SANDIA REPORT

SAND2002-3591
Unlimited Release
Printed November 2002

Evaluation of Islanding Detection Methods for Utility-Interactive Inverters in Photovoltaic Systems

Ward Bower and Michael Ropp

Prepared by
Sandia National Laboratories
Albuquerque, New Mexico 87185 and Livermore, California 94550

Sandia is a multiprogram laboratory operated by Sandia Corporation, a Lockheed Martin Company, for the United States Department of Energy under Contract DE-AC04-94AL85000.

Sandia National Laboratories

Issued by Sandia National Laboratories, operated for the United States Department of Energy by Sandia Corporation.

Printed in the United States of America. This report has been reproduced directly from the best available copy.

Available to DOE and DOE contractors from
U.S. Department of Energy
Office of Scientific and Technical Information
P.O. Box 62
Oak Ridge, TN 37831

Telephone: (865)576-8401
Facsimile: (865)576-5728
E-Mail: reports@adonis.osti.gov
Online ordering: http://www.doe.gov/bridge

Available to the public from
U.S. Department of Commerce
National Technical Information Service
5285 Port Royal Rd
Springfield, VA 22161

Telephone: (800)553-6847
Facsimile: (703)605-6900
E-Mail: orders@ntis.fedworld.gov
Online order: http://www.ntis.gov/ordering.htm

SAND2002-3591
Unlimited Release
Printed November 2002

Evaluation of Islanding Detection Methods for Utility-Interactive Inverters in Photovoltaic Systems

Ward Bower
Photovoltaic Systems Research and Development
Sandia National Laboratories
P. O. Box 5800
Albuquerque, NM 87185-0753

Michael Ropp
South Dakota University
Electrical Engineering Department
Brookings, SD 57007-2220

ABSTRACT

This report describes the various methods and circuits that have been developed to detect an islanding condition for photovoltaic applications and presents three methods that have been developed to test those methods and circuits. Passive methods for detecting an islanding condition basically monitor parameters such as voltage and frequency and/or their characteristics and cause the inverter to cease converting power when there is sufficient transition from normal specified conditions. Active methods for detecting the island introduce deliberate changes or disturbances to the connected circuit and then monitor the response to determine if the utility grid with its stable frequency, voltage and impedance is still connected. If the small perturbation is able to affect the parameters of the load connection within prescribed requirements, the active circuit causes the inverter to cease power conversion and delivery of power to the loads. The methods not resident in the inverter are generally controlled by the utility or have communications between the inverter and the utility to affect an inverter shut down when necessary. This report also describes several test methods that may be used for determining whether the anti-islanding method is effective. The test circuits and methodologies used in the U.S. have been chosen to limit the number of tests by measuring the reaction of a single or small number of inverters under a set of consensus-based worst-case conditions.

This page intentionally left blank

CONTENTS

FOREWORD

This report has been prepared as part of Sandia National Laboratories' Photovoltaic Systems Research and Development work for the U.S. Department of Energy. Sandia is the DOE's lead laboratory for photovoltaic systems research. The development and approach for accomplishing meaningful systems goals for the nation's photovoltaic program and the photovoltaic industry is defined through five technical objectives: (***1) reduce the life-cycle costs; (2) improve the reliability; (3) increase and assure the performance and safety of fielded systems; (4) remove barriers to the use of the technology; and (5) support market growth for commercial U.S. photovoltaic systems***. This evaluation of the various islanding detection methods for photovoltaic inverters and utility-interactive power systems complements Sandia's photovoltaic inverter development and evaluation goals, provides valuable information for standards and codes input, and summarizes the strengths and weaknesses of the developed anti-islanding methods available today.

For more information contact the authors listed below:

Ward Bower
Sandia National Laboratories
MS0753
P. O. Box 5800
Albuquerque, NM 87185-0753
Telephone: +1-505-844-5206
Fax: +1-505-844-6541
email: wibower@sandia.gov

and

Michael Ropp
Assistant Professor
Electrical Engineering Department
Box 2220, HH205
South Dakota State University
Brookings, SD 57007-2220
Telephone: +1-605-688-4664
FAX: +1-605-688-5880
email: michael_ropp@sdstate.edu

ABSTRACT

This report describes the various methods and circuits that have been developed to detect an islanding condition for photovoltaic applications and presents methods that have been developed to test those methods and circuits. The methods described are separated into three categories. They are:

- Passive Methods Resident in the Inverter
- Active Methods Resident in the Inverter
- Methods Not Resident in the Inverter and Generally at the Utility Level

Passive methods for detecting an islanding condition basically monitor parameters such as voltage and frequency and/or their characteristics and cause the inverter to cease converting power when there is sufficient transition from normal specified conditions. Active methods for detecting the island introduce deliberate changes or disturbances to the connected circuit and then monitor the response to determine if the utility grid with its stable frequency, voltage and impedance is still connected. If the small perturbation is able to affect the parameters of the load connection within prescribed requirements, the active circuit causes the inverter to cease power conversion and delivery of power to the loads. The methods not resident in the inverter are generally controlled by the utility or have communications between the inverter and the utility to affect an inverter shut down when necessary.

This report also describes several test methods that may be used for determining whether the anti-islanding method is effective. The test circuits and methodologies used in the U.S. have been chosen to limit the number of tests by measuring the reaction of a single or small number of inverters under a set of consensus-based worst-case conditions.

BACKGROUND AND OBJECTIVES

Grid interconnection of photovoltaic (PV) power generation systems has the advantage of immediate and efficient utilization of generated power. However, the technical requirements from the utility-system side need to be satisfied to ensure the safety of the PV system installer and the reliability of the utility grid. Clarifying the technical requirements for grid interconnection and solving the problems are therefore very important issues for widespread application of PV systems. Anti-islanding protection is a requirement for connecting to the utility grid in the United States and has undergone extensive study and discussion.

Islanding is a condition in which a portion of the utility system, which contains both load and generation, is isolated from the remainder of the utility system and continues to operate. The isolation point is generally on the low-voltage distribution line when an islanding condition exists, but islanding may also occur on the higher voltage distribution or transmission lines when large numbers of PV and other distributed generation sources are present. In photovoltaic distributed resource islanding, one or more non-utility generation sources (more specifically, sources over which the utility has no direct control) and a portion of the utility system operate while isolated from the remainder of the utility system.

This report is a summary of an evaluation of islanding detection methods for photovoltaic utility-interactive inverters conducted jointly by Sandia National Laboratories and South Dakota State University. The islanding condition covered in this document occurs when the low voltage distribution lines are interrupted. A worst case for this condition is when the island is localized and major transformers are not part of the local island.

Findings

Passive methods for detecting an islanding condition basically monitor selected parameters such as voltage and frequency and/or their characteristics and cause the inverter to cease converting power when there is sufficient transition from normal specified conditions. Active methods for detecting the island introduce deliberate changes or disturbances to the connected circuit and then monitor the response to determine if the utility grid, with its stable frequency, voltage and impedance, is still connected. If the small perturbation is able to affect the parameters of the load connection within prescribed requirements, the active circuit causes the inverter to cease power conversion.

All of the methods evaluated are listed with all the common alternative names and the theory of operation is given for each. The strengths and weaknesses of each are treated individually, and the analysis for each is then reported using non-detection zone (NDZ) criteria to show the effectiveness of the method. No ranking is given to any of the methods.

Overview

This report provides an unbiased description of each of the islanding detection methods along with discussions of the strengths, weaknesses and non-detection zone characteristics. There is no attempt to draw conclusions on which method is best for given interconnect conditions or which, if any, could be recommended for interconnection.

The passive methods described and evaluated are methods such as:

- Over/under Voltage
- Over/under Frequency
- Voltage Phase Jump
- Detection of Voltage Harmonics
- Detection of Current Harmonics

The active islanding detection methods generally contain an active circuit to force voltage, frequency or the measurement of impedance. The methods analyzed are:

- Impedance Measurement
- Detection of Impedance at a Specific Frequency
- Slip-mode Frequency Shift
- Frequency Bias
- Sandia Frequency Shift
- Sandia Voltage Shift
- Frequency Jump
- ENS or MSD (a device using multiple methods)

The methods not resident in the inverter are generally controlled by the utility or have communications between the inverter and the utility to affect an inverter shut down when necessary. They are also discussed in detail and include:

- Impedance Insertion
- Power Line Carrier Communications
- Supervisory Control and Data Acquisition

1 Introduction

This report is a summary of evaluations of islanding detection methods for photovoltaic (PV) utility-interactive inverters. Islanding is a condition in which a portion of the utility system, which contains both load and generation, is isolated from the remainder of the utility system and continues to operate. The isolation point is generally on the low voltage distribution line when an islanding condition exists, but islanding may also occur on the higher voltage distribution or transmission lines when large numbers of PV inverters or other distributed generation is present. The islanding condition covered in this document occurs when the low voltage distribution lines are interrupted. A worst case for this condition is when the island is localized and major transformers are not part of the local island.

In photovoltaic distributed resource islanding, one or more non-utility generation sources (more specifically, sources over which the utility has no direct control) and a portion of the utility system operate while isolated from the remainder of the utility system. Many methods for detection of the islanding condition have been used. Requirements for the performance of these detection circuits have now been spelled out in Institute for Electrical and Electronic Engineers (IEEE), Underwriters Laboratories (UL), International Electrotechnical Commission (IEC) and other "National Standards" worldwide.

Utility-interactive PV inverter islanding may occur as a result of the following conditions:

1. A fault that is detected by the utility, and which results in opening a disconnecting device, but which is not detected by the PV inverter or protection devices.
2. Accidental opening of the normal utility supply by equipment failure.
3. Utility switching of the distribution system and loads.
4. Intentional disconnect for servicing either at a point on the utility or at the service entrance.
5. Human error or malicious mischief.
6. An act of nature.

2 Rationale for Anti-islanding Requirements

There are diverse motivations for preventing islanding when photovoltaic or any other distributed energy generation that is connected to a utility grid. Safety, liability and maintaining the quality of delivered power to customers rank high on the utility lists of reasons to prevent islanding without regard for costs and complexity. However, the probability of the matched (islanding) conditions lasting for enough time to create additional safety problems is very low and measured to be approximately 10^{-8} in a recent study conducted in the Netherlands. The fact that the addition of inverters to the grid does not significantly change the risks already in place needs additional study but is cited as a reason to ease the requirements for anti-islanding.

Today's scenario is that utilities are liable for providing quality power to paying customers; therefore, they currently require anti-islanding on PV inverters for the broad-based reasons listed below:

1. The utility cannot control voltage and frequency in the island, creating the possibility of damage to customer equipment in a situation over which the utility has no control.
2. Utilities, along with the PV distributed resource owner, can be found liable for electrical damage to customer equipment connected to their lines that results from voltage or frequency excursions outside of the acceptable ranges.
3. Islanding may create a hazard for utility line-workers or the public by causing a line to remain energized that is assumed to be disconnected from all energy sources.
4. Reclosing into an island may result in re-tripping the line or damaging the distributed resource equipment, or other connected equipment, because of out-of-phase closure.
5. Islanding may interfere with the manual or automatic restoration of normal service by the utility.

Note that islanding and its probability of creating an additional hazard to utility line-workers has been discussed extensively as a reason to require anti-islanding with photovoltaic inverters. Given the profusion of alternative generation that may now be connected to the utility grid, it is becoming essential that line-workers follow established rules for line maintenance and repairs. With line-workers operating under established hot-line rules or dead-line rules, an inverter islanding situation will not increase the probability for line-worker hazards.

Anti-islanding requirements have been evolving for many years and today they still vary considerably. Some countries such as the Netherlands require only passive frequency drift to destabilize an island condition with inverter shutdown associated with an out-of-frequency condition. Other countries such as Germany and Austria require a specific method based on sudden impedance changes and described as ENS or MSD in this report for detecting an island. The United States has adopted standards that require inverters to detect and shut down within a specific amount of time that is determined by the out-of-tolerance condition that exists on the island or on the utility grid. The National Electrical Code® requires that utility-interactive inverters be listed (certified) for the purpose, and the listing process tests the inverter using a standard test circuit and test method that has been determined to be a worst-case condition and is part of the UL1741 standard. The test method was chosen to allow any single inverter to be tested rather than requiring multiple inverter tests. The standards used for anti-islanding requirements and testing requirements for islanding detection are listed in the "Standards" (Section 10) of this report.

3 Glossary

AFD	Active Frequency Drift Anti-islanding Method
dpf	Displacement Power Factor
EMC	Electromagnetic Compatibility
ENS	Selbsttaetig wirkende Freischaltstelle mit 2 voneinander unabhängigen Einrichtungen zur Netzueberwachung mit zugeordneten allpoligen Schaltern in Reihe (also See MSD)
FCC	Federal Communications Commission
Hz	Hertz (cycles per second)
IEA	International Energy Agency
IEC	International Electrotechnical Commission
IEEE	Institute for Electrical and Electronics Engineers
Islanding	Islanding is a condition in which a portion of the utility system, which contains both load and generation, is isolated from the remainder of the utility system and continues to operate via a photovoltaic power source.
MPPT	Maximum Power Point Tracking
MSD	Mains Monitoring Units with Allocated All-pole Switching Devices Connected in Series (also see ENS)
NDZ	Non-Detection Zone
OFP	Over Frequency Protection Device or Method
OVP	Over Voltage Protection Device or Method
PCC	Point of Common Coupling
PJD	Phase Jump Detection Anti-islanding Method
PLCC	Power-line Carrier Communications
PLL	Phase Lock Loop
Q	Quality Factor of a Resistor, Inductor, Capacitor (RLC) Circuit
RFI	Radio Frequency Interference
SCADA	Supervisory Control and Data Acquisition
SFS	Sandia Frequency Shift Anti-islanding Method
SMS	Slip Mode Phase Shift Anti-islanding Method
SVS	Sandia Voltage Shift Anti-islanding Method
THD	Total Harmonic Distortion
UFP	Under Frequency Protection Device or Method
UL	Underwriters Laboratories, Inc.
UVP	Under Voltage Protection Device or Method
VCO	Voltage Controlled Oscillator
Z	Impedance

4 Methods for Detection of Islanding

Islanding detection methods may be divided into three convenient categories: passive inverter-resident methods, active inverter-resident methods, and methods not resident in the inverter including the use of communications between the utility and PV inverter. These methods are further described below:

1. Passive inverter-resident methods rely on the detection of an abnormality in the voltage at the point of common coupling (PCC) between the PV inverter and the utility.
2. Active inverter-resident methods use a variety of methods to attempt to cause an abnormal condition in the PCC voltage that can be detected to prevent islanding.
3. Active methods not resident in the inverter also actively attempt to create an abnormal PCC voltage when the utility is disconnected, but the action is taken on the utility side of the PCC. Communications-based methods involve a transmission of data between the inverter or system and utility systems, and the data is used by the PV system to determine when to cease or continue operation.
4. Passive methods not resident in the inverter such as utility-grade protection hardware for over/under frequency and over/under voltage protection relaying is the utility fall-back to assure loads are not damaged by out-of-specification voltage or frequency and may be required for very large PV installations.

In this section, we review the existing methods in each of these categories. For each method, we list similar methods with alternate names used in the literature, discuss its theory of operation, strengths, weaknesses, and also describe the non-detection zone (NDZ) of each method. The NDZ is the range of local loads (that is, loads within the potential island) for which the islanding prevention method under consideration can be made to fail to detect islanding. Special attention is given to the behavior of islanding prevention modes in the multiple-inverter case, in which several small PV systems may be operating in a given island instead of one large system.

It should be noted that it is usually assumed that the local load (the load inside the potential island) can be modeled as a parallel *RLC* circuit. This is done because for most islanding prevention methods it is some type of *RLC* load that causes the most difficulty in detection. In general, nonlinear loads such as harmonic-producing loads or constant-power loads do not present as much difficulty in islanding prevention [1,2].

In particular, *RLC* loads with a high value of the quality factor *Q* are problematic for islanding detection. The quality factor is defined as

$$Q = R\sqrt{\frac{C}{L}} \tag{1}$$

This parameter describes the relative amounts of energy storage and energy dissipation in the *RLC* circuit. High-*Q* loads generally have large capacitances and small inductances, and/or large parallel resistances. This is because large inductances typically have associated series resistance that lowers the Q of the circuit. Most of the islanding prevention methods described here have NDZs that encompass a range of high-*Q* *RLC* loads.

The reader is urged to bear in mind throughout these discussions that inverter-resident islanding prevention methods can have variations that are also dependent upon the implementation. One of the important variations includes dilution of detection sensitivity with multiple inverters. The selection of test methods must take into account the weaknesses discussed in this report. In order to fully eliminate any NDZ, islanding prevention methods that are not resident in the inverter are required.

Finally, it bears mentioning that the NDZs of many of the inverter-resident methods discussed here have been mapped in the *RLC* load space. To avoid lengthening this report excessively, all of those mappings are not repeated here, but the reader is encouraged to review references [1,2,3].

4.1 Passive Methods Resident in the Inverter

4.1.1 Under/over Voltage and Under/over Frequency

4.1.1.1 Similar Methodologies and Other Names

Standard Protective Relays; Abnormal Voltage Detection

4.1.1.2 Theory of Operation

All grid-connected PV inverters are required to have over/under frequency protection methods (OFP/UFP) and over/under voltage protection methods (OVP/UVP) that cause the PV inverter to stop supplying power to the utility grid if the frequency or amplitude of the voltage at the point of common coupling (PCC) between the customer and the utility strays outside of prescribed limits. (Note: These "protection methods" may not be actual physical relays; and, in fact, they are generally implemented in software.) These protection methods protect consumers' equipment but also serve as anti-islanding detection methods. Consider the configuration shown in Figure 1, in which power flows and node "**a**" have been labeled. Node "**a**" is the point of common coupling (PCC) between the utility and PV inverter. When the recloser is closed and the utility is connected, real and reactive power $P_{PV} + jQ_{PV}$ flows from the PV inverter to node "**a**", and power $P_{load} + jQ_{load}$ flows from node "**a**" to the load. Summing power flows at node "**a**",

$$\begin{aligned} \Delta P &= P_{load} - P_{PV} \\ \Delta Q &= Q_{load} - Q_{PV} \end{aligned} \tag{2}$$

is the real and reactive power flowing into node **"a"** from the utility. If the PV inverter operates with a unity power factor (that is, the PV inverter output current is in phase with the voltage at node **"a"**), then $Q_{PV} = 0$ and $\Delta Q = Q_{load}$.

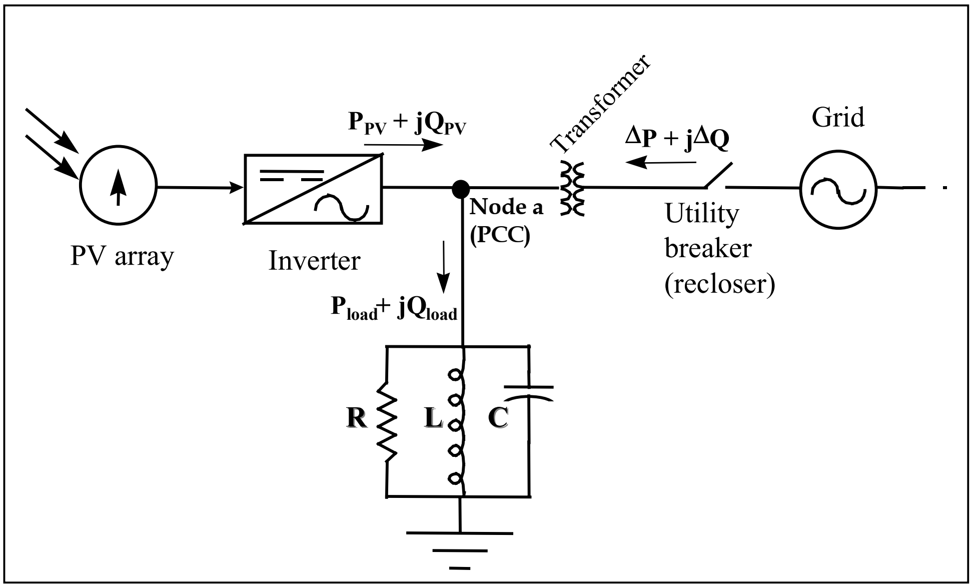

Figure 1. PV System/Utility Feeder Configuration Showing Power Flows and Terminology

The behavior of the system at the time of utility disconnection will depend on ΔP and ΔQ at the instant before the switch opens to form the island. If $\Delta P \neq 0$, the amplitude of v_a will change, and the OVP/UVP can detect the change and prevent islanding. If $\Delta Q \neq 0$, the load voltage will show a sudden shift in phase, and then the inverter's control system will cause the frequency of the inverter output current, and thus the frequency of v_a, to change until $\Delta Q=0$ (that is, until the load's resonant frequency is reached). This change in frequency can be detected by the OFP/UFP. Note that a fast tracking PLL changes the frequency but slower PLL circuits may limit the change in frequency and a step phase shift in voltage equal to the power factor will take place.

It bears repeating at this point that all PV inverters for utility interface applications are required to have various degrees of OVP/UVP and OFP/UFP protection in most countries. Therefore, if *either* the real power of the load and PV system (inverter output) is not matched, *or* the load's resonant frequency does not lie near the utility frequency, islanding will not occur. This covers the vast majority of practical cases.

4.1.1.3 Strengths

The OVP/UVP and OFP/UFP are required for several reasons other than islanding prevention. Also, several other islanding prevention methods act to produce an abnormal voltage frequency or amplitude, and rely on the OFP/UFP or OVP/UVP to actually deactivate the inverter. This is a low-cost option for detection of islanding. Cost is extremely important since a 1-kW PV system produces approximately $200 per year of energy and typically costs $6000 to install. Also in perspective, this is the same method used by utilities to assure loads and equipment are not damaged by out-of-spec conditions.

4.1.1.4 Weaknesses

The primary weakness of the OVP/UVP and OFP/UFP, in terms of islanding prevention, is their relatively large NDZ, as discussed below. In addition, the reaction times for these protective methodologies may be variable or unpredictable.

4.1.1.5 NDZ

If $\Delta P = \Delta Q = 0$ when the utility disconnects or opens, there will be insufficient change in the amplitude or frequency of v_a to activate any of the standard over/under voltage or frequency protection devices. This corresponds to a case in which the PV (inverter output) power production is matched to the load power requirement, and the load has a unity power factor at the line frequency. In reality, ΔP and ΔQ do not have to be exactly equal to zero for this to occur because the magnitude of the utility voltage can be expected to deviate slightly from nominal values, and therefore the thresholds for the four over/under protection devices cannot be set arbitrarily small or the PV inverter will be subject to nuisance trips.

The ΔP NDZ arises from Ohm's Law that states the load voltage is the load resistance times the inverter output current, which is constant. An inverter with UVP/ OVP trips at 88% and 110% will have an NDZ for a corresponding load range of up to 114% down to 91%. The ΔQ_{NDZ} can be calculated using the equations for reactive load imbalance and resonant frequency:

$$\Delta Q = V^2\left({}^{1}\!/_{X_C} - {}^{1}\!/_{X_L} \right)$$

where the fundamental frequency

$$F = 1/2\pi\sqrt{LC}$$

The literature suggests that the probability of ΔP and ΔQ falling into the NDZ of the OVP/UVP and OFP/UFP can, in some cases, be significant [4,5,6]. Because of this concern, the standard over/under voltage and frequency protective devices alone are generally considered to be insufficient anti-islanding protection. A mapping of the NDZ of the four standard over/under voltage and frequency protection methods in the *RLC* load space and the ΔP-ΔQ space can be found in the literature [1,3]. As an example, the NDZ of the over/under frequency protective devices in the *RLC* load space is plotted in Figure 2a. The figure shows a plot of normalized load capacitance as a function of load inductance. (For the frequency protection alone, the load resistance *R* plays no role, and thus does not appear in Figure 2a.) The normalized capacitance, C_{norm}, is defined as the load capacitance, C_{load}, divided by the capacitance that resonates with the load inductance L_{load} at the line frequency ω_{line}, denoted C_{res}:

$$C_{norm} = \frac{C_{load}}{C_{res}} = C_{load} L_{load} \omega_{line}^2 \tag{3}$$

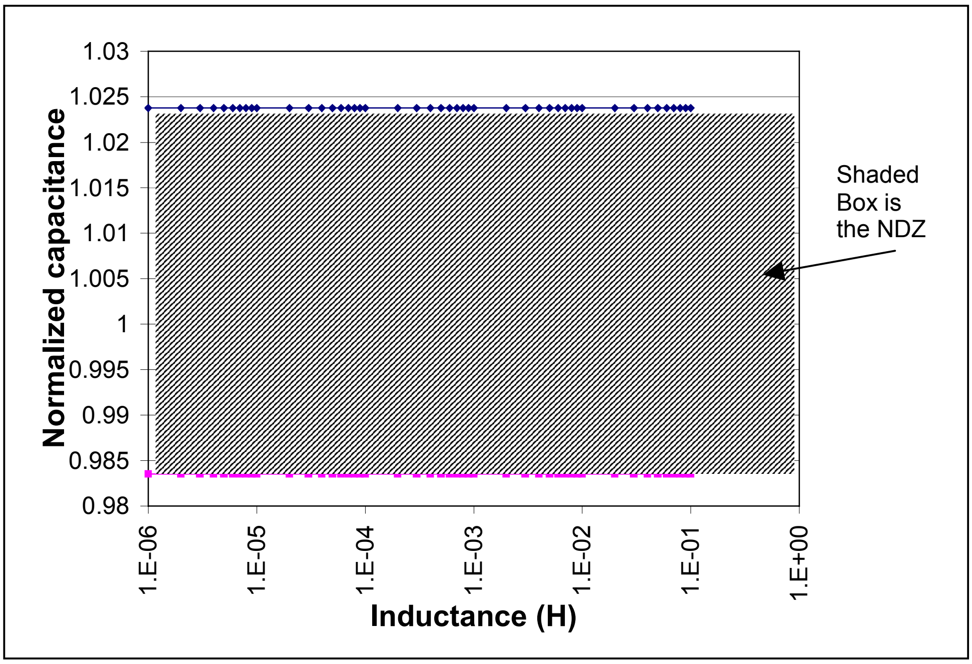

Figure 2a. Mapping of the NDZ of the Over/under Frequency Protective Devices in the *RLC* Load Space. (Note that for the frequency devices only, the load resistance has no effect, and thus only inductance and capacitance appear in the figure.)

The NDZ of the over/under frequency protective devices includes all *L* and *C* combinations falling in the cross-hatched area in Figure 2a. Figure 2b shows the same NDZ for changes of voltage and frequency.

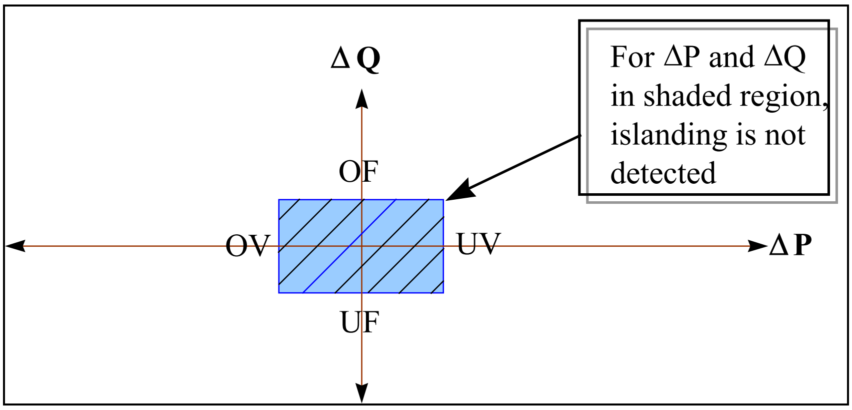

Figure 2b. Mapping of the NDZ in ΔP Versus ΔQ Space for Over/under Voltage and Over/under Frequency

4.1.2 Voltage Phase Jump Detection

4.1.2.1 Similar Methodologies and Other Names

Power Factor Detection; Transient Phase Detection

4.1.2.2 Theory of Operation

Phase jump detection (PJD) involves monitoring the phase difference between the inverter's terminal voltage and its output current for a sudden "jump" [7,8]. Under normal operation and for current-source inverters, the inverter's output current waveform will be synchronized to the utility voltage by detecting the rising (or falling) zero crossings of v_a at node **"a"** in Figure 1. This is generally accomplished using an analog or digital phase-locked loop (PLL) [9,10]. For voltage-source inverters the roles of voltage and current are reversed for the following discussion.

For current-source inverters, when the utility is disconnected, the voltage v_a is no longer rigidly fixed by the utility voltage source. However, the inverter output current $i_{PV\text{-}inv}$ is fixed, since it is still following the waveform template provided by the PLL in the inverter. This happens because the synchronization between $i_{PV\text{-}inv}$ and v_a occurs only at the zero crossings of v_a. Between zero crossings, the inverter is essentially operating in open-loop mode. Therefore, suddenly it is the PV inverter output current $i_{PV\text{-}inv}$ that becomes the fixed phase reference. Since the frequency has not yet changed, the phase angle of the load must be the same as before the utility disconnected, and therefore v_a must "jump" to this new phase as shown in Figure 3. At the next zero crossing of v_a, the resulting phase error between the "new" voltage and the inverter's output current can be used to detect islanding. If this phase error is greater than some threshold value, the controller can de-energize or shut down the inverter.

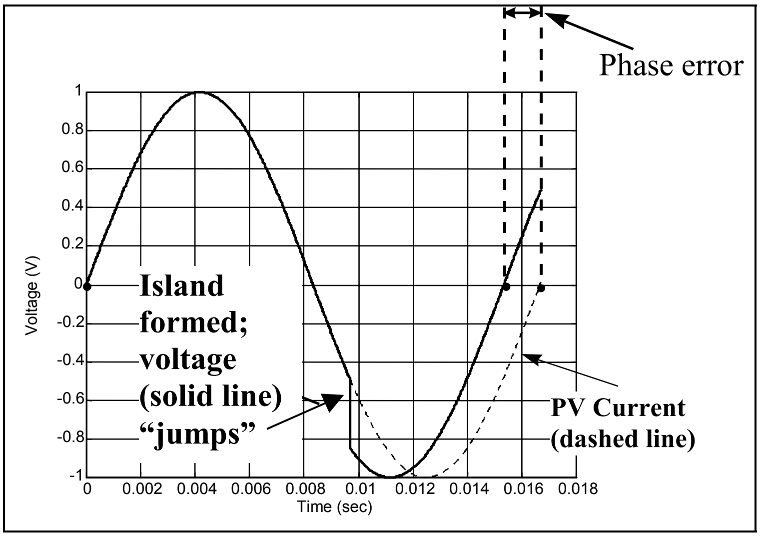

Figure 3. Diagram Showing the Operation of the Phase Jump Detection Method

4.1.2.3 Strengths

A major strength of PJD is its ease of implementation. Since the inverter requires a PLL for utility synchronization anyway, all that is required to implement PJD is to add the capability to deactivate the inverter if the phase error detected between $i_{PV\text{-}inv}$ and v_a exceeds some threshold. Also, as a passive method, PJD does not affect the output power quality of the inverter and does not impact system transient response. Finally, like most of the passive islanding prevention methods, the effectiveness of PJD is not reduced when multiple inverters are connected to the island.

4.1.2.4 Weaknesses

PJD suffers from a serious implementation difficulty in that it is difficult to choose thresholds that provide reliable islanding detection but do not result in frequent nuisance trips. The starting of certain loads, particularly motors, often causes transient phase jumps of significant size, and these will cause nuisance trips of the PV inverter if the thresholds are set too low. PJD thresholds could be altered for a given installation site, but such site-specific parameters increase the difficulty in installing utility-interactive PV systems.

4.1.2.5 NDZ

A load with a zero phase angle at the utility frequency will not produce a phase error when the utility is disconnected. Thus, PJD has an NDZ within the passive standard (utility) over/under protection devices. This NDZ can be changed when the inverter is operating at a non-unity power factor, but this is often undesirable from the utility's perspective, and it also requires the inverter to be capable of bi-directional power flow, which would make it more expensive. A mapping of this NDZ in the *RLC* load space can be found in the literature [1,3].

4.1.3 Detection of Voltage Harmonics and Detection of Harmonics

4.1.3.1 Similar Methodologies and Other Names

Detection of Impedance at a Specific Frequency

4.1.3.2 Theory of Operation

In this method, the PV inverter monitors the total harmonic distortion (THD) of the node **"a"** voltage v_a and shuts down if this THD exceeds some threshold. Under normal operation, the utility, being a "stiff" voltage source, forces a low-distortion sinusoidal voltage (THD $\approx$ 0) across the load terminals, causing the (linear) load to draw an undistorted sinusoidal current. Summing at node **a**, when the utility is connected the harmonic currents produced by the inverter will flow out into the low-impedance grid. Because these harmonic currents are kept small and the impedance of the utility is generally low, these harmonic currents interact with the very small utility impedance to produce only a very small amount of distortion in the node-**"a"** voltage. Typically, when the inverter is connected to the utility grid, the THD of the voltage v_a is below the detection point.

When an island occurs, there are two mechanisms that can cause the harmonics in v_a to increase. One of these is the PV inverter itself. A PV inverter will produce some current harmonics in its AC output current, as all switching power converters do. A typical requirement for a grid-connected PV inverter is that it produce no more than 5% THD of its full rated current [11,12]. When the utility disconnects, the harmonic currents produced by the inverter will flow into the load, which in general has much higher impedance than the utility. The harmonic currents interacting with the larger load impedance will produce larger harmonics in v_a [8]. These voltage harmonics, or the change in the level of voltage harmonics, can be detected by the inverter, which can then assume that the PV inverter is islanding and discontinue operation.

The second mechanism that may cause the harmonics to increase is the voltage response of the transformer shown in Figure 1. This second mechanism is currently not tested for using today's testing standards, but deserves mention at this time. When current-source inverters are used, and when the switch that disconnects the utility voltage source from the island is on the primary side of the transformer, as shown in Figure 1, the secondary of the transformer will be excited by the output current of the PV inverter. However, because of the magnetic hysteresis and other non-linearities of the transformer, its voltage response is highly distorted [8] and will increase the THD in v_a. There can also be non-linearities in the local load, such as rectifiers, which would similarly produce distortion in v_a. These non-linearities tend to produce significant third harmonics in general. Thus, when this method is used in practice it is frequently the third harmonic that is monitored. One other method tried in the past was detection of the PWM switching frequency on the output of the inverter.

4.1.3.3 Strengths

In theory, the voltage harmonic monitoring method promises to be highly successful in detecting islanding under a wide range of conditions [8], and its effectiveness should not change significantly in the multiple-inverter case.

4.1.3.4 Weaknesses

Harmonic detection suffers from the same serious implementation difficulty as PJD; it is not always possible to select a trip threshold that provides reliable islanding protection but does not lead to nuisance tripping of the PV inverter. It is clear that a threshold must be selected that is: (a) higher than the THD that can be expected in the grid voltage; but (b) lower than the THD that will be produced during islanding by either of the two mechanisms described above. Let us assume that the PV inverter produces 5% THD in its output current, the maximum allowable limit. For a resistive load fed by this current, in the absence of the utility voltage source, the THD of v_a will also be 5%. However, for RLC loads, it is possible for the THD of v_a to be less than

5%, because the parallel RLC circuit can exhibit low-pass characteristics that attenuate the higher frequencies. It is therefore clear that the THD threshold will have to be set lower than 5% [1]. In reality, the utility voltage distortion that we assumed to be ≈ 0 in the foregoing discussion can actually be expected to be 1-2% under normal conditions (because of the interaction of harmonic currents drawn or supplied by loads with the utility source impedance), but there are many conditions, such as the presence of power electronic converters that produce current harmonics at frequencies at which the utility system has resonance, which can cause this value to increase significantly [13]. Also, transient voltage disturbances, particularly large ones such as those that accompany the switching of capacitor banks [14], could be interpreted by PV inverter controls as a momentary increase in THD, depending on the measurement technique used. It is clear that in some cases it is not possible to select a threshold that meets criteria (a) and (b). It may be possible to overcome this problem using digital signal processing and harmonic signature recognition, but these techniques have not been implemented cost-effectively in small PV inverters. For these reasons, the harmonic monitoring technique has not been used commercially.

4.1.3.5 NDZ

This method can be made to fail if the load has strong low-pass characteristics, which occurs for loads with a high value of the quality factor Q, and for loads that may occur with a service entrance disconnect that do not include a transformer inside the island. It is also possible that a nonlinear load might exist that would require an input current with a harmonic spectrum matching that of the output current of the inverter, but in all likelihood this load is purely a theoretical abstraction. This method is prone to fail when loads at the generator shunt reactive currents. This method may also fail when inverters have high quality, low distortion outputs.

4.2 Active Methods Resident in the Inverter

4.2.1 Impedance Measurement

4.2.1.1 Similar Methodologies and Other Names

Power Shift; Current Notching; Output Variation

4.2.1.2 Theory of Operation

When the PV inverter appears as a current source to the utility

$$i_{PV-inv} = I_{PV-inv} \sin(\omega_{PV} t + \phi_{PV}) \tag{4}$$

There are three output parameters that may be varied: the amplitude I_{PV-inv}, the frequency ω_{PV}, and the phase ϕ_{PV}. In the output variation method, a variation is continuously imposed upon one of these parameters [8], usually the amplitude. When connected to the utility grid, the size of the voltage "perturbation" that results from a current amplitude "perturbation," which is also a “perturbation” in power, depends on the nominal values of utility resistance and power. The relationship is:

$$\Delta V = \frac{\Delta P}{2}\sqrt{\frac{R}{P}}$$

If the utility is disconnected, this variation will force a detectable change in v_a that can be used to prevent islanding. In effect, the inverter is measuring dv_a/di_{PV-inv}, and for this reason, this method is often called the impedance measurement method [15,16, 17,18]. As the inverter can be loaded so that the islanding voltage would fall to the limit of the grid-connected UVP/OVP window, the minimum current shift required for island detection is equal to the full UVP/OVP window size. For example, with grid-connected UVP/OVP at +/-10% of rated voltage, a 20% change in current is required.

4.2.1.3 Strengths

The primary advantage of the impedance measurement method is that theoretically it has an extremely small NDZ for a single PV inverter with any local load with impedance larger than the grid impedance. If the load and PV inverter output power is balanced upon disconnection of the utility, the output variation of the inverter will upset this balance and cause the UVP to trip.

4.2.1.4 Weaknesses

Output variation has many weaknesses. One that stands out is that the effectiveness of impedance methods decreases in the multi-inverter case. This happens even if all inverters in the island are using output variation, unless the variation is somehow synchronized. The reason is that as more inverters are added to the island, the amount of variation introduced by each inverter into the total i_{PV-inv} being generated by all PV inverters is reduced, and eventually the variation becomes so small that the change in v_a becomes undetectable. This phenomenon is demonstrated in the simulation shown in Figure 4. In the top panel, a single inverter’s output is shown. This system is designed to reduce its output power by 20% every 20 time-units. This single inverter probably would not island because the 20% power drop would most likely lead to a large enough drop in voltage to trip the UVP. However, the lower panel shows the power production of 50 inverters, all identical to the one in the top panel except that the 20% power “perturbations” are not synchronized. The maximum variation from the mean power production of the 50

PV inverters is less than 2%, and the UVP will probably no longer detect a trip condition.

In addition to the loss of effectiveness in the multiple inverter case, the output variation used to measure the grid impedance can create a multitude of other problems, particularly on high-impedance grids or when the output variation is synchronized. These problems include voltage flicker, grid instability, and false tripping, among others. A method to make sure multiple inverters do not vary output power at the same time will decrease magnitude of flicker but may still contribute to instability. These problems worsen as the connection density of PV inverters in a local area increases. These difficulties imply that impedance detection is suitable only for single small systems, and cannot be effectively used for either multiple small systems or single large systems.

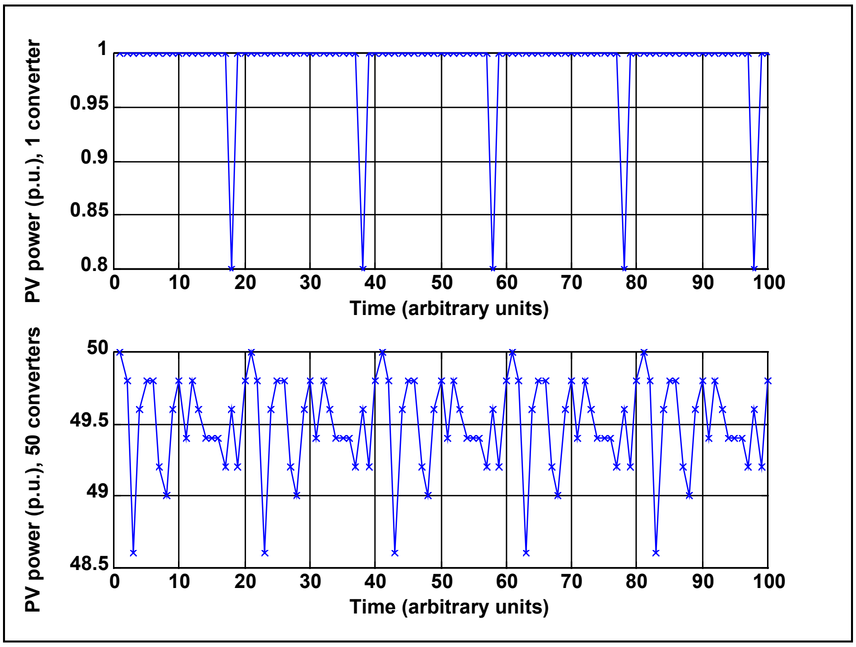

Figure 4. Simulated Demonstration of the Failure of the Impedance Measurement Method in the Multiple-inverter Case

4.2.1.5 NDZ

Even for very strong grids, the impedance of the utility voltage source is not zero. Therefore, it is necessary to set an impedance threshold, below which the impedance detection method assumes that the grid is still connected. This gives rise to an NDZ for this method; if a local load's impedance is less than the threshold, impedance detection would fail to recognize it as being a local load and would allow islanding to continue. This NDZ is probably of little practical consequence, because the grid impedance is usually very small, and a local load having impedance that is smaller than this would be an extremely high-power load (approaching a short circuit). Thus, it is believed that the loss of effectiveness in the multiple-inverter case is a more serious drawback. In higher-impedance grids, the impedance threshold would need to be set higher, increasing the size of the NDZ.

In summary, output variation can be an effective islanding prevention method, but only in the case in which the PV inverter output power is much less than the demand of the load and only one inverter is connected in the potential island. The combination of the weaknesses of this method and its loss of effectiveness in the multiple inverter case have led some to conclude that this method is of little practical value.

4.2.2 Detection of Impedance at Specific Frequency

4.2.2.1 Similar Methodologies and Other Names

Harmonic amplitude jump

4.2.2.2 Theory of Operation

This method is a special case of the Harmonic Detection method. The difference, and the reason that this method is considered active rather than passive, is that this method injects a current harmonic of a specific frequency intentionally into node **"a"** via the PV inverter. One variant of the Harmonic Detection method relies on those current harmonics that are unintentionally injected into node **"a"**. When the utility is connected, if the utility impedance is much lower than the load impedance at the harmonic frequency, then the harmonic current flows into the grid, and no abnormal voltage is seen.

Upon disconnection from the utility, the harmonic current flows into the load. If it is assumed that the local load is linear (i.e., can be represented by a parallel RLC circuit), then it is possible to inject a harmonic current into node **"a"**. The (linear) load then produces a harmonic voltage, which can then be detected. The name of this method derives from the fact that the amplitude of the harmonic voltage produced will be proportional to the impedance of the load at the frequency of the harmonic current.

4.2.2.3 Strengths

Because this method is a special case of the Harmonic Detection method, it has the same strengths as Harmonic Detection.

4.2.2.4 Weaknesses

This method has the same weaknesses as Harmonic Detection. It is possible to partially overcome this weakness if a sub-harmonic voltage is used. This is usually undesirable from the utility's perspective because, unless the sub-harmonic amplitude is very small, it can cause improper operation of equipment and problems with transformers [19]. Multiple inverters injecting the same harmonics may experience false trips as the amplitude of the voltage at that harmonic increases even with the low impedance grid connection and reducing the amplitude of the injected harmonic would dilute the detection method if an island were to occur.

4.2.2.5 NDZ

This method has the same NDZ as Harmonic Detection. Again, if a sub-harmonic is injected, this NDZ can usually be eliminated, but such sub-harmonic injection is usually problematic for the utility. This method dilutes in the multiple inverter application. Also, a load may exhibit a trapped frequency response that defeats the method

4.2.3 Slip Mode Frequency Shift

4.2.3.1 Similar Methodologies and Other Names

Slide Mode Frequency Shift; Phase Lock Loop Slip; "Follow the Herd"
Note that there are also similarities to the SVS and SFS except the acceleration (gain in this case) is nearly a constant value.

4.2.3.2 Theory of Operation

Slip-mode frequency shift (SMS) is one of three methods described in this report that uses positive feedback to destabilize the PV inverter when the utility is not present, thereby preventing the reaching of a steady state that would allow a long run-on. As noted in Equation 4 above, there are three parameters of the voltage v_a to which positive feedback can be applied: amplitude, frequency, and phase. All three possibilities have been explored. SMS applies positive feedback to the phase of the voltage v_a as a method to shift the phase hence the short-term frequency. The frequency of the grid will not be impacted by this feedback.

Normally, PV inverters operate at unity power factor, so the phase angle between the inverter output current and the PCC voltage is controlled to be zero (or as close to it as possible). In the SMS method, the current-voltage phase angle of the inverter, instead of always being controlled to be zero, is made to be a function of the frequency of the PCC voltage (v_a) as shown in Figure 5 and addressed in further detail in Figure 6. The phase response curve of the inverter is designed such that the phase of the inverter increases faster than the phase of the (*RLC*) load with a unity-power factor in the region near the utility frequency ω_0. This makes the line frequency an unstable operating point for the inverter [7]. While the utility is connected, it stabilizes the operating point at the line frequency by providing a solid phase and frequency reference. However, after the island is formed, the phase-frequency operating point of the load and PV inverter must be at an intersection of the load line and inverter phase response curve. Consider the load line of the unity power factor load shown in Figure 5. The load line and inverter curve intersect at the point labeled B, at a frequency of 60 Hz and a phase of zero, and operate there as long as the utility is connected. Now assume the utility is disconnected. If there is any small perturbation of the frequency of the node "**a**" voltage away from 60 Hz, the S-shaped phase response curve of the inverter causes the phase error to *increase*, not decrease. This is the positive feedback mechanism, and it causes a classical instability. This instability of the inverter at ω_0 causes it to reinforce the perturbation and drive the system to a new operating point, either at point A or C depending on the direction of the perturbation. If the inverter phase curve has been properly designed for this *RLC* load, points A and C will be at frequencies lying outside the OFP/UFP trip window, and the inverter will shut down on a frequency error.

SMS is implemented through the design of the input filter to the PLL. Consider first the case in which the PLL input filter does not have SMS. In this case, the inverter's current-voltage phase angle is zero for all line frequencies. If the frequency in the island were perturbed upward, the PLL would detect a negative phase error and would reduce its frequency to bring the PV inverter current and node **"a"** voltage into phase. Now consider the case in which the phase versus frequency characteristic of the PLL input filter is the SMS curve in Figure 6. When the frequency increases, because of the positive feedback on phase caused by the SMS characteristic in the input filter to the PLL, the PLL increases its frequency. The PLL's control action acts *in the wrong direction* to correct the phase error. This condition persists until a frequency is reached at which the load and inverter frequency response curves intersect again. This demonstrates the instability of SMS; it acts to drive the operating point of the system away from the utility frequency, because the SMS phase increases *faster than* and *in the opposite direction from* the phase of the RLC load.

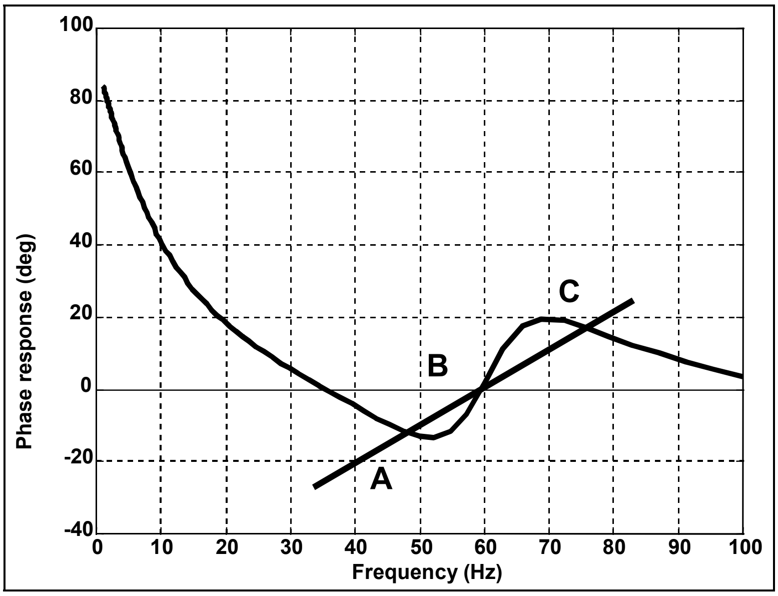

Figure 5. Plot of the Current-Voltage Phase Angle versus Frequency Characteristic of an Inverter Utilizing the SMS Islanding Prevention Method [7]

4.2.3.3 Strengths

This method, like many of the other active methods discussed here, is relatively easy to implement, since it involves only a slight modification of a component that is already required. Also, it is highly effective in islanding prevention (small NDZ), and when compared to other active methods. SMS is highly effective in the multiple inverter applications and provides a good compromise between islanding detection effectiveness, output power quality, and impact on the transient response of the overall power system.

4.2.3.4 Weaknesses

SMS requires a decrease in the output power quality of the PV inverter, albeit a small one. Also, at very high penetration levels and high gains in the feedback loop, SMS could potentially cause system-level power quality and transient response problems. This problem is common to all three methods utilizing positive feedback.

4.2.3.5 NDZ

This scheme has been shown to be highly effective, both theoretically and experimentally [7]. However, it is known that some RLC loads have phase response curves such that the phase of the load increases faster than the phase of the PV inverter [1,16]. This problem is demonstrated in Figure 6, which shows several *RLC* loads with frequency responses that defeat the instability of this particular SMS curve. For the top two loads in the legend, SMS works as described above, but for the bottom three the phase of the load increases faster than that of the inverter. For these loads, the nominal line frequency is a stable operating point and renders SMS ineffective. It has been shown that the loads that cause this problem--and thus lie in the NDZ of SMS--are the high-*Q* loads with resonant frequencies very near the line frequency [1,3]. A mapping of this NDZ in the *RLC* load space may be found in the literature [1,3].

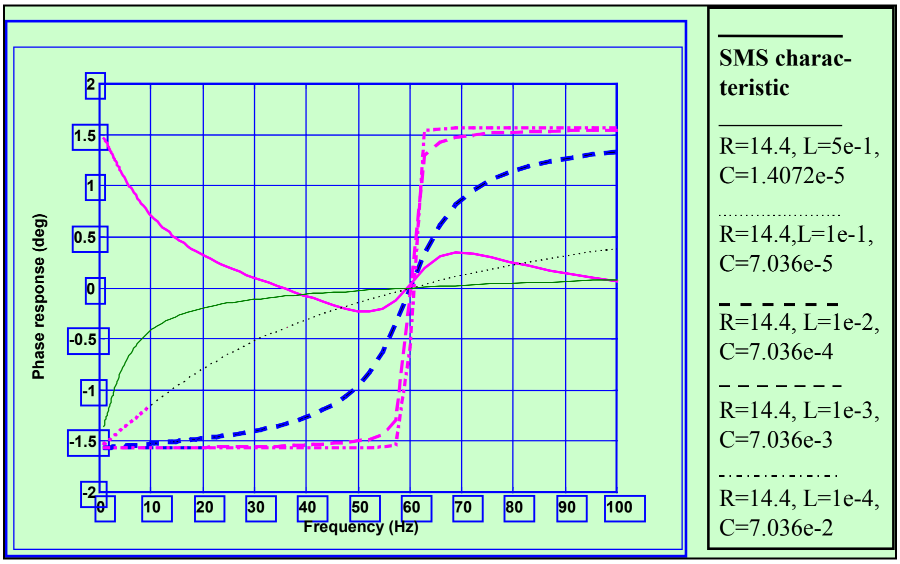

Figure 6. SMS Phase Response Curve and RLC Load Frequency Responses [1]

4.2.4 Frequency Bias

4.2.4.1 Similar Methodologies and Other Names

Frequency Shift Up/Down; Active Frequency Drift

4.2.4.2 Theory of Operation

The frequency bias or active frequency drift (AFD) method is easily implemented in a PV inverter with a microprocessor-based controller [16]. In this method, the waveform of the current injected into node **"a"** by the PV inverter is slightly distorted such that there is a continuous trend to change the frequency. When connected to the utility it is impossible to change the frequency.

When disconnected from the utility, the frequency of v_a is forced to drift up or down, augmenting the "natural" frequency drift caused by the system seeking the load's resonant frequency. An example of a PV inverter output current ($i_{PV\text{-}inv}$) waveform that implements upward AFD is shown in Figure 7, along with an undistorted sine wave for comparison. This can also be accomplished smoothly with little or no radio-frequency interference using smooth waveforms such as a second harmonic sine wave. T_{Vutil} is the period of the utility voltage, T_{Ipv} is the period of the sinusoidal portion of the current output of the PV inverter, and t_z is a dead or zero time. The ratio of the zero time t_z to half of the period of the voltage waveform, $T_{Vutil}/2$, is referred to as the "chopping fraction" (cf):

$$cf = \frac{2\,t_z}{T_{Vutil}} \qquad (5)$$

During the first portion of the first half-cycle, the PV inverter current output is a sinusoid with a frequency slightly higher than that of the utility voltage. When the PV inverter output current reaches zero, it remains at zero for time t_z before beginning the second half cycle. For the first part of the second half-cycle, the PV inverter output current is the negative half of the sine wave from the first half-cycle. When the PV inverter current again reaches zero, it remains at zero until the rising zero crossing of the utility voltage. It is important to note that the zero time in the second half cycle is not fixed and need not equal t_z.

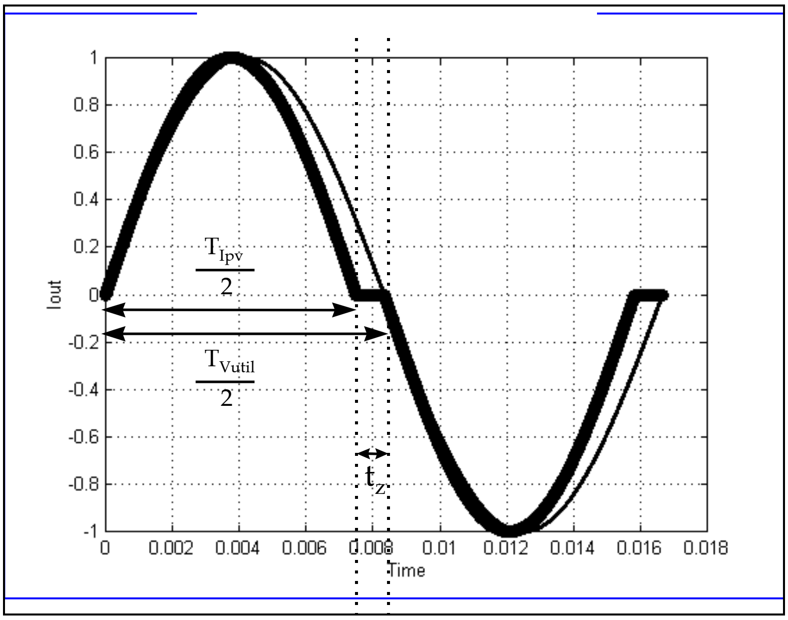

Figure 7. Example of a Waveform used to Implement the Frequency Bias Method of Islanding Detection. A Pure Sine Wave is Shown for Comparison.

When this current waveform is applied to a resistive load in an island situation, its voltage response will follow the distorted current waveform and go to zero in a shorter time (T_{Vutil} - t_z) than it would have under purely sinusoidal excitation. This causes the rising zero crossing of v_a to occur sooner than expected, giving rise to a phase error between v_a and $i_{PV\text{-}inv}$. The PV inverter then increases the frequency of $i_{PV\text{-}inv}$ to attempt to eliminate the phase error. The voltage response of the resistive load again has its zero crossing advanced in time with respect to where it was expected to be, and the PV inverter still detects a phase error and increases its frequency again. This process continues until the frequency has drifted far enough from ω_0 to be detected by the over/under frequency protection (OFP/UFP).

4.2.4.3 Strengths

In micro-controller-based inverters, this method is relatively easy to implement.

4.2.4.4 Weaknesses

Frequency bias requires a small degradation of the PV inverter output power quality. In addition, in order to maintain effectiveness in the multiple-inverter case, there would have to be agreement between all manufacturers of inverters in the direction of the frequency bias. If some inverters were biased upward but others downward, they could cancel each other out when the utility was disconnected. Discontinuous current waveforms may cause radiated and conducted radio frequency interference (RFI).

4.2.4.5 NDZ

The NDZ of the frequency bias method depends on the value of chopping fraction used. If the chopping fraction is small (< 1%), then the NDZ of frequency bias is essentially the same as that of SMS. As the chopping fraction increases, for low-*Q* loads the NDZ shifts toward capacitive loads (that is, loads with a non-unity, leading power factor). The NDZ for high-*Q* loads does not shift significantly for any value of chopping fraction. Also, the overall size of the NDZ is relatively large as compared with the NDZs of other active methods. It can be concluded that this method is not particularly effective in islanding prevention. A mapping of this NDZ in the *RLC* load space can be found in the literature [1,3]. It should be noted that the NDZ of the frequency bias method has been independently experimentally verified [1,17,18].

4.2.5 Sandia Frequency Shift

4.2.5.1 Similar Methodologies and Other Names

Accelerated Frequency Drift; Active Frequency Drift with Positive Feedback; “Follow the Herd”

4.2.5.2 Theory of Operation

Sandia Frequency Shift (SFS) is an extension of the frequency bias method, and is another method that utilizes positive feedback to prevent islanding. In this method, it is the frequency of voltage at node **“a”** to which the positive feedback is applied. There are two cases that must be considered. They are: (1) the inverter is bi-directional, and (2) the inverter is unidirectional. To implement the positive feedback, the “chopping fraction” defined in Figure 7 is made to be a function of the error in the line frequency:

$$cf = cf_0 + K\left(f_a - f_{\text{line}}\right) \tag{6}$$

Where cf_0 is the chopping fraction when there is no frequency error, K is an accelerating gain that does not change direction, f_a is the measured frequency of v_a, and f_{line} is the line frequency. Other functions of the frequency error are also possible, and some piecewise-linear functions have been employed with success.

When connected to the utility grid, minor frequency changes are detected and the method attempts to increase the change in frequency but the stability of the grid prevents any change.

When the utility is disconnected and as f_a increases the frequency error increases, the chopping fraction increases, and the PV inverter also increases its frequency. The inverter thus acts to reinforce the frequency deviation, and this process continues until the frequency reaches the threshold of the OFP. The process is similar if f_a decreases; eventually the chopping fraction becomes negative, meaning that the period of $i_{PV\text{-}inv}$ becomes longer than that of v_a. The advantages of acceleration for this method are explained in 4.2.6.2.

4.2.5.3 Strengths

This method is not difficult to implement, and has one of the smallest NDZs of all the active islanding prevention methods. It has been extensively studied and shown to be very effective [1,3,17]. Also, SFS, like SMS, appears to provide a good compromise between islanding detection effectiveness, output power quality, and system transient response effects. It should also be noted that SFS has been implemented in combination with the Sandia Voltage Shift (SVS) islanding prevention method. This combination has been found to be extremely effective [20].

4.2.5.4 Weaknesses

SFS requires that the output power quality of the PV inverter be reduced slightly when it is connected to the grid because the positive feedback amplifies changes that take place on the grid. Also, it is possible that the instability in the PV inverter’s power output can cause undesirable transient behavior in the system when a weak utility is connected. This problem would grow more severe as the penetration level of PV inverters into the network increased. Both of these effects can be managed by reducing the gain *K*, which increases the size of the NDZ. It is believed, although not yet proven, that of the three positive-feedback methods, this method will cause the least problems with transient response and power quality at high penetration levels. This belief stems largely from the fact that frequency tends to be a very tightly regulated parameter in power systems, in comparison with amplitude and phase.

This method and other positive feedback methods are usually stimulated by noise or harmonics on the reference waveform. Extremely high quality inverter waveforms, linear loads, and low noise decrease the sensitivity. Some inverters have passed anti-islanding testing at the manufacturing facility but have failed in well-controlled laboratory tests. The exact reasons are currently being investigated, but theory for some methods suggests the laboratory test setup used shielding and a very low noise test setup that reduced the trigger needed to initiate the positive feedback.

4.2.5.5 NDZ

SFS, like most of the other methods, has been shown to have an NDZ for loads with a large C, a small L, and/or high R, or in other words a very high value of quality factor *Q*. However, it has also been shown experimentally that this NDZ can be made extremely small. A mapping of this NDZ in the *RLC* load space can be found in the literature [1,3]. A non-islanding inverter can be manufactured for any practical Q, if K is sufficiently large, but this may lead to false trips and reduced power quality.

4.2.6 Sandia Voltage Shift

4.2.6.1 Similar Methodologies and Other Names

Voltage shift, positive feedback on voltage; “Follow the Herd”

4.2.6.2 Theory of Operation

This is the third method that uses positive feedback to prevent islanding. Sandia Voltage Shift (SVS) applies positive feedback to the amplitude of v_a. If there is a decrease in the amplitude of v_a (usually it is the RMS value that is measured in practice), the PV inverter reduces its current output and thus its power output. If the utility is connected, there is little or no effect when the power is reduced.

When the utility is absent and there is a reduction in v_a, there will be a further reduction in the amplitude of v_a as dictated by the Ohm’s Law response of the (RLC) load impedance to the reduced current. This additional reduction in the amplitude of v_a leads to a further reduction in PV inverter output current, leading to an eventual reduction in voltage that can be detected by the UVP. It is possible to either increase or decrease the power output of the inverter, leading to a corresponding OVP or UVP trip. It is however preferable to respond with a power reduction and a UVP trip as this is less likely to damage load equipment.

U.S. researchers have proposed and developed an acceleration concept of the response [2]. The concept is that the inverter responds to small changes in voltage or frequency with corresponding changes in real or reactive power that are sufficient to cause a further change in the same direction. If the voltage or frequency then continues to move in the same direction, each response is “accelerated” exponentially until a voltage or frequency trip occurs. For example, the reduction in power in response to an island could be 0.5%, 1%, 2%, 4%, 8%, 16%, and 32%, and then UVP would trip. Acceleration improves response time, keeps power changes very small (typically <1%) when the grid is present, and works in multiple-inverter systems.

4.2.6.3 Strengths

In micro-controller-based inverters, this method is easy to implement. Also, of the three positive feedback-based methods, it is believed that this one will be most effective in terms of islanding prevention. As was previously noted, SVS is commonly implemented simultaneously with SFS, and this combination of methods has been demonstrated to be highly effective in preventing islanding, with an NDZ so small that it is extremely difficult to locate experimentally [20].

4.2.6.4 Weaknesses

This method has two minor weaknesses. The first is that it requires a very small reduction in output power quality again because of the positive feedback with gain. The magnitude of this loss will be dependent upon the power quality of the grid to which it is connected. Secondly, there is a small reduction in the PV inverter's operating efficiency due to different maximum power point controls. Normally the PV inverter will be operated at its maximum power point via controls within the inverter but under normal operating conditions, small variations in the amplitude of v_a will cause the PV inverter to respond by reducing its power and moving the PV inverter off of the maximum power point for a period of time.

The second weakness of SVS is that there are indications that this method may have small impacts on the utility system transient response and power quality. If the preliminary indications were correct, penetration levels of inverters using SVS may have to be kept low on weaker grids in order to avoid system-level problems.

4.2.6.5 NDZ

SVS will have an NDZ similar to that of the four standard over/under voltage and frequency protection methods, lying in the range of *RLC* loads for which the real and reactive power requirements are almost exactly matched to the output of the PV inverter. However, this NDZ is significantly smaller than that of the over/under voltage and frequency protection methods. As was previously mentioned, this method has been demonstrated to be highly effective in laboratory experiments, particularly when used in combination with SFS [20]. The Q of the load has negligible effect on the operation of the method.

4.2.7 Frequency Jump

4.2.7.1 Similar Methodologies and Other Names

Zebra method

4.2.7.2 Theory of Operation

The Frequency Jump (FJ) method is a modification of the frequency bias method, and is conceptually similar to impedance measurement. In the FJ method, dead zones are inserted into the output current waveform, but not in every cycle. Instead, the frequency is "dithered" according to a pre-assigned pattern. For example, the dead zones might be inserted in every third cycle. In some implementations, such as the Zebra method, the dithering pattern can be quite sophisticated.

When connected to the utility grid, the frequency jump results in a modified inverter current $I_{pv\text{-}inv}$ that is occasionally distorted but the utility grid dominates the voltage waveform at v_a.

When disconnected from the utility, the FJ method prevents islanding either by forcing a deviation in frequency, as in the frequency bias method, or by enabling the inverter to detect a variation in the PCC voltage frequency that matches the dithering pattern used by the inverter.

4.2.7.3 Strengths

If the pattern is sufficiently sophisticated, FJ can be relatively effective in islanding prevention when used with single inverters.

4.2.7.4 Weaknesses

The primary weakness of the FJ method is that it, like the impedance measurement and frequency bias methods, loses effectiveness in the multiple inverter case unless the dithering of the frequency is somehow synchronized. If not, the variations introduced by the multiple inverters could act to cancel each other out, resulting in detection failure.

4.2.7.5 NDZ

It is thought that this method should have almost no NDZ in the single-inverter case, due to its similarity to impedance measurement. A coded frequency jump may improve the dilution with multiple inverters. Experimental results using the Zebra method support this conclusion [2].

4.2.8 Mains Monitoring Units with Allocated All-pole Switching Devices Connected in Series (MSD). Also called (ENS).

4.2.8.1 Similar Methodologies and Other Names

Sudden change in impedance, (ENS) Selbsttaetig wirkende Freischaltstelle mit 2 voneinander unabhängigen Einrichtungen zur Netzueberwachung mit zugeordneten allpoligen Schaltern in Reihe.

4.2.8.2 Theory of Operation

ENS is actually the description of an automatic isolating capability consisting of two independent, diverse parallel mains monitoring devices with allocated switching devices connected in series in the external and neutral conductor. In other words, the two switching devices in series are independently controlled. This method is currently a requirement for interconnection in Germany and Austria but is beginning to appear in imported inverters in the United States.

Multiple methods for detection of an island are used in the ENS. They are an impedance change detection method with additional over/under voltage and frequency trips. Each of these independent units continuously monitors the connected grid by monitoring voltage, frequency and impedance. The redundant design, as well as an automatic self-test before each connection to the grid, provides an improvement in the reliability of the method. The redundant design is shown in Figure 8. The different designs being used by manufacturers today vary according to when the design was implemented relative to the evolutionary improvements that have taken place.

All units monitor the utility voltage, frequency and impedance. When and how the impedance is checked by the method has been the focus of most evolutionary improvements. The general block diagram as outlined in German standard DIN VDE 0126 is shown in Figure 8.

Typically a small current pulse is injected into the utility by the device to determine the impedance. The circuit is designed to detect significant changes in impedance over a short period of time such as what would occur if the utility were to be disconnected. Typically the required change (when connected to the utility grid versus when disconnect from the grid) to be detected in impedance is $\Delta Zac > 0.5$ ohms for residential size inverters. Additional studies using the specific grid configuration, which varies considerably by country and sometimes by utility in the United States, and the rating of the inverter will likely find a different value for ΔZac.

The all-pole switches used in this method are required to have a load break rating according to the inverter's nominal power output and to have electromechanical elements such as relays or contactors. When the inverter utilizes an isolation transformer, one of the poles may use an interruptible semiconductor device provided the circuit checks its functionality on a prescribed and regular basis. All inverters using this method are required to undergo a 100% test on the circuit at the factory before delivery.

4.2.8.3 Strengths

The redundant design and regular self tests on inverter startup allow the user to install the unit without the need for periodic checks to determine if the anti-islanding circuitry is functional. The strengths described in the impedance measurement method above also hold for this method. Note, it is predicted, but not yet proven, that up to hundreds of units working together can be connected to a common feeder without interference.

4.2.8.4 Weaknesses

Since the impedance detection method utilizes a pulse of current injected into the utility, the same weaknesses as the output variation methods apply. For the multiple inverter situations, eventually there will be enough units connected to the same utility branch where their ENS injections will interfere with another or interaction of multiple units cause false trips. Most inverters manufactured today check for other ENS installations and adjust the current injection times in order to reduce the interference probabilities. Interference of multiple units may result in nuisance trips, but the new de-synchronized designs have increased the number of units that can be connected without interference. Dealing with variations in utility-line impedance is a weakness that will likely require several sets of firmware or software designs that increases the number of models and versions of software.

4.2.8.5 NDZ

Non-detection zones include values in impedance changes, voltages, and frequencies that result in conditions inside the detection limits. This is also similar to other impedance detection methods but is extremely unlikely with the impedance changes typically detected with ENS. Note also that the de-synchronization of the impedance detection times discussed under the weakness topic will actually increase the size of the non-detection zone as the number of inverters increases. Where the increase in non-detection zone and decrease in interference are optimized is still a topic for much study. The topic of whether multiple-inverter testing for certification and listing purposes (if so, how many) also must be addressed soon.

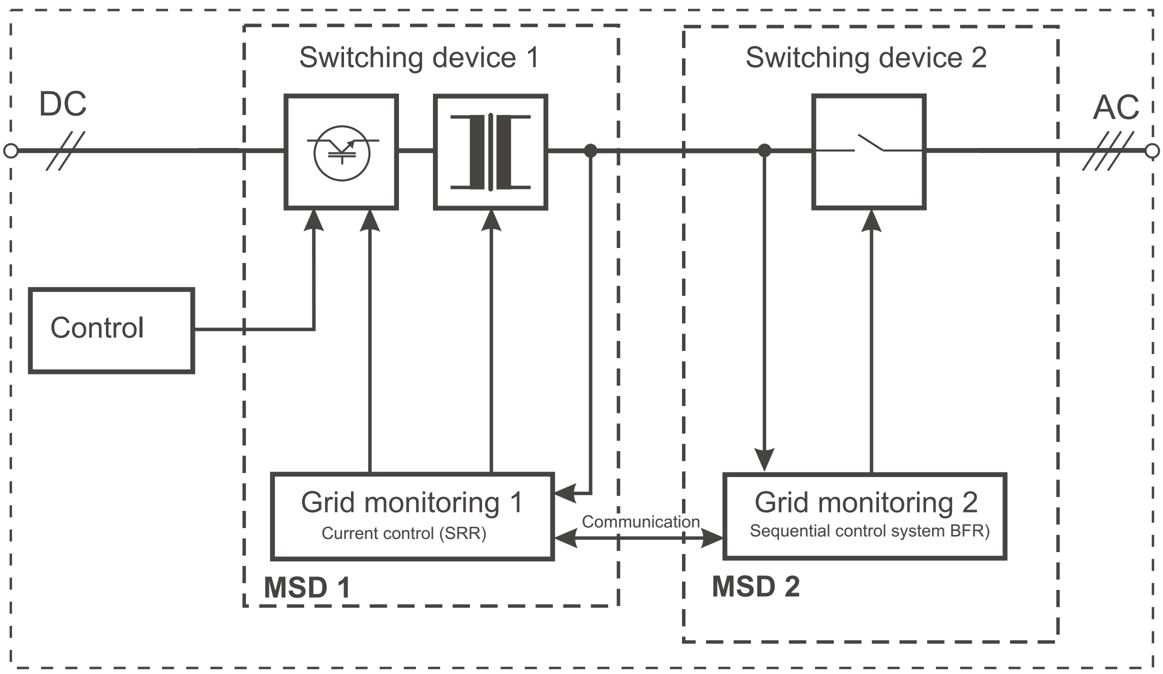

Figure 8. Design of an Automatic Disconnection Device According to DIN-VDE-0126

4.3 Methods at the Utility Level

4.3.1 Impedance Insertion

4.3.1.1 Similar Methodologies and Other Names

Reactance insertion; Resistance insertion

4.3.1.2 Theory of Operation

In the impedance insertion method, a low-value-impedance, usually a capacitor bank [21, 22, 23] is installed on the utility system inside the potential island at point **"b"** as shown in Figure 9. The switch is normally open. When the switch opens to interrupt the utility connection to node **"a"**, the capacitor bank switch is commanded to close after a short delay. If the local load were of the type that causes difficulty in islanding detection, the addition of the large capacitor would upset the balance between the generation and load, causing a step change in phase ø and a sudden drop in ω_{res} and leading to a frequency decrease that the UFP can detect.

The short delay between circuit interruption and switching in of the capacitor bank is necessary because it is theoretically possible for the addition of the large capacitor to compensate an inductive load, actually causing a balanced load and islanding detection failure. In this case, the load would be highly inductive before the addition of the capacitor bank, and there would be a large frequency deviation upon disconnection. The short delay allows sufficient time for this frequency deviation to be detected.

It is theoretically possible to use some other type of impedance as well, such as a large resistance that would cause a detectable change in the amplitude of the node **"a"** voltage. However, there are some advantages to using a capacitor, because such capacitor banks are the same design as those that serve as a reactive power support function for the utility.

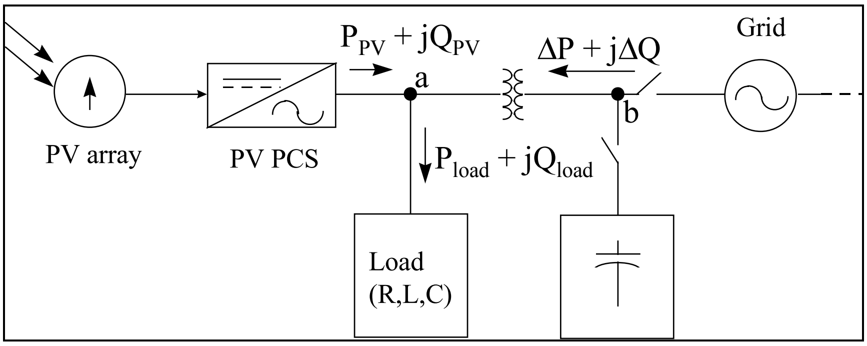

Figure 9. The Impedance Insertion Method Shown Implemented with a Capacitor Bank

4.3.1.3 Strengths

This method offers several advantages. It is highly effective in preventing islanding [21, 22] as long as the small delay is allowed between the time of switch opening and the time of capacitor insertion to ensure that insertion of the capacitor will not actually create a balanced situation between the PV inverter and a lagging load. Capacitors of this type are readily available, and utilities have a great deal of experience with them. As previously mentioned, the same capacitor bank could be used for reactive power (voltage) support and islanding prevention. This would be implemented by toggling the capacitor switch after the delay period expired (that is, if the capacitor were already activated, it would be switched out shortly after interruption of the main circuit).

4.3.1.4 Weaknesses

Impedance insertion has four serious drawbacks. One is that the capacitors needed add a great deal of expense to the PV or any distributed generation system, expense that can make the distributed generation economically unfeasible. Also, if multiple PV or distributed generation systems are installed at different times, it is unclear which party would be responsible for the expense of the capacitor bank. Another problem is that there may be multiple switches in series leading into the potential island, and possibly multiple branches capable of energizing the potential island, each with its own switch. Each switch would need to be equipped with a switchable capacitor bank, or communications would have to be provided between all switches and a central capacitor bank. (Note that if such communications were provided the capacitor might be redundant; the signal produced by the disconnect method discussed in section 4.4 might be possible instead.) A third problem is that its speed of response will be much slower than that of other methods, partially because of the speed of action of the capacitor switches but mostly due to the necessary delay in switching. The needed delay time in some cases could cause difficulties in compliance with standards. Finally, this method requires the installation of equipment on the utility side of the PCC. This greatly complicates the permitting and installation process, and utilities generally look unfavorably on such an arrangement.

4.3.1.5 NDZ

No non-detection zone has been described for this method, when it is properly coordinated (i.e. the proper delay in switching is provided). The method requires a minimum change in impedance and must be sized sufficiently to obtain the minimum $\Delta ø$ and/or Δf.

4.4 *Methods Using Communications Between the Utility and Photovoltaic Inverter*

4.4.1 Use of Power Line Carrier Communications

4.4.1.1 Similar Methodologies and Other Names
None.

4.4.1.2 Theory of Operation
The use of power line carrier communications (PLCC) has been proposed as a way to solve many of the problems associated with inverter-based islanding prevention methods [23,24,25]. PLCC systems send a low-energy communications signal along the power line itself. Figure 10 shows an example of a system configuration that includes a power line carrier method for islanding prevention. Because the line is used as the communications channel, it is possible to use the PLCC signal to perform a continuity test of the line. If such a PLCC signal is provided, a simple device installed on the customer side of the PCC can detect the presence or absence of the PLCC signal. If the PLCC signal disappears, this indicates a break in the continuity of the line, and the inverter can be instructed to cease operation. A PLCC transmitter (T) sends a signal along the power line to a receiver (R). Note that the receiver is located on the customer side of the PCC. The receiver can be included within the PCU, or it can be separate and communicate with the PCU, or it can contain its own circuit interrupter and not be connected to the PCU at all. When the PLCC signal is lost, the receiver can command the inverter(s) to cease operation, or it can open its own switch to isolate the PV inverter and load from the PCC.

PLCC-based islanding prevention could facilitate the use of PV as a backup power supply, because the receiver could disconnect the customer from the PCC with a utility signal without deactivating the inverter itself. This possibility could enhance the value of PV and other distributed generation to the utility and to the customer.

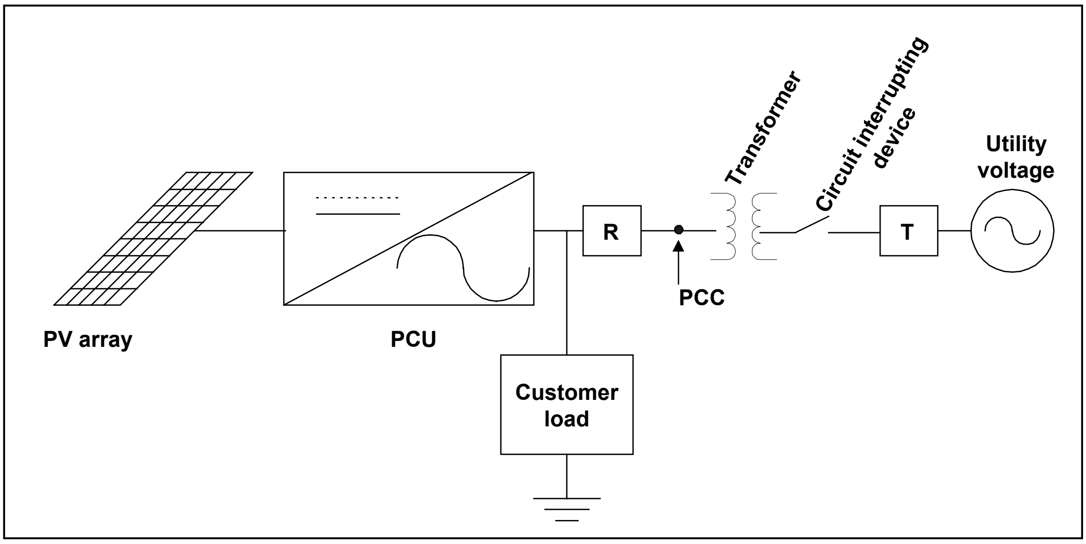

Figure 10. System Configuration Including a PLCC Transmitter (T) and Receiver (R)

It is possible to use an existing utility PLCC signal for islanding prevention, without interfering with its normal utility use and without decoding the information in the signal. The PLCC methods are currently used to load shed with signals sent from the utility to non-critical loads during periods of high loads and is used today in areas where there is high population density and industrialized customers. Alternatively, automated meter reading is using signals sent from the customer to the utility in a small number of distribution areas.

To be effective in this scheme, the PLCC signal should have three characteristics. First, it must be sent from the utility end to the customer end. Several PLCC systems used for automatic meter reading use a signal that is sent only from the customer end to the utility end. These could be used as part of a harmonic detection scheme as previously described, but obviously not as a PLCC-based continuity test of the line. Second, the signal should utilize a continuous carrier. If the carrier is intermittent, the ability to use it as a line continuity test is lost, because it is not possible to differentiate between a loss of signal due to a break in the line and a loss of signal due to cessation of transmission without decoding the signal. Also, the use of a continuous carrier makes the system essentially fail-safe, in that a failure of the transmitter or receiver results in a loss of the PLCC signal that would cause a PV inverter shutdown. Third, the signal should be one that will propagate well throughout the distribution network to which PV inverters are connected. Because the series inductances of transformers will block any high-frequency signals, this requirement will necessitate the use of low-frequency signals. Sub-harmonic signals would be preferred, as these would propagate easily throughout the system and would not be mistakenly produced inside an island except under highly abnormal conditions.

4.4.1.3 Strengths

PLCC-based islanding prevention has multiple strengths especially with increased connection density of distributed generation. First, it does not have an NDZ within the range of normally functioning loads, and promises to be extremely effective in islanding prevention. Second, it requires no degradation in the PV inverter's output power quality, and would not cause the PV inverter to have an adverse impact on system transient response or power quality. In fact, under certain circumstances, PLCC-based islanding prevention could actually improve the system-level performance by allowing the PV inverter and other distributed generation to "ride through" some disturbances and support the system voltage during these disturbances. Third, it is unaffected by the number of inverters on the system, and would be effective at any penetration level, with any size system, and with any type of distributed generator. Fourth, it is possible to use existing utility PLCC signals for this purpose without interfering with their normal functions using an inexpensive receiver [24]. Thus, there is no conflict between this and other uses of limited utility bandwidth. Fifth, if a signal of the type described above were used, only one transmitter would be required to cover a large section of the utility system. It would not be necessary to separately instrument series or parallel switches.

4.4.1.4 Weaknesses

PLCC-based islanding prevention has one primary weakness. To be implemented, there must be a PLCC transmitter on the utility system capable of sending signals through the distribution system to all inverters, as shown in Figure 10. Such transmitters do exist, but they are somewhat uncommon and quite expensive and would be economical only in high-density distributed generation areas. Also for commercial installations, unless the PV inverter that is being installed is very large the expense of adding a transmitter could be an insurmountable barrier to using this method.

4.4.1.5 NDZ

It is possible that a load inside the island could replicate the PLCC signal, even if a sub-harmonic carrier is used. For example, it has been shown that motors subjected to externally applied vibrations will draw harmonic currents, which in an islanded situation could produce harmonic voltages [25]. If these harmonics coincide with the PLCC carrier, it would be possible for the PLCC-detecting device to detect this signal instead and fail to disconnect the PV inverter from the PCC. Other conditions, such as ferro-resonance, have also been mentioned as potential producers of sub-harmonics that could cause the failure of a PLCC-based islanding prevention system. However, it appears that only loads operating under highly abnormal conditions could cause such problems. In addition, it should be borne in mind that islanding is far less likely with nonlinear loads in general, as mentioned previously. In any case, it should be possible to eliminate this problem using a small amount of information in the PLCC signal in the form of multiple carriers or frequency hopping.

4.4.2 Signal Produced by Disconnect

4.4.2.1 Similar Methodologies and Other Names

None

4.4.2.2 Theory of Operation

Like the PLCC-based method just described, the Signal Produced by Disconnect (SPD) method also relies on communication between the utility and PV inverters to prevent islanding. SPD differs from the PLCC-based method in that the power line is not used as the communications channel. Instead, the utility recloser is equipped with a small transmitter that sends a signal to the distributed generator via microwave link, telephone line, or other means, when the recloser opens. In this way, the state of the switch is directly communicated to the distributed generator. Also, when using this method a continuous carrier signal should be used. This will prevent a failure of the method due to a malfunctioning transmitter, channel, or receiver.

4.4.2.3 Strengths

The SPD method should be effective in islanding prevention, if the weaknesses addressed below are overcome. Also, this method would allow additional control of the distributed generators by the utility, resulting in coordination between distributed generators and utility resources. An example of a situation under which such coordination would be useful would be a black-start condition. Inverters could be used to help bring weak sections of the grid back on-line, and control and coordination of the inverters and utility could improve the system start-up characteristics.

4.4.2.4 Weaknesses

This method suffers from many drawbacks. It would be necessary to instrument all series or parallel switches leading to a potential island, as was the case with impedance insertion. If a telephone link were used, additional wiring to every distributed generator in a potential island would be necessary. This could be avoided using a microwave link, but such a link would require FCC licensing, and "coverage holes" could exist in an area that could potentially form an island, so that PV inverters in certain locations might have difficulty receiving the signal without repeaters or boosters. The foregoing problems make it clear that this method would be relatively expensive and could involve significant permitting and design complications.

4.4.2.5 NDZ

No NDZ has been described for this method.

4.4.3 Supervisory Control and Data Acquisition (SCADA)

4.4.3.1 Similar Methodologies and Other Names

None

4.4.3.2 Theory of Operation

The inclusion of inverters within SCADA systems is a logical choice for islanding prevention. Utility systems already use an extensive communications and sensing network to control their own systems, monitor the state of their systems, and enable rapid responses to contingencies. Most utility systems include instrumentation from the highest transmission voltage level down to the lowest-level controllable switching device in the distribution system (usually in a distribution substation), and thus SCADA networks cover much of the grid.

The use of SCADA for islanding prevention is straightforward. When a PV inverter is installed, voltage-sensing devices could be installed in the local part of the utility system, if such sensors were not already available. If these sensors detect a voltage at a time when the utility source is disconnected from that part of the system, alarms could be sounded or corrective action taken. For example, if a customer-side voltage were detected after manual operation of a switch, an alarm could be sounded to alert service personnel that the line is still energized. Also, a recloser might be coordinated with the inverter such that out-of-phase reclosure does not occur. Alternatively, if an abnormal customer-side voltage is detected, the recloser might allow a longer "off" interval before locking out, giving the inverter sufficient time to get off-line before reclosure. Finally, if the inverter were connected to the SCADA system, the utility could exercise some control over the inverter.

4.4.3.3 Strengths

The strengths of SCADA are essentially the same as those of the signal produced by disconnect method just described. If the system is properly instrumented and the necessary communications links are all available, this method should eliminate islanding and provide the benefits of partial or full DG control by the utility.

4.4.3.4 Weaknesses

This method also shares many of the weaknesses of the signal produced by disconnect method. If there were multiple inverters, they would all require separate instrumentation and/or communications links. Another problem is that this method requires major utility involvement in the inverter installation and permitting process, which would be a significant complication for smaller systems and could tax utility resources. In addition, it is important to note that SCADA systems often do not extend into the system below the substation level, but below the substation level is probably where most small inverters would be deployed.

4.4.3.5 NDZ

Properly implemented, this method should not have an NDZ.

5 Rationale for Anti-island Test Methods

Accepted testing procedures by which PV inverter controls can be verified to detect an islanding condition and cause the inverter to cease feeding power to the loads normally serviced by the utility grid are needed for interconnection. Testing procedures for islanding prevention measures contribute to establishing safe and reliable operation of PV systems connected to utility grids and they enhance the wide-spread use of environmentally friendly PV to supplement conventional power sources. Most countries are drafting anti-islanding requirements for interconnection. Testing procedures have been or are being written by the IEEE, IEC and UL that may be used to verify hardware meets the requirements.

One factor that varies widely with the established test requirements is the ability to test a single inverter versus the need to simultaneously test multiple inverters. The standards available today contain test requirements that attempt to limit the time and cost required for testing. A worst-case test condition is used in both of the tests described in Section 6. The severity of the test setup may be reduced but could result in requirements for multiple inverter tests. The high-Q for the test circuit in the IEEE Std. 929-2000 was intended for inverters rated at 10 kW and less and was chosen to allow testing agencies to minimize inverter testing by using a single unit, while assuring the anti-islanding circuits would be functional under multiple inverter connections. Both methods disconnect the utility on the PV inverter side of the local distribution transformer thus eliminating the non-linearity associated with the magnetizing currents of the transformer core. The non-linearity varies considerably and depends upon transformer design and impedance in the lines. Newer utility transformers typically are more efficient resulting in lower magnetizing currents and more linear operation.

One of the optional components shown in Figure 11 is a motor. Many researchers have included a single-phase induction motor with a high-inertia rotating load along with the parallel RLC in their tests. Some have found that including the motor can result in longer run-on times but further analysis is needed to assure equivalency of the static and rotating loads. It has been hypothesized that this extended run-on time is the result of the high-Q tuned RLC circuit established by the motor and not a result of the inertia of the motor [26].

There has been much discussion on whether it is necessary to include such motors in the islanded load, and studies on this subject are ongoing. The available evidence to date, however, suggests that the single-phase motor case can be simulated using the parallel RLC only, perhaps with a small adjustment of the quality factor Q, and that it is not necessary to include motors when testing islanding prevention methods. Further, the effective rotational frequency of an induction motor is always less than the theoretical for a given line frequency due to slip. The induction motor alone is incapable of supplying power at the line frequency [26].

All test methods today use utility disconnect criteria that disconnect the local distribution transformer from the island leaving only the local loads. In reality, this is an extremely unlikely configuration for an unexpected island. Islands without the transformer connected are most likely when the local service has been disconnected for maintenance or service. With the transformer connected, the inverter must be capable of supplying the non-linear currents and harmonics required to magnetize the connected transformers (magnitude depends upon the transformer design and size) once the utility is disconnected. Because the feedback used by the inverter tries to keep the voltage and the inverter output current in phase, most inverters, and all current source inverters, are theoretically incapable of supplying the magnetizing current and the island cannot be sustained.

6 Anti-islanding Test Methods and Test Circuits

Anti-islanding test methods, circuits and procedures have been documented in several published standards and are now being included in a multitude of standards being written by international standards groups and several standards groups associated with individual countries. In evaluating the standards already published and those being written, there seems to be a wide variation in approaches to verify the anti-islanding circuitry and methodology are meeting the interconnect requirements for all countries. The test methods are generally written to include single- and three-phase inverters and requirements for rotating loads such as unloaded motors are often included.

6.1 USA (IEEE Std. 929-2000) and (UL1741) Standards Methods

There is now an accepted worst-case testing procedure in the U.S. by which PV inverter controls can be verified to be incapable of maintaining a distributed resource islanding condition. The test is to attempt to island the inverter under test with an RLC load that has been tuned to the local utility operating frequency – 60 Hz in North America. This load should have a real power match as close as reasonable (test procedures appear in annex A of IEEE Std 929-2000) to the PV inverter output, and a $Q \leq 2.5$, where Q is the quality factor defined in Equation (1). Because the test conditions include a worst-case assumption that the reactive supply from capacitors exactly matches the inductive load (both are linear), Q can be mathematically associated with the power factor of an uncorrected line. That is, even though the line may have capacitors connected to improve power factor, the following calculation is performed using the power factor of the utility line, as it would be without the capacitors connected. Then Q=tan(arccosine[pf]). Thus, the selected Q of 2.5 equates to a power factor of 0.37. The test requirement that $Q \leq 2.5$ (equating to utility lines with uncorrected power factors from 0.37 to unity) has been determined to cover all reasonable distribution line configurations. Note the local distribution transformer is not part of the islanded circuit for this standard and that this test was written to test inverters rated at 10 kW and less. Large systems have typically used conventional utility protection relay equipment. Testing very large inverters to the 929 test criteria requires very large capacitors and inductors and becomes economically restrictive.

This islanding detection test with a tuned RLC load is included in the minimum test procedure for a non-islanding PV inverter described in Annex A (Minimum test procedure for a non-islanding PV inverter) of the IEEE Std. 929-2000 standard and is currently included in UL Standard 1741 for inverters of less than 10 kW capacity.

A minimum test procedure as described in IEEE Std. 929-2000 is reproduced here for convenience.

a) Connect the output of the inverter to a simulated utility source that is capable of absorbing the energy to be delivered by the inverter. It is not necessary to run the inverter at full output to verify the fixed frequency and voltage set points.

b) Adjust the simulated utility source to nominal frequency and voltage and verify the inverter is delivering power.

c) Verify the voltage trip points and time to trip as specified in Table 1 of this recommended practice by raising and lowering the voltage to values outside the normal operating windows.

d) Verify the frequency trip points and time to trip by varying the frequency at a rate no faster then 0.5 Hertz per second to the trip points specified in Table 1.

e) Following disconnection from the simulated utility source, restore the voltage and frequency to the nominal output values of the inverter and verify that:

    1) An inverter that is provided with manual reset remains disconnected from the simulated utility source.

2) An inverter with automatic reset does not reconnect to the simulated utility source until the utility voltage and frequency are restored for the period specified in Table 1.

Table 1. Response to Abnormal Voltages (From IEEE Std. 929-2000) [S3]

Voltage (at PCC)		Maximum Trip Time*
V< 60	(V<50%)	6 cycles
60≤V<106	(50%≤V< 88%)	**120 cycles**
106≤V≤132	(88%≤V≤110%)	Normal Operation
132<V<165	(110%<V<137%)	120 cycles
165≤V	(137%≤V)	2 cycles

*Note: *"Trip time" refers to the time between the abnormal condition being applied and the inverter ceasing to energize the utility line. The inverter may remain connected to the utility to allow sensing for use by the "reconnect" feature.*

Each of the above tests shall be repeated 10 times. The actual tripping time shall be recorded in each test. A single failure of any of these tests is considered a failure of the entire test sequence.

6.1.1 Test procedure to Verify Non-islanding

Figure 11 shows a recommended test circuit for conducting the IEEE Std. 929-2000 testing. Once the fixed frequency and voltage limits have been verified, test to determine that the inverter cannot maintain stable operation without the presence of a utility source. A utility source means any source capable of maintaining an island within the recommended voltage and frequency windows. An engine-generator with voltage and frequency control and with no anti-islanding protection is considered a utility source for the purpose of this test. However, because of the uncertainty associated with the need to sink both real and reactive power from the inverter, this test may be performed most conveniently with a utility connection, rather than a simulated utility. This test should be conducted with voltage and frequency values set near the middle of their operating ranges. Voltage should be at least 3% inside the most restrictive voltage trip limits. Frequency should be at least 0.25 Hertz inside the most restrictive frequency trip limits. (Note that frequency and voltage variation are not required for this testing.)

This test procedure is based on having the Q of the islanded circuit (<u>including</u> load <u>and</u> inverter) set equal to 2.5 and having the load at resonance or unity power factor at the line frequency. The definitions for distributed resource (PV system) islanding and the point of common coupling imply how this should be done. From the definition for quality factor

$$Q = (1/P)\sqrt{P_{qL} \times P_{qC}} \tag{7}$$

Note also that, in the resonant case

$$P_{qL} = P_{qC} = P_q \tag{8}$$

Therefore, in the resonant case,

$$Q = P_q/P. \tag{9}$$

These formulas apply to the unity-power-factor inverter.

6.1.2 General Test Setup Precautions

In reality, the test setup as described in 6.1.1 must use values for L and C that also compensate for the output reactance of the inverter.

One of the optional components shown in the Figure 11 is a motor. Many researchers have included a single-phase induction motor with a high-inertia rotating load along with the parallel RLC in their studies, and some have found that including the motor can result in longer run-on times.

Recently, there has been much discussion on whether it is in fact necessary to include such motors in the islanded load, and studies on this subject are ongoing. However, the available evidence to date suggests that the single-phase motor case can be simulated using the parallel RLC only, perhaps with a small adjustment of the quality factor Q, and that it is not necessary to include motors when testing islanding prevention methods [26].

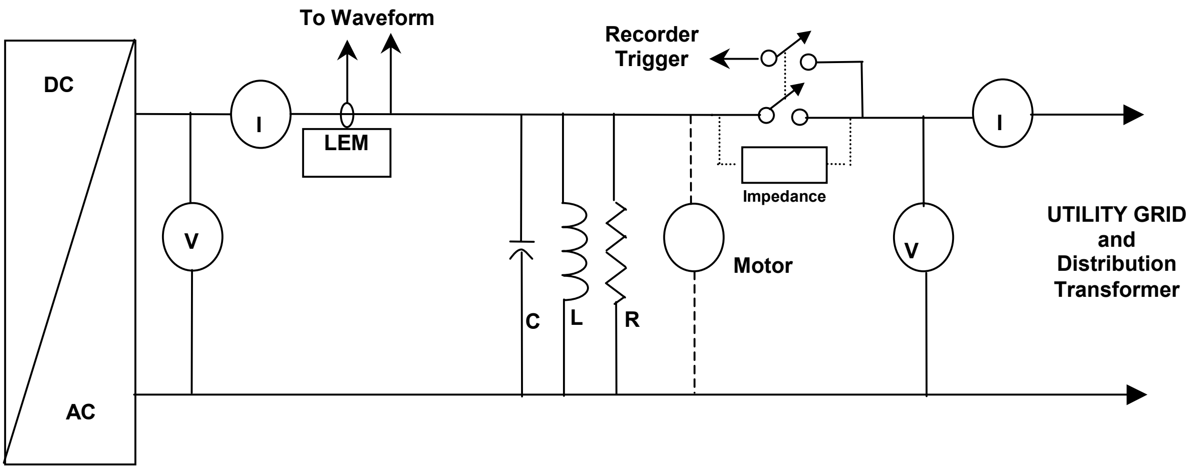

Figure 11. A Universal Test Circuit for Anti-islanding Test for IEEE Std. 929-2000 and UL1741.

An ongoing argument about the inclusion of the distribution transformer as a circuit element in the island is again at the forefront, with some advocating it must be included to simulate the most prevalent uncontrolled islanding condition. The addition of the distribution transformer to the test circuit combined with the inability of a current sourced inverter to supply sufficient reactive power would make islanding more easily detected. The minimum range of acceptable magnetizing current and the transformer impedance will need to be determined and specified for test condition consistency when transformers are included in the test.

6.1.3 Implementation Pitfalls

Because many of the anti-islanding detection methods are initiated by voltage and/or frequency variations, the level of electrical and measuring circuit noise can significantly affect test results. The impedance of the utility grid or utility simulator can also influence the outcome of tests. Simulated utilities can simplify the testing procedure but the simulated voltage waveform must have specified harmonics and waveform quality in order to assure consistent results. The simulated utility must also represent the proper source impedance at fundamental and harmonic frequencies for the inverter under test.

Testing at various power levels is advised. It has been found experimentally that some inverters respond more quickly at lower power levels. Others have been found to react more quickly at or near rated power levels. Until all of the anti-islanding methods and models are thoroughly understood, testing over a range of power levels is necessary.

6.2 *International Standard IEC 62116*

The IEC 62116, an International Electrotechnical Commission Standard, is being prepared through IEC Technical Committee 82 - Solar Photovoltaic Energy Systems. This standard entitled “Testing Procedure Of Islanding Prevention Measures For Grid Connected Photovoltaic Power Generation Systems.” Figure 12 shows the recommended test configuration for conducting the anti-islanding tests under this standard. Note this method also uses a worst-case islanded circuit by not including the local distribution transformer after utility disconnect.

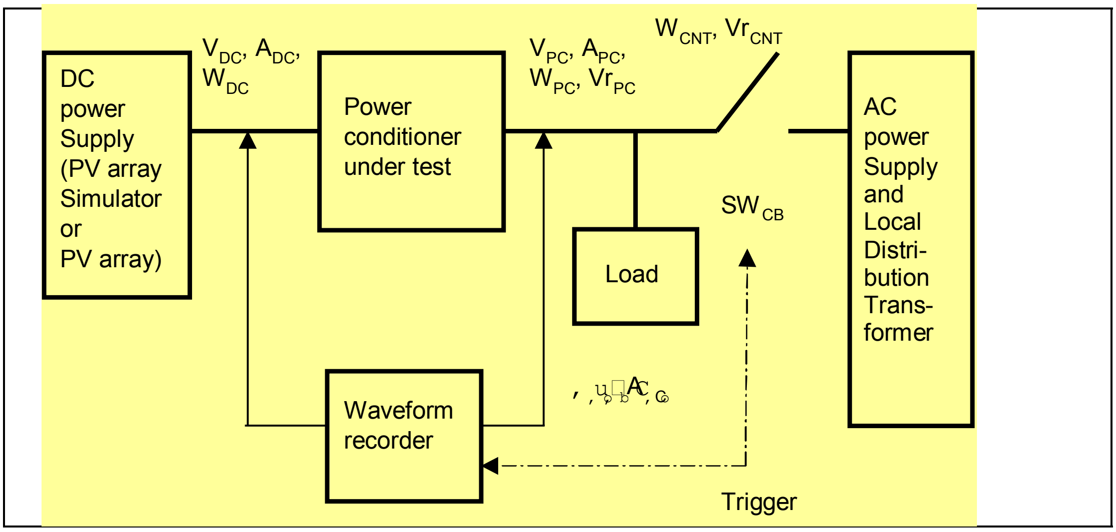

Figure 12. Suggested Anti-island Test Circuit in the DRAFT of the International Electrotechnical Commission Standard IEC 62116.

6.2.1 IEC Proposed Test Under Balanced Conditions of Generation Power and Load

The typical test configuration required to perform the tests in the IEC 62116 standard for anti-islanding applies to both:

(a) Conditions of AC and DC power supplies where AC voltage and frequency of AC power supply shall be adjusted to the rated values. DC power shall be adjusted so that the power conditioner operates at the rated output.

(b) Load conditions where rotating loads shall be operated with no load. Effective power and reactive power at the fundamental frequency flowing at SW_{CB} shown in Figure12 shall be set at 0 kW and 0 kVar respectively by means of adjusting resistance for effective power and inductance and /or capacitance for reactive power. In this condition, SW_{CB} shall be disconnected. Time is measured until the power conditioner output current supplied to loads becomes equal to zero.

Above test shall be repeated under the condition that the power conditioner output power is set at the 50% and 25% of the rated output.

Note 1: The fluctuation caused by control system like MPPT should be identified after testing several times.

Note 2: The load must consist of L and C that are as linear (as a function of the voltage frequencies present in the tests) as practical under the test conditions.

6.2.2 IEC Proposed Test Under Unbalanced Conditions of Generation Power and Load

In the case of a three-phase four-wire power conditioner and unbalanced load among phases, the test procedures are the same as the case of multiple power conditioners.

In the case of a three-phase three-wire power conditioner, the conditioner trips on over voltage or the phase difference under the unbalanced three-phase load. Typically, no test is carried out under the unbalanced three-phase load. The tests are conducted according to (a) and (b) below.

(a) Conditions of AC and DC power supplies where the voltage and frequency of AC power supply shall be adjusted to the rated values. DC power shall be adjusted so that the power conditioner operates under the rated output.

(b) Load condition where the rotating load is operated with no load. Effective power and reactive power flowing at SW_{CB} shown in Figure 12 shall be sequentially set to $\pm$20%, $\pm$15%, $\pm$10%, and $\pm$5% of output power of the power conditioner respectively by adjusting resistance, inductance, and/or capacitance.

In each condition, SW_{CB} shall be disconnected and the time measured until the power conditioner output current supplied to loads becomes zero.

Each test as described above shall be repeated under the condition that the power conditioner output power is set at the 50% and 25% of the rated output.

NOTE: The fluctuation caused by a control system such as the MPPT must be quantified by testing it several times.

6.2.3 Implementation Pitfalls

The same pitfalls described in 6.1.3 apply for this test method. It is also cautioned that the techniques used to implement an anti-islanding method can affect the NDZ of the method. Even though the techniques described are straight forward, an NDZ can easily be created due to errors in implementation. For example, insufficient voltage resolution with the SVS method may allow a NDZ for islands with extremely low noise and very high quality (low distortion) inverter sine waves.

7 Summary

Passive methods for detecting an islanding condition basically monitor selected parameters such as voltage and frequency and/or their characteristics and cause the inverter to cease converting power when there is a transition from normal grid connected conditions. Active methods for detecting the island introduce deliberate changes or disturbances to the connected circuit and then monitor the response to determine if the utility grid with its stable frequency, voltage and impedance is still connected. If the small perturbation is able to affect the parameters of the load connection within prescribed requirements, the active circuit causes the inverter to cease power conversion.

This report describes a broad range of methods for detecting the islanding condition. All of the methods are listed with alternative names. The theory of operation when connected to the utility grid and after the utility grid is disconnected is given for each. The strengths and weaknesses of each are treated individually, and each is then analyzed using the non-detection zone (NDZ) criteria to show the effectiveness of the method. No ranking is given to any of the methods.

The passive methods described and evaluated include:

- Over/under Voltage
- Over/under Frequency
- Voltage Phase Jump
- Detection of Voltage Harmonics
- Detection of Current Harmonics

The active detection methods for islanding that are typically resident in the inverter are also described. The active methods generally contain an active circuit to force voltage, frequency or the measurement of impedance. The methods analyzed are:

- Impedance Measurement
- Detection of Impedance at a Specific Frequency
- Slip-mode Frequency Shift
- Frequency Bias
- Sandia Frequency Shift
- Sandia Voltage Shift
- Frequency Jump
- ENS or MSD (a device using multiple methods)

The methods not resident in the inverter are generally controlled by the utility or have communications between the inverter and the utility to affect an inverter shut down when necessary. They are also discussed in detail and include:

- Impedance Insertion
- Power Line Carrier Communications
- Supervisory Control and Data Acquisition

This report also described the rationale for the need for anti-island test methods and test circuits. Several test methods that may be used for determining whether the anti-islanding method is effective were described in detail. Preliminary results of testing using motors instead of RLC circuits indicate islanding tests can be conducted using only RLC circuits. Most test circuits and methodologies prescribed in standards have been chosen to limit the number of tests by measuring the reaction of a single or small number of inverters under worst-case islanding conditions.

8 References [as indicated in this report]

[1] Ropp, M., *Design Issues for Grid-Connected Photovoltaic Systems*, Ph.D. dissertation, Georgia Institute of Technology, Atlanta, GA, 1998.

[2] Kern, G., Bonn, R., Ginn, J., Gonzalez, S., "Results of SNL Grid-Tied Inverter Testing," *Proceedings of the 2nd World Conference and Exhibition on Photovoltaic Solar Energy Conversion*, Vienna, Austria, Jul 1998.

[3] Ropp, M.E., Begovic, M., Rohatgi, A., "Determining the Relative Effectiveness of Islanding Prevention Techniques Using Phase Criteria and Non-detection Zones," *IEEE Transactions on Energy Conversion* vol. 15 no. 3, Sep 2000, p. 290-296.

[4] Begovic, M., Ropp, M., Rohatgi, A., Pregelj, A., "Determining the Sufficiency of Standard Protective Relaying for Islanding Prevention in Grid-connected PV Systems," *Proceedings of the 26th IEEE Specialists Conference,* Sep 30-Oct 3, 1997, p. 1297-1300.

[5] Kobayashi, H., Takigawa, K., "Statistical Evaluation of Optimum Islanding Preventing Method for Utility Interactive Small Scale Dispersed PV Systems," *Proceedings of the First IEEE World Conference on Photovoltaic Energy Conversion (1994),* p. 1085-1088.

[6] IEEE Std. 929-2000, *IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) Systems*, Sponsored by IEEE Standards Coordinating Committee 21 on Photovoltaics, IEEE Std. 929-2000, Published by the IEEE, New York, NY, Apr 2000.

[7] Jones, R., Sims, T., Imece, A., Investigation of Potential Islanding of Dispersed Photovoltaic Systems, Sandia National Laboratories report SAND87-7027, Sandia National Laboratories, Albuquerque, NM, 1988.

[8] Kobayashi, H., Takigawa, K., Hashimoto, E., "Method for Preventing Islanding Phenomenon on Utility Grid with a Number of Small Scale PV Systems," *Proceedings of the 21st IEEE Photovoltaic Specialists Conference (1991),* p. 695-700.

[9] Best, R., Phase-Locked Loops: Theory, Design, and Applications, 2nd. Ed., pub. McGraw-Hill Inc., 1993.

[10] Brennan, P.V., Phase-Locked Loops: Principles and Practice, pub. MacMillan Press Ltd., 1996.

[11] Ranade, S.J., Prasad, N.R., Omick, S., Kazda, L.F., "A Study of Islanding in Utility-Connected Residential Photovoltaic Systems, Part I: Models and Analytical Methods," *IEEE Transactions on Energy Conversion,* vol. 4(3) Sep 1989, p. 436-445.

[12] Wills, R.H., The Interconnection of Photovoltaic Systems with the Utility Grid: An Overview for Utility Engineers, a publication of the Sandia National Laboratories Photovoltaic Design Assistance Center, publication number SAND94-1057, Oct 1994.

[13] Handran, D., Bass, R., Lambert, F., Kennedy, J., "Simulation of Distribution Feeders and Charger Installation for the Georgia Tech Olympic Electric Tram System," *Proceedings of the 5th IEEE Workshop on Computers in Power Electronics,* Aug 11-14 1996, p. 168-175.

[14] Grebe, T.E., "Application of Distribution System Capacitor Banks and Their Impact on Power Quality," *IEEE Transactions on Industry Applications* 32(3), May/Jun 1996, p. 714-719.

[15] Becker, H., Gerhold, V., Ortjohann, E., Voges, B., "Entwicklung, Aufbau und erste Testerfahrung mit einer Prüfeinrichtung zum Test der automatischen Netzüberwachung bei netzgekoppelten Wechselrichtern". Paper supplied by Dr. Paul Lynn, managing editor of *Progress in Photovoltaics*.

[16] Yuyama, S., Ichinose, T., Kimoto, K., Itami, T., Ambo, T., Okado, C., Nakajima, K., Hojo, S., Shinohara, H., Ioka, S., Kuniyoshi, M., "A High-Speed Frequency Shift Method as a Protection for Islanding Phenomena of Utility Interactive PV Systems," *Solar Energy Materials and Solar Cells*, vol. 35, 1994, p. 477-486.

[17] Ropp, M., Begovic, M., Rohatgi, A., "Prevention of Islanding in Grid-Connected Photovoltaic Systems," *Progress in Photovoltaics* vol. 7, 1999, p. 39-59.

[18] Wyote, A., Belmans, R., Leuven, K., Nijs, J., "Islanding of Grid-Connected Module Inverters", *Proceedings of the 28th IEEE Photovoltaic Specialists Conference,* Sep 17-22, 2000, p. 1683-1686.

[19] Chakravarthy, S.K.; Nayar, C.V.; Determining the Frequency Characteristics of Power Networks Using ATP, Source: Electric Machines and Power Systems, Vol. 25, No. 4, May 1997, p. 341-353.

[20] Stevens, J., Bonn, R., Ginn, J., Gonzalez, S., Kern, G., Development and Testing of an Approach to Anti-Islanding in Utility-Interconnected Photovoltaic Systems, Sandia National Laboratories report SAND2000-1939, Albuquerque, NM, Aug 2000.

[21] Kitamura, A., Okamoto, M., Yamamoto, F., Nakaji, K., Matsuda, H., Hotta, K., "Islanding Phenomenon Elimination Study at Rokko Test Center," *Proceedings of the 1st World Conference on Photovoltaic Energy Conversion, 1994*, pt. 1, pp. 759-762.

[22] Kitamura, A., Okamoto, M., Hotta, K., Takigawa, K., Kobayashi, H., Ariga, Y., "Islanding Prevention Measures: Demonstration Testing at Rokko Test Center for Advanced Energy Systems," *Proceedings of the 23rd IEEE Photovoltaic Specialists Conference, 1993,* p. 1063-1067.

[23] Toggweiler, P., "Summary and Conclusions," *Proceedings of the IEA-PVPS Task V Workshop "Grid Connected Photovoltaic System,"* Sep 15-16, 1997, p. 15-17.

[24] Ropp, M., Aaker, K., Haigh, J., Sabbah, N., "Using Power Line Carrier Communications to Prevent Islanding," *Proceedings of the 28th IEEE Photovoltaic Specialists Conference,* Sep 17-22, 2000, p. 1675-1678.

[25] Riley, C., Lin, B., Habetler, T., Kilman, G., "Stator Current Harmonics and Their Causal Vibrations: A Preliminary Investigation of Sensorless Vibration Monitoring Applications," *IEEE Transactions on Industry Applications,* vol. 35 No. 1, Jan-Feb 1999, p. 94-99.

[26] Ropp, M., Bonn, R., Gonzalez, S., Whitaker, C., Investigation of the Impact of Single-phase Induction Machines in Islanded Loads - Summary of Results, Sandia National Laboratories SAND Report (to be published in 2002), Albuquerque, NM.

9 **Bibliography** (additional reading)

B1. Stevens, J., Bonn, R., Ginn, J., Gonzalez, S., Kern, G., Development and Testing of an Approach to Anti-Islanding in Utility-interconnected Photovoltaic Systems, SAND-2000-1939, Sandia National Laboratories, Albuquerque, NM, Aug 2000.

B2. Ropp, M., Begovic, M., Rohatgi, A., "Prevention of Islanding in Grid-connected Photovoltaic Systems," *Progress in Photovoltaics Research and Applications,* published by John Wiley & Sons, Volume 7, Number 1, Jan-Feb 1999.

B3. Bonn R., Kern, G., Ginn, J., Gonzalez, S., *Standardized Anti-Islanding Test Plan,* Sandia National Laboratories Web Page, www.sandia.gov/PV, 1998.

B4. He, W., Markvart, T., Arnold, R., "Islanding of Grid-connected PV Generators: Experimental Results," Presented at the 2^{nd} *World Conference on PV Energy Systems*, Vienna, Austria, Jul 1998.

B5. Begovic, M., Ropp, M., Rohatgi, A., Pregelj, A., "Determining the Sufficiency of Standard Protective Relaying for Islanding Prevention in Grid-connected PV Systems," *Proceedings of the* 2^{nd} *World Conference and Exhibition on PV Energy Systems*, Hofburg Congress Center, Vienna, Austria, Jul 6-10, 1998.

B6. Utility Aspects of Grid Interconnected PV Systems, IEA-PVPS Report, IEA-PVPS T5-01: 1998, Dec 1998.

B7. Kobayashi, H., Takigawa, K., "Islanding Prevention Method for Grid-interconnection of Multiple PV Systems," *Proceedings of the* 2^{nd} *World Conference and Exhibition on Photovoltaic Solar Energy Conversion,* Hofburg Congress Center, Vienna, Austria, Jul 6-10, 1998.

B8. Gonzalez, S., "Removing Barriers to Utility-Interconnected Photovoltaic Inverters," *Proceedings of the* 28^{th} *IEEE PV Specialists Conference*, Anchorage, AK, Sep 2000.

B9. Van Reusel, H., et al., "Adaptation of the Belgian Regulation to the Specific Island Behaviour of PV Grid-connected Inverters," *Proceedings of the* 14^{th} *European Photovoltaic Solar Energy Conference and Exhibition,* Barcelona, Spain, pp 2204-2206, 1997.

B10. Häberlin, H., Graf, J., "Islanding of Grid-connected PV Inverters: Test Circuits and Some Test Results," *Proceedings of the* 2^{nd} *World Conference and Exhibition on Photovoltaic Solar Energy Conversion*, Vienna, Austria, pp 2020-2023, 1998.

B11. Ropp, M., Begovic, M., Rohatgi, A., "Analysis and Performance Assessment of the Active Frequency Drift Method of Islanding Prevention," *IEEE Transactions on Energy Conversion,* Vol. 14, No. 3, pp 810-816, 1999.

B12. Ambo, T., "Islanding Prevention by Slip Mode Frequency Shift," *Proceedings of the IEA PVPS Workshop on Grid-interconnection of Photovoltaic Systems,* Sep 1997.

B13. Kitamura, A., "Islanding Prevention Measures for PV Systems," *Proceedings of the IEA PVPS Workshop on Grid-interconnection of Photovoltaic Systems,* Sep 1997.

B14. Nanahara, T., "Islanding Detection – Japanese Practice," *Proceedings of the IEA PVPS Workshop on Grid-interconnection of Photovoltaic Systems,* Sep 1997.

B15. Häberlin, H., Graf, J., Beutler, C. "Islanding of Grid-connected PV Inverters: Test Circuits and Test Results", *Proceedings of the IEA PVPS Workshop on Grid-interconnection of Photovoltaic Systems,* Sep 1997.

B16. Bonn, R., Ginn, J., Gonzalez, S., Standardized Anti-Islanding Test Plan, Sandia National Laboratories, Jan 26, 1999.

B17. S. Yuyuma, T. Ichinose, K. Kimoto, T. Itami, T. Ambo, C. Okado, K. Nakajima, S. Hojo, H. Shinohara, S. Ioka, M. Kuniyoshi, “A High-Speed Frequency Shift Method as a Protection for Islanding Phenomena of Utility Interactive PV Systems,” *Solar Energy Materials and Solar Cells,* vol. 35, 1994, pp 477-486.

B18. Kitamura, A., Okamoto, M., Yamamoto, F., Nakaji, K., Matsuda, J., Hotta, K., “Islanding Phenomenon Elimination Study at Rokko Test Center,” *Proceedings of the 1st IEEE World Conference on Photovoltaic Energy Conversion (1994),* Part 1, pp 759-762.

B19. Kobayashi, H., Takigawa, K., “Islanding Prevention Method for Grid Interconnection of Multiple PV Systems,” *Proceedings of the 2nd World Conference and Exhibition on Photovoltaic Solar Energy Conversion,* Hofburg Congress Center, Vienna, Austria, Jul 6-10, 1998.

10 Standards, Codes and Guidelines

S1. ANSI/NFPA 70, *The National Electrical Code*, 2002, National Fire Protection Association, Batterymarch Park, MA, Sep 2001.

S2. UL1741, *UL Standard for Safety for Static Converters and Charge Controllers for Use in Photovoltaic Power Systems,* Underwriters Laboratories, First Edition, May 7, 1999, Revised Jan 2001.

S3. IEEE Std. 929-2000, *IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) Systems*, Sponsored by IEEE Standards Coordinating Committee 21 on Photovoltaics, Published by the IEEE, New York, NY, Apr 2000.

S4. DIN VDE 0126:1999, Automatic Disconnection Facility for Photovoltaic Installations With a Nominal Output < 4,6 kVA and a Single-phase Parallel Feed by Means of an Inverter Into the Public Grid, (*German National Standard for Utility Interconnection of Photovoltaic Systems*).

S5. *Small Grid-connected Photovoltaic Systems*, KEMA Standard K150, Draft Issue 2, 2001 (final in preparation).

S6. *Guidelines for the Electrical Installation of Grid-connected Photovoltaic (PV) Systems*, Dutch guidelines to comply with NEN1010 (Safety provisions for low voltage installations), EnergieNed and NOVEM, Dec 1998.

S7. *Supplementary Conditions for Decentralized Generators - Low Voltage Level*, Dutch guidelines to comply with NEN1010 (Safety provisions for low voltage installations), EnergieNed and NOVEM, Apr 1997.

S8. JIS C 8962:1997, *Testing Procedure of Power Conditioners for Small Photovoltaic Power Generating Systems,* Japanese Industrial Standard, 1997.EN61277, *Terrestrial Photovoltaic (PV) Power Generating Systems – General and Guide.*

S9. ÖNORM/ÖVE 2750, *Austrian Guideline for Safety Requirements of Photovoltaic Power Generation Systems.*

S10. AS3000*, Australian Guidelines for the Grid Connection of Energy Systems Via Inverters.*

S11. AS4777, *Grid Connection of Energy Systems Via Inverters,* Proposed joint Australia/New Zealand Consensus Standard, Under preparation, Nearing Completion, Dec 2001

S12. DIN VDE 0100 Teil 712 *Photovoltaische Systeme, Amendment to Germany's Basic Electrical Safety Code*.

S13. G77, *UK Standard for Interconnection of PV and Other Distributed Energy*, Generation, Standard Under Development, Expected Completion, Jan 2002.

S14. CSA F381*, Canadian Standard for Power Conditioning Systems*.

S15. ASTM Std. E 1328, *Standard Terminology Relating to Photovoltaic Solar Energy Conversion.*

S16. EN61277, *Terrestrial Photovoltaic (PV) Power Generating Systems – General and Guide.*

S17. IEEE/ANSI Std. C37.1-1994*, IEEE Standard Definition, Specification, and Analysis of Systems Used for Supervisory Control, Data Acquisition, and Automatic Control.*

S18. IEEE Std. 519-1992, *IEEE Recommended Practices And Requirements For Harmonic Control In Electric Power Systems (ANSI),* Published by the IEEE, New York, NY.

S19. ESTI Nr. 233.0690 'Photovoltaische Energieerzeugungsanlagen – Provisorische Sicherheitsvorschriften' ("Photovoltaic Power Generating Systems – Safety Requirements"), Adopted by Switzerland, 1990 draft.

S20. VSE Sonderdruck Abschnitt 12 *'Werkvorschriften über die Erstellung von elektr. Installation'* Elektrische Energieerzeugungsanlagen, Completes the VSE2.8d-95, Adopted by Switzerland, 1997.

S21. International Standard IEC 62116 DRAFT, *Testing Procedure of Islanding Prevention Measures for Grid Connected Photovoltaic Power Generation Systems*, International Electrotechnical Commission.

S22. IEC 61836: 1997, *Solar Photovoltaic Energy Systems – Terms and Symbols*.

11 Distribution

0753	Ward Bower, 6218 (200 copies)
0753	PV Library (Brooks) (5 copies)
9018	Central Technical Files, 8945-2
0899	Technical Library, 9616 (2 copies)
0612	Review & Approval Desk, 9612, for DOE/OSTI