SANDIA REPORT
SAND2013-9880
Unlimited Release
Printed November 2013

Test Protocols for Advanced Inverter Interoperability Functions – Main Document

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Distributed energy resources (DER) such as photovoltaic (PV) systems, when deployed in a large scale, are capable of influencing significantly the operation of power systems. Looking to the future, stakeholders are working on standards to make it possible to manage the potentially complex interactions between DER and the power system.

In 2009, the Electric Power Research Institute (EPRI), Sandia National Laboratories (SNL) with the U.S. Department of Energy (DOE), and the Solar Electric Power Association (SEPA) initiated a large industry collaborative to identify and standardize definitions for a set of DER grid support functions. While the initial effort concentrated on grid-tied PV inverters and energy storage systems, the concepts have applicability to all DER. A partial product of this on-going effort is a reference definitions document (IEC TR 61850-90-7, Object models for power converters in distributed energy resources (DER) systems) that has become a basis for expansion of related International Electrotechnical Commission (IEC) standards, and is supported by US National Institute of Standards and Technology (NIST) Smart Grid Interoperability Panel (SGIP). Some industry-led organizations advancing communications protocols have also embraced this work.

As standards continue to evolve, it is necessary to develop test protocols to independently verify that the inverters are properly executing the advanced functions. Interoperability is assured by establishing common definitions for the functions and a method to test compliance with operational requirements. This document describes test protocols developed by SNL to evaluate the electrical performance and operational capabilities of PV inverters and energy storage, as described in IEC TR 61850-90-7. While many of these functions are not currently required by existing grid codes or may not be widely available commercially, the industry is rapidly moving in that direction. Interoperability issues are already apparent as some of these inverter capabilities are being incorporated in large demonstration and commercial projects. The test protocols are intended to be used to verify acceptable performance of inverters within the standard framework described in IEC TR 61850-90-7. These test protocols, as they are refined and validated over time, can become precursors for future certification test procedures for DER advanced grid support functions.

ACKNOWLEDGEMENTS

Sandia National Laboratories acknowledges the support of the U.S. Department of Energy Solar Energy Program that sponsored the development of this protocol and of the Electric Power Research Institute, who is leading the related effort to develop definitions for utility-based functions for advanced inverters and Distributed Energy Resource controls. SNL also acknowledges SRA International for their valuable technical review and content contributions.

CONTENTS

FIGURES and TABLES

ACRONYMS

AMI	Advanced Metering Infrastructure
ANSI	American National Standards Institute
DER	Distributed Energy Resources
DMS	Distribution Management System
DOE	Department of Energy
ECP	Electrical Coupling Point
EMS	Emergency Management System
EPRI	Electric Power Research Institute
EPS	Electric Power System (electric utilities or their surrogates)
EUT	Equipment Under Test
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
NEC	National Electric Code
NFPA	National Fire Protection Association
NIST	National Institute for Standards and Technology
NTP	Network Time Protocol
PV	Photovoltaic
RLC	Resistive/Inductive/Capacitive
SEP	Smart Energy Profile
SEPA	Solar Electric Power Association
SGIP	Smart Grid Interoperability Panel
SOC	State Of Charge
SNL	Sandia National Laboratories
SNTP	Simple Network Time Protocol
TCP/IP	Transmission Control Protocol/Internet Protocol
UL	Underwriters Laboratories

1. INTRODUCTION

1.1 Background

Distributed energy resources (DER) such as photovoltaic (PV) systems, when deployed in a large scale, are capable of significantly influencing the operation of power systems. Looking to the future, stakeholders are working on standards to make it possible to manage the potentially complex interactions between DER and the power system. The interconnection of DER to the grid is subject to performance and safety requirements that vary significantly among jurisdictions. Fulfillment of some of these requirements often requires that DER capabilities be certified by an independent testing entity. These codes and certification requirements are in a state of evolution worldwide, and the trend is toward expanding grid support features; this requires greater interoperability between DER and utility or energy management systems.

In North America, for example, the performance requirement for DER is defined in the IEEE 1547[1]. (A revision to IEEE 1547, designated 1547a, is being prepared that will incorporate some of the advanced functionality defined in IEC TR 61850-90-7.) UL 1741[2] is a certification test procedure designed to be used in conjunction with and to supplement IEEE 1547, in order to ensure safe operation of certain equipment associated with distributed generation, in compliance with the U.S. National Electrical Code, NFPA 70. As the level of distributed generation increases on the electric power system, the distributed generation sources may be called upon to perform additional functions that are not defined in the current version of the IEEE 1547 standard. It is expected future grid codes will contain allowances for an expanded set of DER functions, and some of these additional functions may be implemented and controlled through communications (from a utility or grid/micro-grid controller or from a facility control system or customer input) and/or from firmware installed in DER device(s).

In 2009, the Electric Power Research Institute (EPRI), Sandia National Laboratories (SNL) with the U.S. Department of Energy (DOE), and the Solar Electric Power Association (SEPA) initiated a large industry collaborative to identify and standardize definitions for a set of grid support functions. While the initial effort concentrated on grid-tied PV inverters and energy storage systems and utility-generated commands and communications, the concepts have applicability to all DER. The International Electrotechnical Commission (IEC) published a Technical Report[3] (IEC TR 61850-90-7) largely based on this on-going effort, and has become the basis for possible enhancements to the IEC61850-7-420 standard[4]. This work is also supported by US National Institute of Standards and Technology (NIST) as part of the Smart Grid Interoperability Panel (SGIP) Priority Action Plan 7. This effort is also of interest to the commercial communications protocols community. For example, a DNP3 Application Note (DNP 2010) was written for several advanced functions.[5]

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[1] IEEE Standard 1547-2003, *Interconnecting Distributed Resources With Electric Power Systems*.

[2] Underwriters Laboratories 1741, *Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources*

[3] IEC Technical Report IEC-61850-90-7 — Communication networks and systems for power utility automation – Part 90-7: Object models for power converters in distributed energy resources (DER) systems Edition 1.0(Feb 2013).

[4] IEC 61850-7-420 — Communications systems for Distributed Energy Resources (DER) – Logical nodes

[5] DNP3 is a communications protocol widely used by US utilities to communicate with distribution system assets.

1.2 Objective and Purpose

The objective is that the test protocols developed here, as improved over time, may become precursors for future industry-standard certification testing procedures. However, the following important caveats should be kept in mind:

- The functions contained in IEC TR 61850-90-7 are not interconnection requirements. The establishment of specific functionality that is required for interconnection is in the purview of Grid Codes issued by standards development organizations such as IEEE, IEC, and ANSI, and by reliability entities.
- The test protocols described in this document are not intended for equipment certification. The protocols provide general guidelines to evaluate emerging functionality and interoperability on a consistent basis in a laboratory environment.
- The test procedures observe and record the electrical output behavior of the Equipment Under Test (EUT), but there may be different ways for the EUT to execute the function or transition from one state to another. It should be recognized that IEC TR 61850-90-7 does not specify what performance is required for DER. It only describes how the function can be configured.

The test protocols described in this document establish a common set of procedures to verify through direct testing conformance with respect to the functions described in IEC TR 61850-90-7. Verification of compliance of a certain device or EUT involves testing two performance aspects:

(1) *Communications* – determining whether and how the EUT is receiving and understanding the request or input (communications);

(2) *Electrical* – determining if the EUT responds appropriately to the input(s) by initiating the correct commands to the electrical and mechanical equipment (control logic), and whether the equipment responds properly to those control commands.

The communications aspects of the interoperability testing will be to verify that the EUT can process inputs provided using a standard communications format. The electrical aspects will examine how the EUT performs the functions or task(s) listed in IEC TR 61850-90-7. (A test protocol for an additional function, Low/High Frequency Ride Through – L/HFRT – has also been developed, as the California Energy Commission and the California Public Utilities Commission are considering making a L/HFRT a required function for DER inverters under their Rule 21.)

SNL has developed test protocols for the functions listed in Table 1, as described in Section 2 and the appendices of this document. The intent of this on-going work is to refine this set of test protocols, in collaboration with national and international stakeholders.

1.3 Advanced DER Inverter Functions

This section provides a brief summary of the advanced DER inverter functions documented in IEC TR 61850-90-7. Table 1 lists the IEC advanced management and information exchange functions. The messages associated with each of the functions are characterized as commands, requests, or instructions to configure performance/control characteristics. Requests or commands may or may not be followed due to equipment limitations or local override by the equipment owner. Instructions to configure performance characteristics are used to specify under what conditions a command will be executed and how.

Table 1. Advanced DER Inverter Functions contained in IEC TR 61850-90-7

Command	Function	Description	Type
INV1	Connect/Disconnect	Physically connect or disconnect from grid	Command
INV2	Adjust Maximum Generation Level	Set maximum generation level at Electrical Coupling Point (ECP)	Command
INV3	Adjust Power Factor	Issues a power factor angle value	Command
INV4	Request Active Power	Request charging or discharging of the storage system	Request
INV5	PV/Storage Functions	Change the signal parameters for the storage system	Request
VV11	Volt-Var mode	Provide vars with no effect on watts	Set Parameter
VV12	Volt-Var mode	Provide maximum vars constrained by WMax	Set Parameter
VV13	Volt-Var mode	Establish fixed var settings	Set Parameter
VV14	Volt-Var mode	No var support	Set Parameter
FW21	Set maximum power output	Active power reduction due to high frequency	Set Parameter
FW22	Set maximum power output	Modify frequency-watts-delivered or watts-received curve according to time of day or other parameters	Set Parameter
TV31	Dynamic reactive power support	Provide var support at times of abnormally high or low voltage	Set Parameter
L/H VRT	Connect/disconnect settings	Set voltage ride-through or disconnect requirements	Set Parameter
WP41	Power factor settings	Set power factor in response to feed-in power	Set Parameter
WP42	Power factor settings	Modify power factor-watts curve according to other parameters	Set Parameter
VW51	Set output to smooth voltage deviations	Voltage-watt curve of generator output based on various parameters	Set Parameter
VW52	Set output to smooth voltage deviations	Voltage-watt curve of storage charge/discharge output	Set Parameter
TMP	Temperature mode behavior	Temperature-based curves	Set Parameter
PS	Signal mode behavior	Mode curves based on utility signal	Set Parameter
DS91	Modify DER Inverter Settings	Set default ramp rate, min. storage level, max. storage charge/discharge rate	Command
DS92	Event/History Logging	Request event logs	Command
DS93	Status Reporting	Request inverter status	Command
DS94	Time Synchronization	Set inverter time	Command
L/H FRT*	Connect/disconnect settings	Set frequency ride-through or disconnect requirements	Set Parameter

*function required under CPUC/CEC Rule 21, not part of IEC TR 61850-90-7

IEC TR 61850-90-7 characterizes the functions of Table 1 as:

- INV1 through INV5: Immediate control functions
- VV11 through VV14: Volt-var management modes
- FW21 and FW22: Frequency-watt management modes
- TV-31: Dynamic reactive current support during abnormally high or low voltage levels
- L/H VRT Functions for "must disconnect" and "must remain connected"
- WP41 and WP42: Watt-triggered behavior modes
- VW 51 and VW52: Voltage-Watt Management Modes
- DS91 through DS94: Parameter Setting and Reporting

In response to control signals or internal settings, DER inverters will initiate the following actions, which roughly correspond to the Table 1 functions following each action in brackets:

- Connect/Enable [INV1, INV4, and L/H VRT]
- Disconnect/Disable [INV1, INV4, and L/H VRT]
- Set output level [INV2, INV5, FW, VW]
- Set power factor [INV3, VV, TV, WP]
- Change control parameters [DS91, TMP, PS]

- Log history (data and/or activity) [DS92]
- Report status or event [DS93]
- Synchronize time [DS94]

Associated with each control function in IEC TR 61850-90-7 are various parameters and characteristics that dictate how, when, and under what circumstances the command will be executed. These parameters and characteristics that determine DER inverters will perform these functions may include the intrinsic capabilities of the DER, various externally-set parameters, locally measured or sensed conditions (e.g., voltage level, frequency, temperature, rate of change in voltage), and outside inputs (such as utility signal, EMS command, or user-entered command).

Testing the ability of the EUT to execute a particular function requires testing alternate sets of parameters and commands that characterize how the function is executed.

There are different methods to manage DER behavior. These can be categorized as follows:

- **Modes** consist of pre-established groups of settings that can enable autonomous DER behavior, where the DER senses local conditions and, using the settings defined for that mode, responds appropriately. This approach minimizes communications requirements and permits more rapid responses when the communications link is inoperable. Modes are often established for volt-var control; frequency-watt control; charging/discharging storage; and other, often complex, actions. They may be communicated remotely and/or programmed directly into the inverter controller. A mode will be defined by:
    - The parameters or other inputs to be sensed
    - The actions to be taken (command, value, time of initiation) based on those inputs
    - The priority of the mode
    - How the parameters of the mode can be modified
- **Schedules** are a type of mode, where the key input is a time sequence and behavior instructions for each time interval, to be executed autonomously. Once established, schedules may operate for a specific time period or indefinitely. For example, a schedule may establish what modes to use during weekdays versus weekends. In order to prevent simultaneous operations by numerous DER, a response time window with a random time delay may be built into the schedule (see "response time" below).
- **Curves and tables** provide settings or actions to take based on the value of an input. Such inputs could include temperature, local voltage measurements, local energy use (i.e., load) level or energy production (e.g., storage output), utility signal, etc. A table based on utility pricing signals (broadcast as in critical peak pricing; stored in a schedule as in time of use rates; or a combination) may initiate charge or discharge actions for energy storage. The power factor (i.e., displacement factor) of the DER inverter output may be set using a curve dependent on system voltage (see, e.g., Figure 15 in IEC TR 61850-90-7).
- **Response times, rate of response, and timeout period** define, respectively, 1) how soon an inverter action is initiated after the command is received, 2) how quickly the desired inverter output is reached, and 3) how long the change from default setting or mode is in effect if a command to the contrary is not received.

- The **response time** is the time period over which a DER inverter should execute the specific action that was requested. For safety-related reasons a short maximum response time (on the order of cycles or seconds) may be specified. A longer response time could make sense for economically- or efficiency-motivated reasons. For example, a DER response time on the order of 5 minutes may be adequate for economic dispatch of generation.
- A **random time delay** between an inverter's receiving a command and executing it may be specified. Immediate and simultaneous action by a large number of DER inverters should be avoided because it could affect system stability or cause unintended transients and actions of system protection devices.
- The **ramp rate** is the constraint on how quickly the DER should change from its present output level (active or reactive) to the desired output level. Specific commands or schedules may specify ramp rates; the DER's default ramp rate would be used if no ramp rate is specified[6].
- The **Timeout Period** parameter guards against the possibility that a missed or lost communication to the DER could affect normal operations. If no "reinforcing" or "repeat" command is received by the DER within the timeout period, then the DER will automatically revert to its default state.

- **Hierarchy of control** is inherent in power system management, where, e.g., system protection and reliability functions would take precedence over economic dispatch. IEC TR 61850-90-7 begins to address this, in differentiating among levels for initiating commands (e.g., autonomous versus broadcast), but currently requires only that the DER inverter implement the last command received. Therefore, uniform methods of specifying and testing control hierarchy are presently beyond the scope of this test protocol. *This means that the test protocols provide for the equipment under test to be a single inverter or DER device – not multiple interconnected inverters.*

IEC TR 61850-90-7 lists many advanced functions, and also several ways each function could be implemented. Not all inverters may have advanced functional capability; for example, at present many inverters do not have the capability to adjust the power factor of their output. As shown above, there are also many options for *how* an advanced function is implemented (e.g., based on local conditions, schedule, table look-up, and/or utility signal; with random time delay before start; constrained by a ramp rate; with a timeout period; etc.) This protocol is designed to verify *whether* a DER inverter executes a function in accordance with IEC TR 61850-90-7, *if* the inverter claims to have the capability to implement that function. Therefore, the first step in testing an inverter is to develop a "Function Capabilities Table" (FCT) that specifies for the inverter which functions and options for executing those functions it has. The FCT will serve to define which tests, and groups of parameters for the tests, are to be used for an inverter.

[6] On a DER inverter, ramp rate constraints may depend upon the operating mode. For example, a PV inverter with storage has different characteristics if power comes from PV or from battery.

1.5 Modes of Communication and Interaction with DER

Inputs to inverters may come from locally-sensed conditions (e.g., voltage; or inputs from a directly-connected switch or keypad); from other control systems (e.g., building energy management systems [EMS] or smart meter); or from a utility (either from a central broadcast or from a utility-operated local distribution management system). Thus, the utility or Electric Power System (EPS) may interact directly with inverters (Direct Management), or indirectly through an external control system such as an EMS (Indirect Management). This test protocol will address both methods: Direct Management and Indirect Management. Indirect Management involves the use of EMSs which may include the ability to translate the commands received from the EPS to another communications protocol to interface with the DER. In such cases, the test protocols assume that EMS or smart meter is part of the EUT. Specific testing of how the EMS interfaces with the DER inverter is beyond the scope of this test protocol.

Broadcast or multicast commands from the EPS can be sent to multiple interoperable inverters. With broadcast commands, there is no expectation of a communication response from the inverter. Broadcast commands may include addresses. A message can be sent, for example, to “all” inverters, to “all inverters on PV panels,” to “all inverters on feeder 2235,” to “all inverters in dispatch group 7,” etc., or even to logically combined combinations of such address groups. However, since the protocol is designed to test only one DER inverter at a time, verifying the inverter addressing and group addressing capabilities is beyond the scope of this test protocol. The test will only include the inverter’s response to a broadcast command.

There are at least 3 levels of information exchange that could set inverter operating modes, as defined in IEC TR 61850-90-7[7]:

- **Autonomous DER behavior responding to local conditions**. The DER controller uses a pre-set mode or schedule that responds to locally-sensed conditions. Remote communications are not required, although such communications may be used to change the parameters of the local control logic or schedule. Remote communications may also be used to change the DER from autonomous control to another mode of control or change control parameters. The data on local conditions may come from sensors (e.g., voltage, frequency, temperature, solar insolation); “smart” meters (e.g., local demand level, voltage or reactive power consumption); time of day; a broadcast signal; and/or customer-entered commands.
- **DER management system interactions with other control systems.** The DER controller interacts with one or more external management systems. These management systems will coordinate multiple DER in order to dispatch and otherwise control a variety of assets and asset types in order to best meet an objective. Examples of such external control systems include a microgrid controller, a building or campus energy management system, or a utility distribution management system.

[7] The information exchanges identified in IEC TR 61850-90-7 have been expanded to include 1) local inputs from a variety of sources and sensors including customer-entered commands; 2) information from other control systems such as building or facility energy management systems; and 3) utility broadcast commands that may be directed to a specific subset or address group of inverters on the system.

- **Broadcast/Multicast**. This consists of one-way notifications with large numbers of DER systems (without one-to-one communications). Such notifications could be pricing signals, emergency signals, or requests for specific DER actions or changes of operating modes. Typically such notifications would originate with the utility or energy services provider. While the signal would be broadcast to all DER, it could include addresses, so that, for example, only inverters in one area would act upon the broadcast signal.

1.6 Communication Protocols

In an actual application, the communication-enabled functionality would be implemented in one of several possible standard communications protocols. There are no explicit requirements in IEC TR 61850-90-7 or in the test protocols with regard to the communication protocol that the EUT needs to use. The only requirement is that the laboratory test equipment have the ability to interface with the EUT, either directly or through a suitable translator.

There can be several possible communication interfaces between the utility EPS and inverters. Communications can also take place over multiple physical layers: direct wire, fiber, radio frequency, power line carrier, etc.). EPSs in the United States are most likely to use DNP3 to communicate with controllable distribution system assets using broadcast commands.

This test protocol assumes a simple scheme where the utility or DMS issues commands or configuration instructions to inverters that may go through several devices (EMS, etc.); however, it is assumed that those devices are transparent to the command.

2. GENERAL TEST REQUIREMENTS

2.1. Test Setup

This section provides general guidelines of the test setup and test equipment requirements to verify DER inverter functional interoperability. The specific testing requirements may vary widely depending on the purpose of the test (i.e., which set of advanced functions are being tested).

A typical laboratory setup for the Equipment Under Test (EUT) should include the following:

- A **Utility Grid Simulator or grid connection**, which provides a power source or a sink to the DER. Some of the functions do not require control of voltage or frequency, such as commands to connect or disconnect (INV1), and connection directly to the grid would suffice. But to test the full range of the parameters that might trigger the function or affect how it is implemented, a range of grid conditions would be required. Therefore, a grid simulator will usually be more appropriate for the test setup than a connection to the actual grid. [Grid Simulator needed for testing many INV, and all FW, TV, L/H VRT, VW commands.]
- A **Utility Management System Simulator**, which provides, using the proper communication protocols, utility-generated signals, information, commands and requests. The Utility Management System Simulator will be used to messages to the EUT, as well as to change the parameters that govern the actions and responses of the EUT (see Section 2.) The messages will be formatted according to IEC TR 61850-90-7 and implemented in a suitable communications protocol. [Utility Management Simulator or equivalent needed to generate and “broadcast” commands for the communications portion of all the functions.]
- The **Equipment Under Test** (EUT), which includes the inverter and controls. The inverter could be connected to a PV array and/or an energy storage device. Because the testing will call for varying the output levels available from the PV array [INV2, INV3, INV4, VV or WP] or the state of charge of the energy storage system [INV4 or INV5], a PV simulator may be used instead of an actual PV array, and an energy storage simulator may be used in place of an actual battery.
- Optional **Load Simulator**, an RLC load bank that can provide time-varying real and reactive electrical loads to be served by the Utility Grid Simulator and/or the EUT. [Load bank is used to limit the amount of power the utility simulator has to sink when testing functions requiring the grid simulator, e.g., many INV, and all FW, TV, L/H VRT, VW functions.]
- **Sources for Local Inputs to the DER,** which could include a meter, an EMS, or other controls or sensors. Inputs such as temperature and time could be provided by the Utility Management Simulator, the Utility Grid Simulator, and/or local sensors or signal generators connected directly to inputs of the EUT. [Such local inputs are needed only when testing INV functions whose parameters are defined by curves or tables that include such local conditions, and for testing TMP functions.]

The Utility Management System Simulator will be configured to send commands formatted to IEC TR 61850-90-7, using a suitable communications protocol (such as DNP3). Since some inverters may not be compatible with the communications protocol used by the Utility Management System Simulator, a protocol translator may be required to convert commands. An EMS, meter or other translator may be used to interface the Utility Management System Simulator with the DER inverter.[8]

Figure 1 shows a diagram of the test setup. An EUT could be an energy storage device, a PV inverter, a PV with storage system, or other DER. Note that the EUT can be connected to either a stable utility grid or to a Utility Grid Simulator that allows the real and reactive power outputs of the DER to be controlled in response to grid voltage and frequency variations, local loads' or resources' energy inputs or outputs (real and reactive), and local voltage levels, depending on the test requirements. Power levels identified in this test protocol may need to be reduced due to power limitations of the utility grid, simulators, PV, and/or storage.

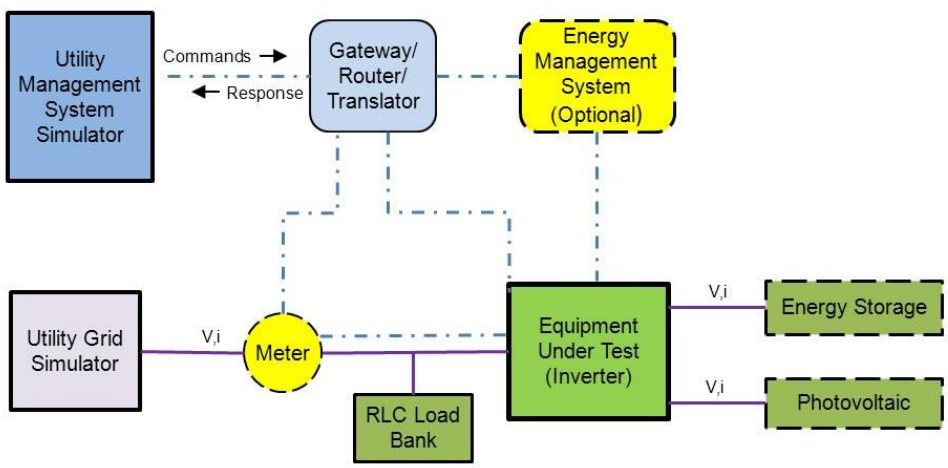

Figure 1. Interoperability Test System.

2.2. Test Procedure

Most of the defined advanced functions have optional parameters, tables, or definitions. Some manufacturers may choose to implement the functions in a particular way, or not to implement some of the functions at all. Different manufacturers also have different equipment ratings. The test procedure must take into account equipment limitations. For example, the test setup should

[8] Because of the complexities of a building EMS, it is likely that a simpler device or software that conforms to the appropriate EMS communications and interconnection standards (e.g., BACNet, ASHRAE 206) would be used in place of an actual EMS. Similarly, an actual meter does not have to be used in the test setup for most of the functions. However, since advanced meters could likely be the EUT's source of information for such parameters as utility pricing signal, on-premise voltage, and net facility power consumption, it is recommended that the test set up include an actual advanced meter when testing functions such as PS. These considerations are important because the interface and communications interoperability between inverters and advanced meters, and between utility communications/management systems and advanced meters, may be critical to evaluate the overall performance of the EUT.

allow for testing of inverter functionality without conflict with voltage and frequency protection. The source(s) of input signals or locally sensed conditions should be enumerated. For example, is local voltage sensed through a potential transducer (PT) directly connected to the EUT or through the smart meter? The implication is that the test procedures need to be customized to some extent.

The test engineer should have knowledge of which of the possible options or capabilities for the functions (as listed in IEC TR 61850-90-7) are implemented in their EUT. A list of tables, modes, default parameters, curves, schedules, control logic, and permissible ranges of parameters should also be provided by the inverter manufacturer. The hierarchy among command functions and the conditions for switching from one mode to another should also be provided. If the EUT technical specifications are insufficient to setup the interoperability test, the manufacturer should be consulted. These capabilities and options are recorded in a Function Capabilities Table (FCT) in order to define the specific tests, and the parameters of those tests, to be conducted.

For each function being tested, the general test procedure is as follows:

- Review manufacturer specifications related to the implementation of standard functions and review communications interface requirements. Prepare a FCT and tailor the test setup and the test sequence accordingly.
- EUT is connected to the sources and sinks under normal operating conditions and for a period of 5 minutes. This is in order to verify that the EUT is operational and stable.
- Verification of communications compatibility. This can be done by issuing a status request to the EUT (DS93 function).
- Test communications functionality. This is performed by issuing a command (as defined in IEC TR 61850-90-7) to the EUT. The purpose is to establish how the EUT implements the function command.
- Test the electrical behavior to determine if the DER successfully executed the communicated command.
- Analysis of the test results.

EUT input and output voltages, currents, reactive power, apparent power, and active power will be measured to observe the action taken in response to the commands. Sufficient electrical measurements should be taken to fully characterize the electrical response or behavior of the EUT. The sampling rate and test duration should be adequate according to the nature of the electrical behavior being evaluated. Points to be measured include:

- AC voltage at the point of connection
- AC current out of the EUT
- Frequency at the point of connection
- Active and Reactive power at the point of connection
- DC voltage of the energy storage device
- Current in to and out of the energy storage
- DC voltage of the PV array or PV simulator
- DC current out of the PV array or. PV simulator

Some of the status reporting and data logging can be accomplished using the DS92 and DS93 commands, with the person conducting the test issuing the DS93 command through the Utility Management System simulator. However, it might be desirable to use a faster sampling rate than possible through utility-issued DS93 commands; that will be accomplished by directly monitoring the outputs of the Equipment Under Test (EUT) (e.g., inverter outputs) (current, voltage, power factor) with appropriate instrumentation and data loggers.

For each test, the following will be logged:

- Time (in seconds)
    - command is sent
    - response is received
    - relevant behavior is observed
    - alarms generated
- Command
    - message sent
    - response received
    - status reports generated and transmitted by the DER
    - commands received (and responses) logged
- Electrical Response (Behavior)
    - time-synchronized data of relevant behavior

Test sequences may be repeated as needed to verify response to external variables (temperature effects, power disturbances, etc.). Additionally, some commands such as power level are not binary; therefore, it may be appropriate to verify interoperability and performance at several power levels.

Appendices 1 through 20 provide the test protocol for the functions in Table 1, as well as for some of the parameters associated with how those functions are executed:

- Appendix 1: Function INV1 – Connect/Disconnect
- Appendix 2: Function INV2 – Adjust Maximum Generation Level Up/Down
- Appendix 3: Function INV3 – Adjust Power Factor
- Appendix 4: Function INV4 – Request Active Power from Storage
- Appendix 5: Function INV5 – Signal for Charge/Discharge Action
- Appendix 6: Function VV – Provide watts and vars as specified
- Appendix 7: Function FW – Set real power output in response to system frequency
- Appendix 8: Function TV – Provide var support at times of abnormal voltage
- Appendix 9: Function L/H VRT – Set settings for voltage ride through or disconnect
- Appendix 10: Function WP – Set power factor and watts output
- Appendix 11: Function VW – Specify voltage-watt curve based on various parameters
- Appendix 12: Function TMP – Specify temperature-based parameter curves
- Appendix 13: Function PS – Mode curves based on a utility signal
- Appendix 14: DS92 – Event/History Logging
- Appendix 15: DS93 – Status Reporting
- Appendix 16: DS94 – Time Synchronization

- Appendix 17: Time Window and Random Time Delay
- Appendix 18: Ramp Rate
- Appendix 19: Command Timeout
- Appendix 20: L/HFRT – Low and High Frequency Ride Through
- Appendix A – Event Log Fields
- Appendix B – Potential Future Expansions of Functionality and Future Tests

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