Maximum PV Size Limited by the Impact to Distribution Protection

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***Abstract* — Utilities issuing new PV interconnection permits must be aware of any risks caused by PV on their distribution networks. One potential risk is the degradation of the effectiveness of the network's protection devices (PDs). This can limit the amount of PV allowed in the network, i.e. the network's PV hosting capacity. This research studies how the size and location of a PV installation can prevent network PDs from operating as intended. Simulations are carried out using data from multiple actual distribution feeders in OpenDSS. The PD TCC are modeled to find the timing of PD tripping to accurately identify when PV will cause unnecessary customer outages. The findings show that more aggressive protection settings limit the amount of PV that can be placed on a network that does not cause more customer outages or damage network equipment.**

***Index Terms* — photovoltaic systems, power distribution faults.**

I. Introduction

As the price of solar PV drops and more distribution network customers see PV as a viable investment, utility engineers must approve new PV installations so long as it will not cause a negative impact on the operational standards of the network. Individual utilities have varying standards, but there is consensus that large amounts of PV can cause problems in distribution networks. There is ongoing research into the power quality issues caused by PV, including voltage violations and line over-currents [1-3]. Another issue arising is the impact PV generation has on the networks' protection devices (PDs) [4, 5].

Radial distribution network protection schemes generally consist of overlapping zones protected by overcurrent relays that trip breakers and reclosers. These relays are set under the assumption that there is no generation in the network. Adding PV will introduce another source of fault current that can either increase or decrease the amount of fault current seen by the PD, hence changing if the PD operates and how long it takes to trip [6]. The amount the fault current is changed is proportional to the size of added PV system. The utility is responsible to operate the grid safely and reliably, so, if the goal is to avoid the cost of reengineering or upgrading the protection schemes but also maintain reliability, then they must limit the size of new PV installations. In other words, the PV hosting capacity of the network can be limited by how PV current injection may interfere with PDs.

The goal of this research is to determine how a distribution network's protection scheme is impacted by a large three-phase PV interconnection arbitrarily placed on the medium-voltage lines of a distribution network. The types of protection violations considered are defined in Section II. In Section III, the network and PV modeling and simulation procedure is laid out. Then, simulations are carried out on real-world distribution networks using protection settings provided by the utility in Section IV. Here the protection violations are identified and analyzed. Lastly, conclusions are drawn in Section V, and potential methods to mitigate protection issues are discussed.

II. Research Scope and Faulted PV Model

There are many things to consider in network protection, and different issues require different tools to investigate. Some issues require the study of harmonics or time-domain simulations. This research focuses on the impact of the PV's steady-state current injection on network protection. The PV's control loops are assumed to converge very quickly to their new operating point during the fault. This research will analyze the impact of this steady-state current assuming the PV does not disconnect from the fault. Many new regulations are requiring PVs to remain connected to support the network under faults, or "low-voltage ride-through". In steady-state, only the solution to the network equations are required for each fault and PV placement scenario. Even still, this problem can require an unreasonable amount of computation if no measures are taken to reduce its complexity.

Before any analysis can be done, the PV system must be properly modeled. Under the assumption of the PV control loops reaching steady state, it will act as a constant power source. This means it will inject fault current based on the solar power available to it and the bus voltage of its point of common coupling (PCC). In protection studies, it is practical to study the worst-case scenario and since this research is interested in the impact of PV current, it is assumed the maximum (peak irradiance) power, P_{PV}, is available to the PV system. However, the PV can only inject current up to the maximum its grid-tie inverter is capable of transferring. A review of literature concerning faulted PV inverters indicates the largest (worst-case) current inverters are typically manufactured to be able to continuously transfer is 2.0pu rated current [7, 8]. Thus, the PV system is modeled as a three-phase current source that injects fault current as in (1).

$$|I_{PV}| = \begin{cases} \dfrac{P_{PV}}{|V_{PCC}|}, & |V_{PCC}| \geq 0.5pu \\ \dfrac{2P_{PV}}{|V_{nom}|}, & |V_{PCC}| < 0.5pu \end{cases} \tag{1}$$

$$\angle I_{PV} = \angle V_{PCC}$$

However, changing the output current of the PV also changes the PCC voltage. Therefore, an iterative solution is required to converge on the steady-state operating point of the PV system under each fault condition. After each solution, the current is changed to the value corresponding to half of the change in voltage from the previous step. This is repeated until the voltage changes by less than 0.01pu.

The system is wye-connected through a wye-wye interconnection transformer in order to transfer the largest amount of current from the low-voltage PV to the medium-voltage network. This is also the most common type of transformer used by utilities in PV interconnection [9]. The PV system is assumed to work in a balanced operation, with $|V_{PCC}|$ being the average of the three phases.

III. Protection Violation Analysis Methodology

A. *Testing Fault Types and PV Locations*

The "intended" operation of the protection scheme is referred to as the "base case" and it is how the PDs respond to a 0.0001Ω resistive fault placed at various buses in the network. The resultant network fault currents are determined by the RMS, steady-state power flow solution provided by the OpenDSS and GridPV simulation software [10, 11]. These fault currents determine the base case protection zones of the network PDs, using their given real-world protection settings. Four basic fault types are considered, as depicted in Figure 1.

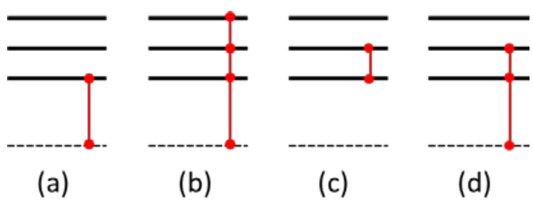

Figure 1. Fault types considered in the analysis (a) single-phase-to-ground (b) three-phase-to-ground (c) phase-phase (d) two-phase-to-ground

Faults are placed at each bus in the network with at least the appropriate number of phases. For each fault type and location, a PV location is tested at several sizes. Realistic network models may have thousands of buses, making the task of testing for every possible fault and PV placement combination very time consuming. Therefore, the network models are reduced to the minimum number of buses that include all ends of lines, topology buses, and PD buses through a process presented in [12] that has been expanded to reduce multi-phase, unbalanced distribution systems.

B. *Measuring Fault Current*

Under each fault and PV location pair, the fault current seen by the network PDs is recorded. A PD in a distribution network may refer to a breaker, recloser, sectionalizer, or fuse. Network fuses may be the most troublesome for the utility if one operates in error, as a crew would have to be sent out to reset it. However, the sheer number of fuses in networks makes discerning patterns and visualizing the results very difficult. Also, no sectionalizers exist in the networks tested. Therefore, in this research only substation breakers and line reclosers are considered.

Even with reduced circuit models, there are still hundreds of thousands of PV and fault combinations, which would be very time consuming to test at many PV sizes. Recall that each placement combination requires many network solutions for (1) to converge. For this reason only five PV sizes are tested that equally span the set of PV sizes considered. A third-order polynomial function is then fit through least-squares regression to estimate how the fault current through each PD in the network changes with PV size for each fault and PV location.

Once all fault currents are known, the PD trip times are calculated using the device ground and phase TCC. The minimum pick-up current is used to determine if the device will trip at all, and if above the pick-up current, the TCC calculates how long the fault is sustained and which PD trips first. Depending on the order and timing of the PD trips, the protection violations are identified for any PV size.

C. *Protection Issues Considered*

In this paper, four types of potential protection issues caused by PV are considered [4, 6]. Listed in decreasing order of severity, the issues are:

1. Under-reach: the PD fails to trip for a fault inside its exclusive base case protection zone
2. Sympathetic tripping: the PD trips for a fault occurring on a separate circuit
3. Coordination loss: a change in PD trip sequence causes a larger number of customers to lose power
4. Nuisance tripping: the PD trips and causes an outage that would not have occurred in the base case

IV. Analysis of Distribution Systems

A. *Distribution System QS1*

The testing of PV induced protection violations described in the previous section is carried out on the 12kV, 7.4MW peak load distribution feeder named QS1 and shown in Figure 2.

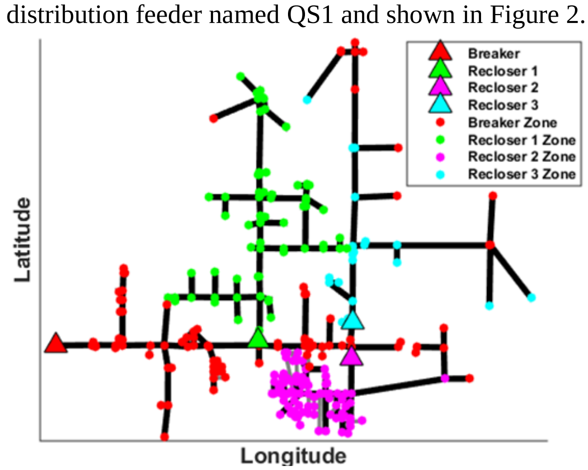

Figure 2. Test circuit QS1 with PDs and their 1PG-fault base-case protection zones indicated by color.

Also indicated in Figure 2 are the locations of the four PDs considered: the substation breaker and three line reclosers. The base case zone of each PD is indicated by correspondingly colored dots. Each dot indicates which PD will trip first for a single phase to ground fault at that location. This figure highlights an important consideration in checking for PV-induced violations: the base case zones may not be ideal in practice. Here, due to intersecting time-current curves (TCC) of the PDs, which are discussed later, some low-current, end-of-feeder faults will trip the substation breaker before a recloser. Additionally, care must be taken when declaring a situation as a "violation", since many tripping changes caused by PVs will not actually have a negative impact on distribution customers. The violations listed in Section III are worded specifically to only consider changes to PD tripping behavior that result in more disconnected customers.

A summary of the negative impact PVs have on the test circuit in Figure 2's protection is presented in Figure 3. Using PD settings provided by the utility, the percent of PV placement locations causing a violation at a given size is shown.

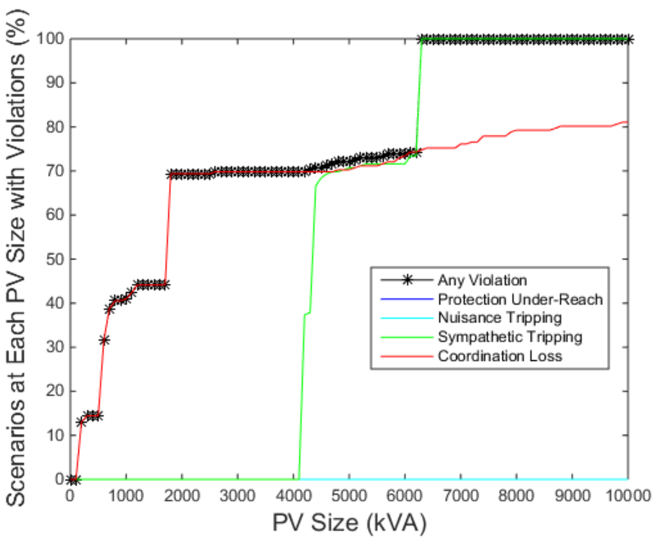

Figure 3. Feeder QS1 PV installation locations with violations broken down by type using original TCC.

Each line in Figure 3 represents a violation described in Section III and the black starred line represents any violation. For this circuit, neither under-reach nor nuisance tripping violations are seen. The main violation limiting PV installation size in this circuit is loss of coordination. As shown by the red line in Figure 3, the PDs in this network lose coordination for PVs as small as 200kVA. If one were to define a network's "PV hosting capacity" as the maximum PV size that causes *zero* violations, then this circuit would have a hosting capacity of 100kVA. However, as alluded to earlier, this network is in fact already in violation of PD coordination.

Looking at this issue in more detail, Figure 4 breaks down the coordination violations only by fault type. Clearly 1PG faults cause the earliest problems. Thus, the base-case zones for only 1PG faults are shown in Figure 2. The red buses downstream of reclosers in Figure 2, if faulted, would trip the breaker before their upstream recloser and cause the entire circuit to go out. This is due to the TCC of the breaker and reclosers intersecting, as shown in Figure 5. It is unknown if this is intentional or a data input error. In cases such as this, it is assumed the protection will have to be studied and corrected anyway since the issue is not caused by the PV. The TCC are fixed and shown again in Figure 6. Here, the breaker's TCC time axes are scaled up by 25% increments until it is not first to trip for any bus downstream of a recloser. Then an additional 25% buffer is given. This type of scaling is possible on modern breaker relays, however older electromechanical types may have a limited set

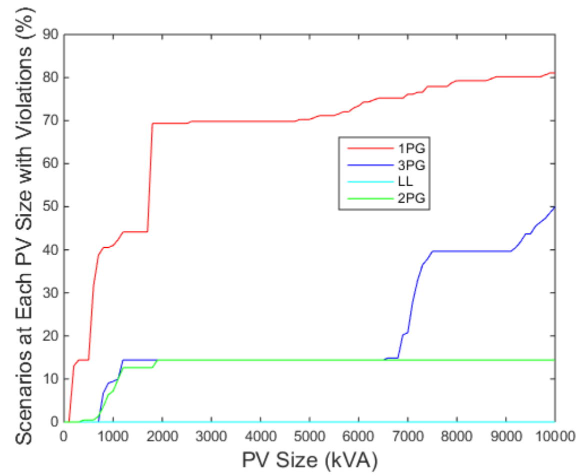

Figure 4. PV locations causing coordination violations per PV size broken down by fault type.

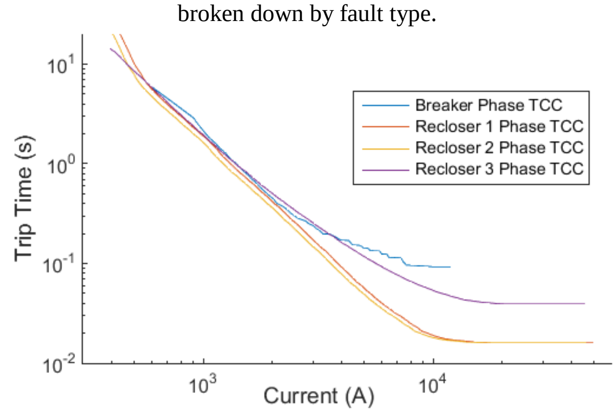

Figure 5. Original Phase TCC for PDs on feeder QS1.

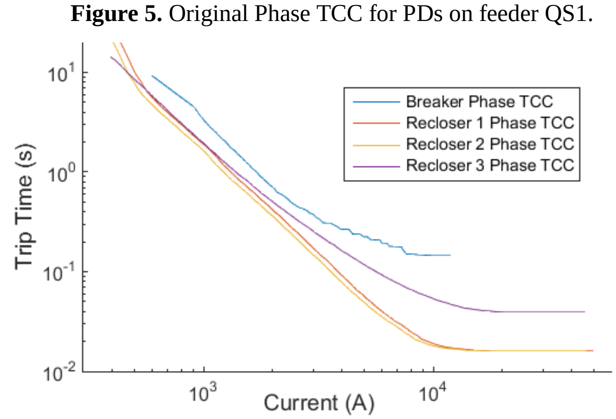

Figure 6. Feeder QS1 PD phase TCC with adjusted time scale.

of time scale settings. With the TCC in Figure 6, PVs cause no coordination violations. Also, no new violations occur due to modifying the PD TCC. This is shown in the new violation summary of QS1 in Figure 7.

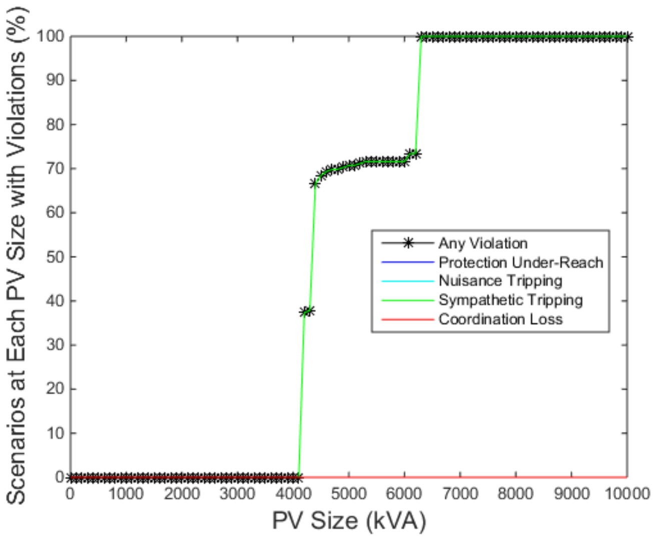

Figure 7. Feeder QS1 PV installation locations with violations broken down by type with fixed TCC.

The only remaining violations then are sympathetic tripping violations, which begin to occur at 4100kVA rated PV systems. These occur when the PV system supplies enough current to a fault on a nearby feeder to pick up a PD's minimum trip value. This first occurs for 3PG faults. The fault currents for one of the PV placements first causing sympathetic tripping is shown in Figure 8. This is a plot of all reverse current seen by Recloser 2 due to every fault location. The dark blue lines are phase currents and the cyan are ground currents. Although all the currents eventually cross its minimum phase pick-up, most of these are not violations because the tripping of the recloser does not cause any outages based on trip timing. The only issue that occurs is when the fault is placed on another feeder. The point at which this recloser first violates sympathetic tripping for this PV location is indicated by the arrow in Figure 8.

The percent of buses violating at around 4100kVA in Figure 7 corresponds to the percent of PV placement buses downstream of reclosers. The buses that are only downstream

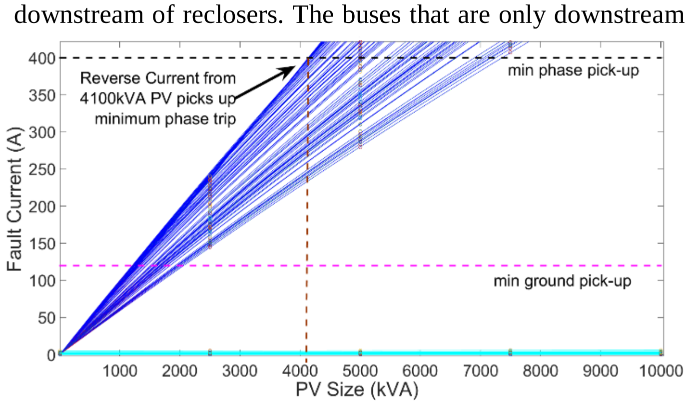

Figure 8. Fault currents changes due to PV size as seen by Recloser 2 for all 3PG faults placed upstream of it.

of the breaker violate at the higher value of 6200kVA. This behavior can be seen in Figure 9 where the lower allowable PV sizes are downstream of the reclosers. It should be noted that although breaker sympathetic tripping would be a serious problem if it did not have reclosing, recloser sympathetic tripping is a minor issue as the recloser would close back once the nearby feeder breaker clears the fault. Thus, if the utility is not concerned about these momentary outages, only the yellow buses in Figure 9 should be considered violation locations.

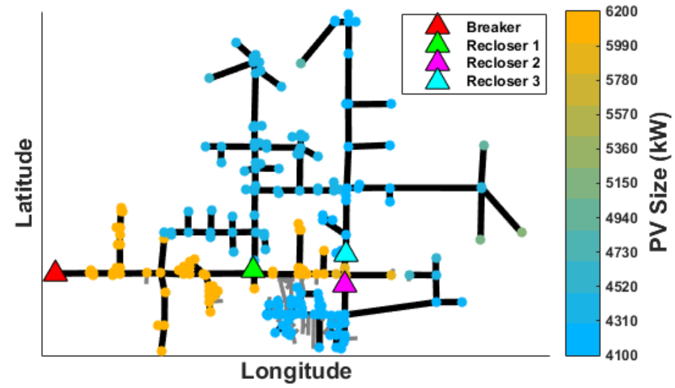

Figure 9. Maximum PV size allowed at each viable placement bus in feeder QS1 due to sympathetic tripping violations.

B. Distribution System QL1

The QL1 test circuit is a 20kV class feeder, so PV interconnections are tested up to 15MVA. Figure 10 shows the protection violation summary for this feeder.

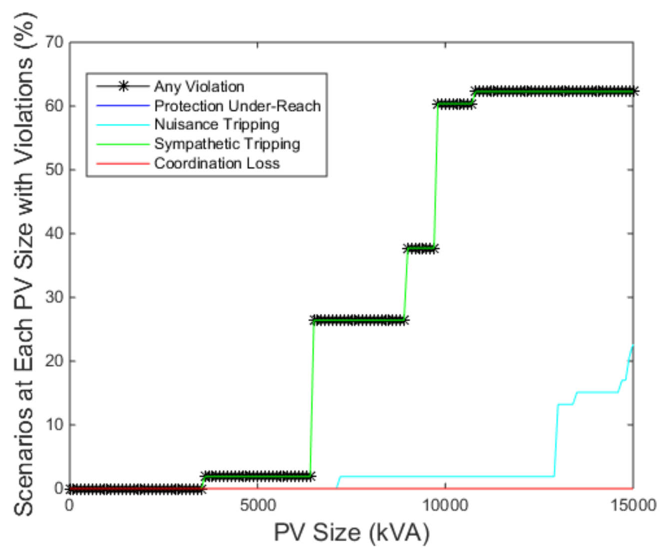

Figure 10. Feeder QL1 installation location violation summary.

There are no coordination issues for this feeder and again no under-reach violations. Again, sympathetic tripping is the main limit of the feeder's hosting capacity with the first violation occurring at 3500kVA. The many steps in this violation are due to there being five reclosers distributed throughout this large feeder, each with a different pick-up. The nuisance tripping violations here are due to reclosers operating on reverse-current from a PV feeding a fault elsewhere in the circuit, not in an upstream PD's zone. Since the recloser must operate first for it to be a violation (otherwise the fault would clear before any trip occurs), violations only occur when a large enough PV is downstream of a recloser with a low setting. This is verified below in Figure 11. Nuisance tripping only occurs when the PV is placed downstream of an end-of-line (EOL) recloser (Reclosers 2 and 5).

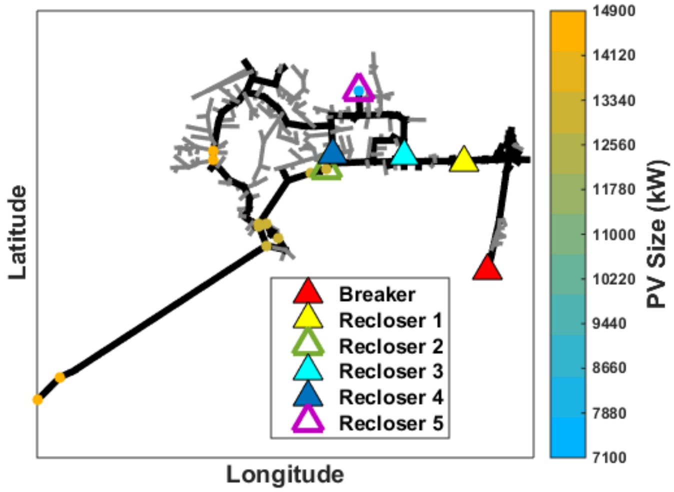

Figure 11. Maximum PV size allowed at each viable placement bus in feeder QL1 due to nuisance tripping.

C. *Distribution System QL2*

Test feeder QL2 is a very robust circuit with only one breaker and no reclosers. As such, its protection-limited hosting capacity is only limited by the point at which the reverse current from the PVs causes sympathetic tripping in the breaker when placed anywhere in the network, as shown in Figure 12.

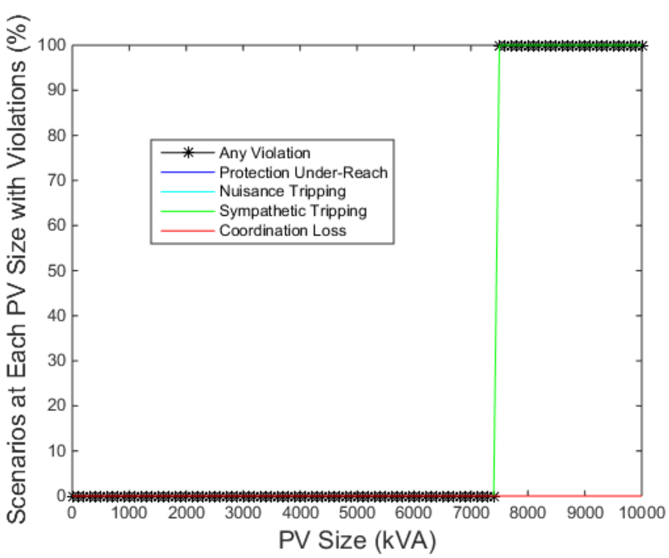

Figure 12. Feeder QL2 PV installation location violation summary.

D. *Distribution System QN1*

Test feeder QN1 has two line reclosers in addition to the substation breaker. It too has no coordination or under-reach issues, indicating its TCC are well buffered. It also has no nuisance tripping since its PDs are all in series. This leaves sympathetic tripping as the only issue, as shown in Figure 13.

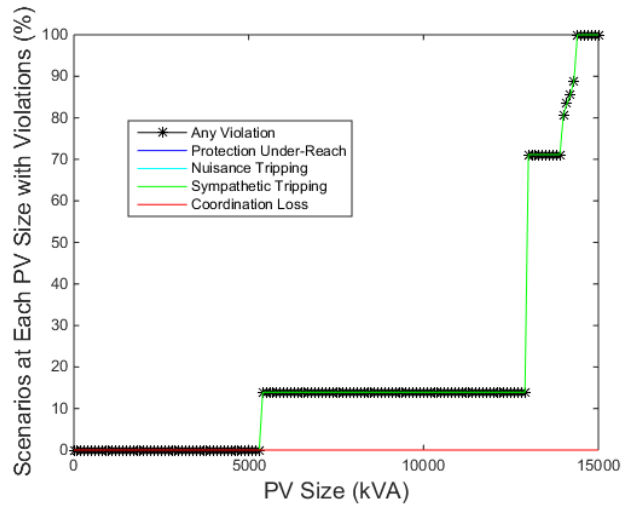

Figure 13. Feeder QN1 PV installation location violation summary.

V. Conclusions and Discussion

This paper presents an approach for determining the PV hosting capacity of actual distribution networks as limited by their impact to the existing network protection scheme due to steady-state fault current injection by the PV. Large numbers of PV installation sites and potential faults are tested to get a complete view of when PV systems cause a failure of network protection. The findings show that the injection of fault current from the PV can increase or decrease the current seen by PDs in the network, potentially causing PDs to fail to trip or trip undesirably.

Since distribution PDs are typically tuned assuming no local generation, the coordination of which PDs trip for which faults can be altered from the intended design by the PVs. If a utility is unwilling to invest in upgrading the protection schemes of their distribution networks or suffer slightly lower reliability, then the PV sizes must be limited. Another way of saying this is that the PV hosting capacity of the network is constrained by their potential negative impact on protection.

It is shown that if the PDs in the network are already tightly coordinated then not much PV may be placed in the network. To fix this issue, a utility would have to re-engineer the protection scheme to allow for more of a coordination buffer between upstream and downstream PD TCC. However, there may be physical constraints such as equipment damage curves, minimum tripping times, and peak load current allowances preventing a re-design.

After coordination, the most limiting violation to allowed PV size is due to reverse current from the PV causing false tripping either due to faults on a nearby feeder or on a lateral branch within its own feeder. One way to completely mitigate this issue would be for the utility to invest in directional current sensing PDs. However, this may be costly if applied over many networks. Some improvement in the size of PV that first causes sympathetic tripping may be gained by increasing the pick-up current of the PDs, particularly the downstream reclosers. However, this of course is constrained by the PDs protection zone and may lead to PV-induced under-reach situations.

The reason under-reach is never a problem in these test feeders is because the PDs that see EOL have large over-reach, as summarized in Table 1. For under-reach to occur, the PDs nearest EOL must not be able to see the fault due to the PV supplying most of the fault current rather than the substation. Therefore, the smallest PV size capable of this must overcome the difference in base-case minimum fault current and the PDs pick-up. Under-reach is easiest to occur with 3PG and LL faults since there is no ground current during the fault that could be picked up by the PD.

Table 1. Summary of test circuit breaker pick-up values and maximum end-of-line (EOL) fault current.

Test Circuit	kV	EOL PD Pickup (A)	Min 3PG I_{Fault} (A)	Min. Ratio of Fault:Pickup
QS1	12	400	866	2.16
QL1	20	360	1665	4.63
QL2	12	720	2066	2.87
QN1	20	300	3174	10.58

For under-reach to occur for even the most likely case in Table 1, a PV placed between the fault and the recloser would have to decrease the current seen by the EOL recloser by 466A. This corresponds to a 9.7MW PV at rated output, which is just within the range of tested sizes. However, the current from the substation feeding the fault through the recloser does not reduce linearly with increasing PV size. For this reason, it takes a PV of 13.0MW to bring the fault current seen by the recloser below its 400A pickup to cause under-reach, as shown in Figure 14.

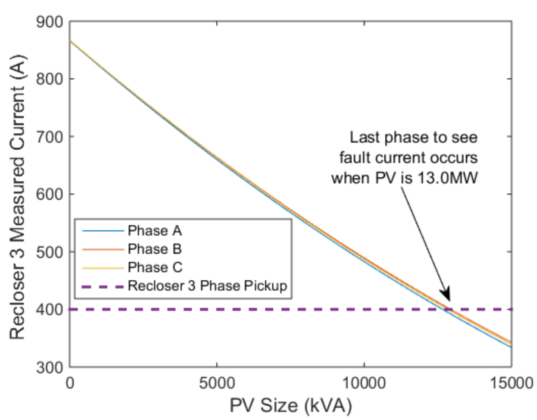

Figure 14. Change in fault current seen in feeder QS1 Recloser 2 due to EOL fault and PV placed just downstream of recloser.

However, if the TCC are modified to raise the minimum pick-up in an effort to prevent reverse-current violations, then under-reach violations would occur at lower PV sizes. Future research will study the trade-off between these two violations and seek to find the maximum amount of PV that may be placed on a network by optimizing the PD TCC around all violation types.

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