TEMPORARY OVERVOLTAGE ISSUES IN DISTRIBUTION-CONNECTED PHOTOVOLTAIC SYSTEMS AND MITIGATION STRATEGIES

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Abstract

Photovoltaic (PV) systems continue to be deployed on U.S. utility systems at a brisk pace. As the industry matures, it is having to contend with issues that are well-known to other types of distributed generator (DG) manufacturers, such as temporary overvoltage (TOV) phenomena. There are TOV concerns with PV, just as there are with other types of DG, but traditional thinking regarding TOV prevention is largely based on experience with rotating machines, which does not necessarily directly apply to inverter-based DG like PV. One particular aspect in which this is true is in the requirement that PV systems present a well-grounded source to the system, with "effectively grounded" being defined in IEEE 142. This paper discusses the rationale behind requiring the PV to be well-grounded, but also presents an argument suggesting that this requirement does not solve the problem, with support from a simulation study.

Introduction

It has long been known that distributed generators (DGs) connected to distribution feeders have the potential to cause temporary overvoltage (TOV) events, particularly during single line to ground (SLG) faults. Photovoltaic (PV) systems are no exception, and in fact may raise concerns more often than other types because they tend to be installed on the lowest-voltage parts of the system, and potentially at any point on a feeder. There are five key physical mechanisms through which DGs can drive a TOV event.

TOV mechanism #1: Ground potential rise

Ground potential rise (GPR) is caused by the finite (actually rather low) conductivity of earth, and occurs when large currents flow into grounding conductors. This current flows through the impedance between the grounding conductor and "remote earth" (usually assumed to be the zero-potential reference), causing a voltage to appear between the grounded conductor and that zero reference. GPR is a somewhat complicated phenomenon, because it depends on the geometry of the grounding conductor, soil types, soil moisture content, and other factors, and varies strongly as a function of season [1]. GPR is discussed in IEEE standard 142-2007, "Grounding of Industrial and Commercial Power Systems" (the Green Book) [2].

TOV mechanism #2: Neutral point shifting, or derived neutral shift

Neutral point shifting occurs in three-wire (delta) systems during an SLG fault, because one corner of the delta becomes ground-referenced by the fault. Figure 1 demonstrates this phenomenon using vector diagrams. Assuming that the phase voltages were initially balanced, in the pre-fault condition the center of the delta is at the origin, so the "neutral point" of the delta is at zero. When the SLG fault strikes (applied to phase b in this case), the faulted phase is now ground-referenced. The system maintains the line-to-line voltage relationships, so voltages V_{ab} and V_{bc} remain the same post-fault, but because the delta is now referenced to phase b, $V_{an} = V_{ab}$ and $V_{cn} = V_{bc}$. The problem with this is that any single-phase load connected between one of the non-faulted phases and the neutral (assumed to be multigrounded) will now see the line-line voltage, instead of the line-neutral voltage it is supposed to see. This overvoltage will be 1.73 p.u. if feeder impedances are neglected, which will fall outside of the CBEMA curve if it persists for more than approximately 2 msec. Damage to those single-phase loads then becomes highly likely. This situation can occur if a PV system is connected to a distribution feeder through a delta-Yg transformer, with the delta on the HV side and the LV Y-side grounded. The substation transformer usually has a grounded-Y on the feeder side, but if the SLG fault causes the substation breaker to open, then the feeder is being fed only by the delta-connected PV which no longer has a ground reference on the feeder side.

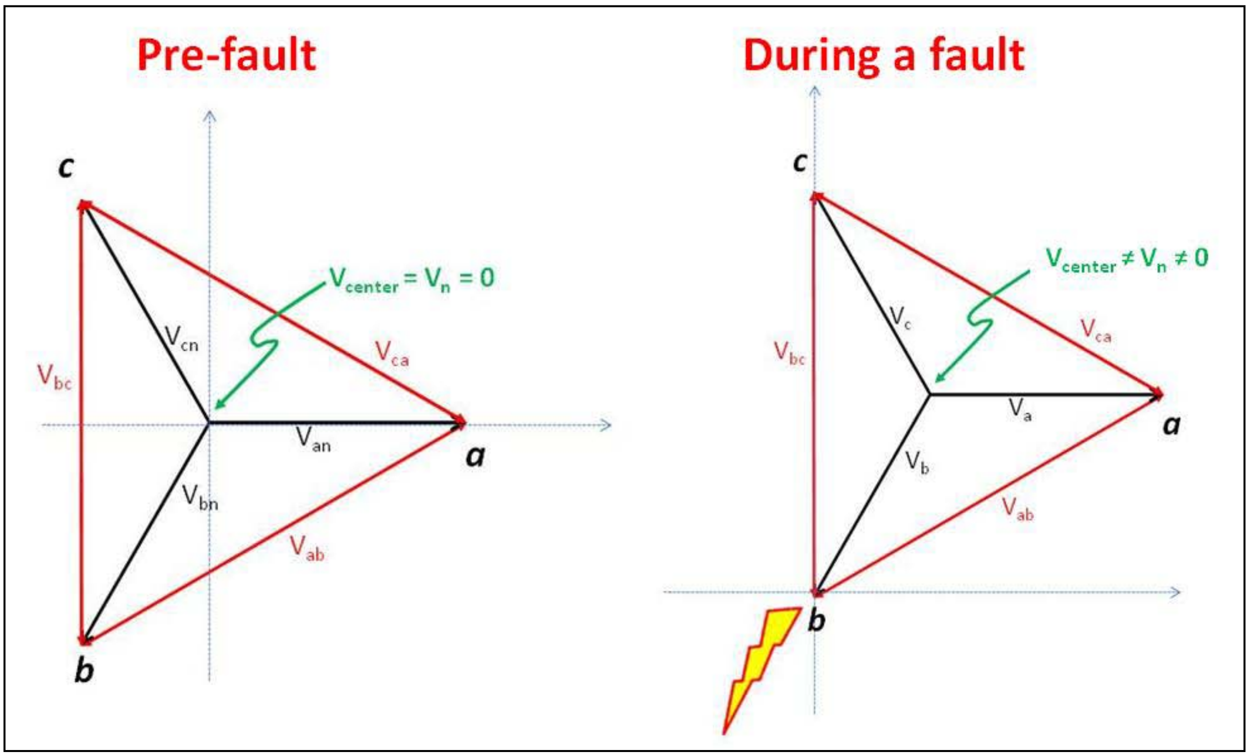

Figure 1. Explanation of TOV mechanism #2, neutral point shifting.

<u>TOV mechanism #3: Inductive coupling between fault currents and non-faulted phases</u>

Under normal operation, each phase induces a small voltage drop in neighboring phases and in the neutral conductor because of inductive coupling of the phase current to the other phases. The mutual inductance between phases is relatively small, particularly for overhead lines, so when carrying load currents these induced voltages usually have only a minor effect. However, fault currents can be more than an order of magnitude larger than load currents, which causes a similar increase in the inductively induced voltage in the unfaulted phases and in the neutral.

Inductive coupling is the dominant TOV-producing mechanism while the substation breaker is still connected [3], but if the distributed generation is PV, the importance of inductive coupling usually diminishes after the breaker opens because the PV system does not supply significant levels of fault current.

TOV mechanism #4: Interruption of significant power export

This condition occurs when a switch opens while the PV is exporting significant power back to the system, which of course requires that the aggregate PV penetration level on the feeder be sufficiently high that the PV is larger than the load during some daylight hours. This situation is depicted in Figure 2. During export, the PV system output current i_{PV} is larger than that required by the local load, i_{load}, and thus the current back to the grid i_{grid} is positive. If the switch at the right opens while i_{grid} is particularly large, then $i_{PV} = i_{load}$, meaning that i_{load} becomes much larger than before the switch opened. By Ohm's law, the load voltage V_{load} will rise in proportion to the level of increase in i_{load}.

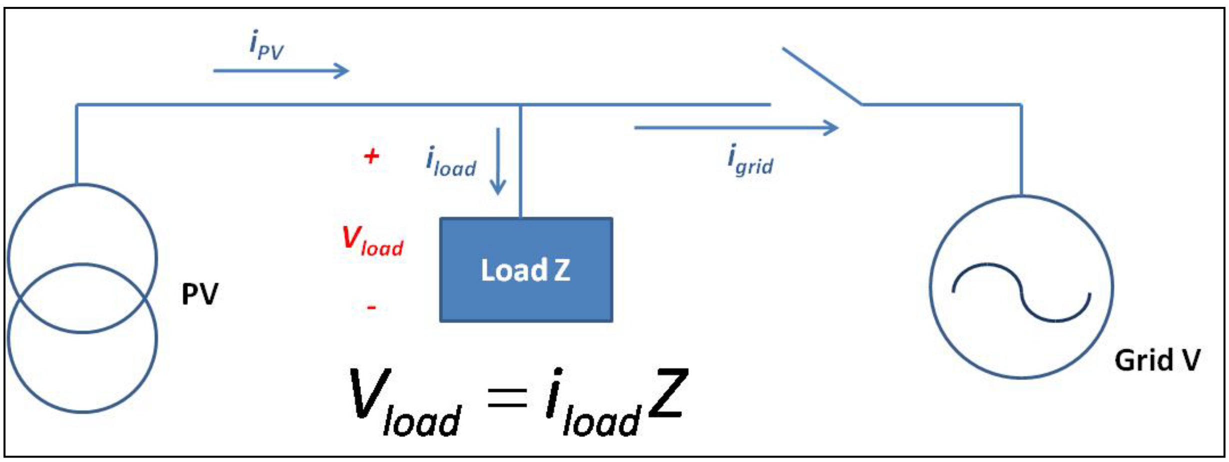

Figure 2. Explanation of TOV mechanism #4, interruption of significant power export.

TOV mechanism #5: Interruption of inductive currents

This problem is well known to (and hated by) power electronics engineers and designers of large AC interrupters. If one attempts to open a switch that is in series with an inductance while that inductance is carrying a current, the inductor's magnetic field collapses and produces a voltage spike that induces an arc. This phenomenon is one key reason for the existence of snubbers on such switches. Any loads connected between the switch and the inductance will also see this voltage spike.

Relative importance of the five mechanisms

Although any of the five mechanisms can be important in different circumstances, only two, mechanisms #2 (derived neutral shift) and #4 (interruption of large export current), are of primary importance for PV. Mechanism #1, GPR, is less important for PV than for some other types of DG because of PV's limited ground current contribution, and is also more of an issue concerning the grounding system than the specific type of DG. As noted earlier, mechanism #3, inductive coupling to fault current, is very important while the grid is connected and in rotating-machine cases because of the large fault currents, but because PV contributions to fault current are relatively small, mechanism #3 is not dominant for PV. Similarly, mechanism #5, interruption of inductive currents, has more to do with the switches involved and the nature of system impedances than with PV in particular.

Problem statement

Because of its increasing frequency of appearance as a utility concern, the focus of this paper is on mechanism #2, the derived neutral shift. As noted above, mechanism #2 occurs when a PV system is tied to a distribution feeder through a delta-Yg transformer and an SLG fault occurs. The utility usually presents a grounded source to the feeder via a delta-Yg substation transformer with the Yg on the feeder side. When the substation breaker opens, the only remaining source (for a very brief time) is the PV, which has a delta on the feeder side. Thus, one apparent mitigating strategy would be to require the PV to connect to the feeder via a Yg-Yg distribution transformer. However, one additional requirement is usually imposed: that the PV plant present a well-grounded source to the utility, with well-grounded defined as in IEEE 142 [4]. The reason for this requirement can be understood more easily by considering the Yg-Yg transformer schematic in Figure 3. Assume for the moment that the SLG fault is applied to phase c. The voltage V_{CH} will then collapse to near zero, and that low voltage is transformed across to V_{CX} on the LV side. This means that phase c is effectively ground-referenced on the LV side of the transformer as well. If a generator is now connected to the X terminals of the transformer, that generator's c phase is ground referenced, and if the generator maintains the phase-phase voltage relationship (i.e., the generator fixes V_{bc} and V_{ca}), then the generator's neutral point can shift, that shifted neutral point is transformed across the Yg-Yg transformer, and the Yg-Yg transformer has not solved the problem.

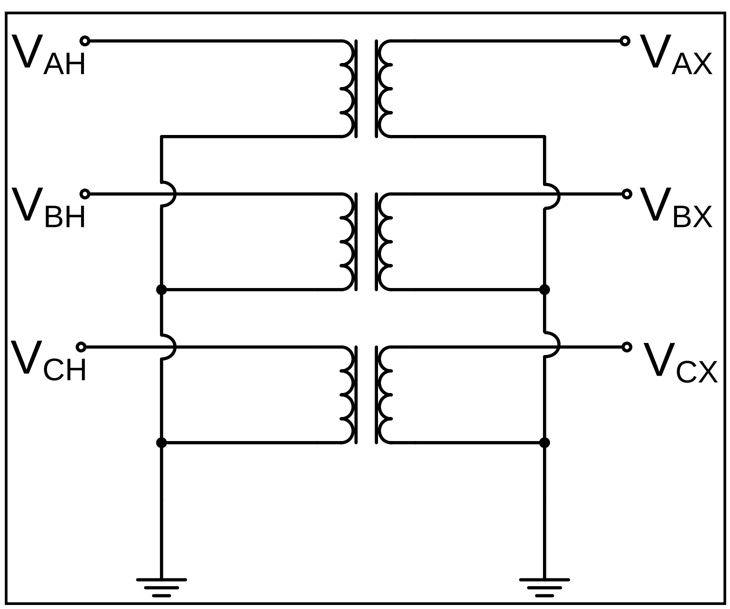

Figure 3. Schematic of a Yg-Yg transformer.

In this case, the solution seems clear: the neutral point of the generator must be effectively grounded, and this is where the IEEE 142 definition comes into play. The IEEE 142 definition of "effectively grounded" requires both of the following two conditions to be met:

$$0 \leq \frac{X_0}{X_1} \leq 3$$

$$0 \leq \frac{R_0}{X_1} \leq 1$$

where X_0 and X_1 are the generator's zero- and positive-sequence reactances, respectively, and R_0 is the generator's zero-sequence resistance.

For synchronous generators, this makes sense, and it should be noted that IEEE 142 is relatively clear that its writers had synchronous generators in mind when the requirements were developed [5]. However, for PV plants, it is very difficult to comply with the IEEE 142 definition of effectively grounded. Because most PV inverters have relatively low positive sequence reactance (the main contributor being the isolation transformer, along with AC filter inductances), the definition of effectively grounded usually cannot be met by an impedance ground, and instead requires solid grounding [6]. Solidly grounding the PV plant in this way leads to significant problems with neutral current flows and harmonics, along with other controls and reliability issues, and is thus generally undesirable. Thus, if such a costly requirement is to be imposed on PV systems, it is imperative to ensure that it actually does solve the problem.

<u>Results and discussion</u>

<u>Theory</u>

There is a fundamental difference between PV and a synchronous generator in that the PV appears to the grid as a controlled current source. It is key to note that the PV does not act as a voltage-behind-impedance source, as a synchronous generator does, and neither does it act as a power-controlled source. The PV inverter controls its AC output current in such a way as to try to maximize the power being extracted from the PV array at any given time. Thus, in the small space of time between the opening of the substation breaker and the shutdown of the PV system, the islanded section of the feeder can be represented as shown in Figure 4 below.

This representation of the PV plant is valid as long as the inverter's terminal voltage does not rise too high. If the voltage does rise too high, the inverter's controls will saturate, and the inverter will enter a square-wave mode of operation, also known as six-step mode [7] in which the PV plant does appear as a voltage-behind-impedance source. However, this condition is easily detectable, and most inverters incorporate self-protection means that shut the inverter down anyway if the AC terminal voltage gets that high. Thus, it is reasonable to represent the PV as shown in Figure 4.

Assume for a moment that the feeder neutral is well-grounded, and that the delta-connected loads are either negligible, or very well balanced so that they can be lumped in with the grounded Y-connected load without much loss in accuracy. Consider the voltage $V_{PV,c}$ in Figure 4. When the island forms, $V_{PV,c}$ becomes equal to the product of $i_{PV,c}$ and the equivalent phase-to-neutral impedance, by Ohm's Law. Note that $V_{PV,c}$ is ground-referenced because the load is ground-referenced, and $V_{PV,c}$ does not depend on whether the inverter is grounded. In other words, this argument suggests that requiring the PV plant to be an effectively-grounded source according to IEEE 142 is unnecessary, because such grounding will not affect the level of TOV produced by a PV inverter, and thus would add cost without solving the problem.

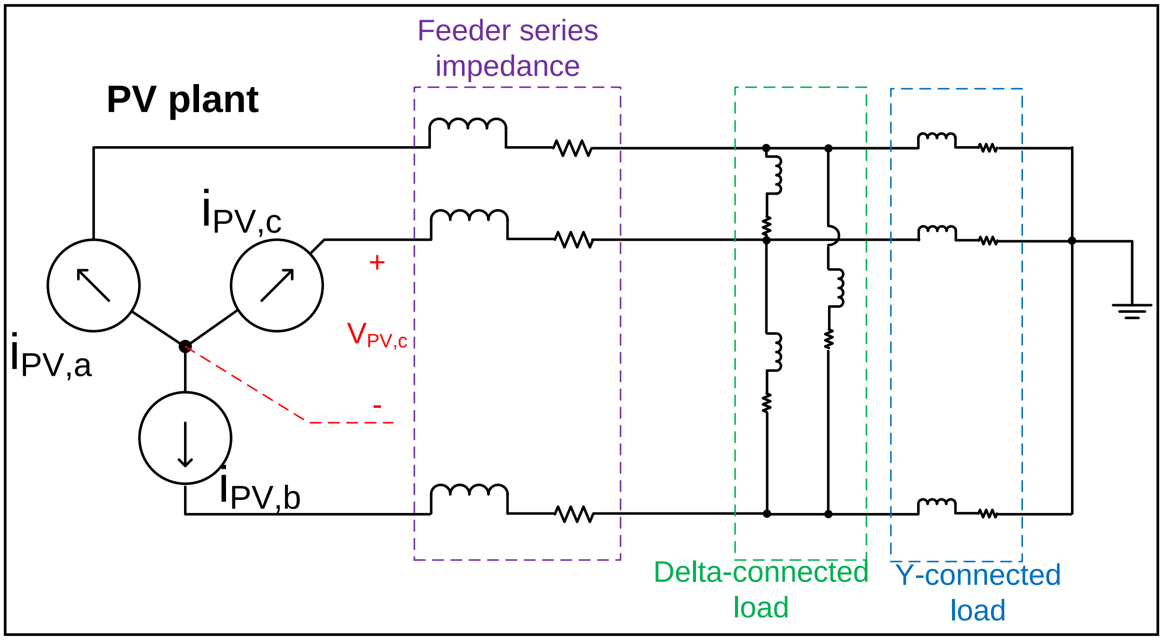

Figure 4. Highly simplified schematic of a grid-tied PV system feeding an islanded load, after opening of the substation breaker.

Simulation study to test theory

To investigate this phenomenon more fully, a lengthy computer simulation study was conducted using the MATLAB-Simulink environment. First, the generic feeder model presented in [3] was built as shown in Figure 5. This model was selected because it is specifically designed for TOV studies, and [3] contains all of the required feeder segment parameters as well as model validation data. Then, a well-verified PV plant model was added. A detailed switching model was used, because it was found early in this work that a switch-averaged model, which uses a current-source representation of the power electronics, significantly overpredicted the levels of TOV seen on the feeder. (This is a subject of interest in itself, but is beyond the present scope.) The inverter's voltage measurements for control and tripping purposes are made from phase to ground. The inverters include all of the IEEE 1547 trips, plus an extra high-voltage fast-trip setting that is included by most manufacturers for self-protection purposes. The PV plant was added at a point near the substation, as shown in Figure 5, because earlier work suggested that the worst case mechanism #2 TOV was produced when the fault was as far downstream from the PV plant as possible. Also, adding the PV plant near the substation provided the most flexibility in locating the fault. Consequently, the fault used for this work is the one labeled "Fault5" on the right side of Figure 5.

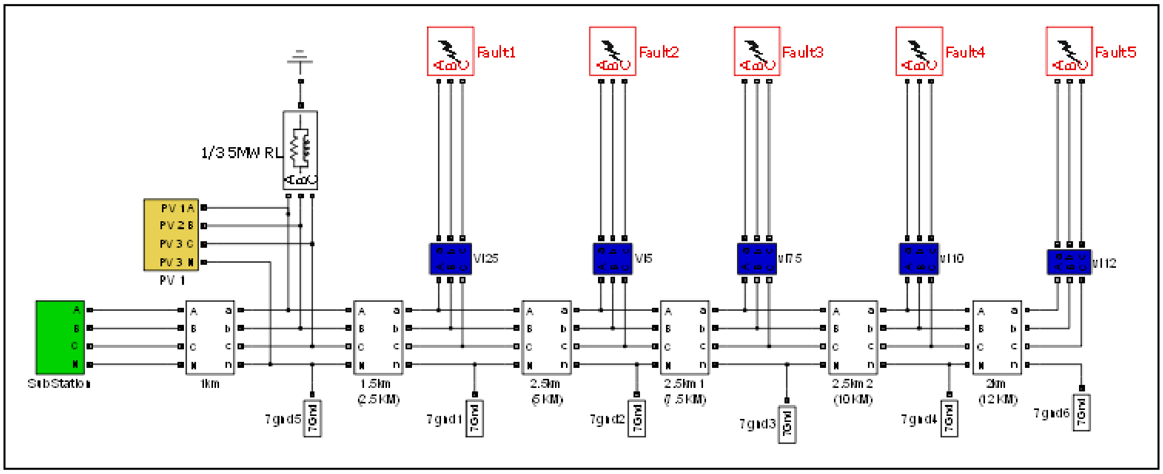

Figure 5. MATLAB/Simulink model of the feeder presented in [3].

Once this was completed, the following matrix of conditions was simulated:
PV to load ratios: 2:1, 1:1, 0.67:1
Distribution transformer configurations: Δ-Yg, Yg-Yg
Isolation transformer configurations: Y-Y, Y-Yg, Δ-Y, Δ-Yg

Every combination of these parameter values (total of 24) was simulated. The impact of the grounding of the 480-V side of the inverter internal isolation transformer on TOV, as seen on the 25 kV distribution feeder, was recorded. One terminological convention that has been adopted here should be explained: this paper refers to a "first TOV" and a "second TOV". The first TOV is the TOV that occurs after the fault occurs, but before the substation breaker opens. This TOV is caused primarily by TOV mechanisms 1 and 3, and is generally fairly small. The second TOV then occurs after the substation breaker opens. If the PV to load ratio is in the range of approximately 1 to 1.5, the second TOV is caused primarily by TOV mechanism #2, derived neutral shift; for PV to load ratios larger than 1.5, the TOV becomes dominated by TOV mechanism #4, interruption of heavy export. The second TOV is the primary concern in this work.

The results of the simulations are shown in Figures 6 and 7. Figure 6 collects the results of all simulations in which the inverter's isolation transformer was a Y-Y or Y-Yg (i.e., the PV system presents an ungrounded Y to the feeder, or a grounded Y, respectively). The figure is read as follows. There are four groups of columns in the figure. The first (leftmost) group of columns shows voltages during the "first TOV" period if the distribution transformer is Yg-Yg, and the second group of columns shows the "second TOV" period for the Yg-Yg distribution transformer. In these two groups of columns, each colored column corresponds to a specific isolation transformer configuration and generation:load ratio. The isolation transformer configuration (either Y-Y or Y-Yg) and generation:load ratio (2:1, 1:1, or 0.67:1) corresponding to each color of column are given in the legend at the right of the figure.

The third and fourth groups of columns in Figure 6 (the rightmost two) are the same as the leftmost two just described, except that the distribution transformer is now delta-Yg (labeled

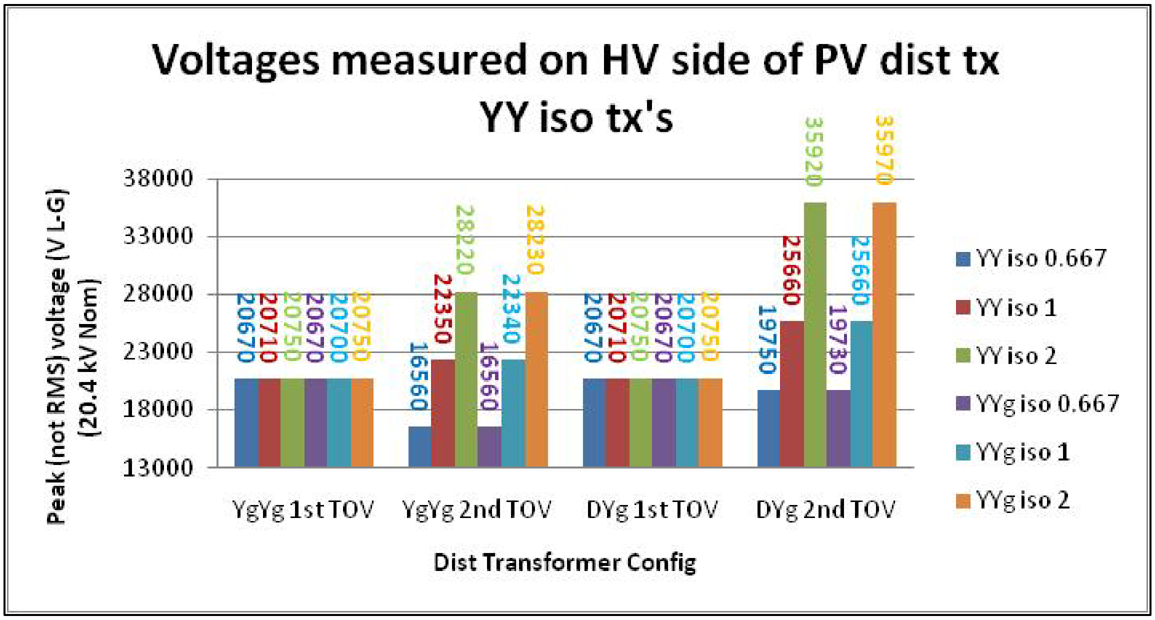

Figure 6. Peak (not RMS) line-to-ground voltages measured on the HV side of the PV distribution transformer during the SLG fault event. Values are shown for the first TOV period (substation breaker closed) and second TOV period (substation breaker open), for two distribution transformer configurations, Yg-Yg and delta-Yg. Colored columns correspond to specific PV inverter isolation transformer configurations and generation:load ratios, as described in the legend at the right.

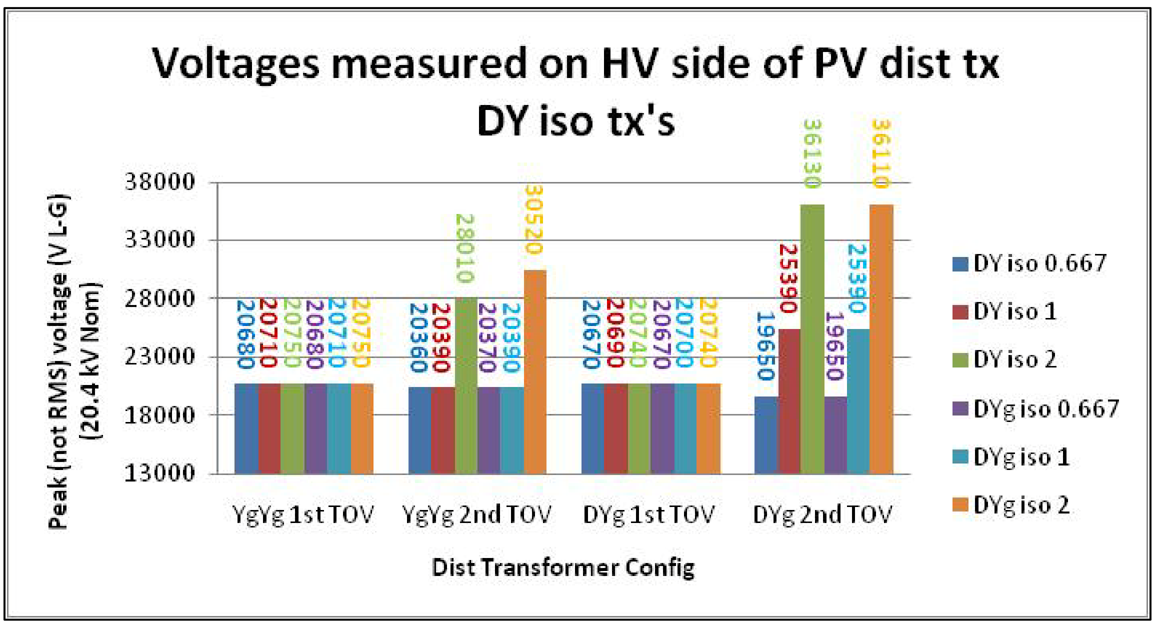

Figure 7. Peak (not RMS) line-to-ground voltages measured on the HV side of the PV distribution transformer during the SLG fault event. Values are shown for the first TOV period (TOV mechanism #3 is dominant) and second TOV period (TOV mechanism #2 is dominant), for two distribution transformer configurations, Yg-Yg and delta-Yg. Colored columns correspond to specific PV inverter isolation transformer configurations and generation:load ratios, as described in the legend at the right.

"DY" and "DYg" in the figure). Figure 7 is similar to Figure 6; the only difference is the isolation transformer configurations, which are delta-Y and delta-Yg (compare the two right-side figure legends). The voltages shown in Figures 6 and 7 are peak (not RMS) voltages, and are the highest voltage recorded during the respective TOV period (first or second), on any phase.

As expected, Figures 6 and 7 show that the distribution transformer makes a considerable difference in the level of TOV seen, with much higher levels of TOV occurring for the delta-Yg transformer because of TOV mechanism #2. It is also clear that the generation:load ratio makes a considerable difference. A full discussion of this issue is outside the present scope, but it should be noted that when the generation:load ratio is less than unity, there really is no second TOV, even with a delta-Yg distribution transformer, because the power-limited PV source has insufficient power available to drive the low-impedance load to high voltage. When the generation:load ratio is greater than unity, TOV mechanism #4 comes into play, and TOV levels rise.

However, the main result for the present discussion is seen by comparing the second TOV levels with grounded and ungrounded inverter isolation transformers. For example, consider Figure 6, and focus on the rightmost group of columns, which give the second TOV for a delta-Yg distribution transformer. Consider the case of a generation:load ratio of 1:1, which is the reddish-colored and the light blue columns (the second and fifth columns of that group). The numerical value of second TOV is given above each column, and they are equal at 25660 V, or about 126% of nominal. The fact that they are equal is the important point: the grounding of the inverter isolation transformer made no difference. This conclusion holds for all of the second TOV cases with either delta-Y or Y-Y isolation transformers.

Conclusions

Both theory and simulation results support the conclusion that requiring PV inverters to be effectively grounded according to the IEEE 142 definition is not justified by concerns arising from asymmetrical fault situations and temporary overvoltage. This does NOT mean that PV systems do not cause TOV, but it does suggest that requiring PV inverter isolation transformers to be grounded does not effectively mitigate TOV.

Acknowledgments

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[2] IEEE standard 142-2007, "IEEE Recommended Practice for Grounding of Industrial and Commercial Power Systems". The GPR discussion is in Sections 1.13, page 63, and in Subsection 2.2.3, page 93.

[3] J. Acharya, Y. Wang, W. Xu, "Temporary Overvoltage and GPR Characteristics of Distribution Feeders with Multigrounded Neutral", *IEEE Transactions on Power Delivery* **25**(2), April 2010, p. 1036-1044.
[4] IEEE standard 142-2007, "IEEE Recommended Practice for Grounding of Industrial and Commercial Power Systems". The definition of "effectively grounded" is on page 2, definition 1.2.1.
[5] IEEE standard 142-2007, "IEEE Recommended Practice for Grounding of Industrial and Commercial Power Systems". The discussion in Section 1.7 makes it clear that the authors meant "rotating generator" when they said "generator". PV does receive a brief mention in Section 1.15.7, but that section is discussing DC-side grounding only.
[6] IEEE standard 142-2007, "IEEE Recommended Practice for Grounding of Industrial and Commercial Power Systems". Solid grounding is defined and discussed in Section 1.4.6, page 17.
[7] N. Mohan, T. Undeland, W. Robbins, Power Electronics: Converters, Applications, and Design, 3rd ed., pub. John Wiley and Sons 2003, ISBN 0471226939. Square-wave inverter operation is described in Section 8-4-2, page 229, and the term "six-step mode" is defined on page 418.