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Integrated Resource Plan Volume V: Evaluation of DG Impacts on the Distribution System

Draft for the Review of the Puerto Rico Energy Commission

Prepared for:

Puerto Rico Electric Power Authority (PREPA)

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Siemens Industry, Inc.

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Siemens Industry, Inc.
Siemens Power Technologies International
400 State Street • P.O. Box 1058
Schenectady, New York 12301-1058 USA
Tel: +1 (518) 395-5000 • Fax: +1 (518) 346-2777
www.siemens.com/power-technologies

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Contents

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Section

1

Introduction

In the context of the Integrated Resource Plan (IRP) study, the Puerto Rico Electric Power Authority (PREPA) requested a planning level study to identify the major costs associated with the necessary distribution system improvements needed to integrate different levels of distributed generation (DG).

As presented earlier in this study (see Volume I), PREPA is expected to integrate large amounts of DG, mainly of the photovoltaic (PV) type. It is PREPA's experience that this generation is not uniform across the system, as some feeders can experience up to 100% of their noon time load levels covered by the PV generation systems while others have almost no DG. This fact, which parallels what we have observed in other utilities, drives the costs of integration of DG as changes must be done to those affected feeders to incorporate the renewable generation.

It is important to note that this is NOT a DG integration study, but rather a high level estimation of the impacts that PREPA may experience based on a limited number of feeders which, while representative of PREPA's reality, are still a small sample and may not cover other more stringent conditions in the system. There are a number of studies that are necessary to determine the maximum amount of PV generation that a particular feeder can safely accept, and these include: a) protection coordination, b) flicker, c) harmonics, d) ferroresonance, e) effective grounding and neutral shifting, and f) operation and safety (including anti-islanding). Later in this report we provide an overview of the contents of these studies.

This study developed power flow models for selected feeders provided by PREPA based on the system information also provided. In the study, solar PV generation was distributed along the feeders. A sensitivity analysis to identify locations where solar PV generation causes major overvoltage issues is beyond the scope of work, but if this generation is concentrated towards the end of the feeder, the effects identified in this study and the investment necessary are magnified as well as the impacts of the other concerns (e.g. flicker) not studied here.

Renewable generation, such as solar PV at the distribution level, is not controllable and it is intermittent as the peak generation output can occur at different demand values. This study analyzes one typical day condition where the maximum solar PV generation output occurs and the lightest power demand of each feeder is registered. Quasi steady state modeling was performed, running 24 power flows for each solar PV integration scenario, simulating a day or 24 hours. For the purpose of the study, the solar PV power generation output was modeled in increasing steps from 10% to 100% of feeder peak demand.

The broad goals for this “Integrated Resource Plan Volume V: Evaluation of DG Impacts on the Distribution System” were as follows:

1. Identify the maximum amount of solar PV generation that a distribution feeder can handle without capital system improvement.

2. Identify capital system improvement needs for additional increase steps up to 100% of feeder peak demand.

This study was limited to steady state conditions only, and as indicated above, additional studies need to be performed before the high levels of DG considered in this assessment can be safely incorporated in the system.

Finally, this study cannot be seen in isolation, since distribution-level DG penetration increase may have system wide effects. Furthermore, the generation fleet needs to be able to handle the entire renewable generation (utility scale and DG) and if reverse power flows from the distribution to the transmission system, the performance of protective schemes, like the under frequency load shedding, need to be updated.

Section

2

Quasi Steady State Modeling

Seven different distribution feeders, supplying different customer classes (residential, commercial and industrial) were modeled. Table 2-1 summarizes the customer classes that each feeder is servicing.

Table 2-1: Customer Class Distribution

Feeder	kV	Customer type
2501-01	4.16	93 % residential; 6 % commercial; 1 % industrial
6306-02	4.16	96 % residential; 4 % commercial; 0 % industrial
7103-04	4.16	94 % residential; 6 % commercial; 0 % industrial
2801-02	8.32	93 % residential; 6 % commercial; 1 % industrial
1529-11	13.2	96 % residential; 4 % commercial; 0 % industrial
1529-12	13.2	95 % residential; 5 % commercial; 0 % industrial
1529-13	13.2	38 % residential; 62 % commercial; 0 % industrial

Steady-state distribution system planning studies are carried out by representing minimum and maximum loading conditions. Based on the results obtained from these simulations, system improvement needs are identified to ensure that voltage levels throughout the model comply with the ANSI C84.1 standard and that equipment loading levels are not exceeded, among others. However, the evaluation of renewable generation systems also requires the representation of the model during its maximum generation which, in the case of PV systems, occurs around noon time. This maximum generation period does not necessarily coincide with the maximum and minimum loading conditions in a feeder, as depicted in Figure 2-1.

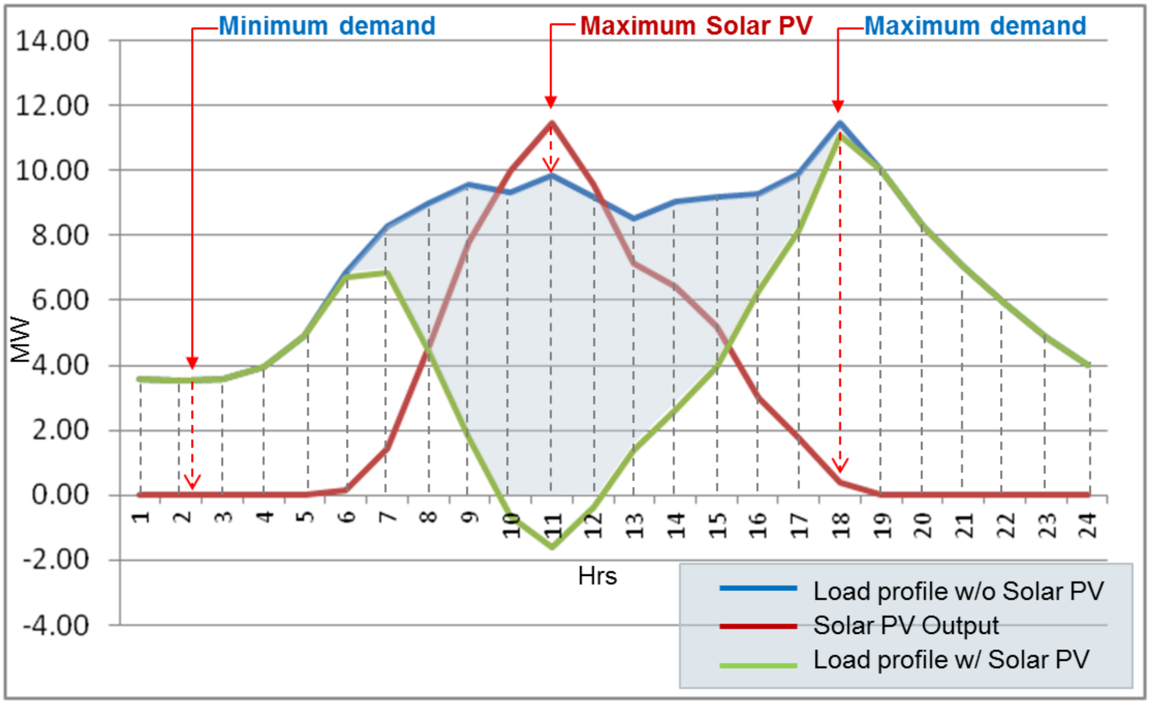

Figure 2-1: Load and Solar PV Generation Profile Sample

2.1 Steady State Model

Siemens PTI modeled seven distribution feeders provided by PREPA (Feeders 2501-01, 6306-02, 7103-04, 2801-02, 1529-11, 1529-12, and 1529-13). These feeders are representative of PREPA's distribution feeders where solar PV generation integration will most likely be increased to high levels. However, it should be mentioned that they may not contain the most stringent conditions in PREPA's system or all the modes in which the system can be stressed. Detecting these conditions would require a feeder by feeder analysis beyond the scope of this limited review.

These feeders were modeled in PSS®SINCAL power flow software which allowed conducting quasi static power flow analysis. The feeders' models captured the peak and light load conditions by performing the steps below:

1. Modeled the PREPA feeder substation and associated controls.

2. Modeled seven distribution feeders by following a geographical representation, similar to the original power flow model, capturing the different conductor and cable sections provided by PREPA.

3. Modeled feeder capacitor banks (originally non-switched type), voltage regulators and associated controls.

4. Modeled the unbalanced lines, transformers and loads.

5. A 24-hour load profile for the peak load day was identified for each feeder. Afterwards, minimum demand multipliers were applied during the maximum PV generation window (9 am – 3 pm) to represent the minimum load conditions.

6. A base case was evaluated to identify improvement needs before solar PV was interconnected and, if necessary, the base case was adjusted to perform the simulations.

7. Solar PV generators were distributed across the feeders' branches to create the DG scenarios. Figures 2-2 to 2-6 represent the resulting feeders' layouts, which include the integration of a minimum of 10 to a maximum of 38 PVs. The total solar PV capacity was equally divided among all solar PV units. It was then increased from 10% to 100% of feeder peak demand to analyze the system impact.

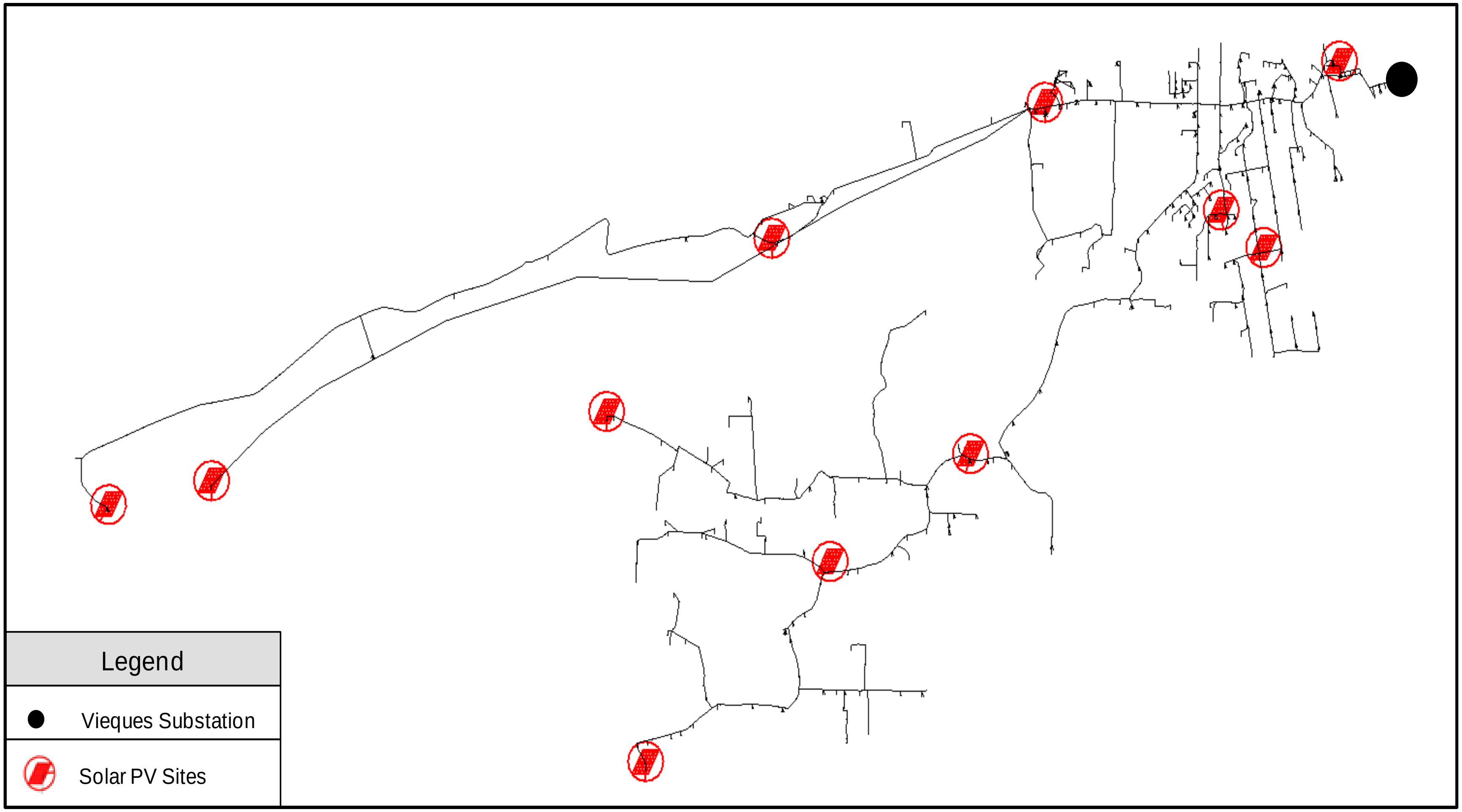

Figure 2-2: Feeder 2501-01 Layout

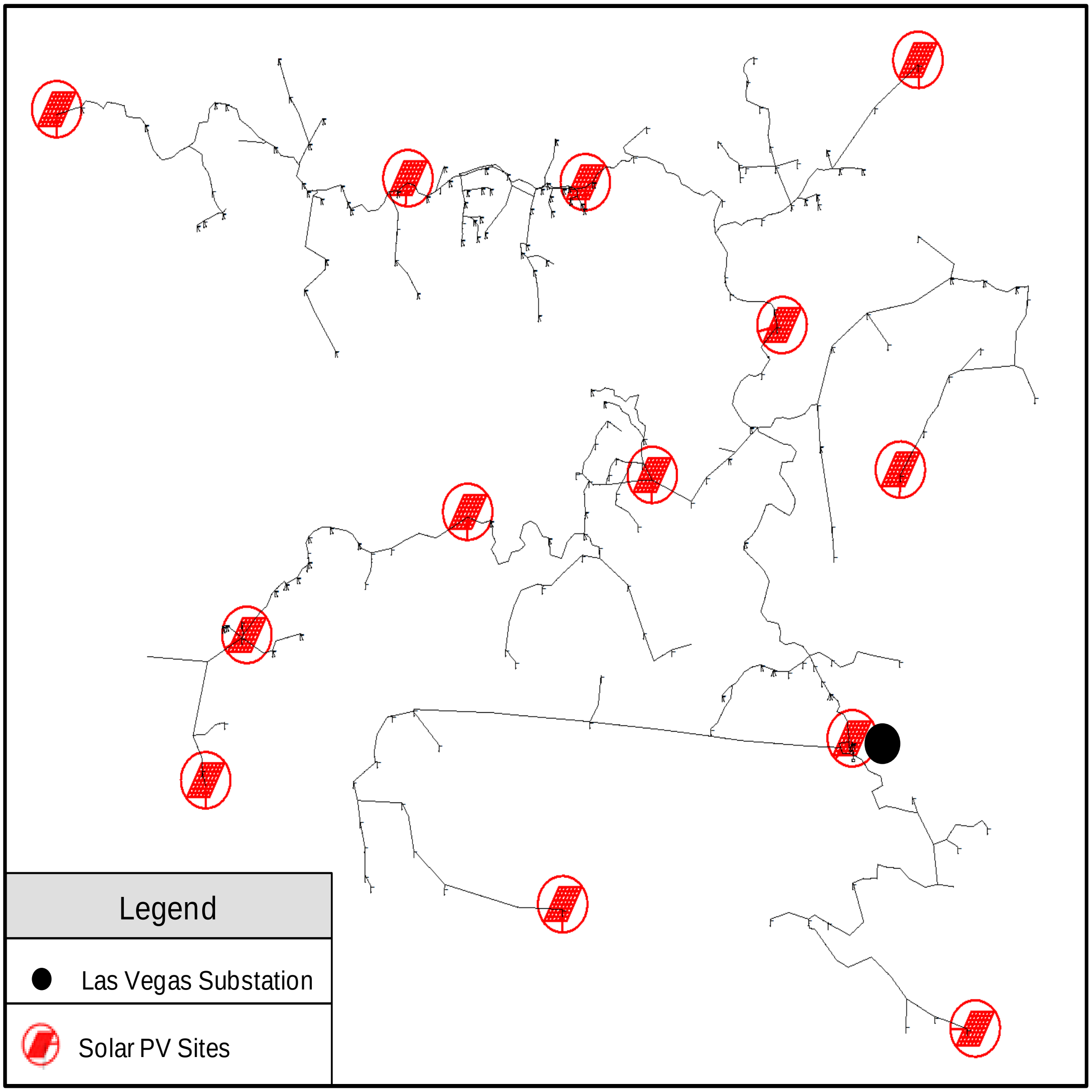

Figure 2-3: Feeder 6306-02 Layout

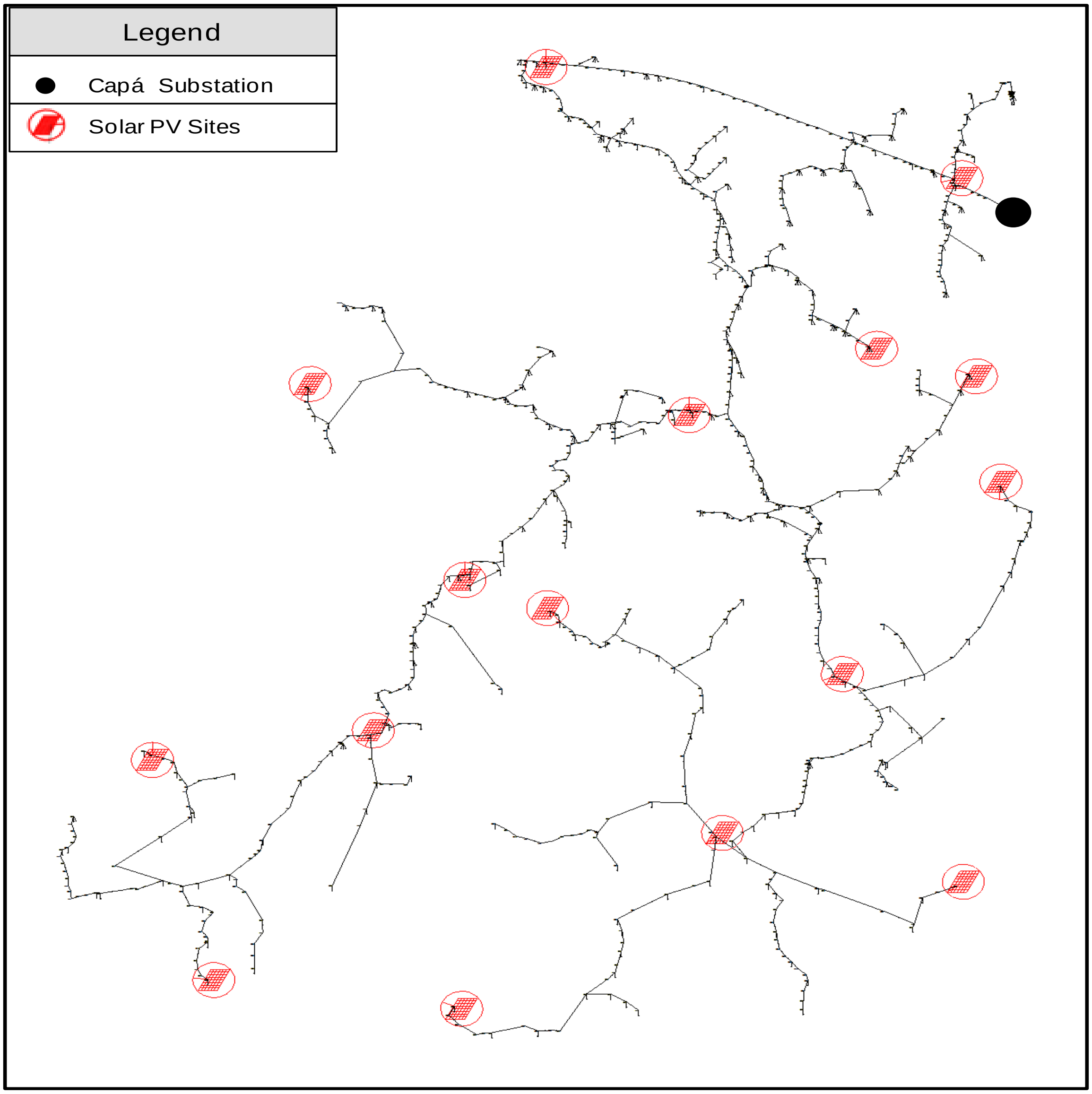

Figure 2-4: Feeder 7103-04 Layout

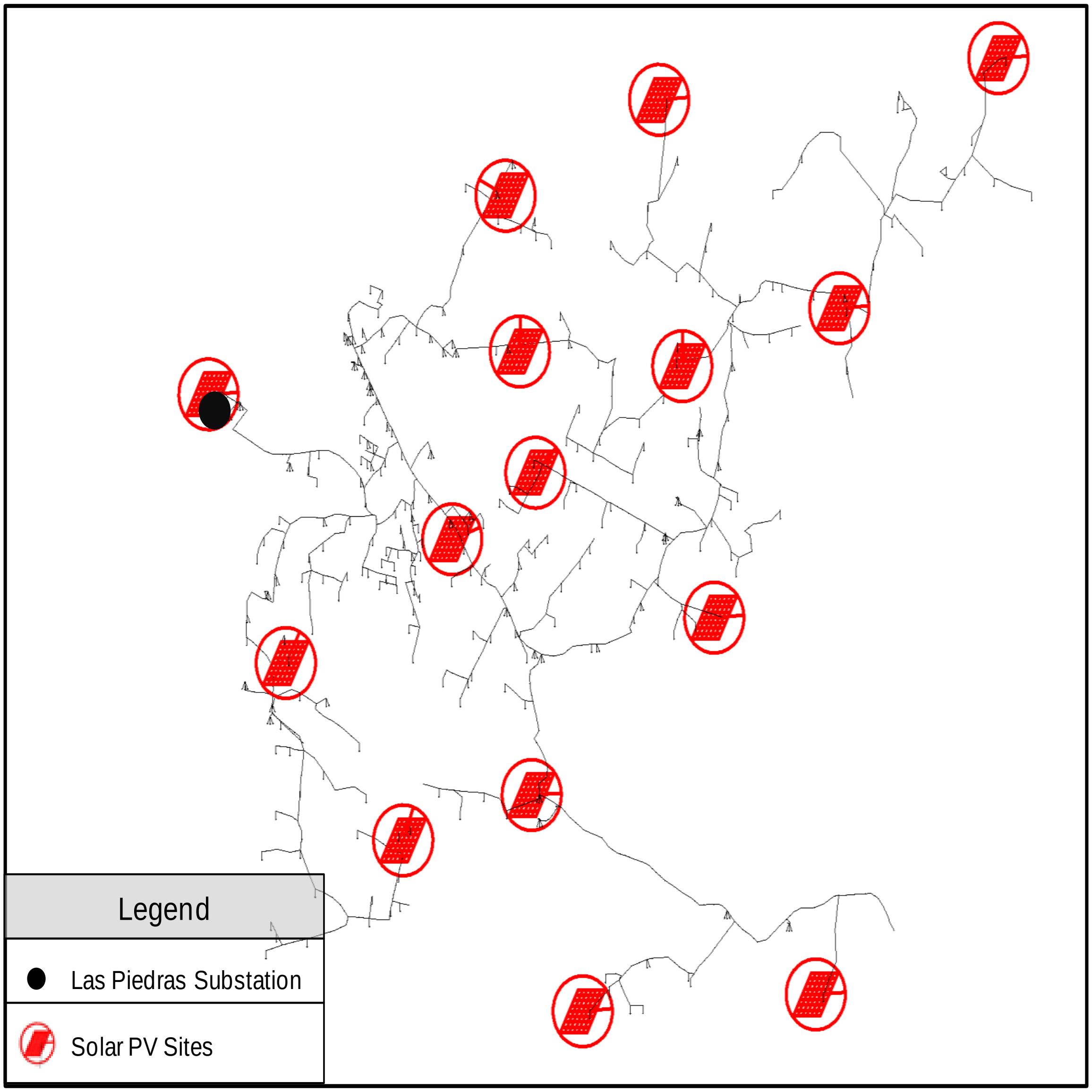

Figure 2-5: Feeder 2801-02 Layout

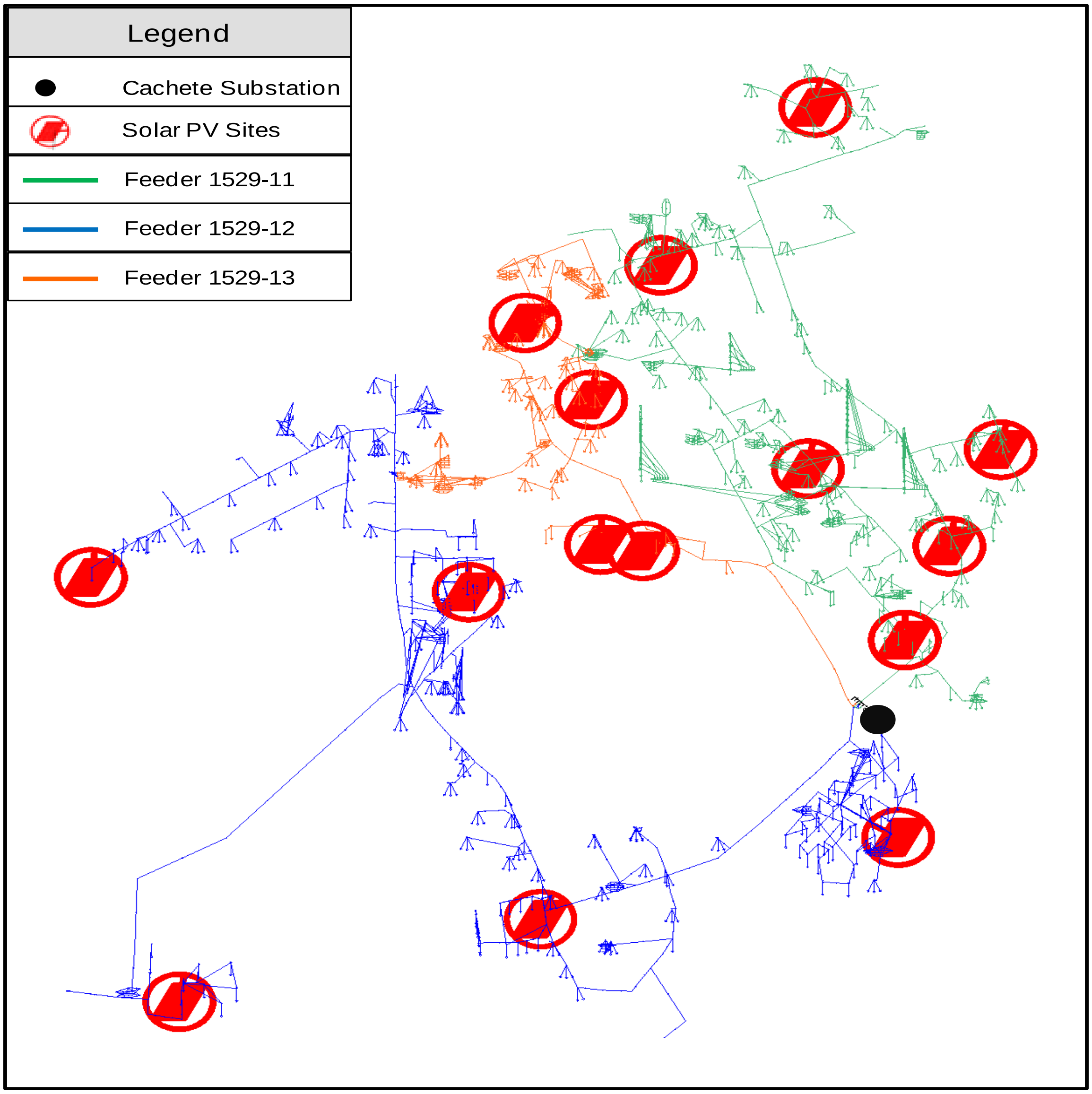

Figure 2-6: Feeders 1529-11, 1529-12, and 1529-13 Layouts

2.2 Generation & Load Profiles

Solar PV generation output is variable over time and not necessarily coincident with peak or light load conditions. Figure 2-7 presents the 24-hour solar PV generation profile that was used in the simulations. This PV profile is representative of a typical cloudless day. The use of a “cloudless” day is common in this type of analysis as the objective is to verify the capability of the feeder to accept the PV generation when it is generating at its potential depending only on the hour of the day.

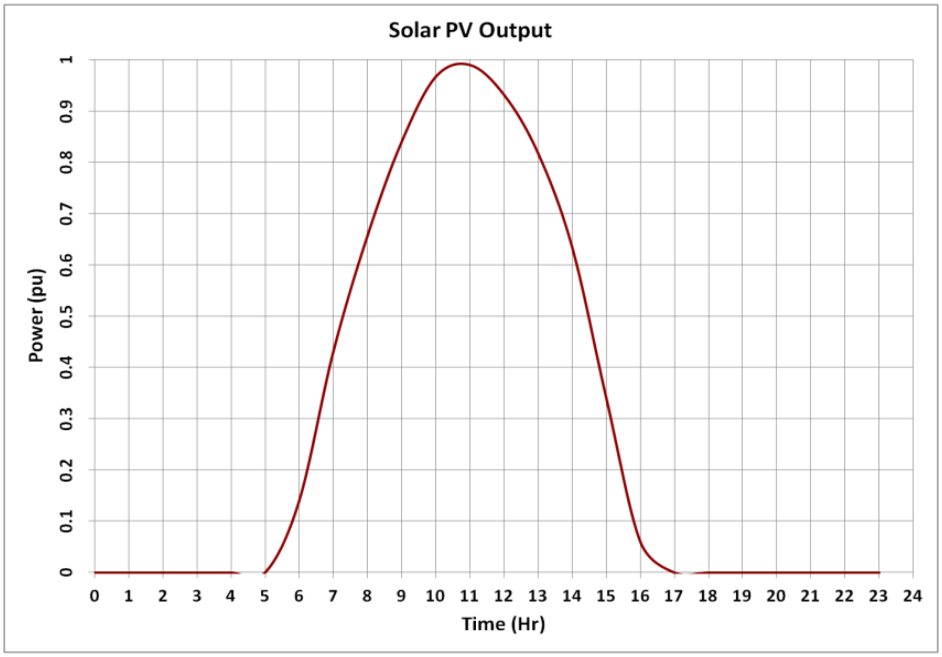

Figure 2-7: Solar PV Output on a Cloudless Day

In order to evaluate the system impact of integrating solar PV and to estimate the maximum amount that can be accommodated in each feeder, successive increases of solar PV were modeled, as shown in Table 2-2. Scenario 1 represents a solar PV integration of 10% of the feeder peak demand; scenario 2 represents 20% of the feeder peak demand, and so on.

Table 2-2: Solar PV Integration Based on Feeders' Peak Demands

Scenario	% of Peak Demand	2501-01	6306-02	7103-04	2801-02	1529-11	1529-12	1529-13
1	10%	201.7	58.7	250.9	211.8	560.3	420.2	707.2
2	20%	403.4	117.3	501.9	423.6	1120.7	840.4	1414.4
3	30%	605.0	176.0	752.8	635.4	1681.0	1260.6	2121.6
4	40%	806.7	234.6	1003.8	847.2	2241.3	1680.8	2828.8
5	50%	1008.4	293.3	1254.7	1058.9	2801.6	2100.9	3536.0
6	60%	1210.1	351.9	1505.7	1270.7	3362.0	2521.1	4243.2
7	70%	1411.8	410.6	1756.6	1482.5	3922.3	2941.3	4950.5
8	80%	1613.4	469.3	2007.6	1694.3	4482.6	3361.5	5657.7
9	90%	1815.1	527.9	2258.5	1906.1	5042.9	3781.7	6364.9
10	100%	2016.8	586.6	2509.5	2117.9	5603.3	4201.9	7072.1

A 24-hour feeder load profile at the substation, provided by PREPA, was allocated to each distribution transformer based on the installed capacity. Load phasing was considered as provided by PREPA.

As indicated above, to assess the effect of PV integration on the distribution feeders, it is necessary to evaluate under the minimum daytime load conditions. Therefore, the load profile of each feeder was adjusted using a load multiplier during the maximum solar PV generation window (9 am – 3 pm). Table 2-3 shows the demand multipliers used for each distribution feeder studied to express the reduction in load as a percentage of the maximum feeder load. The other hours of the day were unmodified, which allowed us to create a single load profile that represents the two critical periods of evaluation: minimum and maximum overall demands.

Table 2-3: Minimum Load Multiplier

Feeder	Minimum Demand Multiplier (%)
2501-01	35
6306-02	48
7103-04	74
2801-02	66
1529-11	67
1529-12	63
1529-13	46

For example, the multiplier for feeder 2501-01 throughout the day would look like Figure 2-8. Figure 2-9 presents a typical day load profile for this feeder, while Figure 2-10 shows the modified load profile.

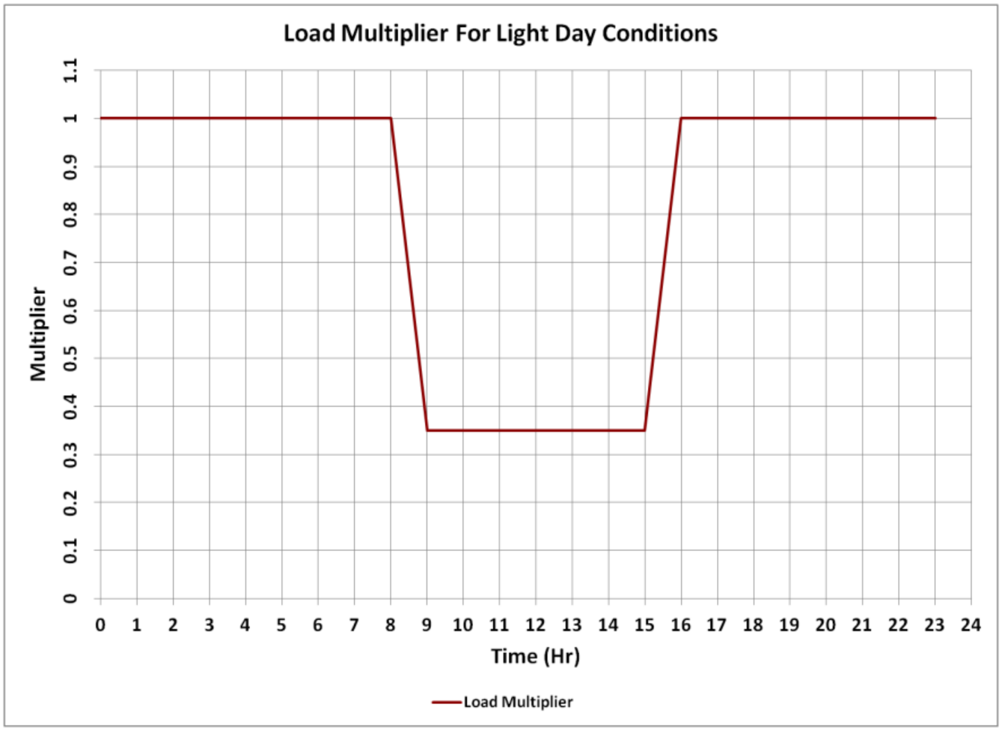

Figure 2-8: Load Multiplier for Feeder 2501-01

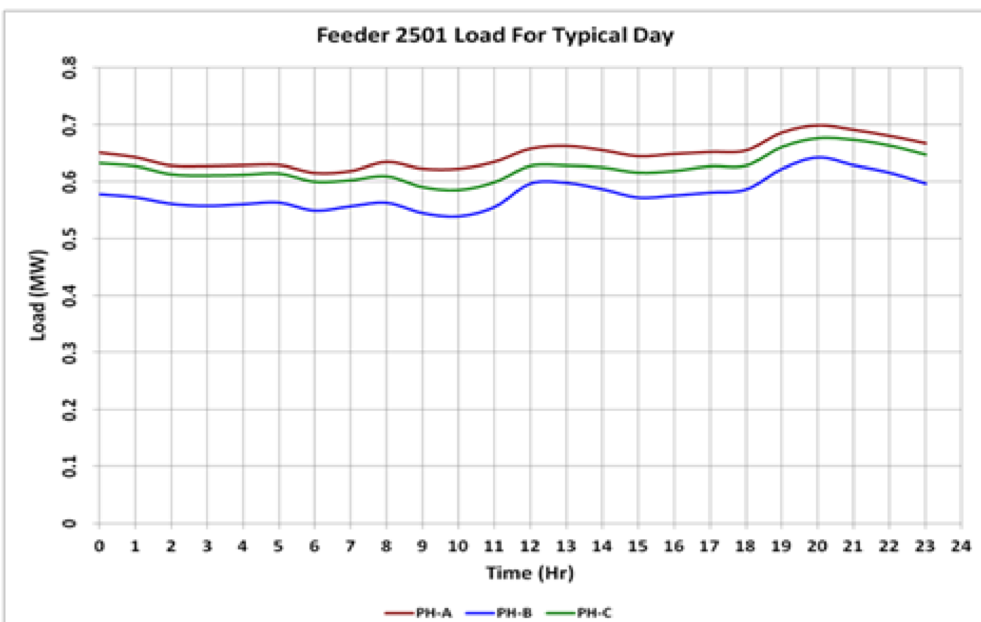

Figure 2-9: Typical Day Load Profile for Feeder 2501-01

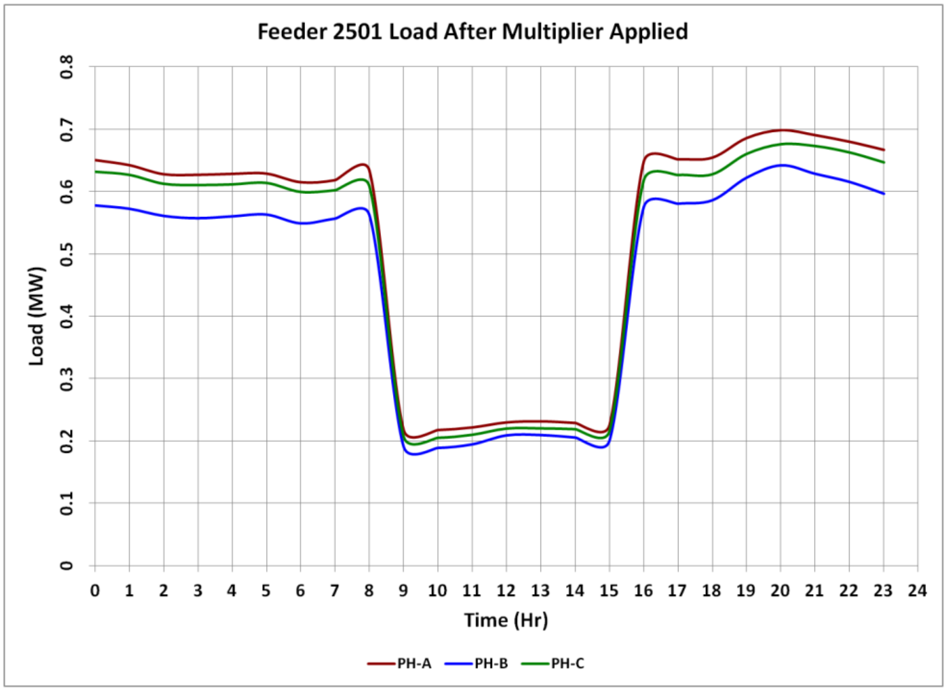

Figure 2-10: Modified Load Profile for Feeder 2501-01

2.2.1 Feeder 2501-01

Figure 2-11 presents a typical day, 24-hour load profile. Figure 2-12 shows the feeder's modified load profile and Figure 2-13 shows the 100% PV penetration profile considered. Also, Table 2-4 provides relevant load and PV generation data used for the different scenarios that were simulated.

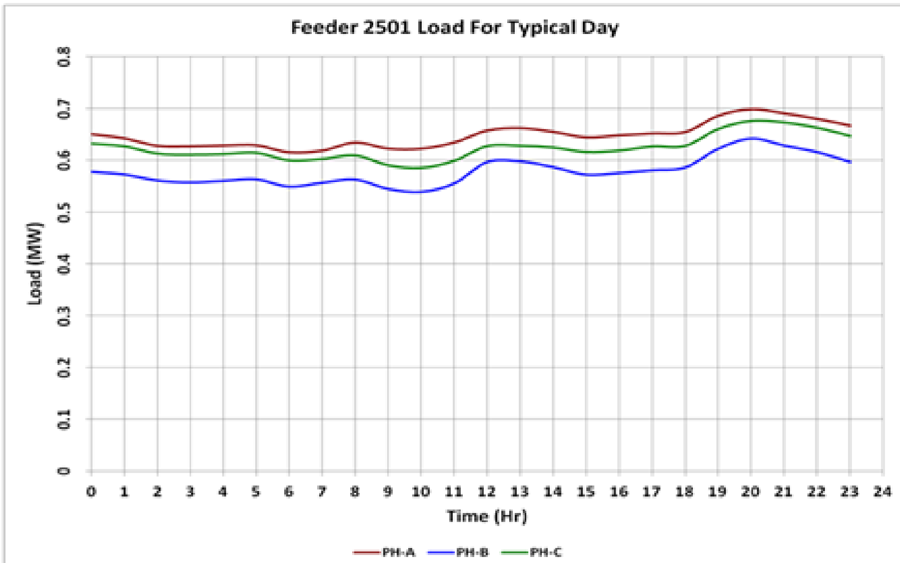

Figure 2-11: Typical Day Load Profile for Feeder 2501-01

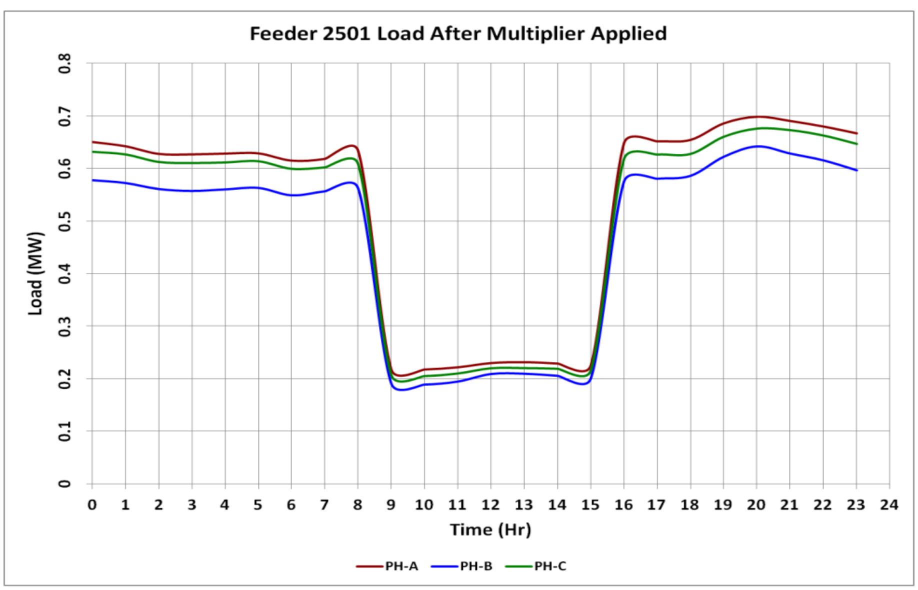

Figure 2-12: Modified Load Profile for Feeder 2501-01

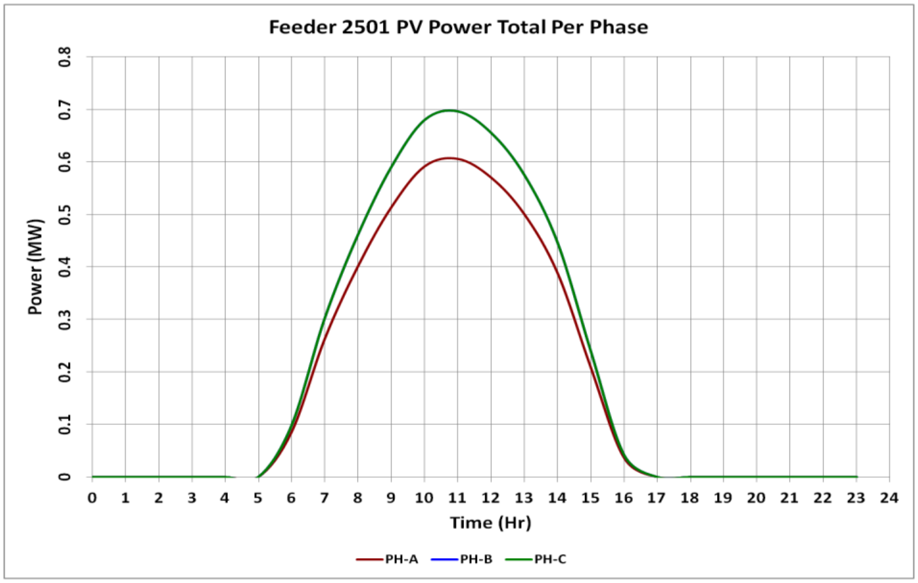

Figure 2-13: 100% PV Penetration Profile for Feeder 2501-01

Table 2-4: Relevant Load and PV Generation Data for Feeder 2501-01

	Time	Load A (MW)	PV A (MW)	Load B (MW)	PV B (MW)	Load C (MW)	PV C (MW)
Min Load	10 am	0.217759	0.590984	0.188701	0.679631	0.204638	0.679631
Max Load	8 pm	0.698328	0	0.642438	0	0.675965	0
Max PV	11 am	0.221977	0.605346	0.194451	0.696148	0.209471	0.696148

2.2.2 Feeder 6306-02

Figure 2-14 presents a typical day, 24-hour load profile. Figure 2-15 shows the feeder's modified load profile and Figure 2-16 shows the 100% PV penetration profile considered. Also, Table 2-5 provides relevant load and PV generation data used for the different scenarios that were simulated.

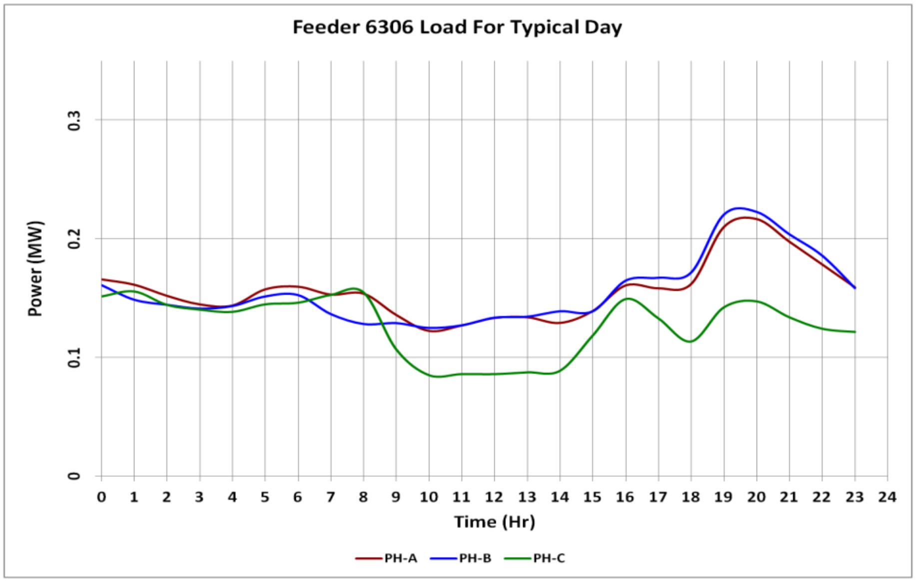

Figure 2-14: Typical Day Load Profile for Feeder 6306-02

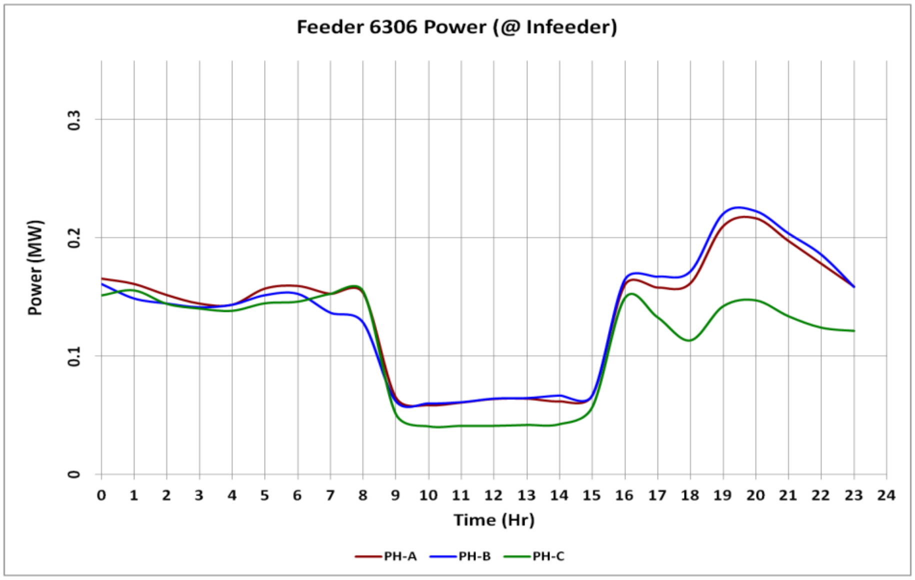

Figure 2-15: Modified Load Profile for Feeder 6306-02

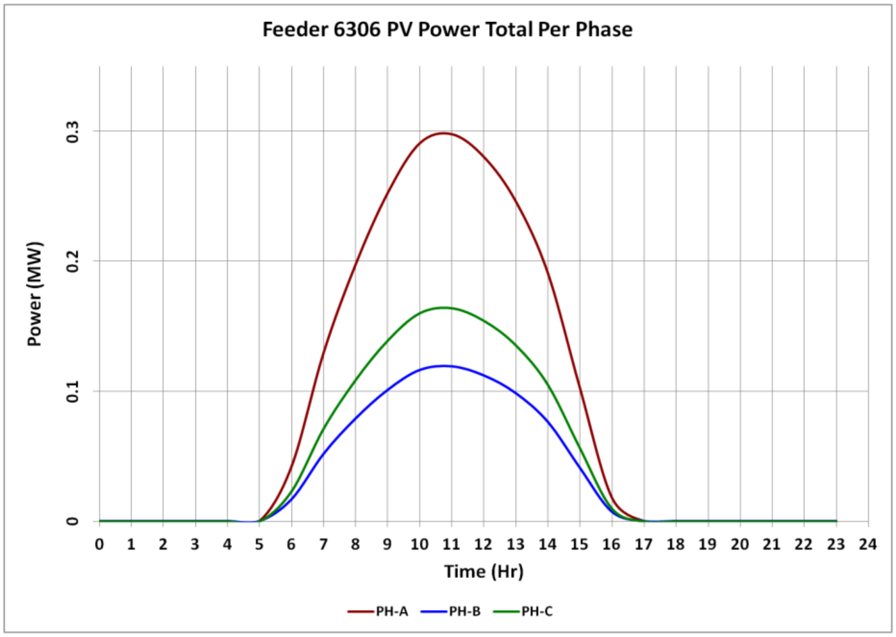

Figure 2-16: 100% PV Penetration Profile for Feeder 6306-02

Table 2-5: Relevant Load and PV Generation Data for Feeder 6306-02

	Time	Load A (MW)	PV A (MW)	Load B (MW)	PV B (MW)	Load C (MW)	PV C (MW)
Min Load	10 am	0.058602	0.290878	0.060048	0.116351	0.040754	0.159983
Max Load	8 pm	0.216733	0	0.22256	0	0.147276	0
Max PV	11 am	0.060826	0.297947	0.061103	0.119179	0.041209	0.163871

2.2.3 Feeder 7103-04

Figure 2-17 presents a typical day, 24-hour load profile. Figure 2-18 shows the feeder's modified load profile and Figure 2-19 shows the 100% PV penetration profile considered. Also, Table 2-6 provides relevant load and PV generation data used for the different scenarios that were simulated.

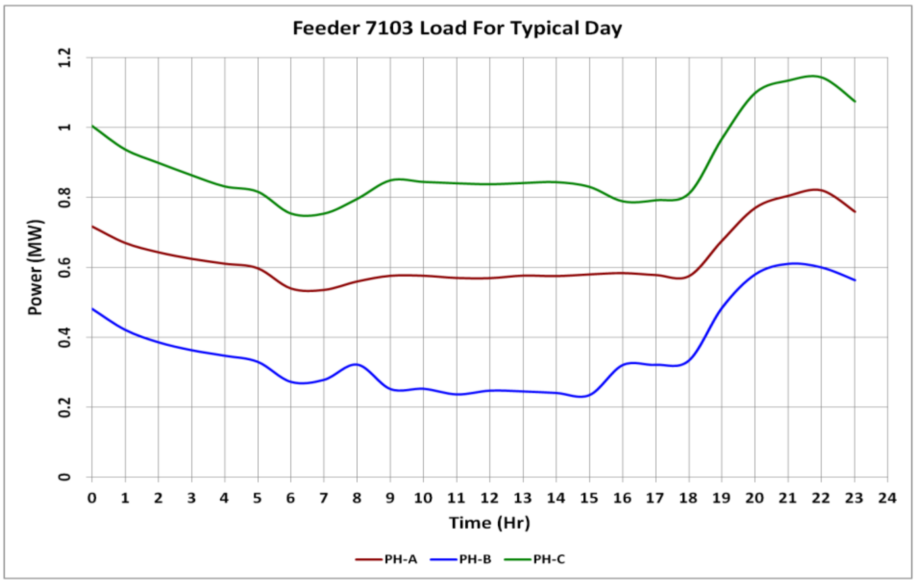

Figure 2-17: Typical Day Load Profile for Feeder 7103-04

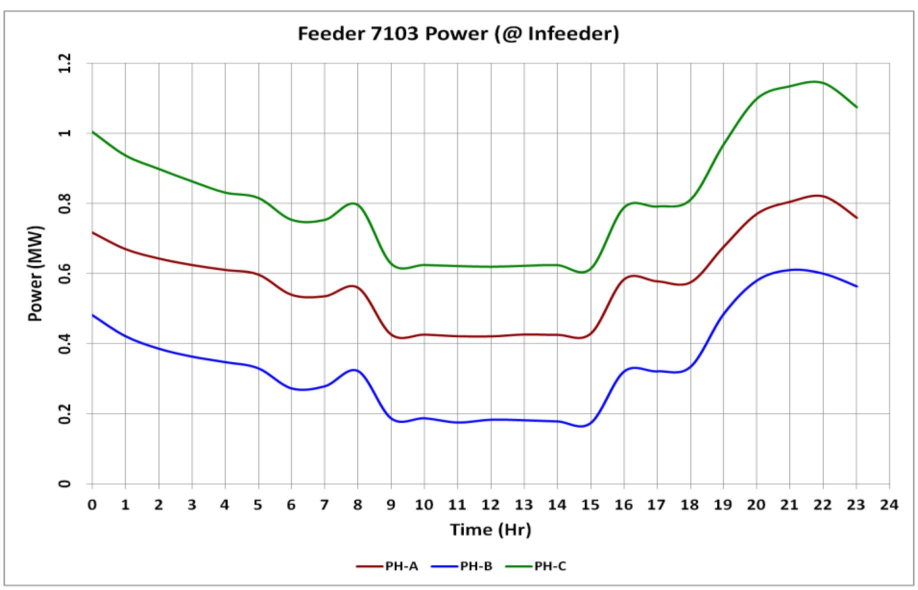

Figure 2-18: Modified Load Profile for Feeder 7103-04

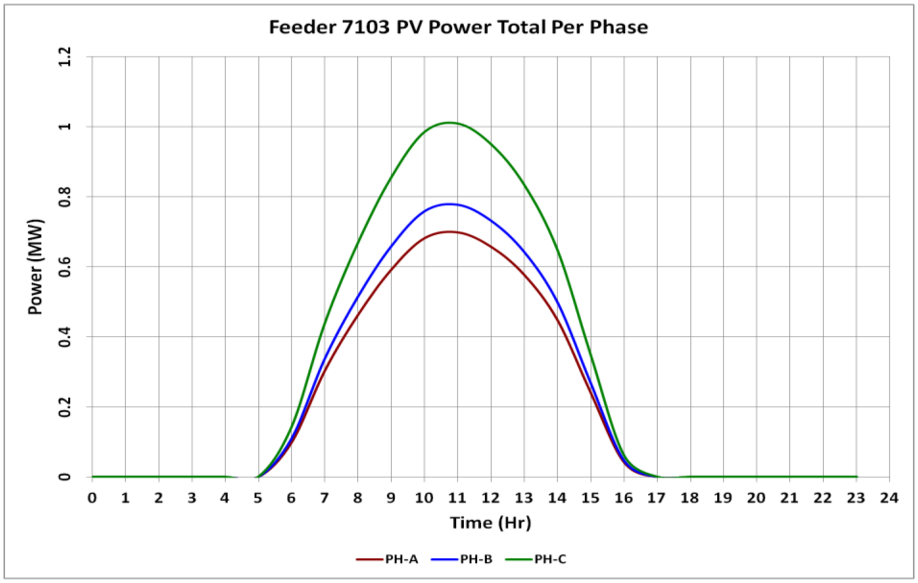

Figure 2-19: 100% PV Penetration Profile for Feeder 7103-04

Table 2-6: Relevant Load and PV Generation Data for Feeder 7103-04

	Time	Load A (MW)	PV A (MW)	Load B (MW)	PV B (MW)	Load C (MW)	PV C (MW)
Min Load	3 pm	0.428991	0.240675	0.173708	0.267417	0.614359	0.347642
Max Load	10 pm	0.819782	0	0.600229	0	1.143649	0
Max PV	11 am	0.421379	0.699088	0.175145	0.776764	0.621834	1.009794

2.2.4 Feeder 2801-02

Figure 2-20 presents a typical day, 24-hour load profile. Figure 2-21 shows the feeder's modified load profile and Figure 2-22 shows the 100% PV penetration profile considered. Also, Table 2-7 provides relevant load and PV generation data used for the different scenarios that were simulated.

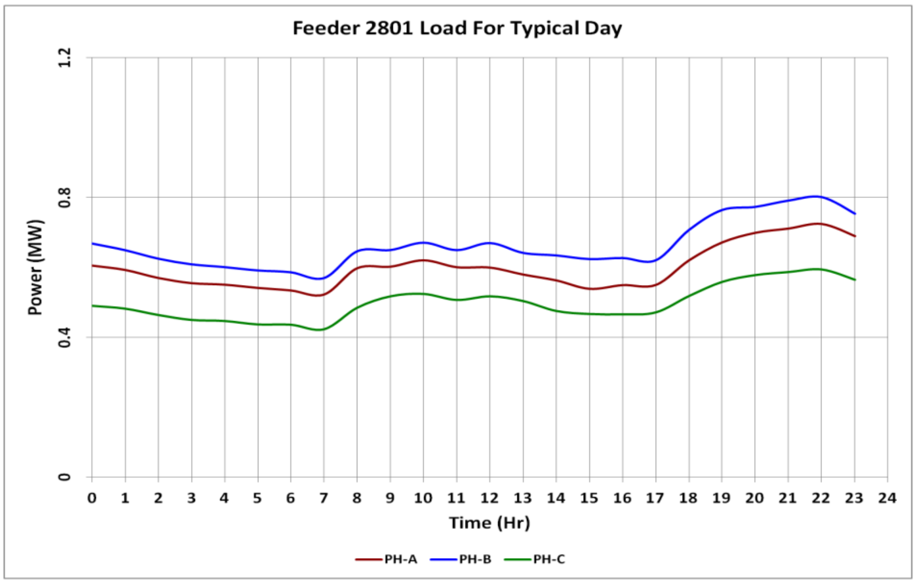

Figure 2-20: Typical Day Load Profile for Feeder 2801-02

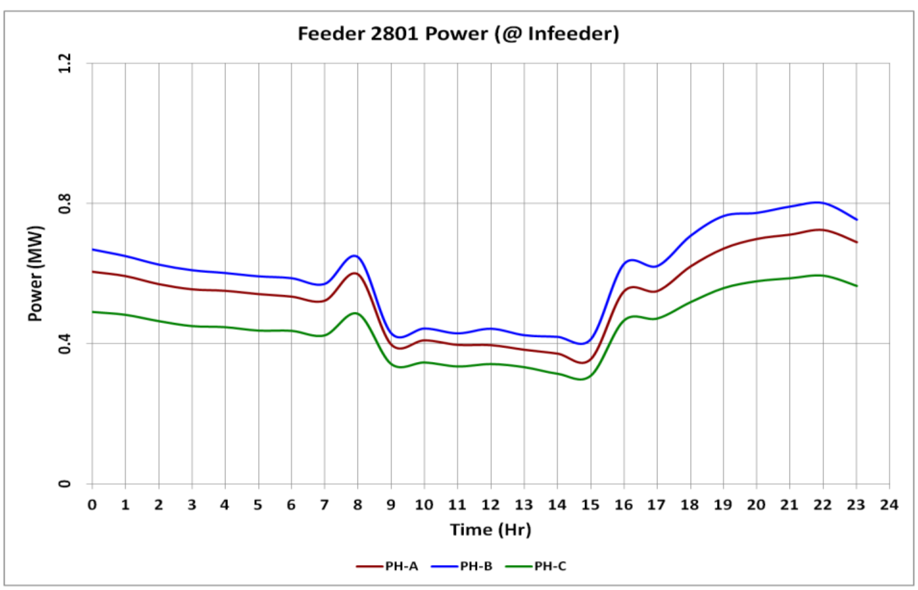

Figure 2-21: Modified Load Profile for Feeder 2801-02

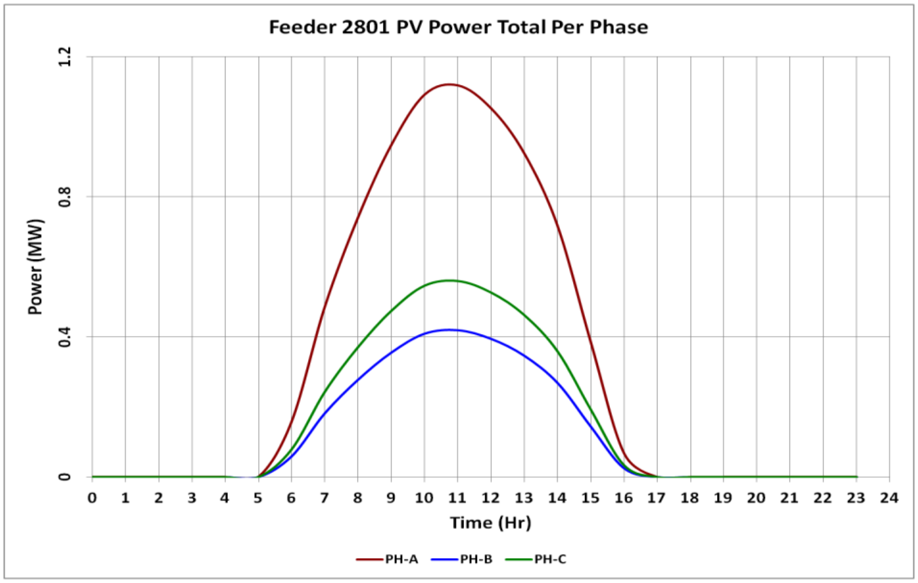

Figure 2-22: 100% PV Penetration Profile for Feeder 2801-02

Table 2-7: Relevant Load and PV Generation Data for Feeder 2801-02

	Time	Load A (MW)	PV A (MW)	Load B (MW)	PV B (MW)	Load C (MW)	PV C (MW)
Min Load	3 pm	0.355392	0.385174	0.411729	0.14444	0.308225	0.192587
Max Load	10 pm	0.723649	0	0.800308	0	0.593935	0
Max PV	11 am	0.396079	1.118812	0.428576	0.419554	0.33462	0.559406

2.2.5 Feeder 1529-11

Figure 2-23 presents a typical day, 24-hour load profile. Figure 2-24 shows the feeder's modified load profile and Figure 2-25 shows the 100% PV penetration profile considered. Also, Table 2-8 provides relevant load and PV generation data used for the different scenarios that were simulated.

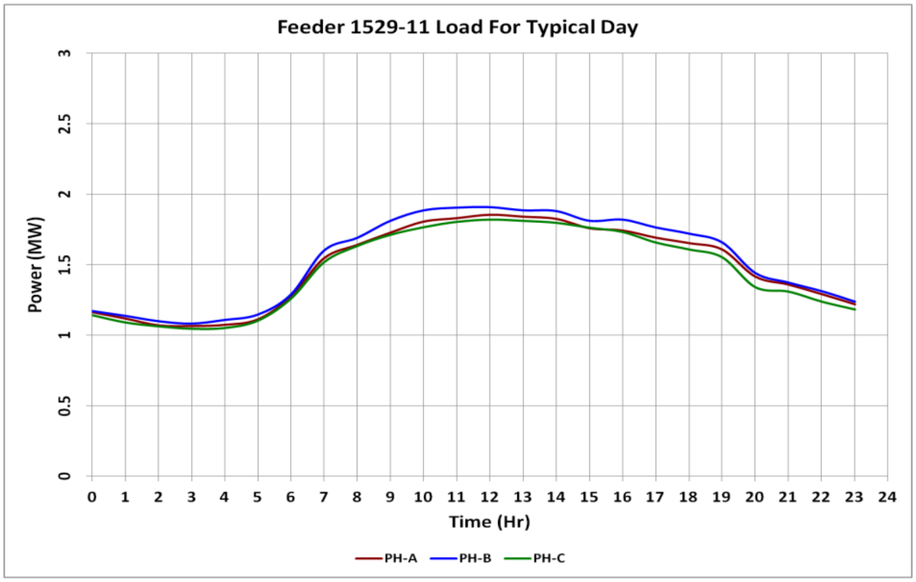

Figure 2-23: Typical Day Load Profile for Feeder 1529-11

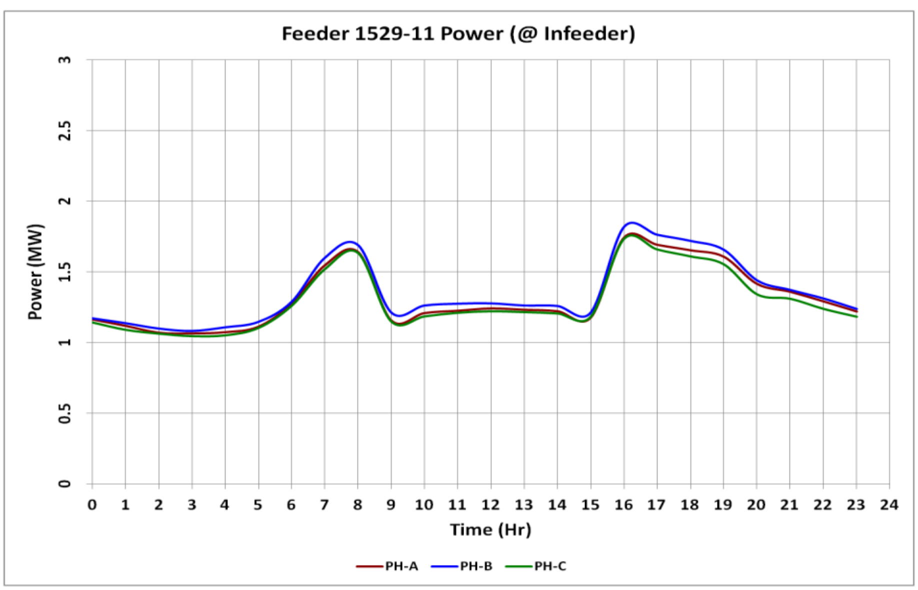

Figure 2-24: Modified Load Profile for Feeder 1529-11

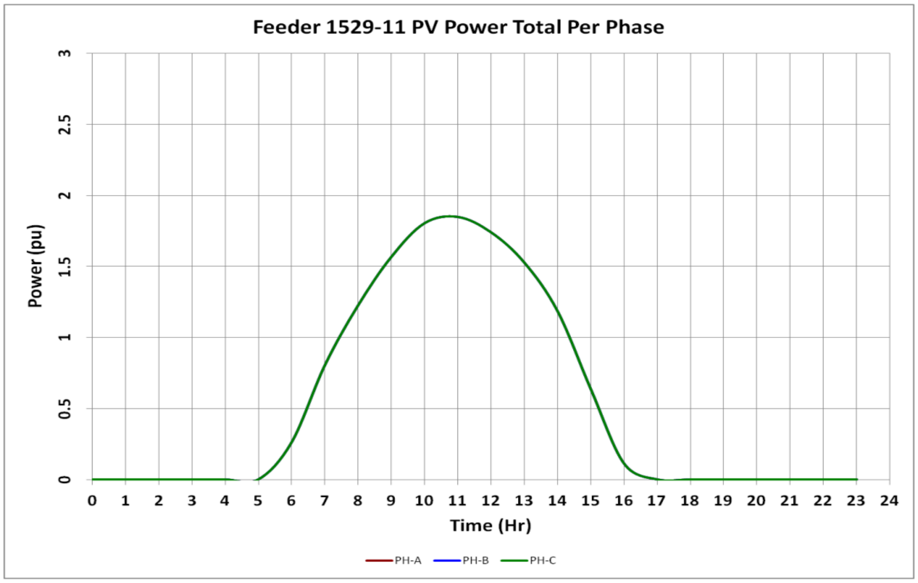

Figure 2-25: 100% PV Penetration Profile for Feeder 1529-11

Table 2-8: Relevant Load and PV Generation Data for Feeder 1529-11

	Time	Load A (MW)	PV A (MW)	Load B (MW)	PV B (MW)	Load C (MW)	PV C (MW)
Min Load	3 am	1.06603	0	1.082688	0	1.043395	0
Max Load	4 pm	1.742768	0.112065	1.818925	0.112065	1.731968	0.112065
Max PV	11 am	1.226255	1.850007	1.275464	1.850007	1.208654	1.850007

2.2.6 Feeder 1529-12

Figure 2-26 presents a typical day, 24-hour load profile. Figure 2-27 shows the feeder's modified load profile and Figure 2-28 shows the 100% PV penetration profile considered. Also, Table 2-9 provides relevant load and PV generation data used for the different scenarios that were simulated.

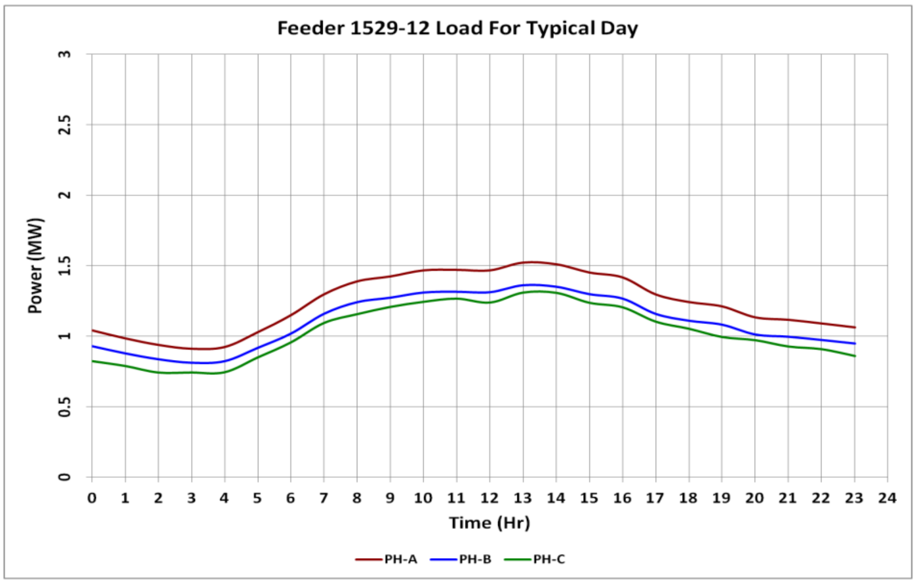

Figure 2-26: Typical Day Load Profile for Feeder 1529-12

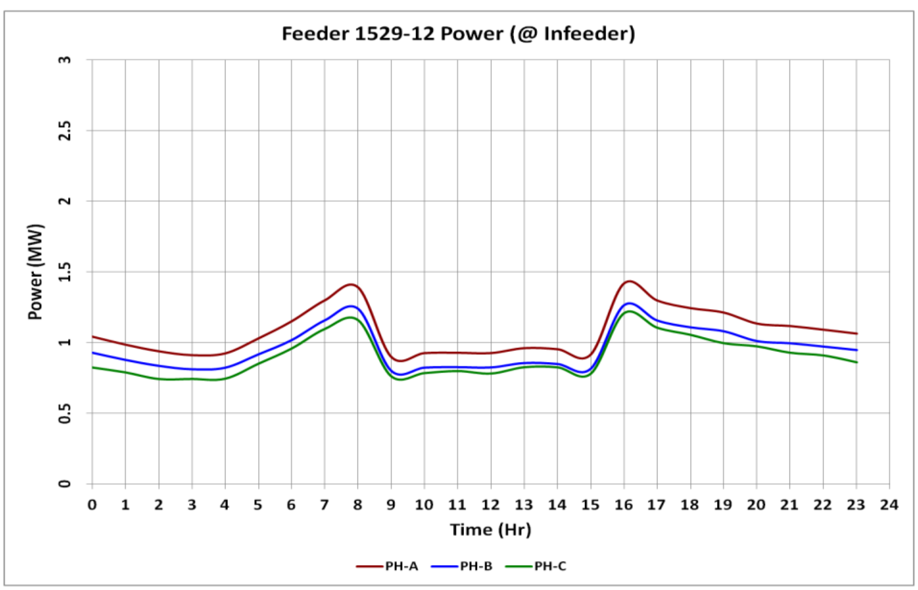

Figure 2-27: Modified Load Profile for Feeder 1529-12

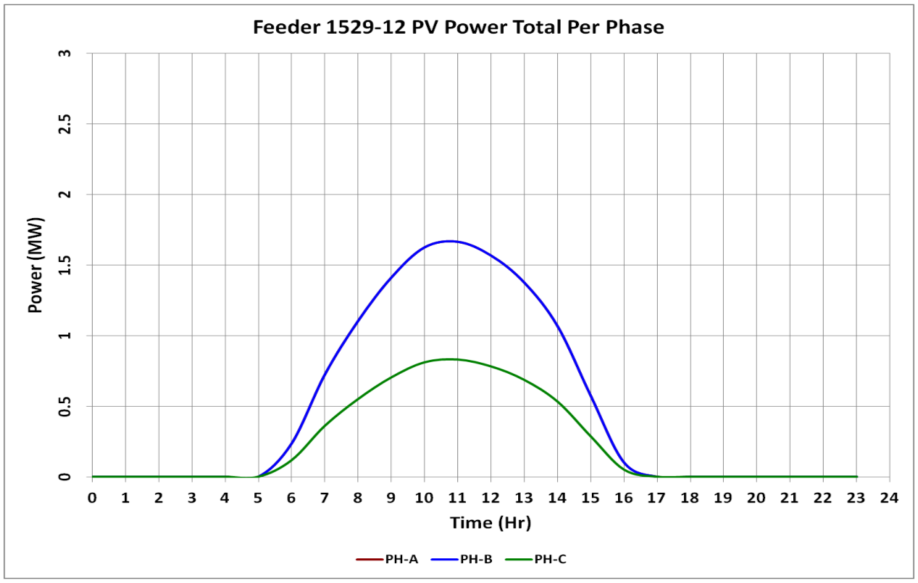

Figure 2-28: 100% PV Penetration Profile for Feeder 1529-12

Table 2-9: Relevant Load and PV Generation Data for Feeder 1529-12

	Time	Load A (MW)	PV A (MW)	Load B (MW)	PV B (MW)	Load C (MW)	PV C (MW)
Min Load	9 am	0.89744	1.410993	0.80103	1.410993	0.761586	0.705496
Max Load	4 pm	1.417172	0.100845	1.264669	0.100845	1.205886	0.050423
Max PV	11 am	0.926814	1.664786	0.827238	1.664786	0.798535	0.832393

2.2.7 Feeder 1529-13

Figure 2-29 presents a typical day, 24-hour load profile. Figure 2-30 shows the feeder's modified load profile and Figure 2-31 shows the 100% PV penetration profile considered. Also, Table 2-10 provides relevant load and PV generation data used for the different scenarios that were simulated.

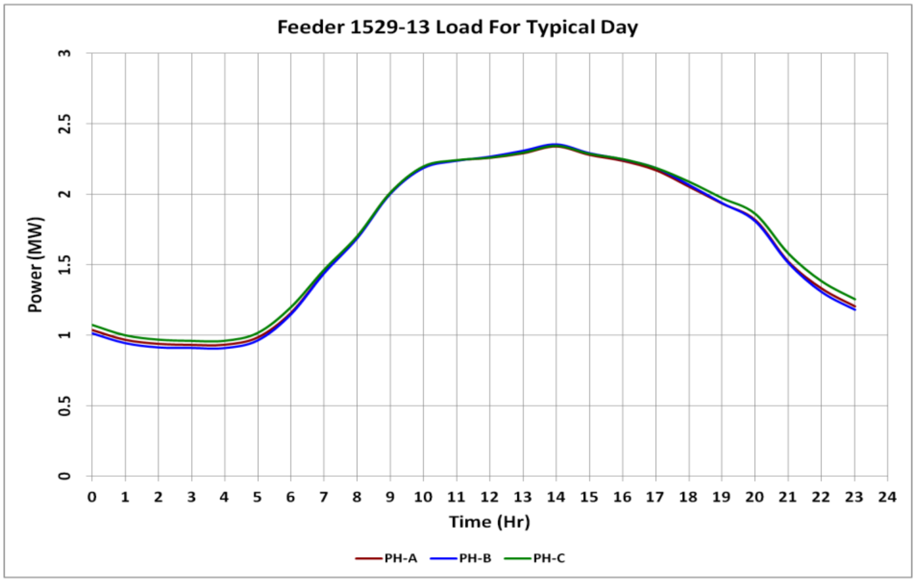

Figure 2-29: Typical Day Load Profile for Feeder 1529-13

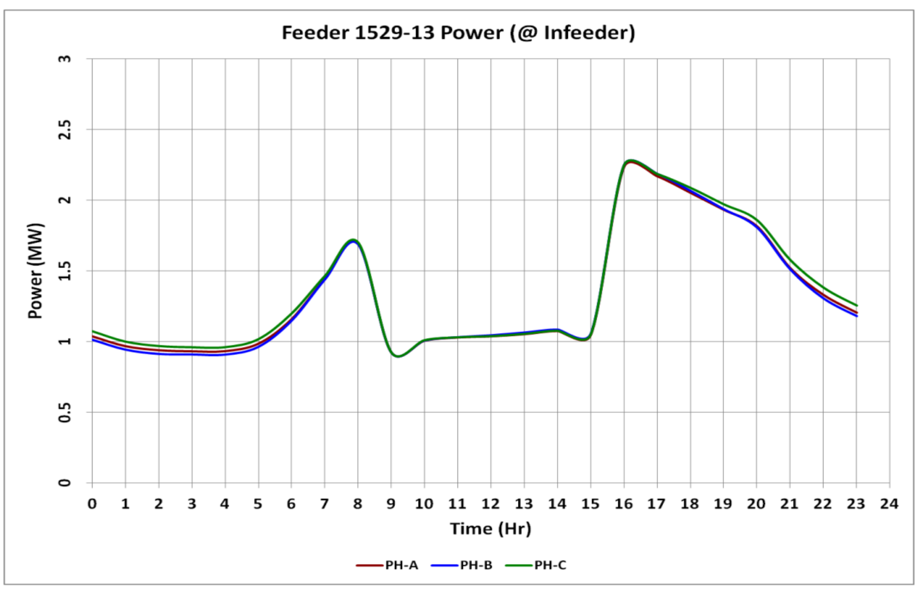

Figure 2-30: Modified Load Profile for Feeder 1529-13

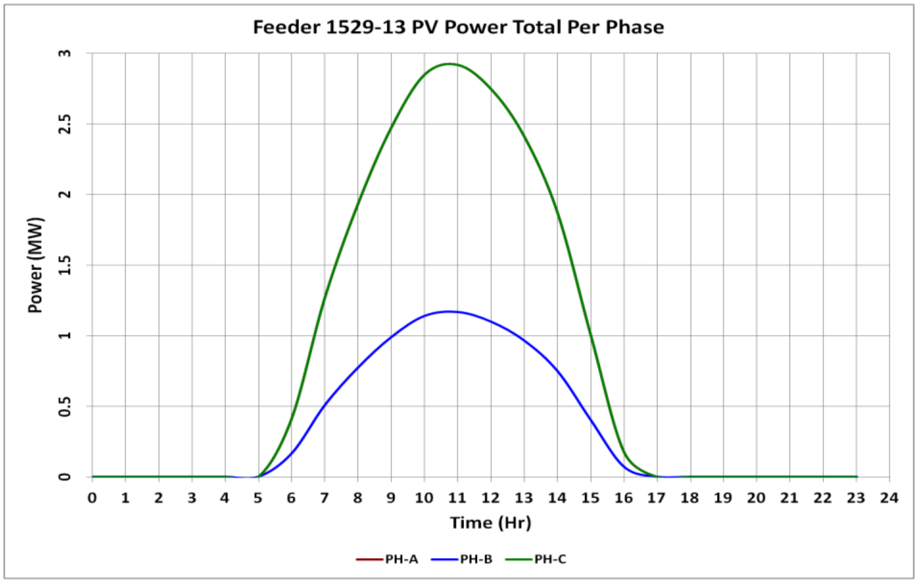

Figure 2-31: 100% PV Penetration Profile for Feeder 1529-13

Table 2-10: Relevant Load and PV Generation Data for Feeder 1529-13

	Time	Load A (MW)	PV A (MW)	Load B (MW)	PV B (MW)	Load C (MW)	PV C (MW)
Min Load	9 am	0.924729	2.473754	0.92185	0.989502	0.924966	2.473754
Max Load	4 pm	2.236011	0.176802	2.248413	0.070721	2.248143	0.176802
Max PV	11 am	1.029947	2.918706	1.029574	1.167482	1.030777	2.918706

2.3 Analysis Assumptions and Limitations

The following items describe the assumptions and limitations of this study:

- All capacitor banks were set initially at fixed-mode of operation, since this is PREPA's standard design. Switched capacitor banks were evaluated as an improvement.

- Feeder capacity is typically defined based on substation transformer normalized capacity, substation voltage regulator capacity, number of feeders sharing those capacities, circuit breaker ratings, terminals ratings, circuit breaker relays ratings, cable or conductor nominal capacity, and lowest voltage at the end of the feeder. To perform a uniform analysis in this study, it was assumed that all feeders have 600 A of maximum capacity and 400 A of nominal capacity (67% of maximum capacity), providing a 200 A room for load transfers during emergency conditions.

- The solar irradiance is the same at each generation site at any given point in time.

- The analysis, results and mitigations specified in this report cover a modified 24-hour day to allow us to create a single load profile that represents the two critical periods of evaluation: minimum and maximum overall demands.

- Typical load factors were used to capture commercial, residential and industrial peak values.

- Load allocation was determined based on installed transformer capacity, so that all distribution transformers are similarly loaded in a manner that the feeder demand matches the feeder load profile provided by PREPA. All loads are assumed to have the same power factor.

- It was not possible to validate the base case power flow results against field measurements.

- Quasi steady state simulations were performed (24-hour profiles). These analyses provided partial feeder assessments of solar PV generation integration. To have a complete system impact assessment, the following additional studies are required:

  - Flicker analysis
  - Harmonic study
  - Protection coordination impact assessment
  - Ferroresonance study
  - Effective grounding and neutral shift
  - Operation and safety

2.4 Performance Assessment Criteria

The performance of each feeder was carried out considering that current and new methods of regulating voltage must comply with the ANSI C84.1 standard. Table 2-11 details the voltage limits established in this standard, which were used as the basis for this study.

Table 2-11: ANSI C84.1 Voltage Values (in Percentages)

Classification	Range B			Range B		
Service Voltage	95%	to	105%	92%	to	106%
Utilization Voltage	92%	to	104%	88%	to	106%

Another major aspect that must be considered in DG integration power flow studies is the occurrence of reverse power flows. High levels of DG penetration in a distribution feeder may cause reverse power flows to the transmission system through the substation transformer. Existing substation transformer load tap changers (LTC) were designed to control voltages on unidirectional power flows from the substation to the connected loads and, therefore, will not operate adequately under reverse conditions. Moreover, during reverse power flows, protection coordination issues are magnified, particularly the creation of unintentional islands and substantial power flow changes in the transmission system.

Additionally, current distribution system protection philosophy is based on identifying downstream overcurrent conditions. Substation relays, fuses and, in some cases, automatic circuit reclosers installed along the feeders are designed to protect the system during faults. When high levels of DG are integrated, the sensitivity of such coordination may be lost. On the other hand, when a fault is located upstream of the substation (i.e. sub-transmission or transmission system), DG will provide short circuit contributions back to the fault, which may not be detected by the existing feeder breaker relays.

2.5 Base Case Assessment (No Solar PV)

This section of the report highlights the results of the steady state analysis of the distribution system feeders without solar PV integration. The purpose of the base case assessment is to ensure that the network model is an accurate representation of PREPA's current system. It also aims to identify any issues that need to be rectified before conducting the solar PV penetration assessment.

2.5.1 Feeder 2501-01

Table 2-12 provides information about the feeder's primary voltage, length and loading. Due to its long extension, high impedance conductors, unbalanced load configuration and relatively high load (63% of feeder capacity at noon and 70% of feeder capacity at night), voltage regulation within the ANSI C84.1 limits is one of its major challenges.

Table 2-12: Feeder 2501-01 Data

Feeder	Voltage Level (kV)	Max Length (km)	Total Length (km)(*)	Max Load (MW)	Load at around noon (MW)
2501-01	4.16	13.0	63.0	2.02	0.63

Without solar PV integration, the results of the simulations presented voltage levels below 95% (in a 120 V base) during peak demand conditions (8 pm). Figure 2-32 depicts the areas with these voltage levels.

Before performing the solar PV assessment, the implementation of a 2 MVA voltage regulator (VR), installed upstream of the area of concern (see Figure 2-33), was simulated. This VR improved the voltages to values above 95% of nominal voltage. Hence, the improved feeder model became the base case model.

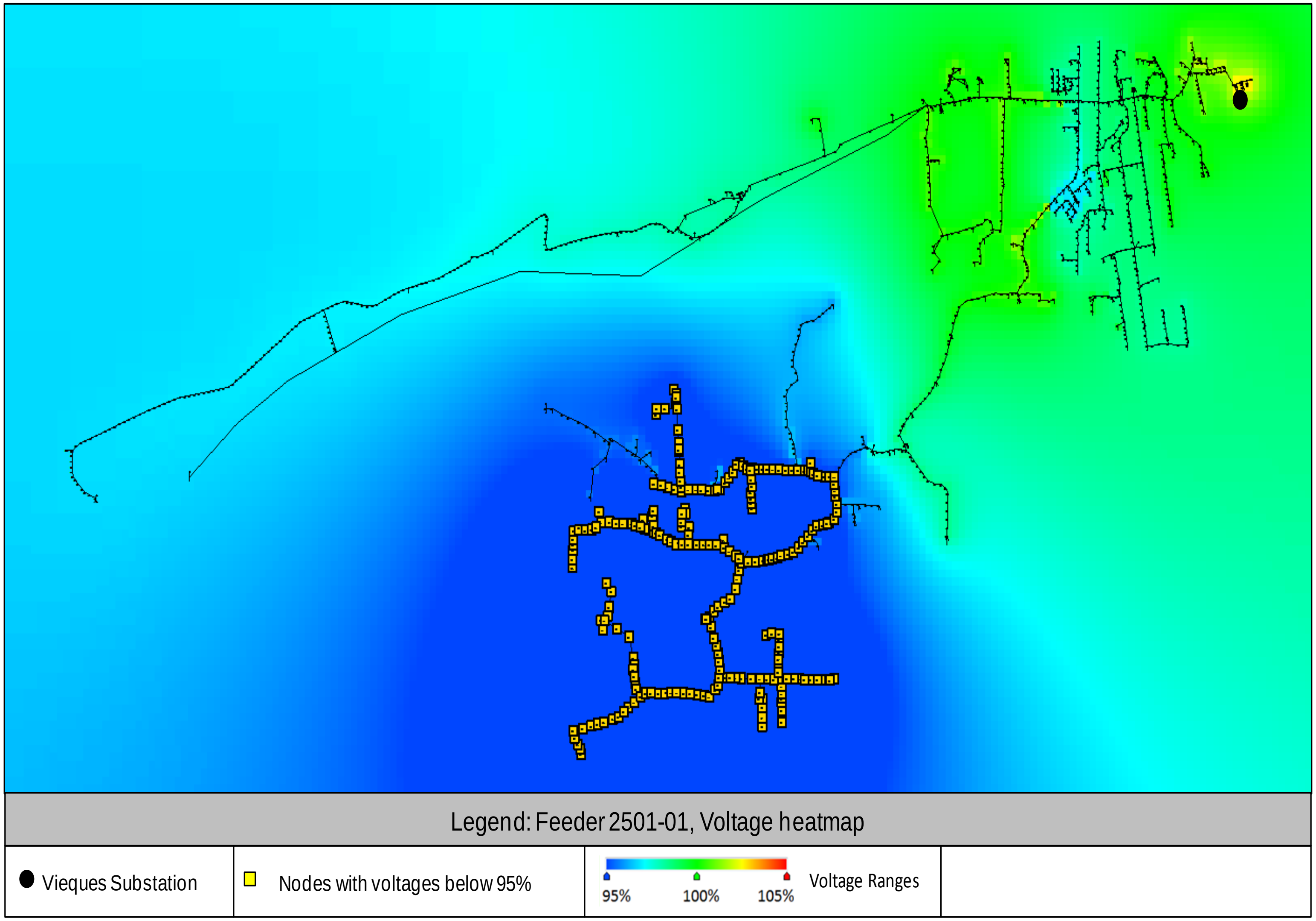

Figure 2-32: Feeder 2501-01 Voltage Heat Map During Maximum Demand (8 pm)

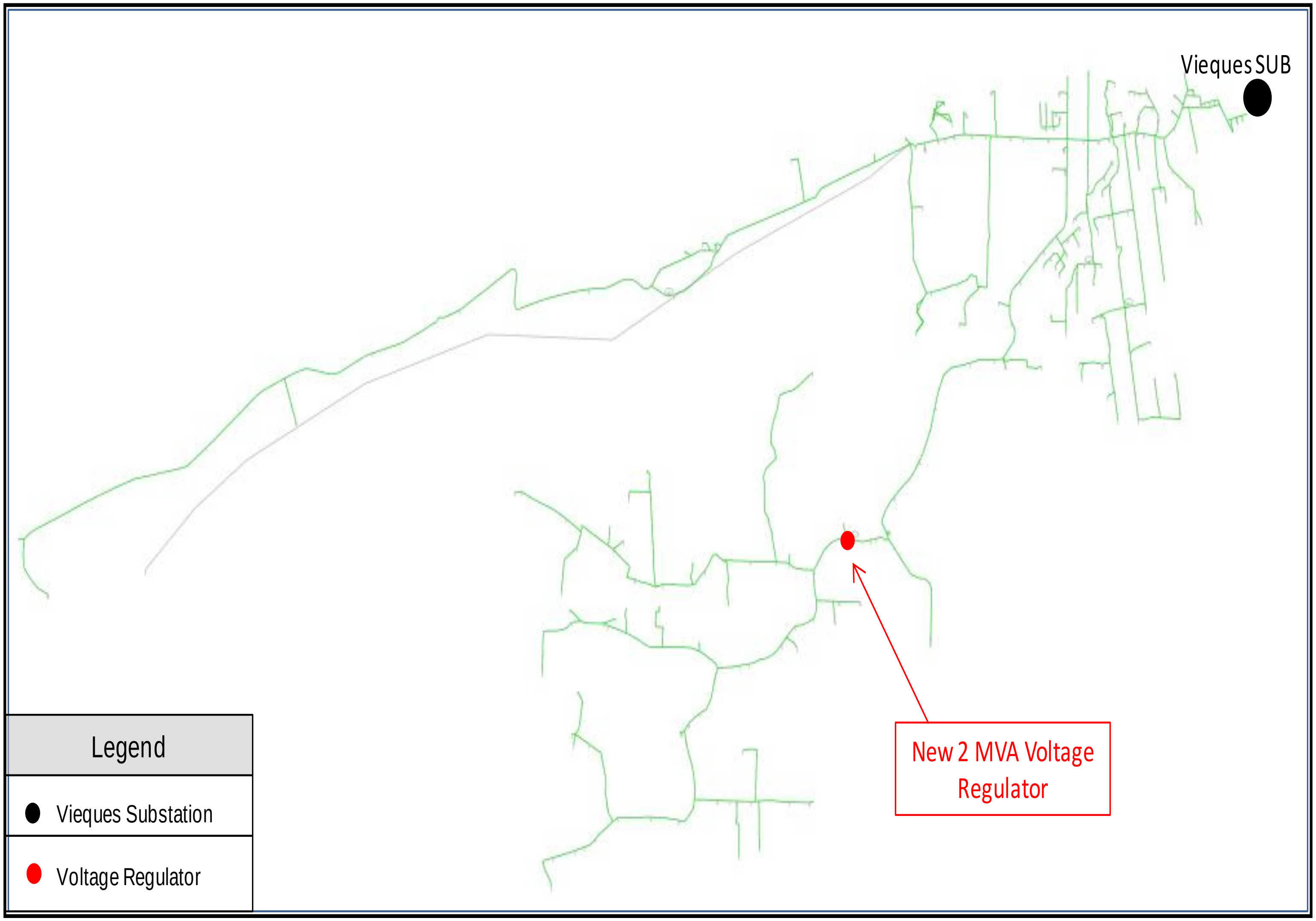

Figure 2-33: Feeder 2501-01 Layout with System Improvement (Adjusted Base Case)

2.5.2 Feeder 6306-02

Table 2-13 provides information about the feeder's primary voltage, length and loading. Due to its long extension, high impedance conductors, unbalanced load configuration, fixed capacitor banks, and relatively light load (12% of feeder capacity at noon and 20% of feeder capacity at night), voltage regulation within the ANSI C84.1 limits is one of its major challenges.

Table 2-13: Feeder 6306-02 Data

Feeder	Voltage Level (kV)	Max Length (km)	Total Length (km)(*)	Max Load (MW)	Load at around noon (MW)
6306-02	4.16	9.6	50.0	0.59	0.16

Without solar PV integration, the results of the simulations presented voltage levels above 105% (in a 120 V base) during minimum demand conditions (around noon). Figure 2-34 depicts the areas with these voltage levels. On the other hand, during maximum demand conditions (8 pm), voltages below 95% (in a 120 V base) were recorded. Figure 2-35 depicts the areas with these voltage levels. The mixed voltage profile behaviors are due to two reasons: fixed capacitor banks and heavily unbalanced branches.

Before performing the solar PV assessment, the following options were analyzed:

- Option 1: Replace existing fixed capacitor banks with switched units. When the capacitor banks are de-energized, the voltage levels dropped to even lower values (below 83%) during maximum demand conditions. Therefore, it did not improve the voltage concern.

- Option 2: Remove two fixed capacitor banks and install a VR. This solution resulted in better voltage control capability, as the VR provided voltage support, in steps, via tap changes. Therefore, this improved feeder model became the base case model.

Figure 2-36 shows the feeder layout, including the improvements detailed in Option 2.

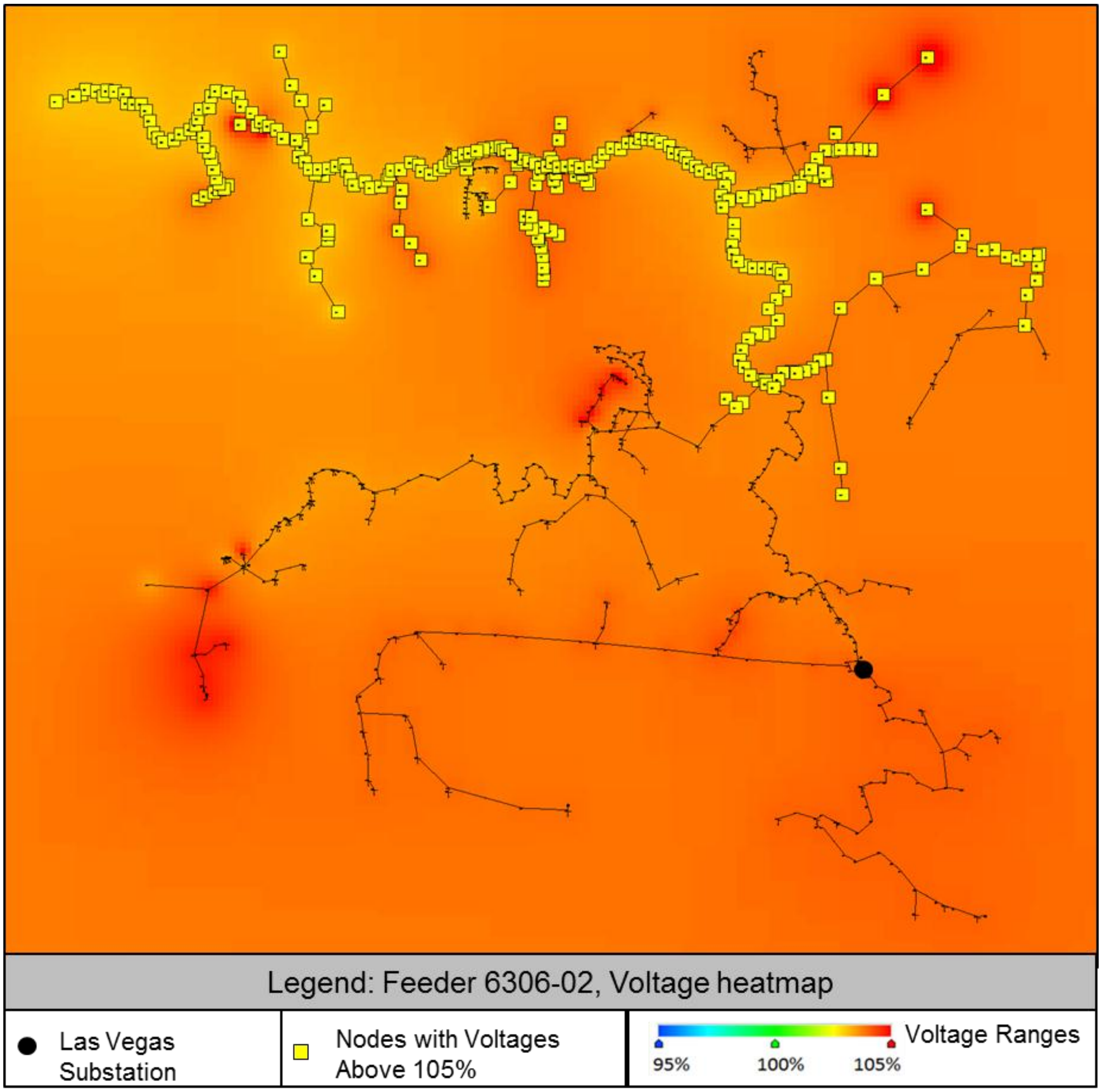

Figure 2-34: Feeder 6306-02 Voltage Heat Map During Minimum Demand

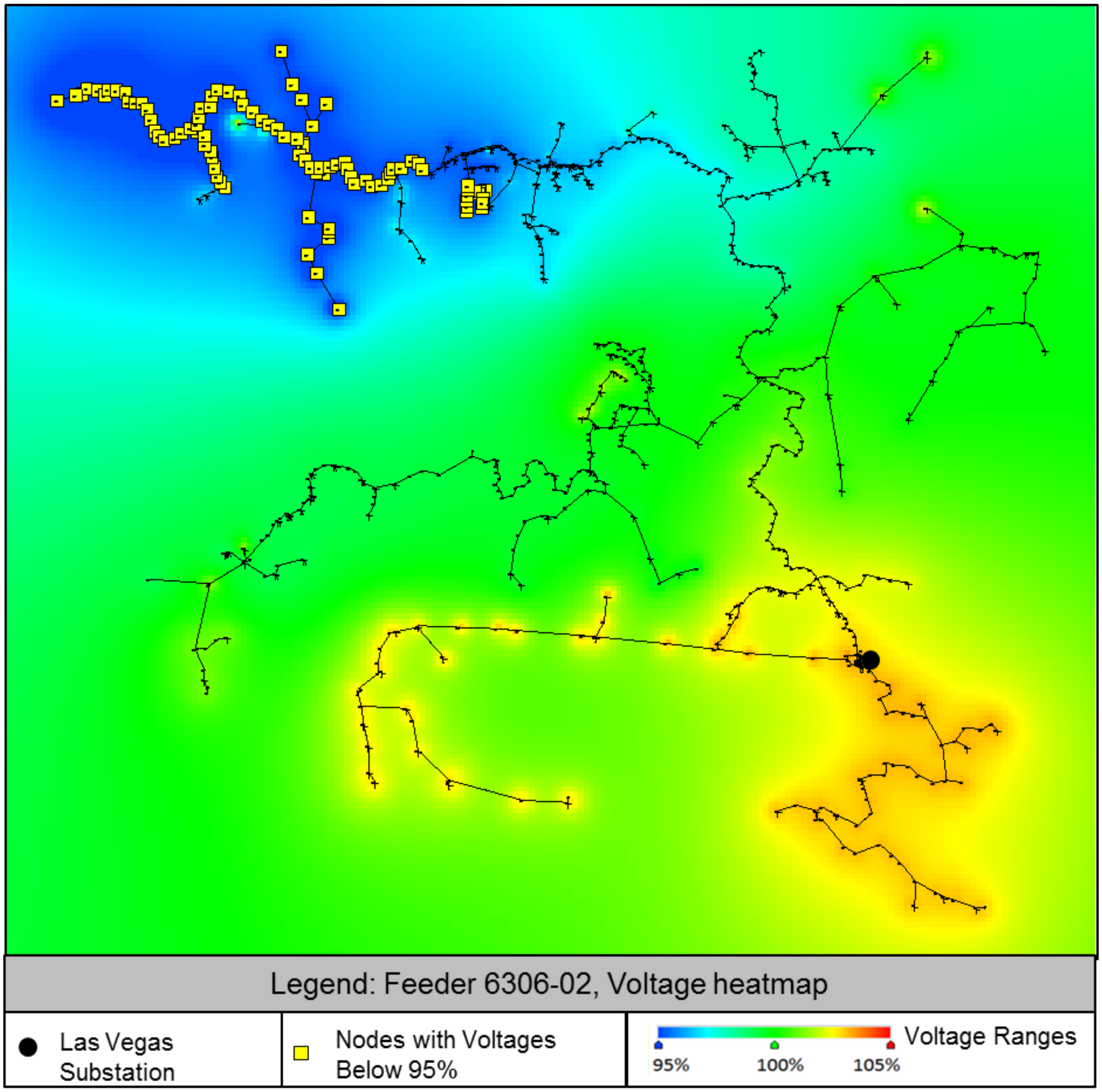

Figure 2-35: Feeder 6306-02 Voltage Heat Map During Maximum Demand (8 pm)

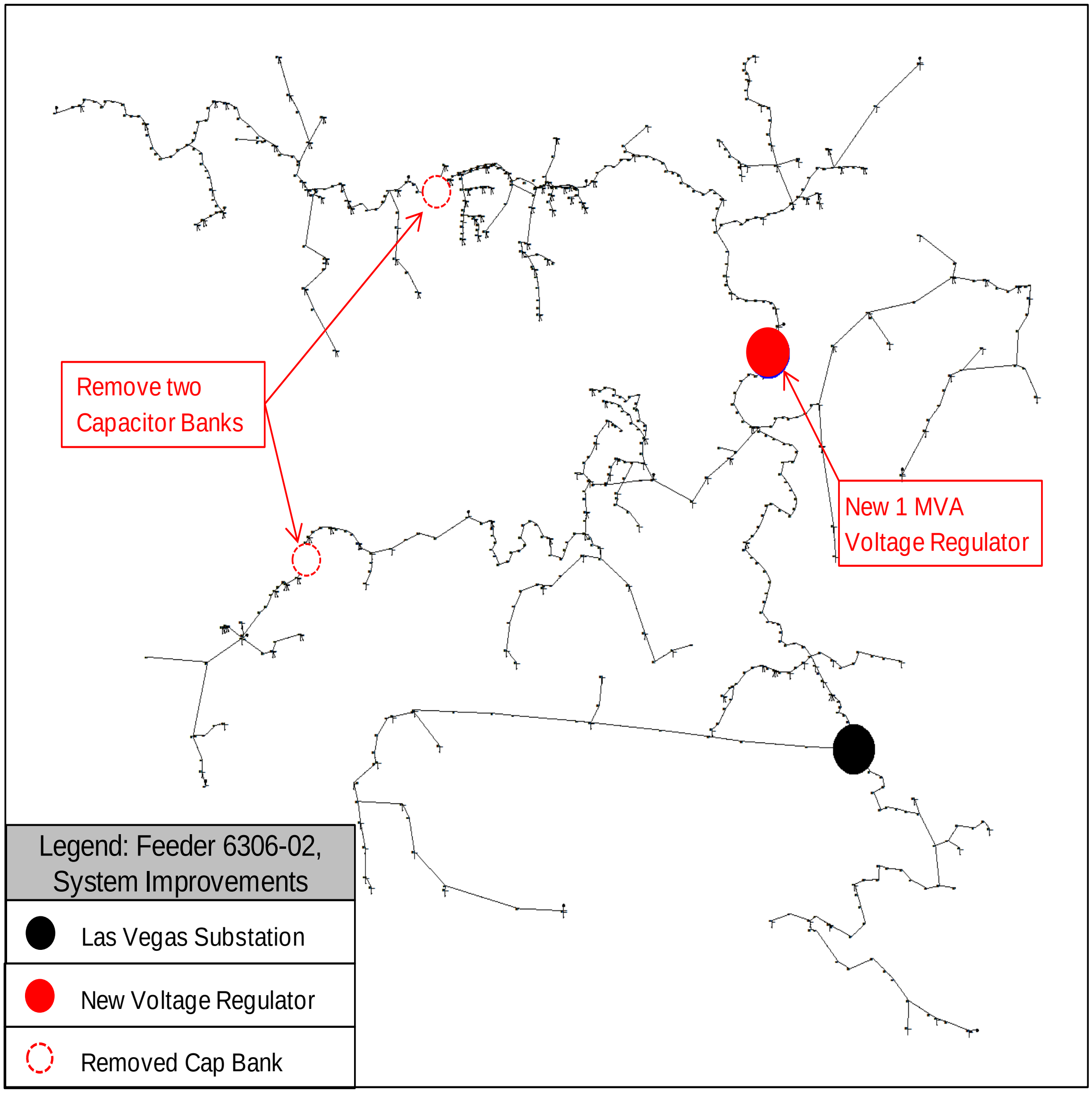

Figure 2-36: Feeder 6306-02 Layout with System Improvement (Adjusted Base Case)

2.5.3 Feeder 7103-04

Table 2-14 provides information about the feeder's primary voltage, length and loading. Due to its long extension, high impedance conductors, unbalanced load configuration, and fixed voltage boosters, voltage regulation within the ANSI C84.1 limits is one of its major challenges.

Table 2-14: Feeder 7103-04 Data

Feeder	Voltage Level (kV)	Max Length (km)	Total Length (km)(*)	Max Load (MW)	Load at around noon (MW)
7103-04	4.16	12.9	49.2	2.56	1.22

Without solar PV integration, the results of the simulations presented voltage levels above 105% (in a 120 V base) during minimum demand conditions (around noon). Figure 2-37 depicts the areas with these voltage levels. On the other hand, during maximum demand conditions (10 pm), voltages below 95% (in a 120 V base) were recorded. Figure 2-38 depicts the areas with these voltage levels. The mixed voltage profile behaviors are due to two reasons: heavily unbalanced branches and fixed voltage boosters.

Before performing the solar PV assessment, the following options were analyzed:

- Option 1: Decrease the voltage regulation set point on existing voltage regulators. This option reduced the overvoltage conditions, but worsened the low voltages values.
- Option 2: Install two, 3 MVA VRs as depicted in Figure 2-39. This solution resulted in better voltage control capability, as the VRs provided voltage support, in steps, via tap changes. Therefore, this improved feeder model became the base case model.

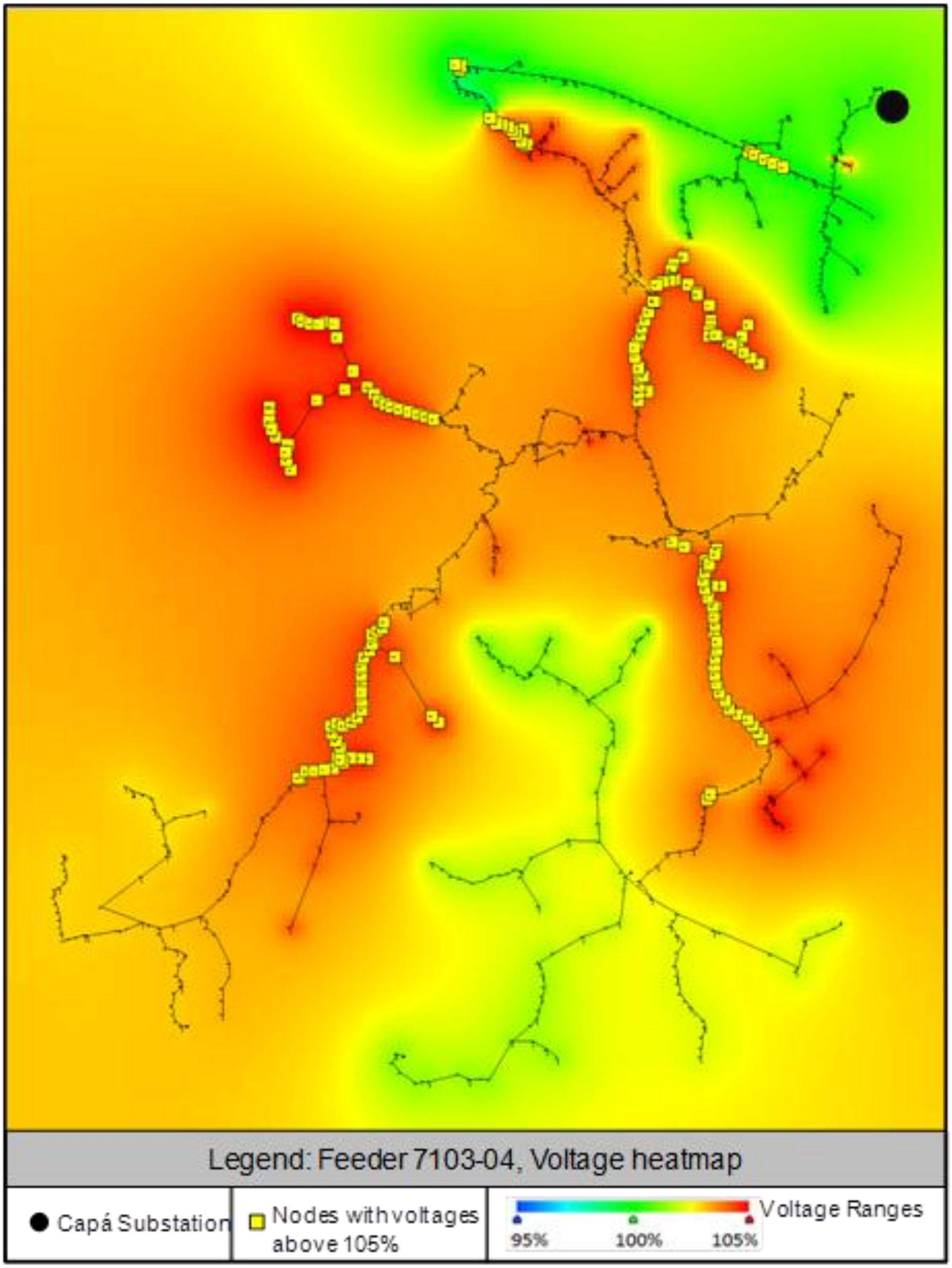

Figure 2-37: Feeder 7103-04 Voltage Heat Map During Minimum Demand

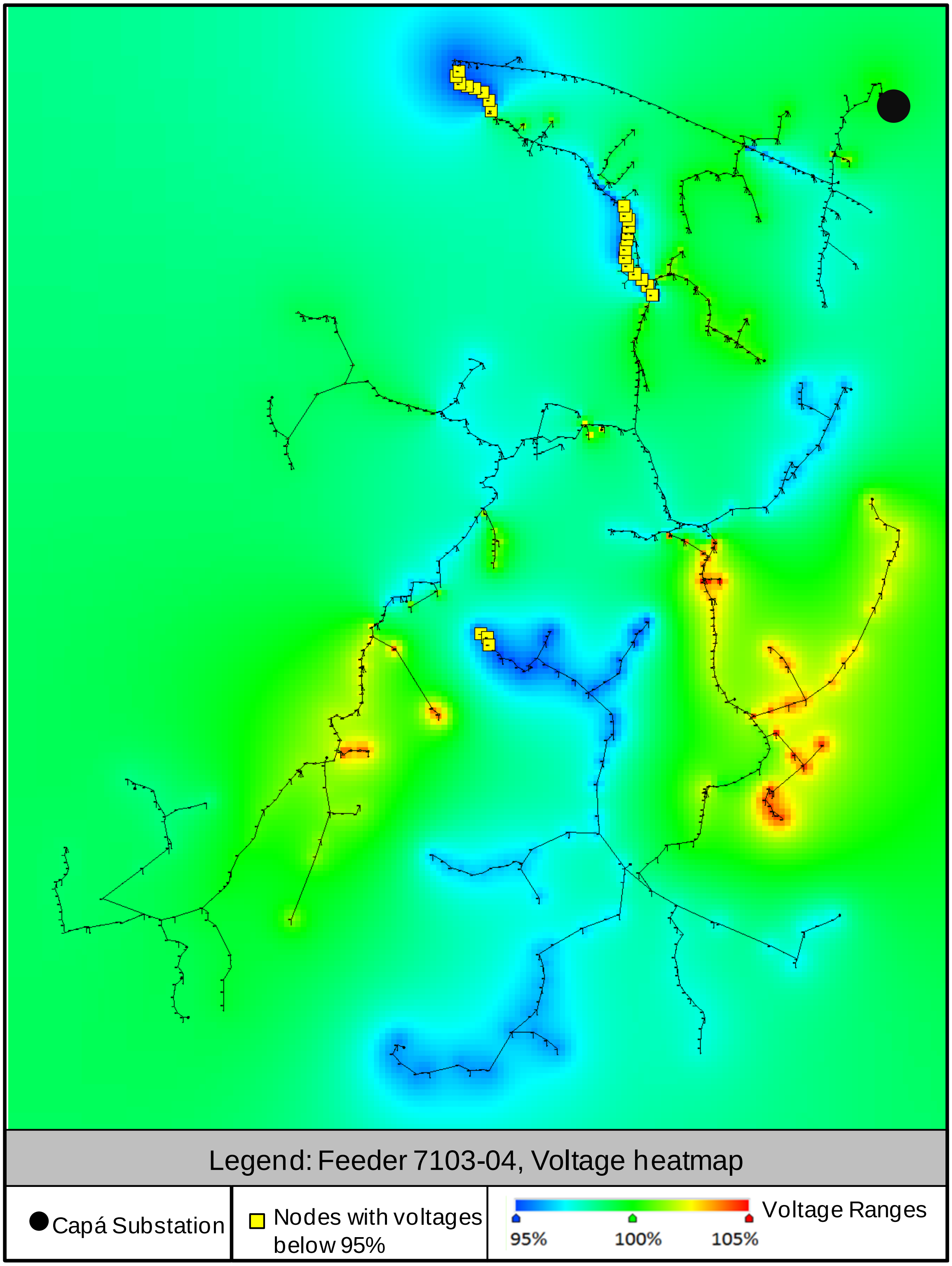

Figure 2-38: Feeder 7103-04 Voltage Heat Map During Maximum Demand (10 pm)

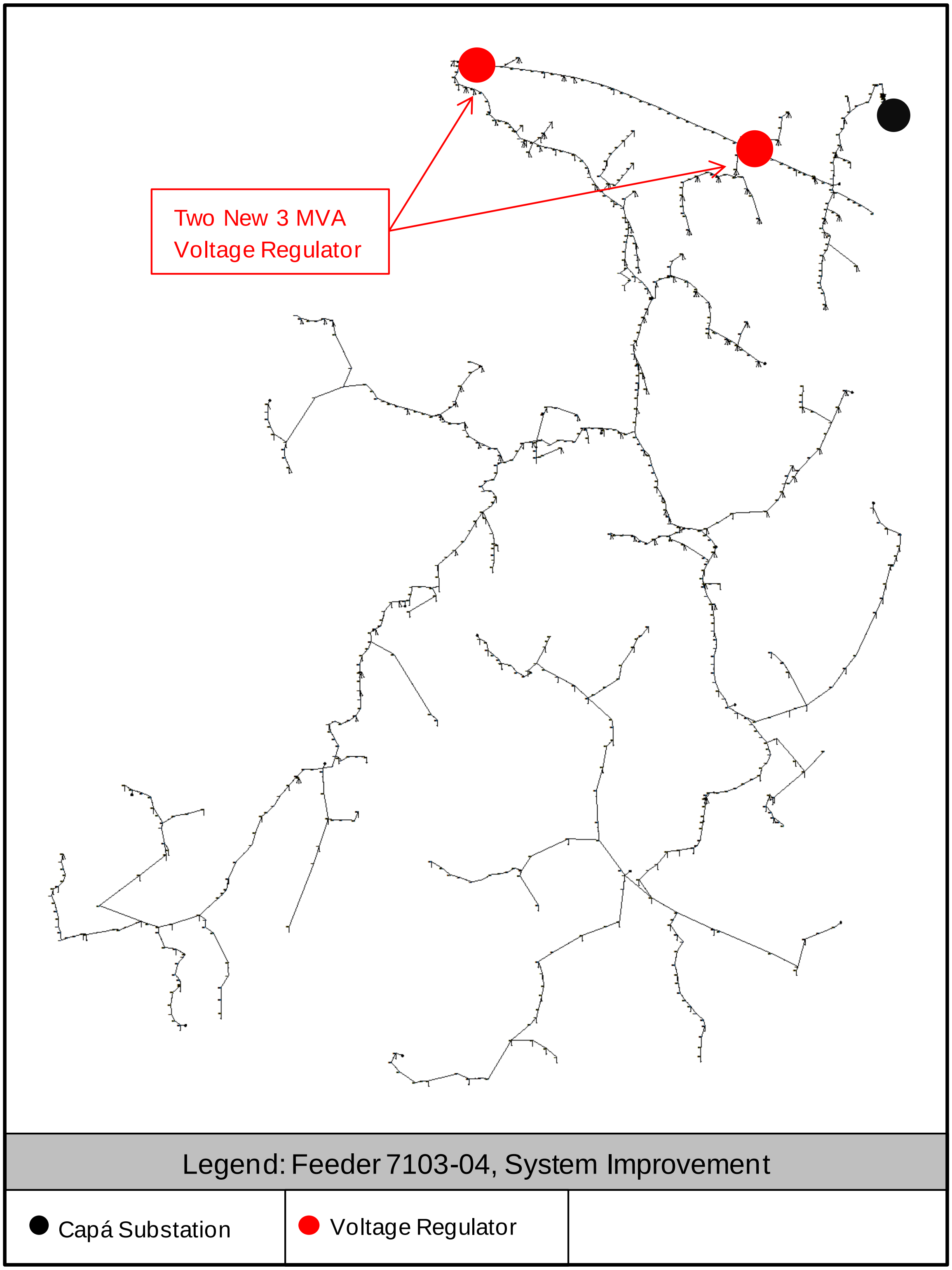

Figure 2-39: Feeder 7103-04 Layout with System Improvement (Adjusted Base Case)

2.5.4 Feeder 2801-02

Table 2-15 provides information about the feeder's primary voltage, length and loading. The power flow simulation results did not present any voltage violations for the base case. Therefore, the existing feeder model was the base case.

Table 2-15: Feeder 2801-02 Data

Feeder	Voltage Level (kV)	Max Length (km)	Total Length (km)(*)	Max Load (MW)	Load at around noon (MW)
2801-02	8.32	7.1	42.3	2.12	1.16

2.5.5 Feeder 1529-11

Table 2-16 provides information about the feeder's primary voltage, length and loading. The power flow simulation results did not present any voltage violations for the base case. Therefore, the existing feeder model was the base case.

Table 2-16: Feeder 1529-11 Data

Feeder	Voltage Level (kV)	Max Length (km)	Total Length (km)(*)	Max Load (MW)	Load at 11 am (MW)
1529-11	13.2	2.4	27.2	5.29	3.71

2.5.6 Feeder 1529-12

Table 2-17 provides information about the feeder's primary voltage, length and loading. The power flow simulation results did not present any voltage violations for the base case. Therefore, the existing feeder model was the base case.

Table 2-17: Feeder 1529-12 Data

Feeder	Voltage Level (kV)	Max Length (km)	Total Length (km)(*)	Max Load (MW)	Load at 11 am (MW)
1529-12	13.2	3.4	30.9	3.89	2.55

2.5.7 Feeder 1529-13

Table 2-18 provides information about the feeder's primary voltage, length and loading. The power flow simulation results did not present any voltage violations for the base case. Therefore, the existing feeder model was the base case.

Table 2-18: Feeder 1529-13 Data

Feeder	Voltage Level (kV)	Max Length (km)	Total Length (km)(*)	Max Load (MW)	Load at 11 am (MW)
1529-13	13.2	3.1	11.4	6.73	3.09

Section

3

DG Impact Assessment

This section describes the findings of integrating up to 100% of feeder peak demand in solar PV generation and the feeder level voltage regulation improvements required to achieve such penetration.

It is important to reiterate that in addition to the voltage regulation improvements, other investments are required to integrate DG, including:

a) The adoption of advanced protection coordination schemes to compensate for loss of sensitivity, creation of unintentional islands, sympathetic trips or non-trips, nuisance fuse burning, etc.

b) Investments at the distribution and transmission levels to address rapid changes in the net load due to the intermittency of high levels of DG penetration and the power flow exchange between both systems. In particular, the analyses of PREPA's transmission system under light load daytime conditions (e.g. when PV generation can be at its maximum) has previously registered elevated voltages at the 38 kV level with most buses between 102% to 105% of the nominal voltage, even before DG integration. This means that advanced voltage control at this voltage level needs to be in place, including control of LTC during reverse power flows and automatic capacitor switching, among others.

c) In weak areas of the system, PV penetration can result in voltage flicker (rapid changes in voltage) that can be costly to address as it could require the reinforcement of feeders, new transmission and distribution infrastructure or the installation of control devices like distribution static synchronous compensators (DSTATCOM).

Some of these additional investments, like advanced protection schemes and voltage control devices, were considered in this study to estimate the investment costs necessary to achieve 100% of PV penetration on the sample feeders. Other investments, like the DSTATCOM, are system-wide solutions beyond the sample assessment done here.

3.1 Feeder 2501-01

The analysis of the feeder was conducted using the load profile presented in Section 2 of this document and the PV generation profile shown in Figure 3-1, which allowed us to study multiple solar PV generation levels up to 100% of feeder peak demand. The multiple solar PV generation levels were increased in steps of 10% of the feeder peak demand in 24-hour periods (i.e. allows studying all levels of solar PV penetration in the same run).

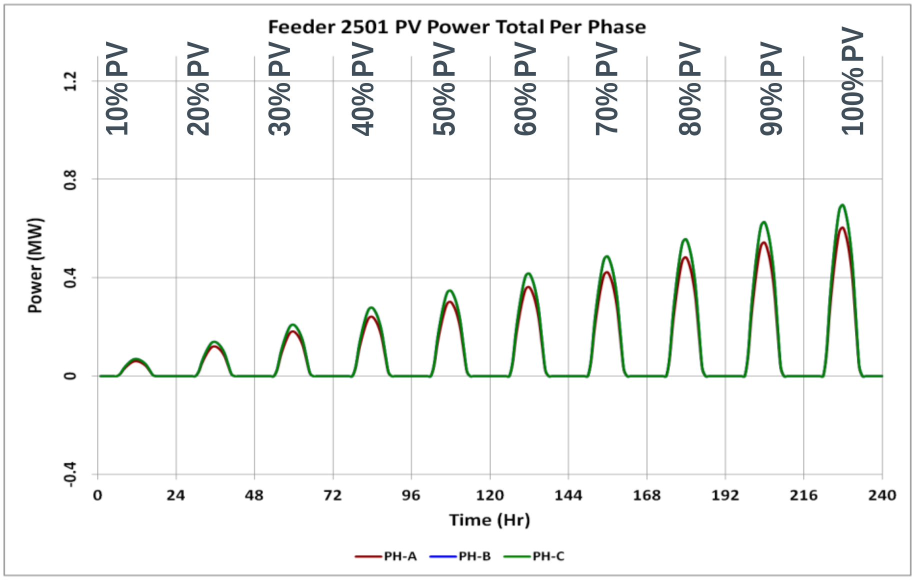

Figure 3-1: Feeder 2501-01 Solar PV Generation Output at Different Levels of Integration

Taking into account the PV generation profile, Figure 3-2 presents the power supplied by the substation to the feeder loads at different levels of solar PV penetration (i.e. from 10% to 100%). As can be noted, phases B and C began to experience reverse power flows at 30% PV penetration, while phase A began at 40%. This means that unless other feeders supplied by the same substation have sufficient demand, there will be power flowing from the distribution to the transmission system with the potential problems indicated above, unless properly addressed.

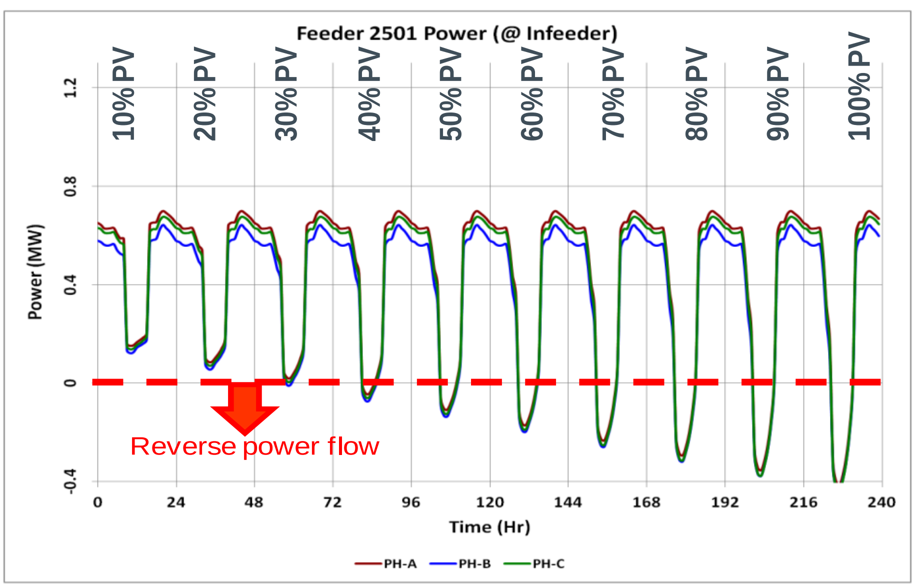

Figure 3-2: Feeder 2501-01 Power Supplied/Received

Figure 3-3 shows the maximum and minimum observed voltage magnitudes in the feeder at different levels of solar PV penetration for each hour simulated as a percentage of nominal voltage (i.e. the voltage percentage for the node with highest voltage and the node with lowest voltage). As depicted, phases B and C began presenting voltages above 105% at 40% PV penetration, while phase A presented high voltages at 50%. These overvoltage magnitudes were registered when solar PV generation was at its maximum power output, i.e. around noon.

No voltages below minimum limits were identified throughout the modified load profile with different levels of solar PV penetration.

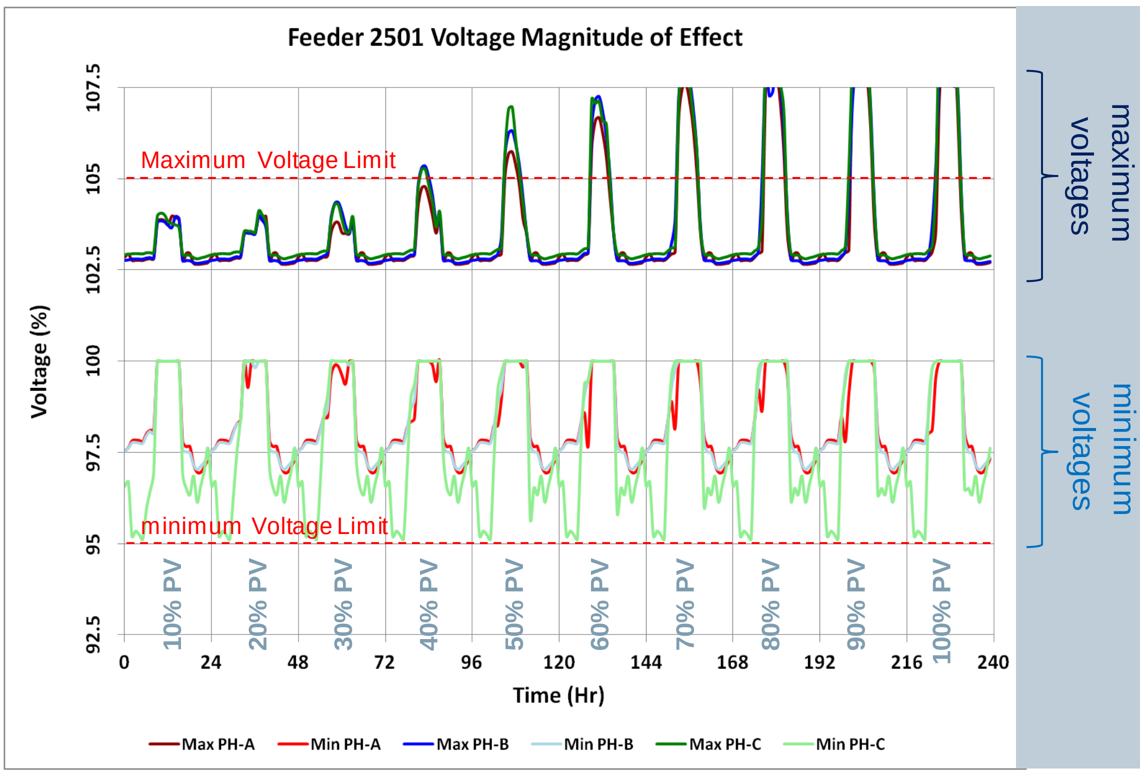

Figure 3-3: Feeder 2501-01 Maximum and Minimum Voltages

To further illustrate the extent of the high voltages, Figure 3-4 provides a voltage contour around noon time with 100% PV penetration. The areas in red represent voltage values close to or above 105% of the feeder nominal voltage. These overvoltage magnitudes concentrated at the farthest end of the feeder and were particularly severe on single phase branches.

As it may be seen in Table 3-1, 20% to 30% of the nodes had voltages above 105% during the 100% PV penetration scenario, being phases B and C the most affected.

Based on the above, it can be concluded that without any additional investments, this feeder can accommodate up to 30% of its peak demand in solar PV penetration.

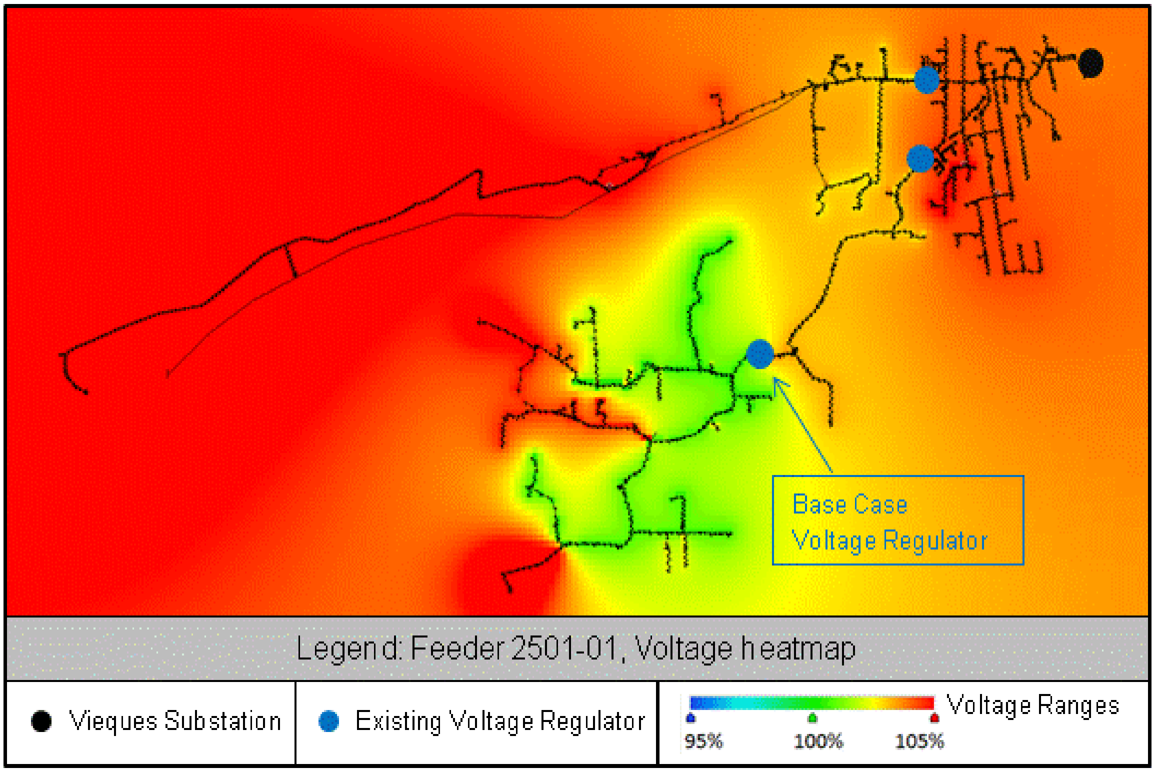

Figure 3-4: Feeder 2501-01 Voltage Contour Around Noon Time

Table 3-1: Feeder 2501-01 Statistics During Maximum PV Output

Phase	Max Voltage (%)	Node with Overvoltage (%)	Min Voltage (%)	Infeeder Power (MW)	PV Power (MW)
A	108.56	19.89	100	-0.414	0.605
B	109.13	30.46	100	-0.435	0.696
C	110.19	30.65	100	-0.437	0.696

3.1.1 Recommended Improvements

To address the voltage issues identified when solar PV penetration equals 100% of feeder peak demand, the following improvements are suggested:

a) In addition to the two existing VRs and the 2 MVA VR that was recommended to create the base case conditions, a new 3 MVA dedicated VR at feeder head, with a voltage setting of 101% to 102%, is recommended. This will allow the feeder to use a different voltage regulation scheme as needed to maintain the voltage limits within the ANSI C84.1 standard. Furthermore, the substation transformer's LTC can regulate the voltage of the other feeders with a different tap setting depending on the load and generation diversity.

b) As seen in Figure 3-5, VR1, VR2 and VR3 represent the regulating equipment along the feeder for the adjusted base case. It is recommended to set these VRs to the “Co-Generation Mode”, which would allow voltage regulation on a forward direction even with reverse power flows. The VRs should be set as detailed below and enable line drop compensation control mode for VR1 and VR3, thus controlling voltages at nodes identified as control nodes (CN):

I. VR1: Voltage set to 98% minimum and 99% maximum, monitoring CN1

II. VR2: Voltage set to 100% minimum and 101% maximum, monitoring CN2

III. VR3: Voltage set to 99% minimum and 100% maximum, monitoring CN3

The proposed voltage regulation scheme will operate as a first-level voltage security and voltage values at the CN should be communicated via radio to the VR, relying on the line drop compensation as a backup.

c) Due to the variability of solar PV generation and the bidirectional power flows experienced in DG impacted feeders, it is recommended to add a volt/var control system at the substation level to monitor and control the voltage profiles. This volt/var control system will operate as a second-level voltage security that will provide signals to all VRs in the system and to the substation’s LTC to achieve optimal performance.

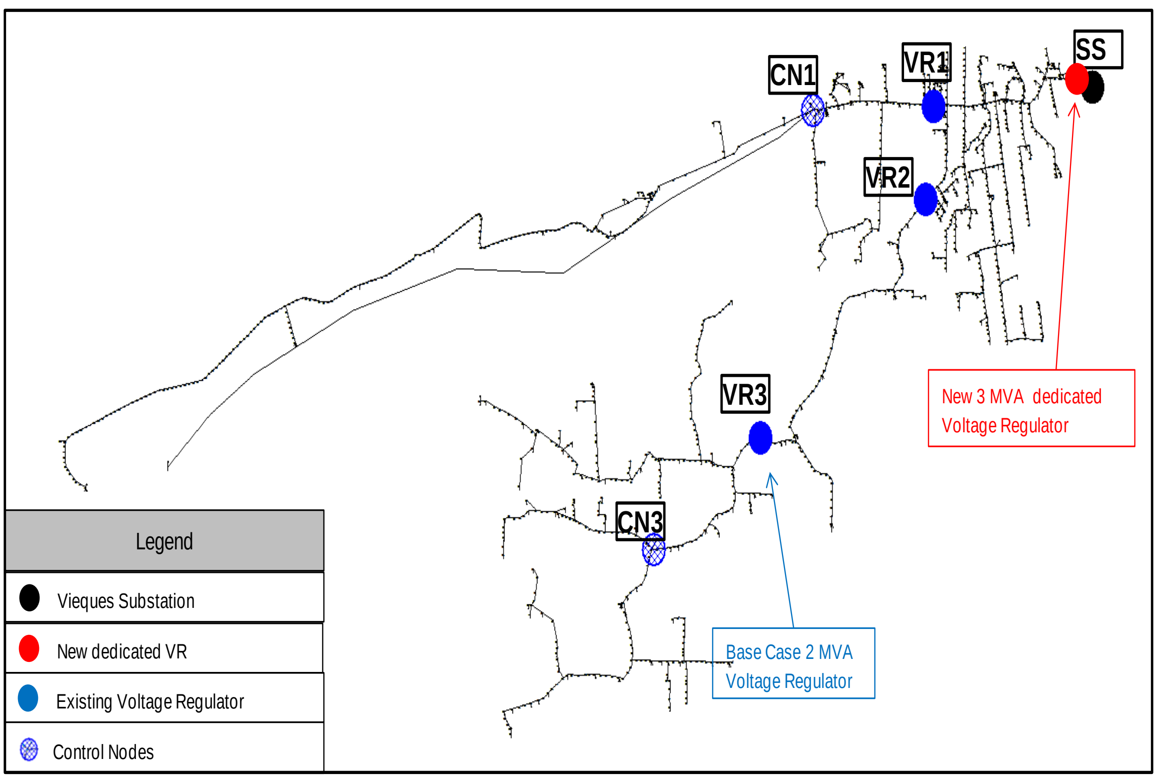

Figure 3-5: Feeder 2501-01 Suggested System Improvements for 100% Solar PV Integration

Figure 3-6 shows the maximum and minimum observed voltage levels in the feeder, at different levels of solar PV penetration, after the recommended system improvements are implemented. As it may be seen, with these improvements the feeder voltages are within limits.

There was only a slight voltage violation on phase C when 100% of feeder peak demand in solar PV generation was simulated. This violation is within the accuracy of our calculations; however, it could be controlled by limiting the amount of solar PV integration at that single phase branch to no more than the branch's minimum noon time demand levels.

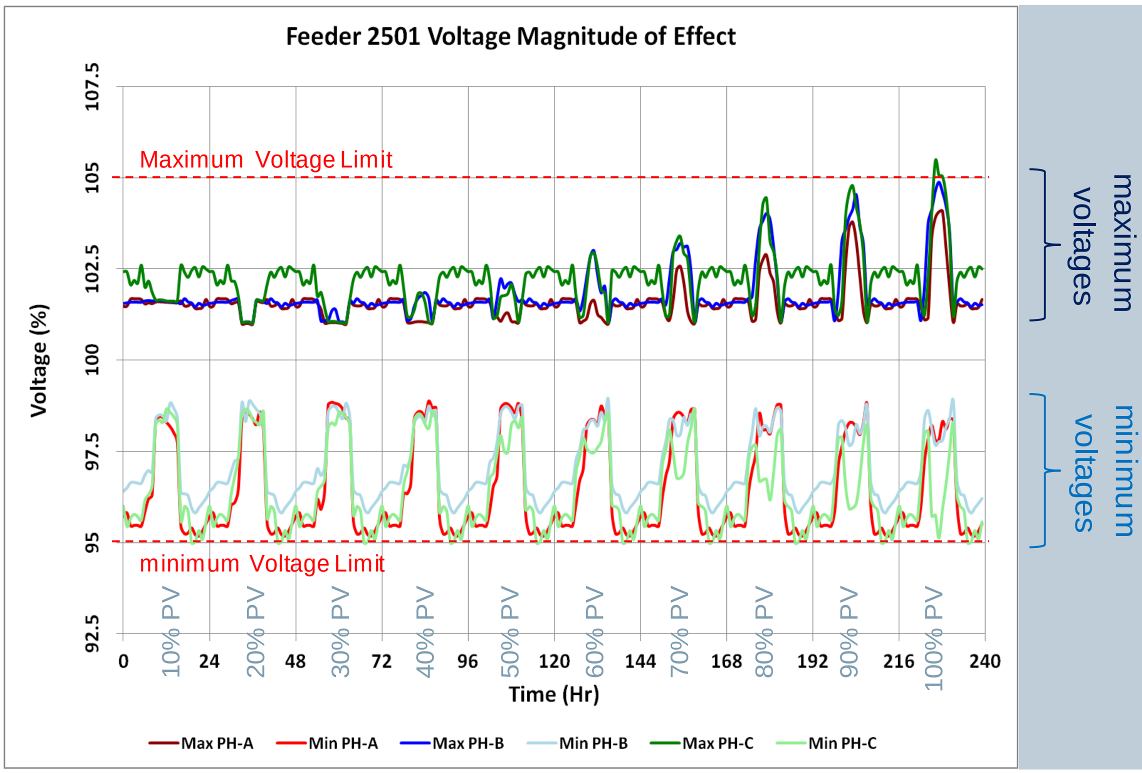

Figure 3-6: Feeder 2501-01 Maximum and Minimum Voltages After System Improvements

100% Solar PV Penetration Case:

Figure 3-7 shows that with the proposed system improvements, voltage levels at noon time are within the acceptable limits. Also, Table 3-2 indicates that only a slight voltage violation affected 0.2% of the nodes, which are located in the south region of the Vieques substation.

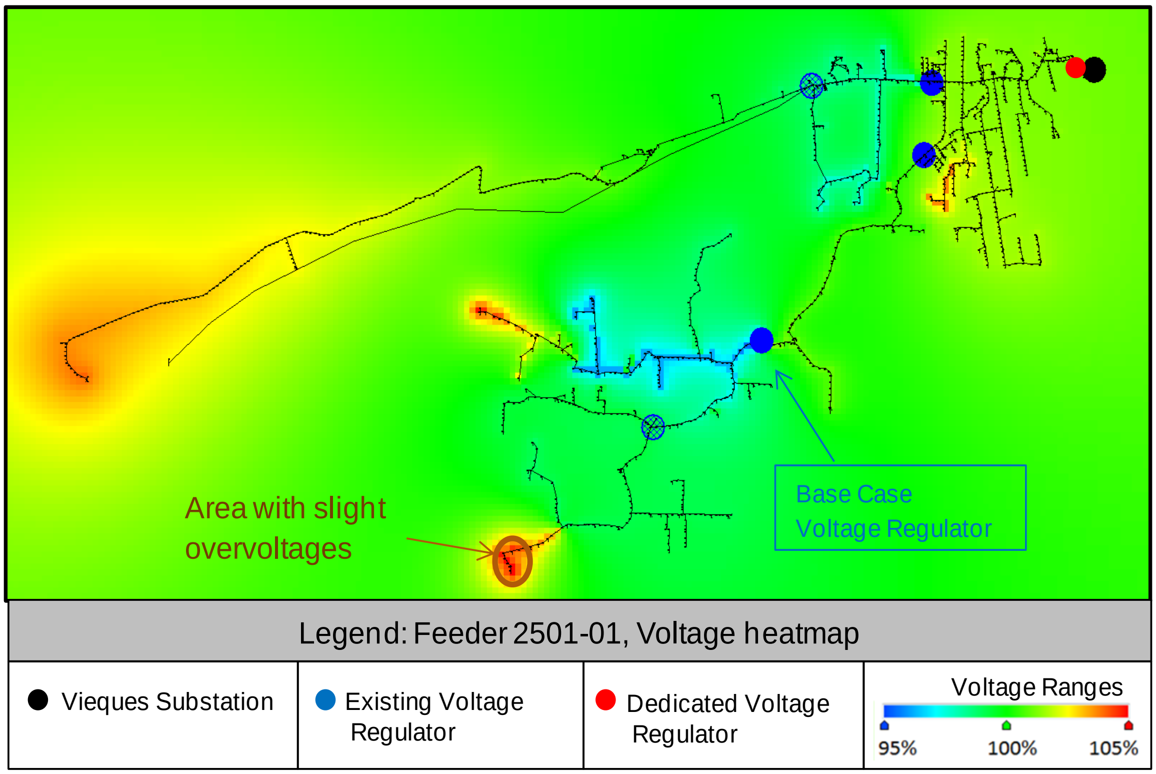

Figure 3-7: Feeder 2501-01 Voltage Contour Around Noon Time After System Improvements

Table 3-2: Feeder 2501-01 Statistics During Maximum PV Output After System Improvements

Phase	Max Voltage (%)	Node with Overvoltage (%)	Min Voltage (%)	Infeeder Power (MW)	PV Power (MW)
A	104.05	0	97.81	-0.41	0.60
B	104.87	0	97.76	-0.43	0.69
C	105.06	0.20	95.12	-0.43	0.69

Maximum Demand Case:

Figure 3-8 and Table 3-3 show that with the proposed system improvements, voltage levels at the maximum demand scenario (9 pm) are within the acceptable limits.

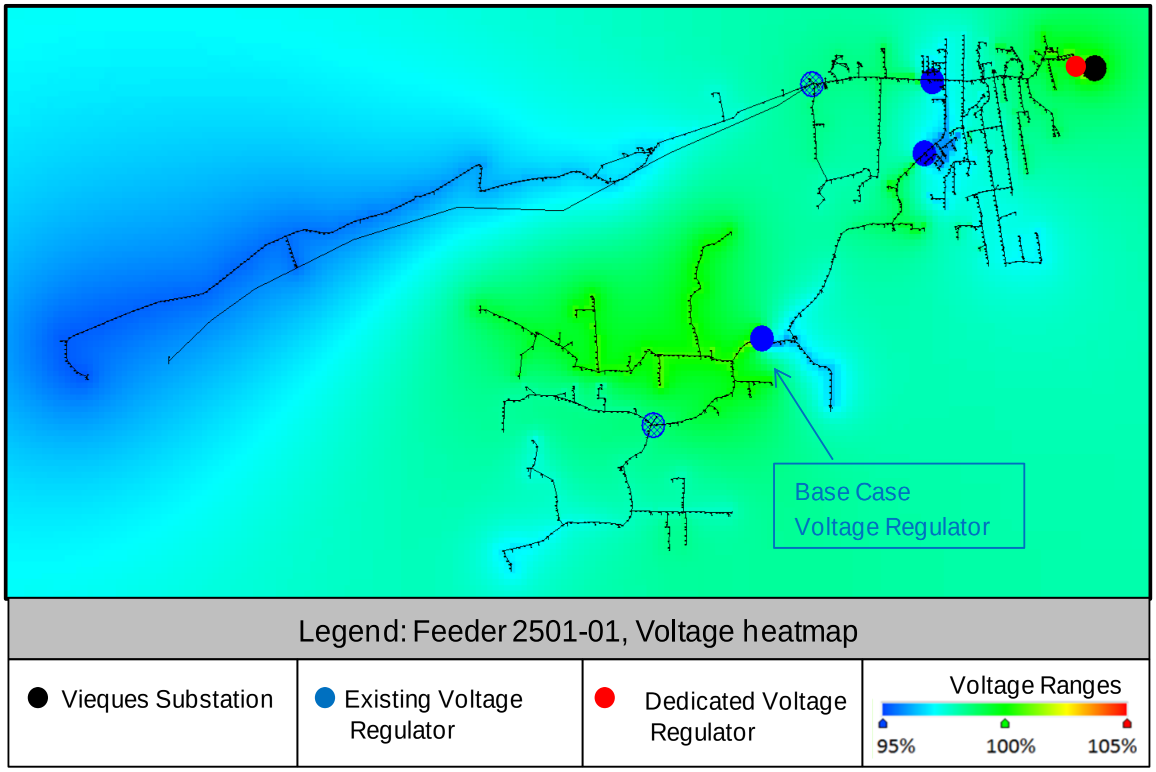

Figure 3-8: Feeder 2501-01 Voltage Contour at 9 pm After System Improvements

Table 3-3: Feeder 2501-01 Statistics at 9 pm After System Improvements

Phase	Max Voltage (%)	Min Voltage (%)	Node with under-voltage (%)	Infeeder Power (MW)	PV Power (MW)
A	101.41	95.17	0.00	0.691	0.00
B	101.56	95.94	0.00	0.630	0.00
C	102.28	95.33	0.00	0.674	0.00

3.2 Feeder 6306-02

The analysis of the feeder was conducted using the load profile presented in Section 2 of this document and the PV generation profile shown in Figure 3-9, which allowed us to study multiple solar PV generation levels up to 100% of feeder peak demand. The multiple solar PV generation levels were increased in steps of 10% of the feeder peak demand in 24-hour periods (i.e. allows studying all levels of solar PV penetration in the same run).

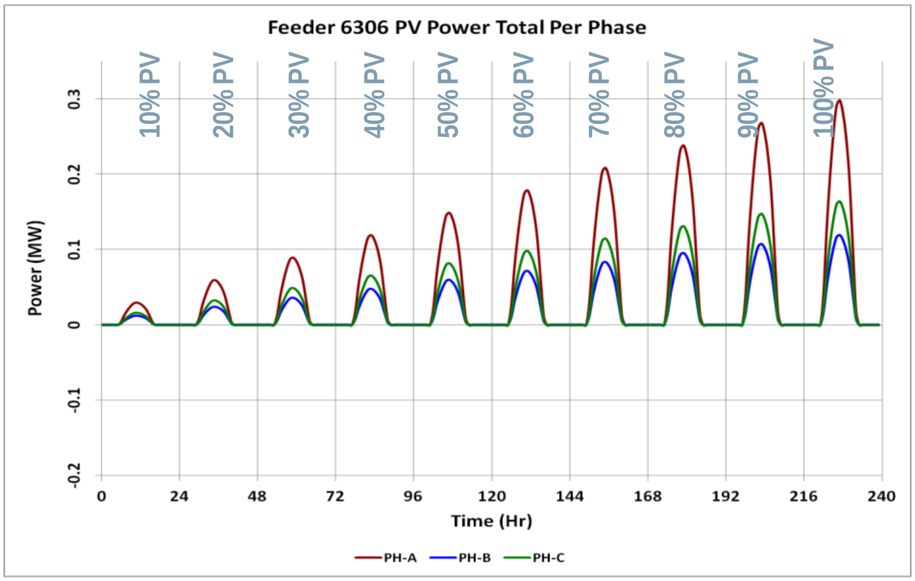

Figure 3-9: Feeder 6306-02 Solar PV Generation Output at Different Levels of Integration

Taking into account the PV generation profile, Figure 3-10 presents the power supplied by the substation to the feeder loads at different levels of solar PV penetration (i.e. from 10% to 100%). As can be noted, phase C began to experience reverse power flows at 20% PV penetration, while phase A began at 30% and phase B began at 40%. This means that unless other feeders supplied by the same substation have sufficient demand, there will be power flowing from the distribution to the transmission system with the potential problems indicated above, unless properly addressed.

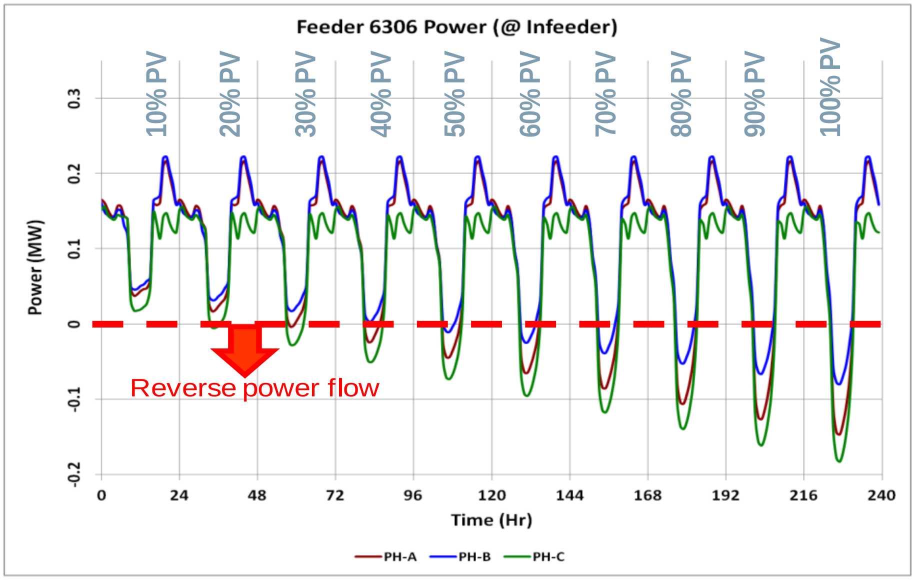

Figure 3-10: Feeder 6306-02 Power Supplied/Received

Figure 3-11 shows the maximum and minimum observed voltage magnitudes in the feeder at different levels of solar PV penetration for each hour simulated as a percentage of nominal voltage (i.e. the voltage percentage for the node with highest voltage and the node with lowest voltage). As depicted, phase A began presenting voltages above 105% at 40% PV penetration, while phase C presented high voltages at 90%. These overvoltage magnitudes were registered when solar PV generation was at its maximum power output, i.e. around noon.

No voltages below minimum limits were identified throughout the modified load profile with different levels of solar PV penetration.

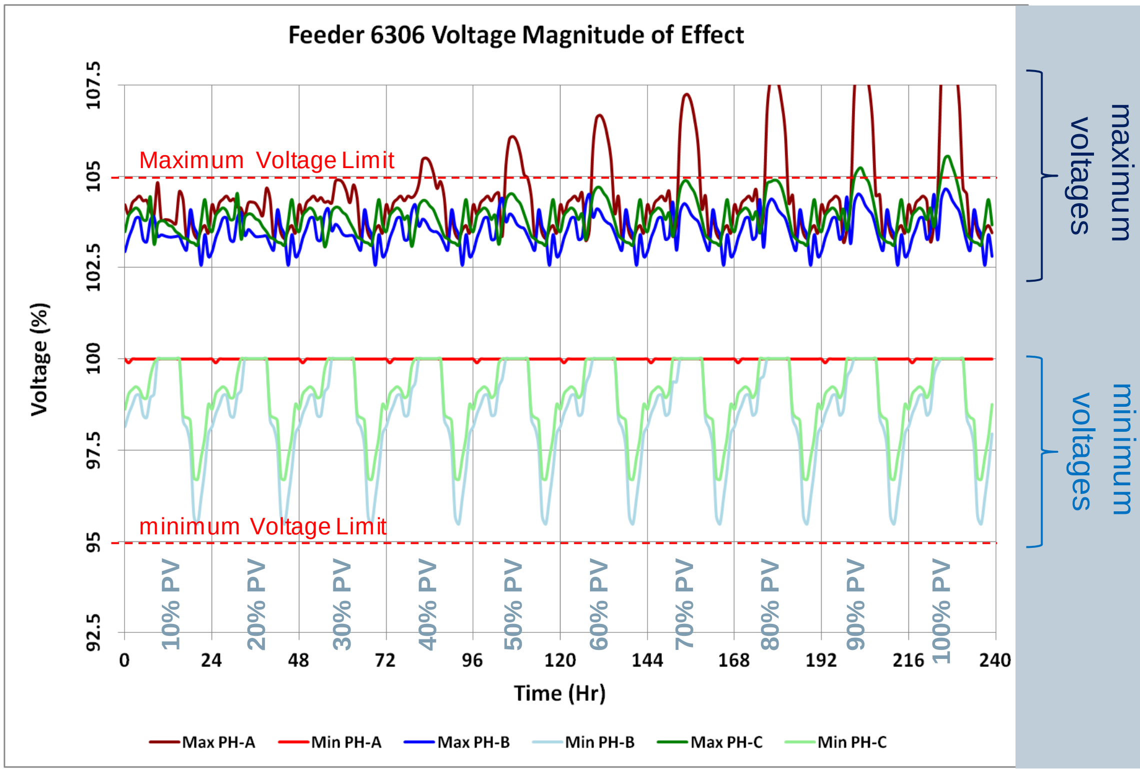

Figure 3-11: Feeder 6306-02 Maximum and Minimum Voltages

To further illustrate the extent of the high voltages, Figure 3-12 provides a voltage contour around noon time with 100% PV penetration. The areas in red represent voltage values close to or above 105% of the feeder nominal voltage. These overvoltage magnitudes concentrated at the farthest end of the feeder and were particularly severe on single phase branches.

As it may be seen in Table 3-4, around 36% of the nodes of phase A had voltages above 105% during the 100% PV penetration scenario.

Based on the above, it can be concluded that without any additional investments, this feeder can accommodate up to 20% of its peak demand in solar PV penetration.

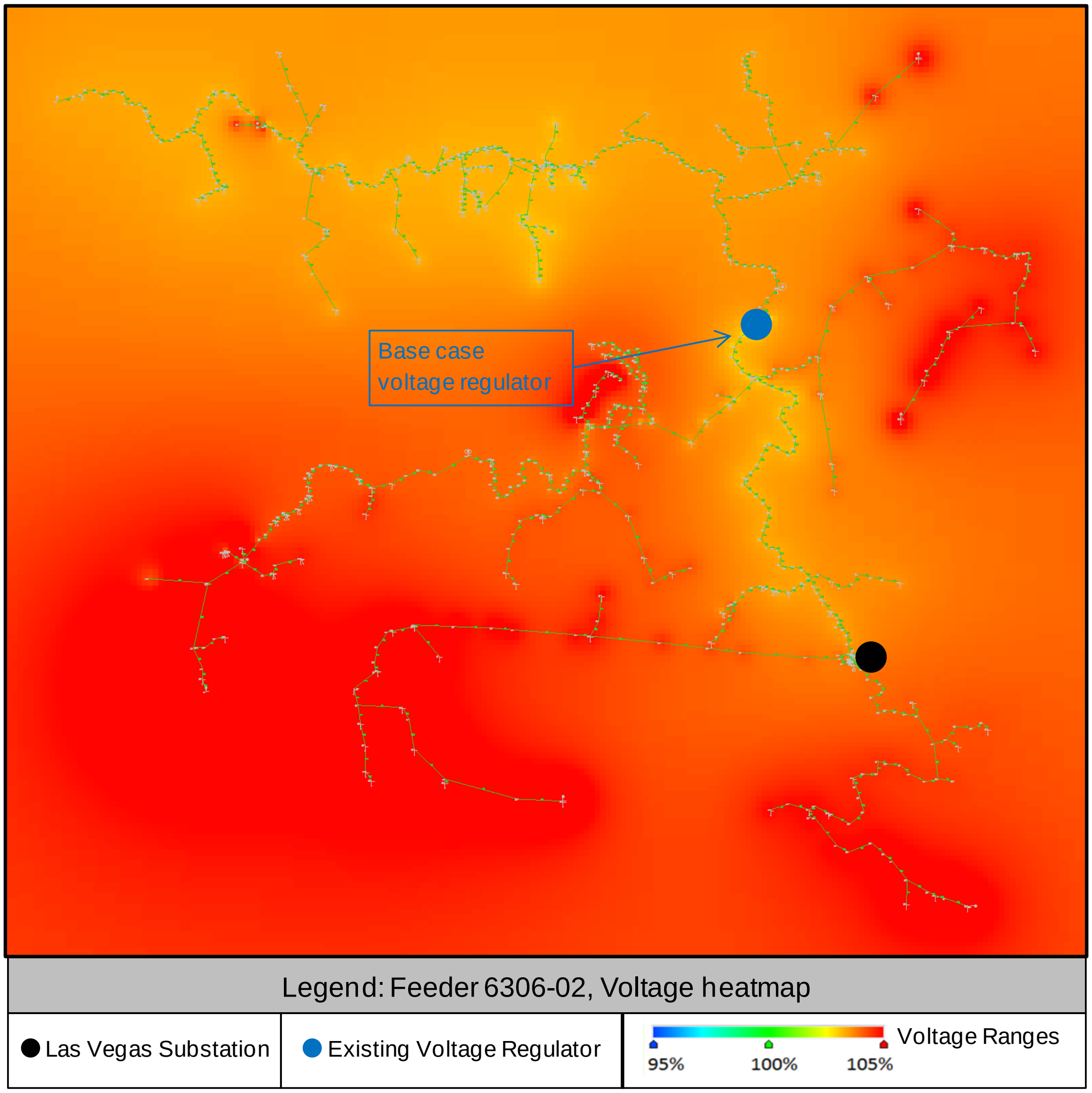

Figure 3-12: Feeder 6306-02 Voltage Contour Around Noon Time

Table 3-4: Feeder 6306-02 Statistics During Maximum PV Output

Phase	Max Voltage (%)	Node with Overvoltage (%)	Min Voltage (%)	Infeeder Power (MW)	PV Power (MW)
A	108.94	36.38	100	-0.146	0.298
B	104.59	0.00	100	-0.080	0.119
C	105.56	1.48	100	-0.182	0.163

3.2.1 Recommended Improvements

To address the voltage issues identified when solar PV penetration equals 100% of feeder peak demand, the following improvements are suggested:

a) In addition to the VR that was recommended to create the base case conditions, a new 3 MVA dedicated VR at feeder head, with a voltage setting of 99% to 100%, is recommended. This will allow the feeder to use a different voltage regulation scheme as needed to maintain the voltage limits within the ANSI C84.1 standard. Furthermore, the substation transformer's LTC can regulate the voltage of the other feeders with a different tap setting depending on the load and generation diversity.

b) Extend two additional phases in a 0.7 km single phase branch.

c) Figure 3-13 represents the regulating equipment along the feeder for the adjusted base case. It is recommended to set the VR to the "Co-Generation Mode", which would allow voltage regulation on a forward direction even with reverse power flows. The VR should be set to 101% minimum and 102% maximum. The proposed voltage regulation scheme will operate as a first-level voltage security.

d) Due to the variability of solar PV generation and the bidirectional power flows experienced in DG impacted feeders, it is recommended to add a volt/var control system at the substation level to monitor and control the voltage profiles. This volt/var control system will operate as a second-level voltage security that will provide signals to all VRs in the system and to the substation's LTC to achieve optimal performance.

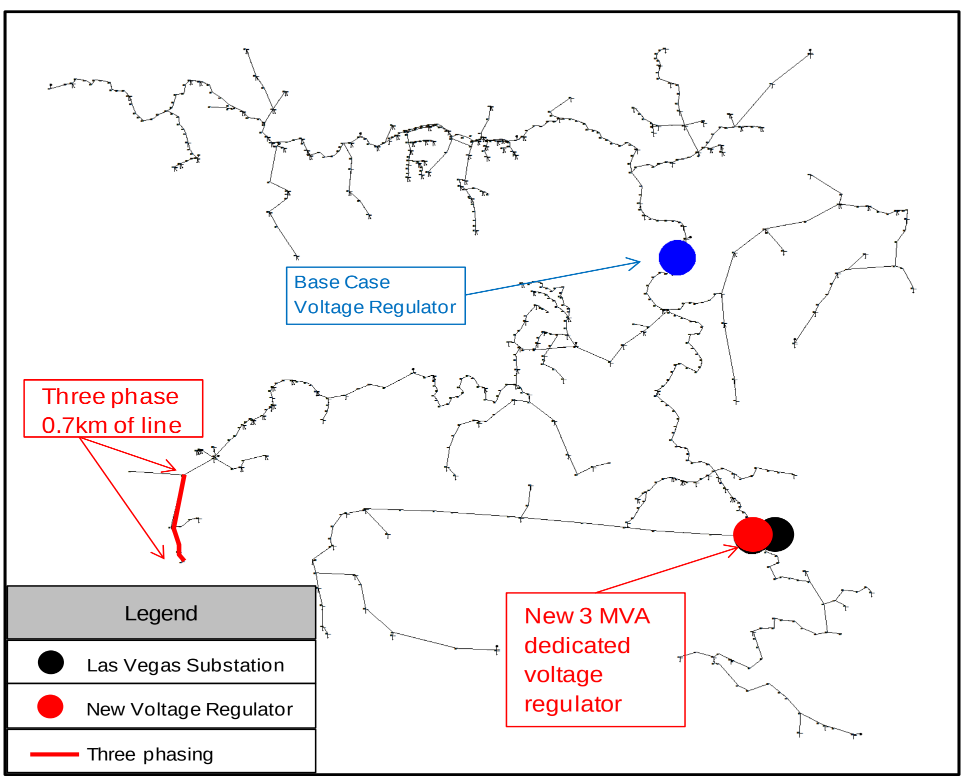

Figure 3-13: Feeder 6306-02 Suggested System Improvements for 100% Solar PV Integration

Figure 3-14 shows the maximum and minimum observed voltage levels in the feeder, at different levels of solar PV penetration, after the recommended system improvements are implemented. As it may be seen, with these improvements the feeder voltages are within limits.

There was only a slight voltage violation on phase B during the maximum demand scenario. However, it was recorded in a node where no loads are connected to it.

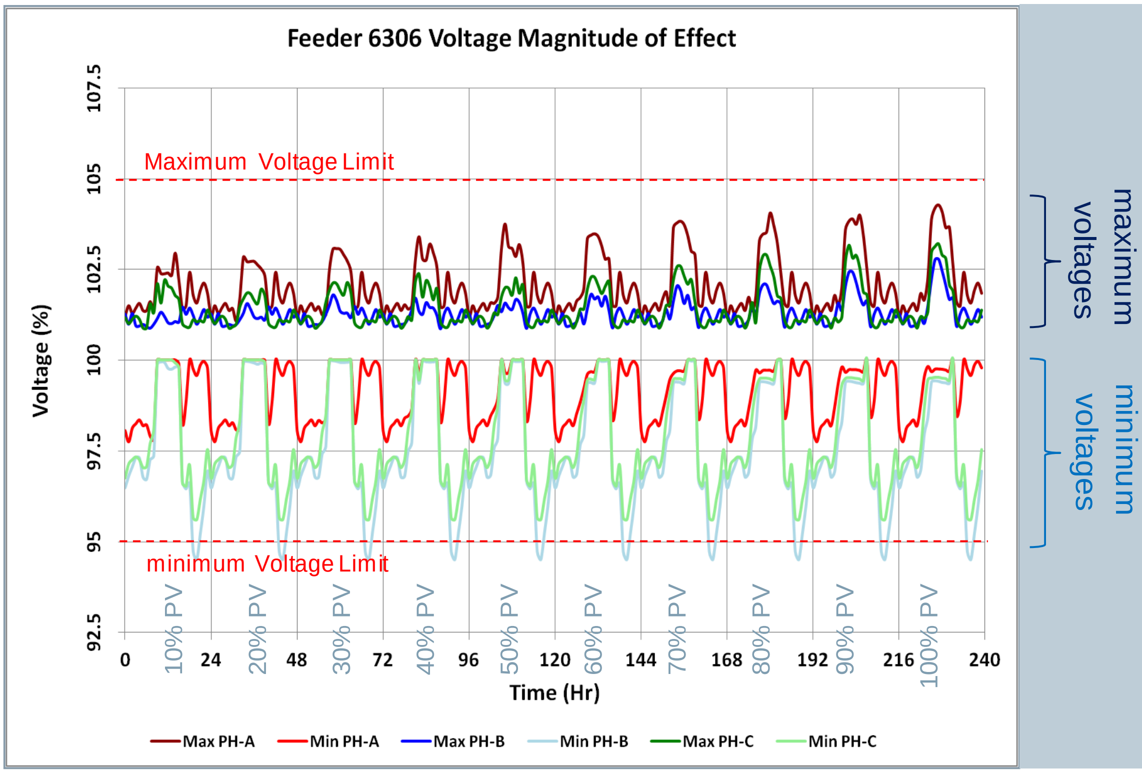

Figure 3-14: Feeder 6306-02 Maximum and Minimum Voltages After System Improvements

100% Solar PV Penetration Case:

Figure 3-15 and Table 3-5 show that with the proposed system improvements, voltage levels at noon time are within the acceptable limits.

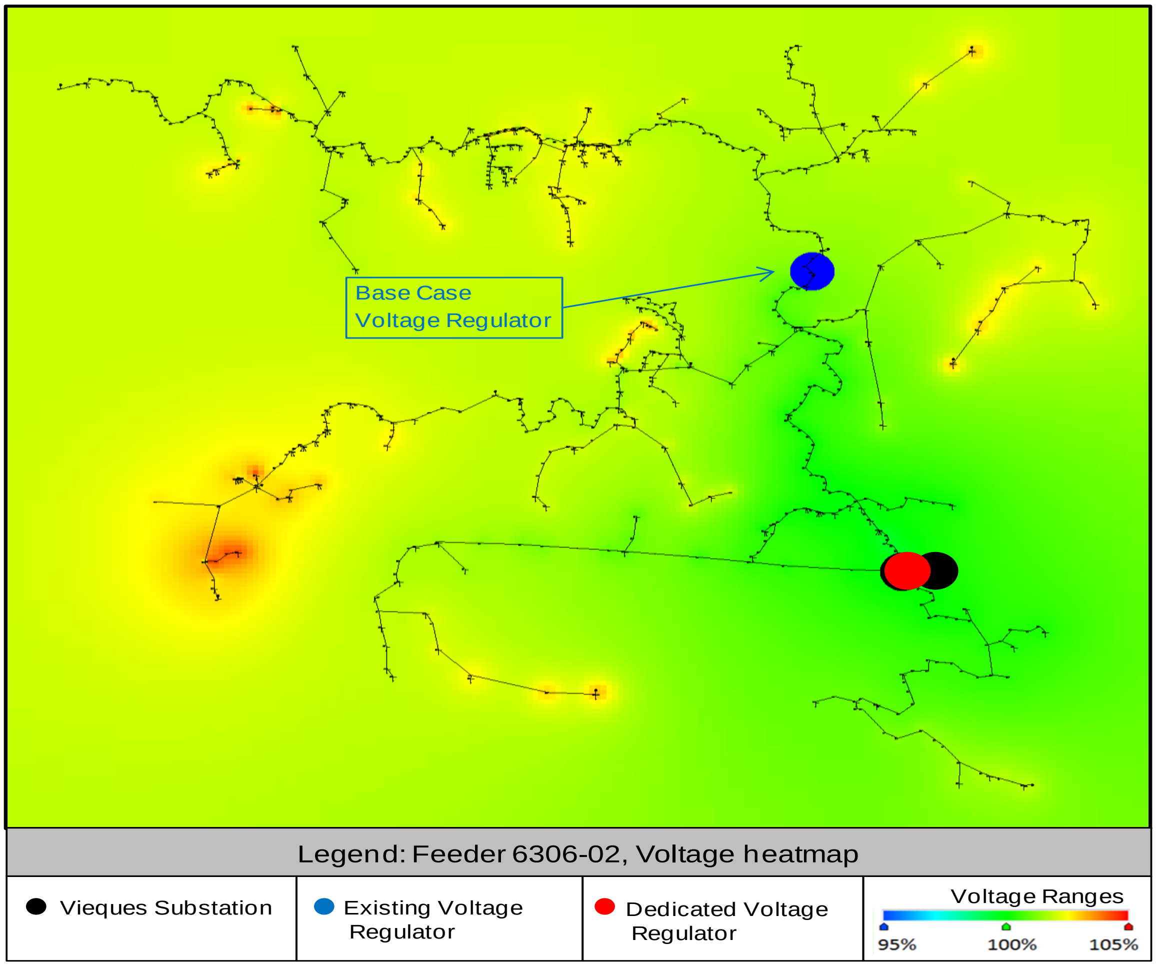

Figure 3-15: Feeder 6306-02 Voltage Contour Around Noon Time After System Improvements

Table 3-5: Feeder 6306-02 Statistics During Maximum PV Output After System Improvements

Phase	Max Voltage (%)	Node with Overvoltage (%)	Min Voltage (%)	Infeeder Power (MW)	PV Power (MW)
A	104.3	0	99.75	-0.137	0.268
B	102.8	0	99.42	-0.093	0.134
C	103.2	0	99.52	-0.174	0.179

Maximum Demand Case:

Figure 3-16 shows that with the proposed system improvements, voltage levels at the maximum demand scenario (8 pm) are within the acceptable limits. Also, Table 3-6 indicates that only a slight voltage violation affected one node, which is located in the northern region of the Las Vegas substation, but no loads are connected to it.

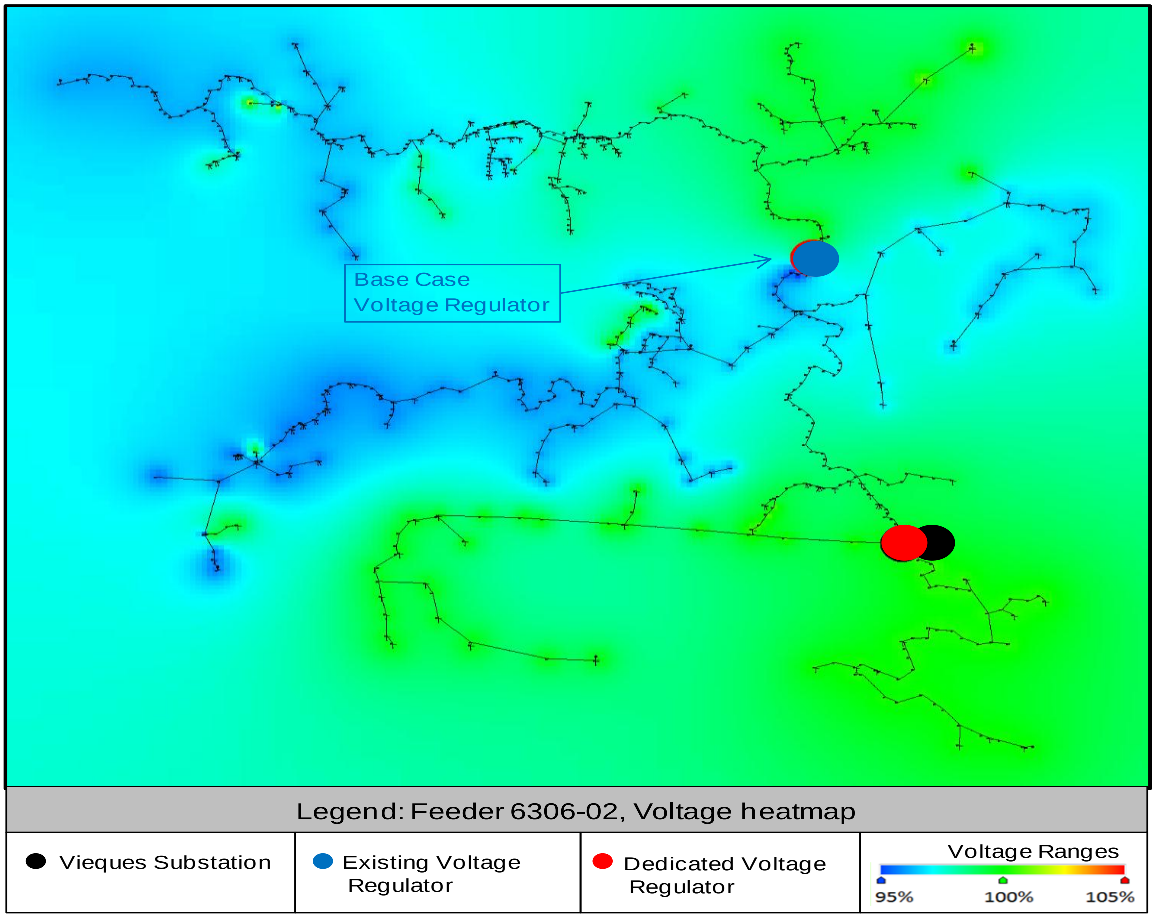

Figure 3-16: Feeder 6306-02 Voltage Contour at 8 pm After System Improvements

Table 3-6: Feeder 6306-02 Statistics at 8 pm After System Improvements

Phase	Max Voltage (%)	Min Voltage (%)	Node with under-voltage (%)	Infeeder Power (MW)	PV Power (MW)
A	101.58	99.57	0	0.211	0
B	100.99	94.50	0.89	0.215	0
C	101.06	95.61	0	0.145	0

3.3 Feeder 7103-04

The analysis of the feeder was conducted using the load profile presented in Section 2 of this document and the PV generation profile shown in Figure 3-17, which allowed us to study multiple solar PV generation levels up to 100% of feeder peak demand. The multiple solar PV generation levels were increased in steps of 10% of the feeder peak demand in 24-hour periods (i.e. allows studying all levels of solar PV penetration in the same run).

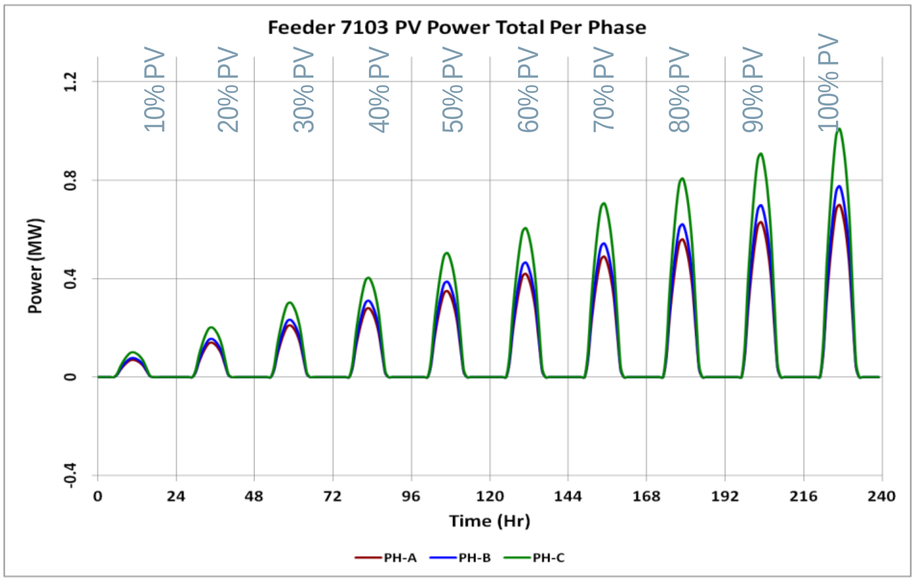

Figure 3-17: Feeder 7103-04 Solar PV Generation Output at Different Levels of Integration

Taking into account the PV generation profile, Figure 3-18 presents the power supplied by the substation to the feeder loads at different levels of solar PV penetration (i.e. from 10% to 100%). As can be noted, phase B began to experience reverse power flows at 10% PV penetration, while phase A began at 60% and phase C began at 80%. This means that unless other feeders supplied by the same substation have sufficient demand, there will be power flowing from the distribution to the transmission system with the potential problems indicated above, unless properly addressed.

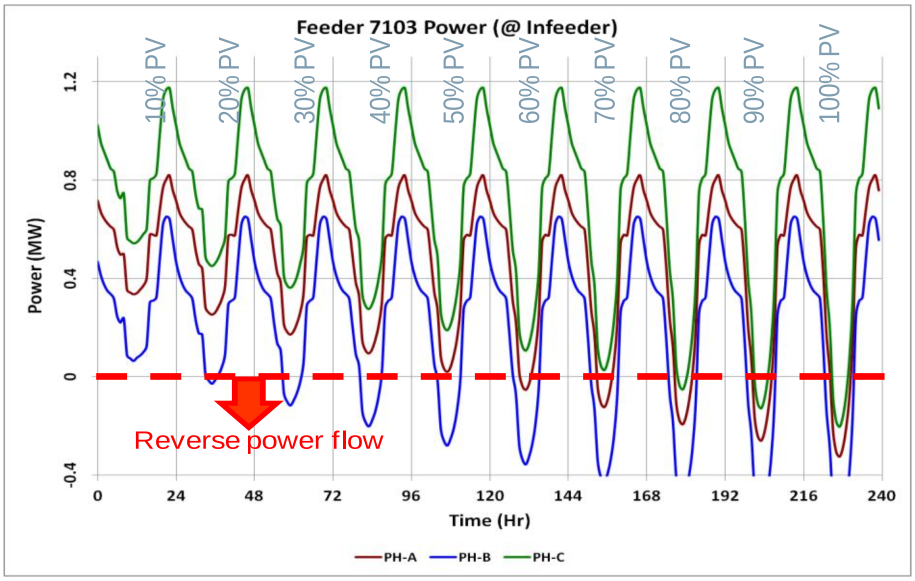

Figure 3-18: Feeder 7103-04 Power Supplied/Received

Figure 3-19 shows the maximum and minimum observed voltage magnitudes in the feeder at different levels of solar PV penetration for each hour simulated as a percentage of nominal voltage (i.e. the voltage percentage for the node with highest voltage and the node with lowest voltage). As depicted, phase C began presenting voltages above 105% at 10% PV penetration, while phase B presented high voltages at 50% and phase A at 100%. These overvoltage magnitudes were registered when solar PV generation was at its maximum power output, i.e. around noon.

No voltages below minimum limits were identified throughout the modified load profile with different levels of solar PV penetration.

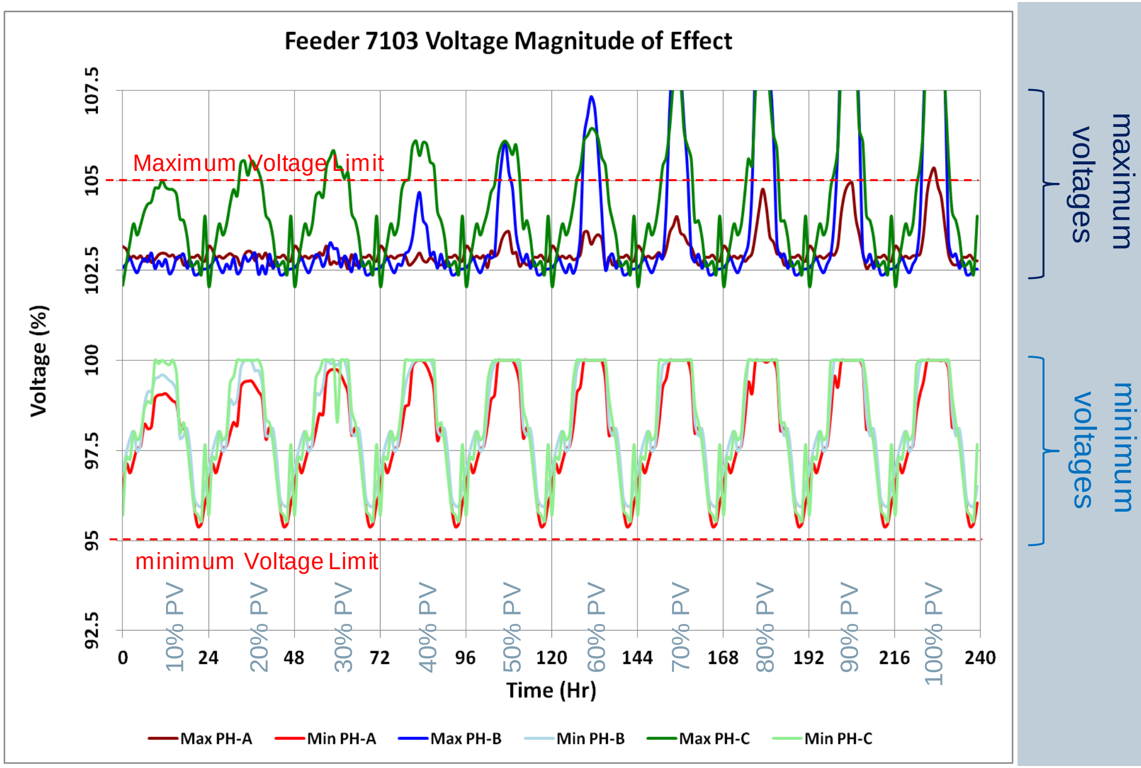

Figure 3-19: Feeder 7103-04 Maximum and Minimum Voltages

To further illustrate the extent of the high voltages, Figure 3-20 provides a voltage contour around noon time with 100% PV penetration. The areas in red represent voltage values close to or above 105% of the feeder nominal voltage. These overvoltage magnitudes concentrated at the farthest end of the feeder and were particularly severe on single phase branches.

As it may be seen in Table 3-7, 33% to 43% of the nodes had voltages above 105% during the 100% PV penetration scenario, being phases B and C the most affected.

Based on the above it can be concluded that without any additional investments, this feeder cannot accommodate any solar PV penetration.

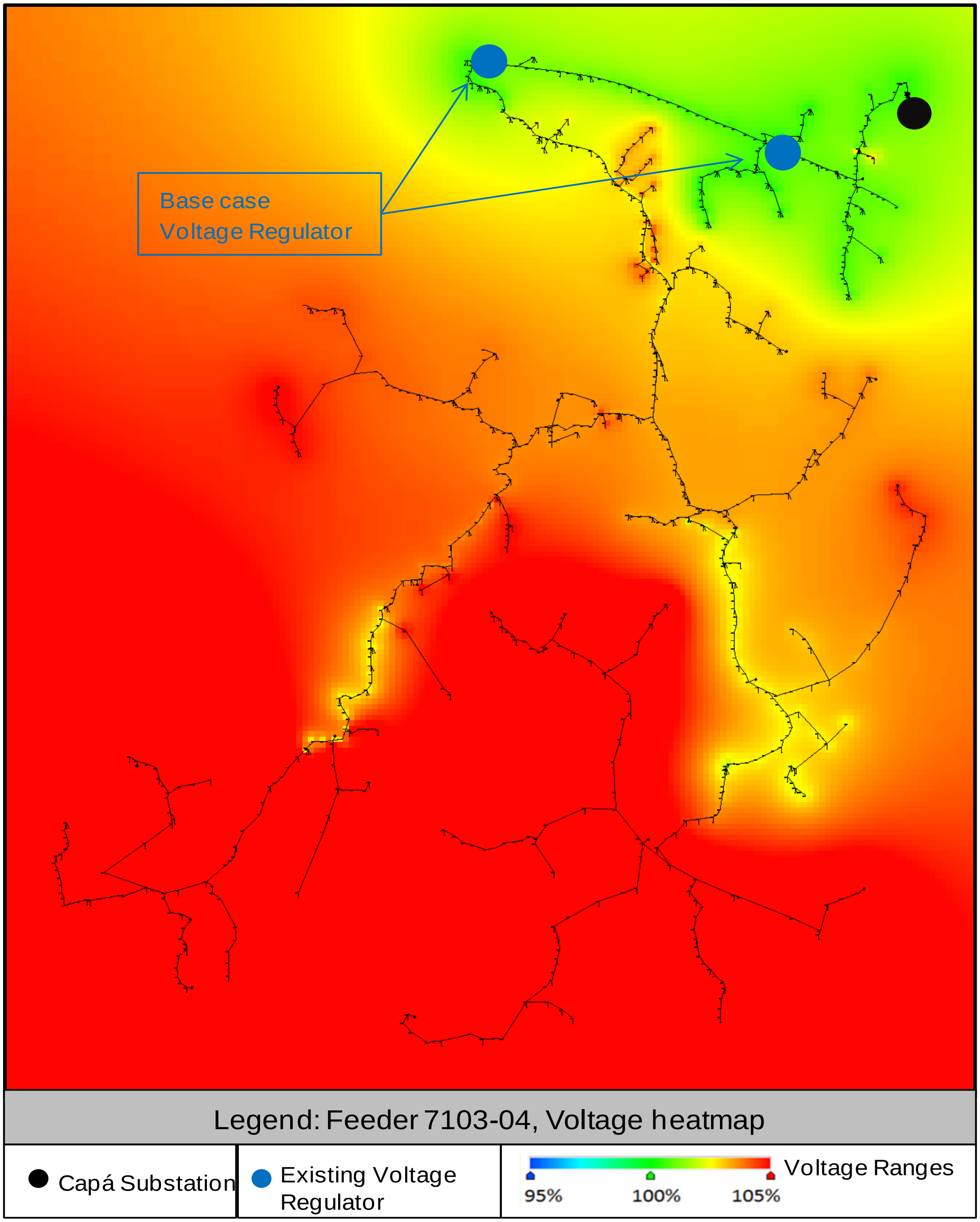

Figure 3-20: Feeder 7103-04 Voltage Contour Around Noon Time

Table 3-7: Feeder 7103-04 Statistics During Maximum PV Output

Phase	Max Voltage (%)	% of Node with Overvoltage	Min Voltage (%)	Infeeder Power (MW)	PV Power (MW)
A	105.35	1.03	100	-0.325	0.699
B	112.40	33.40	100	-0.607	0.776
C	110.79	43.45	100	-0.228	1.009

3.3.1 Recommended Improvements

To address the voltage issues identified when solar PV penetration equals 100% of feeder peak demand, the following improvements are suggested:

a) In addition to the two 3 MVA VRs that were recommended to create the base case conditions, a new 3 MVA dedicated VR at feeder head, with a voltage setting of 99.5% to 100%, is recommended. This will allow the feeder to use a different voltage regulation scheme as needed to maintain the voltage limits within the ANSI C84.1 standard. Furthermore, the substation transformer's LTC can regulate the voltage of the other feeders with a different tap setting depending on the load and generation diversity.

b) Replace four voltage boosters with VRs.

c) Figure 3-21 presents the regulating equipment along the feeder for the adjusted base case. It is recommended to set the VRs to the "Co-Generation Mode", which would allow voltage regulation on a forward direction even with reverse power flows. The VRs should be set as specified in Table 3-8. The proposed voltage regulation scheme will operate as a first-level voltage security.

d) Due to the variability of solar PV generation and the bidirectional power flows experienced in DG impacted feeders, it is recommended to add a volt/var control system at the substation level to monitor and control the voltage profiles. This volt/var control system will operate as a second-level voltage security that will provide signals to all VRs in the system and to the substation's LTC to achieve optimal performance.

Table 3-8: Feeder 7103-04 Proposed VR Settings

VR ID	Description	Setting
SS VR	Dedicated at feeder head	99.5 – 100%
VR1	Added for base case	99-100%
VR2	Added for base case	100-101%
VR3	Replacing a Voltage booster	101-102%
VR4	Existing VR	101-102%
VR5	Existing VR	101-102%
VR6	Replacing a Voltage booster	102-103%
VR7	Replacing a Voltage booster	102-103%
VR8	Replacing a Voltage booster	99-100%

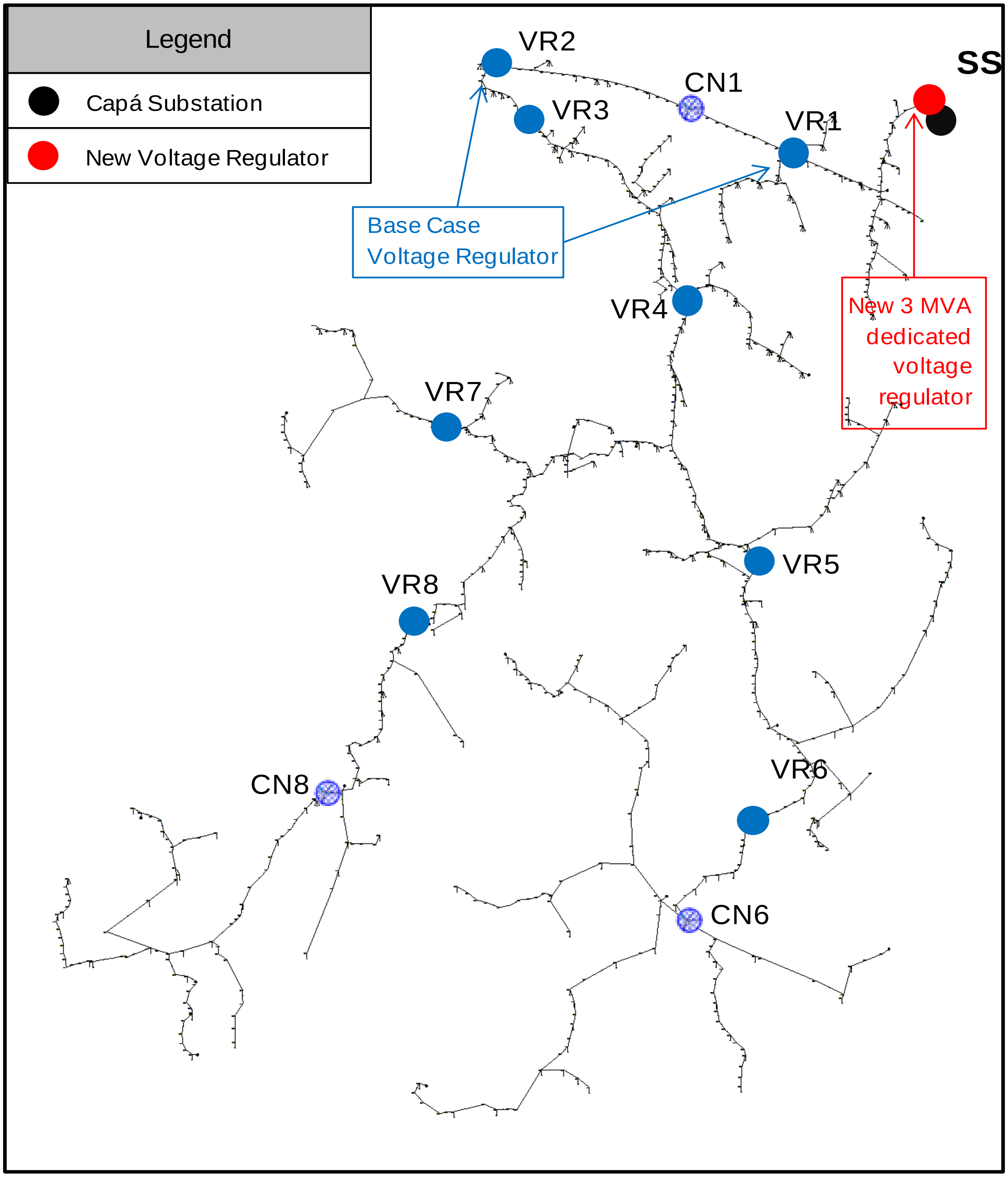

Figure 3-21: Feeder 7103-04 Suggested System Improvements for 100% Solar PV Integration

Figure 3-22 shows the maximum and minimum observed voltage levels in the feeder, at different levels of solar PV penetration, after the recommended system improvements are implemented. As it may be seen, with these improvements the feeder voltages are within limits.

There was only a slight voltage violation on phase A during the maximum demand scenario and on phase C when 100% of feeder peak demand in solar PV generation was simulated.

However, on phase A it was recorded in a node where no loads are connected to it, while on phase C it occurred in a node where a PV system was interconnected. This over voltage on phase C could be controlled by limiting the amount of solar PV integration at that feeder branch to no more than the branch's minimum noon time demand levels.

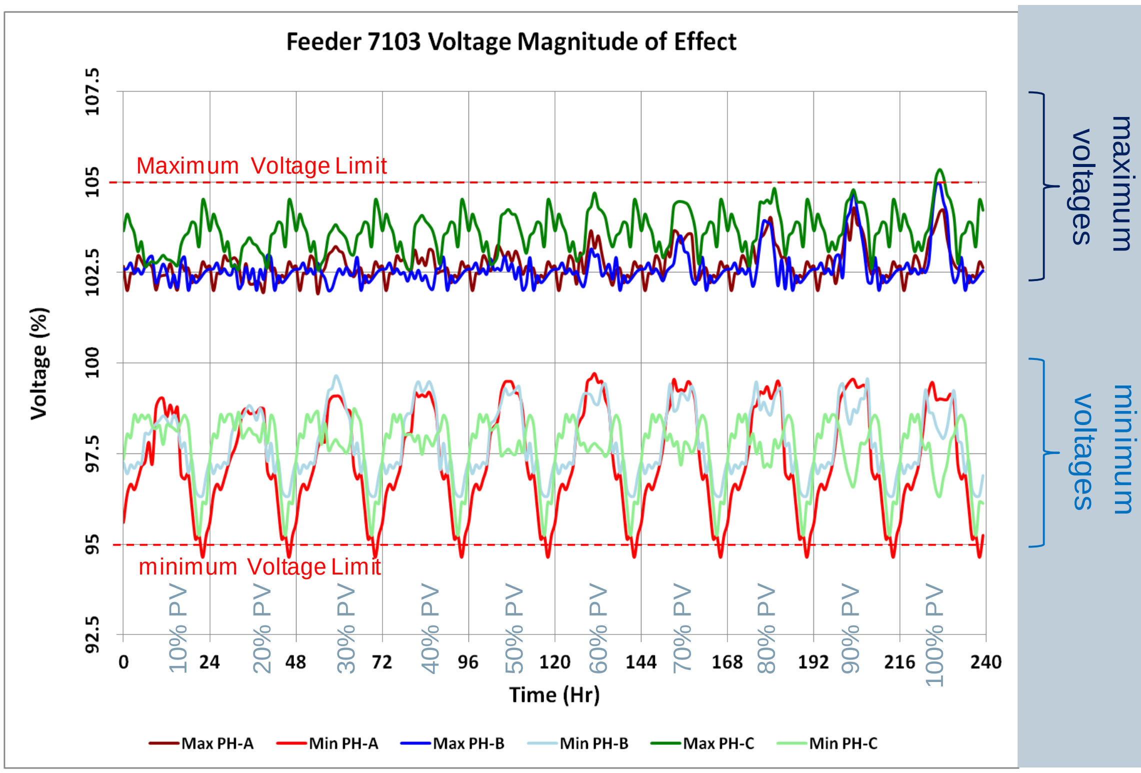

Figure 3-22: Feeder 7103-04 Maximum and Minimum Voltages After System Improvements

100% Solar PV Penetration Case:

Figure 3-23 shows that with the proposed system improvements, voltage levels at noon time are within the acceptable limits. Also, Table 3-9 indicates that only a slight voltage violation affected around 1% of the nodes, which are located in the south region of the Capá substation.

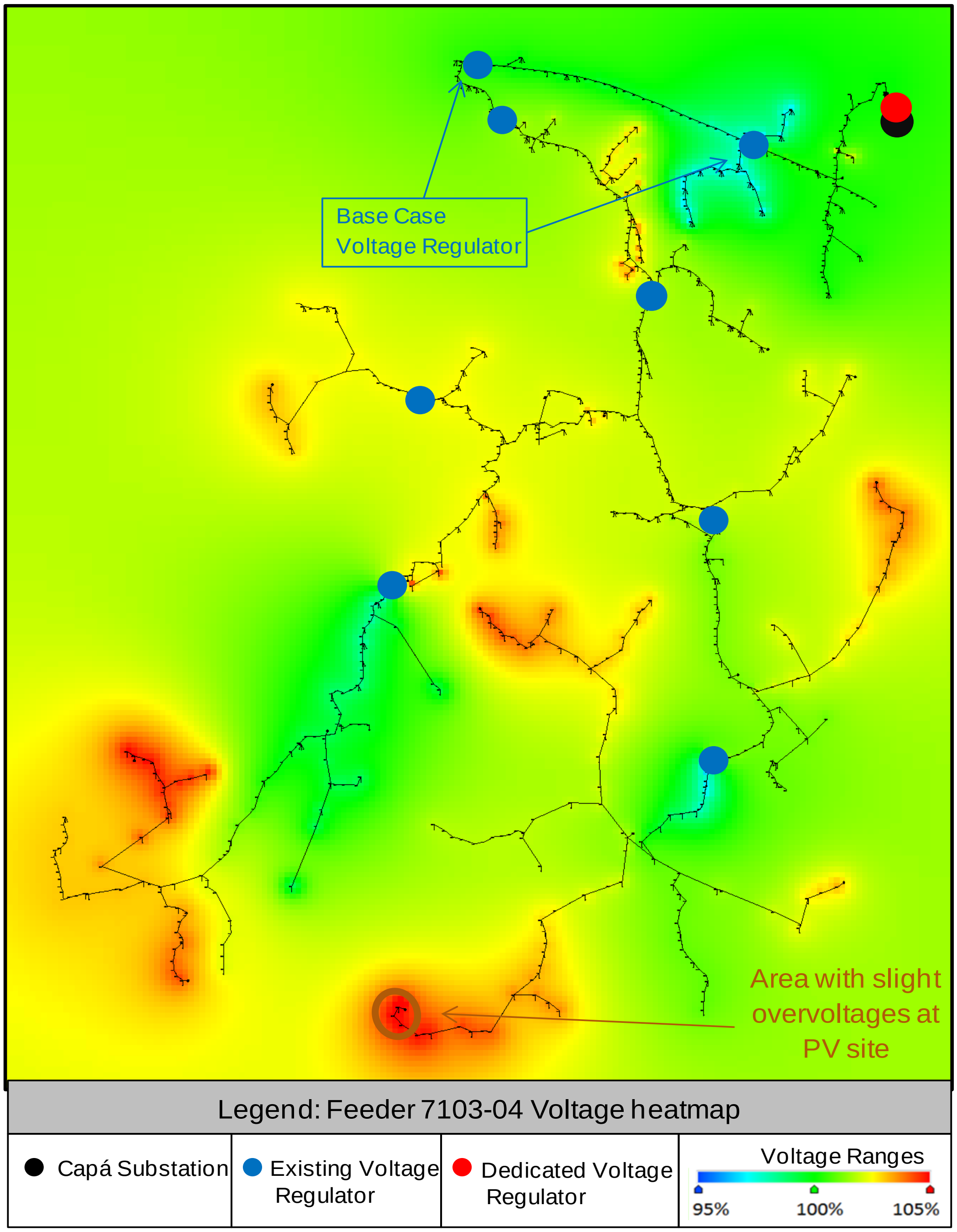

Figure 3-23: Feeder 7103-04 Voltage Contour Around Noon Time After System Improvements

Table 3-9: Feeder 7103-04 Statistics During Maximum PV Output After System Improvements

Phase	Max Voltage (%)	Node with Overvoltage (%)	Min Voltage (%)	Infeeder Power (MW)	PV Power (MW)
A	104.95	0.00	98.05	-0.599	0.777
B	104.18	0.00	99.02	-0.325	0.699
C	105.34	1.075	96.32	-0.229	1.009

<u>Maximum Demand Case:</u>

Figure 3-24 shows that with the proposed system improvements, voltage levels at the maximum demand scenario (10 pm) are within the acceptable limits. Also, Table 3-10 indicates that only a slight voltage violation affected one node, but no loads are connected to it.

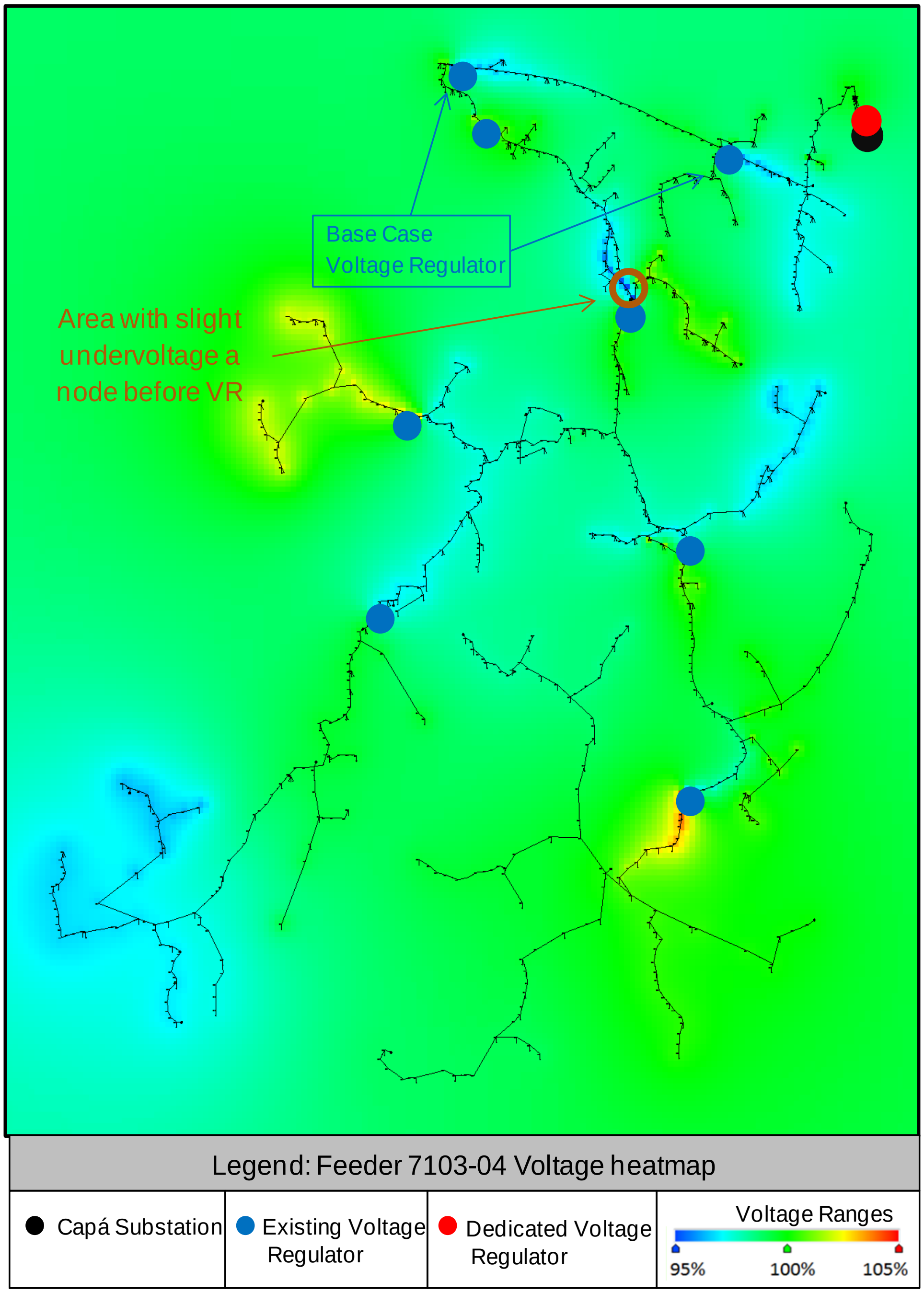

Figure 3-24: Feeder 7103-04 Voltage Contour at 9 pm After System Improvements

Table 3-10: Feeder 7103-04 Statistics at 10 pm After System Improvements

Phase	Max Voltage (%)	Min Voltage (%)	Node with under-voltage (%)	Infeeder Power (MW)	PV Power (MW)
A	102.80	94.64	0.62	0.828	0.00
B	102.43	96.34	0.00	0.605	0.00
C	104.49	96.16	0.00	1.144	0.00

3.4 Feeder 2801-02

The analysis of the feeder was conducted using the load profile presented in Section 2 of this document and the PV generation profile shown in Figure 3-25, which allowed us to study multiple solar PV generation levels up to 100% of feeder peak demand. The multiple solar PV generation levels were increased in steps of 10% of the feeder peak demand in 24-hour periods (i.e. allows studying all levels of solar PV penetration in the same run).

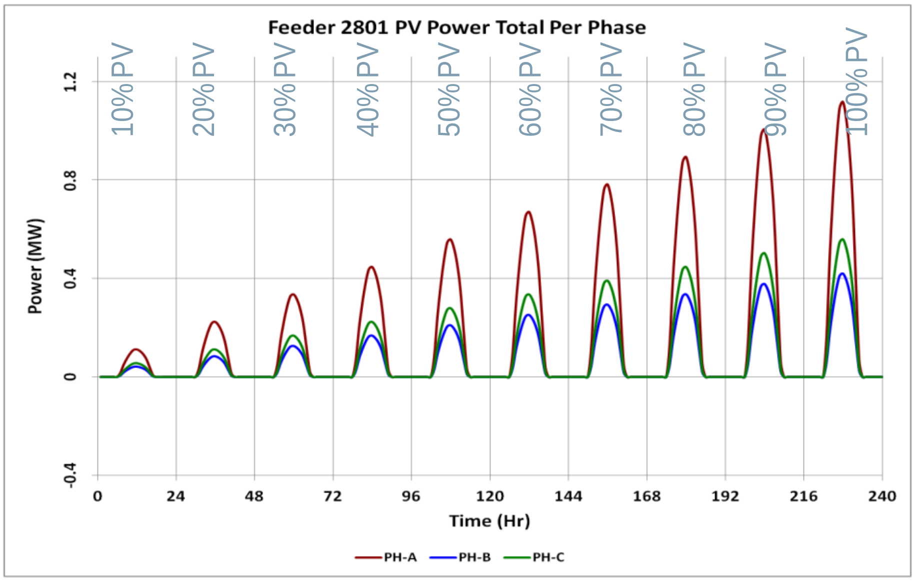

Figure 3-25: Feeder 2801-02 Solar PV Generation Output at Different Levels of Integration

Taking into account the PV generation profile, Figure 3-26 presents the power supplied by the substation to the feeder loads at different levels of solar PV penetration (i.e. from 10% to 100%). As can be noted, phase C began to experience reverse power flows at 50% PV penetration, while phase A began at 60% and phase B at 80%. This means that unless other feeders supplied by the same substation have sufficient demand, there will be power flowing from the distribution to the transmission system with the potential problems indicated above, unless properly addressed.

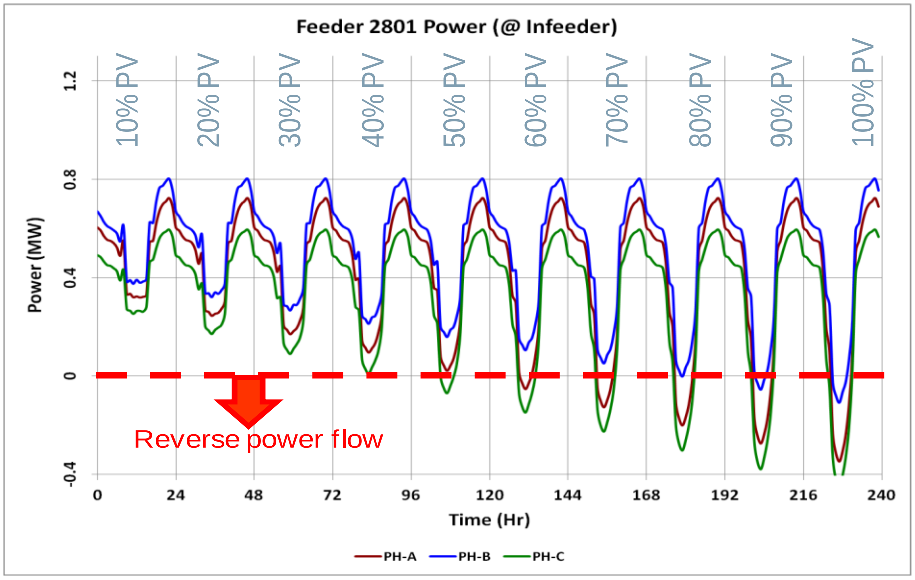

Figure 3-26: Feeder 2801-02 Power Supplied/Received

Figure 3-27 shows the maximum and minimum observed voltage magnitudes in the feeder at different levels of solar PV penetration for each hour simulated as a percentage of nominal voltage (i.e. the voltage percentage for the node with highest voltage and the node with lowest voltage). As depicted, phase A began presenting voltages above 105% at 80% PV penetration. These overvoltage magnitudes were registered when solar PV generation was at its maximum power output, i.e. around noon.

No voltages below minimum limits were identified throughout the modified load profile with different levels of solar PV penetration.

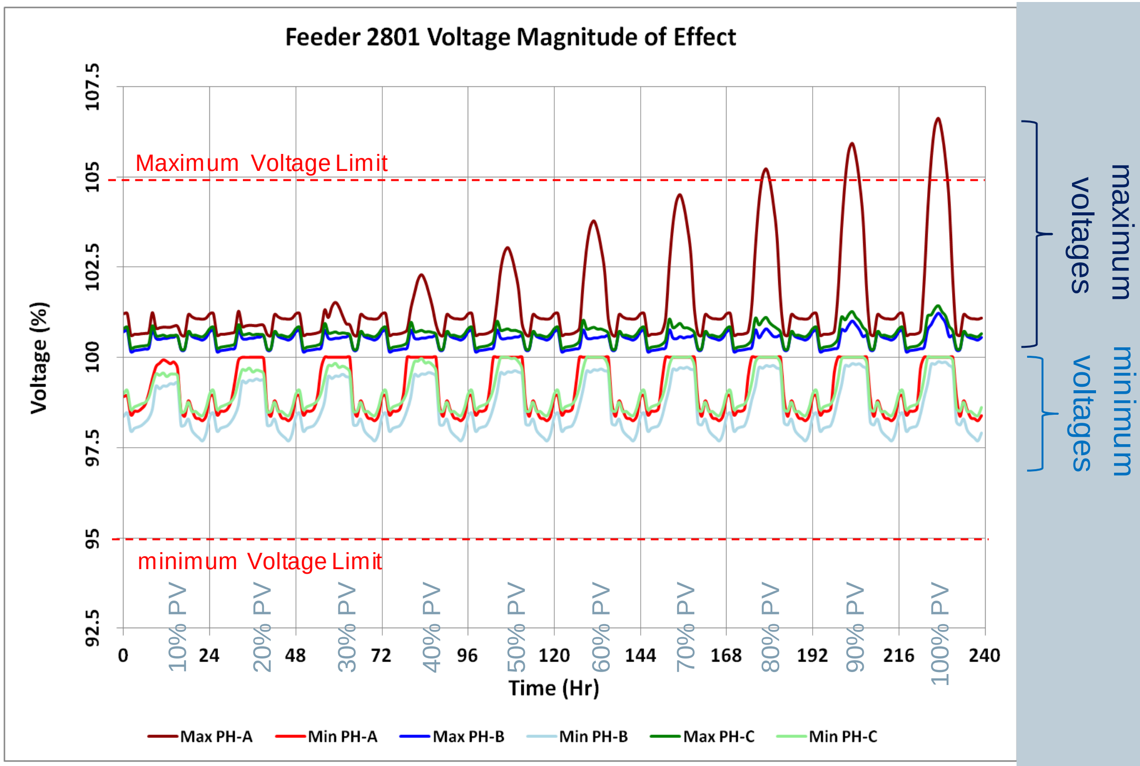

Figure 3-27: Feeder 2801-02 Maximum and Minimum Voltages

To further illustrate the extent of the high voltages, Figure 3-28 provides a voltage contour around noon time with 100% PV penetration. The areas in red represent voltage values close to or above 105% of the feeder nominal voltage. These over voltages concentrated at the farthest north eastern end of the feeder and were particularly severe on single phase branches.

As it may be seen in Table 3-11, 17% of the nodes of phase A had voltages above 105% during the 100% PV penetration scenario.

Based on the above it can be concluded that without any additional investments, this feeder can accommodate up to 40% of its peak demand in solar PV penetration.

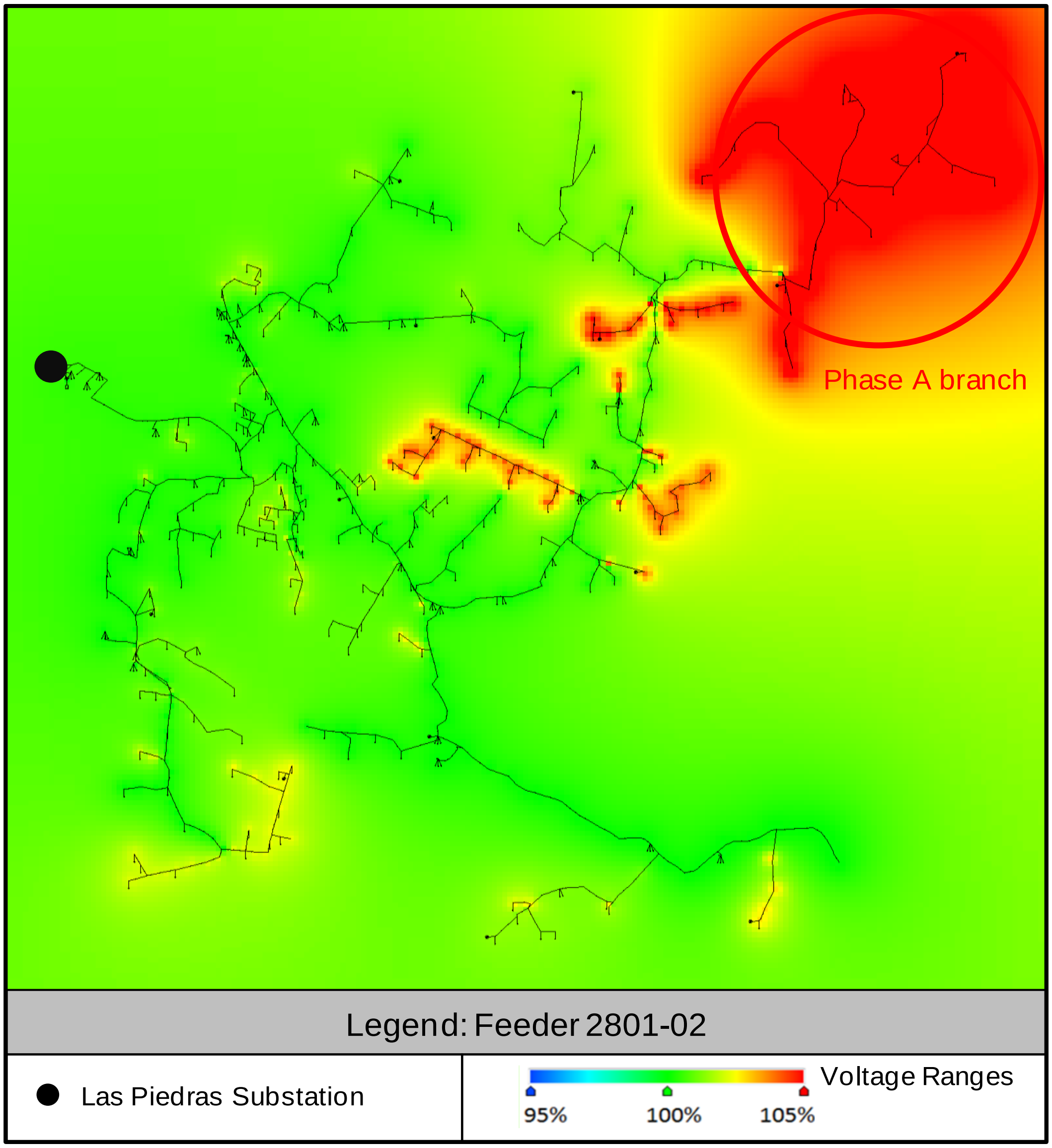

Figure 3-28: Feeder 2801-02 Voltage Contour Around Noon Time

Table 3-11: Feeder 2801-02 Statistics During Maximum PV Output

Phase	Max Voltage (%)	Node with Overvoltage (%)	Min Voltage (%)	Infeeder Power (MW)	PV Power (MW)
A	106.63	17.70	100	-0.346	1.119
B	101.22	0.00	100	-0.109	0.420
C	101.44	0.00	100	-0.455	0.559

3.4.1 Recommended Improvements

To address the voltage issues identified when solar PV penetration equals 100% of feeder peak demand, the following improvements are suggested:

a) Add a new 6 MVA dedicated VR at feeder head (see Figure 3-29), with a voltage setting of 98% to 99%, is recommended. This will allow the feeder to use a different voltage regulation scheme as needed to maintain the voltage limits within the ANSI C84.1 standard. Furthermore, the substation transformer's LTC can regulate the voltage of the other feeders with a different tap setting depending on the load and generation diversity.

b) Due to the variability of solar PV generation and the bidirectional power flows experienced in DG impacted feeders, it is recommended to add a volt/var control system at the substation level to monitor and control the voltage profiles. This volt/var control system will operate as a second-level voltage security that will provide signals to all VRs in the system and to the substation's LTC to achieve optimal performance.

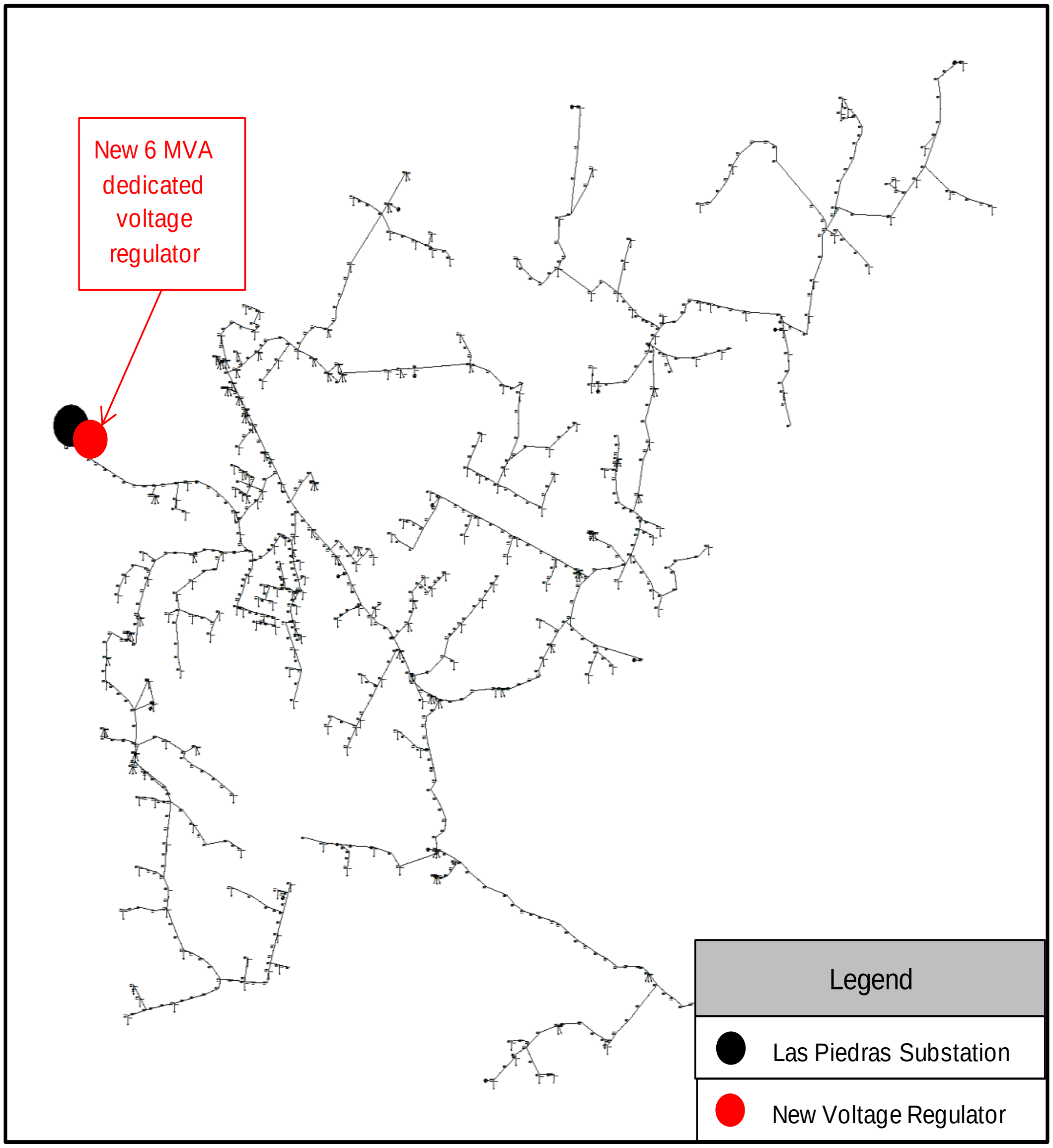

Figure 3-29: Feeder 2801-02 Suggested System Improvements for 100% Solar PV Integration

Figure 3-30 shows the maximum and minimum observed voltage levels in the feeder, at different levels of solar PV penetration, after the recommended system improvements are implemented. As it may be seen, with these improvements the feeder voltages are within limits.

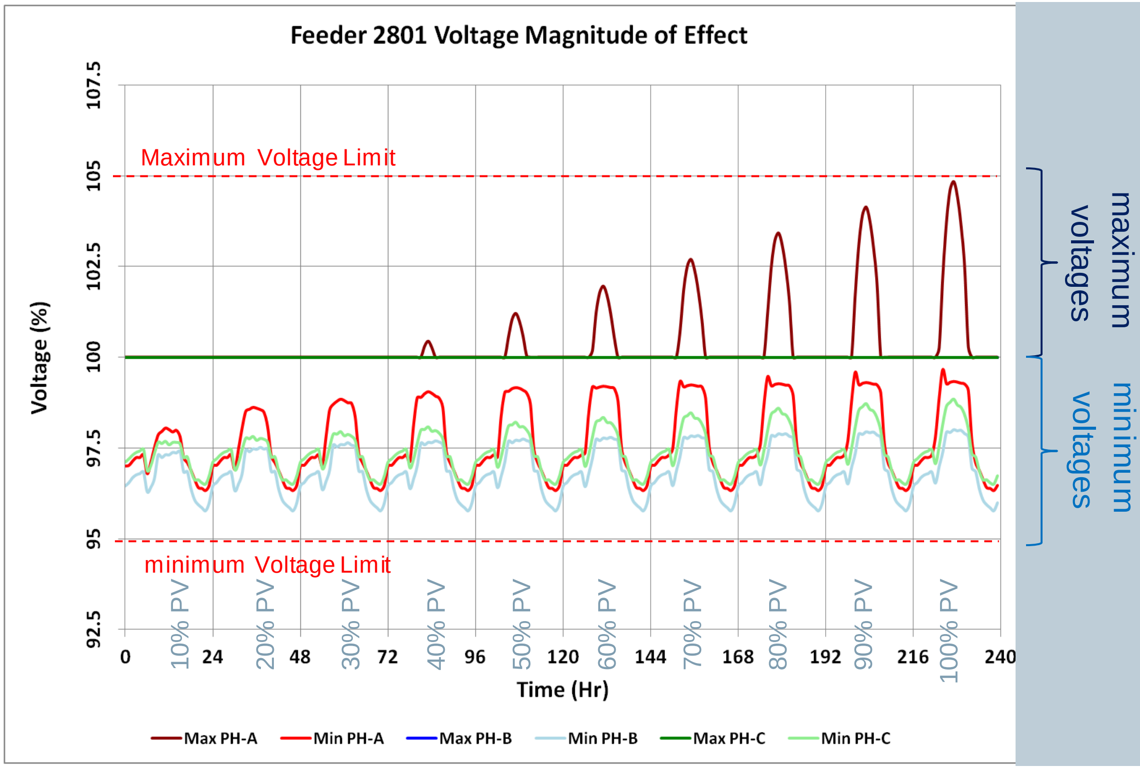

Figure 3-30: Feeder 2801-02 Maximum and Minimum Voltages After System Improvements

100% Solar PV Penetration Case:

Figure 3-31 and Table 3-12 show that with the proposed system improvements, voltage levels at noon time are within the acceptable limits.

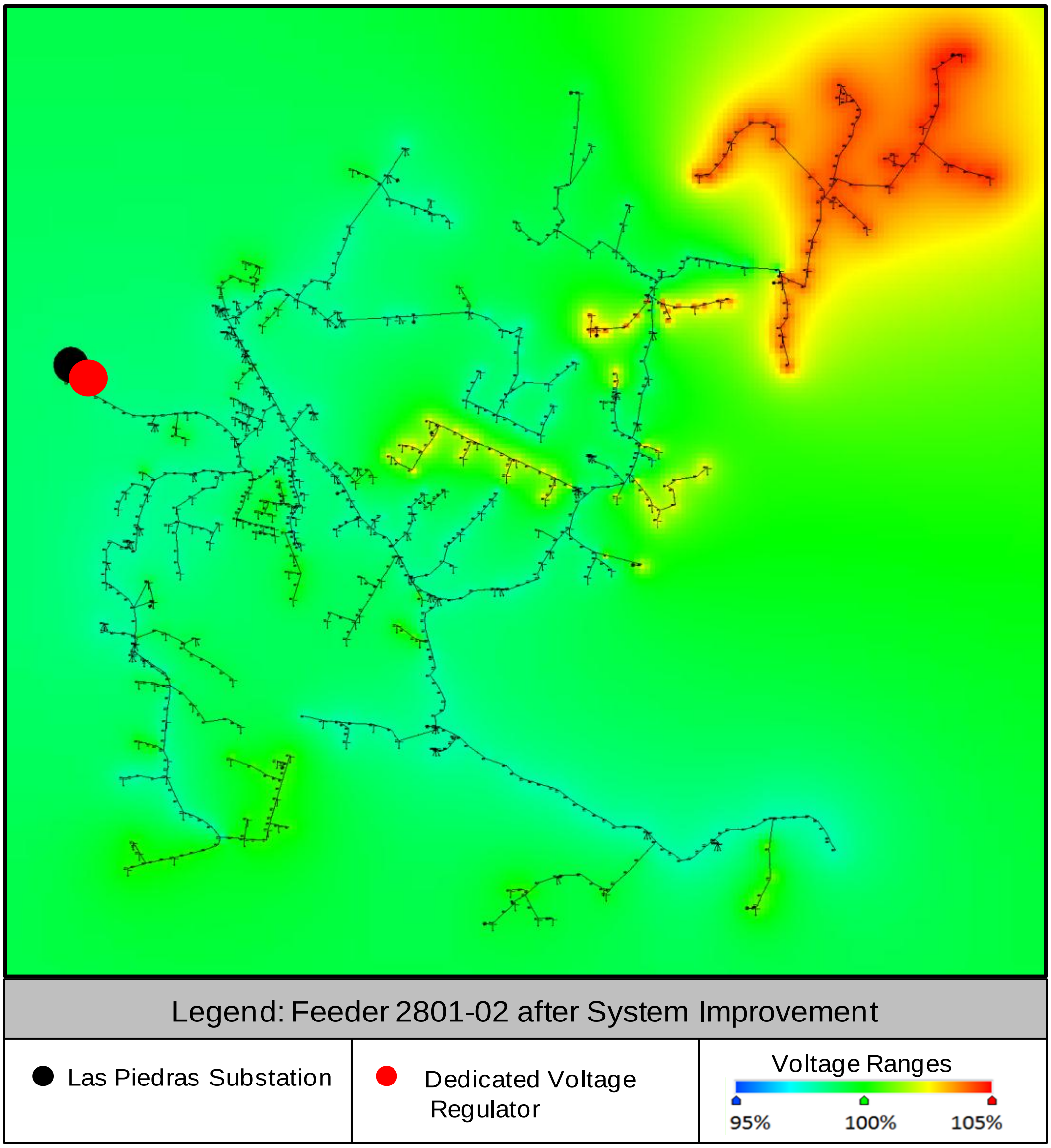

Figure 3-31: Feeder 2801-02 Voltage Contour Around Noon Time After System Improvements

Table 3-12: Feeder 2801-02 Statistics During Maximum PV Output After System Improvements

Phase	Max Voltage (%)	Node with Overvoltage (%)	Min Voltage (%)	Infeeder Power (MW)	PV Power (MW)
A	104.84	0.00	99.32	-0.346	1.119
B	100.00	0.00	98.01	-0.109	0.420
C	100.00	0.00	98.85	-0.454	0.559

Maximum Demand Case:

Figure 3-32 and Table 3-13 show that with the proposed system improvements, voltage levels at the maximum demand scenario (10 pm) are within the acceptable limits.

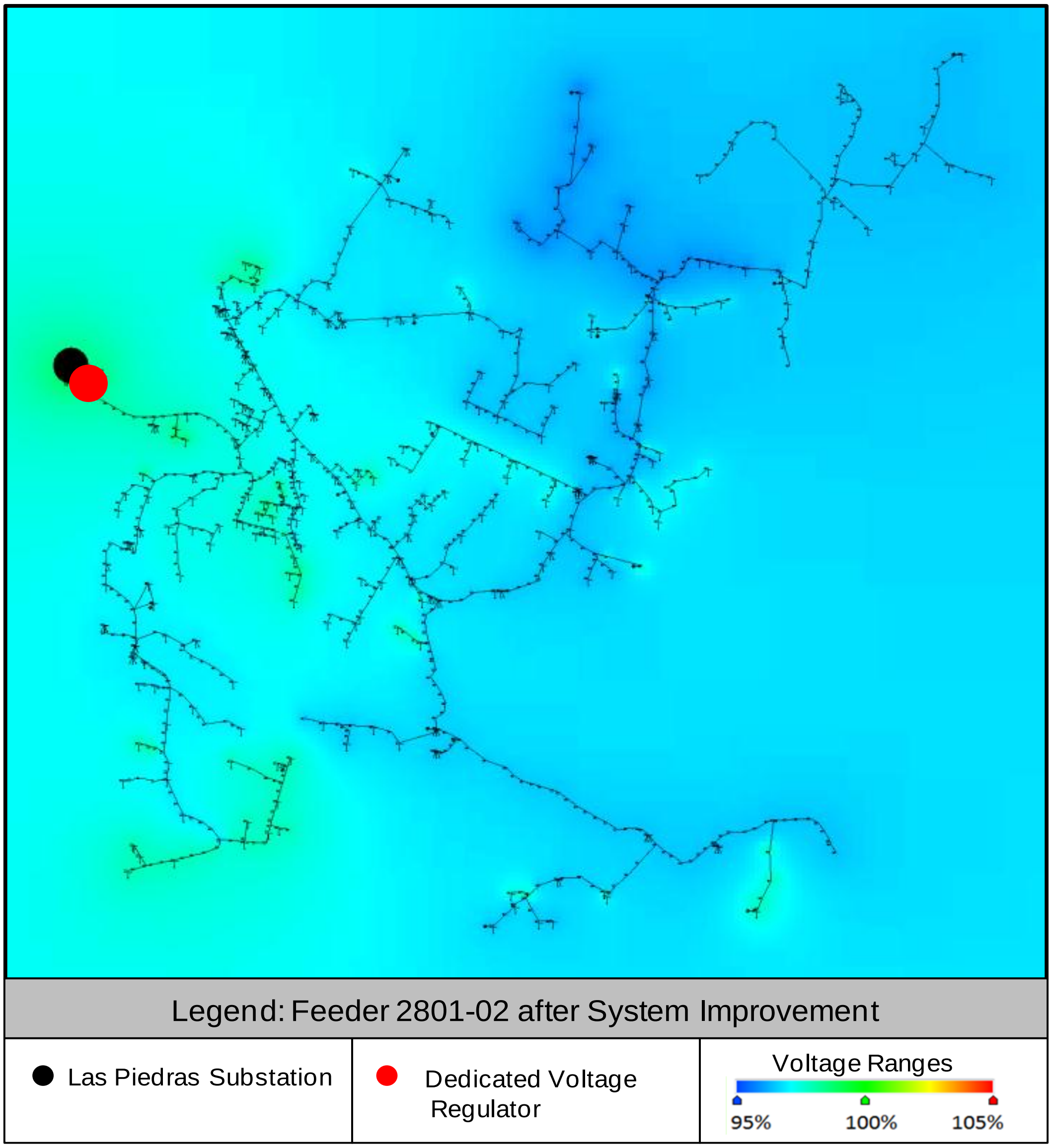

Figure 3-32: Feeder 2801-02 Voltage Contour at 10 pm After System Improvements

Table 3-13: Feeder 2801-02 Statistics at 10 pm After System Improvements

Phase	Max Voltage (%)	Min Voltage (%)	Node with under-voltage (%)	Infeeder Power (MW)	PV Power (MW)
A	100	96.32941	0	0.723956	0
B	100	95.77567	0	0.800542	0
C	100	96.50039	0	0.594047	0

3.5 Feeders 1529-11, 1529-12, and 1529-13

As seen in Figure 3-33, PREPA's Cachete substation has three feeders that are tied with normally open switches (NO) at the 13.2 kV level. Following PREPA's operational practices, during major events, which include load transferring among those feeders, the scenarios described in Table 3-14 were analyzed.

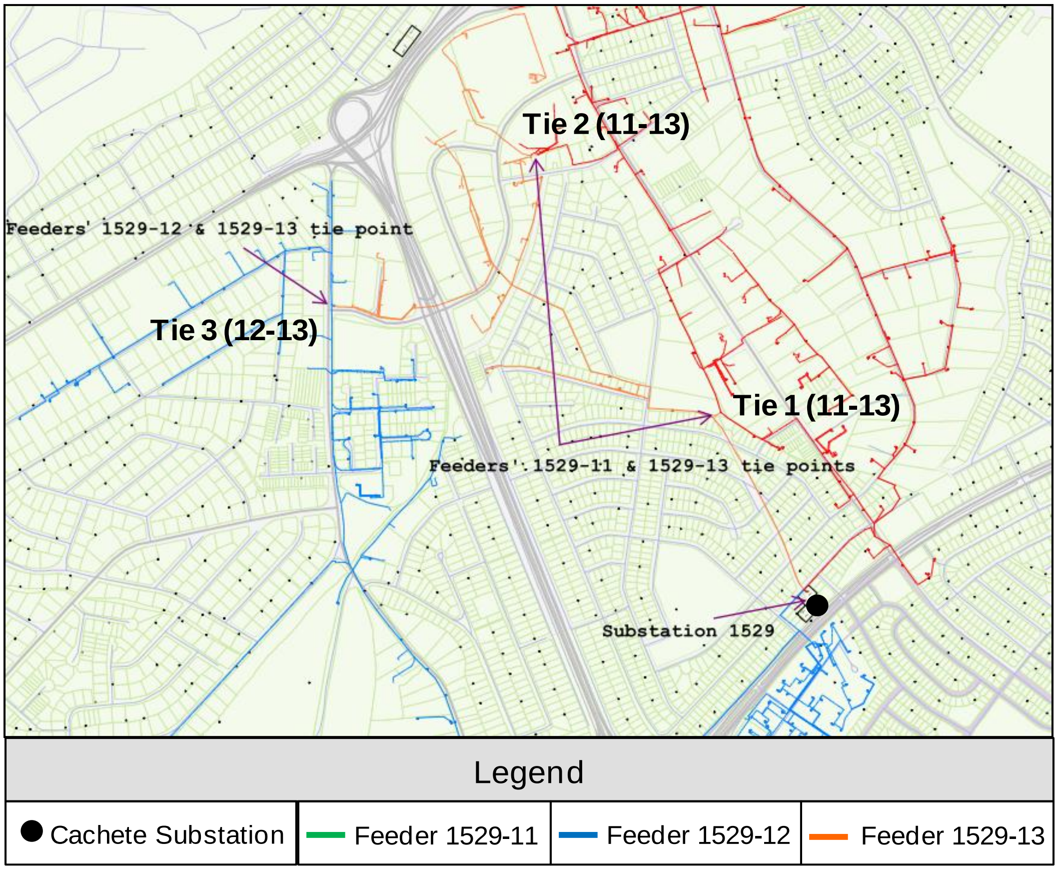

Figure 3-33: Feeders 1529-11, 1529-12 and 1529-13

Table 3-14: Feeders 1529-11, 1529-12 and 1529-13 Scenarios

	Scenarios	Feeder 1529-11	Feeder 1529-12	Feeder 1529-13	Tie 3	Tie 1	Tie 2
1	Three Separate Feeders	Closed	Closed	Closed	Open	Open	Open
2	Feeders 12 &13 connected And Fed by 13	Closed	Open	Closed	Closed	Open	Open
3	Feeders 11 &13 connected via Tie 1 And Fed by 11	Closed	Closed	Open	Open	Closed	Open

3.5.1 Feeder 1529-11_Scenario 1

The analysis of the feeder was conducted using the load profile presented in Section 2 of this document and the PV generation profile shown in Figure 3-34, which allowed us to study multiple solar PV generation levels up to 100% of feeder peak demand. The multiple solar PV generation levels were increased in steps of 10% of the feeder peak demand in 24-hour periods (i.e. allows studying all levels of solar PV penetration in the same run).

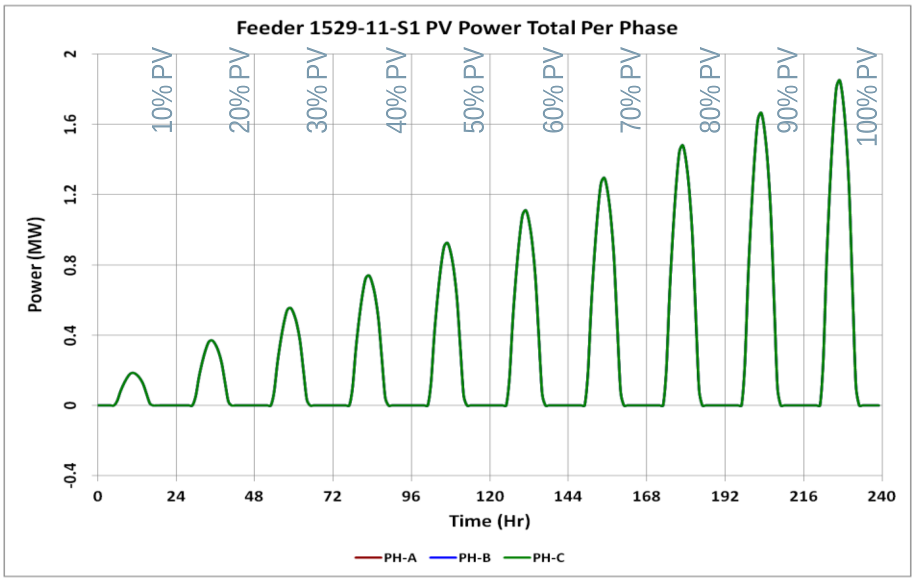

Figure 3-34: Feeder 1529-11 Solar PV Generation Output at Different Levels of Integration

Taking into account the PV generation profile, Figure 3-35 presents the power supplied by the substation to the feeder loads at different levels of solar PV penetration (i.e. from 10% to 100%). As can be noted, all phases began to experience reverse power flows at 70% PV penetration. This means that unless other feeders supplied by the same substation have sufficient demand, there will be power flowing from the distribution to the transmission system with the potential problems indicated above, unless properly addressed.

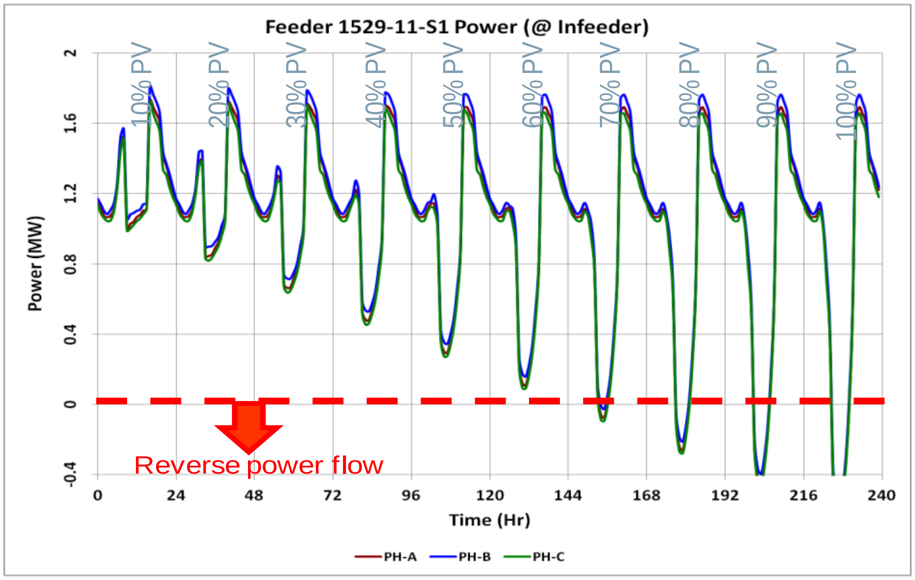

Figure 3-35: Feeder 1529-11 Power Supplied/Received

Figure 3-36 shows the maximum and minimum observed voltage magnitudes in the feeder at different levels of solar PV penetration for each hour simulated as a percentage of nominal voltage (i.e. the voltage percentage for the node with highest voltage and the node with lowest voltage). As depicted, no voltage violations were identified throughout the modified load profile with different levels of solar PV penetration.

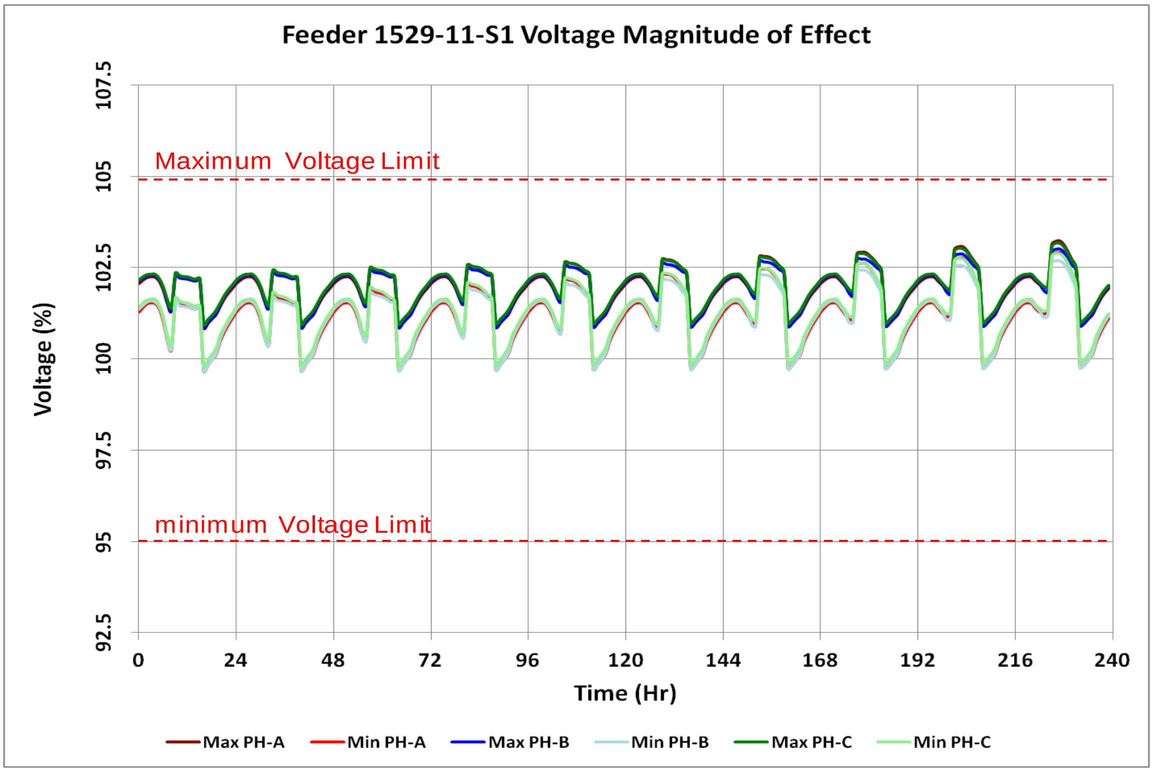

Figure 3-36: Feeder 1529-11 Maximum and Minimum Voltages

Based on the above, it can be concluded that without any additional investments, this feeder can accommodate up to 70% of its peak demand in solar PV penetration.

3.5.2 Feeder 1529-12_Scenario 1

The analysis of the feeder was conducted using the load profile presented in Section 2 of this document and the PV generation profile shown in Figure 3-37, which allowed us to study multiple solar PV generation levels up to 100% of feeder peak demand. The multiple solar PV generation levels were increased in steps of 10% of the feeder peak demand in 24-hour periods (i.e. allows studying all levels of solar PV penetration in the same run).

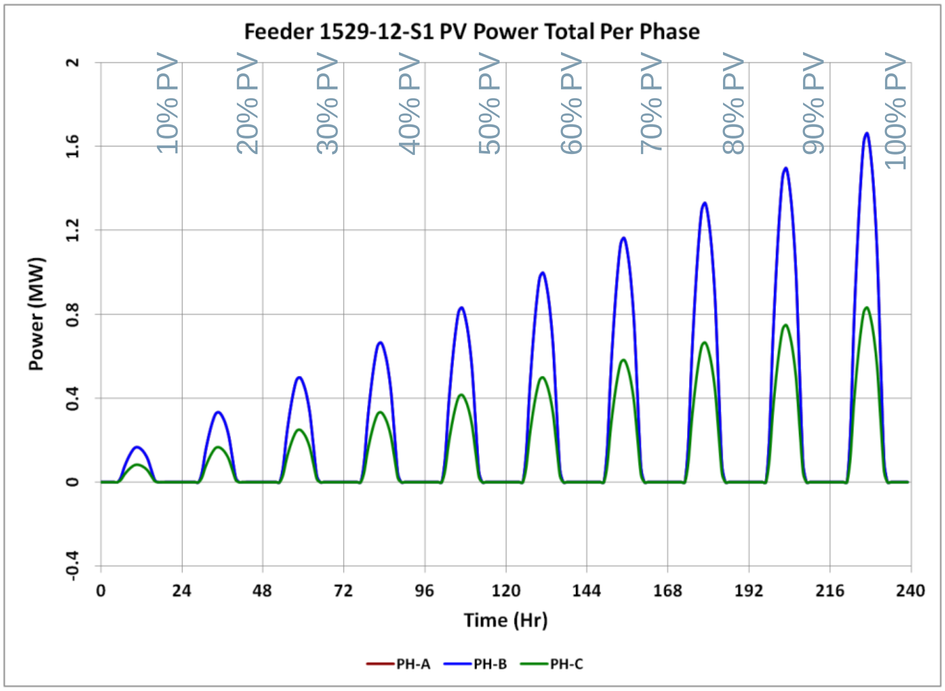

Figure 3-37: Feeder 1529-12 Solar PV Generation Output at Different Levels of Integration

Taking into account the PV generation profile, Figure 3-38 presents the power supplied by the substation to the feeder loads at different levels of solar PV penetration (i.e. from 10% to 100%). As can be noted, phase B began to experience reverse power flows at 40% PV penetration, while phase A began at 50% and phase C at 80%. This means that unless other feeders supplied by the same substation have sufficient demand, there will be power flowing from the distribution to the transmission system with the potential problems indicated above, unless properly addressed.

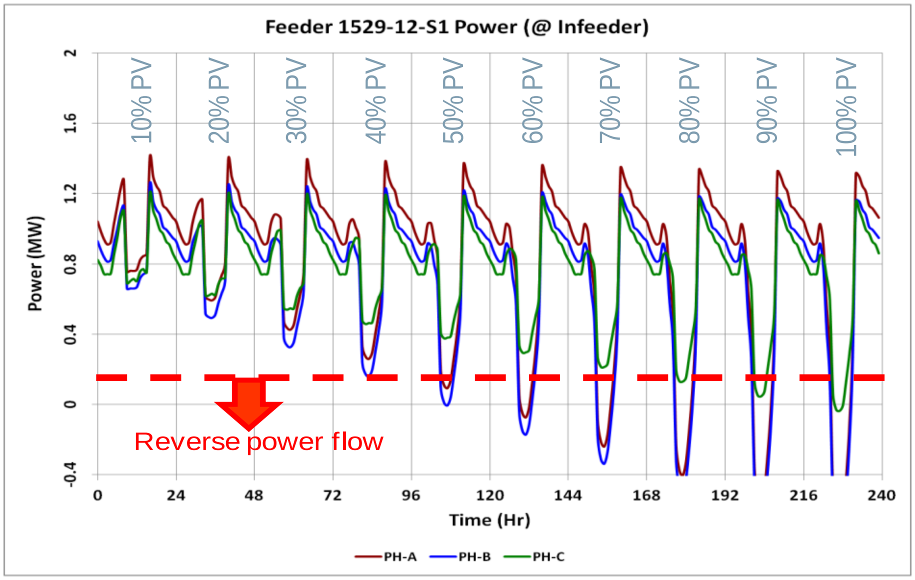

Figure 3-38: Feeder 1529-12 Power Supplied/Received

Figure 3-39 shows the maximum and minimum observed voltage magnitudes in the feeder at different levels of solar PV penetration for each hour simulated as a percentage of nominal voltage (i.e. the voltage percentage for the node with highest voltage and the node with lowest voltage). As depicted, no voltage violations were identified throughout the modified load profile with different levels of solar PV penetration.

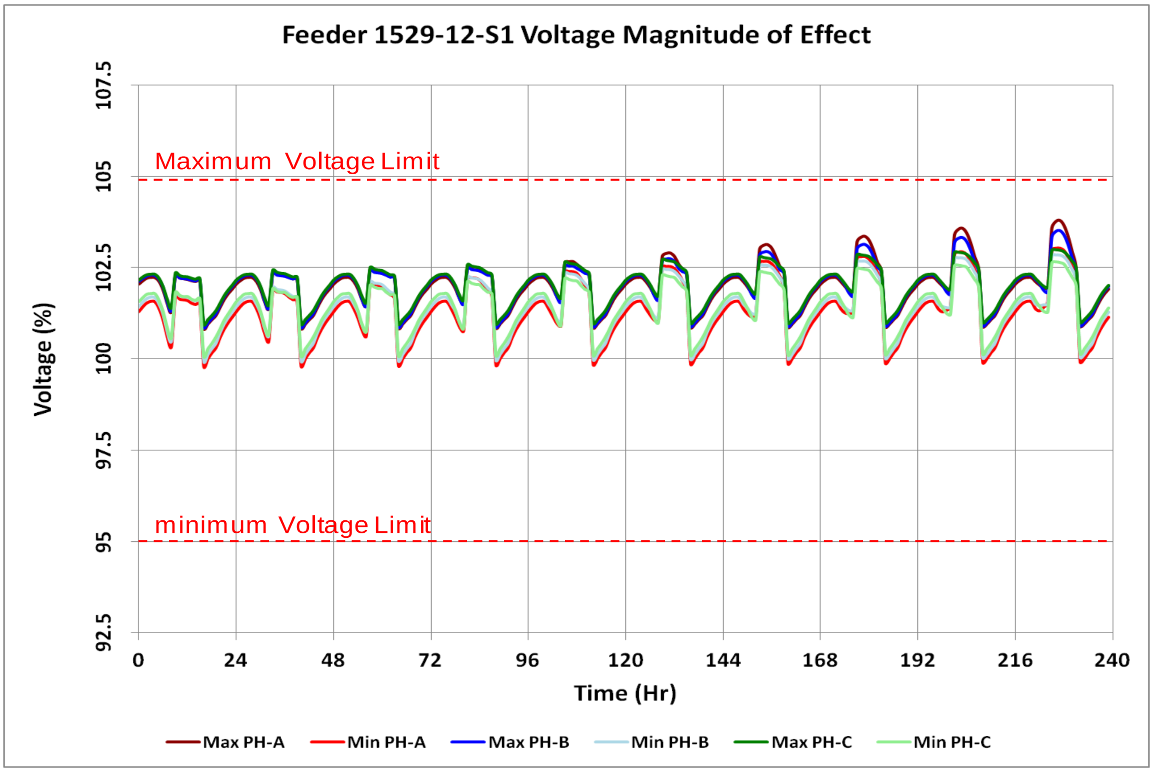

Figure 3-39: Feeder 1529-12 Maximum and Minimum Voltages

Based on the above, it can be concluded that without any additional investments, this feeder can accommodate up to 40% of its peak demand in solar PV penetration.

3.5.3 Feeder 1529-13_Scenario 1

The analysis of the feeder was conducted using the load profile presented in Section 2 of this document and the PV generation profile shown in Figure 3-40, which allowed us to study multiple solar PV generation levels up to 100% of feeder peak demand. The multiple solar PV generation levels were increased in steps of 10% of the feeder peak demand in 24-hour periods (i.e. allows studying all levels of solar PV penetration in the same run).

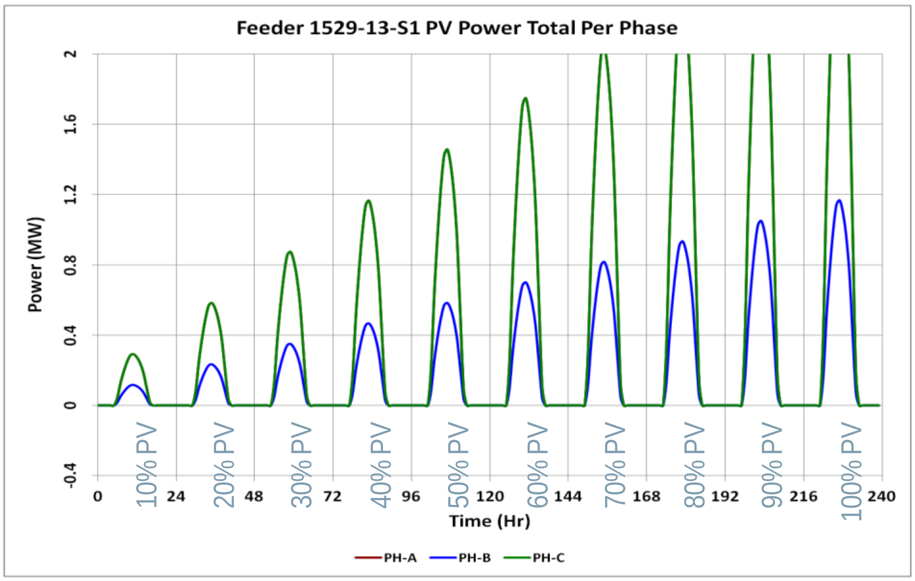

Figure 3-40: Feeder 1529-13 Solar PV Generation Output at Different Levels of Integration

Taking into account the PV generation profile, Figure 3-41 presents the power supplied by the substation to the feeder loads at different levels of solar PV penetration (i.e. from 10% to 100%). As can be noted, phases A and C began to experience reverse power flows at 30% PV penetration, while phase B began at 80%. This means that unless other feeders supplied by the same substation have sufficient demand, there will be power flowing from the distribution to the transmission system with the potential problems indicated above, unless properly addressed.

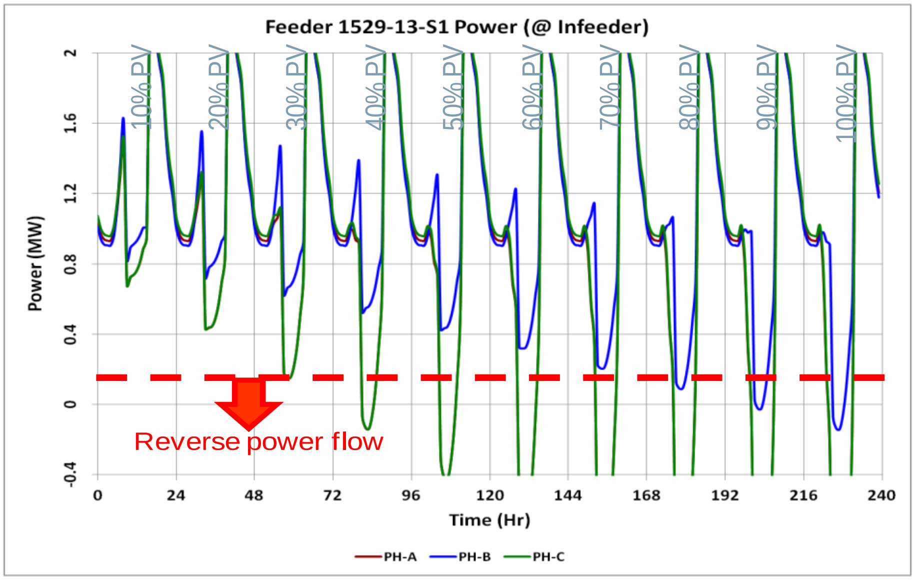

Figure 3-41: Feeder 1529-13 Power Supplied/Received

Figure 3-42 shows the maximum and minimum observed voltage magnitudes in the feeder at different levels of solar PV penetration for each hour simulated as a percentage of nominal voltage (i.e. the voltage percentage for the node with highest voltage and the node with lowest voltage). As depicted, no voltage violations were identified throughout the modified load profile with different levels of solar PV penetration.

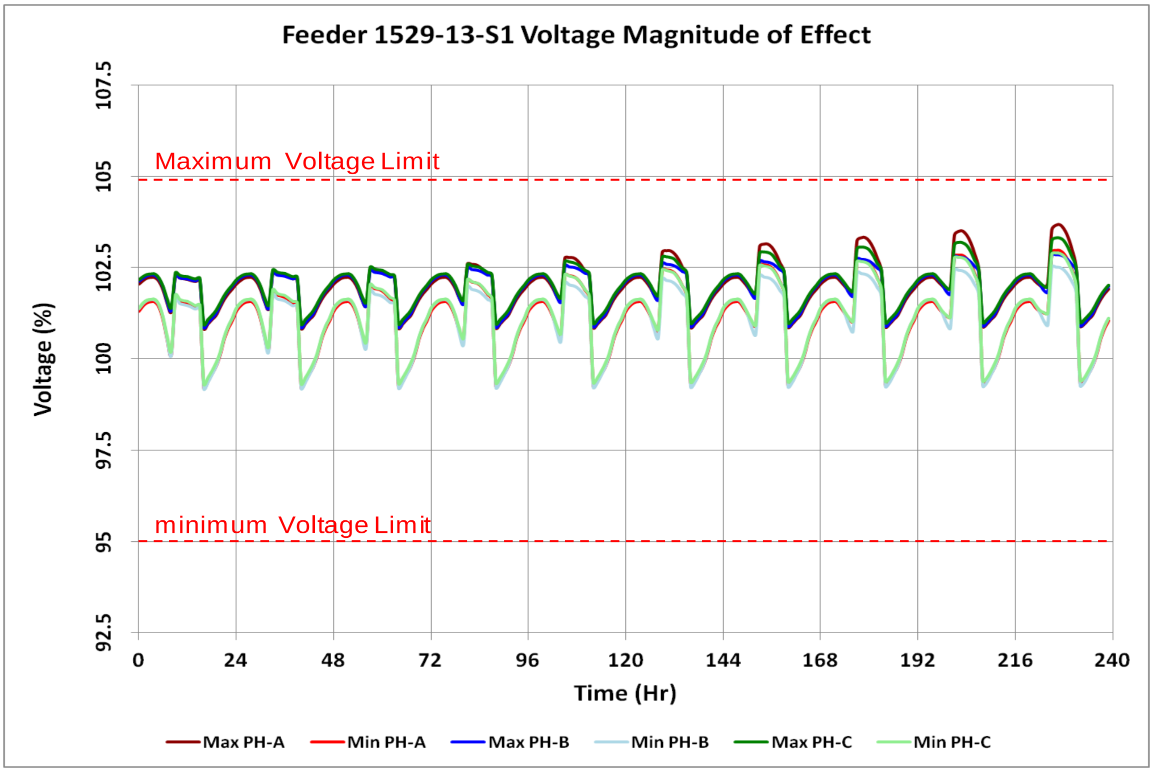

Figure 3-42: Feeder 1529-13 Maximum and Minimum Voltages

Based on the above it can be concluded that without any additional investments, this feeder can accommodate up to 30% of its peak demand in solar PV penetration.

3.5.4 Feeder 1529-12/Feeder 1529-13 Tie_Scenario 2

The analysis of this scenario, where feeder 1529-12 is being supplied by feeder 1529-13 through tie 3 (see Figure 3-33), was conducted using the load profile presented in Section 2 of this document and the PV generation profile shown in Figure 3-43. This allows us to study multiple solar PV generation levels up to 100% of the peak demand. The multiple solar PV generation levels were increased in steps of 10% of the feeder peak demand in 24-hour periods (i.e. allows studying all levels of solar PV penetration in the same run).

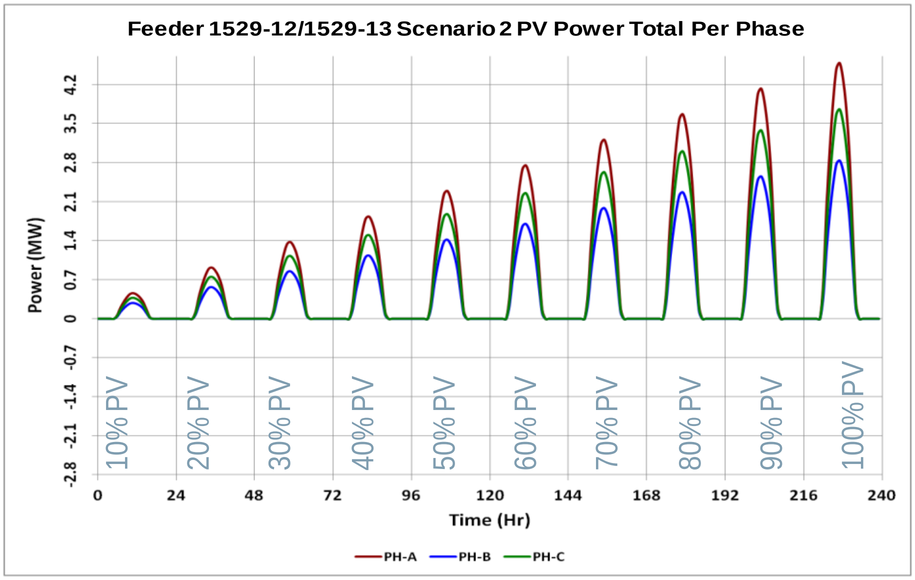

Figure 3-43: Feeders 1529-12/1529-13 Tie Solar PV Generation Output at Different Levels of Integration

Taking into account the PV generation profile, Figure 3-44 presents the power supplied by the substation to the feeder loads at different levels of solar PV penetration (i.e. from 10% to 100%). As can be noted, phases A and C began to experience reverse power flows at 50% PV penetration, while phase B began at 70%. This means that unless other feeders supplied by the same substation have sufficient demand, there will be power flowing from the distribution to the transmission system with the potential problems indicated above, unless properly addressed.

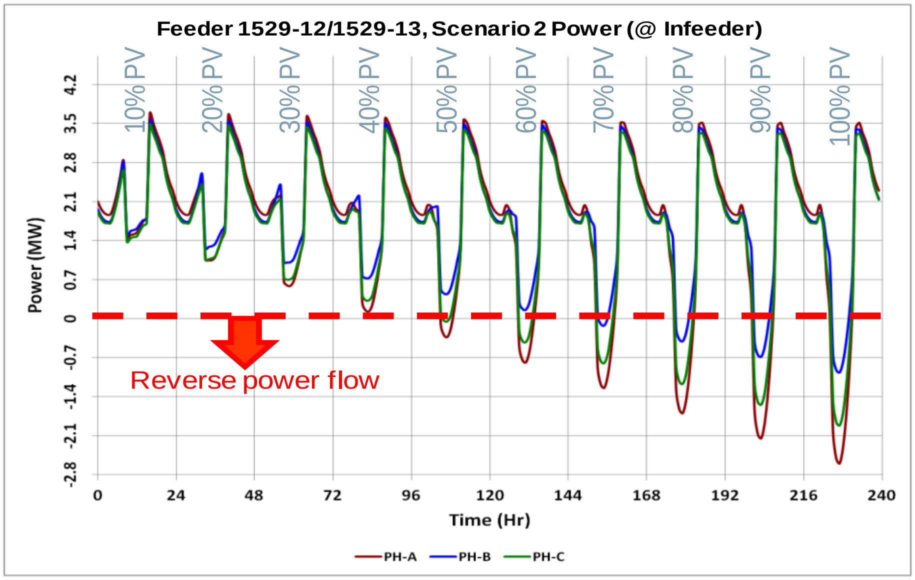

Figure 3-44: Feeders 1529-12/1529-13 Tie Power Supplied/Received

Figure 3-45 shows the maximum and minimum observed voltage magnitudes in the feeder at different levels of solar PV penetration for each hour simulated as a percentage of nominal voltage (i.e. the voltage percentage for the node with highest voltage and the node with lowest voltage). As depicted, no voltage violations were identified throughout the modified load profile with different levels of solar PV penetration.

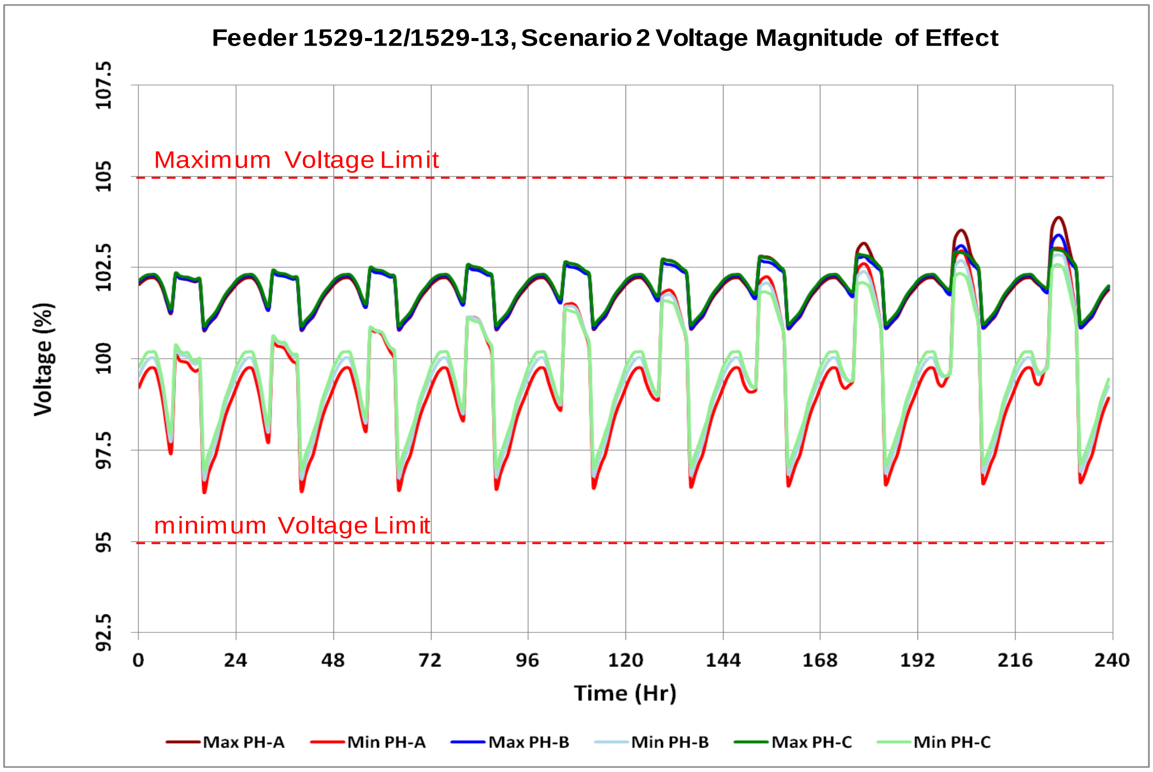

Figure 3-45: Feeders 1529-12/1529-13 Tie Maximum and Minimum Voltages

Based on the above, it can be concluded that without any additional investments, this scenario can accommodate up to 50% of its peak demand in solar PV penetration.

3.5.5 Feeder 1529-11/Feeder 1529-13 Tie_Scenario 3

The analysis of this scenario, where feeder 1529-13 is being supplied by feeder 1529-11 through tie 1 (see Figure 3-33), was conducted using the load profile presented in Section 2 of this document and the PV generation profile shown in Figure 3-46. This allows us to study multiple solar PV generation levels up to 100% of the peak demand. The multiple solar PV generation levels were increased in steps of 10% of the feeder peak demand in 24-hour periods (i.e. allows studying all levels of solar PV penetration in the same run).

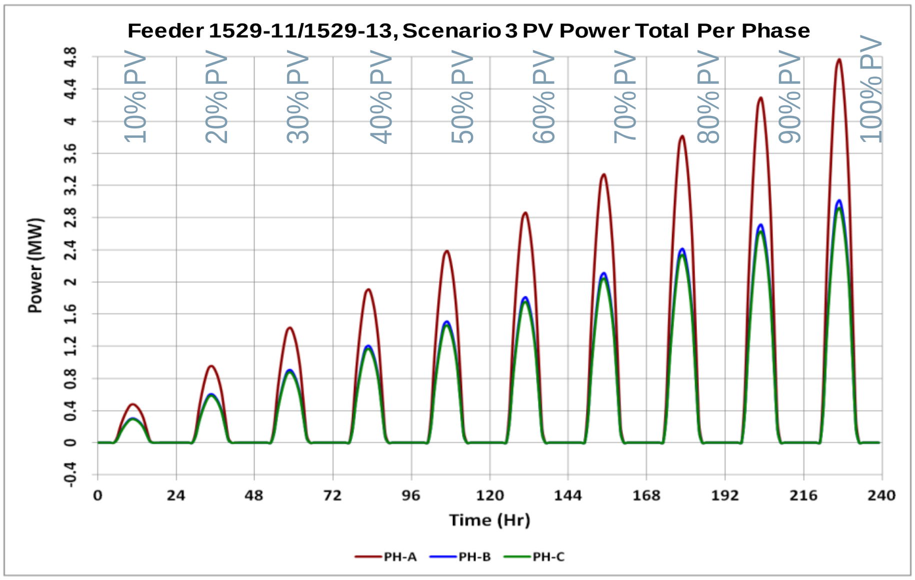

Figure 3-46: Feeders 1529-11/1529-13 Tie Solar PV Generation Output at Different Levels of Integration

Taking into account the PV generation profile, Figure 3-47 presents the power supplied by the substation to the feeder loads at different levels of solar PV penetration (i.e. from 10% to 100%). As can be noted, phase C began to experience reverse power flows at 50% PV penetration, while phases A and B began at 80%. This means that unless other feeders supplied by the same substation have sufficient demand, there will be power flowing from the distribution to the transmission system with the potential problems indicated above, unless properly addressed.

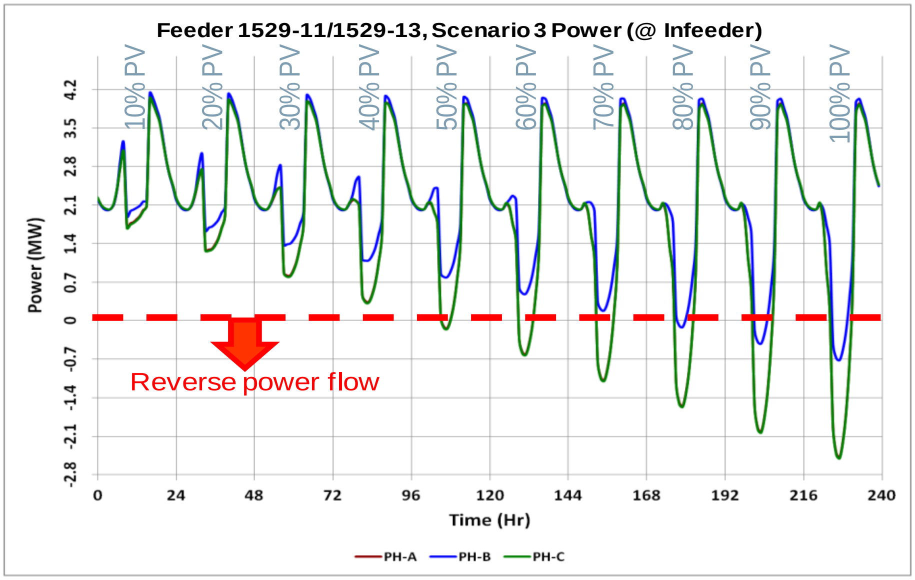

Figure 3-47: Feeders 1529-11/1529-13 Tie Power Supplied/Received

Figure 3-48 shows the maximum and minimum observed voltage magnitudes in the feeder at different levels of solar PV penetration for each hour simulated as a percentage of nominal voltage (i.e. the voltage percentage for the node with highest voltage and the node with lowest voltage). As depicted, no voltage violations were identified throughout the modified load profile with different levels of solar PV penetration.

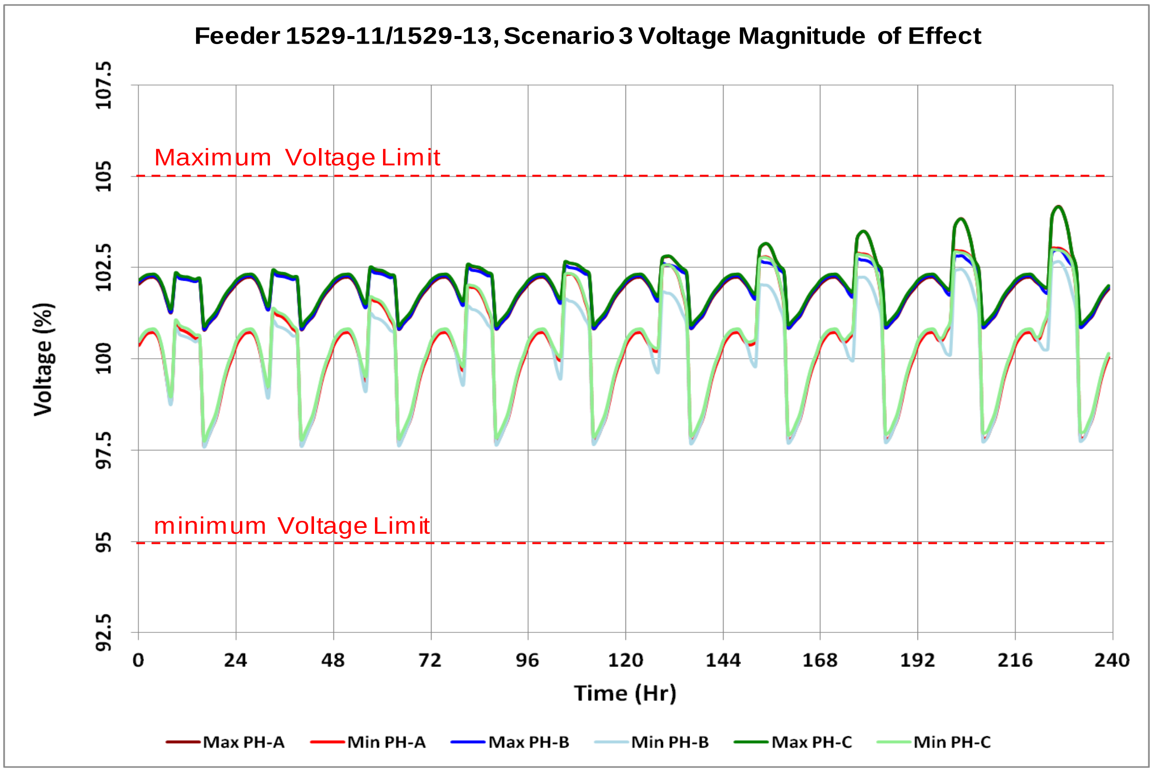

Figure 3-48: Feeders 1529-11/1529-13 Tie Maximum and Minimum Voltages

Based on the above, it can be concluded that without any additional investments, this scenario can accommodate up to 50% of its peak demand in solar PV penetration.

3.6 Additional Studies Required

DG based on solar PV integration disrupts the distribution system design. The existing distribution equipment were designed to provide voltage regulation and protection coordination for radial unidirectional power flow only. Solar PV generation at the local DG level is an uncontrolled generation and intermittent in nature, hence, it can introduce reverse power flow, disrupt voltage regulation practices, challenge protection coordination, and due to sudden output changes, flicker (rapid changes in voltage).

The studies presented in this report address the power system issues that may arise with the integration of PV; voltage and overloads. However, there are other important issues that need to be reviewed before DG can be safely accepted into the system. These issues are identified by the studies below:

3.6.1 Protection Coordination

The basic protection coordination of a distribution feeder is based on unidirectional flow from the substation to the load, which may not be the case anymore with DG. With the high levels of DG considered in this study, it is necessary to review the protection coordination to: a) add directional blocking to prevent trips on back flows, b) confirm that distant faults are still detectable, and c) confirm that breakers are not over-dutied (i.e. their interrupting capacity has been exceeded).

3.6.2 Harmonics

Harmonics can be an important factor to consider in the integration of solar PV generation on the distribution system. Capacitor banks are either installed at the substation or spread out on the distribution feeders. PV inverters introduce harmonic currents that under certain conditions can lead to voltage and current distortions, which can be outside the limits required by the IEEE Standard 519-2014. Furthermore, if one of the characteristic frequencies of the harmonic source (PV inverter) matches a system parallel resonant frequency, overvoltage conditions may occur due to the voltage amplification of the harmonic source.

Harmonic studies evaluate the total harmonic distortion (THD) generated by the PV equipment. The spectrum of the harmonic current distortion generated by each type of the PV inverter should be provided for the harmonic distortion evaluation. The results will be compared against the limits specified in IEEE 519-2014 and IEEE 1547 standards.

3.6.3 Flicker / Voltage Dips

Flicker, in general, can be caused by events that introduce a significant variation in power production or consumption that, in turn, causes rapid variation in voltage at a frequency and level that can be perceived as annoying to some degree by the human eye. Voltage dips are similar in nature to flicker but of short duration and may have an impact on sensitive loads.

In the case of large concentrated PV installations or dispersed PV installations, flicker and voltage dips (or rise) are most likely to be caused by the passing of clouds, causing variations in the output of the PV panels.

To study flicker on distribution feeders, the transition from full output to no output of the PV is simulated and the resulting voltage impact is recorded. If the impact of this full transition is acceptable, then the impact of a more realistic partial transition should be acceptable. Flicker analysis is required for different levels of solar PV integration scenarios. The flicker evaluation is based on IEEE 141-1993 and IEEE 519-1992 standards.

3.6.4 Ferroresonance

Ferroresonance is a phenomenon that can create overvoltage conditions in a distribution system. It may occur when a three-phase transformer is supplied by only one or two phases and can be initiated after some type of switching event such as energizing a transformer, load rejection, fault clearing, single-phase switching, or loss of system grounding is experienced. Also, there are high probabilities of occurring when solar PV generation reaches capacities similar to the load at a particular time (generally at mid-day) and causes low resistive damping. In distribution systems, this phenomenon can be avoided with fast anti-islanded protection which clears solar PV from the system before islanding is formed or by having three-phase switchgear on the primary side of the transformer instead of the more common fused cutouts.

Siemens PTI suggests performing this study in case by case basis where solar PV are already integrated or the integration of solar PV is known.

The above studies may conclude with the need of dynamic voltage regulation equipment such as Energy Storage or Dynamic Var Compensators (DVARs) distributed along the feeder. Those improvements are significant, and based on Siemens PTI's experience, investments could go over $2 million per case.

3.6.5 Effective Grounding and Neutral Shifting Analysis

Utility scale or three-phase solar PV generation may be connected to the distribution system through grounded YnYn or Delta-Yn step up transformers. Depending on the effectiveness of the grounding system, the solar PV will act as a grounded or an ungrounded source feeding out the distribution system. If ungrounded, after a phase to ground fault the voltage levels of the un-faulted phases can reach up to 1.732 nominal voltages. If no reverse power flow is occurring, the substation transformer acts as a grounded source and helps to suppress ground fault overvoltage conditions until the feeder circuit breaker opens. On the other side, when power is flowing through the transformer to the sub-transmission system, the transformer acts as an ungrounded source without helping to suppress ground fault overvoltage conditions.

3.6.6 Operations and safety

An assessment of PREPA's current operating practices is recommended to ensure safety and welfare of people and PREPA's personnel.

As an example, the following aspects are required to be cautious on:

- Solar PV interconnection requirement: customers and developers must coordinate the installation of a solar PV system with PREPA prior to interconnecting such system regardless of the unit capacity. This will allow PREPA to evaluate the interconnection and keep record on every unit and the accumulated solar PV interconnected to the system.

- All installed PV systems must have effective anti-islanding and, in general, at least comply with UL-1741.

- PREPA is required to continuously run studies for DG integration with its distribution system.
- Revise safety practices to operate and perform preventive and corrective maintenance.

Section

4

Investment Plan to Accommodate 100% of Solar PV

Instead of proposing traditional system reinforcing such as reconductoring or three phasing, Siemens PTI has explored non-wire solutions to effectively manage the feeder voltage profile whenever possible, as these solutions can be implemented with minimum customer impact and, in general, are more cost effective. As identified in this steady state study, adding voltage regulators complemented by replacing protection relays, upgrading the substation transformer's LTC control, and introducing a system capable of monitoring and controlling the feeder voltage (volt/var control system) are some of the common improvements that are required.

Table 4-1 provides a summary of system improvements required for each studied distribution feeder to integrate solar PV generation up to 100% of the feeders' peak demand.

It is important to stand out that large amounts of solar PV generation introduce reverse short circuit current contributions with temporary islanding conditions. Due to safety for public and line crew and proper protection coordination, Siemens PTI recommends adding at least two electronic reclosers for each distribution feeder. This new scheme will allow a proper fault detection and faulty area isolation.

Table 4-1: Cost Estimation to Integrate 100% of Feeders' Peak Demand in Solar PV Generation

Feeder	kV	Case	Project Description	Cost Estimation ($) Project	Cost Estimation ($) Total
2501-01	4.16	Base Case	One 2 MVA Voltage Regulator	$ 89,210.0	$ 662,363.0
		100% Solar PV	One 3 MVA Voltage Regulator at feeder head (dedicated)	$ 90,500.0	
		100% Solar PV	Two Electronic Reclosers	$ 180,000.0	
		100% Solar PV	Feeder relay replacement	$ 32,453.0	
		100% Solar PV	LTC Control replacement	$ 20,200.0	
		100% Solar PV	Volt/Var Control System	$ 250,000.0	
6306-02	4.16	Base Case	One 1 MVA Voltage Regulator	$ 65,000.0	$ 661,519.2
		Base Case	Remove two capacitor banks	$ 4,000.0	
		100% Solar PV	One 3 MVA Voltage Regulator at feeder head (dedicated)	$ 90,500.0	
		100% Solar PV	Threephasing 0.7 km of single phase line	$ 19,366.2	
		100% Solar PV	Two Electronic Reclosers	$ 180,000.0	
		100% Solar PV	Feeder relay replacement	$ 32,453.0	
		100% Solar PV	LTC Control replacement	$ 20,200.0	
		100% Solar PV	Volt/Var Control System	$ 250,000.0	
7103-04	4.16	Base Case	Two 3 MVA Voltage Regulator	$ 181,000.0	$ 1,110,993.0
		100% Solar PV	One 3 MVA Voltage Regulator at feeder head (dedicated)	$ 90,500.0	
		100% Solar PV	Four Voltage booster replacement to 2 MVA voltage regulator each	$ 356,840.0	
		100% Solar PV	Two Electronic Reclosers	$ 180,000.0	
		100% Solar PV	Feeder relay replacement	$ 32,453.0	
		100% Solar PV	LTC Control replacement	$ 20,200.0	
		100% Solar PV	Volt/Var Control System	$ 250,000.0	
2801-02	8.32	100% Solar PV	One 6 MVA Voltage Regulator at feeder head (dedicated)	$ 108,000.0	$ 590,653.0
		100% Solar PV	Two Electronic Reclosers	$ 180,000.0	
		100% Solar PV	Feeder relay replacement	$ 32,453.0	
		100% Solar PV	LTC Control replacement	$ 20,200.0	
		100% Solar PV	Volt/Var Control System	$ 250,000.0	
1529-11	13.2	100% Solar PV	Feeder relay replacement	$ 32,453.0	$ 52,653.0
		100% Solar PV	LTC Control replacement	$ 20,200.0	
1529-12	13.2	100% Solar PV	Feeder relay replacement	$ 32,453.0	$ 52,653.0
		100% Solar PV	LTC Control replacement	$ 20,200.0	
1529-13	13.2	100% Solar PV	Feeder relay replacement	$ 32,453.0	$ 52,653.0
		100% Solar PV	LTC Control replacement	$ 20,200.0	

Section

5

Conclusions

The integration of solar PV generation to a distribution system introduces opportunities for typical residential, commercial and industrial customers to be part of the energy business transformation and understanding of the value of self-generating energy. However, great technical challenges come along for the utility companies. The distribution system was conceptualized to provide unidirectional power flow (radial unbalanced system) with no opportunity to continuously operate in loop conditions. An overview of the challenges that utility companies may face is summarized in the Table 5-1.

Table 5-1: Overview of Operating Challenges due to Solar PV Integration

	Issue	Discussion
Distribution System	• Voltage Regulation	• DG may create overvoltage conditions that can affect the electrical service provided to other customers. • Traditional voltage regulation is disrupted with intermittent DG. • Equipment life cycle perturbed.
	• Maintaining Frequency	• DG penetration may increase the system spinning reserve needs.
	• Handling Reverse Power Flows	• May create protection coordination problems unless protective equipment is updated or replaced.
Transmission System	• Flows from Distribution System	• Substation transformers' LTC may be disrupted; control equipment might require replacement. • Protection coordination may need to be revised.
	• Over/Under Relative to Schedule	• Sudden DG changes may create difficulty in predicting system operation.
	• System Stability	• Increase of DG may require increase of spinning reserve needs.
Resource	• New Energy Source	• IRP with DER integration.

In addition to the typical effects mentioned above, since PREPA has an islanded system, the integration of large amounts of DG needs to be considered, together with the utility scale renewable generation, to assess system impacts, and in particular:

a) Prevent excessive curtailment of renewable generation during noontime conditions when the conventional generating fleet reaches its minimum regulating limits and there may not be enough loads to absorb the conventional generation (required for the night peak) plus the renewable output.

b) Pursue proper operation of the under frequency load shedding that the system depends on for its stability during the trip of large generators, as is the case of Aguirre 1&2. Large amounts of DG can dynamically change the load expected to be tripped, and in reality, if the event happens at noontime, it might trigger additional load shedding blocks causing service interruptions to more clients throughout the Island.

In this study, seven distribution feeders were modeled to investigate the amount of system improvements that are required to accommodate up to 100% of feeders' peak demand in solar PV generation based on a distributed generation scheme.

In order to accommodate 100% of the feeders' peak demand in solar PV generation, the following system improvements are required:

a) Protection relays replacements at feeder head

b) Substation transformer LTC controls' upgrades

c) Integration of voltage control systems capable of monitoring and controlling a feeder's voltage profile, such as volt/var control systems

d) Integration of a dedicated voltage regulator at each feeder head

Feeders 1529-11, 1529-12 and 1529-13 are short in distance and no major changes are required, resulting in an investment of around $50,000 to manage the reverse power flow conditions and protection upgrades, as needed. On the other hand, the investment required for the other feeders ranges from around $590,000 to over $1 million, depending on the voltage level and feeder's total length, as depicted in Table 5-2.

Table 5-2: Investment Required per Feeder

Feeder	kV	Feeder		Total Cost ($)
		Max Length (km)	Total Length (km)(*)	
2501-01	4.16	13	63	$ 662,363.0
6306-02	4.16	9.6	50	$ 661,519.2
7103-04	4.16	12.9	49.2	$ 1,110,993.0
2801-02	8.32	7.1	42.3	$ 590,653.0
1529-11	13.2	2.4	27.2	$ 52,653.0
1529-12	13.2	3.4	30.9	$ 52,653.0
1529-13	13.2	3.1	11.4	$ 52,653.0

Note: Feeder maximum length is the distance between the feeder's circuit breaker and the farthest node.

It must be stressed here again that in addition to the complementary studies indicated earlier, there are other power systems engineering studies that need to be carried out before the final acceptable levels of renewable DG can be finalized for a particular feeder, and that the sample analyzed here may have not identified additional stringent conditions on PREPA's system.

Siemens Industry, Inc.
Siemens Power Technologies International
400 State Street • P.O. Box 1058
Schenectady, New York 12301-1058 USA
Tel: +1 (518) 395-5000 • Fax: +1 (518) 346-2777

www.siemens.com/power-technologies