Distributed Energy Management (DER):

Advanced Power System Management Functions and Information Exchanges for Inverter-based DER Devices, Modelled in IEC 61850-90-7

Version 27

Acknowledgements

These advanced functions for inverter-based distributed energy resources (DER), as well as their data object modelling as input to the IEC 61850 standard, were originally developed through an EPRI Project (Program 174) and championed by the National Institute of Standards and Technology (NIST) and Smart Grid Interoperability Panel (SGIP) Priority Action Plan (PAP) 7 on Energy Storage and DER. This effort was also supported by Sandia National Laboratories and the US Department of Energy.

The advanced functions and their IEC 61850 models were then submitted to the International Electrotechnical Commission (IEC) Technical Committee 57 Working Group 17, where members from many IEC National Committees enhanced these functions and models where they will be used to enhance Edition 2 of the IEC 61850-7-420 object models, while first being published as the IEC 61850-90-7 Technical Report.

Participants

Brian Seal (EPRI) and the 100+ participants in the EPRI project

Frances Cleveland (Xanthus Consulting International, editor of IEC 61850-90-7)

Allen Hefner (NIST Lead of PAP 7)

IEC TC57 WG17 members

Contents

Figures

Tables

Advanced Power System Management Functions for Inverter-based DER Devices

1. Executive Summary of inverter-based DER functions

1.1 Introduction

The advent of decentralized electric power production is a reality in the majority of the power systems of the world, driven by the need for new types of energy converters to mitigate the heavy reliance on non-renewable fossil fuels, by the increased demand for electrical energy, by the development of new technologies of small power production, by the deregulation of energy markets, and by increasing environmental constraints.

These pressures have greatly increased the demand for Distributed Energy Resources (DER) systems which are interconnected with distribution power systems, leading to high penetrations of these variable and often unmanaged sources of power. No longer can they be viewed only as "negative load". Their large numbers, their unplanned locations, their variable capabilities, and their fluctuating responses to both environmental and power situations make them difficult to manage, particularly as greater efficiency and reliability of the power system is being demanded.

This paradigm shift in management of power systems can be characterized by the following issues:

The numbers of interconnected DER systems are increasing rapidly. The advent of decentralized electric power production is a reality in the majority of power systems all over the world, driven by many factors:

- The need for new sources of energy to mitigate the heavy reliance on externally-produced fossil fuels.
- The requirements in many countries and US states for renewable portfolios that have spurred the movement toward renewable energy sources such as solar and wind, including tax breaks and other incentives for utilities and their customers.
- The development of new technologies of small power production that have made, and are continuing to improve, the cost-effectiveness of small energy devices.
- The trend in deregulation down to the retail level, thus incentivizing energy service providers to combine load management with generation and energy storage management.
- The increased demand for electrical energy, particularly in developing countries, but also in developed countries for new requirements such as Electric Vehicles (EVs).
- The constraints on building new transmission facilities and increasing environmental concerns that make urban-based generation more attractive.

These pressures have greatly increased the demand for Distributed Energy Resources (DER) systems which consist of both generation and energy storage systems that are interconnected with the distribution power systems.

DER systems challenge traditional power system management. These increasing numbers of DER systems are also leading to pockets of high penetrations of these variable and often unmanaged sources of power which impact the stability, reliability, and efficiency of the power grid. No longer can DER systems be viewed only as "negative load" and therefore insignificant in power system planning and operations. Their unplanned locations, their variable sizes and capabilities, and their fluctuating responses to both environmental and power situations make them difficult to manage, particularly as greater efficiency and reliability of the power system is being demanded.

At the same time, DER systems could become very powerful tools in managing the power system for reliability and efficiency. The majority of DER systems use inverters to convert their primary electrical form (often direct current (dc) or non-standard frequency) to the utility power grid standard electrical interconnection requirements of 60Hz or 50Hz and alternating current (ac). Not only can inverters provide these basic conversions, but inverters are also very powerful devices that can readily modify many of their electrical characteristics through software settings and commands, so long as they remain within the capabilities of the DER system that they are managing and within the standard requirements for interconnecting the DER to the power system.

DER systems are becoming quite "smart" and can perform "autonomously"[1] most of the time according to pre-established settings or "operating modes", while still responding to occasional commands to override or modify their autonomous actions by utilities and/or energy service providers (ESPs). DER systems can "sense" local conditions of voltage levels, frequency deviations, and temperature, and can receive emergency commands and pricing signals, which allow them to modify their power and reactive power output. These autonomous settings can be updated as needed. To better coordinate these DER autonomous capabilities while minimizing the need for constant communications, utilities and ESPs can also send schedules of modes and commands for the DER systems to follow on daily, weekly, and/or seasonal timeframes.

Given these ever more sophisticated capabilities, utilities and energy service providers (ESPs) are increasingly desirous (and even mandated by some regulations) to make use of these capabilities to improve power system reliability and efficiency.

None of the functions described in this document are necessarily "mandatory" from an implementation perspective – actually requiring certain functions to be implemented is the purview of regulators and of the purchasers of systems. What this document states is *"**if** a function is to be implemented, **then** it must be implemented according to these specifications".*

1.2 Inverter configurations and interactions

Bulk power generation is generally managed directly, one-on-one, by utilities. This approach is not feasible for managing thousands if not millions of DER systems.

DER systems cannot and should not be managed in the same way as bulk power generation. New methods for handling these dispersed sources of generation and storage must be developed, including both new power system functions and new communication capabilities. In particular, the "smart" capabilities of inverter-based DER systems must be utilized to allow this power system management to take place at the lowest levels possible, while still being coordinated from region-wide and system-wide utility perspectives.

This "dispersed, but coordinated intelligence" approach permits far greater efficiencies, reliability, and safety through rapid, autonomous DER responses to local conditions, while still allowing the necessary coordination as broader requirements can be addressed through communications on an as-needed basis.

1 Not controlled by others or by outside forces; independent. This word is used in the context of "**distributed process computer system** set of spatial distributed process computer systems for the monitoring and control of basically autonomous sub-processes" (IEC Electropedia ref. 351-30-05

Communications, therefore, play an integral role in managing the power system, but are not expected or capable of continuous monitoring and control. Therefore the role of communications must be modified to reflect this reality.

Inverter-based DER functions range from the simple (turn on/off, limit maximum output) to the quite sophisticated (volt-var control, frequency/watt control, and low-voltage ride-through). They also can utilize varying degrees of autonomous capabilities to help cope with the sophistication.

At least **three levels of information exchanges** are envisioned:

- **Autonomous DER behaviour responding to local conditions** with controllers focused on direct and rapid monitoring and control of the DER systems: This autonomous behaviour would use one or more of the pre-set modes and/or schedules to direct their actions, thus not needing remote communications except occasionally to modify which modes or schedules to use.
  - Autonomous behaviour is defined as DER systems utilizing pre-set modes and schedules that respond to locally sensed conditions, such as voltage, frequency, and/or temperature, or to broadcast information, such as pricing signals or requests for using specific modes. These pre-settings are updated as needed (not in real-time), possibly through the Internet or through other communication methods.
  - The DER systems would utilize its detailed knowledge of the status and capabilities of the DER equipment as well as the status of the local electric power grid, such as voltage and frequency, to determine the output from the DER system.
  - Common types of autonomous DER systems consist of the controllers that directly manage one or more inverters, such as a small PV system, a battery storage system, an electric vehicle service element (EVSE), and each of the individual DER systems within an office building, a wind farm, or a microgrid.
  - Interaction times are millisecond to seconds.
- **DER management system interactions with multiple DER systems** in which the DER management system has a more global vision of all the DER systems under its control. It understands the overall capabilities of the DER systems under its management but may not have (or need) detailed data.
  - DER management systems can issue direct commands but they primarily establish the autonomous settings for each DER system.
  - On start-up, the DER management system may provide various possible autonomous mode settings to each of the DER systems, and then over time modify which of these autonomous mode settings are active, possibly in response to utility requests or pricing signals.
  - Common scenarios include a campus DER management system coordinating many DER systems on different buildings or an energy service provider managing disparate DER systems within a community.
  - Additional scenarios include an ISO/RTO managing a large storage device through Automatic Generation Control (AGC) or requesting a specific power factor at the PCC of a wind farm.
  - A microgrid scenario would include a microgrid management system managing the intentional islanding of the microgrid and then coordinating the generation, storage, and load elements to maintain microgrid stability through the combination of setting autonomous modes for some DER systems and issuing direct commands to other DER systems.
  - Interaction frequency may be seconds to minutes, hours, or even weeks.

- **Broadcast/multicast** consist essentially of one-way notifications without one-to-one communications with large numbers of DER systems. These notifications could be emergency signals, pricing signals, or requests for specific DER modes. Typically these would come from utilities and/or Energy Service Provider (ESP).
  - No direct responses from the DER systems would be expected. If there were power system changes expected, these would be monitored elsewhere, such as on the feeder or in a substation. If there were financial implications to the broadcast/multicast request, the DER system responses would be determined during the billing and settlements process.
  - These broadcast or multicast requests may be to DER management systems or to individual DER systems.
  - These broadcast/multicast requests would be interpreted by the DER systems as possible modifications of their current autonomous behaviour or could be direct commands for response to emergency situations.
  - Since broadcast/multicast can be used to request actions without necessarily knowing which DER systems can or will respond, the expectation could be that only a certain percentage will respond.
  - Common scenarios include an energy service provider broadcasting a pricing signal, which is then reacted to by the individual DER systems, or a utility multicasting a reduction in generation to all DER systems on a constrained feeder that cannot handle reverse power flows.
  - Broadcast/multicast frequency may be hours, weeks, or seasons.

These hierarchical DER management interactions are shown in Figure 1.

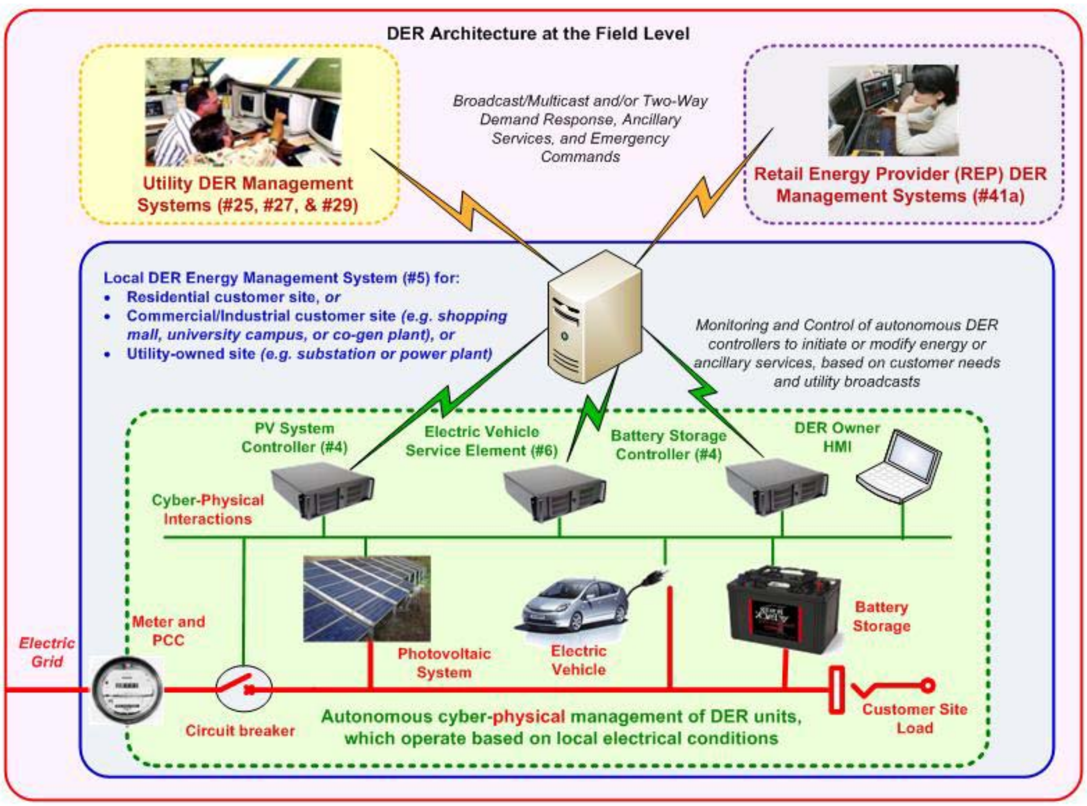


Figure 1 – DER management hierarchical interactions: autonomous, broadcast/multicast

1.3 Inverter methods

DER inverters and their controllers can perform many autonomous functions, based on their intrinsic capabilities, various parameter settings, and locally measured conditions, such as voltage levels, frequency, rates of changes in voltage and frequency, temperature, and other information.

The methods for inverters to manage their autonomous behaviour include the following:

- "**Modes**" consist of pre-established groups of settings that can enable autonomous DER behaviour, where the DER senses local conditions, and, using those mode settings, responds appropriately. This approach minimizes the communications requirements and permits more rapid responses."Modes" can be established for volt-var control, frequency-watt control, charging/discharging storage, and some other complex actions, where the arrays and parameters for each mode are sent ahead of time - maybe once a year or season, and then "go to mode" commands/requests can be broadcast/multicast.
- **Schedules** can also be established, which can operate for a specific time period or indefinitely (once initiated) completely autonomously. For instance, a schedule can establish what modes to use during weekday mornings, versus mid-afternoon, versus weekends.
- **Temperature-based curves and pricing-signal curves** provides settings for what actions to take based on the current temperature or pricing signal. A pricing signal curve can indicate which mode(s) to go to, based on the pricing signal level (can be $$, but can also be tiers, or H-M-L, or other signal). When a new pricing signal is broadcast, the DERs can ramp to the specified modes. There can even be a schedule of pricing signals so that they do not need to be broadcast, unless an emergency calls for a different level.
- **Ramp rates and parameters based on "% of capability"** (rather than absolute amounts) are also included. In addition there is a **time-window randomization** that requires DERs to respond to commands using a random number within the time window to actually initiate the command. This prevents sharp jumps whenever a new command/request/pricing signal is broadcast. (Obviously the time window can be set to zero if immediate emergency action is required.)

Although the DER generator and storage inverter functions do not directly cover loads, the same mechanisms of modes, schedules, graphic curves, arrays, timing constraints, etc. could be very readily applied to loads. The actual modes would be different (lighting cannot create vars, but could dim slightly), but the mechanisms would be the same.

1.4 Inverter functions

Inverter functions range from the simple to the complex. Most inverter functions are based on settings or curves that allow them to respond autonomously to local conditions, while some require direct control commands.

This document covers many of these key inverter functions, including:

- Immediate control functions for inverters
  - Function INV1: connect / disconnect from grid
  - Function INV2: adjust maximum generation level up/down
  - Function INV3: adjust power factor
  - Function INV4: request active power (charge or discharge storage)

– Function INV5: pricing signal for charge/discharge action

- Volt-var management modes
  – Volt-var mode VV11: available vars support mode with no impact on watts
  – Volt-var mode VV12: maximum var support mode based on WMax
  – Volt-var mode VV13: static inverter mode based on settings
  – Volt-var mode VV14: passive mode with no var support
- Frequency-watt management modes
  – Frequency-watt mode FW21: high frequency reduces active power
  – Frequency-watt mode FW22: constraining generating/charging by frequency
- Dynamic reactive current support during abnormally high or low voltage levels
  – Dynamic reactive current support TV31: support during abnormally high or low voltage levels
- Functions for “must disconnect” and “must remain connected”
  – “Must disconnect” MD curve
  – “Must remain connected” MRC curve
- Watt-triggered behaviour modes
  – Watt-power factor WP41: feed-in power controls power factor
  – Alternative Watt-power factor WP42: feed-in power controls power factor
- Voltage-watt management modes
  – Voltage-watt mode VW51: volt-watt management: generating by voltage
  – Voltage-watt mode VW52: volt-watt management: charging by voltage
  – Non-power-related modes
  – Temperature-function mode TMP: ambient temperature indicates function
  – Pricing signal-function mode PS: pricing signal indicates function to execute
- Parameter setting and reporting
  – Function DS91: modify inverter-based DER settings
  – Function DS92: event/history logging
  – Function DS93: status reporting
  – Function DS94: time synchronization
- Scheduled commands, in which a schedule is sent to the inverter with commands scheduled for particular times. These commands can also invoke pre-established parameters. Examples include:
  – Week-day schedule for volt-var actions
  – Weekly schedule for frequency-watt actions

It is expected that functions will be added in the future, for instance for handling intentional and unintentional islanding.

These different mechanisms can be intermingled, or only a specific type used, depending upon the requirements of implementations and configurations.

1.5 Differing DER architectures

1.5.1 Conceptual architecture: electrical coupling point (ECP)

Some inverter-based DER systems may be directly connected to the utility grid, while others may be part of a site microgrid. In either case, the inverter-based DER systems will have a point of electrical connection, which is defined as:

> *"The electrical coupling point (ECP) is the point of electrical connection between the DER source of energy (generation or storage) and any electric power system (EPS). Each DER (generation or storage) unit has an ECP connecting it to its local power system; groups of DER units have an ECP where they interconnect to the power system at a specific site or plant; a group of DER units plus local loads have an ECP where they are interconnected to the utility power system.*

1.5.2 Conceptual architecture: point of common coupling (PCC)

For those ECPs that demarcate the point between a utility EPS and a plant or site EPS, this point is identical to the point of common coupling (PCC) defined as "*the point where a Local EPS is connected to an Area EPS*" in the IEEE 1547 "Standard for Interconnecting Distributed Resources with Electric Power Systems".

Many functions reflect conditions at the DER's ECP. For instance, the measured voltage levels used for volt-var management are those at the DER's ECP.

ECPs are also hierarchical, such as in a university campus environment where the PCC is between the campus and the utility, but where multiple ECPs exist for the different DER systems located in different university buildings. Requests for DER actions can be made at the highest level, say for volt-var settings at the PCC. The university DER energy management system would then allocate different volt-var settings for each of the DER ECPs to reflect their DER capabilities, the needs/desires of the university buildings (people), and the overall campus reliability and efficiency requirements.

This hierarchical concept is illustrated in Figure 2.

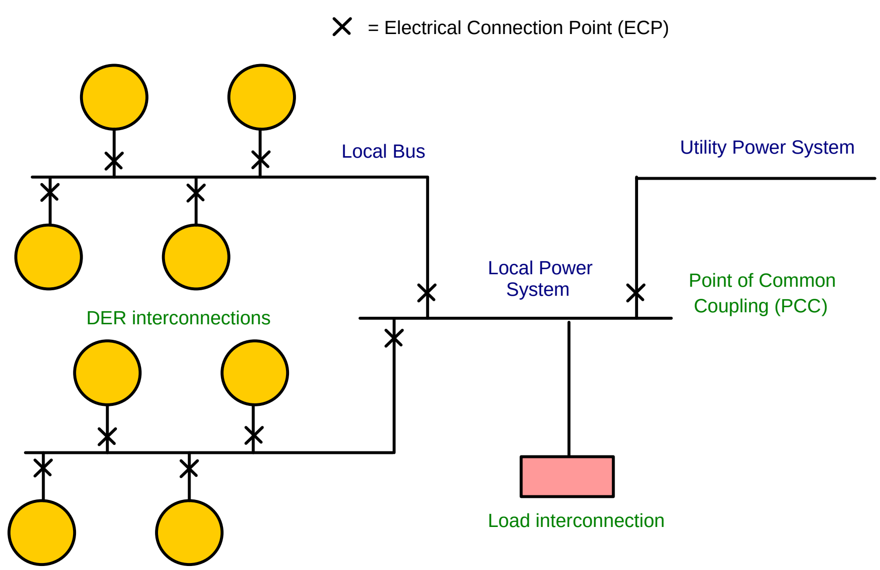


Figure 2 – Electrical Connection Points (ECP) and Point of Common Coupling (PCC)

1.5.3 Utility interactions directly with inverters or indirectly via a customer EMS

Utilities/ESPs can interact with inverter-based DER systems using different architectures. They may issue requests or commands directly to the DER systems either one-on-one or via broadcast/multicast communications.

Alternatively, a customer EMS can help manage inverter-based DER system responses to the broadcast utility request, with the idea that this customer EMS will possibly be managing multiple inverter-based DER systems, customer appliances, other types of distributed generators and storage devices, and plug-in electric vehicles.

For instance, if the utility broadcasts a specific mode request for inverter-based DER system actions, then these can be passed directly or indirectly (through explicit commands) to the inverter-based DER systems. If the utility broadcasts Demand Response signals or more generic volt-var requests, then the customer EMS could use other devices in addition to inverter-based DER systems to meet these requests. With this approach, the customer EMS could manage responses locally to meet the requests with the most effective mix of devices.

1.5.4 Communication profiles

The communication profiles between the utility and the customer EMS, will consist of different technologies at different layers, for example:

- Data object models: IEC 61850
- Application protocols: Mapping of IEC 61850 data objects to Web services, MMS, IEC 60870-5, ModBus, and/or IEEE 1815 (DNP3)
- Transport protocols: TCP/IP, UDP/IP, ModBus, IEC 60870-5-101, IEEE 1815 (DNP3) serial
- Media layers: Public Internet, GPRS cellphone network, AMI network, utility private network, leased services from telecommunication providers

1.6 General Sequence of information exchange interactions

The (generic) sequence for interactions between a utility/ESP and inverter-based DER systems is:

1. **The DER systems operate autonomously by default,** based on pre-established settings and curves. Multiple groups of these settings/curves may be available to be triggered by a remote command, and may be updated as needed through local or remote communications.
2. **The utility determines what types of services** are desired from inverter-based DER systems within a region, on a feeder, or in some other area. This determination will be based on assessments of the power system status, abilities of other equipment to perform the required actions (e.g. capacitor banks for var control), market considerations, etc.
3. **The utility broadcasts a general request** that inverter-based DER systems (within a region or feeder or other area) go into a specific mode or that certain parameters are set. This request may be sent either to individual inverter-based DER system controllers, or to more general “customer EMSs” that know how to interpret such requests for the inverter-based DER system controllers that they are managing. In either case, the utility does not necessarily need to know anything about the inverter-based DER system capabilities,

current PV status, market or tariff agreements on using the inverter-based DER system, or desires of the PV owner.

4. At each customer site or other facility, the inverter-based DER system controller OR a Customer “energy management system” (EMS) receives and interprets this broadcast utility request.
5. **If a customer EMS is used:**
   a. **The customer EMS interprets the utility request.** It determines whether it will take any action, and what the command(s) will be to the inverter-based DER system controller(s) under its control, including responding to any customer overrides or changes. These actions could be explicit commands to each inverter-based DER system it is managing, or could be a schedule of commands if the inverter-based DER system has the ability to handle schedules.
   b. **The customer EMS then issues specific commands to the inverter-based DER system(s)**: First it requests (or already has) the current status of the inverter-based DER system(s), modifies the command if necessary to reflect the status, and then issues the appropriate command.
   c. **The inverter-based DER system(s) respond to the customer EMS command**, indicating success or rejection, as well as any error codes. In addition, the current status of the inverter-based DER system could be sent if either explicitly requested by the customer EMS or if it is “automatically” sent as part of the sequence.
   d. **The customer EMS may or may not be required to respond** to the utility request.
      - If the utility does not expect a direct response, it may both monitor conditions to determine if enough power system changes have occurred and/or read the meter (or meter event log) to determine if the inverter-based DER system responded appropriately.
      - If it does respond, it will acknowledge receipt of the command and returning the appropriate information.
6. **If an inverter-based DER system controller directly receives the broadcast request from the utility:**
   a. **The inverter-based DER system controller determines internally how best to respond,** and performs those actions.
   b. **The inverter-based DER system controller may or may not respond** to the command from the utility with an acknowledgement and any appropriate information.
      - If the utility does not expect a direct response, it may both monitor conditions to determine if enough power system changes have occurred and/or read the meter (or meter event log) to determine if the inverter-based DER system responded appropriately.
      - If it does respond, it will acknowledge receipt of the command and returning the appropriate information.
7. **The inverter-based DER system(s) are metered either individually or via net metering**, with their output (in response to the command) captured as part of the metering data. If electric storage is part of the inverter-based DER system, then it could be metered separately or the inverter-based DER system as a whole could just be metered. (Metering is out of scope for this document).
8. **If communications are lost, the inverter-based DER system goes to a default mode**, possibly after a timeout period. The default mode, the timeout period, and other parameters for this situation would be established ahead of time.
9. **Customers can override or modify commands**, at any time if they desire.

2. Concepts and constructs for managing inverter functions

2.1 Basic settings of inverters

2.1.1 Nameplate values versus basic settings

Nameplate values are expected to be fixed, based on the type, model, and capabilities of the inverter. However, installation-specific requirements may require modifications to the nameplate values, so long as these basic settings remain within the constraints of the nameplate values. These basic settings are usually established upon installation and start-up, and are usually due to varying inverter configurations, power grid environments, desired inverter capabilities, and DER owner preferences.

Basic inverter settings are needed for several functions and include power and voltage settings. These basic settings will be applied to power adjusting functions. At the beginning of this clause the power settings will be described and afterwards voltage settings. The basic setting functions assume a tightly coupled interaction between the inverter-based DER systems and a controlling entity (utility, energy service provider, or customer EMS).

2.1.2 Power factor and inverter quadrants

Figure 3 shows the possible working areas of a DER inverter from both a Producer Reference Frame (PRF) and from a Consumer Reference Frame (CRF). In general for DER systems, the PRF is used, in which the 1st and 4th quadrants are for delivering power to the grid (vars either overexcited or underexcited, respectively), while the 2nd and 3rd quadrants are for receiving power from the grid (vars either overexcited or underexcited, respectively).

DER inverters can work in any of these four quadrants, depending upon their capabilities and the desired functions. Historically, there are two conventions, IEC and EEI, which are reflected in the two PFSign conventions. These conventions are illustrated in Figure 3 and Figure 4, and are shown in Table 1 from the point of view of the Producer Reference Frame:

Table 1 – Producer Reference Frame (PRF) conventions

Quadrant	Excitation	PFSign Active Power (usually IEC)	PFSign (usually EEI)
I	Overexcited	+	–
II	Overexcited	–	+
III	Underexcited	–	–
IV	Underexcited	+	+

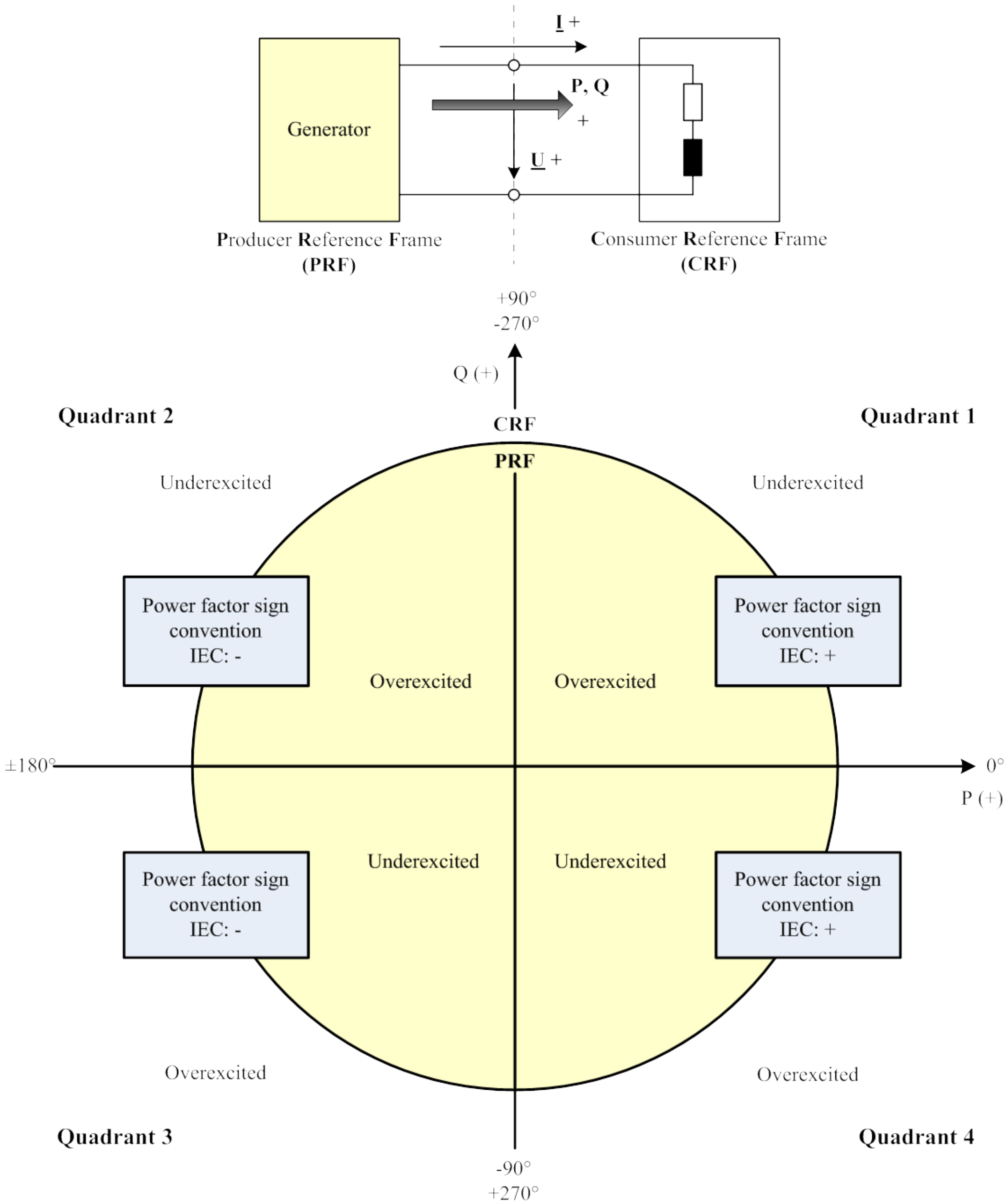


Figure 3 – Producer and Consumer Reference Frame conventions

Therefore, all commands that affect the power factor (PF) must include three elements in order to specify which quadrant is being referenced:

- The signed power factor value
- PFExt identification of “overexcited” or “underexcited”
- PFsign convention indicator (which may be set as either nameplate or basic setting for an implementation)

If the inverter does spontaneously change between charging and discharging without an explicit command, it can continue to maintain the vars according to what it was previously doing, either providing vars or absorbing vars, or the reverse. The spontaneous change action (reversing or maintaining var direction) is set either as nameplate or basic setting (VArAct).

The EEI Power Factor sign convention is based on the
Power Triangle acc. Handbook for Electricity metering (EEI) and IEC 61557-12 (2007).

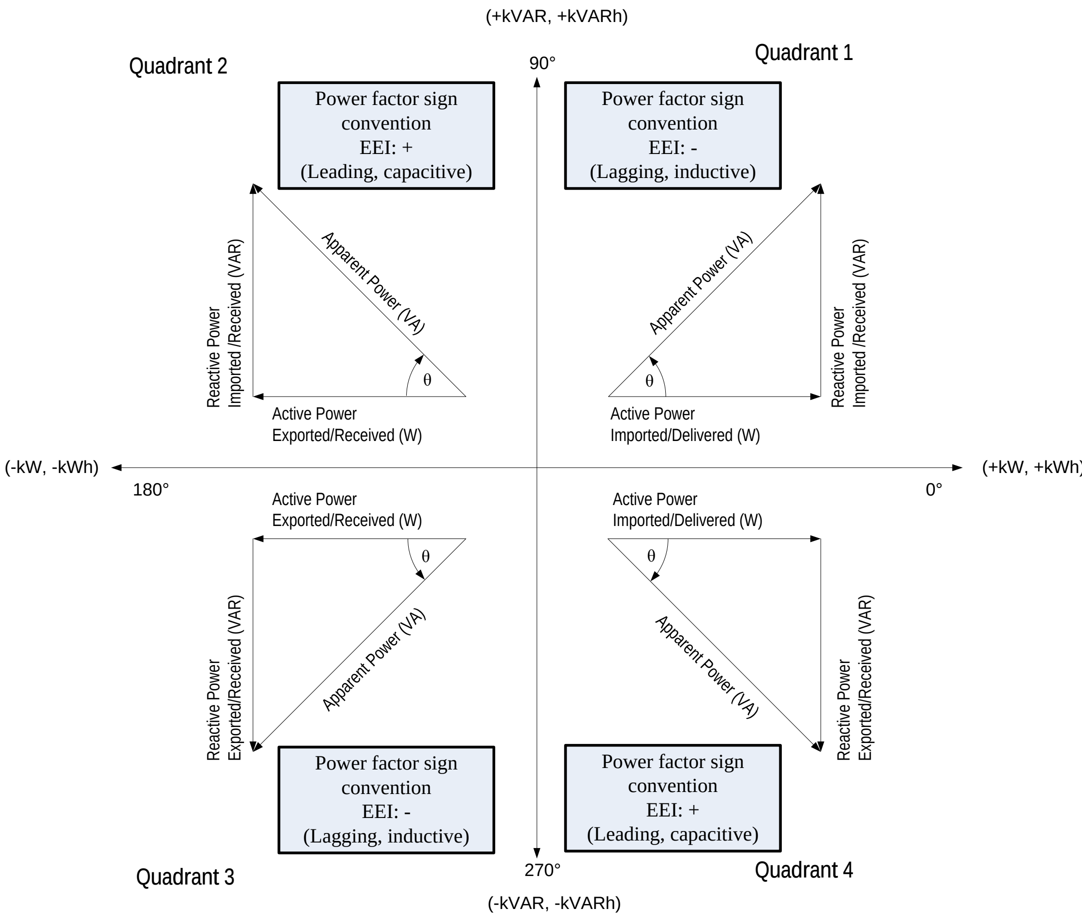


Figure 4 – EEI Power Factor sign convention

2.1.3 Maximum watts, vars, and volt-amp settings

Each inverter's power connection to its local grid is called its electrical connection point (ECP). If there are multiple inverters within a site, they may all contribute to the interconnection of the site to the main grid at the point of common coupling (PCC).

The inverter quadrant areas can be constrained in order to meet specified limits at its ECP or at the PCC. In order to determine the limits at the PCC, all inverters must have three parameters, called WMax (for active power), VAMax (for apparent power), and VArMax (for reactive power) that establish their limits at the ECP of each inverter. Collectively, these ECP limits provide the limits at the PCC.

WMax, VAMax, and VArMax are these settable limits that may be the same as the nameplate values, or may be (typically) lower values reflecting actual implementation limits. They would normally be set at the initial deployment time, although they could be modified occasionally to reflect changes to the implementation.

The parameter WMax is the most critical value: it is used as the reference value for power requests. VArMax may be the same as WMax, such that a single process can set the limits for both real and reactive power functions, but these settings may also be set separately. Active power control commands can then be issued as a percentage of WMax: each inverter can then calculate its own actual values from its own WMax value. This approach allows the reduction of a DER's power level by relative values in an unlimited range.

For a facility with multiple inverters, the maximum continuous active power output capability of the facility is given by the sum of parameter WMax of all inverters. Likewise, the maximum continuous reactive power output capability is given by summing the VArMax parameters of all inverters. Furthermore, in some cases it can be an advantage to set the maximum continuous reactive power output capability in same manner as WMax. However, the basic settings for power do not intend to limit the energy flow to be one directional.

An example is shown in Figure 5 for the 1st and 4th quadrant (assuming the arrows indicate a producer reference frame).

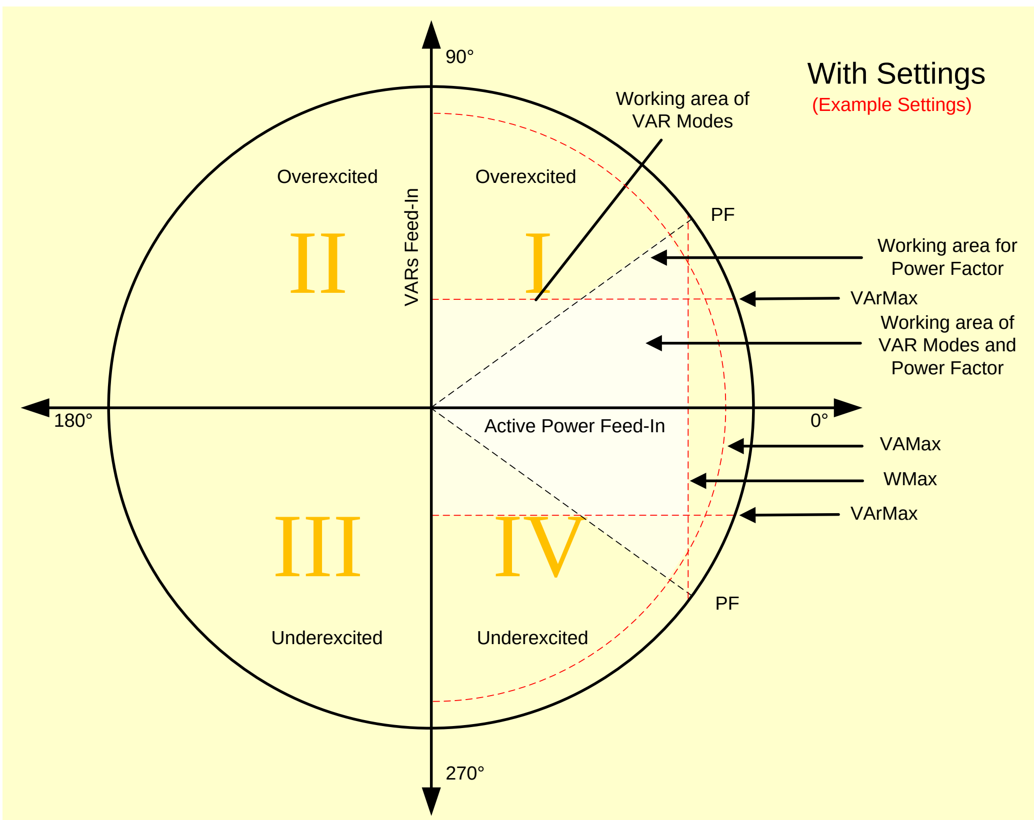


Figure 5 – Working areas for different modes

The different hatched areas show the different working areas and working area limits. The red hatched lines show the maximum values for active power WMax, reactive power VArMax and apparent power VAMax.

Possible power factor settings may range from a minimum PF (OutPFSet) (underexcited) in quadrant 4, going through the maximum value of 1 to a minimum power factor (overexcited) in quadrant 1. Possible var settings (see function INV2 below) are limited by VArMax.

Since some possible settings are limited by regulations or device capabilities, more than one boundary may apply to a selected DER management function for inverters, resulting in zones limited by more than one hatching type.

2.1.4 Active power ramp rate settings

The default ramp rate of change of active power is provided by the parameter WGra. This parameter sets the change of active power due to either a change by a command or by an internal action such as the release of power reduction by use of the hysteresis in the function Active Power Reduction by Frequency. This ramp rate (gradient) does not intend to replace the specific ramp rates that are set by the commands or schedules, but acts as the default if no specific ramp rate is specified. WGra is defined as a percentage of WMax per second.

2.1.5 Voltage phase and correction settings

In the case of single phase inverters, the voltage value used in the inverter functions is based on whichever phase circuit (A, B, or C) the inverter is connected to. The identity of the phase can be set in the inverter as a basic setting. In the case of three-phase inverters that do not act independently, the mean value of A, B, and C is to be used, unless abnormally high or low voltage levels of individual phases are measured in unbalanced systems, in which case the voltage levels of those individual phases may be used.

For functions using voltage parameters (like the volt-var modes, volt-watt modes, and dynamic reactive current support), a reference voltage (VRef) and a correction voltage (VRefOfs) are additionally introduced to the previously mentioned parameters, WMax, VAMax and WGra. All inverters behind one PCC have a common reference voltage, but differ in the voltage between their own ECP and the PCC due to configuration differences within a plant. These differences can be corrected by the parameter VRefOfs that will be applied to each inverter, as can be seen in Figure 6, where a positive value means that voltage at the ECP is higher than the voltage at the PCC. This correction voltage will be applied to the voltage-based modes and will allow a homogenous setting and broadcasts for the plant.

The equation for the effective percent voltage is:

Effective Percent Voltage = 100 (local voltage*-VRef*Ofs) / (*VRef*)*

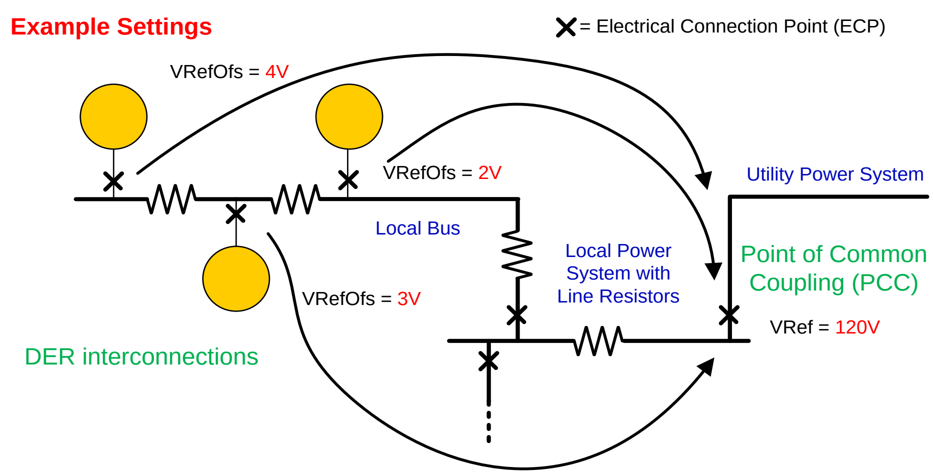


Figure 6 – Example of voltage offsets (VRef**Ofs) with respect to the reference voltage (**VRef**)**

2.1.6 Charging settings

For those inverters that manage storage DER units that can both deliver power (discharging in quadrants 1 and 4) and absorb power (charging in quadrants 2 and 3), additional parameters[2] are needed if the maximum discharge limits are different from the maximum charge limits: WChaMax VAChaMax, and WChaGra.

2.1.7 Example of basic settings

An example of settings for an inverter is shown in Table 2.

Table 2 – Example basic settings for a storage DER unit

Parameter	Example Values
PFsign	1 = IEC; 2 = EEI;
PFExt	Underexcited = True; Overexcited = False
VArAct	1 = reverse var underexcited/overexcited characterization when changing between charging and discharging) 2 = maintain var characterization
WMax, delivered	14 500 W
WChaMax, received	–14 500 W
VAMax	16 000 VA
VAChaMax	16 000 VA
VArMax	12 000 VAR
VRef	120 V
VRefOfs	2 V
WGra	20 % WMax/second
WChaGra	15 % WChaMax/second

2.1.8 Basic setting process

The settings described above are expected to only be set once or infrequently over the life time of the system. The utility/ESP or the customer EMS would take the following actions:

- (Optional) Request status of inverter-based DER system: Request a pre-defined set of the status information, including the status values, the quality flag, and the timestamp of the status (see Function DS93 for details of status points).
- Issue command or mode to modify inverter-based DER settings:
  - Data element to be modified (e.g. WMax, VAMax, VArMax, VRef, VRefOfs, WGra, mode)
  - New value for that data element
- Receive response to the command:
  - Successful (plus new value of data element)

2 The additional details on storage parameters are being developed in IEC 61850-90-9.

– Rejected (plus reason: equipment not available, message error, overridden, security error)

2.2 Modes for managing autonomous behaviour

2.2.1 Benefits of modes to manage DER at ECPs

Modes are methods for managing DER systems by pre-setting desired parameters and curves that describe desired behaviour in response to local conditions (e.g. voltage, frequency, power factor, temperature, and pricing signal). Many different mode settings can be defined once and updated only infrequently. Utilities and/or ESPs can then invoke a specific mode by a single command whenever they wish the DER to follow the behaviour defined by that mode.

The use of modes allows the DER to act autonomously without moment-by-moment commands, thus both simplifying the tasks of the utilities/ESPs, as well as minimizing the necessary communications burden. Utilities and ESPs can either monitor the behaviour of the DERs or can simply monitor the power system to determine how well their mode requests are affecting the power system.

Generally, modes will be applied to one inverter or groups of inverters that are connected at different levels of ECPs (see Figure 7 for examples).

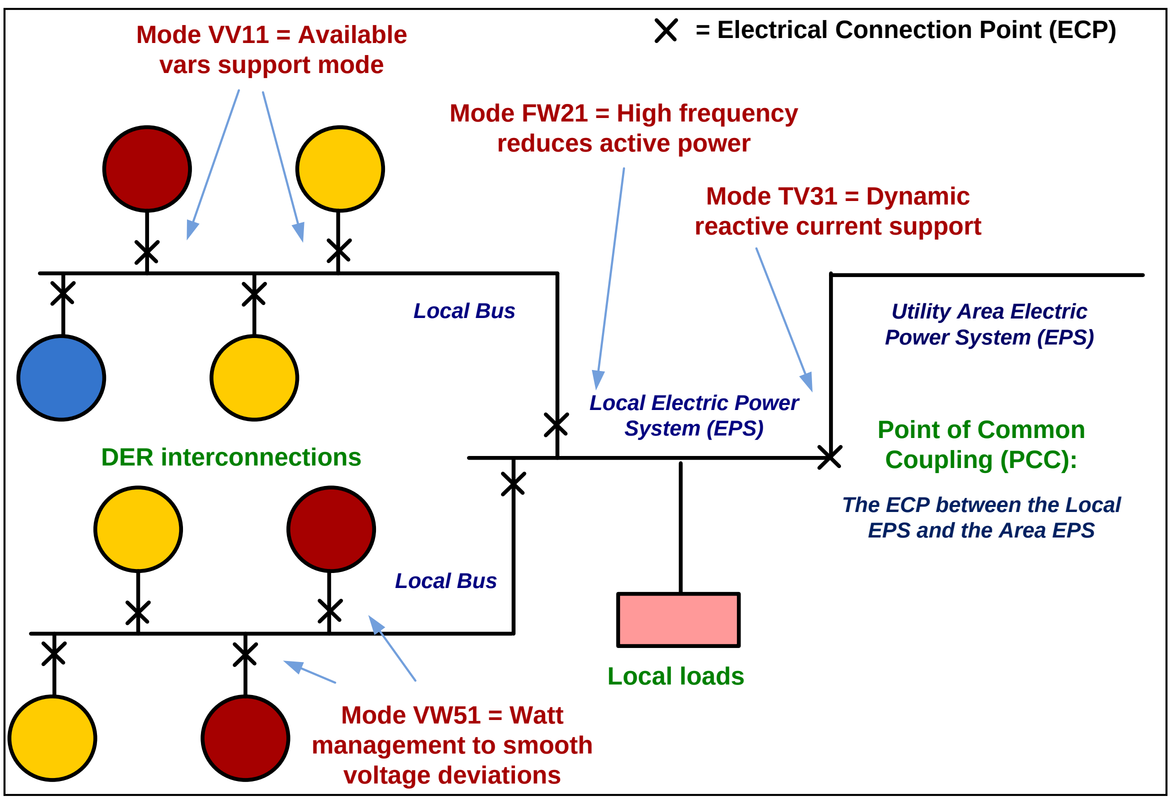


Figure 7 – Example of modes associated with different ECPs

2.2.2 Modes using curves to describe behaviour

Modes are defined as using curves to describe autonomous behaviour. These curves correlate a measured or triggering value (the independent variable) with a requested response by the DER (dependent variable).

In order to generate a curve, two-column arrays are used, with the first column containing monotonically increasing triggering values (x-axis) and the second column containing the response values (y-axis). These arrays are combined into a piecewise linear curve by interpolating each response values to correspond with each triggering value.

When an operational mode is invoked, the real-time measured value or stipulated external value of the triggering parameter is used to derive the interpolated response value.

Examples include the following modes, although others could be added. The first four modes are power-related modes, while the last two modes utilize non-power-related triggering values:

- Volt-Var Mode: Voltage values to determine what vars the inverter should produce at each voltage level
- Frequency-Watt Mode: Frequency values to determine what watts the inverter should produce for each frequency value
- Dynamic reactive current support Mode: Apply volt-var management during short times of abnormally low or high voltage values to support the grid until either the voltage returns within its normal range or the inverter must disconnect.
- Volt-Watt Mode: Voltage values to determine what watts the inverter should produce as a function of the voltage level
- Temperature-var Mode: Temperature values to determine what vars or what volt-var mode the inverter should produce within each temperature range
- Pricing Signal Mode: Pricing signal values to determine what watts, vars, power-related mode, or other ancillary service the inverter should produce for each range of pricing signals.

In most of these modes, the real-time triggering values (voltage, frequency, etc.) are measured locally. In some modes, the triggering value might be received from external sources, such as regional average temperature or energy pricing signal.

Unlike direct control commands, modes indicate behaviour that the inverter should follow autonomously without further intervention. This approach alleviates the need for continuous control commands being sent out to large numbers of inverters.

Because autonomous behaviour must take into account the current capabilities of the DER system, these inverter modes are designed to request DER systems to provide the needed mode support as best as their capabilities allow them. For this reason, the curve settings are generally in percentages of nominal or nameplate values, rather than absolute values. That approach permits both small and large inverter-based DER systems to respond within their limits.

An example of a curve used in a volt-var mode is shown in Figure 8.

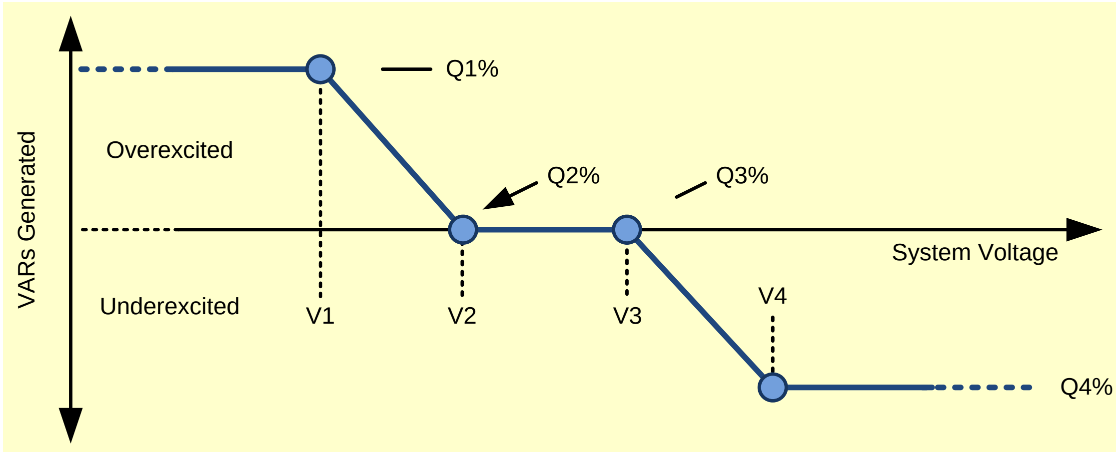


Figure 8 – Example of a volt-var mode curve

2.2.3 Paired arrays to describe mode curves

Each mode curve is described by a two-column array of pairs of values: the first column in the array contains the breakpoints of the independent variable values, while the second column contains the dependent variable values at those breakpoints. These two columns of values can be used to derive a piece-wise linear curve.

The independent variables are typically values which may be measured locally or calculated from locally available measurements or values. For instance, when a DER controller receives a mode curve which uses voltage as the independent variable, the DER may determine its current location along the curve by averaging the three voltage phase values at the ECP and applying the appropriate voltage offset. The independent variable may be an absolute value (e.g. frequency value) or may be a percentage of nominal (e.g. % of nominal voltage).

The dependent variables are typically (but not exclusively) percentages of a nominal value. These dependent variables are used to calculate what behaviour the DER is being requested to follow. For instance, if the dependent variable is the percentage of the maximum watts (WMax) and the independent variable is % of nominal voltage, the DER controller can determine its desired watts based on its measured voltage.

The paired arrays therefore consist of the breakpoints of the independent variables, the breakpoints of the dependent variables, and the units (either SI units or percentage of SI units).

2.2.4 Percentages as size-neutral parameters: voltage and var calculations

As noted previously, because broadcast/multicast commands cannot necessarily know the size or capabilities of an inverter, the curve settings are generally in percentages of nominal or nameplate values, rather than absolute values. That approach permits both small and large inverter-based DER systems to respond within their limits.

In particular, given this size-neutral and connection-point-neutral approach, inverters will need to calculate an effective percent value for the locally measured voltage as follows:

$$EffectiveLocalVoltage = \left(\frac{LocallyMeasuredVoltage - VRefOffset}{VRef} \right) * 100$$

An inverter would then compare this *EffectiveLocalVoltage* to the voltage percentages (X-Values) in the configuration curve, so the X-Values of the curve points would be calculated as follows:

$$PercentVoltage = \left(\frac{DesiredVoltageValue}{VRef} \right) * 100$$

These definitions allow the same *PercentVoltage* values to be used in the configuration curves of many different inverters without adjusting for local conditions at each inverter. Such adjustments can be made by setting the global Reference Voltage (VRef) or Reference Voltage Offset (VRefOfs) when the device is first commissioned or occasionally thereafter, without affecting the curve settings.

In similar fashion, the requested var (y-values) to be written for each curve point would be a percentage calculated in one of three ways, as indicated by the y-value type specified in the curve:

VArs based on %WMax

$$PercentVArs = \left(\frac{DesiredVArValue}{WMax} \right) * 100$$

VArs based on %VArMax

$$PercentVArs = \left(\frac{DesiredVArValue}{VArMax} \right) * 100$$

VArs based on available vars as measured and calculated by the DER system

$$PercentVArs = \left(\frac{DesiredVArValue}{AvailableVArs} \right) * 100$$

The percentage of VARs is a signed value, so that it can represent VARs generated (positive) or absorbed (negative).

2.2.5 Hysteresis as values cycle within mode curves

Although the simplest curve is a piece-wise linear curve, hysteresis can be added to provide different return routes. This hysteresis adds stability to the inverter responses to possibly fluctuating primary curve values by not following the minor fluctuations, but by maintaining a constant level until the trend of the primary curve value stabilizes.

There are two modes available (*parameter names are shown in the example Figure 9*):

- by specifying a hysteresis path, or
- via a deadband path to simulate hysteresis.

A ramp rate can be configured by RmpTmsPT1 for getting of system voltage to this function. This parameter is configured in seconds. This is the time this function requires reaching 95 % of the grid voltage change (3 times the RC time constant).

Examples of volt-var curves with hysteresis are shown in Figure 9 and Figure 10.

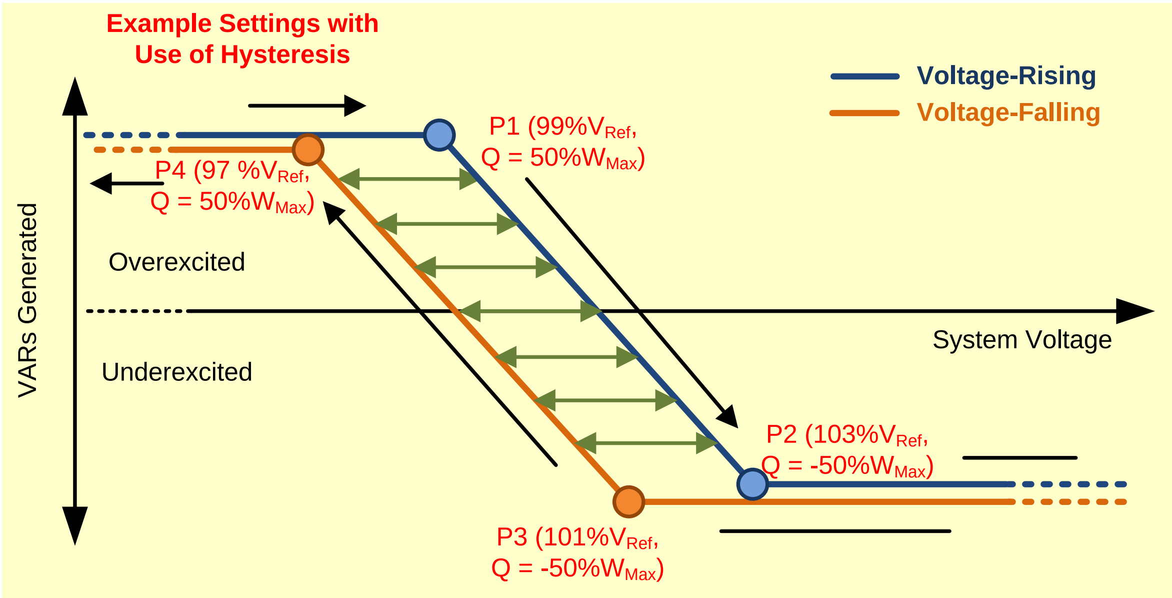


Figure 9 – Example of hysteresis in volt-var curves

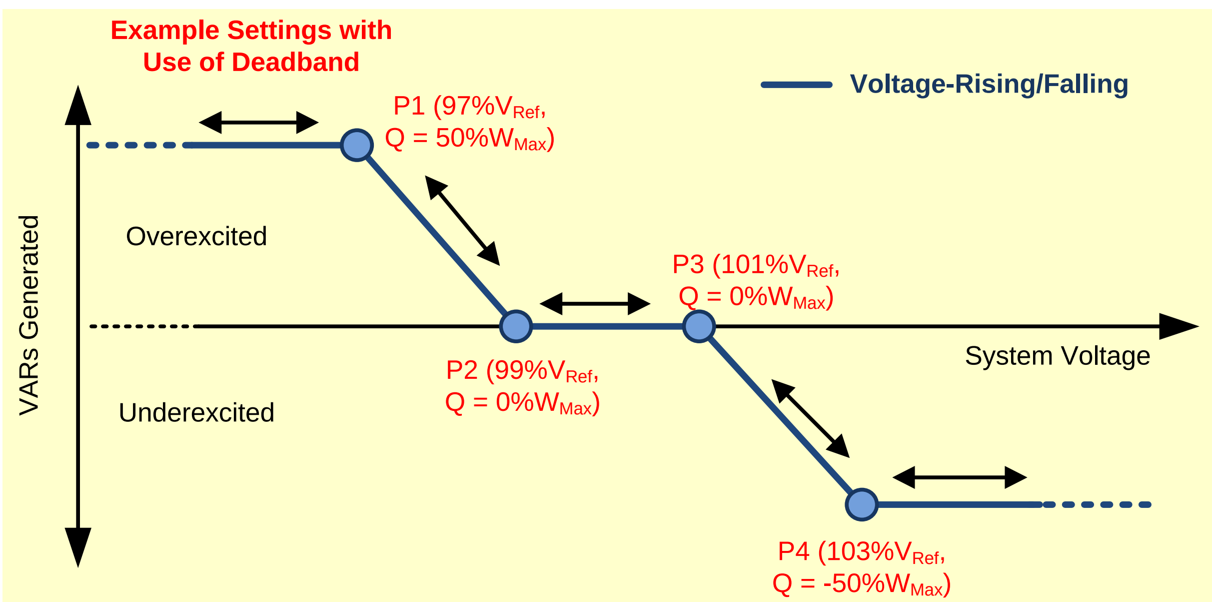


Figure 10 – Example of deadband in volt-var curves

2.2.6 Low pass exponential time rate

The local function block diagram in Figure 11 shows the topology for Low Pass, Utility Defined Curve Shapes and Linear Gradient (ramp rates). The Utility Defined Curve Shape can be assumed to be the any function defined by paired arrays.

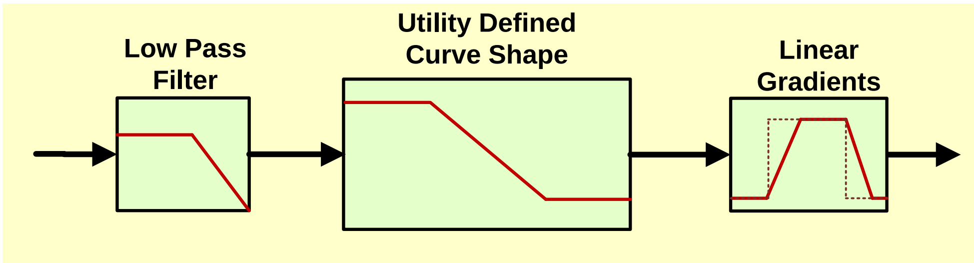


Figure 11 – Local function block diagram

The Low-Pass filter is a simple first-order filter with a frequency response magnitude given by:

$$\left|\frac{Output}{Input}\right| = \frac{1}{\sqrt{1+(\omega\tau)^2}}$$

where

ω = 2π*frequency;

τ is the the time constant of the filter

The time-response of such a filter to a step change in the input is as illustrated in Figure 4.

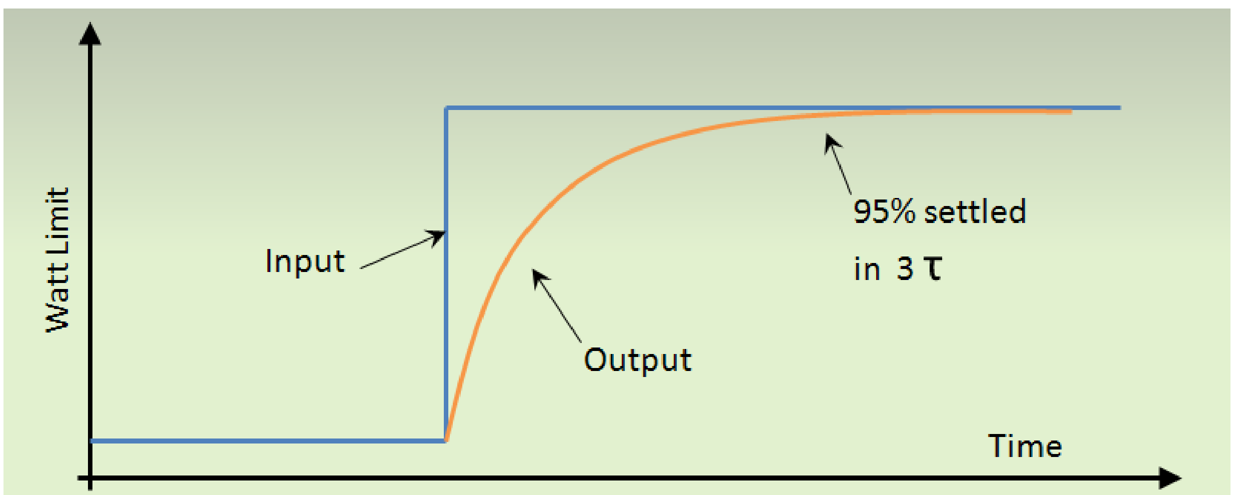


Figure 12 – Time domain response of first order low pass filter

The configuration parameter for this filter is a time, in seconds, in which the filter will settle to 95% of a step change in the input value. This is equivalent to 3τ.

2.2.7 Ramp rates

To avoid sharp shifts at the breakpoints of the piecewise linear curve, a ramp rate is included for each transition in order to smooth and stabilize the responses of large numbers of inverter-based DER systems. In order to distinguish the decrease and increase of the independent output value two ramp rates are in use, called RmpTmmDec and RmpTmmInc.

2.2.8 Randomized response times

Since mode requests will (most likely) be broadcast or multicast to large numbers of DER systems at the same time, it may be beneficial to stagger the responses. This is achieved by providing a time window within which a random “start” time actually triggers the execution of the mode.

2.2.9 Timeout period

A timeout period is available for reverting to a default state of the DER system, to ensure that a missed or lost command does not impact normal operations beyond that timeout period. If the mode is the default state, then the timeout period would be set to infinite.

2.2.10 Multiple curves for a mode

Each type of operational mode could have multiple curves with different settings. For instance, a volt-var mode could have different curves that could be invoked during colder days or hotter days. The pricing signal mode could have different curves for weekdays and for weekends. The low-voltage-ride-through mode could have different curves for different situations.

2.2.11 Multiple modes

Multiple modes may be in effect at any one time, so long as they are not mutually exclusive. Modes may also be overridden by immediate control commands, such as for emergency situations. For instance, DER systems that are executing a volt-var mode under normal circumstances could be triggered by a high temperature to execute a temperature-var mode to provide or absorb more vars.

Multiple pricing signal modes could be effect. For instance there could be different pricing signal modes for energy, for vars, for frequency response, or for other ancillary services. When actual pricing signals are received for each type, then an assessment would be performed to determine which may be mutually exclusive, which of those may be the preferred mode, and which modes might co-exist at the same time. For instance, a high pricing signal for vars might out-weigh a lower pricing signal for watts, while frequency-watt mode might co-exist with either.

2.2.12 Use of modes for loosely coupled, autonomous actions

Inverter mode requests to inverter-based DER systems are examples of decentralized coordination of generation or loosely-coupled generation control. Loosely-coupled interactions also cannot expect complete compliance from all DER systems. For instance, inverter-based DER systems may not be able to respond completely for any number of reasons: the sun is behind a cloud, the customer has overridden the mode setting, local situations are impacting what response the inverter-based DER system can provide, etc.

Therefore the expectation for issuing mode requests is that an aggregated response will be gotten from many or most inverter-based DER systems, but not necessarily all. Any financial ramifications will be determined by the metering results.

Since these mode requests maybe broadcast (multicast) to specific groups of inverter-based DER systems and since the responses from the inverter-based DER systems will generally not be explicit, the utility may not know what the actual responses will end up being, and could require subsequent interactions not only with these inverter-based DER systems but possibly with distribution grid capacitor controllers, load tap changers, voltage regulators, storage devices, and other types of DER.

2.3 Schedules for establishing time-based behaviour

2.3.1 Purpose of schedules

Larger inverter-based DER systems and large aggregations of small inverter-based DER systems have significant influence on the distribution system and have local volt-var characteristics that may vary throughout the day. As a result, a single function or operational mode such as a specific volt-var curve may not be suitable at all times. Yet sending many control commands every few hours to many different DER systems may impact bandwidth-limited communications systems or may not be received in a timely manner, leading to inadequate DER system responses. However, if schedules can be established that the DER systems can follow autonomously, then these communication impacts can be minimized.

Schedules establish what behaviour is expected during specified time periods. A schedule consists of an array of time periods of arbitrary length, with each time period associated with a function or mode.

Schedules use relative time, so that increasing time values are the delta seconds from the initial time value. The actual start date/time replaces the initial time value when the schedule is activated. A ramp rate sets the rate at which the function or mode in one time period moves to the function or mode in the subsequent time period, while the ramp type indicates how the ramp is to be understood. A stop time indicates when the schedule is deactivated.

Schedules can be used to allow even more autonomous control of the behaviour of DER equipment. They may be sent ahead of time, and then activated at the appropriate time.

2.3.2 Schedule components

The interrelationship of schedule controllers, schedules, and schedule references, along with some example settings are shown in Figure 13. These components are described as:

- Electrical Connectivity Point (ECP) manager: An ECP manager handles one or more DER unit controllers that provide energy through that ECP. It is expected that the ECP manager will handle the schedule controllers for its interconnected DER units.
- Schedule controllers: One or more schedule coordinators may be available at the ECP. Each schedule controller can control multiple schedules so long as they are not running at the same time. The schedule controller indicates which schedule is currently ready-to-run or running. For one schedule controller, only one schedule can be running.
- Schedules: Each schedule must have a non-zero identifier that is a unique schedule identity within the ECP. A schedule consists of time periods of arbitrary length that reference delta time from the initial entry.
- Schedule references: Each entry in a schedule references a specific value, a mode, or a function. Configuration parameters indicate the units and other characteristics of the entries.
  - Values are direct settings, such as maximum watt output. These are absolute values or a percentage, to be used primarily where specific values are needed.
  - Modes are the settings and arrays of independent and dependent variables that manage output through algorithmic calculations, such as the volt-var modes
  - Functions are the combination of settings for immediate control commands, such as INV3, adjust power factor. These usually involve percentages of maximum to allow inverters with different capabilities to respond appropriately.

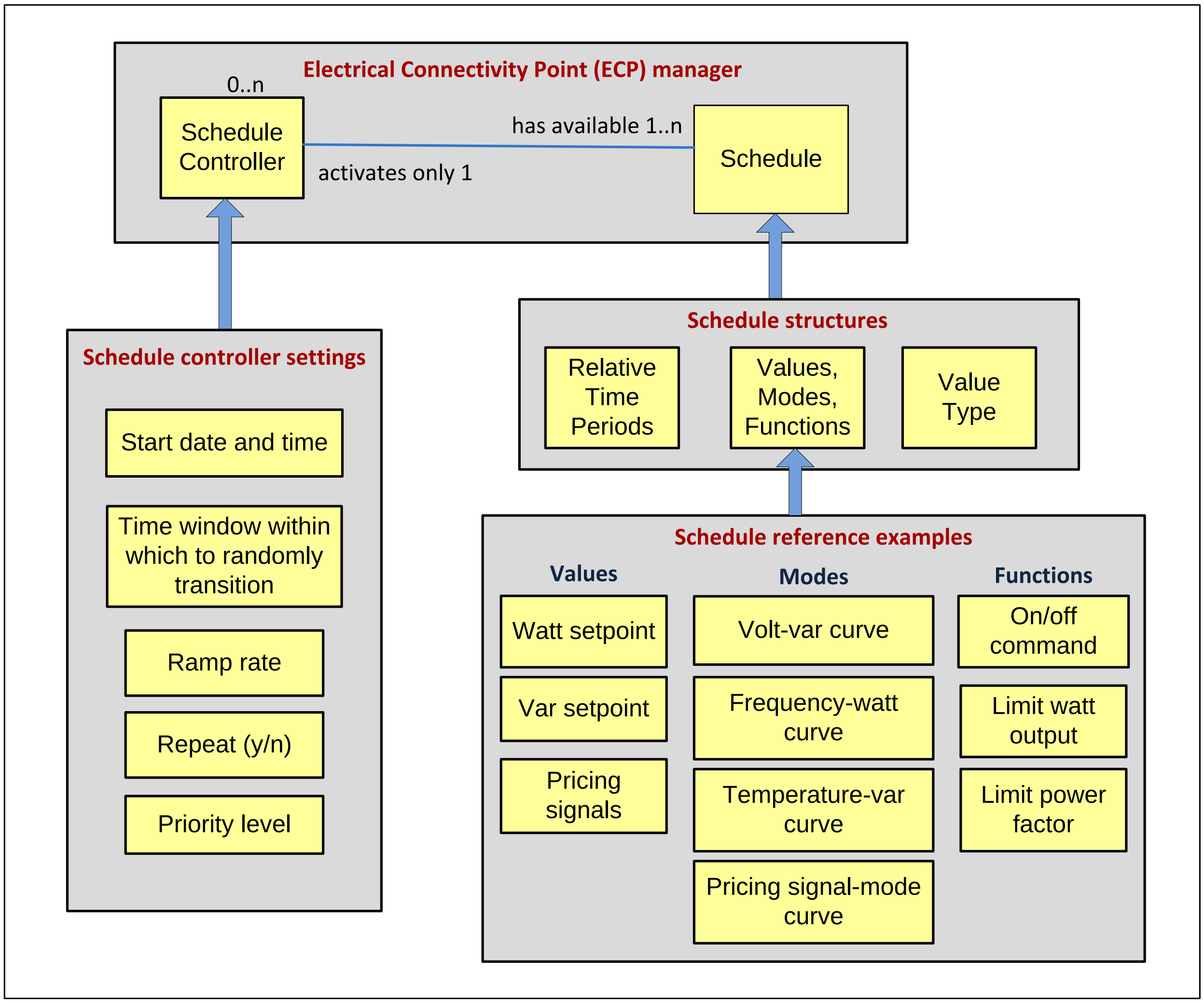


Figure 13 – Interrelationships of schedule controllers, schedules, and schedule references

The details of scheduling are described in IEC 61850-90-10.

3. DER management functions for inverters

3.1 Immediate control functions for inverters

3.1.1 General

Immediate control functions assume a tightly coupled interaction between the inverter-based DER systems and a controlling entity (utility, energy service provider, or customer EMS). This implies that the controlling entity has knowledge about the capabilities of the inverter-based DER systems, can request updates on their current status, can expect the inverter-based DER system to follow the command to the best of their capabilities, and will receive a direct response from the inverter-based DER systems on the results from following the command.

Basic commands will supersede each other and any inverter mode commands in effect, based on the time they were issued by the controlling entity.

Basic commands also imply communication channels with high availability between the controlling entity and the inverter-based DER systems, since the controlling entity must maintain direct knowledge of the inverter-based DER system status and capabilities. Nonetheless, it is expected that inverter-based DER systems will revert to "default" states if communications are unavailable for some pre-specified length of time (implementation dependent).

It is expected that, in general, utilities will use direct controls with larger, utility-owned inverter-based DER systems, while ESPs could use direct commands with groups of inverter-based DER systems, and customer EMSs could use direct controls with those inverter-based DER systems belonging to the customer. However, other interactions are possible, depending upon business decisions and specific implementations.

3.1.2 Function INV1: connect / disconnect from grid

This function causes the inverter-based DER system to immediately physically connect or disconnect from the grid via a disconnect switch at the inverter-based DER system's ECP to the grid.

The utility/ESP or the customer EMS takes the following actions:

- (Optional) Request status of inverter-based DER system: Request a pre-defined set of the status information, including the status values, the quality flag, and the timestamp of the status (see Function DS93 for details of status points).
- Issue connect/disconnect command to inverter-based DER system:
  - Binary command to open or close a switch.
  - Time window within which to randomly execute the command. If the time window is zero, the command will be executed immediately (optional – if not included, then default time window for this function will be used). The connection may be delayed due to necessary safety functions.
  - Timeout period, after which the inverter-based DER system will revert to its default status, such as closing the switch to reconnect to the grid (optional – if not included, then default timeout period for this function will be used)
- Receive response to the command:
  - Successful (plus resulting switch position)
  - Rejected (plus reason: equipment not available, message error, overridden, security error)

3.1.3 Function INV2: adjust maximum generation level up/down

This function sets the maximum generation level at the electrical coupling point (ECP) as a percentage of set capacity (WMax). This limitation could be met by limiting PV output or by using the excess PV output to charge associated storage.

In addition, a ramp rate (power versus time) and a time window within which to randomly start will be included so that not all inverter-based DER systems change state abruptly at the same time.

A timeout period is included for reverting to the default state of the inverter-based DER system, to ensure that a missed or lost command does not impact normal operations beyond that timeout period.

The utility/ESP or the customer EMS takes the following actions:

- (Optional) Request status of inverter-based DER system: Request a pre-defined set of the status information, including the status values, the quality flag, and the timestamp of the status (see Function DS93 for details of status points).
- Issue command to adjust power setpoint:
  - Command to adjust the power setpoint to the requested generation level
  - Requested ramp time for the inverter-based DER system to move from the current setpoint to the new setpoint if either it is now being constrained or it is now being released from a constraint (optional – if not included, then use previously established default ramp rate: WGra)
  - Time window within which to randomly execute the command. If the time window is zero, the command will be executed immediately, (optional – if not included, then default time window for this function will be used)
  - Timeout period, after which the inverter-based DER system will revert to its default status, such as resetting the maximum power setpoint to its default value (optional – if not included, then default timeout period for this function will be used)
- Receive response to the command:
  - Successful (plus actual maximum power setpoint)
  - Rejected (plus reason: equipment not available, message error, overridden, security error).

3.1.4 Function INV3: adjust power factor

Fixed power factor will be managed through issuing a power factor value and corresponding excitation. In addition, a ramp rate (change versus time) and a time window within which to randomly start will be included so that not all inverter-based DER systems change state abruptly or at the same time.

A timeout period is included for reverting to the default state of the inverter-based DER system, to ensure that a missed or lost command does not impact normal operations beyond that timeout period.

The utility/ESP or the customer EMS takes the following actions:

- (Optional) Request status of inverter-based DER system: Request a pre-defined set of the status information, including the status values, the quality flag, and the timestamp of the status (see Function DS93 for details of status points).
- Issue command to adjust power factor setpoint:

- Command to adjust the power factor
- Command to adjust power factor excitation
- Requested ramp time for the inverter-based DER system to move from the current setpoint to the new setpoint (optional – if not included, then use previously established default ramp rate)
- Time window within which to randomly execute the command. If the time window is zero, the command will be executed immediately, (optional – if not included, then default time window for this function will be used)
- Timeout period, after which the inverter-based DER system will revert to its default status, such as resetting the power factor setpoint to its default value (optional – if not included, then default timeout period for this function will be used)

- Receive response to the command:
  - Successful (plus actual output power factor value)
  - Rejected (plus reason: equipment not available, message error, overridden, security error)

3.1.5 Function INV4: request active power (charge or discharge storage)

Inverter-based DER systems which can manage energy production through additional generation reserve and/or storage capabilities can also respond to requests to increase or decrease this energy production, although it is understood that they will always be in ultimate control of what actions they take and that these functions are “requests” to perform certain actions if feasible within pre-specified constraints. For example, a storage system cannot charge when the storage element is full nor can it discharge if at the storage reserve limit.

This function requests the storage system to charge or discharge at a specific rate (% of max charging or discharging rate). A controller might use this command frequently, in conjunction with reads of the battery charge level, to achieve a desired daily charge / dump characteristic.

To account for diversity in the size of storage systems, the function requests a percentage quantity based on the capacity of the system. For active power out requests (storage discharging), the percent is relative to the present maximum discharge rate (WMax, delivered). For active power in requests (storage charging), the percent is relative to the present maximum charging rate (WMax, received). It is acknowledged that the discharging capacity of the inverter and the charging capacity of the charger may differ.

A timeout period is included for reverting to the default state of the inverter-based DER system, to ensure that a missed or lost command does not impact normal operations beyond that timeout period.

The inverter-based DER system may also determine if only inverter-based DER system output is used for charging or whether grid power can be used.

The utility/ESP or the customer EMS takes the following actions:

- (Optional) Request status of inverter-based DER system: Request a pre-defined set of the status information, including the status values, the quality flag, and the timestamp of the status (see Function DS93 for details of status points).
- Issue command to request active power (charge/discharge) setpoint for the storage system:
  - Command to adjust the active power charge/discharge setpoint for the storage system

- Requested ramp time for the inverter-based DER system to move from the current setpoint to the new setpoint (optional – if not included, then use previously established default ramp rate)
- Time window within which to randomly execute the command. If the time window is zero, the command will be executed immediately, (optional – if not included, then default time window for this function will be used)
- Timeout period, after which the inverter-based DER system will revert to its default status (optional – if not included, then default timeout period for this function will be used)
- Storage charge from grid setting (yes/no)

- Receive response to the command:
  - Successful (plus actual active power setpoint)
  - Rejected (plus reason: equipment not available, message error, overridden, security error)

3.1.6 Function INV5: pricing signal for charge/discharge action

This function provides a pricing signal (actual price or some relative pricing indication) from which the inverter-based DER system may decide whether to charge the storage or discharge the storage, and what rate to charge or discharge.

The utility/ESP or the customer EMS takes the following actions:

- Issue pricing signal (the actual form or content of the pricing signal will be established by the utility/ESP and is outside the scope of this specification):
  - Pricing signal
  - Requested ramp time for the inverter-based DER system to move from its current output to any new output (optional – if not included, then use previously established default ramp rate)
  - Time window within which to randomly execute the command. If the time window is zero, the command will be executed immediately, (optional – if not included, then default time window for this function will be used)
  - Timeout period, after which the inverter-based DER system will revert to its default status (optional – if not included, then default timeout period for this function will be used)
- Receive response to the command:
  - Successful (plus actual active power setpoint)
  - Rejected (plus reason: equipment not available, message error, overridden, security error)

3.2 Modes for volt-var management

3.2.1 VAr management modes using volt-var arrays

3.2.1.1 Purpose of volt-var modes

Since utilities (and/or other energy service providers) will be requesting var support from many different inverter-based DER systems with different capabilities, different ranges, and different local conditions, it would be very demanding of the communications systems, unnecessary, and ultimately impossible for the utilities to issue explicit settings to each inverter-based DER system every time a change is desired.

Therefore, volt-var behaviours can be configured into an inverter using arrays that establish a volt-var relationship or curve for use during normal power system. Each volt-var behaviour is associated with a volt-var mode, and requests can be made to change modes by simply specifying the desired mode. This allows DER inverters to be addressed in groups, with each having tailored volt-var behaviours, and yet all able to be switched from one mode to another with minimal communication overhead.

Key inverter modes are described below, with the understanding that additional modes may be defined at a later date. In any of these modes, the inverter-based DER system would still be limited to what it can safely or physically provide, and will log its actions. It is also expected that any of these mode may be overridden by dynamic reactive current support modes as described in 3.4.

3.2.1.2 Volt-var modes

A number of examples of inverter modes have been defined (see Modes VV11 – VV14) for typical types of var support requests. For each inverter mode, one to a few volt-var arrays of settings can be associated (the maximum number that may be configured into an inverter is limited only by the device itself). Controlling entities (utility or other) may choose what kind of volt-var behaviour is desired for each mode and may configure inverters accordingly.

Each volt-var array consists of volt-var pairs: a set of voltage levels and their corresponding var levels that will be treated as a piecewise linear function. These arrays can be of variable length, depending upon the number of volt-var pairs. Utilities can issue these volt-var arrays initially and update them when necessary. For uniform vars across all voltage levels, parameters may be used to set the fixed percent of vars.

Disabling all volt-var modes permits the inverter to revert to its default var behaviour.

3.2.1.3 Invoking volt-var modes

There are three ways a utility can invoke a volt-var mode:

- Direct requests to specific inverter-based DER systems
- Broadcasts or multicasts to all inverter-based DER systems in a selected area (region, feeder, substation) to use a particular volt-var array.
- Scheduling volt-var modes using different criteria.

Multiple volt-var modes may be ready-to-run at any one time. The most recently activated mode will take precedence over other modes. If the most recent mode is deactivated, the next most recent will take effect.

3.2.2 Example setting volt-var mode VV11: available var support mode with no impact on watts

As one example of volt-var modes, the available vars mode reflects the calculation of the most efficient and reliable var levels for inverter-based DER systems at specific distribution points of common coupling (PCC) without impacting the watts output. This mode could also help compensate for local high voltage due to PV kW back flow on the circuit.

In this mode, inverter-based DER systems will be provided with a double array of setpoints: a set of voltage levels and their corresponding var levels as % of available vars. The voltage levels will range between V1 and Vx in increasing voltage values (decreasing for hysteresis if used). Values between these setpoints will be interpolated to create a piecewise linear volt-var function. The corresponding var levels define the percent of VArAval (available vars) requested for the voltage level.

Figure 14 provides one example of volt-var settings for this mode. It is assumed that the var value between VMin and V1 is the same as for V1 (shown as 50 % VArAval, in this example). The equivalent is true for the var value between V4 and VMax (which is assumed to be 50 % VArAval in this example). PT1 is the low-pass exponential time rate filter described in 2.2.6.

Example Settings

Voltage Array (% VRef)		VAr Array (% VArAval)	
V1	97	Q1	50
V2	99	Q2	0
V3	101	Q3	0
V4	103	Q4	–50

VAr Ramp Rate Limit – fastest allowed decrease in VAR output in response to either power or voltage changes	50 [%VArAval/s]
VAr Ramp Rate Limit – fastest allowed increase in VAR output in response to either power or voltage changes	50 [%VArAval/s]
The time of the PT1 in seconds (time to accomplish a change of 95 %).	10 s
Randomization Interval – time window over which mode or setting changes are to be made effective	60 s

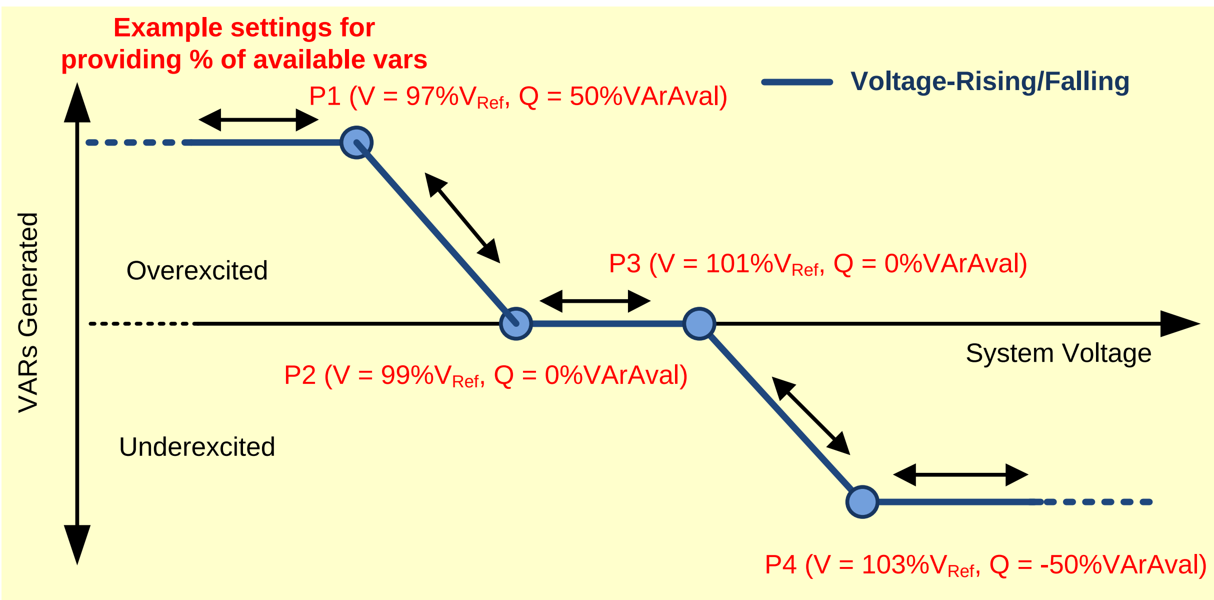


Figure 14 – Volt-var mode VV11 – available vars mode

The steps to invoke the VV11 available vars mode are as follows:

- Issue request to go into VV11 Mode:
  - Request to go into VV11 Mode
  - Array of volt-var of setpoints identifying the y-value type as the percent vars of available vars rather than of maximum vars (optional – if not included, then use previously established default array)

- Requested ramp time for the inverter-based DER system to move from the current setpoint to the new setpoint if either it is now being constrained or it is now being released from a constraint (optional – if not included, then use previously established default ramp rate)
- Time window within which to randomly execute the command. If the time window is zero, the command will be executed immediately, (optional – if not included, then default time window for this function will be used)
- Timeout period, after which the inverter-based DER system will revert to its default status, such as resetting the maximum power setpoint to its default value (optional – if not included, then default timeout period for this function will be used)

- Receive response to the command:
  - Successful
  - Rejected

3.2.3 Example setting volt-var mode VV12: maximum var support mode based on WMax

As another volt-var example, inverter-based DER systems provide the maximum vars without exceeding 100 % WMax. This mode would typically be invoked by the utility to support transmission emergencies or other var emergencies.

This function would essentially be represented as a straight horizontal line at y-values in the curve = 100 % and the y-value type set to “maximum vars”, until the regulated limits or the inverter protective limits are hit.

Figure 15 provides one example of how a VV12 mode may be configured. In this example, the inverter generates maximum capacitive vars for reduced voltages down to the cut-off limit VMin. As voltage increases above configuration point V1, var generation is ramped down, reaching zero at V2, so as not to drive the local system voltage too high.

The ramp rates and/or the randomized time-constant settings are also required.

Example Settings

Voltage Array (%VRef)		**VAr Array** (%WMax)	
V1	101	Q1	100
V2	103	Q2	0

VAr Ramp Rate Limit – fastest allowed decrease in var output in response to either power or voltage changes	50 [%WMax/s]
VAr Ramp Rate Limit – fastest allowed increase in var output in response to either power or voltage changes	50 [%WMax/s]
The time of the PT1 in seconds (time to accomplish a change of 95 %).	10 s
Randomization Interval – time window over which mode or setting changes are to be made effective	60 s

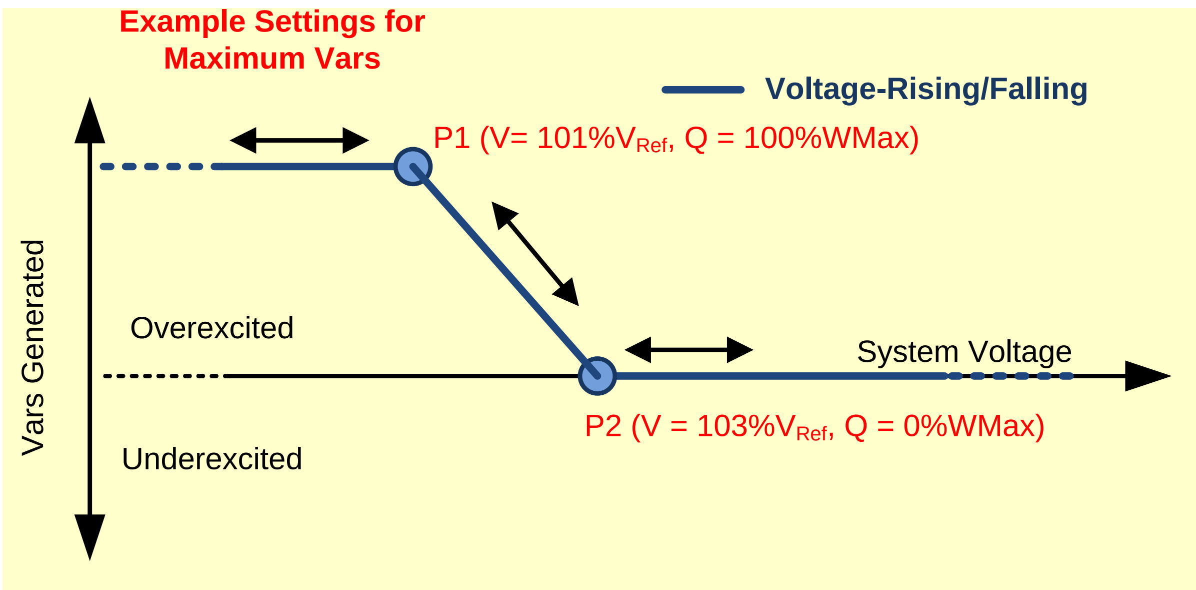


Figure 15 – Inverter mode VV12 – Maximum var support mode based on WMax

The steps to invoke the VV12 maximum var support mode are as follows:

- Issue request to go into VV12 Mode:
  - Request to go into VV12 Mode
  - Array of volt-var of setpoints identifying the y-value type as the percent vars of maximum watts rather than of available vars (optional – if not included, then use previously established default array)
  - Requested ramp time for the inverter-based DER system to move from the current setpoint to the new setpoint if either it is now being constrained or it is now being released from a constraint (optional – if not included, then use previously established default ramp rate)
  - Time window within which to randomly execute the command. If the time window is zero, the command will be executed immediately, (optional – if not included, then default time window for this function will be used)
  - Timeout period, after which the inverter-based DER system will revert to its default status, such as resetting the maximum power setpoint to its default value (optional – if not included, then default timeout period for this function will be used)
- Receive response to the command:
  - Successful
  - Rejected

3.2.4 Example setting volt-var mode VV13: static inverter mode based on settings

Another example mode, VV13, establishes fixed var settings for inverters as illustrated in Figure 16. This mode does not use curves but only settings.

This function can be typically represented as a straight horizontal line at a Q percentage value between ± 100 % until the regulatory VMin/VMax levels or the inverter protective limits are reached. The percentage can be one of three options: percent available vars (no impact on watts output) or percent maximum watts (watts output may be impacted) or percent maximum vars.

This mode is likely to be of interest in cases where a separate inverter-based DER system controller is managing the PV site. In such a case, the controller would be the point of intelligence, monitoring system voltage and communicating with the utility, then managing the local inverters moment by moment to achieve the desired results.

The ramp rates and/or the randomized time-constant settings are also required.

Example Settings

VArWMaxPct	50 % of max watts
VArMaxPct	50 % of max vars
VArAvalPct	50 % of max available vars
Randomization Interval – time window over which mode or setting changes are to be made effective	60 s

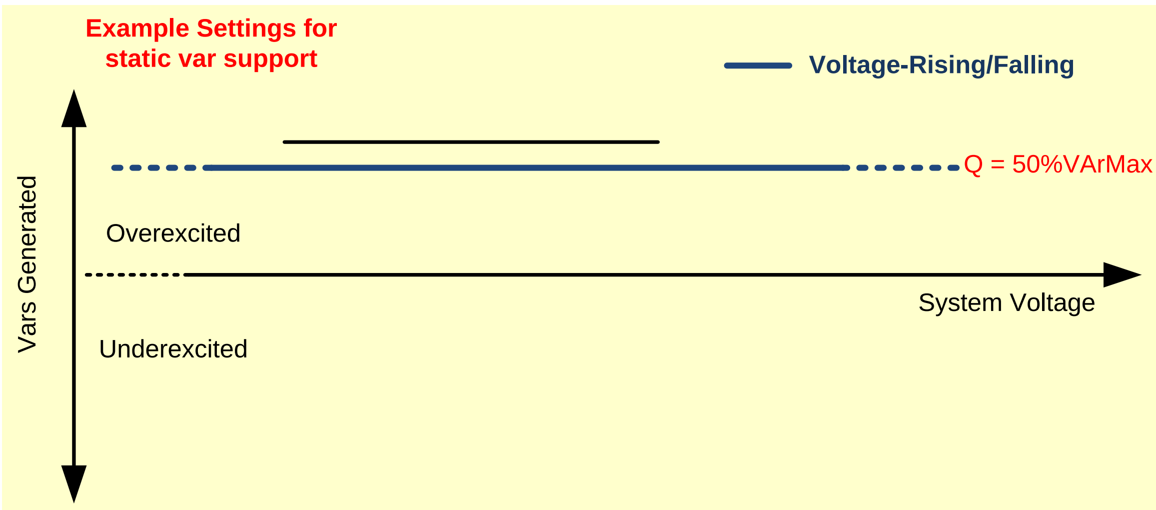


Figure 16 – Inverter mode VV13 – Example: static var support mode based on VArMax

The steps to invoke the VV13 static var support mode are as follows:

- Issue request to go into VV13 Mode:
  - Set the constant percent of vars for the appropriate type of vars (percent available vars, percent maximum watts, or percent maximum vars)
  - Request to go into VV13 Mode via the constant VAr Mode of Operation
  - Requested ramp time for the inverter-based DER system to move from the current setpoint to the new setpoint if either it is now being constrained or it is now being released from a constraint (optional – if not included, then use previously established default ramp rate)
  - Time window within which to randomly execute the command. If the time window is zero, the command will be executed immediately, (optional – if not included, then default time window for this function will be used)

– Timeout period, after which the inverter-based DER system will revert to its default status, such as resetting the maximum power setpoint to its default value (optional – if not included, then default timeout period for this function will be used)

- Receive response to the command:
  - Successful
  - Rejected

3.2.5 Example setting volt-var mode VV14: passive mode with no var support

This example mode is the same as mode VV13 above, except that the var levels are zero. In this mode, inverters will follow the system voltage levels within their capability range, presumably at their most efficient settings.

This mode will serve as the default mode for inverter-based DER systems upon power up, if all other volt-var modes are disabled, when schedules expire, or if no communications have been received within a defined period (e.g. if no additional signals have been received over x hours or if the schedule has run out without further updates).

Utilities could switch some or all inverters to this mode if other modes presented unexpected difficulties.

The steps to invoke the VV14 Mode are as follows:

- Issue request to go into VV14 Mode:
  - Set the percent of vars to zero (0) for the appropriate type of vars
  - Request to go into VV14 Mode via the constant VAr Mode of Operation
  - Requested ramp time for the inverter-based DER system to move from the current setpoint to the new setpoint if either it is now being constrained or it is now being released from a constraint (optional – if not included, then use previously established default ramp rate)
  - Time window within which to randomly execute the command. If the time window is zero, the command will be executed immediately, (optional – if not included, then default time window for this function will be used)
  - Timeout period, after which the inverter-based DER system will revert to its default status, such as resetting the maximum power setpoint to its default value (optional – if not included, then default timeout period for this function will be used)
- Receive response to the command:
  - Successful
  - Rejected

3.3 Modes for frequency-related behaviours

3.3.1 Frequency management modes

Frequency management modes are used to mitigate frequency deviations by countering them with reduced or increased power. These modes can be used for emergency situations involving very large frequency deviations, but can also be used continuously to smooth minor frequency changes. These modes also include the addition of hysteresis.

The curve shapes shown in Figure 17 provide a generic example of the operating areas that could be specified. The vertical axis would be percent of WMax, and the horizontal axis is frequency, with nominal frequency (ECPNomHz) shown in the middle.

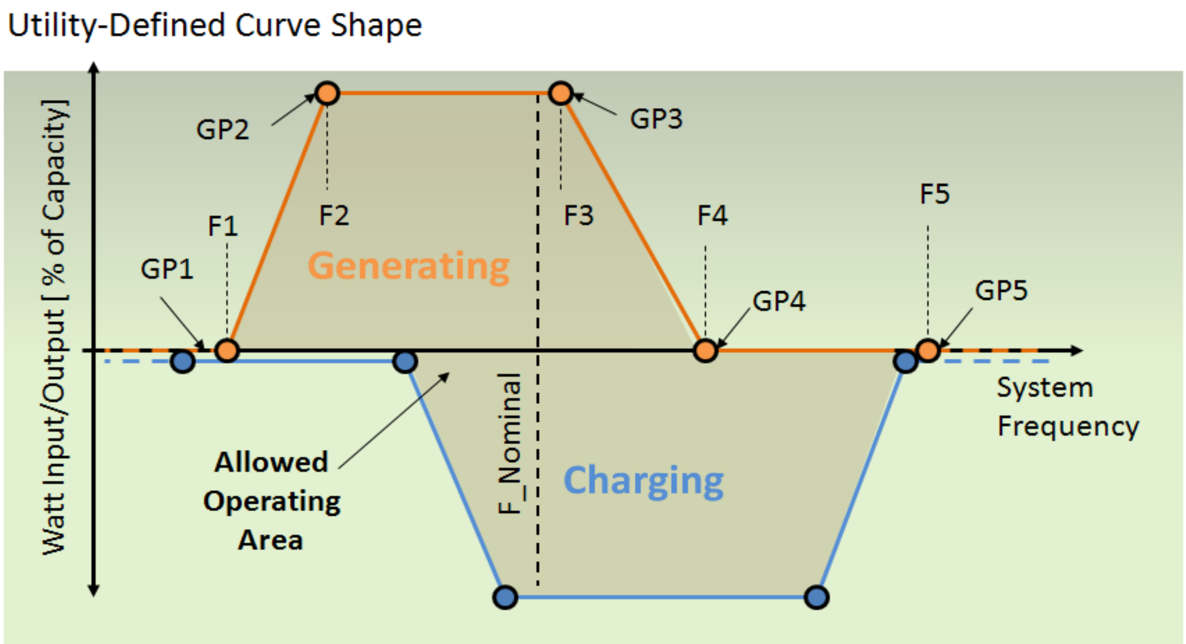


Figure 17 – Frequency-watt mode curves

3.3.2 Frequency-watt mode FW21: high frequency reduces active power

This frequency-watt mode addresses the issue that high frequency often is a sign of too much power in the grid, and vice versa. These extreme deviations from nominal frequency can cause grid instability, particularly if they cause significant amounts of generating equipment to trip off-line.

One method for countering this over-power problem is to reduce power in response to rising frequency (and vice versa if storage is available). Adding hysteresis provides additional flexibility for determining the active power as frequency returns toward nominal. Figure 18 shows the necessary settings for the active power reduction by frequency.

The parameters for frequency are relative to nominal grid frequency (ECPNomHz). The parameter HzStr establishes the frequency above nominal at which power reduction will commence. If the delta grid frequency is equal or higher than this frequency, the actual active power will be "capped" at its current output level, shown as P_M. If the grid frequency continues to increase, the power cap will be reduced by following the gradient parameter (WGra), defined as percent of P_M per Hertz.

The parameter HysEna can be configured to activate or deactivate hysteresis. Without hysteresis (HysEna is deactivated), the power curve follows the same gradient back up as frequency is reduced (see top left graph in Figure 18). With hysteresis (HysEna is activated), the power curve remains capped at the lowest power level reached until the delta grid frequency reaches the delta stop frequency, HzStop (see top right graph and example in Figure 18).

For generation, the output power could be decreased to zero; for combinations of generation and storage, the output power may shift from decreasing generation to absorbing power (charging).

Whether or not hysteresis is active, the actual power will be uncapped when the delta grid frequency becomes smaller than or equal to the parameter HzStop. In order to prevent abrupt power increases after this uncapping of the actual power, an active power gradient is used as a time-based recovery ramp rate. This power gradient parameter, HzStopWGra, is defined in WMax/minute. The default could be around 10 % WMax/minute.

Example Settings

Name	Description	Example settings
WGra	The slope of the reduction in the maximum allowed watts output as a function of frequency	40 % P_M/Hz
HzStr	The frequency deviation from nominal frequency (ECPNomHz) at which a snapshot of the instantaneous power output is taken to act as the "capped" power level (PM) and above which reduction in power output occurs	0.2 Hz
HzStop	The frequency deviation from nominal frequency (ECPNomHz) at which curtailed power output may return to normal and the cap on the power level value is removed.	0.05 Hz
HysEna	A boolean indicating whether or not hysteresis is enabled	On
HzStopWGra	The maximum time-based rate of change at which power output returns to normal after having been capped by an over frequency event.	10 % WMax/minute

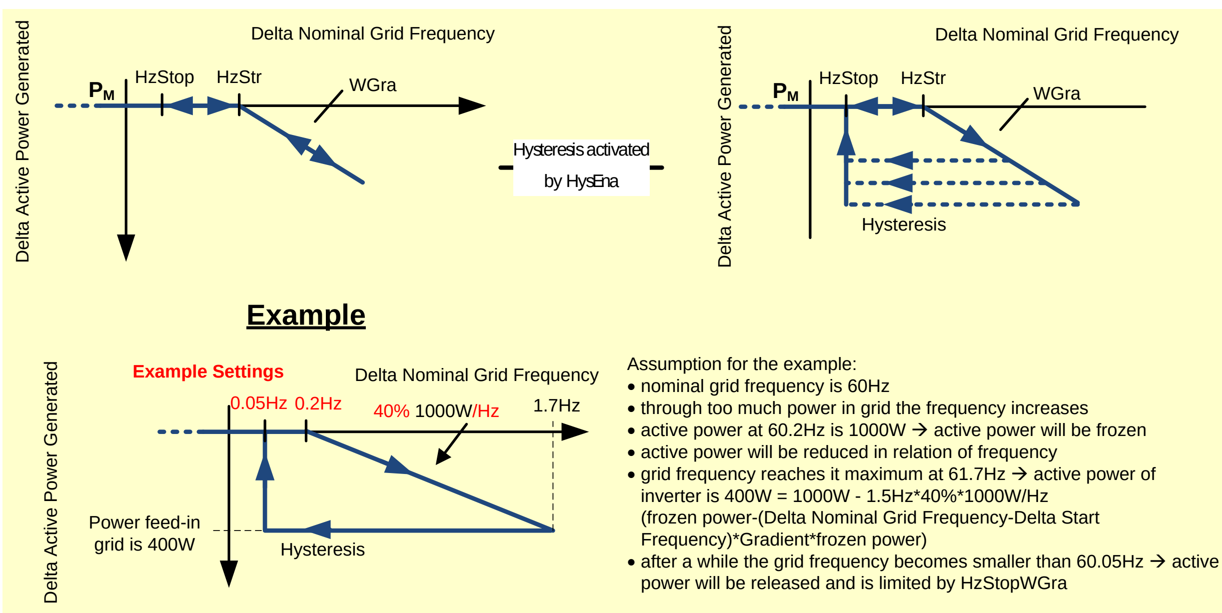


Figure 18 – Frequency-based active power reduction

This frequency-watt mode is specifically designed for emergency situations involving grid stability concerns, and thus is expected to be rarely invoked. However, like all modes, it could be activated in conjunction with other modes, including frequency-watt modes that respond to minor frequency deviations, such as FW22.

The frequency-watt mode settings can be pre-specified at installation to act in all high/low frequency situations or can be modified and activated at a later time via the following actions:

- Issue command to modify frequency-watt settings:
  - Frequency-watt mode
  - Triggering settings for frequency

- Hysteresis activation setting
- Gradient values
- Recovery ramp rate

- Receive response to the command:
  - Successful (plus new value of data element)
  - Rejected (plus reason: equipment not available, message error, overridden, security error)

3.3.3 Frequency-watt mode FW22: constraining generating/charging by frequency

If more general response to minor frequency deviations is desired, particularly if both generation and charging of storage is included, then frequency-watt arrays need to be used, rather than the individual parameters defined in the FW21 mode.

There can be multiple frequency-watt modes configured into an inverter. For example, the desired frequency-watt settings might be different on-peak versus off-peak, or different when islanded (in isochronous mode) versus grid connected. A simple mode change broadcast could move the inverters from one pre-configured frequency-watt mode to another

The settings for this mode would include a frequency-watts-delivered curve (generation) and/or a frequency-watts received curve (storage), ramps for changing power, time of the input filter, and as with other functions, a time window, ramp rate, and timeout.

As another example, Figure 19 shows an equivalent approach to frequency-watt mode FW21, but using frequency-watt curves instead of individual parameters.

Example Settings

RmpTms for P1	10s
RmpTmmDec	100 % WMax/minute
RmpTmmInc	40 % WMax/minute
RmpRsUp	10 % WMax/minute

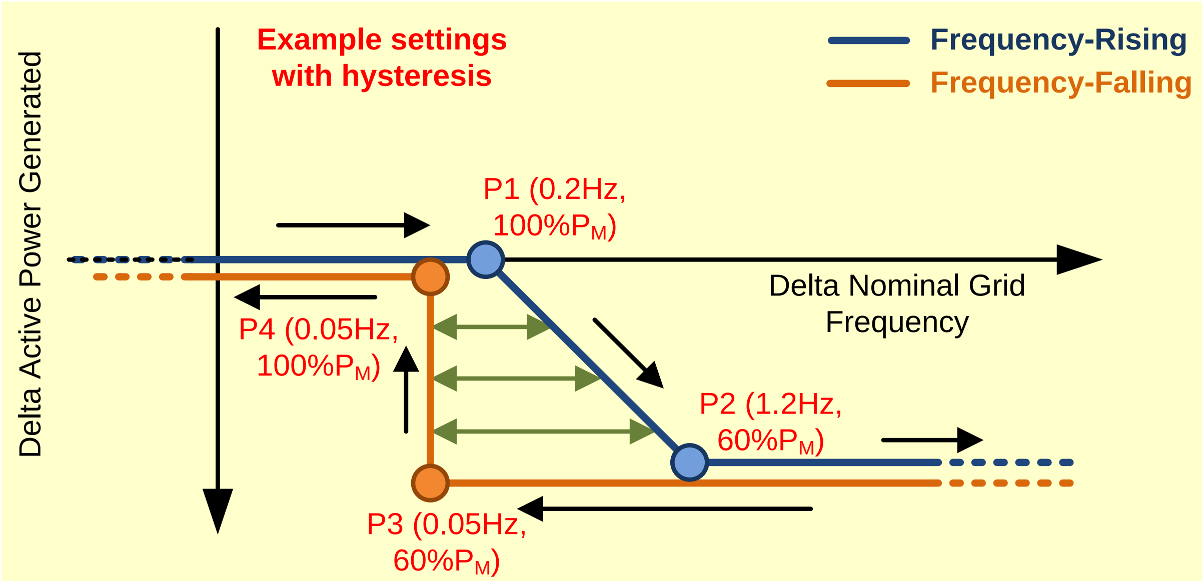


Figure 19 – Frequency-based active power modification with the use of an array

<u>Modes</u>

As with the volt-var modes, there could be multiple frequency-watt modes configured into an inverter. For example, the desired frequency-watt settings might be different on-peak vs. off-peak or different when islanded vs. grid connected. A simple mode change broadcast could move the inverters from one pre-configured frequency-watt mode to another.

<u>Basic Concept</u>

The basic idea is illustrated in Figure 20.

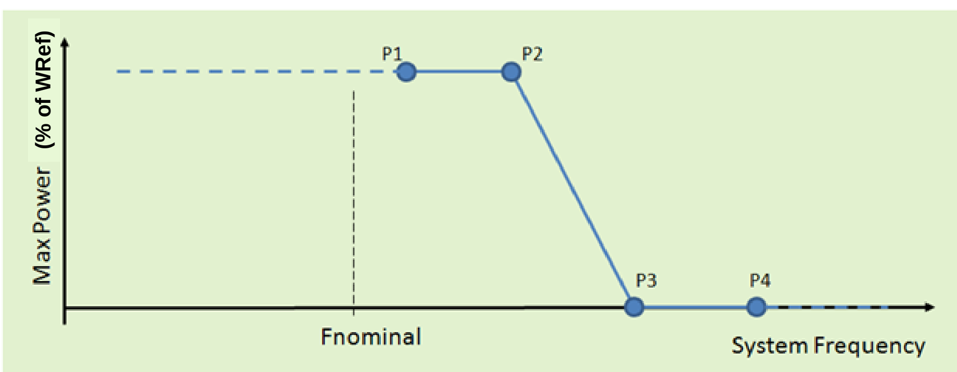


Figure 20 – Example of a basic frequency-watt mode configuration

The desired frequency-watt behaviour is established by writing a variable-length array of frequency-watt pairs. Each pair in the array establishes a point on the desired curve such as those labelled in Figure 20 as P1-P4. The curve is assumed to extend horizontally to the left below the lowest point and to the right above the highest point in the array. The horizontal X-axis values are defined in terms of actual frequency (Hz). The vertical Y-axis values are defined in terms of a percentage of a reference power level (WRef) which is, by default, the maximum

Watt capability of the system, WMax (defined in prior work, may differ from the nameplate value). As will be explained later in this document, these Y-axis values are signed, ranging from +100 % to –100 %, with positive values indicating active power produced (delivered to the grid) and negative values indicating power absorbed.

Setting a Snap Shot Power Reference (WRef) Value

In some cases, it may be desirable to limit and reduce power output relative to the instantaneous output power at the moment when frequency deviates beyond a certain frequency. To enable this capability, each frequency-watt mode configuration will include the following parameters, in addition to the array.

Snapshot Enable (DeptRef): An enumeration which when set to watts as percent of frozen active power WRef, instructs the inverter that the WRef value is to be set to a snapshot of the instantaneous output power DeptSnptRef at a certain point. When Snapshot is enabled, no reduction in output power occurs prior to reaching the WRef Capture Frequency (WRefHz).

WRef Capture Frequency: The frequency deviation from nominal frequency, in hertz, at which the WRef value is established at the instantaneous output of the system at that moment. This parameter is only valid if Snapshot Enable is true.

WRef Release Frequency: The frequency deviation from nominal frequency, in hertz, at which the WRef value is released, and system output power is no longer limited by this function. This parameter is only valid if Snapshot Enable is true.

Optional Use of Hysteresis

Hysteresis can be enabled for this frequency-watt function in the same way as with the volt-var function defined previously. Rather than the configuration array containing only points incrementing from left to right (low frequency to high frequency), as indicated in Figure 2, hysteresis is enabled by additional points in the configuration array which progress back to the left. Figure 21 illustrates this concept.

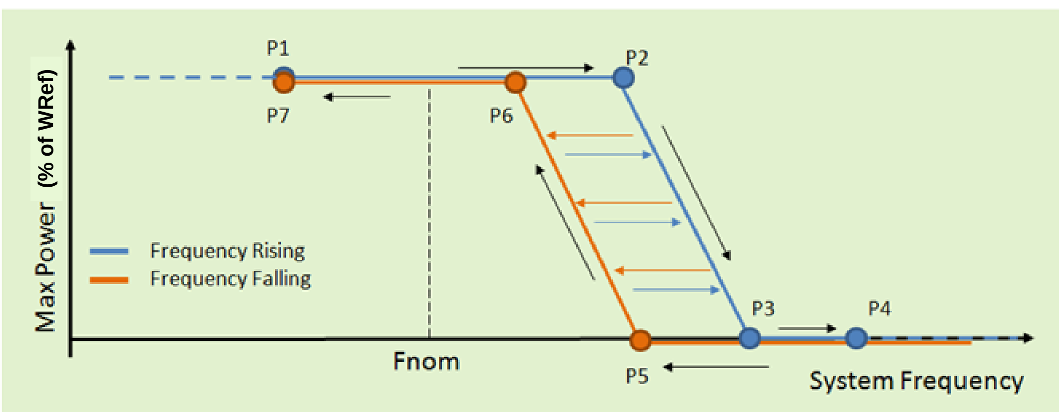


Figure 21 – Example array settings with hysteresis

In this case, the points in the configuration array can be thought-of as the coordinates for an X-Y plotter. The pen goes down on the paper at the first point, then steps through the array to the last point, tracing out the resulting curve. As with any configuration (including those without hysteresis), inverters must inspect the configuration when received and verify its validity before accepting it. The hysteresis provides a sort of dead-band, inside which the maximum power limit does not change as frequency varies. For example, in Figure 3, if frequency rises until the max power output is being reduced (somewhere between points P2 and P3), but then the frequency begins to fall, the maximum power setting would follow the light orange arrows horizontally back to the left, until the lower bound is reached on the line between points P5 and P6.

The return hysteresis curve does not have to follow the same shape as the rising curve. Figure 22 illustrates an example of such a case.

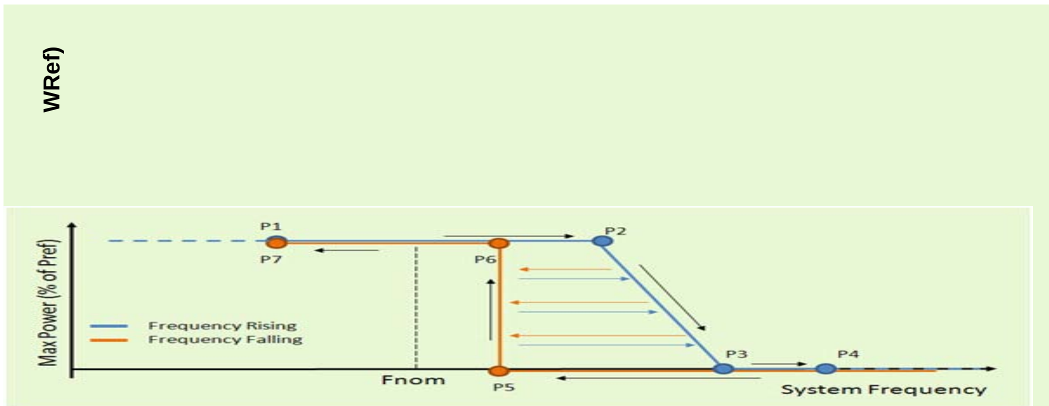


Figure 22 – Example of an asymmetrical hysteresis configuration

Controlling Ramp Time

It may be desirable to limit the time-rate at which the maximum power limit established by these functions can rise or fall. To enable this capability, each frequency-watt mode configuration will include the following parameters, in addition to the array.

Ramp Time Increasing and Ramp Time Decreasing: The maximum rates at which the maximum power limit established by this function can rise or fall, in units of % WMax/second.

Supporting Two-Way Power Flows

Some systems, such as battery storage systems, may involve both the production and the absorption of Watts. To support these systems, a separate control function is defined, which is identical to that described above, except the vertical axis is defined as maximum watts absorbed rather than maximum watts delivered. This allows for battery storage systems to back-off on charging when grid frequency drops, in the same way that photovoltaic systems back-off on delivering power when grid frequency rises. Figure 23 illustrates an example setting.

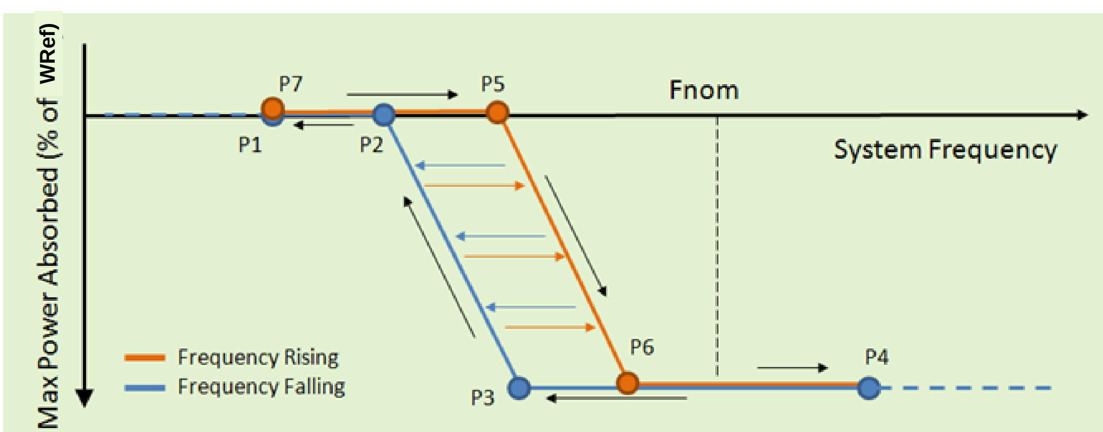


Figure 23 – Example array configuration for absorbed watts vs. frequency

A further characteristic of systems capable of two-way power flows is that the maximum power curtailment illustrated in Figures 2 through 4 need not stop at 0 %. It may pass through zero, changing signs, and indicating that power must flow in the opposite direction (unless prevented from doing so by some other hard limitation).

For example, a battery storage system may be in the process of discharging, delivering power to the grid. If the grid frequency then rises above normal, the maximum delivered power level may begin to be curtailed. Once it has been curtailed to zero, if the frequency keeps rising, the system could be required to absorb watts, taking power out of the grid. Likewise, a battery storage system could curtail charging if the grid frequency drops too low, and begin discharging if frequency continues to drop further. These array configurations would utilize the signed nature of the array Y-values, as mentioned above.

3.4 Dynamic reactive current support during abnormally high or low voltage levels

3.4.1 Purpose of dynamic reactive current support

The dynamic reactive current support function defines the requirements for inverters to support the grid during short periods of abnormally high or low voltage levels by feeding reactive current to the grid until the voltage either returns within its normal range or the inverter is forced to disconnect. This function is required in some regions in order to meet international laws and regulations[3].

3.4.2 Dynamic reactive current support mode TV31: support during abnormally high or low voltage levels

3.4.2.1 Basic concepts of dynamic reactive current support

During abnormally high and low voltage levels, dynamic reactive current support by inverter-based DER systems may and/or must be taken to counter these abnormal conditions. These dynamic support actions are based on a combination of the rate of change of the voltage levels and the duration of these abnormal voltage dips/spikes. The basic concept is shown in Figure 24, where ArGraSag and ArGraSwell identify the additional reactive current as a percent of the rated current, based on the delta voltage (DelV) from the moving average of voltage (voltage averaged across a window of time). A deadband, defined by DbVMin and DbVMax, can be used to limit this function to be activated only when the delta voltage exceeds some limit.

3 The function may contain a description of the relevant European Standard EN 50549 law that is being met. Event logging will show when a law and its parameters have been changed.

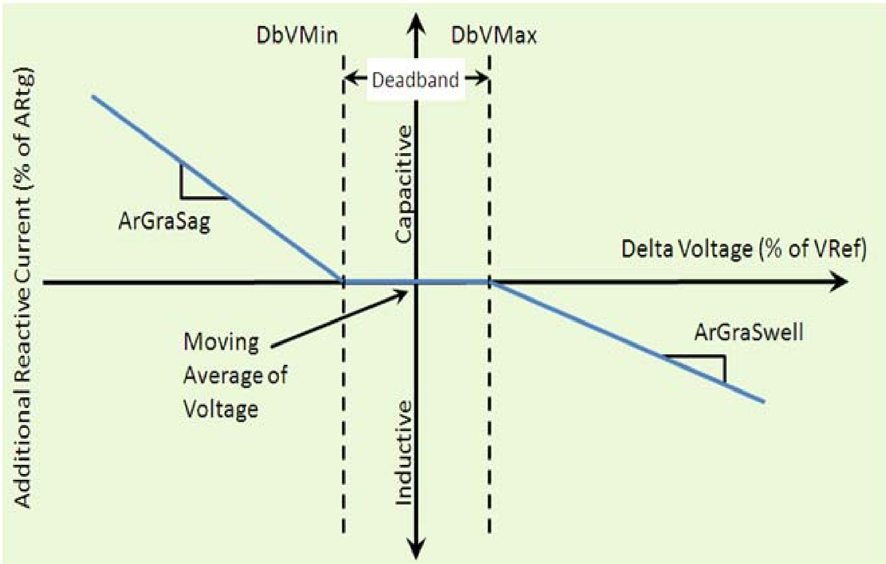


Figure 24 – Basic concepts of the dynamic reactive current support function

3.4.2.2 Calculation of delta voltage

More precisely, the delta voltage DelV is calculated as the difference between the present measured voltage and the moving average of voltage (VAv**)**. This moving average voltage is calculated using a sliding linear filtering over a preceding window of time specified as FilTms (shown as FilterTms). The calculation of delta voltage (delta voltage = present voltage – moving average voltage, expressed as a percentage of VRef) is illustrated at time = "Present" in Figure 25.

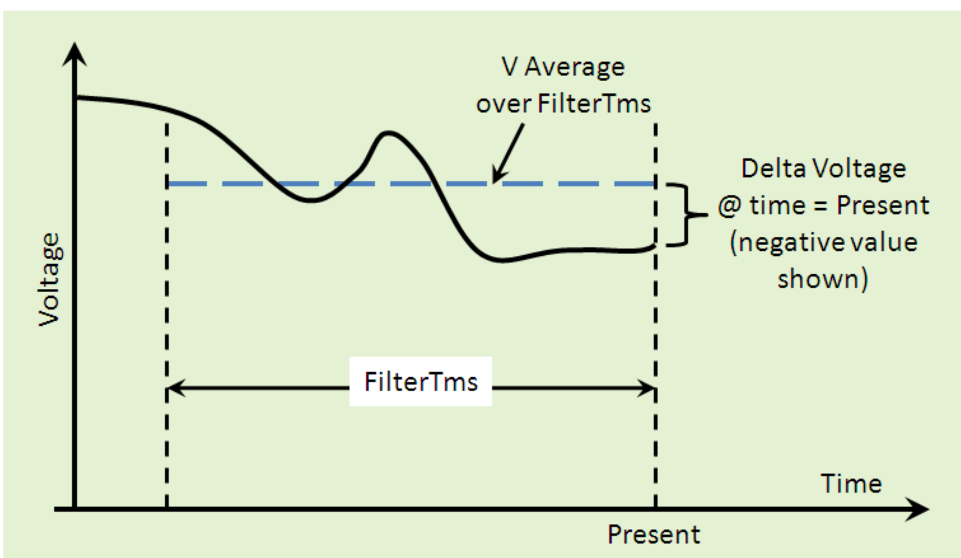


Figure 25 – Calculation of delta voltage over the filter time window

3.4.2.3 Activation of dynamic support

The use of the deadband between DbVMax and DbVMin allows the activation of this behaviour for a voltage sag or swell to be thought of as an "event". The event begins when the present measured voltage moves above the moving average voltage by DbVMax or below by DbVMin, as shown by the blue line in Figure 26 and labelled as t0.

In the example shown, reactive current support continues until a time HoldTmms after the voltage returns above DbVMin as shown. In this example, this occurs at time t1, and this event continues to be considered active until time t2 (which is t1 + HoldTmms).

When this behaviour is activated, the moving average voltage (VAv) and any reactive current levels that might exist due to other functions (such as the static volt-var function) are frozen at t0 when the "event" begins and are not free to change again until t2 when the event ends. The reactive current level specified by this function continues to vary throughout the event and be added to any frozen reactive current.

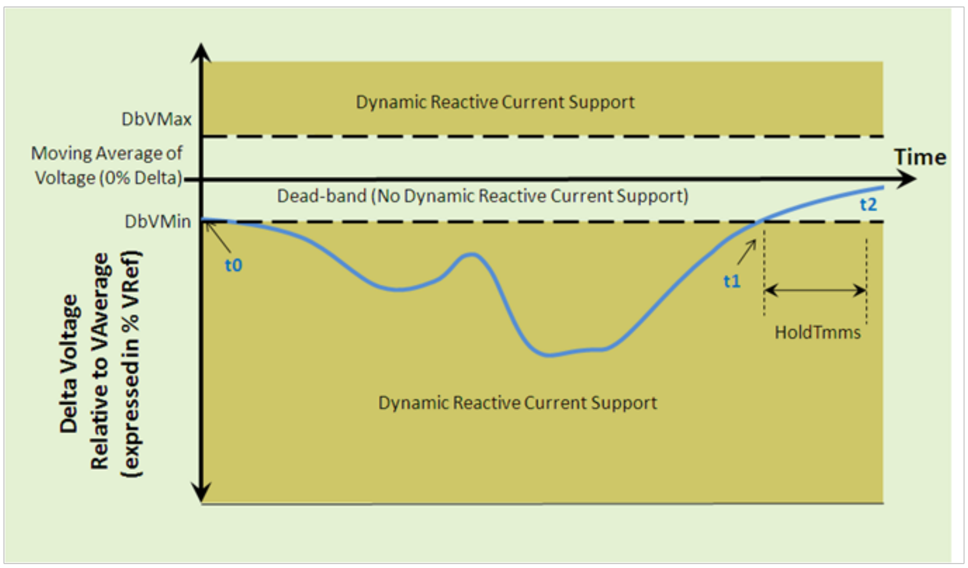


Figure 26 – Activation zones for dynamic reactive current support

3.4.2.4 Deactivation of dynamic support

Dynamic support may be effectively deactivated by setting ArGraSag and ArGraSwell to zero (0), so that the function does not modify any reactive current output.

3.4.2.5 Alternative Gradient Shape

This function includes the option of an alternative behaviour to that shown in Figure 24. ArGraMod selects between that behaviour where gradients trend toward zero at the deadband edges, and that of Figure 27 where the gradients trend toward zero at the centre. In this alternative mode of behaviour, the additional reactive current support begins with a step change when the "event" begins (at DbVMin for example), but then follows a gradient through the centre until the event expires, HoldTmms after the voltage returns above the DbVMin level.

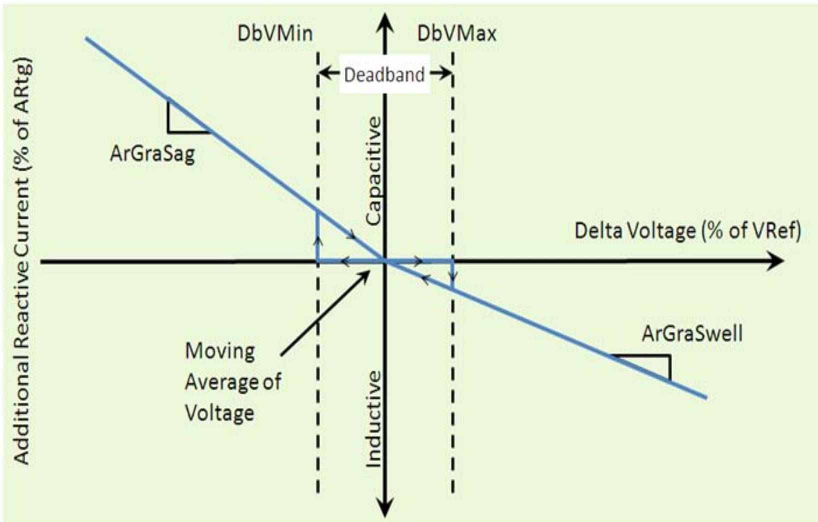


Figure 27 – Alternative gradient behaviour, selected by ArGraMod

3.4.2.6 Blocking zones

This function also allows for the optional definition of a blocking zone, inside which additional reactive current support is not provided. This zone is defined by the three parameters BlkZnTmms, BlkZnV, and HysBlkZnV. It is understood that all inverters will have some self-imposed limit as to the depth and duration of sags which can be supported, but these settings allow for specific values to be set, as required by certain country grid codes.

As illustrated in Figure 28, at t0 the voltage at the ECP falls to the level indicated by the BlkZnV setting and dynamic reactive current support stops. Current support does not resume until the voltage rises above BlkZnV + HysBlkZnV as shown at t1. BlkZnTmms provides a time, in milliseconds, before which dynamic reactive current support continues, regardless of how low voltage may sag. BlkZnTmms is measured from the beginning of any sag "event" as described previously.

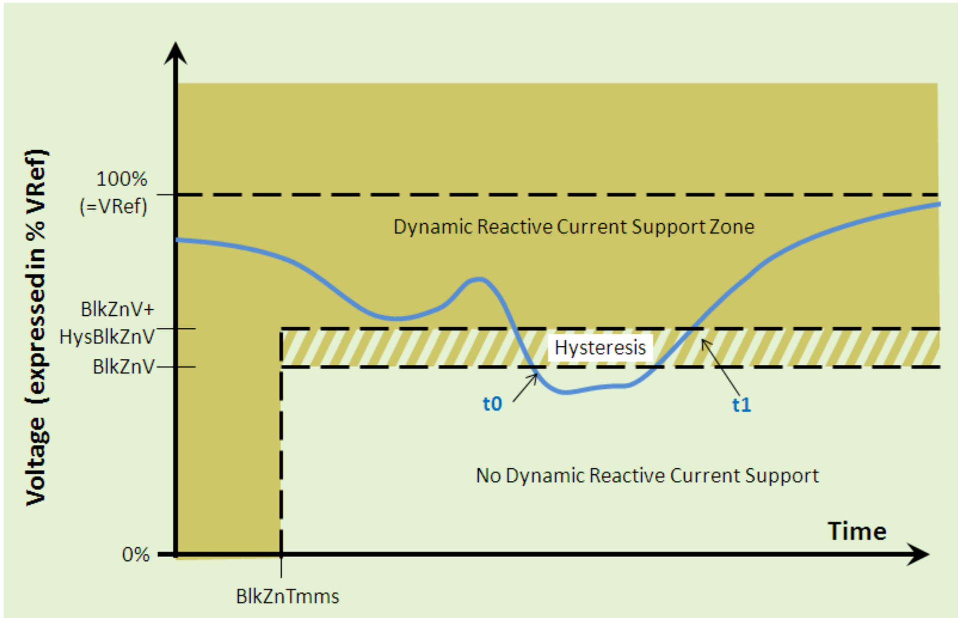


Figure 28 – Settings to define a blocking zone

3.5 Low/high voltage ride-through curves for “must disconnect” and “must remain connected” zones

3.5.1 Purpose of L/HVRT

A flexible mechanism is needed through which general Low/High Voltage Ride-Through (L/HVRT) behaviour may be configured, if so desired. In this context, L/HVRT refers only to the connect/disconnect behaviour of the DER, essentially defining the voltage conditions under which the DER may and must connect and disconnect.

This function defines only the mechanism through which the L/HVRT settings may be made and does not define the settings that would be used. Various countries, states, or other organizations such as the IEEE may issue specific L/HVRT requirements. The intention is that this function will be sufficiently flexible to support all such requirements.

For low/high voltage ride through situations, either parameters or curves can be used to define the “must disconnect” and “must remain connected” zones, where the option for either remaining connected or disconnecting lies between these two zones:

- “Must disconnect” zone of voltage levels versus time. This zone is defined by a combination of the inverter safety constraints, local regulatory requirements, and any specific operational situations (anti-islanding requirement).
- “Remaining connected or disconnecting is allowed” zone of voltage levels versus time. This zone is defined by the area (if any) between the the must disconnect and the must remain connected curves.
- “Must remain connected” zone of voltage levels versus time. This curve is also defined by a combination of the inverter safety constraints, local regulatory requirements, and any specific operational situations (e.g. microgrid creation requirement).

3.5.2 “Must disconnect” (MD) and “must remain connected” (MRC) curves

Some “must disconnect” curves are defined in standards like IEEE 1547/IEC PAS 63547. In addition, inverters have their own must-disconnect settings for safety reasons and/or to prevent possible damage to the equipment. This can be modelled by the existing over and under voltage protection functions.

Increasingly regulations are also requesting DER systems to remain connected during voltage anomalies, so long as they are not too long in duration or the voltage levels are not too high or low,. These "must disconnect" and "must remain connected" zones are illustrated in Figure 29.

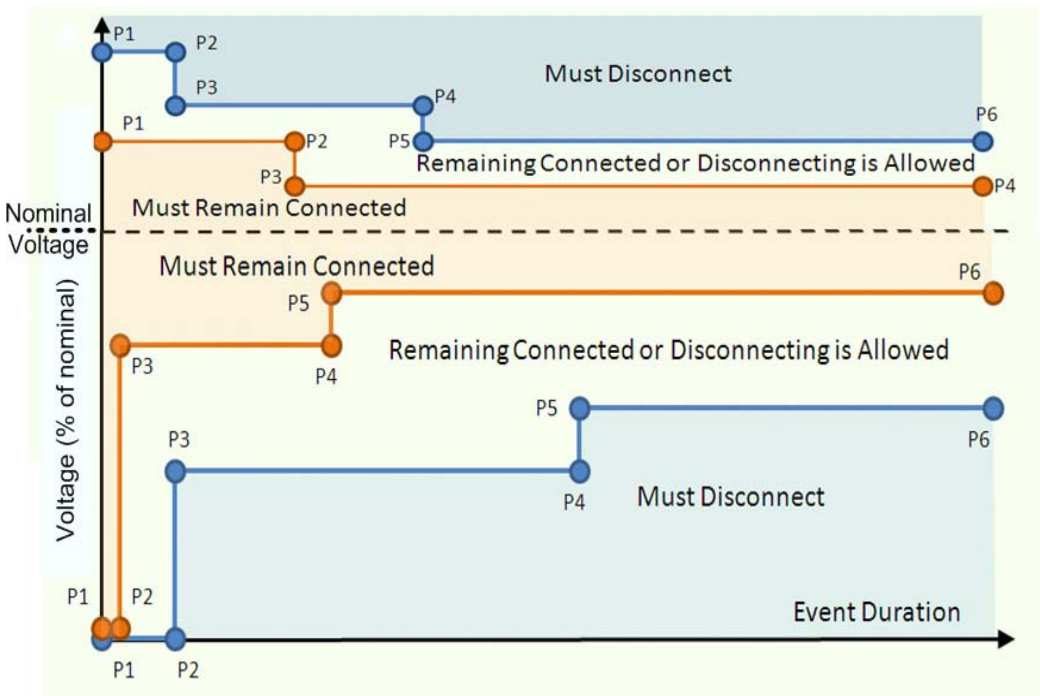


Figure 29 – Must disconnect and must remain connected zones

As described in the TV31 function, these "must stay connected" curves may be the same as those defined by regulations for that function, but may also be different. For instance, these curves may be modified by individual inverter sensitivities, since the safety of the equipment overrides any general regulations.

Examples of different "must stay connected" curves are shown in Figure 30.For implementation purposes in order to allow precise time-based triggers, any curve segments that are not parallel to the x or y axes may be approximated by steps.

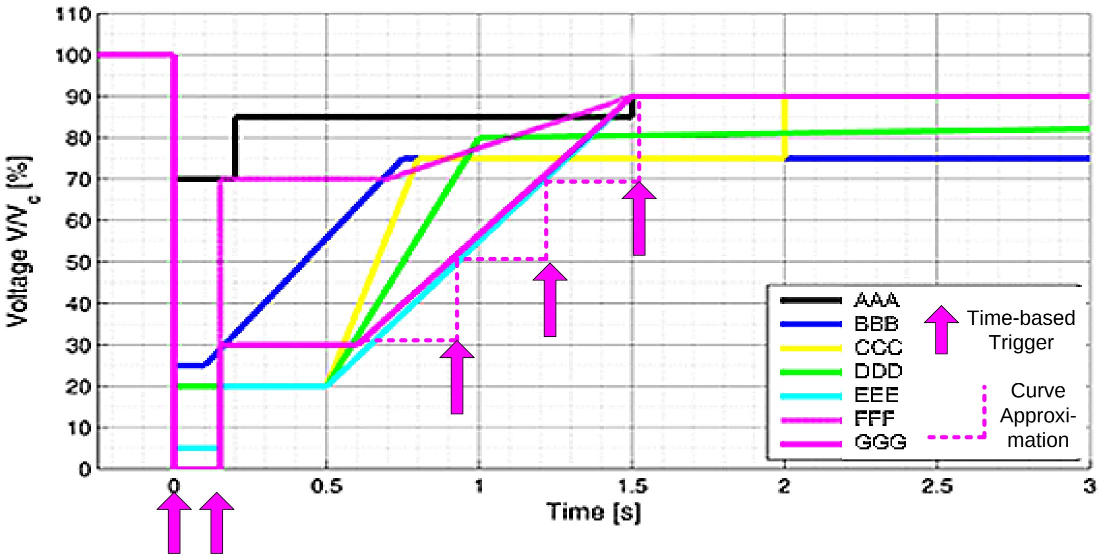
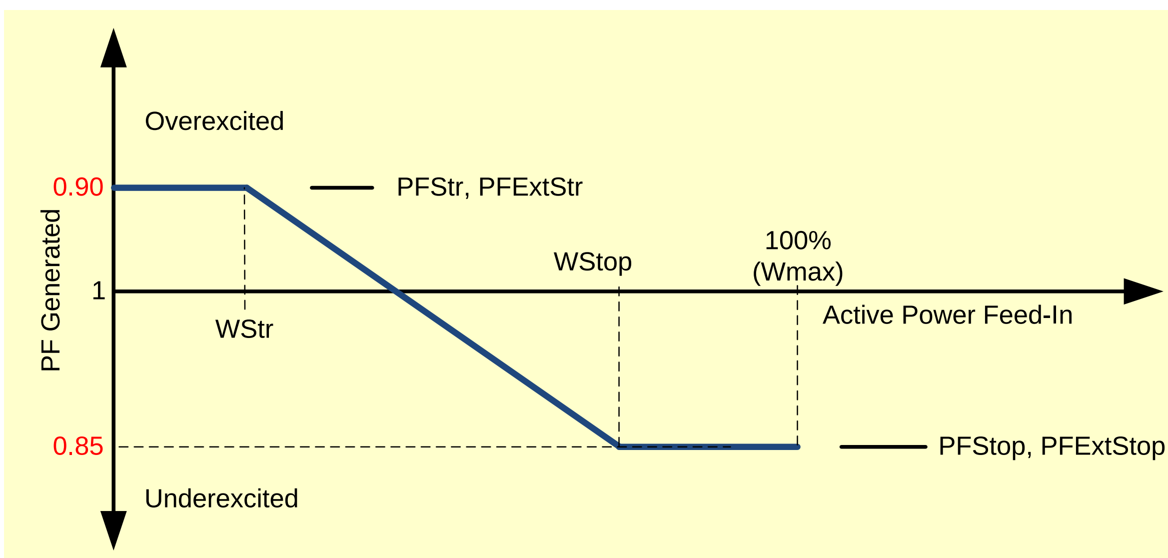


Figure 30 – Examples of "must stay connected" requirements for different regions

3.6 Modes for watt-triggered behaviours

3.6.1 Watt-power factor mode WP41: feed-in power controls power factor

The amount of watts provided at the ECP can be set to gradually modify the power factor. This watt-power factor mode WP41 is shown in Figure 31. The power factor will be set in relation to the feed-in power, in this example ranging from .85 overexcited to .90 underexcited. These settings are not expected to be updated very often over the life time of the system.



Example Settings

Power (% WMax)		Power Factor		Power Factor with convention defined by PFsign and PFExt	
WStr	20	PFStr	0.9	PFExtStr	Overexcited→ False
WStop	40	PFStop	0.85	PFExtStop	Underexcited→ True

Figure 31 – Power factor controlled by feed-in power

The six parameters can be set with the inverter defining the curve via the parameters.

3.6.2 Alternative watt-power factor mode WP42: feed-in power controls power factor

Alternatively, the curves can be defined using arrays, as is done for other modes.

The utility/ESP or the customer EMS takes the following actions:

- (Optional) Request status of inverter-based DER system: Request a pre-defined set of the status information, including the status values, the quality flag, and the timestamp of the status (see Function DS93 for details of status points).
- Issue command to modify watt-PF settings:
  - Watt-PF paired array to create the curve
  - Requested ramp time for the inverter-based DER system to move from the current setpoint to the new setpoint if either it is now being constrained or it is now being released from a constraint (optional – if not included, then use previously established default ramp rate)
  - Time window within which to randomly execute the command. If the time window is zero, the command will be executed immediately, (optional – if not included, then default time window for this function will be used)
  - Timeout period, after which the inverter-based DER system will revert to its default status, such as resetting the maximum power setpoint to its default value (optional – if not included, then default timeout period for this function will be used)
- Receive response to the command:
  - Successful (plus new value of data element)
  - Rejected (plus reason: equipment not available, message error, overridden, security error)

3.7 Modes for voltage-watt management

3.7.1 Voltage-watt mode VW51: voltage-watt management: generating by voltage

Similar to the frequency-watt mode FW22 a voltage-watt management can be used for smoothing voltage deviations.

There can be multiple voltage-watt modes configured into an inverter. For example, the desired frequency-watt settings might be different on-peak versus off-peak, or different when islanded versus grid connected. A simple mode change broadcast could move the inverters from one pre-configured voltage-watt mode to another.

Figure 32 shows one example for maximum watts generated versus voltage.

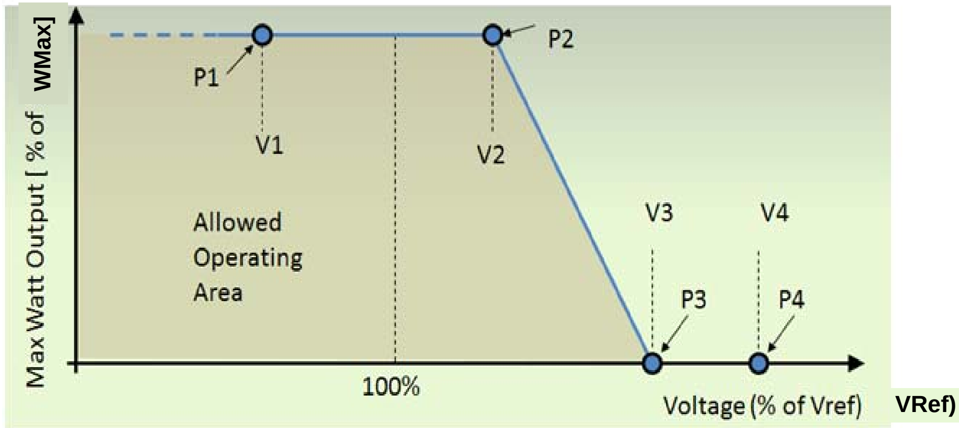


Figure 32 – Example configuration curve for maximum watts vs. voltage

3.7.2 Voltage-watt mode VW52: voltage-watt management: charging by voltage

In addition to voltage-based management of generation, charging of storage units also can be affected by voltage-watt management. Figure 33 illustrates maximum watts absorbed by a storage device versus voltage.

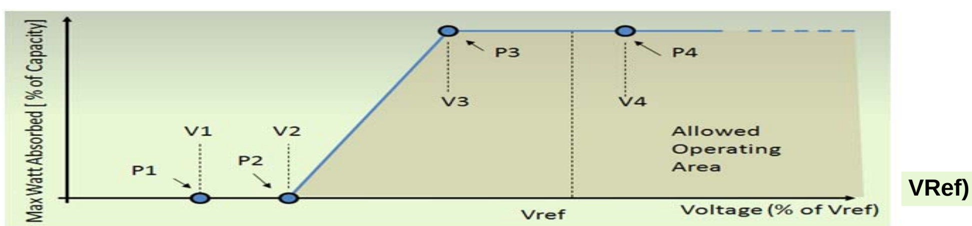


Figure 33 – Example configuration curve for maximum watts absorbed vs. voltage

The settings for this mode would include a voltage-watts-delivered curve (generation) and/or a voltage -watts received curve (storage), ramps for changing power, time of the input filter, and as with other functions, a time window, ramp rate, and timeout.

The curve shapes shown in Figure 33 above are one example. The vertical axis would be percent of WMax, and the horizontal axis is voltage, with reference voltage (VRef) shown in the middle.

3.8 Modes for behaviours triggered by non-power parameters

3.8.1 Temperature mode TMP

The temperature mode invokes the temperature curve. In the temperature curve, the temperature is the primary value of the curve, while the secondary value identifies the action to take. Actions to take when the temperature is within one of the specified ranges can include functions, such as adjust power factor (INV3), or other modes, such as maximum var support mode (VV12).

A typical use would be for the inverter to respond with additional vars during very high temperatures, similar to a feeder's capacitor bank that is set to respond to temperature.

3.8.2 Pricing signal mode PS

The pricing signal mode invokes the pricing signal curve. In the pricing signal curve, the pricing signal is the independent variable of the curve, while the dependent variable identifies the action to take. Actions can include functions, such as adjust maximum generation level (INV2), or other modes, such as frequency-watt mode (FW21).

Multiple pricing signal curves can be established to reflect different energy and ancillary services. For instance, one pricing signal curve could be for watts, another for var support, and a third for frequency support. So long as they are not contradictory (e.g. two curves for watts), these modes can be activated for the same time periods.

The actual pricing signal would be received from an external source (e.g. broadcast by the utility/ESP) or from a schedule (e.g. pricing signal between 6 am and 2 pm, between 2 pm and 4:30 pm, and between 4:30 pm and 6 am). This pricing signal would be used with the activated curve to determine the DER response.

3.9 Setting and reporting functions

3.9.1 Purpose of setting and reporting functions

In addition to functions which directly control functions, many individual parameters can be set to different values in order to change the inverter's behaviour. Some of these settings are described below.

3.9.2 Establishing settings DS91: modify inverter-based DER settings

This function permits the utility, energy service provider, customer EMS, and/or other authorized entities to dynamically modify or update various parameters for inverter-based DER systems. This list of parameters may be expanded, but will include:

- **Intermittency Ramp Rate Limit**. This setting will limit the rate that watts delivery to the grid can increase or decrease in response to intermittent PV generation. The configuration will be in units of "percent of WMax per minute". A single setting will be applied to both increasing and decreasing power output. This ramp rate limit does not apply to output power changes in response to commands that are received. Such commands contain their own ramp limits. Inverter-based DER systems must manage the details of their battery charging such that the rate of change in power delivery to and from the grid remains below this limit – even when the PV generation is intermittent.
- **Storage Reserve** (Minimum energy charge level allowed, % of maximum charge level). This level may be set by the vendor, asset owner, or system operator for a variety of purposes. In some cases, depth of discharge may be limited in order to extend battery service life. In other cases, a minimum reserve may be desired to provide some carryover during outage. It is intended that reserve settings be maintained even while managing intermittency ramp rate limits as described above. For example, a system with a 20 % minimum reserve setting may charge up to 40 % before beginning to generate to the grid so that a sudden loss of the PV source can be covered by a controlled ramp-down of generation, and yet without dropping below 20 % charge.
- **Maximum Storage Charge and Discharge Levels**. These settings establish the maximum charge and discharge rates for storage elements that might be part of the DER. These settings are expressed in terms of a percentage of WMax, delivered and WMax, received, and by default are equal to 100 % of these settings. Charge/Discharge commands, as described in INV4, are expressed in terms of a percentage of these settings.

The utility/ESP or the customer EMS takes the following actions:

- (Optional) Request status of inverter-based DER system: Request a pre-defined set of the status information, including the status values, the quality flag, and the timestamp of the status (see Function DS93 for details of status points).
- Issue command to modify inverter-based DER settings:
  - Data element to be modified
  - New value for that data element
- Receive response to the command:
  - Successful (plus new value of data element)
  - Rejected (plus reason: equipment not available, message error, overridden, security error)

3.9.3 Event logging DS92: log alarms and events, retrieve logs

3.9.3.1 Event log concepts

Event/history logs are maintained by the inverter-based DER systems to record key time-stamped events. The event log can be queried by selecting time ranges.

Different users of inverter-based DER systems will need varying timeframes for retrieving event log information and different types of information from these event logs:

- Utility operations will typically only need key operations-related information, possibly infrequently or only under special circumstances.
- Owners/managers (including utility owners) will want more detailed information, probably periodically or after certain types of events.
- Energy management systems with tightly-coupled interactions will need complete event logs relatively frequently.
- Larger PV plants are different from large numbers of small inverter-based DER systems: more types of event data may be collected from these larger plants, while only basic event data may be collected from the smaller inverter-based DER systems. Larger plants may also aggregate and/or amalgamate events from multiple individual inverter-based DER systems.

In general the following types of events will be logged, but decisions on exactly which ones are logged or which ones are retrieved by any specific user, will be determined on an implementation basis by DataSets, Logs, and LogControlBlocks:

- All errors or failures (service tracking and logging)
- All startup and shutdown actions (logging)
- All control actions (service tracking and logging)
- All responses to control actions (service tracking and logging)
- All limit violations, including returns within limits (logging)

NOTE Service tracking is a new service defined in IEC 61850-7-2.

3.9.3.2 Event Log Fields

All event logs will contain the following fields at a minimum:

- Date and time stamp: The accuracy of this timestamp will be determined by the frequency of time synchronization and the innate precision in keeping time of the inverter-based DER system, and is therefore outside the scope of this specification. Zeros can be used to pad any timestamp if the accuracy does not match the format.
- Data reference: the reference to the data item that triggered the event log entry. For instance, if it is a voltage-related event, the Data reference will be to that data object. If it is an inverter mode event, the Data Reference will be to the inverter mode data object.
- Value: Value field of the Data reference field that is triggering the event, including commands, state changes of monitored values, quality code changes, mode setting, etc. For instance, the request to go into a specific inverter mode will be logged with the Value containing the inverter mode identity.

To enable the filtering of events so that different users can select different types of events to retrieve, different logs can be used. These different logs may be set up to differentiate different types of events, such as:

- Communications (for communication-related events)
- Grid power (for power system events)
- Device asset (for time and asset-related events)
- Security (for security-related events)
- Inverter-based DER system (for inverter-based DER system events, as well as other PV events)
- Storage system (for storage inverter events, as well as other storage events)

Table 3 shows some examples of events that are logged.

Table 3 – Events

Domain	Part	Type	Attribute	Description
Communications	Messaging	Status	Success	Request received successfully. Value field identifies the request as a "demand response"
	Messaging	Status	Success	Command received successfully. Value field identifies the command as a "Direct command"
	Messaging	Status	Acknowledged	Response – acknowledgment sent
	Messaging	Alarm	Message failed	Response – alarm invalid message. Value field contains type of error.
	Network interface	Alarm	Comm. failed	Alarm communications error. Value field contains type of error.
PV System	Inverter	Command	Success	Action taken successfully (details are provided in Mode and Command events)
	Inverter	Command	Failed	Requested action failed. Value field contains type of error.
	Inverter	Command	Deviation	Action taken is a deviation from the requested action. Data Reference and Value fields contain indication of this deviation
	Mode	Status	Inverter mode	Inverter is in one of the inverter modes, as indicated in the Value field
	Inverter	Command	INV Command	Inverter responded to one of the INV commands, as indicated in the Value field
	Inverter	Status	Limit exceeded	Inverter status changed due to internal control threshold exceeded. Data Reference and Value fields provide details

Domain	Part	Type	Attribute	Description
	Schedule	Schedule change	Success	Action was successfully taken in response to the scheduled requirement
	Schedule	Schedule change	Failed	Action failed in response to the scheduled requirement. Value field indicates the type of error
	Power	Status	Power out	Inverter power turned off
	Power	Status	Power on	Inverter power turned on
	Power	Alarm	Power out	Power tripped off due to internal situation
	Power	Alarm	DC voltage	Inadequate DC bus voltage, Value field provide measured value
	Power	End alarm	DC voltage	DC bus voltage within limits. Value field provide measured value
	Temperature	Alarm	Limit exceeded	Temperature limit exceeded. Value field contains type of error.
	Temperature	End alarm	Limit exceeded	Returned within temperature limit. Value field contains type of error.
Grid Power	ECP Switch	Status	Connected	Switch at the ECP between inverter and the grid is connected
	ECP Switch	Status	Disconnected	Switch at the ECP between inverter and the grid is disconnected
	Voltage	Alarm	Limit exceeded	Voltage limit exceeded. Value field contains voltage measurement.
	Voltage	End alarm	Limit exceeded	Returned within voltage limit. Value field contains voltage measurement.
	Voltage	Alarm	Limit exceeded	Voltage distortion limit exceeded. Value field contains voltage distortion.
	Voltage	End alarm	Limit exceeded	Returned within voltage distortion limit. Value field contains voltage distortion.
	Current	Alarm	Limit exceeded	Current limit exceeded. Value field contains current measurement.
	Current	End alarm	Limit exceeded	Returned within current limit. Value field contains current measurement.
	Power quality	Alarm	Limit exceeded	Harmonic limit exceeded. Value field contains harmonic measurement.
	Power quality	End alarm	Limit exceeded	Returned within harmonic limit. Value field contains harmonic measurement.
	Other 1547 parameters	Alarm	Limit exceeded	High/low limit exceeded
	Other 1547 parameters	End alarm	Limit exceeded	Returned within high/low limit
Device asset	Logs	Status	Almost full	Log is almost full. Value contains percentage full.
	Logs	Alarm	Full	Log full: new events to overwrite unread events
	Time	Alarm	Clock failed	Clock failure. Value contains error information.
	Time	Alarm	Synch failed	Synchronization failed. Value contains error information
	Time	Setting	Synchronized	Synchronized. Value contains delta between new time and old time
	Time	Setting	Daylight adjust	Daylight time or Standard time adjustment. Value indicates Daylight of Standard
	Firmware	Alarm	Data error	Data error detected in firmware. Value indicates type of error

The retrieval of the event log consists of the following command and response:

- Retrieve event log
  - Event log retrieval command
  - Start time/ stop time (start time = 0 means start from beginning of log; stop time = 0 means include through the final log entry)
- Receive response to the command:
  - Requested log entries
  - Success/Failure (plus reason: no log event fulfils the retrieval criteria, log not available, message error, security error, request type not supported, etc.)

Additional event log interactions can include:

- Notification if event log is almost full or completely full without having been retrieved
- Notification of an event log error

3.9.4 Reporting status DS93: selecting status points, establishing reporting mechanisms

Many functions require the status of the inverter-based DER system either periodically, on significant change of a value, or upon request.

Examples of status information that is standardized in the corresponding Logical Nodes are listed in Table 4. These status information points and any other information (standardized and extended Logical Nodes and Data Objects) can be used to configure DataSets that ware used by ReportControlBlocks. The ControlBlocks can be configured to get the required reporting behaviour (periodic, sequence of events, or general interrogation).

Table 4 – Examples of status points

Status Point	Description
Primary information	
Connect status	Whether or not the device is currently connected at its ECP.
PV output available	Yes/No
Storage output available	Yes/No
Status of var capability	Yes/No
Inverter active power output	Present active power output level (Watts). This is an instantaneous (minimum averaging) reading.
Inverter reactive output	Present reactive power output level (VArs). This is a signed quantity.
Current inverter mode	Identity of mode or function that the inverter-based DER is in, including “owner mode” (Enumeration with range left open for proprietary vendor)
Detailed information	
Inverter status	Inverter is switched on (operating), off (not able to operate), or in stand-by mode (capable of operating but currently not operating)
DC Current level available for operation	Indicates whether or not there is sufficient DC current to allow operation. – Value, not yes/no
Inverter active power output	Present active power output level (Watts). This is an instantaneous (minimum averaging) reading.
DC inverter input power	Use for determining efficiency of inverter
Local/Remote control mode	Inverter is under local control or can be remotely controlled

Status Point	Description
Active power setpoint	Value of the active power setpoint
Reactive power setpoint	Value of the output reactive power setpoint
Power factor setpoint	Value of the power factor setpoint
Power measurements	
Active power	Active power value, plus high and low limits
Reactive power	Reactive power value, plus high and low limits
Phase to ground voltages	Voltage values per phase, plus high and low limits
Power factor	Power factor value, plus high and low limits
Battery storage status (if storage is included in inverter-based DER system)	
Capacity rating	The useable capacity of the battery, maximum charge minus minimum charge from a technology capability perspective (Watt-hours)
State of charge	Currently available energy, as a percent of the capacity rating (percentage)
Available energy	State of charge times capacity rating minus storage reserve (Watt-hours) See storage settings section for definition of "storage reserve"
Maximum battery charge rate	Set using DS91. The maximum rate of energy transfer into the storage device. (Watts) This establishes the reference for the charge percentage settings in function INV4.
Maximum battery discharge rate	Set using DS91. The maximum rate of energy transfer out of the storage device (Watts).This establishes the reference for the discharge percentage settings in function INV4.
Internal battery voltage	Internal battery voltage
DC inverter power input	Used for determining efficiency of inverter
Nameplate and Settings Information	
Manufacturer name	Text string
Model	Text string
Serial number	Text string
Inverter power rating	The continuous power output capability of the inverter (Watts)
Inverter VA rating	The continuous Volt-Amp capability of the inverter (VA)
Inverter var rating	Maximum continuous var capability of the inverter (var)
Maximum battery charge rate	The maximum rate of energy transfer into the storage device. (Watts) This establishes the reference for the charge percentage settings in function INV4.
Maximum battery discharge rate	The maximum rate of energy transfer out of the storage device. (Watts) This establishes the reference for the discharge percentage settings in function INV4.
Storage present indicator	Indication of whether or not battery storage is part of this system.
PV present indicator	Indication of whether or not PV is part of this system.
Time resolution	Time resolution and precision
Source of time synchronization	Text string

The retrieval of status items may be undertaken using one or all of the following methods:

- Single status values:

- On-demand, request a single status value. That status value will then be returned to the requester.
- Upon a status value change or upon exceeding a deadband or upon exceeding a limit (depending upon the type of status point), that status value will be transmitted

- Sets of status values:
  - During initialization of the inverter-based DER system, sets of status values can be assigned to one or more “data sets”. These data sets can then be used in the following ways:
    - On-demand, request one of these data sets. All of the status values in the requested data set will be returned to the requester
    - Periodically, all of the status values in each data set will be transmitted
    - Upon change or upon exceeding a deadband or upon exceeding a limit of a status point in the data set, all of the status values in the affected data set will be transmitted
  - After initialization, using the communications network, data sets can be created, modified, and/or deleted, and the reporting triggers can be established (e.g. upon demand, periodically, upon change).

The “on-demand” retrieval method for a single status values and at least one data set are mandatory. The other retrieval methods may be optional or may be deemed mandatory for different implementations.

3.9.5 Time synchronization DS94: time synchronization requirements

The inverter-based DER system will use the time synchronization services specified in IEC 61850-8-1.

4. Terms, definitions and abbreviations

For the purposes of this document, the following terms, definitions and abbreviations apply.

4.1 Terms and definitions

autonomous

responding, reacting, or developing independently of the whole; not controlled by others or by outside forces; independent.

[Merriam-Webster dictionary]

common data class
CDC

classes of commonly used data structures which are defined in IEC 61850-7-3

device

material element or assembly of such elements intended to perform a required function

[IEV 151-11-20]

NOTE A device may form part of a larger device.

electrical connection point
ECP

point of electrical connection between the DER source of energy (generation or storage) and any electric power system (EPS)

Each DER (generation or storage) unit has an ECP connecting it to its local power system; groups of DER units have an ECP where they interconnect to the power system at a specific site or plant; a group of DER units plus local loads have an ECP where they are interconnected to the utility power system.

NOTE For those ECPs between a utility EPS and a plant or site EPS, this point is identical to the point of common coupling (PCC) in the IEEE 1547 "*Standard for Interconnecting Distributed Resources with Electric Power Systems*".

electric power system
EPS

facilities that deliver electric power to a load

[IEEE 1547]

event
event information

a) something that happens in time [IEV 111-16-04]

b) monitored information on the change of state of operational equipment

[IEV 371-02-04]

NOTE In power system operations, an event is typically state information and/or state transition (status, alarm, or command) reflecting power system conditions.

function

a computer subroutine; specifically: one that performs a calculation with variables provided by a program and supplies the program with a single result

[Merriam-Webster dictionary]

NOTE This term is very general and can often be used to mean different ideas in different contexts. However, in the context of computer-based technologies, it is used to imply software or computer hardware tasks.

generator

a) energy transducer that transforms non-electric energy into electric energy [IEV 151-13-35];

b) device that converts kinetic energy to electrical energy, generally using electromagnetic induction

The reverse conversion of electrical energy into mechanical energy is done by an electric motor, and motors and generators have many similarities. The prime mover source of mechanical energy may be a reciprocating or turbine steam engine, water falling through a hydropower turbine or waterwheel, an internal combustion engine, a wind turbine, a hand crank, or any other source of mechanical energy. [WIKI 2007-12]

information

a) intelligence or knowledge capable of being represented in forms suitable for communication, storage or processing [IEV 701-01-01];

b) knowledge concerning objects, such as facts, events, things, processes, or ideas, including concepts, that within a certain context has a particular meaning [ISO/IEC 2382-1, definition 01.01.01]

NOTE Information may be represented for example by signs, symbols, pictures, or sounds.

information exchange

communication process between two or more computer-based systems in order to transmit and receive information

NOTE The exchange of information between systems requires interoperable communication services.

inverter

a) static power converter (SPC);

b) device that converts DC electricity into AC electricity, equipment that converts direct current from the array field to alternating current, the electric equipment used to convert electrical power into a form or forms of electrical power suitable for subsequent use by the electric utility

[IEC 61727:2004, definition 3.8]

NOTE Any static power converter with control, protection, and filtering functions used to interface an electric energy source with an electric utility system. Sometimes referred to as power conditioning subsystems, power conversion systems, solid-state converters, or power conditioning units.

measured value

physical or electrical quantity, property or condition that is to be measured

[IEC 61850-7-4]

NOTE 1 Measured values are usually monitored, but may be calculated from other values. They are also usually considered to be analogue values.

NOTE 2 The result of a sampling of an analogue magnitude of a particular quantity.

monitor

to check at regular intervals selected values regarding their compliance to specified values, ranges of values or switching conditions

[IEV 351-22-03]

photovoltaic system

a) a complete set of components for converting sunlight into electricity by the photovoltaic process, including the array and balance of system components [US DOE];

b) a system comprises all inverters (one or multiple) and associated BOS (balance-of-system components) and arrays with one point of common coupling, described in IEC 61836 as PV power plant [IEC 61727:2004, definition 3.7]

NOTE The component list and system configuration of a photovoltaic system varies according to the application, and can also include the following sub-systems: power conditioning, energy storage, system monitoring and control and utility grid interface.

photovoltaics
PV

of, relating to, or utilizing the generation of a voltage when radiant energy falls on the boundary between dissimilar substances (as two different semiconductors)

[Merriam-Webster dictionary]

point of common coupling
PCC

point of a power supply network, electrically nearest to a particular load, at which other loads are, or may be, connected [IEV 161-07-15]

NOTE 1 These loads can be either devices, equipment or systems, or distinct customer's installations.

NOTE 2 In some applications, the term “point of common coupling” is restricted to public networks.

NOTE 3 The point where a local EPS is connected to an area EPS [IEEE 1547]. The local EPS may include distributed energy resources as well as load (see IEV definition which only includes load).

power conversion

power conversion is the process of converting power from one form into another

This could include electromechanical or electrochemical processes.

In electrical engineering, power conversion has a more specific meaning, namely converting electric power from one form to another. This could be as simple as a transformer to change the voltage of AC power, but also includes far more complex systems. The term can also refer to a class of electrical machinery that is used to convert one frequency of electrical power into another frequency.

One way of classifying power conversion systems is according to whether the input and output are alternating current (AC) or direct current (DC), thus:

DC to DC

– DC to DC converter

– Voltage stabiliser

– Linear regulator

AC to DC

– Rectifier

– Mains power supply unit (PSU)

– Switched-mode power supply

DC to AC

– Inverter

AC to AC

– Transformer/autotransformer

– Voltage regulator

[WIKI 2007-12]

prime mover

equipment acting as the energy source for the generation of electricity

NOTE Examples include diesel engine, solar panels, gas turbines, wind turbines, hydro turbines, battery storage, water storage, air storage, etc.

set point

the level or point at which a variable physiological state (as body temperature or weight) tends to stabilize

[Merriam-Webster Dictionary]

set point command

command in which the value for the required state of operational equipment is transmitted to a controlled station where it is stored

[IEV 371-03-11]

NOTE A setpoint is usually an analogue value which sets the controllable target for a process or sets limits or other parameters used for managing the process.

4.2 Acronyms

SEP: Smart Energy Profile

DNP3: Distributed Network Protocol

GPRS: General Packet Radio Service