*Title:* ***Puerto Rico Distribution Modeling***

*Synopsis:* *Summary of Results of modeling of high penetrations of distributed photovoltaic / battery energy storage systems in the Puerto Rican Distribution System.*

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**Table I-1 – Revision History**

| Date | Revision No. | Description |
|---|---|---|
| 12/15/2020 | 01 | Initial Revision for Review |
| 01/05/2021 | 02 | Revised per Review Comments |
| 02/08/2021 | 03 | Revised per Review Comments |

**Table I-2 – Table of Figures**



**Table I-3 – List of Abbreviations**

| ***Abbreviation*** | ***Definition*** |
|---|---|
| AAAC | All Aluminum Alloy Conductor |
| ACSR | Aluminum Conductor Steel Reinforced |
| AL | Aluminum |
| ANSI | American National Standards Institute |
| AWG | American Wire Gauge |
| BESS | Battery Energy Storage System |
| CU | Copper |
| DER | Distribution Energy Resource |
| EPR | Ethylene Propylene Rubber |
| EPRI | Electric Power Research Institute |
| ESRI | Environmental Systems Research Institute |
| GIS | Geographic Information System |
| HD | Hard Drawn |
| IEEE | Institute of Electrical and Electronic Engineers |
| LTC | Load Tap Changer |
| PREPA | Puerto Rico Electrical Power Authority |
| PSS/e | Power System Simulator for Engineering |
| PV | Photovoltaic / Photovoltaic System |
| SOW | Scope of Work |
| URD | Underground Residential Distribution |
| VAR | Volt Ampere Reactive |
| XLP | Cross-linked Polyethylene (insulation) |

# I. Executive Summary

In cooperation with Cambio PR, Telos Energy and the Energy Futures Group, EE Plus has performed a comprehensive analysis of the impact of high penetrations of highly distributed DER facilities on the Puerto Rico distribution system. This analysis contemplated four analytical scenarios, aligned with analyses performed by Telos Energy on the generation and transmission system. The four scenarios included:

- Base Case scenario, including Photovoltaic (PV) systems and Battery Energy Storage Systems (BESS) currently installed and approved for operation on the distribution system;
- 25% Penetration Scenario, including existing systems and 50% resilient homes, with approximately 1500 MW of PV and BESS systems;
- 50% Penetration Scenario, including existing systems and 75% resilient homes, with approximately 3200 MW of PV and BESS systems; and
- 75% Penetration Scenario, including existing systems and 100% resilient homes, with approximately 5000 MW of PV and BESS systems.

The analyses included the construction of distribution models of approximately 90% of the Puerto Rico Electric Power Authority (PREPA) system within the OpenDSS distribution modelling software. Models were developed based on:

- Distribution GIS data provided by PREPA;
- 7 representative Distribution models in Synergi;
- Annual PV dispatch data provided by the Plexos modelling performed by Telos Energy;
- Annual regional load data provided by the Plexos modelling performed by Telos Energy;
- System impedance and bus loading allocation provided by the PSS/e modelling performed by Telos Energy; and
- Industry and PREPA distribution standards.

The assumptions and methodologies applied to these analyses are documented within this report, and have been coordinated throughout the analytical process with all participating entities. Additional more detailed analyses, with greater granularity, are provided in Volume II of this report, and the data files that support the analyses are included in Volume III of the report.

Although data used was provided by PREPA the model has been independently developed by

EEPlus on behalf of CAMBIO PR and in no way represents any proposal, projection or representation of the Puerto Rico Electric Power Authority.

The results of the analysis indicate that on a steady state basis, the Puerto Rico distribution system can support high levels of distribution penetration, if deployed as envisioned by Cambio and the Queremos Sol group. The deployment will require infrastructure improvements within the distribution system throughout the island. The magnitude of the infrastructure is obviously contingent upon the scenario considered, but even at the highest penetration levels, only approximately 2,525 lines miles of distribution improvement may be required. It is important to note that these results are constrained by both the assumptions detailed herein and the accuracy of the GIS data provided by PREPA. To the extent that these factors are changed, the results may be impacted.

These results are both encouraging and somewhat more favorable in terms of both scope and projected cost than were initially anticipated. Prior experience with the analysis of larger, lumped PV / BESS applied to distribution systems had yielded much higher levels of infrastructure improvement necessary to support deployment. Similar results were anticipated for these analyses. However, owing to two key factors, EE Plus analyses yielded only modest need for infrastructure improvement. The first of these factors is the highly distributed, "behind the meter" nature of the DER contemplated by the proposed deployment. By placing the generation effectively at the load point, the use of the distribution system was minimized. This mitigated both thermal and voltage rise impacts that are common in larger, lumped installations.

The second factor was the coordinated deployment of the PV and BESS systems. By using the PV system to charge the BESS system during peak production conditions, the impacts on system voltage were minimized. Likewise, the use of relatively small individual systems that largely displace local load rather than export excess energy to other loads within the distribution system mitigates any thermal issues.

While certainly favorable, the results of these analyses are not necessarily definitive in the sense that there are multiple, real world considerations that must be factored into actual deployment planning. The ability of the grid to sustain a largely inverter driven system, without significant rotational inertia is questionable. Please reference the Telos report for further details on this issue. Likewise, the ability to defeat the anti-islanding features that are standard in small scale PV inverter systems must be considered to provide a reliability / resiliency benefit to individual consumers. Anti-islanding provisions are typically built into modern inverter systems to prevent inappropriate or unwanted backfeed into the distribution system when the grid is unavailable. To provide reliability benefits for individual customers, this feature must be disabled or otherwise defeated so that the PV / BESS system may serve the individual household loads. Finally, this set of analyses only considered steady state analysis. The impacts on protection systems were not considered, nor were the harmonic impacts associated with this level of inverter penetration. Both of these issues deserve further review. With that said, this novel and forward-looking approach to renewable deployment certainly seems feasible, particularly in light of the rapid advancement of inverter technologies.

# II. Scope of Work

The Scope of Work (SOW) for the project has evolved somewhat from the original proposal, predicated on the availability of data from the Puerto Rico Electric Power Authority (PREPA). As originally envisioned, the project contemplated the use of native Synergi distribution models provided by PREPA. However, PREPA provided only seven representative distribution models, less than one percent of the total distribution plant within the system. EE Plus did not believe that an accurate extrapolation of system performance could be made from a sample this small, and as such sought to develop alternate models from other available data.

To that end, EE Plus chose to use the data provided in the PREPA Geographic Information System (GIS) to build new models in OpenDSS, an open-source distribution modeling software developed and distributed by the Electric Power Research Institute (EPRI). Using the approach, EE Plus was able to model approximately 90% of the PREPA distribution system, providing a much better representation of the impacts of high penetrations of PV and battery energy storage systems.

Based on this analytical approach, EE Plus performed the following distribution analysis and remediation planning based on 4 distinct scenarios, intended to align with the transmission and sub-transmission analysis scenarios. The scenarios included:

- Scenario 0: PREPA base case, in accordance with the PREPA Integrated Resource Plan
- Scenario 1: 25% aggregate renewable energy by 2035, with 50% of residences with combined rooftop solar and batteries.
- Scenario 2: 50% aggregate renewable energy by 2035, with 75% of residences with combined rooftop solar and batteries.
- Scenario 3: 75% aggregate renewable energy by 2035, with 100% of residences with combined rooftop solar and batteries.

The analyses performed for the SOW included:

- Evaluation of voltage profile of each feeder, evaluated against ANSI / IEEE criteria;

- Evaluation of thermal performance of each feeder, evaluated against conductor and device ampacities;
- Evaluation of the thermal performance of each substation transformer, based on the published rating of the transformer; and
- Remediation analysis of any violations based on the remediation necessary to support Scenario 3. Remediation included the upgrade of conductors necessary to mitigate voltage or thermal violations at the existing operating voltage of the feeder.

The assumptions, techniques, methodology and evaluation criteria used for these analyses are delineated in subsequent sections.

# III. Assumptions

While the information contained in the PREPA GIS was reasonably comprehensive for the purposes of this analysis, there were a number of analytical assumptions that were necessary to fill in gaps and incomplete data in the GIS. The remainder of assumptions used in the analyses were based on published standards and drawings from PREPA.

## A. Data Correction / Completion

There were multiple ESRI shapefiles provided as part of the GIS data from PREPA. These included:

- Primary Conductor
- Bus
- Primary Node
- Regulator
- Capacitor Bank
- Transformer Bank
- Switch
- Step Transformer and
- Distributed Generator
- Booster
- Fuse

Most of these required some degree of correction or completion for at least some of the feeders. The assumptions used to correct deficiencies in the GIS data are as follow:

- Where primary conductor voltage was in error or in question, the conductor inherited its operating voltage from the feeder operating voltage;

- Phase rotation was not taken into account. Phasing was considered for topology and connectivity purposes. All three phase lines were modeled as "ABCN". All two phase lines were modeled as either "ABN", "ACN", or "BCN". All single phase lines were modeled as either "AN", "BN", or "CN", with "N" representing the grounded neutral.
- Where the upstream or downstream termination node of a primary conductor segment was not identified, the line was connected to the geospatially closest node of the same feeder, or treated as a "end of line" node, if there was no adjacent conductor of the same feeder
- If the conductor size was not identified, the size was inherited from the upstream conductor. If the inheritance methodology did not work, overhead conductors were set to #2 ACSR, and underground conductors were set to #2 Copper XLP cable.
- Only capacitor banks with a status of "Closed" were modeled.
- Phase rotation was not taken into account. Phasing was considered for topology and connectivity purposes. All three phase capacitors were modeled as "ABCN". All two phase capacitors were modeled as either "ABN", "ACN", or "BCN". All single phase capacitors were modeled as either "AN", "BN", or "CN", with "N" representing the grounded neutral.
- As most capacitors were missing their size kVAR size, capacitors were set to 100 kVAR / can multiplied by the number cans listed. If neither were available, capacitor banks were set to a nominal size of 300 kVAR.
- For voltage regulators, if the connectivity could not be discerned from the feeder topology, the regulator was <u>not</u> modeled.
- Only regulators with a status of "Closed" were modeled.
- All reclosers were assumed to have a continuous current rating of 630 A. Interrupting rating was not modeled as device switching was not contemplated for the analyses.
- Only normally closed switches were modeled, as no feeder reconfiguration was contemplated. Switches were rated in accordance with their "Capacity_A" parameter from the GIS.
- For switches, if the connectivity could not be discerned from the feeder topology, the switch was <u>not</u> modeled.

- The existing PV systems were not assigned to a particular feeder or conductor segment in the GIS. As such, it was necessary to use GIS analysis to assign the individual systems to the geospatially closest conductor segment that matched its phase configuration, i.e. single-phase systems assigned to either single-phase lines and three phase systems assigned to three phase lines. EE Plus cannot guarantee that this methodology represents with 100% fidelity with the physical system, but it is believed to provide at least a reasonable approximation thereof.

## B. Analytical Assumptions

In addition to the assumptions necessary to correct or fill in gaps in the data, it was necessary to make some overarching assumptions about the distribution system to appropriately model it in OpenDSS. For the most part, these assumptions were based on distribution standards from PREPA.

The first of the analytical assumptions were relevant to the substation transformer. EE Plus explicitly modeled the substation transformers within the Open DSS models. Transformer size, both normal and emergency, were as promulgated in the GIS database. All substation transformers were assumed to have a ±16 set on load tap changer (LTC), regulating to ±10% of the nominal transformer secondary voltage. The setpoint of the LTC was set at 1.03 per unit or 123.6 V on a nominal 120 V base. The impedance and X/R ratio of the transformer was in accordance with IEEE C57.12.00-2015 (IEEE Standard for General Requirements for Liquid-Immersed Distribution, Power, and Regulating Transformers).

Overhead conductors were assumed to be mounted on 35' Class 3 poles. Additional reinforcement or resiliency measures that have or may be undertaken by PREPA were not included as part of the OpenDSS model. The framing of the poles and attendant overhead conductors were based on drawings from "Patrones De Construcción De Distribución Aérea" or Aerial Distribution Construction Patterns, obtained from the PREPA website (1986 version). Note that "narrow" profile construction, using standoff brackets, was assumed, rather than conventional crossarm construction. Also, where the conductor type was "spacer", narrow profile spacer brackets were assumed to have been used, similar to the illustration in Figure III-1 below. Conductor ampacity was determined using the methodology described in IEEE 738-2012 (IEEE Standard for Calculating the Current-Temperature Relationship of Bare Overhead Conductors). Other parameters required to fully define the conductor within the OpenDSS models were obtained from (Square D Company, 2006) and (Southwire Corporation, 2020).

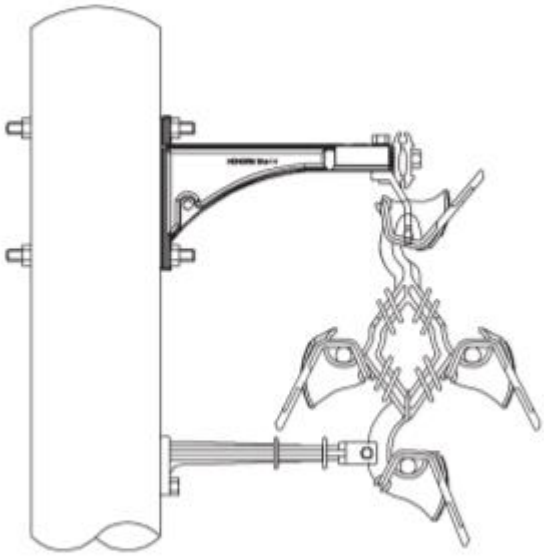

**Figure III-1 – Triangular Cable Spacer Bracket** **(source: Hendrix Aerial Cable Systems)**

Underground conductors within the GIS were similarly configured to fit within the OpenDSS modelling framework. For the purposes of this analysis, the concentric neutral model within OpenDSS was utilized, as opposed to the tape shield model. Data required for this modelling effort was obtained from (The Okonite Company, 2020). The installation configuration was based on Drawing URD-6, Page 7 Rev 1 (Trinchera Para La Instalacion Alimentadores Principales Primarios) of the Manual of Underground Distribution Patterns (PREPA, February 2002). The configuration was modeled as shown Figure III-2 in below. Underground conductor ampacity was determined based on data from IEEE 835-1994, IEEE Standard Power Cable Ampacity Tables. Cable terminations, cable elbows and switchgear bus were assumed to be rated for 200 A if the cable was #2 AWG AL or smaller, and 600 A if the attendant cable was larger than #2 AWG AL.

As noted above, capacitor banks were assumed to be composed of 100 kVAR cans, in multiples of three for three phase units, multiples of two for two phase units, and single cans for single phase units. All capacitors were assumed to be fixed, as no control information was provided.

Voltage regulators were assumed to be rated in accordance with the provided GIS data. Regulators were assumed to have ±16 steps, and operate in a range of ±10% of the nominal primary voltage. Secondary voltage was set to 1.03 per unit of the primary side voltage, with a 2 volt bandwidth, and a 2 minute time delay. Regulators were set to accommodate reverse power flow and regulate in either direction.

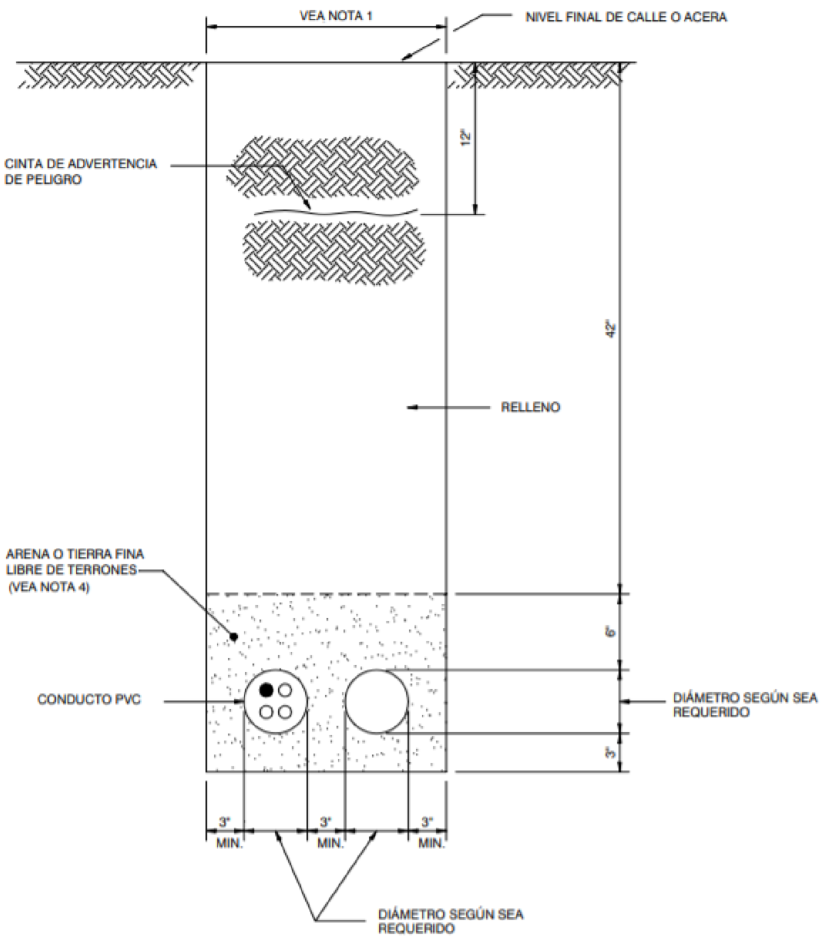


**Figure III-2 – Typical Underground Conductor Installation**

## C. Transmission Interface Assumptions

The interface point between the transmission and sub-transmission systems, as modeled by Telos, was the primary side of each load serving substation transformer. In most cases this interface was at 38 kV. There were, however, some 115 kV buses that directly serve distribution loads as well as the transmission grid. Throughout the analyses, the transmission system was considered the "master" source, even when there was appreciable downstream generation. As referenced above, the transmission source was set to a value of 1.03 per unit.

The power factor for the secondary side of each substation transformer, which was ultimately inherited by all downstream loads, was set to the value of the load at the corresponding transmission bus within the Telos Plexos and PSS/e models. Likewise, Telos used the PSS/e model to define the source impedance of the transmission system at each load bus. This value was included as the positive sequence source impedance for the source on the primary side of the substation transformer.

Finally, the 8760 hour load shape associated with each region was allocated to the individual substations for both commercial and residential load, based on. The load shapes were used to define the interaction of the PV and BESS systems with the loads at each distribution substation bus. An example of a typical load shape for both residential and commercial loads are shown in Figure III-3 and Figure III-4 below.


**Figure III-3 – Example of Residential Load Shape**


**Figure III-4 – Example of Commercial Load Shape**

## D. PV / BESS Interface Assumptions

The final set of assumptions were related to the application of both existing and contemplated PV and BESS systems. As noted above, the existing PV was connected to the physically closest feeder segment via GIS analysis, and the size and phase configuration was as documented in the GIS database. Only those systems whose status was "Connected Authorized to Operate" were included in the distribution models. Where battery systems were also included, it was assumed that the PV would charge the battery until the state of charge was 100%, and then flow power onto the grid or serve local load.

New PV / BESS combinations were added based on multiple criteria. PV/BESS systems were added to the distribution models at the location of existing transformer in the GIS. This allowed EE Plus to geospatially distribute the interconnections in a manner that was reasonable, as the presence of a distribution transformer inherently implies the presence of a load to serve. Note that regulating transformers and booster transformers were excluded from this placement exercise.

The number and type of individual PV/BESS systems at each location was based on the size and configuration of transformation at each geospatial location. Single phase transformation was assumed to serve primarily residential load, and three phase transformers were assumed to serve commercial loads. All residential systems were assumed to be a combination of 2.7 kW PV systems and 10 kWh BESS systems. An integer number of residential PV/BESS systems were added at each single phase transformer location, with the number allocated based on the size of the transformer; that is, a 10 kVA transformer location would receive fewer installations than a 37.5 kVA transformer location.

New PV systems were assumed to serve local load at the transformer location and simultaneously charge the BESS until the state of charge of the battery was 100%. In the absence of the PV system, the BESS was assumed to serve local load until the state of charge reach 10%. Note that the batteries were assumed to be charged from the PV system only; no direct charging from the grid was contemplated. PV/BESS systems were set to regulate their output voltage to 1.0 per unit.

Finally, the total new amount of both residential and commercial PV systems had to be matched to the scenario definitions associated with the transmission interface. This necessitated a two-step allocation process. The first step was to allocate the maximum value (in MW) of the regional commercial and residential PV, as determined by Plexos, to the individual transmission buses / distribution substations. This allocation was based on the load represented at each transmission bus within the PSS/e model. The second step was to allocate the requisite PV to each substation feeder. This allocation was based on the total connected kVA for each feeder on a given substation bus. As noted above, the residential systems were then geospatially distributed to the single phase transformer locations based on transformer size, and the commercial systems were lumped at the three phase transformer locations based on transformer size. Below shows a representation of how the systems were allocated for a sample feeder.

**Figure III-5 – Example of PV System Placement**

# IV. Methodology

## A. General Approach

The methodology for performing the various analyses required for the project was straightforward. Based on the assumptions discussed in the preceding section, models were developed for all substations and feeders for which a matching transmission bus from the PSS/e model could be identified. The matching process was largely manual, as there was not a consistent numerical key that could be used to tie the two models together. In some cases, there were transmission buses with no corresponding distribution substation in the GIS. Likewise, there were some distribution substations within the GIS that did not have an obvious match to a bus in the transmission model. In total however, EE Plus matched at total of 267 substations with a corresponding transmission model. This yielded a total of 987 feeders of the 1097 provided in the GIS or approximately 90%.

Because the GIS model used multiple ESRI shapefiles to present the distribution system data, EE Plus wrote multiple Python script files to extract the required modeling data from the GIS and write it to text files for use in OpenDSS. In addition to the basis data extraction used to construct individual feeder models, it was necessary to prepare additional OpenDSS files that were common among all feeder models. The general data structure used for all feeder models is shown in Figure IV-1 below. Note that an additional general file, defining the line geometry of the various styles of overhead lines and underground cables was included. Each substation also had a separate file defining the source impedance and substation transformer size. Finally, an individual file that defined the interconnection of the PV / BESS for each feeder was created for each development scenario. The explicit details of the field mapping between OpenDSS, the GIS and the Telos PSS/e models is provided in Volume III of this report.

| Overhead Conductors | Underground Conductors | Wire Data | Voltage Regulators | Transformers | Capacitors |
|---|---|---|---|---|---|
| • Spacing<br>• Phasing<br>• Distance from ground level<br>• Wire details<br>• Kron reduction | • Spacing<br>• Phasing<br>• Thickness of tape shield<br>• Number of Concentric Neutrals<br>• Cable details | • Geometric mean Radius (GMR) feet<br>• Diameter (inches)<br>• Resistance (ohms/mile)<br>• Ampacity<br>• Repair rate | • Potential Transformer ratios<br>• Current transformer ratios<br>• Compensator settings<br>• R and X settings | • kVA rating<br>• Voltage rating<br>• Impedance settings (R and X)<br>• No-load power loss | • Capacity<br>• Phasing<br>• Control type<br>• ON-OFF settings<br>• Power factor |

**Figure IV-1 – OpenDSS data structure.**

The Python scripts created the file grouping listed above for each modeled feeder. These were combined with the "common" files, regional load shape files and additional instructions within OpenDSS to perform the power flow analysis for each feeder. A group of reports were produced by the power flow analysis. These included the two main reports used to formulate the results for this report; the overload report and the voltage exception report. These reports flag instances where line currents or bus voltages are outside the evaluation criteria for the particular device. These results were cataloged for each scenario, identifying the line segments or buses that exhibited the violating performance. For the purposes of this summary report, the results of the violation analysis were aggregated to the regional level. Volume II of this report provides the breakdown by substation and feeder for the purposes of addressing specific mitigation needs.

## B. Evaluation Criteria

As noted in the Assumptions sections, the ampacity ratings of the conductors and equipment were based on either their nameplate ratings, applicable IEEE standards or PREPA standards. It is important to note, that since the evaluations were based on "normal" operating (i.e. non-emergency) operating conditions, the normal steady state ratings of conductors and equipment were applied. The ampacity ratings of all conductors within the PREPA system are shown in Table IV-1 below. Note that while emergency ratings are included in the model for completeness, if a conductor exceeded the normal ampacity rating for even a single hour over the analysis horizon, it was cataloged as a violation.

**Table IV-1 – Overhead Conductor Ampacity Ratings**

| Conductor Type | Normal Rating (Amps) |
|---|---|
| 6_CU_HD | 100 |
| 6_CU | 100 |
| 4_CU_HD | 120 |
| 2_ACSR | 165 |
| 2_CU | 170 |
| 1/0_ACSR | 220 |
| 2/0_ACSR | 250 |
| 1/0_AAAC | 256 |
| 2/0_CU | 275 |
| 1/0_CU | 282 |
| 3/0_SPACER_15_KV | 285 |
| 3/0_ACSR | 285 |
| 3/0_AAAC | 342 |
| 4/0_ACSR | 357 |
| 4/0_CU | 375 |
| 250_CU | 430 |
| 266_ACSR | 475 |
| 266_SPACER | 475 |
| 3/0_CU | 480 |
| 300_CU | 485 |
| 336_SPACER | 529 |
| 336_ACSR | 529 |
| 556_ACSR | 726 |
| 556_SPACER | 726 |
| 652.4_AAAC | 729 |
| 795_ACSR | 907 |

**Table IV-2 – Underground Cable Ampacity Ratings**

| Conductor Type | Normal Rating (Amps) |
|---|---|
| **6_CU_XLP_5_KV** | 100 |
| **4_CU_XLP_15_KV** | 125 |
| **2_CU_XLP_15_KV** | 150 |
| **2/0_CU_XLP_15_KV** | 224 |
| **3/0_CU_XLP_15_KV** | 225 |
| **4/0_CU_XLP_15_KV** | 293 |
| **250_CU_XLP_15_KV** | 322 |
| **300_CU_XLP_15_KV** | 322 |
| **350_CU_XLP_15_KV** | 400 |
| **500_CU_XLP_15_KV** | 472 |
| **500_CU_EPR_15_KV** | 472 |
| **750_CU_XLP_15_KV** | 532 |
| **750_CU_EPR_15_KV** | 532 |
| **800_CU_XLP_15_KV** | 550 |
| **1200_CU_XLP_15_KV** | 667 |

Please reference 

Table I-3 – List of Abbreviations for an explanation of the terminology used in these tables. For devices other than conductors, the nameplate rating as promulgated in the GIS database was used as both the normal and emergency rating.

In addition to the assessment of thermal (ampacity) violations, all buses were screened for steady state voltage violations as well. Voltage violations were defined based on ANSI C84.1-2020: Electric Power Systems Voltage Ratings. Specifically, Range A of this standard was used. It is defined in the standard as:

> *"Range A provides the normally expected voltage tolerance on the utility supply for a given voltage class. Variations outside the range should be infrequent".*

The applicable ranges used for evaluation of voltage violations are illustrated inFigure IV-2 below.

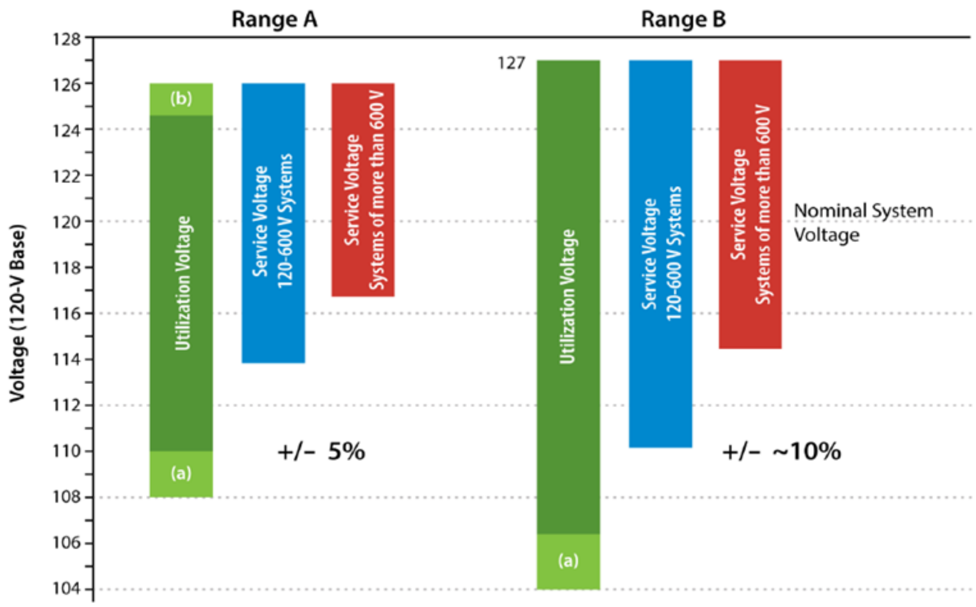


**Figure IV-2 – Voltage Range for Violation Evaluation**

Note that the voltage range for Service Voltage (Systems of more than 600 V), illustrated in the red bar above, were used as the evaluation criteria for bus voltages throughout the distribution system.

In addition to the conductor and device evaluations, for each substation and scenario, the capacity of the substation transformer was evaluated with all feeders simultaneously connected. If there was forward or reverse power through the substation transformer, in excess of the transformer's normal rating, the transformer was flagged for remediation. Individual distribution transformers were not evaluated for overload as the DER resource allocation methodology prevented the placement of excess (i.e. greater than the transformer size) DER at any given distribution transformer location. Distribution systems routinely have as much as 40% more connected kVA than actual load, so the appropriate level of DER penetration could be deployed without the risk of overloading individual transformers.

## C. Mitigation / Remediation

To estimate the amount remediation necessary for a particular violation, two simple approaches were used. For thermal violations, the length of every conductor segment for which a violation was identified was aggregated for the by feeder and scenario. For voltage violations, the length of every conductor segment between busses exhibiting voltage violations were aggregated by feeder and scenario. Additionally, if only one bus, either the "from" or "to" bus of a line segment, exhibits a voltage violation, then the length of the segment immediately preceding the violating bus was included in the aggregation. The aggregation was stratified by multiple factors to determine the type of mitigation ultimately applied. The stratification / classification included:

- Number of phases (note: phase rotation was not classified);
- Operating voltage;
- Existing conductor type / size;
- Overhead or underground installation; and
- Type of violation (voltage or thermal or both).

Based on this characterization, a second iteration (and in some cases multiple iterations) of the analysis was applied with modified conductor sizing for the violating line segments / busses. If the violations were mitigated, these sizes were accepted as the appropriate remediation for the given scenario. If they were not, an additional iteration was performed with larger conductor sizes applied to the segments that were still in violation of the evaluation criteria. This process was repeated to until no violations were noted.

Mitigation of substation transformer loading was evaluated only for peak power flow values, as these define the MVA size by which the transformer must ultimately be increased. While in practice, PREPA would likely upgrade the transformer to next "standard" size within their transformer fleet, for analytical purposes only the MVA overload was considered.

In determining the type and ultimate cost of the system improvements necessary to mitigate the identified violations, the following rules were applied:

- Mitigation necessary to accommodate the 75% scenario were the only system improvements contemplated;
- Improvements to lines were based on the practical limitations for distribution construction:
    - If the mitigation required an increase in conductor size of less than or equal to two sizes, the line would be reconductored (i.e. poles and arms retained, conductor replaced).
    - If the mitigation required an increase in conductor size of more than two conductor sizes, the line would be completely rebuilt in the violating sections.
- If transformer reverse power overloads are less than 125% of the emergency rating of the transformer for no more than 500 hours annually – no upgrade was

applied.

- Power flows greater than 125% of the emergency rating of the transformer for more than 500 hours annually – replacement of the transformer was assumed.

Note that the emergency rating of the transformer was selected because most transformers of this type will accommodate short term overloads without appreciably shortening their useful life.

# V. Results

The results of each scenario are presented below. For brevity, these have been aggregated to the highest level; region and type of mitigation to be applied. A breakdown of remediation by feeder, conductor type and number of phase conductors is presented in Volume II of this report. Note that each of the DER penetration cases represent "incremental" infrastructure improvement beyond the base case. However, the nature of the mitigation varies as the level of penetration increases (i.e. under-voltage conditions replaced by localized over-voltage conditions, along with variations in the location and severity of thermal overloads.

## A. Base Case Scenario

The base case scenario is based on the application of regional load shapes and the regional PV profile over an 8760 hour period (1 year), using only the existing PV, as provided by PREPA, as DER.

| Region | Total Line Miles | Line Miles Reconductor | Line Miles Rebuild | % Mitigation | Transformer Upgrades |
|---|---|---|---|---|---|
| **Arecibo** | 4,790 | 13.7 | 315.9 | 6.9 | 0 MVA |
| **Bayamon** | 2,442 | 81.7 | 106.6 | 7.7 | 0 MVA |
| **Caguas** | 6,761 | 136.9 | 317.3 | 6.7 | 0 MVA |
| **Carolina** | 3,310 | 100.7 | 140.8 | 7.3 | 0 MVA |
| **Mayaguez** | 5,482 | 37.7 | 303.9 | 6.2 | 0 MVA |
| **Ponce ES** | 2,828 | 12.1 | 127.7 | 4.9 | 0 MVA |
| **Ponce OE** | 2,526 | 21.4 | 125.5 | 5.8 | 0 MVA |
| **San Juan** | 2,908 | 29.1 | 95.2 | 4.3 | 0 MVA |
| **Vieques** | 166 | 0.8 | 10.4 | 6.7 | 0 MVA |

| | | | | | |
|---|---|---|---|---|---|
| **Culebra** | 68 | 1.0 | 2.4 | 5.0 | 0 MVA |

## B. 25% Penetration Scenario

The 25% penetration case scenario is based on the application of regional load shapes and the regional PV profile over an 8760 hour period (1 year), including the existing PV and residential and commercial PV placed as described in Section III.D as DER.

| Region | Total Line Miles | Line Miles Reconductor | Line Miles Rebuild | % Mitigation | Transformer Upgrades |
|---|---|---|---|---|---|
| **Arecibo** | 4,790 | 11.6 | 278.2 | 6.1 | 0 MVA |
| **Bayamon** | 2,442 | 73.5 | 93.8 | 6.9 | 0 MVA |
| **Caguas** | 6,761 | 123.2 | 278.9 | 5.9 | 0 MVA |
| **Carolina** | 3,310 | 90.7 | 114.7 | 6.2 | 0 MVA |
| **Mayaguez** | 5,482 | 33.9 | 264.0 | 5.5 | 0 MVA |
| **Ponce ES** | 2,828 | 10.9 | 111.8 | 4.3 | 0 MVA |
| **Ponce OE** | 2,526 | 19.3 | 109.1 | 5.1 | 0 MVA |
| **San Juan** | 2,908 | 20.4 | 84.6 | 3.6 | 0 MVA |
| **Vieques** | 166 | 0.7 | 9.8 | 6.4 | 0 MVA |
| **Culebra** | 68 | 0.8 | 2.2 | 4.3 | 0 MVA |

## C. 50% Penetration Scenario

The 50% penetration case scenario is based on the application of regional load shapes and the regional PV profile over an 8760 hour period (1 year), including the exitsing PV and residential and commercial PV placed as described in Section III.D as DER

| Region | Total Line Miles | Line Miles Reconductor | Line Miles Rebuild | % Mitigation | Transformer Upgrades |
|---|---|---|---|---|---|
| **Arecibo** | 4,790 | 16.5 | 344.1 | 7.5 | 3 MVA |
| **Bayamon** | 2,442 | 63.2 | 117.2 | 7.4 | 5 MVA |
| **Caguas** | 6,761 | 117.7 | 349.9 | 6.9 | 11 MVA |
| **Carolina** | 3,310 | 86.6 | 160.1 | 7.5 | 4 MVA |

| | | | | | |
|---|---|---|---|---|---|
| **Mayaguez** | 5,482 | 32.4 | 335.6 | 6.7 | 6 MVA |
| **Ponce ES** | 2,828 | 10.4 | 153.1 | 5.8 | 3 MVA |
| **Ponce OE** | 2,526 | 18.4 | 149.8 | 6.7 | 5 MVA |
| **San Juan** | 2,908 | 24.8 | 105.0 | 4.5 | 12 MVA |
| **Vieques** | 166 | 0.7 | 11.4 | 7.3 | 0 MVA |
| **Culebra** | 68 | 0.8 | 3.1 | 5.6 | 0 MVA |

## D. 75% Penetration Scenario

The 75% penetration case scenario is based on the application of regional load shapes and the regional PV profile over an 8760 hour period (1 year), including the exiting PV and residential and commercial PV placed as described in Section III.D as DER

| Region | Total Line Miles | Line Miles Reconductor | Line Miles Rebuild | % Mitigation | Transformer Upgrades |
|---|---|---|---|---|---|
| **Arecibo** | 4,790 | 19.0 | 381.8 | 8.4 | 15 MVA |
| **Bayamon** | 2,442 | 114.4 | 131.0 | 10.1 | 22 MVA |
| **Caguas** | 6,761 | 191.6 | 384.0 | 8.5 | 30 MVA |
| **Carolina** | 3,310 | 141.0 | 172.3 | 9.5 | 15 MVA |
| **Mayaguez** | 5,482 | 52.7 | 365.7 | 7.7 | 18 MVA |
| **Ponce ES** | 2,828 | 16.9 | 160.0 | 6.3 | 11 MVA |
| **Ponce OE** | 2,526 | 26.8 | 177.3 | 8.1 | 10 MVA |
| **San Juan** | 2,908 | 35.0 | 133.4 | 5.8 | 28 MVA |
| **Vieques** | 166 | 1.0 | 14.5 | 9.3 | 0 MVA |
| **Culebra** | 68 | 1.2 | 3.6 | 7.1 | 0 MVA |