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Effective Grounding for Inverter-Connected DER

Final Report

3002020130

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Technical Update, February 2021

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ABSTRACT

Effective grounding is a characteristic of electric power systems for limiting ground fault overvoltage and considered in coordination of fault current protective devices. Adding distributed energy resources (DER) can affect power system grounding and is normally evaluated in the interconnection review process. The research reported here focused on effective grounding during island conditions and aimed to clarify grounding requirements with inverter-based DER. The research is motivated by the need to true up long-standing grounding practices for machine DER with evolving practices for today's more common inverter-based DER. It also provided DER plant ground source screening guidelines for a more transparent and consistent review process.

This report starts with the fundamentals. It explores the meaning of effective grounding, basic principles, ground sources, and the role of DER transformer connections, load types and tripping response of inverters. It also addresses the application and sizing of grounding transformers, impedance selection, protection coordination considerations and related side effects. DER capabilities such as negative sequence current compensation are discussed. An inverter grounding design tool (ISGT) is introduced.

Key takeaways for the work are:

- Effective grounding is a "power system" characteristic, affected by DER.
- Inverters' need for supplemental grounding and their responses to ground fault and grid disconnection are significantly different than synchronous machines.
- Many classical power system grounding practices are not ideal for inverter-based DER plants.
- Supplemental grounding can have undesirable side-effects and optimum design is less well-defined for inverters.
- Load is becoming a key factor to consider with increasing inverter penetration.

Keywords

Distributed energy resources
Inverter-based DER
Effective grounding
Supplemental grounding
Ground source
Inverter negative sequence impedance
Ground fault overvoltage

EXECUTIVE SUMMARY

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PRIMARY AUDIENCE: Utility technical staff, planners and research community involved with distributed energy resources (DER) interconnection criteria, technical reviews or protection requirements. Results are particularly applicable in areas with expected high-penetration of inverter-based DER systems (PV or energy storage batteries) on distribution circuits.

SECONDARY AUDIENCE: Stakeholders responsible for distributed energy resources (DER), planning activities, project design, interconnection reviews, and system impact studies. This included consultants and plant developers, inverter manufacturers and other stakeholders in the business of DER.

KEY RESEARCH QUESTION

The key questions to answer are:

1. What is different about inverter-based generation in comparison to rotating machines?
2. Is an assumption that inverters are current sources always accurate and when do the start to look like voltage sources? Can this complex transition be modeled?
3. Are there any negative impacts of supplemental grounding – such as protection de-sensitization, arc flash?
4. What is important to consider from a modeling perspective? What are limitations of models?
5. When is supplemental grounding needed and why?
6. Which type of supplemental grounds could provide the optimal solution and how to size it? Why should grounding impedance be matched to the load?

RESEARCH OVERVIEW

This project aims to true up long-standing grounding practices with evolving practices for inverter-based DER with capabilities such as negative sequence current compensation. Specific objectives are to improve the technical review process and to make grounding requirements more transparent and consistent. The project explores the meaning of effective grounding, basic principles, and important role of DER transformer connections, load types and fast tripping capability of DER. It also will address application and sizing of grounding transformers, grounding impedance selection, potential interference with protection coordination and related side effects.

KEY FINDINGS

- Effective grounding is a “power system” characteristic, affected by DER.
- Inverters’ need for supplemental grounding and their responses to ground fault and grid disconnection are significantly different than synchronous machines.

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- Many classical power system grounding practices are not ideal for inverter-based DER plants.
- Supplemental grounding can have undesirable side-effects and optimum design is less well-defined for inverters.
- Load is becoming a key factor to consider with increasing inverter penetration.

WHY THIS MATTERS

This research work is expected to provide a better understanding of grounding and other related issues for inverter-based DER making interconnections more cost-effective. For example, mitigation of ground fault overvoltage from inverter's dynamic response as opposed to relying on external supplemental grounding transformers or time coordinated direct transfer trips. This can translate into a lower installation and maintenance costs, and potential efficiency improvements for both PV and battery storage systems. Power quality may also be improved. Results will inform utilities and support inverter manufacturers to better optimize designs and to make future inverter-based DER more capable of ground fault overvoltage (GFOV) and load rejection overvoltage (LRO) mitigation.

Moreover, this work may help to avoid unnecessary costs of grounding transformer or a time coordinated DTT, which could bring additional expense ranging from 5% to 10% of PV system cost depending on the system size and location. Associated energy loss and maintenance needs will be avoided as well. In addition, avoiding unneeded devices and systems should in theory improve system reliability and resiliency.

HOW TO APPLY RESULTS

Results suggest that for utilities contemplating grounding requirements for high DER penetration applications, use this material as a reference and to guide questions about effective grounding of inverter-based DER. Confirm that supplemental grounding is really needed and well designed for specific systems. Share lessons-learned regarding grounding issues as well as the mitigation and protection such as submittal requirements, screening review, protection studies and commissioning practices. Moreover, DER manufacturers need to consider the "masking" effect that could be brought by interconnection transformers with zero sequence discontinuity, and to ensure the effectiveness of transient overvoltage limit for MV side ground faults. With expected higher penetration levels, the risk of ground fault overvoltage and load rejection overvoltage and their mitigations should be reviewed as early as possible in the inverter design stages.

LEARNING AND ENGAGEMENT OPPORTUNITIES

- This ongoing project promotes industry collaboration including workshops with participants, sharing of DER interconnection practices and recommendations on DER interconnection transformer configuration selection and/or measures to provide supplemental grounding.
- The results are of wide interest not only for any utility handling inverter-based DER interconnections to their distribution system (penetration level may be high or low), but also other stakeholders in grid connected. EPRI research programs directly involved in this work are Integration of Distributed Generation (P174) and Distribution Protection (P200C).

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PROGRAM: Integration of Distributed Energy Resources (P174)

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1
INTRODUCTION

Overvoltage Concerns with DER In Distribution

When islanded from the primary system ground, DERs can contribute to a ground fault overvoltage (GFOV) on the unfaulted phases in a 4-wire system. As illustrated in Figure 1-1, for machine based DER, a fault on one phase causes a neutral shift toward the faulted phase. This elevates phase to neutral voltage on the unfaulted phases shown as a swell. At the same time there is a dip in the faulted phase voltage (see vector diagrams) until the fault is removed.

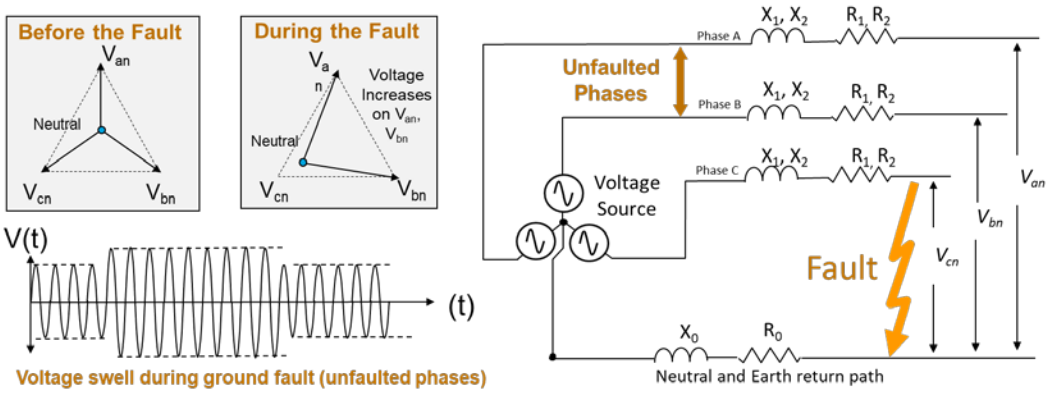


Figure 1-1
Overvoltage caused by neutral shift during a ground fault on phase C

The greater the neutral shift, the higher the overvoltage will be on the unfaulted phases. The worst case occurs with ungrounded neutral with infinite impedance for neutral and earth return path. In this case the neutral voltage shifted to the pre-fault V_{cn} (faulted phase), leading to V_{an} and V_{bn} with line-to-line magnitudes (173%), as shown in Figure 1-2. Voltage line to neutral on the faulted phase C is therefore zero.

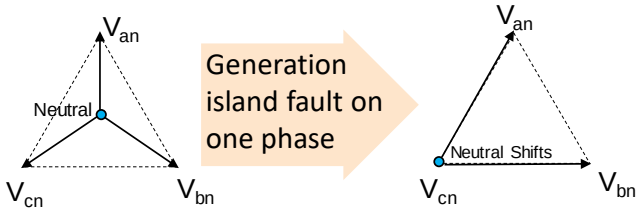


Figure 1-2
Overvoltage with ungrounded neutral during a ground fault on phase C

Figure 1-3 illustrates example GFOV potentials in medium voltage (MV) and sub-transmission. The feeder has a primary ground source provided by the Δ-Yg transformer at the distribution substation. A ground fault on the distribution feeder causes the substation breaker to open and removes the primary system ground source. With all ungrounded sources within the island system (orange area), equipment such as arresters may be exposed to a sustained power

frequency overvoltage if DER continues operating. A similar scenario can be seen at sub-transmission in the yellow area. Aggregate DER in both sub-transmission and distribution systems can cause GFOV on unfaulted phases after loss of the bulk system ground source.

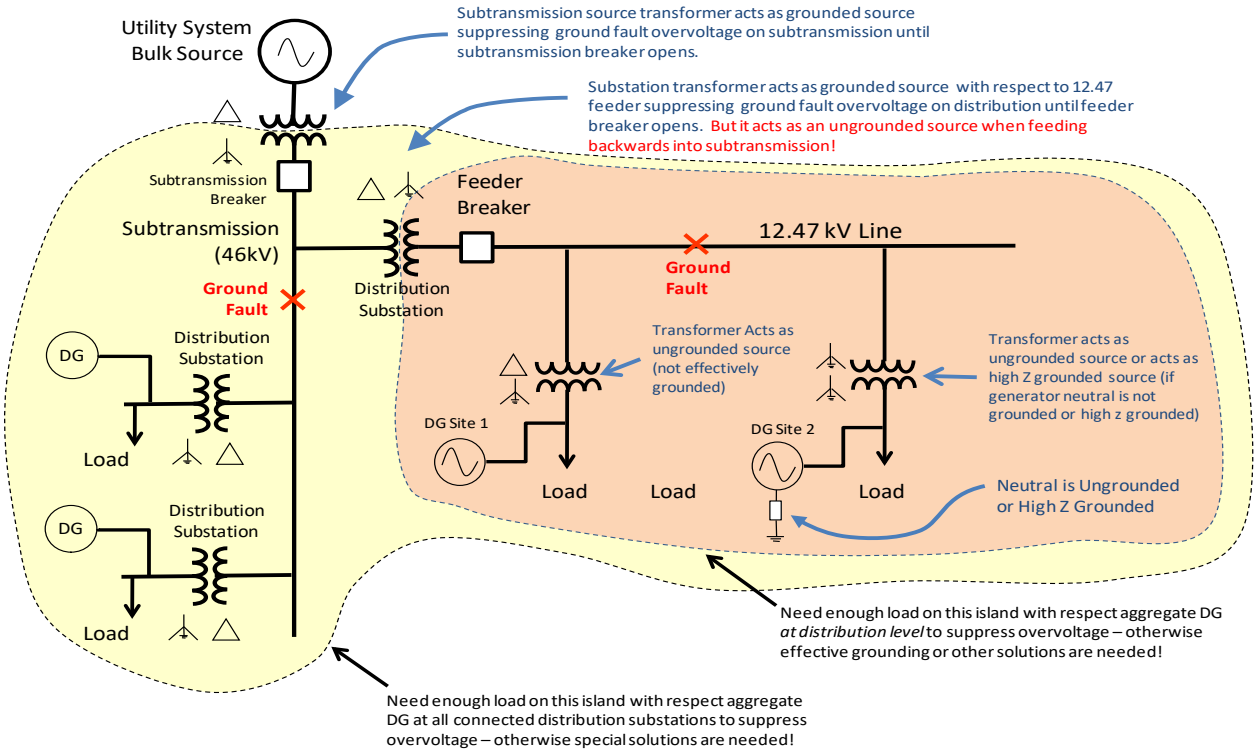


Figure 1-3
Example island with ground fault overvoltage risk

For both distribution and transmission, the GFOV can stress line-to-ground connected devices including MV surge arresters, power and measurement transformers, and end-use customer equipment.[1]

Effective Grounding of Power Systems

Coefficient of Grounding

As defined in IEEE C62.92.1, if a system or isolated subsystem has a coefficient of grounding (CoG) less than 80%, it is "effectively grounded". CoG is the ratio of the greatest unfaulted phase-to-ground voltage during a ground fault divided by the line-to-line voltage without the fault, i.e., $V_{L\text{-}G(fault)}/V_{L\text{-}L\ (no\ fault)}$. Therefore, ***COG ≤0.8 p.u. limits GFOV to 0.8 × $V_{l\text{-}l}$ or 0.8 x $\sqrt{3}$ ~ 138% of $V_{L\text{-}G\ (no\ fault)}$***. Note that a high unfaulted phase voltage at high gen/load ratios could still be effective grounding (i.e., $V_{L\text{-}G(GFO+LRO)}/V_{L\text{-}L\ (LRO)}$ ***≤0.8 p.u.***). Effective grounding is not a characteristic of the generation source exclusively but a characteristic of the whole system.

[1] *Protection from Unintended Islanding and Substation Primary GFO caused by DER Infeed*. EPRI, Palo Alto, CA: 2018. 3002011008.

IEEE C62.92.1 states that effective grounding "is obtained approximately when, for all system conditions, the ratio of the zero-sequence reactance to the positive-sequence reactance, (X_0/X_1) is positive and ≤ 3, and the ratio of zero-sequence resistance to positive-sequence reactance, (R_0/X_1) is positive and < 1", as illustrated in orange area in Figure 1-4. To a reasonable degree of accuracy, this impedance ratio approach does identify effective grounding conditions for classical electric power systems where synchronous generators are involved. However, on 4-wire multi-grounded neutral power distribution systems, good design practice per IEEE C62.92.4 implies that COG should be about 72% or less where possible (roughly $R_0/X_1 \leq 0.7$ and $X_0/X_1 \leq 2$), as shown by the dashed red lines. Table 1-1 summarizes the overvoltage level on faulted phase for various CoG.

Note that in IEEE C62.92.1, CoG calculation was simplified assuming the same positive- and negative- sequence impedances ($Z_1 = Z_2$). This assumption is generally true for rotating machines, lines, cables and transformers, but it does not hold for current-regulated inverters that effectively have extremely high Z_1 and where $Z_1 \neq Z_2$. Therefore, these impedance ratios generally cannot provide a good approximation when inverters are the dominant sources.

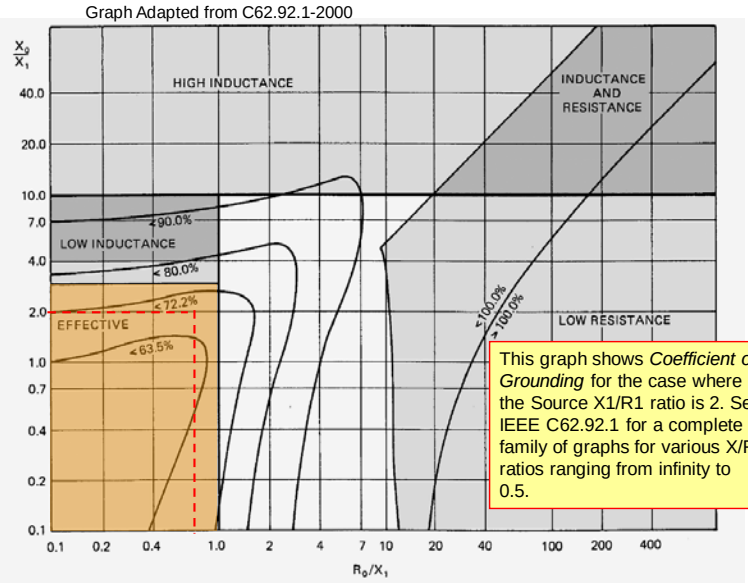


Figure 1-4
Overvoltage level for varying R_0/X_1 and X_0/X_1 ($X_1/R_1 = 2$)

Table 1-1
Overvoltage level on faulted phase for various CoG

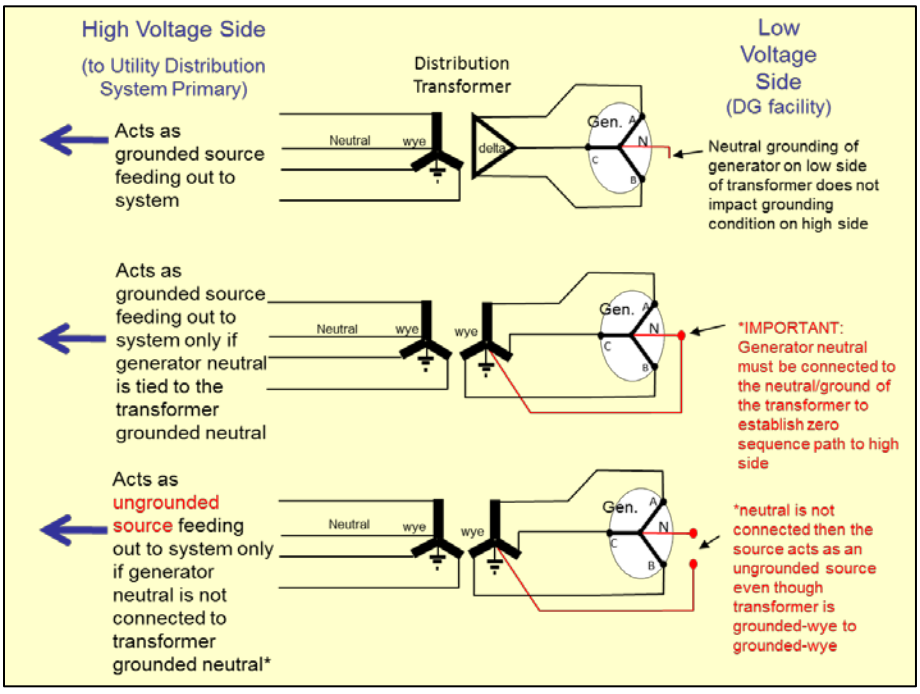
Type of Neutral Grounding	COG	Line to Ground Overvoltage Level	Overvoltage Level (including ANSI 5% regulation factor)
Ungrounded	100%	1.73	1.82
Barely Effectively Grounded (barely meets the definition)	80%	1.38	1.46
Effectively Grounded with good 4-Wire Practice Per IEEE	<72%	<1.25	<1.31
Ideally Grounded	<58%	<1.0	<1.05

Transformer Generation Combinations

In the traditional distribution feeder with synchronous generator based DER, effective grounding can be preserved by DER interconnections themselves, when it is disconnected from the substation. This can be achieved by:

- Interconnection or generator step-up transformer winding configurations providing a small zero-sequence shunt impedance (e.g., grounded wye on the utility primary feeder side and delta on the DER side). For synchronous generators, the zero-sequence shunt impedance should be specified to meet the constraints of $0 < X_0/X_1 \leq 3$, and $0 < R_0/X_1 \leq 1$, if looking into the sequence impedances of the DER source at the utility primary feeder side.
- Separate grounding transformer connected to the utility primary feeder side of the interconnection transformer, or on the DER side if the interconnection transformer is connected grounded-wye/grounded-wye (Yg/Yg). The separate grounding transformer can be connected in the zig-zag configuration, or it can be grounded-wye/delta (Yg/Δ) configuration.
- Synchronous or induction generator with a grounded-wye winding (Yg) configuration and interconnected to the utility primary via a grounded-wye/grounded-wye (Yg/Yg) transformer.

Different combinations of generator and transformer are illustrated in Figure 1-5. The first two cases, i.e., Yg/Yg transformer with grounded generator and Yg/Δ transformer (regardless of generator grounding), act as grounded source feeding out to the system. Other combinations, in contrast, cannot provide an effective grounding, and thus an extra grounding transformer may be needed for GFOV mitigation. Note that when interconnection transformer has delta or ungrounded Y connections at either primary (utility) or secondary (DER) side, the generator neutral grounding will not affect the primary side grounding conditions.



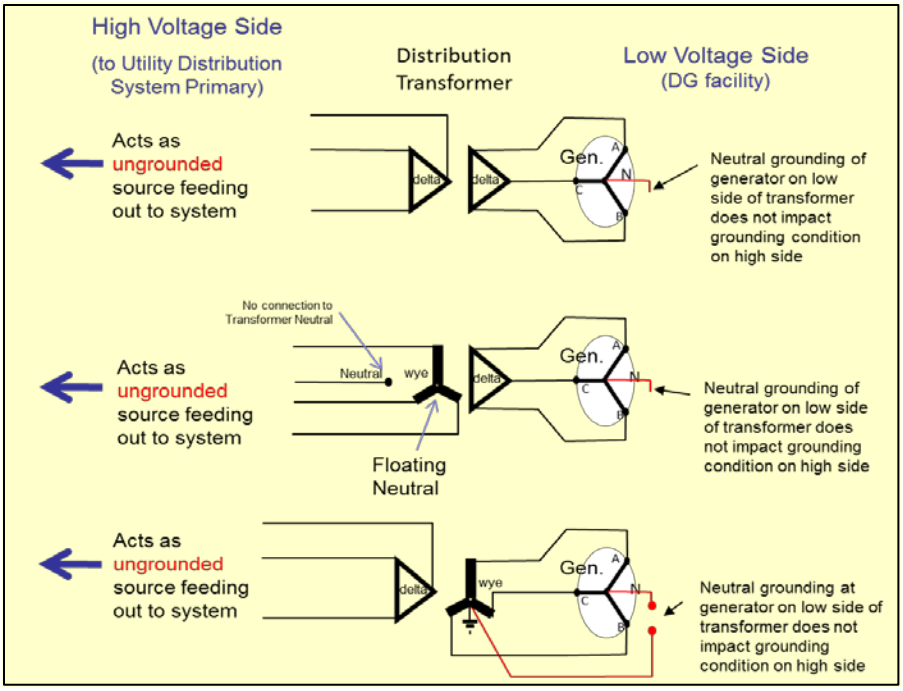


Figure 1-5
Combinations of synchronous generator and transformer

Motivation for this Report

Apparent incompatibilities between distribution system grounding and DER neutral grounding often challenge the technical review process and lead to additional grid interconnection requirements. Evolution from rotating machines to inverters, and differences in medium-voltage grounding philosophies have led to a wide-range of utility practices. In addition to differences in distribution system design, there are fundamental differences between inverters and traditional rotating machine generation. Developers point out that they are uncertain what requirements must be met from one jurisdiction to another.

Utility feeders vary in characteristics and grounding requirements. The variety of three-phase transformer connection options adds to seeming inconsistencies. Both the connection type and grounding method affect DER performance and grid interactions when the power system is abnormal, such as during a ground fault. Among several protection and power quality concerns, ground-fault overvoltage (GFOV) during DER islands is related to the system grounding effectiveness. Compared to balanced unintended island conditions, limited by standards to 2 seconds, an unbalanced GFOV condition is mitigated immediately by effective grounding.

Achieving GFOV mitigation during islands often leads to higher DER installation cost and longer times for technical review. Supplemental grounding transformers, fault-clearing and relay protection equipment may be required. Many current practices have evolved for synchronous generators and are difficult to apply to inverter-connected DER. PV plant developers point out a wide range of, and apparently inconsistent, requirements and practices among utilities.

Typical 3-phase inverters do not have grounded neutrals beyond a sensing circuit. Depending on local distribution grounding practices this can lead to uncertainties, delays, and special

interconnection studies. The concern is GFOV during an island. Overvoltage, even short duration, can stress line to neutral connected equipment such as lightning arresters. DER grounding method is an important factor in this risk.

IEEE/ANSI C62.92, Guide for the Application of Neutral Grounding in Electrical Utility Systems, addresses grounding considerations for various parts of the grid. Grounding for feeders and services from the medium voltage grid are the subject of C62.92.4. The IEEE Surge Protective Device committee recently added a new guide to the series, C62.92.6, for current-regulated generation (inverters). It addresses some of the fundamental differences with inverters compared to rotating machine connections. This report is aimed to complement the guide with methods and recommended practices for evaluation of inverter interconnection cases.

Topics Covered in this Report

Aiming to provide solutions, this project worked through the theory, examined the specific feeder circumstances and mechanisms, modeled typical scenarios, and provided recommendations on practices that are expected to simplify interconnection decisions and reduce uncertainties around this issue. Clarifications are also provided regarding when supplemental grounding is needed and recommendations for economic alternatives. Sizing criterion are also developed in this project to achieve optimal performance.

The topics covered in this report include:

Chap 2. Difference between synchronous-based and inverter-based generation

Chap 3. Utility practices on effective grounding

Chap 4. Sequence network analysis of inverter-based generation for fault analysis and sampled inverter behaviors. Impact of grounded load and supplemental grounding on ground fault overvoltage.

Chap 5. What is expected overvoltage tolerance of end user loads and of medium voltage connected equipment.

Chap 6. Negative impacts, side effects, of supplemental grounding. When is supplemental grounding needed and how to size it? Recommendation for updates to standard interconnection requirements (preliminary and supplemental screening, technical review and studies) related to effective grounding.

Chap 7. Conclusions and next steps.

This project trued up long-standing grounding practices with evolving practices for inverter-based DER with capabilities such as current unbalance compensation. Specific objectives are to improve the technical review process and to make grounding requirements more transparent and consistent. The project explored the meaning of effective grounding, basic principles, and important role of DER transformer connections. It also addressed application and sizing of grounding transformers, impedance grounding, interference with protection coordination, arc flash considerations, and related side effects.

2
DIFFERENT FAULT RESPONSES OF INVERTER- AND MACHINE-BASED DER

Symmetrical Component Analysis

A synchronous generator can be characterized as a voltage source that is series connected with a relatively low impedance. Symmetrical component analysis is used to evaluate different circuit fault conditions. An example sequence network for a synchronous generator dominated system during a SLG fault is provided in Figure 2-1. In symmetrical fault analysis, the source impedance (Z_1, negative sequence impedance Z_2, zero s sequence impedance Z_0 and Z_n) and other series impedances contributed by lines (Z_{1line}, Z_{2line}, and Z_{0line}) and transformers (Z_{1trans}, Z_{2trans}, and Z_{0trans}) dominate the power system sequence impedances at any point. Here the subscripts $_1$, means positive sequence, $_2$, means negative sequence and $_0$, means zero sequence.

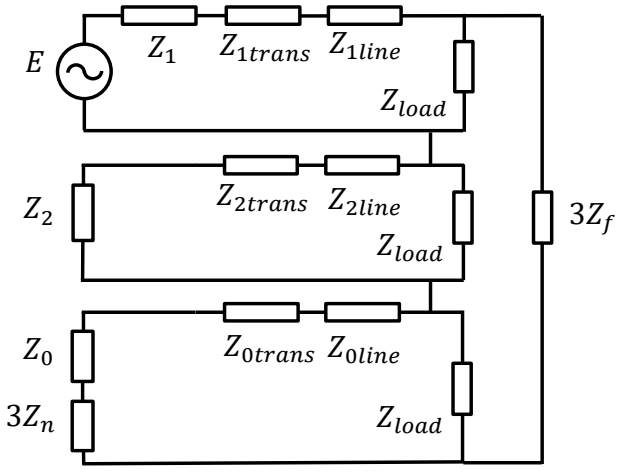


Figure 2-1
Sequence network for fault analysis of a synchronous generator dominated system

For synchronous generators $Z_1 \approx Z_2$, and for lines, cables, and transformers $Z_1 = Z_2$. Load impedances (Z_{load}) that connect in parallel are normally much larger and thus usually are ignored. Therefore, the term "effectively grounded source" is frequently used in the utility industry when a strong source has an $X_0/X_1 \leq 3$ and $R_0/X_1 < 1$. These criteria tend to be met elsewhere in any power system where strong source is dominant. An exception is zero-sequence (ground current) blocking by a transformer winding configuration such as delta or ungrounded-wye. In addition, rotating generators can easily withstand large over-currents (e.g., 4 – 6 times rated) for many cycles.

Inverter based-DER, on the other hand, have distinct behaviors, and cannot be represented as a voltage source. A PV inverter, for example, regulates its dc voltage to achieve the maximum power at the specific irradiance level. Through power and current control loops, the inverter regulates its output current (mainly positive sequence) automatically attempting to maintain its power generation when the terminal voltage varies, thus operating as a voltage controlled current

source. The power electronic devices used in inverters, unlike synchronous machines, are highly sensitive to overcurrent and may fail due to even a sub-cycle exposure to large current (e.g., several times rated). To protect the electronics, these grid-following inverters use high-speed regulation of current that effectively limits maximum 60 Hz current from the inverter to slightly above the rated value. Because modern inverters switch at kHz speeds, the response time of the current controls are typically on the order of a fraction of a 60 Hz cycle.

During fault conditions, the reduced positive-sequence voltage will cause the power regulator in the inverter controls to increase the current regulator reference, or target value, to the maximum allowed value to maintain constant power. Under this circumstance, inverter will act as a constant current source instead.

In both cases, there will be a large impedance connected in parallel following the Norton equivalent circuit. In very rare conditions, the inverter controller gets deeply saturated due to the large control error and cannot regulate its current generation in a timely matter (i.e., duty cycle of 1). The voltage output is then directly determined by its dc voltage and the inverter acts as a voltage source. This situation could occur when there is a serious load rejection overvoltage, but it generally lasts for a very short duration because of overvoltage protections.

Inverter negative sequence impedance is closely related to its control algorithms. The inverter may eliminate the negative sequence current and result in an infinite negative sequence impedance. Or it may mitigate the 2^{nd} order power ripple by injecting more negative sequence current, thus inducing a relatively low negative sequence impedance. For inverters that do not have specific negative sequence current regulation, the negative sequence current superimposes 120 Hz variations on the constant positive sequence current in d-q coordinates, due to the rotating reference frame. Practically the positive sequence current regulator has a bandwidth around hundreds of Hz, and it therefore responds to the 120 Hz variations and partially mitigate the negative sequence current. This typically results in an effective negative sequence impedance around 1 p.u. on the inverter's rating base. At the opposite extreme, inverters that have an unusually slow positive sequence current regulator (with bandwidth < 120 Hz) would not respond to the current imbalance. In this case, their negative-sequence impedance will be defined by their physical output inductors and can be on the order of 0.1 p.u.

Negative-sequence impedance characteristics are not typically provided by inverter manufacturers. GFOV analysis, therefore, may need to consider this parameter as an unknown and sweep across the possible range of values. Recently, German grid code VDE-AR-N 4110 and IEEE P2800 require DER to provide certain negative sequence current during abnormal

conditions, which hopefully will standardize the negative sequence impedance of inverter-based DER and facilitate more accurate fault analysis.[2,3]

Zero sequence impedance of DER are determined by the configuration of power inverters. Diagram for both older style and more recent three-phase PV inverters are provided in Figure 2-2 and Figure 2-3, respectively. For older style PV inverters, the neutral grounding connection usually comes from the factory as essentially an open or high impedance grounded unit. It is not intended for serving zero-sequence load current and thus the inverter acts as an ungrounded-neutral source. The neutral is used for voltage sensing to measure L-N voltage. Some manufacturers can change the grounding if requested. Unit shown here has an isolation transformer, but this style is obsolete and most today do not.

The recent PV inverters, as shown in Figure 2-3, are typically three-phase three-leg and have no zero-sequence current generation capability. In this arrangement, the neutral connection is brought to the inverter but is used only as a voltage sensing reference for control purposes. It is also not intended to serve as a zero-sequence power carrying connection. Internally it is connected to the control circuitry via high impedance and will appear to be a very high impedance or open connection. Therefore, for DER with three-phase three-leg inverters, which dominate the market, the zero-sequence impedance is expected to be ideally infinite.

There are also inverters that are primarily designed for off-grid applications. Their power electronic devices are configured to allow zero-sequence neutral current in certain situations such as while disconnected from the grid. However, their operating mode while grid-connected is critical because if they are controlled to be a positive-sequence current source, they may still

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[2] VDE-AR-N 4110, 4120 and 4130 (German Grid Code), Technical Connection Rules: 10.2.3.3 Dynamic Network Stability for Type 2 power generating plants

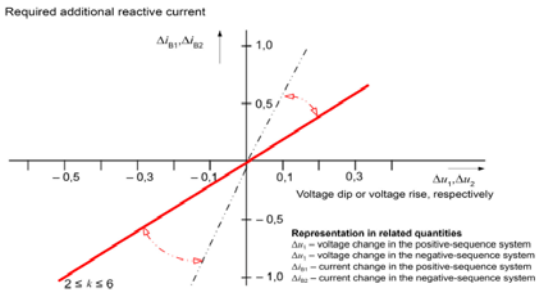


Figure 13 – Principle of the voltage support in the event of a network fault

- Additional reactive current Δi_{B2} is proportional to the change of negative sequence voltage Δu_{B2}. The required settling time is 60ms.
- The specification of reactive current implies a 90 degree phase shift w.r.t voltage
- The amplification factor k shall be adjustable, in steps of 0.5 between 2 and 6
- Any limitation of reactive current is preferably achieved through a uniform reduction of the positive sequence and negative sequence currents

[3] IEEE P2800, Draft Standard for IBR with Transmission Systems. Clause 7.2.2.3.4 Current injection during ride-through mode:

- For unbalanced faults, in addition to increased positive sequence reactive current, IBR unit shall inject negative sequence current. Dependent on IBR unit terminal (PoC) negative sequence voltage
- Leads the IBR unit terminal (PoC) negative sequence voltage by 90-100 degrees, for full converter based IBR units, with settling time of 4 cycles (65ms)
- If total current limit is reached, any or both of positive and negative sequence current may be reduced with a preference in equal reduction in both currents. Positive sequence current shall not be reduced below negative sequence current.
- The standard intentionally does not specify magnitude of incremental positive and negative sequence reactive current injection.

present a very high zero-sequence impedance. Unlike synchronous generators, physical connectivity only partially determines the zero-sequence behavior of inverters, and controls can play a significant role and even completely counteract the grounding that might otherwise be provided by the configuration.

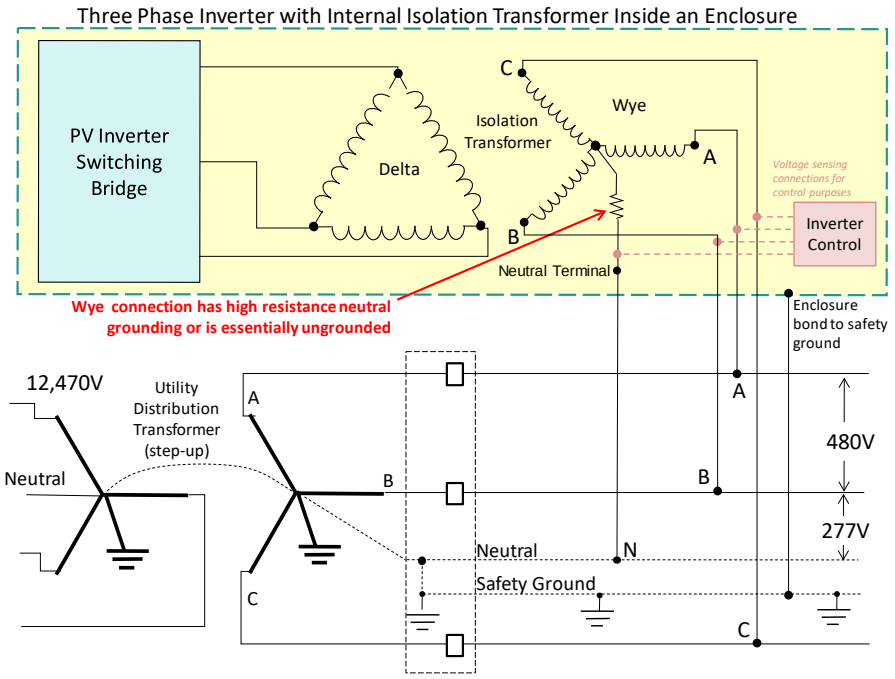
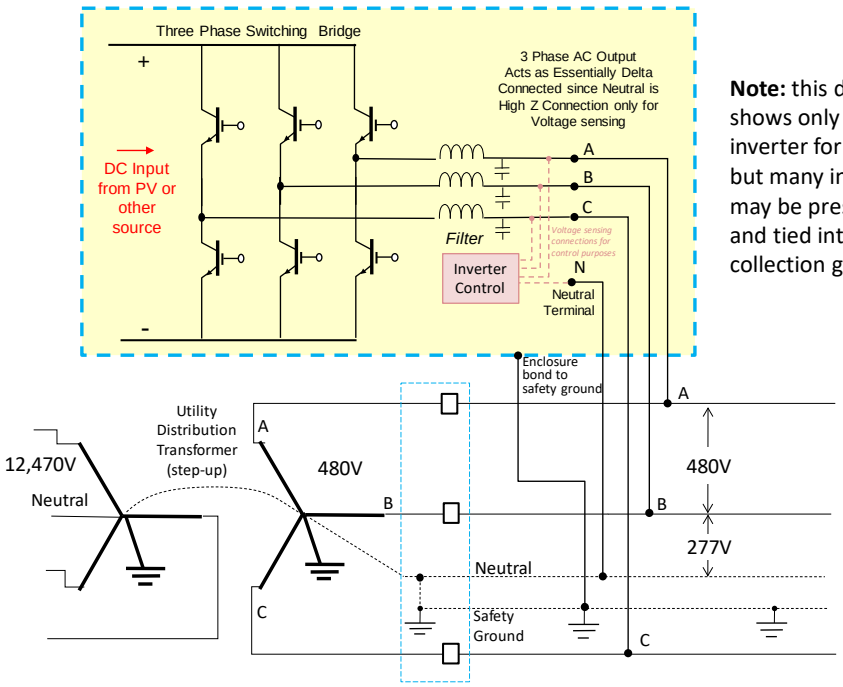


Figure 2-2
Older style 3-phase PV inverter with isolation transformer



Note: this drawing shows only one inverter for clarity, but many inverters may be present and tied into the collection grid.

Figure 2-3
Prevalent transformer-less three-phase PV inverter

In some cases, three-phase inverters are composed of three separately controlled single-phase inverters in one box. These will inherently inject current at a defined phase angle relative to their individual terminal phase voltages and thus the 120° phase relationship is not maintained during unbalanced faults. Three-phase aggregations of single-phase inverters (e.g., residential rooftop PV distributed amongst the phases) will perform similarly. Symmetrical components are not a useful means to study such situations.

Table 2-1 summarizes the differences between power distribution system fed by utility supplied substation source, synchronous machine-based or the vast majority of three-phase inverter-based DER. Different from the other two types, the inverter-based DER operates as a current source and has distinct sequence impedances. Therefore, the existing knowledge on GFOV and DER grounding may not be applicable and should be revisited.

Table 2-1
Comparison between different types of DER

Type of Source	Characteristics During Short Time Transient Events Such as Faults
Power Distribution System Fed by Utility Supplied Substation Source	• Power system acts as a voltage source • Positive and negative sequence impedance are essentially equal or similar • 4-wire systems have zero sequence impedance to positive sequence impedance ratios that meet classical effective grounding criteria • System impedances are considered constant during fault conditions • System frequency is considered constant for purposes of analysis
Typical DER Synchronous Rotating Machine	• Machine acts as a voltage source. • Positive and negative sequence impedance are slightly different but still roughly similar • Can be configured for effectively grounded zero sequence impedance • The impedance changes over time (subtransient and transient reactance) • The impedance is mostly reactance (high X/R ratio) • Exciter control may significantly adjust excitation after many cycles (easily modeled if settings and type known) • Effects of prime mover governor, inertia and speed compound the dynamics (easily modeled if data is available) • The dynamics of the machine early in the event are very much dictated by well-established machine physics
Typical DER Inverter ***(different than a classical rotating machine)***	• Operates as a current controlled source • Has high positive sequence impedance (effectively infinite) • Negative sequence impedance may be high, controller may not allow unbalanced current output • Has infinite or very high zero sequence impedance • Dynamics of the inverter response at the mercy of the control software programming

With the above analysis, the sequence network for DER inverters with a Yg/Δ interconnection transformer during a single line to ground (SLG) fault is given in Figure 2-4. DER is represented as a voltage controlled or constant current source for the positive sequence. The positive sequence impedance ($Z_{1current}$) is connected in parallel and ideally infinite. To emulate the inverter control saturation, an additional non-linear element like MOV surge arrester or extremely non-linear resistor is also connected in parallel. It has extremely high impedance at nominal voltage but goes through a knee point at some voltage such as1.5-2.0 per unit to represent inverter saturation during overvoltage condition.

The open circuit for negative sequence in Figure 2-4 is to illustrate the effect of a very high negative sequence impedance ($Z_{2current}$). $Z_{2current}$ may change depending on the inverter control design. With a very large $Z_{2current}$ and no load, a severe unfaulted phase voltage could be created, despite the low impedance zero sequence path created by the Yg/Δ transformer. Inverter zero-sequence impedance $Z_{0current}$ does not affect the zero-sequence path in this case and is assumed to be infinite. Note the zero-sequence path is subject to change with different transformer interconnection windings.

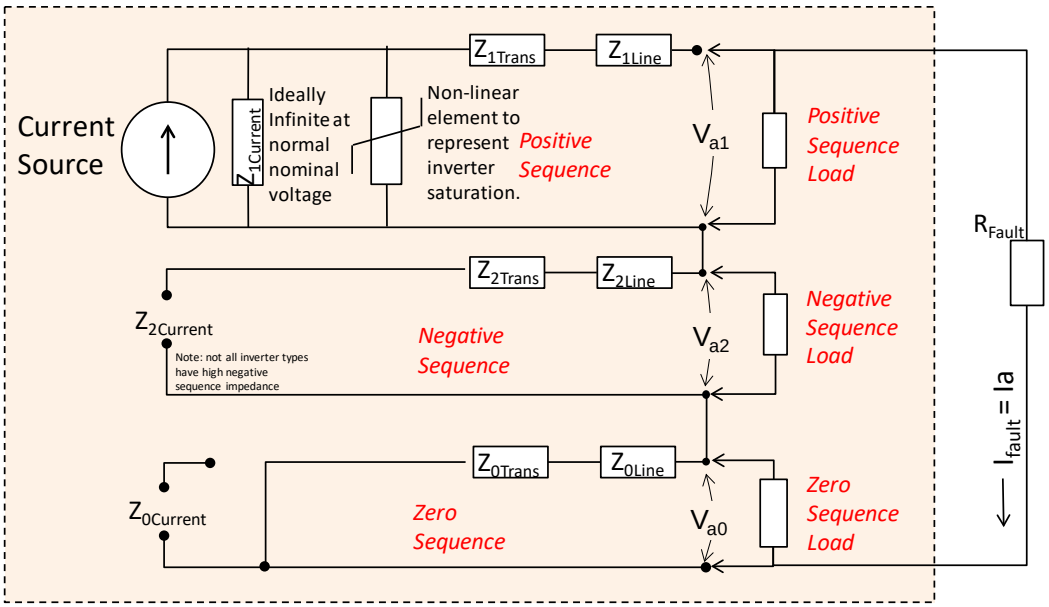


Figure 2-4
Sequence network for fault analysis of a inverter-based DER dominated system

Connected load must be considered to analyze neutral shift and resulting GFOV and any load rejection overvoltage (LROV) that may occur. LROV is another component of overvoltage caused by the DER response to sudden loss of load. For inverter islands, if real power generation to load ratio is < 1, voltage falls and if > 1, voltage rises.[4] There is a brief generation to load mismatch as power controls adjust to the change. Worst case overvoltage occurs when there is very light or total loss of load with full DER power generation in the island.

LROV is a balanced overvoltage (positive sequence) that is *independent of* neutral grounding situation, as illustrated in Figure 2-5. In contrast, GFOV is an unbalanced overvoltage that is greatly related to the system grounding and neutral point shifts from the center position during a fault. Effective grounding only helps with GFOV mitigation and does not affect LROV. These two types of overvoltage may occur separately or in combination depending on the specific circumstances.

[4] *Do Grid Support Functions have Negative Impacts on Smart Inverter's On-board Islanding Detection?* EPRI, Palo Alto, CA: 2020. 3002019665.

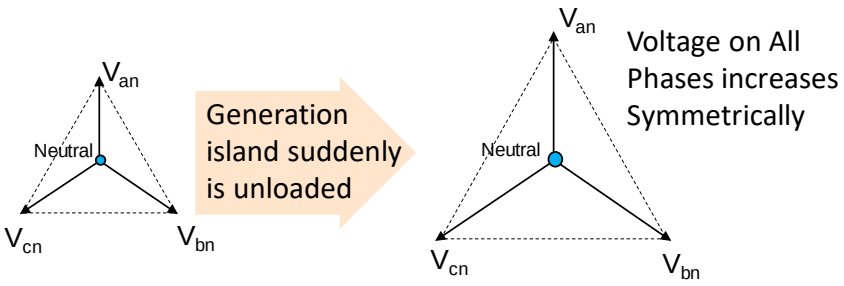


Figure 2-5
Load rejection overvoltage

Figure 2-6 defines the GFOV and LROV. In practice, GFOV and LROV only occur during islanded operation. GFOV is overvoltage caused by a persistent SLG fault, when load matches DER generation (gen/load =1) and the islanded system is not effectively grounded. LROV, as discussed, is overvoltage purely induced by gen/load > 1, when no fault exists. With SLG fault and gen/load > 1, both GFOV and LROV could occur, which may impose high voltage stress on equipment connected to the circuit.

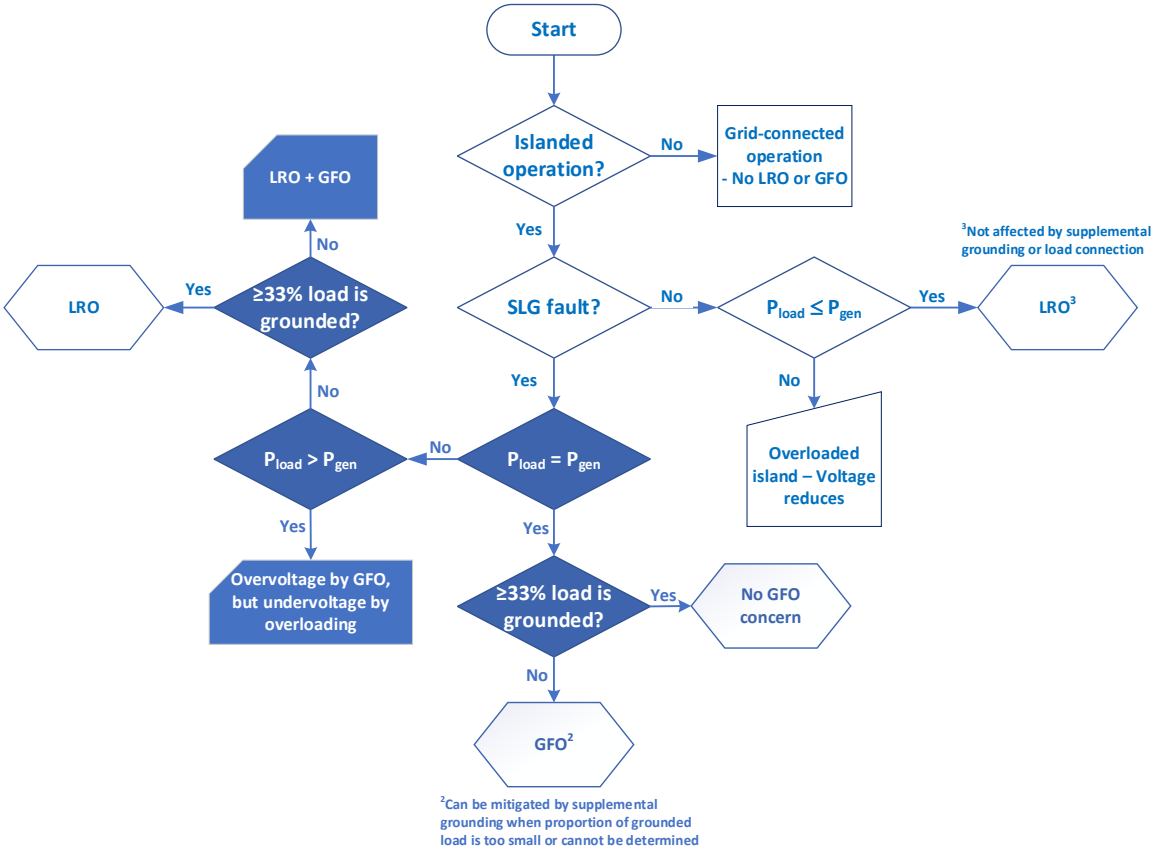


Figure 2-6
GFOV and LROV

Heavy loads (gen/load < 1), on the other hand, tend to reduce islanded voltage and compensate GFOV. As shown in Figure 2-7, with heavy loads, voltage does not rise much on V_{ag} and V_{bg} since the overall size of the triangle has been reduced (phase to phase voltage has dropped) due

to the excessive loading on the generator. This conclusion holds for islands with either machine- (voltage source) or inverter- (current source) based DER, where voltage drop is caused by line impedance or current limiting of inverters.

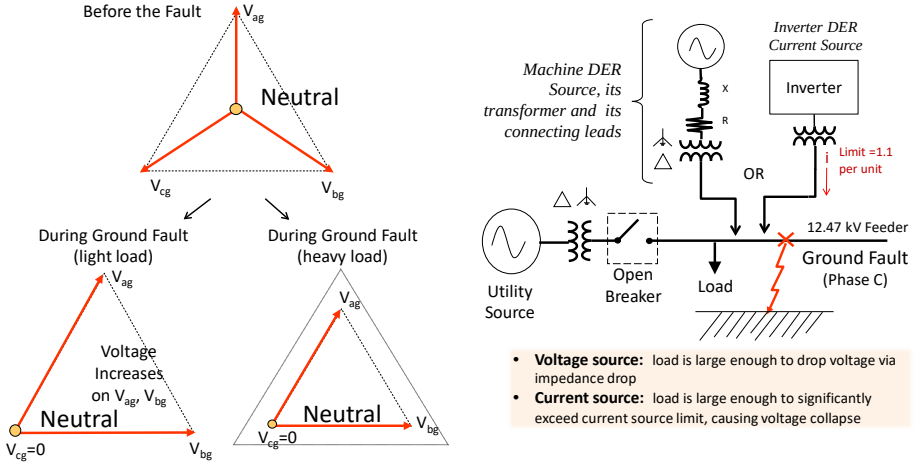


Figure 2-7
Overvoltage with light and heavy loads

Transformer Inverter Combinations

The combination of interconnection transformer and DER inverter is shown in Figure 2-8. With open or high Z_2 and Z_0 of inverters, the Yg/Δ transformer or Yg/Yg transformer and grounded DER will no longer enable an effective grounding as it does for the synchronous generators, and a separate grounding transformer may be needed for this purpose.

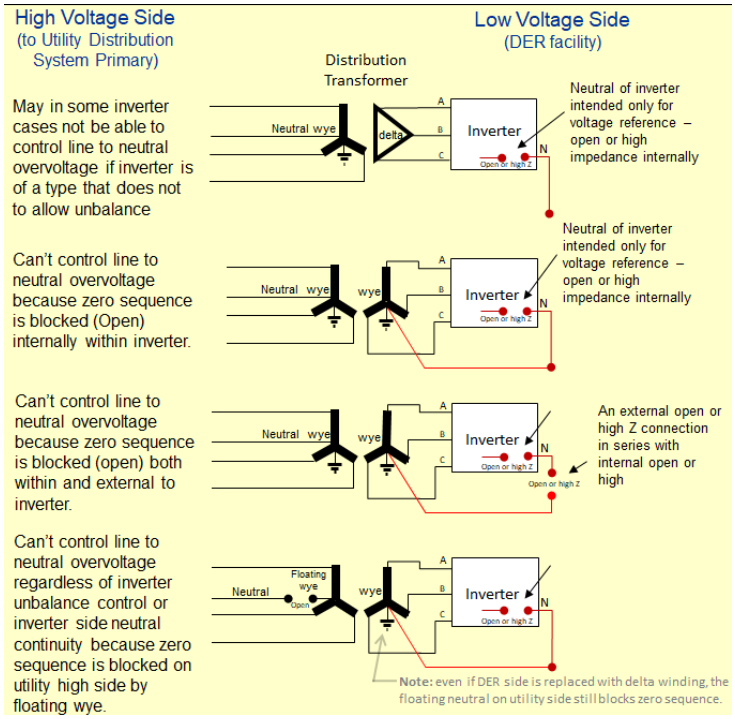


Figure 2-8
Combination of interconnection transformer and inverter-based DER

Fault Response Summary

Behavior of inverter-based DERs during faults is fundamentally different than synchronous generators. The typical model of an inverter positive sequence a voltage-controlled current source or a pure constant current source with a magnitude equal to the maximum inverter current (typically on the order of 1.1 times rated current).

Inverter negative-sequence impedance is largely an unknown value. It can be between 0.1p.u. and infinity with any impedance angle, depending on the inverter control algorithms. Inverters designed to German VDE standards will have inductive negative-sequence characteristics settable from 0.17 to 0.5 p.u. The zero sequence is an open circuit, except in very unusual inverter designs.

Most DER interconnection and related system grounding practices have evolved from experience with, and characteristics of, synchronous generators. Applying these practices to inverter connected DER may result in specifying a nonoptimized supplemental ground source with protection coordination side effects. Fundamental differences with inverter-based DER response to power system faults requires new approaches. Currently there is uncertainty related to inverter control design and response. This can be overcome, and system grounding can be optimized, by standards requiring clarity in inverter fault characteristics.

3
UTILITY GROUNDING PRACTICES SURVEY

2019 Survey Results

In 2019, EPRI conducted guided interviews with 20 utilities to determine their current practices and plans regarding DER supplemental grounding requirements.[5] Interview discussion points included:

- What MV transformer connections are specified for 3-phase DER customers?
- Do you require, define type, and specify parameters of supplemental grounding?
- Are load types and short circuit impedances considered in grounding calculations?
- Do you have the analytical tools needed to evaluate inverter-based DER protection requirements?
- What is your experience with MV arrester failures? Were events associated with DER GFOV?
- Are you familiar with the new IEEE Std C62.92.6 addressing effective system grounding with inverters?

The interviewed utilities were composed of 6 utilities from New York and 14 from other areas of the United States and Canada. Although DER-related supplemental grounding objectives and concerns were found to be very similar, individual utility practices varied. Practices reflected differences in system protection philosophies, feeder characteristics, and consideration for characteristics of inverter-based DER. Experience in connecting large inverter-based plants ranged from significant to very limited. Utility practices related to inverter-based DER generally fell into 4 categories:

1. **Require Supplemental Grounding** – 13 of 20 utilities required at least some DER installations to provide a ground source. The threshold of their requirement was typically around 500 kVA and ranged from 250 to 1000 kVA.
2. **Require and Actively Re-evaluating** – 4 of the 13 utilities requiring grounding indicated they were considering relaxing this requirement for inverters-based resources based on IEEE Std C62.92.6 and EPRI research findings.
3. **Don't Require** – 7 of 20 utilities did not require supplemental grounding for inverter-based DER.
4. **Don't Require and Don't Allow** – 2 of the 7 utilities that do not require supplement grounding prohibit inverter-based DER from adding a supplemental ground source.

With increasing numbers of DER interconnections, there was also motivation for new practices. Other technical points related to the implementation and specification of supplemental ground sources for inverter-based DERs are summarized below.

[5] *Utility Grounding Practices for Distributed Inverter-Based Resources.* EPRI, Palo Alto, CA: 2020. 3002018653.

- Most utilities requiring supplemental grounding were flexible in interconnection transformer configurations. These included (medium voltage (MV):low voltage (LV)):
    - Yg:Yg grounding transformer connected to LV side
    - Δ:Yg with a grounding transformer on MV side
    - Yg:Δ usually with a neutral reactor to limit I_0 or reduced size if used for supplement grounding
    - Zig-Zag configuration specifically for supplement grounding
- Utilities usually require supplemental grounding based on DER size and specify its zero-sequence impedance (Z_0) and X/R to achieve effective grounding.
    - Using IEEE Std C62.92.1-2000 (for synchronous machines), effective grounding was defined as: Ratio of X_0/X_1 is positive and ≤ 3 and R_0/X_1 is positive and <1.
    - There was uncertainty and lack of agreement on impedance values to use for inverters.
    - Several utilities surveyed used sequence component ratios more appropriate for synchronous machines, for example X_0 = 0.6 p.u. and X_0/R_0>4.
    - IEEE Std C62.92.6-2017 addresses grounding for inverter-based DER and four utilities were considering updating their practices to follow the calculation guidelines (symmetrical component) in the standard.
    - Since commercial tools are not available for the symmetrical component analysis, spreadsheet analysis was being used.

Ongoing Grounding Practices Discussion

As DER grounding research continued in 2020, several additional utility polling sessions were conducted by EPRI to further inform system grounding discussions. The results indicate several areas where research has influenced utility thinking on the specification of DER interconnection transformers and ground sources. Electromagnetic transient (EMT) modeling of DER overvoltage scenarios also has provided insight into inverter behaviors, the importance of load, and the role of the interconnection transformer connections.

Figure 3-1 identifies the primary issues that were identified during a July 2020 EPRI webinar by roughly 50 utilities for selecting one transformer topology over another. Results show that, along with open phase detection, the main concern was GFOV. These concerns are expected to be the main drivers of DER interconnection mitigation requirements and costs.

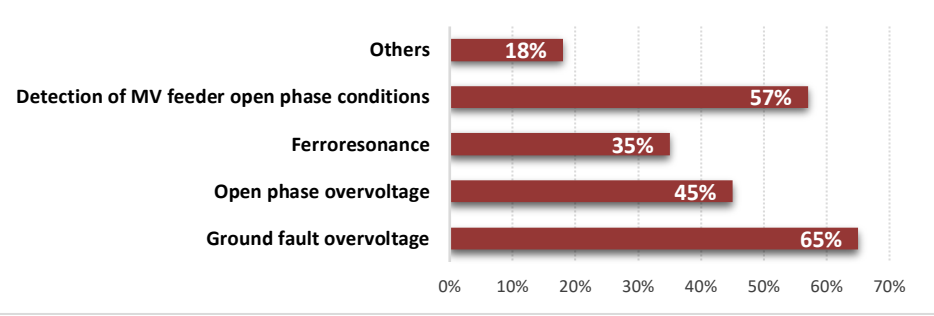


Figure 3-1
Issues and concerns for specification of DER interconnection transformers

Most utility distribution feeders in North America comprise a 4-wire, multi-grounded configuration. As indicated in the transformer selection poll result shown in Figure 3-2, the Yg:Yg configuration is the most common DER transformer interconnection. Other configurations are also used depending on MV configuration, concern for effective grounding, and the other issue described above. The key takeaway is that there is not a single best option for connecting DERs.

DER grounding configuration is also an important factor in the selection of the interconnection transformer. For example, the popular Yg:Yg connection passes through the zero sequence but does not act as a MV ground source. Nearly all 3-phase inverters deployed today have no neutral connection and are not grounded. One-fifth of polled utilities indicated that they require the Yg:Δ configuration for many DER applications. Where Yg:Δ is used, utilities indicated that a neutral-to-ground impedance is required or specified. Both the Yg:Δ and addition of a supplemental grounding transformer can provide a ground source from the grid side, as discussed in Chapter 2.

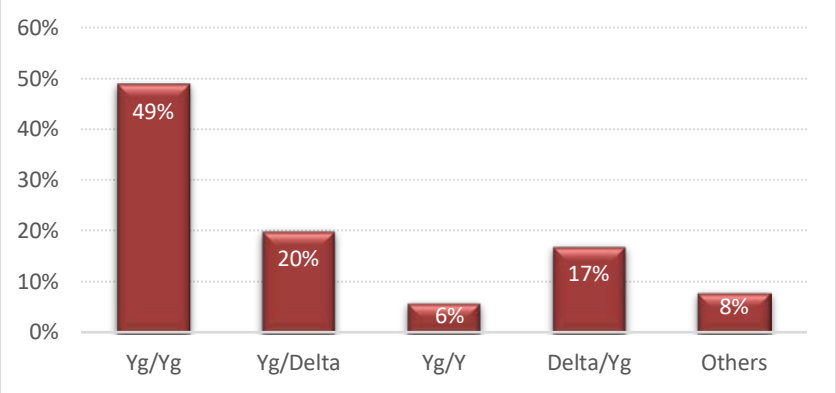


Figure 3-2
Utility preferences for DER interconnection transformers

Figure 3-3 shows another DER interconnection transformer preference on specification of MV compared to LV side. Responses indicated that there may be less interest in the LV winding configuration, which is sometimes the developer's choice. This approach is not recommended because both windings need to be considered to define DER response for open phase and fault responses.

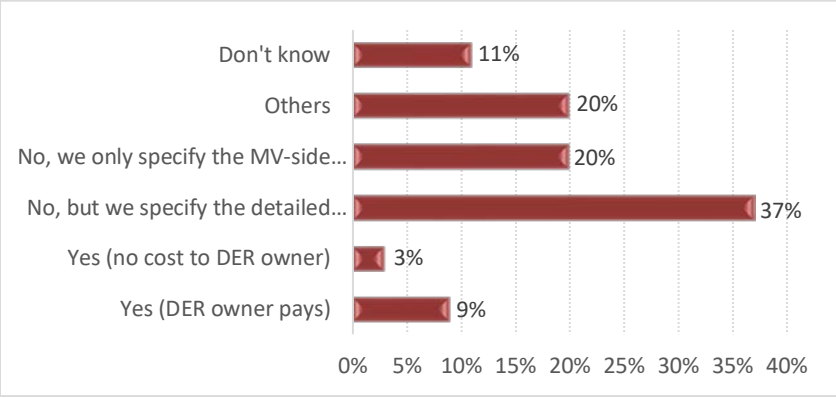


Figure 3-3
Responsibility for customer-owned DER transformer connections

It is important for utilities to specify both the MV and LV winding configuration that is consistent with the utility protection philosophy. Moreover, given the preponderance of non-utility owned DER installations, it is again recommended that utilities specify the transformer winding configuration.

Feedback was also obtained on the state of analytical tools available to support utilities in reviewing DER interconnections. There is widespread agreement that better tools are needed. Relevant polling comments include:

- Short-circuit analysis tools (e.g., Aspen, Cape) are effective for evaluating scenarios when DER is connected to the grid. Islanded, not grid, behavior is what drives grounding requirements.
- Utilities aiming to apply IEEE Std C62.92.6 in calculations for inverters are having to using ad hoc tools (e.g., spreadsheets, hand calculations). There is not a good way to address cases where aggregations of single-phase DERs may pose grounding concerns.
- GFOV scenarios and sequence behavior of inverters needs to be defined and further characterized.
- Analytical methods are needed to support application and sizing of grounding transformers for inverter-based DERs, including how to consider load contribution to system effective grounding.
- Any new practices and procedures need to be vetted with utility protection engineers.

Applying Research Results to Grounding Decisions

To improve understanding of industry DER ground sourcing practices, EPRI held a series of utility virtual workshops in the fall of 2020.[6] During these workshops messaging of the issues was refined based on available knowledge. As most DER interconnections today are inverter-based the industry approach has been to go with a best estimate of behavior and identify areas where future research is needed.

During the workshops, there was a lot of agreement that analytics and tools for evaluating islanded inverter-based DER grounding issues are not well developed. Given the fundamental differences between inverter-based and synchronous machine DERs, analytical methods are still evolving. A key detail relative to analytical methods is to address behavior after the main grid connection is lost, as this result is completely different from typical utility system dynamics.

Specific issues considered in the workshops included determination of inverter and response to grid faults, island overvoltage, and the role of other system components, such as surge arresters. Meanwhile identified objectives of related research were to predict transient over-voltage (TOV), including the combination of GFOV plus inverter characteristic load-rejection overvoltage (LRO). Figure 3-4 and Figure 3-5 present utility workshop responses and accompanying comments to questions about DER review procedures and approaches for mitigating GFOV risk.

Workshop Comments (w.r.t. DER Review Procedures)

- We use Excel tools that consider assumptions of the DER impedances to predict contribution.

[6] EPRI convened three 2-hour DER grounding workshops on Sept 2-11, 2020, with approximately 50 utilities.

- Typically, we apply ground referencing for DER ~100kW, but we are looking to modify criteria for customer sited DER, and to consider load with some margin in load/gen ratio.

Workshop Comments (w.r.t. GFOV Risk Mitigation)

- We run the calculation in C62.92 to see if the system is effectively grounded, if not a grounding transformer would be required.
- Each DER provides their fair share of ground referencing. As you progress to high DER integration levels, we expect the needed ground referencing will be in place.

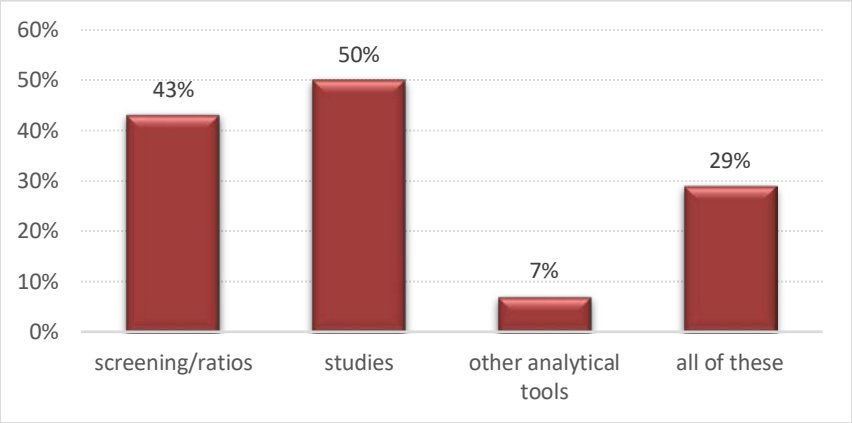


Figure 3-4
What technical review procedures are relied on for DER protection issues

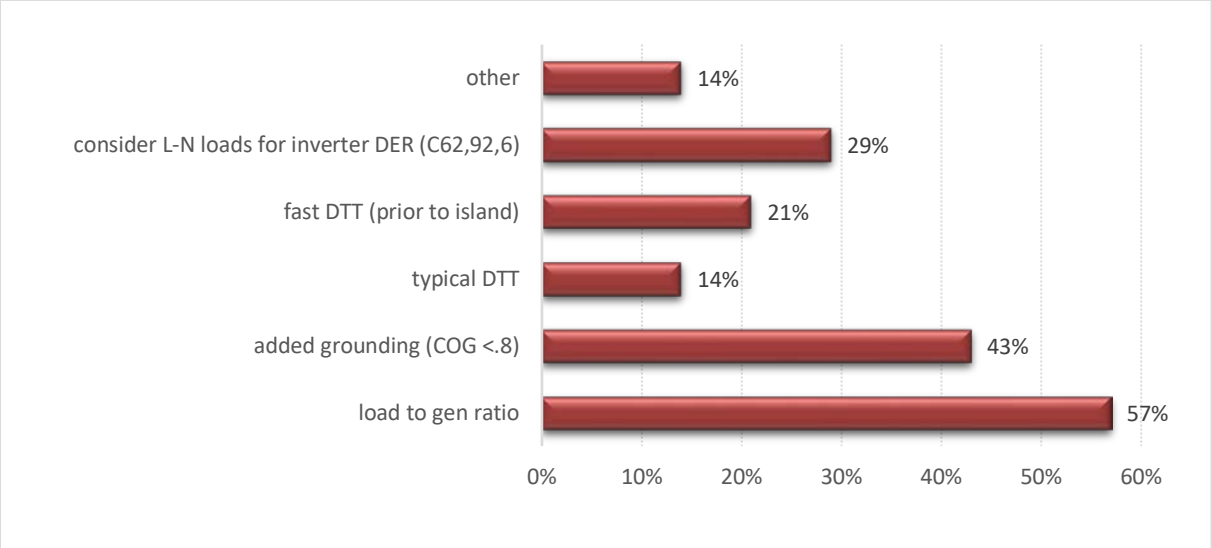


Figure 3-5
Identify practices to prevent GFOV with increasing penetrations of DER > 1MW

These results indicate that research is beginning to pay off in providing more options and expanding understanding. The growing usage of C62.92.6, shown as being selected by 29% of respondents in Figure 3-5, is a good indicator. EPRI study indicates 33% and above L-N loads can sufficiently mitigate GFOV, and the poll result in Figure 3-6 shows a good acceptance of it already (38%). Also, recognition of effective grounding as a systems issues and consideration of

aggregated load to generation are practices borne out from ongoing research. Although, the ratios used continue to be more conservative than studies indicate are necessary, as shown in Figure 3-7. For example, from 1 to 3 times more load than generation required to alleviate overvoltage concerns.

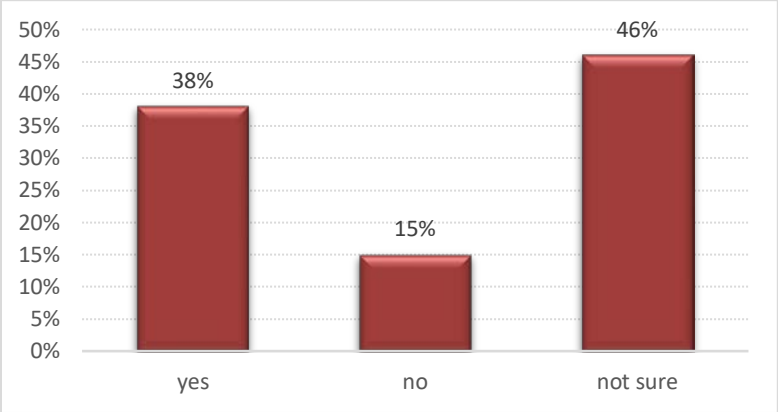


Figure 3-6
Will you consider using 33% L-N load as sufficient criteria with regard to OV concerns?

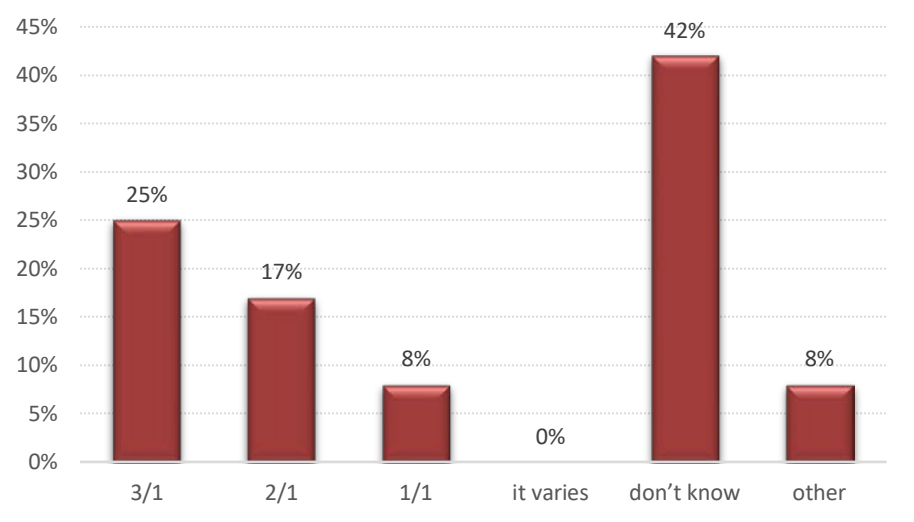


Figure 3-7
Min load to gen (1 MW plants) ratios for OV concerns

Another area that utilities shared their experiences was related to the side effects of adding ground sources. During the workshops, considerations related to over grounding were identified and discussed. As indicated in Figure 3-8, the need to re-coordinate protection was a significant consideration.

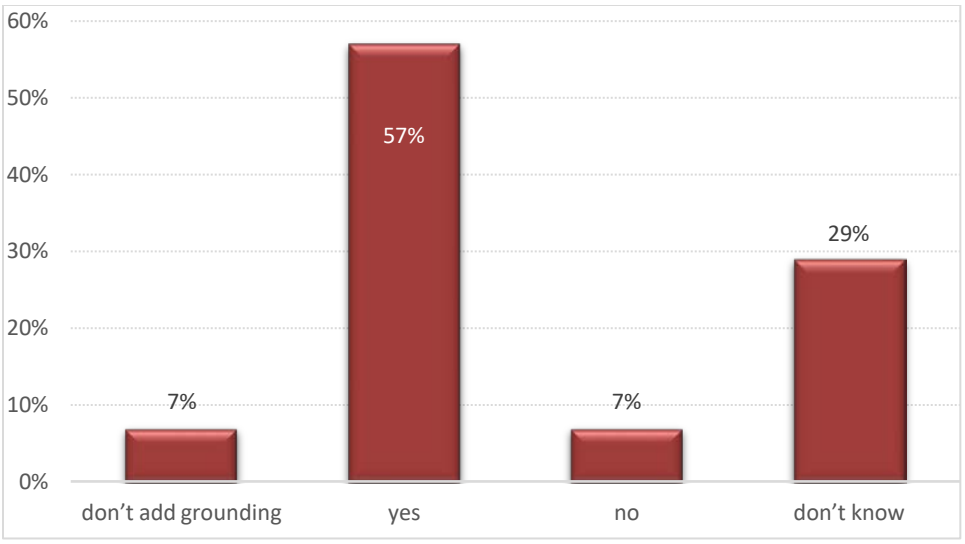


Figure 3-8
If adding supplemental grounding, have you seen a need to re-coordinate protection?

Utility Practices Summary

Grounding practices and requirements for DER connection are evolving because of inverter technologies. As a result, inverter-based DERs are currently being treated inconsistently among utilities and jurisdictions. The fundamental differences between inverter-based and synchronous machine generation is being recognized by utilities. The impact on traditional system grounding practices and guidelines is also gradually evolving. Research on inverter behavior and its aggregate influence on temporary overvoltage during ground faults can provide better understanding of the key issues and is leading to more consistent utility practices

4
TRANSIENT ANALYSIS AND LAB TEST RESULTS

Electromagnetic Transient Program (EMTP) Simulations

To estimate inverter based DER overvoltage, simulations were performed under a full range of operating conditions. The combined ground fault overvoltage (GFOV) and load rejection overvoltage (LROV) were investigated. Variables included gen/load ratio, with and without supplemental grounding and changing the inverter trip parameters from IEEE Std 1547-2003 compared to 1547-2018.

It is worth mentioning that these simulation results are specific to the inverter, load, and feeder models used, as well as the system configurations and operating conditions assumed. They will likely change when any of the system and/or inverter parameters vary. Additionally, for all simulated cases, the overvoltage analysis and protection mechanisms were based on the phase-to-neutral voltage.

The circuit used in simulation is shown in Figure 4-1, where the transmission system was represented as a stiff bus with an equivalent impedance. A generic inverter model with 1 MW power generation and unity power factor is simulated. It is connected to the 4-wire grid via a Yg/Yg interconnection transformer, if not specified otherwise. In some cases, a supplemental grounding transformer adjacent to the DER is included in the model (not shown in the figure and described in more detail later in this section).

For simplicity, the simulated load is resistive and balanced. Load is connected in both delta and Y configurations to show differences in simulation results, with and without ground faults. Note a load step-down transformer is not simulated, load is treated as if directly connected to MV. Line to neutral connected load acts as a system ground source, with 1 p.u. impedance. Delta-connected loads do not act as a ground source. More complicated, unbalanced, as well as non-unity power factor loads such as motors, are material for a future study.

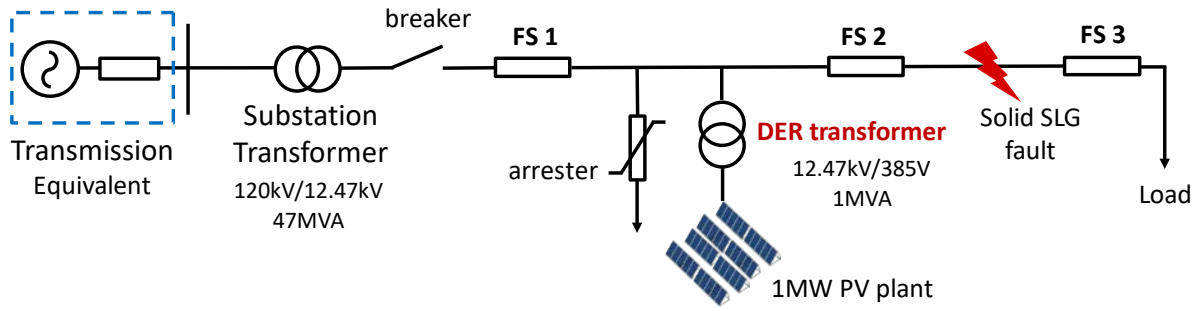


Figure 4-1
Test circuit in simulation study

Directly connecting the load removes the additional complexity to model load transformers with different winding configurations. The simulations do cover various and commonly used DER interconnection transformer configurations. Note, three phase line to neutral connected loads, although balance in these simulations, could be connected as many single-phase service

transformers with load at different locations on the feeder, such as in residential neighborhoods and in rural areas. Other, less common, service connections are not considered here and could result in different levels of load participation as a ground source.

A single 7.7 kV heavy duty arrester (MCOV of 8.4 kV and joules per kV is 2.2) was placed at the point of common coupling (PCC), with an IV characteristic shown in Figure 4-2. In most practical situations, a substantial number of surge arresters will be connected to the phases and will, to some degree, share energy duty. Location of the arresters along the distribution feeder on the open phases has little impact due to the low-frequency characteristic of arrester discharge current during TOV. For this reason, there is sharing of energy during the overvoltage. However, due to the extreme non-linearity of the metal oxide arresters and the inherent variability of arrester voltage-current characteristics, sharing is not balanced.

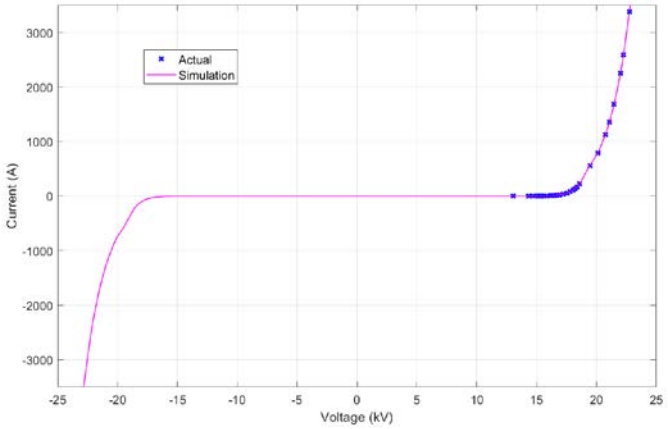


Figure 4-2
IV characteristic of emulated arrester (note voltage is kVpeak)

Nevertheless, the energy duty imposed on the most-affected arrester is likely to be less than that to which the single arrester, modeled in the simulations, is subjected. Since sharing among multiple arresters was not directly addressed in the simulation, an arrester energy higher than the single published limit (17 kJ) does not necessarily mean arrester failures in practice. Arrester sharing of power frequency overvoltages is an important consideration, as discussed in chapter 5 of this report, addressing equipment susceptibility to OV.

It is important to note, the published arrester energy capabilities pertain to a higher-current, shorter duration switching surge test waveform and this energy capability does not necessarily apply accurately to TOV duty.

The grounding transformer (GT) used in several scenarios had X0 = 0.6 p.u. and X/R = 4. These parameters were commonly used by utilities but are shown to be not optimal for inverter-based DER.

In the inverter model, no negative sequence control was implemented and the inverter negative sequence impedance ($Z_{2\text{-}inv}$) was induced by its "natural response". This is illustrated in Figure 4-3, where the $Z_{2\text{-}inv}$ is around 0.26 p.u. and mainly resistive. Here current following out from the inverter was defined as positive following generator convention. To model inverter negative sequence as an impedance, load convention needs to be used and therefore the phase angle here should be reversed (e.g., 173° instead of -173°).

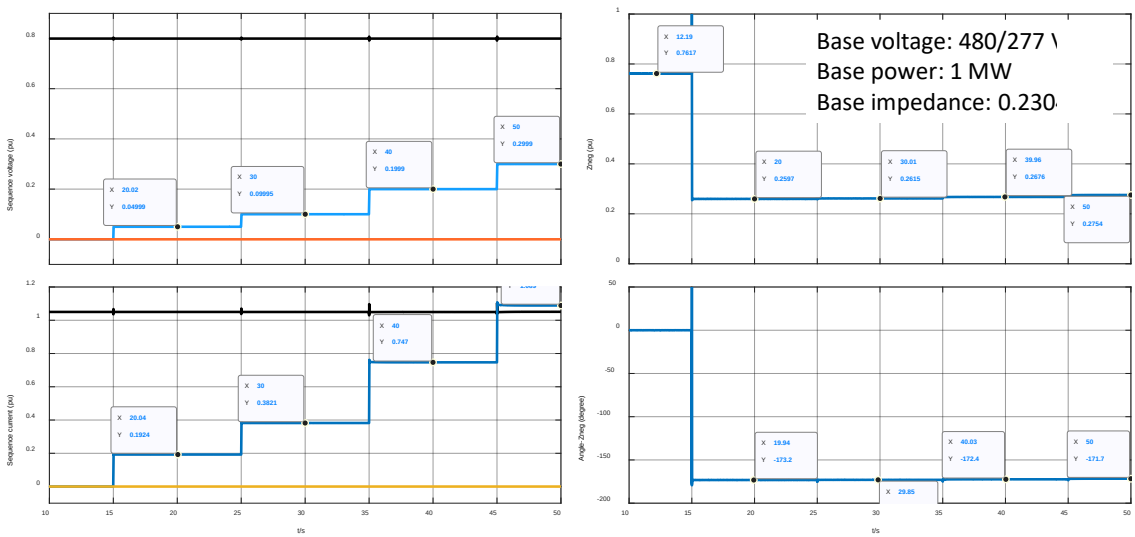


Figure 4-3
Negative sequence impedance of inverter model used in simulation

To extend the inverter trip time and better investigate the inverter response to GFOV and LROV, IEEE 1547-2018 Category II extended trip settings, as shown in Table 4-1, were used. Additionally, the inverter was assumed to have internal self-protection for overvoltage (SPOV) that protects the power switches against damaging transients.

Table 4-1
IEEE 1547-2018 Category II extended trip settings

Element	Default Pickup Value	Pickup Value Used	Default Time Delay	Time Delay Used
Undervoltage	0.45 pu	0.45 pu	0.16 sec	1 sec
Undervoltage	0.7 pu	0.7 pu	10 sec	10 sec
Overvoltage	1.1 pu	1.1 pu	2 sec	2 sec
Overvoltage	1.2 pu	1.2 pu	0.16 sec	0.16 sec
Underfrequency	56.5 Hz	56.5 Hz	0.16 sec	0.16 sec
Underfrequency	58.5 Hz	58.5 Hz	300 sec	300 sec
Over frequency	61.2 Hz	61.2 Hz	300 sec	300 sec
Over frequency	62 Hz	62.5 Hz	0.16s	0.16 sec

Inverters self-protection (SPOV) behaviors vary between manufacturers and are difficult to confirm. For purposes of this study a pick-up level of 2 p.u. and a time delay of .0016 seconds were used. From experience these are believed to be conservatively robust and appropriate for the simulation to predict the higher end self-protection levels. Inverter on-board islanding detection function was disabled, and no other feeder level protection was considered. These settings were intentionally chosen to analyze the worst-case scenario.

Inverters that meet temporary overvoltage limits, as newly defined in standard IEEE 1547-2018[7], were simulated to determine how the limit may affect GFOV and LROV. The effectiveness to limit overvoltage magnitude and duration is examined in different simulation scenarios.

Simulation results are provided in the following sections. They focus on the impact of gen/load ratios, supplemental grounding, load connection configuration, interconnection transformer windings and with/without the new IEEE 1547 TOVP requirements.

Overvoltage Sensitivity to Generation/Load Ratios

Load Rejection Overvoltage (no ground fault)

In this simulation there was no ground fault emulated and the overvoltage was exclusively caused by power generation exceeding load after grid disconnection (island formation). Peak overvoltage, trip time and arrester energy, without and with transient overvoltage limit/protection (TOVP) are provided in Figure 4-4 and Figure 4-5.

As the generation to load ratio grew, the peak overvoltage increased until the arrester starts to conduct (at a ratio of around 2.5, as indicated the reduction in rate of voltage rise). When load exceeded generation, the voltage fell below 1 p.u., and continued dropping as load increased. The high-side voltage was slightly lower than the LV side due to the voltage drop from the transformer impedance.

Peak voltage typically occurred during the first several cycles, and thus the fast TOVP trip did not have significant impact on the peak voltage. As shown in Figure 4-5 higher voltage contributed to much shorter trip times at high gen/load levels (green curve). Otherwise DER trip time was at least 160 ms (blue curve) with the trip settings in Table 4-1. Note that the DER was tripped by over-frequency protection when gen/load ≤ 1.1. In this case reactive power mismatch within the islanded area was induced by line impedance. Arresters started to operate when gen/load ≥ 4, and due to the relatively low peak overvoltage, the arrester energy stayed below 0.2 kJ for all cases.

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[7] IEEE 1547-2018, "Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces". Clause 7.4.2 - Limitation of cumulative instantaneous overvoltage "The DER shall not cause the instantaneous voltage on any portion of the Area EPS to exceed the magnitudes and cumulative durations shown in Figure 13. The cumulative duration shall only include the sum of durations for which the instantaneous voltage exceeds the respective threshold over a one-minute time window."

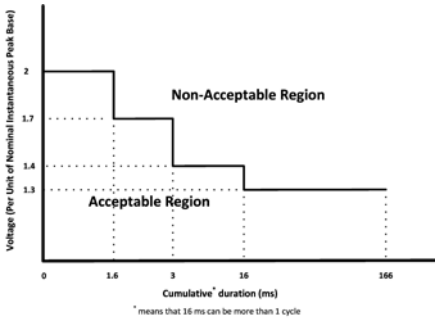
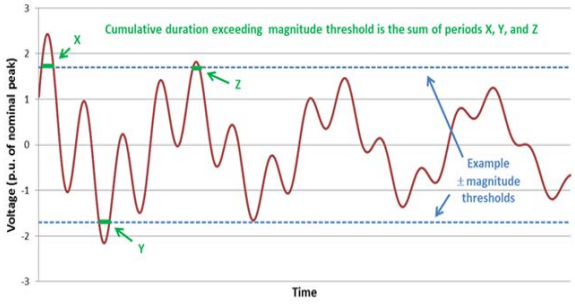


Figure 13



An example of the cumulative duration

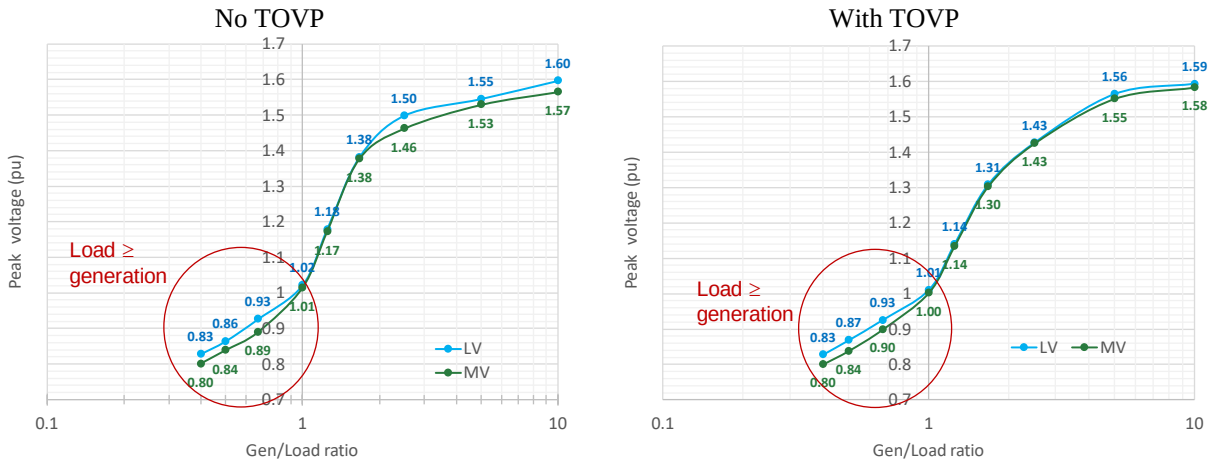


Figure 4-4
MV and LV side peak voltage as gen/load ratio varies, without (left) and with (right) TOVP, and no SLG fault

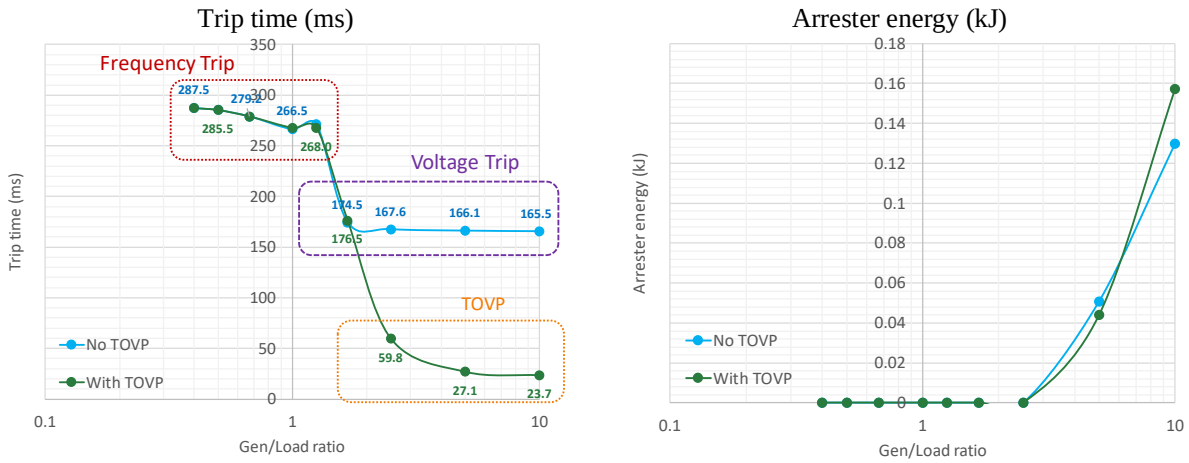


Figure 4-5
Trip time (left) and arrester energy (right) as gen/load ratio varies, and no SLG fault

Combined LRO and GFO (with ground fault)

When a SLG fault remains or occurs during islanding, the peak voltage was created by both neutral shift and load rejection, i.e. GFO + LRO, and was much higher than that with only LRO, as shown in Figure 4-6. Note that 100% of the load in this case was ungrounded (delta connected) and therefore provides no supplemental grounding effect. This represents the worst case, rarely encountered on four-wire feeders. The peak voltage dropped as load increased and stayed below 1.38 p.u.[8] When gen/load ≤ 0.67, even without supplemental grounding or

[8] In a situation where the phase-to-phase voltage remains constant during a fault, a voltage magnitude of <1.38 p.u. on the unfaulted phase implies effective grounding. However, with inverter sources, the phase-to-phase voltage once islanded is a function of the gen/load ratio and thus there is a combination of LROV and GFOV. Therefore, a voltage magnitude greater than 1.38 p.u. cannot be the basis for determining if effective grounding is present. Because insulation systems and surge protection on a four-wire multi-grounded wye feeder are designed

grounded load. TOVP still did not help much on the peak overvoltage mitigation, but it enabled much shorter trip time and thus lower arrester energy when gen/load ≥ 1 (Figure 4-7).

When TOVP was absent, the highest arrester energy occurred at gen/load = 2.5 without TOVP, because of the coincidence of high voltage and long trip time. SOVP served in a similar way as TOVP at high gen/load ratios and enabled short trip times. Lower trip threshold of SOVP could ensure faster DER trip during overvoltage conditions, as illustrated in Figure 4-8, but has higher risk of nuisance tripping.

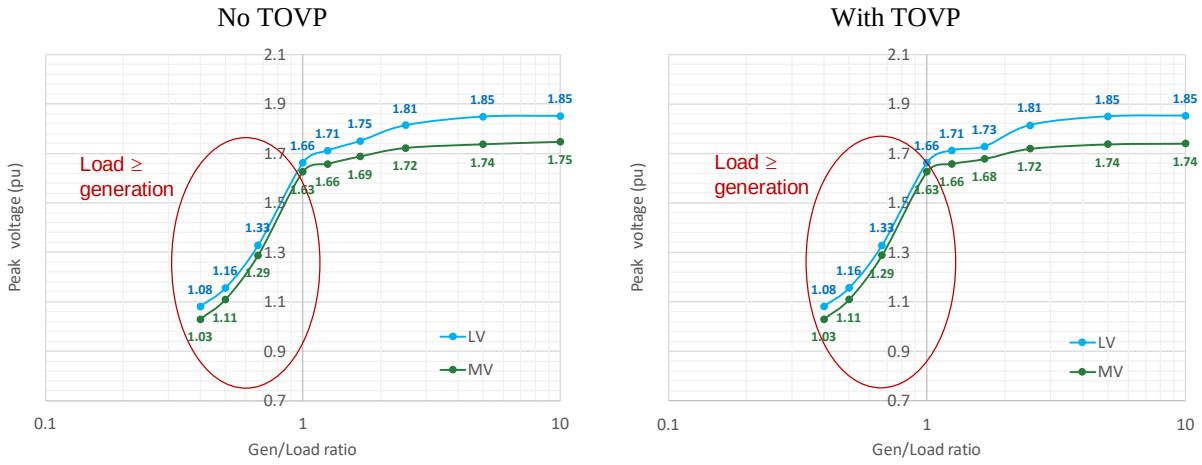


Figure 4-6
MV and LV side peak voltage as gen/load ratio varies, without (left) and with (right) TOVP, when SLG fault presents

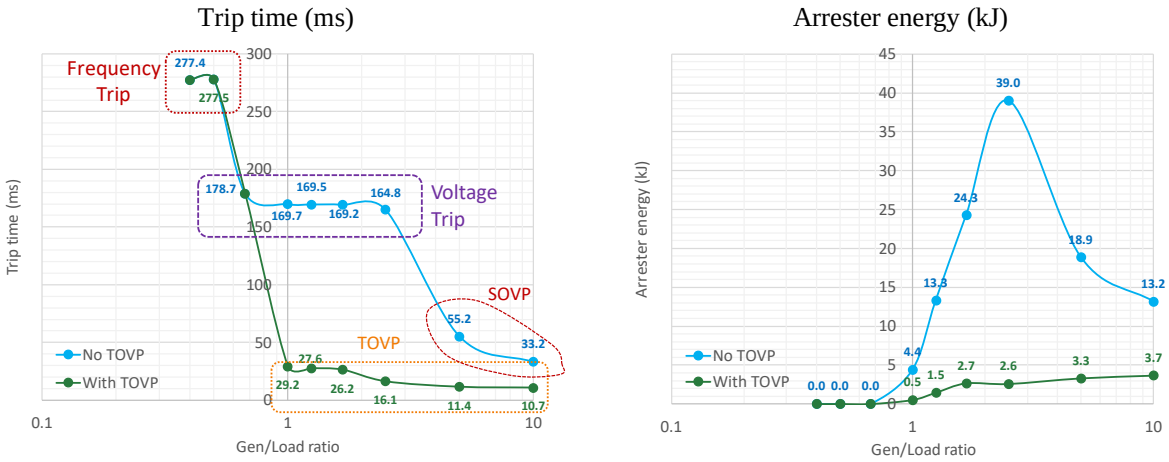


Figure 4-7
Trip time (left) and arrester energy (right) as gen/load ratio varies, when SLG fault presents

on the basis of effective grounding with a voltage source (the substation), a 1.38 p.u. unfaulted-phase overvoltage criterion is a useful threshold for evaluation of results.

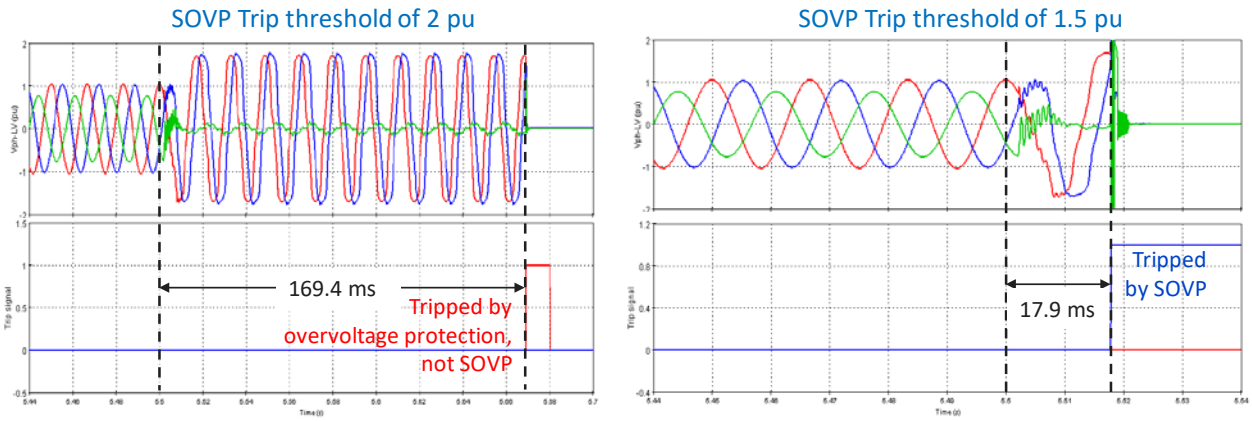
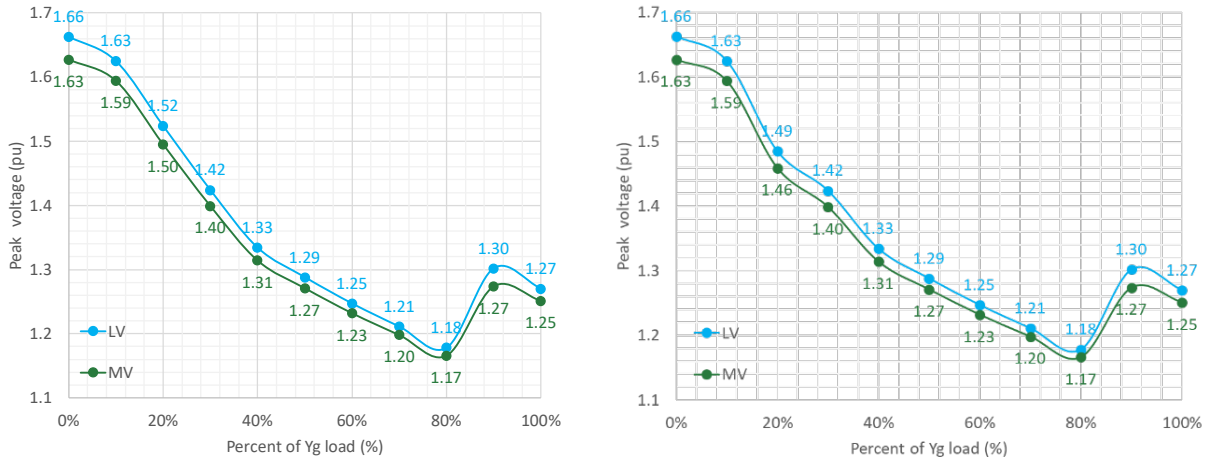


Figure 4-8
Impact of self-overvoltage protection

Transformers and Loads as Ground Sources

In Figure 4-9 and Figure 4-10, a SLG fault persisted while the load/gen ratio remained at 1, i.e., only GFO and no LRO involved[9]. The load was partially grounded and percent of grounded load (Yg load) varied from 0% to 100%. In general, grounded load contributed to lower GFO. TOVP reduced inverter trip time and arrester energy when most of loads were delta connected, while such contribution was not clear when majority of loads were grounded due to the less severe overvoltage.



No TOVP With TOVP

Figure 4-9
MV and LV side peak voltage as percent of grounded load varies, without (left) and with (right) TOVP, when SLG fault presents and gen/load = 1

[9] Because the inverter seeks to inject a constant balanced 3-phase power, however on the faulted phase with depressed voltage power is reduced cannot be transmitted on the faulted phase, the inverter controls tend to increase the current on the unfaulted phases to compensate. The current is only increased to the inverter's current limit, however, and thus the LRO effect at load/gen = 1 is limited.

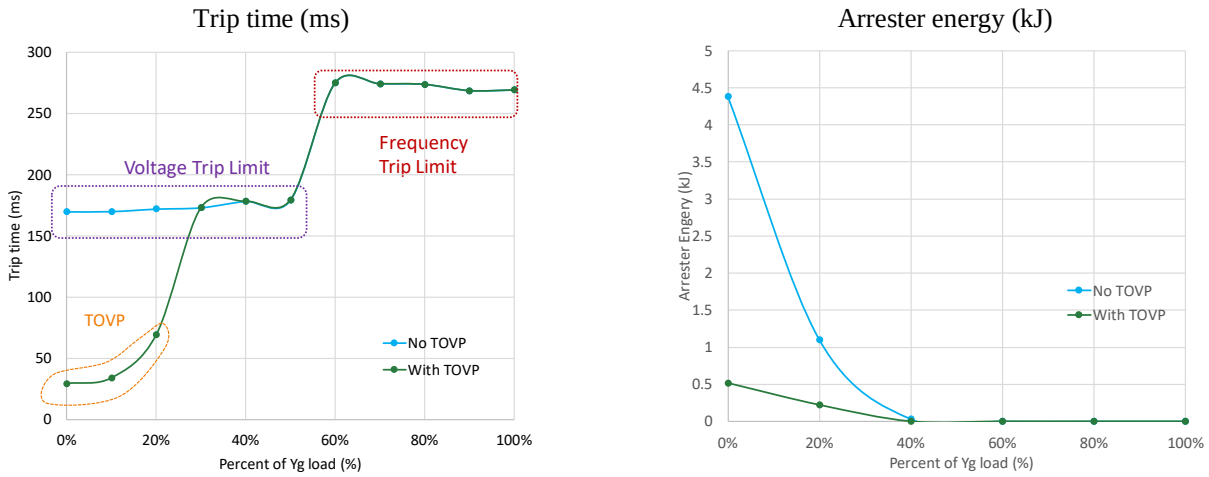


Figure 4-10
Trip time (left) and arrester energy (right) as percent of grounded load varies, when SLG fault presents and gen/load = 1

Figure 4-11 and Figure 4-12 give the impact of supplemental grounding (through a grounding transformer, GT) and grounded load, when both GFO and LRO were involved. In this study, load was either 100% delta connected or 100% grounded (Yg), and TOVP was activated. Similar as the previous case, both GT and grounded load reduced the peak voltage, and grounded load (green curve) showed relatively higher effectiveness than GT (blue curve) on overvoltage reduction when gen/load ≤ 3. Therefore, the benefits provided by supplemental grounding may not be worth the adverse system protection impacts and cost when sufficient grounded load exists.

The lower voltage enabled by GT and/or Yg load, on the other hand, extended the trip time. The arrester energy, as the time integral of arrester voltage (MV side), reduced with the ground source provided by GT or Yg load. TOVP prevented long-lasting overvoltage for most of simulation cases, and the arrester energy stayed below 4 kJ.

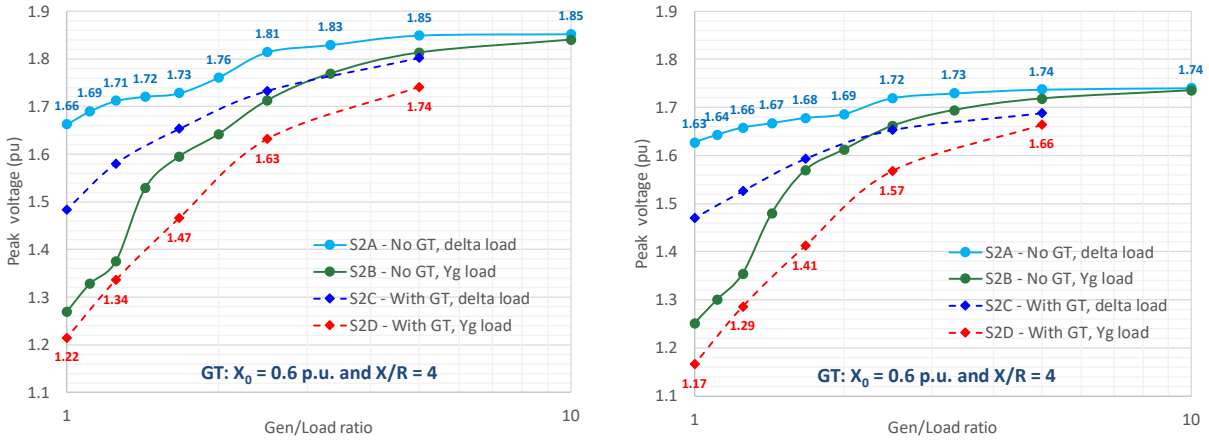


Figure 4-11
LV (left) and MV (right) side peak voltage as gen/load, and/or grounding means (through grounded load or grounding transformer (GT)) vary, when SLG fault presents

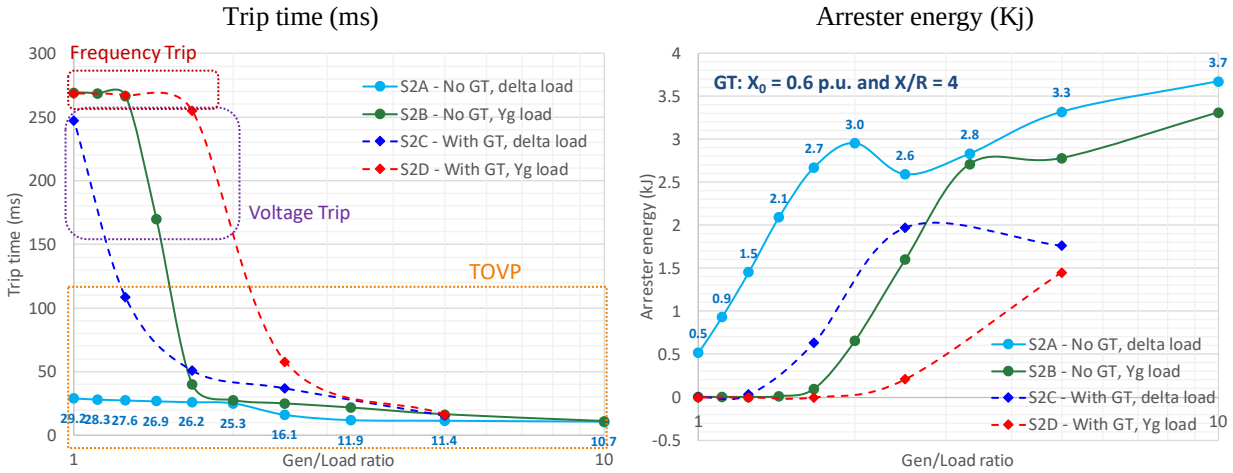


Figure 4-12
Trip time (left) and arrester energy (right) as gen/load, and/or grounding means (through grounded load or grounding transformer (GT)) vary, when SLG fault presents

To sum up, transient overvoltage can be induced by SLG fault or load rejection, and the worst case occurs when the islanded system is not effectively grounded and has no load. The transient overvoltage protection (TOVP) implied by IEEE 1547-2018 can significantly reduce the trip time and arrester energy at high overvoltage conditions. TOVP does not help much on peak overvoltage reduction. The grounding transformer and grounded load both help to mitigate GFOV and thus relieve arrester stress. For cases with low gen/load ratio (high loading conditions), grounded load is more effective than the grounding transformer on overvoltage mitigation.

Different Interconnection Transformer Configurations

Example Waveforms (With Yg/Yg or Δ/Yg Transformer)

The interconnection transformer effects the voltage the LV side (inverter terminals) compared to the MV side. This affects the inverters GFOV response as well as trip times once an overvoltage is detected. Figure 4-13 and Figure 4-14 compare the MV and LV side voltage waveforms when Yg/Yg or Δ/Yg transformer were used. For both cases, there was no load in the islanded area, SLG fault occurred at 5.4 s, and breaker opened (island formed) at 5.5 s (after 6 cycles of the fault occurrence). *In this section and hereafter*, transformer configurations are defined as the grid-side medium voltage listed first and followed by DER-side, as MV/LV. Other conventions may list the generator side of a step-up transformer first, but not here.

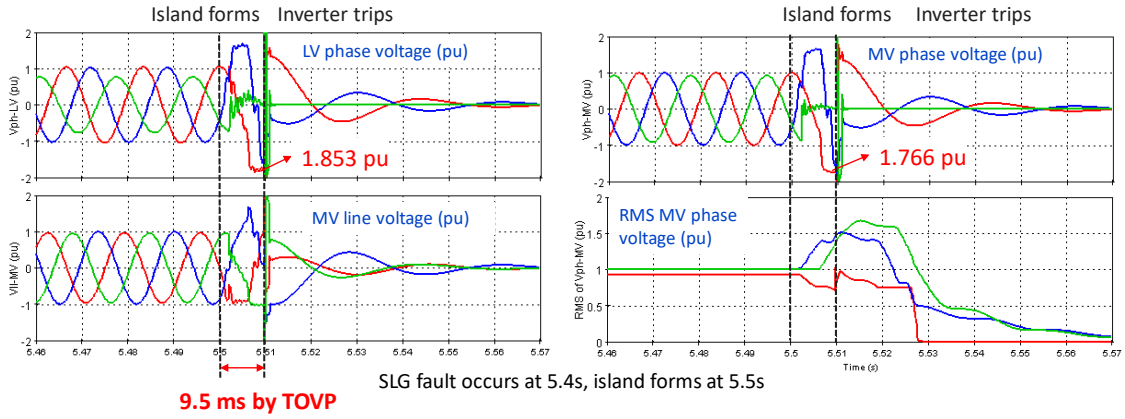


Figure 4-13
Simulated phase-to-ground and line-to-line voltage with persistent SLG fault and Yg/Yg interconnection transformer

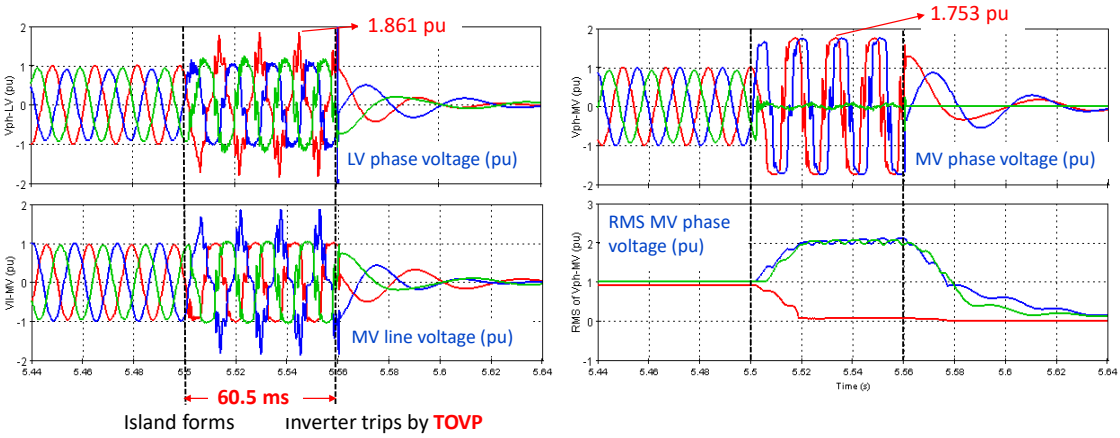


Figure 4-14
Simulated phase-to-ground and line-to-line voltage with persistent SLG fault and Δ/Yg interconnection transformer

After the island formation, the SLG fault caused unbalanced phase-to-ground voltages (V_{ph}) at both LV and MV side for the case with a Yg/Yg transformer. In response to the high overvoltage, inverter was tripped after 9.7 ms by TOVP. The delta connection of Δ/Yg transformer, on the other hand, blocked the zero-sequence path, and "masked" the faulted phase voltage at the LV side, making the GFOV less severe to the inverter. [10,11] The distortions around peak voltage were caused by the arrester operation, leading to a voltage spike with peak of 1.861 pu. The inverter tripped after 60.5 ms also by TOVP. The nearly balanced phase voltage at LV

[10] *Impact of Interconnection Transformer Configuration on DER Operation*. EPRI, Palo Alto, CA: 2020. 3002019423.

[11] If the Reference Point of Applicability (RPA), as defined in IEEE 1547-2018, is on the MV side, then the DER owner is responsible for meeting the TOV limits even if the inverters cannot sense the overvoltage. Other measures to achieve this performance will be necessary, such as providing MV-side potential transformer outputs to inverters.

side and shifted neutral at MV side led to quite balanced MV line-to-line voltage (V_{ll}) but elevated MV phase voltage (V_{ph}) on the unfaulted phases.

Results without Fast Trip (TOVP) Activated

To identify the overvoltage risk for existing/installed DER, the TOVP implied by IEEE 1547-2018 was deactivated for these simulations. Figure 4-15 shows the impact of transformer winding and load connection on the MV side phase-to-ground voltage. Among the studied transformer configurations, Yg/Δ (Yg/d) without a neutral impedance has the lowest voltage regardless of the load connection and gen/load ratio, due to the high degree of grounding it provided.[12] The other three transformer configurations introduced very similar MV side voltages. Grounded load reduced MV side overvoltage but its effect dropped as gen/load ratio increased (less load).

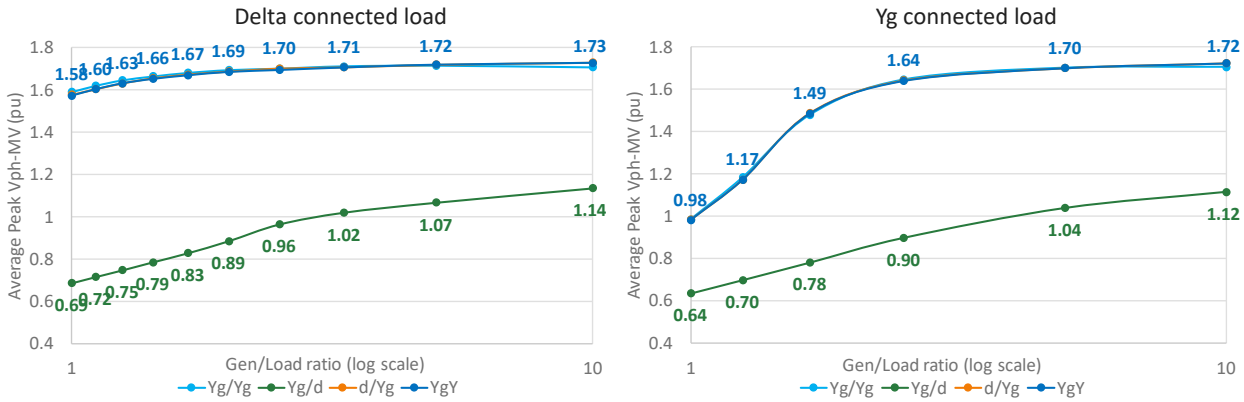


Figure 4-15
Average Peak MV side, Y and Δ connected load, various transformer connections and no TOVP

The LV side phase-to-ground voltage is given in Figure 4-16. The average peak overvoltage, i.e., the peak voltage averaged over the run-on-time (ROT, time between island forms and DER inverter ceases to energize or trips) is provided to include both information. With Yg/Y and Δ/Yg (d/Yg in the figures below) transformers, the MV side overvoltage was "masked" and became less severe on the LV side. Same as at the MV side, the overvoltage was highest with Yg/Yg transformer and lowest with Yg/Δ (Yg/d). Additionally, grounded load reduced LV side overvoltage at low gen/load levels (more load).

Since an inverter makes trip decisions based on its terminal voltage (unless auxiliary inputs such as MV-side potential transformer inputs are provided)[13], the trip time was affected by the

[12] Yg/delta transformers, without a neutral impedance, are problematic to apply, and rarely allowed, on distribution feeders because of the excessive grounding they provide. These transformers are prone to overloading due to ordinary feeder voltage imbalance, are subjected to frequent severe current duty as a result of feeder ground faults, and can greatly diminish the sensitivity of feeder ground fault protection. For these reasons, when these transformers are used, they typically have a neutral-to-ground impedance added to limit the grounding provided.

[13] Such inputs are not commonly provided on inverters, but may become necessary to achieve IEEE 1547-2018 compliance for inverters installed using Δ/yg transformers (or other transformers blocking zero sequence continuity) if the transformer is not utility owned but rather provided by the DER owner.

transformer configuration and load connection, as shown in Figure 4-17. Due to the high LV side voltage, a Yg/Yg transformer enabled the fastest inverter tripping by overvoltage protection. For other transformer types, the inverter trip time was similar, except at very high gen/load ratios. In addition, the frequency trip was triggered at most conditions, because of the reactive power mismatch and low overvoltage at the LV side. Grounded load reduced the LV side overvoltage and tended to increase the inverter trip time.

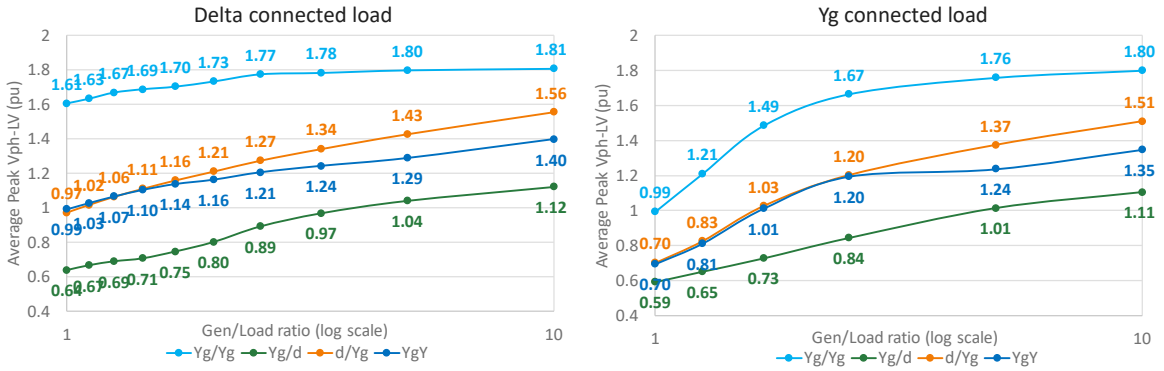


Figure 4-16
Average Peak LV side, Y and Δ connected load, various transformer connections and no TOVP

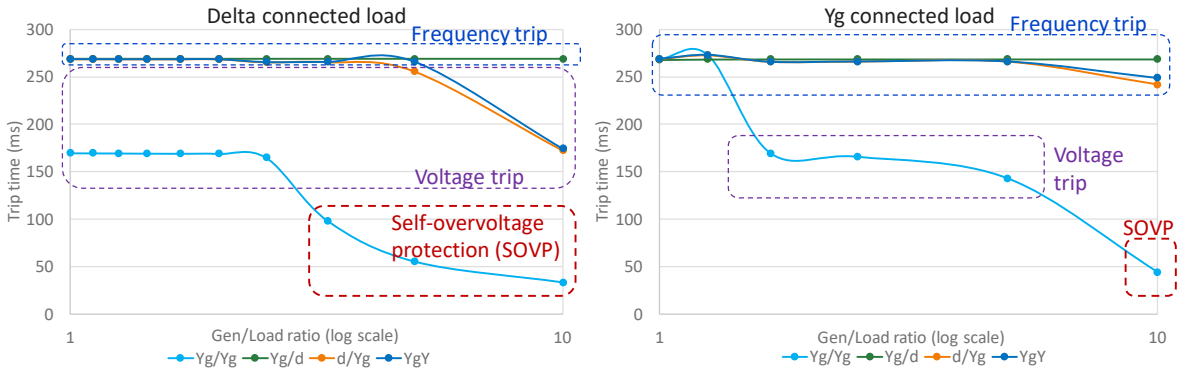


Figure 4-17
Trip times, Y and Δ connected load with various transformer connections and no TOVP

Figure 4-18 presents the corresponding arrester energy. The highest arrester energy occurred with Yg/Y and Δ/Yg (d/Yg) transformers, because of the coincidence of high voltage and long trip time. The Yg/Yg transformer, on the other hand, induced the highest overvoltage but shortest trip time, thus lower arrester energy. In contrast, the LV side voltage was too low with Yg/Δ (Yg/d) transformers and arrester did not operate (i.e., zero arrester energy). Grounded load helped reduce the arrester energy, except at very high gen/load ratios, where the arrester energy increased due to the prolonged inverter trip time.

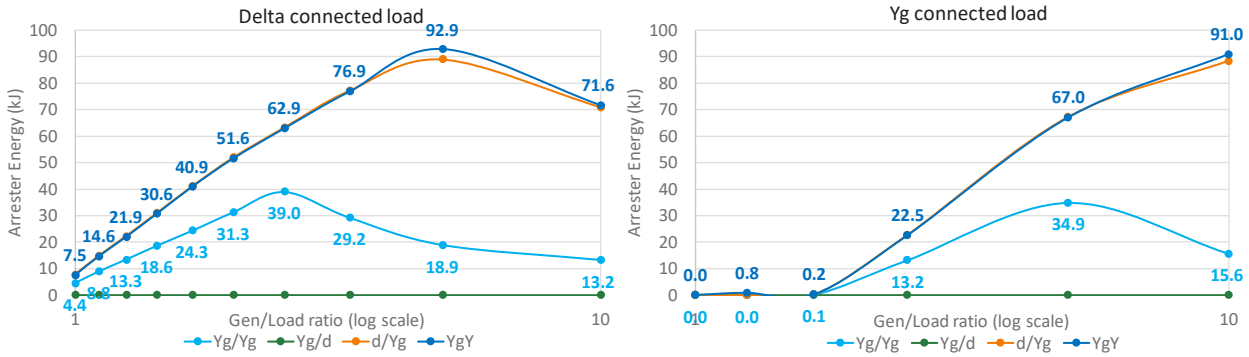


Figure 4-18
Arrester energy, Y and Δ connected load with various transformer connections and no TOVP

Results with Fast Trip LV Sensing (Inverter side)

As expected, activating TOVP was found to have very limited impact on the peak MV and LV side overvoltage, regardless of the transformer configuration. This is shown in Figure 4-19 and Figure 4-20. The transformer connection type and generation to load ratios were the primary determining factors of the average peak voltage.

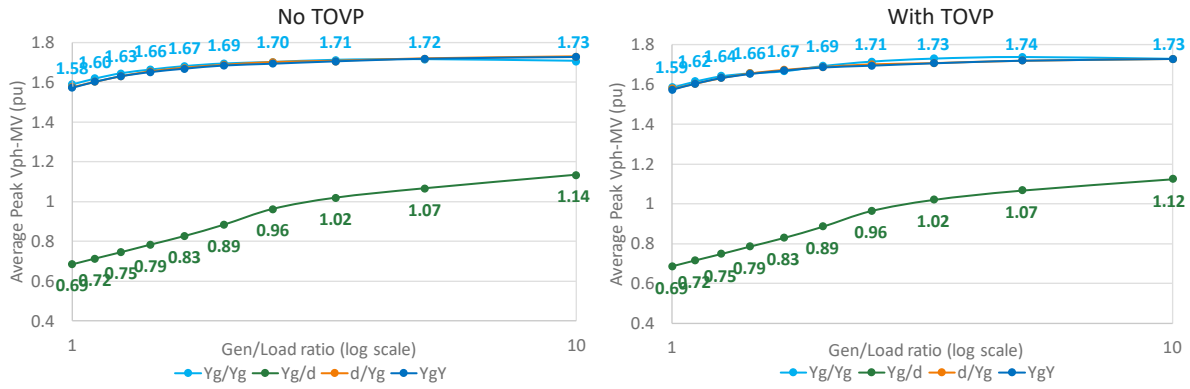


Figure 4-19
Average Peak MV side, with and without TOVP with various transformer connections

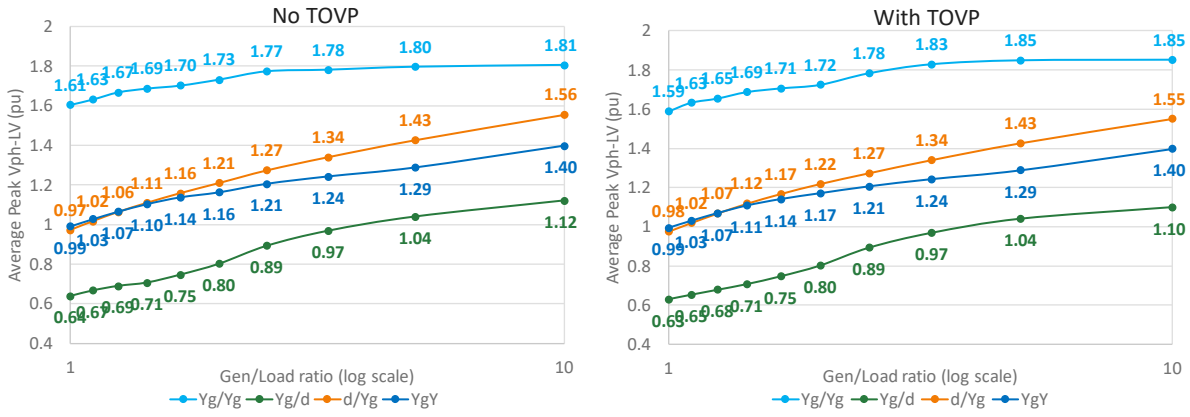


Figure 4-20
Average Peak LV side, with and without TOVP with various transformer connections

On the other hand, Figure 4-21 and Figure 4-22 show that activating TOVP significantly reduced the inverter trip time and the arrester energy when Yg/Yg transformer was used. This was not the case for Yg/Y and Δ/Yg transformers, where high side overvoltage was "masked" at the inverter terminals and implementing TOVP on the LV side did little to reduce the inverter trip time or arrester energy, since it took actions based on inverter terminal voltages. Meantime, the Yg/Δ transformer enabled the lowest overvoltage and least arrester energy.

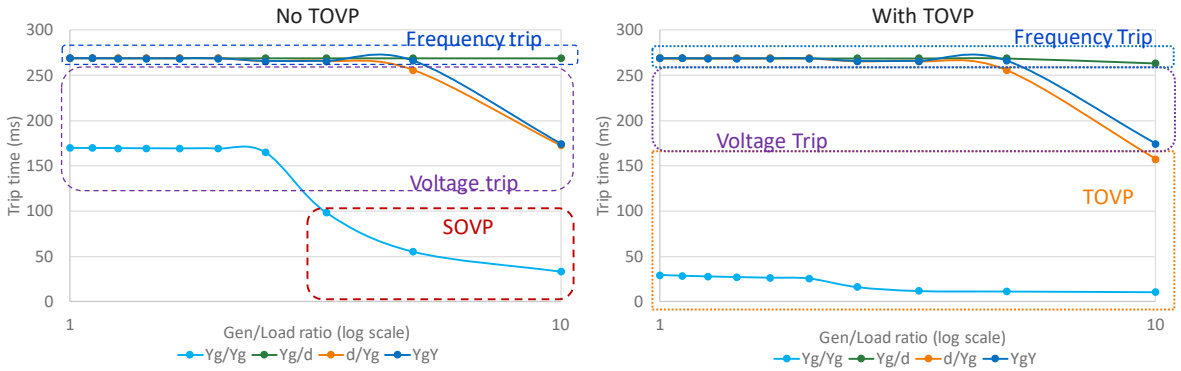


Figure 4-21
Trip times, with various transformer winding connections, with and without TOVP

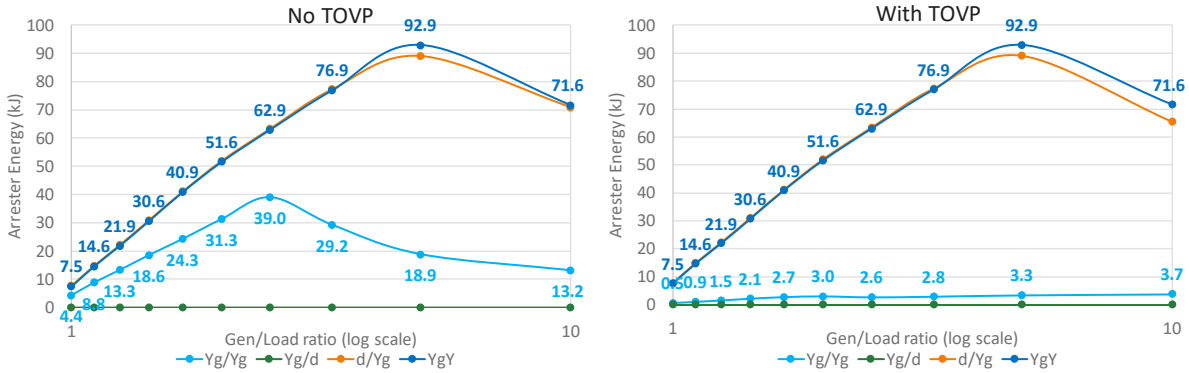


Figure 4-22
Arrester energy, with various transformer winding connections with and without TOVP

Results with Fast Trip MV Sensing (feeder side)

IEEE 1547-2018 specifies a reference point of applicability (RPA) for requirements such as the TOVP fast tripping. For example, in case of zero-sequence discontinuity between the DER units (i.e., inverters) and the PCC, the RPA is at the PCC. This is to overcome masking of MV level at the DER terminals. Therefore, for Yg/Y, Δ/Yg and Yg/Δ connected transformers, the RPA would be at PCC. Applicability is on the MV side of the transformer (assuming the transformer is owned by the DER owner and not the utility) and TOVP response is consequently based on MV levels.

While this is the correct interpretation of IEEE 1547-2018, there has been little indication that inverter OEMs have given consideration of this requirement, and capabilities for meeting this requirement (e.g., remote potential transformer inputs to inverters) have not appeared on currently-available inverters. This is a gap that will need to be filled in the near future, and

utilities need to be diligent in ensuring that the IEEE 1547-2018 requirements are met for DER facilities with an MV-side RPA, particularly facilities with multiple inverters where it may not be feasible to bring potential transformer secondary leads to each and every inverter. For example, achieving MV-side TOVP (as short as 1.6 ms, 1/10 cycle at high voltage levels) via MV relay activated circuit breaker may be difficult due to the time required for breaker operation. Blocking the gate signals of inverter (cease to energize) could work but sending the voltage or trip signal to each inverter may not be feasible.

In this simulation, the MV side voltage signal was sent to inverter for the TOVP implementation. Due to the lack of field experience, we don't know yet how this has been, or will be implemented, in commercial inverters.

As shown in Figure 4-23 and Figure 4-24, transformer configuration presented similar impact on MV and LV side overvoltage, regardless of TOVP location. With MV activated TOVP, the MV side average peak voltage was only slightly reduced for all transformers. The difference being voltage drop in the transformers.

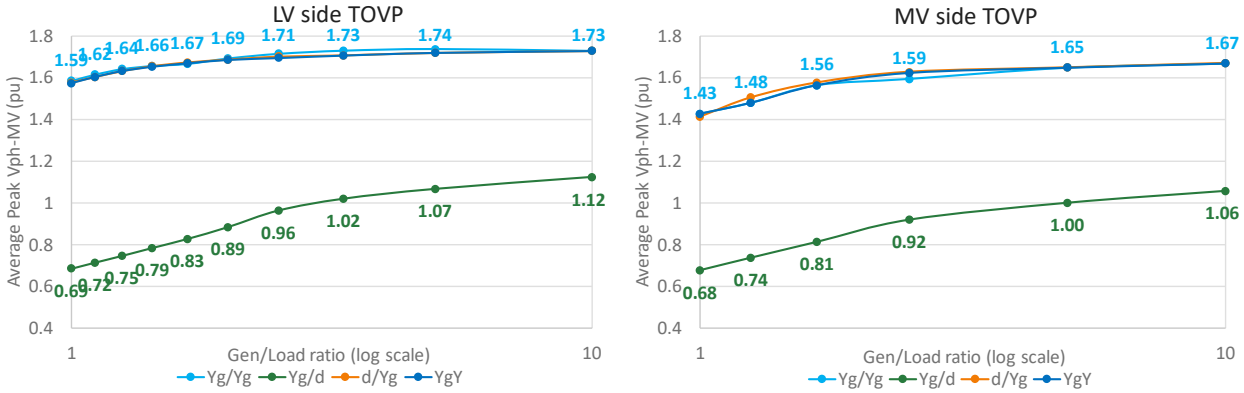


Figure 4-23
MV side average peak voltage with LV (left) or MV (right) side activated TOVP

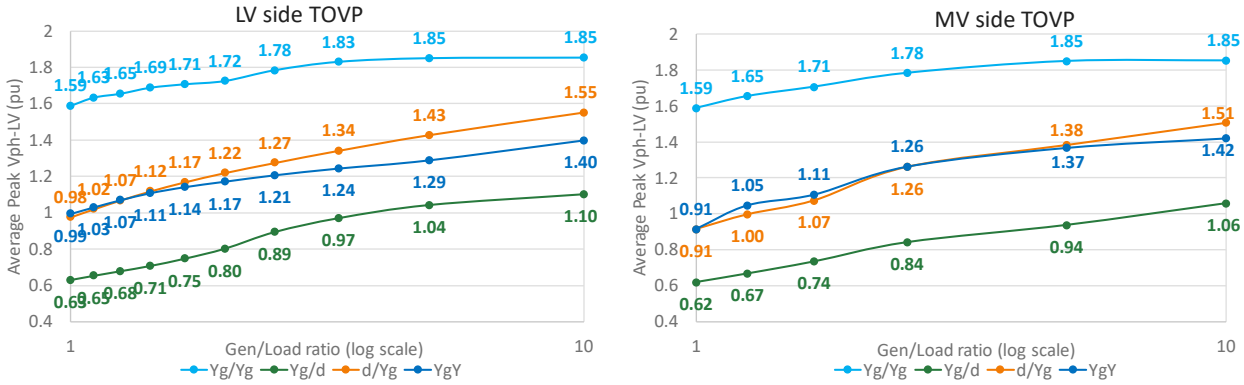


Figure 4-24
LV side average peak voltage with LV (left) or MV (right) side activated TOVP

The MV side activated TOVP significantly reduced inverter trip time for Δ/Yg and Yg/Y transformers, as shown in Figure 4-25. In this case high MV side overvoltage was directly

utilized to assist inverter fast tripping, no longer “masked” by the transformer connection. The fast inverter trip greatly reduced the arrester energy as in Figure 4-26.

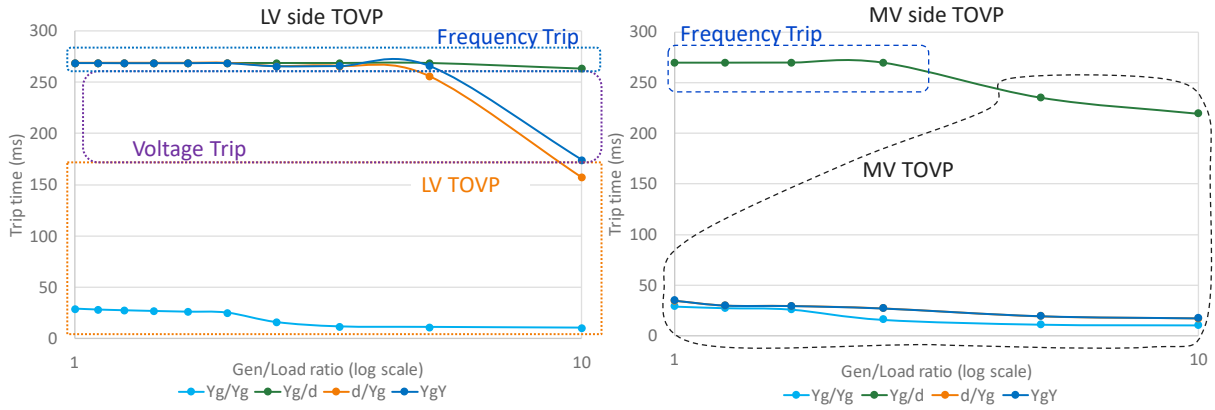


Figure 4-25
Trip time with LV (left) or MV (right) side TOVP

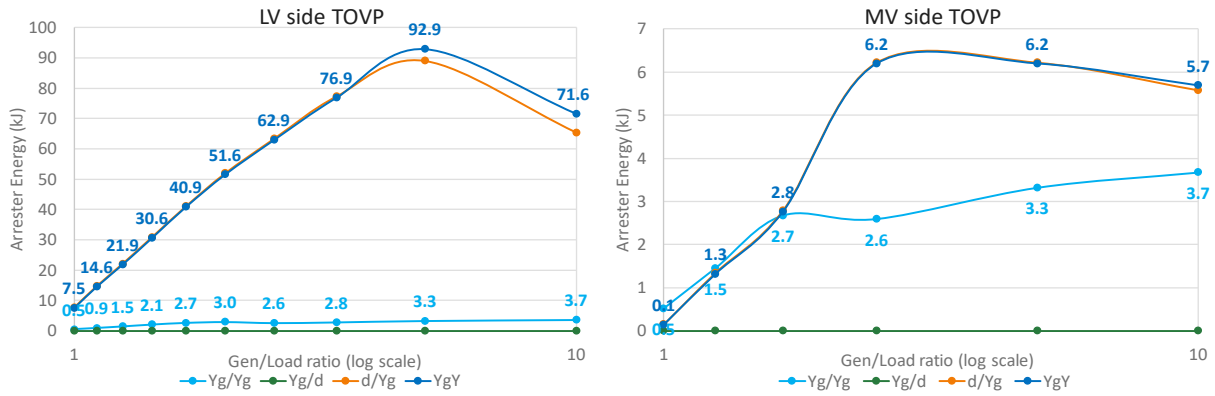


Figure 4-26
Arrester energy with LV (left) or MV (right) side TOVP

At high gen/load levels, the Yg/Yg transformer enabled higher overvoltage but shorter trip time, and the arrester energy was lower compared to cases with Δ/Yg and Yg/Y transformers. In this case, the TOVP didn’t make any difference with a Yg/Δ transformer because the inverter tripped by over-frequency protection for all studied cases.

To sum up, as illustrated in Figure 4-27, the following conclusions can be reached:

- Yg/Yg transformer “passes” the information of MV ground fault (zero-sequence) to the LV side, and creates high overvoltage at both MV and LV sides. This facilitates fast inverter tripping and results in low arrester energy.
- Yg/Δ transformer without a neutral impedance, in contrast, provides very strong ground source for MV feeder, which is far more than effective grounding, and limits overvoltage at both MV and LV sides. Providing LV activated TOVP does not help to limit the energy. The inverter relies on power mismatch and/or islanding detection function to trip.

- Δ/Yg and Yg/Y present similar overvoltage behaviors. The MV SLG fault is "masked" and difficult to be detected by the inverter, and thus MV TOVP is needed. The coincidence of relatively high MV voltage and long trip time can cause significant arrester energy if relying on only LV side overvoltage protection.

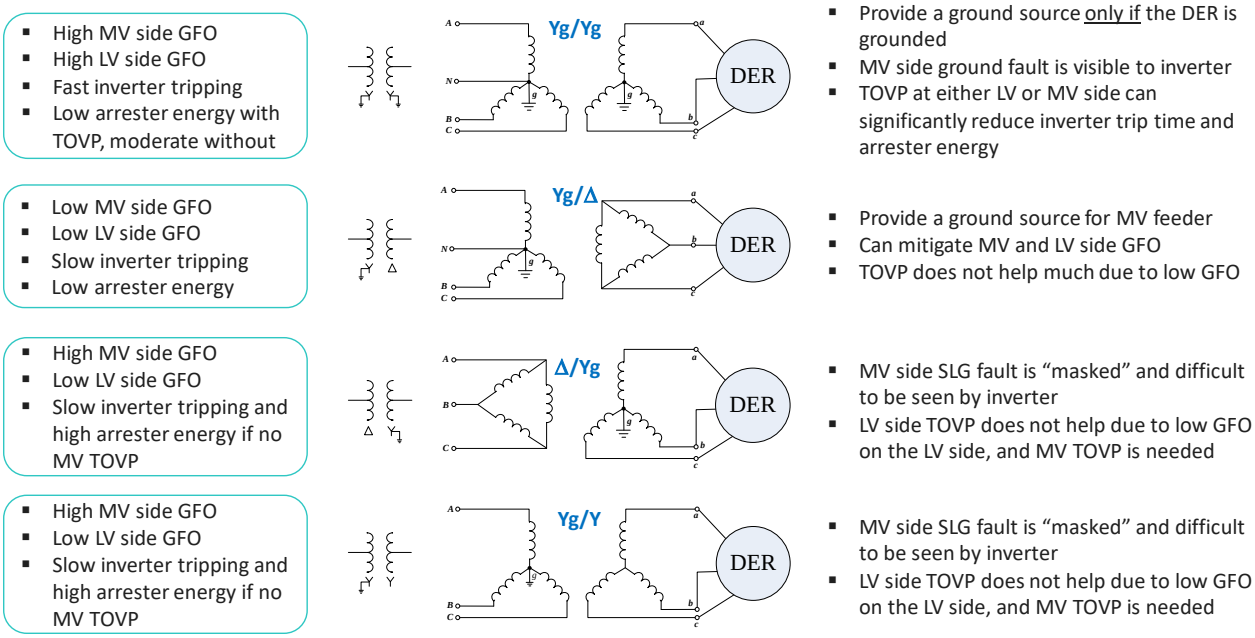


Figure 4-27
Ground fault overvoltage and transformer connection summary

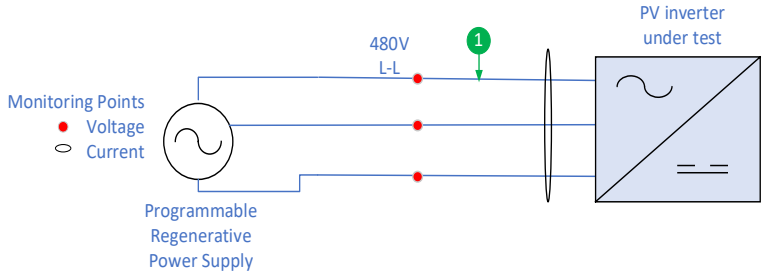
Commercial Inverter Lab Tests

Lab tests were planned to provide empirical results as support for the modeling and simulation analysis. Aiming to identify the actual inverter responses to negative sequence voltage, three commercial inverters were tested in the EPRI lab: 1) Inverter A – 33 kVA, 2) Inverter B – 33 kVA, 3) Inverter C – 36 kVA.

As shown in Figure 4-28, each commercial inverter was directly connected to a programmable regenerative power supply, and the irradiance was emulated by varying the dc voltage through a dc voltage source. Since inverters under test are three-phase three-wire, i.e., no zero-sequence current generation capability (open circuit for I_0), only positive and/or negative sequence voltage were varied. For all tests, inverters were configured with the widest allowable trip settings to maintain operation and to obtain a ***steady state*** negative sequence impedance (Zneg = Vneg / Ineg) using load convention.

In each test, the inverter terminal voltage and current data were recorded at high resolution (20 kilo-samples per second), and the negative sequence voltage and current were extracted afterwards for negative sequence impedance calculation. Impact of the volt-var function was studied, while that for islanding detection and frequency-watt functions was not because all tests were conducted during grid-connected operation. Standard Category II volt-var settings shown in Figure 4-29 were implemented in all inverters under test.

Three-line diagram



Lab test setup

Figure 4-28
Test setup for inverter negative sequence impedance evaluation

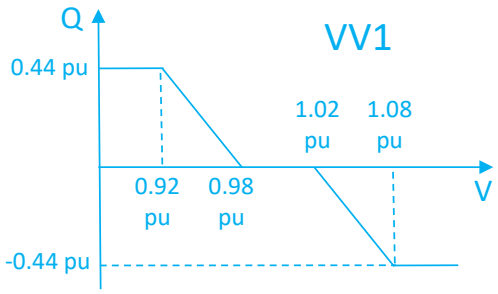


Figure 4-29
Volt-var settings used in lab test

Constant Positive Sequence Voltage and Varying Negative Sequence Voltage

The first test condition was created with fixed positive sequence voltage (V_{pos}) and varying negative sequence voltage (V_{neg}). The setpoints for programmable power supply (grid emulator) are provided in Table A- 1, where V_{pos} stayed at 0.8 pu, and V_{neg} increased from 0.05 pu to 0.3 pu. Here V_{pos} lower than 1 pu was selected to avoid inverter tripping at high V_{neg} conditions. The initial angle of phase A remained 0° for both V_{pos} and V_{neg}.

Figure 4-30 provides the responses of inverter A to voltage variations, when irradiance was 500 W/m^2 and volt-var function was disabled. The positive sequence current (I_{pos}) remained the same, and negative sequence current (I_{neg}) slightly increased as V_{neg} grew, indicating a decoupling between I_{pos} and V_{neg}. The negative sequence impedance ($Z_{neg} = V_{neg} / I_{neg}$) was nearly constant (~ 5.9 pu) and mainly inductive.

After the volt-var function was enabled, as shown in Figure 4-31, this inverter generated reactive power in response to the voltage drop, and positive sequence current became higher. Negative sequence current also increased if comparing to cases without volt-var. This caused a reduced negative sequence impedance with varying values and more resistive characteristics. It is worth mentioning that here the steady-state negative sequence impedance was calculated, which allowed the volt-var function to be fully executed. In practice, however, vol-var has very limited open loop response (e.g., minimum 1s according to IEEE 1547-2018 std.), and it likely will not significantly affect the GFOV and/or LROV which last for very short durations. In other words, the change in negative sequence impedance with volt-var enabled is due to the change in the inverter's power factor and/or output current rather than from any dynamic response of the volt-var function.

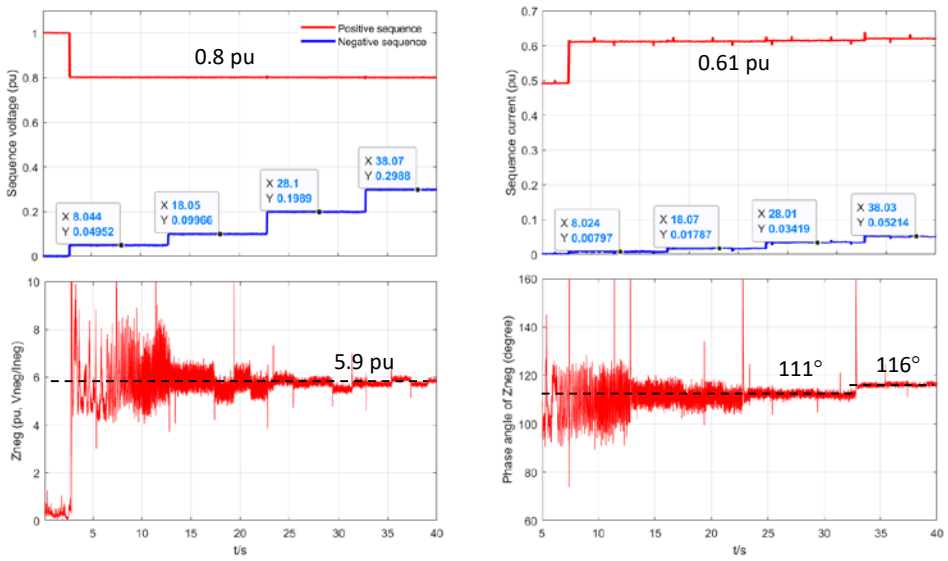


Figure 4-30
Negative sequence behavior of inverter A, with varying V_{neg} and constant V_{pos}, no volt-var

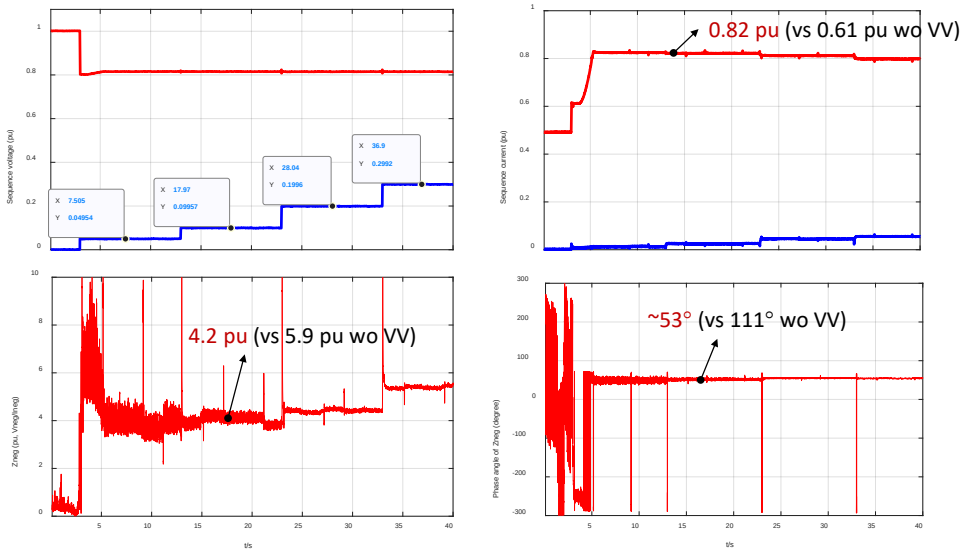


Figure 4-31
Negative sequence behavior of inverter A, with varying V_{neg} and constant V_{pos}, VV activated

The negative sequence impedance (Z_{neg}) of inverter A is summarized in Figure 4-32. As V_{neg} grew, magnitude of Z_{neg} increased while its phase angle tended to reduce, regardless of volt-var function (VV). The inverter behaved nearly inductively without VV, while more resistively when VV was enabled. Activation of VV also reduced both magnitude and phase angle of Z_{neg}. Inverter B and C, on the other hand, presented much lower negative sequence impedance, as shown in Figure 4-33 and Figure 4-34. For inverter B, magnitude of Z_{neg} was nearly constant without VV, while it increased with V_{neg} when VV was enabled. Like inverter A, it also behaved nearly inductively without VV, while more resistively with VV. Inverter C, however, had a decreased Z_{neg} as V_{neg} grew, even when VV was disabled, and distinct phase angle of Z_{neg} was observed.

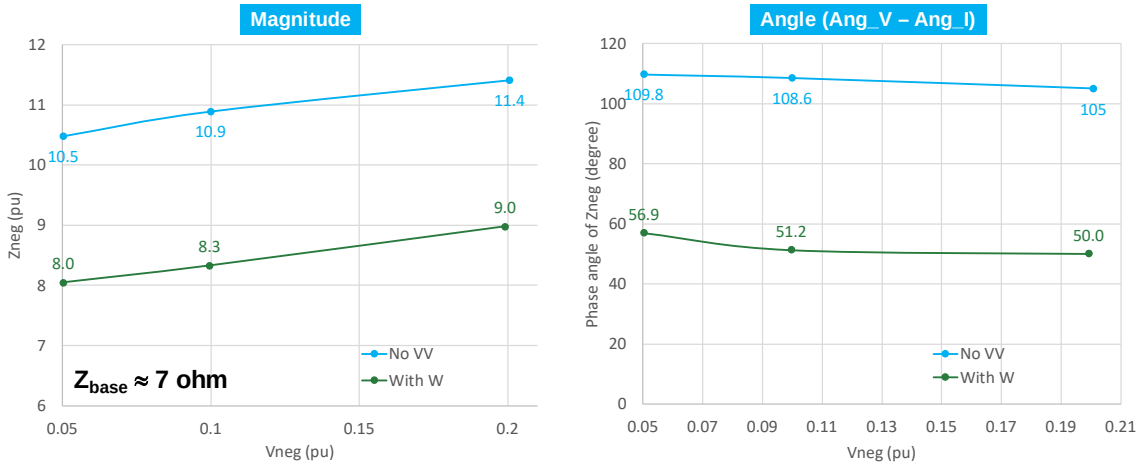


Figure 4-32
Negative sequence impedance of inverter A, with varying V_{neg} and constant V_{pos}

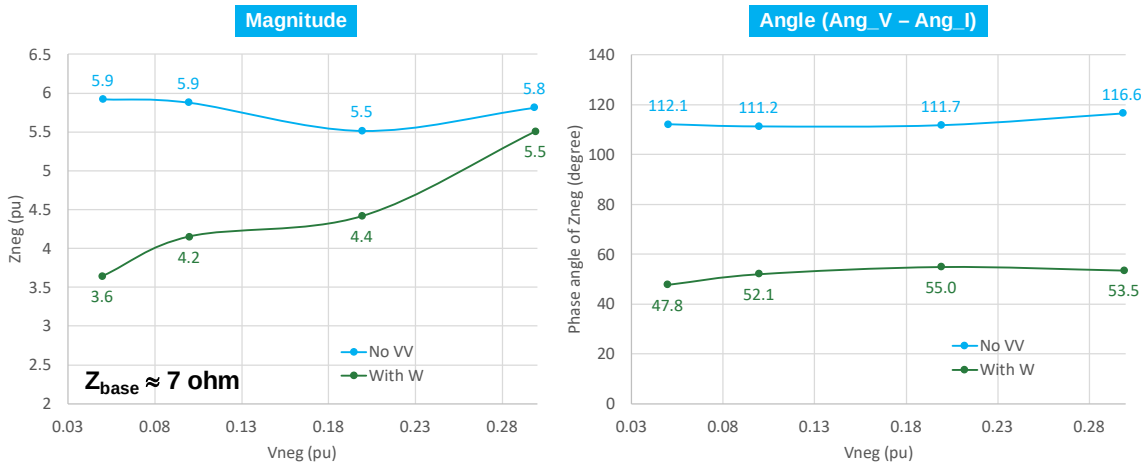


Figure 4-33
Negative sequence impedance of inverter B, with varying V_{neg} and constant V_{pos}

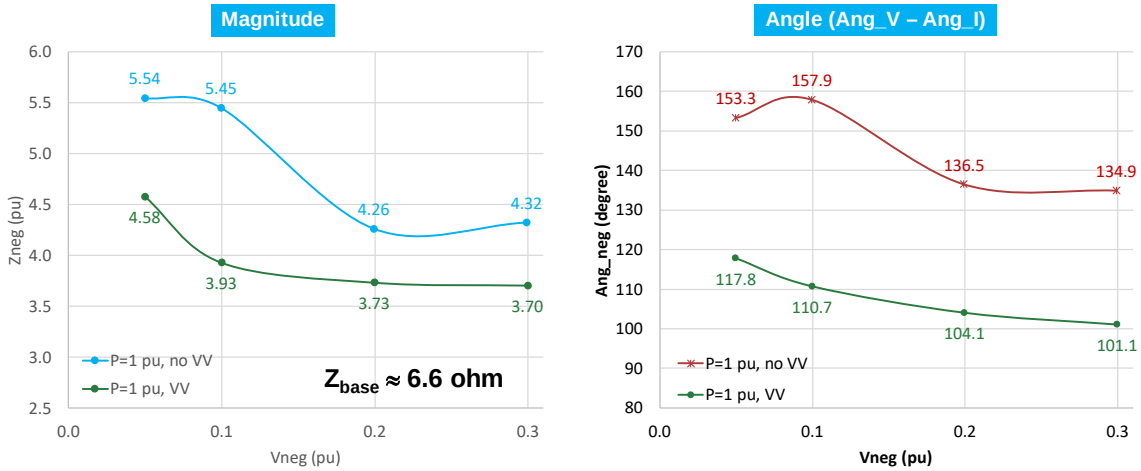


Figure 4-34
Negative sequence impedance of inverter C, with varying V_{neg} and constant V_{pos}

For all three inverters, the volt-var function induced varying power factor and/or positive sequence current (I_{pos}) and reduced both magnitude and phase angle of the steady-state Z_{neg}. This indicates a strong relationship between I_{pos} or V_{pos} and I_{neg}.

Constant Negative Sequence Voltage and Varying Positive Sequence Voltage

To investigate the impact of positive sequence voltage (Vpos), test cases with setpoints in Table A- 2 and Table A- 3 were conducted. These setpoints formed a V_{pos} varying from 0.95 pu to 0.6 pu, and negative sequence voltage (V_{neg}) at 0.1 pu or 0.2 pu, respectively. The initial angle of phase A remained 0° for both V_{pos} and V_{neg}.

Figure 4-35 shows the negative sequence impedance (Z_{neg}) of inverter B, with irradiance of 500 W/m^2. The change trend of Z_{neg} as V_{pos} grew was found to be consistent when V_{neg} increased from 0.1 pu to 0.2 pu. In other words, impact of V_{pos} and V_{neg} can be treated separately for this inverter. When volt-var (VV) was disabled, magnitude and phase angle of Z_{neg} slightly increased as V_{pos} grew. The activation of VV induced distinct characteristics of Z_{neg}. When V_{pos} was above 0.8 pu, VV reduced both magnitude and phase angle of Z_{neg}, which did not change much with varying V_{pos}. After V_{pos} went below 0.8 pu, however, Z_{neg} significantly increased with VV and its phase angle reversed (~ -110°).

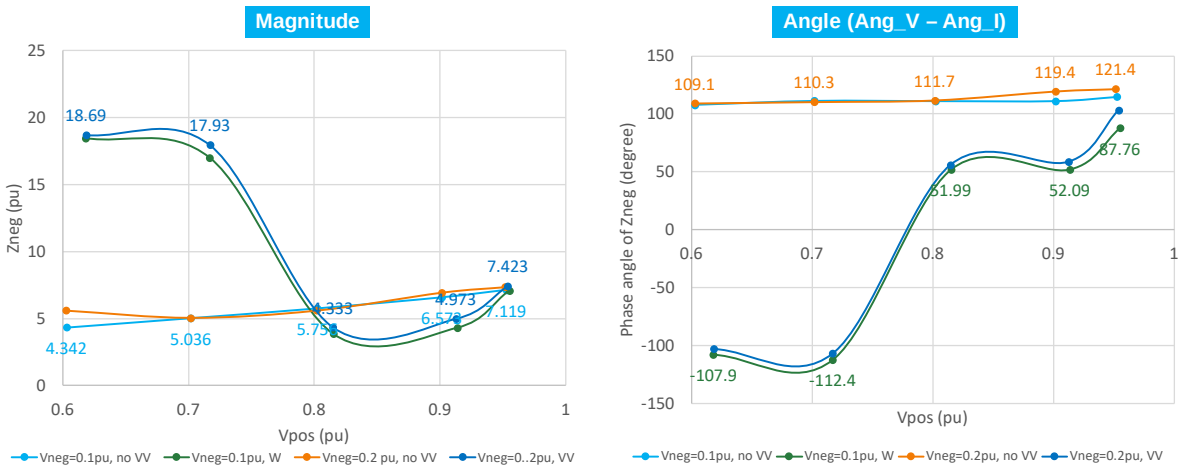


Figure 4-35
Negative sequence impedance of inverter B, with varying V_{pos} and constant V_{neg}

The varying V_{pos}, on the other hand, led to inconsistent change trend of Z_{neg} for inverter C, when V_{neg} increased from 0.1 pu to 0.2 pu. For cases without VV, Z_{neg} remained as V_{pos} grew, until V_{pos} went to 0.95 p.u. While the magnitude of Z_{neg} bounced after VV was activated and no clear trend can be observed. Note that the impedance oscillation could be caused by current distortion and inaccurate estimation.

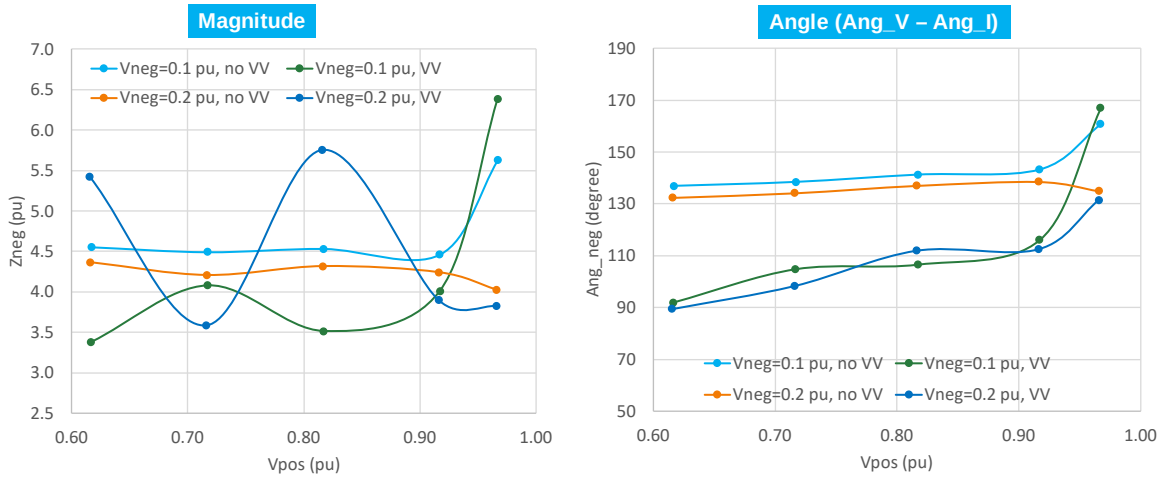


Figure 4-36
Negative sequence impedance of inverter C, with varying V_{pos} and constant V_{neg}

Varying Positive Sequence and Negative Sequence Voltage

In real applications, the positive (Vpos) and negative (Vneg) sequence voltage may vary at the same time (Vneg increases as Vpos reduces). Therefore, how the negative sequence impedance would change under this circumstance was also studied. The voltage setpoints are listed in Table A- 4, and test results for inverter A and B are provided in Figure 4-37 and Figure 4-38. Inverter tripped in several cases where no result was available.

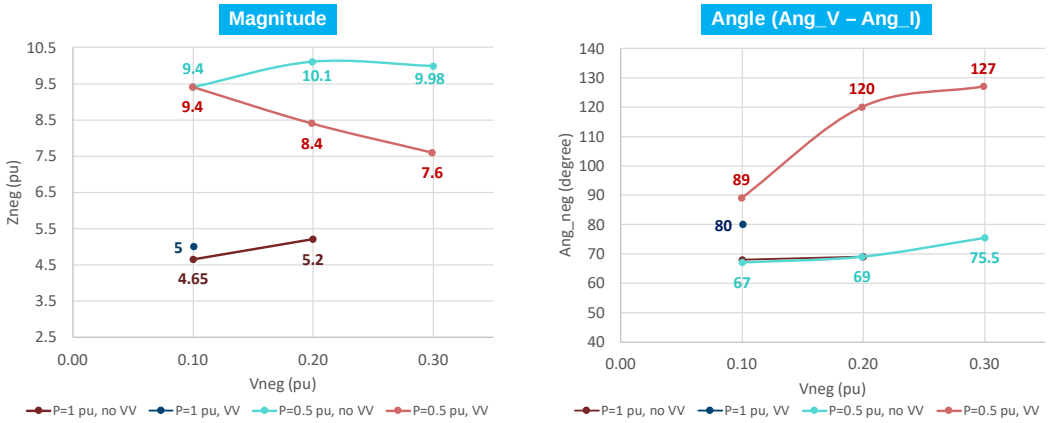


Figure 4-37
Negative sequence impedance of inverter A, with varying V_{pos} and V_{neg}

For inverter A, the magnitude and phase angle of Z_{neg} were affected by both volt-var function (VV) and power generation (P). ***This indicates a strong relationship between Z_{neg} (I_{neg}) and I_{pos} that changes with either VV or P.*** The increased I_{pos} induced higher I_{neg}, and thus magnitude of Z_{neg} reduced with VV and higher P. Power generation did not affect phase angle of Z_{neg} and the inverter behaved more inductively when VV was enabled. The highest phase angle occurred with P = 0.5 pu and VV active.

Inverter B presented distinct characteristics of Z_{neg}. As shown in Figure 4-38, Z_{neg} were affected more by power generation but less by volt-var. P = 1 pu induced much larger magnitude and

reversed phase angle of Z_{neg} (capacitive instead of inductive) if compared to the case with P = 0.5 pu, which is opposite to that of inverter A. On the other hand, VV only slightly reduced Z_{neg} magnitude and phase angle.

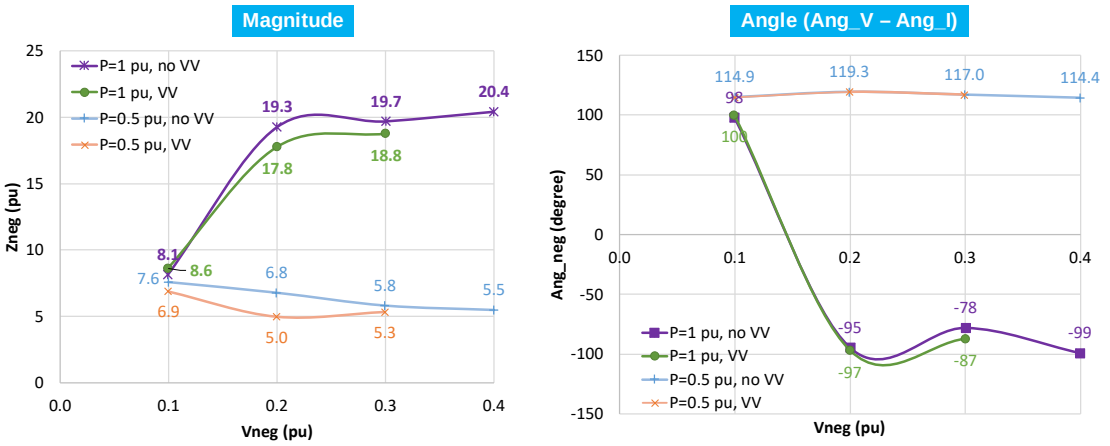


Figure 4-38
Negative sequence impedance of inverter B, with varying V_{pos} and V_{neg}

Varying Phase Angle of Negative Sequence Voltage

The above test scenarios all assume 0° initial phase angle for Vneg, and in this section, its impact on Zneg is studied. The voltage setpoints are listed in Table A- 5, where V_{pos} = 1pu, V_{neg} = 0.1pu, while initial phase angle of phase A changed from -60° to 40°.

Inverter A showed an insignificant and symmetrical Z_{neg} magnitude change as phase angle varied, and the lowest magnitude appeared at around 0° phase angle. This trend held for cases with both P = 1 pu and P = 0.5 pu. VV also did not have much effect on Z_{neg} magnitude due to the fixed V_{pos} and V_{neg}. Phase angle of Z_{neg}, on the other hand, grew towards more inductive with higher phase angle of V_{neg}.

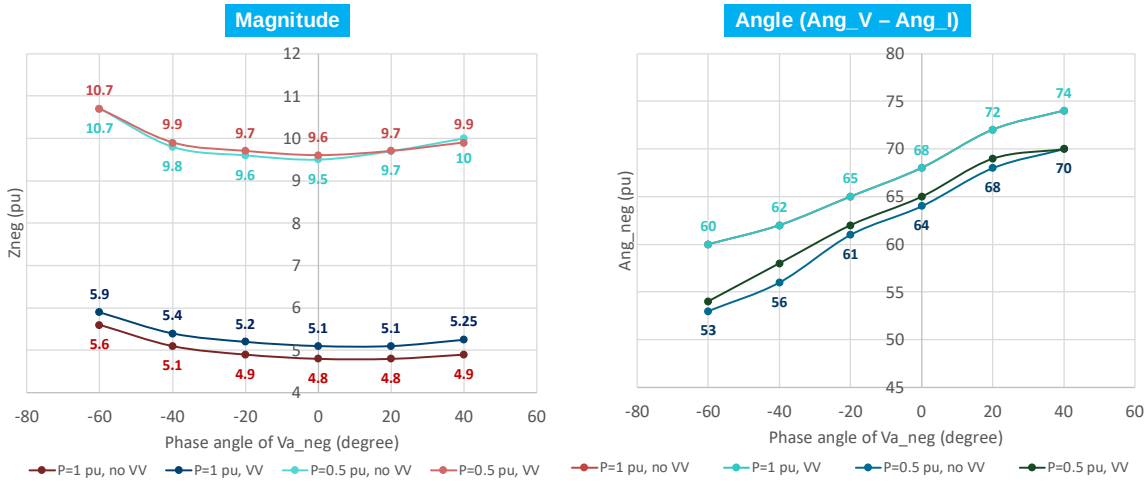


Figure 4-39
Negative sequence impedance of inverter A, with varying *phase angle of* V_{neg}

Inverter B was more sensitive to the phase angle change and tripped at most of the test cases in Figure 4-40. According to the available data, both magnitude and phase angle of Z_{neg} were slightly affected by phase angle change of V_{neg} ($\angle V_{a_neg}$). Z_{neg} had its peak at around 0° phase angle and changed in a symmetrical manner as $\angle V_{a_neg}$ varied from 0°. VV led to reduced magnitude and phase angle of Z_{neg}.

Inverter C was only tested with P = 1 pu, and its Z_{neg} showed larger variations than those of inverter A and B as phase angle of V_{neg} ($\angle V_{a_neg}$) changed. No clear trend was observed, especially when VV was disabled. Impact of $\angle V_{a_neg}$ was reduced by VV, which stabilized Z_{neg} and mitigated the magnitude as well as phase angle variation of Z_{neg} as $\angle V_{a_neg}$ changed.

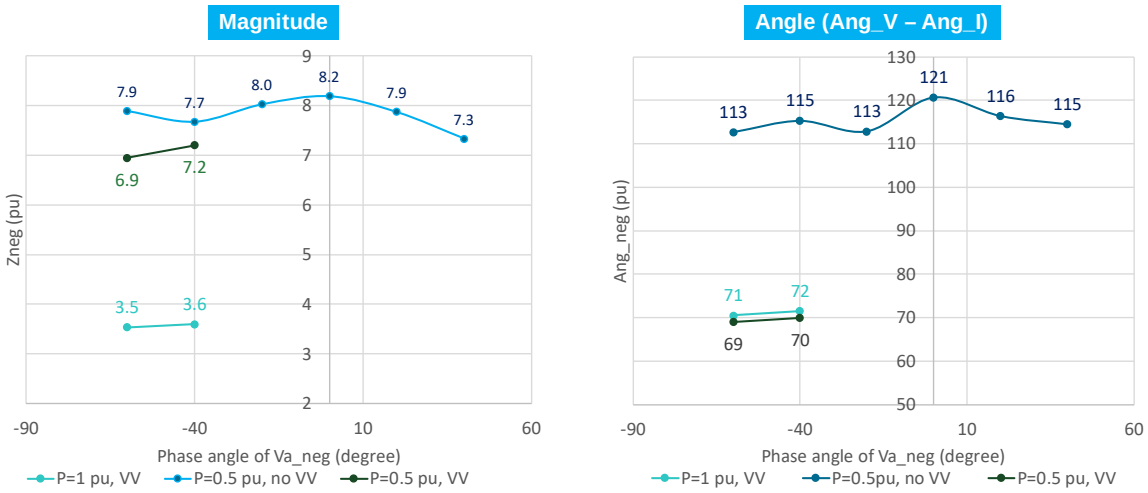


Figure 4-40
Negative sequence impedance of inverter B, with varying *phase angle of V_{neg}*

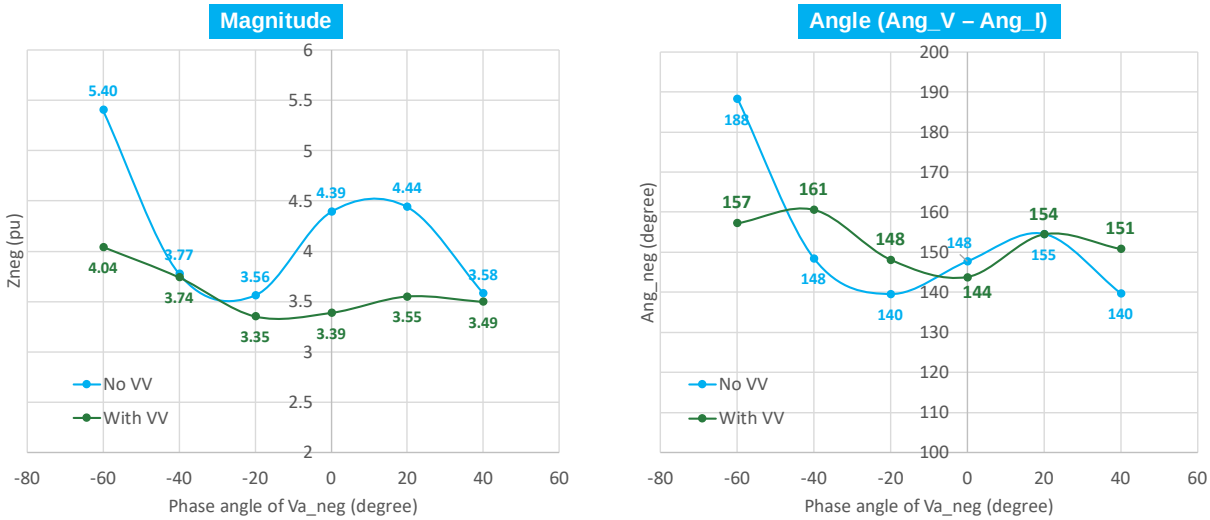


Figure 4-41
Negative sequence impedance of inverter C, with varying *phase angle of V_{neg}* and P = 1 pu

EMTP Simulation and Lab Test Findings

EMT simulations with a detailed inverter model were conducted to evaluate the potential of combined GFOV and LROV during unintentional islanding operation. The impacts of generation to load ratio, load type, and the three-phase transformer winding configuration were investigated. Simulations covered the implementation of inverter fast tripping added in IEEE 1547-2018 (TOVP), including activation from both the LV and MV side of the grid connection. Also covered is the effect of adding supplemental grounding transformers on the GFOV.

The key takeaways from simulations with inverter-based DERs are summarized below:

1. Both GFOV and LROV can contribute to overvoltage when DER is islanded.
2. Sufficient loading can eliminate the LROV and compensate (or reduce) GFOV. According to simulations, voltage will stay below 138% if gen/load ≤ 0.67, regardless of the load connection type (Δ or Yg), and without supplemental grounding.
3. In case of gen/load >0.67, both grounded load and supplemental grounding can further help to mitigate GFOV. Grounded load alone (line to neutral connected) can provide effective system grounding for inverter connected DER. At high gen/load ratio, however, there will still be an overvoltage (LROV) even with effective grounding. And because effective grounding allows a limited degree of unfaulted phase voltage increase, the presence of a ground fault with a high gen/load ratio will somewhat increase the maximum voltage compared to the LROV without the ground fault.
4. Ungrounded load does not contribute to grounding, and thus GFOV mitigation, but it contributes to lower LROV
5. Where a large percentage of the load is ungrounded, a grounding transformer can be utilized to provide sufficient grounding to achieve the threshold of effective grounding and to thus reduce GFOV.
6. Transient overvoltage protection (TOVP) as implied in IEEE 1547-2018 can significantly reduce inverter trip time when generation is much higher than load, and this reduces arrester energy duty, especially for overvoltage with combined LROV and GFOV.
7. When other than Yg/Yg transformer connections are employed (Yg/Y, Δ/Yg, Yg/Δ, Δ/Δ, Y/Δ, and Y/Yg) a MV SLG fault is not accurately detected by the LV connected inverter. Inverter-side TOVP is therefore less effective. However, often where these transformers are used, the Reference Point of Applicability, as defined in IEEE 1547-2018, is on the primary (MV) side. When the RPA is on the primary side the DER owner is responsible for implementing protections that do meet the requirements of the standard.

Lab tests were also performed to identify the negative sequence impedance of typical commercial inverters, and the key findings include:

1. The negative sequence impedance of inverters varied a lot with different control designs. There is currently no standard requirement effective in North America. A German standard specifying an allowed range has been applied in Europe to better define inverter response to faults.

2. Test results from the sample inverters supported our assumption of relatively high Z_{neg} (> 4pu and up to 20 pu). In simulations we assume that the inverter Z_{neg} had negligible impact as it is in parallel with the smaller load $Z_{neg.}$ It may be a factor in cases of very high gen to load. This was not evaluated.

3. Negative sequence impedance varies with conditions and was found to depend on both active and reactive power generation, and negative sequence voltage magnitude and phase angle.

It is worth mentioning that the inverter model used in these EMT simulation has a very high negative sequence impedance that does not match that of the commercial inverters tested. Exact values may vary, but the conclusions above still hold since the change trend of overvoltage, trip time and arrester energy remain.

5
EQUIPMENT SUSCEPTIBILITY TO TOV

Temporary overvoltage (TOV) is normally referred to as a ***power frequency*** overvoltage condition lasting anywhere from about ½ cycle and up to many seconds in duration. ***Transient*** overvoltage, on the other hand, has historically referred to lightning or switching surges that last a much shorter time. Surges typically have risetimes defined in microseconds and may ring for a few cycles. Surge events and TOV conditions are significantly different environments, although they are sometimes lumped together in time. With faults and devices switching, surges can accompany TOV conditions, and thus the lumping.

End user and utility equipment susceptibility to TOV is discussed in this section. The equipment surge withstand is not considered as being lumped with TOV. Here we address the longer duration power frequency overvoltage conditions measured in per unit of nominal. As discussed in the previous chapters, DERs may contribute load rejection overvoltage (LROV) and ground fault overvoltage (GFOV), both are power frequency events. These can exceed 1.73 p.u. and perhaps even 2 p.u. in certain cases. Power frequency overvoltage above these levels are not expected. Anecdotal references to 3 p.u. usually conflate switching surges with the lower frequency events.

End-User Equipment

TOV can have deleterious effects on some customer loads depending on the load type and the ac power interface. Most ac appliances with power supplies can withstand TOV for a short time and without noticeable effect. Directly affected examples are incandescent lamps that are stressed by increased output (I^2R), loosing life, or failing in a short time. Motor torque increases and there is potential for higher winding leakage current and possible breakdown of otherwise compromised insulation. Electronic equipment with ac transient voltage surge suppression devices connected line to neutral may be damaged with persistent overvoltage.

Mitigating factors include safety certifications requiring relatively high voltage withstand levels for ac connected equipment. Traditional power system design practices are expected to limit fundamental frequency overvoltage line to ground to below 138% of nominal voltage.

Another ac compatibility criteria that relates to end-use equipment voltage tolerance is the ITIC curve, as illustrated in Figure 5-1. This is also an IEEE recommended compatibility criteria published in the Emerald Book.[14] The original target for specifying a voltage tolerance was computer equipment, led by the Computer Equipment Business Manufactures Association.[15] The concept has been adopted, with variations, by several industry appliance groups including semiconductor tools, adjustable speed drives and lighting.

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[14] I*EEE Recommended Practice for Powering and Grounding Sensitive Electronic Equipment, IEEE Std 1100-2005*

[15] "Diagnosing Power Quality-Related Computer Problems" IEEE Transactions on Industry Applications, v. IA-15, No. 4, pp. 381-393., New York, New York, August 1979.

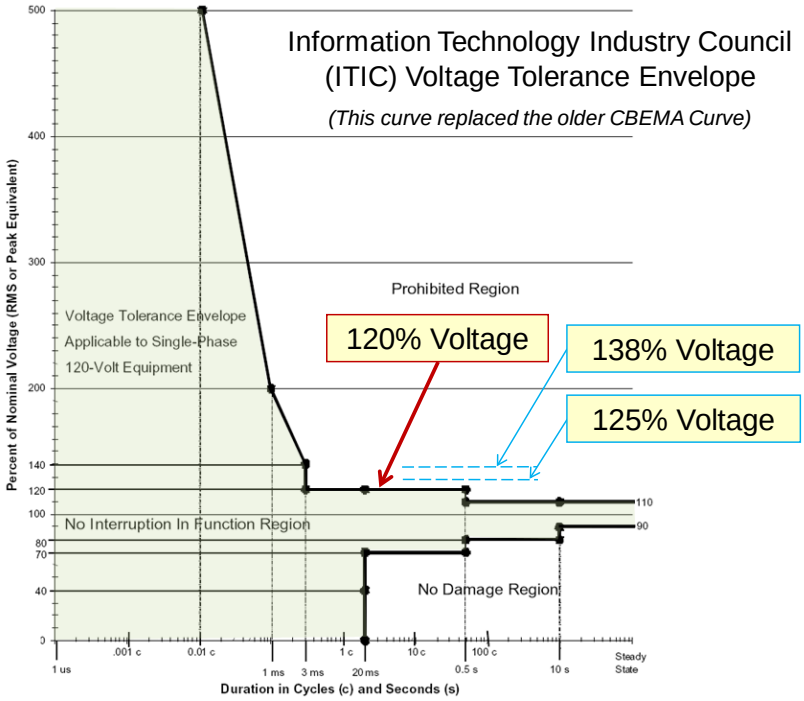

Figure 5-1
ITIC Voltage Tolerance Envelope

The key questions are what are safe limits for TOV and how can we be certain such limits are satisfied? Aiming to provide answers, the effects of TOV on common residential electrical and electronic devices have been investigated by EPRI. Research covers the common causes of TOV, evaluation of equipment tolerance to TOV through destructive testing, and documentation of failed test specimens that were destroyed during TOV testing. A summary of results is provided in this section and more details are available in the reports. [16,17,18,19]

A key takeaway is that many appliances are quite tolerant of TOV. Any breakdown or upset is generally well above the over voltage limits for DER. The more recent IEEE 1547 limit and previously required limits by Hawaiian Electric [20] are comparable to the original ITIC curve, as shown in Figure 5-2. These DER limits should be well below typical appliance withstand.

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[16] *Effects of Temporary Overvoltage on Residential Products: System Compatibility Research Project.* EPRI, Palo Alto, CA: 2005. 1008540.

[17] *Effects of Temporary Overvoltage on Residential Products, Part II: System Compatibility Research Project.* EPRI, Palo Alto, CA: 2005. 1010892.

[18] *Mitigating the Effects of Temporary Overvoltage on Electronic Devices*, March 2008.

[19] *Embedded Solutions for Temporary Overvoltage in Residential Products*, November 2008.

[20] https://www.hawaiianelectric.com/documents/products_and_services/customer_renewable_programs/grid_supportive_utility_inverter_certification_req_20180312.pdf

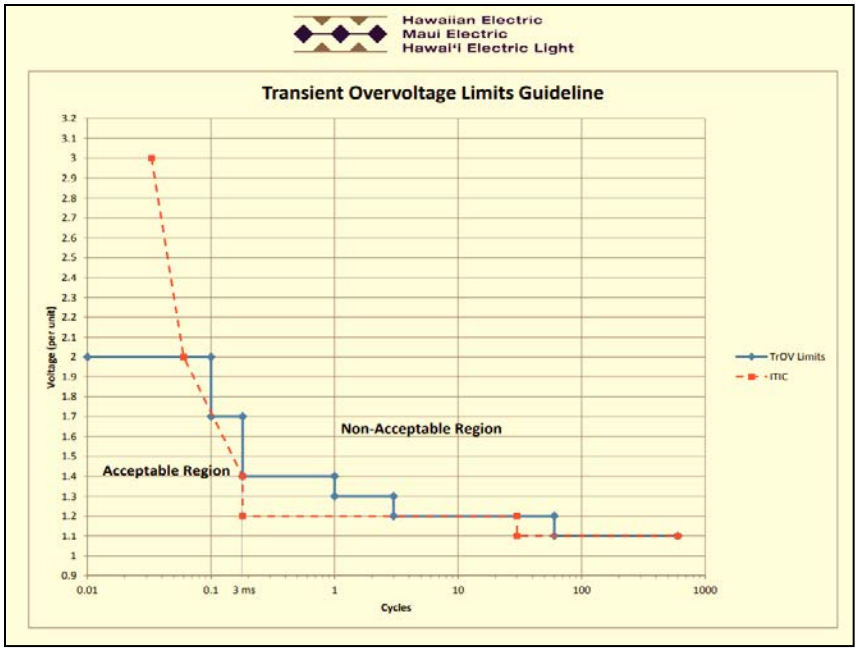


Figure 5-2
Hawaii Electric published limit for DER

Figure 5-3 summarize the results of EPRI's testing of appliance TOV withstand. Among the equipment under test, the majority survived 1.5 p.u. TOV for several hours. The clock radio failed after almost 2 hrs (118 min) while audio receiver failed after 5.7 seconds. Given the requirement that DER needs to detect an island and trip within 2 s, all devices would have survived TOV of 1.5 pu. Another interesting point is the same type of equipment but from different manufacturer could have distinct TOV withstand capability. It is not surprising to see computer power supplies, designed to operate at either 120 or 240V are able to withstand TOV of 3.0 pu, relative to 120V.

	Temporary Overvoltage			
Device	**1.5pu (180V)**	**2.0pu (240V)**	**2.5pu (300V)**	**3.0pu (360V)**
Clock Radio	**Fail** 118 min.			
Audio Receiver	**Fail** 5.7 sec.			
DVD Player, Brand 1	**Pass** (2hr)	**Pass** (2hr)		
DVD Player, Brand 2	**Pass** (2hr)	**Fail** 8.7 sec		
Compact Fluorescent Lamp, Brand 1	**Pass** (4hr)	**Fail** Within 1 min.		
Compact Fluorescent Lamp, Brand 2	**Pass** (4hr)	**Fail** within 1 min.		
Compact Fluorescent Lamp, Brand 3	**Pass** (4hr)	**Fail** Within 1 min.		
Computer Power Supply				**Pass**

Figure 5-3
Summary of equipment under test and overvoltage levels

Figure 5-4 gives more test results from EPRI's power quality program. All devices under test survived 138V (1.15 pu) for six hours and 156V (1.3 pu) for 2 seconds. Except for transient

voltage surge suppressors (SPDs), other equipment survived 180V (1.5 pu) for 4 hours. When voltage was further elevated to 360 V (3 pu), most devices failed within 1 second.

Sample Description		Results Summary				
Type	Technology	Test 1	Test 2	Test 3	Test 4	Test 5
		138 V, 6 hr	156 V, 2 s	180 V, 4 hr	240 V, 1 min	360 V, 1 s
SPD, plug strip	130 V MOV	OK	OK	Fail	Fail	Fail
SPD, plug strip	130 V MOV	OK	OK	Fail	Fail	Fail
SPD, plug strip	Multiple 130 V MOVs + filtering	OK	OK	Fail	Fail	Fail
PLC		OK	OK	OK	OK	Fail
PLC		OK	OK	OK	OK	OK
PLC		OK	OK	OK	OK	OK
PC + monitor		OK	OK	OK	Not tested	Not tested
PC + monitor		OK	OK	OK	Not tested	Not tested
PC + monitor		OK	OK	OK	Not tested	Not tested
PC + monitor		OK	OK	OK	Fail	
PC + monitor		OK	OK	OK	OK	Fail
Incandescent bulb, 60W	Tungsten	OK	OK	OK	Fail	Fail

Note: SPD = surge protective device; PLC = programmable logic controller; PC = personal computer; MOV = metal oxide varistor.

Figure 5-4
Summary of overvoltage test results – from EPRI TPQ Techwatch, Oct. 2014

The resulting TOV characterization curves for eight categories (each had four samples) of common household electronic equipment are provided in Figure 5-5. More than half of the sample groups had a representative failure at each test point. In other words, for a particular brand, all four samples failed during the tests, creating a TOV tolerance curve with a full set of four data points. In general, all devices under test survived way beyond both ITIC and IEEE 1547-2018 TOV limits.

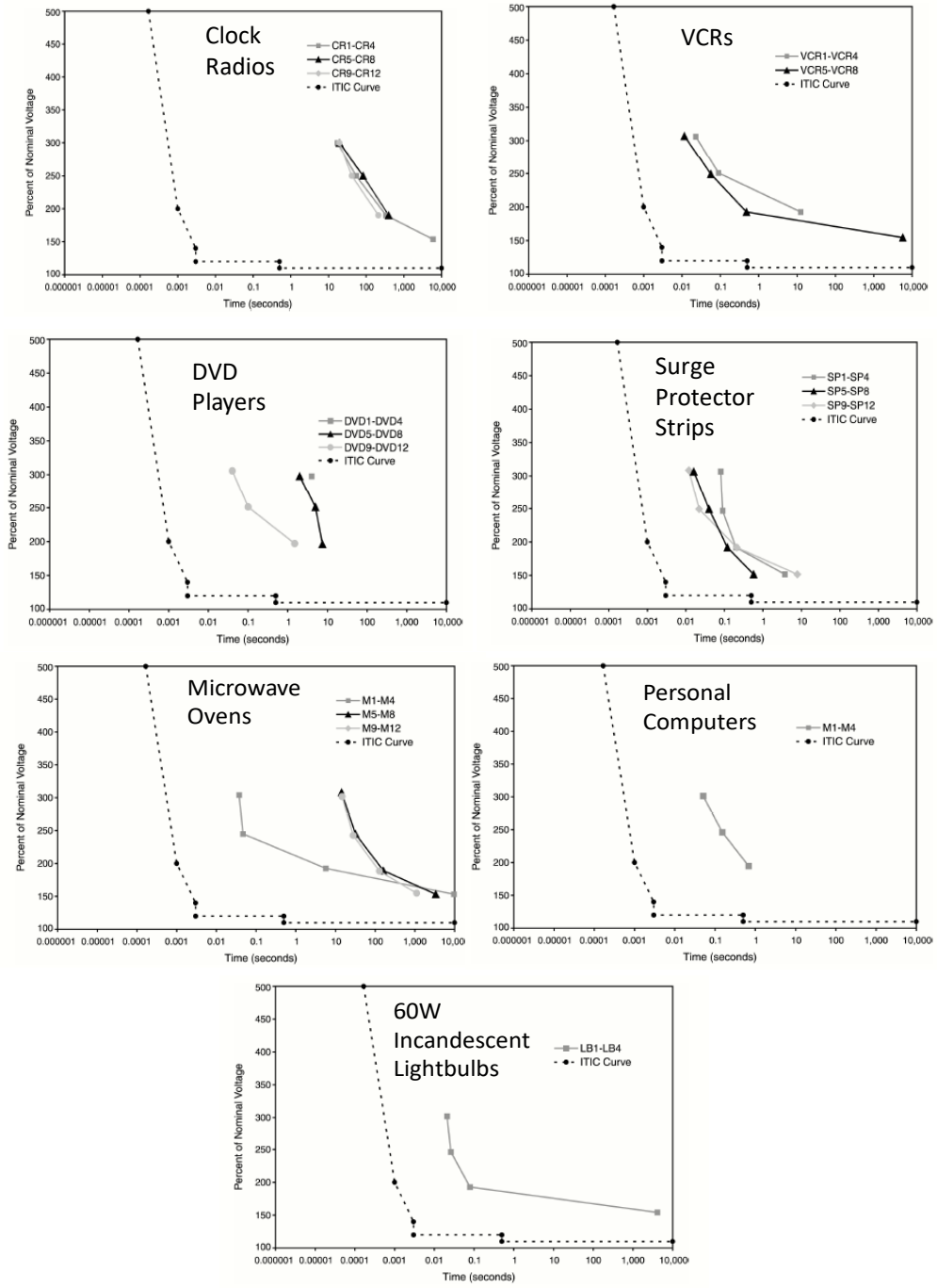


Figure 5-5
Results of EPRI testing compared to ITIC

The concept applied in IEC and IEEE electromagnetic compatibility standards is that equipment immunity levels should be comfortable above the expected environment of disturbance levels. As shown in Figure 5-6, a compatibility level is defined above the planning levels and below the equipment immunity test levels. Incompatible events should be rare.

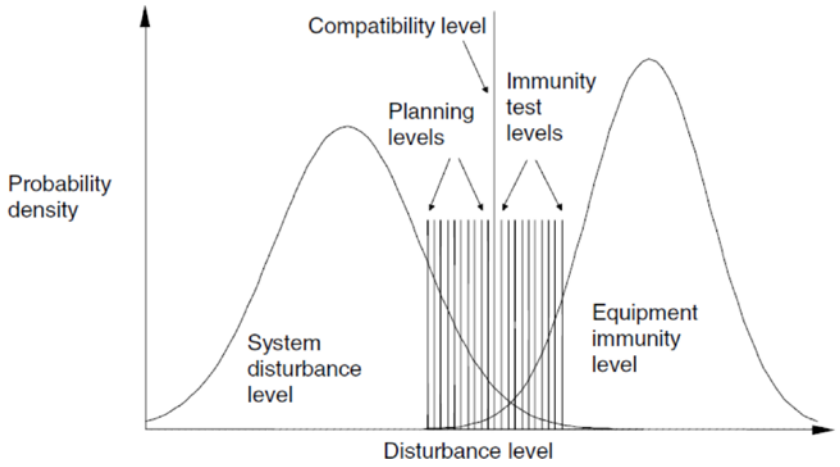


Figure 5-6
Concepts applied to achieve electromagnetic compatibility

Figure 5-7 illustrates the hypothetical probability of a customer load device upset or failure for overvoltage magnitude at longer and shorter durations. There is no specific voltage threshold above which loads will start malfunction or fail. Therefore, if DER can limit their overvoltage contribution as required by IEEE 1547-2018, the common loads compliant with ITIC curve should not be damaged.

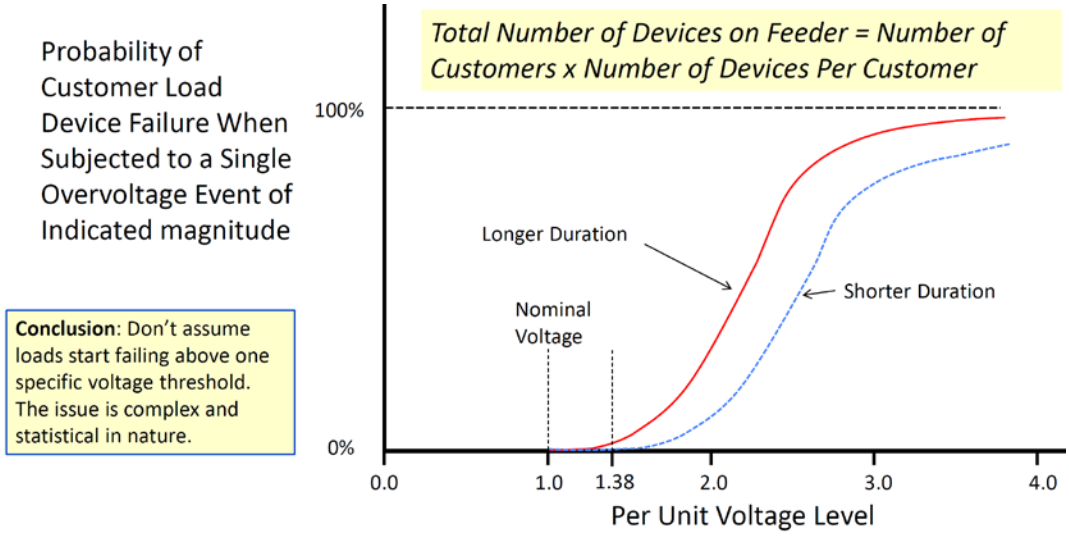


Figure 5-7
Hypothetical Overvoltage Failure Probability of Loads

Medium Voltage Surge Arresters

Surge arresters are commonly used to limit lightning or switching overvoltages in power systems. The most common arrester type is a metal oxide material. These conduct when exposed to overvoltages following a nonlinear impedance characteristic. With increasing conduction as surge voltage grows, overvoltages are limited or clamped for equipment connected in parallel,

line to ground or line to line. Standards for metal oxide surge arresters including rating and testing are IEEE C62.11 and IEC 60099-4.

Arresters are typically made from stacked blocks of metal oxide material, as illustrated in Figure 5-8, with energy ratings in Kilojoules per kV. The higher the voltage rating of the arrester, the larger the number of "blocks" and the greater the total joules capability.

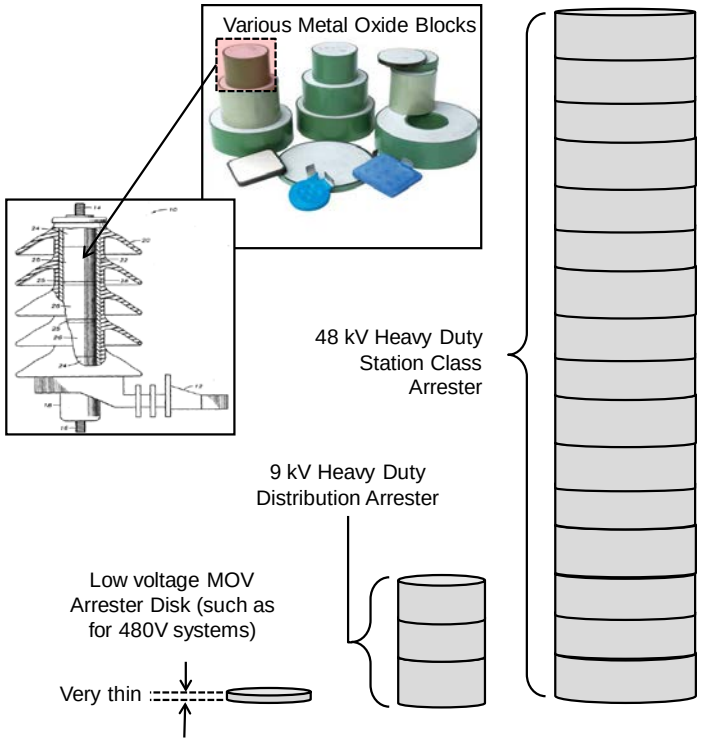


Figure 5-8
Metal Oxide Arrester structure

The total energy capability of an arrester can be calculated as (1), with the commonly cited surge energy ratings (kJ per kV of MCOV rating) listed in Table 5-1.

$$E = (MCOV\ Rating\ in\ kV) \times (kJ\ per\ kV\ of\ MCOV) \quad (1)$$

For example, a distribution class heavy duty arrester with MCOV of 8.4 kV is:

$$(8.4\ per\ kV\ of\ MCOV) \times \left(2.2\,\frac{kJ}{kV}\right) = 18.48\ kJ.$$

Main factors that impact the total TOV energy absorption capability of a surge arrester include:

- Diameter of the blocks and nature of block material
- Height (thickness) of the blocks and total number of blocks present
- Starting temperature of the blocks at the beginning of the surge event (prior duty or no prior duty)
- Nature of the current waveform and magnitude (Surge arrester energy capability for power frequency is not the same as switching or lightning surge capability)
- The magnitude of applied voltage after the TOV event

- Energy sharing between arresters which varies significantly depending on case specifics (discussed in more detail later)

Due to the sharing effect among arresters, for example, arresters exposed to the same power frequency overvoltage all conduct. This then limits the energy to be dissipated by any single arrester. Also, if the TOV scenario involves de-energization of generators immediately after the event, then removing ac voltage enables cool down. Therefore, the energy capability of the arrester with temporary TOV may be significantly increased over the capability with continuous voltage applied.

Table 5-1
Common surge energy ratings

Type of Surge Arrester	Commonly Cited Surge Energy Ratings (kilojoules per KV of MCOV Rating)
Normal Duty Distribution Class	1.4
Heavy Duty Distribution Class	2.2
Intermediate Class Surge Arrester	3 or 4
Station Class	Anywhere from 3 to over 10 depending on block size and material

Figure 5-9 gives an example voltage/current curve for a station class arrester. The arrester current should be negligible at nominal voltage, and gradually increases as voltage grows. Given the DER provides arrester current during islanded operation, the expected overvoltage ranges from 1.4 p.u. – 2 pu, according to typical DER overcurrent capabilities.

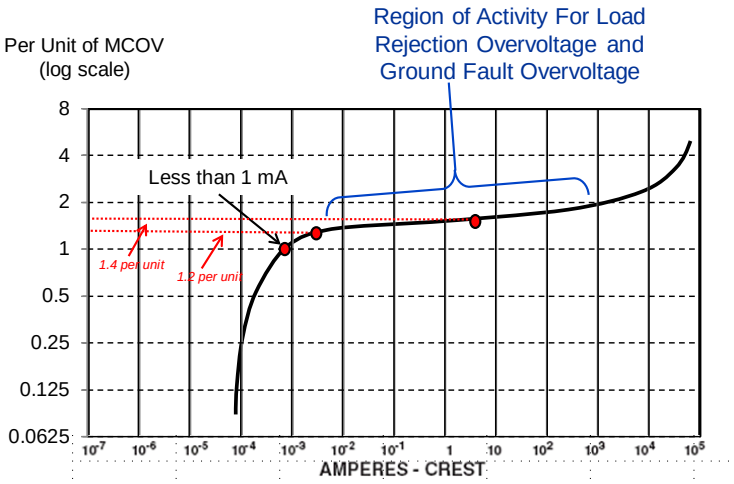


Figure 5-9
Example arrester voltage-current curve

It is worth mentioning that a wide range of arrester products are available in the market. The I-V curves can be higher or lower than the one shown in Figure 5-9, depending on brand, class, rating, heating conditions, etc. Users must consult specific manufacturer's data sheets for the exact product specified to perform a study.

Figure 5-10 shows an example arrester current during TOV operation. It is very distorted and has a quite low RMS to peak ratio. The energy level is consequentially lower than a linear waveform, which is true for many cases.

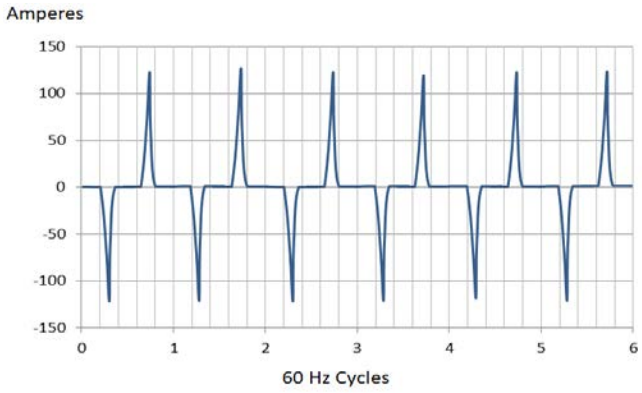


Figure 5-10
Example arrester current waveform

Figure 5-11 illustrates the arrester temporary overvoltage capability for a specific arrester brand (3 models of normal duty distribution class arresters), all with no prior duty. The coefficient of grounding (CoG) defines the upper and lower voltage limits (blue dotted horizontal lines). The duration limits, on the other hand, defines the maximum operating time (black vertical lines). The intersection between the arrester TOV capability curve (green, purple and red) and required time duration determines the overvoltage level the arrester has to withstand. Specific arrester curve data is needed to identify the overvoltage level for other applications. Prior duty would lower the withstand to a lesser value than shown.

Note many designers apply TOV curve assuming an “infinitely strong source.” DER sources are typically “weaker”, especially for the inverter-based ones with very limited overcurrent capability and fixed peak dc voltage. Additionally, the surge arrester loading effect will also suppress the TOV condition. A TOV curve, therefore, cannot accurately determine if an overvoltage condition will damage surge arresters when dealing with weak sources (such as inverter-based DER) due to reasons below:

- The arrester may survive much longer than indicated by the TOV curve where the analysis assumes DER acting as an infinite source
- The arrester(s) themselves will suppress the TOV level and distort the waveform due to their own loading effect

The more accurate and secure way is to perform an EMTP or equivalent type simulation of the energy absorption of the surge arrester during the overvoltage operation. Then compare EMTP results to the expected energy capability of the arrester and apply safe margins to prevent arrester failures. However, it must be noted that the published energy capabilities of surge arresters are specific to a switching-surge type waveform and may not accurately indicate the ability of arresters to endure lower-level, multi-cycle events like TOV.

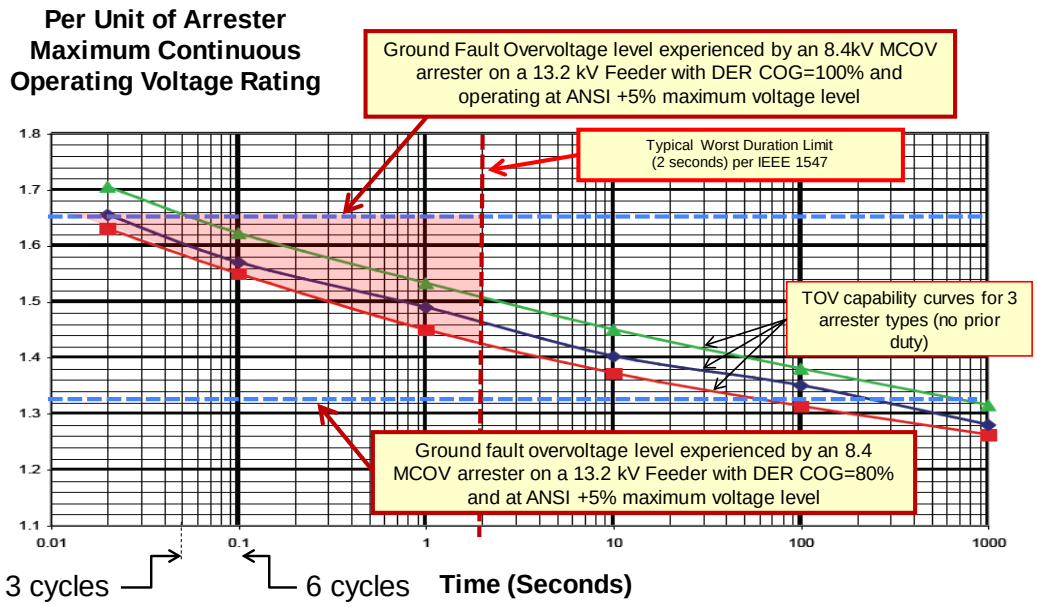


Figure 5-11
Arrester temporary overvoltage capability

Sharing among arresters could also substantially reduce the energy absorption of each arrester from none (in the case of one arrester only) up to roughly a factor of 15 in the case of a large population of arresters of the same type. Note that the impedance of the feeder is typically low compared to the DER sources, which means the LRO and/or GFO exposure is over a broad area. This helps to ensure that a large number of arresters (if present) could see the LRO and GFO conditions.

Monte-Carlo analysis was performed on an assortment of paralleled distributed arresters with a standard deviation in V-I characteristic of 5% and 10%.[21] The ratio of the energy absorbed by the hardest working arresters (with maximum clamping duty) divided by the total energy of all the arresters was determined. Considering statistical scatter, the average duty ratio (max. energy/sum of energy) are plotted along with a capability multiplier in Figure 5-12. The energy capability multiplier is calculated by inverting duty ratios. This is the factor that can be applied times the energy rating of one arrester to determine the approximate amount of energy that can be absorbed by the group of arresters without failing the most vulnerable. As voltage elevates, the average duty ratio drops and energy capability multiplier increases, indicating a better sharing among arresters and higher overvoltage susceptibility. Larger number of arresters and smaller mismatch between arrester characteristics also serve in a similar way.

[21] *Island prevention practices and IEEE 1547 ride-through*. EPRI, Palo Alto, CA: 2020. 3002018950.

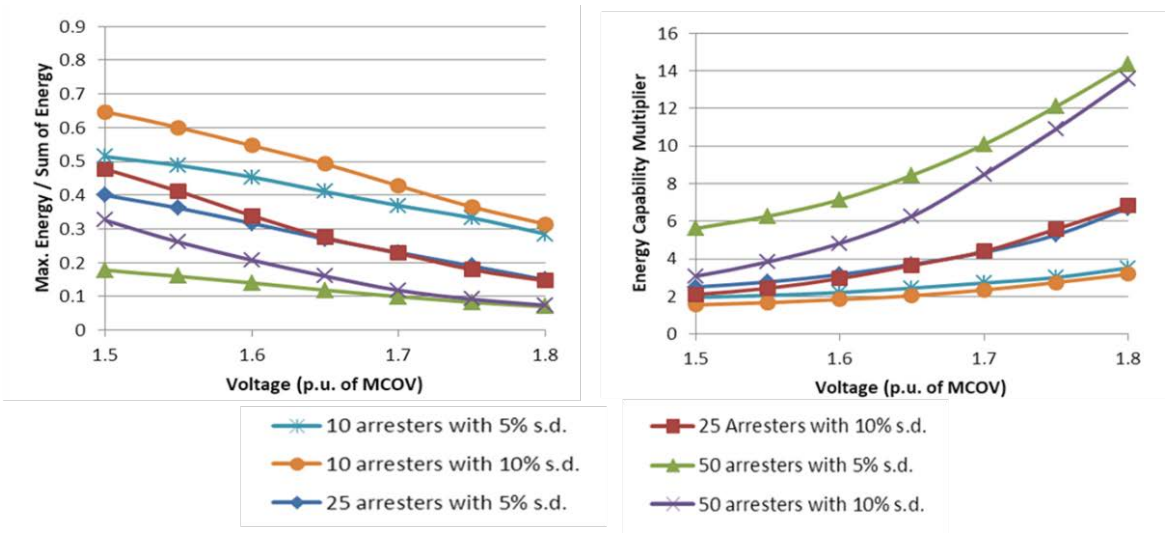


Figure 5-12
Average of duty ratios (left) and expected sharing relative to the standard deviation in arrester characteristics (right)

Assuming TOVs are in the range of 1.7 – 1.8 of nominal, Figure 5-13 shows the linear dependency of the energy capability multiplier with the number of arresters, assuming a 10% standard deviation.[14] Similar conclusion can be reached that more arresters and higher overvoltage enhances the energy sharing and thus higher overvoltage susceptibility.

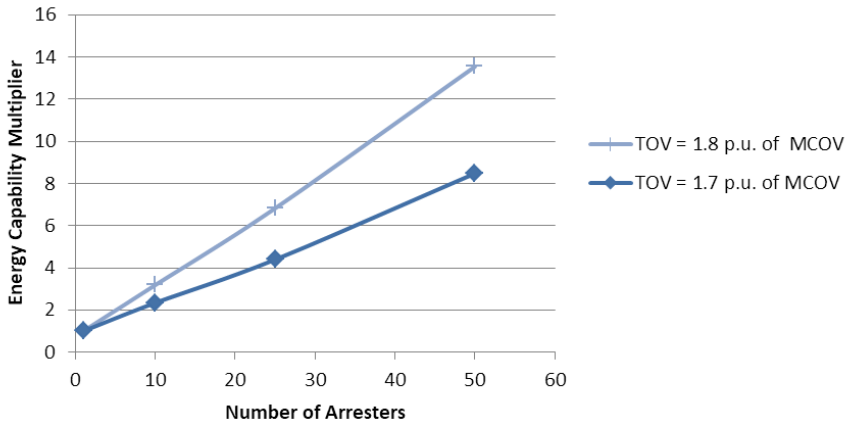


Figure 5-13
Energy capability multiplier for power frequency TOVs at 1.7-1.8 per unit

With many arresters on a typical feeder, energy absorbing capability can be estimated as a multiple of a single arrester for current-limited events (e.g., inverter GFO and/or LRO). The suggested multiplier accounts for expected uneven energy absorption amongst the arresters due to differences in characteristics.

Also, this analysis shows that larger numbers of arresters tend to outweigh disparities in current sharing. Given typical arrester characteristics, we find that the “harder the hit” (i.e., higher applied voltage), the better the sharing will be. These characteristics support the important role of arresters in limiting power frequency overvoltages.

Susceptibility Summary

Typical residential end-user appliances, such as TVs, DVD, microwave ovens, computers equipment, etc., are likely able to survive TOV events. This includes DER-related GFOV and/or LROV during islanding operation, and for durations longer than 2 seconds. As noted in chapter 4, limiting DER overvoltage contribution as required by IEEE 1547-2018 significantly shortens the expected duration of TOV events. With the new limits, DER contribution to TOV is compliance with the relatively conservative ITIC (or CBEMA) curve. End-user equipment upset or damage from DER born overvoltages is therefore not expected.

Regarding utility MV equipment susceptibility to DER related TOV, there are several important considerations and potential mitigating factors. The first is that inverters are not a stiff source. Considering the limited overcurrent capability of inverter-based DER helps to accurately predict TOV exposure and to specify appropriate mitigation. Surge arresters act as both a vulnerability and a mitigation factor.

Arresters are normally applied to mitigate lightning and switching surges, based on other utility system equipment's surge withstand and basic insulation level (bil) ratings. Arresters may also be active and conducting during a non-surge, TOV condition. This causes concern that the duration of a TOV will exceed the arrester device's energy rating. A key takeaway of this research is that there are several mitigating factors that can relieve this concern. These factors include the:

1. Island load plays a role in mitigating TOV in case of inverter-based DER.
2. Arrestor MCOVs and energy capacity are reasonable for the application.
3. Number of arrestors involved matters because a power frequency TOV occurs throughout the island and there will be energy sharing, albeit uneven.
4. Inverter DER responds to the same overvoltages that would stress surge arresters and they may quickly remove the source of OV and limit the duration.

6
SYSTEM GROUNDING GUIDELINES WITH INVERTER-BASED DER

Interconnection Transformer Selection

As the DER interconnection transformer is an added active component in the area EPS, utilities need to know the details and retain final say regarding selection. Configuration details of both the high- and low-side windings, as well as any proposed supplemental grounding devices, require utility review.

Existing published screening criteria related to DER grounding are not sufficient. The most common indicate as illustrated in Figure 6-1 that the **transformer connection needs to be compatible with the grid**. Screens in this format imply that ground fault overvoltage is always an issue with a 3-phase, 4-wire distribution. Consequently, as indicated in the sample table "All others Fail" when the distribution line configuration is three phase, 4-wire. The exception to pass is limited to aggregate DER ≤ 10% of peak load.

Screen D: Is the Line and Grounding Configuration Compatible with the Interconnection Type?

1. Identify primary distribution line configuration that will serve the distributed generation or energy storage. Based on the DER interconnection and using the table below, determine compatibility with the electric power service, including, phase balance, line and grounding configuration. The following table shall be used to determine risk for ineffective grounding

Primary distribution line configuration	Type of DER connection to primary	Result/Criteria
Three-phase, three-wire	Any type	Pass
Three-phase, four-wire > 5 kV	Single-phase line-to-neutral	Pass
All Three-phase, four-wire (For any line that has sections or mixed three-wire and four-wire)	All others	Fail. To pass aggregate DER AC nameplate rating must be less than or equal to 10% of line-section peak load

2. Based on aggregate DER on the feeder, is phase balancing maintained within utility limits?
   - If items 1 & 2 pass, (Pass Screen)
   - If items 1 or 2 fail, (Fail Screen)

Figure 6-1
Typical grounding configuration screens use peak load a proxy for minimum load[22] (similar to requirements in CA Rule 21 and many other jurisdictions screening criteria)

At this first level of interconnect review, specific consideration if the DER is a machine or an inverter is not clear. Given the significant difference in effective grounding requirements for

[22] From New York Department of Public Service Standard Interconnection Requirements, December 2019

machines and inverters, the next step after failing this screen has not been consistent. With similar situations some jurisdictions require supplemental grounding for DER, and some do not.

As currently embedded in most screening procedures and experience with machine-based generation, DER presence in an island suggests a need for a supplemental grounding. This is less clear with inverter-based generation.[23] Due to the unique characteristics of inverter-based DER, conventional interconnection transformer selection criteria for synchronous generator needs to be adapted. Details of selection depend on system characteristics and protection objectives. In addition to voltage and phase matching, there are objectives related to fault response, voltage sensing and coordination with other system protection discussed here.

The first step in system grounding is selection of the primary interconnection transformer. Given this, the following provides selection considerations based on interconnection transformer objectives to decide on the best fit configuration:

- Connection to provide a zero-sequence ground source for island conditions:

The desire is for the transformer to *provide zero sequence continuity path* from DER side to high side if 1) analysis shows that supplemental grounding is needed, and 2) the plan is to have that supplemental grounding on the DER side – **Select a grounded-wye to grounded-wye type transformer** ***Note if there is a need for the DER to detect of zero sequence, a grounding transformer may be placed on the MV side.***

The desire is for the transformer to be a ground source *by itself* if 1) analysis shows such a source is needed and will work with the inverter, 2) the neutral grounding impedance on the high side limits its influence to a suitable level, and 3) the plan is to use a separate PT bank to measure high side voltages for protection – **Select grounded-wye with neutral impedance high side to delta DER side**

The desire is to prevent *a zero- sequence path or source* if 1) the analysis shows that such capability is not needed and 2) plan to use a separate PT bank to measure high side voltages for protection or don't need V_{LN} measurements. – **Select an ungrounded interface transformer winding on high side such as delta winding or floating wye winding**.

- Connection to enable low-side V_{LN} measurement indicating high-side conditions:

The objective to allow a *direct measurement path* to the DER side accurately indicating the primary line to neutral voltage. This is needed for inverter high speed response per IEEE 1547-2018 Part 7.4 limiting overvoltage magnitude and duration and is needed when high side PT bank is either not available or may be too slow to meet IEEE limits. – **Select grounded-wye to ground wye**

- Connection is to avoid distributed supplemental ground source and possible interactions with upstream existing system protection:

The objective is to *avoid grid interactions* related to ground fault relaying desensitization, increasing arc flash, single phasing back-feed, I_0 circulating currents, ground potential rise, stray

[23] Impact of Interconnection Transformer Configuration on DER Operation, EPRI Palo, CA 3002019423, Dec 2020

voltage, etc. - **Avoid grounded-wye high side to delta DER side, or if this type must be used, then employ suitably high neutral grounding impedance and protection to reduce issues.**

Figure 6-2 shows the zero-sequence path for various interconnection transformers with inverter-based DER, where Z_E is the earth grounding impedance for three wire systems or the neutral connection impedance for four wire systems. As described in previous sections, typical DER inverters do not have zero sequence current generation capability and thus present open circuit for zero-sequence. The Yg/Δ transformer, with or without Z_E on the Yg connection at utility side, creates a zero-sequence path and acts as a ground source to utility side by itself. A Yg/Yg transformer passes through the zero sequence (i.e., zero-sequence continuity), but requires a supplemental grounding to become a ground source. Other transformer configurations block zero sequence and do not act as ground sources relative to the utility side.

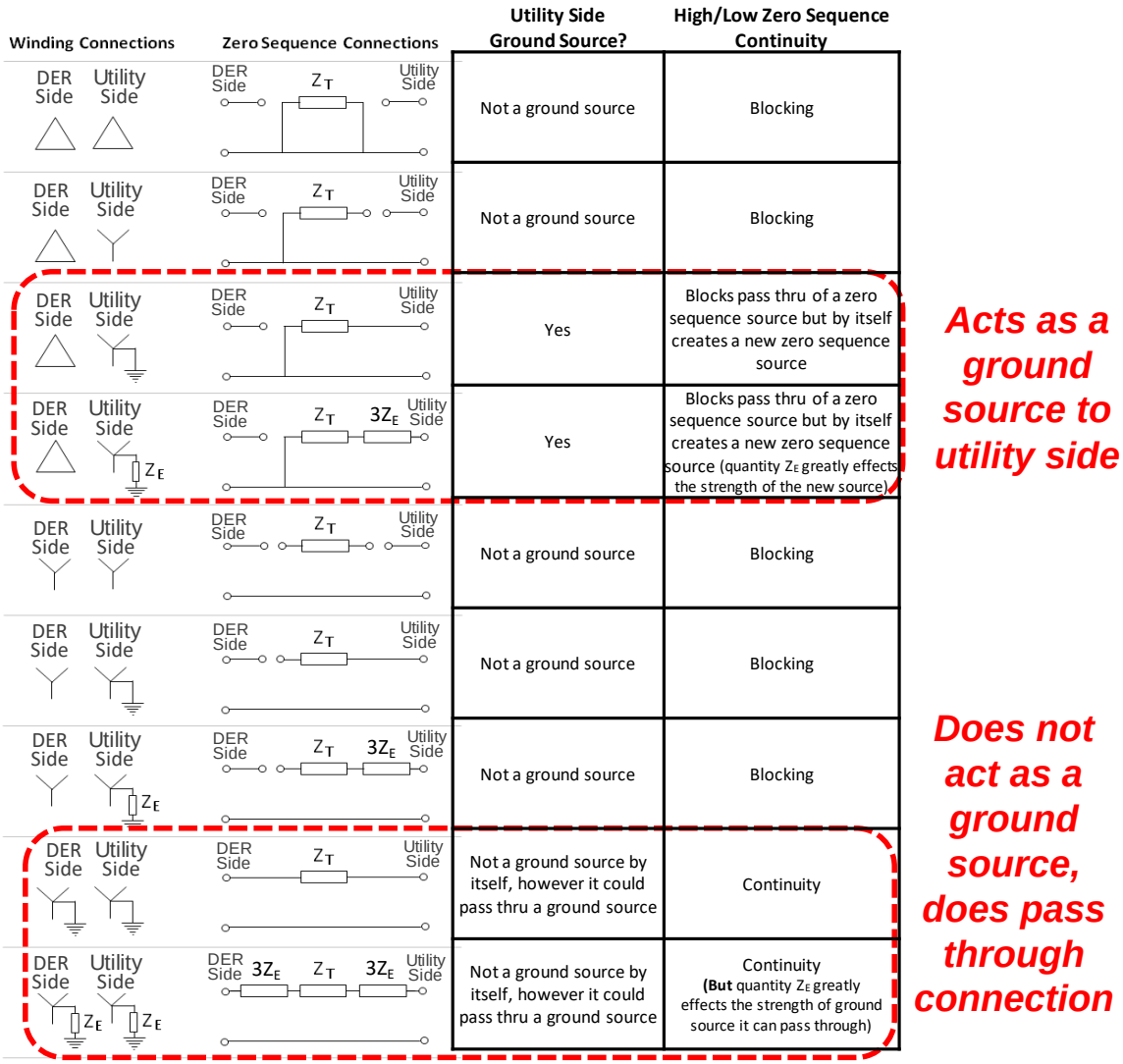


Figure 6-2
Zero sequence path for various interconnection transformers

Updated Grounding Considerations for Inverter DER

In this section different rules of thumb are discussed that support screening of proposed DER plants to determine the need for supplemental grounding. "Screening" in this context generally refers to making decisions to allow DER interconnection without additional studies and without addition of mitigations or power system upgrades. As will be discussed, supplemental grounding is one of several possible preventions and mitigations for TOV during islanding.

Screening criteria are often considered as more art than science. A challenge in discrete screening of specific technical issues is that one screen probably affects more than one technical issue. Examples of screen considerations are relative DER size to load or a short circuit current ratio at the PCC. This type of screen normally necessitates the use of conservative criteria and/or ratios for most technical screens.

The expectation of screening is that using conservative criteria like load to generation ratios, will be a sufficient deterrent to one or more issues, without mitigation. Given different screening criterion for assessing different DER issues there is often overlap for any set of screens, e.g. FERC SGIP or CA Rule 21, initial and supplemental screens.[24] More sophisticated screening approaches are made less conservative by using additional feeder data, specific DER characteristics, load data and by applying analytical tools. The screening guidance given here aims to address the specific issues of LRO and GFO related to DER without comingling with other integration issues.

Both conservative and more refined screening approaches are addressed. The refining of conventional approaches considers the unique characteristics of inverter DER as well as the combination of both LRO and GFO response. Results of this effective grounding research project are also applied to evolve from the more to less conservative screening criteria. An inverter supplemental grounding assessment tool (IGST) is introduced with example scenarios and calculations.

Evolution of Overvoltage Screening Criteria

The relative size of DER generation to feeder peak load or feeder minimum load are common screening criterion. Examples of generation to peak load screens such as 20% for machine DER, 33% or 67% for inverter DER, are given in Table 6-2. Typical use of these ratios may include voltage regulation and island prevention concerns, in addition to TOV. They are not refined to the nuances of TOV for different cases of DER and load characteristics and tend to be conservative if only considering TOV.

Including a better understanding of the inverter and load characteristics supports this evolution of screening. As shown in the table, screening criterion allowing up to 100% generation to minimum load can be argued.

[24] FERC Small Generator Interconnection Procedure, Section 2 page 6.

Table 6-1
Evolution of Screening Criteria Addressing DER Overvoltage Concerns

Type of DER Device	Limits on DER Needed to Reliably Suppress TOV (GFO + LRO)
For Synchronous Rotating Machines (typical for DER machine and step-up transformer impedance)	Load 5:1, or 20% generation to load ratio in p.u. of DER rated power (see note 1)
For Inverters (covers more than TOV) (evolving with increasing experience inverter penetration and clearly includes a safety factor)	Load 3:1 or 1.5:1, that is 33% or 67% generation to load ratio in p.u. of DER rated power (see note 2)
For Inverters (refined to consider load)[25] (recommended based on this NYSERDA/EPRI research including modeling characteristics of inverter, load for both LRO plus GFO behavior)	100% of minimum load if at least 1/3 of the load is connected via single phase or Yg/Yg and L-N (see note 3)

Note 1: This conservative ratio is common for rotating machine DER and does not consider any other ground sources that may be present in an islanded area.

Note 2: Less conservative for inverter DER. Also benefits from some part of the load connected L-N and providing weak ground source. Both ratios are sufficient to suppress inverter LRO, completely mitigated by load greater than generation.

Note 3: Refined based on simulations that indicate 33% grounded load provides effective grounding. Analysis indicates a level as low as 19% grounded load is effective for most inverters. Uncertainty in mix and future load changes, dynamics of loading during fault events, reality of system reconfigurations, etc. indicate a that a screen needs to be conservative. Therefore use 33%, not 19%, or do a risk of islanding study.

As indicated, if the only objective is to limit TOV during an island ground fault, an inverter DER may be rated 100% of the expected load if there is > 33% of the load connected L-N. In this case we are considering the ground source contribution of the L-N load. Modeling and simulation results show that neutral-connected loads contribute as a supplemental ground source and in case of a typical inverter can effectively reduce GFO (see notes in the table). When the minimum load, line to neutral or line to line connected, is at least 100% of the DER generation then the issue of inverter LRO is also mitigated.

In other words, there will be no overvoltage concern if load/gen ratio > 1 and 33% or higher load is grounded. When the grounded load is insufficient, or when mix of L-N and L-L load combination is unknown, higher ratios may be considered. These ensure that overvoltages stay within acceptable levels such as COG < 80% in case of GFO. Safety factors in screening ratios and in technical review are appropriate. Applying, results from this research is expected to

[25] IEEE ANSI C62.92.6, IEEE Guide For Application Of Neutral Grounding In Electrical Utility Systems, Part VI

inform utilities to use safety factors that are reasonable to the DER generation type, load mix and any other OV mitigating factors.

Choosing Mitigation or Prevention Options

With all the aforementioned information, an initial TOV (considering both GFO and LFO) screening process is developed in Figure 6-3 for four-wire, multi-grounded neutral distribution systems. This is the most common configuration of utility distribution feeders in North America. This flow chart approach is for the distribution primary feeder level on the sections with potential to island. A separate screen is needed at the sub-transmission level. Aggregate DER and load must be considered.

For example, the flowchart applies the gen/load < 67%, gen/load < 100% and available grounded load > 33% criteria in Table 6-1. It also includes the prevention option of inverter built-in DER overvoltage limiting. That is, the inverter meets the IEEE 1547-2018, Section 7.4, requirement to trip for MV side overvoltages. Mitigation effects from supplemental grounding and inverter islanding detection are also considered, and the associated risks are provided. It is worth mentioning that supplemental grounding only suppresses GFOV, but other measures, such as overloading or rapid tripping can reduce or eliminate both GFOV and LROV.

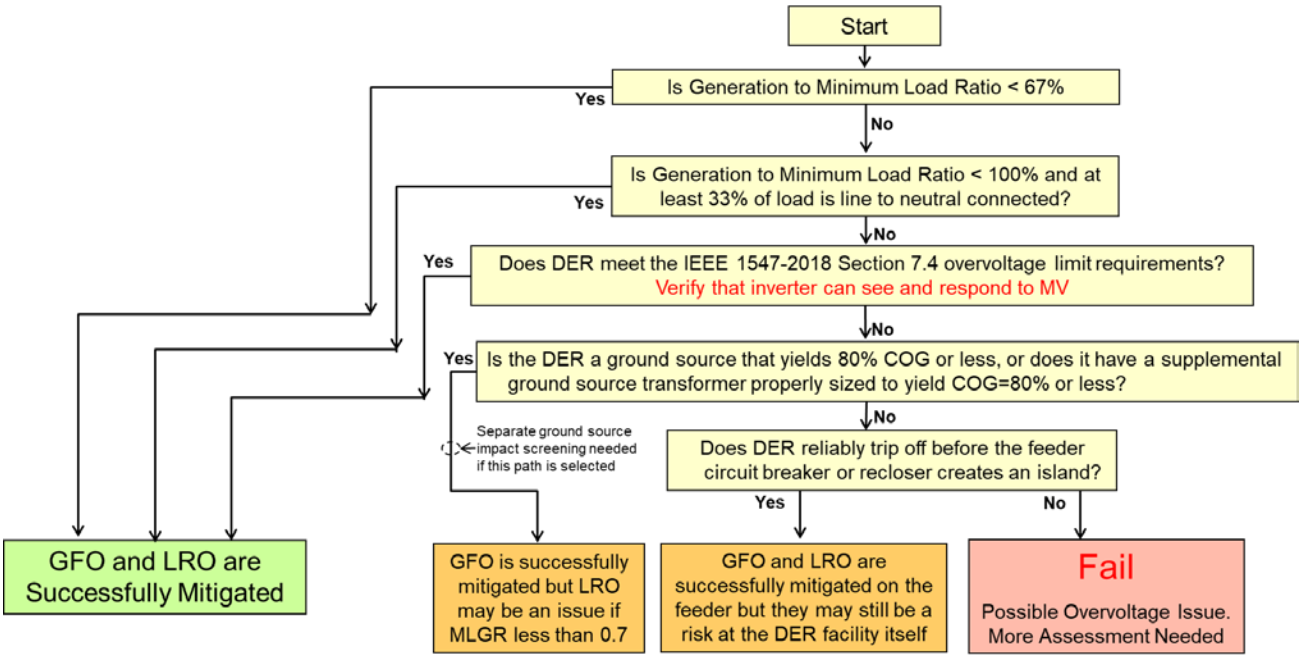


Figure 6-3
Initial screening for four-wire multi-grounded neutral distribution systems with DER

Another screen is developed to help identify the best solution for overvoltage mitigation. As shown in Figure 6-4, it takes users through many approaches to see which one gives the best solution. This screen assumes the DER has already failed the minimum load to generation screens and then investigates four possible solutions. Solution 1 and 2 aim to provide a ground source and thus only reduce GFOV, while the other two solutions break the island and mitigate both GFOV and LROV. The trip time of DTT, if applicable, should be examined to ensure a timely tripping of DER and to prevent equipment damages during the transient overvoltage.

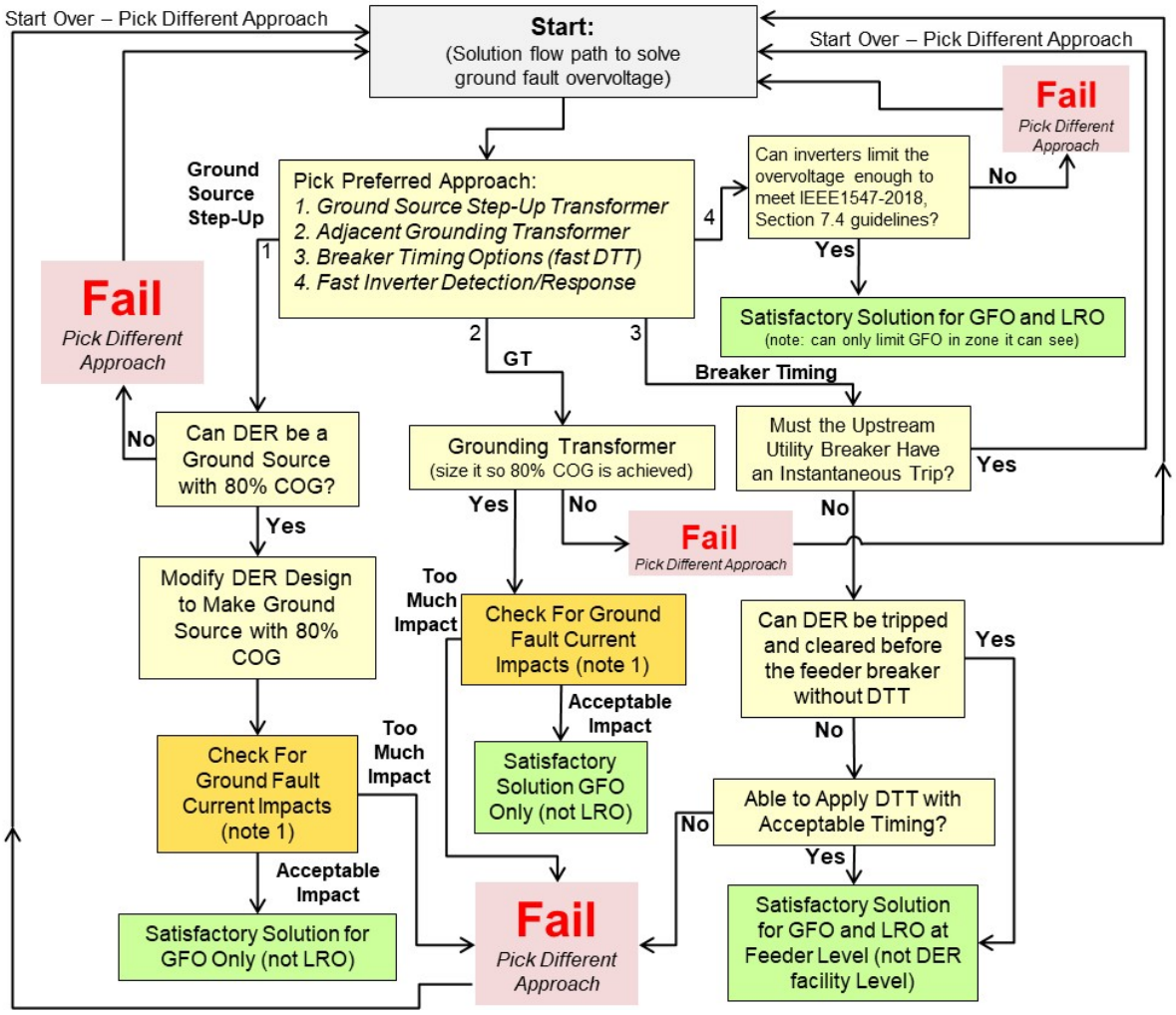


Figure 6-4
Ground fault overvoltage and LRO solution screening

- This screening approach helps identify the best mitigation choice by linking several different choices and criterion in the same flow chart tool.
- It assumes the DER has already failed the minimum load to generation screen (see the prior slide) and the lead to four other possible solutions
- Some solutions as noted only solve GFO and others both GFO and LRO

DTT provides a reliable islanding prevention but using it for overvoltage mitigation may not be effective because of communication and tripping time delays. Other drawbacks with DTT include:

- It suffers from high cost and is useful primarily only for a single large DER site (or perhaps a few sites per feeder) rather than cases involving many sites per feeder

- It usually can't be used in a "time coordinated" fashion to prevent DER overvoltage due to timing issues (unless added feeder breaker delay or inverter gate signal blocking (i.e., cease to energize) are used)
- It may react to, but it does not suppress the DER caused LROV and GFOV.

If DTT is the mitigation choice, maintaining reliable communication and time coordination between DTT and other protection devices become critical. There are a couple ways to make DTT coordinate better:

- Delay upstream feeder breaker a few extra cycles as shown in Figure 6-5 *(Drawbacks: could be problematic with protection coordination and may not be viable due to increase of arc-flash energy)*,

  or
- If only time-overcurrent curve is used for the feeder source, then use a faster tripping approach for the DER *(Drawbacks: could cause some nuisance DER trips where the feeder breaker did not trip but the DER did trip or where low voltage ride through requirements won't be satisfied)*

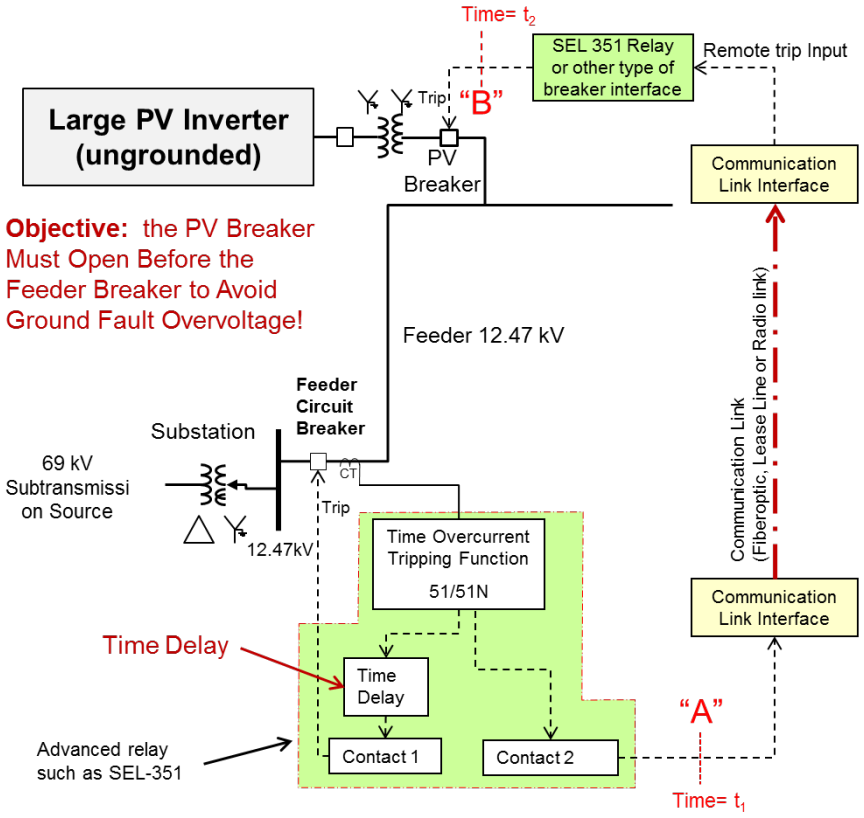


Figure 6-5
Time coordinated DTT

Use of the fastest possible plant recloser capable of inverter blocking is probably the only way to ensure DER tripping prior to the feeder breaker open (that is $t_1 > t_2$).

Table 6-3 compares several classical overvoltage mitigation methods with prevention alternatives. The mitigation methods, options 1-3, are typical approaches for synchronous

machines (classical solutions) and have been applied to larger inverter connected plants. These mitigations can introduce negative side effects or in the case of DTT, present upkeep challenges.

The options 4-6 are overvoltage prevention methods that rely on sufficient load and/or self-limiting at the DER. he last two preventions are proposed based on this research work, which proves that 1) the required load/gen ratio can be further reduced, if accurate inverter models and load presence are available, and 2) the overvoltage limit defined in IEEE 1547-2018 can effectively mitigate the overvoltage risks, if MV side overvoltage is visible to inverter.

Table 6-2
Evolution from overvoltage mitigation to overvoltage prevention for inverter-based DER

Overvoltage Mitigation Method	Check List of Considerations	Application Comments
1. Provide a ground source via DER Step-up Transformer	• May not work for certain inverters • Prone to side effects depending on design • Does not suppress LRO	Usually requires a reactor in neutral conductor to manage side effects.
2. Add supplemental Grounding Transformer in the GFO Zone	• May not work for certain inverters • Prone to side effects depending on design • Does not suppress LRO	Needs to be right sized, with impedance values depending on system.
3. Install DER Time Coordinated Direct Transfer Trip	• Is relatively expensive • DER to be tripped before EPS source (in many situations this is not possible) • Does not cover all possible island situations	Generally applied only to larger DER. Solves LRO and GFO in the feeder zone
4. Assume the overloaded DER lead to reduce + sequence voltage, i.e. conservative gen to load ratios (such as 20, 33 or 67%)	Higher levels of DER penetrations limit scenarios where overload is dependable mitigation. Uncertainty in time-varying load and generation levels is a concern.	Can work well in case of low DER penetration. Solves LRO and can mitigate GFO
5. Rely on at least 33% line-neutral connected load and aggregate generation not exceeding load.	• Uncertainty in time-varying load and generation levels is a concern. • Sharpening the load prediction reduces margin for error and for future load changes.	Improves with better models of inverter behavior and prediction of the load characteristics and timing. May solve LRO and GFO
6. Determine if sufficient proportion of islanded DER meets IEEE 1547-2018, 7.4.2, over-voltage detection and fast trip	• Only newer DER, most likely inverter only, can be expected to meet this requirement. • Existing installed DER are probably not certified to meet this requirement.	Solves both GFO and LRO without relying on load or other mitigations. Needs accurate sensing of island voltage level.

Application of Supplemental Grounding

As previously discussed, supplemental grounding refers to any distributed ground source that is in addition to the primary grid ground source, usually at the substation. Possible ground sources includes line to neutral connected load, the interconnection transformer windings for either load or generation, as well as parallel-connected grounding transformers. Table 6-2 identifies typical supplemental grounding design parameters for synchronous machine DER (Classical) and for

two different views of inverter-based DER (applying a Classical approach and adjusting for new Reality of inverter characteristics).

The righthand column is adjusted for inverter test results and is recommended approach based on the results of this research and our current expectation for inverter response characteristics. Several key differences are identified in the table as we evolve from machine to inverter DER.

Supplemental grounding for synchronous machines will normally have much lower sequence impedances than grounding for inverters. Inverter supplemental grounding is recommended to be more resistive. Inverter ground sources can be smaller relative to the kVA rating of the generator. Transformers used for inverter supplemental grounding will have higher impedance than for machines. In case of a Δ secondary of the main interconnect transformer a reactor is likely needed in the high side neutral connection. For inverters the line to neutral connected load can be an effective ground source and should be considered.

Table 6-3
Comparison of Supplemental Ground Sources Evolving from Machine to Inverter DERs

Parameter	Supplemental Grounding for Machine DER	Machine Supplemental Grounding ***Incorrectly*** Applied to Inverter DER	Recommenced Based on Reality of Inverter DER Characteristics
Target Ratios of ground source impedance for ≤ 80% COG	• $X_0/X_1 < 3$ • $R_0/X_1 < 1$ • X_0/R_0 ratio > 3	• $X_0/X_1 < 3$ • $R_0/X_1 < 1$ • X_0/R_0 ratio > 3	• X_0/R_0 ratio of 0.3 to 0.01 • Z_0/Z_{1load} ratio of ground source 1-2
Typical Percent Impedance of Generator Used in Calculation	• 10-25% Positive Sequence • 12-30% negative sequence • 2-10% zero sequence (if machine is solidly grounded)	• 50-100% Positive Sequence • 50-100% negative sequence • Zero sequence assumed very high (open)	Operates as ideal current source Very high negative sequence impedance Zero sequence assumed very high (open)
Typical Rating of the Grounding Transformer Applied to handle Zero Sequence Currents	• X0= 30-60% • R0= 10-20% • KVA rating = 15-25% of the Machine rating	• X0= 100-200% • R0= 33-67% • KVA rating = 3-5% of the Inverter Rating	Examples of Optimized Grounding Solutions: Z_{0gt} = 131% + j45% [26] Z_{0gt} = 210% + j6% [27] KVA Rating = 3-5% of Inverter Rating
Problems with the Method	No issues – works great for machines and standard power system impedance characteristics.	The method is **inaccurate and may not provide mitigation in some cases** because:	The effectiveness of the method depends on the negative sequence impedance characteristic

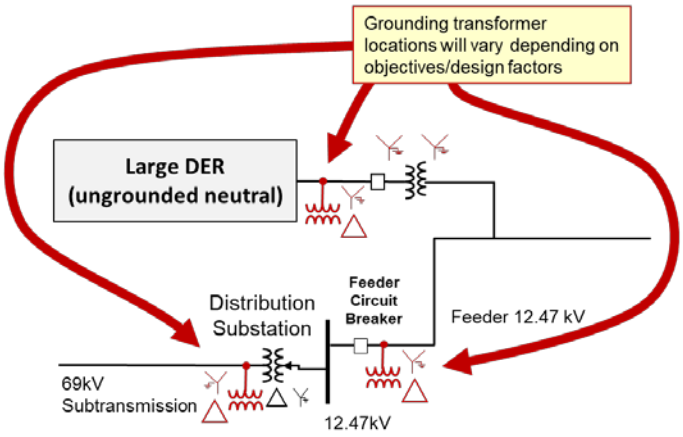
[26] *Effective Grounding and Inverter-based DER*: *A "new" look at an "old" subject*. presented at ITWG, Feb 1, 2019

[27] *Mitigating the Effects of Temporary Overvoltage on Electronic Devices*, March 2008.

		• Inverters are voltage controlled current sources • Inverter negative sequence impedance is high and L-N loads define the GFOV system impedance.	inverters, which varies, and also on the presence of L-N loading in the island.

The location of parallel connected supplemental grounding transformers (GT) varies depending on the objectives and design factors. For example, a properly size GT at the DER facility may solve the MV ground fault overvoltage concerns, but it will not help with GFOV mitigation at the sub-transmission level. Location depends on the protection zone. Several different zones are illustrated in Figure 6-6.

Protection Zone	Grounding Transformer Location
Solve GFO at Transmission Level	• Locate at Sub-transmission level
Solve GFO at Feeder Level	• Locate at feeder level **Or** • Locate at DER site if DER step-up transformer is Yg to Yg
Solve GFO at at Facility Level	• Locate at DER facility level



Note: *Grounding transformers work only if suitable impedance ratios are satisfied and if inverter characteristics allow.*

Figure 6-6
Supplemental grounding transformer (ground source) locations

Figure 6-7 provides a flowchart for the supplemental grounding transformer design and application decisions. The zero-sequence impedance of the grounding transformer should satisfy the impedance ratios in Table 6-2. Also, it is important to meet any current withstand requirements, and to not cause any unmanageable side effects during normal and fault operating conditions. Iterating this process may be needed to achieve the optimal parameter values.

Several tests are identified to check different fault scenarios given the addition of the grounding transformer. When required, these tests can be specific based on utility standing practices. But they can also draw on industry standards for specific guidance.

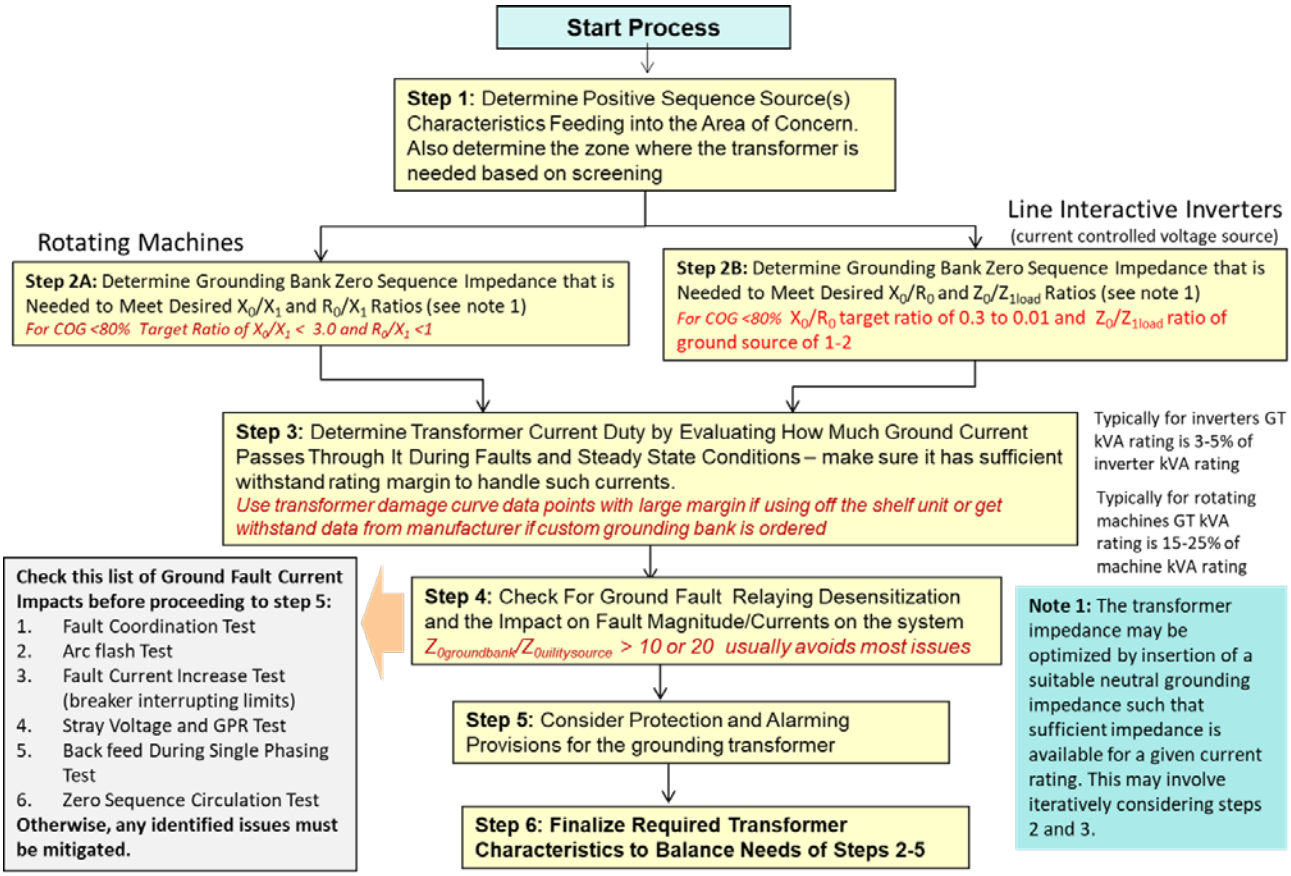


Figure 6-7
Flowchart for supplemental grounding transformer design

The first three tests are related to increased fault current with DER and may be addressed by other screens and interconnection technical reviews. For example, issues such as exceed ing protective device interrupting capabilities or mis-coordinate. FERC-SGIP and CA Rule 21, for example, suggest a study is required if DER increases fault current by more than 10%. In case of arc flash requirements these can vary depending on specific utility work practices. Arc flash risk is also discussed as one of the side effects of supplemental grounding. It is also covered in a recent IEEE standard,[28] and could very well evolve into a new DER screening criteria.

Stray voltage and ground potential rise issues are typically addressed case by case based on complaints. Location experience, such as faming, dairy cows and lake front areas could point to the need for a closer look. Standards applying to these include IEEE 80, IEEE 1590, IEEE 487.

Back feed that may occur during single phasing and zero sequence circulation (items 5 and 6 on your list) has been reported with DER plants with supplemental grounding.[29] Also, several IEEE standards support evaluation of transformer issues such as, IEEE C57.12, C57.109 and C37.91-2000.

[28] IEEE Guide for Performing Arc-Flash Hazard Calculations, IEEE Standard 1584-2018

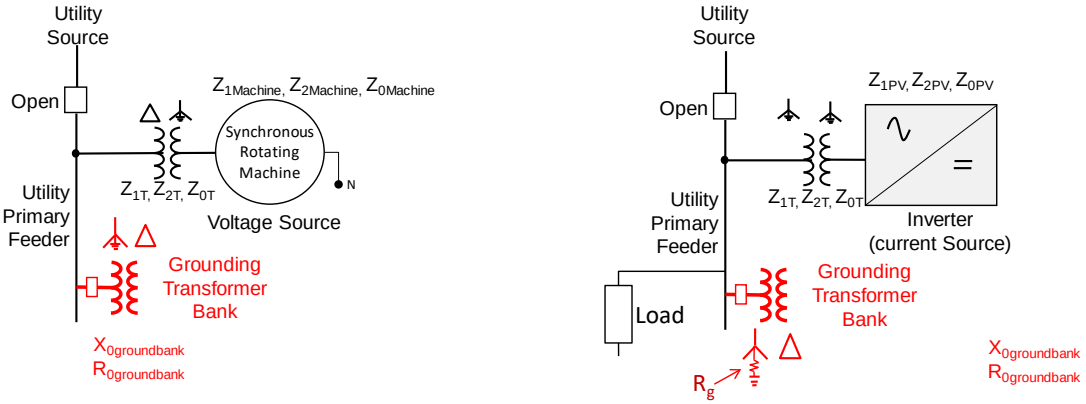
[29] Distributed Energy Resources Field Experience: Open Phase, EPRI Palo Alto, 3002015949, 2019

Side Effects of Supplemental Grounding

Supplemental grounding may not be needed in case of inverter DER and l-n connected load acting as a ground source. A grounding transformer may be needed when 1) there is insufficient l-n load to suppress GFOV, or 2) the inverter won't limit overvoltage per IEEE 1547-2018, clause 7.4 (voltage limits), or 3) limited withstand and lacking other overvoltage mitigation in the zone (e.g., service transformer with configurations other than Yg/Δ or Yg/zig-zag). It is important to avoid over grounding because of side effects discussed here.

Examples of case where supplemental grounding is needed are provided in Figure 6-8. Neither the ungrounded synchronous machine with a Δ/Yg interconnection transformer, nor the DER inverter with a Yg/Yg transformer, provide effective grounding. Noting here, transformer configuration convention is MV/LV.

In the machine case, a grounding transformer with Yg/Δ configuration and impedance satisfying $X_0/X_1<3$ and $R_0/X_1<1$ can be used. Note that the impedance criteria are defined by the machine impedance characteristics. Parallel load impedances can be ignored as relatively larger. In contrast, a resistive approach is more suitable for the inverter-based DER, and the parallel load effect should be considered due to the high sequence impedance of inverters, as described in Chapter 2. Designing supplemental grounding is discussed in the next section of this report.



For synchronous machine **For inverter-based DER**

Figure 6-8
Typical Supplemental grounding for synchronous machine and inverter-based DER

With the transition to more inverter-based DER, there have been reported field experiences of overgrounding and related side effects. When grounding transformers are oversized and relatively low impedance, they become a strong source of ground currents (providing zero sequence currents). This can cause side effects both during faults and as listed below.

Feeder ground faults – DER contribution to these currents must not exceed the temporary current rating of transformers and other equipment including neutral grounding reactors.

Feeder open phase – Backfeed via grounding transformers can cause a sustained overvoltage on the open phase requiring additional protection to disconnect for such a situation.

Feeder steady-state voltage imbalance – currents must not exceed the transformer continuous current rating and other equipment exposed to the current, including neutral grounding reactors.

Consequently, care must be exercised when adding supplemental grounding. Management of ground (zero-sequence) current flow should be considered in sizing and in design of any supplemental ground source to avoid these side effects:

Desensitizing upstream protection relaying during ground faults

Nuisance tripping, or reduced selectivity for faults on an adjacent feeder

Increased fault currents and durations impacting devices, arc flash levels, etc.

Stress due to additional zero sequence currents normally and during faults.

Overvoltage on open phases from backfeed via grounding transformers

Increased ground potential rise and stray voltage near added ground sources.

Given the importance to consider side effect from ground sources, these are each discussed below in more detail.

A. Ground fault relaying desensitization

During lateral circuit ground fault events, some of the current going to the lateral ground fault comes from the DER "ground source" transformer, as shown in Figure 6-9. The fuse is therefore exposed to more zero sequence current than the feeder breaker, and the feeder breaker also sees less ground fault current than before DER. This effect can cause coordination problems between circuit breakers, reclosers and fuses, as well as increased arc flash duration, etc.

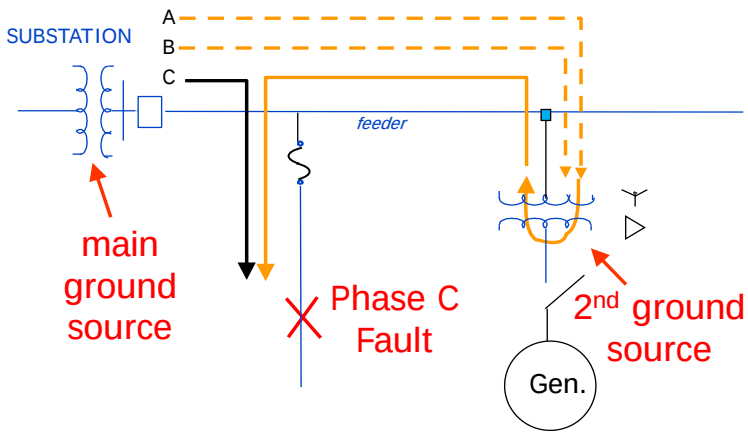


Figure 6-9
Ground fault current from grounding transformer

The nature of the impedances of the grid compared to DER changes how fault current sequence components divide. If the DER provides a ground source the zero-sequence current (ground fault current) contribution of the DER can become significant. As shown in , the zero-sequence impedance of the grid source is shown to be one half compared to DER, while grid's positive and negative sequence impedance 1/20th compared to DER. The zero-sequence current contribution of the DER becomes significant and desensitization of upstream relays is possible.

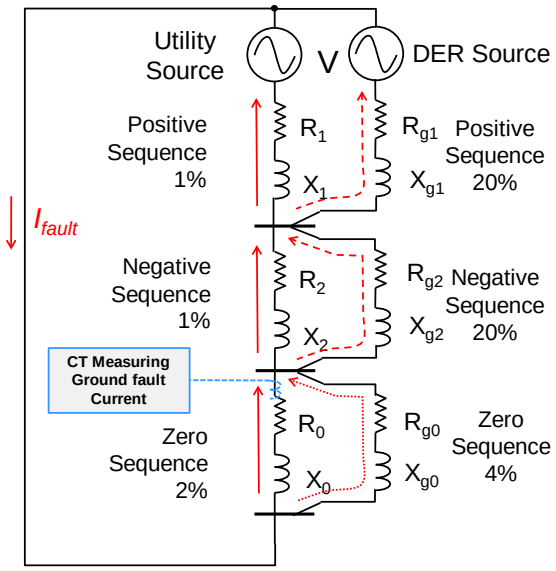


Figure 6-10
Ground fault current division effect

For better understanding, a case study is provided below in Figure 6-11. In this case a 2 MW PV plant DER is connected to the grid through a solidly grounded 2 MVA Yg/Δ step-up transformer. The zero-sequence impedance for line (Z_{0Line}) and substation transformer (Z_{0sub}) are 0.83 + j1.96 ohms and 0.07 + j1.318 ohms, respectively. Hence the total utility $Z_{0\text{-}grid}$ at POC = 0.90 + j3.278 ohms = 3.4 ohms. The DER step-up transformer $Z_{0\text{-}DER}$ = 5% × (12.47^2/2) = 5% × 77.75 ohms = 3.89 ohms, reducing fault current from the utility sources. This ground source is larger than necessary and can lead to protection failures. A proper sized grounding impedance (reactor or resistor) is shown in Figure 6-12, reducing the effect by roughly a factor of 50 while still maintaining the target COG of 80% or less.

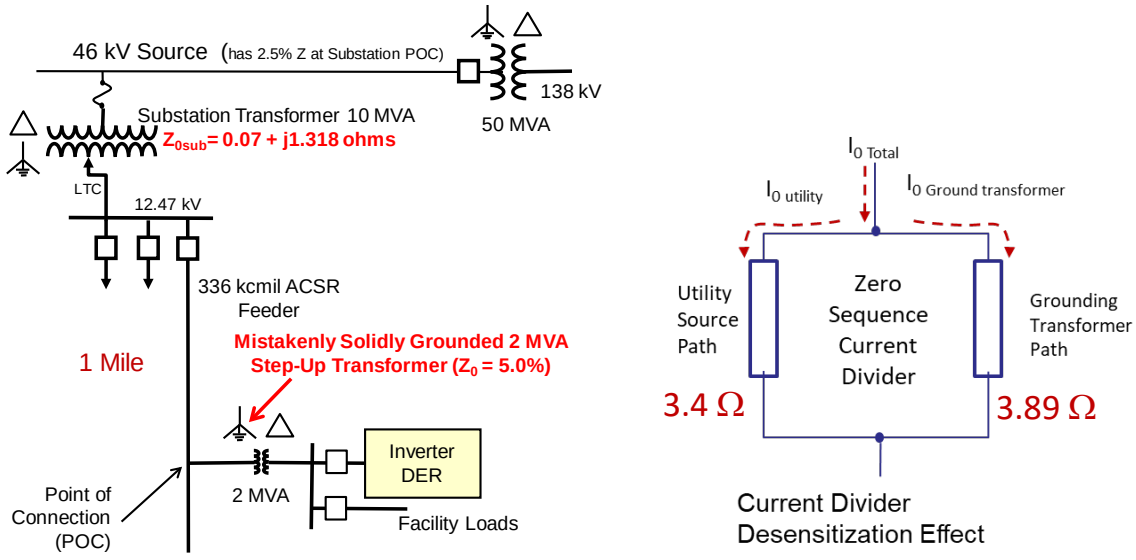


Figure 6-11
Case study for ground fault relaying desensitization

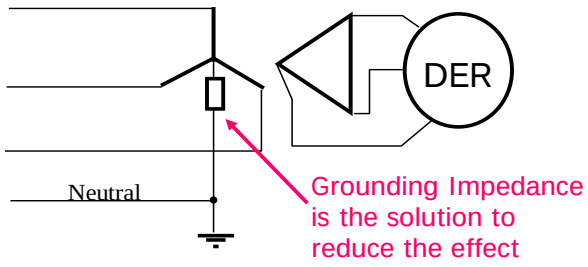


Figure 6-12
Grounding impedance to prevent ground fault relaying desensitization

B. Zero-sequence circulation in delta transformer winding

The normal imbalances of line-neutral connected load could cause background zero sequence return current and impose a steady state zero sequence voltage (up to a few percent) on the wye side of the transformer. This induces an additive zero sequence voltage on the delta connection and circulating current in that loop. The circulating current can be estimated as V_0/Z_0 as shown in Figure 6-13, where V_0 is zero sequence voltage component and typically ranges from 1% to 3%, Z_0 is zero sequence impedance and ranges from 2% to 6% for distribution transformers. Too much circulating current may result in the need to derate the transformer if operating near its maximum load.

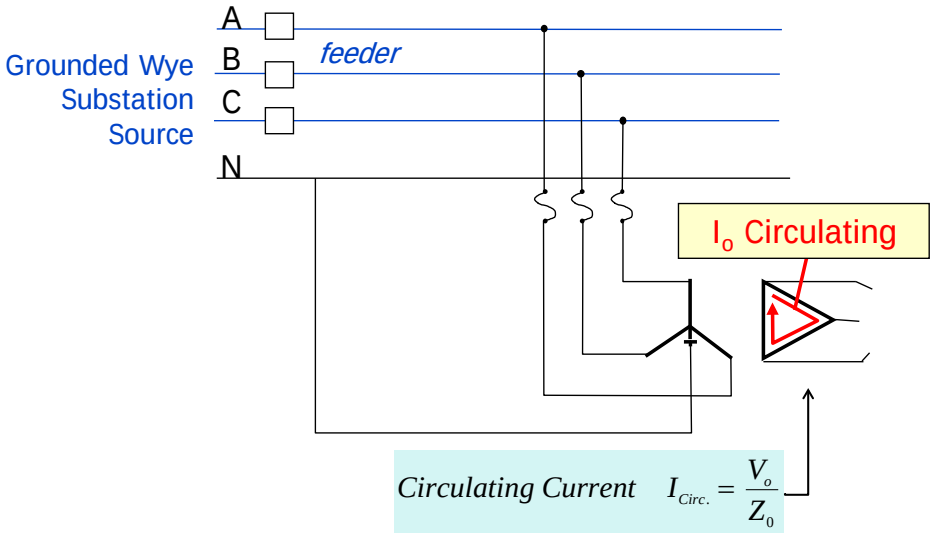


Figure 6-13
Zero sequence circulating current due to normal imbalance

C. Grounded-wye to delta transformer back-feed to utility feeder during single phasing

During a single phasing event as in Figure 6-10, if a Yg/Δ interconnection transformer is used, the healthy (energized) phases will back feed power through the delta winding. This creates voltage on the otherwise de-energized (opened) phases. It can happen with one or two open phases.

Voltage on an open phase is an undesirable condition and may lead to safety issues for the power system or power quality issues for customers connected on the affected phases. In addition, such

unbalanced and increased loading may overload the interface transformer. Therefore, local protection is sometimes specified to detect the condition and trip the transformer before reaching its damage curve limits.

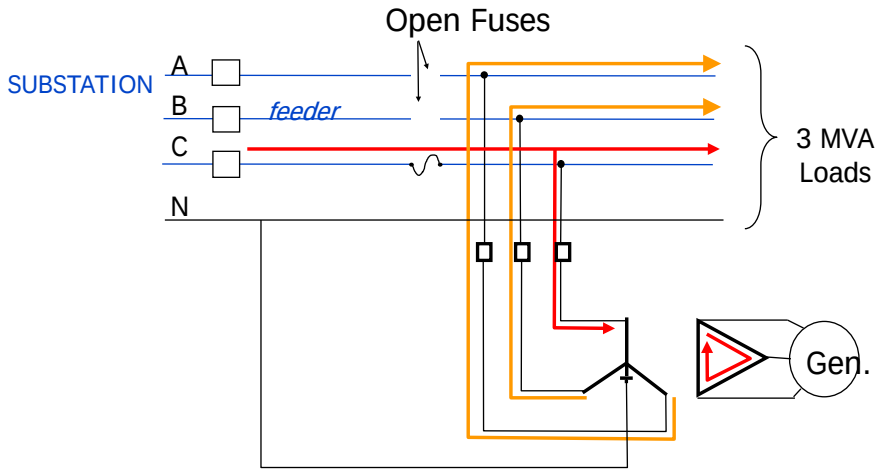


Figure 6-14
Power back-feed during single phasing

D. Ground Potential Rise and Stray Voltage

Ground Potential Rise (GPR) occurs during substation faults or lightning events, when a large amount of current enters the earth. Figure 6-15 illustrates the GPR voltage during a fault event. The GPR is relative to remote earth and can create step and touch potential hazards. The issue is typically mitigated by increasing earth grounding near sources such as additional rebar at substations, added copper grounding, fence grounding etc. GPR, if severe, can also cause problems for other services such as telecommunications.

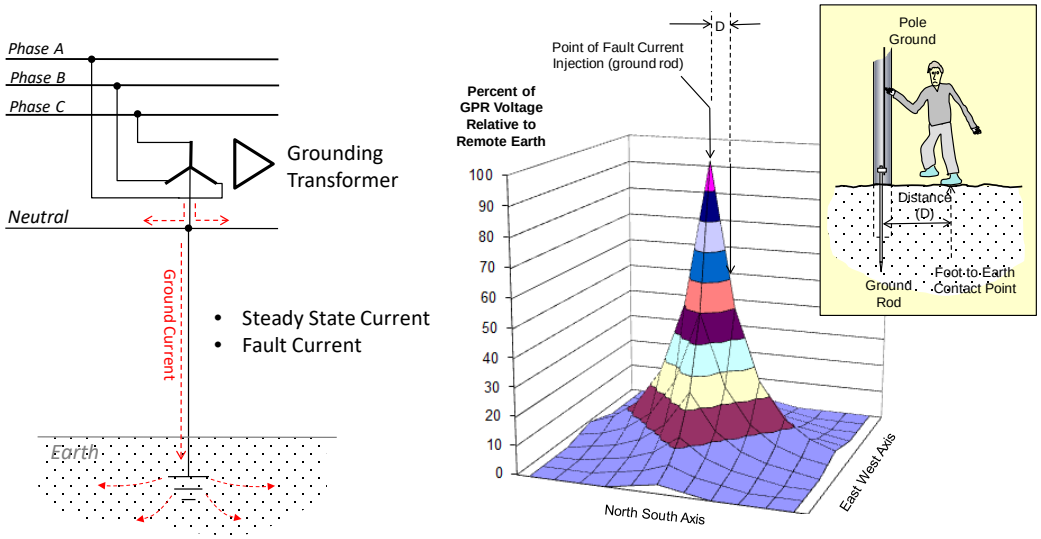


Figure 6-15
Ground potential rise

An example is given in Figure 6-16, where the fence step potential exposure is high due to the improper ground grid design that does not extend beyond fence. It can be addressed by extending the grid well outside the fence line as shown in the photo. Stray voltage is where steady state ground current can be upsetting to some equipment, people and animals. Communication circuits may be affected, for example telephone interference in the old analog systems. People in swimming pools or lakes, and dairy cattle connected to milking machines are common sources of stray voltage complaints.

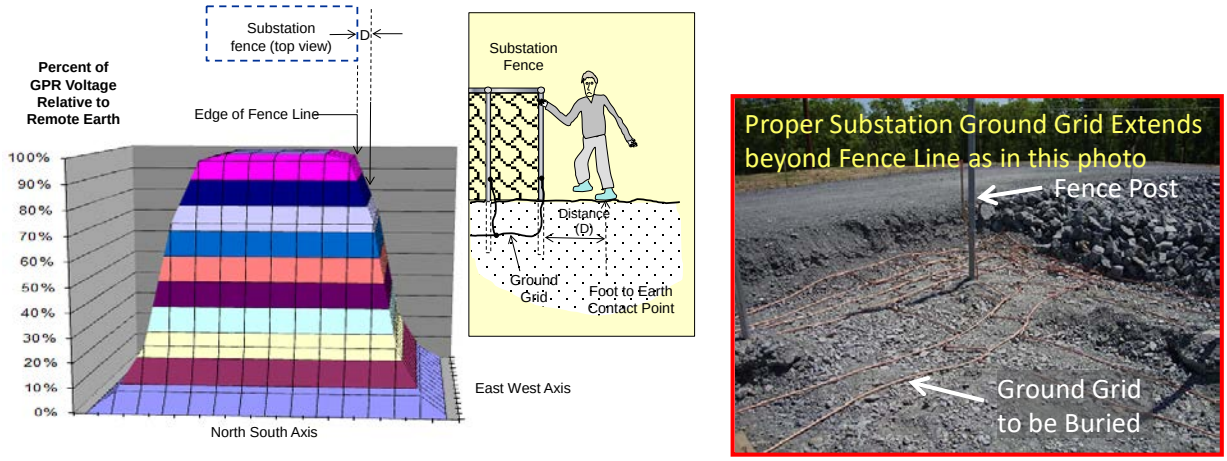


Figure 6-16
Impact of GPR at substation fence

To sum up, these potential side effects should be considered with other factors related to the DER transformer selection and design. Nearly all decisions around the transformer detailed design are trade-offs. Utility practices have evolved from experience and in making these trade-offs. Examples of learnings are:

- More local ground sourcing is not better. Large ground-source step-up transformers are more likely to cause side effects and have less benefit with inverter-based DER.
- Small local grounding transformers, properly sized to mitigate GFO, are less likely to cause coordination issues, but can aggravate open phase conditions and add to arc flash.
- Ground sources related to DER installations at certain types of customers (such as dairy farms or swimming pools) may lead to stray voltage and current complaints.

Inverter-based Supplemental Grounding Tool (ISGT)

Support determination of the need, estimation of the overvoltage and design of supplemental grounding, EPRI has developed an Excel-based tool.[30] The Inverter-based Supplemental Grounding Tool (ISGT) is intended to help engineers in assessing the need for and specifying the impedance parameters of a supplemental ground source for islanded inverter-interfaced DER.

[30] *Inverter-based Supplemental Grounding Tool (ISGT) v1.0 Beta*, EPRI, Palo Alto, CA: 2020. 3002019326.

This tool addresses the need for supplemental grounding to manage GFOV and includes any relevant LROV when islanded generation exceeds load.

The software tool provides distribution and protection engineers with a convenient means to analyze supplemental grounding needs and excessive generation related overvoltages in islands that are energized solely by inverter based DERs. Conventional short-circuit analysis software does not have the capability to appropriately analyze these types of situations. The ISGT includes a grid following inverter, modeled as a positive sequence current source. Inverter parameters are based upon its commonly understood control behaviors, and ISGT calculates the ground fault overvoltage using symmetrical component analysis.

A beta version has been provided to approximately a dozen utilities for testing purposes, including the five NY State regulated utilities. Since the current tool user population and number of applications are limited it is a research grade software at this stage. EPRI plans to work with NY and other utilities and with NYSERDA to further evolve this tool and increase its effectiveness. Meantime, Figure 6-17, generated from feedback at EPRI's Fall 2020 modeling workshop, indicates how utilities expect to use this tool in the future.

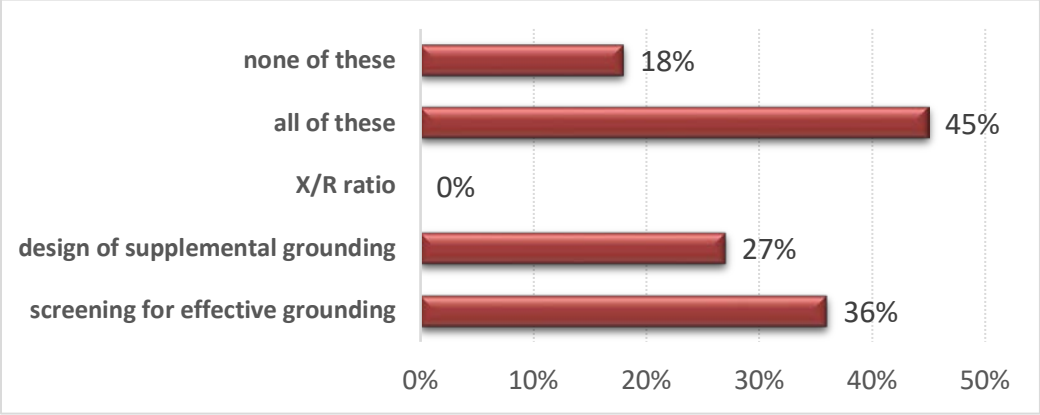


Figure 6-17
How do you expect to use the EPRI grounding effectiveness calculation tool?

ISGT is a power system grounding tool. requires the user to enter the system and inverter characteristics as input (shown in Figure 6-18), and gives the maximum phase-to-ground voltage with and without ground faults. By adjusting the input parameters, the impact of loading level and inverter behaviors on overvoltage can be identified, and the need for supplemental grounding can be determined. This tool also supports supplemental grounding design, if needed. The users can adjust the zero-sequence impedance and X/R ratio of the ground source to achieve desired ground fault overvoltage.

To verify the results generated by ISGT, the overvoltage from this tool (GFO Tool_v1.0-Optimization-betaR10) were compared with the full EMT simulation results. Since the nonlinear effects introduced by arrester is not modeled in ISGT, it is also excluded from the simulation model, which therefore results in higher overvoltage in comparison with results shown in Chapter 3.

Figure 6-18 illustrates the configuration of ISGT for the case with delta connected load (0% L-N load) and no supplemental grounding. The inverter current limit was 1.1 pu and its negative

sequence impedance was 0.26∠170° according to Figure 4-3. The load/gen ratio can be adjusted by inputting different values for "minimum concurrent load in islanded grid", and in this figure load/gen = 1.

EPRI Inverter-based Supplemental Grounding Tool (ISGT)

About | Help | Custom Data

= Nu
= Do
= Res
= Res

Input Data

Connected load power factor	1	(positive if inductive, negative if
DER rating	1000	kVA
User defined positive sequence current reference limit	1.1	p.u. of rating Adjusted po
Inverter negative sequence impedance	0.2600	p.u. on DER rating base
Inverter negative sequence impedance angle	170.00	degrees (+90 degrees for pure in
Minimum concurrent load in islanded grid	1000	kW
Percentage of load connected line-ground	0%	
Supplemental ground source zero-sequence impedance	99999.000	p.u. on DER rating base
Supplemental ground source zero-sequence X/R ratio		Reset Zo and Zo X/R to Pre-Optimization Value
Maximum phase - ground voltage target	1.38	p.u.

Overall Results

Maximum phase - ground voltage during fault	1.732	p.u.
Max. phase voltage without ground fault (all phases)	1.00	p.u.
Inverter active (real) power	1.00	p.u.

Figure 6-18
Analysis for overvoltage with delta load and no supplemental grounding, using EPRI ISGT

The comparison between simulation and analysis results are provided in Figure 6-19. The overvoltage given by ISGT (red diamond) is closer to the average peak (red line) for the available test points. The Inverter trips (user settable in ISGT and defaulted to 2.0 pu L-G) when generation to load ratio (gen/load) exceeds 1.1 p.u. in this example. For the scenarios with gen/load of less than 1.1 p.u, the results from ISGT are very similar to the EMT results. As the gen/load ratio increases, the EMT and ISGT results begin to diverge due to nonlinearities that are not captured in the symmetrical component analysis and assumptions about the control behavior.

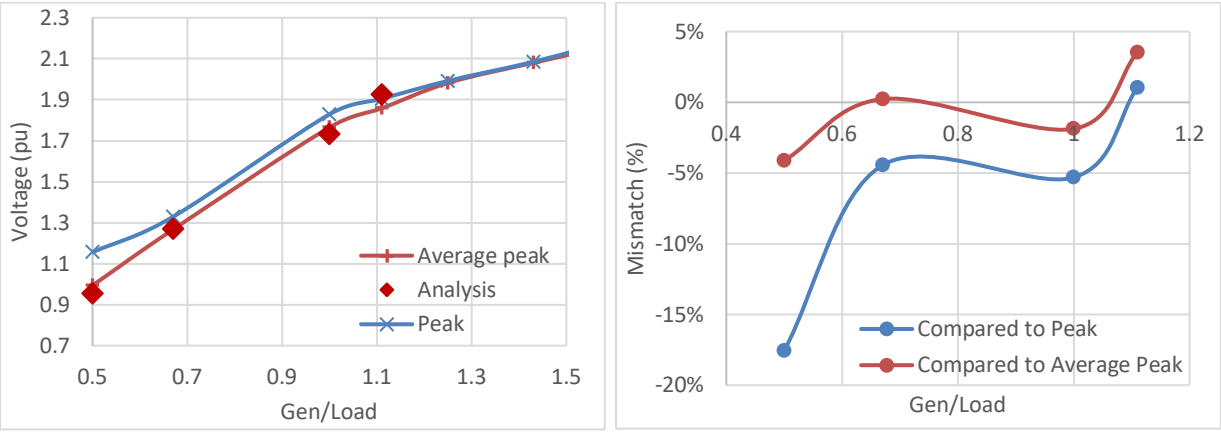


Figure 6-19
Comparison between simulation and analysis results for cases with delta load and no supplemental grounding (note mismatch around 1pu is on no practical significance)

Figure 6-20 shows how the configuration of ISGT with 100% L-G load that might be typical of a feeder dominated by residential load and no supplemental grounding source. Different from the previous case, the percentage of load connected line-ground is set to 100%. Other parameters remain. The results comparison is provided in Figure 6-21. In this case, the overvoltage analysis from ISGT matches well with the peak voltage from the simulation, and the mismatch stays within 5% expect when gen/load = 1 where load characteristics dominate.

EPRI Inverter-based Supplemental Grounding Tool (ISGT)

= Nu
= Do
= Res
= Res

About | Help | Custom Data

Input Data

Connected load power factor	1	(positive if inductive, negative if
DER rating	1000	kVA
User defined positive sequence current reference limit	1.1	p.u. of rating Adjusted po
Inverter negative sequence impedance	0.2600	p.u. on DER rating base
Inverter negative sequence impedance angle	170.00	degrees (+90 degrees for pure in
Minimum concurrent load in islanded grid	1000	kW
Percentage of load connected line-ground	100%	
Supplemental ground source zero-sequence impedance	99999.000	p.u. on DER rating base
Supplemental ground source zero-sequence X/R ratio		Reset Zo and Zo X/R to Pre-Optimization Value
Maximum phase - ground voltage target	1.38	p.u.

Overall Results

Maximum phase - ground voltage during fault	1.101	p.u.
Max. phase voltage without ground fault (all phases)	1.00	p.u.
Inverter active (real) power	0.68	p.u.

Figure 6-20
Analysis for overvoltage with Yg load and no supplemental grounding, using EPRI ISGT

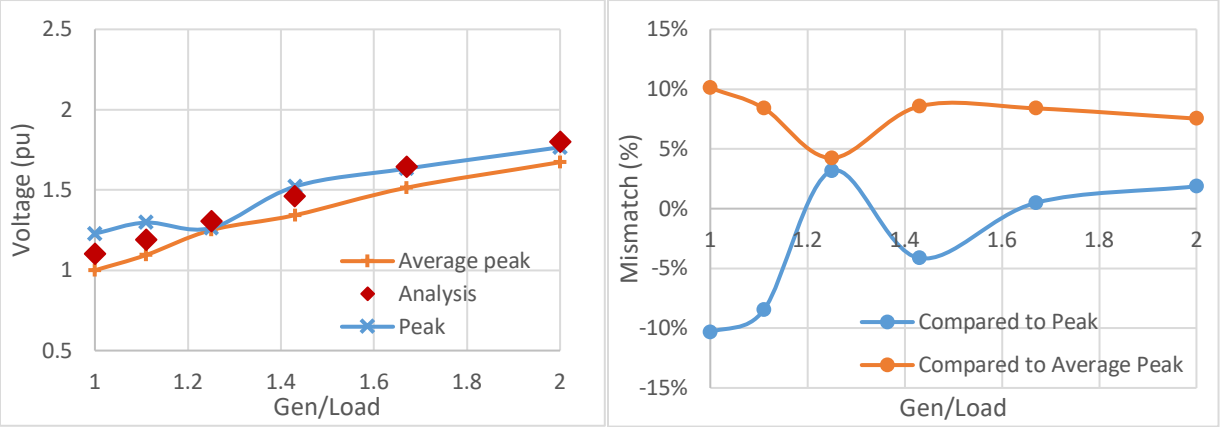


Figure 6-21
Comparison between simulation and analysis results for cases with Yg load and no supplemental grounding

The last case involves both Yg load and supplemental grounding, as illustrated in Figure 6-22 and Figure 6-23. Due to the time limit, only two simulation points are available. For these two points, the analysis results from ISGT is more accurate for the peak voltage prediction and the mismatch stays below 5%. The mismatch from simulated average peak, on the other hand, is quite high and more data are needed to better evaluate the analysis performance.

EPRI Inverter-based Supplemental Grounding Tool (ISGT)

About | Help | Custom Data

= Nu
= Do
= Res
= Res

Input Data		
Connected load power factor	1	(positive if inductive, negative if
DER rating	1000	kVA
User defined positive sequence current reference limit	1.1	p.u. of rating Adjusted po
Inverter negative sequence impedance	0.2600	p.u. on DER rating base
Inverter negative sequence impedance angle	170.00	degrees (+90 degrees for pure ind
Minimum concurrent load in islanded grid	1000	kW
Percentage of load connected line-ground	100%	
Supplemental ground source zero-sequence impedance	0.600	p.u. on DER rating base
Supplemental ground source zero-sequence X/R ratio	4.000	Reset Zo and Zo X/R to Pre-Optimization Value
Maximum phase - ground voltage target	1.38	p.u.

Overall Results		
Maximum phase - ground voltage during fault	1.156	p.u.
Max. phase voltage without ground fault (all phases)	1.00	p.u.
Inverter active (real) power	0.60	p.u.

Figure 6-22
Analysis for overvoltage with Yg load and supplemental grounding, using EPRI ISGT

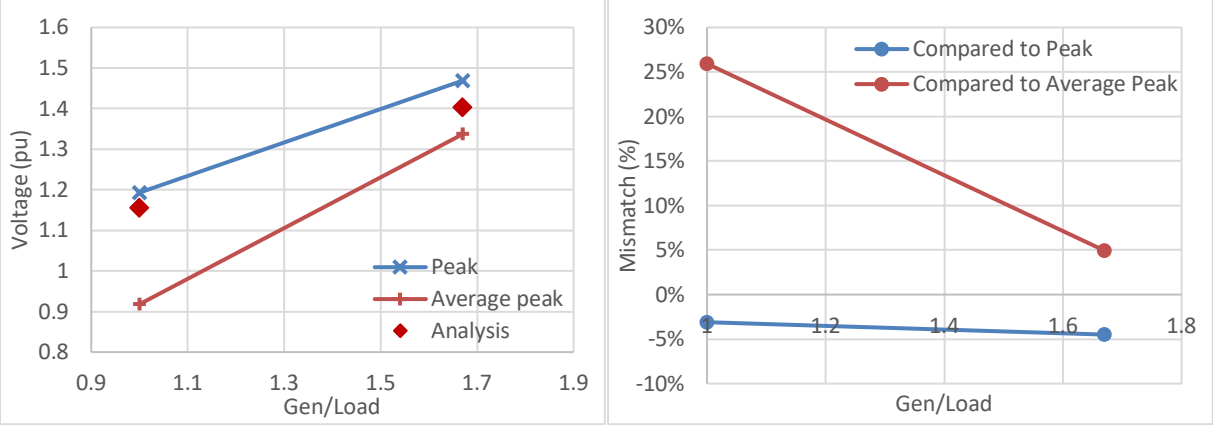


Figure 6-23
Comparison between simulation and analysis results for cases with Yg load and supplemental grounding

Guidelines Summary

As deployment of inverter-based DER increases, conventional DER criteria for specification and selection of interconnection transformers need to be revisited. This includes both the initial screening for island and ground fault overvoltage, when supplemental grounding is indicated, and the ground source design methodology. Both are covered in this chapter, which summarizes research outcomes and provides recommendations on new criteria and screens.

Supporting the need for a more detailed look is EPRI's (ISGT). This tool currently applies to islanded scenarios. It was evaluated here in several different operating conditions. In general, it gives quite reasonable overvoltage prediction when gen/load is not too high (nonlinearity from inverter controls and transformer saturation) or too low (overvoltage is dominated by loads). Testing of this supplemental grounding tool will continue and modifications will be made accordingly.

In the future the guideline provided in this section may be modified to also address intentional islanding or microgrid grounding requirements. At the present time microgrid neutral grounding requirement tend to conflict with on-grid and islanded ground source objectives.

7
CONCLUSIONS AND FUTURE WORK

Conclusions

This project aimed to true up long-standing DER grounding practices with the evolving change over to inverter-based DER. It is appropriate because of significant differences in the fault response seen in inverter-based compared to synchronous machine DER. Key differences include current versus voltage source characteristics, negative sequence impedance, and the resulting impact these have on ground fault overvoltage contribution. All these are primary determinates in effective grounding. Specific objectives have been to improve interconnection technical review processes and to make grounding requirements more transparent and consistent.

The project explored the meaning of effective grounding, basic principles, and important role of DER transformer connections, load types and new requirements for faster inverter response. A key area, previously unexplored, is the relationship and combination of GFOV and LROV during an island. From those results the project also addressed the application and sizing of grounding transformers, grounding impedance selection, potential interference with protection coordination and grounding related side effects.

Key takeaways from this report:

- Effective grounding is a “power system” characteristic.
- Inverter response to ground fault and grid disconnection is significantly different than synchronous machines.
- Many classical power system grounding practices are not appropriate for inverter plants
- Load is becoming a more critical and essential factor to consider any need for supplemental ground sources with increasing inverter penetration.
- With relatively high system penetration of inverter-based generation, the undesirable side-effects of adding supplemental ground sources have become more apparent.
- Design guidance and trade-offs to optimize the sizing and impedance values for supplemental ground sources are becoming better defined for inverters and they are different than for synchronous machines.

Overall recommendations:

1. Jurisdictions to adopt IEEE 1547-2018 where new overvoltage limits in Section 7.4 are effective in reducing DER OV contributions:
    - Meeting 1547-2018 Section 7.4 duration and voltage limits at the reference point of applicability will solve most LRO and GFO problems without any additional mitigation or grounding devices.
    - In cases where the inverter can’t see the GFO overvoltage due to an upstream transformer blocking the view, the standard still requires that the overvoltage limits are not exceeded. If loads are insufficient to suppress in that zone, a

supplemental grounding transformer located in the zone may be a means for the DER to meet the requirements of the standard.

2. Inverter manufactures to test for unbalanced output dynamics during islanded and faulted conditions. From these test results, inverter impedance models should be provided to facilitate improved analysis of overvoltage conditions and efficacy of supplemental grounding solutions. Note that, short circuit tests, from which impedance models can be deduced, are now mandated in IEEE 1547.1-2020.
3. Utilities to be proactive in the review and specification of DER interconnection and supplemental grounding transformers. There are many tradeoffs and not one clear winner. Some of the characteristics that make for a good transformer choice include:
    - It interferes least with the utility system (both upstream and downstream) as far as adverse ground source impacts are concerned
    - It allows for direct measurement by the inverter of line to neutral voltage (which enables higher speed IEEE 1547 Section 7.4 inverter overvoltage tripping to be utilized more easily)
    - It allows for supplemental zero sequence neutral grounding where effective grounding is not otherwise provided (for example, if insufficient neutral-connected load and if a GFOV risk has been identified)
    - A wye-ground to wye-ground unit may be best solution in many situations, but other types may be appropriate in certain cases.
4. With inverter DER the make-up of load for different island scenarios is a critical factor. Some considerations to suppress GFOV are:
    - A load 3 times the inverter generation on the island has been used as a rule of thumb for nearly 20 years and is quite effective but is now outdated.
    - The 3:1 ratio is now considered too conservative and a factor of 1.5:1 has been recommended since about 2014 as sufficient to suppress essentially all possible LROV and GFOV conditions without regard to the ratio of L-G and L-L load.
    - Recent EPRI analysis indicates that an even lower loading is sufficient to limit overvoltage where there is at least 1:1 load to generation ratio and at least 33% of it connected in the line to neutral mode.
    - If the load to generation ratio is not satisfied, or if load uncertainty increase risk too much, then some form of mitigation such as ground source step-up transformer, supplemental grounding, IEEE 1547-2018 Section 7.4 voltage limiting, or time coordinated DTT may be needed. Not all solutions can work in every case so each must be evaluated based on case specifics

Future Work

In this research, we have examined the negative sequence impedance of several commercial inverters, but their characteristics have not been implemented in the simulation model yet. This however may not be an issue since the negative sequence impedance changes the overvoltage values but does not affect the conclusions from sensitivity study results.

Below gives the recommendations and comments from utilities about the recent research results reported during EPRI's Fall 2020 workshops and potential next steps.

- Research and conclusions look great, but there are more factors that need to be involved.
- Conduct more research to determine inverter negative sequence behavior.

- What fault current can be expected from inverter-based DER?
- When is GFOV not a concern for inverters with lower negative sequence impedance?
- Need more application guidance on required % of N-G load in cases of high (1:1) penetration.

Workshop attendees also voiced some frustration about the undefined fault response of inverter DER. This was apparent in response to the poll question "Is there a future need for standards that define inverter negative sequence behavior?" (see Figure 7-1).

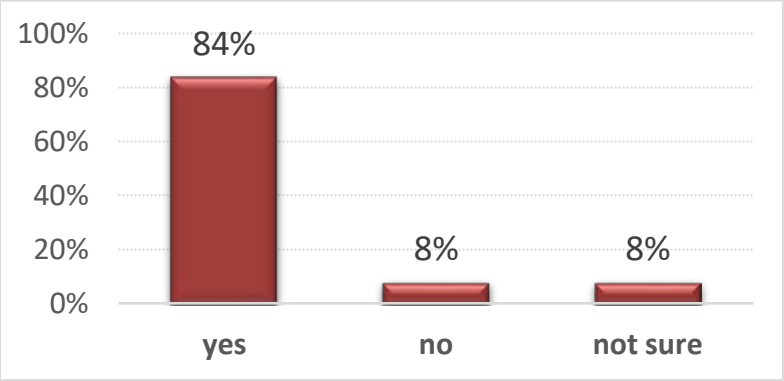


Figure 7-1
Do you see future need for a standard on inverter negative-sequence behavior?

Looking ahead, and based on input from utilities, EPRI has determined next research steps to be:

- Characterize inverter negative sequence behavior and specify the range of negative sequence impedance.
- Continue and refine analytical methods on the application and sizing of grounding transformers.
- Further develop criteria for load contribution to effective grounding of inverter DER.
- Vet new practices and procedures with utility protection engineers.
- Continue providing technical transfer via research updates, webcasts, and workshops.

A
VOLTAGE SETPOINTS IN LAB TEST

Table A- 1
Voltage setpoints for constant V_{pos} and varying V_{neg}

	Positive sequence		Negative sequence		Voltage setting for grid emulator	
	Mag (pu)	Phase angle	Mag (pu)	Phase angle	Mag/ pu	Phase angle
Setpoint 1, 10 s duration						
A	0.8	0°	0.05	0°	0.85	0
B	0.8	-120°	0.05	120°	0.7762	-123.1979
C	0.8	120°	0.05	-120°	0.7762	123.1979
Setpoint 2, 10 s duration						
A	0.8	0°	0.1	0°	0.9	0
B	0.8	-120°	0.1	120°	0.7550	-126.5868
C	0.8	120°	0.1	-120°	0.7550	126.5868
Setpoint 3, 10 s duration						
A	0.8	0°	0.2	0°	1	0
B	0.8	-120°	0.2	120°	0.7211	-133.8979
C	0.8	120°	0.2	-120°	0.7211	133.8979
Setpoint 4, 10 s duration						
A	0.8	0°	0.3	0°	1.1	0
B	0.8	-120°	0.3	120°	0.7000	-141.7868
C	0.8	120°	0.3	-120°	0.7000	141.7868

Table A- 2
Voltage setpoints for constant V_{neg} (0.1 pu) and varying V_{pos}

	Positive sequence		Negative sequence		Voltage setting for grid emulator	
	Mag (pu)	Phase angle	Mag (pu)	Phase angle	Mag/ pu	Phase angle
Setpoint 1, 10 s duration						
A	0.95	0°	0.1	0°	1.05	0
B	0.95	-120°	0.1	120°	0.9042	234.5036
C	0.95	120°	0.1	-120°	0.9042	125.4964
Setpoint 2, 10 s duration						
A	0.9	0°	0.1	0°	1	0
B	0.9	-120°	0.1	120°	0.8544	234.1825

C	0.9	120°	0.1	-120°	0.8544	125.8175
Setpoint 3, 10 s duration						
A	0.8	0°	0.1	0°	0.9	0
B	0.8	-120°	0.1	120°	0.755	233.4132
C	0.8	120°	0.1	-120°	0.755	126.5868
Setpoint 4, 10 s duration						
A	0.7	0°	0.1	0°	0.8	0
B	0.7	-120°	0.1	120°	0.6557	232.4109
C	0.7	120°	0.1	-120°	0.6557	127.5891
Setpoint 5, 10 s duration						
A	0.6	0°	0.1	0°	0.7	0
B	0.6	-120°	0.1	120°	0.5568	231.0517
C	0.6	120°	0.1	-120°	0.5568	128.9483

Table A- 3
Voltage setpoints for constant V_{neg} (0.2 pu) and varying V_{pos}

	Positive sequence		Negative sequence		Voltage setting for grid emulator	
	Mag (pu)	Phase angle	Mag (pu)	Phase angle	Mag/ pu	Phase angle
Setpoint 1, 10 s duration						
A	0.95	0°	0.2	0°	1.15	0
B	0.95	-120°	0.2	120°	0.8675	228.4825
C	0.95	120°	0.2	-120°	0.8675	131.5175
Setpoint 2, 10 s duration						
A	0.9	0°	0.2	0°	1.1	0
B	0.9	-120°	0.2	120°	0.8185	227.7837
C	0.9	120°	0.2	-120°	0.8185	132.2163
Setpoint 3, 10 s duration						
A	0.8	0°	0.2	0°	1	0
B	0.8	-120°	0.2	120°	0.7211	226.1021
C	0.8	120°	0.2	-120°	0.7211	133.8979
Setpoint 4, 10 s duration						
A	0.7	0°	0.2	0°	0.9	0
B	0.7	-120°	0.2	120°	0.6245	223.8979
C	0.7	120°	0.2	-120°	0.6245	136.1021
Setpoint 5, 10 s duration						
A	0.6	0°	0.2	0°	0.8	0
B	0.6	-120°	0.2	120°	0.5292	220.8934
C	0.6	120°	0.2	-120°	0.5292	139.1066

Table A- 4
Voltage setpoints for varying positive sequence and negative sequence voltage

	Positive sequence		Negative sequence		Voltage setting for grid emulator		
	Mag (pu)	Phase angle	Mag (pu)	Phase angle	Mag		Phase angle
Setpoint 1, 10 s duration							
A	0.95	0°	0.1	0°	290.85 V	1.05 pu	0°
B	0.95	-120°	0.1	120°	250.45 V	0.9 pu	-125.5°
C	0.95	120°	0.1	-120°	250.45 V	0.9 pu	125.5°
Setpoint 2, 10 s duration							
A	0.9	0°	0.2	0°	304.7 V	1.1 pu	0°
B	0.9	-120°	0.2	120°	226.73 V	0.819 pu	-132.22°
C	0.9	120°	0.2	-120°	226.73 V	0.819 pu	132.22°
Setpoint 3, 10 s duration							
A	0.8	0°	0.3	0°	304.7 V	1.1 pu	0°
B	0.8	-120°	0.3	120°	193.9 V	0.7 pu	-141.79°
C	0.8	120°	0.3	-120°	193.9 V	0.7 pu	141.79°
Setpoint 4, 10 s duration							
A	0.7	0°	0.4	0°	304.7 V	1.1 pu	0°
B	0.7	-120°	0.4	120°	168.5 V	0.61 pu	-154.72°
C	0.7	120°	0.4	-120°	168.5 V	0.61 pu	154.72°
Setpoint 5, 10 s duration							
A	0.6	0°	0.5	0°	304.7 V	1.1 pu	0°
B	0.6	-120°	0.5	120°	154.23V	0.556pu	-171.05°
C	0.6	120°	0.5	-120°	154.23V	0.556pu	171.05°

Table A- 5
Voltage setpoints for varying phase angle of negative sequence voltage

	Positive sequence		Negative sequence		Voltage setting for grid emulator		
	Mag (pu)	Phase angle	Mag (pu)	Phase angle	Mag		Phase angle
Setpoint 1, 10 s duration							
A	1	0°	0.1	-60°	291.84 V	1.054 pu	-4.72°
B	1	-120°	0.1	60°	249.3 V	0.9 pu	-120.00°
C	1	120°	0.1	-180°	291.84 V	1.054 pu	124.72°
Setpoint 2, 10 s duration							
A	1	0°	0.1	-40°	298.75 V	1.079 pu	-3.42°
B	1	-120°	0.1	80°	251.15 V	0.907 pu	-122.16°
C	1	120°	0.1	-160°	283.13 V	1.022 pu	125.53°
Setpoint 3, 10 s duration							
A	1	0°	0.1	-20°	303.18 V	1.094 pu	-1.79°
B	1	-120°	0.1	100°	256.40 V	0.926 pu	-123.98°

C	1	120°	0.1	-140°	273.55 V	0.988 pu	125.72°
Setpoint 4, 10 s duration							
A	1	0°	0.1	0°	304.7 V	1.1 pu	0°
B	1	-120°	0.1	120°	264.24 V	0.954 pu	-125.21°
C	1	120°	0.1	-120°	264.24 V	0.954 pu	125.21°
Setpoint 5, 10 s duration							
A	1	0°	0.1	20°	303.18 V	1.094 pu	1.79°
B	1	-120°	0.1	140°	273.55 V	0.988 pu	-125.72°
C	1	120°	0.1	-100°	256.40 V	0.926 pu	123.98°
Setpoint 6, 10 s duration							
A	1	0°	0.1	40°	298.75 V	1.079 pu	3.42°
B	1	-120°	0.1	160°	283.13 V	1.022 pu	-125.53°
C	1	120°	0.1	-80°	251.15 V	0.907 pu	122.16°

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