Evaluation of Anti-Islanding Protection Methods through Simulations and Real Inverter Testing

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Abstract: This paper describes active and passive methods for detecting unintentional islanding, which can pose risks to both customer equipment connected to the distribution network and the electrical distribution infrastructure. The work herein introduces a real-time simulation of an unintentional islanded network and evaluates the performance of passive detection methods, under thorough testing. Finally, the paper discusses testing of actual inverters equipped with active islanding detection methods, which are more effective in identifying island operation, particularly in cases where the isolated network is balanced in terms of active and reactive power generation and consumption.

Keywords: islanding detection; distributed generation; unintentional islanding; loss of mains; power system protection; hardware-in-the-loop simulation; inverter testing

1 Introduction

The operation of distribution systems is increasingly impacted by the growing number of connected distributed power sources, particularly photovoltaic power generation systems. These systems are typically equipped with protections, such as over/under-frequency and over/under-voltage protections, to protect the grid from negative effects. However, real-world operational experience shows that these protections are inadequate for preventing unwanted islanding.

According to [1] [2], islanded operation occurs when a section of the electrical grid, containing both load and generation, becomes isolated from the rest of the system. This condition becomes problematic when it happens unintentionally, as it prevents the operator from controlling critical grid parameters such as voltage, frequency, harmonic distortion, and asymmetry. Unintentional islanding can result from various causes, including faults such as short circuits or overloads, accidental disconnection due to equipment failure, operational manipulations, human error or deliberate damage, and natural events.

Preventing unintentional islanding is important for several reasons. When a section of the grid becomes unintentionally isolated, the operator cannot control its voltage or frequency. Deviations in these parameters beyond acceptable limits can damage customer appliances, leading to liability for the operator. Additionally, islanding makes it more difficult to restore normal grid operations. It can also pose risks to maintenance personnel who might assume that disconnected lines are de-energized. Finally, attempts to reconnect the islanded section to the main grid can fail if there is a large phase difference between their voltages.

To address these risks, it is necessary according to [1-3] to disconnect sources in an unintentional island within two seconds. While conventional voltage and frequency protection systems are effective in most cases, they may fail under certain conditions. Therefore, it is essential to explore and implement additional protection methods and algorithms to improve grid safety and reliability.

Several studies have investigated similar objectives, but many have notable limitations. For instance, [4] tests inverter anti-islanding protection but only considers passive voltage and frequency methods. Study [5] offers a broad evaluation, although the inverters tested all complied with the requirement to disconnect within 2 seconds, revealing little about potential weaknesses. Study [6] involves modelling and testing but remains largely theoretical and offers no significant new findings. Our work aims to fill these gaps by providing a comprehensive analysis of the performance and limitations of anti-islanding protections, including those commonly considered reliable.

2 Methods for Detecting Island Operation

Island operation detection methods can be categorized into active, passive, and communication-based techniques. The occurrence of islanding can be demonstrated using the distribution network shown in Figure 1. This network includes a high-voltage (HV) feeder, followed by a three-winding HV/MV transformer, with the secondary side connected to the busbars of the medium-voltage (MV) substation. A line is branched from the substation, with the load positioned in the middle and the power generating unit at the end.

Islanding occurs when the feeder breaker (FB) in the MV substation is opened. The generating unit has its own interface breaker (IB), controlled by the protection system that manages the interface between the generation and the network. This example serves as an illustration, as islanding can also occur at the low-voltage (LV) level in a similar manner.

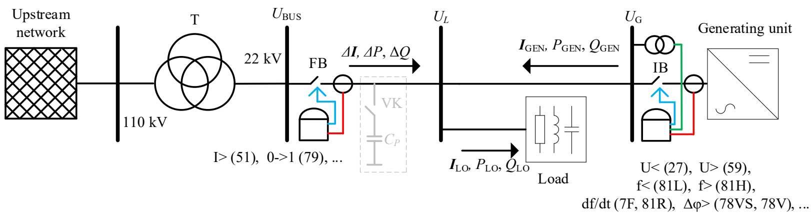


Figure 1

A schematic of the network illustrating island operation

2.1 Passive Methods

Passive methods of islanding detection rely on monitoring network parameters without actively influencing the system. These methods can be integrated directly into the generating unit, such as within the inverter, or implemented as external devices that can be retrofitted to existing generation units.

2.1.1 Overvoltage / Undervoltage and Overfrequency / Underfrequency Protection

The primary protection against island operation consists of overvoltage (U>) / undervoltage (U<) and overfrequency (f>) / underfrequency (f<) protections. These systems are typically integrated directly into inverters or in external protection relays, which controls the circuit breaker. The protection system trips the generating unit if the voltage and/or frequency at its point of connection reach outside the specified range.

These protections primarily safeguard both the equipment connected to the distribution system (DS) and the DS itself from potential adverse effects caused by backflow from the generating unit. Additionally, they can be utilized for the automatic tripping of the generating unit in the event of islanding. However, it is important to note that undesired islanding does not always immediately trigger these protection mechanisms, particularly in cases where the separated area has a balanced active (P) and reactive (Q) power. During normal operation, when the feeder breaker (FB) is closed, and the power generated by the unit does not match the power consumed by the load, an imbalance of active power ΔP and reactive power ΔQ occurs. This imbalance is covered by the upstream network and can be expressed by:

$$\begin{aligned} \Delta P &= P_{\mathrm{LO}} - P_{\mathrm{GEN}} \\ \Delta Q &= Q_{\mathrm{LO}} - Q_{\mathrm{GEN}} \end{aligned} \tag{1}$$

,where P_{LO} and Q_{LO} is the active and reactive power of loads and P_{GEN} and Q_{GEN} is the active and reactive power generated by the distributed generating units. The behavior of the system after separation from the upstream network, as described in [7], will depend on the values of ΔP and ΔQ at the moment just before the feeder breaker (FB) opens, i.e., before islanding occurs. If $\Delta P \neq 0$, the amplitude of the voltage in the islanded system will change, potentially triggering the overvoltage (U>) or undervoltage (U<) protection of the generating unit, which can disconnect the island within a reasonable time. If $\Delta Q \neq 0$, the voltage phase angle will shift suddenly, causing the inverter to adjust the frequency of its output current. This adjustment will alter the frequency in the islanded system, until the condition $\Delta Q = 0$ is satisfied. At that point, the frequency of the voltage in the island stabilizes at the resonant frequency of the load, which is determined by the system's electrical characteristics:

$$f_{\mathrm{R}} = \frac{1}{2\pi\sqrt{LC}}, \tag{2}$$

where L is the total inductance of the island system and C is the total capacity of the island system.

Islanding is prevented by overfrequency (f>) or underfrequency (f<) protection only if the resonant frequency of the loads differs significantly from the nominal frequency of 50 Hz and there is a perfect balance between the reactive power generated and consumed in the potentially islanded network.

However, according to [8], the actual behavior of an islanded system with a dominant share of inverters is more complex, both in real-world scenarios and simulations. As noted in [9], the previously described islanding behavior applies primarily to networks where inverters are the dominant. In islanded networks where synchronous generators are dominant, the dynamics are reversed: an imbalance in active power results in a frequency deviation, while an imbalance in reactive power causes a change in voltage magnitude. Moreover, the behavior of an islanded network is also strongly influenced by the line parameters, such as the R/X ratio, as well as the characteristics of the load. The load behavior (whether modeled as constant current, constant power or constant impedance) can significantly affect the stability and response of the system during islanding.

The areas where islanding cannot be detected by frequency and voltage protections are shown in Figure 2. These protections fail when the active and reactive power flow from the upstream network is equal to or close to zero. Although the probability of this condition is relatively low, as the number of distributed resources increases and reactive power flow is minimized, the likelihood of unintended islanding rises rapidly. For this reason, it is crucial to implement additional protection measures against unintentional islanding. On the other hand, U>/U< and f>/f< protections form the foundation for preventing unintentional islanding. In fact, some active methods rely on these protections secondarily, by driving the voltage and/or frequency parameters out of the non-detectable zone through active interventions in the network.

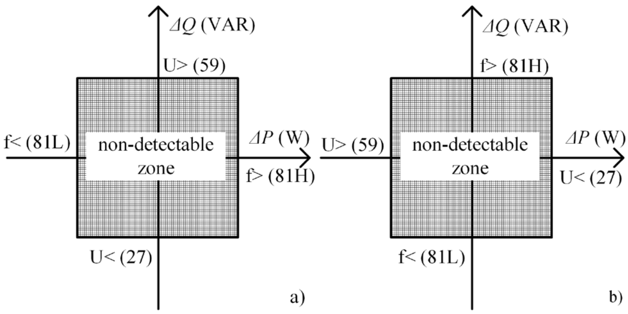


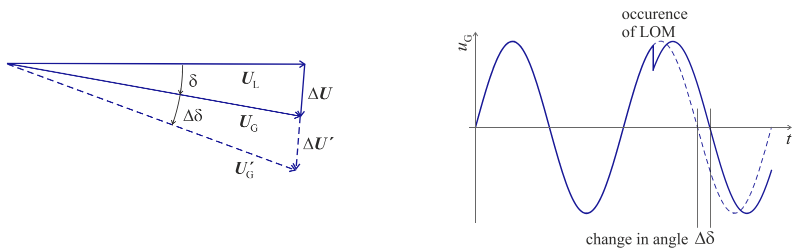
Figure 2
Indication of non-detectable zone of U>/ U< and f> f< protection in ΔP-ΔQ area
for systems with predominant influence of synchronous generators
for systems with predominant influence of inverters

2.1.2 Vector Shift of the Voltage Detection Method (Δφ)

Figure 3a illustrates the principle of voltage vector shift detection, showing the difference between the load voltage phasor ($\boldsymbol{U}_L$) and the phase displacement change of the generator voltage ($\boldsymbol{U}_G$ to $\boldsymbol{U}_G'$) when the feeder breaker (FB) is opened, causing the system to island. The detection method analyzes the angle δ change ($\Delta\delta$) over time, as shown in Figure 3b, where the "Occurrence of LOM" point marks the islanding event. During the voltage period with the vector shift, frequency changes are also observed. This protection function, known by various terms like 78VS, 78V, Δφ, VS, VVSPPAM, phase jump, or vector shift protection, is commonly integrated into multifunctional protection devices or used for distributed generation protection.

Standards [3] [11] [12] specify a 20° vector shift immunity in the positive sequence component of voltage. The protection potentially used would therefore have to be set above this value. The Australian NS194 standard [13] recommends vector jump protection, while the UK G59 standard [14] strictly prohibits it after the 2017 revision. Vector shift protections monitor the duration difference between two consecutive voltage periods ($\Delta\delta$), and if $\Delta\delta$ exceeds a set limit ($\Delta\delta_{SET}$), the protection trips. The range for $\Delta\delta_{SET}$ is typically 2° to 30°. Some protections can block tripping if voltage magnitude falls below a threshold or if the frequency is outside preset limits to avoid false trips [10]. Although vector shift protection and standard frequency protection measure the same quantity (frequency), their operating principles differ. Frequency protection uses a fixed reference value (50 Hz), while vector shift protection periodically updates its reference value, allowing for more sensitive settings.

This protection method has two main drawbacks. First, it is sensitive to voltage events that can lead to false trips, such as faults outside the feeder or sudden load changes (e.g., starting a large motor). These events cause $\Delta\delta$ changes, which may be misinterpreted as islanding. Routine network manipulations (e.g., switching radial feeders) can also lead to false operation. Second, an undetectable zone exists when the current ΔI is near zero or when line reactance is too small, amplifying the risk of false trips.



a) b)

Figure 3
Vector shift representation a) in a phasor diagram, b) in the voltage waveform

2.1.3 Detection Method by Rate of Change of Frequency

The Rate of Change of Frequency (ROCOF) function is a well-known method for detecting imbalance between generated and consumed power. Power imbalances in an islanded system cause transient phenomena, leading to dynamic changes in the frequency and/or voltage. These changes can be used to detect islanding. The ROCOF is calculated over a window of several voltage periods, typically between 2 and 50 periods. The voltage values are processed through filters, and if the rate of change of frequency exceeds a set threshold, a trip signal is sent to the circuit breaker. ROCOF protection is commonly set between 0.1 and 10 Hz/s. To prevent false tripping, the ROCOF function is typically blocked if the voltage drops below a set threshold, preventing issues such as motor start-up, large load switching, or short circuits. This protection is often referred to as ROCOF, d*f*/d*t*, or ANSI codes 7F or 81R. Protection must not limit the immunity of generating modules, which is 1 Hz/s for synchronous generation and 2 Hz/s for non-synchronous generation (with a 500 ms window), as specified in [11] [12]. The disadvantage of this method is that if the difference between generated and consumed power is small, the frequency changes slowly, so the protection may not detect it.

2.1.4 Detection Method by Rate of Change of Voltage

This method is similar to ROCOF but evaluates the rate of change of the voltage's effective value. It is not commonly used in commercial protection terminals or as a standalone feature, as it can cause false trips during load switching, motor start-up, short circuits, or transformer tap changes. However, it serves as a useful supplement to other islanding protection functions. This function is typically referred to as dV/dt, 27R/59R or ROCOV (Rate of Change of Voltage).

2.1.5 Detection Method by the Change of Harmonic Distortion

This method is based on monitoring the total harmonic distortion (THD) of the voltage. If the THD exceeds a predefined threshold, the protection trips. Under normal operating conditions the upstream network, acting as an infinite bus, results in negligible harmonic distortion of the voltage, due to the low impedance of the upstream network. Consequently, the harmonic distortion produced by the inverter remains below the detection threshold. In islanded operation, the load impedance is typically much higher than that of the upstream network, causing the inverter to generate higher harmonic distortion, which can be detected by the protection. This detection is based on either the absolute level of harmonic distortion or its rate of change.

A key advantage of this method is its independence on the imbalance of active and reactive power. However, there are notable limitations. This method is only applicable in networks with a predominance of inverter-based generation, as it is ineffective in systems dominated by synchronous generators. Additionally, accurately determining the level of harmonic distortion or its change can be challenging. High-quality inverters, which produce minimal harmonic distortion, or the presence of significant harmonic distortion under normal operating conditions, can lead to detection difficulties. Currently, protection devices utilizing this method for islanding detection are not commercially available. However, power quality meters or power quality monitoring functions within multifunctional protection relays can be adapted for this purpose. Given its limitations, this method is most effectively employed in conjunction with other islanding detection techniques.

2.1.6 Detection Method by Voltage Unbalance

This method is based on the assumption that voltage unbalance will change after islanding, similar to the previously discussed method based on harmonic distortion. It is not typically used as a standalone, but is always combined with other islanding detection techniques. For instance, in [15], an islanding detection system that utilizes both harmonic distortion and voltage unbalance monitoring is presented. Currently, this principle is not implemented in commercially available protection devices.

2.2 Active Methods

Active methods for detecting island operation are based on the principle of intervening in the parameters of the distribution network, either with the intent to shift its parameters (voltage and/or frequency) outside the undetectable zone of voltage and frequency protections, or with the intent to induce a measurable change in the monitored variables, from which it is possible to determine whether the network is islanded or not.

2.2.1 Method based on Forced Change of Active or Reactive Power

This method operates on the principle of forcing a change in active or reactive power, which can involve either supply or consumption. The most cost-effective solution is to use the inverter itself to enforce these changes, as it eliminates the need for additional equipment.

A change in active or reactive power can influence system parameters such that the frequency or voltage exceeds the undetectable zone of protections, resulting in the tripping of the generating unit. This method can also be implemented at the distribution system operator level, for instance, by automatically switching a compensation capacitor (C_p in Figure 1) after a circuit breaker is opened. If the system were stable without the capacitor, its connection might destabilize the system, causing the voltage and/or frequency to deviate from the undetectable zone, which in turn leads to the tripping by voltage and/or frequency protection. An example of such a system is provided in [16]. The method can also be implemented directly in an inverter, which periodically injects reactive power, for example.

If the inverter periodically injects current directly into the grid while simultaneously measuring voltage, it can calculate the grid impedance based on the known current change and the measured voltage change. If the measured impedance is low, it indicates that the system is not operating in island mode, as the impedance of the upstream grid is also low. However, if the measured impedance is high, the inverter can determine that undesirable island operation is occurring and disconnect itself. A drawback of this method is the difficulty in defining a precise threshold impedance for disconnection. Additionally, measurement errors may occur, as there is no guarantee that the observed voltage change in the grid was caused by the inverter's current injection rather than by a random event within the grid. Detection methods based on impedance measurements are described, for example, in [17].

2.2.2 Active Frequency Shift

This method is used exclusively in inverters. The detection principle involves deliberately introducing a slight distortion into the waveform of the current supplied by the inverter. During parallel operation with the grid, the frequency is stable and unaffected by the inverter's current distortion. In the event of island operation, the lack of grid inertia allows the inverter's influence to dominate. The voltage crosses zero earlier than expected due to the intentional distortion in the shape of the injected current. This results in a phase error between the voltage and current output of the inverter. To eliminate this phase error, the control system of the inverter causes the frequency of the output current to drift. This frequency drift further alters the timing of the voltage zero-crossing, creating a feedback loop. The frequency of the inverter's output current continues to drift until the voltage frequency in the islanded network exceeds the overfrequency protection threshold, at which point the inverter disconnects. This method relies on the assumption that the islanded system has low inertia and limited capability to counteract the frequency drift induced by the inverter. Active frequency shift is described, for example, in [15].

3 Testing of Passive Anti-Islanding Protections with Hardware-In-the-Loop Simulation

A realistic real-time simulation of the islanded network was created to demonstrate the function of passive protections to prevent islanding. In this simulation, voltage, frequency and vector jump parameters were recorded and evaluated. The model network is shown in Figure 4.

3.1 Model Network

The network is powered by a 110 kV HV network with a short circuit current of 11 kA, through a 40 MVA three winding transformer in a YNynd connection. The secondary side of the transformer is connected to the 22 kV busbars of the MV substation. On the secondary side of the transformer, the neutral node is connected to the earth through a 12 Ω resistor (resistively earthed network with a 1 kA limiting resistor). There is one feeder leading from the 22 kV substation, which consists of a total of three sections of overhead lines. Each section is 15 km long. Behind the first section there is a generating unit and behind the second section there is a load. The third section is unloaded. The lines are modelled as PI sections with all series and shunt parameters. The active power of the generating unit and the active power of the load are slightly different and this is due to the fact that after the transition to the island the voltage drops and the power of the load drops slightly as well. Therefore, the generating unit is configured so that the active power generated is in balance with the power input of the load after the transition to the islanded operation. In addition to the load, the source must also be able to cover the series and shunt line losses after the islanding occurs. Distributed generation is at 400 V level and is connected to the MV network through a transformer in Dd connection.

The network was modeled using a real-time simulator RTDS that provides a simulation with a time step of 50 us. A real protection REX615 from ABB is interfaced to this simulator. Voltage and frequency protection functions are set according to Table 1. The protection is connected to the simulator via low-level (sensor) inputs. The analogue output card has a range of ±10 V (peak). Voltage dividers with a ratio of 10000:1 were simulated. At a nominal phase voltage of 12.7 kV (22 kV line-to-line), the voltage at the input to the protection is 1.27 V. The current sensors are simulated as Rogowski coils with a nominal current of 300 A and a rated secondary voltage of 150 mV at 50 Hz. Both the transformation ratio and the derivative component are included in the simulator. The simulator sends binary signals to the protection about the status of the circuit breaker and the protection sends commands to the simulator to control it. This communication is carried out using IEC61850 GOOSE.

Table 1

Set values for protection functions

Protection			Start Value	Operate delay time
			(p.u.)	(ms)
PHPTOV1	U>	Overvoltage 1st stage	1.15	20000
PHPTOV2	U>>	Overvoltage 2nd stage	1.2	5000
PHPTOV3	U>>>	Overvoltage 3rd stage	1.25	100
PHPTUV1	U<	Undervoltage 1st stage	0.7	2000
PHPTUV2	U<<	Undervoltage 2nd stage	0.45	80
FRPFRQ1	f>	Overfrequency 1st stage	1.03	200
FRPFRQ2	f<	Underfrequency 1st stage	0.95	200

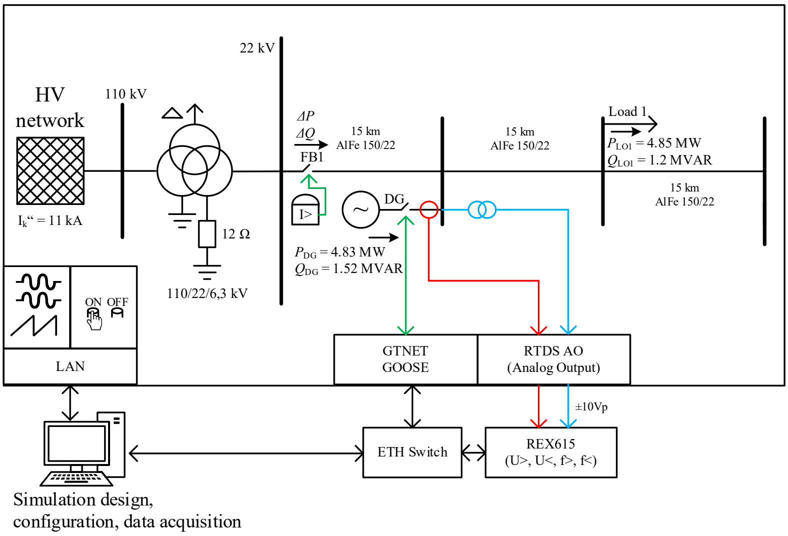


Figure 4
Schematic of the simulated network

3.2 Simulated Scenarios

Different scenarios were simulated with respect to the balance of active and reactive power in the modelled network. The individual scenarios and characteristic values are shown in Table 2. A balanced state was achieved by fixed setting of the loads, both active and reactive power. The initial values of the source's active and reactive power were set approximately. Final tuning was carried out after disconnection from the upstream network, aiming to bring the frequency as close as possible to nominal (50 Hz). The issue of voltage is not as straightforward as it might seem, because it is influenced by both active and reactive power. It was therefore not possible to achieve the same voltage before and during island operation (see Figure 4). When the voltage decreases, the load also decreases, which again alters the conditions in the simulated network. The overall behavior of the network tends to show a stronger dependence of active power on frequency and reactive power on voltage. However, unlike in a real network, the reverse influence is also significant. This means that active power affects voltage and reactive power affects frequency. The reactive power drawn by the load is 1.2 MVAR (inductive). Generating unit is set to cover the reactive power of the load and reactive power required by the overhead line. The unloaded sections of overhead lines are capacitive, the loaded section (between the source and line) is inductive. In the islanded network, the inductive reactive power is predominant.

After FB1 is opened, the network with the parameters shown in Figure 4 becomes islanded, with a stable frequency of 50.00038 Hz (1.0000076 p.u.) and a voltage at the source location of 21.48 kV (0.977 p.u.). This condition is considered as a reference. Neither voltage nor frequency protections will operate during the transition to the island in the reference (balanced) state. Furthermore, the P+1MW and P-1MW states are tested, where there is a surplus or deficit of 1 MW of active power compared to the reference state before islanding. The same tests were also performed with reactive power, again with a surplus or deficit of 1 MVAR. These states are listed in Table 2.

Table 2
Recorded characteristic values of the simulated network

State before opening FB1	Protection trip	u_{pre} (p.u.)	u_{trip} (p.u.)	f_{trip} (p.u.)	VS (°)	t_{trip} (ms)
balanced	No trip	1.034	0.977*	1.0000076*	0.390	NO
P+1MW	PHPTOV3	1.040	1.779	0.971	2.300	468.200
P-1MW	FRPFRQ2	1.028	0.886	0.904	4.890	829.400
Q+1MVAR	PHPTOV3	1.048	1.461	0.847	9.290	501.500
Q-1MVAR	FRPFRQ1	1.021	1.009	1.169	8.300	625.000

** steady-state values after transition to island mode*

In Table 2, the first column shows the protective function that caused the tripping of the generating unit. In the second column is the relative value of the voltage at the point of connection of the generating unit, before the islanding u_{pre}. In the next column is the relative value of the voltage at the connection point of the generating module, at the moment of protection tripping u_{trip}. In the next column is the relative value of the frequency at the time of tripping f_{trip}. In the next column is the value of the vector shift at the moment of islanding (opening of the FB1). The last column contains the values of the tripping time t_{trip}.

The islanding under the reference (balanced) condition is shown in Figure 5. The first part shows the active and reactive power supplied by the generating module, followed by the supplied currents. The next section of the figure illustrates the relative line-to-line voltages at the connection point of the generating unit. Another section depicts the frequency behavior in per-unit values. This is followed by the waveform of the vector shift. The final section shows the states of the FB1 breaker (*Feeder1 breaker*) and the generation module breaker (*DG breaker)*.

The value of the vector shift is evaluated from the change in the angle of the positive sequence component of voltage between two floating windows, each having a size equal to one period of the system frequency. Table 2 shows the peak value. The waveform of the vector shift from the simulation is illustrated in Figure 5. Evaluation using the zero-crossing of the voltage (as shown in Figure 3) is practically impossible due to transient phenomena, during which the voltage waveform may cross zero multiple times.

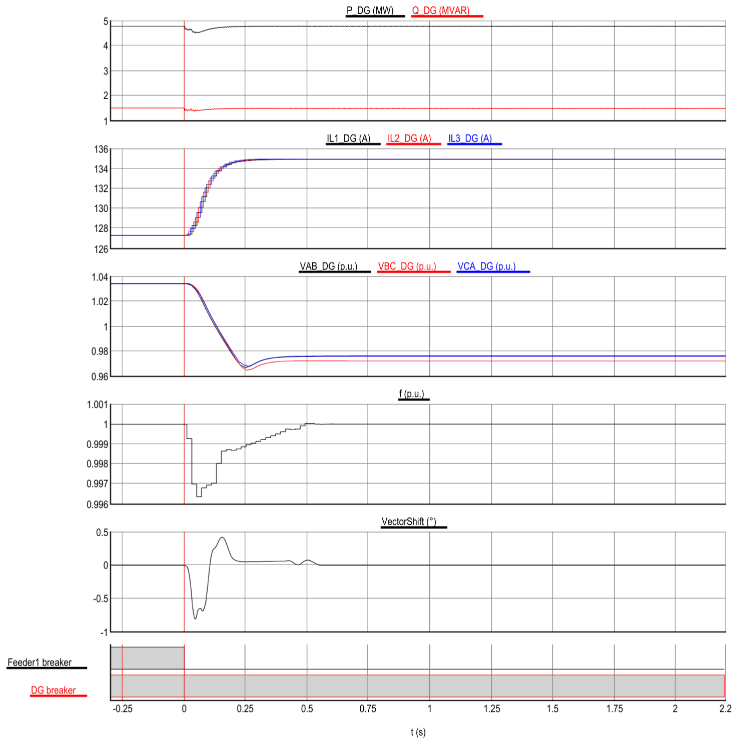


Figure 5

Waveforms of selected variables during transition of the network to the island mode

3.3 Results and Discussion

The results clearly show that if the system is balanced in terms of active and reactive power, the transition to island operation does not trigger any of the passive protections (voltage, frequency, or vector shift). Both the frequency and voltage stabilize within the set protection thresholds, preventing any protection mechanisms from activating. Additionally, the vector shift value of 0.39° is significantly below the required threshold of immunity, which is 20°. So even protection evaluating the vector shift would not operate. In all states of imbalance in active or reactive power, the voltage or frequency protection was triggered within a short time, never exceeding the required 2 seconds. This confirms that voltage and frequency protections are effective in most cases. However, for the condition of balanced active and reactive power, the use of active detection methods is necessary. These methods are typically implemented directly in inverters.

4 Laboratory Testing and Verification of Active Detection Methods for Unintentional Island Operation

From the simulations presented in Chapter 3, it is clear that passive methods are not able to provide the required level of detection of unintentional island operation in all possible cases. Active detection methods should be the solution that can detect unintentional island operation even in specific conditions. Their real-world performance as an integrated protection in photovoltaic inverters has been verified by laboratory tests, which are presented in this section.

4.1 Test Platform and Testing Procedure

For this purpose, a test platform was assembled in accordance with EN 62116 [1] and IEEE 1547.1-2020 [19], respectively. The wiring diagram of the test platform is shown in Figure 6.

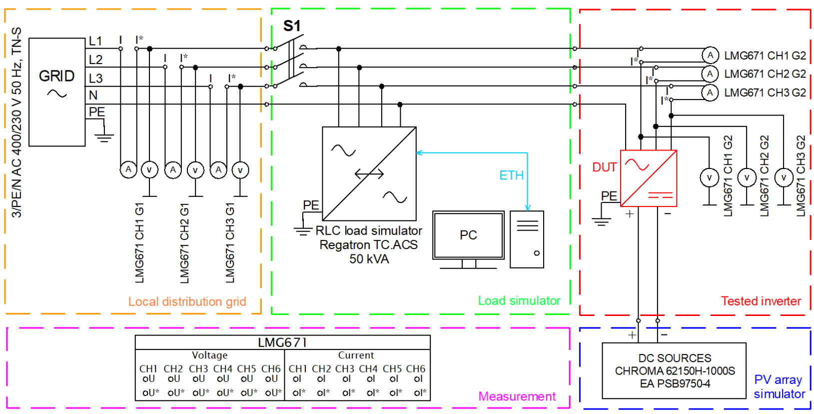


Figure 6

Test setup

The test setup consists of PV simulators, DUT connected to the distribution grid, load, S1 switch and measuring equipment. Chroma 62150H-1000S and EA PSB9750-4 were used as the PV simulators. The load was created by the symmetrical simulated impedance. The series-parallel combination of R, L and C elements was simulated by a full 4-quadrant three-phase Regatron TC.ACS 50 kVA AC power supply, Test platform is further described in [20].

A total of three samples that use some kind of the active detection method were tested. The description and labelling of the tested samples can be seen in Table 3.

All of the inverters are available at the European market. Detection method is stated as declared by the manufacturer in the datasheet of each of the inverter.

For verification, the test procedure detailed in EN62116 was used, reduced to the least favorable condition in terms of the probability of islanding - generation and consumption of active and reactive power at the fundamental frequency was balanced and power flow was close to zero at the switch S1 at the moment of its opening. The RMS voltages and currents before and after S1 opening were calculated and subsequently recorded by LMG671 power analyzer. The measurement window is 1 period of the system frequency (~20 ms in a system with a nominal frequency of 50 Hz) with recording of consecutive 1-period values. The real time measured values were also used for balancing the power flow close to zero. Accuracy of power analyzer is ± (0.02% of measured value + 0.04 of maximum peak value) for both the voltage and current measurements. Current and voltage range was set to 32 A RMS and 400V RMS, respectively.

All tests were repeated multiple times, and under the above described conditions, the transition to island operation occurred repeatedly. Typical examples were recorded and discussed in the results section of this contribution.

4.2 Results

Measured data were analyzed and evaluated in terms of clearing time for all of the tested inverters. It is the difference between the moment of S1 opening and inverters disconnection from the unintentionally islanded grid. The detection is considered to be successful when clearing time is up to 2 s.

Following figures represents the waveforms of RMS values of current at S1 and RMS values of voltage at the tested device terminals. Current drop to zero is the moment of S1 opening and voltage drop to zero represents the detection of unintentional island operation and following disconnection of tested device. The exact times of these events are marked directly in the figures.

Inverter A (Figure 8) was the only one to successfully detect island operation in less than 2 s. It has an active detection method based on the AFS principle. According to the manufacturer, the second tested inverter labeled as B has also AFS method implemented. In this case, the results are different and the inverter was not able to detect unintentional island operation. The inverter operates in island operation more than 1000s and then it was turned off manually (Figure 8). The inverter C has also active detection method implemented, but based on a different principle – response to reactive power impulse. The tested inverter disconnects from the islanded grid, but it was not able to detect unintentional island operation immediately (Figure 9). The overall clearing time was in orders of hundreds seconds and this is also considered as insufficiently accurate and fast detection. The results summary can be found in Table 3.

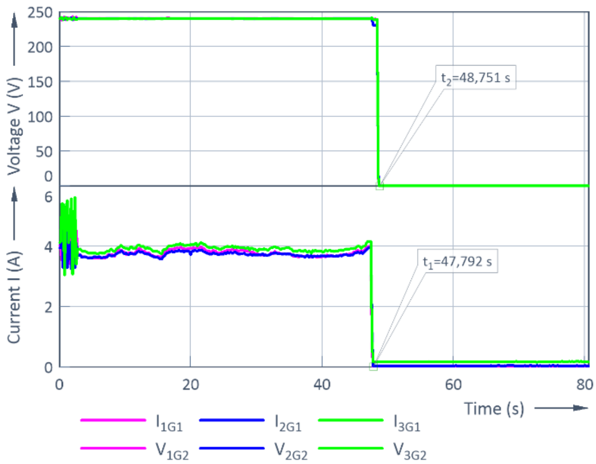


Figure 7
RMS voltage and current at fundamental frequency during the test – inverter A

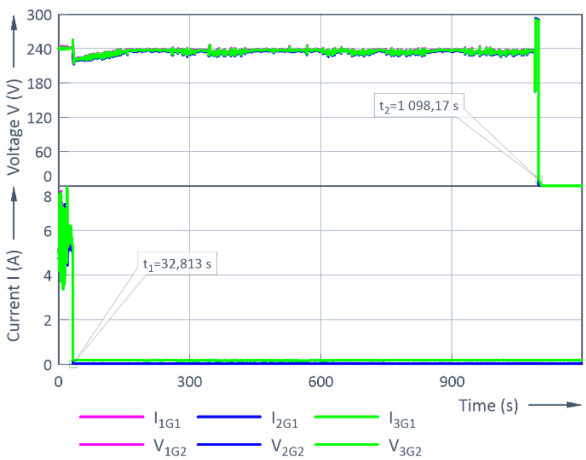


Figure 8
RMS voltage and current at fundamental frequency during the test – inverter B

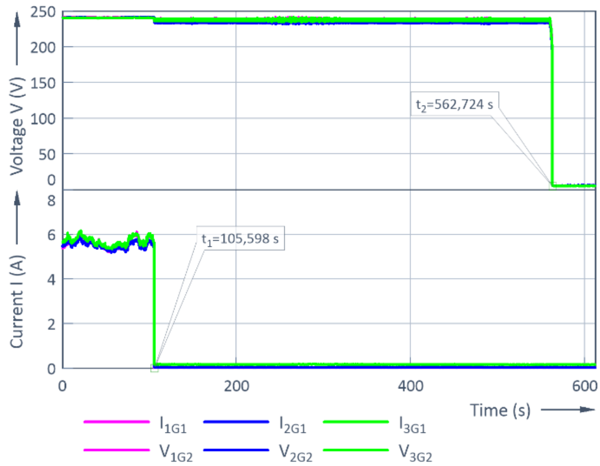


Figure 9

RMS voltage and current at fundamental frequency during the test – inverter C

Table 3

Description of tested PV inverters and results

DUT	Type	Detection method	Nominal power	Measured clearing time	Result
A	Hybrid	Active (AFS)	6 kW	0.96	Passed
B	Hybrid	Active (AFS)	10 kW	-	Failed
C	On-grid	Active (response on reactive current impulse)	20 kW	457.13	Failed

Conclusions

This paper deals with an assessment of the capability to detect an island operation, using active and passive detection methods. It provides an overview of the physical principles that are used for this purpose. Furthermore, the ability to detect an island operation using passive methods is evaluated. using hardware in the loop simulations. In order to investigate the ability to detect an island operation and therefore, the real situation in this field, using active methods, laboratory testing, according to the EN 62116 standard, was carried out. This was done on a total of 3 photovoltaic inverters, with integrated active protection against unintentional island operation. Results for both the simulation and tests are clearly presented and discussed.

Based on the detection methods overview, it can be concluded that each category has its own advantages and disadvantages and none of them is ideal from all points of view. In most cases, passive methods are able to detect transition to island operation. There are also some specific cases, when the disconnected part of the network is perfectly balanced, and there is very minor change in voltage or frequency in the island network that was established. In this case, it is impossible for passive methods to detect and react. On the other hand, active methods are capable of island operation detection even in these specific cases, but their disadvantage lies in the negative impact on power quality.

The above mentioned drawbacks regarding passive detection methods were confirmed by the presented hardware in the loop simulation, where in a balanced scenario, the voltage or frequency protection, does not trip. On the contrary, they trip in all other simulated scenarios.

Laboratory testing focused on active detection methods and the real life situation in this field shows that only one of the inverters was able to reliably a quickly detect the island operation when the disconnected part of the grid was perfectly balanced. Inverter B was completely unable to detect the island operation. This finding is all the more interesting because the manufacturer declares the use of the same method as in the case of inverter A. Failure to pass the test may be due to incorrect implementation of the detection method, or even its inactivity. Inverter C detects the island operation, but it takes approximately 457 s.

Although a small number of samples were tested, the findings presented, demonstrate that protection against unintentional islanding is not fully guaranteed for all possible operating conditions and further investigation is needed in the future.

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