Sequential Mitigation Solutions to Enable Distributed PV Grid Integration

Preprint

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Sequential Mitigation Solutions to Enable Distributed PV Grid Integration

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***Abstract*—This paper presents a method to assess the technical impacts of a series of distribution system mitigations for integrating increasing penetrations of distributed generation from solar photovoltaics (DGPV). Solutions considered include distribution grid upgrades and advanced control technologies. This study helps pave the way to estimate the distribution integration costs needed to reach various PV penetration levels. The approach uses three stream-lined, bounding scenarios for increased PV penetration patterns. It begins by studying the distribution impact of PV power and quantifying the PV hosting capacity. Then, it studies multiple mitigation solutions to increase PV penetration on distribution feeders. These mitigation solutions are implemented in a sequential manner according to their typical costs. The proposed technique is demonstrated on two representative distribution feeders.**

***Index Terms*—Photovoltaic, hosting capacity, PV grid integration, voltage mitigation, smart inverter.**

I. INTRODUCTION

The Department of Energy launched the SunShot Initiative in 2011 with the objective of making solar electricity cost-competitive with conventionally generated electricity by 2020. Since the SunShot Initiative, solar power has made great strides in the United States. Through the first half of 2015, the installed capacity of solar photovoltaic (PV) connected to the U.S. distribution system has increased to more than 11 GW, and distributed solar PV is expected to comprise 50-60% of total PV capacity through at least 2020 [1].

Hosting capacity is defined as the total PV capacity that can be accommodated on a given feeder without adversely impacting voltage, protection, and power quality, and without any grid upgrades [2]. PV hosting capacity is typically a circuit-by-circuit, feeder-by-feeder analysis. The historical industry rule of thumb ranges from 15% to 25%, with the assumption that solar penetration beyond 15% is likely to cause the risk of voltage violations, inverter ride-through issues and other two-way power flow challenges that require grid equipment to balance out. However, multiple research studies have revealed that PV hosting capacity varies significantly for different feeders [3]-[5].

By definition, integrating PV systems up until the hosting capacity limit does not require changes in the existing grid infrastructure. However, to mitigate challenges caused by increasing PV penetration beyond the hosting capacity, it may be necessary to modify communications and controls, change protection schemes, upgrade the devices on the distribution circuit, and/or upgrade distribution equipment. All these mitigation solutions have associated costs, referred as distribution system upgrade costs in this paper. These costs are in addition to the traditional system-level levelized cost of energy (LCOE). To meet the SunShot Initiative objective of making solar electricity cost competitive, it is important to understand these distribution system upgrade costs as a function of penetration level. A bottom-up approach can be used to fulfill this objective. That is, a detailed analysis will be conducted to study the impact of different mitigation solutions on increasing PV penetration in distribution feeders, and then the associated costs of these mitigation solutions can be determined.

Accordingly, this paper studies multiple mitigation solutions in a sequential manner and quantifies their effects on increasing PV penetration on distribution feeders. First, the initial PV hosting capacity of the feeder is obtained without using any upgrades. Then, the sequence of applying these mitigation solutions is determined based on their typical costs, and each solution is studied to evaluate its impact on the studied feeder with increasing amount of PV power.

II. PV HOSTING CAPACITY ANALYSIS

A Monte Carlo simulation-based stochastic analysis approach can be used to estimate PV hosting capacity of a distribution feeder [2], [3], [6]. This paper uses this approach to quantify certain impacts of increasing PV capacity on two representative distribution feeders; Fig. 1 illustrates the framework of the study. The critical level of PV capacity that does not violate the following operational criteria (named as *distribution impact* in this paper) is considered as the PV hosting capacity:

- Steady-state voltages within 0.95-1.05 p.u.
- Overhead and underground line loadings within limits
- Transformer loadings within thermal limits
- Voltage flicker level within the tolerance

PV hosting capacity can be studied using a steady-state or a time-varying approach. The latter requires sufficient data and quasi-static time-series simulation to obtain the maximum PV capacity under time-varying load demands and variable energy generation. In contrast, the steady-state approach studies the worst-case scenario, which typically refers to minimum load demand and full PV generation. For simplicity, this paper focuses on the steady-state PV hosting capacity. Thus, the results of steady-state voltages,

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line loading levels, and transformer loading levels are analyzed under the condition of minimum load and full PV production. The magnitude of the voltage flicker is considered as the voltage difference between the minimum load/zero PV scenario and the minimum load/full PV production scenario. This paper assumes 3% as the tolerance limit for voltage flicker.

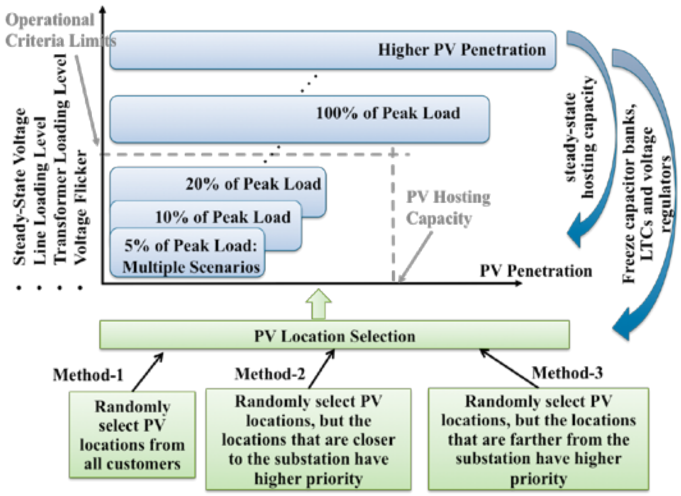


Figure. 1 The study framework of the PV hosting capacity analysis.

Traditional electromechanical equipment like voltage regulators, load tap changers (LTCs) and capacitor banks may be subject to increased operations and hence accelerated wear and tear with higher quantities of PV. Thus, we follow the traditional hosting capacity assumption when analyzing the steady-state PV hosting capacity of a distribution feeder and freeze equipment state, i.e. states (tap positions of regulators and LTCs, on/off status of capacitor bank) are kept same as in the no PV scenario. This conservative assumption may underestimate the hosting capacity since it prevents these pieces of equipment from providing adaptive assistance to voltage changes. The use of time-series simulation could allow for a more precise accounting of equipment operations and associated operations and maintenance (O&M) costs, and this will be addressed in our future work.

When creating scenarios to increase PV penetration, both locations and sizes of distributed PV systems are randomly selected. Since PV locations affect PV hosting capacity significantly [6], this paper studies three different methods to randomly select PV locations:

Method-1: randomly select PV locations from all customers;

Method-2: assign higher priority to select PV locations from the customers that are closer to the substation;

Method-3: assign higher priority to select PV locations from the customers that are farther from the substation.

Fig. 2 shows the mechanism of method-2, and the mechanism of method-3 is similar except the PV locations are selected starting with the customers located within the last 10% of feeder length.

Method-2 Select customers close to the substation first			
Initialize S.0	Set $\mathcal{X}$={customers within 10% of feeder length} Set $\mathcal{Y}$={}, representing unavailable customers, Set $\mathcal{Z}$={}, representing selected customers.		
Repeat			
	S.1	Repeat	S.1.1 Randomly select one customer $\boldsymbol{\alpha}$ from $\mathcal{X}-(\mathcal{Y}\cup\mathcal{Z})$, and randomly determine the PV size (**P**). Then total PV power at this customer location is **existPV + P**.
			S.1.2 If **existPV + P** > 2*peak load at this location, curtail **P** to 2*peak load-**existPV**, and include $\boldsymbol{\alpha}$ into $\mathcal{Y}$.
			S.1.3 Include $\boldsymbol{\alpha}$ into $\mathcal{Z}$
			S.1.4 If $\mathcal{X}=(\mathcal{Y}\cup\mathcal{Z})$, let $\mathcal{Z}$={}
		Until	$\mathcal{X}-\mathcal{Y}=\{\}$
	S.2	Set $\mathcal{X}$={customers within the next 10% of feeder length}, $\mathcal{Y}$={} and $\mathcal{Z}$={}	
Until	Reach the required PV penetration		

Figure. 2 The algorithm used for selecting PV locations in method-2.

III. Mitigation Solutions

Upgrading distribution systems is the traditional approach to mitigate the technical issues caused by high PV penetration beyond the hosting capacity critical limit. There are multiple upgrade options, such as capacity upgrades (new conductors, transformers, substations, etc.), new voltage regulating devices, adjustment in station voltages and settings, and enhanced protection systems. Table I lists the unit costs for some wires-type mitigation options that have been identified by Southern California Edison (SCE) [8]. Multiple units of each type (e.g. multiple miles of recondutoring, replacement of several voltage regulators), are common, depending on the specific scenario. When more distributed PV power is deployed beyond the initial hosting capacity, more mitigation efforts are generally needed and thus higher costs are expected.

Table I Mitigation Costs [8]

Description	***Cost ($)***
Reconductor OH – 1 phase (per mile)	481,000
Reconductor OH – 3 phase (per mile)	581,000
Capacitor bank setting adjustment	5,000
New capacitor bank	54,000
LTC controls	80,000
New regulator	203,000

On the other hand, advanced inverter functions have been shown to be able to increase PV capacity significantly [3], [9]-[11]. Nowadays, advanced inverter features are already integrated into most inverters for sale worldwide, so it is reasonable to assume that the use of advanced inverter functions on new inverters equipped with these features typically does not change customer capital or O&M costs significantly [12]. Also, the autonomous smart inverter controls do not require any data exchange and hence do not need any additional communication infrastructure. Thus, it is expected that a relatively lower mitigation cost can be achieved by using advanced inverters compared to solely using traditional distribution system upgrade options.

Accordingly, this paper uses autonomous smart inverter controls as the first mitigation solution to achieve a higher PV penetration beyond the hosting capacity limit. Table I shows that adding a new capacitor bank and/or voltage regulator is much more expensive than adjusting the setpoints of existing ones, but still much cheaper than reconductoring a new line. Thus, following smart inverter mitigation solution, this paper considers other mitigation solutions in the following order:

1. Revise setpoints of existing capacitors
2. Add new capacitor
3. Revise setpoints of existing LTCs and regulators
4. Add LTC and/or regulator
5. Reconductor lines.

IV. Case Study

A. Feeder Characteristics

This paper studies two real utility distribution feeders: 1) J1 feeder [13], located in the northeastern U.S. and selected because its information is public and hence this paper can provide a transparent benchmark study; and 2) Another real-world feeder we will refer to as feeder G, that is located in the southwestern U.S., and has distinct characteristics from the J1 feeder. These two feeders enable this paper to capture a variety of mitigation solutions. Table II shows key characteristics of the two feeders.

TABLE II Characteristics of the Studied Two Feeders

Characteristics	***J1 Feeder***	***Feeder G***
Medium-Voltage Class	12 kV	12.47 kV
Maximum Load	5.95 MW*	7.65 MW
Minimum Load	1.19 MW	1.04 MW
Maximum bus distance from the substation	18.08 km	9.7 km
Maximum X/R ratio of primary bus	9.724	5.71
Minimum X/R ratio of primary bus	1.206	0.669
Capacitor Count	5	6
Line Regulator Count	8**	0
LTC Count	1	0

* There is another 5 MW load directly connected at the secondary side of the substation transformer.

** Eight single-phase regulators exist in J1 feeder in three clusters: two 3-phase and one 2-phase.

B. J1 Feeder

As shown in Fig. 1, the three methods described earlier are used to create PV systems with increasing penetration levels. We use 600 PV scenarios for each method to quantify the distribution impact of increasing PV. To understand the differences among the three methods, one scenario with 100% PV penetration is selected from all 600 PV deployment scenarios for each method. Fig. 3 shows the locations of all PV systems (highlighted in blue) in the three selected scenarios. Under 100% PV penetration, PV systems created by method-1 are distributed among the entire feeder, while PV systems created by method-2 and -3 are respectively clustered close to the substation and spread far from the substation.

1) Hosting Capacity: The distribution impact of increasing PV capacity on the J1 feeder is first analyzed without using any mitigation solution, and the results are shown in Fig. 4. The maximum voltage magnitude, maximum voltage flicker and maximum thermal loading level in the feeder are provided for increasing PV penetration levels. For the three PV scenarios created using three methods, overvoltage occurs when PV penetration reaches 694 kW, 958 kW and 294 kW respectively, and voltage flicker exceeds 3% limit at 1218 kW, 4500 kW and 294 kW respectively. The maximum loading level of all lines and transformers are generally increasing with the higher PV penetration; however, the critical PV penetration causing overloading is larger than the one causing voltage problems.

According to Section II, PV hosting capacity is defined as the critical PV penetration that doesn't violate any operational criteria. Thus, the PV hosting capacity results obtained for three PV location selection methods are 694 kW, 958 kW and 294 kW respectively. It can be concluded that PV hosting capacity of J1 feeder significantly depends on the locations of PV systems. When PV systems are located far from the substation, voltage problems occur at low PV penetration levels.

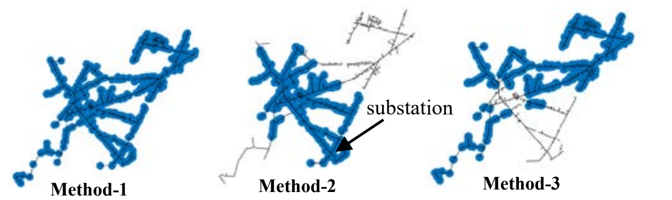
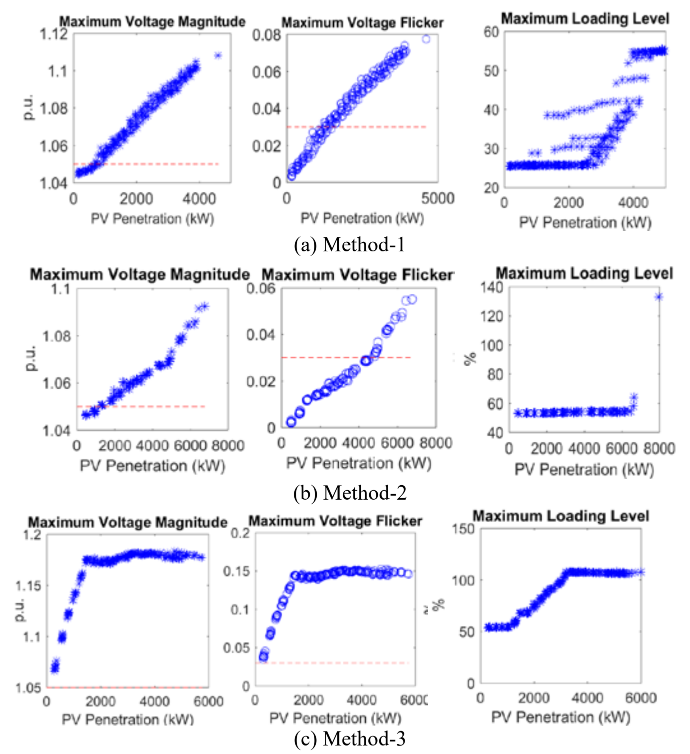


Figure 3 Locations of the PV systems on J1 created using the three methods described in Section II.



(a) Method-1
(b) Method-2
(c) Method-3

Figure 4 Distribution impact of increasing PV capacity on J1 feeder.

2) PV Capacity with Smart Inverters: Following the mitigation order from Section III, smart inverter functions are first used to mitigate the problems caused by high PV penetration. Two functions including the fixed 0.95 absorbing (lagging) power factor and autonomous volt/VAR control are studied. Fig. 5 shows the PV capacity results obtained for different functions, compared with the initial hosting capacity. The two smart inverter functions are both effective at helping to mitigate overvoltage and this mitigation effect is most significant for the PV scenarios created using method-2 (PV located closer to the substation).

After applying smart inverter functions, we need to determine how to implement other mitigation solutions as defined in Section III. A PV scenario that still causes overvoltage problem with the use of the fixed 0.95 lagging power factor is selected for analysis purpose. In this scenario, PV penetration is 2186.4 kW. Fig. 6 shows the voltage profile under this scenario, which reveals that the overvoltage problem is caused by the phase-a voltage at the end of the feeder. Possible solutions to overcome overvoltage problems include switching off capacitor banks or tapping down the voltage regulator. We analyzed the status of all the capacitor banks in the feeder and all these capacitors have been switched off. Thus, the next mitigation solution to use is to adjust the settings of the existing voltage regulators in the feeder.

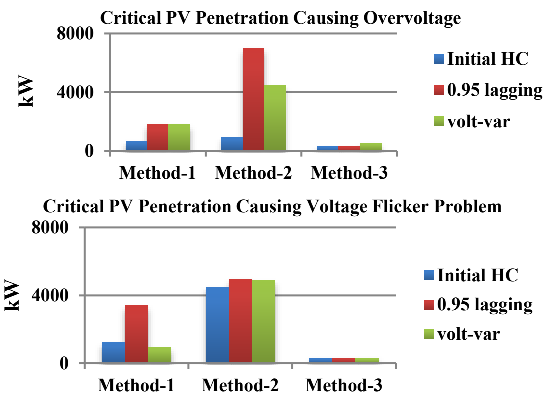


Figure 5 PV capacity of J1 with smart inverter mitigation solution.

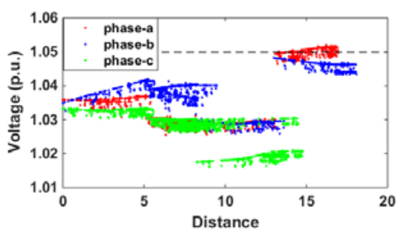


Figure 6 Voltage profile for the selected PV scenario with overvoltage.

3) PV Capacity with Regulator Mitigation Solution: All J1 voltage regular controls are intitally configured with 124V load centers and 2V bandwidth. The required voltage profile reduction should be achievable by lowering these load center voltage setpoints. However, to appropriately adjust the settings of voltage regulators, we first needed to analyze the voltage profile of the feeder for no PV/maximum load scenario to ensure there are no under voltage (<0.95 p.u.) events using the lower setpoints. Fig. 7(a) shows this voltage profile, and it is seen that there is extra headroom to lower the voltage. Thus, after assessing the new voltage profiles by heuristically reducing setpoints, the setpoints of all voltage regulators are adjusted to 122V, and the setpoint of the regulator at the end of the feeder is further reduced to 119 V. The new voltage profile is shown in Fig. 7(b).

After adjusting setpoints of all voltage regulators and LTC, the distribution impact of PV capacity is studied again. The new results of allowed PV capacity without violating any operational criteria are shown in Fig. 8, along with the initial hosting capacity and the results obtained the use of smart inverters alone.

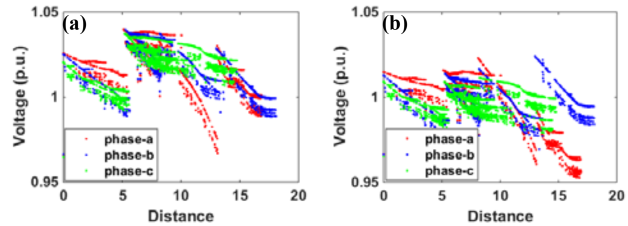


Figure 7 Revised voltage profile of J1 under (a) max load and (b) no PV scenario.

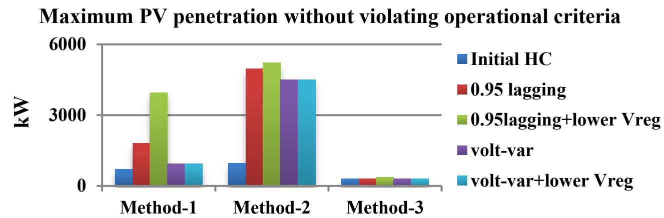


Figure 8 PV capacity of J1 with voltage regulator mitigation solution.

4) PV Capacity with Reconductor Mitigation Solution: All the results above show that the maximum PV capacity is still quite low for the PV scenarios created by method-3, which sees only small changes uses advanced inverter functions and adjusting voltage regulators. To understand these results, we carefully analyzed the scenario with PV penetration at 5% of peak load. As shown in Fig. 9, PV systems are clustered at the end of the feeder. Although the PV penetration is low, the segments circled in Fig. 9 already have an overvoltage problem. In the steady-state analysis regime, the only remaining mitigation option is to reconductor the lines. All the overhead lines used in these segments are of the same conductor type. We replace these lines with lower impedance conductors, and then re-analyze the effects of PV on the feeder at increasing penetration levels for all three location scenarios. The new results of critical PV penetration causing voltage and thermal issues are displayed in Fig. 10. After reconductoring, voltage flicker problems are mitigated and thus the maximum allowed PV capacity is increased, although there is no improvement in overvoltage or thermal loading.

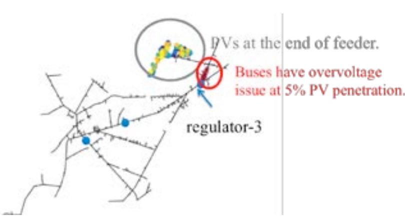


Figure 9. A PV scenario created by using method-3.

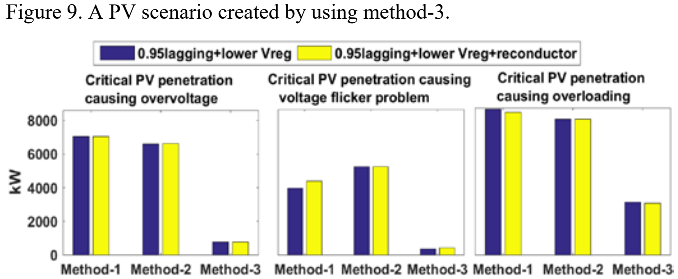


Figure 10. Critical PV capacity obtained with line reconductor.

C. Feeder G

As for the J1 feeder, the initial PV hosting capacity and the new critical PV capacity after applying smart inverter functions are obtained for the G feeder (Fig. 11). Three smart inverter functions are studied: fixed 0.98 and 0.95 lagging power factors and volt/VAR control. Unlike the J1 feeder, results for three functions are effective on mitigating overvoltage and voltage flicker problems caused by the high PV penetration in feeder G. However, the volt/VAR control reduces the critical PV penetration causing overloading. Additionally, the results of J1 feeder show that while the three spatial PV scenarios have distinct distribution impacts on the J1 feeder, feeder G shows similar results across all scenarios. This may be because feeder G is shorter and more heavily loaded.

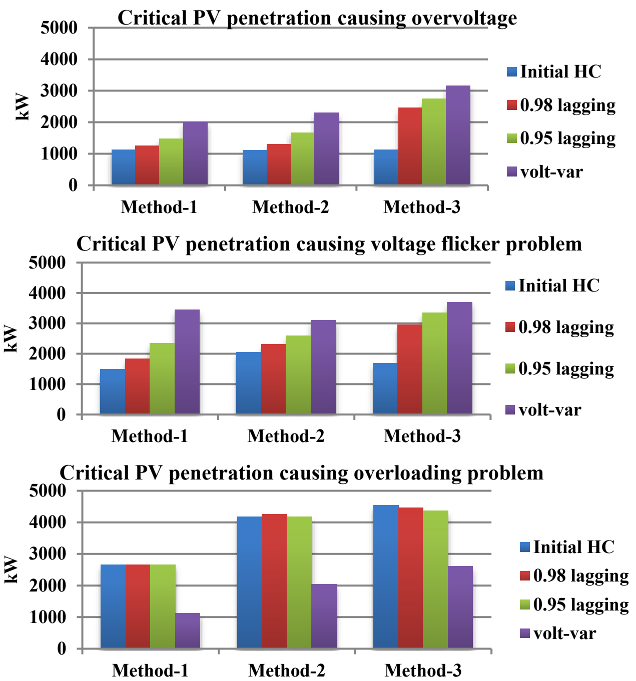


Figure 11 Distribution impact analysis results of the G feeder.

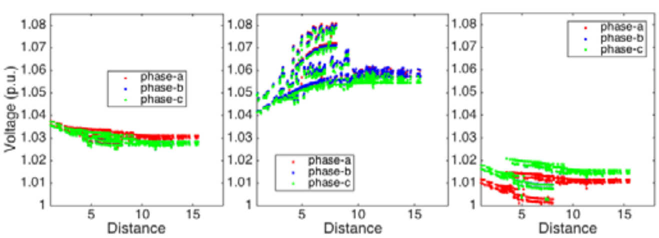


Figure 12 Voltage profile of the G feeder for: no PV (left), high PV (middle), high PV and with new voltage regulating device (right).

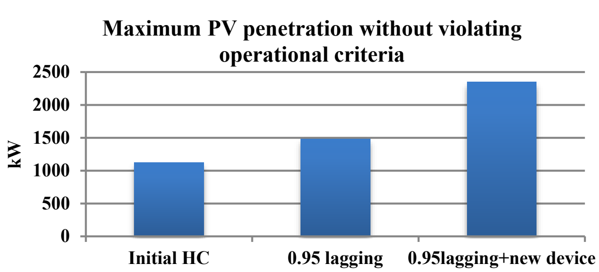


Figure 13 PV capacity of the G feeder obtained for method-1.

Fig. 12 shows the voltage profile of feeder G for the base case (no PV) scenario and one PV scenario (method-1). In the case with PV, the voltages at the end of the feeder increase as do the voltages at buses around 5-7 km from the substation, which also increase significantly. Since there is no voltage regulator or LTC in feeder G, the next mitigation solution used is to add a LTC at the substation transformer and a voltage regulator at the middle of the feeder. The resulting new voltage profile of feeder G without any PV is shown in Fig. 12. Compared with original case, the voltage profile gets lowered significantly. Finally, the maximum PV capacity allowed in the feeder is assessed again and compared with the initial hosting capacity and the capacity with only smart inverter mitigation, as shown in Fig. 13. The results demonstrate that adding new voltage regulation devices can help increase PV capacity dramatically.

V. Conclusions

This paper uses two representative distribution feeders to demonstrate the sequential implementation of multiple mitigation solutions to increase distributed PV penetration. It is shown that smart inverter controls can help increase PV penetration significantly and keep integration costs low. To increase PV penetration further, distribution grid upgrade solutions must be used and their effects are dependent on feeder characteristics. The study provided in this paper can be used by utilities to conclude the upgrade costs needed for fulfilling the objective of increasing PV penetration to certain levels.

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