Protection of Distribution Grid with DER and IEEE1547.2-2023 Protection Guidance

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Abstract— The objective of this paper is to inform utility protection engineers about updated practices to protect the distribution grid with distributed energy resources (DER) in coordination with bulk power system reliability needs by reviewing specific terms and concepts from IEEE Std 1547™-2018. Standards like IEEE 1547-2018 specify minimum technical capability and performance requirements for interconnection and interoperability. IEEE Std. 1547-2018 specifies DER equipment and requirements to meet the challenges of high DER penetration futures. Distribution utility protection engineers may not have fully recognized and embraced the necessary coordination of distribution protection schemes to support the integration of DERs in this transformation of modern power systems. The guidance provided in this paper builds on protection guidance provided in IEEE Std 1547.2™-2023, a new Guide for Application of IEEE Std 1547™-2018 that is expected to be published in 2024. While much of the protection information provided here applies to any technology of DER, a focus is placed on inverter-based, distribution-connected generation and storage.

Keywords—DER, High Penetration, Ride-through, Inverters, Rotating Machines

I. Introduction

The policy- and market-driven deployment of distributed energy resources (DERs), that is, distribution-connected generation and storage and to some extent controllable loads, increasingly impacts the planning, protection, and operation of distribution and bulk power systems in ways that require attention from utility engineers. Standards like IEEE 1547-2018 specify minimum technical capability and performance requirements for interconnection and interoperability. IEEE 1547-2018 specifies DER equipment and requirements to meet the challenges of high DER penetration futures. Distribution utility protection engineers may not have fully recognized and embraced the necessary coordination of distribution protection schemes to support the integration of DER in this transformation of modern power systems. The objective of this paper is to review specified terms and concepts from IEEE 1547-2018, the potential impacts of DERs on the distribution and bulk power systems, and to inform utility protection engineers of improved practices to protect the distribution grid in coordination with bulk power system reliability needs. The guidance in this paper builds on guidance provided in IEEE Std 1547.2™-2023, a new Guide for Application of IEEE 1547-2018 that is expected to be published in 2024. While much of the information provided here applies to any technology of DER, a focus is placed on inverter-based, distribution-connected generation and storage.

II. Important Terms Defined in IEEE 1547-2018

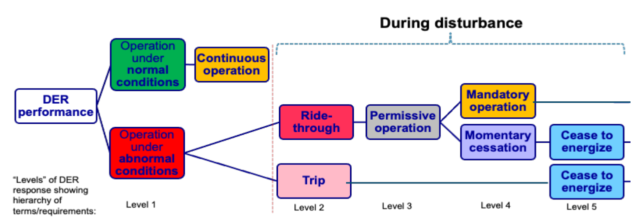


Figure 1: Overview of important terms defined in IEEE 1547-2018

The following list paraphrases the meaning of terms that are explicitly defined in IEEE 1547-2018, shown in Fig, 1 and used throughout the standard, and that are important for utility protection engineers to understand:

Ride-through – ability to withstand voltage or frequency disturbances.

Permissive operation – DER may either continue operation or may cease to energize, at its discretion.

Mandatory operation – required active and reactive current delivery.

Momentary cessation – cessation of energization for the duration of a disturbance with rapid recovery when voltage or frequency returns to a defined range; sometimes also called “current blocking”; note the exceptions for reactive power exchange from passive devices as specified in Clause 4.5 of the standard.

Restore output – DER recovery to pre-disturbance output following a disturbance that does not cause a trip.

Trip – cessation of power output without immediate return to service; not necessarily disconnection

Return to service – re-entry of DER to service following a trip; equivalent to enter service or start-up of DER.

Fig. 2 illustrates that “cease to energize” is a state of the DER that applies both for momentary cessation during ride-through and for trip. The difference is that a ride-through operation is followed by a relatively fast restoration of DER output, but a trip must be followed by some intentional delay of DER return to service after both voltage and frequency have stabilized within specified ranges.

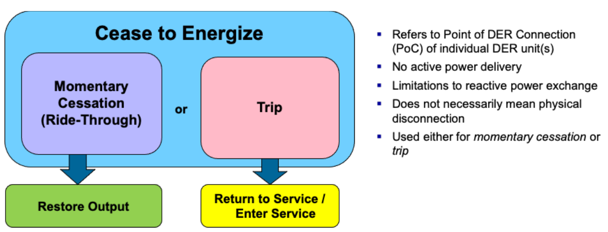


Figure 2: Illustration of the relationship between cease to energize, momentary cessation (ride-through), trip, restore output, and return to service / enter service performance as specified in IEEE 1547-2018

III. Protection Coordination

For DERs to interconnect and operate in parallel with the area electric power system (area EPS), i.e., distribution system, proper coordination of all protective devices is necessary. The protective devices’ settings should be designed to properly differentiate local faults from system disturbances on the bulk power system so that the devices do not trip necessary resources offline prematurely adversely affecting the reliability of the bulk power system.

The reaches of protective devices are impacted by the presence of DERs in distribution feeders, which results in increased fault current. Therefore, every device should be checked to verify that all protective devices can see faults only within their respective zones of protection and are still coordinated with each other.

As fault current from DERs increases due to high penetration, the fault current contribution from the substation feeder breaker decreases. Such a reduction in current contribution may result in desensitizing upstream protective devices, including the substation feeder relay, resulting in failure to trip, sequential tripping, or coordination problems. Such conditions require a detailed short circuit study to determine the minimum trip setting on the grid side and still achieve coordination to clear the fault. This issue is not limited only to the feeder that the DERs are on but also to adjacent feeders that are on the same substation distribution bus.

There are protective devices that need to be coordinated to allow the DER to ride-through system frequency and voltage disturbances without sacrificing the “Shall Trip” requirements of IEEE 1547-2018. Normally, PCC Protective Device are set to back up DERs and all other upstream protective devices should be set to serve as backups to the PCC Protective Device. Failure to coordinate these protective devices may lead to wide area tripping of DERs that adversely impacts the bulk power system.

This paper looks at the identified issues and provides information and mitigation strategies to allow the interconnection of DER on the distribution system.

IV. Short Circuit Considerations

The addition of DER to any feeder can have a substantial effect on short circuit values and their effect on protection systems. All DER have the potential of contributing to short circuit current. Inverters are usually limited in short circuit contribution by their design. Most rotating machines contribute a large amount of short circuit current for an extended amount of time. Ground fault currents are of particular concern since they are very common and affect many protection systems.

The effect of short circuits on the distribution system may be to desensitize or polarize protective relays which results in protective relaying not properly tripping. This miscoordination may also result in fuse melting, which can result in future false trips.

A. Causes of Short Circuits

Short circuits are typically caused in the distribution system when a phase conductor touches the ground or another phase conductor. In rare instances, all three phase conductors touch each other simultaneously. These conductors can be in cables, overhead lines, and equipment. Most short circuits on distribution lines are temporary due to the nature of the fault or protective devices clearing the fault.

The amount of short circuit current at the fault location is dependent on the contribution from DER, other generators, and the grid. It is limited by the impedance of the lines, transformers, and other equipment.

Short circuits are classified in the order of likelihood of occurring as single phase-to-ground, phase-to-phase, double phase-to-ground, and bolted three-phase.

Magnitudes of fault currents on distribution systems can typically range from 200,000 amperes down to less than 1 ampere. To properly protect equipment from extensive damage short circuits can cause, the clearing time for high current faults is less than a second, while lower current faults may have a clearing time of 5 to 10 seconds or longer. High current faults with an extended trip time may result in extensive damage and possibly an arc flash hazard.

In some cases, the level of additional short circuit current contributed by the DER may result in exceeding the short circuit rating of existing equipment. Even the limited contribution from inverters can create problems.

B. Technology

The contribution to short circuit levels by DER is dependent on the type of technology the DER incorporates. The most common technologies are synchronous machines, induction machines, and inverters.

C. Synchronous machines

Synchronous machines have the potential to produce a large amount of short circuit current. In some cases, the ground fault current can exceed the three-phase fault current. The three-phase fault current produced by synchronous machines is typically in the range of 5 to 8 times the full load current of the machine. This fault current level can typically be maintained for seconds or minutes unless a protective device shuts down the generator or the relevant circuit breaker.

Fault current from synchronous machines can have a large effect on the short circuit current levels experienced by equipment and protective devices.

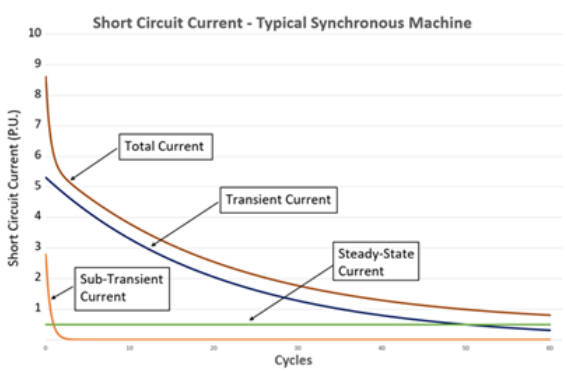
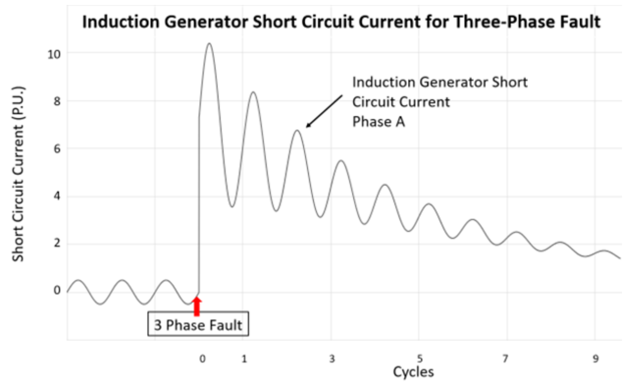


Figure 3: Synchronous generator short circuit components and total

D. Induction Machines

Induction machines have the potential to produce fault currents in the range of 5 to 8 times the full load current. However, they typically can maintain that level of fault current for only 1 or 2 cycles.

The short circuit current of induction machines usually does not have a large effect on short circuit currents in the grid and at any equipment.



Figures 4: Induction generator current for a three-phase fault

E. Inverters

Inverters typically produce little or no short circuit current. However, this limitation of fault current is based on the design of the inverter. Typical modern inverters produce short circuit current in the range of 100% to 120% of full load current. Historically inverter short circuit current has reached as high as 150% of full load current. The limitation of the short circuit current level is based on the limitation of the inverter to carry large currents and the inverter control system. The short circuit current produced by inverters can be limited in magnitude and can maintain the short circuit level indefinitely. Note that inverters do not produce zero-sequence current.

The control systems on modern inverters are designed to trip off the inverter within a few cycles of sensing a short circuit. This helps to minimize the effect of short circuits on the distribution system and associated equipment.

F. Fault Types and Effects

Bolted three phase faults have the potential of creating the largest fault current. This large fault current may result in the destruction of conductors and equipment as well as the DER itself unless it is properly controlled and protected against. If DER is contributing large amounts of fault current, it has the potential to desensitize protective relaying meant to protect the distribution feeder. The miscoordination between protective relaying and fuses may cause the incorrect protective device to trip. This type of miscoordination may also cause fuse melting that may cause future false trips on the distribution line.

Line to line faults have a lower magnitude but similar characteristics and issues as three phase faults.

1) Ground Faults

Ground faults have the potential to create differing levels of short circuit currents. However, the analysis of ground faults is more complex since distribution systems may have various ground sources. The addition of DER may create additional ground sources.

In these cases, the result may be the desensitization of protection systems. It is also possible that ground fault currents may have magnitudes that exceed expectations causing potential mis-coordination.

G. *Fault Duty*

Short circuit currents must not exceed the ratings of the equipment the current flows through. The addition of short circuit current from DER connected to distribution lines may result in a higher level of short circuit current. This additional short circuit current may, in some cases, cause the distribution equipment to have a short circuit level above its fault duty. This may be the case even if the DER are inverters.

V. Intertie Transformer Configuration and Area EPS Fault Detection and Clearing

Configuration of the intertie transformer that DER uses to interconnect to the distribution system has an impact on detecting open phases and phase to ground faults.

Most distribution networks are four wire grounded systems that require a wye grounded interconnection transformer on the grid side. However, in a case where the transformer has a Delta on the DER side or wye grounded with delta tertiary winding, the transformer becomes a source of zero sequence current during a phase to ground fault on the distribution feeder upstream of the DER. Unless taken out of the circuit at the inception of the fault, these transformers continue to be ground sources to the fault even in the absence of the DER behind them. Since such ground sources can contribute a significant amount of current (zero sequence current) to the fault (See Fig. 6 and 7), they may mask the fault from the substation breaker by lowering the contribution below the relay pickup or delay fault clearing operation of protective devices upstream of the fault. As depicted in Fig. 5, for a phase "B" to ground fault F between PCC and Mid-Line Reclosers, the waveform shown in Fig. 6 shows the fault current contribution, three times the phase currents, from the transformer with delta tertiary.

Therefore, it is essential to make sure the ground source transformer is modeled correctly for a detailed short circuit study to be able to determine the minimum fault current that needs to be detected and cleared by the upstream protective device and PCC Recloser in the fastest possible time.

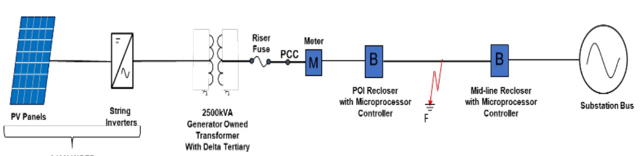


Figure 5 - Interconnection layout when a phase B to ground fault between POI and Mid-line Reclosers occurs.

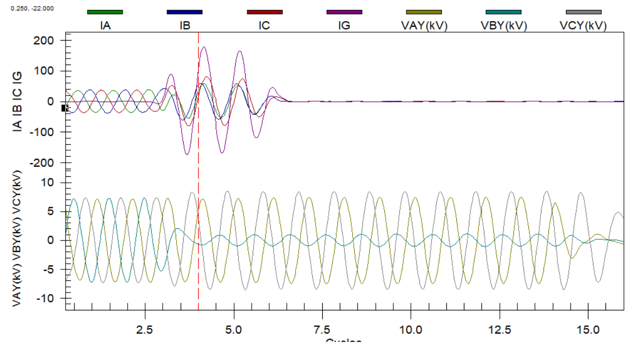


Figure 6 – Ground fault current contribution from a DER intertie Transformer

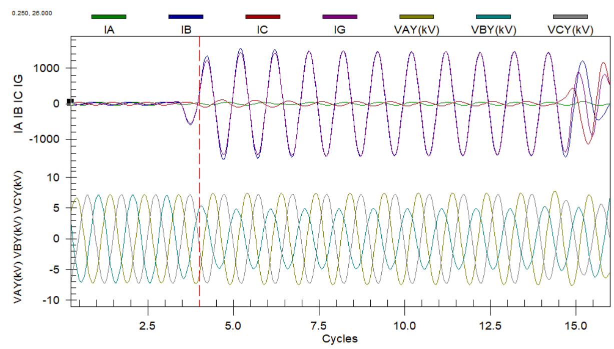


Figure 7 – Ground fault current contribution from the Grid side to the same fault in Fig.5

VI. Open Phase Condition Detection and Ceasing to Energize the Area EPS

Open phase is an abnormal system condition that occurs on distribution feeders for different reasons such as broken conductor, blown fuse, single pole recloser operation, etc. It is a condition that adversely affects distribution customers on the feeder that a DER is connected to if it is not detected and cleared in time. As described in IEEE 1547-2018 Clause 6.2.2, the DER is responsible for detecting any open phase at the Reference Point of Applicability (RPA) and stopping to energize the area EPS. Per IEEE 1547-2018, the RPA can be at the PCC, PoC or anywhere in between depending on the zero-sequence continuity and other factors.

To have an effective open phase detection, several areas of integrating the DER need to be addressed during the design and commissioning process. DER's detection of an open phase can be hampered by several circumstances, such as incorrect DER/protective relay settings, using a Delta-Wye grounded intertie transformer, or having a Delta-Wye transformer for station service or other purpose on the same bus that a DER is connected to.

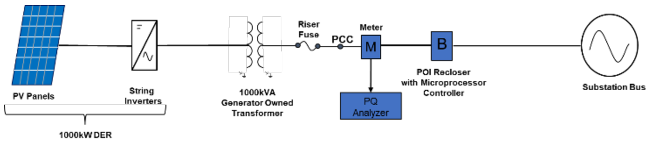


Figure 8 – Open Phase Witness Test Layout (Phase "A" opened at the Triple/Single POI Recloser)

Below are waveforms captured by the PQ Analyzer in the Open Phase Witness Test Layout in Fig. 8, which shows the response of the DER for an open phase at the PCC during witness testing (Figs. 9 and 10). In this case, the open phase was created at the PCC Recloser by opening one phase at a time.

As can be seen in the waveforms below, the DER was able to detect the open "A" phase and cease to energize the area EPS in 25 msec. It is also worth noting that all three phases did not carry any current while the open phase was there. These test setup and response waveforms are typical for a DER interconnected to a distribution system through a wye grounded – wye grounded intertie transformer.

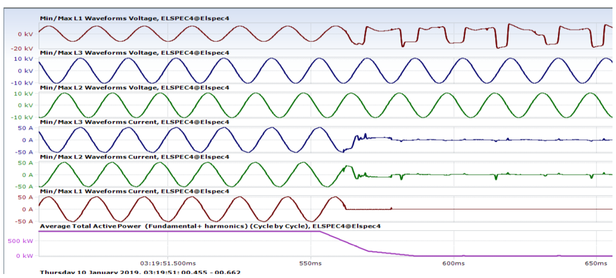


Figure 9 – DER response to open phase "A" at the PCC - Waveform capture

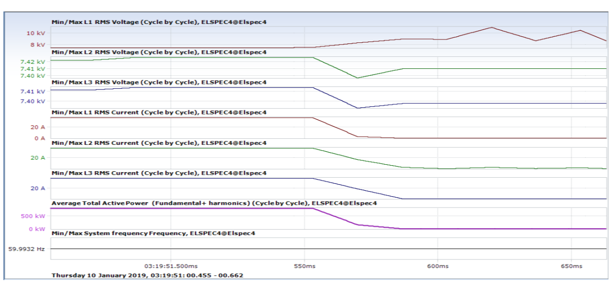


Figure 10 – DER response to open phase "A" at the PCC - RMS signals capture

However, in a case where a Delta-Wye grounded transformer on the bus is used for another purpose, the DER cannot detect the open phase. The voltage that should be affected by the open condition that the DER uses to detect the open phase condition is made up by the delta winding of the Delta-Wye transformer keeping the voltage unaffected. As shown in Figs. 11 and 12, the current through the open phase goes to zero, but the voltage stayed unaffected. As a result, the DER stayed online producing active power and energizing the area EPS.

Therefore, it is prudent for the DER to put the necessary open phase detection mechanism in place before integrating the DER with the area EPS.

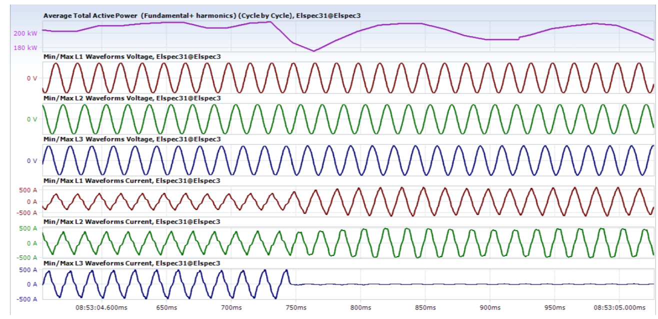


Figure 11 – DER response to the open "C" phase at the PCC (Current, Voltage and Power waveform capture)

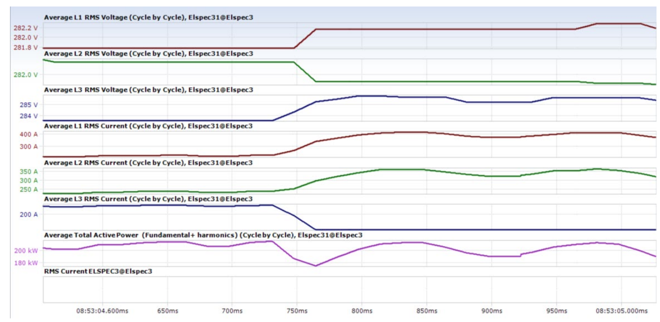


Figure 12 – Open "C" Phase at the PCC and DER response to the open phase (Current, Voltage and Power RMS signal capture)

VII. Ride-Through

IEEE 1547-2018 calls for both Frequency and Voltage ride-through of DER in response to disturbances on the Area EPS that are not occurring on the feeder or section of feeder the DER is connected to. It is important to note that the frequency ride-through settings apply to all types of DERs and coordinate with the frequency requirements of all the North American Coordinating Councils.

Ride-through requirements mostly impact the settings of a utility PCC device that uses frequency and voltage elements to detect issues at the DER, though protection at the feeder level may also be impacted. The protective functions often used at the PCC are phase shift, negative sequence, over/under frequency, and over/under voltage. At the PCC or feeder head, underfrequency or undervoltage load shedding schemes or rate-of-change-of-frequency (ROCOF) trip schemes can interfere with ride-through. The failure to coordinate with ride-through may result in widespread tripping of DER, possibly leading to system stability issues.

A. Guidance and Recommendations provided by IEEE 1547.2-2023

1) Frequency Protection

Over-frequency (81O) and under-frequency (81U) are typically used by the DER to meet the frequency requirements, aid with island detection and protection of the

DER. If the frequency trip settings are set per IEEE 1547-2018, they will not interfere with frequency ride-through. If using a PCC device to back up the DER, it is important to set the frequency trip wider than that of the DER in order not to impede the frequency ride-through of the DER.

Frequency is not normally used in feeder protection, but more likely used for underfrequency load shedding and can defeat the frequency ride-through. It is important to determine if the DER can provide support during a frequency event and if disabling load shedding on the feeder the DER is attached to is appropriate.

2) Voltage Protection

Overvoltage (59), undervoltage (27), and negative sequence voltage (47) are typically used by the DER to meet the voltage requirements, aid in anti-islanding function, and protection of the DER. Negative sequence voltage is used for alarming not tripping. If the voltage trip settings are set per IEEE 1547-2018, they will not interfere with the voltage ride-through requirements. Setting the PCC device with voltage settings wider than the DER voltage trip settings will not impede the voltage ride-through of the DER.

Voltage is typically not used directly in feeder protection but used for supervision and load shedding. The use of undervoltage load shedding can defeat the voltage ride-through of the DER. It is important to determine if the DER can provide support during a voltage event and if it is appropriate to disable load shedding on the feeder to which the DER is attached.

3) Current Protection

Overcurrent (50) and time-overcurrent (51) relays have little impact on DER ride-through.

Negative sequence overcurrent relays (46) should be avoided with DER, especially inverter-based DER that uses negative sequence response. Coordination with ride-through is very difficult.

Voltage time overcurrent relays (51V) are not recommended for use with ride-through of DER. Voltage time overcurrent relays are susceptible to operating on load currents during the voltage recovery period following a fault. In addition, voltage time overcurrent relays must be coordinated with the voltage trip requirements as to not impede ride-through.

4) ROCOF protection

Rate-of-Change-of-Frequency (ROCOF) is sometimes used to protect against unintentional islanding. The use of ROCOF can defeat the ROCOF ride-through of the DER. Any ROCOF relays will need to be disabled or desensitized, it should not impede the ROCOF ride-through of the DER.

5) Voltage phase angle jump/vector shift protection

Voltage phase angle jump/vector shift is typically used to protect synchronous generation-based DER and is not used in feeder protection. Thus, any vector shift relays present in feeder protection should be disabled or desensitized. At the PCC device vector phase angle jump/vector shift may be used to back up DER anti-islanding functions. If used, vector shift protection should be set to not impede voltage phase angle jump ride-through of the DER.

VIII. PCC Recloser and its application

Point of Common Coupling (PCC) reclosers are protective devices that some utilities use to tie DERs to the distribution system. This practice is more commonly used by utilities at the East Coast of the United States and less so by utilities at the U.S. West Coast. PCC reclosers used on DERs that have the capability of exporting 1 MW of real power and above. They are three-phase and/or single-phase operated devices with microprocessor-based protective and control relays. In some cases, depending on the type of transformer configuration that the DER uses to tie to the distribution system, DERs with less than 1MW capability may also be required to connect via PCC reclosers.

There are several reasons that utilities may employ PCC Reclosers to interconnect DER to area EPS: to implement temporary settings to support energized work on the feeder the DER is connected to, to have control of the interconnection during abnormal operating conditions such as during a storm, to provide additional or redundant protection against unintentional islanding, to implement DTT scheme, etc.

The protection functions in these devices are used to protect the distribution system and the DER. However, if the functions are not applied properly or without adequate coordination with the intent of DER ride-through requirements specified in IEEE 1547-2018, they may adversely affect the operation of the distribution system and the reliability of the bulk power systems. Thus, due diligence and coordination between distribution protection engineers and bulk system reliability planners is essential.

The pickup and time delay settings of 81, 59, 27, and other protective elements of the PCC Recloser should be set such that they back up corresponding settings in the DER (as shown in Fig. 13 below) and allow the DER to ride-through abnormal system conditions that are not faults on the feeder that the DER is connected to. In case of a fault on the feeder that the DER is on, the PCC recloser may/should trip to protect both the system and the DER. The example DER and PCC recloser settings shown in Fig.14 are coordinated with default settings for Category II DERs; note that less sensitive trip settings may be used to utilize the advanced ride-through capability of Category III DERs.

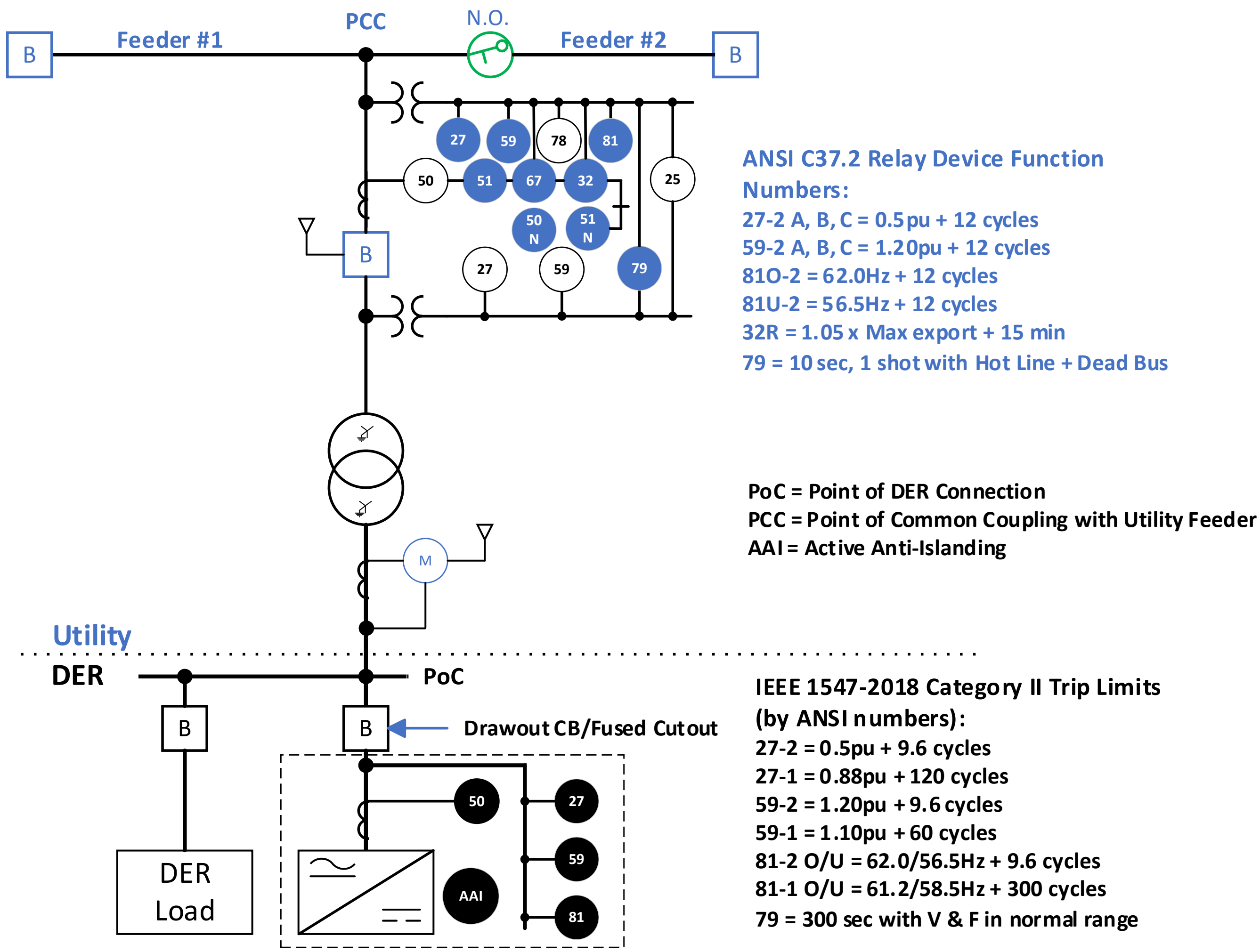


Figure 13: PCC recloser Application

IX. High Penetration

A. Islanding

1) Unintentional Islanding and Risks

Unintentional islands occur when a portion of the electrical power system remains energized through local DER after the normal utility power source is disconnected**.** Protection engineers and utilities are concerned about the safety, reliability, and adherence to frequency and voltage standards during unintentional islanding events.

2) Traditional Methods and Challenges:

Traditional methods involve evaluating the generation-to-load ratio within a potential island to screen for the risk of islanding. The 3-to-1 load-to-generation factor has been historically used for screening. This criteria is based upon the generally established practice that induction or synchronous generation will be unable to energize loads within the islanded portion of the Area EPS and still maintain frequency and voltage within acceptable limits.

Passive Anti-Islanding methods such as under/over frequency and under/over voltage protection were traditionally used, but they may be less suitable with the rise of Inverter-Based Resources (IBR) DER.

3) Islanding Detection Techniques:

Islanding detection techniques are classified as passive or active. Passive methods rely on monitoring DER voltage, frequency, or vector jump/vector shift parameters, while active methods involve more sophisticated detection mechanisms.

Passive methods are simple but may have non-detection zones. Active methods are less impacted by load-to-generation ratios but can interact in complex ways, potentially leading to sustained unintentional islands.

B. *Ground Fault Overvoltage and Load Rejection Overvoltage for High-Penetration of DER*

There are challenges associated with the integration of Distributed Energy Resources (DERs), particularly inverter-based resources (IBR), in power distribution systems. Two specific concerns addressed are Ground Fault Overvoltage (GFOV) and Load Rejection Overvoltage (LROV).

Physics and control differences between conventional voltage-controlled sources (rotating generators) and current-controlled sources (inverters) contribute to the challenges. Inverters exhibit high positive-sequence impedance, negative-sequence impedance that is highly dependent on the inverter control algorithm, and don't produce zero-sequence impedance.

1) GFOV, LROV and IBRs

GFOV and LROV risks depend on DER technology characteristics, external ground sources, and the characteristics of the remaining load during island conditions. Overvoltage evaluation is more complex for current-regulated sources like inverters, especially during islanded conditions. This may include requirements to perform more dynamic time-domain simulations utilizing Electromagnetic Transients Programs (EMTP). LROV is an overvoltage condition that is not affected by neutral grounding, while GFOV is an unbalanced overvoltage that is influenced by the type of system grounding during a ground fault. Grounding is effective in mitigating GFOV but does not significantly impact the positive- and negative-sequence components of LROV. These distinctions are crucial for understanding and addressing overvoltage issues in power systems. The risk of overvoltages for inverter-based DER is typically limited to *island* conditions.

2) GFOV Concerns

GFOV is a significant concern during unintentional islanding with ground faults. Increased penetration of DER in a power system raises concerns about sustained island conditions, which can compromise system grounding and lead to overvoltage on unfaulted phases during ground faults. Inverters' unique characteristics, such as high impedance and lack of a traditional ground source, make traditional approaches less applicable. Overvoltage protection in inverters generally limits the duration of GFOV during islanded conditions. GFOV is an unbalanced overvoltage condition. Unlike LROV, GFOV is influenced by the type of system grounding during a ground fault. Grounding is effective in mitigating GFOV, but it does not significantly affect the positive- and negative-sequence components of LROV.

LROV Issues

LROV can occur in situations where the DER suddenly transitions from grid-connected to islanded operation (disconnected from the main grid), it continues to output regulated current. However, since it's no longer connected to the grid, the source impedance rises, potentially causing a rise in terminal voltage. This increase in voltage is what's referred to as Load Rejection Overvoltage (LROV).

This scenario highlights the importance of having protective measures in place to prevent excessive voltage rise and ensure system stability during load disconnections or transitions between grid-connected and islanded operation.

LROV associated with inverters can damage line-to-ground-connected equipment and require proper sizing of utility equipment like surge arresters. The issue is limited to inverters certified to IEEE 1547-2018, which includes high-speed overvoltage tripping. LROV is generally a balanced overvoltage condition that contains primarily positive sequence components but may also have some negative sequence components that is produced by the inverter. This type of overvoltage is not influenced by the type of neutral grounding in the system. The positive- and negative-sequence components of LROV are typically the largest components.

3) GFOV and LROV Mitigation Strategies

For GFOV, grounding considerations and DER control tuning are discussed. The role of grounded load is also highlighted. GFOV relaying detection associated with zero-sequence voltage is commonly known as 59N (Ground Overvoltage Element) or "$3V_0$" protection. This type of relaying is specifically designed to protect against Ground Fault Overvoltage (GFOV). The neutral shift or unbalance in the system is three times the zero-sequence voltage component. In summary, the 59N or "3V0" detection relay is crucial for protecting against GFOV in DER systems, especially in scenarios where the DER is ungrounded. GFOV protection may include either $3V_0$ (Protective Device Function 59N) or phase overvoltage protection (59), which may trip a protective device or send a transfer trip to the DER. The use of $3V_0$ (59N) and phase overvoltage (59) protection schemes may be utilized to directly trip protective devices to disconnect or isolate the DER or other equipment in response to detected overvoltage conditions. Other $3V_0$ (59N) and phase overvoltage (59) protection schemes may initiate a transfer trip signal to the DER.

Availability of sufficient line-neutral connected load can be a solution for overvoltage issues. The presence of effective grounding through connected loads is beneficial, but relying on it may not always be feasible due to the dynamic nature of distribution systems. Different transformer winding configurations that do not accurately indicate primary line-neutral voltages can also impact the ability to mitigate GFOV.

LROV is mitigated through faster tripping times and transfer trip mechanisms. Consideration of potential side effects of overvoltage mitigation strategies is crucial.

In summary, the considerations for DER-related overvoltages are complex and depend on factors such as DER technology characteristics, external ground sources, and the presence of rotating generators. While conventional analysis practices are well-defined for certain DER types, specific recommendations and alternate analysis procedures are provided for current-regulated sources like inverters to ensure accurate assessments, especially during islanded conditions.

C. Reverse Power Flow

Feeders with high penetration of DERs potentially experience reverse power flow when generation exceeds the available load in a specific section of the feeder, feeder head, or at the substation transformer level that is normally fed from the transmission system. Reverse power flow impacts how protection schemes are implemented and work, distribution devices perform, switching is done, and loads are transferred. Therefore, areas impacted by reverse power need to be addressed appropriately.

Therefore, such a situation requires a $3V_0$ protection scheme explained in the Mitigation Strategies section for GFOV and LROV on the high side of the substation transformer to detect transmission phase-to-ground faults and be able to take the DER offline.

D. Protection Mitigation Methods for High Penetration

- Direct Transfer Trip (DTT) involves sending a trip signal from a utility device to the DER location to isolate it. Implementation costs, including communication, can be high.
- Distribution Power Line Conducted Permissive Signal (DPLCPS)**:** Utilizes the distribution system as a communication channel, offering advantages over traditional DTT but has limitations in signal propagation.
- Wide Area Protection Using Synchrophasor Data**:** Proposes using Synchrophasor data to detect unintentional islands across a wide area. It is still in early adoption and faces cost and performance challenges.
- Other Protection Schemes**:** Grounding switches and capacitor switching at the utility level are mentioned, with grounding switches inducing three-phase ground faults to trip DERs.
- Reclose Blocking: Prevents reclosing into an island, and the Area EPS operator can consider extending reclosing times for DER to trip first.
- $3V_0$ (59N): Protects against GFOV on the high side of the substation transformer, may trip feeder or use transfer trip.

X. Conclusion

This paper discussed some of the increasing impacts of the policy- and market-driven deployment of distributed energy resources (DERs) on the planning, protection, and operation of distribution and bulk power systems. The objective of this paper was to inform utility protection engineers of improved practices to protect the distribution grid in coordination with bulk power system reliability needs.

The paper reviewed some of the technical minimum capability and performance requirements for interconnection and interoperability of DER (systems) with the distribution grid as specified in IEEE 1547-2018 to meet the challenges of high DER penetration futures. The paper reviewed the specific behavior of inverter-based DER in response to and during faults on the distribution and bulk power system. It also discussed open phase condition detection, potential use cases for PCC reclosers with backup protection settings, and some high DER penetration opportunities and challenges like islanding, ground fault overvoltage and load rejection overvoltage, and reverse power flows. It is time that utility protection engineers recognize the capabilities and performance of DERs and their potential impacts, even for areas where DER penetration levels are currently still moderate. By embracing the necessary coordination needs of distribution protection schemes to support the integration of DER, utility protection engineers can prepare for and reduce technical barriers for the ongoing transformation of modern power systems. Further guidance on related topics is provided in IEEE 1547.2-2023, a new Guide for Application of IEEE 1547-2018 that is expected to be published in 2024 and that is recommended for further study.

References

[1] IEEE Std 1547™-2018, IEEE Standard for Interconnection and Interoperability of Distributed Energy Resourceswith Associated Electric Power Systems Interfaces

[2] IEEE Std 1547.2™-2023, IEEE Appliction Guide for IEEE Std 1547™, IEEE Standard for Interconnection and Interoperability of Distributed Energy Resourceswith Associated Electric Power Systems Interfaces