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Suggested Guidelines for Assessment of DG Unintentional Islanding Risk

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Abstract

As increasing numbers of Distributed Generation (DG) systems are connected to utility systems, distribution engineers are becoming increasingly interested in evaluating the risk of unintentional islanding. Utilities desire to keep their systems secure, while not imposing unreasonable burdens on customers wishing to connect DG. However, utility experience with these systems is still relatively sparse, so distribution engineers often are uncertain as to when additional protective measures, such as direct transfer trip, are needed to avoid unintentional islanding. Utilities tend to err on the side of caution, which in some cases may lead to the unnecessary requirement of additional protection. The purpose of this document is to provide distribution engineers with guidance on when additional measures or a more in-depth evaluation may be prudent. The guide also describes situations in which utilities may be able to ascertain that the risk of an unintentional island is extremely low and no additional mitigation or study are needed. The goal is to reduce the *unnecessary* application of additional protection for DG interconnection. While the content applies to any DG, this document has a focus on photovoltaic (PV) installations.

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Scope and Applicability

The purpose of this document is to suggest a technical evaluation procedure that may be used by utility protection engineers to assess the risk of unintentional islanding of a proposed distributed generator (DG) installation. While the content applies to any DG, this document focuses on photovoltaic (PV) installations. The document describes cases in which islanding for any extended period of time is virtually impossible, and thus the need for additional technical evaluation or protection mitigation measures are not justified. It also describes cases in which additional technical evaluation should be considered. This document does not specifically address temporary overvoltage-related issues.

The guidelines provided in this document are technically involved and data intensive. As such, the technical guidelines contained in this document are designed for a purpose that is different from the screening criteria used in the FERC small generator interconnection procedures (SGIP) initial review process. However, the guidelines could be applied at a stage of the interconnection process where detailed studies are being conducted, to help determine whether or not anti-islanding study is needed. **The procedure described here leads to reasonable conclusions about the risk of unintentional islanding only if it is applied in its entirety.**

Introduction

An electrical island is any stand-alone power system with its own generation and loads operating in balance. Islanding itself is not necessarily undesirable, but unintentional islanding can have undesirable impacts on customer and utility equipment integrity. If the unintentional island is sustained for a significant period of time, personnel safety could become a concern. Even if the unintentional islanding period is short, the potential degraded power quality could still be a concern. For these reasons, the risk of unintentional islanding must be kept low. Applicable standards such as IEEE 1547 and IEC 62116 require that a DG detect an unintentional islanding condition and cease to energize within 2 s, even in the worst-case condition of very close load-generator balance. For this reason, DG equipment connected to the lower-voltage parts of utility systems usually incorporates islanding detection and prevention schemes, or so-called "Loss of Mains Detection" (LOMD), of varying levels of sophistication. Interconnection procedures applicable to commercial and residential PV systems require that the utility interface (the inverter itself in most cases) be certified specifically for LOMD. Existing LOMD certification tests, including UL 1741, are applied to a single inverter connected to an RLC (resistive-inductive-capacitive) circuit where real power demand matches the inverter output, and the capacitive and reactive elements are resonant at 60 Hz with a circuit quality factor of 1.0.

To understand how an unintentional island may form, consider the schematic representation shown in Figure 1. This figure shows a DG at the left, which in this case is labeled as a PV system; a local load; a circuit interrupter, indicated by the switch; and the utility, represented by the voltage source labeled "Grid V." The PV plant is an inverter-based DG controlling output current magnitude and phase with respect to terminal voltage. In order for this system to enter a sustained unintentional island when the switch is opened, the fundamental-frequency grid current i_{grid} must be nearly zero at the moment when the switch is opened. This means that the PV output and the local load demand must match closely in terms of both real and reactive power. If this is not the case, either the voltage or the frequency will quickly drift outside of normal operating range when the switch opens, and the Loss of Mains condition can be detected. If such a balance does exist, then the island may "self-excite," in the sense that the PV output current flowing into the load creates a voltage V_{load} that appears sufficiently similar to the grid voltage that the inverter cannot tell the difference. In that case, LOMD may fail. The loading condition that could result in unintentional islanding is referred to as a non-detection zone (NDZ). In a way, the extent of the NDZ is a measure of the effectiveness of the anti-islanding scheme.

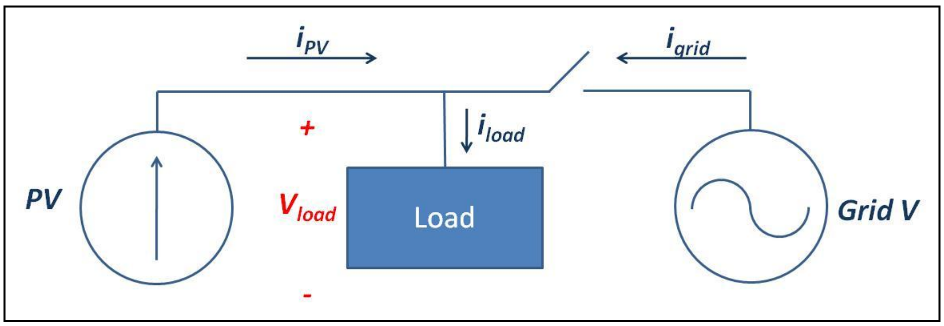

Figure 1. Simplified schematic representation of a distributed generator (in this case, a PV system), local load, circuit interrupter, and utility voltage source.

LOMD techniques are usually subdivided into the following categories [1-3]:

- Passive methods. Passive methods monitor various parameters of the inverter's terminal voltage, and trip the inverter if the selected parameter exceeds some threshold. What defines them as passive is that the inverter does not actively try to change the value of the parameter being monitored; it simply monitors, processes and reacts. Some parameters that have been used in passive anti-islanding methods include the following:

    - Over/undervoltage and over/underfrequency
    - Voltage phase (the phase is monitored for a sudden jump)
    - Voltage or current harmonic distortion (THD)
    - Rate of change of frequency (RoCoF)
    - Rate of change of real power
    - Rate of change of voltage vector
    - Various harmonic pattern recognition methods, using FFTs, wavelets, Kalman filters, or other spectral techniques

    In general, passive methods have great difficulty eliminating all NDZs because it is difficult to find thresholds or patterns that are totally unique to islanding, and do not occur under normal operating conditions. Thus, passive methods usually involve a trade-off between the extent of the NDZ and the rate of occurrence of nuisance trips. The behavior and performance of passive methods is difficult to predict when multiple inverters are present in the potential island.

- Active methods. Effectively, active methods are similar to passive methods in that the inverter watches for some threshold to be exceeded. The difference is that the inverter takes an active role in driving the system state toward that threshold. Active methods are generally more successful in LOMD than passive methods because they tend to destabilize the potential island by making the generation-load balance more difficult to achieve. Active methods include the following:

    - Impedance detection. In impedance detection, the inverter periodically perturbs its output current and checks to see whether there is a corresponding change in voltage, thereby measuring the source impedance as seen from the inverter. If the detected impedance is too high, the inverter trips.
    - Positive feedback based methods, such as the Sandia Frequency Shift (SFS) or Sandia Voltage Shift (SVS). In these methods, the inverter employs positive feedback on voltage or frequency. If the inverter detects a change in one of these parameters, it attempts to "push" on that parameter in the same direction, trying to drive it out of bounds. If it can, the inverter trips.
    - Impedance detection plus positive feedback. Most commercial inverters today use some variant of this technique, in which the benefits of positive feedback are combined with the benefits of impedance detection. This method has been vetted in simulation, laboratory tests, and field deployments.

- Communications-based methods. In these methods, communications are used to send utility status information back to the inverter, which the inverter can interpret to determine whether an island has been formed. Communications-based methods include the following:

    - Direct transfer trip (DTT). In DTT, the utility's breaker or other isolation device is tied to a transmitter that sends the breaker's status to the DG.
    - Power line carrier communications (PLCC). PLCC is a form of DTT in which the communications channel is the power line itself.
    - Integration of inverters into utility SCADA.
    - Synchrophasor-based methods [4].

Where Can Islands Form?

In this document, the phrase "potential island" is used to describe some section of the local electric power system (EPS) that can be isolated and that contains DG and loads. Theoretically, any subsection of the local EPS that contains both a DG and loads, and can be fully isolated from the utility voltage source by automatic protection/control or operator action, could be considered a potential island. If a particular feeder contains downstream reclosers, sectionalizing switches, or other circuit interrupters, the section of the local EPS that is isolated by these devices would be a “potential island” as defined in this document. Also, again in theory, if a PV system is within the customer premises, the customer premises themselves could be a potential island.

Cases in Which the Possibility of Unintentional Islanding Can Be Ruled Out

There are several cases in which the, accumulated field experience, findings described in the literature, and physical reasoning suggest that islanding is so unlikely as to be considered impossible for all practical purposes. Those cases are described below.

- Cases in which the aggregated nameplate AC rating of all DG systems within the potential island is less than some fraction of the minimum real power load within the potential island. If PV is the only type of DG in the potential island, then the value that should be used is the minimum load during daylight hours. Considering that load and PV output both rise during the morning hours, the time at which the fraction of PV output to load may realistically become meaningful is not sunrise, but rather closer to 10 a.m., at which point feeder load is well above absolute minimum load levels. In the case in which the aggregate DG rating is well below the specified loading fraction, after the switch opens, the load’s voltage (V_{load} in Figure 1) will quickly drop to levels that the inverter can easily detect as abnormal. Theoretically, the definition of “some fraction” would be 77% (88% squared), because below this level, the voltage should drop to less than 0.88 p.u. and the inverter would enter a regime in which IEEE 1547 requires a 2-second trip. Said another way, provided the DG has protection programmed to comply with the IEEE 1547 0.88 p.u. static voltage threshold, the 77% fraction effectively rules out the possibility of unintentional islanding, regardless of the effectiveness of the anti-islanding algorithm. This rationale is strictly true only for impedance loads. Very conservatively, one could say that a sustained island is not physically possible if the sum of the AC nameplate ratings of all the DG in a potential island is less than 2/3 of the minimum feeder load within the potential island. If all of the DG are PV systems, then the minimum load to be considered is the minimum daylight-hours feeder load. The 2/3 fraction is somewhat conservative and easy to remember. Application of this evaluation assumes that reliable data on minimum load exists, which of course is not always the case. It is important to note that if IEEE 1547 is changed to allow low-voltage ride through (LVRT) capability, this criterion may need to be revisited.

- Cases in which it is not possible to balance reactive power supply and demand within the potential island. In order for an island to be sustained, both the real and reactive power demand of the load and power system components must be satisfied. Since most loads and power system components absorb VArs, there must be a source of VArs in the potential island in order for islanding to be sustained. The most obvious VAr source is capacitance, which may be deliberately added for power factor correction or may arise as a parasitic from underground cabling. Most of today’s PV inverters are designed to operate at unity power factor, but, increasingly, larger inverters are being equipped with the ability to operate at a fixed power factor according to a schedule or command. In this case, the inverters may source or sink VArs. If the load VAr demand is larger than the

VAr sources in the island, then the risk of a sustained run-on is very close to zero, because the frequency within the island will quickly rise beyond the IEEE 1547 mandated limit of 60.5 Hz. The mechanism of this frequency change is the phase locked loop (PLL) used by the inverters to synchronize to the grid frequency. (Not all inverters use an actual PLL, but they all do have some kind of synchronization mechanism, and these behaviorally are roughly equivalent to an actual PLL, so the discussion here holds in all cases.) When the grid source is lost, the PLL will change the frequency of the inverters' output current to bring the inverters' voltage and current into whatever phase relationship the PLL is programmed to maintain (usually, zero). If there is VAr imbalance in the island, that steady-state frequency will lie above 60.5 Hz. Most of today's inverters use active anti-islanding that incorporates positive feedback on frequency. The action of active anti-islanding is such that for an unintentional island to persist there must be an *exceedingly* close VAr balance in order for islanding to be sustained [5, 6], and also that VAr balance must be maintained during the unintentional islanding duration. The term "exceedingly close" is quantified below.

- Cases in which DTT is used. Note that "power line carrier permissive" (PLCP), in which a power line carrier signal is used for island detection, is included here as a form of DTT. If DTT is properly implemented, only a failure of the DTT communications system would result in a failure to detect an unintentional island. Other forms of communications-based anti-islanding, such as SCADA and synchrophasor-based methods, may also fall into this category if future accumulated experience suggests that they are sufficiently effective. In some cases, DTT implemented on a dominant large DG within the potential island is sufficient to rule out the possibility of unintentional islanding.

Cases in Which Additional Study May Be Considered

There are several cases that are known to be difficult for LOMD methods to guarantee a negligible risk of failure to detect. Some of these cases, as described below, correspond to conditions commonly encountered in distribution systems. The examples refer to PV generation, but could be adapted to apply to other inverter-based DG as well.

- Cases in which the potential island contains large capacitors, *and* is tuned such that the power factor within a potential island is very close to 1.0 [1-3]. Under common deployment situations and with active anti-islanding in operation, a very small amount of reactive power imbalance is sufficient to rule out the possibility of unintentional islanding. Reference 5 suggests the following approach for determining when there is sufficient capacitance in a potential island to trigger the need for further evaluation, assuming that (a) all of the inverters in the potential island are from the same manufacturer, (b) there is little impedance between the inverters, and (c) all inverters are utilizing some form of positive feedback based active anti-islanding:

1. Based on PV forecasts and daylight-hours load data, determine the range of PV power levels at which the PV is producing more than 2/3 of the load demand in the potential island.
2. Calculate the expected reactive power draw of the load at this matching condition, Q_{load}:

$$Q_{load} = P_{match} \tan[\cos^{-1}(pf)] \quad \text{Eq. (1)}$$

where P_{match} is a power level at which PV-load matching[1] is likely and pf is the expected power factor of the feeder or load section (including losses) at this condition, again based on the historical load data. If the sum of Q_{load} and Q_{PV} (the PV system's VAr output, with absorption being positive and production being negative) is within 1% of the capacitor's VAr rating for any expected value of P_{match}, this indicates that the capacitor's VAr output could match the load demand, and more detailed evaluation may be advisable. In equation form, this criterion is:

$$0.99 \leq \frac{Q_{cap}}{Q_{PV}+Q_{load}} \leq 1.01 \quad \text{Eq. (2)}$$

If measurements of the real and reactive power flowing through the interrupting device are available, those data can substitute for this calculation. In that case, the distribution engineer should check to see whether the feeder power factor, with capacitors but without the DG, is higher than 0.99 (lag or lead) for an extended period of time. For PV, only daytime hours need to be reviewed. Past results suggest that the 1% matching requirement is quite conservative for inverters incorporating positive feedback on frequency. If the inverters do not use positive feedback on frequency, then Equation (2) or the power factor thresholds described above may be insufficient to determine the risk of islanding. Depending on other factors described in this document, further study may be prudent.

- Cases with very large numbers of inverters. The literature indicates that the speed with which inverters detect an island decreases as the number of inverters in the island increases [5-8], and that the amount by which the effectiveness degrades depends on both the specific anti-islanding method used [9] and on the configuration of the potential island [5,6]. The definition of "very large number" depends on several factors. Results to date suggest that there is little to no degradation in LOMD performance, if (a) all of the multiple inverters use positive feedback-based LOMD, *and* (b) the interconnecting impedances between the inverters are low. An example of such a deployment may be a commercial installation using multiple inverters on a common distribution transformer. In

[1] In this context, Pmatch should be taken to be the power level at which the closest generation-load match occurs. For example, if it was determined in Step 1 that the PV rating is 80% of the minimum feeder load, then one should use that power value for Pmatch in Equation (1). Then, Equation (1) will give the reactive power demand of the load at the point at which the real powers are most closely matched, and this reactive power demand is the one that should be used in Equation (2).

such a case, even feeders with more than 20 inverters still reliably trip within IEEE 1547 mandated limits. Multi-inverter problems seem to arise when:

- different types of LOMD are mixed, which can occur when inverters from several different manufacturers are used together (see below); or
- when there is significant interconnecting impedance between the inverters. "Significant" in this context is difficult to define, and work to quantify this factor is ongoing.

- Cases with inverters from several different manufacturers [8-10]. Some studies have found that mixing different types of LOMD, or even mixing inverters with the same type of LOMD but different implementations, leads to a degradation of islanding detection effectiveness in the multi-inverter case. This situation could represent a case in which a multi-inverter installation uses units from several different manufacturers.

- Cases including both inverters and rotating generators [4]. If a potential island includes both rotating and inverter-based DGs, the case should be scrutinized carefully. It has been shown that the rotating generator, particularly if it is a synchronous machine, can lead to greatly increased run-on times for the inverter-based DG because the synchronous machine simply looks too much like the grid for the inverters to be able to tell the difference. Similarly, some of the most common anti-islanding methods used in synchronous machines, such as positive feedback based or governor clustering methods [11], are largely defeated by the much faster action taken by inverter-based DG.

Summary of Methodology to Evaluate DG Unintentional Islanding Risk

The evaluation procedure shown in Steps 1 through 4 below can be useful in assisting a distribution system engineer in determining whether there is any realistic probability of a failure of LOMD for a given DG plant. The procedure summarizes the preceding discussion as a sequence of steps, and runs through a list of criteria for determining when a possible risk of LOMD failure justifies a more in-depth evaluation of the problem. The procedure never suggests that islanding is a problem; instead, it indicates when the risk may not be negligible. In such cases, a more detailed technical evaluation or additional protective measures, such as DTT or more restrictive trip setpoints, may be warranted.

The numbers given in the evaluation procedure are conservative guidelines, based on a considerable amount of accumulated experience. Of course, no set of values could accommodate every situation, and the utility distribution or protection engineer must exercise his/her judgment when evaluating any specific situation.

It must be emphasized that these suggestions assume a) that the inverters are utilizing positive feedback based active anti-islanding; and b) that the DG is compliant with existing IEEE 1547 requirements[2]. Future experience may indicate that either of these assumptions are not required, but at present, if either of these assumptions does not hold the utility engineer should exercise prudent judgment regarding further studies.

To emphasize, the guidelines provided in this document lead to reasonable conclusions about the risk of unintentional islanding only if it is applied in its entirety. The guidelines could be applied at a stage of the interconnection process beyond the initial review process, when detailed studies are being conducted, to help determine whether or not anti-islanding study is needed.

Step 1. Determine whether the aggregate AC rating of all DG exceeds 2/3 of the minimum feeder loading. If all of the DG in the case of interest are PV systems, then the appropriate loading value to use is 2/3 of the minimum daylight-hours load. If the aggregate AC DG rating is less than 2/3 of the minimum feeder load, then the voltage in any unintentional island will drop below the 88% IEEE 1547 undervoltage trip setting, and the risk of a persistent unintentional island is negligible. In this case, no further assessment is warranted and one need not execute the next steps of this procedure. If the aggregate AC DG rating is above 2/3 of the minimum rest of the appropriate minimum feeder load, then proceed to Step 2.

Step 2. Determine whether $Q_{PV} + Q_{load}$ is within 1% of the total aggregate capacitor rating within the island (Equation (2)), or alternatively, use real and reactive power flow measurements or simulations at the point at which the island can form to determine whether the feeder power factor is ever higher than 0.99 (lag or lead) at that point for an extended period of time. If $Q_{PV} + Q_{load}$ IS within 1% of the capacitor rating, or the feeder power factor is higher than 0.99, then further study may be prudent. If $Q_{PV} + Q_{load}$ is not within 1% of the capacitor rating, or the feeder power factor is not higher than 0.99, then proceed to Step 3.

[2] As of the date this report was printed, the current version of the standard is IEEE 1547 (2008).

Step 3. Determine whether the potential island contains both rotating and inverter-based DG, *and* the sum of the AC ratings of the rotating DG is more than 25% of the total AC rating of all DG in the potential island. If the sum of all rotating machine AC ratings is greater than 25% of the total DG, then further study may be prudent. If the sum of all rotating machine AC ratings is less than 25% of the total DG, then proceed to Step 4.

Step 4. Sort the inverters by manufacturer, sum up the total AC rating of each manufacturer's product within the potential island, and determine each manufacturer's percentage of the total DG. If no single manufacturer's product makes up at least 2/3 of the total DG in the potential island, then further study may be prudent. If the situation is such that more than 2/3 of the total DG is from a single manufacturer, then the risk of unintentional islanding can be considered negligible.

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