Direct Transfer Trip With Distributed Energy Resources, and Alternatives

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EXECUTIVE SUMMARY

Direct Transfer Trip (DTT) is a technology commonly used in power systems that can be energized from more than one location, to ensure that power circuits can be disconnected from all sources of energization when required. Most North American distribution circuits are designed to be energized only from one point. However, when Distributed Energy Resources (DERs) are deployed on these circuits, the circuits can be energized both from the grid and from the locations of the DERs. It is then necessary to ensure that these circuits can be de-energized from all locations, and DTT is a logical alternative for doing so. However, DTT is a relatively high-cost option, both in terms of initial capital cost and ongoing maintenance costs, and it has certain properties that make it undesirable in the DER application, such as the fact that it is generally point-to-point. There is thus a need for alternatives to DTT that have lower cost but still can perform the basic function of ensuring that power circuits are fully de-energized when required. Several such alternatives exist, including DTT using lower-cost communications channels; power line carrier permissive; and unintentional islanding detection resident in the distributed energy resources. Undervoltage relaying backed up by unintentional islanding detection (UV + UID) is the lowest-cost option that provides the required functionality. UV + UID may be considered as a DTT alternative, while recognizing that a) UV + UID does not have the same speed as DTT in all cases, and b) UV + UID makes the utility operator dependent on third-party equipment for ensuring complete circuit de-energization, so there may exist situations in which DTT would still be preferred.

This report also provides a brief description of an updated risk-of-islanding screening procedure that can be utilized by utilities to help assess when the unintentional islanding detection functions built into distributed energy resources can be relied upon to perform that function.

ACRONYMS AND DEFINITIONS

Abbreviation	Definition
DER	Distributed Energy Resource
DTT	Direct Transfer Trip
GDSS	Geographically Dispersed Sources and Storage
GFL	Grid Following
GFM	Grid Forming
IBDER	Inverter Based Distributed Energy Resource
PLCP	Power Line Carrier Permissive
UID	Unintentional Islanding Detection
UV	Under Voltage
VSR	Voltage Supervised Reclosure

1. INTRODUCTION

1.1. Understanding power system circuit diagrams

It is often helpful to visualize an electric power system using a simplified diagram. Figure 1 shows what is called a three-line diagram of a power system.

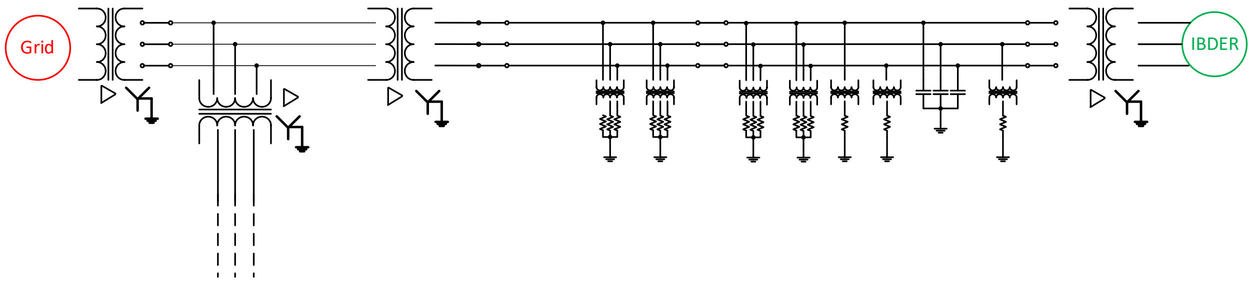

Figure 1. Three-line diagram of a distribution circuit.

Utility engineers often use this and similar diagrams to discuss the various reasons why direct transfer trip and other techniques are used, so it is important to have a basic understanding of such diagrams. Some of the symbols in the diagram may be unfamiliar to those of us who are not power engineers, so we will first walk through and explain this diagram.

The power system includes the large generation stations that provide power, and the high-voltage long-distance transmission network that moves the power cross-country from the generators. This portion of the system is usually lumped together and referred to as “the grid”. This “grid” is everything in the purple box in Figure 2.

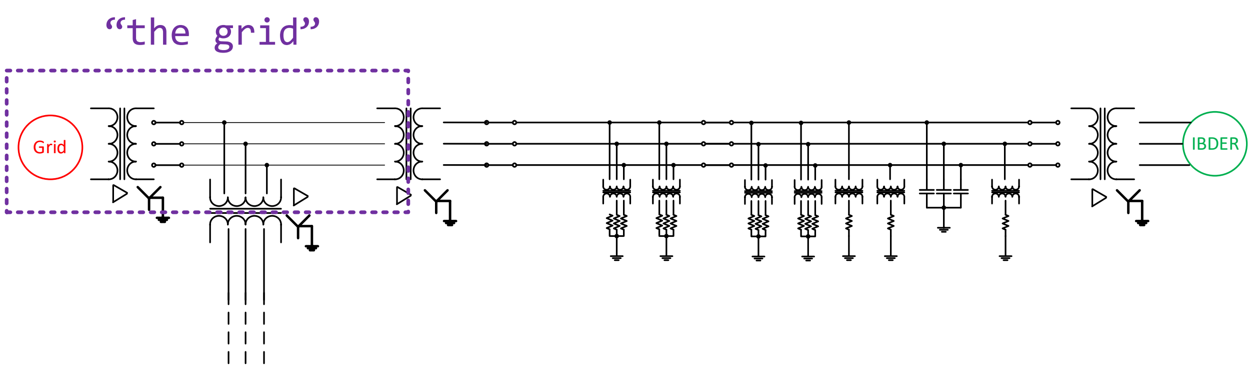

Figure 2. Everything between our example distribution circuit and the large generating stations that supply power is “the grid”, shown in the purple box at the left.

One crucial component of power systems is the transformer. Transformers are used to step voltages up and down, and there are *many* of them in a typical power system. Transformers step generator voltages up to the high voltages used in long-distance transmission. Other transformers step that voltage back down to the levels used to distribute power to end customers, and yet more transformers step the voltage from the power distribution system down to the levels users find at their electrical outlets. The symbol for a transformer is shown in Figure 3.

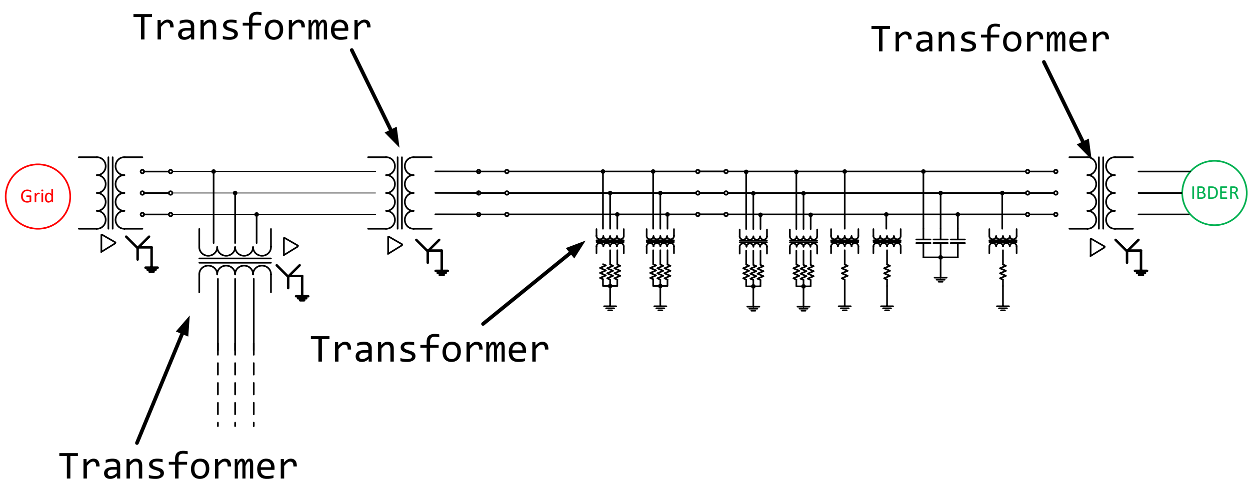

Figure 3. Transformers.

In an electrical diagram, homes, businesses, and everything else to which the system is supplying power is called a "load". Loads are represented by the electrical symbol circled in red in Figure 4.

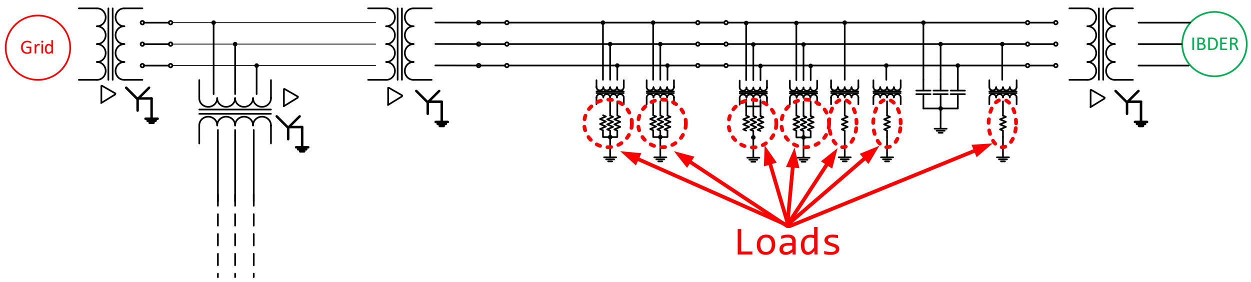

Figure 4. Loads.

Utility operators will often use a device called a capacitor to help regulate the voltage on a distribution circuit, especially on long ones. A capacitor is shown in Figure 5.

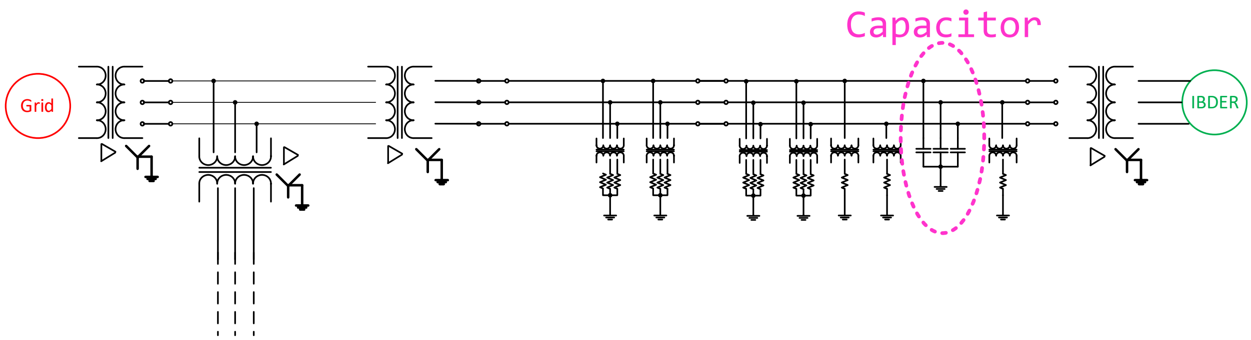

Figure 5. Capacitor.

It is often necessary to electrically disconnect parts of the power system. There are many different types of devices that do this, including circuit breakers, reclosers, switches, sectionalizers, and fuses. These all have different operational functions and characteristics, and many have their own circuit-diagram symbols. For purposes of this discussion, the locations of isolation devices will be indicated by switches, as shown in Figure 6.

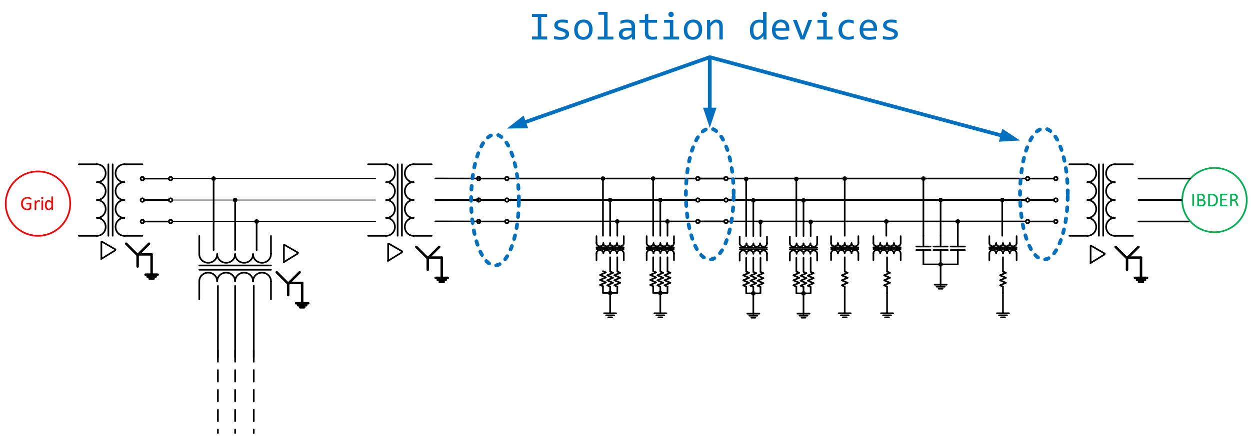

Figure 6. Isolation devices, such as circuit breakers.

The discussion that follows primarily concerns the interconnection of Distributed Energy Resources (DERs) with distribution circuits. DERs can be subdivided into two types: rotating machine-based DERs, and Inverter-Based Distributed Energy Resources (IBDERs). The green circle at the far right of Figure 6 is an IBDER.

1.2. The engineering need: fully de-energizing circuits that can be energized from more than one location

The vast majority of distribution circuits in North America were designed to be energized only from one point (where they connect to "the grid"). Such circuits are described as "radial". In a radial circuit, when the utility breaker opens, the rest of the circuit is de-energized because at that point there are no energization sources connected to it. Adding DERs to a radial distribution circuit changes that situation; these circuits can now be energized from more than one location. In this case, when the utility breaker opens, it is important that all of these DERs also cease to energize the host distribution circuit[1], for reasons of safety, avoidance of asynchronous reclosure, and avoidance of abnormal voltages, among others.

The speed with which this has to happen depends on a variety of factors, as is discussed in more detail in Section 2.6 below. The connection to the grid generally opens only when something goes seriously wrong on the distribution circuit, such as a fault that can create significant risks of fire, explosion or electrocution, so in general, the faster the circuit can be fully de-energized, the better. During the research leading to this document, speed-of-response requirements from different utilities with different system characteristics were found to vary from as little as 160 ms to as much as 5 s. It is thus desirable that any technology used to de-energize a circuit from all endpoints would be capable of doing so in 160 ms.

[1] If some portion of a distribution circuit is designed for intentional-island (microgrid) operation, then as long as the system has been appropriately designed and permitted and there is not a fault in that portion of the circuit, entering the intentional-island mode can be substituted for ceasing to energize.

1.3. Direct Transfer Trip

Direct Transfer Trip (DTT) is a technique in which when one circuit breaker is opened, a command is sent from that circuit breaker to a second breaker to open that second breaker. This is shown in Figure 7: the trip of the first circuit breaker, B1, is "transferred" to the second, B2, over a direct communications pathway.

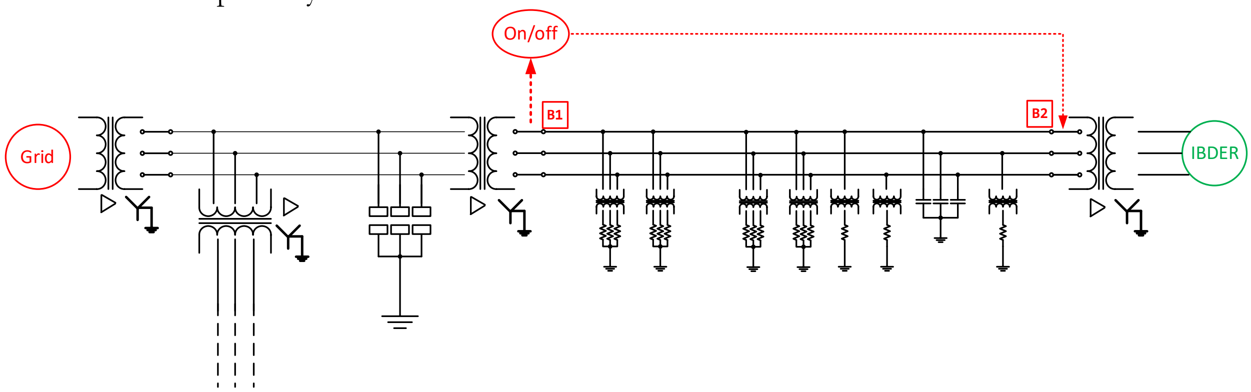

Figure 7. Representation of a direct transfer trip scheme between breakers B1 and B2. This system includes a transmission or subtransmission section at the left, and a three-phase distribution circuit that serves loads and hosts an Inverter-Based Distributed Energy Resource (IBDER), in green at the far right of the figure.

DTT requires that there be a communications channel between the two circuit breakers. In theory, any communications channel can be used, but to obtain high speed and reliability, power system operators often require that the DTT signal be transmitted over a dedicated hard-wired circuit, such as a telephone or fiber optic line.

DTT is a mature technology. It is widely used, suitable equipment is readily available from multiple vendors, and it is highly reliable. Also, DTT is very fast. The total operation time of DTT is the time required for the logic at B1 to issue the trip command, plus the transit time over the DTT channel from B1 to B2, plus the response time of B2. The time between an event occurring and the logic issuing an 'open' command to B1 depends on the specifics of the event and the settings used in B1, and can be less than 50 ms under faulted conditions. Once the B1 logic issues the trip command, the other two items require only a few milliseconds.

So, DTT can provide the needed functionality and can meet the speed requirement. Unfortunately, DTT has some shortcomings in the DER application.

- DTT has a relatively high capital cost[2]. DER installations generally tend to be fairly cost-constrained, so these DTT costs are often burdensome for DERs.
- DTT has a non-negligible ongoing maintenance cost. In some cases, utilities obtain DTT communications services from a third party, and this has an ongoing subscription cost.

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[2] The cost of DTT installation can vary widely depending on the communication medium and the utility involved. A 2019 NREL project reported average installation costs ranging from $122,000 to $275,000 (https://data.nrel.gov/submissions/101). PG&E estimates upgrades at approximately $610,000 per project (https://www.pge.com/assets/pge/docs/about/doing-business-with-pge/unit-cost-guide.pdf). In New York, costs range from $25,000 for radio communication to $410,000 for fiber (JU - Upgrade Cost Matrix Combined V3 (July 2024)). Dominion Energy in Virginia estimates substation relaying equipment at around $250,000, with fiber installation costs between $150,000 and $250,000 per mile (https://www.washingtonpost.com/dc-md-va/2024/05/27/solar-panels-dominion-energy/).

- DTT is typically point-to-point, meaning that there needs to be a DTT circuit from each utility breaker to each affected DER. If there is a large number of affected DERs, the DTT situation can become complex and "messy".
- DTT will not operate if breaker B1's logic does not issue a trip command. There are several situations in which this could happen. One such situation occurs when a breaker is opened that is not part of the DTT scheme. For example, Figure 8 shows a system with DTT between two distribution circuit breakers B1 and B2, and a transmission-level circuit breaker TB1", highlighted in yellow at the left in Figure 8. Opening TB1 will not result in a DTT signal from B1 to B2. If opening of B2 is desired in this situation, then *another* DTT circuit from TB1 to B1 is required.

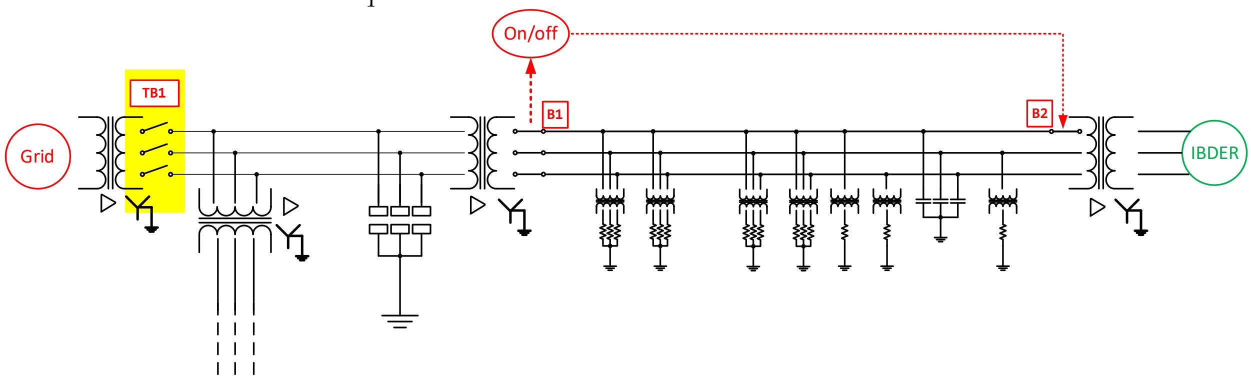

Figure 8. Case in which breaker B1 is equipped with DTT, but a different breaker (TB1, highlighted in yellow) is opened.

Because of these shortcomings of DTT in the IBDER application, it is desirable to have alternatives to DTT that allow IBDERs in distribution circuits to "know" when the utility breaker has been opened and reliably de-energize the distribution circuit in that case. In the sections that follow, this report explores some potential alternatives to DTT and discusses their pros and cons.

2. ALTERNATIVES TO DTT FOR APPLICATION WITH IBDER

In this section, we consider some alternative methods that perform the basic function of ensuring that the distribution circuit is de-energized when the utility breaker opens.

2.1. Lower-cost and point-to-multipoint DTT

The cost of DTT is a moving target, with several identified approaches to lower-cost implementations. Utilities commonly require fiber-optic communications to implement DTT. Fiber is extremely fast and highly reliable, but it is also the key driver of the high cost of DTT. Radio-based DTT, usually using the 900 MHz band and commonly employing spread-spectrum techniques to avoid interference, and 5G cellular-based DTT are both commercially available, and some utilities are fielding these systems today[3]. Experience to date suggests that these systems can implement DTT at typically half to two-thirds of the cost of fiber-based DTT[4]. Also, it is sometimes possible to create wirelessly networked DTT systems that are point-to-multipoint, using a protocol like IEC 61850, allowing one breaker's status to be communicated to multiple DERs. This could spread the overall cost of DTT over several DERs, significantly decreasing the cost per DER.

Radio-based DTT usually requires clear line-of-sight communications, so it cannot always be used. Cellular-based DTT has historically struggled with less-than-desirable reliability, leading to excessive downtime of the IBDERs. Utility experience reported during this i2X project has been mixed; some have had success with cellular DTT, but many have experienced that the reliability of these systems is still too low.

2.2. Undervoltage relaying coupled with unintentional islanding detection

The required functionality of ensuring that all DERs are offline when the main utility breaker (B1) opens can be provided by a combination of undervoltage relaying, specifically the "UV2" function required by IEEE 1547-2018 and modified by IEEE 1547-2020a; and DER-resident unintentional islanding detection (UID), which is also required by IEEE 1547[5].

2.2.1. Undervoltage relaying and the UV2 function

IEEE Std 1547-2018 requires that all DERs have undervoltage (UV) relaying functions that disable the DER if the voltage becomes too low. The standard describes different performance categories that use different settings for these UV functions. In "Abnormal Performance Category III", if a relevant voltage falls to less than 50% of the nominal value of that voltage, then by default an undervoltage function called "UV2" is required to cause the IBDER to cease to energize. In IEEE 1547-2018, UV2 was required to act within 2 seconds, but it quickly became clear that it would be desirable to allow DERs to get offline faster than this for such low voltages because voltages in that range typically indicate a local fault. To that end, IEEE 1547-2018 was amended via IEEE 1547a-

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[3] For example, see "New Intelligent Direct Transfer Trip Over Cellular Communication", IEEE Conference for Protective Relay Engineers, March 2019, https://ieeexplore.ieee.org/document/8765861.

[4] This figure is from private communications with representatives of utilities who have used these techniques, gathered during this i2X project.

[5] Manufacturers have implemented these capabilities into their DER equipment so that they can meet the IEEE 1547-2018/2020a requirements. This means that these capabilities are generally available in all new DER plants in all jurisdictions, regardless of whether a jurisdiction has yet officially adopted 1547-2018.

2020[6], which allows a utility to specify a UV2 time as low as 160 ms from the onset of the undervoltage. The UV2 function is tested as part of third-party certification under UL 1741. Thus, for cases in which the voltage drops below 50% of nominal, UV2 is a substitute for DTT—it provides the required functionality and meets the speed requirement.

2.2.2. Backup by the UV1 function

DERs are also required to have another undervoltage function, "UV1", that acts for higher voltages but in longer times than UV2 (in other words, UV1 and UV2 implement a discrete time-undervoltage function). According to IEEE 1547a-2020, under Abnormal Performance Category III, UV1 can be set to cause the DER to cease to energize in 2 seconds for voltages between 50% and 88% of nominal.

2.2.3. Backup by the unintentional islanding detection function

On top of the UV2 and UV1 functions, IEEE 1547 requires that DERs detect that a utility breaker has been opened to isolate it from the grid and to cease to energize the distribution system within 2 s, even if the voltage does not decrease at all. This is achieved via Unintentional Islanding Detection (UID).

2.2.3.1. A brief primer on unintentional islanding detection in grid-following DERs

Most IBDERs are operated in what is called a grid-following (GFL) mode, meaning that the IBDER derives its reference signal from the voltage at its terminals and thus "follows" that voltage. From the perspective of the distribution circuit, these IBDERs appear as current sources whose amplitude, and phase angle relative to the voltage, are controlled to maintain a specific active (P) and reactive (Q) power output.

When the utility breaker is closed, as shown in the top picture in Figure 9, the distribution circuit has two current sources: a current i_{grid} flows from the grid at the left, and a current i_{DER} flows from the IBDER at the right. When the utility breaker opens to form an island, as shown in the bottom picture in Figure 9 (the island boundary is shown by the dashed red box), the current i_{grid} becomes zero and the only current into the distribution circuit is i_{DER}. If prior to opening the breaker the current i_{grid} was nonzero (in other words, the island's active or reactive loads and generation are not exactly matched), then when the breaker opens there is a change in the island voltage that can indicate to the DER that the utility breaker has opened. The DER can then safely de-energize the circuit. This mechanism is the basis for UID by IBDERs.

UID can be passive, in which case the UID simply watches for the aforementioned change in the island voltage and uses that to detect island formation. However, nearly all grid-following IBDERs on the market today augment the passive UID with an active UID technique that acts to actively exacerbate the change in island voltage that occurs when the island is formed. When active UID is used, the formation of an island can be detected even when the current i_{grid} prior to breaker opening is extremely small. In this way, UID can perform the same function of "transferring the trip" from the utility breaker to the DER. It is also important to note that when a fault is present, the fault will

[6] IEEE Std 1547a-2020, "IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces Amendment 1: To Provide More Flexibility for Adoption of Abnormal Operating Performance Category III", March 2020.

typically drive the voltages on the distribution circuit to low levels[7]. IBDERs will also cease to energize their host circuits when these low-voltage conditions are detected.

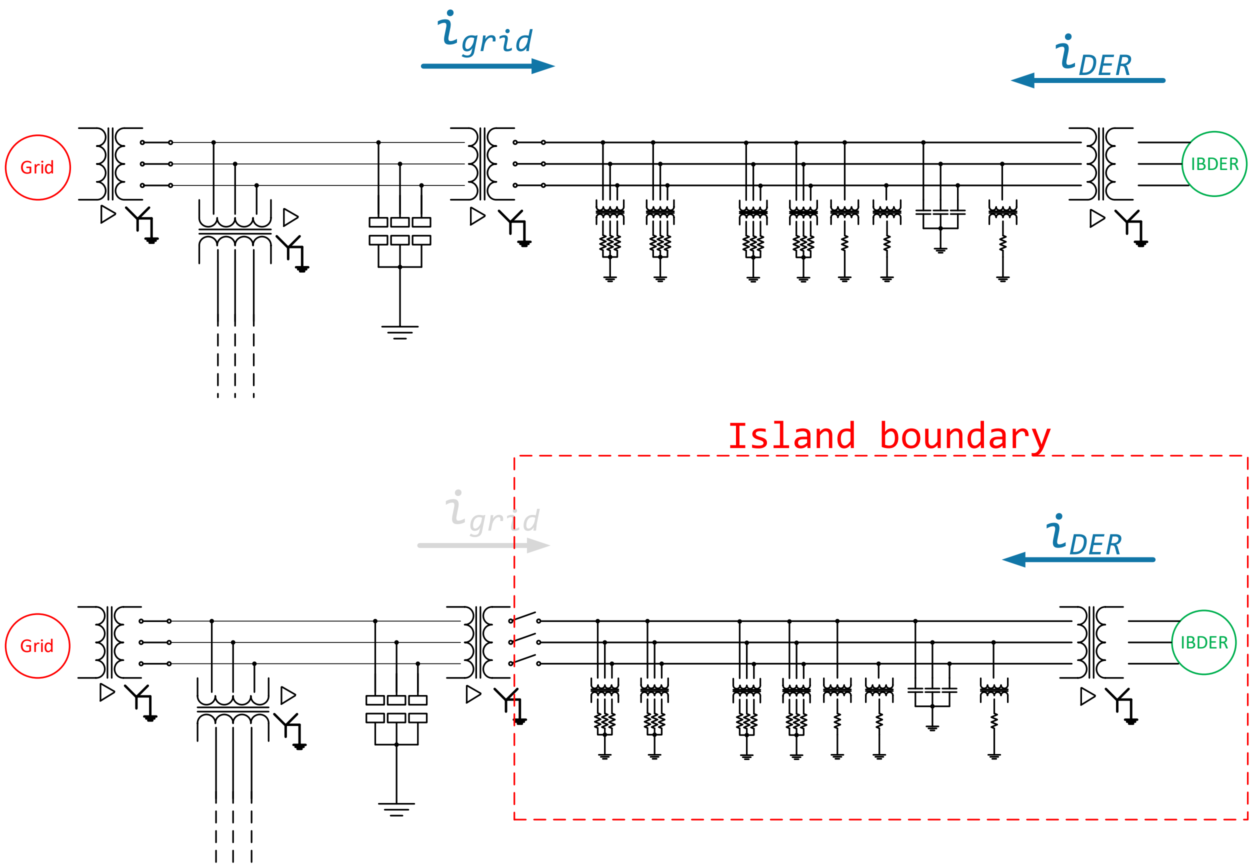

Figure 9. Distribution circuit with an IB DER. Top: utility breaker closed. Two currents, the current from the grid (i_{grid}) and the current from the IBDER (i_{DER}) are indicated by the labeled blue arrows. Bottom: utility breaker opens to form an island (island boundary shown by the dashed red box).

2.2.3.2. UID requirements in IEEE 1547

IEEE Std 1547-2018 sets requirements for the performance of UID. According to this standard, a DER is required to have the capability to detect formation of an island and de-energize its host distribution circuit within 2 seconds. Additional controls or measures may be required to prevent asynchronous reclosure, especially in a situation in which the DER is on a circuit with a first reclose interval shorter than 2 seconds. IEEE Std 1547.1-2020 lays out a protocol for testing the UID functions in DER equipment, and this IEEE Std 1547.1-2020 protocol has been adopted by the DER certification standard UL 1741. Thus, a DER that is certified to UL 1741 has been tested to ensure that it has this UID function and that the function meets certain performance requirements.

[7] This may actually become more true as the system becomes more dependent on IBDERs, because IBDERs are fault-current-limited and allow the voltage to collapse once they reach that limit.

2.2.3.3. UID in grid-forming DERs

Many in the industry have expressed a concern that the use of grid-forming (GFM) controls in IBRs might compromise the UID capability of these DERs. NERC[8] and the UNiversal Interoperability for grid-Forming Inverters (UNIFI) Consortium[9] use the following definition for grid-forming controls:

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GFM IBR controls maintain an internal voltage phasor
that is constant or nearly constant in the sub-
transient to transient time frame.
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This means that a GFM IBR maintains an internal voltage phasor reference that behaves similarly to the internal EMF in a synchronous generator. This property gives GFM inverters some desirable properties when they are connected to the grid, although it should be borne in mind that fault current limitations, inertial energy storage, and other physical considerations are not automatically or directly addressed by GFM controls.

Grid-forming controls have already been shown to have significant beneficial on-grid impacts and are likely to come into widespread use. It is thus important to determine the compatibility between active UID methods and GFM controls. At this time, relatively little study of this issue has been conducted. Preliminary results[10] have suggested that active UID can still be used effectively with GFM controls, but they may respond more slowly. The data set presently available is still too small, and more study of this topic is needed.

2.2.4. Pros and cons of UV + UID as a substitute for DTT

UV backed up by UID (notated "UV + UID" here) is a much less expensive option than DTT because UV + UID is already required to be built into the DER, and they have essentially no ongoing maintenance costs. However, UV + UID has some disadvantages relative to DTT.

- UV + UID consistently and predictably meets the 160 ms time requirement only when the voltage drops below 50% of nominal, triggering UV2. There are cases in which the utility breaker might open without the voltage dropping below 50% of nominal. These cases are covered by UV1 and UID, which act within 2 seconds.
- Legacy DERs designed to a standard that predates IEEE Std 1547-2018 will have the UID functions, but they may not have a UV2 function with the above-described capability. UV2 can be added externally, but this adds cost, and it may not consistently act in 160 ms.
- If the current i_{grid} in Figure 9 is "exactly" zero prior to opening the breaker (in other words, if the active and reactive power sources in the island are sufficiently closely matched to the active and reactive loads within the island), then opening the utility breaker results in no change in current flow and there is no change in the island voltage. Thus, there is a small range of non-faulted cases called a "nondetection zone" (NDZ) in which inverter-resident UID may take a long time to detect, and in some cases may not detect island formation at

[8] North American Electric Reliability Corporation Technical Report, "Grid forming technology: Bulk power system reliability considerations," Atlanta, GA, USA, 2021.

[9] "UNIFI Specification for Inverter-Based Grid Forming Resources", v.2, March 21, 2024, https://www.nrel.gov/docs/fy24osti/89269.pdf.

[10] M. Ropp, Sandia National Laboratories, unpublished data.

all. However, a) there are no fault cases that fall within the NDZ *and* lead to opening of the utility breaker, and b) when active UID methods are employed, the definition of "exactly" zero can be made so small that the probability of encountering it in the real world is remote. It has been demonstrated that under practical conditions, IBDER-resident UID typically operates in much less time than the 2 s allowed by IEEE Std 1547-2018[11].

- Each DER equipment manufacturer uses a proprietary UID method. Some of these methods are more effective than others, and it can sometimes be difficult to determine the effectiveness of a specific manufacturer's method without an electromagnetic transient study using detailed DER models. Furthermore, when there are multiple DERs, many of these methods are compatible, but some UID methods may interact with each other in unfavorable ways that degrade their effectiveness[12]. Some utilities have addressed this factor by requiring that only DERs equipped with specific UID methods be allowed to interconnect within their territories[13].
- There is also a potential future issue connected with widespread reliance on inverter-resident UID. Positive feedback-based DER-resident UID works by destabilizing the power system to which it is connected. At sufficiently high penetration levels, DERs may come to dominate the power system even when on-grid, in which case this destabilization effect would lead to degradation of the whole system's transient response. The penetration level at which this could become a problem has not yet been fully quantified, but initial results suggest that it is probably higher than 50%.
- While UV1 and UV2 can be implemented in utility-controlled equipment, active UID methods cannot, because they are part of the internal controls of the DER. Thus, utilities are sometimes reluctant to rely on UID because they lack control over and visibility into this function as settings and software are changed over time[14].

2.3. Power line carrier permissive

Power line carrier permissive (PLCP) is a technique in which a communications signal is sent over the distribution circuit's power conductors and is used as a continuity test of the circuit. Loss of this signal indicates a loss of continuity of the line and signals the DER to de-energize. Figure 10 illustrates PLCP. There is a transmitter, TX, that injects a signal into the distribution circuit's power conductors. This signal may be high frequency (much greater than 60 Hz), or subharmonic (less than 60 Hz). Both types are commercially available. A receiver RX at the DER site receives this injected signal. As long as the signal is present, the DER has permission to operate. When the signal disappears, the receiver assumes that a breaker has been opened and it triggers the DER to cease to energize the distribution circuit.

[11] A. Hoke, A. Nelson, B. Miller, S. Chakraborty, F. Bell, M. McCarty, "Experimental Evaluation of PV Inverter Anti-Islanding with Grid Support Functions in Multi-Inverter Island Scenarios", National Renewable Energy Laboratory Technical Report NREL/TP-5D00-66732, July 2016, https://www.nrel.gov/docs/fy16osti/66732.pdf.
[12] SAND2018-8431, "Unintentional Islanding Detection Performance with Mixed DER Types", August 2018, https://www.osti.gov/servlets/purl/1463446.
[13] For example, see National Grid ESB 756 – "Supplement to Requirements for Parallel Generation Connected to a National Grid owned EPS", Section 7.6.12.3, "Certified DER".
[14] During this i2X project, a statement that was made often by some utilities was, "Utility systems must be protected by utility equipment." This is a reflection of the fact that the utility is typically the party ultimately held responsible for power system protection and safety.

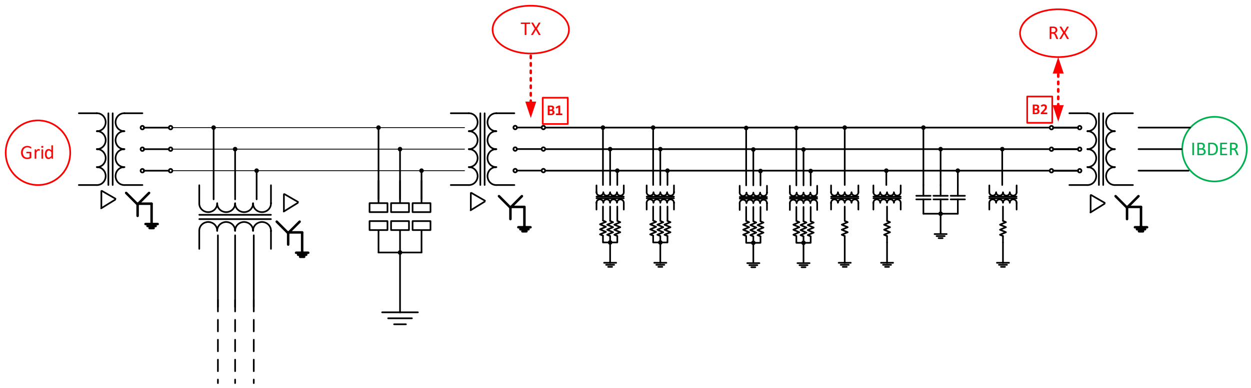

Figure 10. Distribution circuit equipped with a Power Line Carrier Permissive system.

PLCP has, for the most part, the same advantages as DTT, and it has the additional advantage that a single PLCP transmitter can cover all DERs on a distribution circuit and all utility breakers between the PLCP transmitter and any DER. It is also possible to send some data using high-frequency PLCP signals, so these can provide additional functionality, such as identifying which phase is which.

The key disadvantages of PLCP include:

- Higher-frequency PLCP signals face propagation challenges. Distribution circuit power conductors are designed for 60 Hz operation. Higher-frequency signals may be blocked by series inductances or attenuated by shunt capacitances, and they usually will not cross a DER's interface transformer because of the transformer's series inductance. Repeaters, shunts and other devices can be used to overcome this limitation, but this raises costs.
- Subharmonic signal transmitters or injectors typically require complex, high-current switching networks, which makes subharmonic signal injection expensive and less reliable.
- The reliability of the PLCP transmitter is critical. Because the presence of the signal is taken as permission to operate, if the transmitter fails, all DERs will interpret that as island formation and will cease to energize. Backup transmitters can be used to improve overall PLCP system reliability, but this increases cost.
- PLCP is still relatively high-cost, including capital and maintenance costs. The cost of PLCP per kilowatt of DER is high for the first DER installation on a feeder, but would diminish as more DERs interconnect over time. PLCP is still far more expensive than UV + UID.
- Switches upstream from the PLCP transmitter will not be covered by the PLCP scheme (i.e., the case shown in Figure 8 also applies to PLCP).

2.4. Wide-area methods

There has been significant study of methods that involve the wide-area broadcast of a utility reference signal, such as a synchrophasor measured at a key node. The status of utility breakers and other aspects of the system are discerned at the DER locations by comparison of that broadcast utility reference with a DER-local reference. A broadcast-based system of this type is shown in Figure 11. The three large red antennae labeled "Ref1", "Ref2" and "Ref3" represent transmitters that broadcast the remote reference signals over-the-air to large geographical areas. The blue diamonds in Figure 11 are Geographically Dispersed Sources and Storage (GDSS), which could be distribution-level DERs or transmission-level Inverter-Based Resources. Each GDSS has a red

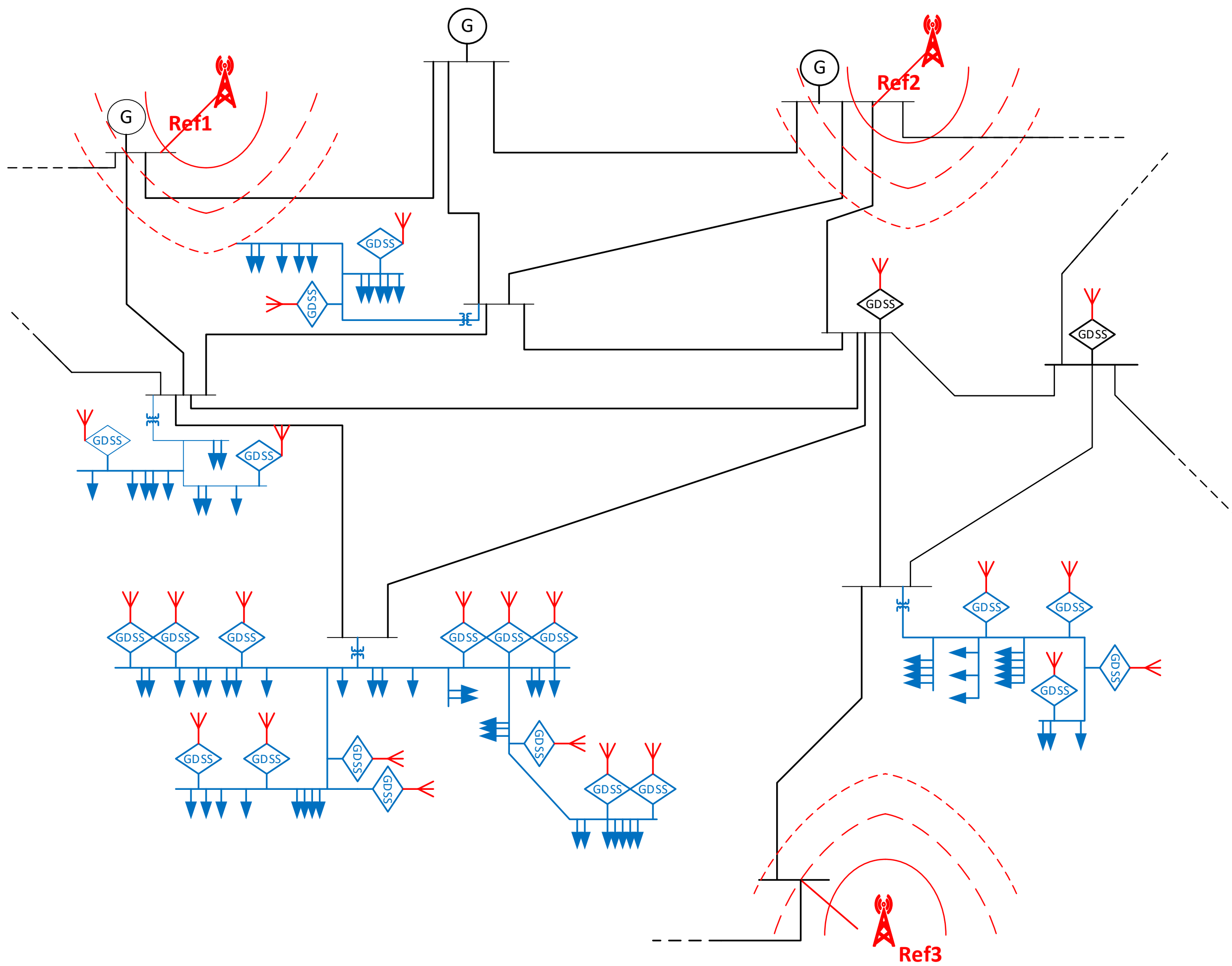

Figure 11. Schematic representation of a wide-area broadcast-based method. Utility reference signals are broadcast by the transmitters shown in red, and all distributed resources within the broadcast footprint can compare these references against local measurements to determine their relationship to the rest of the system.

antenna indicating its receiver for the broadcast signal. Each GDSS receives one or more remote reference signals, measures its own local reference, and determines its relationship to the rest of the system using a comparison between the local and remote references.

There are multiple methods for using comparisons between local and remote synchrophasors to detect islanding[15,16], and this method has been demonstrated in the field[15]. The over-the-air broadcast channel is highly scalable relative to a fiber-based communications network; adding new DERs in such a system is no more difficult than adding a new receiver to an FM radio station. Because it is unidirectional and could not be spoofed over a wide area without highly visible equipment, the over-the-air broadcast reference system enjoys a certain inherent level of cybersecurity.

[15] "A statistically-based method of control of distributed photovoltaics using synchrophasors", IEEE PES General Meeting, July 2012, https://ieeexplore.ieee.org/document/6344693.

[16] Schweitzer Engineering Laboratories Application Note AN2009-55, "Islanding Detection for Distributed Generation", https://selinc.com/api/download/6160/.

The key disadvantages of a broadcast-reference-based system are:

- The high cost of such systems remains a barrier to their deployment, although it may be possible for utilities to recover those costs through rate-basing or via a subscription service. Another possible model could be that a government agency would build and manage the system, similar to the U.S. Coast Guard's management of the LORAN system.
- A broadcast reference-based system will also have a variable operation time, and the available evidence to date suggests that such a system can be expected to operate on a similar time frame as, or perhaps slightly more slowly than, DER-resident active UID. The broadcast reference-based approach is thus often much slower than DTT.
- Over-the-air broadcast systems are limited in bandwidth. To achieve high effectiveness, these systems would require new data protocol standards.

2.5. Utility-side methods

2.5.1. Impedance insertion

Impedance insertion involves switching a significant active or reactive load (i.e., a shunt impedance) into the island after the utility breaker is opened, as shown in Figure 12. The idea behind this method is that if the generation and load within the island were balanced, such that i_{grid} in Figure 7 is nearly zero, then inserting the impedance will disrupt that balance and allow opening of the breaker to be detected via the resulting voltage amplitude or frequency deviation. In Figure 12, the impedance being inserted is shown as a resistance R_{shunt}, but it can also be a reactance or capacitance. R_{shunt} can be close to zero, in which case the impedance effectively grounds the island (i.e., it becomes a so-called "grounding switch") and it pulls the island voltage to near-zero when triggered.

Impedance insertion has essentially no NDZ. Also, because impedance insertion impacts the island-wide voltage, it can be used to cause all IBDERs within the island to cease to energize, including even the smallest single-phase units that would be too expensive to include in a DTT scheme. This is a highly desirable property.

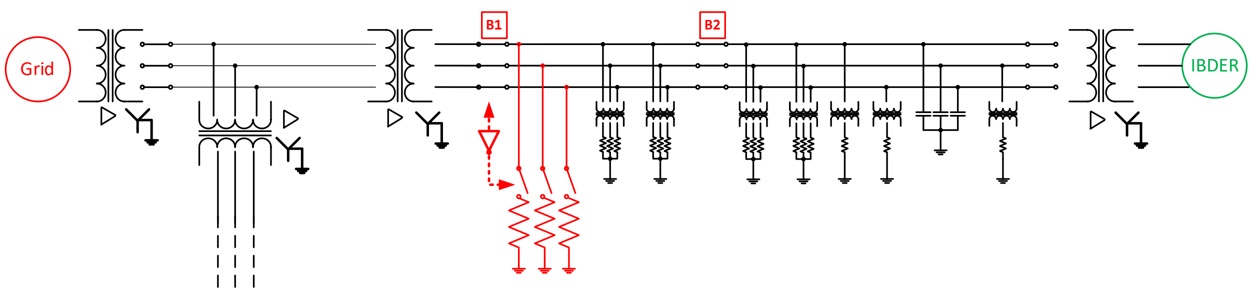

Figure 12. Impedance insertion. The red impedance (a shunt resistance R_{shunt} in this case) is switched complementarily with the utility breaker B1.

The key drawbacks of impedance insertion are:

- Impedance insertion ensures that whenever the switch opens, the voltage falls into the range in which the DER undervoltage function will operate. Thus, its operation time is the operation time of the main breaker logic + the operation time of the impedance insertion mechanism + the operation time of the undervoltage trip.

- Impedance insertion can be less expensive than DTT or PLCP, but it is still far more expensive than reliance on DER-resident UV + UID.
- It is complex and expensive, and in some cases impossible, to make impedance insertion work with more than one utility breaker. Two key reasons:
  - A communications channel may be required. For example, if there is a mid-circuit recloser (B2 in Figure 12), then the impedance would have to be inserted at that point, to ensure that it is inside the island formed by either B1 or B2. This would require a communications channel from B1 to the inserted impedance, which triggers the same cost and maintenance issues as DTT.
  - The impedance to be inserted has to be connected to electrical ground via a low-impedance path. This is fairly straightforward to do at the substation, where B1 is, because there is a ground grid there. That will not be the case at the location of B2, so installing an impedance at B2 may require installation of grounding equipment, mitigation of ground potential rise, protective fencing, and other measures.

2.5.2. Voltage-supervised reclosure

Voltage-supervised reclosure (VSR) is illustrated in Figure 13. In VSR, when the utility breaker opens, it is blocked from automatically reclosing if the voltage on the "downstream" side of the breaker is above some threshold.

VSR is a mature technology and is easy to implement. There is some cost associated with it because it requires that the breaker have potential transformers on the DER side. Also, because of the voltages involved, those potential transformers can be large, and in some cases there may not be physical space to accommodate them. However, for purposes of this "DTT alternatives" conversation, the key point to remember about VSR is that *it does not actually replace DTT*, in the sense that it does not cause the DERs to stop energizing the circuit. VSR prevents asynchronous reclosure[17] of the breaker onto an island still being energized by the DERs; it does not prevent energization of the island by the DERs. VSR is thus most useful in situations in which the utility operator wishes to rely on the DER-resident UID+UV, *and* the first reclose interval of the utility's breaker is "short", which is usually taken to mean less than 1 s.

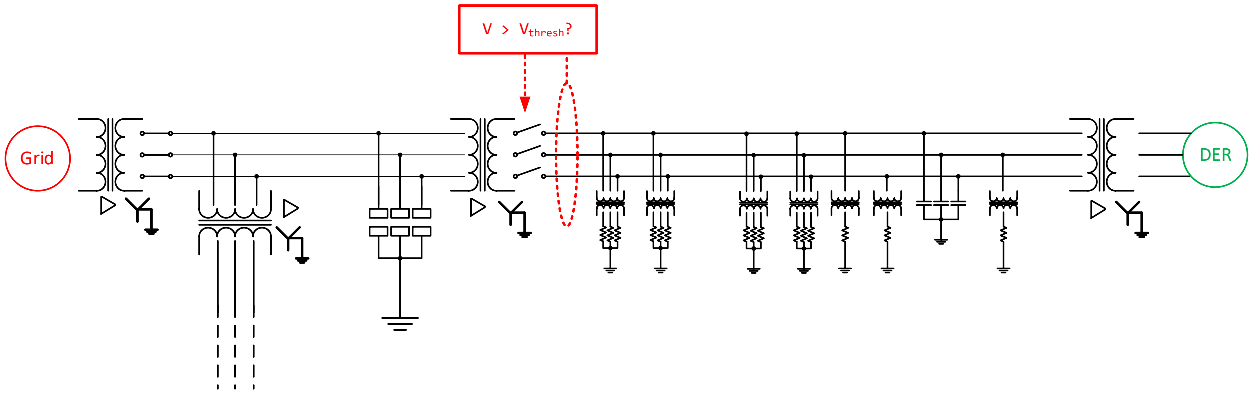

Figure 13. Schematic representation of voltage-supervised reclosure (VSR).

[17] Asynchronous reclosure can damage rotating machines and cause large transients.

2.6. Quantifying the required speed of operation

As discussed above, the main utility breaker serving a distribution circuit will in general open only when there is a severe abnormal condition on the circuit, such as a fault. The speed with which that breaker will open is generally dependent on the severity of the abnormal condition. These abnormal conditions pose imminent risks of fire, explosion, electrocution, or thermal damage to equipment. It is impossible to completely prevent faults, and thus it is the job of power system protection to minimize and mitigate the adverse effects of faults. Time is of the essence in deenergizing the circuit, and a critical factor in deciding which of these alternatives may be acceptable is the speed with which they take the IBDERs offline once the main utility breaker opens.

This issue has been discussed extensively in the Working Groups that wrote the IEEE 1547 standards from 2003[18] and 2018[19]. These Working Groups included broad stakeholder representation from across the power industry, including utilities, equipment manufacturers, DER developers, researchers, and consultants. The consensus reached in IEEE 1547 was that UID must be able to cause DERs to cease to energize the circuit in no more than 2 s after opening of the utility breaker, and UV2 should be able to de-energize the circuit in 160 ms or less[20], because a voltage below the UV2 threshold indicates a fault on the DER's host circuit.

Still, all distribution systems are different, and distribution system operators always retain discretion regarding the requirements for interconnection to their systems. Some utilities have examined their speed-of-response needs and have arrived at different conclusions. The fastest requirement for IBDER de-energization stated by any utility contacted for this paper was 160 ms from the opening of the first breaker, *under all conditions* (i.e., regardless of why the breaker opened). The primary reason cited by the utility for this requirement is safety in a downed-wire scenario. DTT and PLCP can consistently meet this requirement in cases resulting in a fault, but they may not operate in a downed-wire situation resulting in a high-impedance fault. Impedance insertion may also be able to meet this requirement, although the speed with which IBDERs de-energize after impedance insertion will be somewhat dependent on distribution circuit conditions. The utility with the 160-ms de-energization requirement is presently experimenting with impedance insertion as a potential DTT alternative.

In a situation in which the downed wire produces high fault current, UV2 would also meet this 160-ms requirement. Some downed-wire scenarios lead to what is called a "high impedance fault", in which case the fault may not draw significant fault current. In this case the voltage may not fall below 50% of nominal, so UV2 would not operate. However, the logic that opens the utility's breaker may also not act quickly in such a situation, or may not respond at all if the fault current is too low. This would affect the speed of response of DTT for this case. High-impedance fault detection is an open research topic that requires more attention. Bear in mind that as long as the

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[18] IEEE Std 1547-2003, "IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems", July 2003. (Superseded.)

[19] IEEE Std 1547-2018, "IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces", February 2018. Active, but expected to be superseded by a new version in 2026. https://ieeexplore.ieee.org/document/8332112.

[20] IEEE Std 1547-2020a, "IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces Amendment 1: To Provide More Flexibility for Adoption of Abnormal Operating Performance Category III", March 2020.

utility breaker opens, regardless of the fault impedance, DERs using UV + UID would be offline within 2 s of the utility's breaker opening.

The highest required DER de-energization time stated by any utility contacted for this paper was within 5 s of opening of the first breaker. These utilities, after considering what they felt are realistic scenarios for their particular systems, did not see a significant safety risk within that time period. All of the DTT alternatives listed above can meet this 5-s requirement.

3. UPDATED RISK-OF-ISLANDING SCREENING SUGGESTIONS

The active UID in IBDERs is intended to reliably replace DTT in ensuring that a distribution circuit is not energized by IBDERs when the main utility breaker is opened. Because the utility system operator retains full discretion over system protection decisions, it is important for that operator to know when UID can be relied upon to provide that function. As a first step in this evaluation, utilities often use what is called a "risk-of-islanding screen" to determine the likelihood that a condition may occur in which UID might have difficulty detecting opening of the utility breaker.

The risk-of-islanding screens used by many utilities today are still based on the suggestions given in a Sandia National Laboratories report, SAND2012-1365, "Suggested Guidelines for Assessment of DG Unintentional Islanding Risk", which was last revised in March of 2013. These suggestions were created within the context of IEEE Std 1547-2003, which was the version of IEEE Std 1547 in effect at that time. In 2018, IEEE Std 1547-2018 was published. IEEE Std 1547-2018 is a complete revision of the standard and includes new requirements for ride-throughs and grid-support capabilities. The approach followed in SAND2012-1365 does not apply to IEEE Std 1547-2018. To develop an approach that *does* apply, investigators conducted an extensive set of studies aimed at leading to an update of the suggestions for risk-of-islanding screens. That work is published in two Sandia National Laboratories reports, SAND2018-8431[21] and SAND2019-0499[22]. The new approach relies on generic knowledge of the physical mechanisms used by the IBDER-resident UID in GFL inverters. First, a set of generic UID Groups was established. Those Groups are described as follows[21]:

- **Group 1:** Inverters in this group utilize an output perturbation in positive-sequence fundamental frequency or phase that is specifically for the purpose of island detection, and that grows continuously in magnitude as frequency error increases in a direction that increases the frequency error (i.e., positive feedback on frequency error), up to the frequency trip limits, and includes no dead zone. In other words, Group 1 inverters use positive feedback on frequency or phase to create instability when the island forms. The output perturbation may be pulsed or continuous, but the key is the positive feedback; the magnitude of the perturbation must continuously increase with increasing frequency error as long as the inverter is within the frequency trip bands.
- **Group 2A:** These inverters are similar to Group 1 in that the inverter produces a pulsed or non-pulsed output perturbation in positive-sequence fundamental frequency or phase that is specifically for island detection and grows with frequency in a direction that increases the frequency error (i.e., positive feedback on frequency error), but not continuously to the trip bands. Inverters in this Group may have a stepped or otherwise discontinuous function of frequency, or a saturation limit that is reached prior to the frequency trip thresholds. However, because the impact of a dead zone (hysteresis about 60 Hz in which the anti-islanding perturbation is not produced) is a special case, inverters with a dead zone about 60 Hz are specifically excluded from Group 2A.
- **Group 2B**: This Group has any or all of the properties of Group 2A, but with a dead zone about 60 Hz in which the active anti-islanding does not act.

[21] Sandia National Laboratories report SAND2018-8431, "Unintentional lslanding Detection Performance with Mixed DER Types", September 2018, https://www.osti.gov/servlets/purl/1463446.
[22] Sandia National Laboratories report SAND2019-0499, "Evaluation of Multi-Inverter Anti-Islanding with Grid Support and Ride-Through and Investigation of Island Detection Alternatives", January 2019, https://www.osti.gov/servlets/purl/1491604.

- **Group 2C:** This group has any or all of the properties of either Group 1 or Group 2A, except that the positive feedback on frequency error is unidirectional; that is, the positive feedback is in the same direction regardless of the algebraic sign of the frequency error.
- **Group 3:** This group produces an output perturbation in positive-sequence fundamental frequency or phase, the magnitude of which does NOT grow with increasing frequency error or is NOT specifically designed for island detection.
- **Group 4:** Inverters in this group produce an output perturbation at a harmonic (not fundamental) frequency that is specifically for the purpose of detecting an island. Typically these are independent of frequency error.
- **Group 5:** Inverters in this group rely on passive methods only (such as RoCoF or vector shift) or advanced signal processing of voltage or current measurements to detect island formation. (A method that drives the frequency of an island to the frequency trip limits and then relies on the passive frequency trip does NOT fall into Group 5.)
- **Group 6:** Inverters in this group manipulate the negative sequence current for the purpose of island detection, and apply positive feedback to that negative-sequence perturbation. This may be achieved by several means, including altering individual phase current magnitudes or dithering the phase angle separation between the three output current phases.

The intention was that these Groups would cover all of the physical mechanisms used for UID[23], and all of them but Group 4 were covered in the two SAND reports. Based on the results of the aforementioned research, the following screening process was developed. This screening process can be used with 1547-2018, and may be applied to determine whether or not additional unintentional island mitigations may be prudent.

- If the potential island contains ONLY grid-following inverter-based DERs:
  - If all of the grid-following inverters are UL-1741 listed and they all have Group 1 or 2A anti-islanding, then the risk of unintentional islanding is extremely low, and no further mitigation is needed. This also applies to the case in which there are both inverters and rotating machines, but *all* of the rotating machines have DTT.
  - If the inverters are not Group 1 or 2A, then the system operator should check the active and reactive power matching criteria, with a particular focus on the reactive power match because with inverter-based DERs the sensitivity of the system frequency to reactive power matching is much higher than the sensitivity of the voltage to active power matching. If the Area EPS operator is confident that a reactive match is not possible, then a sustained unintentional island is still extremely unlikely, and additional mitigation is not needed.
  - If the inverters are not Group 1/2A and the likelihood of a reactive match is unacceptably high or cannot be determined with certainty, then further study is justified and encouraged, and mitigation by DTT or a DTT alternative may be needed.
- If the potential island contains ONLY rotating machine-based DERs, then because of the complex dynamics of the system, there are no simple screening tools that are reliable. History suggests that in this case mitigation is likely to be needed, so most utilities skip the time and expense of further study and go straight to DTT or other mitigation.

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[23] One commonly used method, the Sandia Voltage Shift, was not explicitly included in the Groups or the studies. It should be explicitly included in future work. The Sandia Voltage Shift is rarely used by itself; it is typically used to augment the effectiveness of a Group 1 or 2A-type method.

- If the potential island contains a mixture of grid-following inverter-based and rotating machine-based DERs, *and* all of the inverters have Group 1 or 2A anti-islanding as defined in SAND2018-8431, *and* none of the rotating machines has DTT, then for an inverter/machine fraction of at least 60% Group 1/2A inverters and no more than 40% rotating generation, no run-on times over 2 s are expected and no further mitigation or study is needed.
  - If the fraction of Group 1/2A inverters is lower than 60%, then further study and/or mitigation might be prudent.
  - In the real world, the rotating machines probably will have DTT, so this situation will be relatively uncommon.

It is likely clear to the reader that these revised screens will have the effect of pushing industry toward specific UID methods. That was not the intention of the study authors, and as a result these revised screens have heretofore not been widely published. They are being more widely distributed now because the power and energy industries have recently indicated openness to this approach.

The guidelines above are based on research that was done with grid-following inverters. As noted in Section 2.2.3.3 above, it is not yet fully clear how a widespread transition to grid-forming controls in inverters will impact these guidelines. If GFM inverters are able to implement the same UID functions as GFL inverters, with similar performance, then these guidelines should still apply. However, if GFM inverters have a somewhat slower UID response than GFL inverters, and some preliminary data indicates that this could be the case[24], then these guidelines may require adjustment for GFM inverters. More study of this issue is needed.

[24] M. Ropp, Sandia National Laboratories, unpublished data.

4. CONCLUSIONS

We conclude the following.

- DTT can play a valuable role in power system protection, in cases when a circuit can be energized from more than one point. DTT is a mature technology, and it has the important advantage of being very fast. However, DTT can be challenging to apply to DERs because of its cost, maintenance requirements, point-to-point nature, and the fact that it may not cover certain cases of importance.
- Potential near-term alternatives:
  - Lower-cost DTT. The cost of DTT is a 'moving target', with lower cost options being developed. The key barrier to the success of lower-cost options appears to be reliability; utility experience with them has been mixed in this regard.
  - Power line carrier permissive. PLCP offers most of the advantages of DTT, at lower cost and with multipoint-to-multipoint capability. However, it is still relatively expensive. Also, both high-frequency and low-frequency PLCP face technical challenges that to date do not appear to have been fully solved.
  - IBDER-resident undervoltage + unintentional islanding detection. UV + UID provides the same functionality as DTT for DERs, and is a viable alternative to DTT in many cases when configured as described above. UV + UID is a mature technology, it is far less expensive than DTT, and it is part of the DER certification process, which provides operational confidence. However, it does have certain disadvantages, particularly that a) it only operates in 160 ms or less for low-impedance fault situations, and b) it requires utilities to rely on third-party equipment for a critical protection function.
- A key factor in whether a DTT alternative might be acceptable is the speed with which the circuit must be de-energized from all endpoints. The fastest de-energization requirement noted by any utility during this work was 160 ms. However, DTT may respond more slowly or not at all for fault conditions that do not cause any line-ground or line-line voltage to drop below 50% of nominal, because the utility's protection functions may react slowly in such a case and DTT does not act until the utility's protection commands the breaker to open.
- Assuming a low-impedance fault such that system voltages drop below 50% of nominal, all of the following technologies can meet the 160 ms requirement:
  - DTT.
  - PLCP.
  - UV + UID.
- Wide-area methods have been proven to work. The key disadvantages of these methods are the high cost of the communications channel, and the fact that they are slower than other options.
- Utility-side alternatives such as impedance insertion may be an effective option in some cases. However:
  - Impedance detection does not directly cause DER de-energization; what it does is to activate the inverter-resident UV + UID.

    - Voltage-supervised reclosing is not actually a substitute for DTT in that it does not cause the DERs to de-energize. Instead, VSR prevents one possible negative outcome of unintentional islanding (asynchronous reclosure).
- It is possible to update the 2012 "Sandia Anti-Islanding Screens" to be compatible with IEEE 1547-2018 requirements, and such an update has been presented here. These updated screens will have a tendency to require the use of specific active UID methods.
- There is a need for more research into the topic of UID with grid-forming inverters. Preliminary results suggest that grid-forming inverters can still perform UID, albeit perhaps a bit more slowly than grid-following inverters, but to date there has been insufficient study of this issue to allow broad conclusions to be drawn.

Additional study in the following areas is needed:

- ❖ UID and grid-forming controls, including the effectiveness of existing UID with grid-forming controls, and possibilities for new UID methods designed for use with GFM controls.
- ❖ Ways to reduce the cost, improve the performance, and maximize the value-added of wide-area methods and PLCP.
- ❖ Lower-cost, non-point-to-point communications options for DTT.
- ❖ High-impedance fault detection.