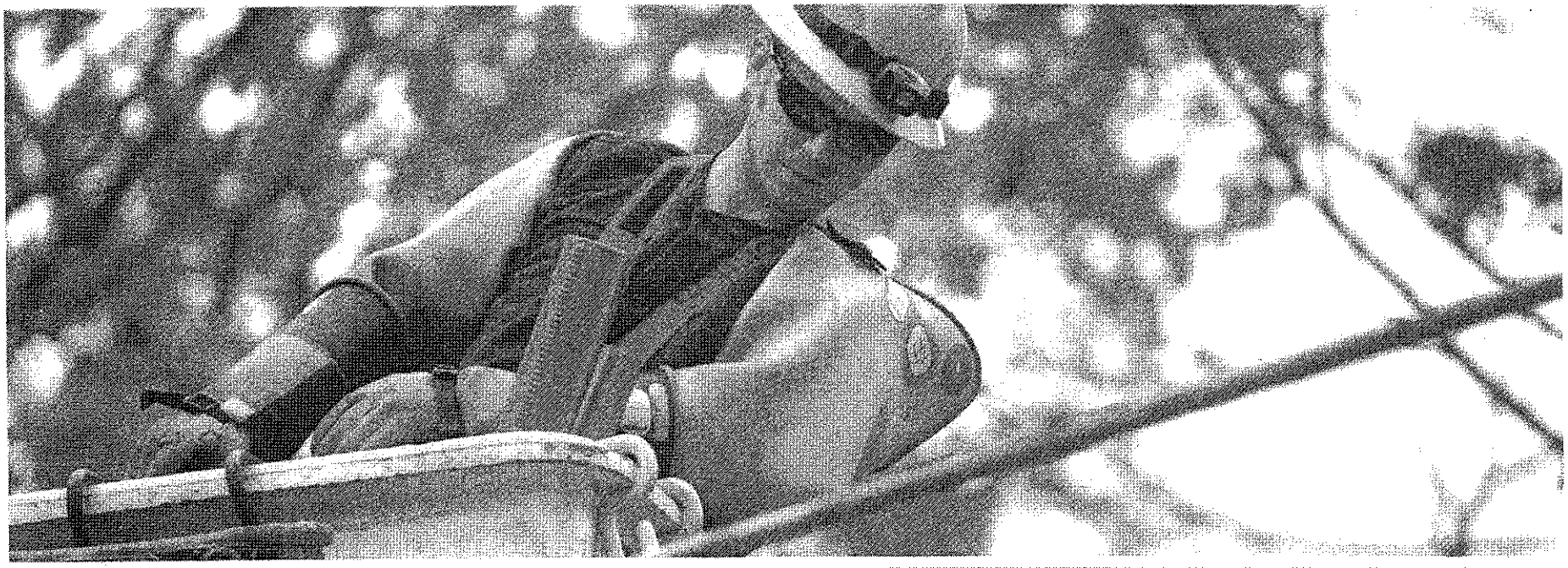
Appendix 2 – Participants at PHI's May 3, 2016 Webinar

The following is a list of organizations who were invited and/or attended PHI's May 3, 2016 webinar.

A.F. Mensah, Inc.
AOBA*
Chesapeake Utilities Corporation*
Clean Air Counsel*
Clean Chesapeake Coalition*
DC Dept of Energy*
DC Solar United Neighborhoods*
DC Water*
Delaware Department of Natural Resources and Energy Control, Division of Energy and Climate
Delaware Division of the Public Advocate
Delaware Gov*
Delaware Public Service Commission
DESEU*
District of Columbia Office of the People's Council
District of Columbia Public Service Commission
Earthjustice
Fuel Fund of Maryland
Grid 2.0*
GSA*
ICF International
Kenergy Solar
Klockner & Company
Lockheed Martin
Maryland DC Virginia Solar Energy Industries Association
Maryland Energy Administration*
Maryland Office of the People's Council*
Maryland Public Service Commission
Microgrid Architect
Mid-Atlantic Renewable Energy Coalition*
Monitoring Analytics*
National Consumer Law Center
National Housing Trust
New Jersey Board of Public Utilities
New Jersey Division of Rate Counsel
NRG Energy*
Passive House Institute - US
POWERUPMONTOCO*
Prince George's County Council
Public Citizen, Inc.
Solar Provider Group

SolarCity
State of New Jersey
The Alliance for Solar Choice
U.S. Photovoltaics Inc.
University of Delaware*
Washington Suburban Sanitary *
WGL*
Yeloha
Note:
* Represents organizations not in attendance but were invited
No asterisk represents organizations in attendance

Appendix 3 – May 3, 2016 Webinar Slides



Distributed Energy Resources (DER) Webinar

Pepco Holdings
An Exelon Company

Maintaining Reliability & Integrating New Technology

Moderated by: Don Hall, Pepco Holdings, Manager Capacity Planning

Date: May 3rd, 2016

Welcome to Pepco Holdings' Distributed Energy Resources (DER) Webinar

- Reason for this Webinar:
  - Continue PHI's commitment to provide reliable service to our customers as well as stay on the forefront of the integration of new technology in the power delivery industry

- Purpose of this Webinar:
  - Share information with our customers concerning the implementation of DER and related topics
  - Present a comprehensive review of established practices and policies
  - Discuss any modifications and clarifications needed to ensure the effectiveness of the formal application process

Pepco Holdings.
An Exelon Company

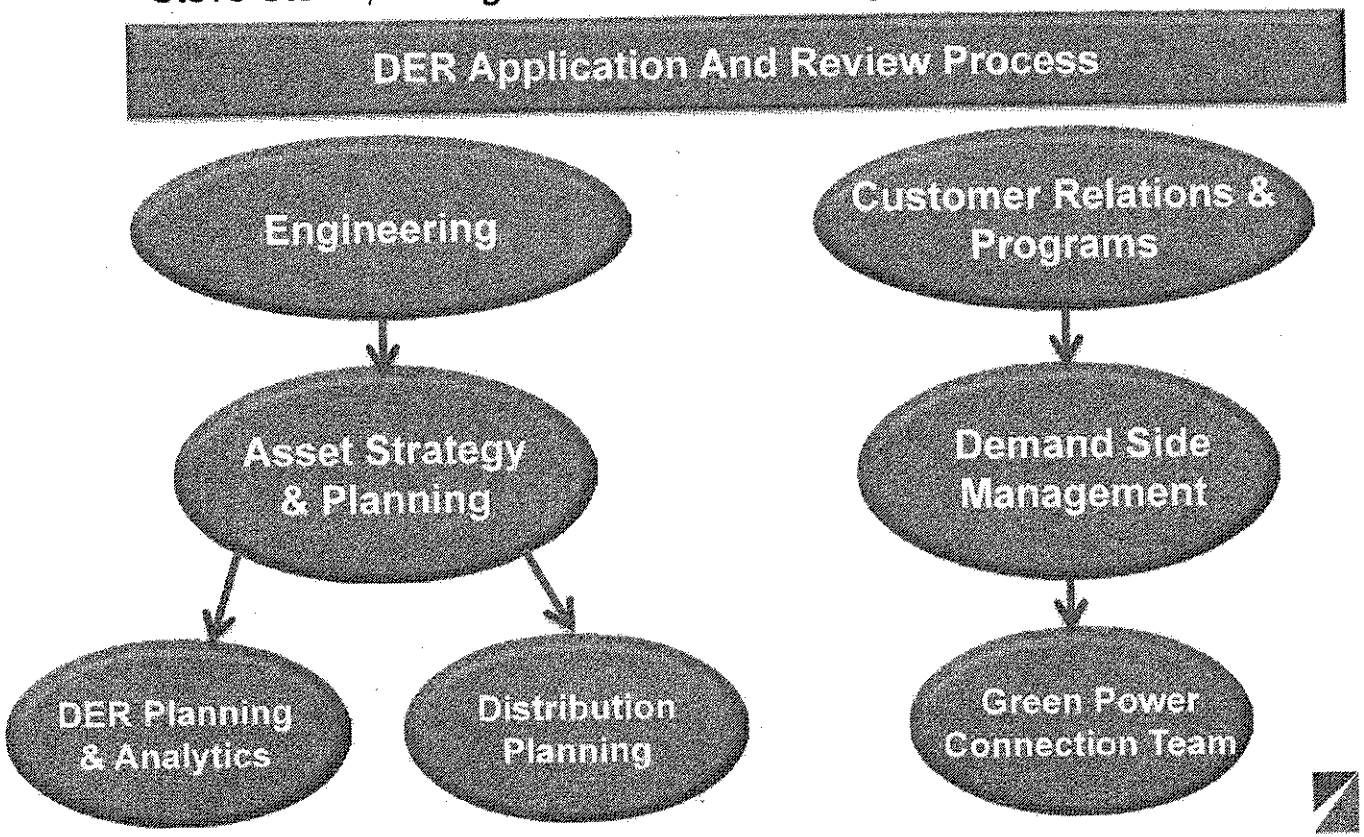
Overview of Webinar

- Presentation Topics:
  - **Green Power Connection (GPC) Process Update**
    - Discuss the streamlined, online application, review, & approval process
  - **NREL/EPRI Survey of Utility Practice**
    - Present an overview of the results of the survey of other utilities across the country
  - **DOE Grant -- "SUNRISE" Report**
    - Review results from Hosting Capacity Study of Pepco Holdings' feeders
    - Provide a more thorough understanding of the impact of new technology on Pepco Holdings' existing system
  - **DER Modeling Methodology and Tools**
    - Overview of new evaluation methodology and tools being implemented at PHI in order to facilitate the installation of higher levels of DER while maintaining reliability to Pepco Holdings' customers
    - Discuss how these new tools and technology are being accepted in the Power Delivery Industry

Pepco Holdings.
An Exelon Company

Introduction to the Organization

- Presenters Representing Various Departments Involved Include:
  - Don Hall, Manager of the Asset Strategy and Planning Department
  - Evan Hebert, Engineer in Distributed Energy Resource Planning & Analytics
  - Josh Cadoret, Lead Consultant on Green Power Connection Team
  - Steve Steffel, Manager of Distributed Energy Resource Planning & Analytics



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Next Steps

- Question & Answer Session will begin after Presentations
  - Please type questions in WebEx during the Q&A session
  - The moderator will receive questions and the appropriate presenters will respond during the Q&A session if time allows
  - Any questions that arise after the Q&A session can be sent to derwebinar@pepcoholdings.com

- Presentation materials will be available on the WebEx website

- Pepco Holdings will complete a final evaluation of criteria and practices and consider any questions and comments received from stakeholders following this webinar to file a report with each of our Public Service Commissions & Board of Public Utilities by end of July

- In-person meetings with Commission staffs and various stakeholders will be scheduled to follow up on our filing and to address any questions that arise from today's presentations or our criteria

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Online Net Energy Metering (NEM) Application Process

Presented by Evan Hebert

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NEM Application Review Process

- Previously, NEM interconnection applications had to be submitted on paper via mail.

- Recently, all PHI companies transitioned to an online application portal that allows customers and contractors to enter all of the application information online and to submit it directly.

- This streamlining of the application process is resulting in shorter overall review and approval times across all PHI companies.

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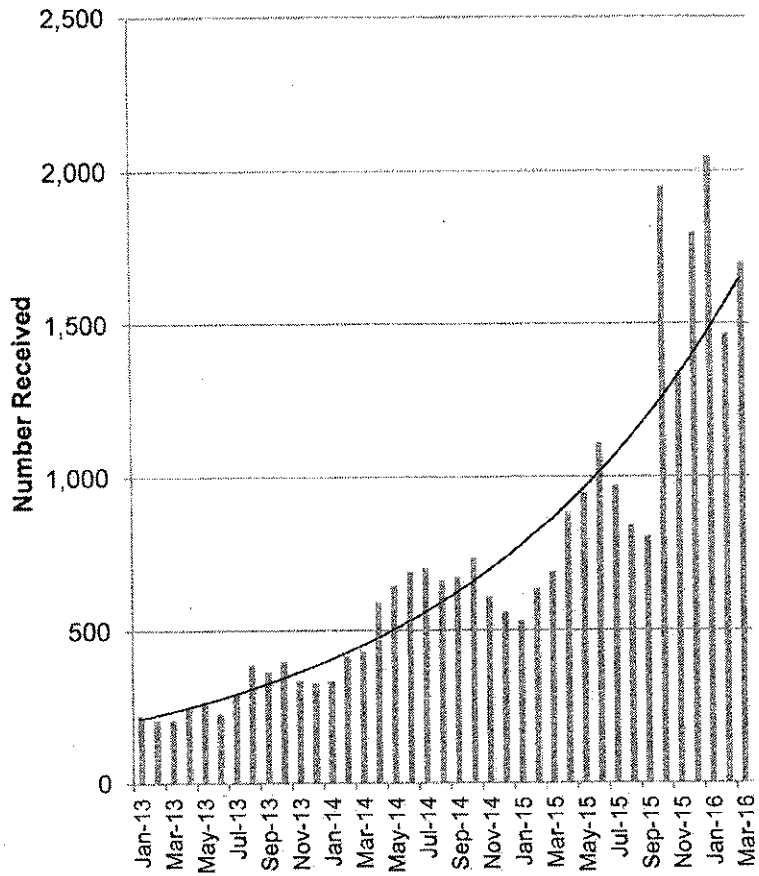
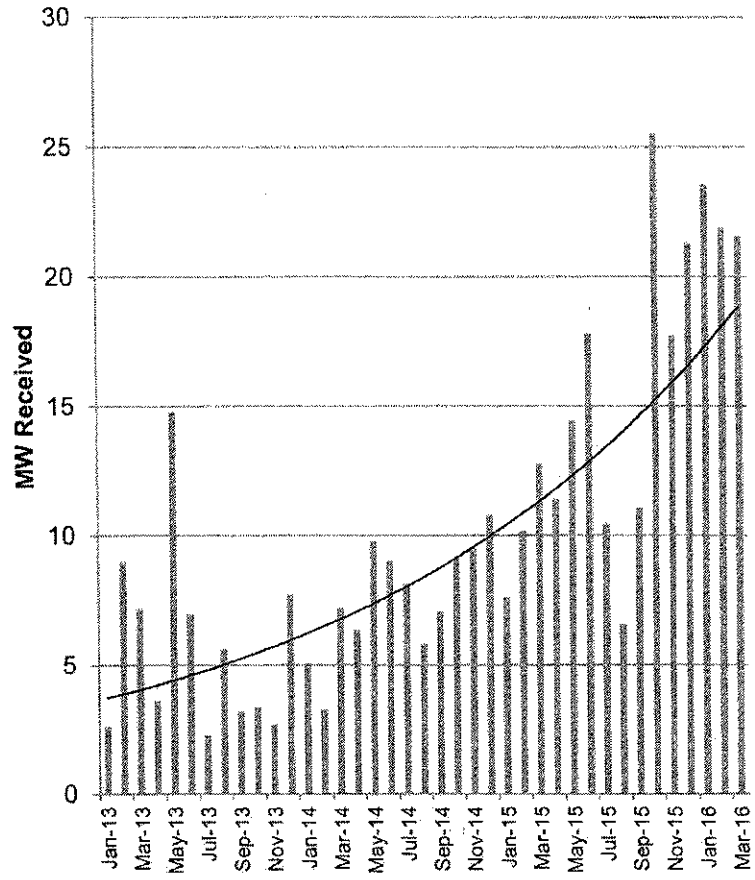
Interconnection applications continue to accelerate in both volume and aggregate size across Pepco, Delmarva Power and Atlantic City Electric

NEM Applications Received by Month



NEM Applications Received by Month (MW)



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Benefits to Customers and Contractors

- Automation quickly moves the application along to the next step in the process
- Automated data validation reduces application errors and missing information
- Allows customers to monitor your application's status 24/7 in near-real-time through a personalized dashboard
- Ability to see aggregated reports for all pending applications submitted online by contractor
- New online contractor account includes ability to designate access to multiple users
- Online application portal is accessible from any internet connection, including tablets in the field

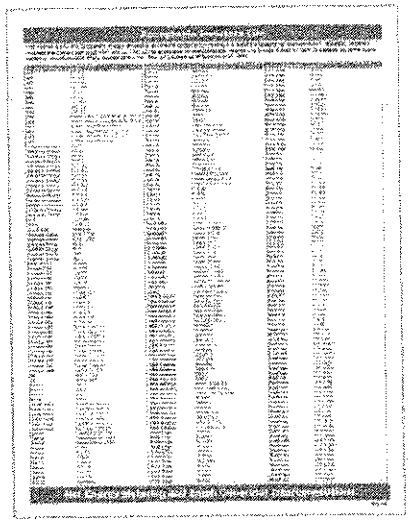
Benefits to Customers and Contractors

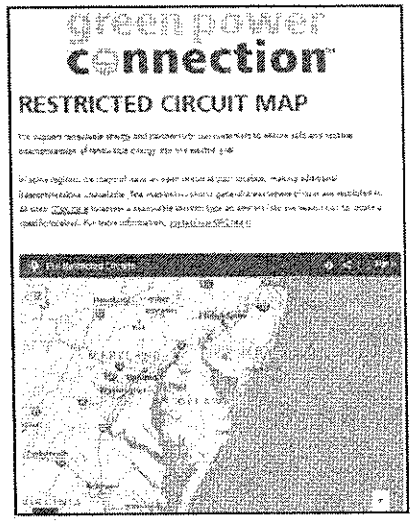
- Improves the quality, speed and effectiveness of the Net Energy Metering (NEM) Application process
- Intuitive and interactive process guides you step by step to complete the application
- Many pull-down lists and field validations for easy input
- Online signature feature eliminates the need for physical signatures
- Upload attachments online — no need to e-mail or mail supporting documents
- Save paper and postage from printing and mailing hard-copy applications
- Self-service provides immediate updates on missing or inaccurate information — no need to wait for returned emails or phone calls

Interconnection Education Tools Available Online

Online Interconnection Tools

- The GPC websites have various brochures available for download relating to: Application Checklist, FAQs, Unauthorized Interconnections, and Billing issues.
- A list of pre-approved inverter models and manufacturers is available as well
- The website contains an interactive map outlining areas that may be restricted to adding certain sizes of any DERs
- All tools can be found at the links below
  - www.atlanticcityelectric.com/gpc
  - www.delmarva.com/gpc
  - www.pepco.com/gpc





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What is PHI Doing to Speed Up the Application Process?

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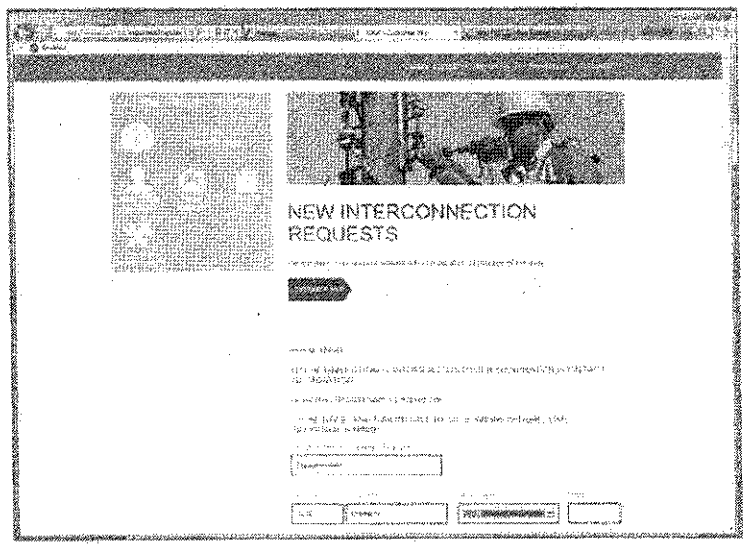
NEM Process Improvements — New and Proposed

New

- Functionality to provide customer usage data – April 2016
  - Enables My*Account* download functionality for customers
  - Enables solar contractors access to customer usage data for their current project



Proposed

- Move meter exchange earlier in the process
- Implement over-the-air meter reprogramming and eliminate truck rolls for meter exchanges
- Clarify process for handling unauthorized installations
- Further simplify application forms and processes

green power connection

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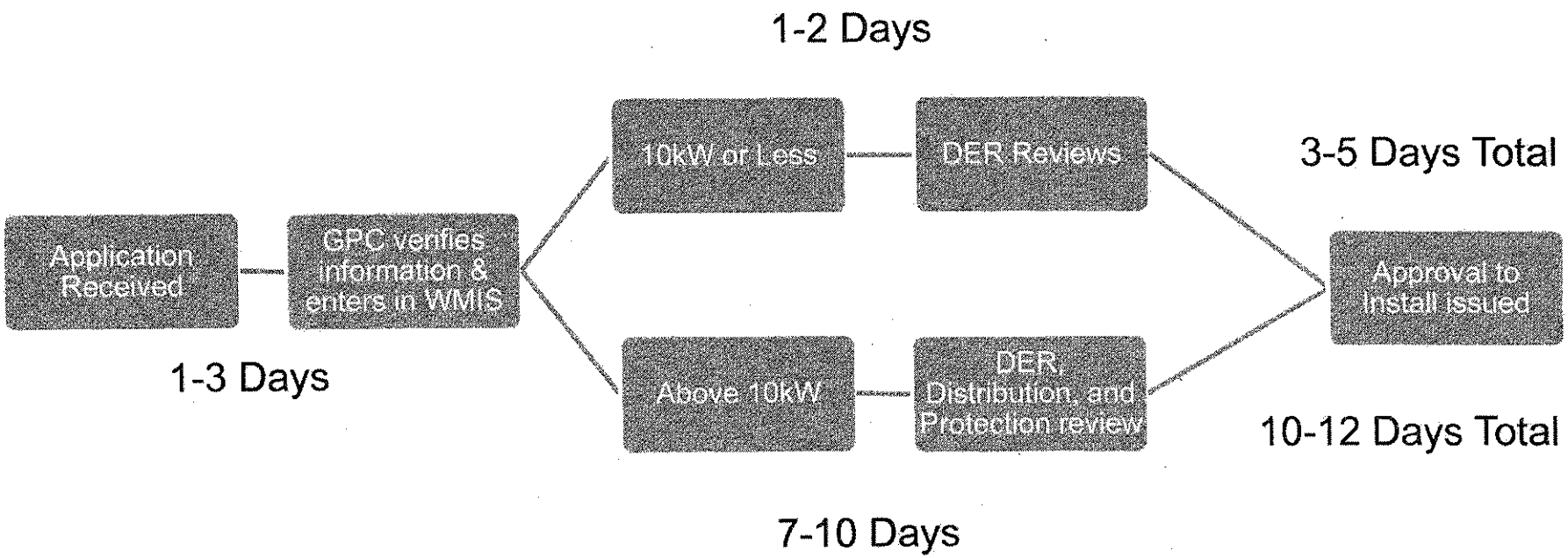
Level 1 Engineering Review Process

Technical Review of PV Applications

- To qualify for the streamlined process, applications:
  - Must be rated 10kW or less
  - Must not be on a restricted or network circuit
  - Inverter must be IEEE/UL Certified
  - Must not share a distribution transformer with an existing PV system

Technical Review Flowchart



- Response time for applications 10kW and below is 3-5 days
- Applications above 10kW may not take the full review time

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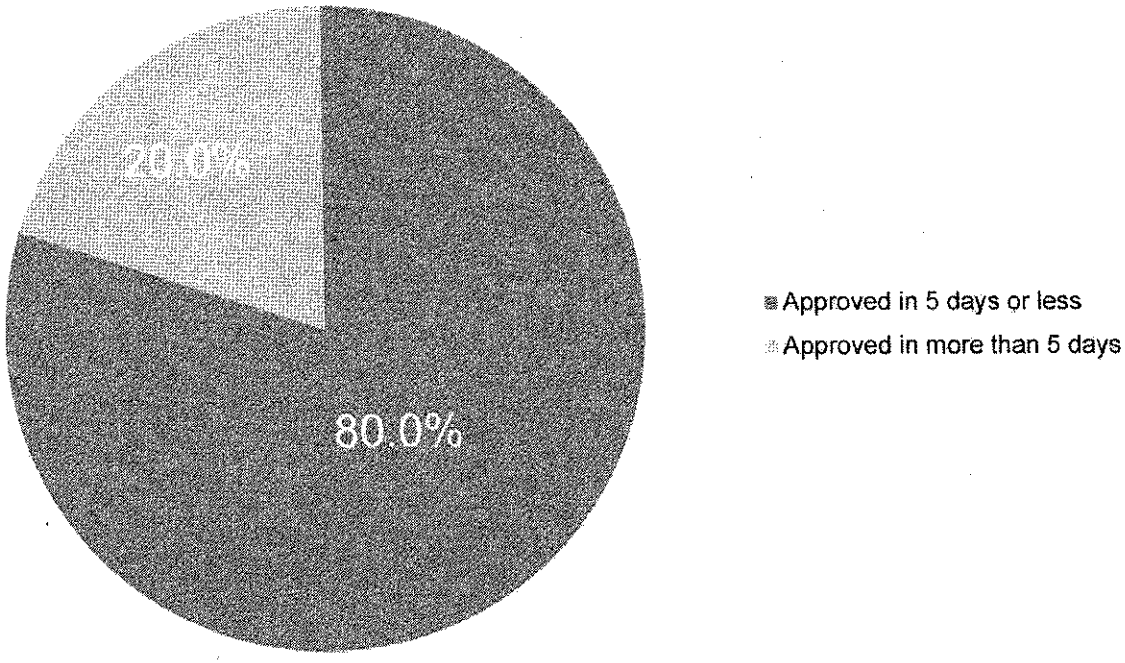
Results & Conclusions

Level 1 Approval Results (2/1-4/25)



- As of 4/25/2016, 80% of Level 1 applications are approved and returned to the customer within 5 days of submission
- The remaining 20% were subject to a more detailed review

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NREL/EPRI Survey of Practice

Presented by Michael Coddington

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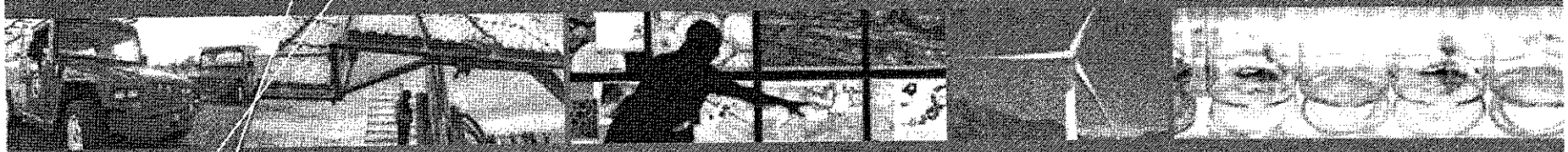
NREL
NATIONAL RENEWABLE ENERGY LABORATORY



Interconnection Processes and Procedures in 21 U.S. Utilities

Michael Coddington
Principal Engineer
National Renewable Energy Laboratory

Alternative Screening Methods

Energy Systems Integration

GO solar CALIFORNIA

EPRI ELECTRIC POWER RESEARCH INSTITUTE

NREL NATIONAL RENEWABLE ENERGY LABORATORY

Sandia National Laboratories

PG&E Pacific Gas and Electric Company®

SDGE A Sempra Energy utility™

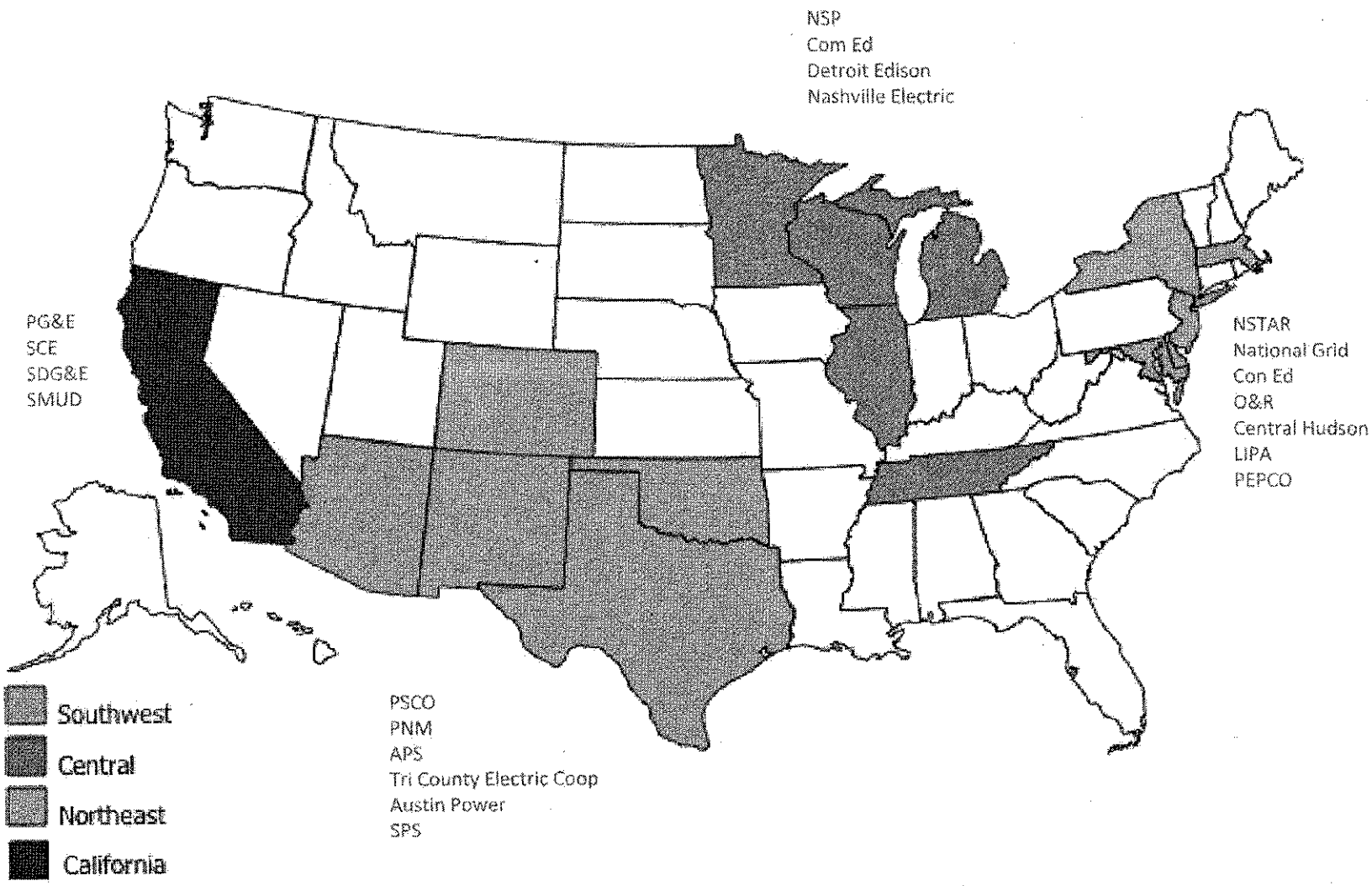
SOUTHERN CALIFORNIA EDISON
An EDISON INTERNATIONAL Company
San Onofre Nuclear Generating Station

Itron CSI RD&D Program Manager

SunShot U.S. Department of Energy

Interconnection Study 21 Utilities

Energy Systems Integration



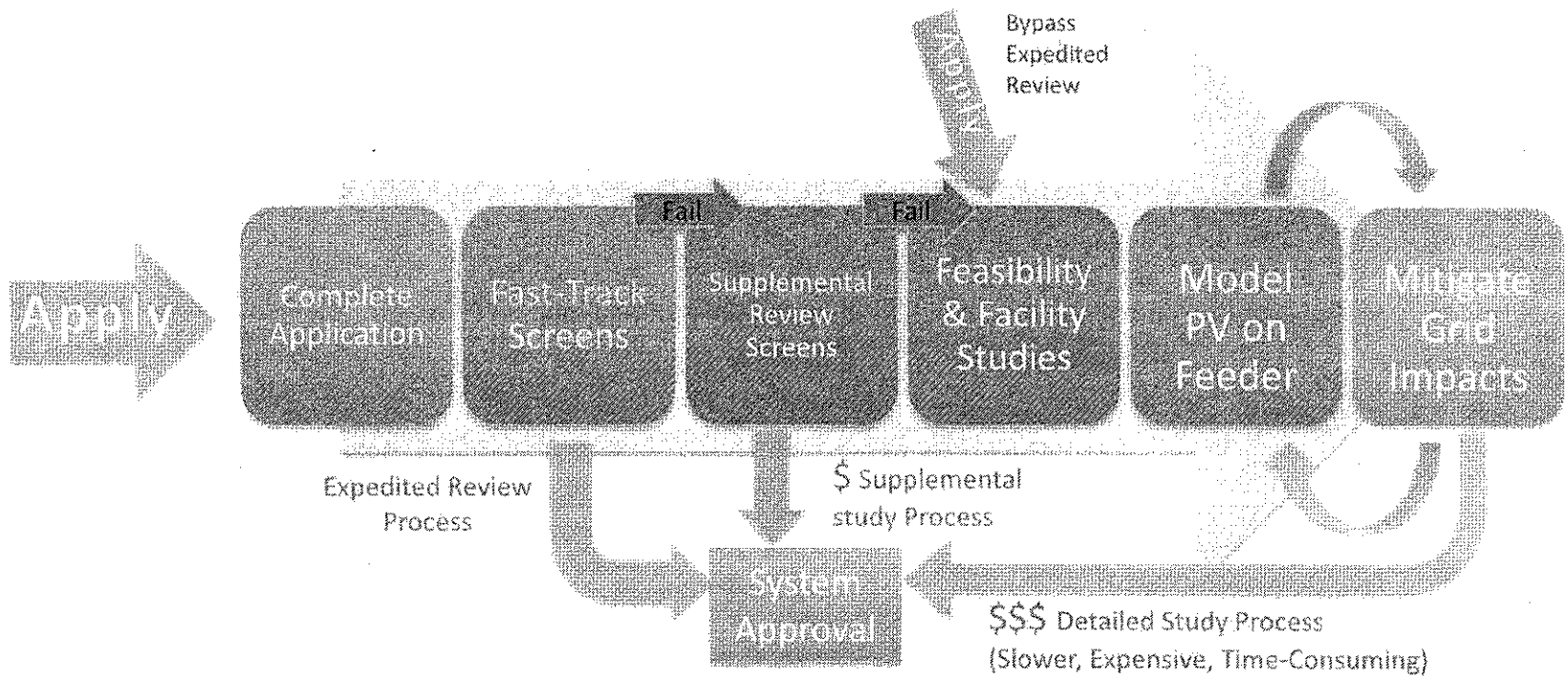
Questionnaire Areas of Focus

Energy Systems Integration

- Application Process
- Screening procedures
- Supplemental screening procedures
- Utility concerns related to interconnection
- Impact study approach & software used
- Mitigation strategies

Classic Interconnection Process

Energy Systems Integration



There are significant differences amongst U.S. Electric utilities in processes, tools, modeling platforms, and mitigation strategies

Application Processes

Energy Systems Integration

Most utilities;

- Follow time constraints with applications
- Have state mandates for applications
- Have multiple tier applications
- Have an inverter-based PV application
- Interconnection applications are available online

Screening Procedures

Energy Systems Integration

Most utilities follow a version of FERC SGIP screens

Some used a minimum daytime load for penetration screen (prior to FERC SGIP 2013 order)

1. Aggregated DG <15% of peak load on line section
2. For connection to a spot network: DG is inverter-based, aggregated DG capacity is <5% of peak load & <50 kW
3. Aggregated DG contribution to maximum short circuit current is <10%
4. Aggregated DG does not cause protective device to exceed 87.5% of short circuit interrupting capability
5. DG interface is compatible with type of primary distribution line (wye/Delta)
6. For a single-phase shared secondary, Aggregated DG capacity <20kW
7. Resulting imbalance <20% of service transformer rating of 240 V service
8. Aggregated transmission connected DG capacity <10 MW for stability-limited area
9. Construction not required for interconnection

Supplemental Screening

Energy Systems Integration

- Used to pass some interconnection applications when fast-track screens are failed (e.g. replace service transformer, secondary, loop)
- Typically quick and inexpensive solutions rather than conducting a detailed impact study
- Implemented only by some utilities
- Now part of the FERC SGIP

Major Utility Concerns

Energy Systems Integration

- Voltage Regulation 16
- Reverse power flow 11
- Protection system coordination 10
- Increased duty of line regulation equipment 8
- Unintentional islanding 8
- Secondary network protection 6
- Variability due to clouds 5
- Increased switching of capacitors 4

Minor Utility Concerns

Energy Systems Integration

- Flicker 4
- Reactive power control 3
- Balancing resources and demand response 3
- Overvoltage due to faults 2
- Multiple inverter stability 1
- Harmonics 1
- Relay desensitization 1
- Exporting power through network protectors 1

Detailed Impact Studies

Energy Systems Integration

Most utilities employ one or more of the following study types

- Feasibility
- Facility
- Power Flow (common)
- Short Circuit (common)
- Voltage (common)
- Flicker
- Power Quality

(these are uncommon)

- Dynamic/Transient Stability
- Electromagnetic Transient

Common software

- SynerGEE
- CymDist
- Milsoft Windmil
- DEW
- ASPEN

Research Software*

- OpenDSS*
- GridLabD*

Mitigation Strategies

Energy Systems Integration

Type	SW (5)	Central (3)	California (4)	NE (7)
Upgraded line sections (16)	4	2	4	6
Modify protection (16)	4	3	3	6
Voltage Regulation devices (13)	4	1	3	5
Direct Transfer Trip (12)	2	3	1	6
Advanced inverters (11)	3	2	3	3
Communication/Control Technology (11)	4	1	2	4
Power factor controls (8)	4	1	x	3
Grounding transformers (8)	2	2	2	2
Reclosers (3)	x	1	x	2
Static VAR Compensator (SVC) (1)	1	x	x	x
Capacitor control modifications (1)	x	x	x	1
Volt/VAR Controls (1)	x	x	x	1

Common Amongst Experienced Utilities

Energy Systems Integration

- Open communication between utility & developer
- Online interconnection applications
- Ease of tracking project status
- Rational screening approach
- Supplemental screening options
- "Safety Valve" approach to solve simple problems and avoid impact studies
- Standard impact study approach, software
- Cost-effective mitigation strategies
- Supportive regulatory organizations
- Uniform state rules/processes for all utilities
- Overall streamlined, transparent processes

DOE Grant "Sunrise" Report

Presented by Steve Steffel

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Model-Based Integrated High Penetration Renewables Planning and Control Analysis

edd

RUTGERS
Edward J. Blaustein School of Planning and Public Policy

Clean Power Research

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

SunShot
U.S. Department of Energy

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SUNRISE Department of Energy Grant

- Model-Based Integrated High Penetration Renewables Planning and Control Analysis
- Award # DE-EE0006328
- Contributors
  - Pepco Holdings
  - Electrical Distribution Design, Inc
  - Clean Power Research
  - Center for Energy, Economic & Environmental Policy (CEEEP), Rutgers University
  - New Jersey Board of Public Utilities

SunShot
U.S. Department of Energy

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SUNRISE Department of Energy Grant

Acknowledgement: This material is based upon work supported by the Department of Energy Award Number DE-OE0006328.

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Solar Utility Networks: Replicable Innovations in Solar Energy (SUNRISE)

SunShot U.S. Department of Energy

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Introduction

- The proposal was put together to address several identified industry needs :
  - Many customers with PV, tend to export during times of low native load and can raise voltage at their premise, sometimes over 126V on a 120V base, and now need "Voltage Headroom".
  - High penetration feeders and feeder sections are starting to exhibit violations such as high voltage. There are a number of optimization and control setting changes that could provide the means to increase hosting capacity at a reasonable cost. These needed to be studied and the cost/benefit of using these approaches published.
  - Real time optimized control of feeder equipment can impact Hosting Capacity, so one goal was to test dynamically adjusting Voltage Regulator and Inverter settings to see the impact on Hosting Capacity.
  - A voltage drop/rise tool is needed for reviewing voltage rise between the feeder and meter, especially when multiple PV systems are attached to a single line transformer.

Hosting Capacity Study Overview

- Twenty radial distribution feeders selected from ACE, DPL and Pepco service territories
- A hosting capacity study was performed on each feeder to determine how much additional PV it could support in its current configuration
- Several improvements were performed on these circuits. After each improvement or combination, the hosting capacity of the circuit was reevaluated in order to determine the impact on the amount of PV that could be hosted
- A cost-benefit analysis was performed in order to evaluate the expected costs of each feeder improvement and how each one was able to increase the hosting capacity of each feeder
- It is hoped that these results can be generalized by PHI and other distribution utilities in order to understand how they can improve the hosting capacity of their feeders and facilitate the deployment of more PV generation at the distribution level

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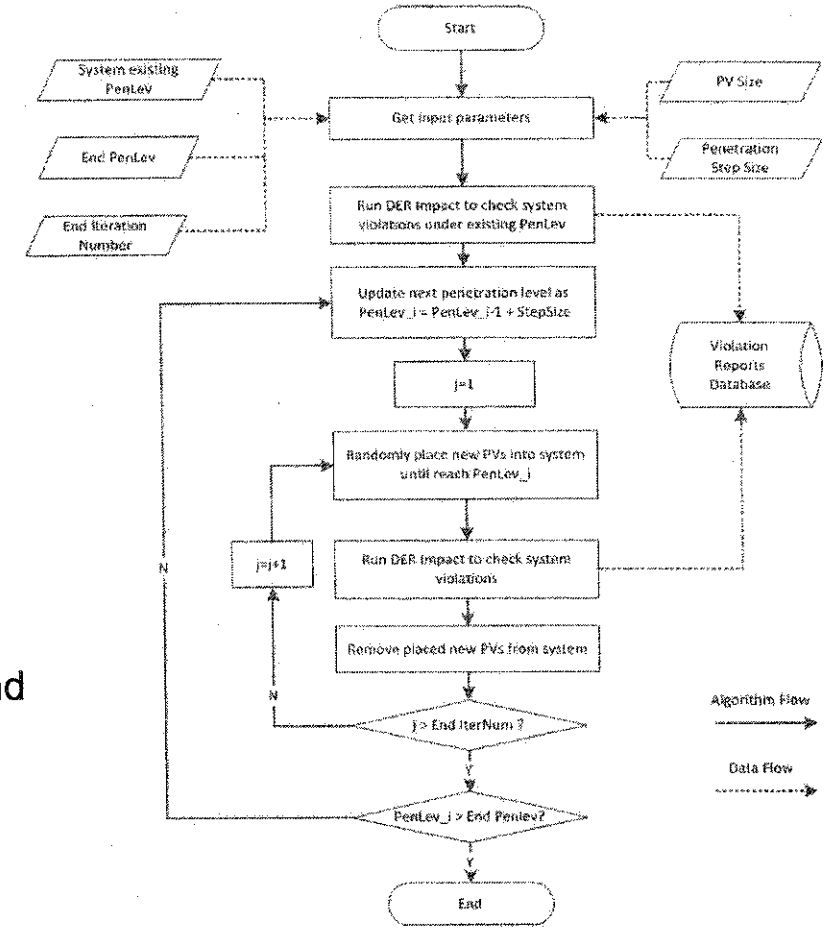
Hosting Capacity Analysis

- Place new PV sites at randomly selected customers on the circuit in order to satisfy the PV Penetration level under test.
- Once the PV is placed the circuit is tested for violations such as over/under voltage and overloads, flicker sensitivity, reverse flows (see table on next slide for full list of violations tested).
- This random placement process is repeated a number of times for each penetration level in order to build a stochastic set of results.
- Steps to the next PV Penetration Level and repeats the random placement and violation testing process.
- The user is able to specify PV penetration levels to test, the size of the placed PV sites, the violations to check for and the number of placement iterations.



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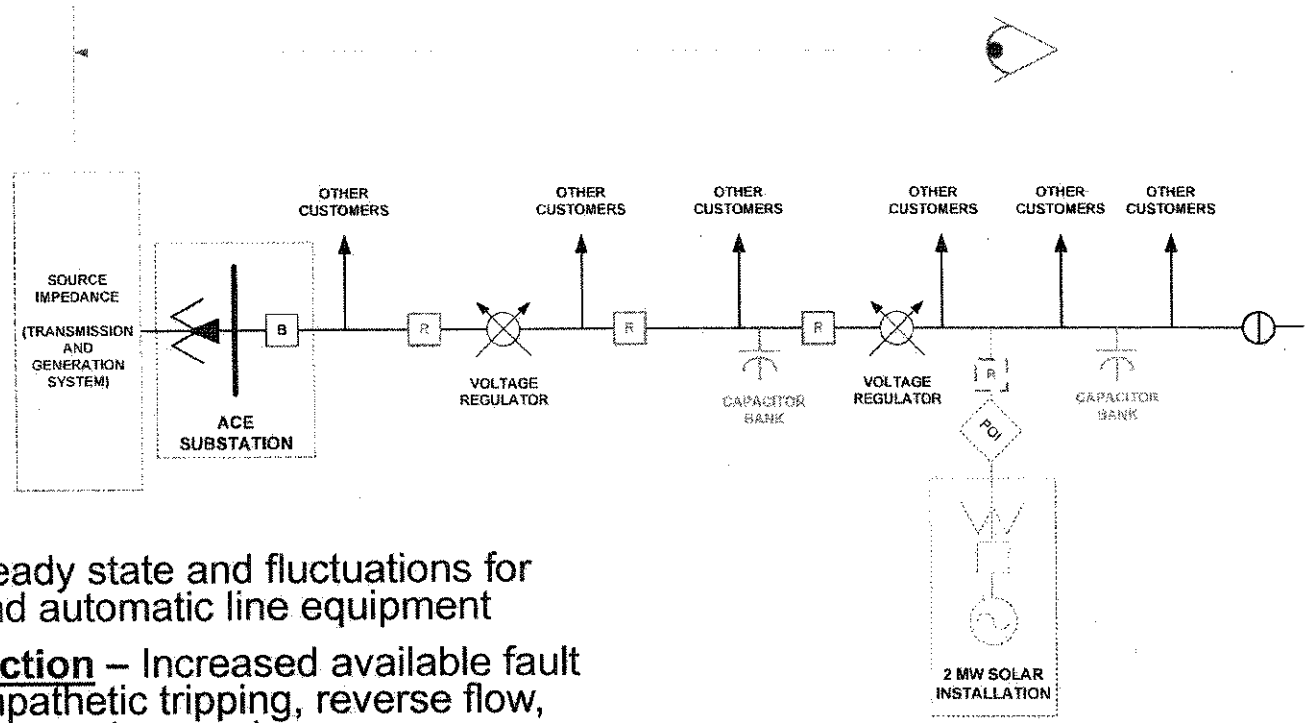
Typical PV System Impacts on a Distribution Circuit



Impacts:

- **Voltage** – Steady state and fluctuations for customers and automatic line equipment
- **Safety/Protection** – Increased available fault currents, sympathetic tripping, reverse flow, reduction of protective reach
- **Loading** – Increases in unbalance, masking of demand, capacity overloads
- **Control Equipment** – potential for increased operations for voltage regulators, capacitors and under load tap changers
- **Power Quality** – potential for harmonic issues

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Hosting Capacity Violations

Violation Variable	Comparison	Threshold	Units	Comment
Customer Level Overvoltage (Steady-State)	>	123.5	Volts	Secondary
Customer Level Undervoltage (Steady-State)	<	116.5	Volts	Secondary
Line Transformer Overvoltage (Steady-State)	>	123.5	Volts	Primary
Line Transformer Undervoltage (Steady-State)	<	116.5	Volts	Primary
Line Transformer Temporary Overvoltage (During PV output Change)	>	126	Volts	Primary
Line Transformer Temporary Undervoltage (During PV output Change)	<	114	Volts	Primary
Generator POI Overvoltage (Steady-State)	>	126	Volts	at POI
Generator POI Undervoltage (Steady-State)	<	114	Volts	at POI
Generator POI Temporary Overvoltage (During PV output Change)	>	126	Volts	at POI
Generator POI Temporary Undervoltage (During PV output Change)	<	114	Volts	at POI
Generator POI Flicker Sensitivity (Irritability - PV Step Up)	>	2	Volts	at POI
Generator POI Flicker Sensitivity (Irritability - PV Step Down)	>	2	Volts	at POI
Voltage Change at Voltage Controller (During PV output Change)	>	1/2 BW	Volts	at Vreg or Cap
Voltage Regulator Reverse Flow	<	-0.1	kW	Reverse Power
Protective Device Reverse Flow	<	-0.1	kW	Reverse Power
Feeder Reverse Flow	<	-0.1	kW	Reverse Power
Feeder Current Imbalance	>	20	%	
Component Voltage Imbalance	>	3	%	
Component Overload	>	100	%	

PV output step change used for analysis: 100% - 20% on all PV sites (% of clear sky output)
Analysis performed at time point with maximum generation / load ratio

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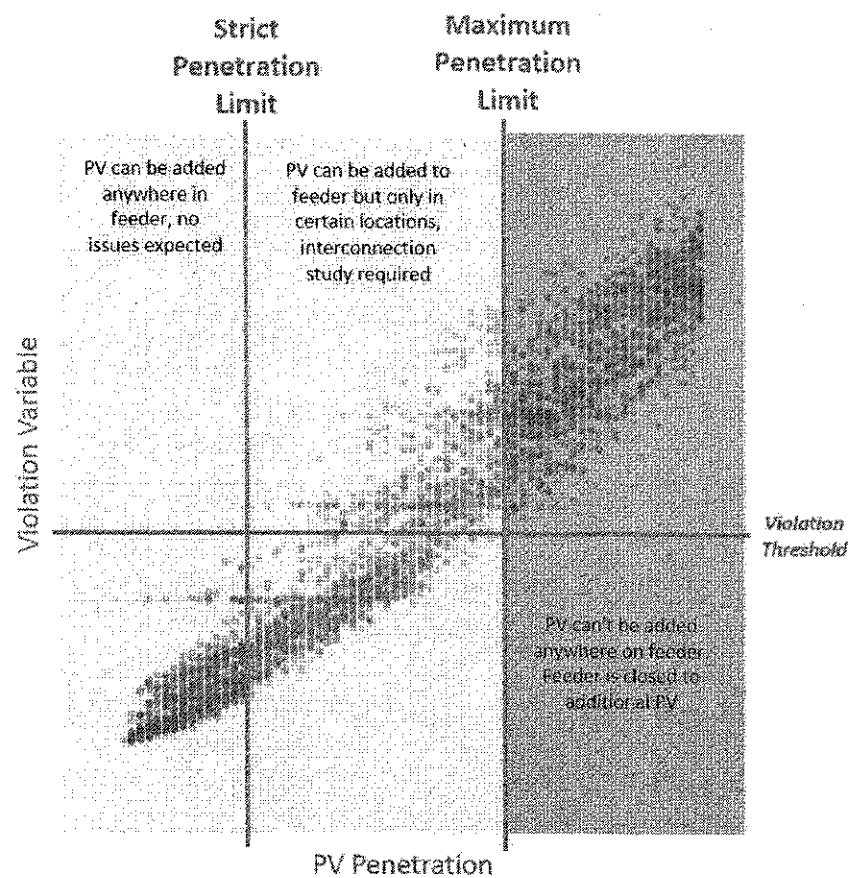
PV Penetration Limits

- Each point corresponds to one random placement of PV satisfying the PV Penetration on the horizontal axis
- Vertical position of each point is the highest observed violation value for that placement of PV
- If the point falls above the violation threshold, it represents a placement of PV which results in an issue on the circuit
- The ***Strict Penetration Limit*** occurs at the point below which all tested random placements are under the violation threshold
- The ***Maximum Penetration Limit*** occurs at the point past which all tested random placements are above the violation threshold



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Feeder Improvements

- ***Base***: circuit as-is (existing PV included)
- ***Balanced***: phase balancing performed on the base case
- ***Capacitor Design***: moves existing or places additional capacitors in order to flatten feeder voltage profile and optimize the capacitor placement
- ***Reduced Voltage Settings***: voltage regulation and LTC set-points are lowered as far as possible while still maintaining acceptable customer voltages at peak load
- ***Dynamic Voltage Control***: voltage regulation and LTC set-points are adjusted over time to be as low as possible while still maintaining acceptable customer voltages at each time point (i.e. using FSMA tool to determine optimal Vreg settings over time)
- ***Fixed PF***: power factor of randomly placed inverters are set to a fixed, absorbing power factor of 0.98. Existing PV sites are unmodified (i.e. all new PV on feeder required to operate at 0.98 absorbing)
- ***Battery Storage***: battery storage in a daily charge/discharge schedule is added to circuit in order to add effective load at peak PV production times

Example Feeder (Study Feeder 16)

- Contains newer 34.5 kV primary out of sub and on most of backbone, also has several areas of older 4.15 kV primary connected through step transformers
- One of the longer feeders in the study, three voltage regulation zones (plus sub LTC), four voltage controlled switched cap banks, one fixed cap bank
- Poor voltage regulation on the 4.15 kV sections and phase imbalances limit the PV penetration of base circuit to about **6%**, limited by customer steady-state high voltages

Study Feeder 16 Summary	
Feeder Type	Res
Primary Voltage	34.5 kV Y-G and 4.15 kV Y-G
Feeder Length (total circuit miles)	64 mi
Distance from Sub to Furthest Load	12.8 mi
Peak Load (SCADA)	8.1 MW
Minimum Daytime Load (SCADA)	2.4 MW
Number of Distribution Transformers	331
Connected KVA (total xfrmr rating)	65 MVA
Number of Capacitor Banks	5
Total Capacitor Bank Rating	7.8 MVAR
Number of Voltage Regulation Zones	3
Number of Existing PV Sites	2
Total Existing PV Generation	15 kW
Existing PV Penetration	< 1%

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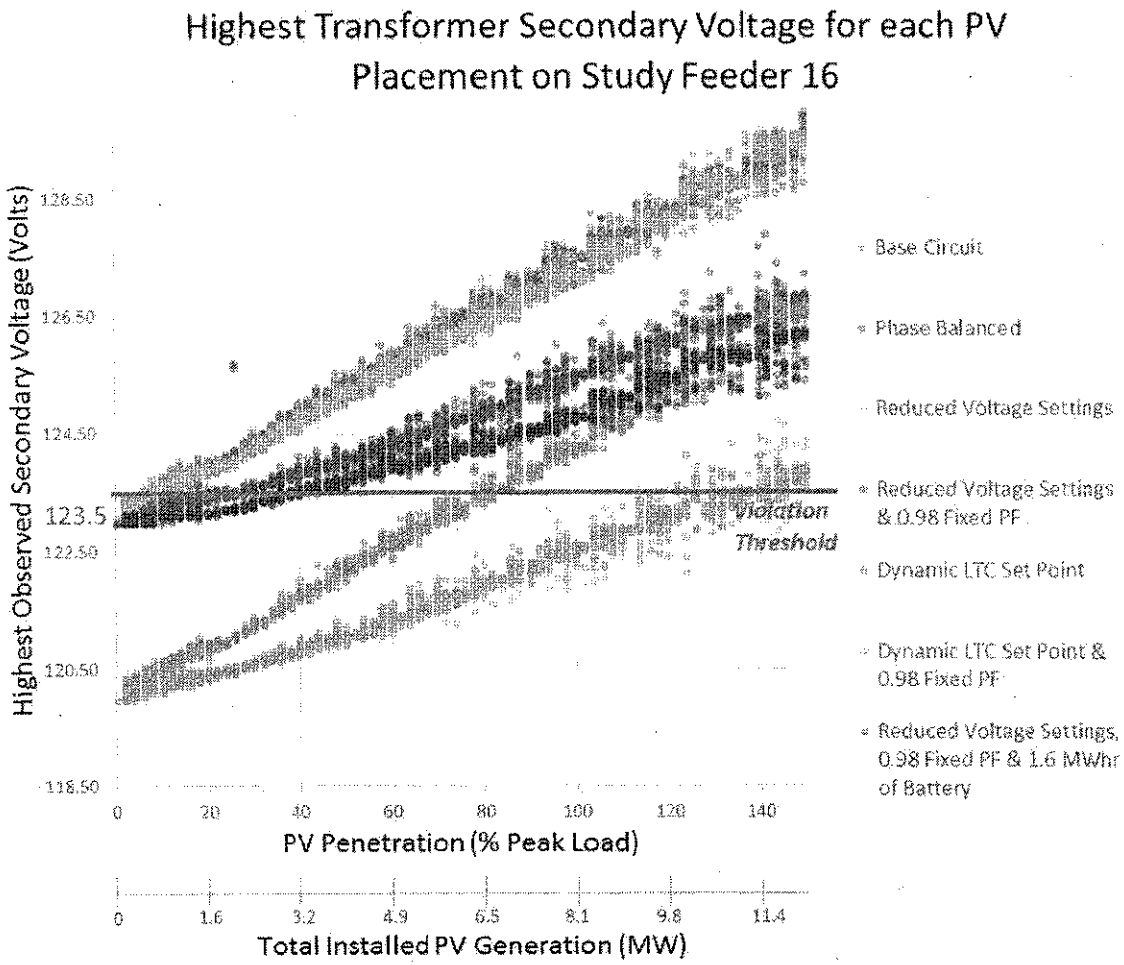
Example Feeder (Study Feeder 16)



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Strict Penetration Limit Increase for Each Feeder

Strict Penetration Limit (Before and After)						
Feeder	Base Case			Max. Penetration w/ Upgrades		
	PV (%)	PV (MW)	Cost (k$)	PV(%)	PV(MW)	Cost(k$)
1	29.7	1.0	0.0	167.9	5.9	60.2
2	29.7	1.5	0.0	197.1	10.4	32.5
3	53.6	2.2	67.9	264.7	10.9	149.3
4	34.9	1.2	0.0	134.5	4.8	22.0
5	43.7	2.0	67.3	193.7	8.7	96.8
6	38.9	2.6	0.0	219.6	14.5	78.5
7	36.9	1.9	0.0	92.7	4.7	131.4
8	23.8	1.4	0.0	129.2	7.6	2.0
9	1.9	0.1	0.0	161.3	8.1	21.0
10	12.8	0.3	0.0	62.9	1.6	27.5
11	39.0	2.0	37.2	61.0	3.1	178.3
12	8.0	0.7	37.2	11.9	1.0	118.7
13	2.9	0.2	0.0	104.9	5.8	150.2
14	15.9	1.5	0.0	18.0	1.7	33.0
15	20.0	1.6	0.0	76.0	6.2	21.5
16	5.9	0.5	59.7	63.9	5.2	167.1
17	17.0	2.0	0.0	104.9	12.1	31.0
18	42.9	2.8	0.0	336.7	22.2	25.0
19	25.9	1.6	74.0	67.8	4.1	80.0
20	44.9	2.7	0.0	184.6	11.0	2.5
AVERAGE	**26.4**	**1.5**	**17.2**	**132.7**	**7.5**	**71.4**

← Minimum Increase

← Maximum Increase

Notes: The above feeders do not include battery deployment.
The above feeders represent different voltage levels.

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Protection and Coordination

- Protection and coordination studies were performed on feeders 6 and 13
- These studies were performed at the ***maximum*** penetration limit for the battery storage cases, representing worst case scenarios for inverter fault contributions (maximum amount of allowable PV and inverter battery storage)
- Even at these worst case scenarios the inverter fault current was not enough to interfere with existing protection. From these results it can be expected that protection issues will not limit PV deployment lower than the penetration levels determined in the hosting capacity studies.

Study Feeder 6 - Maximum Fault Currents

	3PhZ0FA (A)	3PhZ0FA (B)	3PhZ0FA (C)	1PhZ0FA (A)	1PhZ0FA (B)	1PhZ0FA (C)
PV off	9327	9327	9327	9159	9159	9159
PV on	9431	9461	9446	9265	9294	9277
Change	104	134	119	106	135	118
%	1.1	1.4	1.3	1.2	1.5	1.3

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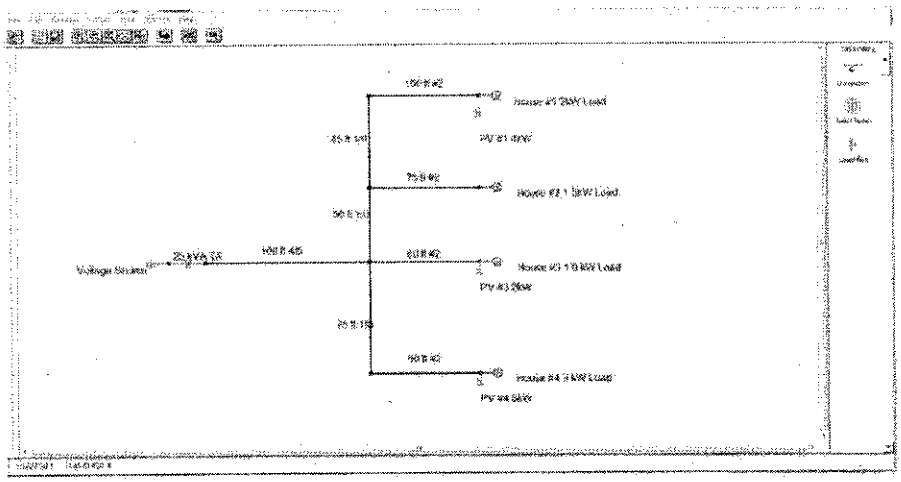
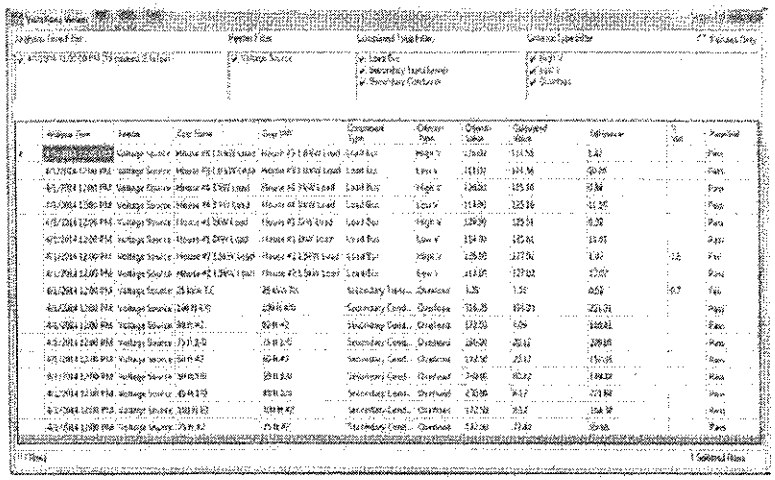
Secondary Design Tool

- This is a standalone application that utilizes a simplified version of EDD's DEW modelling software package. It is designed to be used by engineers, technicians, or PV contractors to identify any violations created by attaching PV systems to the secondary/services fed by a single phase distribution transformer.
- The user can modify components in the model such as transformer size, conductor size and length, and PV size to mitigate violations created by adding PV sites at selected locations.
- The application is designed to check for the following types of violations:
  - High Voltage – customer voltages greater than 126 volts
  - Low Voltage – customer voltages lower than 114 volts
  - Overload – current flow (amps) in excess of component rating for conductors and transformers





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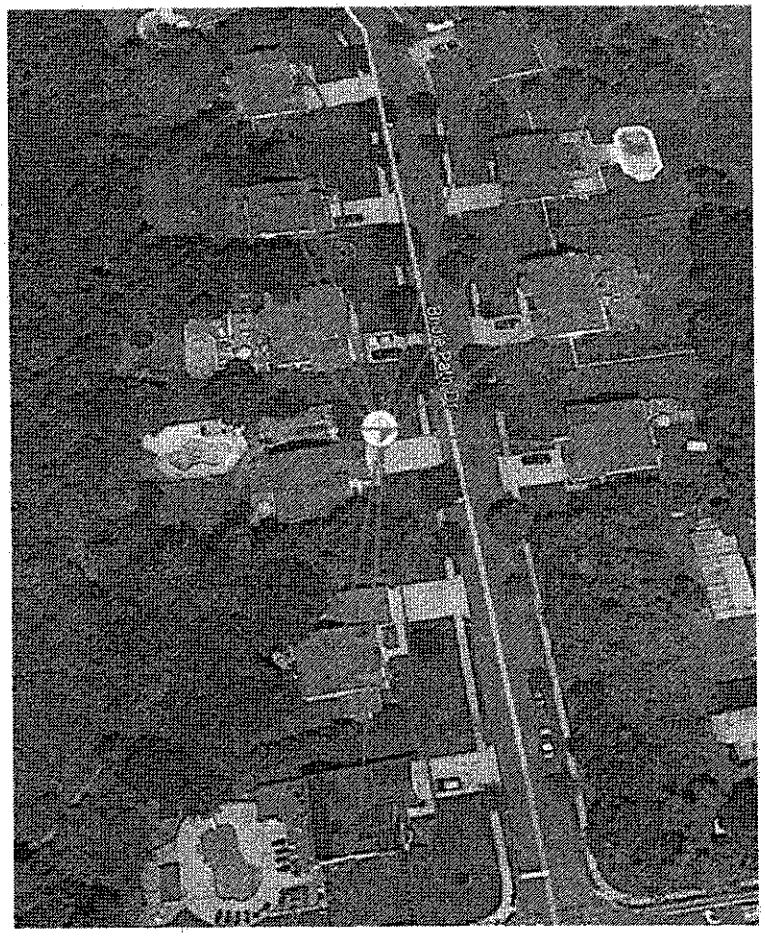
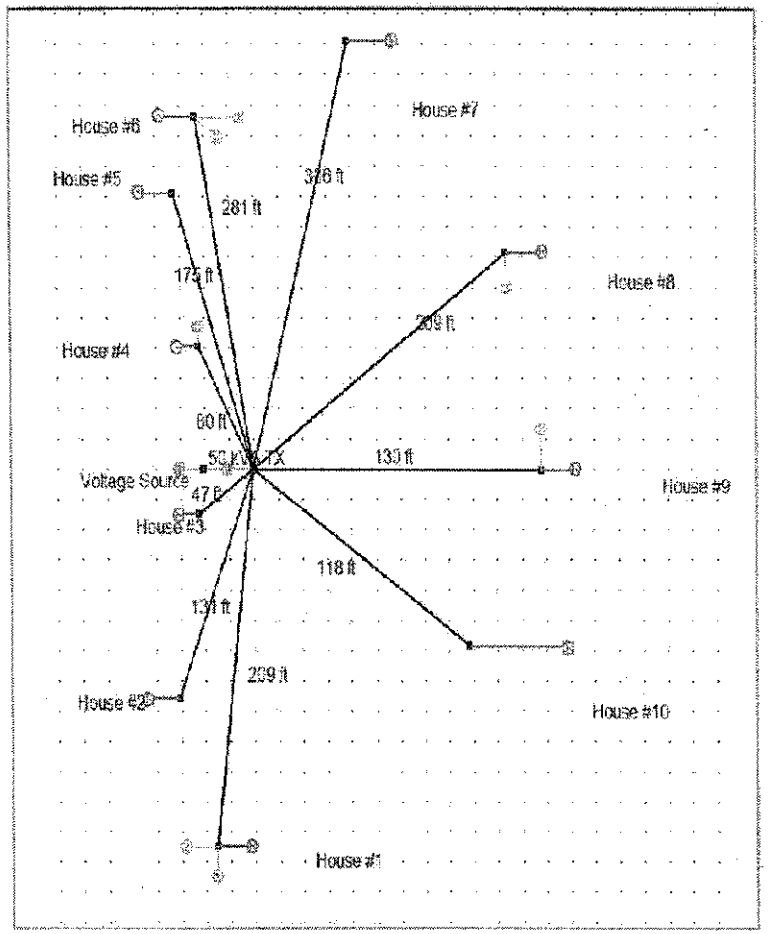
Secondary Design Tool (Example)

10 Homes on a single transformer, 5 homes with PV systems totaling 54.6 kW





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Secondary Design Tool (Example cont.)

Based on the assumptions used in this analysis, there are some premises with high voltage.

Feeder	Component Name	Component UID	Component Type	Phase	kW	kVAR	kVA	Voltage
Voltage Source	50 kVA TX	50 kVA TX	Secondary Transformer	AB	-47.09	2.87	47	126.0
Voltage Source	209 ft	209 ft	Secondary Conductor	AB	-11.05	0.13	11	130.6
Voltage Source	PV #6	PV #6	Inverter Type DR	AB	-12.00	0.00	12	130.6
Voltage Source	House #8	House #8	Load Bus	AB	0.54	0.11	1	130.6
Voltage Source	281 ft	281 ft	Secondary Conductor	AB	-12.96	0.15	12	133.0
Voltage Source	PV #4	PV #4	Inverter Type DR	AB	7.60	0.00	8	133.0
Voltage Source	PV #5	PV #5	Inverter Type DR	AB	-6.00	0.00	6	133.0
Voltage Source	House #6	House #6	Load Bus	AB	0.55	0.11	1	133.0
Voltage Source	80 ft	80 ft	Secondary Conductor	AB	-10.45	0.12	10	127.6
Voltage Source	PV #3	PV #3	Inverter Type DR	AB	-11.00	0.00	11	127.6
Voltage Source	House #4	House #4	Load Bus	AB	0.53	0.11	1	127.6
Voltage Source	47 ft	47 ft	Secondary Conductor	AB	0.52	0.11	1	125.9
Voltage Source	House #3	House #3	Load Bus	AB	0.52	0.11	1	125.9
Voltage Source	175 ft	175 ft	Secondary Conductor	AB	0.52	0.11	1	125.8
Voltage Source	House #5	House #5	Load Bus	AB	0.52	0.11	1	125.8
Voltage Source	131 ft	131 ft	Secondary Conductor	AB	0.52	0.11	1	125.8
Voltage Source	House #2	House #2	Load Bus	AB	0.52	0.11	1	125.8
Voltage Source	209 ft	209 ft	Secondary Conductor	AB	-11.98	0.14	12	131.0
Voltage Source	PV #1	PV #1	Inverter Type DR	AB	-10.00	0.00	10	131.0
Voltage Source	PV #2	PV #2	Inverter Type DR	AB	3.00	0.00	3	131.0
Voltage Source	House #1	House #1	Load Bus	AB	0.55	0.11	1	131.0
Voltage Source	306 ft	306 ft	Secondary Conductor	AB	0.52	0.11	1	125.7
Voltage Source	House #7	House #7	Load Bus	AB	0.52	0.11	1	125.7
Voltage Source	130 ft	130 ft	Secondary Conductor	AB	-4.45	0.11	4	126.7
Voltage Source	PV #7	PV #7	Inverter Type DR	AB	-5.00	0.00	5	126.7
Voltage Source	House #9	House #9	Load Bus	AB	0.53	0.11	1	126.7
Voltage Source	118 ft	118 ft	Secondary Conductor	AB	0.52	0.11	1	125.9
Voltage Source	House #10	House #10	Load Bus	AB	0.52	0.11	1	125.9

High Voltage

Voltage OK

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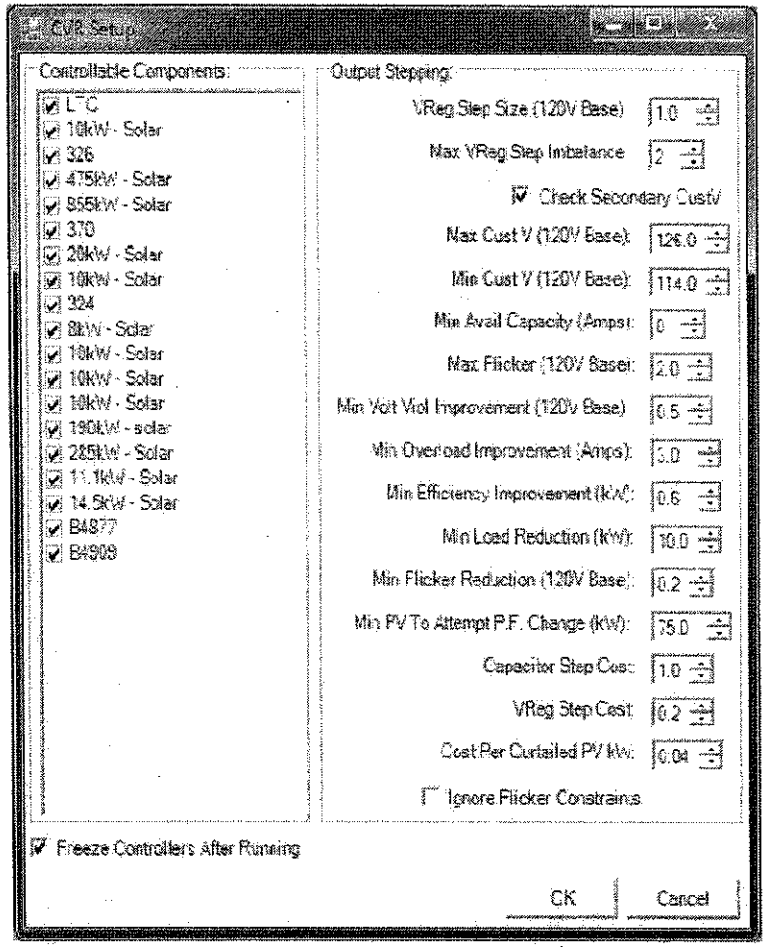
Forecast, Schedule, Monitor, Adjust (FSMA) Tool

- Application within EDD's DEW modelling software package, it is designed to be used for operations monitoring using real-time measurements
- Also can be used for detailed planning analysis using time step simulation that will allow planners to evaluate control device interactions with PV and load changes using historical load measurements, historical PV output data from CPR and NREL, and historical measurements from SCADA
- Inputs all of these measurement sources, attaches the measurement values to a distribution feeder model and to determines optimal voltage regulator, capacitor bank and inverter controller settings in order to maximize a set of user defined objectives while minimizing control costs
- Uses a tabular search to determine the optimal control positions for capacitors, voltage regulating transformers, and solar panel supplying inverters with user-configurable weighting factors



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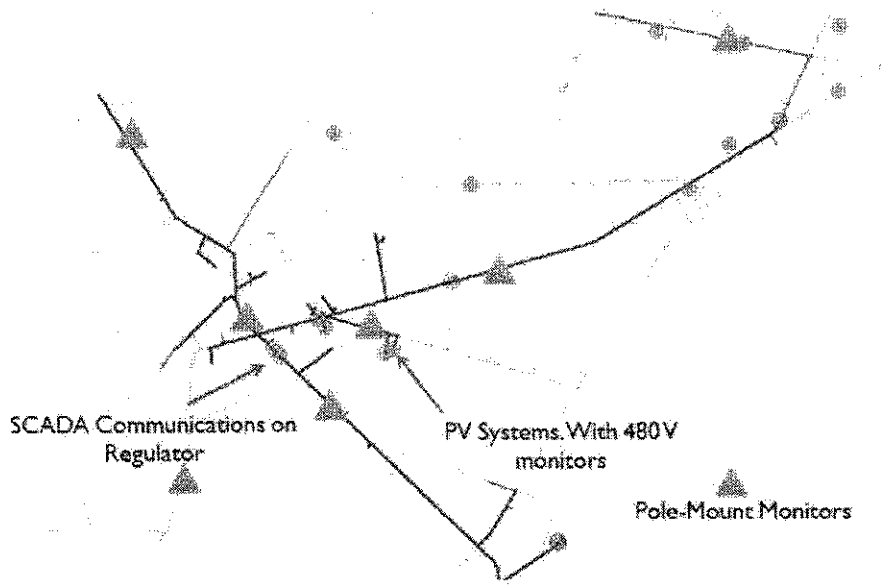
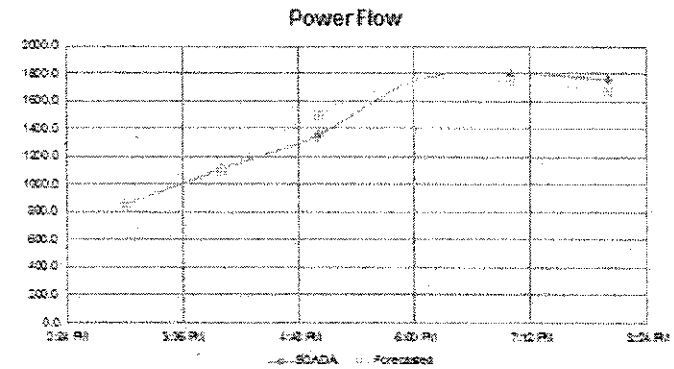
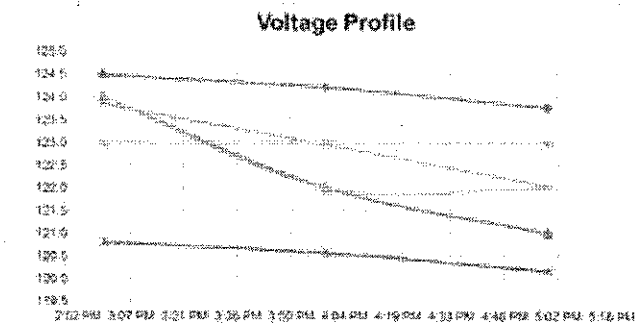
FSMA Demonstration

- Study Feeder 11 - Industrial/Residential circuit with 1.9 MW of PV
- Input real time SCADA data and voltage readings to program (FSMA), implement forecasted values in the field
- Solar output forecast using Clean Power Research data
- Testing was done on relatively sunny days with moderate temperatures







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Conclusions

- Every feeder is unique and can have a different hosting capacity
- There are a number of methods to leverage existing equipment to increase Hosting Capacity and provide Voltage Head Room
- Phase Balancing shows little direct impact, but it is important to keep the circuit balanced as PV penetration increases
- Dynamic Volt/VAR will take new controls, communications and central logic to run (some utilities have already implemented Volt/VAR control, may need some new logic)
- Smart Inverters have promise but modeling and operation at high penetration levels still poses some unknowns
- Even after dealing with Voltage issues, reverse power on V. Regs., on Power transformers, Distribution Automation Schemes, loading and protection issues will make analysis more complex
- For higher penetration levels on the distribution system, it will be important to keep an eye on the Transmission system

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DER Interconnection Review Process

Presented by Steve Steffel and Evan Hebert

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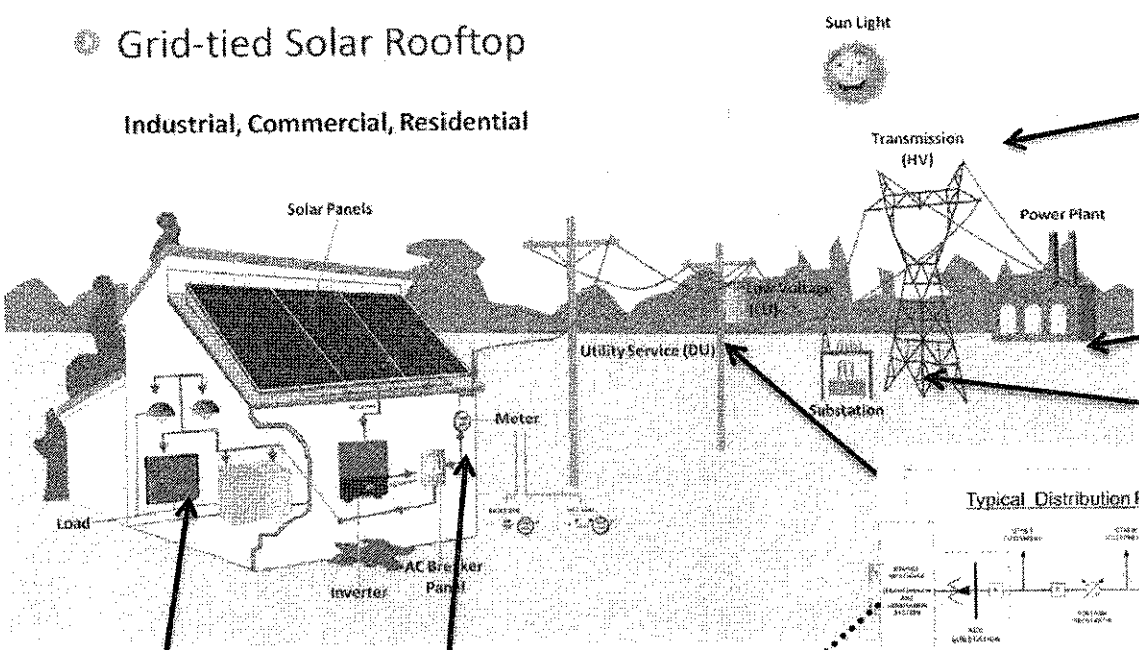
Interconnection Review Processes

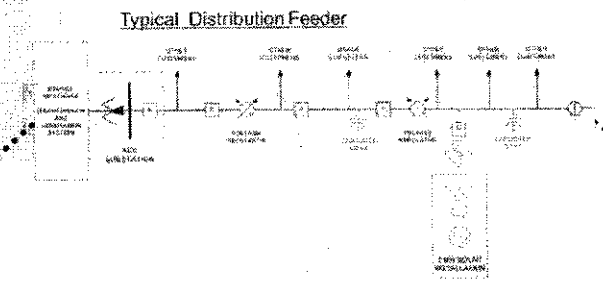
- Due to an increased volume of applications, PHI implemented a comprehensive review process for DERs applying to interconnect to the grid
- As PV penetration increases, in general, operating issues also increase
- This review process was put in place to ensure safe and reliable interconnection for both the grid and the DER

DER Affects the Entire Electric System

- Grid-tied Solar Rooftop

Industrial, Commercial, Residential





Transmission

- Voltage challenges at low load
- Near term, it will reduce losses, on high penetration losses may increase

Generation

- Scheduling changes required to meet volatile load
- May increase need for ancillary services
- Steep ramp rate when sun goes down affects capacity needs

Feeder & Substation

- Increase phase unbalance for three phase circuits
- Capacity spikes may overload equipment

Home Power Quality

- Higher voltage caused by generation reduces efficiency of appliances and HVAC
- Can stress appliances or motors

Interconnection Pt.

- Inverters trip or cloud shear can create volatility
- Must maintain voltage within mandated bands
- Net metering masks true load demand

POI

- Every POI requires study to determine impacts to the system and other customers
- The customer is required to pay for the upgrades

Dist. Automation

- DER can prevent DA schemes from locating fault
- True load to be transferred not easy to calculate

Voltage

- High or low voltage can result in mis-operation, damage, or reduced equipment life – both on the grid or at premises

Safety

- Can increase fault current level
- Trip of breaker or recloser may result in inverter out of synchronization
- Reduction of protective reach

System Reliability – Interconnection Requirements

Reliability of the electric system requires criteria that can be used to assess the impact of DER on the grid. Criteria includes:

- Accurate single-line drawing of the proposed generator system submitted with each application
- UL 1741-certified inverters
- System passes electrical inspection
- Systems shall not overload line transformers or cause high voltage for themselves or adjacent customers (otherwise upgrades would be required)
- Single Phase Limit — the largest capacity single phase generator or DER (battery) operating in parallel with the grid is 100 kW. Above that size, a balanced 3-phase system is required

Levels of Engineering Review

- Pre-screen
- Screen
- Advanced Study

Engineering Pre-screens

- Required for systems between 50-250 kW
- Option 1: Determine distance from substation, radial or lateral connection and voltage level
  - Main radial connections typically have larger wires, allowing systems further away to interconnect without problems
  - Higher tolerance for larger voltage levels (25 kV vs 12 kV)
- Option 2: Calculate impedance at point of interconnection (POI)
- Failed Pre-screen
  - Distance from substation and size of system are not in the allowable range to pass the pre-screen or impedance is too high
  - Screen is required
  - Operating requirements must be signed by customer (not required if application passes pre-screen)

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Engineering Screens

- Required for systems > 250 kW or failed the pre-screen
- High level power flow analysis required
- Screening Criteria
  - Voltage fluctuation is not greater than 2% at the POI or half the deadband at any capacitor or regulator
  - Reverse power-generation does not exceed 80% of the daytime minimum load at voltage regulators, feeder terminals and/or substation transformer without proper mitigation
  - DER does not cause high voltage anywhere on the circuit

Engineering Screens

- Step 1: Ensure accurate model
  - Power flow (MVA, MW, MVAR) at peak and minimum load (typically use SCADA at feeder terminal to verify load)
  - Capacitor, voltage regulator and LTC settings
  - Power factor at feeder terminal
  - Large customer loads
  - Nearby PV installations (systems within ~2,000 ft. of proposed system will act as one system during cloud passing)

- Additional Information
  - Back-up feeders
  - Distribution automation schemes

Engineering Screens

- Step 2: Peak Load Voltage Study
  - Run power flow at peak load with generators on
  - Lock capacitors and voltage regulators to prevent from operating
  - Turn generation on/off and record voltage at POI and closest capacitor or voltage regulator
  - Calculate difference to determine voltage fluctuation
    - If fluctuation is greater than 2%, apply absorbing power factors from 0.99 to 0.95 until criterion is met
    - If above method fails, reduce the size of system until violation no longer occurs

Engineering Screens

- Step 3: Minimum Circuit Load Voltage Rise Study
  - Run power flow at minimum load with generators on and capacitors and voltage regulators unlocked
  - Record highest voltage on feeder
    - If voltage exceeds upper limit, apply power factor from 0.99 to 0.95 absorbing power factor until criterion is met
    - If power factor mitigation does not work, reduce size of system until high voltage no longer occurs
  - Lock capacitors and voltage regulators to evaluate voltage fluctuation (similar to peak load study)

Engineering Screens

- Step 4: Reverse Power
  - If the aggregate generation exceeds 80% of the daytime minimum load at a specified location, the following mitigation techniques are required:
    - Feeder Terminal – Relay package as determined by Atlantic City Electric System Protection
    - Voltage Regulator – Install Beckwith controller with co-generation mode
    - Substation Transformer – Transfer trip

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Engineering Advanced Study

- Required if application does not pass high level screening process (at maximum output)
- Time series power flow analysis required
- AMI smart-meter data is used to ensure accurate loads (as opposed to feeder terminal SCADA data and connected KVA loads)
- Same criteria as screening procedure
- Different types of advanced studies include:
  - Phase balancing
  - Capacitor controls
  - Lowering load tap changer (LTC) voltage
  - Distribution Automation Operation

Existing Distribution Circuit Capacity Limits Guidelines

- The aggregate limit of large (250 kW and over) generators running in parallel with a single, existing distribution circuit is:
  - 4 kV 0.5 MWs
  - 12 – 13.8 kV 3 MWs
  - 23 – 25 kV 6 MWs
  - 33.26 – 34.5 kV 10 MWs

- After these limits are reached, customers and developers can continue to request connection of systems less than 250 kW. The circuit will continue to accommodate distributed energy resource (DER) systems until voltage limits or other limits are reached

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Express Circuit Capacity Limits

- Distributed generation installations which exceed the limit for an existing circuit require an express circuit. The maximum generator size for express circuits is:

  - 4 kV 0.5 MWs
  - 12 – 13.8 kV 10 MWs
  - 23 – 25 kV 10 MWs
  - 33.26 – 34.5 kV 15 MWs

- The maximum length of an express feeder shall be 5 miles and must have demand and energy losses less than 3%

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Distribution Power Transformer Limit

- The aggregate limit of large (250 kW and over) generator injection to a single distribution transformer of 22.5 MVA nameplate or larger is 10 MWs. Transformers with nameplate ratings lower than 22.5 MVA may be given lower generation limits.

- We will consider adding a new transformer if there is no availability on any of the existing transformers and space is available in an existing substation. Any proposed transformers would be PHI's standard distribution transformer (37 MVA nameplate rating).

Network Solutions

- **Spot and Area Networks** — to ensure a safe level of import, if Pepco Holdings determines that the proposed system could export or cause the network protector to operate, the following control scheme will be required:
  - Customer shall install a monitoring system on the service(s) to the facility and install inverters that can receive a control signal and curtail output to maintain the target level of import on each phase
  - Customer system shall provide a web link and access to PHI to have read-only access to view the electrical parameters and operation of the system
  - Customer shall provide an alert to PHI via email or text if the import goes below a set point
  - Customer shall send a trip signal to the inverters if the import level falls to another set point

DER Advanced Modeling Tools and Results

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Purpose for Pursuing Advanced Modeling Tools

- The need to do detailed time series studies for the interconnection of DER
- The ability to assess aggregate impact of DER continuing impact on the PHI electrical grid
- The need to quickly screen whether PV adoption will cause a violation
- The ability to assess the hosting capacity of radial distribution circuits or the secondary network
- The ability to model smart inverters along with other new types of DERs
- The need to understand gross load, net load and generation on each feeder

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Advanced Modeling Software and Data

- Distribution Engineering Workstation
- Three-phase Unbalanced Circuit Model
  - Build circuit maps from GIS system and models are geospatial
  - Simulates the movement of Voltage Regulators, Capacitors, etc.
  - Automatically maps all DERs to the correct location in the model
  - Brings in hourly load – customer load and SCADA
  - Interfaces and brings in historical irradiance for the specific location
- Time Series Analysis
  - Hourly interval is standard
  - Finds the critical points looking at all hours of year
- Measurement data (time synchronized)
  - Start of circuit (SCADA)
  - Customer load data (from AMI or profiled consumption data)
  - Generation measurements

DEW's Advanced Modeling Tools to Complete High-Pen PV Integration Studies

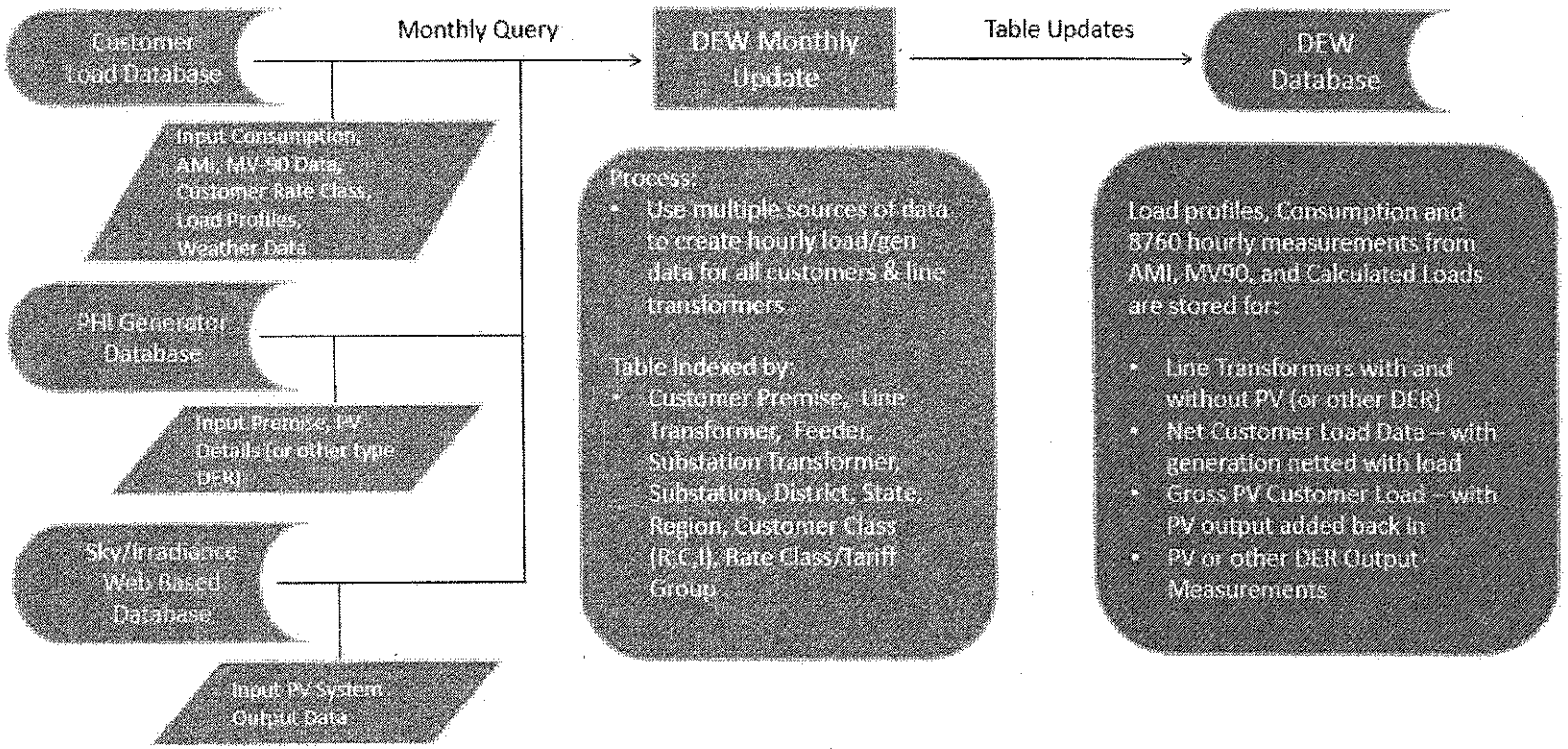
- Generation Time Series Analysis
  - Determines the most critical time points for analysis by analyzing all intervals

    Minimum Daytime Load (MDL) Max Load Point Low Load Point
    Max PV Point Max PV/Load Ratio Max Difference Point
  - Movement of utility control equipment

- Generation Impact Analysis (Hourly data for critical days)
  - Detail Studies covering the periods of worst case circuit conditions
  - Analyze the loss and return of generation with and without regulation
  - Analyze PV power factor settings if needed

- Generation Fault Analysis
  - Screening & fault studies

PHI Advanced Modeling Tool Development



- Load Generation Database
  - Updated monthly from customer billing and CPR (Clean Power Research) PV output service
  - Stores monthly system wide parsed data
  - Used to provide detailed download data for PV & Planning Analysis

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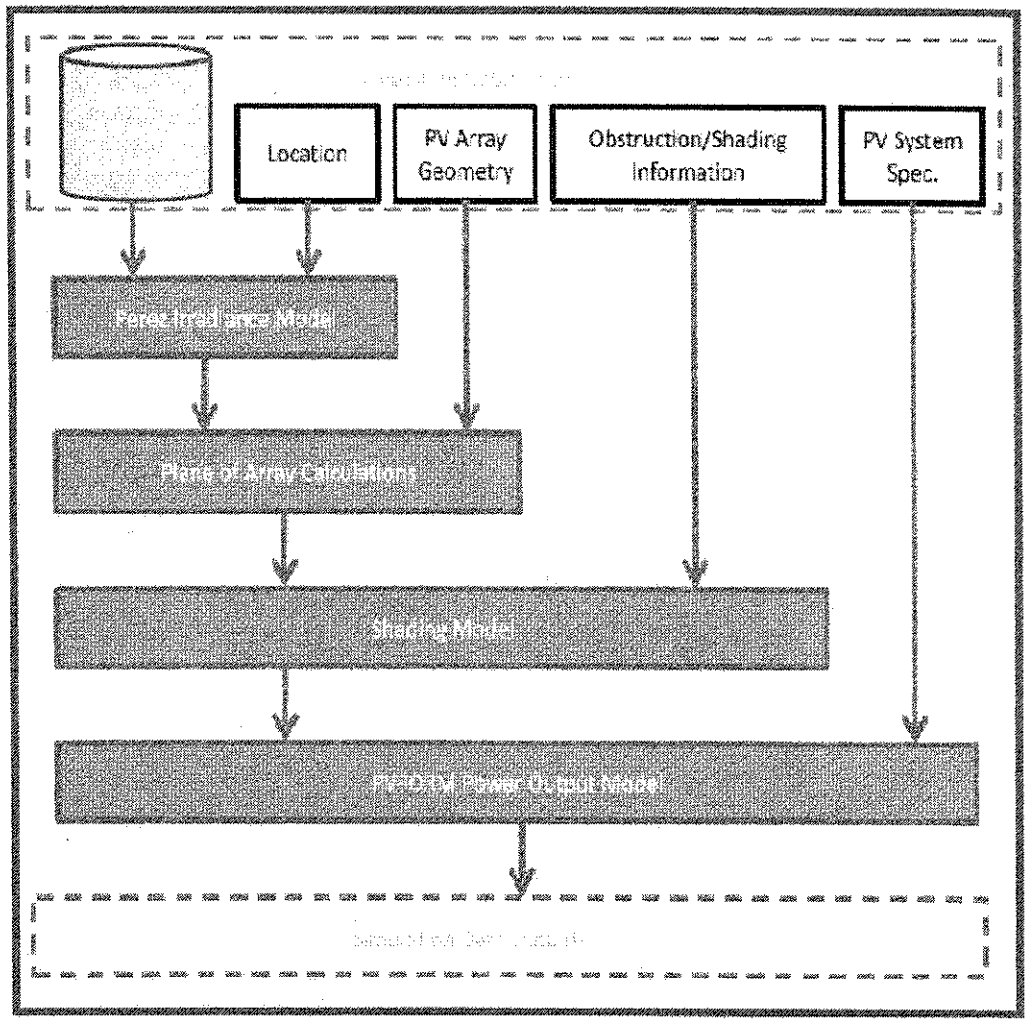
Clean Power Research Data

CPR provides irradiance based generation modelling for PV systems

System output is applied to DEW component and used in Power Flow calculations

Minimum input requirements:

- Array Size,
- Inverter Make/Model or Efficiency
- Module Make/Model or Efficiency
- Tracking Type (Fixed or Axis-Based)
- Tilt Angle
- Azimuth Angle
- Azimuthal Obstructions



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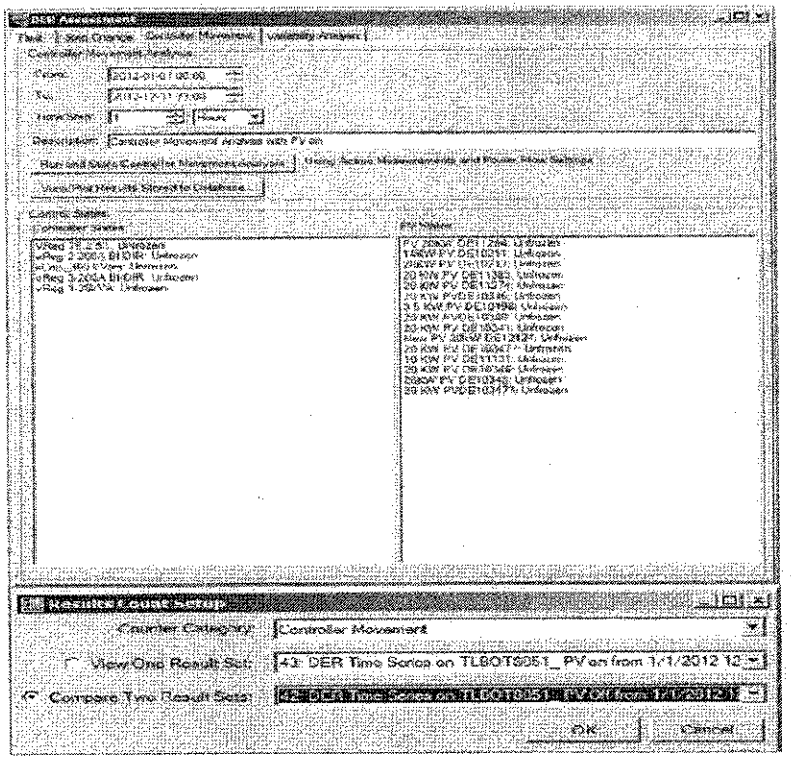
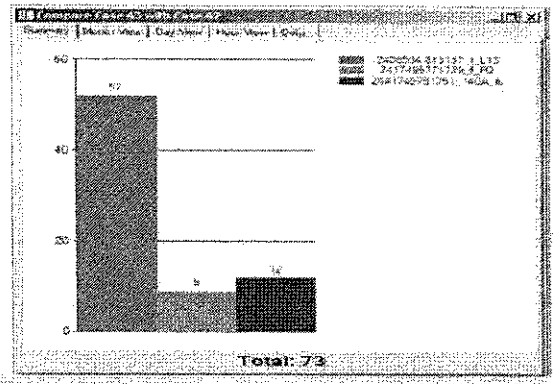
DER Assessment Device Movement (Net Difference w/wo PV)

Controller Movement Summary – DEW automatically adds up the number of operations of caps and Vregs to quickly view which devices are operating more frequently with the generator.



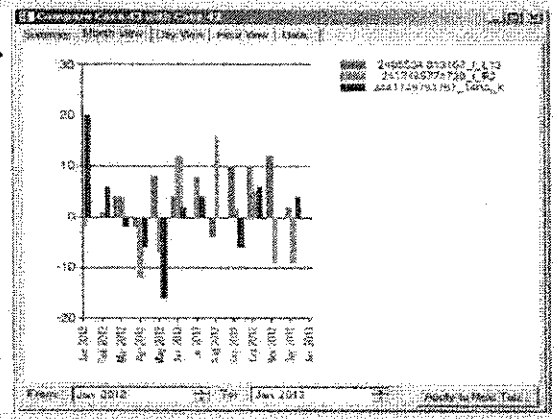
Ckt VReg
Vreg 1
Vreg 2
Vreg 3



Comparing Device Annual Movement Count with and without PV

Increase in no of operations

Decrease in no of operations



Comparing Device Monthly Movement Count with and without PV

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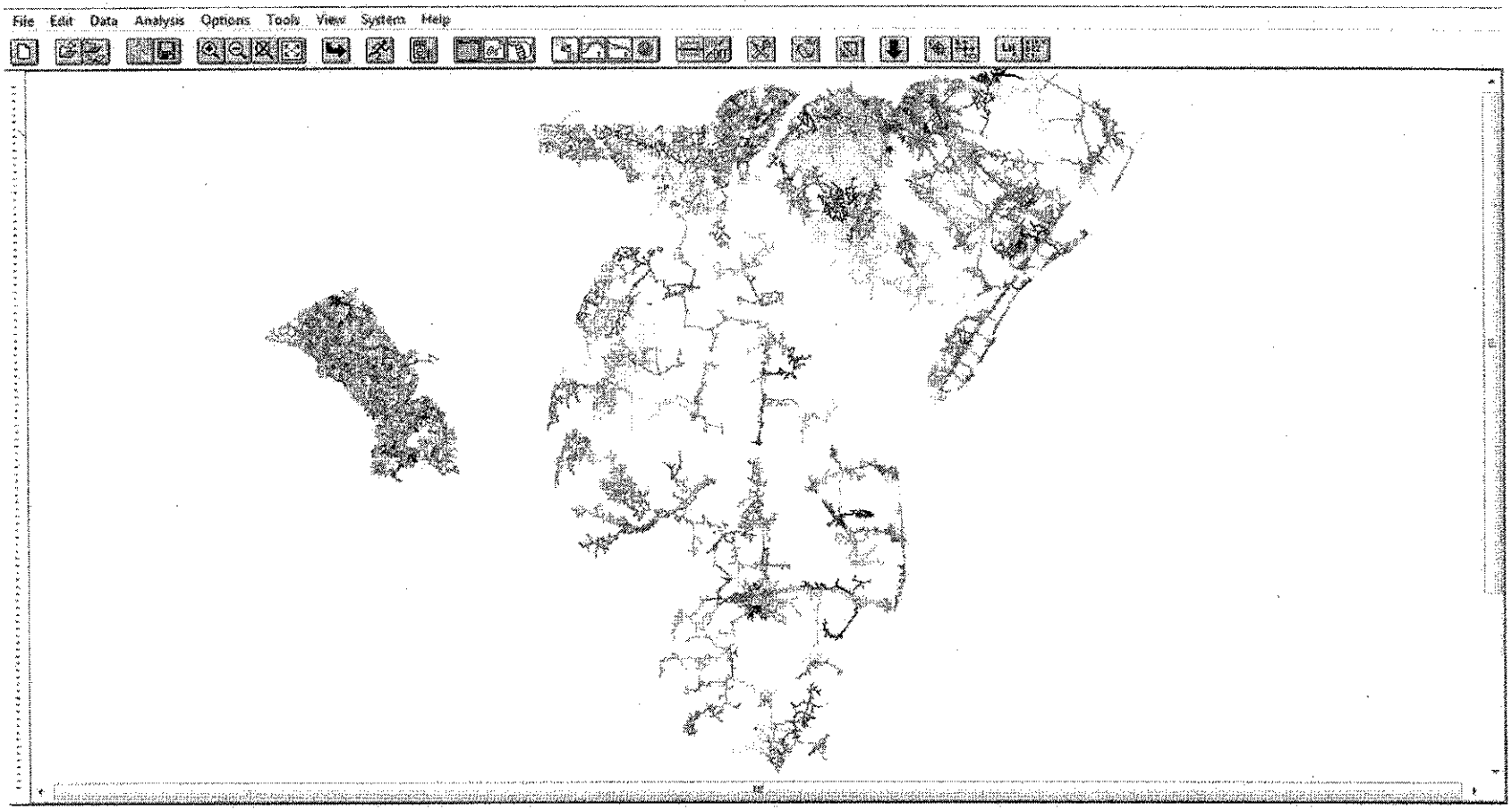
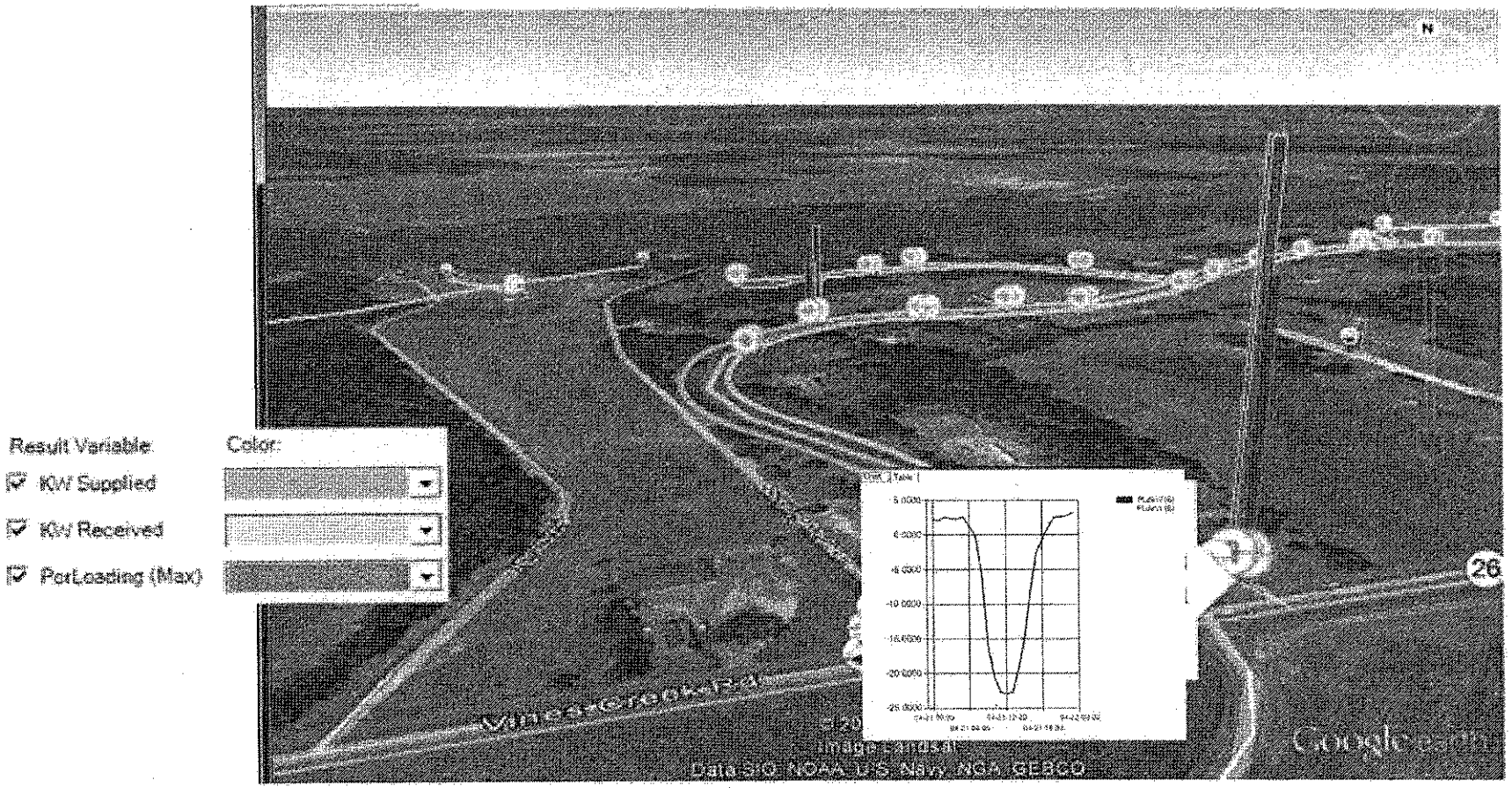
Integrated System Model

- PHI has over 2,000 distribution circuits, and all can map into the model from the GIS system.
- All the DERs map onto those circuits in the correct location from a DER database which now has over 26,000 systems.



Transformer With Reverse Flow due to PV



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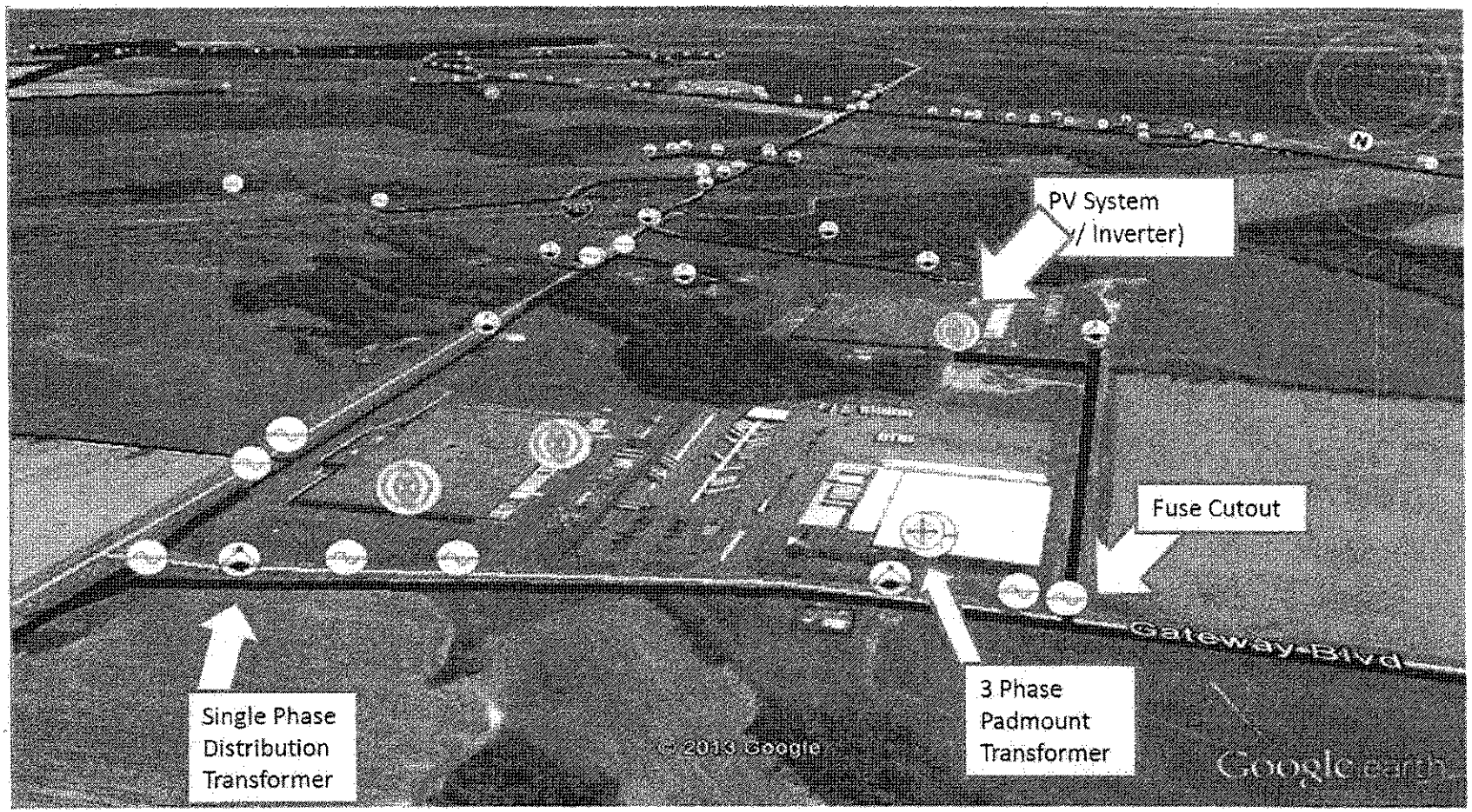
PV Systems Map into Model



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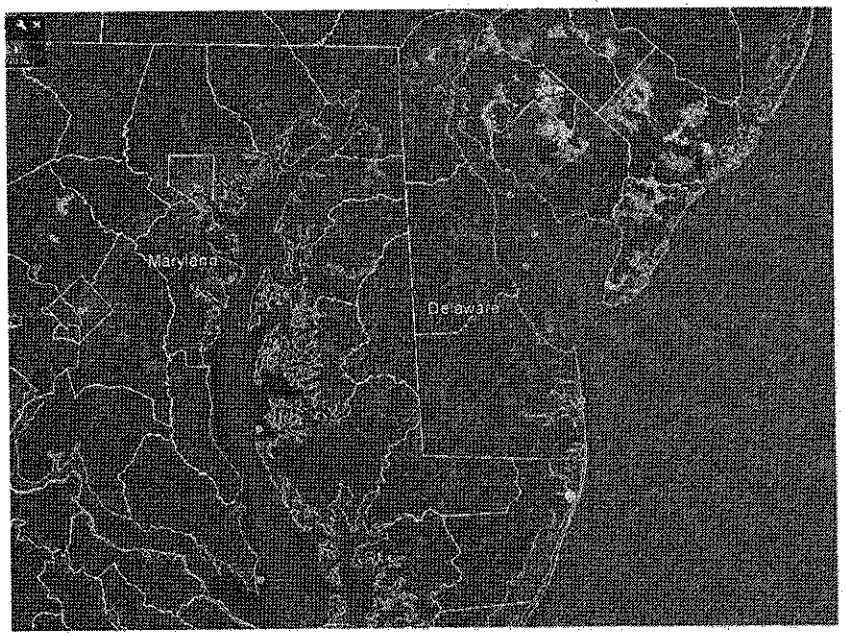
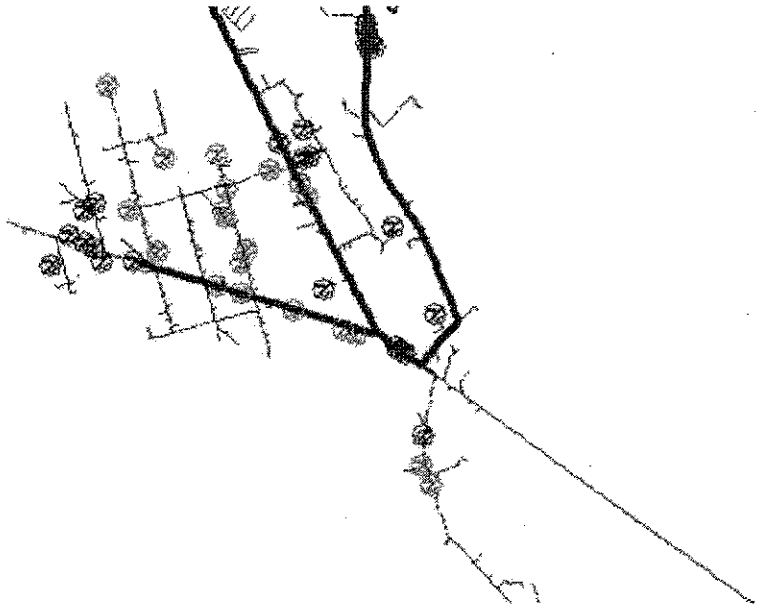
DER Semi-Automated Impact Assessment





- This application performs a semi-automated series of power analyses on any number of selected circuits which checks for many violations such as voltage flicker, over-voltages, and reverse power flow violations.
- The 50 circuits with the highest DER penetrations were selected for review (shown on the map above).
- Voltage Fluctuation violation locations are marked in red (example shown on the right above)

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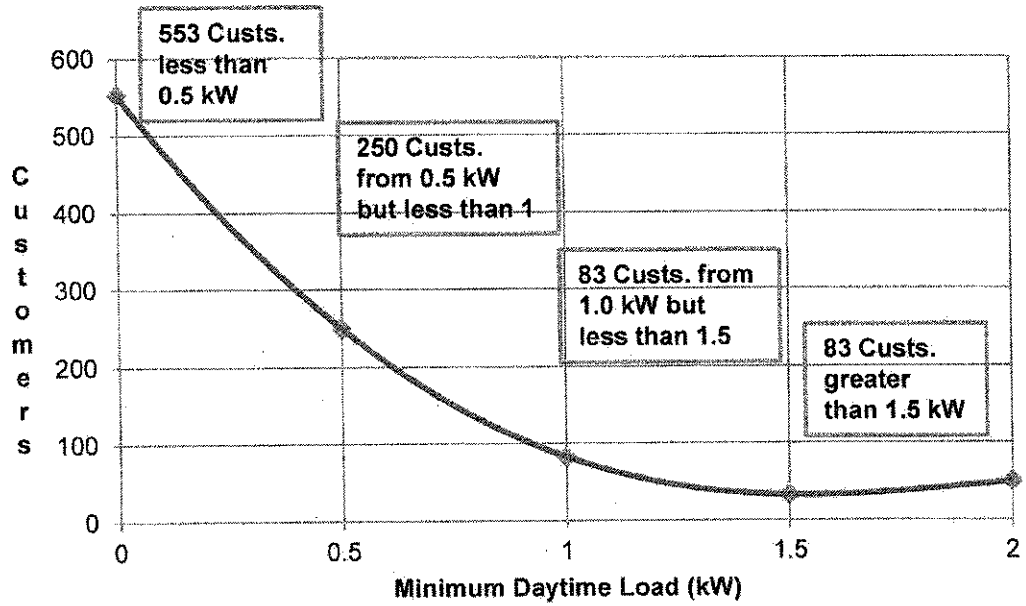
PV Impact at Minimum Daytime Load (MDL)

Minimum Daytime Load for Approx. 1,000 Residential Customers (w/o PV)



The above analysis shows that at MDL, during high solar output hours, the customer load can be extremely low. This means that most of the solar at that point in time will be exported into the system. This not only causes voltage rise at the customer site, but can also cause voltage rise on the distribution circuit and, for large enough concentrations, on the transmission system.

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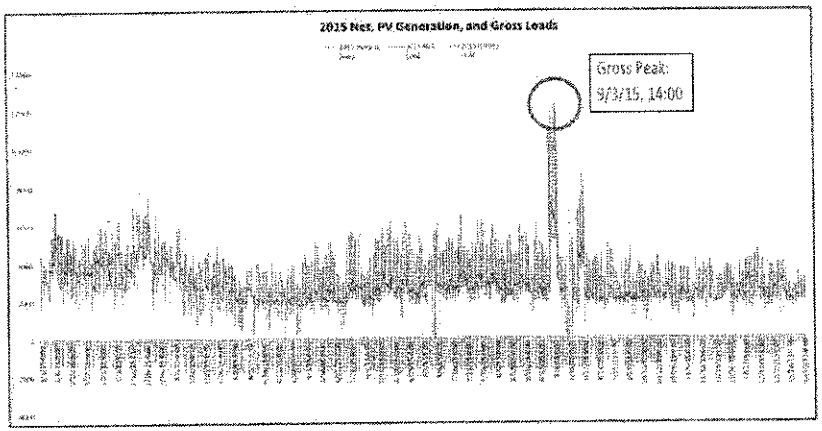
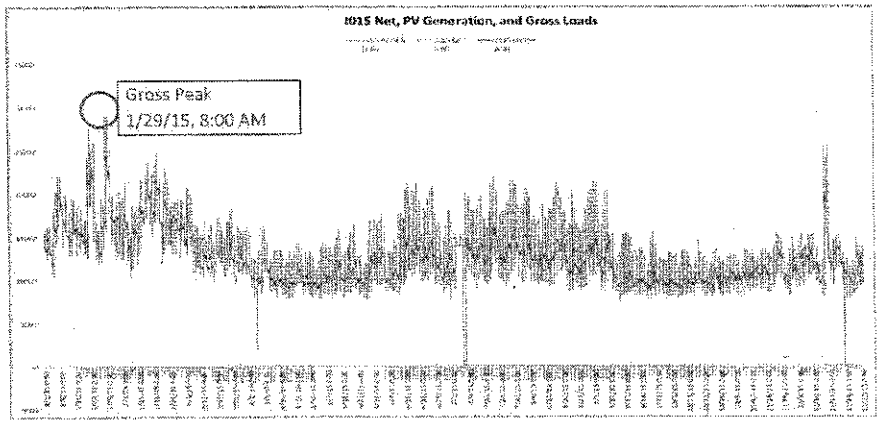
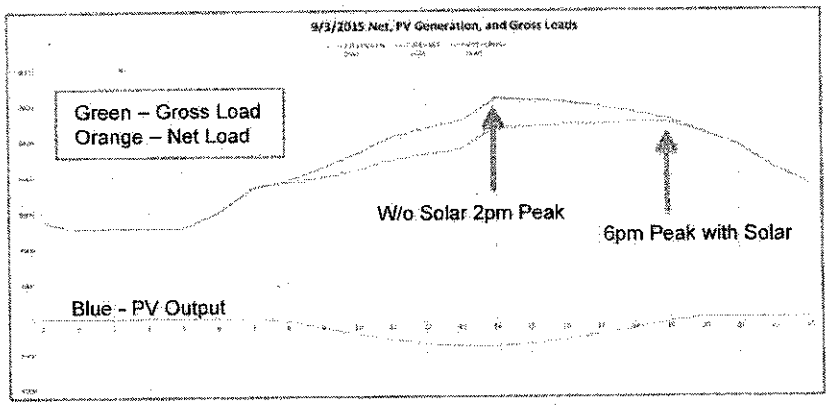
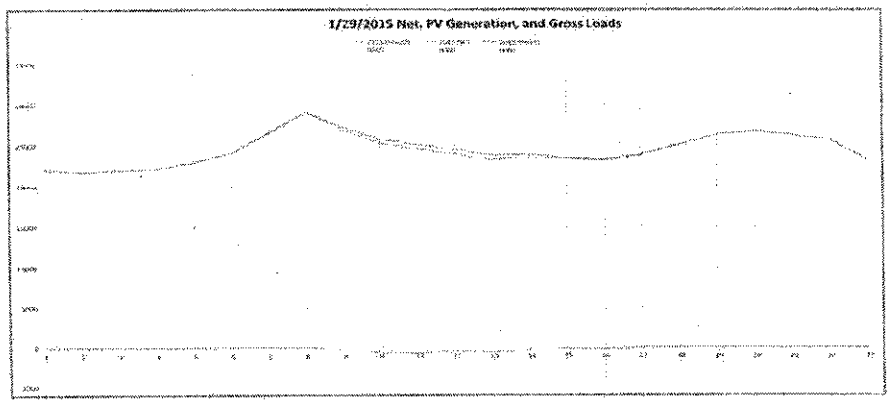
PV Impact on Distribution Feeder Peak

- The impact of solar is different on every feeder and each year can be different
- The reduction in peak on this circuit is 79% (1,617 kW) of the installed solar capacity (2,045 kW) because the peak occurs at 2pm on 9/3/15 and was shifted to 6 pm.
- The reduction in peak on this circuit is less than 1% (17 kW) of the installed solar capacity (2,055 kW) because the peak occurs at 8AM on 1/29/15



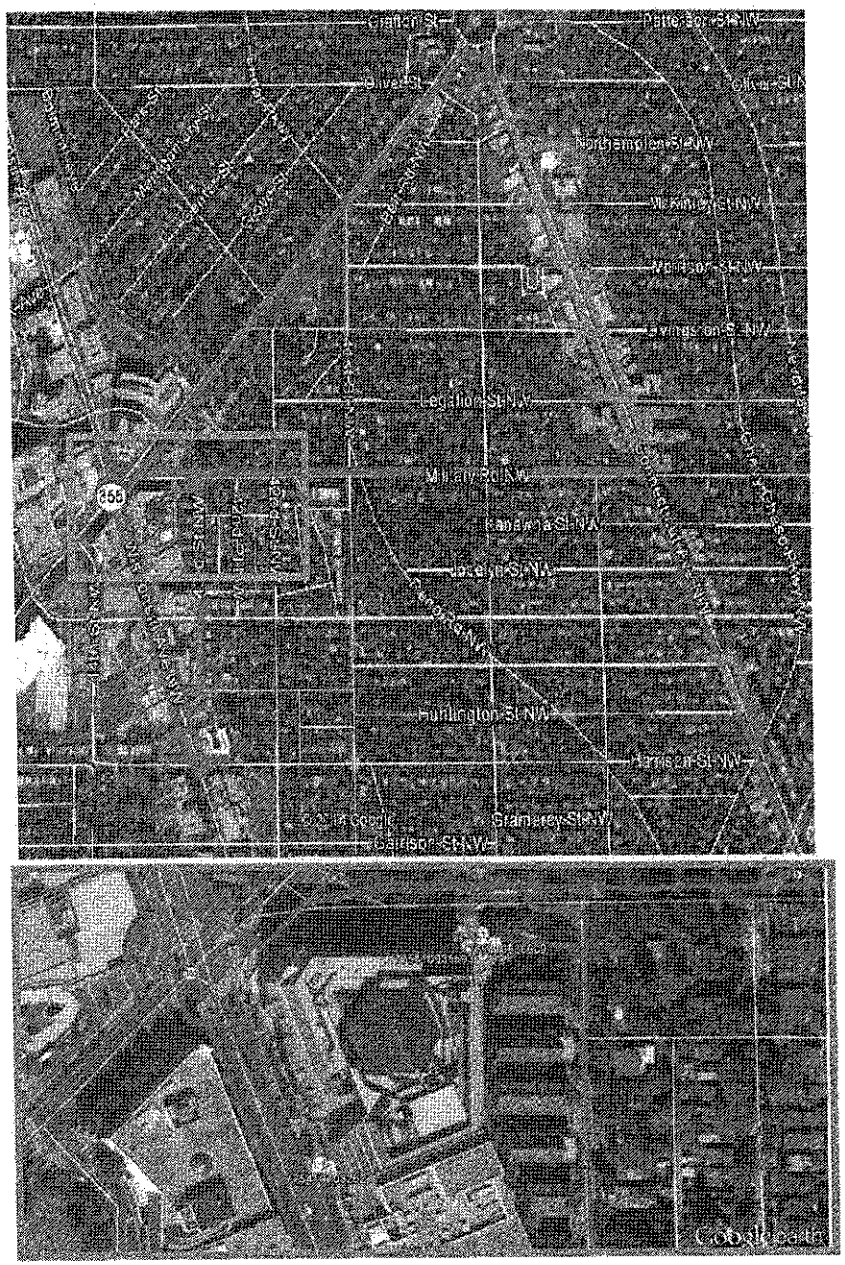




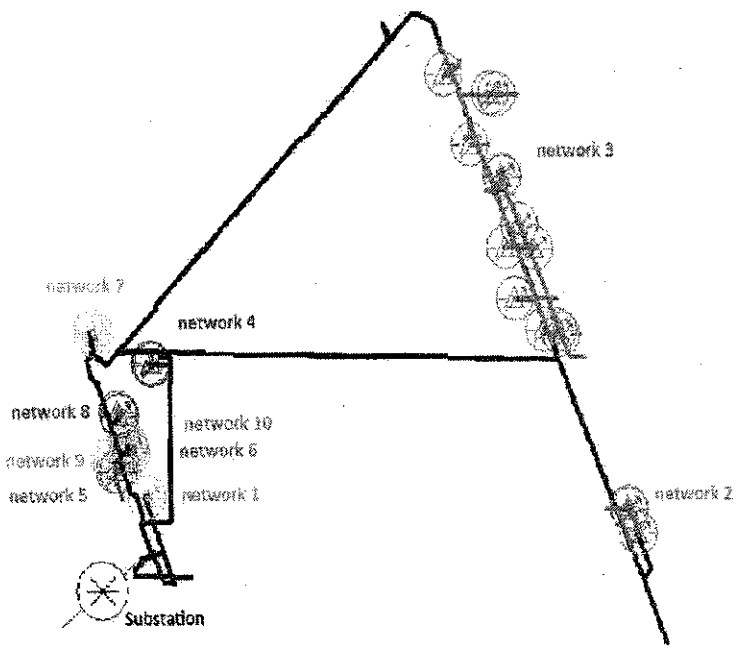


Network Hosting Capacity

- The Hosting capacity tool in DEW is designed to quantify how much DER generation can be reliably added to the Pepco secondary network without violating established criteria, which is preventing reverse power through the network transformer.
- The results will help provide the approximate amount of solar PV that can be installed on a grid or spot network.
- In general, primary circuits dedicated to feeding secondary network groups will not experience violations if the hosting capacity on the secondary network is adhered to.
- These results only verify there will be no reverse flow from the customer through the network protector. That will be the only violation being analyzed in this secondary network hosting capacity study.



Network Hosting Capacity



Max PV within the grid network

Max PV allowed on a spot network

Secondary PV Hosting Summary

	#	Network	Max PV Rating	Total PV Ratings M.I.L. (Max Ratio)
▶	1	775409920733 + 1 others	350.2	286.2
	2	775409625647 + 2 others	107.8	109.4
	3	778411721528 + 12 others	159.9	574.6
	4	775410968593 + 2 others	472.0	342.5
	5	775409687896 + 1 others	212.8	152.5
	6	775410780050 + 1 others	336.9	273.5
	7	[illegible] + 2 others	262.5	220.9
	8	775410714250 + 2 others	719.3	587.5
	9	[illegible] + 2 others	345.0	289.2
	10	[illegible] + 3 others	156.4	129.0

- The left image shows a sample of 10 secondary networks (8 spot and 2 grid) on which the hosting capacity analysis was performed
- The table to the right shows the results on each of the networks (the 2 grid networks boxed in red)
  - The maximum penetration level of the network group was determined to be just over 3MWs

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Advanced Studies and Demonstrations

Advanced Studies and Demonstrations

- Department of Energy "SUNRISE" Grant – PHI just completed this study with other collaborators, investigating cost effective ways to increase hosting capacity, and developed a tool that analyzes secondary voltage rise.
- Advanced Distribution Control and Communications – PHI is collaborating with Chesapeake College, Solar City, A F Mensah and others to do a demonstration project that will control smart inverters, battery storage, flexible load, along with substation and feeder equipment in an integrated system. This along with development of low cost, secure communications will prepare PHI to maintain a robust, reliable Grid of the future.
- Monitoring and Control of Smart Inverters via the AMI or alternate communication system for the LVAC – PHI is collaborating with the University of Hawaii and others to develop this functionality which will allow for more DER to be deployed. Additional testing and demonstration of PV and other new technology is taking place at the Water Shed facility in Rockville, MD.

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QUESTIONS

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