حكومة دبي

GOVERNMENT OF DUBAI

هيئة كهرباء ومياه دبي

Dubai Electricity & Water Authority

SHAMS DUBAI

STANDARDS FOR DISTRIBUTED RENEWABLE RESOURCES GENERATORS CONNECTED TO THE DISTRIBUTION NETWORK

VERSION 3.0, DECEMBER 2023

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1 GENERAL PROVISIONS

1.1 Definitions

Active Power - Active Power is the real component of the apparent power, expressed in watts or multiples thereof (e.g. kilowatts (kW) or megawatts (MW)). In the text, this will be generically referred to as P or Pn in case of rated active power of equipment.

Apparent Power - Is the product of voltage (in volts) and current (in amperes). It is usually expressed in kilovolt-amperes (kVA) or megavolt-amperes (MVA) and consists of a real component (Active Power) and an imaginary component (Reactive Power). In case of inverters, the rated apparent power corresponds to the maximum active power deliverable by the inverter at unity power factor. In the text, this will be generically referred to as S or Sn in case of rated apparent power of equipment.

Available Maximal Active Power Output - Is the Active Power Output determined by the primary resource (for example, sun irradiance) and by the maximum steady-state efficiency of the power conversion within the Generating Unit for this operating point.

Building Applied Photovoltaics (BAPV) - BAPV refers to PV modules that are mounted on the building envelope, where the integrity of the building functionality is independent of their existence.

Building Integrated Photovoltaics (BIPV) - A BIPV module is a PV module and a construction product together, designed to provide one or more functions of a building envelope, including:

- Mechanical rigidity or structural integrity;
- Primary weather impact protection;
- Energy economy such as shading daylighting or thermal insulation;
- Fire protection;
- Noise protection.

A BIPV product is the smallest (electrically and mechanically) non-divisible photovoltaic unit in a BIPV system which retains building-related functionality. If the BIPV product is dismounted, it would have to be replaced by an appropriate construction product.

Connection Point - Is the location at which Renewable Resource Generating Units, Renewable Resource Generating Plants as well as consumer loads are connected to the Network and where the Main Meter is installed. In the connection schemes, this is also referred to as POC (Point Of Connection).

Contract - Any agreement signed with DEWA, which stipulates the conditions and terms for the connection and operation of a Generating Plant.

Contactor - An electrically controlled switch having only one position of rest, operated otherwise than by hand, capable of making, carrying and breaking currents under normal circuit conditions, including operating overload conditions.

Converter - Also called Power Converter. See **Inverter**.

Current - Unless stated otherwise, current refers to the root-mean-square value of phase current.

Derogation - A time limited or indefinite (as specified) acceptance in writing of a non-compliance of a Power Generating Plant with regard to identified Standards requirements.

Distribution System / Network - Is the medium (6.6, 11 or 33 kV) or low voltage (0.4 kV) electricity grid for supplying electricity to the end consumers.

Existing Renewable Resource Generating Plant - A Renewable Resource Generating Plant which is either physically connected to the Network or under construction or for which a formal agreement exists between the Producer and DEWA for the connection of the Generating Plant to the Network at the day of the entry into force of these Standards.

Generating Unit (Plant) - Is an indivisible set of installations which can generate electrical energy. A set of Generating Units, circuits and auxiliary services for the generation of electrical energy forms a Generating Plant. See also the definition of "Renewable Resource Generating Unit / Plant".

Grid Connection: The connection of a Renewable Resources Generating Plant (RRGP) to the electrical grid.

$I_{MOD\text{-}MAX\_OCPR}$ - the PV module maximum overcurrent protection rating as determined by IEC 61730-2.

$I_{SC\ ARRAY}$ - the short circuit current of a PV array at Standard Test Conditions (STC), and equal to:

$I_{SC\ ARRAY} = I_{SC\_MOD} \times S_A$

where S_A is the number of parallel-connected PV strings in the PV sub-array.

I_{SC_MOD} – the short circuit current of a PV module or PV string at Standard Test Conditions (STC), as specified by the manufacturer in the product plate / data sheet.

$I_{SC\ S\text{-}ARRAY}$ – the short circuit current of a PV sub-array at Standard Test Conditions (STC), and equal to:

$$I_{SC\ S\text{-}ARRAY} = I_{SC\_MOD} \times S_{SA}$$

where S_{SA} is the number of parallel-connected PV strings in the PV sub-array.

Interface Protection - The electrical protection required to ensure that either the Generating Plant or any Generating Unit is disconnected for any event that could impair the integrity or degrade the safety of the Distribution Network.

Inverter - A device which converts the direct current produced by the photovoltaic modules to alternating current in order to deliver the output power to the grid. The inverter is also capable of controlling the quality of this output power.

Unintentional Islanding (Islanding) - A situation where a section of the distribution network, containing generation, becomes physically disconnected from the rest of distribution network and one or more generating units maintain a supply of electrical energy to the isolated section of the distribution network.

Low Voltage (LV) Network - Is a Network with nominal voltage lower than 1kV.

Manufacturer's Data and Performance Type Certificate (MD&PTC) - Certificates issued by authorised certifiers and accredited with DEWA, defining verified data and performance, which can include models and testing for the purpose of replacing specific parts of the compliance process.

Maximum Capacity - The maximum continuous Active Power which a Generating Plant can feed into the Network as agreed between DEWA and the Plant Producer. This corresponds to the sum of the maximum active power deliverable by the inverters at the AC side that is also the sum of the rated power of the inverters at unity power factor (to be noticed that this latter may also be lower than the sum of the power at STC of the photovoltaic modules). In the text, this maximum capacity will also be indicated as P_{MC}.

Medium Voltage (MV) Network- A Network with nominal voltage included in the range from 1kV up to 33 kV. In Dubai, four voltage levels may be found on MV distribution network, namely 6.6 - 11 - 22 - 33 kV. The 11 kV voltage level is the most used and diffused.

Main Electricity Meter - Is the main electricity meter installed at the Connection Point (DEWA side) and will perform the Net Metering of: i) the electricity delivered by the RRGP to the Distribution Network; and ii) the energy absorbed from the Distribution Network on a monthly basis.

RRGP Electricity Meter - Is the electricity meter installed at the common output point of all the Generating Units, to measure the total energy produced by the RRGP.

Network - Plant and apparatus connected together in order to transmit or distribute electrical power, and operated by DEWA.

New Renewable Resource Generating Unit / Plant - A Renewable Resource Generating Unit which is neither physically connected to the Network nor for which a formal agreement exists between the Producer and DEWA for the connection of the Generating Unit / Plant to the Network at the day of the entry into force of these Standards.

Non-Synchronously-Connected Renewable Resource Generating Unit - A Renewable Resource Generating Unit that is not electromagnetically directly-connected to the Network. All types of installations that are fully connected to the Network through Power Electronic Converters, for instance photovoltaic power generating Units, fall into this category.

Peak Power (Wp) - The output power achieved by a Photovoltaic Module under Standard Test Conditions (STC). It is measured in Wp (W peak). The sum of the peak power of the photovoltaic modules of either a string or an array determines the peak power of the string and the array respectively (usually measured in kWp). The peak power of a photovoltaic array at STC is conventionally assumed as the rated power of the array.

Phase unbalance – Condition in a polyphase system in which the r.m.s. values of the line currents (fundamental component), or the phase angles between consecutive currents, are not all equal.

Photovoltaic (PV) cell - The most elementary device that exhibits the photovoltaic effect, i.e. the direct non-thermal conversion of radiant energy into electrical energy.

Photovoltaic (PV) Module –Also called Photovoltaic (PV) panel. The smallest complete environmentally protected assembly of interconnected cells.

Photovoltaic (PV) array – assembly of electrically interconnected PV modules, PV strings or PV sub-arrays.

Photovoltaic (PV) sub-array – an electrical subset of a PV array formed by parallel connected PV strings.

Photovoltaic (PV) string – A circuit of one or more series-connected modules

Photovoltaic (PV) string (array) combiner box – A junction box where PV strings (sub-arrays) are connected which may also contain overcurrent protection devices and/or switch-disconnectors

Power Factor - Is the ratio of Active Power to Apparent Power.

P-Q-Capability Diagram - Describes the ability of a Generating Unit to provide Reactive Power in the context of varying Active Power and at the rated voltage.

Producer - Any entity authorised by the Authority to produce electricity connected to the network in the Emirates. In other documents the term “Generator” may be used.

Power Distribution System - The electrical network and its components which are owned and operated by DEWA with the main purpose of delivering electricity to consumers from the Power Transmission System. The 33kV and below voltage level are considered as distribution system. The components of the Power Distribution system include all associated equipment, including but not limited to interconnecting lines, electrical substations, pole mounted transformers, analogue electrical elements such as resistors, inductors, capacitors, diodes, switches and transistors.

Power Transmission System - The system belonging to DEWA which entirely or mainly comprises the High-Voltage (>33 kV) electricity cables, lines and electricity installations and facilities owned and/or operated by DEWA and used to transmit electricity from a power unit to a power substation or other electricity generation unit.

Reactive Power - Reactive Power is the imaginary component of the apparent power, usually expressed in kilovar (kVAr) or Megavar (MVAr).

Regulatory Authority - Is the Regulatory and Supervisory Bureau (RSB) for the Water and Electricity Sector in the Emirate of Dubai.

Representative - Means any person representing or mandated to represent a party, including, but not limited to, its directors, and members of management, officers, employees, or professional advisors.

Renewable Resource Generating Plant (RRGP) - Is a set of Renewable Resource Generating Units.

Renewable Resource Generating Unit (RRGU) - Is a Generating Unit that produces power exclusively from renewable primary resources. This Renewable Resource Generating Unit can be part of a Generating Plant that includes non- renewable resources. In this latter situation, the Renewable Resource Generating Unit mentioned in these Standards is the part of the Plant that is able to produce energy without input from non-renewable resource. The case of a Photovoltaic Generating Plant is shown here:

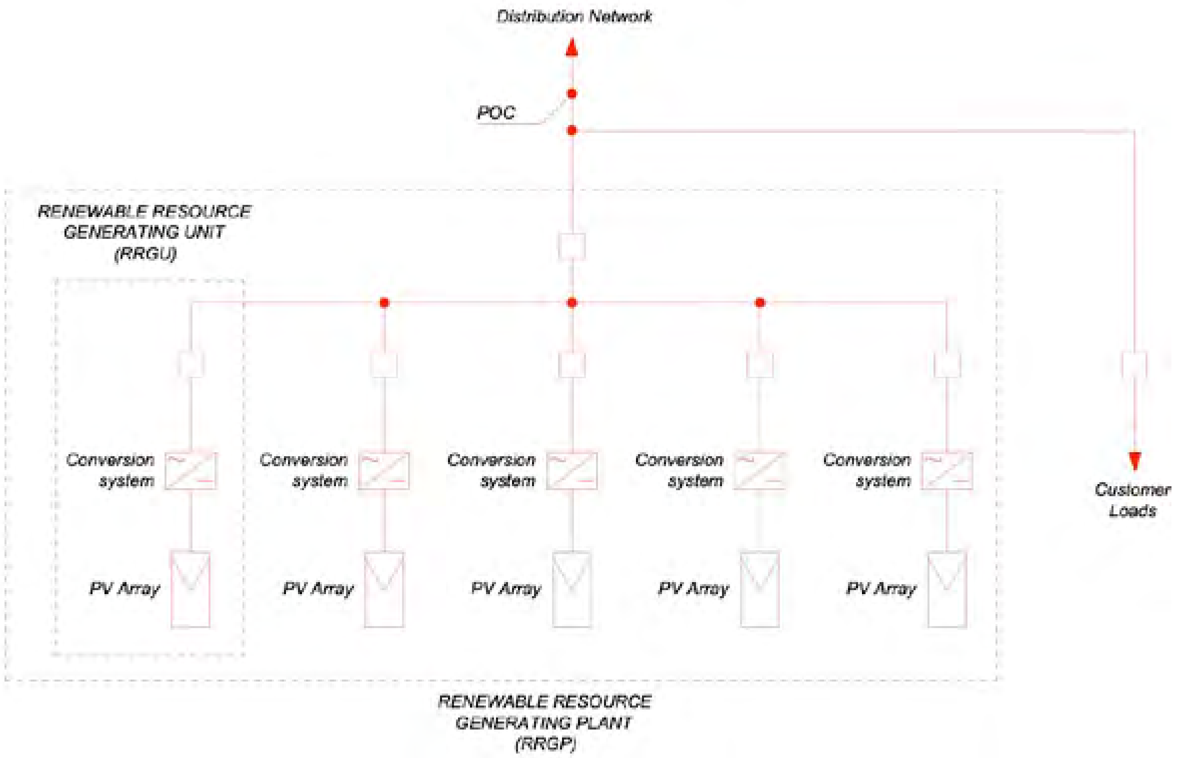


Figure 1 – RRGU and RRGP

Standard Test conditions (STC) - A standard set of reference conditions used for the testing and rating of photovoltaic cells and modules. The standard test conditions are:

a) PV cell temperature of 25 °C;
b) Irradiance in the plane of the PV cell or module of 1000 W/m^2;
c) Light spectrum corresponding to an atmospheric air mass of 1.5.

Steady-State Stability - If the Network or a Generating Unit previously in the steady state reverts to this state again following a sufficiently minor disturbance, it has Steady-State Stability.

Switch – Mechanical switching device capable of making, carrying and breaking currents in normal circuit conditions and, when specified, in given operating overload conditions. In addition, it is able to carry, for a specified time, currents under specified abnormal circuit conditions, such as short-circuit conditions.

Switch disconnector (Isolator) – Switch that also complies with the requirements for a disconnector.

Synchronously-Connected Renewable Resource Generating Unit – A Renewable Resource Generating Unit that naturally provides stability to the Network frequency through inertia and that has abilities to provide high short- circuit current contribution. Partial or full directly-connected Synchronous Generators and Induction Generators fall in this category.

Transient Stability - Is the ability of a Generating Unit to remain connected to the Network following a severe transient disturbance.

Voltage - Unless stated otherwise, voltage refers to the root-mean-square value of phase-to-phase voltages.

1.2 Reference documents

This document is a revision of the "Renewables Standards" Rev. 1.0 November 2013 (in the following "Renewables Standards", published on the site www.rsbdubai.gov.ae, focusing on Distributed Renewable Resources connected to LV and MV Distribution Networks.

The following documents available on DEWA website www.dewa.gov.ae are always in force as a technical reference:

- for LV installations: "DEWA Regulations for Electrical Installations" 1997 Edition

- for MV installations: DEWA Distribution Substation Guideline, 2014 Edition; "General conditions / requirements for providing direct 11 kV supply"; "Power Supply Guidelines for Major Projects" – Rev. 1 March 2013; Design Requirements & Guidelines for MV (11kV-22kV) supply, December 2008

Reference to DEWA "Connection Guidelines for Renewable Resources Generators connected to the Distribution Network", will also be addressed in these Standards.

1.3 Subject Matter

These Standards define a common set of requirements for **Renewable Resource Generating Plants** connected to DEWA Distribution Network and establish a common framework for grid connection agreements between DEWA and the (RRGP) Producers.

Like any other generation plant, RRGPs connected to medium and low voltage networks will have to make a contribution to the static voltage stability. These Standards will then summarize the essential aspects that have to be taken into consideration for the connection to the medium and low voltage network of a RRGP. The limit values of voltage quality specified have to be observed in order to maintain the safety and reliability of network operation.

1.4 Scope

1. The requirements set forth by these Standards describe the functional behaviour of RRGUs and RRGPs, with particular reference to solar photovoltaic plants (i.e. Non-Synchronously-Connected RRGUs), as seen from the Connection Point unless otherwise specified in these Standards. These result from the document "Renewables Standards", focusing on Distributed Renewable Resources Generators (DRRG) connected to LV and MV Distribution Networks. Future revisions of these Standards will also take into account Synchronously-Connected Renewable Resource Generating Units.

2. The requirements set forth by these Standards shall apply to New Renewable Resource Generating units unless otherwise specified in these Standards. This principle also applies when requirements change over time.

3. The requirements set forth by these Standards shall apply to Existing Renewable Resource Generating Units if the Producer wishes to connect them to the Distribution Grid and when requested by DEWA. However, the application of standards to Existing Renewable Resource Generating Units should be exceptional.

4. Whenever required, existing Renewable Resource Generating Units shall adapt their characteristics to the current standards in order to be connected to the Distribution Network.

5. A Renewable Resource Generating Unit has to comply with the categories defined hereinafter (Table 2) and according to the voltage level of its Connection Point.

6. Two criteria are used to define the category in which the Renewable Resource Generating Plants fall (see Table 1):

   a) The first criterion is the "Maximum Capacity (kW)". This criterion is justified since investments in advanced technical abilities provide a better cost/benefit ratio for larger units. Furthermore, larger units have an additional impact on the system security.

   b) The second criterion is the Network Voltage Level (kV) at which the RRGP is connected.

   Within these, a further segmentation with respect to the services to be provided to the network is considered (see Table 2). This is justified by the fact that the level of requirements has to increase with the maximum capacity.

   Table 1 presents the segmentation of New Renewable Resource Generating Units to determine the voltage level of the Distribution Network to which the RRGP will be connected:

Table 1 – RRGP segmentation as a function of Maximum Capacity and voltage level

Connection to the network			
Maximum Capacity (MW)	LV Network Vn = 0.4 kV	MV Network Vn = 6.6; 11; 33 kV	HV Network Vn > 33 KV
<0.1	X		
0.1-0.4	X	X	
0.4-1.0		X	

DEWA will evaluate the feasibility of the connection of a RRGP by means of network studies. Different solutions with respect to the above conditions may then be considered by DEWA for the connection of a RRGP, in case:

- a MV network with a specific voltage level is not available in the area where the RRGP is going to be built;
- a connection to a lower voltage level network is deemed feasible (case of a feeder which can bear power larger than the threshold as per Table 1);
- a connection to a higher voltage level network is deemed necessary due to technical constraints.

Table 2 presents a further segmentation of New Renewable Resource Generating Plants to determine the minimum requirements the RRGPs have to comply with. The meaning of these requirements will be clarified hereinafter.

Table 2 - Segmentation of New Renewable Resource Generating Plants

RRGP Maximum Capacity (kW)	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
< 10 kW	No	-	Limited	required	No	Only if the DC component in the output current may not be limited otherwise	Not required	Not required
10 kW ≤ P_{MC} ≤ 20 kW	Yes (For multiple inverter projects) No* (For single inverter projects)	-	Required	Required	Yes	Only if the DC component in the output current may not be limited otherwise	Required	Not required
20 kW < P_{MC} ≤ 150 kW	Yes (For multiple inverter projects) No* (For single inverter projects)	Backup to I.P. trip required	Required	Required	Yes	Only if the DC component in the output current may not be limited otherwise	Required	Not required
150 kW <P_{MC} ≤400 kW	Yes	Backup to I.P. trip required	Required	Required	Yes	If the DC component in the output current may not be limited otherwise, but always recommended	Required	Required
P_{MC} > 400 kW (MV connected RRGP)	Yes	Backup to I.P. trip required	Required	Required	Yes	Mandatory	Required	Required

1. Need for an external Interface Protection (I.P.)
   *No external interface protection is required on PV systems less than 150kW$_{AC}$ that use a single inverter
2. Connection scheme
3. Contribution to Reactive power generation
4. Contribution to Active power limitation
5. Low Voltage Ride Through (LVRT) capability
6. Need for a transformer
7. Remote Control
8. Remote Monitoring

7. For LV connections, the use of three-phase inverters shall be preferred, also according to typical existing connections to DEWA network.

8. RRGPs may also be made of single-phase units connected to the LV network. Use of these is regulated as specified in 2.3.1.

2 TECHNICAL REQUIREMENTS

2.1 General Rules

The following general rules shall hold for photovoltaic plants:

1. The limit to the P_{MC} under a contract account is defined by DEWA as part of the Conditions complementing the regulatory framework set by the Executive Council Resolution No. (46) of 2014 Concerning the Connections of the Generators of Electricity from Solar Energy to the Power Distribution System in the Emirate of Dubai".

2. PV arrays for installation on buildings shall not have maximum voltages greater than 1,000 Vdc, as calculated at the minimum outdoor temperature of 0 °C. PV arrays for installation on private villas shall not have maximum voltages greater than 600 Vdc, as calculated at the minimum outdoor temperature of 0 °C. All the equipment (PV modules, inverter, and cables) shall withstand the maximum voltage of the array.

3. Arrays with voltages which exceed the above mentioned value of 1,000 Vdc (but not exceeding 1,500 Vdc) may be allowed only for canopies, urban design and any other solutions that do not involve the installation of PV modules, inverters or other related equipment on buildings. In any case, all the equipment must withstand the maximum voltage reached for the system, as calculated at the minimum outdoor temperature of 0°C.

4. The inverters shall be provided with an IP65 enclosure for outdoor application and IP54 enclosure for indoor application. In this latter case, lower protection grades shall only be permitted if the characteristics of the room will be properly conceived to protect the equipment. The inverter shall be able to withstand the maximum temperatures with effective heating dispersion and with a power derating smaller than or equal to 25% of its rated power as determined for an ambient temperature of 50°C at the DC design voltage. This temperature is to be considered the maximum outdoor value at which all equipment, apparatus, materials and accessories used in electrical installations must be capable of operating with satisfactory performance in the climatic conditions of the Emirate of Dubai. In addition, provisions which prevent the increase of the internal heating of the inverters shall be taken for outdoor installation (e.g. protections against direct exposition to the sun). For those inverters which do not comply with the above set rule, a placement in cooled room or enclosures with effective ventilation shall be required, inside which the ambient temperature will be kept below the value which determines a power derating equal to 25% of the inverter rated power at the DC design voltage.

5. For Safety Issues also refer to 2.6.

2.2 Earthing and Protection Schemes

2.2.1 Protections required at the Connection Point

2.2.1.1 GENERAL REQUIREMENTS

The protection system is of considerable importance for the secure and reliable operation of the network and of the electric facilities (both passive and active). According to DEWA rules, automatic installations must be provided for short-circuit clearing in electric facilities, which must also be selective with the upstream protections ruled by DEWA. The Producer is responsible for the reliable protection of his plants (e.g. short-circuit, earth-fault and overload protection). An accredited Consultant will properly design the installation, and an accredited Contractor shall install an adequate amount of protection equipment. For plants capable of injection of power in the Distribution Network, these protections also need to guarantee that the plant does not contribute to sustaining a fault in the network itself.

2.2.1.2 PROTECTION SYSTEM FOR RRGPs

1. The following protections shall be adopted by the Producer:

   - General Overcurrent Protection at the main incomer at the connection point
   - Interface Protection to separate the production plant from the network

   Other protections may be required for each RRGU (Generator protection) (see 2.2.1.3).

2. For the General Overcurrent Protection, two different situations may be met, according to the voltage level:

   - for LV connections, the incomer protection shall be chosen and installed according to the criteria and rules set by the standards of the series IEC 60364 as well as to "DEWA Regulations for electrical installations"
   - for MV connections, the standards IEC 60255, IEC 61936-1 as well as the "General Conditions / requirements for providing direct 11 kV supply" shall apply

3. An Interface Protection shall be installed with the purpose of separating the production plant (which could be just a portion of an installation) thus ensuring that the connection of a RRGU or a RRGP will not impair the integrity or degrade the safety of the Distribution System. Therefore, this protection will intervene, disconnecting the RRGU / RRGP from the Distribution Network, any time a problem with this latter is sensed (usually for a fault, where the RRGP has to be disconnected in order to prevent from feeding it).

   3.1 The Interface Protection shall be located:

   - Integrated into the inverter, in case the maximum capacity of the RRGP <10 kWac and the number of inverters does not exceed 3.
   - Integrated into the inverter, in case the maximum capacity of the RRGP <= 150 kWac and the RRGP consists of only one inverter.
   - Shall be in a separate unit for any RRGP otherwise.

   In the former case, an intervention of the protection will determine the tripping of the Interface Switch (see Connection Schemes in Appendix A), whereas in the latter, the devices within the control of the RRGU (typically integrated in the Inverter) will act to disconnect the unit from the network. Tripping through integrated protection relays must not be delayed by other functions of the control system.

   The loss of the auxiliary voltage of either the protection equipment or the plant's control system must lead to an instantaneous tripping of the interface switch.

   DEWA shall be responsible for ensuring through the design that the voltage and frequency at the Connection Point remain within statutory limits. The Interface Protection settings have to be chosen to allow for voltage rise or drop within the Producer's Installation and to allow the RRGU to continue to operate outside of the statutory frequency range as required.

The protection functions required in the Interface Protection are the following:

Table 3 – Protection functions required

Function	ANSI Code
V<, V<<- Undervoltage	27
V>, V>> - Overvoltage	59
f>, f>> - Overfrequency	81>
f<, f<< - Underfrequency	81<
Vector shift (or jump)	78
Rate Of Change Of Frequency (ROCOF)	81R

3.2 With the exception of functions 78 and 81R, at least 2 thresholds for each of the above listed functions shall be required, in order to avoid nuisance tripping setting long time delays for smaller excursions and allowing a faster tripping time in case of greater excursions. The thresholds to be activated will be defined in the following. Some of the required ones may be for future use.

One of the main goals of the Interface Protection is to prevent the RRGU / RRGP supporting an islanded section of the Distribution Network, when it would or could pose a hazard to the Network itself or to the customers connected to it. In order to ensure this, functions 78 (Vector shift) and 81R (ROCOF), known as Loss Of Mains (LOM) protections, must be both implemented in the Interface Protection. These functions have to be available in the interface protection, but they shall be activated only on explicit demand of DEWA.

3.3 The number and position in the installation of this Interface Protection is indicated in the Connection Schemes (see Appendix A). The Interface Protection will act on an Interface Switch with the purpose:

- to separate the generating part of the plant from the network;
- to prevent the RRGU not being synchronised with the network in case of reclosure of circuit breakers made by DEWA in the Distribution Network.

When implemented in the MV side of the plant, the Interface Switch shall consist of:
- three-polar withdrawable automatic circuit breaker operated by an undervoltage release, or
- three-polar automatic circuit breaker operated by an undervoltage release along with an isolator (either upstream or downstream the circuit breaker).

When implemented in the LV side of the plant, the Interface Switch shall consist of:
- automatic circuit breaker or switch disconnector operated by an undervoltage release, or
- omnipolar AC3 contactor.

3.4 In case of a RRGP with a Maximum Capacity > 150 kW_{AC}, as a rule a separate Interface Protection and Interface Switch along with a back-up switch are installed.

Projects that are ≤150 kW_{AC} in size and use one inverter are not required to install a separate Interface Protection device, as long as the inverter complies with IEC 62109 requirements and has been proven to implement anti-islanding protection.

Alternatively, in extended plants, it is possible to install more than one Interface Protections, each one which controls a single Interface Switch. However, in this case an OR logic shall be adopted between the protections, in order to open all the Interface Switches once one of the protections has detected an abnormal condition of the grid. This circuital condition shall be evaluated and preliminarily approved by DEWA.

3.5 For RRGPs with a Maximum Capacity > 20 kW and with a separate interface protection device, a backup switch to the Interface Switch shall be provided. This may also consist of an already existing switch, e.g. a main incomer, in any case a device which will be able to separate the RRGUs from the network in case of failure of the Interface Switch.

The backup may be achieved:

- by sending the opening command, as elaborated by the Interface Protection, to both the Interface Switch and the backup switch,
- Sending a signal to Inverters that comply with UL-1741 SB and have implemented remote shutdown capability, or
- by sending the opening command, as elaborated by the Interface Protection, to the Interface Switch and, in case of failure (monitored by the protection through a dry contact from the Interface Switch), by sending the opening command to the backup switch at most after 0.5 s. The opening release on the backup switch shall be reliable, in order to ensure the separation from the network. Only manual reclosing of the backup switch shall be permitted

3.6 For the three-phase systems, both for LV and MV connections, the protection functions:

- Under and Overvoltage shall be fed by voltages proportional to the 3 line voltages
- Under and Overfrequency shall be fed by voltages proportional to at least one line voltage

In case of voltage sensing at the MV side, these voltages will be obtained by means of VTs. The connection of the Interface Protection at the LV side, with direct sensing of the line voltages, is however always allowed.

3.7 Automatic reclosure of the Interface Switch: the opening of the Interface Switch shall occur for either a fault or a disturbance on the distribution network, whose duration exceeds the Interface Protection setting times, or as an effect of a remote tripping command. After these disturbances will have been cleared by the network protections or the remote tripping command will have been withdrawn, the automatic reclosure of the Interface Switch shall be made possible. The Interface Protection will have to sense a healthy network condition and give the consensus to the closing of the Interface Switch. The following provisions shall then apply:

- the voltages which feed the Interface Protection shall always be sensed in order to measure them at the network side (see Connection Schemes in Appendix A);
- in case the Interface Switch consists of an automatic circuit breaker, this shall be motorized. The undervoltage release which operates the switch shall be fed by an auxiliary voltage derived from the network side and not from the producing plant side.

3.8 The Interface Protection shall include the ability to receive signals with protocol IEC 61850, inalized to remote tripping.

3.9 In accordance with established practice, it is the Producer's responsibility to install, own and maintain these protections.

4. The protection system of the Renewable Resource Generating Plant, including connection installations to the Network, shall be able to eliminate faults inside the installation and, in backup, faults outside the installation, within the time given in Table 4.

Table 4 –Maximum times to fault elimination by protection (the provided times include the time needed to open the circuit breaker)

Line, cable or transformer fault							Busbar fault
Voltage level (kV)	Base time (ms)	Simple failure* (ms)	Breaker failure (ms)	Backup busbar	Auto-reclosure	Base time (ms)	Simple failure* (ms)
33 UGC	120	1000		500 ms	Not allowed for 3-phase faults and UGC faults Mandatory for 1-phase fault in OHL	120	1000
33 OHL	1000					120	1000
11 UGC	1000					120	1000
6.6 UGC	1000					120	1000
LV	Compliance with international standard IEC 60364 is required.						

*Simple failure = failure of protection or measurement transformer or DC supply
OHL = Overhead Line, UGC = Underground Cable.

2.2.1.3 PRODUCER RESPONSIBILITY

The Producer shall be responsible for protecting the generating plant or the generating units, respectively. Consequently, the protection concept described in these Standards needs to be adequately extended. However, intrinsic protection must not undermine the requirements described in these Standards regarding steady-state voltage control and dynamic network support of the RRGP or RRGUs.

2.2.2 Short-circuit contribution of the Renewable Resources Generating Units and Plants

1. Requirements related to the neutral earthing and the coupling of the transformer and to the 1-phase short-circuit current contribution will be provided by DEWA. As regards the 1-phase to earth values for the different voltage levels of the Distribution Network, refer to point 2.2.3.
2. Maximum admissible short-circuit current

Due to the operation of a RRGP, the short-circuit current is increased by its contribution, particularly in the vicinity of the connection point. Therefore, information about the anticipated short-circuit currents of the RRGP at the network connection point has to be provided together with the application for connection to the network.

To ensure correct calculations, the impedances between the RRGP and the connection point (MV/LV transformer, lines, etc.) need to be taken into consideration.

If a short-circuit current increase above the rated values (see next 2.2.3) occurs in the network because of RRGP, DEWA and the Producer shall agree upon appropriate measures, such as limitation of the short-circuit current from the RRGP (e.g. by using series reactors or other means).

2.2.3 Equipment rating, characteristics and Insulation of the installation at the Connection Point

2.2.3.1 EQUIPMENT RATINGS AND INSULATION OF INSTALLATION

1. The equipment rating and the insulation values of the RRGPs, including connection installations to the Network, shall be designed to withstand at least the Network side currents and voltages defined in Table 5.

Table 5: Equipment rating and Insulation of installation by voltage level. The rating is expressed at maximum ambient operating conditions (55°C)

Voltage level	Isc	Ithermal		I dynamic	Um (phase-to-phase)
(kV)	(kA)	(kA)	(s)	(kA)	(kV)
33	25	25	3	63	36
11	31.5	31.5	3	84	12
6.6	25	25	3	63	7.2
LV	40	40	1		

2. The single phase to earth short circuit currents in the MV networks, as deriving from the state of the neutral, and to be used for the design of the earthing system for the generation plant, are defined in Table 6.

Table 6: Maximum Single-phase to earth short circuit currents for MV networks

Voltage level	**I 1-ph**
(kV)	(kA)
33	2.4
11 (1)	6
11 (2)	25
6.6	25

(1) When directly derived from 132 kV network via a 132/11 kV Ynd transformer
(2) When derived from 33 kV network via a 33/11 kV Dyn transformer

2.2.3.2 OTHER CHARACTERISTICS FOR MV PANELS

In addition to the above, when a direct MV supply is necessary for a RRGP and the MV panel is provided by the Producer, the following specified conditions have to be complied:

1. The incomer protection relays shall comply with standard IEC60255 (or equivalent) and will be supported by a type test and guaranteed routine manufacturer's works test certificates. A certificate confirming that the relays have been duly type tested shall be produced by the Producer.

2. The overcurrent relay shall operate correctly for the fault currents up to the values specified in 2.2.3.1.

3. The instrument transformers shall comply with standard IEC60044 and IEC 61869 (or equivalent) and be supported by type test and guaranteed routine manufacturer's works test certificates. A certificate confirming that the transformers have been duly type tested shall be produced by the Producer.

4. The incomer current transformer shall be dimensioned so that the protection scheme will operate effectively for the fault currents up to the values specified in 2.2.3.1.

2.3 Power quality (Phase unbalance, harmonics and flicker) and Electromagnetic compatibility

2.3.1 General Requirements

1. RRGPs may also be made of single-phase units connected to the LV network, provided that the Maximum Capacity of a plant at the point of connection is lower than or equal to 10 kW per line conductor, and that the total capacity of the units is well balanced amongst the three phases, without exceeding the maximum permissible imbalance of 5 kW. Therefore, it shall be possible to connect in single-phase units, distributed amongst three line conductors, at maximum capacity of 3x10 kW.

   In the case of the above limits are exceeded at the point of connection, the additional extension shall be three- phase connected.

2. The maximum permissible phase power imbalance of 5 kW shall apply for each network connection. The power imbalance is calculated as the difference between the DRRG generated power in the most and the least loaded phases. Whenever a power imbalance larger than 5 kW takes place proper provisions shall be adopted in order to limit it. Therefore, an automatic system shall be installed for this purpose. Such system will act to reduce the imbalance among the phases below 5 kW, within 1 min. Conversely, if the maximum acceptable imbalance is not reached by the specified time, the automatic system shall disconnect the whole RRGP from the network.

   In case of Producers with a single-phase connection to the LV network, the maximum power (P_{MC}) of 5 kW and the use of single-phase inverters shall be allowed for each single connection point, provided the balance of the load along the feeder is possible. DEWA will verify this feasibility at the Application stage.

3. The RRGP equipment emissions created in the grid shall be lower than the limits specified by DEWA. These individual emission levels for each grid user are compliant with the international standards and technical reports as specified hereinafter.

4. The RRGP equipment immunity to grid disturbances shall be higher than DEWA commitment to provide a voltage in line with standard EN 50160, which describes the level of disturbances that should be expected during normal operation.

   The mean value of the fundamental frequency measured over 10 s shall be within a range of:

   - 50 Hz ± 1% (i.e. 49,5 Hz... 50,5 Hz) during 99,5% of a year;
   - 50 Hz + 4% / - 6% (i.e. 47 Hz... 52 Hz) during 100% of the time.

   Under normal operating conditions, excluding the periods with interruptions, supply voltage variations should not exceed ± 5% of the nominal voltage Un for MV network and ± 6% of the nominal voltage Un for LV network, as per DEWA regulations. These values may rise to ±10% in particular and transitorily periods (Contingencies).

   Supply voltage unbalance: Under normal operating conditions, during each period of one week, 95% of the 10 min mean r.m.s. values of the negative phase sequence component (fundamental) of the supply voltage shall be within the range 0% to 2% of the positive phase sequence component (fundamental).

Under normal operating conditions, during each period of one week, 95% of the 10 min mean r.m.s. values of each individual harmonic voltage shall be less than or equal to the values given in EN50160. Resonances may cause higher voltages for an individual harmonic.

Unless differently specified, the THD of the supply voltage (including all harmonics up to the order 40) shall be less than or equal to 8% for LV network and 6.5% for MV network.

To demonstrate that a RRGP does not contribute to exceed the above mentioned limits at the point of connection, a harmonic study might be required by DEWA, particularly at the planning stage. Power quality tests should be conducted as part of the commissioning process for RRGPs ≥100kW_{AC} to ensure these systems do not have any adverse effects on the DEWA system.

If statistics are collected, voltage dips/swells shall be measured and detected according to IEC 61000-4-30, using as reference the nominal supply voltage. The voltage dips/swells characteristics of interest for this standard are residual voltage (maximum r.m.s. voltage for swells) and duration (In this standard, values are expressed in percentage terms of the reference voltage).

Typically, on MV networks, the line to line voltages shall be considered.

On LV networks, for four-wire three phase systems, the line to neutral voltages shall be considered; for three-wire three phase systems the line to line voltages shall be considered; in the case of a single phase connection, the supply voltage (line to line or line to neutral, according to the network user connection) shall be considered.

Conventionally, the dip start threshold is equal to 90% of the nominal voltage; the start threshold for swells is equal to the 110% of the nominal voltage. The hysteresis is typically 2%; reference rules for hysteresis are given in 5.4.2.1 of IEC 61000-4-30.

Evaluation of voltage swells shall be in accordance with IEC 61000-4-30. The method of analyzing the voltage swells (post treatment) depends on the purpose of the evaluation.

Typically, on LV networks:

- if a three phase system is considered, polyphase aggregation shall be applied; polyphase aggregation consists of defining an equivalent event characterized by a single duration and a single maximum r.m.s. voltage;
- time aggregation applies; time aggregation consists of defining an equivalent event in the case of multiple successive events; the method used for the aggregation of multiple events can be set according to the final use of data; some reference rules are given in IEC/TR 61000-2-8.

Typically, on MV networks:

- polyphase aggregation is applied; polyphase aggregation consists in defining an equivalent event characterized by a single duration and a single residual voltage;
- time aggregation applies; time aggregation consists of defining an equivalent event in the case of multiple successive events; the method used for aggregation of multiple events can be set according to the final use of data; some reference rules are given in IEC/TR 61000-2-8

2.3.2 Low voltage connections

For RRGU with an output current I ≤ 16 A per phase, the harmonic components of the current produced and measured at the output terminals shall comply with the standard IEC 61000-3-2. The limitation of voltage changes, voltage fluctuations and flicker shall comply with the standard IEC 61000-3-3.

For RRGU with an output current 16 < I ≤ 75 A per phase, the harmonic components of the current produced and measured at the output terminals shall comply with the standard IEC 61000-3-12. The limits specified in the same standard, may be reasonably extended to RRGU with output current > 75 A. The limitation of voltage changes, voltage fluctuations and flicker shall comply with the standard IEC 61000-3-11.

For all the RRGP connected to the LV grid, the detriment of the RRGP to the voltage quality measured at the Point of Connection shall be in accordance with IEC 61000-2-2 and IEC/TR 61000-3-14.

The following aspects shall be addressed:

- voltage fluctuation and flicker;
- harmonics and interharmonics up to 50th;
- voltage distortion at higher frequencies (above 50th harmonic);
- voltage dips and short supply interruptions;
- voltage unbalances;
- transient overvoltages;
- d.c. components;
- mains signalling

The contribution of other disturbances on the grid shall be taken into consideration in the calculations, in order not to impute them to the operation of the RRGP.

According to the type of installation, the following standards shall be applied:

- IEC 61000-6-1 and IEC 61000-6-3 for residential, commercial and light-industrial environments;
- IEC 61000-6-2 and IEC 61000-6-4 for industrial environments;

If a transformer between the DC section(s) and the AC section of the RRGU is not present, a suitable protection shall be used in order to avoid any relevant DC injection into the grid (see Point 2.4.6).

2.3.3 Medium voltage connections

For all the RRGP connected to MV grid (6.6 kV, 11 kV, and 33 kV), the detriment of the RRGP to the voltage quality measured at the Point of Connection shall concern the following aspects and standards:

- voltage fluctuation and flicker – IEC/TR 61000-3-7;
- harmonics and interharmonics – IEC/TR 61000-3-6 (see table 7);
- voltage unbalances – IEC 61000-3-13.

At the network assessment stage, a special harmonic evaluation will be performed by DEWA to verify that a MV connected RRGP does not contribute to exceed the harmonic content limits at the Point of Connection.

Table 7: Indicative planning levels for Harmonic Voltages (in% of fundamental voltage) in MV, HV and EHV systems (source IEC/TR 61000-3-6)

Odd harmonics						Even harmonics		
Not multiples of 3			Multiples of 3					
Order h	Harmonic voltage %		Order h	Harmonic voltage %		Order h	Harmonic voltage %	
5	5.0	2.0	3	4.0	2.0	2	1.8	1.4
7	4.0	2.0	9	1.2	1.0	4	1.0	0.8
11	3.0	1.5	15	0.3	0.3	6	0.5	0.4
13	2.5	1.5	21	0.2	0.2	8	0.5	0.4
$17 \leq h \leq 49$	$1.9 \times 17/h - 0.2$	$1.2 \times 17/h$	$21 \leq h \leq 45$	0.2	0.2	$10 \leq h \leq 50$	$0.25 \times 10/h + 0.22$	$0.19 \times 10/h + 0.16$

NOTE: The corresponding planning level for the total harmonic distortion is THD = 6.5%

The contribution of other disturbances on the grid shall be taken into consideration in the calculations, in order not to impute them to the operation of the RRGP.

It is assumed that DC section(s) in the RRGP are separated from MV AC section by an MV/LV transformer. Therefore no DC currents injection shall be possible from DC/AC converters to the MV grid.

2.4 Normal and Emergency mode of operation

2.4.1 Mode of operation

1. A RRGU shall connect to the Distribution Network only when the grid is assumed to be in undisturbed operating conditions; this means that the grid frequency is within the range [49.9-50.1Hz] and grid voltage in the range +/- 5% of grid rated value.

2. The connection of the RRGU (or RRGP) to the Network shall not create transient voltage variation of more than 4% of rated value.

3. During start-up/shutdown phases, the RRGU shall not vary its power output at a rate greater than 20%/min of Maximum Capacity.

2.4.2 Ability to stay connected - Voltage/Frequency/Change of frequency ranges

1. With regard to Frequency ranges, a RRGU / RRGP shall be capable of staying connected to the Distribution Network and operating within the Frequency ranges and time periods specified here:

   - Unlimited time operation without disconnection is required within the range 47.5-52.5 Hz

   - Outside these limits, the intervention time shall be defined by DEWA.

Possible frequency and time settings are defined in Table 8:

Table 8 – Frequency settings for RRGP disconnection (to be set in the Interface Protection)

Function	Setting	Delay
f> (81>-1), overfrequency stage 1	52.5 Hz	0.1 s
f< (81<-1), underfrequency stage 1	47.5 Hz	4.0 s

The power in feed shall be maintained within the limits specified in section 2.4.3 (Active power limitation).

2. Any rate of change of frequency up to 2 Hz/s shall be withstood by the Renewable Resource Generating Unit without disconnection from the network other than triggered by loss of mains protection. The frequency shall be measured using 100 ms average.

3. All the RRGUs / RRGPs shall be capable of staying connected to the Distribution Network and operating within the ranges of the Network Voltage at the Connection Point and time periods specified here, expressed in terms of the nominal voltage Vn:
   - Unlimited time operation without disconnection is required within the range 85% Vn ≤ V ≤ 110% Vn
   - Outside these limits, the intervention time shall be defined by DEWA.

Possible voltage and time settings are defined in Table 9a, for RRGP connected to the LV network, and 9b for RRGP connected to MV network:

Table 9a – Voltage settings for RRGP disconnection (to be set in the Interface Protection) – Low Voltage network (0.4 kV)

Function	Setting	Delay
V< (27-1) Undervoltage Stage 1	0.85 Vn	0.4 s
V< (27-1) Undervoltage Stage 1	0.4 Vn	0.2 s
V> (59-Av) Overvoltage 10 min avg (*)	1.10 Vn	3 s
V> (59-1) Overvoltage Stage 1 (**)	1.1 Vn	90 s
V>> (59-2) Overvoltage Stage 2	1.15 Vn	0.20 s

Table 9b – Voltage settings for RRGP disconnection (to be set in the Interface Protection) – Medium Voltage network (6.6, 11 and 33 kV)

Function	Setting	Delay
V< (27-1) Undervoltage Stage 1	0.85 Vn	1.5 s
V< (27-1) Undervoltage Stage 1	0.3 Vn	0.2 s
V> (59-Av) Overvoltage 10 min avg (*)	1.10 Vn	3 s
V> (59-1) Overvoltage Stage 1 (**)	1.1 Vn	90 s
V>> (59-2) Overvoltage Stage 2	1.2 Vn	0.60 s

(*) In case the protection is not equipped with the overvoltage 10 mins average value function 59-Av, an overvoltage stage 59-1, in addition to 59-2, can be accepted to replace it.
(**) To be used as an alternative to 59-Av

The LOM protection functions can be set according to values suggested by the international practice, i.e. as indicated in Table 9c, for any voltage level.

Table 9c – LOM suggested settings

Function	Setting
Rate Of Change Of Frequency (ROCOF) 81R	0.5 ÷ 1 Hz/s
Vector shift (or jump) 78	8 ÷ 12°

4. Steady-state stability of a Generating Unit is required for any operating point in the P-Q-Capability Diagram in case of power oscillations.

2.4.3 Ability to predict the behaviour - Frequency behaviour

1. In case of deviation of the Network frequency from its nominal value above 52.5Hz, the Renewable Resource Generating Unit shall be disconnected from the network.

2. In case of deviation of the Network frequency from its nominal value below 47.5Hz, the Renewable Resource Generating Unit shall be disconnected from the network.

3. Following the disconnection stated in previous paragraphs (1 & 2), the Renewable Resource Generating Unit shall not be reconnected to the Network before the Network frequency is within the range 49.9 Hz – 50.1 Hz during a minimum of 60 seconds. The Active Power Output shall not be recovered with a gradient above 20% of the Maximum Capacity per minute.

4. In case of deviation of the Network frequency from its nominal value, due to a deviation within the frequency ranges and time periods given in 2.4.2, the Renewable Resource Generating Unit, for whatever voltage level the RRGP is connected to (MV and LV), shall have a predicable behaviour in terms of active power output:

   a) Due to over-frequency deviations, the ratio between the Active Power Output and the Maximum Active Power Output of the Renewable Resource Generating Plant available at the time the frequency exceeds 50.3 Hz, shall not be changed for frequencies below 50.3 Hz and shall be decreased linearly by a minimum of 45.5% (droop = 4.4%) of nominal active power per Hertz until 52.5Hz, as illustrated in Figure 2.

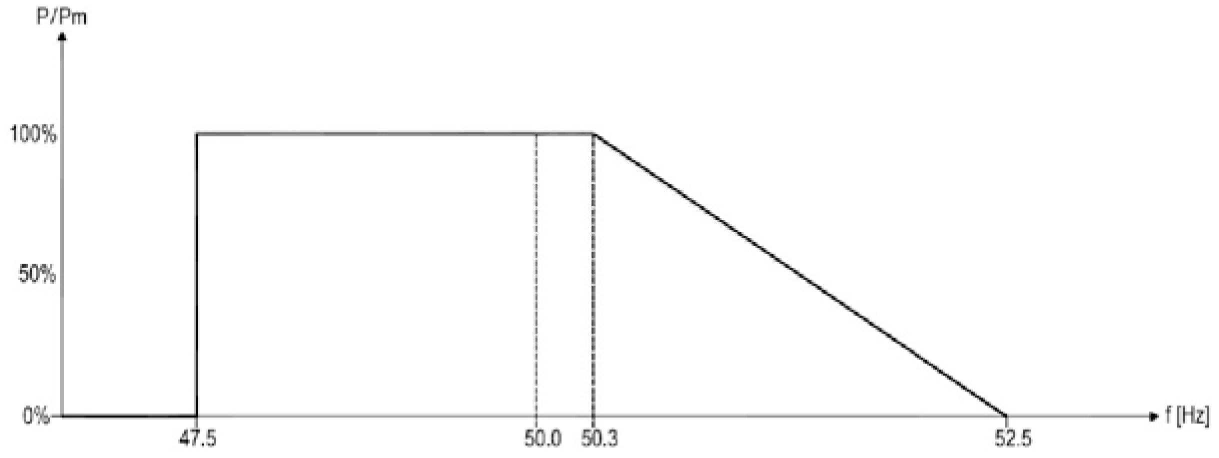


Figure 2 – Curve of active power limitation with overfrequency

   b) In the frequency range between 47.5 Hz and 50.3 Hz, the RRGPs provided with Non-Synchronously-Connected Renewable Resource Generating Units shall produce the maximum allowable active power.

5. The Active Power output of the Renewable Resource Generating Unit connected to the Network shall be controllable. For this purpose, the Renewable Resource Generating Plant control system shall be capable of receiving an Instruction containing a required Set point, given orally, manually or through automatic remote control system by DEWA.

6. The accuracy of frequency measurements for Active Power Frequency Response must be better than 10 mHz.

2.4.4 Ability to predict the behaviour – Steady State Voltage behaviour

All the Renewable Resources Generation Units connected to either MV or LV Distribution Network have to participate in voltage control by means of production and absorption of reactive power. The purpose of this is the limitation of over and undervoltages caused by the RRGUs themselves, due to the injection of active power to the grid.

1. In LV and MV networks, in case of deviation of the Voltage at the Connection Point from its nominal value above 110% of nominal voltage, the Renewable Resource Generating Unit shall be disconnected from the network with a delay consistent with settings indicated in Tables 9a and 9b.

2. Following the disconnection stated in paragraph 1, the Renewable Resource Generating Unit shall not be reconnected to the Network before the Voltage at the Connection Point is within the range 95% - 105% of nominal Voltage during a minimum of 60 seconds. The Active Power Output shall not be recovered with a gradient above 20% of the Maximum Capacity per minute.

3. The RRGUs will be allowed to operate in parallel with the LV and MV Distribution Network if complying with the following requirements:

   - Non-Synchronously-Connected Renewable Resource Generating Units as part of Renewable Resources Generating Plants with Maximum Capacity < 10 kW, which shall be able to maintain their power factor in the range [0.98 leading (underexcited operation), 0.98 lagging (overexcited operation)] for nominal Voltage if the active power output is above 20% of rated power. No deviations from these ranges due to voltage deviation are accepted. The acceptable range of operation for nominal voltage is illustrated by the hatched areas in the capability curve in Figure 3;

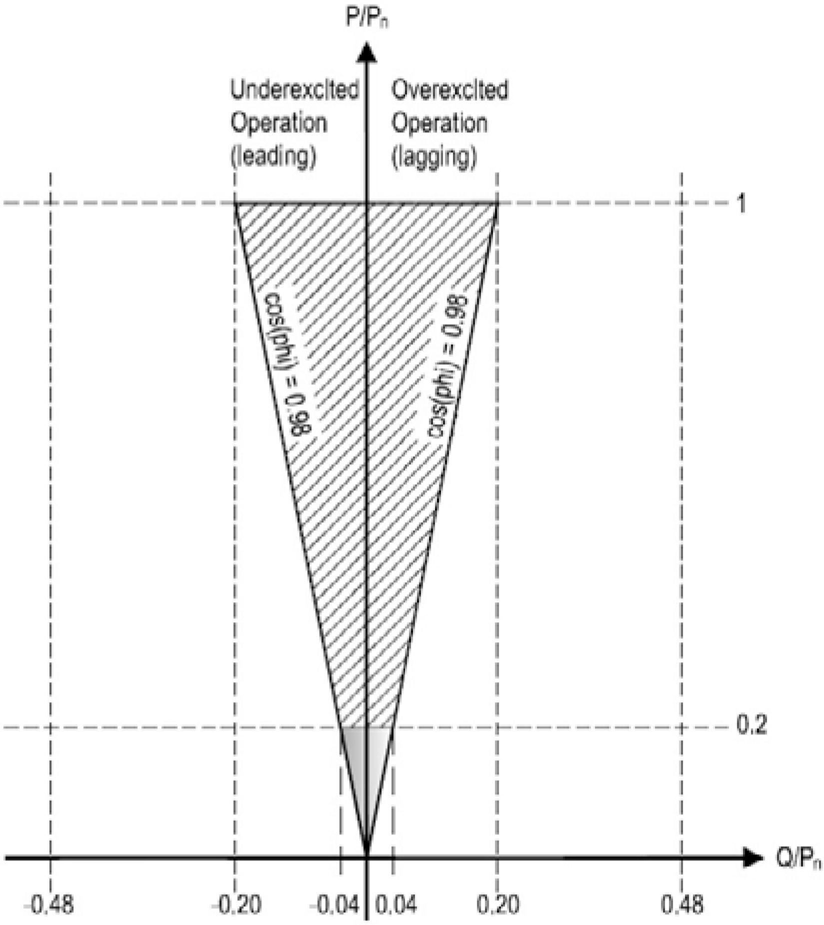


Figure 3 – P-Q capability curve required to a RRGU included in a RRGP with P_{MC} < 10 kW

- Non-Synchronously-Connected Renewable Resource Generating Units as part of Renewable Resources Generating Plants with Maximum Capacity ≥ 10 kW and ≤ 400 kW, which shall be able to provide a reactive power as a function of the active power according to a semi-circular capability curve as in Fig. 4. They shall mandatorily keep their power factor in the range [0.9 leading (under excited operation), 0.9 lagging (overexcited operation)] for nominal voltage, whereas the ability to provide reactive power within the remaining part of the capability curve will be optional.

For a low produced power (S≤10% Sn), due to the uncertainty of the inverter behaviour there are no particular requirements in terms of reactive power provision.

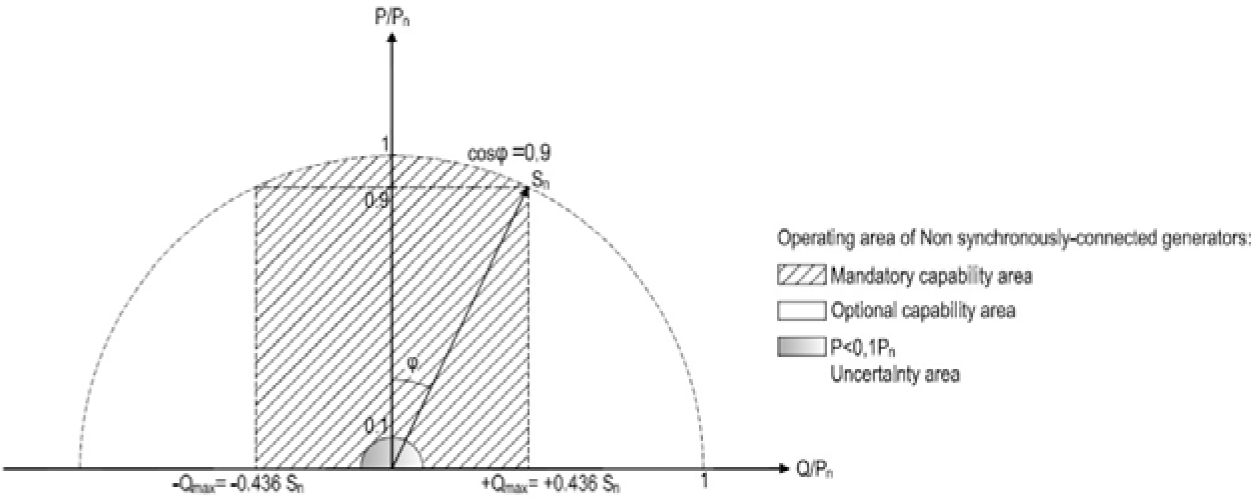


Figure 4 – P-Q capability curve required to a RRGU included in a RRGP with 10 kW ≤ P_{MC} ≤ 400 kW

4. The Maximum Capacity limits shall be referred to the RRGP, which is the maximum capacity of the overall set of RRGUs connected to the network.

5. The RRGUs will be allowed to operate in parallel with the MV Distribution Network if compliant with the following requirements:

   - Non-Synchronously-Connected Renewable Resource Generating Units as part of Renewable Resources Generating Plants with Maximum Capacity larger than 400 kW and then connected to the MV Distribution Network, which shall be able to provide a reactive power as a function of the active power according to a semi- circular capability curve as in Fig. 5. The acceptable range of operation for nominal voltage is illustrated by the hatched area in the capability curve in Figure 5.

For a low produced power (S≤10% Sn), due to the uncertainty of the inverter behaviour there are no particular requirements in terms of reactive power provision.

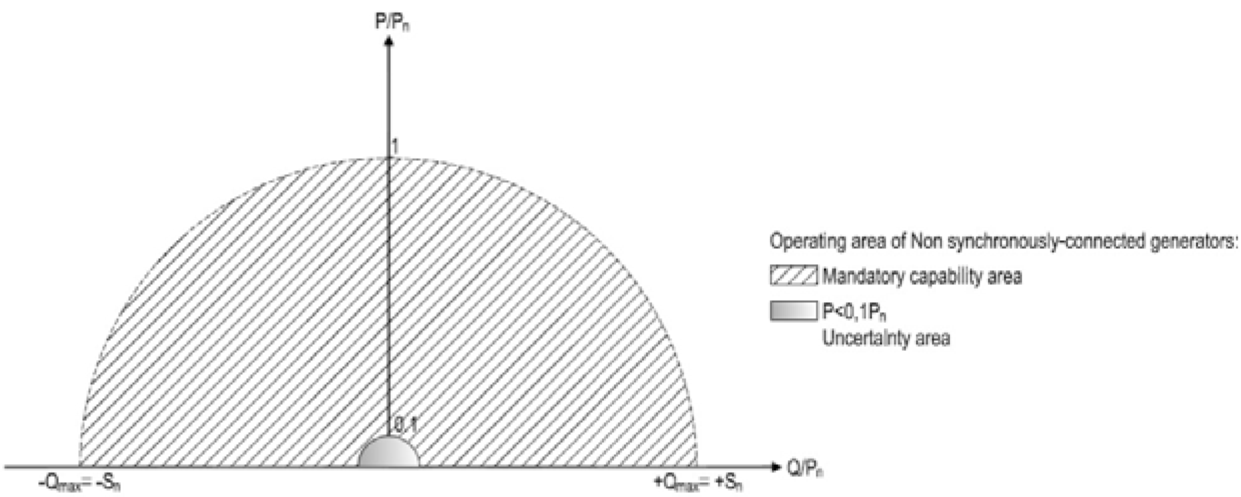


Figure 5 – P-Q capability curve required to a RRGU included in a RRGP with P_{MC} > 400 kW

6. To achieve this ability of voltage regulation for RRGUs connected either to MV or LV (only for $P_{MC} \geq 10$ kW) Distribution Network, the provision of reactive power shall be automatic, with a local logic, according to one of these two methods:

  - power factor fixed and settable (see Fig. 6, curve type a);
  - power factor as a function of the produced active power P, according to a curve defined by three points A, B, C (see Fig. 6, curve type b)

This control logic, according to DEWA request, shall be activated either locally or from remote control through a proper interface. This possible choice between local and remote control shall be adjustable inside the inverter.

In particular, this provision of reactive power shall be based on the ratio P/Pn (where Pn is the rated active power of the inverter), in a way that the RRGU must absorb lagging reactive power above 50% of its nominal power in order to reduce the voltage:

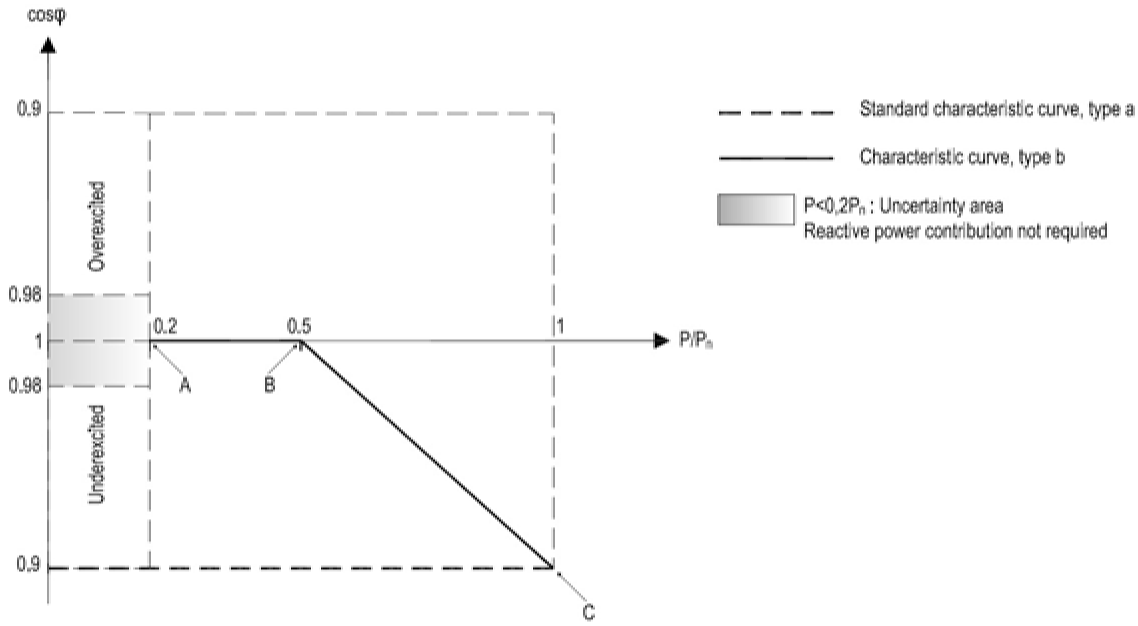


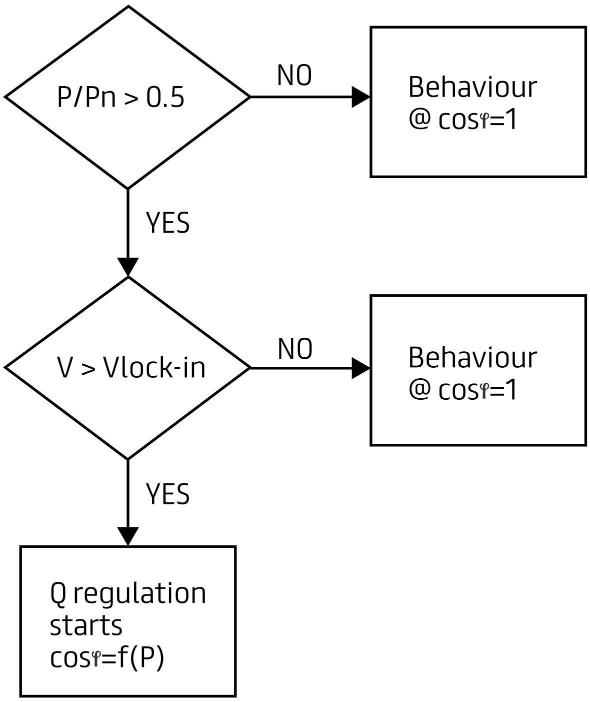
Figure 6 – Characteristic curve cosφ = f(P) defined on three points

- A: P = 0,2 Pn; cos φ = 1
- B: P = 0,5 Pn; cos φ = 1
- C: P = Pn; cos φ = 0.9

(for P<0.2 Pn the reactive power contribution is not required and a cos φ around the unity, e.g. 0.98 lead-lag, may be kept).

Moreover, the voltage at the inverter terminals shall also be discriminating, making this contribution possible only when the voltage exceeds a lock-in voltage adjustable in the range 1.0 Vn - 1.1 Vn and stopping it when the voltage goes below a lock-out voltage settable in the range 0.9 Vn – 1.0 Vn, being Vn the nominal voltage at the inverter terminals. The following processes shall then apply for the activation (Fig. 7a) and De-activation (Fig. 7b) of reactive power control:

a)



b)

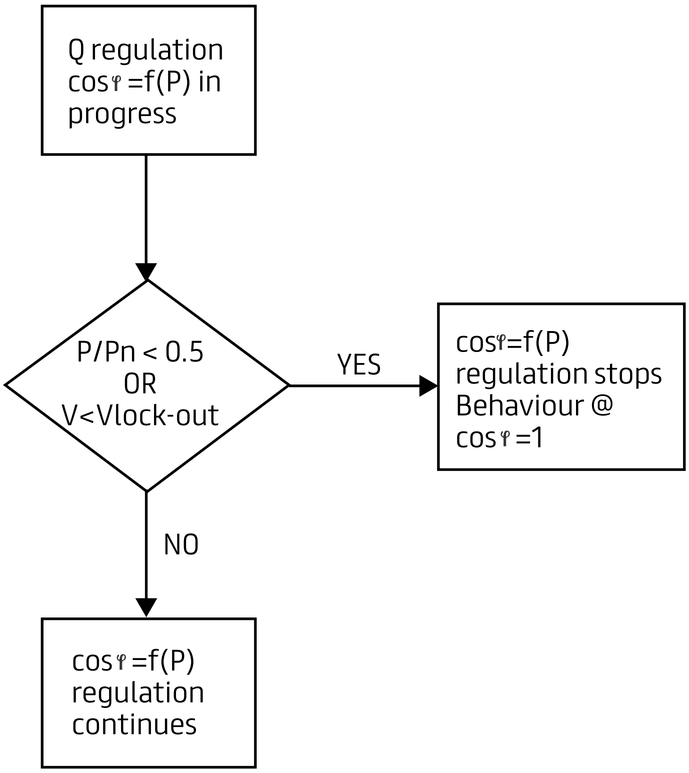


Figure 7 – a) Activation of reactive power control – b) De-activation of reactive power control

2.4.4.1 DISCLAIMER

The requirement of provision of reactive power by the RRGUs, with the rules and ranges set above, must be carefully taken into account by the Customer's appointed consultants when sizing the inverters. In order for an inverter to provide both active and reactive power, with active power equal to 100% of the maximum input power at the DC side of the inverter (depending on the PV array characteristics and working condition) and a cos φ = 0.9, it must be considered that the inverter itself has to be oversized to 111% of the photovoltaic generator capacity.

2.4.5 Ability to predict the behaviour – Transient Voltage behaviour

2.4.5.1 GENERAL RULES

To avoid the disconnection of a Non-Synchronously-Connected Renewable Resource Generating Unit in the occurrence of voltage dips due to faults on the higher voltage level networks, a RRGU being part of a RRGP shall be able to ride through, that is:

- not to disconnect from the network in the event of network faults
- not to extract from the network to which the RRGP is connected after fault clearance more inductive reactive power than prior to the occurrence of the fault

These requirements apply to all types of short circuits (i.e. to single-phase, two-phase and three-phase short circuits); whatever the voltage level considered (MV or LV).

2.4.5.2 REQUIREMENTS FOR RRGUs CONNECTED TO LV DISTRIBUTION NETWORK

1. Low Voltage Ride Through (LVRT) capability shall be possible for RRGUs being part of a RRGP with Maximum Capacity P_{MC} ≥ 10kW. This capability is illustrated by the curve of Figure 8.

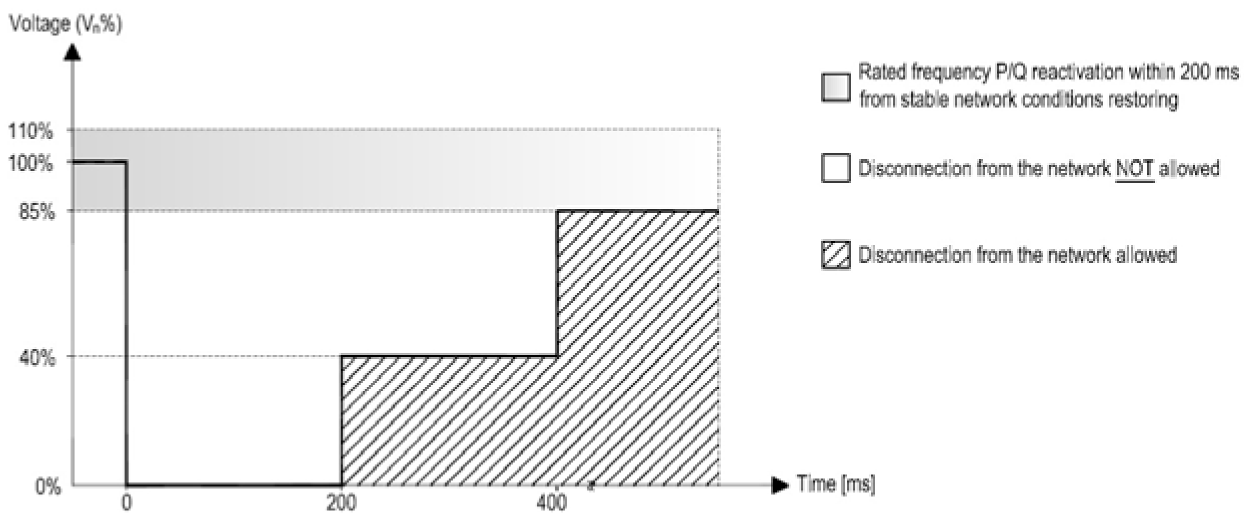


Figure 8 – LVRT Characteristic for RRGUs connected to LV Distribution Network

2. The following functional requirements shall be satisfied:

   - in the non-hatched area the RRGU shall not disconnect from the network. Performance with a zero voltage for 200 ms shall be endured. The temporary interruption of the production of active and reactive power is in this case allowed;
   - in the hatched area the RRGU may be disconnected;
   - within 200 ms from the restoring of a network voltage included in the range 85% Vn ≤ V ≤ 110% Vn (grey shaded area), the RRGU will restore the export of active and reactive power to the network as it was before the fault occurrence, with a maximum tolerance of ±10% of the RRGU rated power. If the voltage is restored, but it remains in the range 0.85 Vn ≤ V ≤ 0.9 Vn a reduction in the produced power is admissible;
   - the LVRT curve shall be coordinated with the settings of the undervoltage function (V<, 27) in the Interface Protection.

3. The compliance tests to verify these requirements will be carried out in accordance to the methods described in Appendix D.

2.4.5.3 REQUIREMENTS FOR RRGUs CONNECTED TO MV DISTRIBUTION NETWORK

1. Low Voltage Ride Through (LVRT) capability shall be possible for all the RRGUs being part of a RRGP connected to the MV Distribution Network. This capability is illustrated by the curve of Figure 9.

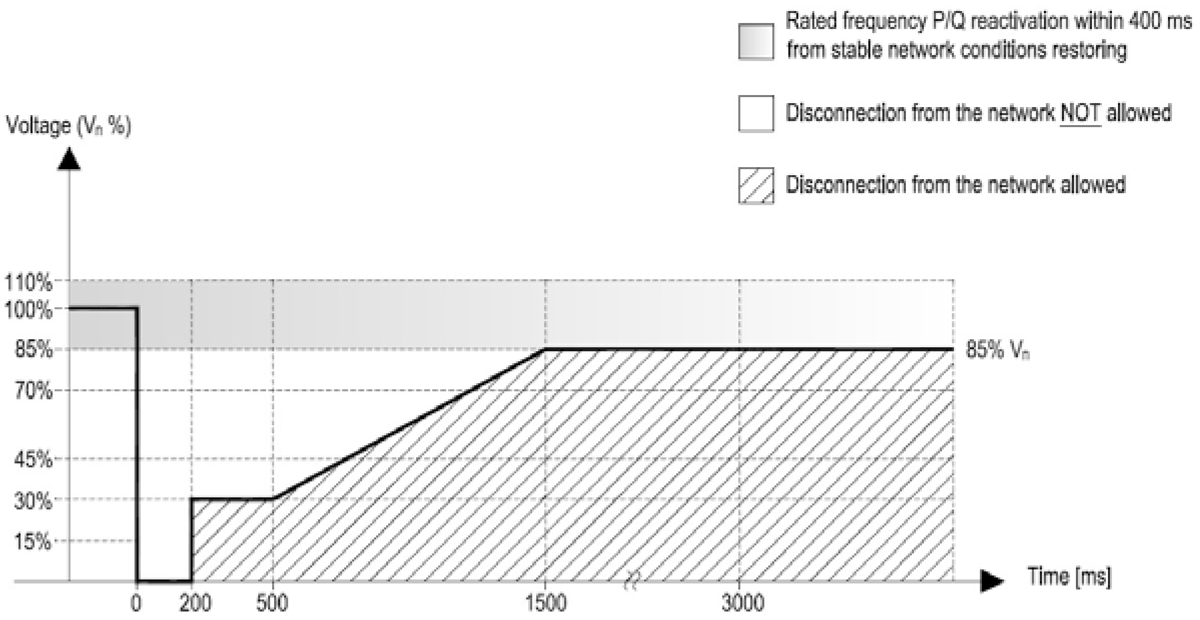


Figure 9 – LVRT Characteristic for RRGUs connected to MV Distribution Network

2. The following functional requirements shall be satisfied:

   - a RRGU shall not disconnect from the network in the event of voltage drops to 0% Vn of a duration ≤ 200ms. This will allow a fault clearing in base time in the HV network;
   - a RRGU shall not disconnect from the network any time during which the voltage is in the non-hatched area. The temporary interruption of the production of active power is in this case allowed;
   - in the hatched area the RRGU may be disconnected;
   - within 400 ms from the restoring of a network voltage included in the range 0.85 Vn ≤ V ≤ 1.1 Vn, the RRGU will restore the export of active and reactive power to the network as it was before the fault occurrence, with a maximum tolerance of ±10% of the RRGU rated power. If the voltage is restored, but it remains in the range 0.85 Vn ≤ V ≤ 0.9 Vn a reduction in the produced power is admissible;
   - the LVRT curve shall be coordinated with the settings of the undervoltage function (V<, 27) in the Interface Protection.

3. The performance as per Figure 9 shall be granted for a dip in any of the phase voltages.

4. The compliance tests to verify these requirements will be carried out in accordance with the methods described in Appendix D.

2.4.6 Injection of a DC component in the current

In the RRGU, a system to avoid, at steady state, the injection of currents with DC components > 0.5% of the inverter rated current shall be foreseen.

The tests described in Appendix D shall be required to demonstrate this. However, this requirement shall be achieved by means of either:
- a separating transformer (operating at mains frequency); or
- a protection function which can sense the DC component injected to the network, embedded into the inverter.

This protection function shall act to trip the RRGU circuit breaker:
- at most in 200 ms if the DC component exceeds 1 A; or
- at most in 1s if the DC component exceeds 0.5% of the inverter rated current.

Irrespective of the presence of this protection feature in the inverter, for RRGPs with relevant Maximum Capacity (typically above 100 kW) the provision of a separating transformer between the generation and the load section of the installation is always advisable. In fact, particularly in case of use of string inverters, which do not need a transformer to be connected to the 0.4 kV network, each inverter may be compliant with the above DC current injection requirement, however the sum of the injected DC currents may still be detrimental for the rest of the equipment in the installation.

2.4.7 Monitoring, remote control and information exchange

2.4.7.1 GENERAL RULES

The RRGUs and RRGPs shall be provided with all the necessary facilities for monitoring, remote control and information exchange.

The remote control shall be required for RRGPs with Maximum Capacity larger or equal than 10 kW, whereas the remote monitoring shall be required for RRGPs with Maximum Capacity larger than 100 kW.

Other requirements related to monitoring, remote control (communication with other protection relays, substations and the Supervisory Control and Data Acquisition) and information exchange will be provided by DEWA.

2.4.7.2 REQUIREMENTS FOR RRGUs CONNECTED TO LV DISTRIBUTION NETWORK

1. 1. The RRGUs as part of a RRGP with a Maximum Capacity P_{MC} >=10 kW shall be capable of:

   - providing reactive power support to the network as per curve in Figure 6 (cos φ = f(P)) rather than with a fixed power factor within the admissible range as defined by curve in Figure 4, as a consequence of the receiving of a set-point signal sent from a remote control centre;
   - receiving a remote signal to reduce active power production. If the produced power will already be below the DEWA's request, the power production shall not change. Conversely, the required power production shall be reached within 1 minute from the receiving of the request signal, with a tolerance of ±2,5% P_{MC}. In case of a request for reduction to a power below 10% P_{MC}, the disconnection of the inverter from the network shall be admissible.

2. The Interface Protection of RRGPs with a Maximum Capacity 10 kW ≤ P_{MC} ≤ 400 kW connected to the LV Distribution Network shall be remotely controllable in case a rapid disconnection of the plant from the network is needed by DEWA.

2.4.7.3 REQUIREMENTS FOR RRGUs CONNECTED TO MV DISTRIBUTION NETWORK

1. The RRGUs as part of a RRGP connected to the MV Distribution Network shall be capable of:

   - providing reactive power support to the network as per curve in Figure 6 (cos φ = f(P)) rather than with a fixed power factor within the admissible range as defined by curve in either Figure 4 or 5 depending on the maximum capacity of the RRGP, as a consequence of the receiving of a set-point signal sent from a remote control centre;
   - receiving a remote signal to reduce active power production. If the produced power will already be below the DEWA's request, the power production shall not change. Conversely, the required power production shall be reached within 1 minute from the receiving of the request signal, with a tolerance of ±2,5% P_{MC}. In case of a request for the reduction to a power below 10% P_{MC}, the disconnection of the inverter from the network shall be admissible.

2. The Interface Protection of a RRGP connected to the MV Distribution Network shall be remotely controllable, in case a rapid disconnection of the plant from the network is needed by DEWA.

2.4.7.4 COMMUNICATION PROTOCOL

Remote control of the RRGUs and RRGPs shall comply with Smart Grid specifications.

The preferred communication protocols shall be suggested or required by DEWA.

2.4.7.5 REMOTE MONITORING

1. With the purpose of a future implementation of the DEWA forecasting system, the RRGP with Maximum Capacity > 100 kW connected to both LV and MV network shall be required to provide measurements of:

   - Solar Irradiance
   - external air temperature,
   - wind speed, and
   - PV module's temperature (as measured on the back of a meaningful number of panels).

2. It is also recommended that the internal temperature of the inverters to be monitored by the Producer, particularly when these are not installed in air conditioned rooms.

3. The following measurements will also be made available at the connection point, from the meter:

   - Voltage,
   - Active power, and
   - Reactive power.

4. The minimum communication requirements for MV connected units are:

   - The meter data should be transmitted through secure wireless or optical fibre communication to the DEWA metering facility;
   - The communication channels should be capable of handling multiple applications over the same infrastructure;
   - The communication protocols should be tunnelling through MPLS (MultiProtocol Label Switching) or transport over other IP infrastructure;
   - The metering protocols should be interoperable with DEWA remote metering system.

2.5 Metering

A dedicated metering system is required for the RRGPs. This shall include the "Main Electricity Metering System" and the "RRGP Electricity Metering System".

The "Main Electricity Metering System" will measure the net energy at the Point of Connection (POC).

The "RRGP Electricity Metering System" will measure the energy produced by the local generator(s) connected to the POC.

The characteristics of the components of these metering systems are described hereinafter. These apply for LV and MV connections, although, with some proper adjustments they can suit also for HV connections.

2.5.1 Meter, CT and VT Requirements

2.5.1.1 EQUIPMENT REQUIRED

2.5.1.1.1 Meters

Electricity Metering Systems shall include the "Main Electricity Metering System" and the "RRGP Electricity Metering System".

The "Main Electricity Metering System" will measure the net energy of the Point of Connection (POC).

The "RRGP Electricity Metering System" will measure the energy produced by the local generator(s) connected to the POC.

"Main Electricity Metering System" and "RRGP Electricity Metering System" equipment shall keep the same levels of accuracy and functionality at all relevant times.

Both the "Main Electricity Meter" and "RRGP Electricity Meter" shall measure the quantities defined below.

"Main Electricity Meter" and "RRGP Electricity Meter" shall be installed, operated and maintained so as to comply at all relevant times with the standards and accuracy classes indicated in Appendix B.1 ("Accuracy of electricity metering system").

Both types of Electricity Meters must measure bi-directional flow of energy.

For each separate Metering Point, a Main Electricity Metering System shall be installed, operated and maintained to measure the following parameters:

1. Positive and Negative Active Energy

2. Positive and Negative of Reactive Energy

Conventionally the energy is considered "positive" when it enters in the meters towards the output connections of the meters itself; the energy is defined "negative" when it flows from the output of the meter towards the input of the meter itself.

DEWA shall configure "Main Electricity Meter" and "RRGP Electricity Meter" such that active energy is measured by the number of measuring elements equal to or one less than the number of primary system conductors. These include the neutral and/or earth conductor where system configurations enable the flow of energy in such conductors.

The "Main Electricity Meter" and the "RRGP Electricity Meter" shall be labelled by DEWA or otherwise be readily identifiable in accordance with Appendix B.2 ("Labelling of meters").

The Electricity Metering Systems shall meter the quantities on a continuous basis and the information shall be shown on a display and must be permanently stored in a non-volatile Meter Register. The Meter Registers shall not pass through zero to zero more than once within the normal meter reading cycle and their contents cannot be modified or altered by any means and by anyone, including even the meter Manufacturer.

DEWA will provide Electricity Metering Systems with "Outstations" which have an output for retrieving data related to each measured quantity.

DEWA will provide two "Outstations" one for the use of DEWA and one for the Producer.

By means of the Outstations the metering data related to the measured quantities shall be retrieved locally and, in the future, remotely, using the communication channels.

DEWA shall provide Test terminals for "Main Electricity Meter" and "RRGP Electricity Meter" to facilitate on-site tests. These terminals shall be in close proximity to the "Main Electricity Meter" and "RRGP Electricity Meter" and shall be capable of providing suitable means for accessing current and voltage signals, injecting test quantities, connecting test Meters, and replacing "Main Electricity Meter" and "RRGP Electricity Meter" without a circuit outage.

The Test terminal must be protected by any tampering action and unauthorized use

2.5.1.1.2 Current Transformers

When necessary, DEWA shall provide current transformers in accordance with the standards and accuracy classes indicated in Appendix B.1 ("Accuracy of electricity metering system").

DEWA shall provide two sets of current transformers.

The first set of current transformers will exclusively supply the Main Electricity Meter. The second set of current transformers will supply exclusively the RRGP Electricity Meter.

The current transformer windings, the cables connecting such windings to the Electricity Meters shall be dedicated exclusively for such purposes; cables and connections shall be securely sealed.

No interconnections or sharing of connections among the two sets of transformers are allowed.

The total burden on each current transformer shall not exceed the rated burden of such current transformer. No other burden shall be connected to these current transformers.

Current transformer test certificates showing errors at the overall working burden or at burdens which allow the error at a working burden to be calculated shall be made available by DEWA, wherever possible, for inspection by the relevant parties.

2.5.1.1.3 Voltage Transformers

When necessary, DEWA shall provide voltage transformers in accordance with standards and accuracy classes indicated in Appendix B.1 ("Accuracy of electricity metering system").

DEWA shall provide one voltage transformer with two or more secondary windings.

The voltage transformer winding supplying "Main Electricity Meter" shall be dedicated to that purpose and such windings and connections shall be securely sealed.

The voltage transformer winding supplying "RRGP Electricity Meter" shall be dedicated to that purpose and such windings and connections shall be securely sealed.

No other burden shall be connected to these voltage transformer secondary windings.

Separately fused voltage transformer supplies shall be provided by DEWA for the "Main Electricity Meter" and the "RRGP Electricity Meter". The fuses shall be located as close to the voltage transformer as possible.

The connections of meters and Measurement (Current and Voltage) Transformers are clearly visible in Appendix A.

2.5.1.2 ACCURACY REQUIREMENTS

2.5.1.2.1 Overall Accuracy

The accuracy of the various items of measuring equipment comprising the "Electricity Metering Systems" shall conform to the relevant IEC standards. Standards relevant are listed in Appendix B.1 ("Accuracy of electricity metering system").

Where relevant standards change from time to time, DEWA will review such changes and recommend to the Regulatory Authority the extent to which any such changes should be implemented.

The Measurement Transformers must be chosen belonging to the appropriate class of accuracy, in order to guarantee the final accuracy of the metering system.

No compensation should be necessary. Only the transformer ratio can be set in the Meters, in order to allow the use of different Measurement transformers, in accordance with the power of the Plant.

2.5.1.3 METER APPROVAL AND CERTIFICATION

Only types of Meters belonging to the DEWA's list of approved meters can be installed. The meters shall be provided by DEWA.

2.5.1.4 OPERATION AND MAINTENANCE

Electricity Metering Systems shall be operated and maintained in accordance with the manufacturer's recommendations or as otherwise necessary for DEWA to comply with its obligations under these Standards.

2.5.2 Meter Constructional and Mechanical requirements

2.5.2.1 Safety

Electricity Meters shall comply with the relevant standards specified under reference standards. Meters shall be designed and constructed in such a way as to avoid introducing any danger in normal use and under normal conditions, so as to ensure especially:

a) Personnel safety against electric shock.
b) Personnel safety against effects of excessive temperature.
c) Safety against the spread of fire.
d) All parts and surfaces which are subject to corrosion under normal working conditions shall be effectively protected.

The meter shall have adequate mechanical strength and shall withstand the elevated temperature, which is likely to occur in normal working conditions.

The electrical connections in the meter shall be resistant to tampering. These shall be made so as to prevent their opening from outside the meter bases/ cover accidentally or deliberately without breaking the seals.

The construction of the meter shall be such as to minimize the risks of short-circuiting of the insulation between live parts and accessible conducting parts due to accidental loosening or unscrewing of the wiring screws, etc.

The meter shall be substantially constructed of good material in good workmanship manner, with the objective of attaining stability of performance and sustained accuracy over a wide range of operating conditions.

2.5.2.2 Degree of Protection

The meter shall be minimum IP53/54 compliant and shall prevent from vermin and dust ingress.

Meter electronics shall be sealed by a water, dust and vermin-resistant layer of special coating. Coating shall also give high humidity resistance performance.

2.5.3 Meter Terminal Block and Cover

All terminals shall be arranged in one terminal block and be suitable for front connections having adequate insulating properties and mechanical strength. The manner of fixing the conductors to the terminals shall ensure adequate and durable contact so that there is no risk of loosening or undue heating of the conductors or the terminals.

The terminals shall permit the connection of both solid and stranded Copper/Aluminium Conductor of cross sectional area of not less than 50sq.mm for 3ph. meters (up to 120 Amps) and 25sq.mm for 1ph. Meters (up to 100 Amps).

Terminals executions should comply with IEC standards (asymmetrical execution) and connection scheme should be clearly highlighted underneath the terminal cover.

Barriers shall be provided to prevent possible short-circuiting of the adjacent terminals of the same or different potentials under normal operating conditions.

The terminals, the conductor fixing screws or the external or internal conductors shall not be liable to come into contact with metal parts. The screw shall have a slot on the head for only flat screwdriver. Each terminal shall have at least two screws to ensure proper tightening of the conductor.

The terminals shall have a separate polycarbonate cover, which can be sealed independently of the meter cover. The cover fixing screws shall be of the captive type and shall be able to accommodate wire seals.

The sealing screws shall be strong enough to withstand all types of forces applied on these during fastening and opening. These screws shall be properly protected against harsh environmental conditions..

2.5.3.1 Sealing – Intrusion Detection

Provision shall be made and seals shall be provided for the sealing of meter electronics housing and terminal cover. Active part of the meter shall be factory sealed. It shall not be possible to remove or open the meter without irreparable damage of the seals.

Main cover and terminal cover shall be equipped with opening detectors (tamper switch)

2.5.4 Meter Communication and remote capability

2.5.4.1 Local communication

Meter configuration shall be able via optical head or the electrical output with software package to be supplied under the project. Manufacturer shall inform about security provided to prevent and track unauthorized resetting and reconfiguration of the meter.

Basic data of the meter (year of manufacture, type, serial number, total kWh cumulative counter and total kVArh cumulative counter) shall not be changeable.

Optical head / terminal shall ensure connection with HHU (Hand Held Unit) or Laptop. In this regard, the meter optical head shall have a magnetic ring on the port so that optical head can stands on it without affecting the proper operation of the meter.

2.5.4.2 Remote communication

The meters installed on the field should be able to communicate at any time on a remote basis, all stored data and therefore have a reliable and recognized open communication protocol and appropriate port for connection of communication module.

2.5.4.3 Communication flexibility

In order to ensure flexibility for future communication such as wired and /or wireless system, modular communication architecture shall be adopted (for WAN/LAN and HAN infrastructures)

2.5.5 Metering System Calibration and Testing

2.5.5.1 INITIAL CALIBRATION

All new "Main Electricity Meter" and "RRGP Electricity Meter" shall undergo relevant certification tests in accordance with Good Industry Practice and with the relevant IEC standards.

All initial calibration of "Main Electricity Meter" and "RRGP Electricity Meter" shall be performed by the meter manufacturer. DEWA will apply a "certification seal" following initial calibration.

The integrity of the "certification seal" of the "Main Electricity Meter" and "RRGP Electricity Meter" will grant the certified status. No person shall break the seal unless properly authorised by DEWA, which is responsible for ensuring that "Main Electricity Meter" and "RRGP Electricity Meter" certification is carried out for compliance with the provisions of these Standards.

"Main Electricity Meter" and "RRGP Electricity Meter" removed from service must be re-certified before reconnection for use under these Standards. It will be possible to apply a new "certification seal" to a meter only after being re-certified with a successful result.

New voltage transformers and current transformers shall be tested prior to installation on any site. The test will prove the compliance with the declared accuracy class. DEWA shall provide manufacturers' test certificates to show compliance with the accuracy classes.

In case that the testing shows non compliance with the Manufacturer's certificate, the component will be discarded. No calibration is required or possible.

2.5.5.2 COMMISSIONING

Commissioning tests shall be carried out on all new Electricity Metering Systems providing Metering Data before the connection is made live and in accordance with Good Industry Practice. Commissioning tests shall also be carried out before reconnection where a replacement Electricity Metering System is fitted as part of existing Electricity Metering System. No connection or reconnection shall be permitted unless the tests are passed.

The "Main Electricity Meter", "RRGP Electricity Meter" and "Measurement Transformers" shall be tested by DEWA for accuracy in accordance with Good Industry Practice, the Connection Guidelines and DEWA procedures for Commissioning, to be defined with the meter manufacturer.

2.5.6 Meter and Data Security and Registration

2.5.6.1 METER ACCESS AND SEALING

All Electricity Metering Systems and associated communications equipment shall be located in secure metering cabinets located in an area that is readily accessible, free from obstructions and well-lit by artificial light. The cabinets shall include, as a minimum, effective protection from moisture and dust ingress and from physical damage, including vibration. Appropriate temperature controls shall be provided. The cabinets must be lockable and capable of being sealed to prevent unauthorised access.

DEWA shall seal the "Main Electricity Meter" and "RRGP Electricity Meter" in the presence of the Producer. The meters shall include data collection and communication means and protocols according to DEWA's requirement. Only DEWA's personnel shall break such seals. The Producer shall be given at least forty-eight (48) hours' advance notice of the breaking of any seals. No such notice will be necessary when the breaking of a seal is necessitated by the occurrence of an emergency.

Neither DEWA nor the Producers shall tamper or otherwise interfere with any part of the Electricity Metering System in any way. Should be an Electricity Metering System found to have been tampered or interfered with, then one of the two following corrective actions should be taken, until such tampering or interference has been rectified:

- If a secondary metering system, not damaged, can measure and record the quantities initially measured by the tampered meter, then the measures will be considered as valid.

- If no other relevant working Metering system is available, the quantity shall be estimated by DEWA considering the records of measures registered in the previous periods.

Where the Producer requires the right of access or to deal in some other way with a Meter or Electricity Metering System for the purposes of these Standards, all such necessary rights shall be granted by DEWA. All such rights should be set down in the relevant contracts.

The right of access provided for in these Standards includes the right to bring into DEWA's property any vehicles, plant, machinery and maintenance or other materials as shall be reasonably necessary for the purposes of performance of obligations under these Standards.

DEWA and the Producer shall ensure that all reasonable arrangements and provisions are made and/or revised from time to time as and when necessary or desirable in accordance with Good Industry Practice to facilitate the safe exercise of any right of access.

2.5.6.2 METER REGISTRATION

Electricity Metering Systems shall be registered in a central database, the Meter Registration System, which is to be operated and maintained by DEWA in accordance with Good Industry Practice. The purpose of the Meter Registration System is to provide a complete, accurate and up to date central database of all Meter Data and to ensure an auditable trail to demonstrate compliance with these standards. The Meter Registration System shall contain, as a minimum, specific information at each Actual Metering Point as indicated in Appendix B.4 ("Meter registration data").

DEWA is responsible for ensuring that data relating to all changes to DEWA's Electricity Metering System, including any changes to the types of data set out in Appendix B.4 is promptly reported in writing, to the Meter Registration System.

The Meter Registration System shall maintain the specified information for a minimum of seven years after the replacement or disconnection of a Meter.

Any data held in the Meter Registration System (a) shall be the intellectual property of DEWA and (b) may be viewed, on request, by the Producer.

2.5.6.2.1 Meter Records

DEWA shall label all "Main Electricity Meter" and "RRGP Electricity Meter" with a unique "identification number". The lists of "identification numbers" must be maintained by DEWA.

DEWA shall ensure that complete and accurate records of the calibration and operation of the Electricity Metering System are maintained. These records shall include, but not be limited to the dates and results of any tests, readings, adjustments or inspection carried out and the dates on which any seal was applied or broken. The reasons for any seal being broken and the Persons, and their affiliations, attending any such tests, readings, inspections or sealing shall be recorded.

DEWA shall ensure that the pertinent data (Appendix B.4 "Meter registration data") is promptly entered into the Meter Registration System. Such data shall be kept up to date. DEWA shall also provide any other Electricity Metering System data requested by other involved parties.

2.6 Safety issues

Where the maximum PV array voltage, as calculated at the minimum outdoor temperature of 0 °C, exceeds 1,000 Vdc, the entire PV array and associated wiring and protection, shall have access restricted to competent persons only. PV arrays for installation on buildings shall not have maximum voltages greater than 1,000 Vdc. PV arrays for installation on private villas shall not have maximum voltages greater than 600 Vdc, as calculated at the minimum outdoor temperature of 0 °C.

2.6.1 Protection against electric shock and overcurrent

Protection against electric shocks

For protection against electric shock, the requirements of IEC 60364-4-41 shall apply. PV module exposed metal earthing and bonding shall be according to applicable standards. Where photovoltaic module mounting systems and devices are used for bonding module frames, the mounting system and devices shall be listed and labelled in accordance with UL2703. Photovoltaic module mounting systems and devices shall be installed in accordance with the manufacturer's installation instructions.

Protection against overcurrent

Overcurrent within a PV array can result from earth faults in array wiring or from fault currents due to short circuits in modules, in junction boxes, PV array combiner boxes or in module wiring.

PV modules are current limited sources but can be subjected to overcurrents because they can be connected in parallel and also connected to external sources. The overcurrents can be caused by the sum of currents from:

- multiple parallel adjacent strings
- some types of inverters to which they are connected and/or
- external sources.

Overcurrent protection shall be provided in accordance with applicable standards and with PV module manufacturer's requirements.

Overcurrent protection devices required for the protection of PV modules and/or wiring shall be selected to reliably and consistently operate within 2 h when an overcurrent of 135% of the nominal device current rating is applied.

PV string overcurrent protection

String overcurrent protection shall be used if:

$[(S_A - 1) \times I_{SC\_MOD}] > I_{MOD\_MAX\_OCPR}$

Where fuses are applied, these fuses need to meet the requirements as described in IEC 60269-6 (Type "gPV")".

Where string overcurrent protection is required, either (see Figure 10):

a) each PV string shall be protected with an overcurrent protection device (e.g. fuse or circuit breaker), where the nominal overcurrent protection rating of the string overcurrent protection device shall be In where:

$I_n > 1.5 \times I_{SC\_MOD}$ and
$I_n < 2.4 \times I_{SC\_MOD}$ and
$I_n \leq I_{MOD\_MAX\_OCPR}$

Or

b) strings may be grouped in parallel under the protection of one overcurrent device provided:

$I_n > 1.5 \times S_G \times I_{SC\_MOD}$ and
$I_n < I_{MOD\_MAX\_OCPR} - ((S_G - 1) \times I_{SC\_MOD})$

Where

S_G is the number of strings in a group under the protection of the one overcurrent device;
I_n is the nominal overcurrent protection rating of the group overcurrent protection device.

In some PV module technologies I_{SC_MOD} is higher than the nominal rated value during the first weeks or months of operation. This should be taken into account when establishing overcurrent protection and cable ratings.

NOTE 1: Strings can generally only be grouped under one overcurrent protection device if $I_{MOD\_MAX\_OCPR}$ is greater than $4 \times I_{SC\_MOD}$.

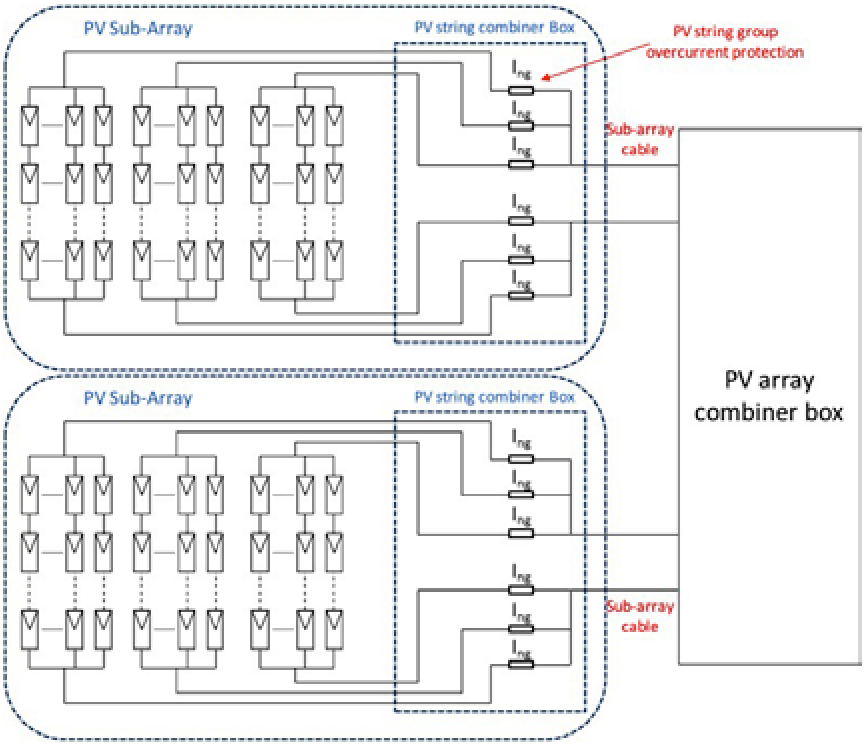


Figure 10 –Example of a PV array diagram where strings are grouped under one overcurrent protection device per group

PV sub-array overcurrent protection

The nominal rated current (I_n) of overcurrent protection devices for PV sub-arrays shall be determined with the following formula:

$I_n > 1.25 \times I_{SC\ S\text{-}ARRAY}$ and
$I_n \leq 2.4 \times I_{SC\ S\text{-}ARRAY}$

The nominal rated current (I_n) of overcurrent protection devices for PV arrays shall be determined with the following formula:

$I_n > 1.25 \times I_{SC\ ARRAY}$ and
$I_n \leq 2.4 \times I_{SC\ ARRAY}$

The 1.35 multiplier used here instead of the 1.5 multiplier used for strings is to allow designer flexibility but also taking into account of the heightened irradiance.

PV arrays with direct functional earth connections

PV arrays that have one conductor directly connected to a functional earth (i.e. not via a resistance) shall be provided with a functional earth fault interrupter which operates to interrupt earth fault current if an earth fault occurs in the PV array. This may be achieved by interruption of the functional earth of the array. The functional earth fault interrupter shall sense an earth fault, interrupt the earth fault current path and provide indication of the earth fault when the earth fault currents exceed the limits shown in Table 10. The functional earth fault interrupter equipment shall provide indication of ground faults at a readily accessible location.

The functional earth fault interrupter shall not interrupt the connection of exposed metal parts to the earth.

Table 10 – Nominal overcurrent rating of functional earth fault interrupter

Total PV array power rating kWp	Rated current A
0 – 25	≤ 1
>25 – 50	≤ 2
>50 – 100	≤ 3
>100 – 250	≤ 4
>250	≤5

2.6.2 Array insulation resistance detection

In a non-isolated inverter connected to the mains, an array earth fault will result in potentially hazardous current flow as soon as the inverter connects to the earthed circuit. In an isolated inverter, if an earth fault in a floating or functionally earthed PV array goes undetected, a subsequent earth fault can cause hazardous current to flow. The detection and indication of the original earth fault is required.

A means shall be provided to measure the insulation resistance from the PV array to earth before starting operation and at least once every 24 h. Inverters that have been tested to the IEC62109-2 standard should include insulation resistance tests as part of the inverter operation. The IEC standard limits the leakage current to 30 ma and if the leakage current is greater than the limit the inverter should not begin operation and annunciate the fault. The insulation test should occur on a daily basis prior to beginning operation for the day. IEC 62446-1 provides details on wire insulation testing that can be done during the commissioning of the system.

Inverters that will be used with PV arrays that are installed on buildings shall comply with the IEC62109 standard. Section 4.8.2 of IEC62109-2 describes the array insulation resistance testing required for both functionally grounded and ungrounded PV arrays. Earth fault protection equipment, external to the inverter shall comply with IEC 63112. IEC 63112 is applicable to earth fault protection equipment used with Photovoltaic arrays. The equipment can be either internal to the inverter or installed as an external protection device..

The action on fault required is dependent on the type of inverter in use, as follows:

- for isolated inverters, it shall indicate a fault (operation is allowed); the fault indication shall be maintained until the array insulation resistance has recovered to a value higher than the limit above;
- for non-isolated inverters, it shall indicate a fault and shall not connect to the mains; the device may continue to make the measurement, may stop indicating a fault and may allow connection to the output circuit if the array insulation resistance has recovered to a value higher than the limit.

2.6.3 Protection by residual current monitoring system

Where required, residual current monitoring shall be provided. The residual current monitoring means shall measure the total (both AC and DC components) RMS residual current.

Detection shall be provided to monitor for excessive continuous residual current, and excessive sudden changes in residual current according to the applicable standards.

2.6.4 Earth fault protection on AC side

PV systems with at least a simple separation between the DC side and AC side do not need any specific earth fault protection on the AC side.

Without at least a simple separation between DC side and AC side an RCD Class B shall be inserted downstream of the output side of the inverter. If the inverter, by construction, cannot inject DC current on the AC side also in case of fault, a RCD Class A or Class B shall be inserted downstream the output side of the inverter.

2.6.5 Protection against the effects of lightning and overvoltage

The installation of a PV array on a building often has a negligible effect on the probability of direct lightning strikes; therefore it does not necessarily imply that a lightning protection system should be installed if none is already present.

However, if the physical characteristics or prominence of the building do change significantly due to the installation of the PV array, it is recommended that the need for a lightning protection system be assessed and installed in accordance with applicable standards.

If a lightning protection system (LPS) is already installed on the building, the PV system should be integrated into the LPS as appropriate.

All DC cables should be installed so that positive and negative cables of the same string and the main array cable should be bundled together, avoiding the creation of loops in the system.

Long cables (e.g. PV main DC cables over about 50 m) should be either:

- installed in earthed metallic conduit or trunking,
- be buried in the ground (using appropriate mechanical protection),
- be cables incorporating mechanical protection which will provide a screen, or
- be protected by a surge protective device (SPD).

These measures will act to both shield the cables from inductive surges and, by increasing inductance, attenuate surge transmission. Be aware of the need to allow any water or condensation that may accumulate in the conduit or trunking to escape through properly designed and installed vents.

To protect the DC system as a whole, surge protective devices can be fitted between active conductors and between active conductors and earth at the inverter end of the DC cabling and at the array. To protect specific equipment, surge protective devices may be fitted as close as is practical to the device.

The need for surge protective devices should be assessed according to applicable standards and appropriate protective measures implemented.

Informational Note: The National Fire Protection Association Standard NFPA 780 Installation of Lightning Protection Systems Chapter 12 contains detailed prescriptive requirements for the installation of lightning protection systems for roof-mounted or ground-mounted photovoltaic arrays.

2.6.6 Emergency system of disconnection

In case of buildings for which the hazard is classified as either Ordinary or High, a manual emergency system (manual call point) for the disconnection of the PV modules from the internal electric plant of the building shall be present. Electrical disconnection may be made either on the DC side (typically when inverters are placed inside the building) or on AC side (typically when inverters are placed outside the building or in an outer cabinet or shelter). The disconnector (DC or AC) can be placed either outdoor or indoor if a fire-compartment area exists.

The manual call point is not necessary in case of One-and-Two-Family Dwelling.

The conveyance of cables from PV modules inside the building before the disconnector is allowed, provided that inside the building they are placed in a tray / trunk with a fire-rated protection of at least 30 minutes.

When required, the manual call point shall be installed at the height of 1.1 – 1.4 m above floor level and in a plain, accessible, well-lit and free from hindrance location. The manual call point shall be close to an external access in order to be easily operated by personnel or firefighters.

The manual call point shall be in accordance with NFPA 72 and a proper label shall indicate that it actuates the disconnection of the PV plant.

2.6.7 Building Integrated PV not installed in fire compartments

In case of Building Integrated PV not installed in fire compartment areas, which is in case where the BIPV is directly accessible from inside the area, it is necessary to adopt one of the following further measures:

- The manual call point also disconnects or short-circuits separately each module or groups of modules each of them having an open circuit voltage at STC not greater than 120 Vdc.
- Installation of an Arc Fault Circuit Interrupter (AFCI) to protect the DC side from series arcs. When AFCI detects a failure it disconnects the DC side of the PV plant and generates an audible signal.
- Arc Fault detection and circuit interruption is typically implemented as an internal function of inverters that are designed for use with BAPV and BIPV systems. Arc Fault detection and circuit interruption equipment is not typically implemented on inverters with a maximum DC voltage of 1500Vdc.
- When installed with external rapid shut down equipment, the designer and installer should verify that the equipment has been tested and listed as being compatible as some external rapid shutdown equipment can interfere with arc fault detection.

2.6.8 Equipment marking

All electrical equipment shall be marked according to the requirements for marking in IEC or to local standards and regulations when applicable. Markings should be in Arabic & English or use appropriate local warning symbols.

2.6.9 System labelling and warning signs

2.6.9.1 Requirements for signs

All signs shall:

a) comply with British Standards (BS 5499 and other related standards) and with applicable International Standards
b) be indelible;
c) be legible from at least 0.8 m unless otherwise specified in the relevant clauses;
d) be constructed and affixed to remain legible for the life of the equipment it is attached or related to;
e) be understandable by the operators;
f) be in Arabic and English.

2.6.9.2 Identification of a PV installation

For reasons of safety of the various operators (maintenance, personnel, inspectors, public distribution DEWA, emergency aid services, etc.), it is essential to indicate the presence of a photovoltaic installation on a building.

Moreover, due to the presence of multiple supplies, as typical for a PV plant, a warning notice must also be affixed along with the above mentioned sign.

1. A switchboard sign such as shown in figure 2.6.7.2 shall be fixed:

  - at the origin of the electrical installation,
  - at the metering position, if remote from the origin,
  - at the consumer unit or distribution board to which the supply from the inverter is connected,
  - at all points of isolation of all sources of supply

	Example of switchboard sign for identification of PV on a building. Notice: the sign is generic and in case of ground mounted PV systems it shall be adapted accordingly.
	Example of switchboard sign for identification of multiple supplies (On-Site Guide BS 7671:2008 (2011)

2.6.9.3 Labelling of PV array and PV string combiner boxes

A sign as shown in figure 2.6.7.3 shall be attached to PV array and PV string combiner boxes as well as labels indicating “live during daylight” to d.c. combiner boxes and switches.

	Example of sign required on PV array combiner boxes (On-Site Guide BS 7671:2008 (2011)

2.6.9.4 Labelling of disconnection devices

Disconnection devices shall be marked with an identification name or number according to the PV array wiring diagram.

All switches shall have the ON and OFF positions clearly indicated.

The PV array d.c. switch disconnector shall be identified by a sign affixed in a prominent location adjacent to the switch disconnector. Where multiple disconnection devices are used that are not ganged, signage shall be provided warning of multiple d.c. sources and the need to turn off all switch disconnectors to safely isolate equipment.

2.6.10 Informational Notes

- PV Rapid shutdown (PVRS) has been implemented in the United States as a method to de-energize the DC conductors of a BAPV or BIPV system to reduce the electric shock hazards for fire fighters that have to fight fires on a building with PV Arrays. PV Rapid shutdown systems are installed on buildings and are not required for ground mounted PV systems.

  The main function of a PV Rapid Shutdown system as defined in section 690.12 of the US National Electrical Code (NFPA 70) and evaluated by UL1741 is to minimize PV system shock hazards by limiting the voltage within the PV array, limiting the distance energized DC conductors can extend beyond the array boundary and indicating that the rapid shutdown system has been initiated.

  The UL3741 PV Hazard control standard provides a method to evaluate Photovoltaic hazard control components, equipment, and systems to reduce shock hazards for fire fighters that fight fires on buildings with PV systems. While most PV Hazard Control Systems (PVHCS) will include PV Rapid Shutdown equipment or system, they will also include other passive protection means to reduce fire fighter shock hazards. PVHCS are subjected to risk assessments that analyze the array shock hazards to Fire fighters (performing specific defined fire fighter interactions with the PV array) when combined with common PV array failure modes like ground faults.

  Installers opting to incorporate Rapid shutdown equipment into a BAPV or BIPV system should require the overall array, including PV system equipment to be evaluated, tested and certified to appropriate safety standards including UL3741 and UL1741. It is also important that all of the individual components have been evaluated to operate properly as a system since some combinations of listed equipment may not be compatible and can compromise PV ground fault and PV arc fault protection functionality within the inverters used with the PV system. Most micro inverters and DC optimizers have been evaluated to typically comply with rapid shutdown requirements, but additional evaluation of DC optimizers is necessary to verify proper operation with specific inverters.

- Labeling of PV system components is important for the safety of system owners, first responders and electricians. Examples of additional labeling requirements can be found in Part IV of Article 690 of the U.S. National Electrical Code.

2.7 Compliance

2.7.1 General provisions

1. Responsibility of the Producer:

   a) The Producer shall ensure that the RRGUs and the RRGP are compliant with these Standards. This compliance shall be maintained throughout the lifetime of the facility.

2. Rights of DEWA:

   a) DEWA shall have the right to request that the Producer carries out compliance tests and simulations not only during the operational notification procedure, but repeatedly throughout the lifetime of the RRGP and more specifically after any failure, modification or replacement of any equipment that may have impact on the RRGUs compliance with these Standards.
   b) DEWA shall have the right to request that the Producer submits recordings from available measurements, covering the period for which such data is available.

3. When DEWA's participation is needed to perform tests, DEWA will provide the Producer with an offer for the cost of the tests.

2.7.2 Compliance Testing

Compliance testing is defined according to the actual power of the plant being connected to the grid. The tests described can be referred to the whole RRGP or to each single RRGU's equipment (inverter) depending on the actual design of the plant.

2.7.2.1 General Rules for Compliance Testing

1. The proof of compliance of the RRGPs with these Standards requires the successful completion of several tests. These tests are divided into three categories:

   a) Laboratory testing:

      i. These tests are required for all RRGUs as part of RRGPs, with the rules and criteria set in Appendix D3 and D4 of these Standards.
      ii. DEWA is entitled to provide a description of the tests and the criteria of fulfilment. Alternatively, and upon DEWA's approval, the laboratory may provide DEWA with the list of tests and fulfilment criteria for approval and validation.
      iii. These tests are to be performed by laboratories on request of a manufacturer. These laboratories have to be accredited EA or ILAC according to the standard ISO/IEC 17025, with an accreditation valid also for the tests required in this document. If the tests are successful, a Manufacturer's Data and Performance Type Certificate (MD&PTC) of compliance with DEWA standards shall be provided by the manufacturer to DEWA, for the tested equipment to be included among the accepted ones on the website. An applicant will be entitled to propose to DEWA some equipment which is not in the list of the eligible one, provided a certificate of testing is submitted at the Design Approval stage. The manufacturer will then be required to support the applicant for the retrieval of the needed documentation.
      iv. These tests are required to certify that the equipment, meant to be sold in large quantities to DEWA grid users, is compliant with these Standards.

b) Simulations and field testing:

i. For Renewable Resource Generating Plants having Maximum Capacity above 400 kW, DEWA is entitled to require the Producer to provide simulation models, that properly reflect the behaviour of the RRGUs in both steady-state and dynamic simulations (50 Hz component). The models shall be verified against the results of laboratory compliance tests. The main purpose of the simulations is to control that a RRGP made of different RRGUs in compliance with these Standards, is still compliant with these Standards, taking into account the particular design of the plant and its location in the grid. In any case, DEWA may grant the permission to use MD&PTC of the single RRGU instead of part or all of the simulations and field tests.

ii. DEWA is entitled to provide a description of the tests and the criteria of fulfilment, unless otherwise agreed between DEWA and the grid user.

iii. These tests are to be performed by the Producer (or a third party on behalf of the Producer), unless otherwise agreed between DEWA and the grid user.

2. The Producer is advised to check with DEWA at an early stage of a project what parts, if any, are acceptable in lieu of the full compliance process and how to proceed to make use of this facility.

2.7.2.2 Required Tests for Compliance

1. The list of the required tests used to prove to DEWA compliance of the Generating Units with these Standards is provided in Appendix D: compliance tests.

2. The Producer shall also refer to what specified in the Connection Guidelines.

3. Voltage disturbance tests will be conducted after the Renewable Resource Generating Plant is connected to the DEWA network but prior to receiving permission to operate in order to determine the impact of voltage disturbances on the DEWA grid.

2.7.3 Compliance Monitoring

1. Data from the monitoring and measurement devices, as required by these Standards, shall be made available by the Producer upon request from DEWA for the sole use of Compliance monitoring.

2. The term Compliance monitoring shall include verification of the continuous compliance of the Renewable Resource Generating Units and Plants with both the requirements that were tested in the process of Compliance Testing and the requirements that were not tested in the process of Compliance Testing.

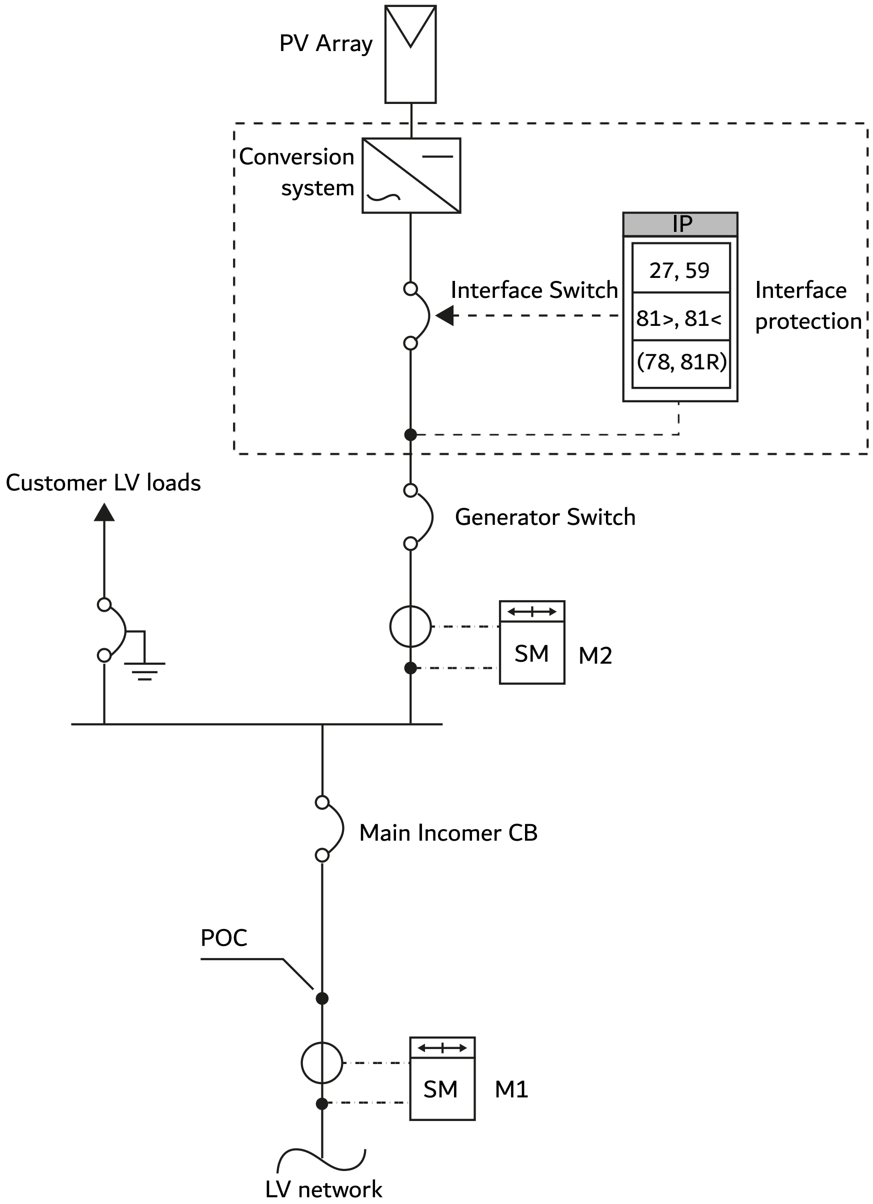
APPENDIX A: CONNECTION SCHEMES

A.0 - General provisions

The connection schemes for the different situations are represented hereinafter, with the following meaning of the symbols adopted:

LEGEND	
	CIRCUIT BREAKER (CB)
	SWITCH DISCONNECTOR WITH FUSES
	EARTH LEAKAGE CIRCUIT BREAKER (CB)
	CURRENT TRANSFORMER (CT)
	TOROIDAL CURRENT TRANSFORMER
	VOLTAGE TRANSFORMER (VT)
	LOAD
	POWER CONVERSION SYSTEM
	PHOTOVOLTAIC ARRAY
	TRANSFORMER
SM	BIDIRECTIONAL ENERGY METER (4 QUADRANTS) - SMART METER
M1	MAIN ELECTRICITY METER: INJECTION TO / CONSUMPTION FROM DISTRIBUTION NETWORK
M2	RRGP ELECTRICITY METER: PRODUCED PV ENERGY

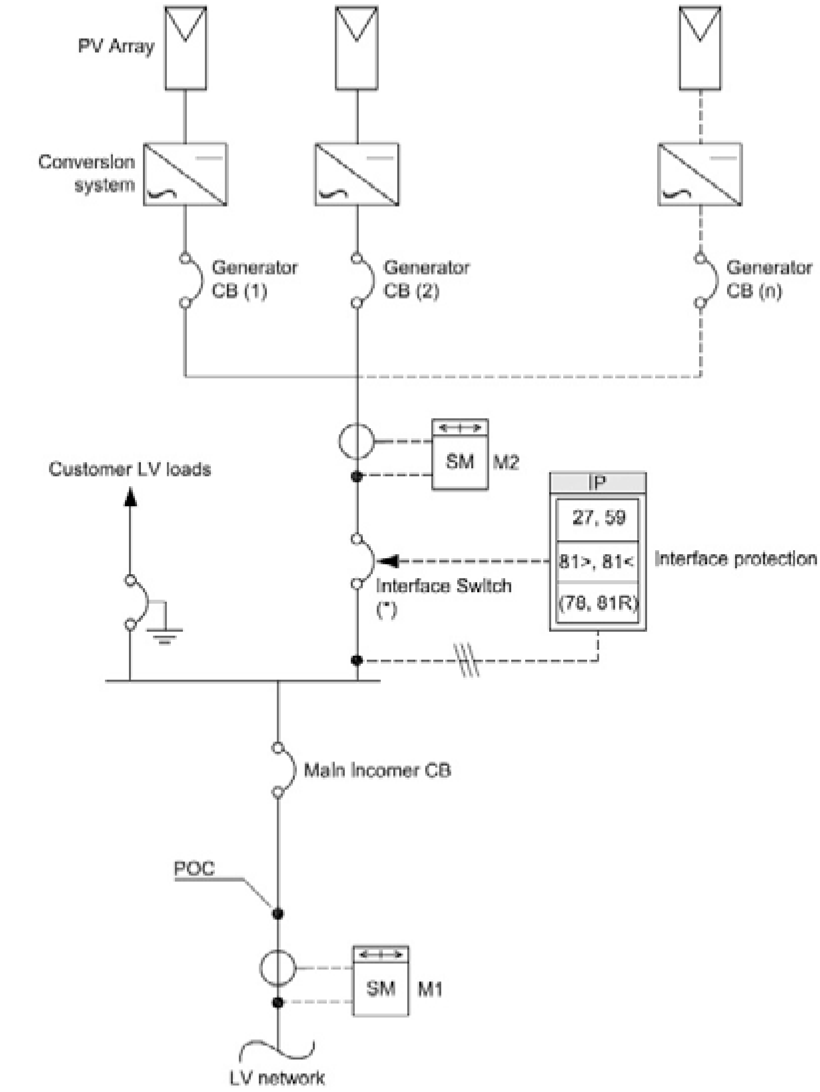
A.1 - LV1 Connection Scheme - One inverter P_{MC} < = 150 kW (Interface Protection embedded in the inverter)



Note:

- Interface protection embedded in the inverter;
- Interface and switches embedded in the inverter

A.2 - LV3 Connection Scheme - Multiple inverter (10 kW ≤ P_{MC} ≤ 20 kW)

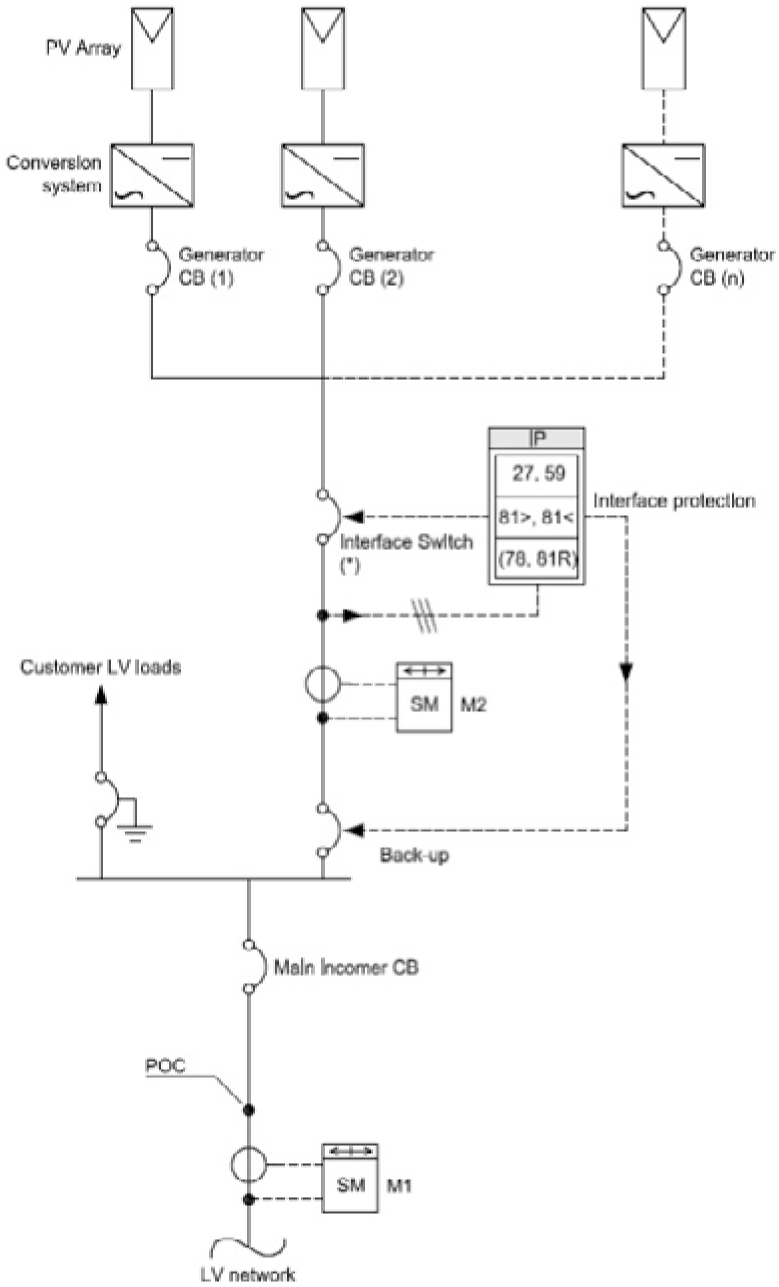


(*) Motorized CB operated by undervoltage release or Contactor

Note:

- Interface switch separated from Generator switch.

A.3 - LV4 Connection Scheme - Multiple inverter (P_{MC} >20 kW)

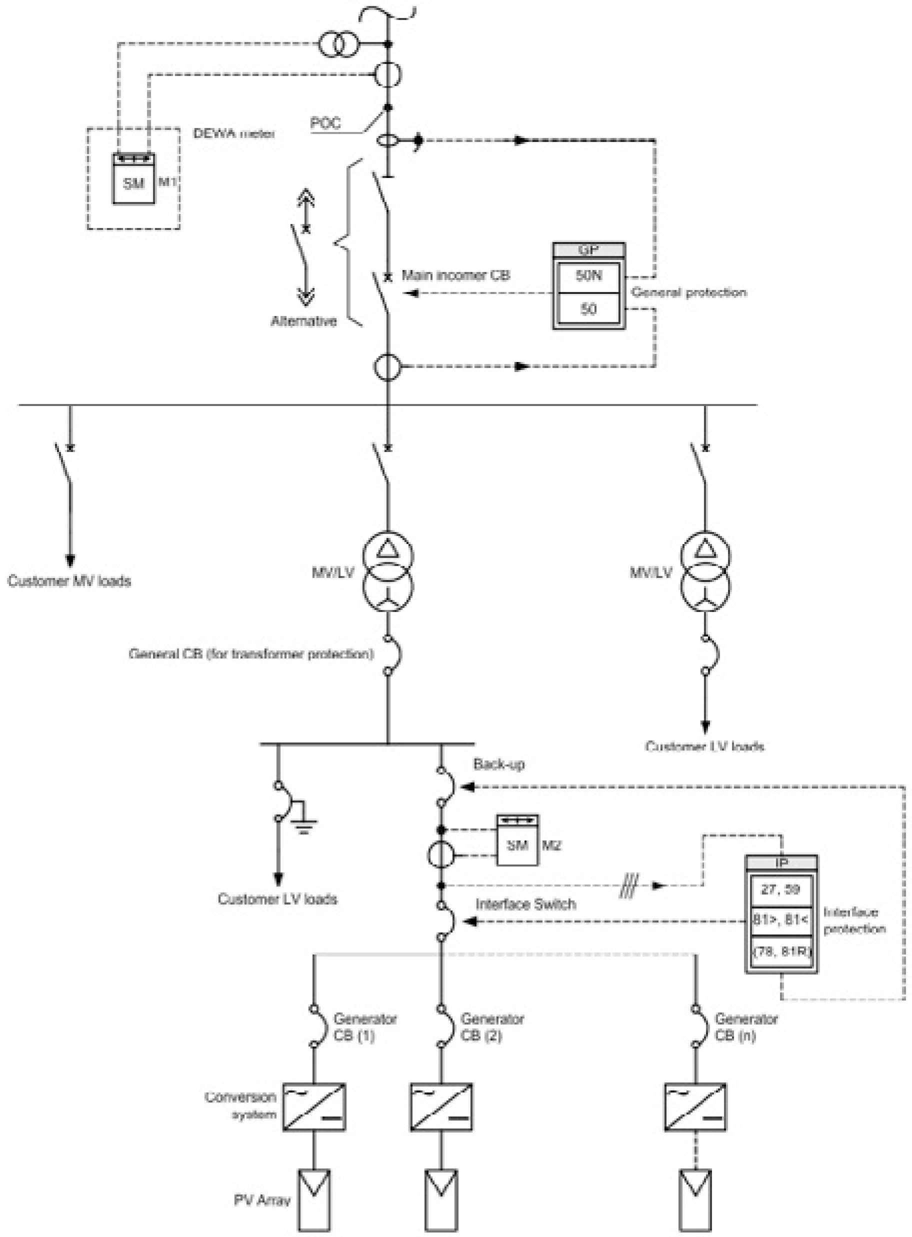


(*) Motorized CB operated by undervoltage release or Contactor

Note:

- General switch separated from Interface switch where the former acts as a back-up of the latter; and
- Interface switch separated from Generator switch.

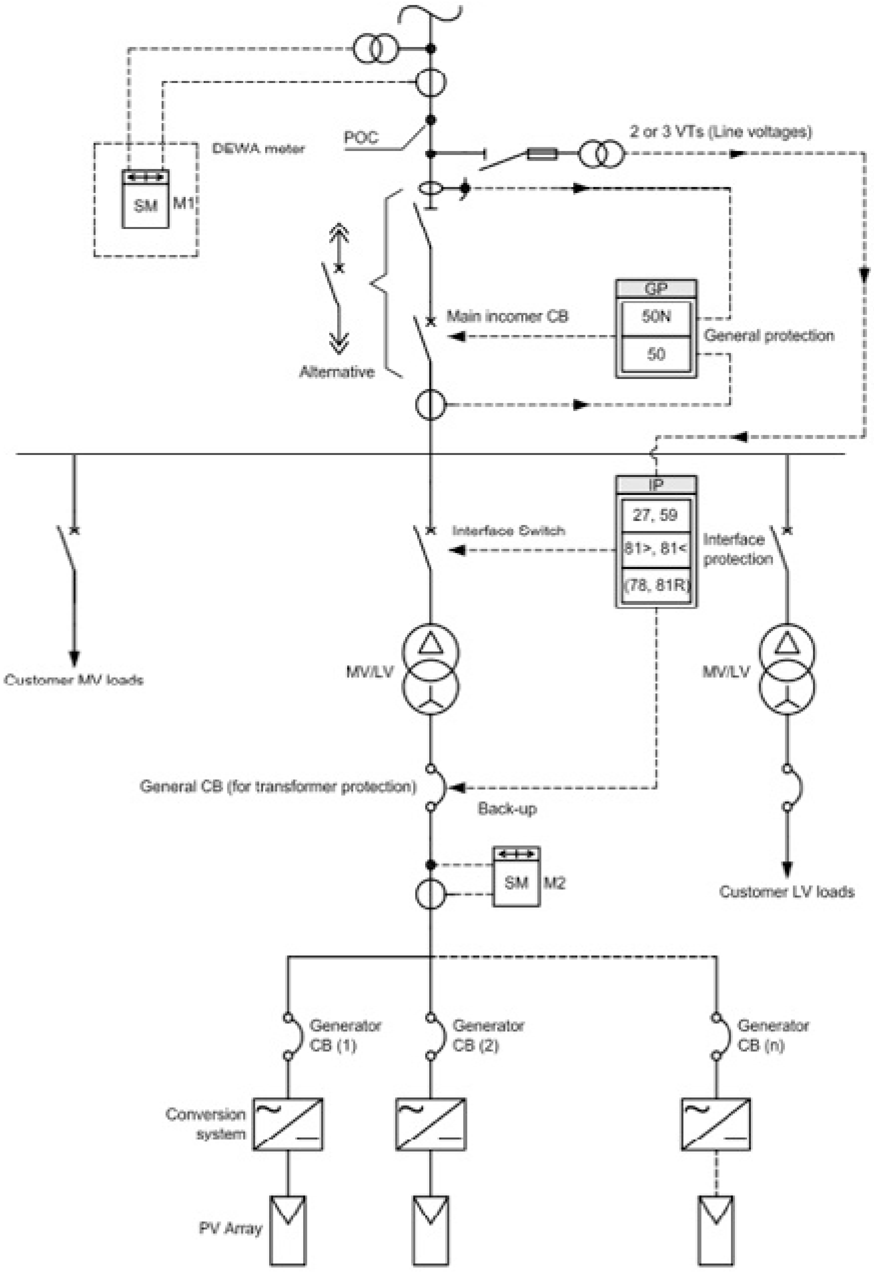
A.4 - MV1 Connection Scheme - Interface Switch on LV side



Note:

- Interface protection and Generator switches on LV side;
- Interface switch separated from Generator switch; and
- The number of transformers represented is entirely indicative.

A.5 - MV2 Connection Scheme - Interface Switch on MV side



Note:

- Interface protection and switch on MV side;
- Back-up on the LV General CB (if no loads are derived at the LV side and PV plant connected via a dedicated transformer); and
- The number of transformers represented is entirely indicative.

APPENDIX B: ELECTRICITY METERING SYSTEM

B.1 - Accuracy of the Electricity Metering System

B.1.1 - Standards

The following standards are applicable for metering systems:

- IEC 62052-11 - Electricity metering equipment (a.c.) - General requirements, tests and test conditions - Part 11: Metering equipment
- IEC 62053-11 - Electricity metering equipment (a.c.) - Particular requirements - Part 11: Electromechanical meters for active energy (classes 0,5, 1 and 2)
- IEC 62053-21 - Electricity metering equipment (a.c.) - Particular requirements - Part 21: Static meters for active energy (classes 1 and 2)
- IEC 62053-22 - Electricity metering equipment (a.c.) - Particular requirements - Part 22: Static meters for active energy (classes 0,2 S and 0,5 S)
- IEC 62053-23 - Electricity metering equipment (a.c.) - Particular requirements - Part 23: Static meters for reactive energy (classes 2 and 3)
- IEC 62054 - Electricity Metering equipment (AC) Tariff and Load Control.
- IEC 62055 - Electricity Metering. Payments Systems.
- IEC 62056 - Electricity Metering. Data exchange for meter reading, tariff and load control.
- IEC 62058 - Electricity Metering equipment (AC), Acceptance Inspection.
- IEC 62068 - Electrical Insulation Systems.
- IEC 60410 - Sampling plans and procedures for inspection by attributes.
- IEC 60529 - Degree of protection provided by enclosures (IP Code)
- IEC 61000 - Electromagnetic compatibility (EMC).
- IEC 61334 - Distribute automation using distribution line carrier systems.
- IEC TR62059-11 - Electricity Metering equipment. Dependability. General concepts.
- IEC 62059-41 - Electricity Metering equipment. Dependability. Reliability prediction.
- IEC 60044-1 - Instrument transformers - Current transformers
- IEC 60044-2 - Instrument transformers - Voltage transformers
- IEC 60044-3 - Instrument transformers - Combined transformers
- IEC 60044-7 - Instrument transformers - Electronic voltage transformers
- IEC 60044-8 - Instrument transformers - Electronic current transformers
- IEC 61107 - Data exchange for meter reading - direct local data exchange.
- The metering system shall withstand harmonic distortion as provided in EN 50160.

All electricity Metering Systems and electricity Meters shall comply with the relevant standards current at the time that the contract is signed.

B.1.2 - Overall Accuracy Requirements

For the measurement and Metering of Active Energy, Reactive Energy, Active Power, Metering System shall be tested to operate within the overall limits of error set out in Table B-1 after taking into account the CT and VT errors and the resistance of cabling or circuit protection. Testing equipment shall be traceable to a recognised national or international standard.

Table B-1 – Overall Accuracy of an Electricity Metering System.

Condition	Limits of Error at Stated Power Factor for Active Power and Energy Measurement	
Current expressed as a Percentage of Rated Measuring Current	Power Factor	Limits of Error for Connections
120% to 10% inclusive	1	± 0.5%
Below 10% to 5%	1	± 0.7%
Below 5% to 1%	1	± 1.5%
120% to 10% inclusive	0.5 lag	± 1.0%
120% to 10% inclusive	0.8 lead	± 1.0%

Condition	Limits of Error at Stated Power Factor for Reactive Power and Energy Measurement	
Current expressed as a Percentage of Rated Measuring Current	Power Factor	Limits of Error for Connections
120% to 10% inclusive	0	± 4.0%
120% to 20% inclusive	0.866 lag	± 5.0%
120% to 20% inclusive	0.866 lead	± 5.0%

B.1.3 - Electricity Meters

General Service Conditions

All materials and equipment shall be designed in accordance with IEC standards for use under the service condition prevailing at the site. The service conditions shall be considered as minimum design values.

Meters shall operate without loss of accuracy or life duration under the following conditions:

Table B-2 – Accuracy of Meters.

Condition	
Reference Voltage	3 x 230 / 400 Volts
Reference Frequency	50 Hz
Voltage Tolerance at 400 Volts	-20% + 15%
Temperature-specified operating Range	70° C
Relative Humidity	100%
Transport & Storage Temperature range	85° C
Relative Humidity	100%

Environmental Conditions

All equipment shall be suitable for operation under the following conditions, as a minimum.

Table B-3 – Environmental conditions.

Condition	
Ambient Temperature	65° C
Max. mean over 24 Hours	55° C
Mean of temperature in the year	40° C
Minimum temperature	0° C

Atmospheric conditions: humid, corrosive, sandy, heavy condensation, air blown salinity and sandstorms also prevail.

Directly Connected Meters ratings

The directly connected meters shall be compliant at least with the following ratings:

Table B-4 – Ratings for Directly Connected Meters.

Standard ratings	
Basic Current (Ib)	10/20 Amps
Max. Current (Imax)	100/120 Amps
Ref.voltage (Uref)	3x230/400V
Ref.frequency	50Hz
Starting Current	0.4% Ib (IEC 62053-21)
PF voltage withstand (1min)	4 kV
Impulse voltage withstand	8 kV
Accuracy Class Active	Class-1 (IEC 62053-21) (Reactive Class-2)

LV CT Operated Electricity Meters ratings

The LV CT operated electricity meters shall be compliant at least with the following ratings:

Table B-5 – Ratings for CT operated meters – LV application.

Standard ratings	
Rated Current	5 Amps
Ref.voltage (Uref)	3x230/400V
Ref.frequency	50Hz
Starting Current	0.4% Ib (IEC 62053-21)
PF voltage withstand (1min)	4 kV
Impulse voltage withstand	8 kV
Accuracy Class Active	Class 0.5 (according to IEC 62053-21) (Reactive Class-1)

HV CT/VT Operated Electricity Meters ratings

The HV CT/VT operated electricity meters shall be compliant at least with the following ratings:

Table B-6 – Ratings for CT/VT operated meters – HV application.

Standard ratings	
Rated Current	0-10 Amps (Programmable)
Ref. voltage (Uref)	Auto range 58 to 400V
Ref. frequency	50Hz
Starting Current	0.4% Ib (IEC 62053-21)
PF voltage withstand (1min)	4 kV
Impulse voltage withstand	8 kV
Accuracy Class Active	Class 0.2 (according to IEC 62053-21) (Reactive Class-0.5)

B.1.4 - Metering System Accuracy Class

The accuracy class or equivalent shall as a minimum be as given in the following tables depending on the maximum capacity of the Generating Unit:

Table B-7: Equipment Accuracy Classes for RRGPs with Maximum Capacity P_{MC} > 400 kW

Equipment type	Equipment Class	Accuracy
Current Transformers	0.2S	
Voltage Transformers	0.2	
Active Energy and Power Meters	0.2S	
Reactive Energy and Power Meters	2	

Table B-8: Equipment Accuracy Classes for RRGPs with Maximum Capacity P_{MC} ≤ 400 kW

Equipment type	Equipment Class	Accuracy
Current Transformers (if applicable)	1.0S	
Voltage Transformers (if applicable)	1.0	
Active Energy and Power Meters	1.0S	
Reactive Energy and Power Meters	≥ 2	

B.2 - Labelling of meters

B.2.1 - General

Each Meter shall be allocated a unique Meter identification number that will be given by DEWA and recorded in the Meter Registration System.

The number shall be marked permanently on the Meter in a clearly visible position under all normal viewing of the Meter. The marking shall resist to harsh environmental conditions and prolonged exposition to sun and UV.

The number shall be quoted on all records arising from and related to the Meter including Meter readings.

Test blocks and other related Metering equipment should be clearly identified with the Metering System with which they are associated.

B.2.2 - Name Plate

Each meter shall bear the following information on the nameplate:

a) Manufacturers name, year & country of manufacture.
b) Designation of type
c) Serial number & barcode
d) Number of phase, number of wires for which the meter is suitable
e) Reference voltage (i.e. 3x230/400V for 3ph. meter and 230V for 1ph. Meter)
f) Operating temperature range
g) Nominal current & rated maximum current i.e. 10/ 20(100/120) Amps
h) Accuracy class: class 1 (IEC62053)
i) Standard frequency: 50Hz
j) LED meter pulse constant (impulse / kWh, impulse / kVARh), (impulse / MWh, impulse / MVARh)
k) Communication data, if applicable
l) Connection diagram
m) Additional window / suitable provision shall be made available for indicating the CT and VT Ratio with sealing facility, for CT operated meters.

B.2.3 - Entry and Exit Labelling

The following standard method of labelling meters, test blocks, etc.; based on the definitions for entry and exit shall be incorporated. The required labelling shall be as follows.

Active Energy

Meters or Meter Registers shall be labelled

"Entry" for all Active Energy flows normally entering the Transmission and Distribution System, and
"Exit" for all Active Energy flows normally leaving or exiting the Transmission and Distribution System,

Reactive Energy

Within the context of these Standards the relationship between Active Energy and Reactive Energy can be best established by means of the power factor.

Meters or Meter Registers for registering entry Reactive Energy should be labelled "Entry" and those for registering exit Reactive Energy should be labelled "Exit".

B.3 - Commissioning tests for meters

This Appendix sets out the tests and checks that shall be included in the Metering Systems commissioning programme. Metering System shall in addition have basic tests carried out on earthing, insulation, together with all other tests that would normally be conducted in accordance with Good Industry Practice.

B.3.1 - Measurement Transformers

For all installations with new/replaced Measurement Transformers DEWA shall ensure that the following information is collected, confirmed and recorded from site tests and inspections:

1. Details of the installed units, including serial numbers, rating, accuracy classes, ratio(s);
2. CT ratio and polarity for selected tap; and
3. VT ratio and phasing for each winding.

For installations with existing Measurement Transformers the Meter Owner shall ensure that, wherever practically possible, the above mentioned points 1, 2 and 3 are implemented; as a minimum requirement at least the VT and CT ratios must be confirmed and recorded, when no other information can be collected. If it is not possible to confirm the CT ratio on site, the reason must be recorded on the commissioning record and details must be obtained from any relevant Person. The installation must be suspended and a new CT, VT transformer must replace the existing if the above information cannot be collected.

B.3.2 - Measurement Transformer Leads and Burdens

For all installations the Meter Owner shall:

1. Confirm that the VT and CT connections are correct;
2. Confirm that the VT and CT burden ratings are not exceeded; and
3. Determine and record the value of any burdens (including any burdens not associated with Metering Systems or Meters) necessary to provide evidence of the overall metering accuracy.

B.3.3 - Metering

General tests and checks

1. The following may be performed on-site or elsewhere (e.g. factory, meter test station, laboratory, etc.):
2. Record the Metering System details required by the Meter Registration System;
3. Confirm that the VT/CT ratios applied to the Meter(s) are compliant with the site Measurement Transformer ratios;
4. Confirm correct operation of Meter test terminal blocks where these are fitted (e.g. CT/VT operated metering);
5. Check that all cablings and wirings of the new or modified installation are correct;
6. Check and confirm that Meter registers correctly increase their values in accordance with consumption for entry and, where appropriate, exit flow directions ; if the meter is required to generate the output pulses to be linked to separate Outstations, the output pulse must also be checked.. Confirm Meter operation separately for each phase current and for normal poly-phase current operation;
7. Where separate Outstations are used, confirm the Meter to Outstation channel allocations and that the Meter units per pulse values or equivalent data are correct; and
8. Confirm that the local interrogation facility (Meter or Outstation) and local display etc... operate correctly.

Site Tests

The following tests shall be performed on site:

1. Check any site cabling, wiring, connections not previously checked under B.1, B.2 and B.3.1 above;
2. Confirm that Meter/Outstation is set to UTC (Dubai time) within +/- 5 seconds;
3. Check that the voltage and the phase rotation of the measurement supply at the Meter terminals are correct;
4. Record Meter starts readings (including date and time of readings);
5. Wherever practically possible, a primary prevailing load test (or where necessary a Primary injection test) shall be performed which confirms that the Meter(s) is registering the correct primary energy values and that the overall installation and operation of the metering installation are correct;
6. When for practical or safety reasons is not possible to perform the tests in (5), then the reason shall be recorded on the commissioning record and a secondary prevailing load or injection test shall be performed to confirm that the Meter registration is correct, including where applicable, any Meter VT/CT ratios. In such cases the VT/ CT ratios shall have been determined separately as detailed under B.3.1: Measurement Transformers, above;
7. Record values of the Meter(s)/Outstation(s) displayed or stored Metering Data (at a minimum one complete half-hour value with the associated date and time of the reading) on the commissioning record;
8. Confirm the operation of Metering System alarms (not data alarm or flags in the transmitted data); and
9. Confirm from the Meter owner that accuracy certificates exist for the Meters

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B.4 - Meter Registration Data

The Meter Registration System forms the Metering database and holds Metering Data relating to Metering.

Data in the Meter Register shall be treated as confidential and only relevant Metering Data should be released to the Producer.

Metering Data to be contained in the Meter Register should include, but is not limited to the following:

- A unique meter identification number;
- Connection and the Actual Metering Point data, including:
  - location and reference details (i.e. drawing numbers)
  - participant details at the Electrical Delivery Point
  - site identification nomenclature
  - meter owner
- Meter installation details, including;
  - serial numbers
  - metering installation identification name
  - meter types and models
  - instrument transformer ratios (available and connected)
  - test and calibration programme details: test results and reference test certificates for Meters and Measurement Transformers
  - asset management plan and testing schedule
  - calibration tables, where applied to achieve Meter installation accuracy
- any Meter summation scheme values and multipliers;
- data register coding details;
- Data communication details (when communication systems are used);
- telephone number for access to data;
- communication equipment type and serial numbers;
- communication protocol details or references;
- data conversion details; and
- Producer identifications and access rights.

APPENDIX C: LIST OF STANDARDS FOR EQUIPMENT

C.1 - Preliminary considerations

The main standards to be used as a reference in the development of PV applications are summarized hereinafter. For each standard a short comment and its importance from a 3-level scale are added.

The meaning of the “stars” is the following:

★ Useful document
★★ Important document
★★★ Fundamental document

C.2 - A - PV modules (building-applied or ground mounted)

Reference	Title	Importance	Application
IEC 61215-1*	Terrestrial photovoltaic (PV) modules – Design qualification and type approval – Part 1: Test requirements*	★★★	Requirements for testing all PV modules.
IEC 61215-1-1*	Terrestrial photovoltaic (PV) modules – Design qualification and type approval – Part 1-1: Special requirements for testing of crystalline silicon photovoltaic (PV) modules *	★★★	Special requirements for testing of silicon crystalline PV modules
IEC 61215-1-2*	Terrestrial photovoltaic (PV) modules – Design qualification and type approval – Part 1-2: Special requirements for testing of thin-film cadmium telluride (CdTe) based photovoltaic (PV) modules*	★★★	Special requirements for testing of cadmium telluride (CdTe) PV modules
IEC 61215-1-3*	Terrestrial photovoltaic (PV) modules – Design qualification and type approval – Part 1-3: Spe-cial requirements for testing of thin-film amor-phous silicon based photovoltaic (PV) modules*	★★★	Special requirements for testing of thin-film amorphous silicon PV modules
IEC 61215-1-4*	Terrestrial photovoltaic (PV) modules – Design qualification and type approval – Part 1-4: Spe-cial requirements for testing of thin-film Cu(In,GA)(S,Se)2 based photovoltaic (PV) modules*	★★★	Special requirements for testing of thin-film Cu(In,GA)(S,Se)2 PV mod-ules
IEC 61215-2**	Terrestrial photovoltaic (PV) modules – Design qualification and type approval – Part 2: Test procedures*	★★★	All PV modules, test procedures
IEC 61853-1	Photovoltaic (PV) module performance testing and energy rating - Part 1: Irradiance and temperature performance measurements and power rating	★	Measurement of the outdoor performance of PV modules (stables)
IEC 61730-1**	Photovoltaic (PV) module safety qualification - Part 1: Requirements for construction**	★★★	All PV modules, especially those installed on buildings, construction

* Level 1 temperature rating required for “close roof mount” and Level 2 temperature rating for “insulated mount” (direct mount) as defined in IEC TS 63126

IEC 61730-2** including Annex B.3	Photovoltaic (PV) module safety qualification - Part 2: Requirements for testing**	★★★	All PV modules, especially those installed on buildings, testing. Annex B.3 is required for PV module fire type classification.
IEC TS 62915	Photovoltaic (PV) modules – Type approval, design and safety qualification – Retesting	★★★	Requirements for retesting for design changes to PV modules previously certified to the IEC 61215 and 61730 series.
UL 62915	Photovoltaic (PV) modules – Type approval, de-sign and safety qualification – Retesting	★★	Requirements for retesting for design changes to PV modules previously certified to the UL 61215 and 61730 series. Expected to be published in early 2022, and will contain retest requirements for fire testing, which is not covered by IEC 62915.
IEC TS 63126	Guidelines for qualifying PV modules, components and materials for operation at high temperatures	★★	New test procedures for PV modules installed with no air flow (Level 2 in the Dubai climate) or with 76 to 102 mm spacing behind the PV module (Level 1 in the Dubai climate). As this is a new document and currently not a requirement in the module performance and safety standards, it is classified as an "important" document. See the table below for future considerations.
IEC 63209-1	Extended-stress testing of photovoltaic modules – Part 1: Modules	★★	Extended duration stress tests for PV modules.
UL 61730-1	Photovoltaic (PV) module safety qualification - Part 1: Requirements for construction	★	All PV modules installed in the U.S.; includes fire testing requirements
UL 61730-2	Photovoltaic (PV) module safety qualification - Part 2: Requirements for testing	★	All PV modules installed in the U.S.; includes fire testing procedures
IEC 61701	Salt mist corrosion testing of photovoltaic (PV) modules	★★★	Not required for locations ≥10 km from saltwater; qualification to severity level C3 required for locations 2-10km from saltwater and to level C4 if ≤ 2 from saltwater
IEC 62716	Photovoltaic (PV) modules - Ammonia corrosion testing	★★	Tests on PV modules used in environments with a high degree of ammonia
IEC 61853-1	Photovoltaic (PV) module performance testing and energy rating - Part 1: Irradiance and temperature performance measurements and power rating	★	Measurement of the outdoor performance of PV modules (stables)
EN 50380	Datasheet and nameplate information for photovoltaic modules	★★	Documentation for PV modules

** Certifications to the third edition of IEC 61730-1/2 (expected publication date October, 2022) shall have a temperature rating of Level 1 for "close roof mount" and Level 2 rating for "insulated mount" as defined in IEC TS 63126.

IEC 62790	Junction boxes for photovoltaic modules	★★	Prescriptions on the construction and testing requirements of junction boxes. Compliance with this standard is a requirement for modules certified to the IEC 61215 and 61730 series.
IEC 62852	Connectors for photovoltaic modules	★★	Prescriptions on the construction and testing of PV connectors. Compliance with this standard is a requirement for modules certified to the IEC 61215 and 61730 series.
IEC 62109-3	Safety of power converters for use in photovoltaic power systems - Part 3: Particular requirements	★★★	Test procedures for PV modules with integrated electronics, such as AC modules. The temperature test (MST 21) of IEC 61730-2:2016 or the guidance in IEC TS 63126 should be followed in combination with IEC 62109-3 to assess the temperature ratings of the module and integrated electronics.
UL 1741	Requirements for modules with integrated electronics		Test procedures for PV modules with integrated electronics, such as AC modules. The temperature test (MST 21) of IEC 61730-2:2016 or the guidance in IEC TS 63126 should be followed to assess the temperature ratings of the module and integrated electronics.
IEC 60068- 2-68	Environmental testing - Part 2-68: Tests - Test L: Dust and sand	★★	Environmental test applied to PV modules installed in desert climates.

Notes on future PV module standards:

IEC TS 63342	Test procedures for the assessment of PV module susceptibility to light and elevated temperature degradation (LETID)	TBD	To reduce performance risks due to LeTID.
IEC 62788-7-3	Dust and abrasion resistance of PV modules	TBD	Dust and abrasion resistance that is specific to PV modules, expected to be published in May, 2022. Upon publication, IEC 62788-7-3 can replace IEC 60068-2-68.

C.2 B - BIPV modules (building-integrated systems)

Reference	Title	Importance	Application
IEC 63092-1*	Requirements for BIPV Modules (Part 1) *	★★★	Requirements for testing BIPV modules (compliance required at the BIPV module level).
IEC 63092-2*	Requirements for BIPV Systems (Part 2)	★★	Requirements for BIPV systems (compliance assessed at the system level)
UL 790	Requirements for BIPV Modules (Part 1) and Systems (Part 2)**	★★★	Requirements for fire testing of BIPV modules used in roofing applications.
UL 7103	Outline for Investigation for Building-Integrated Photovoltaic Roof Coverings	★★	Requirements for BIPV roofing systems, including fire testing; wind uplift testing; adhesive test requirements; resistance to water penetration; and a point load test (unintentional human load).
UL 2703	Mounting Systems, Mounting Devices, Clamping/ Retention Devices, and Ground Lugs for Use with Flat-Plate Photovoltaic Modules and Panels	★★	Testing and construction requirements for mounting systems, temperature ratings of mounting components, bonding and grounding devices used with PV modules. Also includes mechanical load tests and fire test classifications (A, B, C) for specific PV module / mounting system combinations.
Other	All requirements for PV modules per Table C.2 A.	★★★	
UL 580, UL 1897, ASTM D3151	Wind uplift resistance test methods for roofing systems	★★	Because IEC 63092-1/2 do not require specific roof uplift testing, these standards in addition to UL 7103 may be applied to verify the wind uplift resistance of BIPV shingles and proofing panels.
ASTM E331	(Standard Test Method for Water Penetration of Exterior Windows, Skylights, Doors and Curtain Walls by Uniform Static Air Pressure Difference	★★	Water penetration resistance of BIPV skylights and walls.

* Level 1 temperature rating required for “close roof mount” and Level 2 temperature rating for “insulated mount” (direct mount) as defined in IEC TS 63126. Refer to the Dubai Building Code for wind and seismic load requirements, maximum deflection of envelope components; structural, acoustic, and impact resistance of BIPV glazing; and requirements for silicone structural adhesives. Refer to the Al Safat (Dubai Green Building System) for energy efficiency requirements for BIPV.

C.3 - Inverters

Reference	Title	Importance	Application
IEC 62109-1	Safety of power converters for use in photovoltaic power systems - Part 1: General requirements	★★★	Safety requirements for inverters, international standards
IEC 62109-2	Safety of power converters for use in photovoltaic power systems - Part 2: Particular requirements for inverters	★★★	
IEC 62109-3	Safety of power converters for use in photovoltaic power systems - Part 3: Particular requirements for electronic devices in combination with photovoltaic elements	★★★	
UL 1741	Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources	★★★	Safety requirements for inverters, US standard
EN 50530	Overall efficiency of grid connected photovoltaic inverters	★★	Test methods for measuring static and dynamic efficiency of PV inverters
EN 50524	Data sheet and name plate for photovoltaic inverters This European Standard describes data sheet and name plate information for photovoltaic inverters in grid parallel operation	★★	Documentation for inverters
IEC 62116	Utility-interconnected photovoltaic inverters - Test procedure of islanding prevention measures	★★★	Test methods for assessing the capacity of an inverter and its protection to avoid islanding
IEC-63112	Photovoltaic Arrays – Earth fault protection equipment – Safety and safety-related functionality	★★	Describes tests and requirements for internal and external ground fault detection equipment used with Photovoltaic arrays.
UL 3741 (provided for reference only)	ANSI/CAN/UL 3741:2020 Photovoltaic Hazard Control	★	PV Hazard Control as defined under UL3741 provides multiple methods to protect fire fighters from hazards including both electronic and passive means. UL3741 does allow for system deigns that do not require protection on each PV module

C.4 - EMC (Electro Magnetic Compatibility)

Reference	Title	Importance	Application
IEC 61000-3-2	Electromagnetic compatibility (EMC) - Part 3-2: Limits - Limits for harmonic current emissions (equipment input current ≤16 A per phase)	★★★	Maximum output harmonic content for small inverters (See note below)
IEC 61000-3-12	Electromagnetic compatibility (EMC) - Part 3-12: Limits - Limits for harmonic currents produced by equipment connected to public low-voltage systems with input current >16 A and ≤ 75 A per phase	★★★	Maximum output harmonic content for medium size inverters (See note below)
IEC 61000-2-2	Electromagnetic compatibility (EMC) - Part 2-2: Environment - Compatibility levels for low-frequency conducted disturbances and signalling in public low-voltage power supply systems	★	Maximum level of voltage disturbances on a LV public grid (See note below)
IEC 61000-3-3	Electromagnetic compatibility (EMC) - Part 3-3: Limits - Limitation of voltage changes, voltage fluctuations and flicker in public low- voltage supply systems, for equipment with rated current ≤16 A per phase and not subject to conditional connection	★★	Non harmonic voltage disturbances on a LV grid and test systems. Valid for I ≤ 16 A per phase (See note below)
IEC 61000-3-11	Electromagnetic compatibility (EMC) - Part 3-11: Limits - Limitation of voltage changes, voltage fluctuations and flicker in public low-voltage supply systems - Equipment with rated current ≤ 75 A and subject to conditional connection	★★	Non harmonic voltage disturbances on a LV grid and test systems. Valid for I>16 A and I ≤ 75 A per phase
IEC 61000-6-1	Electromagnetic compatibility (EMC) - Part 6-1: Generic standards - Immunity for residential, commercial and light-industrial environments	★★	Immunity requirements and test for LV equipment installed in residential, commercial and light- industrial environments
IEC 61000-6-2	Electromagnetic compatibility (EMC) - Part 6-2: Generic standards - Immunity for industrial environments	★★	Immunity requirements and test for LV equipment installed in industrial environments
IEC 61000-6-3	Electromagnetic compatibility (EMC) - Part 6-3: Generic standards - Emission standard for residential, commercial and light- industrial environments	★★	Immunity requirements and test for LV equipment installed in residential, commercial and light- industrial environments
IEC 61000-6-4	Electromagnetic compatibility (EMC) - Part 6-4: Generic standards - Emission standard for -industrial environments	★★	Immunity requirements and test for LV equipment installed in industrial environments
IEC/TR 61000- 3-14	Electromagnetic compatibility (EMC) - Part 3-14: Assessment of emission limits for harmonics, interharmonics, voltage fluctuations and unbalance for the connection of disturbing installations to LV power systems	★★	Guide to LV IEC 61000 series standards with examples of application
IEC/TR 61000- 3-6	Electromagnetic compatibility (EMC) - Part 3-6: Limits - Assessment of emission limits for the connection of distorting installations to MV, HV and EHV power systems	★	Harmonic current in MV and HV RRGU

Reference	Title	Importance	Application
IEC/TR 61000- 3-7	Electromagnetic compatibility (EMC) - Part 3-7: Limits - Assessment of emission limits for the connection of fluctuating installations to MV, HV and EHV power systems	★	Flicker effects and other rapid voltage changes in MV and HV RRGU
IEC/TR 61000- 3-13	Electromagnetic compatibility (EMC) - Part 3-13: Limits - Assessment of emission limits for the connection of unbalanced installations to MV, HV and EHV power systems	★	Effects of unbalances in MV and HV RRGU
IEC 61400-21	Wind Energy Generation Systems – Measurement and assessment of electrical characteristics – Wind Turbines	★	Provides guidance on harmonics and voltage disturbance limits for larger power converters. This is listed as a reference document only

C.5 - Cables and connectors

Important: cable standards and designations are mainly subjected to local standards. It is therefore not possible to mention all the possibilities considering the different applications.

In the following list the main local standards referring PV cables are reported but this is only indicative.

Reference	Title	Importance	Application
IEC 62930	Electric cables for photovoltaic systems	★★★	Standard on cables for DC arrays
IEC 62852*	Connectors for photovoltaic systems - Safety requirements and tests*	★★★	IEC standard for PV connectors. Note: To ensure that connectors assembled in the field have been evaluated for field assembly, reference UL 6703 Tables 9.1, 9.2 (Note 3) regarding connector intermatability
UL 6703	Standard n for Connectors for Use in Photovoltaic Systems	★★	Widely used US standards for PV connectors
UL 6703A	Standard for Multi-Pole Connectors for Use in Photovoltaic Systems	★★	
CEI 20-91	Fire retardant and halogen free electric cable with elastomeric insulation and sheath for rated voltages not exceeding 1 000 V a.c and 1 500 V d.c for use in photovoltaic system (PV)	★★★	Standards for DC cables of PV systems. Cables shall meet requirements of at least one of these standard or other equivalents
UL 854	Standard for Service-Entrance Cables	★	These standards or other equivalent
UL 4703	Standard for Photovoltaic Wire	★	PV cables up to 2000 V DC.
IEC 60227-3	IEC standard for PVC wire	★★	PVC wire
IEC 60245-7	Standard for rubber insulated cable	★★	Rubber insulated wire
IEC 60227-4	Standard for non-metallic sheathed cables	★★	Non-metallic sheathed cables
UL 3003	Outline of Investigation for Distributed Generation Cables	★	Distributed Generation Cables (DG)

C.6 - LV switchgears and control gear

Reference	Title	Importance	Application
IEC/TR 61439-0	Low-voltage switchgear and control gear assemblies - Part 0: Guidance to specifying assemblies	★	A guide with the explanation of main characteristics
IEC 61439-1	Low-voltage switchgear and control gear assemblies - Part 1: General rules	★★★	The main standard for the design and construction of LV switchgears and controlgear assemblies
IEC 61439-2	Low-voltage switchgear and control gear assemblies - Part 2: Power switchgear and Control gear assemblies	★★★	
IEC 61439-3	Low-voltage switchgear and control gear assemblies - Part 3: Distribution boards intended to be operated by ordinary persons (DBO)	★★	LV switchgears and control gear for specific applications
IEC 61439-5	Low-voltage switchgear and control gear assemblies - Part 5: Assemblies for power distribution in public networks	★★	
IEC 61439-6	Low-voltage switchgear and control gear assemblies - Part 6: Busbar trunking systems (busways)	★★	
IEC 61439-7	Low-voltage switchgear and control gear assemblies - Part 7: Assemblies for specific applications such as marinas, camping sites, market squares, electric vehicles charging stations	★★	
IEC 60947-3	Low-voltage switchgear and controlgear - Part 3: Switches, disconnectors, switch-disconnectors and fuse-combination units	★★★	Characteristics of LV circuit- breakers and protection devices
NFPA 70 National Electrical Code	Article 705 Interconnected Electric Power Production Sources	★	Provides guidance for sizing, labeling, protecting and installing generation sources that will operate in parallel with the local utility. Included here as an informational note.

C.7 - HV switchgears and controlgear

Reference	Title	Importance	Application
IEC 62271-1	High-voltage switchgear and controlgear - Part 1: Common specifications	★★	All the PV plants connected to the MV grid
IEC 62271- 100	High-voltage switchgear and controlgear - Part 100: Alternating current circuit-breakers	★★	
IEC 62271- 103	High-voltage switchgear and controlgear - Part 103: Switches for rated voltages above 1 kV up to and including 52 kV	★★	
IEC 62271- 200	High-voltage switchgear and controlgear - Part 200: AC metal-enclosed switchgear and controlgear for rated voltages above 1 kV and up to and including 52 kV	★★	
IEC 62271- 202	High-voltage switchgear and controlgear - Part 202: High-voltage/low-voltage prefabricated substation	★★	

C.8 - Transformers

Reference	Title	Importance	Application
IEC 60076-8	Power transformers - Part 8: Application guide	★★	MV/LV dry-type and liquid-filled transformers
IEC 60076-11	Power transformers - Part 11: Dry-type transformers	★★	
IEC 60076- 13	Power transformers - Part 13: Self-protected liquid-filled transformers	★★	
EN 50541-1	Three phase dry-type distribution transformers 50 Hz, from 100 kVA to 3150 kVA, with highest voltage for equipment not exceeding 36 kV - Part 1: General requirements	★★	

C.9 - Electrical installation

Reference	Title	Importance	Application
IEC 60364-1	Low-voltage electrical installations - Part 1: Fundamental principles, assessment of general characteristics, definitions	★★	Main standards for electric safety
IEC 60364- 4-41	Low-voltage electrical installations - Part 4-41: Protection for safety - Protection against electric shock	★★	
IEC 60364- 4-42	Low-voltage electrical installations - Part 4-42: Protection for safety - Protection against thermal effects	★★	
IEC 60364- 4-43	Low-voltage electrical installations - Part 4-43: Protection for safety - Protection against overcurrent	★★	
IEC 60364- 4-44	Low-voltage electrical installations - Part 4-44: Protection for safety - Protection against voltage disturbances and electromagnetic disturbances	★★	
IEC 60364- 5-52	Low-voltage electrical installations - Part 5-52: Selection and erection of electrical equipment - Wiring systems	★★	
IEC 60364- 5-53	Electrical installations of buildings - Part 5-53: Selection and erection of electrical equipment - Isolation, switching and control	★★	
IEC 60364- 5-54	Low-voltage electrical installations - Part 5-54: Selection and erection of electrical equipment - Earthing arrangements and protective conductors	★★	
IEC 60364-6	Low-voltage electrical installations - Part 6: Verification	★★	
IEC 60364- 7-712	Electrical installations of buildings - Part 7-712: Requirements for special installations or locations - Solar photovoltaic (PV) power supply systems	★★★	Standard for electric safety of PV plants
IEC/TS 62548	Photovoltaic (PV) arrays - Design requirements	★★★	Fundamental for the design of DC sections of PV plants
IEC 62446	Grid connected photovoltaic systems - Minimum requirements for system documentation, commissioning tests and inspection	★★	Important for the start-up and verification of PV plants
IEC 61829	Crystalline silicon photovoltaic (PV) array - On- site measurement of I-V characteristics	★	Measurement of PV arrays on field

IEC 62305-1	Protection against lightning - Part 1: General principles	★	Main standards on lightning effects
IEC 62305-2	Protection against lightning - Part 2: Risk management	★	
IEC 62305-3	Protection against lightning - Part 3: Physical damage to structures and life hazard	★	
IEC 62305-4	Protection against lightning - Part 4: Electrical and electronic systems within structures	★	
NFPA 780	Standard for the Installation of Lightning Protection Systems	★	Chapter 12 Protection for Solar Arrays provides lightning protection requirements for BAPV and BIPV systems

C.10 - PV mounting system

Reference	Title	Importance	Application
UL 2703	Outline of Investigation for Mounting Systems, Mounting Devices, Clamping/Retention Devices, and Ground Lugs for Use with Flat- Plate Photovoltaic Modules and Panels	★★	Important document especially for building applied PV. See section C.12 for building-integrated PV modules and systems.

C.11 - Grid connection

Reference	Title	Importance	Application
EN 50160	Voltage characteristics of electricity supplied by public electricity networks	★★	Minimum requirements for a grid supply
EN 50438	Requirements for the connection of micro- generators in parallel with public low-voltage distribution networks	★	Different requirements for connection in Europe
EN 61727	Photovoltaic (PV) systems - Characteristics of the utility interface	★	General requirements for grid connection

APPENDIX D: COMPLIANCE TESTS

D.0 - General Rules

This Appendix describes the procedures to test the Interface Protection System (IPS) and Inverters as part of Non- Synchronously-Connected Renewable Resource Generating Units.

The Interface Protection system may be:

- built-in in the inverter: this is allowed for RRGUs as part of a RRGP which has a single inverter and a Maximum Capacity P_{MC} < 150 kW or when the Maximum Capacity $P_{MC} \leq 10$ kW and the number of inverters does not exceed three;
- external in all the other cases.

The Appendix on IPS shows characteristics and methods to test the Interface Protection System. The rules to be applied are based on IEC 60255-1 and related series standards. The specification of the characteristics and of the test methods is essential, given the significant need for reliability and tripping speed that the interface device must ensure in case of faults external to the RRGP, to eliminate the contribution to the fault.

With the only exception of the functional tests, the remaining tests mentioned in the following paragraphs must be performed only at a laboratory accredited according to ISO/IEC 17025 that has in its scope of accreditation the required tests. To ensure the validity and acceptance of related certificates in countries other than that of issuance, the accreditation of the laboratory has to be issued by the local institution.

This Appendix is organized such that:

- The characteristics and tests for IPS in Low Voltage RRG Units / Plants are described in D.1
- The characteristics and tests for IPS in Medium Voltage RRG Units / Plants are described in D.2
- The characteristics and tests for Inverters in Low Voltage RRG Units / Plants are described in D.3
- The characteristics and tests for Inverters in Medium Voltage RRG Units / Plants are described in D.4

D.1 - Interface Protection System for Low Voltage connected RRGUs

D.1.0 - Definitions

Interface Switch (IS) - One or more switches, the opening of which (controlled by a suitable protection system) ensures the separation of the RRGUs from the grid.

Interface Protection (IP) - The electrical protection required to ensure that either the Generating Plant or any Generating Unit is disconnected for any event that could impair the integrity or degrade the safety of the Distribution Network.

Interface Protection System (IPS) - Overall protection system composed by:

- voltage transformers/transducers with their connections to the Interface Protection;
- Interface Protection (IP) with its power supply;
- Interface Switch (IS).

D.1.1 - Types of test

The tests to be run on the Interface Protection System (IPS) and on the inverter in case of built-in IPS, are the following:

- type tests
- on site tests (both at commissioning and under operation), as required by DEWA.

The type tests must be performed on a specimen identical to those marketed.

Type tests include those listed in D.1.3, D.1.4. According to the results obtained, the relevant documentation as required in D.1.4 shall be issued.

The type tests on a built-in IPS must be carried out using the required apparatus (see D.2.4.1). A built-in IPS is a set of software functions implemented within the same board on which the inverter control is built (or other electronic board inserted into the inverter), which performs the protection functions.

The on-site tests on non-integrated IPS must be carried out with the equipment referred to in D.2.5.1 and shall include those A) and D) of D.1.4.3.1, A) and D) of D.1.4.3.2, and those of D.1.4.3.4.2, D.1.4.3.4.3.

The on-site tests on the built-in IPS must be performed with the equipment referred to in D.2.5.1 or through the self- test function as per D.1.4.4 and must include those A) and D) of D.1.4.3.1, A) and D) of D.1.4.3.2, and those of D.1.4.3.4.2.

The on-site tests should concern the continuity of the circuit between the IPS, the related electronic devices and voltage measurement circuits. In the case of built-in IPS these verifications are made through a self-test function.

Errors detected during on-site tests and at commissioning must not exceed the limit error increased by the change of the limit error inferred according to type test ε $(1+\Delta\varepsilon)$.

D.1.2 - IPS characteristics

The IPS must provide the following functions and performance:

- Undervoltage (27, with two thresholds)
- Overvoltage (59, with two thresholds)
- Overfrequency (81> with two thresholds)
- Underfrequency (81< with two thresholds)
- Loss Of Mains (LOM) functions (81R, 78)
- a remote tripping function
- a backup function (if required depending on the maximum capacity of the plant)
- signal processing of communication signal availability
- a watchdog function
- self-test function (in case of built-in IPS inside inverter installed in plant with overall Maximum Capacity smaller than 10 kW)
- any transducers aimed at the acquisition of the voltage signals
- an opening circuit of the interface device
- only for not built-in, IPS auxiliary power system which in the absence of power from mains allows IPS operation for at least 5 s. Such power supply must get to shut-down condition without any malfunction or without the need of further manual reset. The auxiliary power system must be suitably sized to allow IPS operation, the command to keep closed the interface device, and of any additional device at least for the time defined above. It is intended that when mains is back, the relay checks the network parameters (voltage and frequency) before allowing reclosing of interface device.

The voltage and nominal frequency of the power grid to be considered as a reference for all the protection functions are:

- Rated Voltage: (230-400) V
- Rated Frequency: 50 Hz

D.1.3 - Setting ranges of the IPS

The thresholds and trip times must be available for setting at the instance of DEWA, therefore the IPS must be programmed with "default" thresholds and trip times as per Table 8 and Table 9a, but it must always be allowed to modify thresholds and trip time according to steps/ ranges in the followings paragraphs.

D.1.3.1 - Minimum phase or line voltage protection [27]

The undervoltage protection can be single phase or three phase with two thresholds. The following setting ranges are envisaged (Maximum allowed calibration steps):

Threshold	27-1	(0.20 ÷ 1) Vn adjustable in steps of 0.05 Vn
Tripping time	27-1	(0.05 ÷ 5) s adjustable in steps of 0.05 s
Threshold	27-2	(0.05 ÷ 1) Vn adjustable in steps of 0.05 Vn
Tripping time	27-2	(0.05 ÷ 5) s adjustable in steps of 0.05 s

D.1.3.2 - Maximum phase or line voltage protection [59]

The overvoltage protection can be single phase or three phase with two thresholds. The following setting ranges are envisaged (Maximum allowed calibration steps):

Threshold	59-Av	(1.0 ÷ 1.20) Vn adjustable in steps of 0.01 Vn
Tripping delay	59-Av	≤ 3 s
Threshold	59-1	(1.0 ÷ 1.20) Vn adjustable in steps of 0.01 Vn
Tripping delay	59-1	≤ 100s
Threshold	59-2	(1.0 ÷ 1.30) Vn adjustable in steps of 0.01 Vn
Tripping time	59-2	(0.05 ÷ 1)s adjustable in steps of 0.05 s

59-Av protection must be based on the calculation of an average value of 10 minutes in accordance with standard IEC 61000-4-30. At least once every 3 s, a new average value of the 10 previous minutes must be created, to be compared with the setting value for the protection 59-Av in Table 9a. As an alternative, another overvoltage stage 59-1 (additional to 59-2) can be accepted in place of 59-Av in the protection, provided this stage can be set in the same voltage range as per 59-Av and the tripping delay can be adjusted to 90.

D.1.3.3 - Underfrequency protection [81<]

The underfrequency protection must be minimum single phase with two thresholds. The following setting ranges are envisaged (Maximum allowed calibration steps):

Threshold	81<-1	(47.0 ÷ 50.0) Hz adjustable in steps of 0.1 Hz
Tripping time	81<-1	(0.05 ÷ 5) s adjustable in steps of 0.05 s
Threshold	81<-2	(47.0 ÷ 50.0) Hz adjustable in steps of 0.1 Hz
Tripping time	81<-2	(0.05 ÷ 5) s adjustable in steps of 0.05 s

Protection must be insensitive to transients of frequency with duration smaller than or equal to 40 ms.

The protection must correctly operate in the voltage range in input included between 0.2 Vn and 1.15 Vn and must be inhibited for input voltages smaller than 0.2 Vn.

D.1.3.4 - Overfrequency protection [81>]

The overfrequency protection must be minimum single phase with two thresholds. The following setting ranges are at least envisaged (Maximum allowed calibration steps):

Threshold	81> -1	(50.0 ÷ 53.0) Hz adjustable in steps of 0.1 Hz
Tripping time	81> -1	(0.05 ÷ 5) s adjustable in steps of 0.05 s
Threshold	81> -2	(50.0 ÷ 53.0) Hz adjustable in steps of 0.1 Hz
Tripping time	81> -2	(0.05 ÷ 5) s adjustable in steps of 0.05 s

Protection must be insensitive to transients of frequency with duration minor or equal to 40 ms.

The protection must correctly operate in the voltage range in input included between 0.2 Vn and 1.15 Vn and must be inhibited for input voltages smaller than 0.2 Vn.

D.1.3.5 – Loss of Mains

The Loss of Mains protection must be able to detect the loss of a single phase of the supply network. If the LOM protection function is realised by means of Rate of Change of Frequency (ROCOF – 81R) and Vector Shift (78), to be used alternatively at the instance of DEWA, the following setting ranges are envisaged:

Threshold	81R	(0.01 ÷ 5.0) Hz/s adjustable in steps of 0.01 Hz/s
Threshold	78	(1 ÷ 50) ° adjustable in steps of 1 °

Inhibition of the LOM protection functions shall be possible in the IP.

Both ROCOF and Vector Shift will use a measurement of the period of the mains voltage cycle to detect either a rapid change in frequency or a shift in the voltage vector.

D.1.4 - Checks and type tests on the IPS

The Interface Protection System (IPS) must be submitted to the following type tests:

-	Functional	(see D.1.4.3 and in particular D.1.4.4 in case of self-test)
-	EMC	(see D.1.4.5)
-	Environmental compatibility	(see D.1.4.6)
-	Insulation	(see D.1.4.7)
-	Overloading of measuring circuits	(see D.1.4.8)

With the exception of only the functional tests, the remaining tests must be executed only at a laboratory accredited according to EN ISO/IEC 17025.

The functional tests may be alternatively performed either:

- at the above mentioned accredited laboratory, or
- at the laboratories of the manufacturer, or non-accredited laboratories.

In this second case, the tests must be carried out under the supervision and responsibility of appropriate certifying body that meets the requirements of EN ISO/IEC 17065:2012 or, alternatively, under the supervision and responsibility of the accredited laboratory where EMC tests were performed.

As a prerequisite, it must always be possible to verify the correct operation of any IP or built-in IPS according to the thresholds and settled times.

In case of a built-in IPS, dropout ratios and the dropout times are not to be checked.

The test is passed when the IPS tripping takes place within the following error limits for at least 3 consecutive tests (1 test if on-site):

- ≤ 5% for the tripping voltage thresholds
- ± 20 mHz for the tripping frequency thresholds
- ≤ 3% ± 20 ms for trip time
- ≤ 5% for the dropout voltage thresholds
- ± 20 mHz for the dropout frequency thresholds
- variation of the error during the repetition of tests
    - ≤ 2% for the voltages
    - ± 20 mHz for the frequency thresholds
    - ≤ 1% ± 20 ms for the trip times

The values of the dropout ratio and dropout time limit are as follows:

Protection	Dropout Ratio	Dropout Time
27	1.03 ÷ 1.05	0.04 ÷ 0.1 s
59	0.95 ÷ 0.97	
81<	1.001 ÷ 1,003	
81>	0.997 ÷ 0.999	

The dropout ratio and the dropout time are not applicable for the overvoltage function 59-Av and for LOM functions.

The verification of the correct operation of the IPS must be performed by interfacing the IPS either to a relay test set with the features listed below, or to an appropriate generator designed to simulate the actual conditions of a low- voltage network and which is set to simulate variations in voltage and frequency so as to detect the trip of the IPS.

D.1.4.1 - Characteristics of the relay test set

Relay test sets suitable for type tests shall be used. The minimum requirements of such sets are given in D.2.4.1.

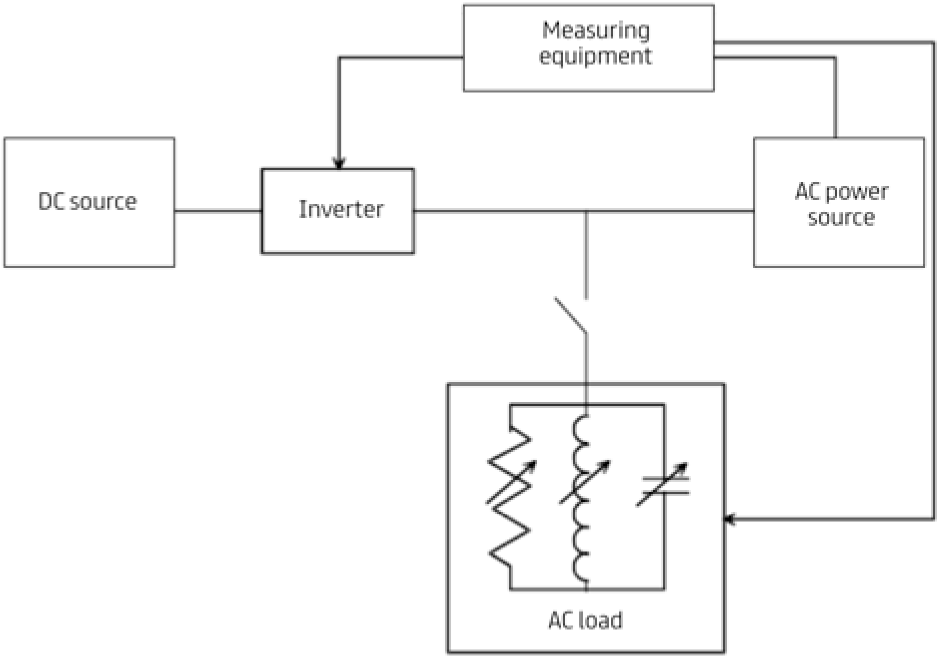
For on-site tests (typically at the Commissioning), the requirements for relay test sets are less restrictive as explained in D.2.5. Test sets suitable for type tests may then be used also for on-site tests, conversely test sets having the minimum requirements as specified for on-site tests may not be used for type tests.

D.1.4.2 - Characteristics of the LV network simulator

The built-in IPS must be tested by interfacing the converter to a suitable generator, able to reproduce the network conditions necessary to check the IPS.

The test system must therefore envisage the following functional architecture:

Figure D1 – LV Network Simulator



The simulator consists of:

- a variable DC power source to feed the inverter;
- an AC power source adjustable both in voltage and frequency with adequate power to provide to the inverter the reference of the network values;
- an AC load necessary for the inverter to deliver the highest power.

The accuracies required by the AC source in terms of voltage and frequency must be at least equal to those of the IPS and therefore:

- Voltage ± 5%
- Frequency ± 20 mHz

The harmonic distortion introduced by the power source (network simulator) must not be higher than the standard limit, i.e. for that power source (network simulator), those indicated by IEC 61000-3-2 and IEC 61000-3-12.

D.1.4.3 - Functional Tests

The tests for checking the functions and for the measurement of accuracies are listed below:

a) check of all functions
b) measure threshold accuracy
c) measure trip time accuracy
d) measure dropout ratio accuracy (not required in case of built-in IPS up to 10 kW)
e) measure the dropout time accuracy (not required in case of built-in IPS up to 10 kW)
f) test on Loss of Mains functions

All of the above tests must be performed with working equipment and with the reference conditions shown in Table D1.

Table D1 – Reference values for checking the functions and measurement accuracies

Quantity	Set-point
Ambient temperature	20 ° C ± 2 ° C
Atmospheric pressure	96 kPa ± 10 kPa
Relative humidity	from 35 to 75%
Auxiliary supply voltage	Nominal

For the tests on built-in IPS, reference will be given to the overall power of the RRGP, not to the power of each single inverter.

The verification of the protection functions must be carried out for both voltage and frequency thresholds according to the test procedures described below.

The checks must be performed on each threshold, and therefore during the verification of the single threshold all the thresholds that may possibly interfere must be inhibited / excluded.

NOTE. Before proceeding with the tests, the inverter must be correctly identified by the laboratory test or by the certification of the product. Therefore the identification of the sample will be properly made, enclosing photographic documentation and also reporting the model name, the serial number and the firmware version installed on the relay and the inverter, in the case of built-in IPS.

D.1.4.3.1 Test procedure for overvoltage and overfrequency functions

The functions of overvoltage and overfrequency must be verified according to the following procedure, by repeating each test 3 times (1 time if on-site) in order to verify the variability of errors that must stay within the provisions of D.1.4.

NOTE. Test values for frequency protections should be defined in absolute terms.

A) Measurement of the accuracy of the trip threshold

1. Apply to IPS an input a voltage equal to 0.9 times the actual tripping setting and a frequency equal to 0.99 times the actual tripping setting.

2. Gradually increase the voltage/frequency input to IPS with a maximum step size of 10 mHz for frequency and 5 V for voltage up to test the trip value.

B) Measurement of the dropout time

1. From the final condition of above point A) bring instantly, that is by a step function, the voltage/frequency to the value of the actual setting decreased by 10% for the voltage and 1% for the frequency.

2. Measure the dropout time as the time interval between the point A) and the instant the command was sent to the interface device.

C) Measurement of the dropout ratio

1. Supply the IPS with a voltage equal to 1.08 times the actual tripping setting and with a frequency equal to 1.01 times the actual tripping setting.

2. Gradually decrease the voltage/frequency input to IPS with a maximum step size of 10 mHz for frequency and 5 V for voltage up to test the dropout value. Evaluate the dropout ratio as the ratio Vdropout / Vtripping.

D) Measurement of the tripping time

1. Apply to IPS an input a voltage equal to 0.9 times the actual tripping setting and with a frequency equal to 0.99 times the actual tripping setting.

2. Increase instantly, that is by a step function, the voltage/frequency of IPS supply, to the value of the voltage tripping setting increased by 8% and to the value of the frequency tripping setting increased by 1%.

NOTE: The above listed tests may be also made by considering frequency tests and voltage tests separately

D.1.4.3.2 Test procedure for undervoltage and underfrequency functions

The functions of minimum voltage and minimum frequency must be verified according to the following procedure, by repeating each test 3 times (1 time if on-site) in order to verify the variability of errors that must stay within the provisions of D.1.4.

A) Measurement of the accuracy of the trip threshold

1. Apply to IPS an input a voltage equal to 1.1 times the related actual tripping setting and a frequency equal to 1.01 times the related actual tripping setting.

2. Gradually decrease the voltage/frequency input to IPS with a maximum step size of 10 mHz for frequency and 5 V for voltage up to test the trip value.

B) Measurement of the dropout time

1. From the final condition of above point A) bring instantly, that is by a step function, the voltage/frequency to the value of the trip threshold increased by 10% for the voltage and 1% for the frequency.

2. Measure the dropout time as the time interval between the point A) at the instant the command was sent to the interface device.

C) Measurement of the dropout ratio

1. Supply the IPS with a voltage equal to 0.92 times the actual tripping setting and with a frequency equal to 0.99 times the actual tripping setting.

2. Gradually decrease the voltage/frequency input to IPS with a maximum step size of 10 mHz for frequency and 5 V for voltage up to test the dropout value. Evaluate the dropout ratio as the ratio Vinitial / Vfinal

NOTE: The above listed tests may be also made by considering frequency tests and voltage tests separately

D) Measurement of tripping time

1. Apply to IPS a voltage input equal to 1.1 times the actual tripping setting and a frequency input equal to 1.01 times the actual tripping setting.

2. Decrease instantly that is by a step function, the voltage/frequency of IPS supply, to the value of the trip threshold increased by 10% for voltage and by 1% for frequency.

D.1.4.3.3 Test procedure for Loss of Mains functions

Type tests on Loss of Mains protection functions on built-in IPS are to be carried out at three levels of output power (10%, 55%, 100% of the nominal power of the equipment under test), or alternatively, at the conditions set by IEC 62116. The time from the switch opening (disconnection from AC source) until the protection disconnection occurs is to be measured and must comply with the value required by DEWA.

D.1.4.3.4 Additional prescriptions for functional tests

D.1.4.3.4.1 Insensitivity to harmonics of the frequency relay

For frequency relays, the insensitivity to harmonics, as listed in Table D2 must be checked when simultaneously applied with phase angles in quadrature with respect to the fundamental, relatively to:

- measurement of the accuracy of the thresholds
- measurement of the precision of the trip times.

Table D2 - Harmonics for the insensitivity of the frequency protective functions

Odd harmonics				Even harmonics	
Not multiples of 3		Multiples of 3			
Order	% (Un)	Order	% (Un)	Order	% (Un)
5	12.0%	3	10.0%	2	4.0%
7	10.0%	9	3.0%		
11	7.0%				
13	6.0%				
17	4.0%				

D.1.4.3.4.2 Check the remote trip

It must be checked that the IPS issues the tripping signal within 50 ms from the receipt of the remote trip signal at the dedicated input.

D.1.4.3.4.3 IPS on-site tests

As part of the on-site commissioning tests, it is also a good practice to carry out a functional check of the IPS, for example by removing the supply from the grid and checking that the IP correctly operates on the IS to disconnect the RRGU.

D.1.4.4 Self-test

In case the IPS functions are built into the inverter, this latter shall be provided with a self-test system that checks the functions of maximum / minimum frequency and maximum / minimum voltage in the IPS as described below:

- for each protection function of frequency and voltage, change linearly up or down the trip threshold with a ramp ≤ 0.05 Hz / s or ≤ 0.05 Vn / s respectively for frequency and voltage protections;
- the above process, at a certain point of the test, brings to the coincidence between the threshold and the value current of the controlled quantity (frequency or voltage) and therefore the trip of the protection and the consequent opening of the interface device.

For each test the values of the quantities and trip times must be readable by the test executor as well as the actual value of voltage and frequency detected by the inverter.
The tests must measure:

- accuracy of trip thresholds;
- accuracy of tripping times.

At the end of each test, the inverter must exit the test mode, reset the settings normally used and automatically reconnect to the network in the presence of the allowing conditions.

The procedure must be initiated by any user and must be clearly described in the inverter's user manual.

NOTE In case of a self-test with negative results (test failed), the software of the inverter must disconnect the inverter from the grid, must report the condition with an appropriate alarm and must not allow to reconnect to the network. It is also recommended that the self-test function is included on the external IPS.

D.1.4.5 EMC compatibility tests

The protection is a very important device in power systems, combined to the safety and safeguard of both the distribution network and generation facilities.

The protection needs to recognize abnormal conditions even in presence of electromagnetic phenomena and the consequent correct behaviour with the precision and rapidity shall not be subject to degradations such as:

- loss of the protective functions
- delay in the exploitation of the protective function
- spurious trips.

In EMC tests, protection functions must not show any degradation.
The storage of the control parameters must not be affected by the electromagnetic phenomena. In EMC tests, the storage of control parameters must not have any degradation.

For acceptance, during EMC tests, the following functions must be verified:

- all the protective functions,
- the measurement of the accuracy of the tripping thresholds,
- the measurement of the accuracy of the tripping times.

D.1.4.5.2 Evaluation Criteria

For the performance evaluation of any electronic device, the so-called evaluation criteria play an important role. Such criteria are intended to provide a classification on the acceptability or not acceptability of the (more or less temporary) degradation of the performance of the single device.

The criteria taken into account in the present standard are as follows.

Performance criterion A: The apparatus must continue to operate as expected during and after the test.

Performance criterion B: The apparatus must continue to operate as expected after the test.

For the purposes of this rule, if

- The acceptance criterion is of type A, the functions as per D.1.4.5 must be checked during the application of test levels required for tests EMC and environmental as of D.1.4.6;
- The acceptance criterion is of type B, the functions as per D.1.4.5.1 must be checked after application of test levels required for EMC tests and environmental as per D.1.4.6.

Table D3 summarizes EMC tests and for each test indicates the related acceptance criterion.

Table D3 - List of immunity tests on measuring relays and protection devices according to IEC 60255-26. Levels of severity of Class B (industrial environment)

IEC Standard	Testing of electrical noise on the relay: acceptance criteria and test procedures	Casing	auxiliary power supply	Communication	Input / Output	Functional ground	Acceptance criteria
IEC 60255- 26 and 61000- 4-18	Immunity test train of oscillations at 1 MHz		1 kV diff. mode 2.5 kV com. mode	1 kV com. mode	1 kV diff. mode 2.5 kV com. mode		B
IEC 60255-26 and 61000-4-2	Tests of electrostatic discharge	6 kV air 8 kV touch					B
IEC 60255-26 and 61000-4-3	Immunity to radiated electromagnetic fields	10 V/m (80 MHz÷2.7GHz) Include 900MHz					A
IEC 60255-26 and 61000-4-4	Immunity to electrical fast transient / burst pulse		2 kV	1 kV	2 kV	2 KV	B
IEC 60255-26 and 61000-4-5	Impulse test		1 kV phase-phase 2 kV phase-ground (succeeding)	1 kV phase-ground (succeeding)	1 kV phase-phase 2 kV phase-ground (following steps)		B
IEC 60255-26 and 61000-4-6	Immunity to conducted disturbances, induced by RF fields		10V	10V	10V	10V	A
IEC 60255-26 and 61000-4-16	Tests of immunity to the mains frequency					100 Vrms diff 300 Vrms com. (10 s. only for binary inputs)	A
IEC 60255-26 and 61000-4-29	Interruption of the auxiliary voltage DC		100% reduction over 50 ms. Required for VRT with UPS				B
IEC 61000-4-8	Power frequency magnetic field	30 A/m (continuous) 300 A/m (1s)					A

D.1.4.6 Tests of environmental compatibility

For the purposes of acceptance, during the environmental (climatic) tests the following functions must be checked:

- all the protective functions,
- the measurement of the accuracy of the tripping thresholds,
- the measurement of the accuracy of the tripping times.

Table D4 - List of test levels and climate

Detail	Notes/Test levels	Standards EN (IEC)	Acceptance criterion
Equipment not powered	Dry hot +70°C ± 2°C(16 h)	60068-2-2	B
	Dry hot +40°C± 2°C, RH = 93% ± 3% (4 days)	60068-2-78	B
	Cold -10°C ± 2°C (16 h)	60068-2-1	B
	Temperature change -10/+70°C ± 2°C (3 h + 3 h)	60068-2-14	B
Equipment powered	Dry hot +55 °C ± 2°C(16 h)	60068-2-2	A
	Dry hot +40°C± 2°C, RH = 93% ± 3% (4 days)	60068-2-78	A
	Cold -10°C ± 2°C (16 h)	60068-2-1	A
	Temperature change -10/+55°C ± 2°C (3 h + 3 h)	60068-2-14	A

D.1.4.7 Insulation tests

Table D5 – Insulation tests

Port	Verification of dielectric properties	Notes/Test levels	Standards EN (IEC)
Power inlet, both AC and DC	Impulse withstand	Overvoltage class IV	60255-27
Power inlet, both AC	dielectric strength	Test voltage 2 kV for AC circuits	
Power inlet, both AC and DC	Insulation Resistance	≥ 100 MΩ @ 500 Vdc	

D.1.4.8 Overloading tests of the measuring circuits

For voltage circuits, the overload must be:

- Permanent ≥ 1.3 Vn;
- Transient (1 s) ≥ 1.5 Vn.

D.1.4.9 Compliance of the equipment

The fulfilment to the conditions listed above must be certified by the "Declaration of conformity "of the equipment. The Declaration of Conformity must be issued by and responsibility of the manufacturer, in the form of self- certification by the manufacturer himself, prepared in accordance to the applicable laws, and delivered to DEWA at the time of connection.

The Declaration of Conformity that testifies the tests were passed (test reports) must be kept securely by the manufacturer for 20 years after the last production. The documentation must, however be available to DEWA through the manufacturer's website.

D.1.4.10 Automation to avoid current imbalances in production

The following tests should be performed only if the entire plant can work with imbalances of power greater than 5 kW.

When the system is completed and before the final connection in parallel to the grid, the following test condition must be checked:

- plant in operation at its nominal conditions;
- create a permanent artificial imbalance exceeding 5 kW;
- check either reduction of this imbalance within 1 min or disconnection of the entire plant after this time has elapsed.

D.2 - Interface Protection Systems for Medium Voltage Connected RRGPs

The following tests apply for those RRGPs where a MV connection is foreseen and the Interface Protection senses MV voltages and acts on a MV circuit breaker.

D.2.1 - Types of test and performance

The tests to be performed on the IPS are as follows:

- type tests;
- on site tests: tests at the time of installation and after installation; these tests and the related frequency can be detailed by DEWA.

The type tests must be performed on a specimen identical to those subsequently marketed.

Type tests include those indicated in D.2.4 and, on the basis of the results the relevant documentation for the purposes required in the aforementioned D.2.4 must be produced.

The on-site tests should concern the continuity of the circuits between the IP and the associated Interface Switch and any voltage measurement input circuits.

The errors found during the verification on –site tests and at commissioning must not exceed the error limit increased according to:

- the variation of the limit error obtained from the type tests;
- the accuracy of the test set and optional amplifying VTs.

In this regard, the identification of the internal components of the IPS, relevant to the requirements that are the subject of this Standard, shall be stated in the type test report issued by the laboratory.

D.2.2 - Characteristics of IPS

The IPS must include the following protective functions:

- Overvoltage (59, with two thresholds);
- Undervoltage (27, with two thresholds);
- Overfrequency (81>-1);
- Underfrequency (81<-1);
- Overfrequency (81>-2);
- Underfrequency (81<-2);
- Loss Of Mains (LOM) functions (81R, 78);
- a remote tripping function;
- a backup function (if required depending on the maximum capacity of the plant)
- a watchdog function;
- any transducers aimed at the acquisition of the voltage signals;
- an opening circuit for the Interface Switch;
- an auxiliary power system which in the absence of the main voltage allows the operation of IPS for at least 5s (Note: the power supply internal to the protection, in the event of a failure of the main power, shall get to shut-down condition without any malfunction or without the need of a further manual reset). The auxiliary power system must be suitably sized to allow, in the absence of the main power, the operation of the IPS, to keep the Interface Switch and any of the back-up circuit breaker in a closed state at least for the time defined above (Note: it is intended that, when mains is back, the relay performs the control of the network parameters (voltage and frequency) before allowing the reclosing of the Interface Switch), the feeding of the communication devices (e.g. GSM / GPRS modems) and their interfaces (if any) necessary for the remote disconnection;
- a function for detecting the state of open / closed of the Interface Switch (optional).

The voltage and nominal frequency of the power grid for all safety features are:

- Rated Voltage: (6-11-33) kV
- Rated Frequency: 50 Hz

To achieve the above said features, the IPS shall be equipped with:

- Interface Protection
- a set of inductive Voltage Transformers compliant with IEC 61869-3 or equivalent

each of these complying with the respective reference standards.

The use of non-inductive Voltage Transformers compliant with IEC 60044-7 or equivalent shall be subject to approval by DEWA.

D.2.3 - Setting ranges of the IPS

The thresholds and tripping times must be available for setting at the instance of DEWA, therefore the IPS must be programmed with "default" thresholds and tripping time as per Table 8 and 9b, but it must always be possible to modify such thresholds and tripping time with the steps and the ranges described in the following paragraphs.

D.2.3.1 Minimum line voltage protection [27]

The undervoltage protection shall control the three line voltages (OR logic) with two thresholds of intervention.

The line voltages shall be measured directly (or derived from the phase voltages if use of non-inductive VTs is made). The direct sensing of LV voltages is also accepted.

The following setting ranges are envisaged:

- Threshold 27-1 (0.20 ÷ 1.00) Vn adjustable in steps of 0.05 Vn
- Tripping time 27-1 (0.05 ÷ 5) s adjustable in steps of 0.05 s
- Threshold 27-2 (0.05 ÷ 1.00) Vn adjustable in steps of 0.05 Vn
- Tripping time 27-2 (0.05 ÷ 5) s adjustable in steps of 0.05 s

D.2.3.2 Maximum line voltage protection [59]

The overvoltage protection shall control the three line voltages (OR logic) with two thresholds of intervention.

The line voltages shall be measured directly (or derived from the phase voltages if use of non-inductive VTs is made). The direct sensing of LV voltages is also accepted.

The following setting ranges are envisaged:

Maximum threshold voltage

- Threshold 59-Av (1.0 ÷ 1.20) Vn adjustable in steps of 0.01 Vn
- Tripping delay 59-Av 3 s (after the trip threshold is reached)
- Threshold 59-1 (1.0 ÷ 1.20) Vn adjustable in steps of 0.01 Vn
- Tripping delay 59-1 ≤ 100 s
- Threshold 59-2 (1.0 ÷ 1.30) Vn adjustable in steps of 0.01 Vn
- Tripping time 59-2 (0.05 ÷ 1) s adjustable in steps of 0.05 s

59-Av protection must be based on the calculation of an average value of 10 minutes in accordance with standard IEC 61000-4-30. At least once every 3 s, a new average value of the 10 previous minutes must be created, to be compared with the setting value for the protection 59-Av in Table 9b.

As an alternative, another overvoltage stage 59-1 (additional to 59-2) can be accepted in place of 59-Av in the protection, provided this stage can be set in the same voltage range as per 59-Av and the tripping delay can be adjusted to 90 s.

D.2.3.3 Underfrequency protection [81<]

Using inductive VTs phase-to-phase connected, the frequency measurement must be performed at least on one line voltage.

In case of use of non-inductive VTs, the frequency can be measured on the phase voltages obtained directly from the voltage sensors, or on the line voltages calculated internally to the relay.

The direct sensing of one LV voltage is also accepted.

In all cases, if more sensing quantities are used the tripping must be provided:

- in case of underfrequency considering the lowest frequency value measured
- in case of overfrequency considering the highest frequency value measured

The following setting ranges are envisaged:

- Threshold 81<-1 (47.0 ÷ 50.0) Hz adjustable in steps of 0.05 Hz
- Trip time 81<-1 (0.05 ÷ 5) s adjustable in steps of 0.05 s
- Threshold 81<-2 (47.0 ÷ 50.0) Hz adjustable in steps of 0.05 Hz
- Trip time 81<-2 (0.05 ÷ 5) s adjustable in steps of 0.05 s

The protection must operate correctly in the voltage range included between 0.2 Vn and 1.3 Vn and must be inhibited for input voltages smaller than 0.2 Vn.

D.2.3.4 Overfrequency protection [81>]

Using inductive VTs phase-to-phase connected, the frequency measurement must be performed at least on one line voltage.

In case of use of non-inductive VTs, the frequency can be measured on the phase voltages obtained directly from the voltage sensors, or on the line voltages calculated internally to the relay,

The direct sensing of the LV voltages is also accepted.

In all cases, if more sensing quantities are used the tripping must be provided:

- in case of underfrequency considering the lowest frequency value measured
- in case of overfrequency considering the highest frequency value measured

The following setting ranges are envisaged:

- Threshold 81>-1 (50.0 ÷ 53.0) Hz adjustable in steps of 0.05 Hz
- Trip time 81>-1 (0.05 ÷ 5) s adjustable in steps of 0.05 s
- Threshold 81>-2 (50.0 ÷53.0) Hz adjustable in steps of 0.05 Hz
- Trip time 81>-2 (0.05 ÷ 5) s adjustable in steps of 0.05 s

The protection must operate correctly in the voltage range included between 0.2 Vn and 1.3 Vn and must be inhibited for input voltages smaller than 0.2 Vn.

D.2.3.5 – Loss of Mains

The Loss of Mains protection must be able to detect the loss of a single phase of the supply network. If the LOM protection functions is realised by means of Rate of Change of Frequency (ROCOF – 81R) and Vector Shift (78), to be used alternatively at the instance of DEWA, the following setting ranges are envisaged:

Threshold 81R (0.01 ÷ 5.0) Hz/s adjustable in steps of 0.01 Hz/s
Threshold 78 (1 ÷ 50) ° adjustable in steps of 1 °

Inhibition of the LOM protection functions shall be possible in the IP.

Both ROCOF and Vector Shift will use a measurement of the period of the mains voltage cycle to detect either a rapid change in frequency or a shift in the voltage vector..

D.2.4 - Checks and type tests on the IPS

The Interface Protection (IP) must be submitted to the following type tests:

- Functional (see D.2.4.2)
- EMC (see D.2.4.3)
- Environment compatibility (see D.2.4.4)
- Insulation (see D.2.4.5)
- Overloading of measuring circuits (see D.2.4.6).

For any IP it must always be possible to verify the correct operation of the same according to the thresholds and setting times.

The test is passed when the trip takes place within the following error limits for at least 5 consecutive tests:

- ≤ 2% for the voltage thresholds
- ± 20 mHz for the frequency thresholds
- ≤ 3% ± 20 ms for response time (excluding the threshold 59-Av)
- variation of the error during the repetition of tests
- ≤ 1% for the voltages
- ± 20 mHz for the frequency thresholds
- ≤ 1% ± 20 ms for the tripping times

The limit values of the dropout ratio and time are as follows:

Protection	Dropout Ratio	Dropout Time
27	1.03 ÷ 1.05	0.01 ÷ 0.04 s
59	0.95 ÷ 0.97	
81<	1.001 ÷ 1.003	
81>	0.997 ÷ 0.999	

The dropout ratio and the dropout time are not applicable for the overvoltage function 59-Av and for LOM functions.

D.2.4.1 Features of the relay test set

Relay test sets suitable for type tests shall have the characteristics described hereinafter.

For on-site tests (typically at the Commissioning), the requirements for relay test sets are less restrictive as explained in D.2.5. Test sets suitable for type tests may then be used also for on-site tests, conversely test sets having the minimum requirements as specified for on-site tests may not be used for type tests.

D.2.4.1.1 Features of the test apparatus

Minimum functions required to the apparatus:

Relay Type	ANSI
Overvoltage / Undervoltage	27/59
Frequency	81
Trip relay	94

D.2.4.1.2 Minimum requirements for relay test sets for type tests

This set may also be used for on-site tests.

Voltage outputs:

- = 4 with phase voltage maximum output of not less than 300 V ;
- independently adjustable outputs : 0 to maximum ;
- distortion (THD) : ≤0.2% ;
- accuracy of the outputs: ≤± 0.2% ;
- Output power (300 V): at least 10 VA per phase.

Phase angle of voltage outputs:

- Adjustable: 0° - 360°;
- Resolution: ≤ 0.1° ;
- Accuracy: ≤ ± 0.1°.

Frequency generator:

- Frequency adjustable: cc (or Hz) to 2,000 Hz;
- Reproduction of transients up to 3 kHz;
- Accuracy : ≤ ± 0.1% (must be declared by the manufacturer)
- Resolution: ≤ 1 mHz ; (must be declared by the manufacturer)
- Ability to generate waveforms with superimposed harmonics ;
- Gradient of frequency programmable between ± 0.1 Hz / s and ± 999 Hz / s.

Measurement of tripping time:

- on the digital inputs with dry contacts or not, with voltages up to 275 V DC and 240 V AC ;
- Resolution : ≤ 0.5 ms ;
- Accuracy : ≤ ± 0.5%.

Auxiliary contacts:

- Two auxiliary contacts shall allow simulating commands and remote trip presence / absence of the communication signal, and verifying the timing of the remote tripping.

Automatic storage of results:

Print the result in the expected format. The test results must not be editable by the operator.

The test equipment must also support protocol IEC 61850 (option).

D.2.4.2 Functional Tests

The tests for checking the protective functions and for the measurement of accuracies include:

a) measurement of the accuracy of the thresholds ;
b) measurement of the accuracy of tripping time;
c) measurement of the accuracy of the dropout ratio ;
d) measurement of the accuracy of the dropout time;
e) verification of the insensitivity to harmonics of over and underfrequency protections;
f) verification of remote tripping;
g) verification of local control;
h) verification of disabling (i.e. protection still fed but with protection function inhibited) of the IP at the activation of the digital input after the opening of the related circuit breaker (optional).

All of the tests above must be made with the equipment under operation and with the reference conditions listed in Table D6.

Table D6 - Reference values for checking the functions and measurement accuracies

Quantity	Setpoint
Ambient temperature	20 ° C ± 2 ° C
Atmospheric pressure	96 kPa ± 10 kPa
Relative humidity	from 35% to 65%
Auxiliary supply voltage	Nominal

The checks must be performed for each threshold and then during each single check all the other thresholds that can interfere can be disabled / excluded.

The tests for the measurement of the threshold accuracy, of the dropout ratios, of the tripping times and of the dropout times, must be performed in the manner indicated hereinafter, repeating each test at least 5 times in order to verify that the errors remain within the limits specified in paragraph D.2.4 .

The point of change of voltage from an initial value to a final value is to be considered as coincident with the zero crossing of the waveform in at least one phase.

The tests specified below are intended with the application of voltage at the input of the IP, if the IP performs the measurement of the line voltages directly in LV or by using VTs complying with IEC 61869-3 and IEC 60044-7. In this case, the voltage is directly applied to the IP using the relay test set.

The precision to be considered in performing functional tests must include the accuracy of the relay (IP) plus the accuracy of the test set.

D.2.4.2.1 Test procedure for verification of the accuracy of the overvoltage function based on the calculation of rms value of 10 minutes and update at most every 3 s

During the tests described below the minimum threshold must be set to 110% of the rated voltage.

Due to the effect of the overall maximum error of ± 2.5% on the threshold of 110% of the nominal voltage, the maximum and minimum value for safe operation are respectively 110% * 1.025 = 112.75% and 110% * 0.975 = 107.25% of the nominal voltage..

By considering the minimum value of the dropout ratio of 0.95, the theoretical value of the recovery threshold is 110

% * 0.95 = 104.5% of rated voltage. Due to the effect of the maximum total error of 2.5%, the lowest value of safe recovery is therefore 104.5% * 0.975 = 101.9% of rated voltage .

The following tests shall be repeated on each input of the function.

A) Checking the accuracy of the tripping threshold and the dropout ratio

1. Apply an input voltage equal to 106% of rated voltage for 10 minutes, checking the non-intervention.
2. Apply an input voltage equal to 114% of rated voltage for 10 minutes, and check that the intervention occurs within 10 minutes + 3s.
3. Apply an input voltage equal to 101% of rated voltage for 10 minutes, and check that the recovery occurs within 10 minutes.

B) Checking the accuracy of the tripping time and dropout time

1. Apply an input voltage equal to 100% of rated voltage for 10 minutes.
2. Apply an input voltage equal to 120% of rated voltage for 10 minutes, and check that the intervention will occur at a time instant between 210 s (time corresponding to an error of +2.5% on voltage) and 375s (corresponding time to an error of -2.5% on the voltage + 3 s due to the uncertainty on the instant the calculation of rms value is updated).
3. Apply an input voltage equal to 100% of rated voltage for 10 minutes, and check that the recovery will occur at a time instant between 333 s (time corresponding to an error of -2.5% and the voltage ratio of maximum recovery 0.97) and 552 s (corresponding to a time error of +2.5% on the voltage and ratio of minimum recovery 0.95 + 3 s due to the uncertainty on the instant the calculation of rms value is updated).

D.2.4.2.2 Test Procedure for measurement of the accuracy of overvoltage functions

The following tests shall be repeated for each input related to overvoltage protective function.

A) Measuring the accuracy of the tripping threshold

1. Set the function with no intentional delay.
2. Apply instantly to an input a voltage equal to 90% of the actual setting value.
3. Increase the voltage ramp with step size ≤ 10% of the voltmetric accuracy and duration of the steps between 2 and 5 times the device starting time (as stated by the manufacturer), up to checking the value of intervention.

B) Measuring the accuracy of the dropout ratio

1. Set the function with no intentional delay.
2. Apply instantly to an input a voltage equal to 110% of the actual setting value.
3. Reduce the voltage ramp, with a step size ≤ 10% of the voltmetric accuracy and duration of the steps between 2 and 5 times the dropout time (as stated by the manufacturer), up to check the value of dropout. This value, compared to the value as determined at point A), represents the dropout ratio.

C) Measuring the tripping time accuracy

1. Apply instantly to an input a step change of the voltage from 0 to 120% of the actual setting value. The time recorded between the instant of application of the voltage and the instant when the tripping contact associated to the function changes its state, represents the response time.

D) Measurement of the dropout time accuracy

1. From the final condition referred to at point C), instantly restore the voltage to 0. The time recorded between the instant of instantaneous variation of the voltage and the instant at which the tripping contact associated to the function changes its state, represents the dropout time.

D.2.4.2.3 Test procedure for measuring the accuracy of undervoltage functions

The following tests shall be repeated for each input related to undervoltage protective function.

During the tests on an input, the voltage on the remaining inputs must remain constant and above the threshold value of the function under test.

A) Measuring the accuracy of the tripping threshold

1. Set the function with no intentional delay.
2. Apply instantly to an input a voltage equal to 110% of the actual setting value.
3. Decrease the voltage ramp, with a step size ≤ 10% of the voltmetric accuracy and duration of the steps between 2 and 5 times the device starting time (as stated by the manufacturer), up to checking the value of intervention.

B) Measuring the accuracy of the dropout ratio

1. Set the function with no intentional delay.
2. Apply instantly to an input a voltage equal to 90% of the actual setting value.
3. Increase the voltage ramp with a step size of the ramp ≤ 10% of the voltmetric accuracy and duration of the steps between 2 and 5 times the dropout time (as stated by the manufacturer), up to checking the value of dropout. This value, compared to the value as determined in point A), represents the dropout ratio.

C) Measuring the tripping time accuracy

1. Apply to an input a voltage step of initial value equal to 120% of the actual setting and final value of 0. The time recorded between the instant of application of the voltage step and the instant when the tripping contact associated to the function changes its state, represents the response time.

D) Measurement the dropout time accuracy

1. From the final condition referred to at point C) instantly restore the voltage to the 120% of the actual setting value. The time recorded between the instant of instantaneous variation of the voltage and the instant when the tripping contact associated to the function changes its state, represents the dropout time.

D.2.4.2.4 Test procedure for Loss of Mains functions

Type tests on Loss of Mains protection functions shall be agreed between DEWA and the manufacturer.

D.2.4.2.5 Check insensitivity to harmonics of the overfrequency and underfrequency protections

A) Check insensitivity to harmonics of the overfrequency protection.

For frequency relays, the insensitivity to harmonics, as listed in Table D7 (same as Table D2, but repeated here for the sake of clarity), must be checked when simultaneously applied with phase angles in quadrature with respect to the fundamental, having an amplitude of 100% of the rated voltage and frequency 50 Hz.

Table D7 - Harmonics for the insensitivity of the frequency protective functions

Odd harmonics				Even harmonics	
Non multiples of 3		Multiples of 3			
Order	% (Un)	Order	% (Un)	Order	% (Un)
5	12.0%	3	10.0%	2	4.0%
7	10.0%	9	3.0%		
11	7.0%				
13	6.0%				
17	4.0%				

1. Feed the IP with a set of three positive sequence voltages having a value of 100% of the rated voltage, at the fundamental frequency equal to the actual overfrequency setting decreased of 200 mHz and with the harmonic content of Table D7. These conditions must be kept for at least 5 s and a check of the non-intervention of the overfrequency protections must be carried out.

2. Apply a step change in the frequency with value of the fundamental equal to the actual overfrequency setting increased by an amount of 200 mHz and keeping the same harmonic content of Table D7. Verify that the protection operates within the setting time including its related tolerances.

B) Verification of insensitivity to harmonics of the underfrequency protection.

1. Feed the IP with a set of three positive sequence voltages having a value of 100% of the rated voltage, at the fundamental frequency equal to the actual under frequency setting increase of 200 mHz and with the harmonic content of Table D7. These conditions must be kept for at least 5 s and a check of the non-intervention of the underfrequency protections must be carried out.

2. Apply a step change in the frequency with value of the fundamental equal to the actual underfrequency setting decreased by an amount of 200 mHz and keeping the same harmonic content of Table D7. Verify that the protection operates within the setting time including its related tolerances.

D.2.4.26 Check the remote trip (in case this function is required)

It must be checked that the IP issues the tripping signal within 50 ms from the receipt of the remote trip signal at the dedicated input

D.2.4.3 EMC compatibility tests

See D.1.4.5.

D.2.4.4 Tests of environmental compatibility

See D.1.4.6.

D.2.4.5 Insulation tests

See D.1.4.7.

D.2.4.6 Overloading tests of the measuring circuits

See D.1.4.8.

D.2.5 Checks and functional on-site tests of IPS

D.2.5.1 Features of the relay test set

Relay test sets must be used for on-site tests, with the characteristics listed hereinafter.

Test sets suitable for type tests may be used for on-site tests, conversely test sets having the minimum requirements as specified for on-site tests may not be used for type tests.

D.2.5.1.1 Features of the test apparatus

Minimum functions required to the apparatus:

Relay Type	ANSI
Overvoltage / Undervoltage	27/59
Frequency	81
Trip relay	94

D.2.5.1.2 Minimum cassette relay test for on-site testing

Voltage outputs:

- 3 with maximum output voltage not less than 300 V;
- independently adjustable outputs: 0 to maximum;
- distortion (THD + N) 0.3% ;
- accuracy of the outputs: ± 0.5%
- Output power (300 V) : at least 10 VA per phase ;
- Phase angle between the three voltages : 0 to 360° ;
- Resolution: ≤ 1°;
- Accuracy of the outputs: ± 1°.

Frequency generator:

- Adjustable frequency : 40 Hz to 60 Hz;
- Accuracy : ± 0.02% ;
- Resolution ≤ 1 mHz ;

Measurement of tripping time:

- On digital inputs with dry contacts or not, with voltages up to 275 Vdc and 240 Vac;
- Resolution 1 ms;
- Accuracy ± 0.1%.

Auxiliary contacts:

- Two auxiliary contacts shall allow simulating commands and remote trip presence / absence of the communication signal, and verifying the timing of the remote tripping.

Automatic storage of results :

1. Print the result in the appropriate format.
2. If the test is not conducted under the ISO 9001 certification, the print test report will be of the automatic type so that it cannot be changed by the operator; anyway it must be issued a paper test report, signed by the person who prepares the Declaration of Adequacy, that brings the brand, model and serial number of the instrument used.

The test equipment shall also support the protocol IEC 61850 (option).

D.2.5.2 On-site checks and tests

On-site tests may be performed :

- for an IP that uses VTs that meet the standards of product IEC 61869-3 and IEC 60044-7, by applying a voltage by the relay test set directly to the inputs of the IP;

- for an IP which directly measures LV line voltages, applying a set of voltages by the relay test set directly to the inputs of the IP (in case the value of the voltage generated by the test set itself is higher than the maximum voltage to be applied during the tests) or by interposing between the test set and the IP, VTs having accuracy class 0.2 or better (in case the value of the voltage generated by the test set is lower than the maximum voltage to be applied during the tests).

Before proceeding with the on-site tests, the IP must have been regulated with the final settings and left connected to the ICB in order to verify the continuity of the opening circuit and the opening of the ICB itself (the tolerance on the trip time is to be calculated on the total time) once the tripping signal has been issued by the IP, for each protection function. The tests can be performed only once for each threshold and tripping time check.

D.2.5.2.1 Check the continuity of the voltage circuits of the IPS

With the IPS in service on the network, by reading directly on the display of the IPS, check:

- that the value of the input voltages is close to the rated voltage
- that the frequency value is close to 50 Hz

D.2.5.2.2 Check the functionality of the tripping circuit of IPS

With the IPS in service on the network, by means of the activation of any threshold, check:

- that the issuance of the trip command causes the opening of the associated device (IS).

D.2.5.2.3 Test procedure for verification of the accuracy of the overvoltage function based on the calculation of rms value of 10 minutes and update at most every 3 s

During the test described below the tripping threshold must be set to 110% of the rated voltage.

The following tests have then to be carried out:

1. Apply a voltage equal to 105% of rated voltage for 11 minutes, checking the non-intervention.
2. Apply a voltage equal to 115% of rated voltage for 10 minutes, checking that intervention occurs within 10 minutes + 3 seconds.

D.2.5.2.4 Checking the threshold and the tripping time of the overvoltage function

The following tests must be carried out without changing the settings of the IP.

A) Measuring the accuracy of the tripping threshold

1. From the value of the rated voltage, instantly apply to the IP inputs a voltage equal to 90% of the actual setting value, checking the non-intervention.
2. Increase the voltage by a ramp with size of steps ≤ 10% of voltmetric accuracy and duration of steps equal to 120% of the tripping time.

B) Measuring the accuracy of the tripping time

1. From the value of the rated voltage, instantly apply to the IP inputs a voltage equal to 120% of the actual setting value. The time recorded between the instant of application of the voltage and the instant when the tripping contact associated to the function changes its state, represents the tripping time.

D.2.5.2.5 Checking the threshold and the tripping time of the undervoltage function

The following tests must be carried out without changing the settings of the IP.

A) Measuring the accuracy of the tripping threshold

1. From the value of the rated voltage, instantly apply to the IP inputs a voltage equal to 110% of the actual setting value, checking the non-intervention.
2. Decrease the voltage by a ramp with size steps ≤ 10% of voltmetric accuracy and duration of steps equal to 120% of the tripping time.

B) Measuring the accuracy of the tripping time

1. From the value of the rated voltage, instantly apply to the IP inputs a voltage equal to 80% of the actual setting. The time recorded between the instant of application of the voltage and the instant when the tripping contact associated to the function changes its state, represents the tripping time.

D.2.5.2.6 Checking the threshold and the tripping time of overfrequency function

The following tests shall be carried out without changing the settings of the IP.

A) Measuring the accuracy of the response threshold

1. From the value of rated voltage and frequency, instantly apply to the IP inputs a frequency equal to the actual setting value decreased by 50mHz, checking the non-intervention.
2. Increase the frequency by a ramp with size steps ≤ 10mHz and duration of steps equal to 120% of the tripping time.

B) Measuring the accuracy of the tripping time

1. From the value of rated voltage and frequency, instantly apply to the IP inputs a frequency equal to the actual setting value increased by 200mHz. The time recorded between the instant of application of the voltage and the instant when the tripping contact associated to the function changes its state, represents the tripping time.

D.2.5.2.7 Checking the threshold and the tripping time of underfrequency function

The following tests shall be carried out without changing the settings of the IP.

A) Measuring the accuracy of the tripping threshold

1. From the value of rated voltage and frequency, instantly apply to the IP inputs a frequency equal to the actual setting value increased by 50mHz, checking the non-intervention.
2. Decrease the frequency by a ramp, with size steps ≤ 10mHz and duration equal to 120% of the tripping time.

B) Measuring the accuracy of the tripping time

1. From the value of rated voltage and frequency, instantly apply to the IP inputs a frequency equal to the actual setting value decreased by 200mHz. The time recorded between the instant of application of the voltage and the instant when the tripping contact associated to the function changes its state, represents the tripping time.

D.2.5.2.8 Check the remote trip

The test is to be carried out as described in par. D.2.4.2. 6.

D.2.5.2.9 Checks at completion of the tests

At the completion of the on-site tests, it is necessary to double check that the settings are consistent with the requirements of this standard and with those provided by DEWA.

D.3 Inverters for Low Voltage connected RRGUs

This section contains test protocols to be applied to static generators, typically for photovoltaic grid-connected systems. This section is for equipment and plants to be connected to LV distribution network.

D.3.1 Scope

This section describes the compliance tests on inverters for Low Voltage photovoltaic applications.

D.3.2 Tests on inverters for low voltage connected RRGUs

The tests on such static generators are typically carried out at a laboratory accredited according to ISO/IEC 17025.

The device must be certified and labelled in order to demonstrate the compliance with all the safety standards in force in UAE (like for example the European “CE” mark, which is a guarantee of compliance with applicable directives LV, EMC, ...). In addition, the same shall have successfully passed the following tests (in parentheses indicates the reference for the tests to be performed):

a) harmonic emission limits for Class A (IEC 61000-3-2 or IEC 61000-3-12); they should be repeated in 3 sessions (33%, 66% and 100% of the nominal power);
b) for devices with phase currents above 75 A it is possible to carry out the tests of harmonic emission, with the same criteria of the IEC 61000-3-12;
c) limits of voltage fluctuations and flicker (IEC 61000-3-3 or IEC 61000-3-11); they should be repeated in 3 sessions (33%, 66% and 100% of the nominal power);
d) method of connection, reconnection and gradual supply of power, as described below in D.3.2.1;
e) reactive power supply, as described in D.3.2.2;
f) active power limitation, as described in D.3.2.3;
g) verification of DC component on the output current, as described in D.3.2.4 ;
h) Verification of insensitivity to voltage dips, as described in D.3.2.5;
i) verification of the absence of damage in case of automatic reclosing, as described below in D.3.2.6.

The tests referred to in points a), b), c), g) must be performed on the device at Reference conditions shown in Table D8 and Table D9. The remaining tests can be performed only under the conditions specified in Table D8.

The inverters must comply with IEC 61000-6-3 for application in residential, commercial and light-industrial environments. In case of industrial environment the inverters must comply with IEC 61000-6-4.

Table D8 - Terms of reference for the performance of the tests in the laboratory

QUANTITIES OF INFLUENCE	REFERENCE VALUES
Environmental temperature	20°C ± 2°C
Atmospheric pressure	96 kPa ± 10kPa
Relative humidity	65%RH ± 10%RH
Position of the equipment	According to the manufacturer declaration
Frequency	50 Hz (in the range 47.5Hz – 52.5Hz, wherever applicable)
Waveform of the reference voltage	Compliant to EN 50160

Table D9 - Terms of reference for the performance of the tests in the laboratory

QUANTITIES OF INFLUENCE	REFERENCE VALUES
Environmental temperature	-10°C ± 55°C
Atmospheric pressure	96 kPa ± 10kPa
Relative humidity	65%RH ± 10%RH
Position of the equipment	According to the manufacturer declaration
Frequency	50 Hz (in the range 47.5Hz – 52.5Hz, wherever applicable)
Waveform of the reference voltage	Compliant to EN 50160

If the requirements referred to in points a), b), c) and g) above are met in a range of temperature stated by the manufacturer other than that indicated in Table D9, the Manufacturer must prevent the operation of the device outside of the said operating range. This feature must be verified by appropriate evidence.

D.3.2.1 Conditions of connection, reconnection and gradual power delivery

D.3.2.1.1 Verifying connection and reconnection

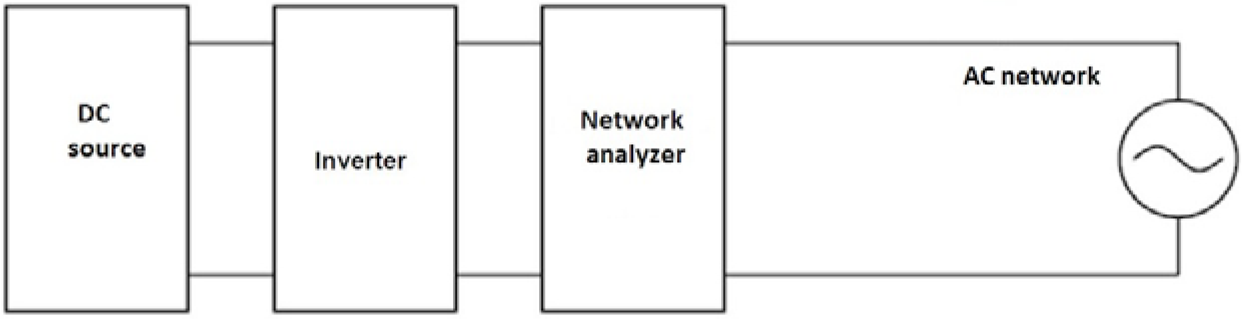
In order to prevent perturbations to the network, the parallel of generators of any type must only happen when the frequency and voltage measured at the output terminals [1] remain within the following limits for a time of 300 s (or not less than 60 s):

- voltage between 95% and 105% Vn; frequency between 49.9 Hz and 50.1 Hz (default setting, adjustment range between 49 Hz and 51 Hz).

1 Or to the connection point of the plant for the systems equipped with external Interface Protection

In addition the power delivery for production plants indirectly connected must be gradual, with a transition from the initial no load conditions at the instant the parallel is operated, to the value of available power with a maximum positive gradient not exceeding 20% per minute of the maximum capacity.

The verification of compliance to these requirements is envisaged by the circuit of Figure D2.



NOTE. The test circuit illustrated is related to single-phase systems; for three-phase systems will need to incorporate an equivalent three-phase circuit.

Figure D2 - Test circuit connection conditions

a) switch the inverter ON with AC voltage respectively less than 95% and greater than 105% of the nominal value Vn (while the frequency must be between 49.9 Hz and 50.1 Hz), and check that the unit prevents the parallel with the grid – no power output according to network analyzer.
b) After at least 30 s from the time of start of the test referred to in point a), check the persistence of the state "open", i.e. absence of output power. At this point bring the voltage within the limits - 95% Vn < V <105% Vn - and simultaneously disable the inverter. In these conditions then proceed to rearm, while checking that the parallel with the network and the start of the power delivery does not take place before at least 60 s from the time the inverter is enabled.
c) At this point it is necessary to simulate with the converter in operation a disconnection due to the voltage being respectively higher and lower than overvoltage and undervoltage thresholds, in order to verify that, when voltage is restored within the expected range 95% Vn < V < 105% Vn, the time before reconnection is at least 300 s.
d) Repeat the test described in a) with voltage - 95% Vn < V <105% Vn – and frequency respectively less than 49.9 Hz and greater than 50.1 Hz, checking that the unit prevents the parallel with the network - no power output according to network analyzer.
e) After at least 60 s from the time of start of the test referred to in paragraph d) check the persistence of the state "open", i.e. the absence of output power. At this point bring frequency f within the limits - 49.9 Hz < f < 50.1 Hz and simultaneously disable the inverter. In these conditions, then proceed to rearm, while checking that the parallel with the network and the start of the power delivery does not take place before at least 60 s from the activation of the inverter.
f) As for point c), it is necessary to simulate with the inverter in operation a detachment due to the frequency being higher and lower respectively than overfrequency and underfrequency thresholds, in order to verify that, when frequency is restored within the expected range 49.9 Hz < f < 50.1 Hz, the time before reconnection is at least 300 s.

The test may be carried out alternatively with a network simulator capable of changing the parameters of frequency and voltage available at the output terminals of the inverter, or directly to the electricity grid. In this case, test performance is allowed by adjusting the parameters that control frequency and voltage in grid connected conditions (of parallel) so that they fall outside the allowed values. To check the minimum delay before connection (start) or reconnection after the intervention of protections, the range of allowed V and f must be reset to default (95% Vn < V < 105% Vn, 49.9 Hz < f < 50.1 Hz). In any case the DC power source must be set to provide a power equal to the DC rated power of the inverter.

D.3.2.1.2 Verification of step release of the active power

The verification of delivery with gradual ramp up from no load up to the nominal value in at least 300 s is performed by recording with the network analyzer, during the test sequences b), c), e) and f), the average value of the parameters of the inverter output every 200 ms (5 samples/s). The samples recorded soon after the inverter exceeds a level of power delivery equal to 5% the rated power Pn, when shown on a graph, must be all below the limit curve P < 0.333% Pn/s with a maximum positive deviation of +2.5% × Pn.

D.3.2.2 Exchange of reactive power

D.3.2.2.1 Verification of constructional requirements: reactive power capability

Static converters used in power plants with power exceeding 10 kW prepared for applications under continuous operation in parallel to the network, must be able to work with power factor different from 1. The reactive power exchange with the network can be performed upon request of DEWA in the following cases:

- if there are needs for network management, in particular in order to contribute to the limitation of the voltage at the output terminals or on the LV line on which also other DG sources may be connected;
- with the aim of providing a network service ; such requirement only applies to plants with total power exceeding 10 kW and according to the regulatory conditions that may be issued by the competent Authority.

The tests referred to in this paragraph are intended to verify the "capability" of reactive power of static converters as a function of the active power, to ensure compliance of the minimum construction requirements, that is : :

a) for all inverters in plants with maximum capacity smaller than 10 kW,

   - an instantaneous power factor between cos φ = 0.98 in absorption of reactive (inductive behaviour) and cos φ = 0.98 in the provision of reactive (capacitive behaviour) ;

b) for all inverters in plants of maximum capacity equal to or larger than 10 kW,

   - an instantaneous power factor between cos = 0.90 in absorption of reactive (inductive behaviour) and cos = 0.90 in the provision of reactive (capacitive behaviour), according to the capability curve shown in Figure D3. In that case the reactive exchange is aimed at the limitation of mains overvoltage or undervoltage caused by the power plant releasing its active power;
   - absorption or delivery of a reactive power up to 48.43% of the rated active power, for any instantaneous value of the active power delivered, according to the capability curve shown in Figure D3, aimed at the supply of a network service requested by DEWA, at the conditions subject to specific regulations issued by the competent Authority..

For the purposes of this test (minimum requirements), the manufacturer shall indicate and set the regulation of maximum reactive power available when the active power output changes, with the aim of allowing the characterization of the maximum capability of the conversion system (since devices of smaller size could also be used on systems of maximum capacity equal to or larger than 10 kW).

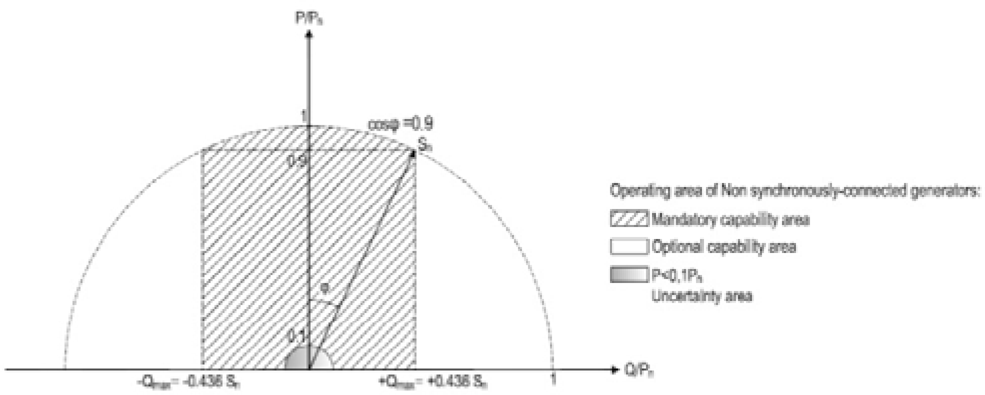


Figure D3- Capability curve for inverters in plants with maximum capacity equal to or larger than 10 kW.

D.3.2.2.2 Mode of execution and registration of the test results

With reference to the test circuit of Figure D2, the following requirements are defined.

- The inverter must be set so that it can respectively absorb (inductive behaviour) and deliver (capacitive behaviour) the maximum reactive power available at each level of the active power delivered according to its capability.

- Set the DC source in such a way that the converter can deliver in a sequence the active power included in the 10 bins [0-10]%; [10-20]%; ... ; [90-100]% of the nominal apparent power (average values at 1 min calculated on the basis of the values measured to the fundamental frequency on a time window of 200 ms).

- For each of the 10 levels of active power report at least 3 average values for inductive and 3 for capacitive reactive power, calculated at 1 min on the basis of the measurements at the fundamental frequency on a time window of 200 ms.

- In addition to the measurements taken to limit values for reactive power setting, record the measured values by setting the reactive power supplied to 0 (cos φ = 1).

The maximum capability of absorption (Qmin) and delivery (Qmax) of reactive power resulting from the sequence of the above measures and the measures for Q = 0 must be reported in a tabular form showing, for each level of active power output between 0% and 100% of nominal power, the corresponding level of reactive power consumption (and delivery), both in absolute terms and in terms of cos . The test is passed according to the conditions settled in D.3.2.2.2.1 or D.3.2.2.2.2.

D.3.2.2.2.1 Inverter in plants with maximum capacity up to 10 kW

The value of the instantaneous power factor resulting in each of the 10 measuring points is equal to or less than 0.98 in both modes of absorption (inductive behaviour) and delivery (capacitive behaviour) of reactive power.

D.3.2.2.2.2 Inverter in plants with maximum capacity larger than 10 kW

The value of the reactive power absorption (inductive behaviour) and delivery (capacitive behaviour) resulting in each of the 10 measurement points is external or at least coincident with the perimeter of the capability curve in Figure D3.

Table D10 - Consumption of inductive reactive power

Power – Bin	Active power [W]	Reactive power [W]	Power factor (cos φ)	DC Power [W]
0% - 10%				
10% - 20%				
20% - 30%				
30% - 40%				
40% - 50%				
50% - 60%				
60% - 70%				
70% - 80%				
80% - 90%				
90% - 100% (*)				

(*) Check that the minimum requirement of cos φ is steadily kept at the thermal equilibrium reached.

Table D11 - Supply of capacitive reactive power

Power – Bin	Active power [W]	Reactive power [W]	Power factor (cos φ)	DC Power [W]
0% - 10%				
10% - 20%				
20% - 30%				
30% - 40%				
40% - 50%				
50% - 60%				
60% - 70%				
70% - 80%				
80% - 90%				
90% - 100% (*)				

(*) Check that the minimum requirement of cos φ is steadily kept at the thermal equilibrium reached.

Table D12 - Supply of reactive power with set point Q = 0

Power – Bin	Active power [W]	Reactive power [W]	Power factor (cos φ)	DC Power [W]
0% - 10%				
10% - 20%				
20% - 30%				
30% - 40%				
40% - 50%				
50% - 60%				
60% - 70%				
70% - 80%				
80% - 90%				
90% - 100% (*)				

The test report must contain the results of measurements of the maximum reactive power absorbed (Qmin) and delivered (Qmax) from the converter also in the form of graph P vs. Q as a function of the active power fed into the grid. See the examples in Figure D4 (inverter in plants up to 10 kW) and Figure D5 (inverters for plants of total power larger than 10 kW).

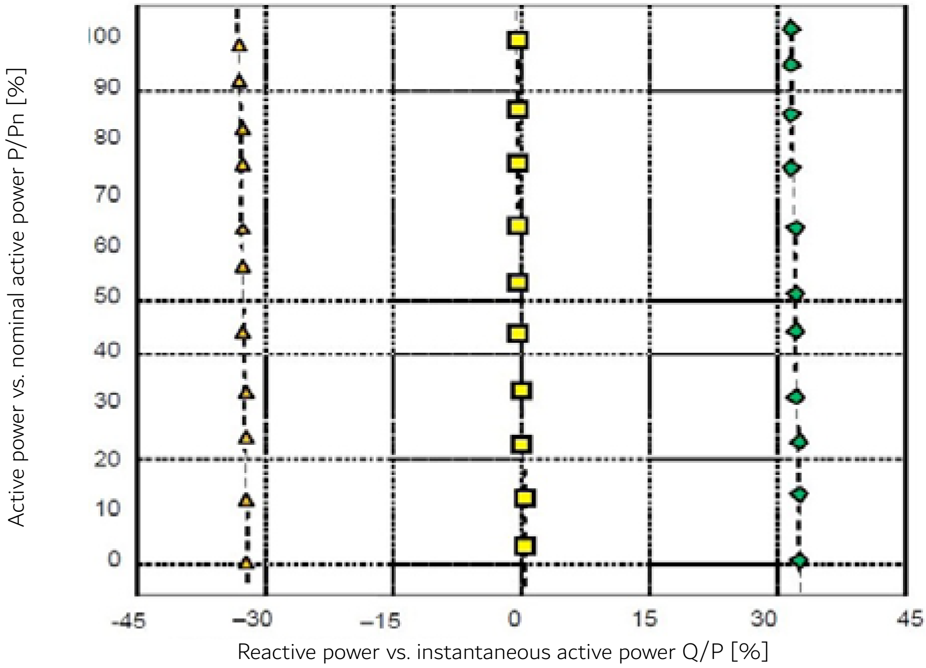


Figure D4 - Example of graph P vs. Q. Maximum inductive and capacitive reactive power delivered as a function of active power (here it is represented the case of a inverter power up to 10 kW, which must be able to supply a reactive power with a cos φ = 0.98)

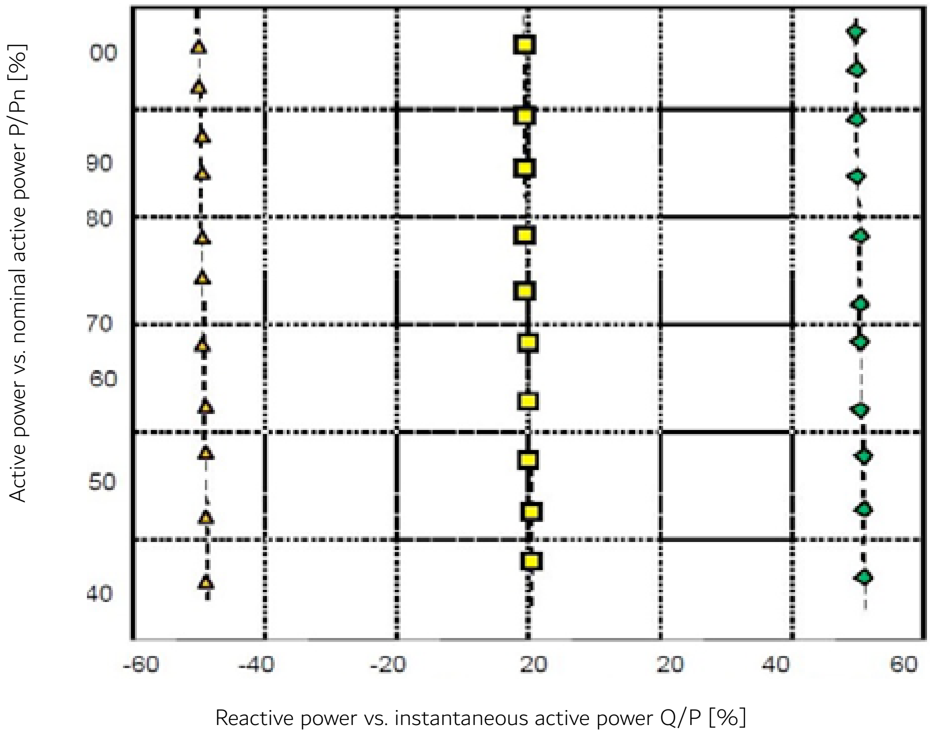


Figure D5 - Example of graph P vs. Q. Maximum inductive and capacitive reactive power delivered as a function of active power (here it is represented the case of an inverter as part of a plant with a maximum capacity larger than or equal to 10 kW, which must be able to absorb or deliver at any level of active power, reactive power of at least 48.43% of the nominal active power Qmin / Pn = 48.43% Pn according to the capability curve)

D.3.2.2.3 Exchange of reactive power according to an assigned level

The DRRG power plants must participate in the control of the voltage of the grid. For inverters in plants of maximum capacity equal to or exceeding 10 kW the possibility of implementing a strategy of centralized control via remote control signal is envisaged.

The tests covered in this section are required only for inverters in power plants with maximum capacity larger than or equal to 10 kW.

The purpose of the test is to verify the ability of the inverter control system to perform the command for adjusting the level of reactive power within the maximum limits of capability both in absorption and in delivery of reactive power, and to verify the adjustment accuracy.

In the absence of a protocol defined to exchange control commands, it is left to the manufacturer to determine how to perform the commands for setting the point of work of reactive power, both as regards the physical signal (analog, on serial protocol, etc.) and for the adopted control parameter (setting according an absolute value of the reactive power Q or as a cos φ value).

D.3.2.2.3.1 Mode of execution and registration of the test results (assuming Q regulation)

- Set the DC source so that the inverter delivers about 50% of the active power nominal Pn.
- Using the methods and the control parameter specified by the manufacturer, vary the reactive power supplied by the inverter, switching from the maximum inductive value (at least equal to Qmin ≤ -0.4843 Pn) directly to zero (Q = 0), and then go from zero to the maximum capacitive value (equal to Qmax ≥ 0.4843 Pn).
- Maintain each of the 3 set-point limit for a time of 180 s.
- Calculate the mean values at 1 minute of reactive power on the basis of the values measured on a time window of 200 ms at the fundamental frequency. The calculation of the 1 minute averaged value must start from samples taken after 30 s from the command of the new set-point of the reactive power, this to ensure that the system has reached steady state.

The test is passed successfully if the maximum deviation between the level assigned and the current value measured for the reactive power is equal to::

- ΔQ ≤ ± 2.5% of the rated active power of the converter (direct setting of level of reactive power)
- Δcos φ ≤ ± 0.01 (set via the power factor)

The test shall be documented both in tabular and graphic form, as shown in the examples of Table D13 and Figure D13.

Table D13 - Measurement accuracy of the reactive power control based on an external command

	Set-point reactive power Q/Pn [%]	Measured reactive power Q/Pn [%]	Deviation from the set-point ΔQ/Pn [%]
Qmax|ind]	-48,43		
0	0		
Qmax|cap]	+ 48,43		

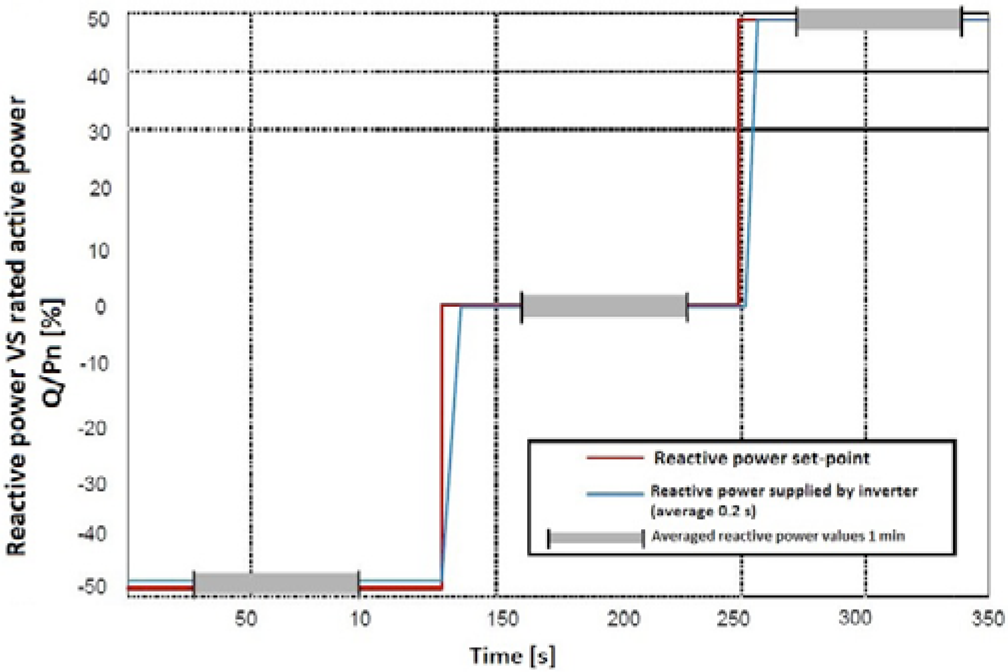


Figure D6 - Measurement of reactive power supplied on the basis of an external command, verification of accuracy

D.3.2.2.4 Time response to a step change in the level assigned

In addition to the requirements covered by the tests referred to in paragraph D.3.2.2.3, relative to the control of the network voltage through the supply of reactive power, it is necessary not only to verify the accuracy of the control system of the converters, but also their response time when a step change in the level of reactive power requested via an external command is applied.

As per the requirements of the preceding paragraph, in this case the tests are required for inverters installed in power plants with maximum capacity larger than or equal to 10 kW, which must be able to implement a strategy of centralized control via signal remote control. It remains to the manufacturer's option to voluntarily carry out the tests also for inverters of smaller size.

The purpose of the test is to measure the response time of the inverter to a step applied to the command of reactive power delivery, passing from one level to another level with the process described below and illustrated in Figure D7.

- According to the results of the capability tests referred to in paragraph D.3.2.2.1, detect the values of + Qmax and - Qmin of the maximum capacitive and inductive reactive power that can be delivered by the converter respectively at 50% and 100% of the nominal active power .
- Put in a graph similar to the template of Figure D7 the values measured as a 0.2 s average of the reactive power during the execution of commands for adjusting the reactive power with a step change when the inverter is providing an active power equal to 50% (Test 1) and 100% of the nominal active power Pn (Test 2).

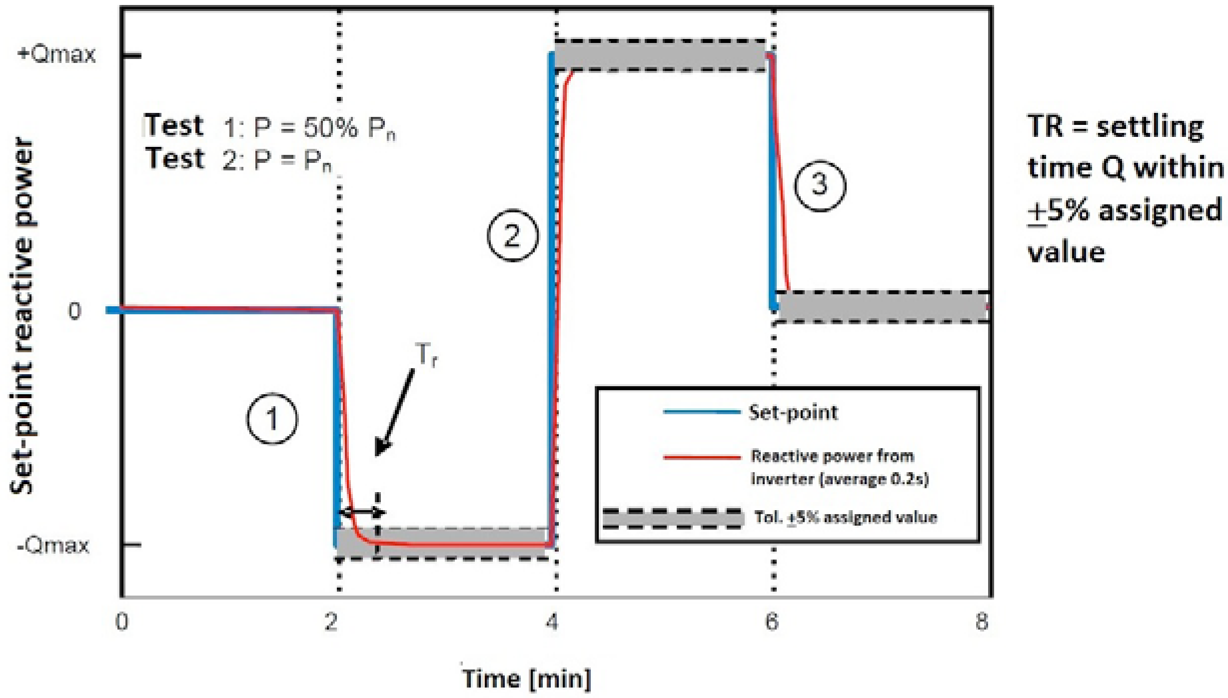


Figure D7 - Measurement of the response time to a step change of the set-point assigned for reactive power

- Detect the response time (Tr = settling time in the graph of Figure D7), that is equivalent to the time that elapses from the instant of application of the new set-point to the instant in which the reactive power reaches a value in a range included within a band of ± 5% of the new set value.
- As shown in Figure D7, the response time has to be detected at a variation of the set-point from zero to - Qmin (step 1), from - Qmin to +Qmax (step 2), and from + Qmax to zero (step 3).

The values of the response time must be documented in the test report, which must also indicate the values of + Qmax,

- Qmin, the AC test voltage and the method used to send the control command of the set-point of the reactive power. The test is passed if the maximum response time reported is less than 10 seconds in all the measurement conditions.

The test is passed if the maximum response time reported is less than 10 seconds in all the measurement conditions.

D.3.2.2.5 Automatic delivery of reactive power according to a characteristic curve cos φ = f (P)

All static converters in plants with maximum capacity larger than or equal to 10 kW must be able to absorb reactive power in an automatic and autonomous (local control) logic according to a characteristic curve of the power factor vs. active power = f (P).

The test aims to verify that the inverter follows the procedures for automatic delivery of the reactive power according to the characteristic curve standard cos φ = f (P) below defined (curve of type b).

The standard curve is defined uniquely by the linear interpolation of the three characteristic points:

A: P = 0.2 Pn; cos φ = 1
B: P = 0.5 Pn; cos φ= 1
C: P = Pn; cos φ = cos φ_max

where cos φ_max is equal to 0.98 (inductive) for converters up to 10 kW and 0.90 (inductive) for converters of size exceeding 10 kW.

The control according to the characteristic curve is enabled when the voltage measured at the output terminals exceeds the "critical" lock-in value (e.g. set to V = 1.05 Vn).

The value of voltage lock-in that enables the delivery mode automatic power reactive and that during the tests must be set to 1.05 Vn (the "default" also for the production of the series) shall be adjustable between Vn and 1.1 × Vn with intervals 0.01 Vn.

The value required for the lock-in voltage should be specified in the Connection Agreement.

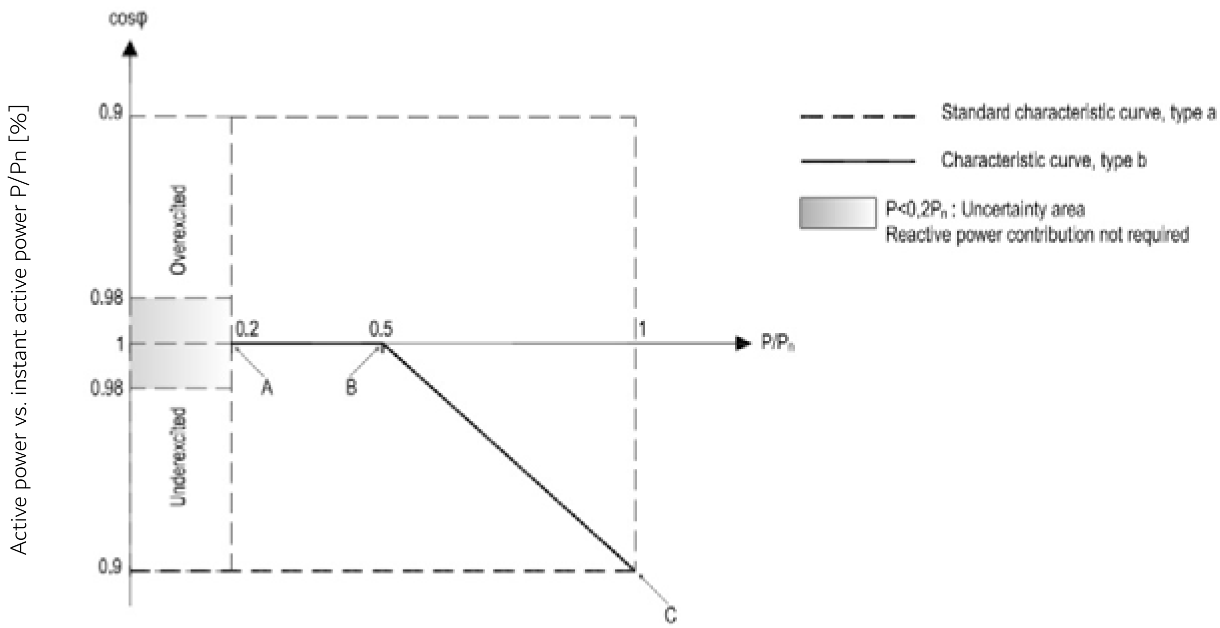


Figure D8 - Characteristic standard curve cos φ= f (P)

It must be borne in mind that the setting time to the new maximum value of reactive power on the characteristic curve have to be adjusted automatically by the inverter within 10 s (see the tests on the trip time in D.3.2.2.4).

The automated adjustment mode is disabled when:

- the active power P output falls below 50% of Pn (point B), defined as the power lock-out, independent of the voltage at the terminals, or:
- the voltage read at the output terminals of the converter falls below the lock-out limit, to be set to a default value equal to Vn, but that must be adjustable in the range of 0.9 Vn and Vn with Vn intervals of 0.01.

D.3.2.2.5.1 Verification of compliance with the rules for the application of the characteristic curve

With reference to Figure D8, for the verification of compliance to the rules for application of the characteristic curve, type b), proceed as follows.

a) Connect the inverter as shown in the test circuit of Figure D2 (directly to AC mains, provided this is adjustable from 0.9 Vn up to 1.1 Vn, or through a network simulator).
b) Enable the type b) curve by acting on the converter according to the manufacturer's instructions.
c) Set the DC source so that the active power supplied by the converter is equal to 20% of the nominal power P = 0.2 Pn (point A), with voltage at the output terminals Vn equal to or not exceeding 1.04 Vn (assuming that the lock-in parameter is set to 1.05 Vn).

d) Measure active power, reactive power and power factor cos φ as averages over 0.2 s, report such values in a table (see Table D12) and in a graph similar to Figure D8.

e) Repeat the measure referred to at above point D) by increasing the active power delivered by steps of 10% of rated power, from 20% Pn up to 60% Pn. Check at the same time during this test, the AC voltage to output terminals does not exceed the limit value V = 1.04 Vn.

f) Report in Table D12 the values of the active power, reactive power and cos φ detected during the measurements performed at 5 levels of active power output from 20% to 60% of rated power. In these conditions, being AC voltage at the output terminals less than 1.05 Vn, the inverter must NOT enable the delivery of reactive power.

g) At this point, with the AC power still delivering at the last level reached before (P = 0.6 Pn), increase the network voltage (or by the simulator), so as this is equal to 1.06 Vn when at the limit "critical" V = 1.05 Vn.

h) Repeat the measure referred to in above point D) by increasing the delivered active power by steps of 10% of rated power, from 60% Pn up to 100% Pn (always with AC voltage read at the output terminals higher than 1.05 V = Vn).

i) Report in the Table the values of active power, reactive power and cos φ detected during the measurements carried out at 5 levels of active power delivered from 60% to 100% of the nominal power. In these conditions, being the AC voltage to output terminals greater than 1.05 Vn, the inverter must enable the delivery of reactive power following the characteristic standard curve.

j) With the inverter in full supply of active power, AC voltage output higher than 105% Vn and therefore reactive power output equal to the maximum limit (cos φ = 0.90 for powers higher than 10 kW in reactive absorption), reduce the ac voltage bringing it to the rated value, and check that the reactive power remains attached to the maximum limit value. This is to verify that, once exceeded the value of Lock-In "critical" voltage, the inverter remains in the mode of reactive power delivery according to the characteristic standard curve, maintaining this behaviour for all the output voltage values exceeding the Lock-Out threshold (default threshold set to Vn).

For each operating point, the maximum deviation of cos φ compared to the expected value according to the characteristic standard curve must be less than Δcos φ_max ≤ ± 0.01.

Table D14 – verification of the delivery of reactive power according to the characteristic curve standard cos φ = f(P)

P/Pn [%]	P [W]	Q [Var]	cos φ Measured	Cos φ Expected	Δ cos φ
20%					
30%					
40%					
50%					
60%					
70%					
80%					
90%					
100%					

NOTE Characteristic curves different from the standard curve according to the type of network, the load and the power input could be required by DEWA. However, the characteristic curve cos φ = f(P) is, in general, uniquely defined as a polygonal line passing through the three points A, B and C of Figure D8.

For this reason, the manufacturer, in addition to an in factory pre-setting of the control system according to the "Standard" curve of the type described in this paragraph subject to verification by tests, must parameterize the curve to make it adjustable by varying only the 3 points A, B and C.

Consequently, the so-called "fixed cos φ" control method (type a) curve), does not require verification, as it can be derived from the characteristic curve cos φ = f (P) in a consistent manner by setting the parameters of adjustment of points A, B and C as follows:

A = B:	P = 0.05;	cos φ = 1
C:	P = Pn;	cos φ = cos_max

D.3.2.3 Active Power Limitation

The tests to be performed on the active power limitation mode will address both the automated mode as a function of frequency and that based on a centralized logic by remote control.

D.3.2.3.1 Control of active power in the presence of transients on the transmission network

The purpose of the test is to check the function of automated reduction of active power in case of overfrequency, through the extrapolation of a graph of P as a function of frequency.

Two sets of measurements have to be performed: starting from 100% of rated power (sequence A) and starting from 50% (sequence B).

For each measurement sequence gradually increase the frequency and measure the value of power (average values of 0.2 s). The test can be performed either by means of a network simulator capable of changing frequency parameters available at the output terminals of the inverter, or directly on mains. In this case it is allowed to adjust the frequency parameters that control the power regulation system in the case of overfrequency, so as to simulate the progressive increase in the frequency and the subsequent coming back around the nominal value.

At the end of each sequence the frequency shall be reset to a value close to the nominal one, in order to verify that time requirements are fulfilled for the gradual restoration of the power delivered before the transition frequency (i.e. before exceeding the limit of 50.3 Hz).

D.3.2.3.1.1 Performance of the tests (2)

- Connect the device to be tested according to the instructions provided by the manufacturer.
- Fix all the parameters of the simulated network to the respective values of normal operation.
- Bring all the parameters of the equipment under test to the respective values of normal operation, so that the AC power at the inverter output is equal to the maximum AC power deliverable for the sequence A, or 50% in the case of sequence B.
- Perform the measurements on 7 points (the frequency value will have an uncertainty of maximum ± 10 mHz) according to the following time sequence:
  1) f = 47.51 Hz (t1 for the sequence A, t'1 for the sequence B)
  2) f = 50 Hz + 0.2 Hz (t2 for the sequence A, t'2 for the sequence B)
  3) f = 50 Hz + 0.40 Hz (t3 for the sequence A, t'3 for the sequence B)
  4) f = 50 Hz + 0.60 Hz (t4 for the sequence A, t'4 for the sequence B)
  5) f = 50 Hz + 2.49 Hz (t5 for the sequence A, t'5 for the sequence B)
  6) f = 50 Hz + 0.11 Hz (t6 for the sequence A, t'6 for the sequence B)
     At this point perform step 7) by bringing the frequency back to the nominal value for the check of the gradual recovery of the maximum delivery (Sequence A) or 50% of the maximum power (sequence B):
  7) f = 50 Hz (t7 for the sequence A, t'7 for the sequence B).

2 In order to perform the tests, possible restrictive thresholds on the frequency protection must be disabled

D.3.2.3.1.2 Results of tests

The results are to be presented in a table and a graphic trend extrapolated on the basis of these (with two curves representing respectively Sequence A and Sequence B, as shown from example in Figure D9). Expected performance for the sequence A and sequence B must also be represented in the chart.

The test is passed if the following conditions are fulfilled for both sequences A and B:

- for each of the 6 points from t1 (t'1) to t6 (t'6) the difference between the expected value of active power and that measured falls within a tolerance of ± 2.5% Pn, where Pn is the rated power of the inverter;

- when mains frequency is restored to the nominal value (step 7 of the sequences in D.3.2.3.1.1), the inverter must keep the minimum level of power attained during the previous frequency increase, for a minimum waiting time equal to 5 minutes, after which it will have to gradually restore the supply with a positive maximum gradient not exceeding 20% / minute of the power supplied before the increase in frequency (stored value).

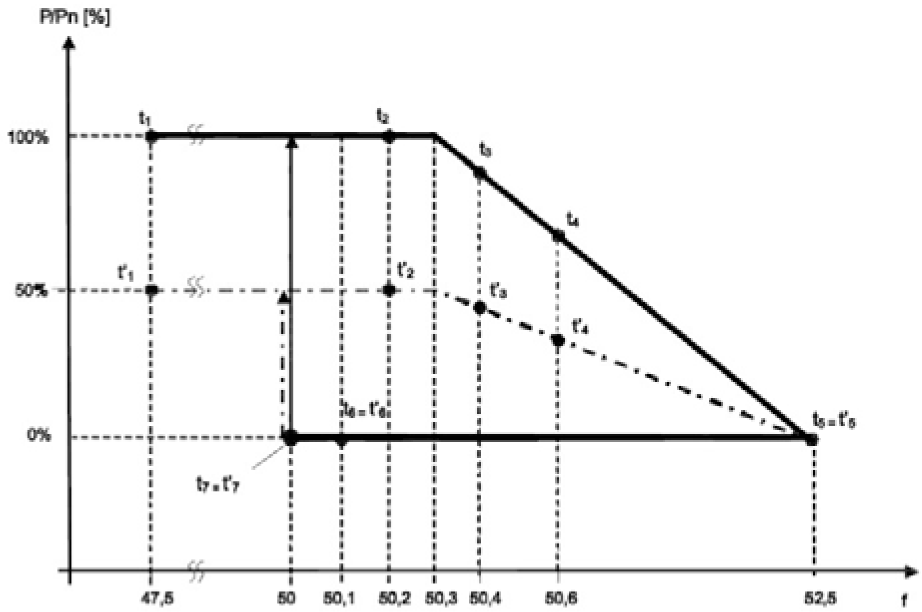


Figure D9 - Curves of active power limitation with respect to the frequency

D.3.2.3.2 Active Power Limitation upon external command

The ability to reduce the active power generated as a result of a signal received from a remote control centre must be tested, by agreeing in advance with the inverter manufacturer the mode of signal collection and processing.

The procedure described hereinafter will be used.

- Set the inverter to produce 100% of the nominal power.
- After 1 minute of operation, reduce the power to 90%.
- Give 1-minute time for the inverter to run the command, and then measure the value of active power (averaged over 1 minute). The deviation from the set point in the minute of measurement shall be within ± 2.5% Pn, to consider the test valid and passed.
- Afterwards, reduce the power of a further 10%, keep that value for 2 more minutes, and repeat until the value of 0% Pn is reached.

In the measurement related to the set point Pn 10% check in accordance to the standards requirements, and then the measured power must be in the range between 12.5% Pn and 0, to consider the test valid and passed.

The test results shall be tabled like in D15:

Table D15 - Verification of active power limitation upon external control

Set point P P/Pn [%]	Set point P [W]	Measured P [W]	Accuracy
100%			
90%			
80%			
70%			
60%			
50%			
40%			
30%			
20%			
10%			
0%			

In addition, the results shall be reported on a graph containing the trend of the set-point, of the measured average power values as well as their tolerances with reference to the set-point.

The chart below shows an example of the performance of the set-point (black) and of the average power (red) for each measurement, which must all be within the grey areas of tolerance, in order to consider the test successfully passed.

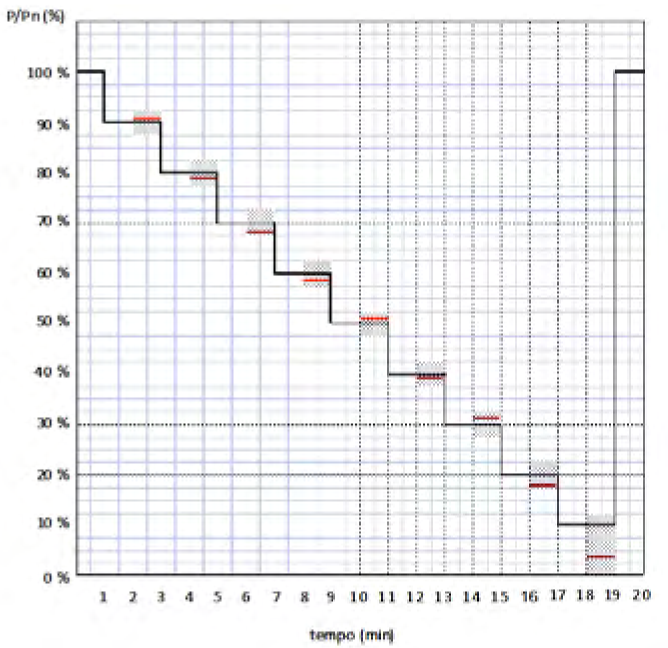


Figure D10 - Example of active power limitation upon application of an external command

D.3.2.4 DC component in the output current

D.3.2.4.1 Verification of emission of a DC component

The test is to be performed as follows:

The test is to be performed as follows:

1. The voltage (or simulator) must be initially set to a value equal to the nominal voltage ± 1% (frequency of 50 ± 0.2 Hz). The total voltage distortion (THD) must be less than 2.5% (inverter switched off). In case a simulator is used, it must produce a sinusoidal voltage with negligible DC offset (<0.1%).

2. The input DC source must be adjusted so that the voltage is equal to the nominal MPPT stated by the manufacturer (or average of minimum and maximum MPPT values, if the nominal value is not declared) and the AC power of inverter output, measured in volt-ampere, is equal to (33 ± 5)% of the nominal value declared by the manufacturer.

3. The system will be left to work in the conditions mentioned in the previous paragraph for at least 5 minutes or the time required to stabilize the inverter internal temperature.

4. At this point measure the DC component of the current injected into the grid (frequency < 1 Hz) on each of the output phases. The measurement should be taken by averaging the measured variable on a time window of up to 1 sec, by recording the performance for a minimum period of 5 minutes and collecting a minimum number of samples equal to the reciprocal of the time window over which the parameter was averaged (in the case of 1 sec, at least 300 samples). With the same procedures measure and record the rms current and rms voltage output of the inverter.

5. Repeat steps 2), 3) and 4) with the converter operating respectively at (66 ± 5)%, and (100 ± 5)% of the nominal power, measured in volt-ampere.

For each power level:

a) calculate the average value of the rms current and rms voltage on each phase. For each parameter, the average must be calculated considering all samples taken during the measurement period.

b) Check that the average value of the rms current of each phase as calculated in step a) is within 5% of the set value (respectively 33%, 66% and 100% of the nominal value) .

c) Check that the average value of the rms voltage of each phase as calculated in step a) is within 5% of the nominal value.

d) Compute the average value of the DC component of the current on each phase. The average is to be calculated by considering the absolute value (i.e. without sign) of the value of each sample recorded during each observation period of 5 minutes (for the 3 power levels).

e) For each phase, divide the average value of the DC component calculated in step d) by the nominal value of the output current of the inverter and multiply this ratio by 100. The calculated values represent the percentage of DC current fed into the grid for each phase, as compared to the nominal current of the inverter.

f) The DC component measured in accordance with this procedure has to be within the specified limits. For indicative purposes, Table D16 shows an example of representation of the test results.

Table D16 – Test report – Measurement of the DC component injected into the grid

Power Level (% nominal VA)	(33 ± 5) %	(66 ± 5) %	(100 ± 5) %
watt			
V rms			
A rms			
PF			
Cos φ			
DC (mA)			
DC (In%)			

NOTE: This test circuit applies to single-phase systems. For three-phase systems will need to incorporate an equivalent three-phase circuit.

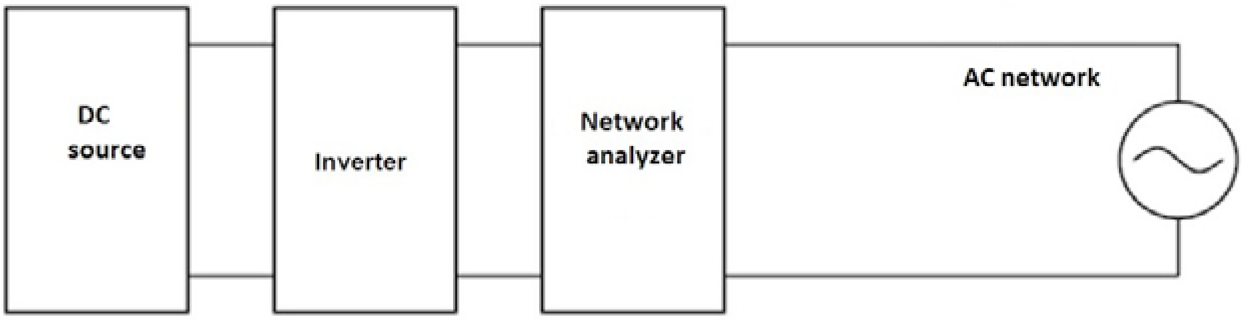


Figure D11 - Test circuit for the measurement of the DC component

D.3.2.4.2 Verification of protections to prevent the injection of a DC component

The test shall be performed as follows:

1. The inverter is connected to a test circuit similar to that shown in Figure D11.
2. Mains voltage (or in the simulator) must be maintained within a value equal to nominal voltage ± 1% (frequency of 50 ± 0.2 Hz). The total voltage distortion (THD) shall be less than 2.5% (inverter off). In case a simulator is used, it must produce a sinusoidal voltage with negligible DC offset (<0.1%).
3. The DC source input must be adjusted so that the voltage is equal to the nominal MPPT stated by the manufacturer (or average of the minimum and maximum MPPT values, if the nominal value is declared) and the AC power of inverter output, measured in volt-ampere, is equal to (33 ± 5)% of the value declared by the manufacturer.
4. The check that the inverter shuts down when the first protection threshold Idc > (> 0.5% In) is exceeded, can be made alternatively as described in points a) and b):
   a) Through a simulation of the drift of the symmetry control of the converter, with modalities to be agreed with the manufacturer and likely to induce an offset on Idc larger than 0.5% of the nominal current. Shutdown must occur within 1 second from the instant of application of the offset.
   b) In the measurement device of the DC component (e.g. current transformer or resistance) a DC current greater than 0.5% of the nominal current is impressed. Shutdown must occur within 1 second from the instant of application of the current imbalance.
5. The check that the inverter shuts down, when exceeding the second protection threshold Idc >> (> 1 A) is carried out alternatively as described in paragraphs c) in case the protection is built into the control system of the converter, or d) for external protections:

a) Through a simulation of the fault, by a measurement, carried in a manner to be agreed with the manufacturer, it must be assessed whether an abnormal plant operation due to a DC component on the current injected into the network exceeding 1 A, brings to the shutdown within 0.2 s after the simulated fault condition is triggered.

b) In the measurement device of the DC component (e.g. current transformer or resistance) a DC current greater than 1 A is impressed. The shutdown must occur within 0.2 s after the fault current is impressed.

6. Repeat steps 2), 3) and 4) with the converter operating respectively at (66 ± 5)%, and (100 ± 5)% of the nominal power, measured in VA.

NOTE: to measure response times and check the levels of fault current (> 1 A DC) or drift (> 0.5% In) a network analyser can be used with built-in oscilloscope, or an oscilloscope equipped with current probes suited to measure DC components.

D.3.2.5 Verification of insensitivity to voltage dips (LVRT capability)

These tests have the purpose to verify that the inverter, if used in plants of maximum capacity larger than or equal to 10 kW, is insensitive to voltage dips according to the voltage-time profile shown in Figure 8. In particular, the tests aim to verify that the following functional requirements are met:

- in the non-hatched area the RRGU shall not disconnect from the network. Performance with a zero voltage for 200 ms shall be endured. The temporary interruption of the production of active and reactive power is in this case allowed;
- in the hatched area the RRGU may be disconnected;
- within 200 ms from the restoring of a network voltage included in the range 85% Vn ≤ V ≤ 110% Vn (grey shaded area), the RRGU will restore the export of active and reactive power to the network as it was before the fault occurrence, with a maximum tolerance of ±10% of the RRGU rated power. If the voltage is restored, but it remains in the range 0.85 Vn ≤ V ≤ 0.9 Vn a reduction in the produced power is admissible.

The verification of compliance with the requirements for immunity to voltage dips is made according to the test sequences reported in Table D17, to be performed with the equipment under test working respectively:

a) between 10% and 30% of the nominal power and
b) above 90% of the nominal power.

For each of the sequences a) and b) the system has to operate under the set conditions for at least 5 minutes or the time necessary for the internal temperature of the converter to stabilize.

The interface protection must be disabled or adjusted to avoid nuisance tripping during the test run.

The fault simulation system must produce the voltage dip profile as reported in Table D17 and Figure 8 both at no load operating condition and when connected to the equipment under test. The result of each sequence must be documented as follows:

- Time behaviour of active power P, reactive power Q and the phase voltages at the output terminals L1, L2, L3, as moving average of rms values computed in a cycle (20 ms) and updated every half a cycle (10 ms), on a time window that begins 100 ms before the test begins and ends at least 400 ms after the end of the transient voltage (in order to monitor the restoration of active and reactive power). The voltage transient ends when the voltage is more than 85% of the rated voltage.
- In the same observation period, oscillograms of voltages and of the phase currents (possibly with enlarged detail of the trend during the rising edges and falling voltage) shall be recorded.

Table D17- Sequence of tests for verifying immunity to temporary voltage dips. Amplitudes, duration and shape related to no load test conditions.

Tests	Residual amplitude of phase-phase voltage V/Vn (i)	Duration [ms]	Shape (ii)
1 – symmetric 3 phase fault	0.05 ± 0.05 (V1/Vn)	= 200 ± 20	
2 – symmetric 3 phase fault	0.45 ± 0.05 (V2/Vn)	= 400 ± 20	
3 – asymmetric 2 phase fault	0.05 ± 0.05 (V3/Vn)	= 200 ± 20	
4 – asymmetric 2 phase fault	0.45 ± 0.05 (V4/Vn)	= 400 ± 20	
5 – LV asymmetric 2 phase fault	0.05 ± 0.05 (V5/Vn)	= 200 ± 20	
6 – LV asymmetric 2 phase fault	0.45 ± 0.05 (V6/Vn)	= 400 ± 20	

(i) The values of residual voltage are shown in per unit of the nominal MV line voltage, hence referred to the voltage levels required for failures caused on MV lines.

(ii) Regardless of the method used to simulate the transient (network impedances, simulator or any other method), the falling and rising edges of voltage must be shorter than 10ms.

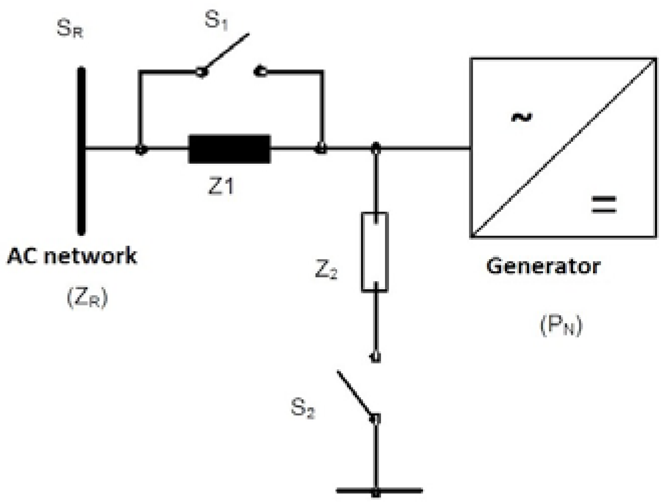


Figure D12 - Example of test circuit for simulating the temporary voltage dips

The tests can be performed using, for example, the test circuit shown in Figure D12. Voltage dips are reproduced by a circuit that simulates a short circuit connecting either the three or the two phases to ground via impedance (Z2), or connecting either three or two phases together via the same impedance. Switches S1 and S2 will allow the definition of the time profiles of individual test sequences.

For the sizing of the test circuit, the following considerations apply:

- The impedance Z1 is used to limit the effect of the short circuit on the power grid that feeds the test circuit (short circuit current limitation). The sizing of Z1 must be in a way to allow a maximum short circuit current of 800 A per phase (in particular in the worst case, that is with 5% residual voltage Vn).
- A bypass switch S1 is usually employed to prevent overheating of the series impedance Z1 before and after the execution of each sequence.
- The voltage drop is created by connecting the impedance Z2 to ground or to another phase, via the switch S2. The value of Z2 must be calculated to produce a voltage at its terminals equal to the values of residual voltage specified in Table D17 (no-load conditions)

- As AC network it has to be intended the low voltage three-phase network. Laboratories are not allowed to connect directly to a public LV network. Hence, the testing laboratory shall be provided with a MV connection and a MV/LV transformer.
- The closing and opening of switch S2 determines the duration of the event when the voltage drops, therefore its control must be accurate in simulations of both two-phase and three-phase faults. The switch can be for example a contactor of suitable size.
- In the absence of the generator, the test circuit must ensure that the envelope of the voltage during the simulation corresponds to that of the graph of Figure D4. The duration of the transient voltage drop must be measured from the instant of closure to that of reopening of switch S2. The tolerances dashed in Figure D13 take into account the deviations and delays in closing and opening of S2 and the gradient of voltage drop and rise. Any deviations from the chart below should be adequately documented and justified in the test report.

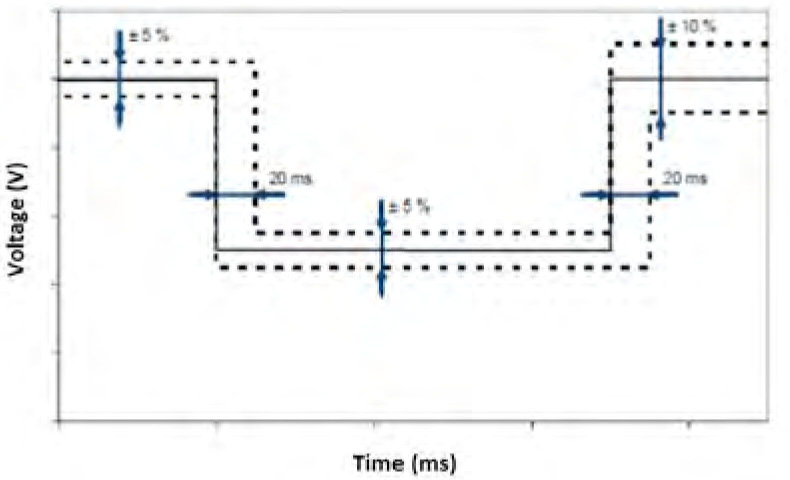


Figure D13-Tolerances of amplitude and time for the test sequences of mains voltage drop (LVRT Test) (Source: IEC 61400-21)

Use of alternative test circuits is allowed and, in particular, of network simulators (Figure D14).

When using a network simulator, this must:
1. ensure the possibility of independent control of the amplitude and phase angle of the three voltages
2. be built with adjustable impedances Z1, Z2 and Z3, ZN parameters in order to reproduce the typical network parameters.

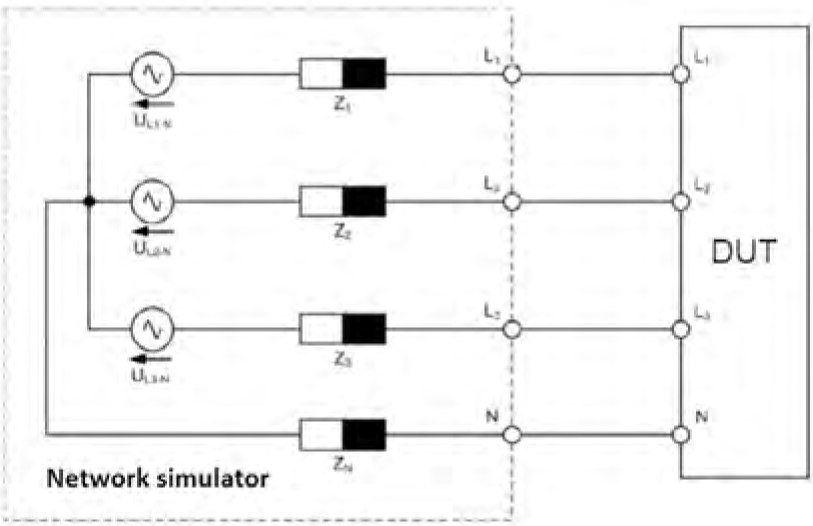
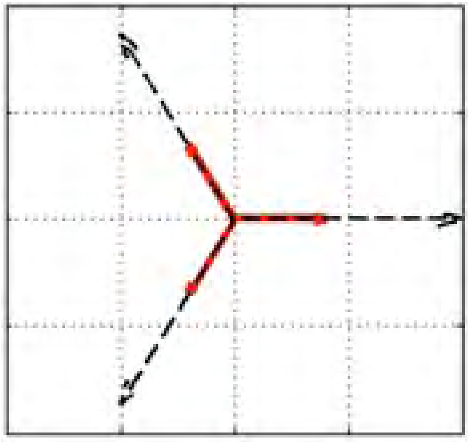


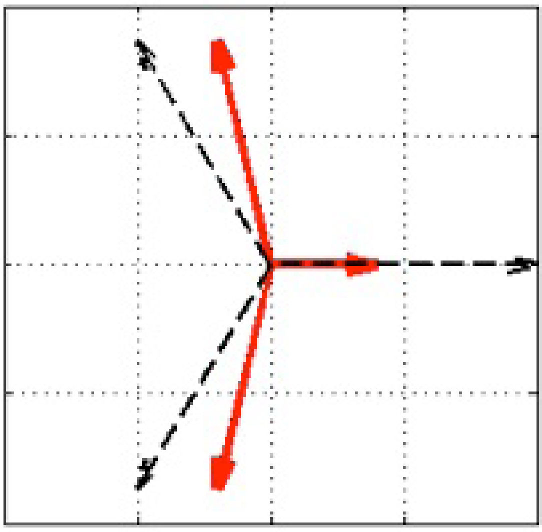
Figure D14 - Network simulator

With reference to the list of Table D14, the voltage drops here tested are actually caused by faults in the low, medium or high voltage networks. The types of fault considered include:



1. three-phase symmetrical fault (Table D17 Tests No. 1 and 2)
2. phase-to-phase (2-phase) asymmetrical faults (Table D17, Tests No. 3 and No. 4)

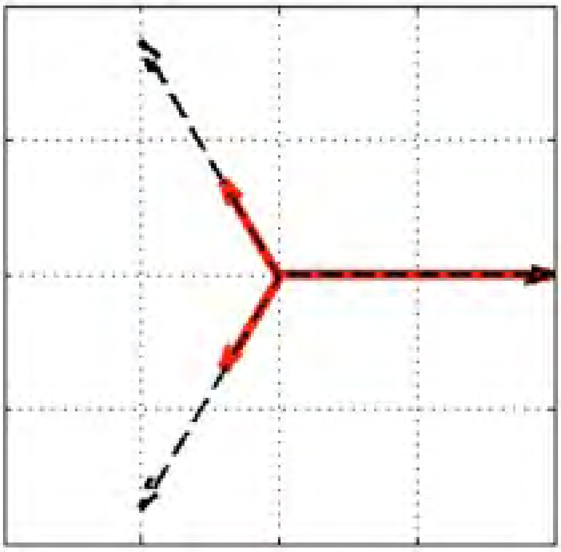
Fault in MV, which causes in LV a change not only in amplitude but also of the phase relationships between voltages (the case considered foresees the presence of a Dy transformer in a secondary substation).



During the phase-to-phase asymmetrical fault, the residual amplitude of the 3 voltages and the shifts between phases must comply with the values in the following Table.

Test N.	V/Vnom	Phase to ground Voltage			Phase angles		
		u1/u1n	u2/u2n	u3 / u3n	ϕu1	ϕu2	ϕu3
1	0.05 ± 0.05	0.87 ± 0.05	0.87 ± 0.05	0.05 ± 0.05	27 °	-147 °	113 °
2	0.45 ± 0.05	0.90 ± 0.05	0.90 ± 0.05	0.45 ± 0.05	15 °	- 135 °	115 °
Norm. Cond.	1	1	1	1	0 °	-120 °	120 °

3. Asymmetrical phase-to-phase (2-phase) fault in the LV network (Table D17, Test No. 5 and No.6)



These voltage variations propagate along the low voltage distribution network lines with amplitude of individual voltages and phase angles that are dependent on the characteristics of the transformers in the distribution substations, in particular on their vector group and impedance.

Therefore, in order to correctly simulate the effects of two-phase faults on the low voltage side of the line, the conditions that arise on the LV lines when the fault is induced on the MV portion of the distribution line are to be reproduced through the simulator, including the phase shifts due to the presence of asymmetric two-phase faults.

D.3.2.6 Verification of insensitivity to automatic reclosing under phase mismatching

This type of test can be performed in two ways:

1. with inverter connected to a simulated network (D.3.2.6.1)
2. with inverter connected to distribution network (D.3.2.6.2 and D.3.2.6.3 alternatively).

The generator must not be damaged as a result of the tests. The shutdown and the protection intervention are however allowed.

D.3.2.6.1 Test on simulated network

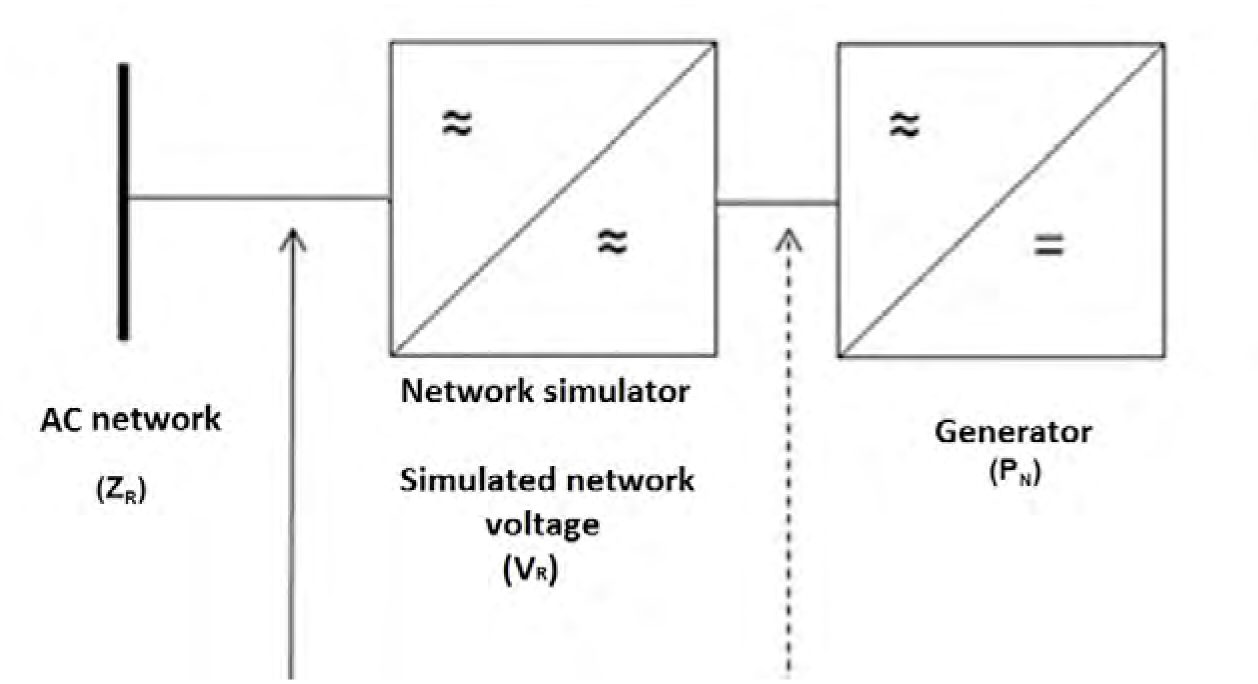


Figure D15 - Circuit for the verification of insensitivity to automatic reclosure with phase mismatch via network simulator

With reference to the diagram in Figure D9 - Use of the simulated network:

- The network simulator must be able to produce phase jumps of the inverter output voltage of 90° and 180° respectively;
- Generator: inverter working at rated power with unity power factor (cos φ=1);
- VR : voltage of the simulated network.

The generator shall be brought into operation at rated power. The system will be left to work in the set conditions for at least 5 minutes or the time required to stabilize the inverter internal temperature.

Two tests shall then be performed, inducing a transient which suddenly introduces a phase shift on the simulated network voltage VR equal to 180° and 90° respectively.

The test report shall include:

- the angle between the voltages measured before and after the phase jump by means of an instrument having a precision of 1°;
- the current of the generator, measured on a time window which lasts from 20 ms before the simulated network voltage phase jump to at least 200 ms after this phase jump..

D.3.2.6.2 Test on the distribution network via a coupling transformer

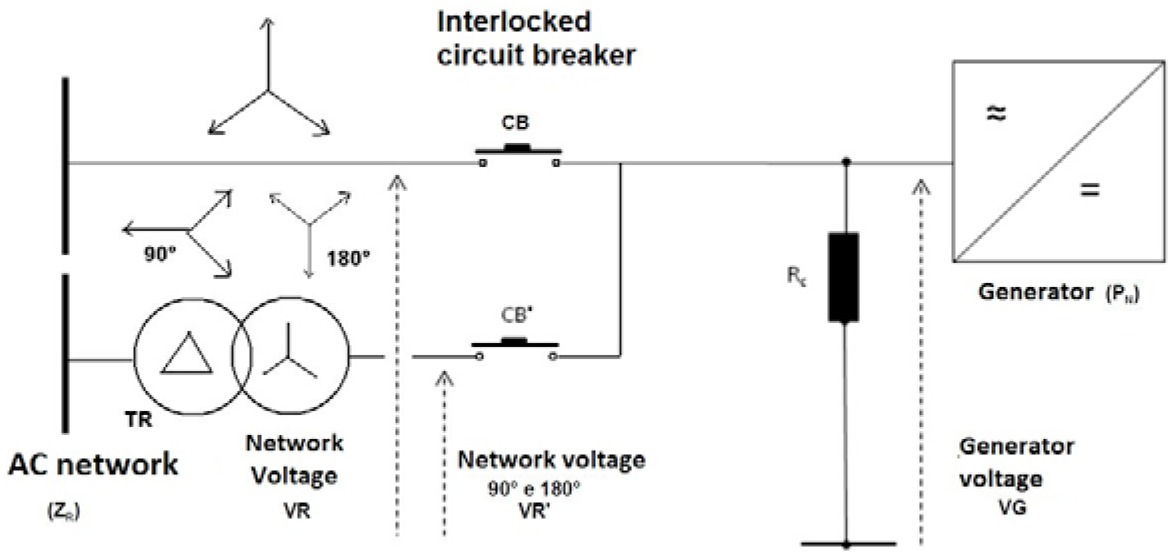


Figure D16 - Circuit for the verification of insensitivity to the automatic reclosure with phase mismatch by means of coupling transformer

With reference to the diagram shown in Figure D15 - Circuit for the verification of insensitivity to the automatic reclosure with phase mismatch via network simulator – this test envisage the use of a coupling transformer:

- TR: transformer with open columns, to configure YYn or DYn as a function of the test to be performed
- Generator: inverter working at rated power with unity power factor (cos φ = 1)
- Rc: resistive ballast load, power equal to the nominal power of the inverter
- VR: voltage of distribution network
- VR': voltage with 90° and 180° phase mismatch with respect to the distribution network, as a function of the test to be performed
- VG: voltage applied to the generator.

The contactor CB is closed, the contactor CB' is open.

The generator shall be brought into operation at rated power. The system will be left to work in the set conditions for at least 5 minutes or the time required to stabilize the inverter internal temperature.

Check that, for at least 1 minute, the current through the circuit breaker CB is less than the 2%. The measured value shall be reported in the test report.

Then open the contactor CB and close contactor CB', in a coordinated way and simultaneously (neglecting the time difference on opening and closing times). The ballast resistance attenuates electrical transients at the inverter output and prevents the inverter disconnection from the network.

The generator shutdown or the protection tripping can only occur afterwards the complete closure of the contactor CB'.

Two tests shall be performed, with phase angle at closure equal to 180° and at 90° respectively. To this purpose the vector group of the transformer TR must be reconfigured in appropriate way.

The test report shall include:

- the angle between the two measured voltages by means of an instrument having a precision of 1°;
- the current of the generator as a result of the closure, measured on a time window which lasts from 20 ms before the mains voltage phase jump to at least 200 ms after this phase jump

.

D.3.2.6.3 Test on the distribution network, simulation of the frequency drift

With reference to the diagram in Figure D17:

- CB: controlled switch or contactor. The making capacity for both, must be adequate. The closing time must be known and stable
- Generator: inverter working at rated power with unity power factor ($\cos\varphi = 1$)
- Rc: Resistive ballast load, with size equal to inverter rated power
- Zc: Drifting reactive load . Zc will be sized to absorb reactive current of the order of 1% as compared the nominal current of the inverter. The actual value and the nature of this impedance (either inductive or capacitive) shall be agreed with the inverter manufacturer and reported in the test report.
- VR: voltage of distribution network
- VG: voltage of generator in islanding condition on the ballast load.

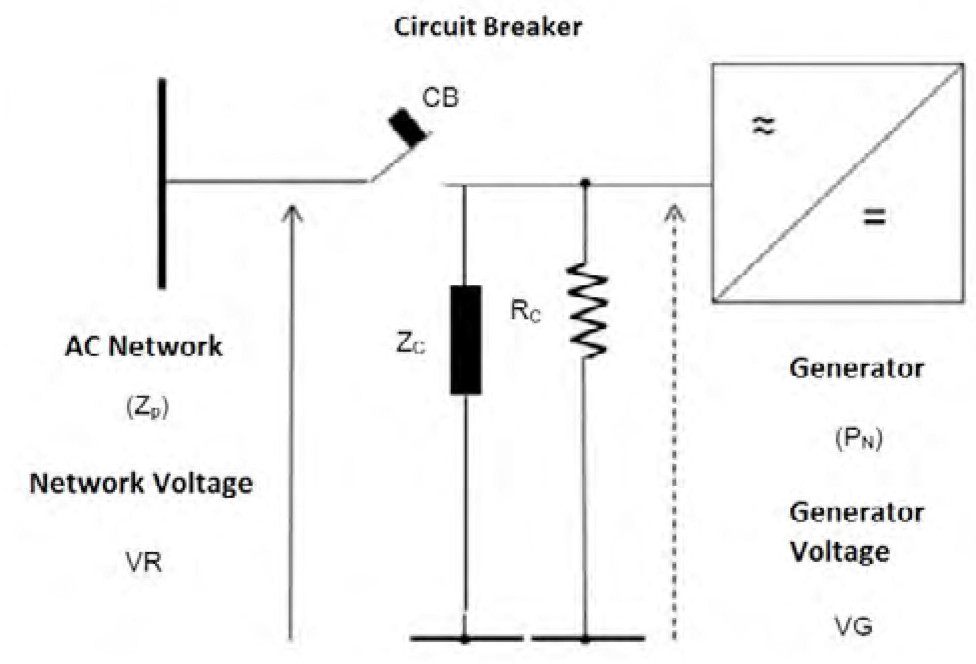


Figure D17 - Circuit for the verification of insensitivity to the automatic reclosure in phase mismatching. Direct connection to the distribution network and simulation of frequency drift

The generator shall be brought into operation at rated power. The system will be left to work in the set conditions for at least 5 minutes or the time required to stabilize the inverter internal temperature.

Because the islanding operation is not expected on grid connected inverters, for the execution of this test it may be necessary to alter certain parameters of control and regulation.

The MPPT algorithm is to be disabled.

For static generators, any internal protection against the loss of mains other than those described in this rule, e.g. based on the measurement of the impedance, phase shift, etc., should be excluded, as well as the protections and controls in frequency that can disconnect the generator.

Check that, for at least 1 minute, the current through the circuit breaker CB is less than 2%. The measured value should be reported in the test report.

At this point the frequency of the inverter drifts with a dynamic dependent on the parameters and the technology of the inverter being tested. The load Zc contributes to make the system unstable and may be not necessary for the performance of the test.

The setup should ensure that the frequency drift is sufficiently slow to allow the observation of the phase difference between VR and VG through an oscilloscope with isolated channels.

Two tests shall be performed, with phase angle at closure equal to 180° and at 90° respectively.

The generator must not be damaged as a result of the tests. The off-service and the intervention of any protections are allowed.

The test report shall include:

- the angle between the two measured voltages with a tool having error of 1°;
- the current of the generator as a result of the closure, measured on a time window that runs from 20 ms before to at least 200 ms after the phase jump of mains voltage.

D.4 Inverters for Medium Voltage connected RRGUs

D.4.1 Scope

This section contains test protocols to be applied to static generators, typically for photovoltaic grid-connected systems. This section is for equipment and plants to be connected to MV distribution network.

D.4.2 List of tests and reference conditions

The inverter must be certified and labelled in order to demonstrate the compliance with all the safety standards in force in UAE (like for example the European "CE" mark, which is a guarantee of compliance with applicable directives LV, EMC, ...). In particular, the technical dossiers required for assessing compliance with the aspects of Electromagnetic Compatibility and Electrical Safety must be produced.

In addition, the same shall have successfully passed the following tests:

D.4.3 Measurements to assess the quality of the voltage;
D.4.4 Check the operating range of voltage and frequency;
D.4.5 Verification of conditions for synchronization and load pickup;
D.4.6 Verification of constructional requirements for reactive power exchange;
D.4.7 Verification of constructional requirements for active power control;
D.4.8 Verification of insensitivity to voltage dips (LVRT capability);
D.4.9 Verification of insensitivity to automatic reclosing while in phase mismatching

NOTE: EMC tests have to be carried out by accredited laboratories or, alternatively, at the customer premises, through evaluation of testing results, under the supervision of the accredited laboratory that is in charge to perform the remaining required tests.

The tests, if carried out in a laboratory, must be performed on the equipment in the reference conditions of Table D18.

Considering the size of the generators used for installations connected to MV network, the characteristics of the primary source and the difficulty of performing tests in an environment where the climatic conditions are controlled, deviations are allowed from the reference values of Table D18, provided they are appropriately documented in the test report.

If the tests are carried out on site, under the environmental conditions that generators actually undergo when operating, it is not possible to guarantee the stability and uniformity of the environmental conditions within the same test, between tests performed in sequence or as well as between different tests carried out on the same generator or on different generators in different places and time intervals.

For all of such cases the previous comments apply, that is the test report shall include the average value of the "quantities of influence" shown in Table D18 detected during the observation time period for each test.

Table D18 - Terms of reference for the performance of the tests in the laboratory

QUANTITIES OF INFLUENCE	REFERENCE VALUES
Environmental temperature	25°C ± 5°C
Atmospheric pressure	96 kPa ± 10kPa
Relative humidity	65%RH ± 10%RH
Position of the equipment	According to the manufacturer declaration
Frequency	50 Hz (in the field 47.5Hz – 52.5Hz, wherever applicable
Waveform of the reference voltage	Compliant to EN 50160

D.4.3 Measurements of Voltage Quality

The measurements of harmonic currents and voltage fluctuations have to be carried out in accordance to paragraphs D.4.3.1, D.4.3.2, D.4.3.3 . Given the uncertainty and unpredictability of the harmonic emissions of User installations and / or equipment including static generators (inverter), they shall not anyway induce disturbances that prevent the normal operation of the network, e.g. invalidating the remote management of electronic metering equipment according to the in force rules, the correct operation of remote tripping or any other remote signals and controls that use the frequency band assigned for the exclusive use of DEWA, for the transmission of signals on the LV network.

The User equipment must not, therefore, introduce interference conducted in the said frequency range on the LV network.

If this does not occur, the User must implement corrective actions (Active Filters) or replace the disturbing equipment, even in the absence of a defined and consolidated IEC standard covering the above frequency range.

D.4.3.1 Measurement of harmonic currents

For the measurement of harmonic currents IEC 61400-21 (section 7.4, harmonic and interharmonic currents and high frequency components) applies. The requirements related to the measurement (calculation methods and uncertainty related to measurements) are according to IEC 61000-4-7.

The measurement is done by assessing the contribution of the harmonic generator, for each power value in the 11 bins [0 ± 5%] ; [10 ± 5]%; ... ; [100 ± 5]% of rated apparent power. In some cases (for example in the case of field measurements) the responsibility of the measured harmonic currents cannot be attributed only to a generator, but it should be better attributed to an interaction between the generator and other loads / users on the network.

D.4.3.2 Measurement of voltage fluctuations due to isolation / separation manoeuvres

The determination of voltage fluctuations, due to switching operations, is carried out in accordance to IEC 61400-21.

For the full evaluation of disturbances at least three switching operations at the generator nominal power must be made, recording the results of each operation. Furthermore, the maximum power factor kImax for all switching operations must be determined.

D.4.3.3 Measurement of voltage fluctuations (flicker) in continuous operating conditions

The determination of flicker is carried out in compliance with IEC 61400-21 (paragraphs 6.3.2 and 7.3.3, voltage fluctuations in continuous operation). The procedure is described for wind turbines but can be adapted to static generators such photovoltaic inverters. The following test methods are allowed.

- Measurements on field (to the point of connection of the network): the flicker is determined with measurements carried out at the actual point of connection of the inverter to the grid (according to the procedure described in IEC 61400-21).

- Using a DC source, on field or a network simulator AC: Flicker is determined by an appropriate DC voltage source, at the actual point of network connection or (alternatively) using a network AC simulator.

- Using a DC source and an AC network simulator with adjustment of the network impedance: if the simulated network allows the adjustment of the phase angles of network impedance, this should be adjusted to values of 30°, 50°, 70° and 85°, tolerance +/- 2°. The values of flicker can be directly measured with an adequate flicker meter compliant with IEC 61000-4-15. The values of resistance and reactance of the impedance of the network must be designed so that the results of the measurements show a value of Pst greater than 0.4.

For the verification of power quality (harmonics and flicker) appropriate methodologies will be defined to account for the presence of pre-existing voltage distortion at the point connection of the generator under test.

D.4.4 Check of the voltage and frequency operating range

The test is intended to check the capacity of the generator to maintain the connection with the network for an indefinite time in the allowed range of voltage and frequency:

- 85% Vn ≤ V ≤ 110% Vn
- 47.5 Hz ≤ f ≤ 52.5 Hz

The test shall assess that a stable operation occurs at the extreme limits of voltage and frequency ranges for a minimum of 5 minutes, for each operating point.

D.4.4.1 Static generators

D.4.4.1.1 Tests at full power on the simulated network

At least 2 tests shall be performed, with the equipment operating at nominal power connected to a network simulator set as follows:

- Test 1 (*): V = 85% × Vn ; f = 47.5 Hz; P = 100% × Sn ; Cosφ = 1

  (*) It is permitted to operate at reduced power, equal to the maximum output deliverable related to the maximum allowable output current (P ≥ 85% × Sn)

- Test 2 (**): V = 110% × Vn ; f = 52.5 Hz; P = 100% × Sn ; Cosφ = 1

  (**) During this sequence it is necessary to disable the automatic power reduction in case of overfrequency.

If the network simulator size is smaller than the size of the converter, testing is still possible. This can be performed by interposing in parallel between the converter and the simulator input a balanced three phase resistive load whose power is equal to or slightly higher than that of the converter (provided the excess does not exceed the flow rate that the simulator can supply). This ensures the stable operation of the simulator in the delivery of power and therefore it allows running the test even using unidirectional (non-regenerative) network simulators or a variable frequency Gen-set.

In the case of photovoltaic conversion systems, the primary source can be simulated by a DC source provided this is capable of continuously delivering the inverter rated power.

During the test it will be necessary to record frequency, voltage and active power measured at the output terminals of the generator with a frequency of at least 1 sample per second. The power output will have to remain stable within a range of ±5% × Sn with reference to the value set for the duration of each test sequence.

D.4.4.1.2 Tests at reduced power on the simulated network

As an alternative to the process described in D.4.4.1.1 it is possible to perform a test using the following procedure in case the test circuit specified above cannot be set up because of the construction and the size of the inverter, or due to the lack of a power source and / or network simulator with suitable characteristics and size.

<u>Test on a network simulator at reduced power</u>, provided the simulator has a size of at least 30kW and the converter is able to operate in a stable manner at this power level (sequences similar to above Test 1 and 2, carried out at reduced power). The same considerations made in D.4.4.1.1 apply as to the recording of results.

D.4.5 Verification of conditions for synchronization and load pickup

D.4.5.1 Verification of synchronization conditions

The test is intended to verify that the generator control system enables the parallel and synchronization to the network ONLY when both following conditions occur.

- Voltage stable between 95% and 105% of Un; frequency between 49.9 Hz and 50.1 Hz (default setting, adjustment range between 49 Hz and 51 Hz).

- minimum time at voltage / frequency within the limits mentioned above before enabling the parallel equal to:

- T = 60s, in case of a new plant start, or to reconnect after maintenance and, in general, at the restart after a disconnection not related to the intervention of IPS protection.

- T = 300s, in case of restart after intervention of IPS protection (time adjustable in steps of 5s in the field 0s-900s)

D.4.5.1.1 Tests at full power on the simulated network

As to the test circuit, the details reported in D.4.4.1.1 apply. Wherever the use of a network simulator able to modify the parameters of frequency and voltage available at the output terminals of the generator is possible, the procedure involves the following steps:

a) Power the generator respectively with AC voltage less than 95% and greater than 105% of nominal value Un (while frequency has to be between 49.9Hz and 50.1Hz), and check that the unit does not enable the parallel with the grid – no power output read by the network analyzer.

b) After at least 60 seconds from the start of the test referred to point a), check state is "open", i.e. no delivery of output power. At this point bring the voltage U within the limits - 95% Un < U <105% Un – and at the same time, disable the generator. In these conditions proceed to reset, checking that the parallel with the network and the start of the power delivery does not take place before the expiration of at least 60 s from the moment of activation of the static generator.

c) At this point simulate with the generator into operation, a disconnection when overvoltage and undervoltage thresholds are exceeded, in order to verify that, once voltage is back within the limits 95% - Un < U < 105% Un, the time to wait before reconnection is at least 300s.

d) Repeat the test described in a) with voltage 95% Un < U <105% Un and frequency respectively lower than 49.9Hz and higher than 50.1Hz, checking that the unit does not enable the parallel with the network - no power output read by the network analyser.

e) After at least 60 seconds from the moment of start of the test referred to at point d), check the state of "open", i.e. no delivery of output power. At this stage bring frequency f within the limits - 49.9Hz < f < 50.1Hz - and the same time, disable the generator. In these conditions, then proceed to reset, checking that the parallel with the network and the start of the power delivery does not take place before at least 60 s from the moment of activation of the static generator.

f) As for point c), with the generator into operation simulate a disconnection when thresholds of overvoltage and undervoltage are exceeded, to verify that, once the voltage is back within the limits 49,9Hz < f < 50.1Hz, the time to wait before reconnection is at least 300s.

D.4.5.1.2 Alternative test methods

To verify operating ranges one of the following alternative methods can be applied. Static converters (and Full wind power converters):

D.4.5.1.2. a) <u>A test on the simulator at reduced power</u>, provided the simulator is of size at least equal to 30kW and the converter is able to operate in a stable manner at this power level. The same considerations made about D.4.5.1.1 apply with reference to the sequence of the test and the expected results.

All generators to which it can be applied, including static converters:

D.4.5.1.2. b) <u>Test the control system only</u>, via signal generator able to simulate the frequency and voltage, the latter with possible scaling. Generally, this test can be performed only in the generator (inverter) on stand-by and disconnected from the network. Therefore, the test in such cases will simply record in a suitable form, the generator enabling signals available as outputs from the control system, as well as the set-point which determines the gradual ramp for load pickup following the start-up.

D.4.5.1.2. c) With generator connected to the network, the test will proceed as in D.4.5.1.2.b), setting in sequence to the input terminals of the control system, values of frequency and voltage assumed in D.4.5.1.1 - letters from a) to e)-, ensuring that the behaviour and timing of activation are compliant with what there reported.

D.4.5.1.2.d) With generator connected to the network with changeable control parameters, in this latter case to perform the tests it is allowed to adjust the parameters of frequency and voltage that monitor the conditions of the parallel of the generator so that they are outside actual network - frequency and voltage – values. To check the minimum delay to the connection (start) or reconnection after intervention of protections, in the frame of such test, the allowed limit values of, respectively, U and frequency should be reset to default (95% Un < U < 105% Un, 49.9Hz<f<50.1Hz). All such matter under the assumption that the system allows to modify the parameters, while the machine is connected to the network or anyway not in standby. The test sequence is similar to that reported in D.4.5.1.1.

D.4.5.2 Verification of step release of the active power (load pickup)

During the parallel load pickup must be done gradually, with a positive power gradient of not more than 20% × PM/ min, where PM is the maximum active power of the generator.

The verification is performed, in the case the testing is operated as reported in D.4.5.1.1, D.4.5.1.2.c) and D.4.5.1.2.d), recording during the test sequences b), c), e) and f) with the network analyzer the generator output power at a rate of one sample per second. The samples recorded from the instant at which the generator exceeds a level of power delivery equal to 10% × Pn, plotted on a graph, must all be below the limit curve P < 0.333% Pn/s, with a maximum positive deviation of +2.5% × Pn. In case of using a network simulator with limited power - set-up shown in D.4.5.1.2. a) - the same acquisition schedule will be performed, limiting the verification to the first portion until the limit power of the simulator is reached. Finally, the test for a case similar to D.4.5.1.2.b) will be similar to those of the tests at full power when the reading of the output power is replaced by the output of the parameter at the control system that manages the limit of deliverable power.

D.4.6 Verification of constructional requirements for reactive power exchange

D.4.6.1 Verifying the capability to supply reactive power

For static generators different capability curves are required depending on the maximum capacity of the plant.

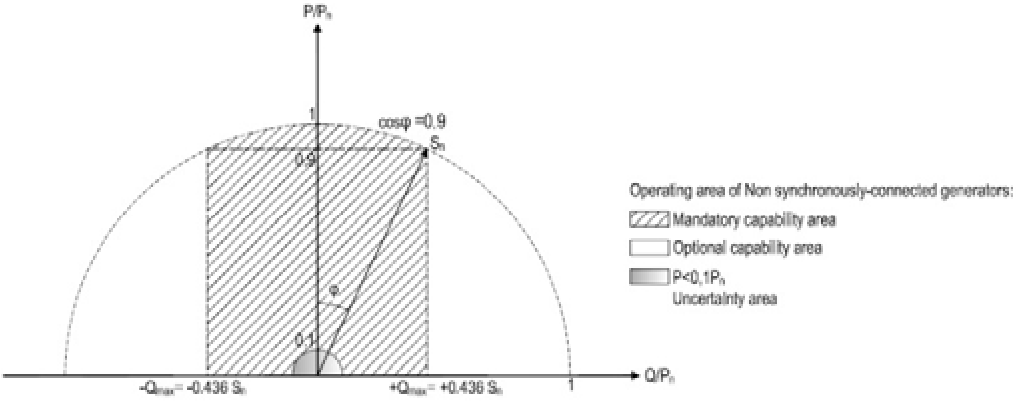
- Generators of plants having maximum capacity lower than or equal to 400 kW: inverters must have a minimum capability of type 'semi-circular limited' with cos φ between 0.90 in absorption and 0.90 in supply (refer to Figure D18, the characteristics of the type of Figure D19, however, are recommended as they allow to provide services to the network);
  For low values of the generated active power (S≤10%Sn) deviations are allowed in the supply of reactive power measured on the edge of the capability curve in correspondence of a predetermined value of S, up to a maximum of 10% of Sn.

- Generators of power plants with maximum capacity higher than 400 kW: the inverters must have a capability of type ' semi-circular ' whose area of work is the inner one in the graph of Figure D19. At this time, compliance with performance requirements of specific capability in the band S≤10%Sn is not required.

For both types of static generators, the active power they can deliver in the basic operating condition at nominal voltage and cos φ =1 coincides with the nominal apparent power of the generator.

In any case, all the points of the capability curves are referred to generators operating at nominal voltage.

The tests referred to in this paragraph are intended to test the "capability" of supplying reactive power while the active power changes.



Legend:

Sn: apparent nominal power deliverable at the nominal voltage Vn

Qmax: maximum reactive power deliverable at the nominal apparent power

Figure D18 – Capability for static generators in plants with power < 400 kW (limited semi-circular characteristic)

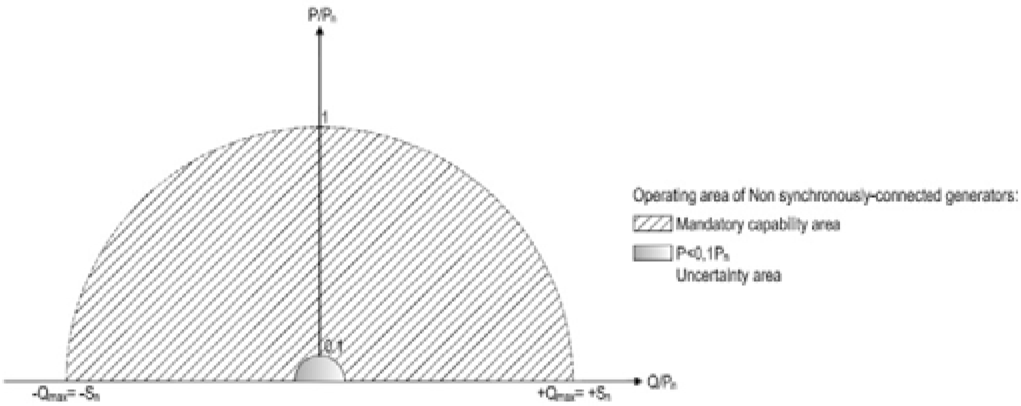


Figure D19 – Capability for static generators in plants with power ≥ 400 kW (semi-circular characteristic)

For the purposes of this test (minimum requirements), the manufacturer shall indicate and set the regulation of reactive power to vary the maximum available active power output, with the aim of making the characterization of the maximum capability of the inverter possible.

For a behaviour like that shown in Fig D8, the generator will also have to deliver reactive power, therefore the maximum deliverable active power shall necessarily be lower than the nominal apparent power.

D.4.6.1.1 Mode of execution and registration of the test results

The measurements can be carried out either by an acquisition test in field (e.g. a test facility) or on a test bench, provided it is representative of the actual operating conditions of the generator.

For the performance of the test, the following requirements apply.

- The inverter must be set so that it can respectively absorb (inductive behaviour) and deliver (capacitive behaviour) the maximum reactive power available at each level of active power output based on its capability.

- Set the DC source in order to make available at least the full rated active power of the generator under test; further adjustments are possible during the test, so that the source is not limiting for the performance to be measured.

- Set (either by setting the source or by setting the system that controls the inverter under test), the active power for power values in the 11 bins [0 ± 5]%; [10 ± 5]%; ... ; [100 ± 5]% of nominal apparent power; make active power measurements in steady state beginning about 1 minute after completion of the adjustment (1 min average values calculated on the basis of the values measured at the fundamental frequency on a time window of 200 ms).

- For each of the 11 levels of active power, record a value of the reactive inductive power and a value of the reactive capacitive power, evaluated as average values at 1 min calculated on the basis of the values measured at the fundamental frequency on a 1s time window. Even the power factor must be detected and reported as an average of 1 minute.

- In addition to the measurements taken at the limit values of the reactive power setting, record the measured values by setting the reactive power supplied to 0 (cos φ= 1).

The maximum absorption (Qmin) and delivery (Qmax) capability of reactive power resulting from the sequence of the above measurements and that for Q = 0 must be documented in a tabular report, indicating for all levels of active power output between 0% and 100% of the nominal apparent power, the corresponding level of reactive power consumption (and delivered), expressed both in absolute terms and in p.u. of the nominal apparent power and terms of cos φ.

The test is successfully passed if the measured value, reported in a graph P - Q, is all external or coincident to the perimeter of the minimum capability of Figure D18 for generators to be used in plants with maximum capacity smaller than or equal to 400 kW, or are on the perimeter of the semicircle shown in Figure D19 for those intended for plants with maximum capacity greater than 400 kW. For each measured point a maximum deviation of reactive power $\Delta Q \leq \pm 5\%$ of the nominal apparent power of the converter is allowed.

NOTE for S values ≤ 10% × Sn the tolerance limits and the exceptions above listed apply. Particularly, deviations are allowed in the supply of reactive power up to a maximum of ±10% of the apparent nominal power of the inverter as compared to the theoretical value of the capability curve for inverter in plants with maximum capacity smaller than or equal to 400 kW. For use in plants with maximum capacity greater than 400 kW the recording of the capability values available in correspondence to values of apparent power delivered less than 10% × Sn is required but the results do not represent a binding prescriptive performance.

The maximum value of reactive power consumption (inductive behaviour) and delivered (capacitive behaviour) resulting in each of the 11 measuring points must be reported in a table similar to the example in Table D19 below. It will then generate 3 tables, for the cases of maximum inductive reactive power, maximum capacitive and behaviour with set-point Q = 0..

Table D19 - Recording the maximum capability P-Q (3 tables, Qmax Ind; Qmax Cap, Q = 0) p.u. = per unit of rated apparent power Sn.

Power – Bin	Active power		Reactive power		DC power [W]		Power factor (cos Ψ)
	[kW]	p.u.	[kVA]	p.u.	[kW]	p.u.	
0% ±5%							
10% ±5%							
20% ±5%							
30% ±5%							
40% ±5%							
50% ±5%							
60% ±5%							
70% ±5%							
80% ±5%							
90% ±5%							
100% ±5%							

The test report must contain the results of measurements of the maximum reactive power absorbed (Qmax Ind) and output (Qmax Cap) from the converter in the form of a graph P (Q) as a function of the active power fed into the grid, all expressed in per unit of apparent power Sn.

D.4.6.2 Exchange of reactive power according to an assigned level

RRGUs must participate in the control of the mains voltage. The possibility to implement a centralized control strategy via remote control signal is also envisaged.

The purpose of the test is to verify the ability of the control system of the converter to perform the command level adjustment of reactive power between the upper limits of the "semi-circular limited" capability curve according to the definition given in D.4.6.1 and shown in Figure D18 in both reactive power absorption and delivery and to verify the accuracy of the adjustment.

In the absence of a specified protocol for the exchange of control commands, the manufacturer has faculty to determine how to execute commands to set the reactive power working point, both as regards the physical signal (analog, on-serial protocol, etc.) and for the control parameter (setting according an absolute value of the reactive power Q, or as a value of cosΨ).

D.4.6.2.1 Mode of execution and registration of the test results (assuming Q regulation)

The measurements can be carried out either through acquisition campaign in the field (e.g. on a test facility) or on a test bench in the laboratory, provided it is representative of the actual operating conditions of the generator (availability of simulated primary source). The following procedure refers to laboratory conditions, but can also be used for measurements in the field, where necessary, replacing the simulated source with the primary and setting the test so that the generator is capable of delivering an active power close to 50% Sn (± 10% × Sn).

- Set the DC source so that it does not present a limit (in power) for the performance of the inverter under test (the setting of the active nominal power of the inverter shall be possible); arrange for the regulation of the active power of the inverter, adjusting it to approximately 50% × Sn.

- Using the methods and the control parameter specified by the manufacturer, vary the reactive power supplied by the inverter, switching from the maximum inductive value (at least equal to Qmax,ind ≤ -0.436 × Sn) directly to zero (Q = 0), and then go from zero to the maximum capacitive value (equal to Qmax,cap ≥ +0.436 × Sn) .

- Maintain each of the 3 set-point limits for a time of 180s.

- Measure the reactive power supplied by the inverter, at least after 30 seconds from the time the command of the new set-point adjustment of the reactive power is sent (this is to ensure that the system has reached a steady state).

The test is successfully passed if the maximum deviation between the level assigned and the actual measured value (average value within a time window of 1 minute) for the reactive power is equal to:

- $\Delta Q \leq \pm 5\%$ of the nominal apparent power of the converter (direct setting of level of reactive power)

- $\Delta \cos \varphi \leq \pm 0.02$ (set via power factor)

The test shall be documented in both tabular and graphic form, as shown in examples of Table D20 and Figure D20.

Table D20 - Measurement of the accuracy of the reactive power control on the basis of an external command

	Set point Reactive power Q/Sn [%]	Reactive power measured Q/Sn [%]	Deviation from the set-point ΔQ/Sn [%]
Qmax,ind	-43,60		
0	0		
Qmax,cap	+ 43,60		

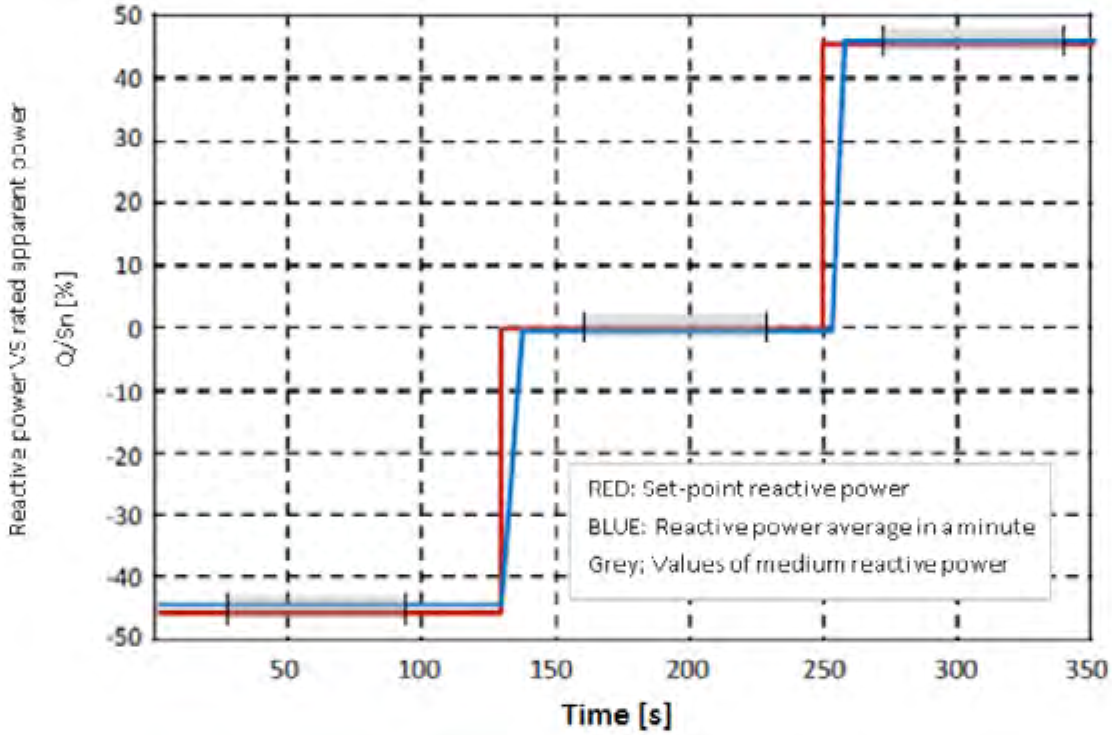


Figure D20 - Measurement of reactive power supplied on the basis of an external command, verification of accuracy

D.4.6.2.3 Response time to a step change in the level assigned

In addition to the requirements covered by the tests referred to in paragraph D.4.6.2, relative to the control of the network voltage via the exchange of reactive power, it is necessary not only to verify the accuracy of the generators control system, but also the response time of the same when a step change in the level of reactive power required by an external command is applied.

The purpose of this test is to measure the response time of the generator to a static step applied to the control of reactive power output, moving from one level to another level with the methods described below and illustrated in Figure D21.

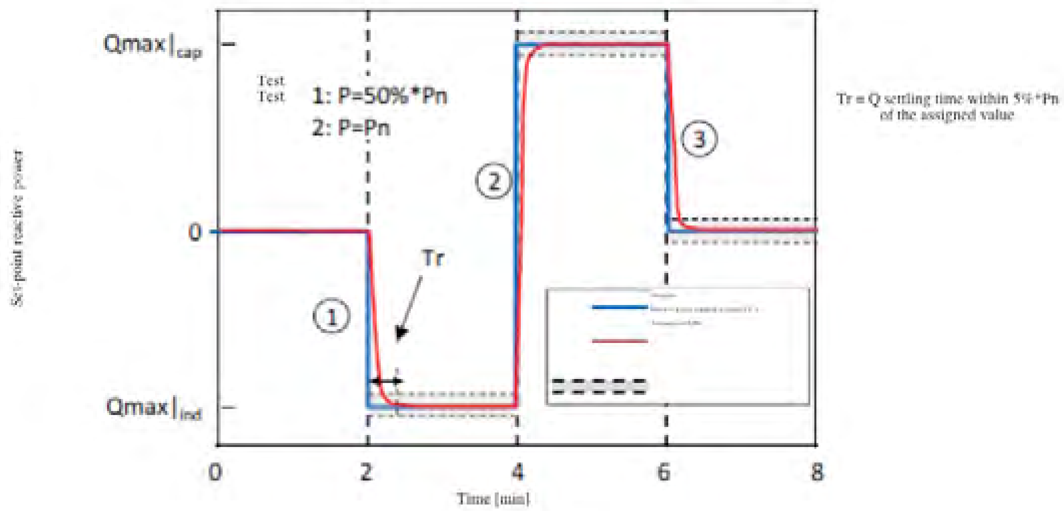


Figure D21 - Measurement of the response time to a step change on the set-point of the required reactive power

- From the results of the capability tests as per D.4.6.1 and D.4.6.1.1 record the values Qmax,cap and Qmax,ind of maximum capacitive and inductive reactive power deliverable by the converter, at 50% and 100% of nominal active power respectively.
- Report in a graph similar to the template of Figure D21, the measured values as a 0.2s average of the reactive power during the execution of commands for adjusting the reactive power with step changes, when generator is providing an active power equal to 50% (Test 1) and 100% of the nominal active power Pn (Test 2).

Record the response time (Tr = settling time as per Figure D21), equivalent to the time that elapses from the instant of application of the new set-point to the instant in which the reactive power reaches a value in a range included within a band of ±5% × Sn of the new assigned value.

As shown in Figure D21, the response time should be recorded at a change in the set-point from zero to Qmax,ind (step 1), from Qmax,ind to Qmax,cap (step 2), and from Qmax,cap to zero (step 3).

The values of the response time must be documented in the test report, which must also indicate the values Qmax,cap, Qmax,ind, the power delivered during the test and the method used to send the command that controls the set-point of the reactive power..

The test is passed if the maximum detected response time is smaller than 10 seconds for all measurement conditions.

D.4.6.3 Automatic control of reactive power according to a characteristic curve cos φ = f (P)

All inverters in plants connected to the MV distribution network must be able to absorb reactive power in an automatic and autonomous (local control logic) mode according to a characteristic curve of the power factor vs. active power

= f (P).

The test aims to verify that the inverter or the combined controller/generator, follows the procedures for automatic delivery of the reactive power according to the standard characteristic curve cos φ = f (P).

The type b) standard curve shown in Figure D22 is univocally defined from the linear interpolation of three characteristic points:

A: P = 0.2 Pn; cos φ = 1 B: P = 0.5 Pn; cos φ = 1

C: P = Pn; cos φ = 0.9 (in reactive absorption)

The control according to the characteristic curve is enabled when the voltage measured output terminals exceeds the "critical" lock-in (e.g. set to 1.05 V = Vn).

The value of voltage lock-in that enables the automatic delivery mode of reactive power and that during the tests must be set to 1.05 Vn (the "default" also for the production of the series), shall be adjustable between Vn and 1.1 Vn with intervals of 0.01 Vn.

The value required for the lock-in voltage should be specified in the Connection Agreement.

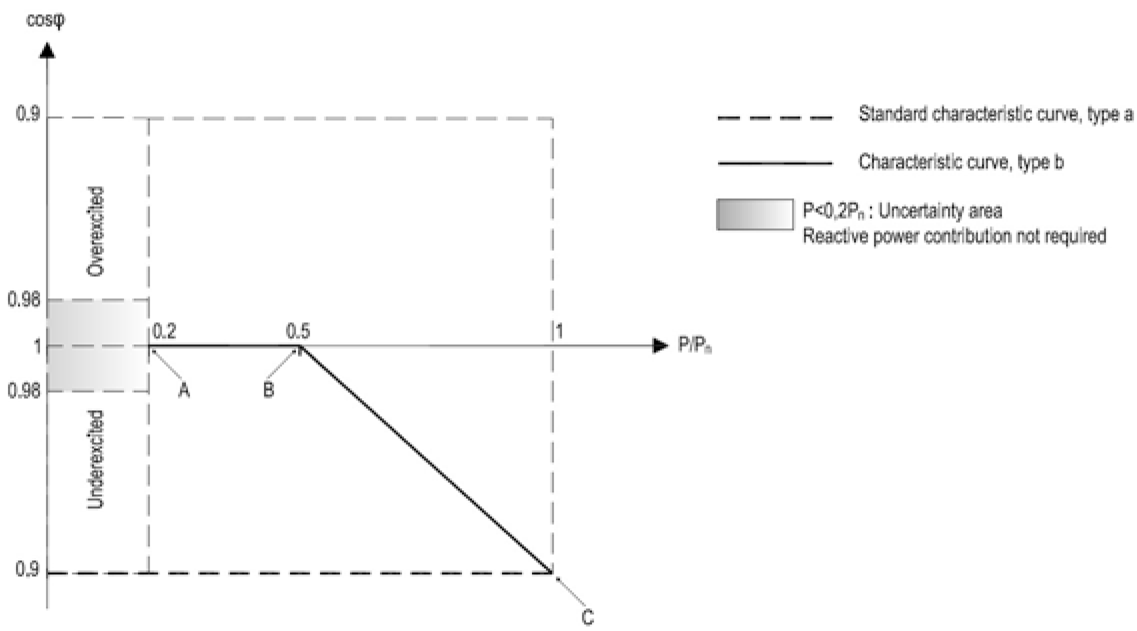


Figure D22 – Characteristic standard curve cos φ = f(P)

It is worth noting that the settling time to the new maximum value of reactive power on the characteristic curve should be automatically adjusted by the generator within 10 seconds (refer to the tests on the response time in D.4.6.3).

The control mode is disabled when:

- the active power P delivered falls below 50% of Pn (point B), defined as the lock-out power, independent of the voltage at the terminals, or:

- the voltage at the output terminals of the converter falls below the limit of lockout to be set to a default value equal to Vn, but that must be adjustable in the range between 0.9 Vn and Vn in steps of 0.01 Vn.

D.4.6.3.1 Verification of compliance to rules for application of the characteristic curve cos φ = f (P)

The measurements can be carried out either through acquisition campaign in field (e.g. a test facility) or on a test bench, provided it is representative of the actual operating conditions of the generator (availability of simulated primary source). The generator output terminals can be connected to the grid or to a simulator. To verify the functionality of the voltage Lock-in mechanism, proceed by varying the parameters that manage this function in the first case (grid), or the direct adjustment of the voltage applied to the output terminals of the generator, in case of simulated network, keeping Lock-In and Lock-out parameters to default.

With reference to Figure D22, for the verification of the compliance to the rules for the application of the characteristic curve, type b), proceed as follows.

a) Connect the converter to the primary source or to the simulated source and at output directly to AC mains, or by using a network simulator, provided that this allows the full power operation of the generator and the adjustment of the voltage at AC output terminals in the range 0.9 × Vn and 1.1 × Vn ;

b) Enable the type b) curve by acting on the converter according to the manufacturer's instructions;

c) Set the simulated primary source, so that active power supplied by the converter is equal to 20% of nominal power P = 0.2 × Pn (point A). Alternatively set the source so that to have at least the generator nominal power and set the active power by acting on the control of the generator so as to deliver 20% of Pn; to this purpose, a software interface and procedure that the manufacturer will make available can be used, provided this will not in any way influence the delivery of reactive power as a function of the curve under consideration. In these conditions, if the system is connected directly to AC mains, set the lock-in parameter to values greater than the actual voltage value available at the converter output terminals. In case the simulator is used, the value of Vlock-in can be kept to the default level (1.05 Vn) and the voltage set to Vn but not more than 1.04. In this way, the function of regulation under concern is disabled;

d) Measure the active power, reactive power and power factor cosφ as average over 1s, bringing these values in a table (see Table D21) and in a graph similar to that of Figure D20;

e) Repeat the measure referred to in point d. above by increasing the delivered active power, acting on the simulator or by adjusting the inverter in steps of 10% of the nominal power, from 20% Pn up to 60% Pn. At the same time check that during these tests the AC voltage at output terminals does not exceed the limit value V

= 1.04 Vn (or the value set to keep the function disabled, in the case of direct connection to the network);

f) Report in Table similar to the model of Table D21 the values of the active power, reactive power and cos φ detected during the measurements performed at 5 levels of active power delivered from 20% to 60% of nominal power. In these conditions, being AC voltage at the output terminals less than 1.05 Vn (or the set value) the inverter must NOT enable the delivery of reactive power;

g) At this point, with AC power delivered always equal to the last level reached above (P = 0.6 × Pn), increase the simulator voltage, so that is equal to 1.06 Vn, higher than the limit V = 1.05 × Vn . Alternatively, in case of system connected directly to network, reduce the value of both lock-out and lock-in parameters below the actual voltage value of the mains (e.g. bringing them respectively to 0.95 Vn and 0.99 Vn in case the available voltage is equal to Vn);

h) Repeat the measure referred to in above point d. by increasing the active power delivered in steps of 10% the nominal power, from 60% Pn up to 100% Pn (always with AC voltage at output terminals above V = 1.05 Vn in case the simulator is used, or Vlock-in equal to 0.99 Vn, being Vn the voltage at the output terminals if the converter is connected to the public network);

i) Report in the Table the values of active power, reactive power and cos φ detected during the measurements performed at 5 levels of active power output from 60% to 100% of rated power. In these conditions, since the AC voltage to output terminals exceeds 1.05 Vn (0.99 Vn in the case of connecting to the network with voltage at least equal to Vn), the generator must enable the delivery of reactive power following the type b) characteristic curve;

j) With the generator fully supplying active power, AC voltage output higher than 105% Vn (or 0.99 Vn) and then reactive power supplied equal to the maximum limit cos φ = 0.90 in reactive absorption, reduce AC voltage to a value below the Lock-in threshold and slightly higher than the Lock-out threshold, for example 1.01 × Vn (or, on the network at voltage Vn, increase the Lock-out parameter so that it is slightly less than the voltage value at the output terminals of the converter (e.g. 0.99 × Vn), while bringing the value of Lock-In parameter to its default equal to 1.05 Vn), checking that the reactive power remains fixed to the upper limit value. This allows to check that, once the "critical" Lock-In value is exceeded, the generator remains in reactive power delivery mode according to the type b) characteristic curve, keeping this behaviour for all values of output voltage above the Lock-out threshold (default threshold set to Vn).

k) At this point, starting from the final conditions of the previous point, bring the sequence to completion by further reducing AC voltage (or further raising the Lock-out threshold) until it falls below the value set for the Lock-out threshold (e.g. bringing Vac to 0.99 × Vn on the simulated network, or raising the Lock-out threshold to 1.01 times the actual voltage value measured at the output terminals of the generator in case such alternative test method is used). In such conditions, the generator will have to stop the supply of reactive power.

For each operating point, the maximum deviation of cos φ as compared to the expected value according to the standard characteristic curve must be less than Δcos φ_max ≤ ± 0.02.

Table D21 – Verification of the delivery of reactive power according to the characteristic curve standard cos φ = f(P)

P/Pn [%]	P [W]	Q [VAr]	cos φ Measured	cos φ Expected	Δ cos φ
20%					
30%					
40%					
50%					
60%					
70%					
80%					
90%					
100%					

NOTE: Characteristic curves different from the standard curve according to the type of network, the load and the power input could be required by DEWA. However, the characteristic curve cos φ = f (P) is, in general, uniquely defined as a polygonal line passing through the three points A, B and C of Figure D21.

For this reason, the manufacturer, in addition to an in factory pre-setting of the control system according to the "Standard" curve of the type described in this paragraph subject to verification by tests, must parameterize the curve to make it adjustable by varying only the 3 points A, B and C.

Consequently, the so-called "fixed cos φ" control method (type a) curve), does not require verification, as it can be derived from the characteristic curve cos φ = f (P) in a consistent manner by setting the parameters of adjustment of points A, B and C.

D.4.7 Verification of constructional requirements about the regulation of the active power

The static generators shall be equipped with control functions of active power fed into the grid in 4 separate modes:

D.4.7.1 Automatic limitation in local logic for voltage values close to 110% Vn
D.4.7.2 Automatic limitation for over-frequency transients originated on the network
D.4.7.3 Upon external command and / or centralized logic.

D.4.7.1 Automatic limitation in local logic for voltage values close to 110% Vn

Not applicable at the present

D.4.7.2 Check automatic reduction of active power in the presence of over frequency transients on the network

The purpose of the test is to verify the function of automatic reduction of active power in case of over frequency, by the extrapolation of a graph of P as a function of frequency. Two sets of measurements have to be performed: starting from 100% of nominal output (sequence A), and starting from 50% (sequence B), as indicated in D.4.7.2.1 for static generators.

Because of the different technologies of converters, the availability of the primary source or a simulated source capable of supplying the nominal power of the generator and availability of an adequate size of network simulator, it is possible to adopt any of the following alternative test methods.

D.4.7.2. a) Tests at full power on the simulated network: applicable in cases where a network simulator is available which can change the frequency parameters at the output terminals of the generator in the range between 47.5 Hz and 52.5 Hz. In the case of PV conversion systems, the primary source may be replaced by a DC source, provided it can deliver in a continuous way the nominal power of the inverter.

D.4.7.2. b) Test on the public network with change of control parameters: to carry out the tests it is in this case allowed to change frequency parameters that control the control system of the power in case of over frequency, so as to simulate a progressive increase in the frequency and its subsequent return in the vicinity of the nominal value (for instance changing the value of nominal frequency). All that is possible provided the system allows the modification of the parameters with the machine connected to the network or anyway not in standby.

D.4.7.2. c) Test on the control system only: via a signal generator capable to simulate frequency and voltage. Generally this test can be conducted only with the generator (inverter) in stand-by and anyway disconnected from the network. Therefore, in such cases the test will be limited to record in a suitable form the control system output signals which define the power limitations of the generator, as well as the set-point which determines the gradual ramp to increase load when frequency returns back in the vicinity of the nominal value.

D.4.7.2. d) With generator connected to public network by acting on the control system: in this case it is required to proceed according to D.4.7.2. c), setting in sequence to the input terminals of the control system the frequency values provided in the test protocol, reported in D.4.7.2.1 for static generators, checking that the power output shown in a chart follows the expected trend, including the ramp to increase load when frequency returns back in the vicinity of the nominal value.

For both measurement sequences (sequence A and B) the procedure envisages to gradually increase the frequency (of either network simulator or signal generator) and to measure the power value (average values over 0.2 s).

In case the procedure D.4.7.2.b) is used on the public network at a fixed frequency, it will be necessary to gradually vary the value of the frequency parameters that control the power reduction of the system in case of over frequency, of an amount such as to simulate the same progressive increase / decrease of the frequency expected according to the other test modes.

At the end of each sequence it will be necessary to bring the frequency (or the parameter) back to a value close to nominal, in order to verify that the time requirements envisaged for the gradual restoration to the power delivered before the frequency transient (or before exceeding limit of 50.3 Hz) are actually fulfilled.

D.4.7.2.1 Performance of tests for static generators

With reference to the test method on simulated network, specified in D.4.7.2. a), procedure is as follows:

- connect generator under test according to instructions provided by the manufacturer on the basis of measurement method chosen;
- fix all parameters of simulated network to the respective values of normal operation;
- bring all parameters of generator under test to the respective values of normal operation, so that the AC power supplied at output is equal to maximum AC power deliverable in case of sequence A, or 50% in the case of sequence B;
- perform the measurements on 7 points (the frequency value will have an uncertainty of maximum ± 10 mHz) according to the following time sequence:

[1] F = 47.51 Hz (t1 for the sequence A, t'1 for the sequence B);
[2] F = 50 Hz + 0.2 Hz (t2 for the sequence A, t'2 for the sequence B);
[3] F = 50 Hz + 0.40 Hz (t3 for the sequence A, t'3 for the sequence B);
[4] F = 50 Hz + 0.60 Hz (t4 for the sequence A, t'4 for the sequence B);
[5] F = 50 Hz + 2.49 Hz (t5 for the sequence A, t'5 for the sequence B;
[6] F = 50 Hz + 0.11 Hz (t6 for the sequence A, t'6 for the sequence B);
At this point perform step 7, by bringing the frequency back to nominal value to verify the conditions for the gradual recovery of maximum delivery (sequence A), or at 50% of maximum power (sequence B);
[7] F = 50 Hz (t7 for the sequence A, t'7 for the sequence B).

In case one of the alternative test methods is used, the procedure is the same as long as the "actual" frequency measured at the output terminals of the generator, can be substituted with that impressed by a signal generator according to the methods described in D.4.7.2. c) and D.4.7.2. d), or by modifying the inverter control parameters of the same quantity reported in each of the 7 measuring points (but with opposite sign), in case the procedure defined in D.4.7.2.b) is applied.

D.4.7.2.2 Results of tests for static generators

The results are to be presented in a table and a graphic trend extrapolated on the basis of these (with two curves representing respectively sequence A and Sequence B, as shown for example in Figure D23). Expected performance for the sequence A and sequence B must also be represented in the chart.

The test is passed if the following conditions are fulfilled for both sequences A and B:

- for each of the 6 points from t1 (t'1) to t6 (t'6) the difference between the expected value of active power and that measured falls within a tolerance of ± 2.5% Pn, where Pn is the nominal power of the generator;
- when mains frequency is restored to the nominal value (step 7 of the sequences shown in D.4.7.2.1), the generator will have to maintain the minimum level of power attained in the previous phase of frequency increase (equal to Pmin) for a minimum time equal to 5 minutes, after which it will be able to restore the pre- transient supply (equal to Pmem) in a gradual manner either by following a linear ramp with a slope equal to 20% * [Pmem-Pmin] / min ([3]), or so as to gradually restore the power to the value before the transient stage in a time window of 5 minutes. For the load gradient, the verification may be carried out from the instant at which the generator exceeds a level of power output equal to 10% × Pn, beyond which maximum positive deviations of +2.5% Pn are allowed on the ramp until the stored power level Pmem (respectively equal to 100% Pn and 50% Pn for the two test sequences A and B) is reached.

3 Shorter recovery of power is possible, when power difference between minimum level reached in overfrequency and the initial power supplied before the frequency transient, is less than 25% P_{MC}, since in such cases it is possible to apply a minimum gradient of 5% P_{MC} / min (where P_{MC} is the maximum capacity of the generation system).

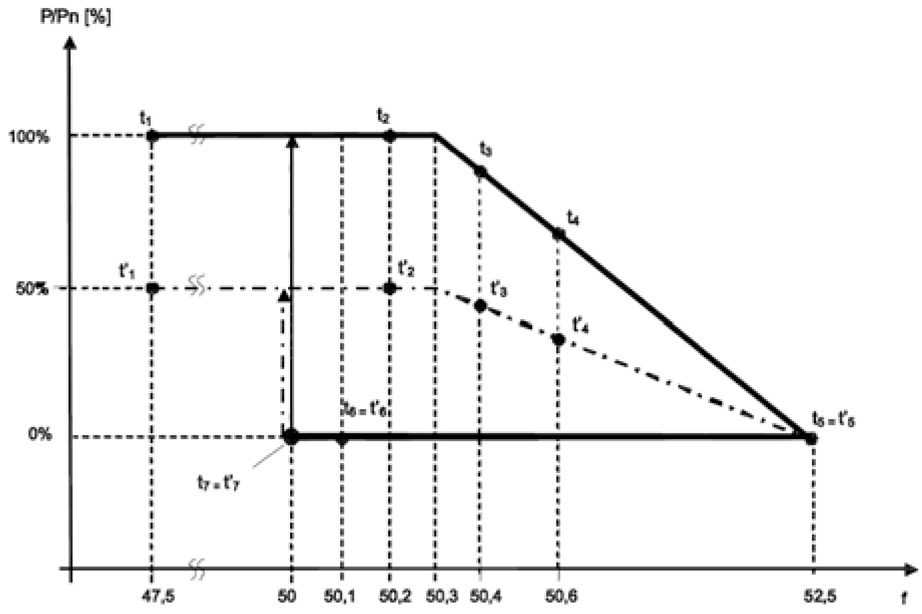


Figure D23 - Curves of active power limitation with respect to the frequency

D.4.7.3 Verification of active power limitation upon external control

The ability to reduce the active power generated as a result of a signal received from a remote control centre must be tested, by agreeing in advance with the inverter manufacturer the mode of signal collection and processing.

The procedure described hereinafter will be used.

- Set the inverter to produce 100% of the nominal power;
- After 1 minute of operation reduce the power to 90%;
- Give 1-minute time for the inverter to run the command, and then measure the value of active power (averaged over 1 minute). The deviation from the set point in the minute of measurement shall be within ± 2.5% Pn, to consider the test valid and passed.
- Afterward, reduce the power of a further 10%, keep that value for 2 more minutes, and repeat until the value of 0% Pn is reached.

The measurement related to the set-point 10% Pn will occur in accordance with regulatory requirements, and then the measured power must be in the range between 12.5% Pn and 0, to consider the test valid and passed.

The test results shall be tabled in the following way:

Verification of active power limitation of external control

Set point P P/Pn [%]	Set point P [W]	Measured P [W]	Accuracy
100%			
90%			
80%			
70%			
60%			
50%			
40%			
30%			
20%			
10%			
0%			

In addition, the results shall be reported on a graph containing the trend of the set-point, of the measured average power values as well as their tolerances with reference to the set-point (see example in Figure D24).

The chart below shows an example of the performance of the set-point (black) and of the average power (red) for each measurement, which must all be within the grey areas of tolerance, in order to consider the test successfully passed.

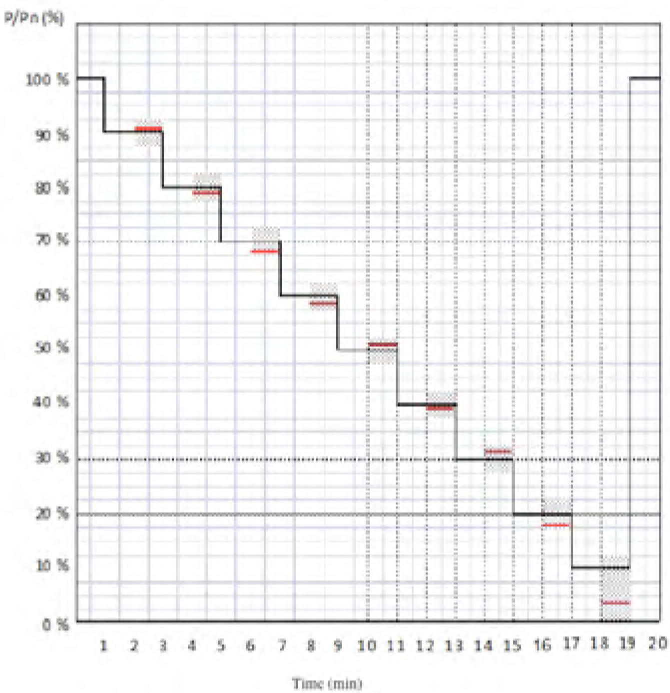


Figure D24 - Example of active power limitation upon application of an external command

D.4.7.3.1 Checking the settling time following a command of power reduction

The verification is done by adjusting the parameter of active power limitation from 100%Pn to 30%Pn at time t0.

The settling time is the time interval from the instant t0 of application of a step of active power limitation from 100%Pn to 30%Pn to the instant when the power enters and remains within a tolerance band of ± 5%Pn with respect to the new value setting.

The maximum settling time measured must be less than 50s, and anyway not higher than 60s in case of a limitation from 100%Pn to 15%Pn.

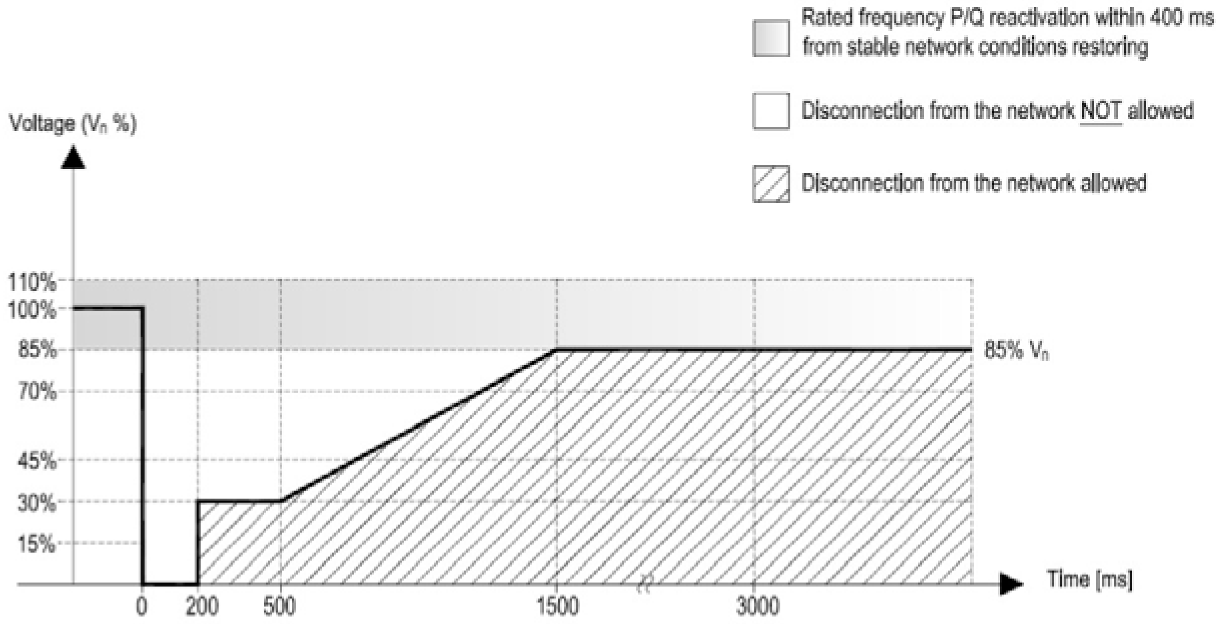
D.4.8 Verification of insensitivity to voltage dips (LVRT capability)

These tests are meant to verify that the generator meets the requirements of immunity to voltage dips according to the voltage - time profile shown in Figure D25.

In particular, the tests aim to verify that the following functional requirements are met:

- a RRGU shall not disconnect from the network in the event of voltage drops to 0% Vn on one out of three line voltages, with a duration ≤ 200ms. This will allow a fault clearing in base time in the HV network;
- a RRGU shall not disconnect from the network any time during which the voltage is in the non-hatched area in fig. D25. The temporary interruption of the production of active power is in this case allowed;
- in the hatched area of fig. D25 the RRGU may be disconnected;

- within 400 ms from the restoring of a network voltage included in the range 0.85 Vn ≤ V ≤ 1.1 Vn, the RRGU will restore the export of active and reactive power to the network as it was before the fault occurrence, with a maximum tolerance of ±10% of the RRGU rated power. If the voltage is restored, but it remains in the range
0.85 Vn ≤ V ≤ 0.9 Vn a reduction in the produced power is admissible..



D.4.8.1 LVRT - Mode of execution and registration of the test results

The purpose of these tests is to verify that the generator is able to correctly deal with the transient voltage dips and to overcome them while maintaining connection without damage, restart the delivery of pre-transient active and reactive power, within a defined time limit from the restoring of voltage in the range 85% to 110% of nominal value.

The analysis of the current delivered during the transient as well as in the immediately preceding and following time instants, will also allow a check of the performances with relation to possible future requirement on dynamic support to the network.

The verification of compliance with the requirements for immunity to voltage dips is made according to the test sequences reported in Table D22, to be performed, in accordance with IEC 61400-21 sect. 7.5, with the generator working, respectively:

a) between 10% and 30% of the rated power and
b) above 90% of the nominal power.

For each of the sequences a) and b), before proceeding with the simulation of the voltage dips according to any of the tests reported in Table D22, the system has to operate under the set conditions for at least 5 minutes or the time necessary for the internal temperature of the converter to stabilize.

The interface protection must be disabled or adjusted to avoid nuisance tripping during the test run.

The fault simulation system must produce the voltage dip profile as reported in Table D22 and Figure D25 at no-load operating conditions.

In general, regardless of the test circuit, the result of each sequence must be documented as follows:

- Time behaviour of active power P, reactive power Q and the phase voltages at the output terminals L1, L2, L3, as moving average of rms values computed in a cycle (20 ms) and updated every half a cycle (10 ms), on a time window that begins 100 ms before the test begins and ends at least 1000 ms after the end of the transient voltage (in order to monitor the restoration of active and reactive power). The voltage transient ends when the voltage is steadily above 85% the value of the nominal voltage. For the phase currents, in addition to the rms values averaged over a cycle, the peak value for each phase will also be recorded.

- In the same observation period, oscillograms of voltages and of the phase currents (possibly with enlarged detail of the trend during the rising edges and falling voltage) shall be recorded.

- The method of calculation used to determine the power, the power factor and the reactive current shall be mentioned in the test report.

An extensive description of the mode of acquisition and recording of the electrical parameters during the performance of the tests of insensitivity to voltage dips/drops is also available in standard IEC 61400-21 sec. 6.5.

If the generator is equipped with an isolation transformer, the measures must be made on the "network side" of the same.

It will be then necessary to complete at least 20 different test sequences, corresponding to 4 residual voltage levels to be replicated to simulate the three-phase symmetric and two-phase asymmetric fault cases. Each sequence will have to be repeated with the generator operating at two levels of initial power output (a: 10% Pn ÷ 30% Pn, b: >90% Pn) .

Table D22 - Sequence of tests for verifying immunity to temporary voltage dips. Amplitudes, duration and shape related to no load test conditions.

Tests	Residual amplitude of phase-phase voltage V/Vn (i)	Duration [ms]	Shape (ii)
1s – symmetric 3 phase fault	0.05 ± 0.05 (V1/Vn)	= 200 ± 20	
1a – asymmetric 2 phase fault	0.05 ± 0.05 (V1/Vn)	= 200 ± 20	
2s – symmetric 3 phase fault	0.30 ± 0.05 (V2/Vn)	= 200 ± 20	
2a – asymmetric 2 phase fault	0.30 ± 0.05 (V2/Vn)	= 200 ± 20	
3s – symmetric 3 phase fault	0.30 ± 0.05 (V3/Vn)	= 500 ± 20	
3a – asymmetric 2 phase fault	0.30 ± 0.05 (V3/Vn)	= 500 ± 20	
4s – symmetric 3 phase fault	0.55 ± 0.05 (V3/Vn)	= 950 ± 20	
4a – asymmetric 2 phase fault	0.55 ± 0.05 (V3/Vn)	= 950 ± 20	
5s – symmetric 3 phase fault	0.80 ± 0.05 (V4/Vn)	= 1400 ± 20	
5a – asymmetric 2 phase fault	0.80 ± 0.05 (V4/Vn)	= 1400 ± 20	

(i) The values of residual voltage are shown in per unit of the nominal MV line voltage, hence referred to the voltage levels required for failures caused on MV lines.
(ii) Regardless of the method used to simulate the transient (network impedances, simulator or any other method), the falling and rising edges of voltage must be shorter than 10ms.

D.4.8.2 Test circuits - requirements

General Requirements:

- the test circuit must allow the execution of each sequence so that the voltage step resulting from each of the ten sequences shown in Table D22 is independent of the phase angle of the mains voltage;
- The test circuit shall not cause interruptions or irregularities in the voltage and power profiles during the execution of each sequence.

D.4.8.2.1 Test circuit - short circuit simulator

This section lists the requirements for the sizing of the test circuit and the verification of the compatibility of the network infrastructure available at the connection point for the execution of the test, if the test is carried out through the short circuit simulator described in IEC 61400-21 (sec. 6.5 and 7.5), based on the principle of the voltage divider (see Figure D26).

This circuit is generally adopted for the verification of LVRT capability of wind generators, through the use of mobile units equipped with all the power equipment, protection, control and measurement necessary for the execution of all the measurements directly in the field, on the generation unit installed in its final configuration, inserting the said circuit between the network and the terminals of the MV / LV generator transformer.

However, the same type of equipment can be used for the execution of the tests also of generators with different primary source, such as the static generators used for photovoltaic applications.

The tests can be performed using, for example, the test circuit shown in Figure D26. Voltage dips are reproduced by a circuit that simulates a short circuit connecting either three or two phases to ground via an impedance (Z2) or connecting either three or two phases together via the same impedance. Switches S1 and S2 will allow the definition of the time profiles of individual test sequences.

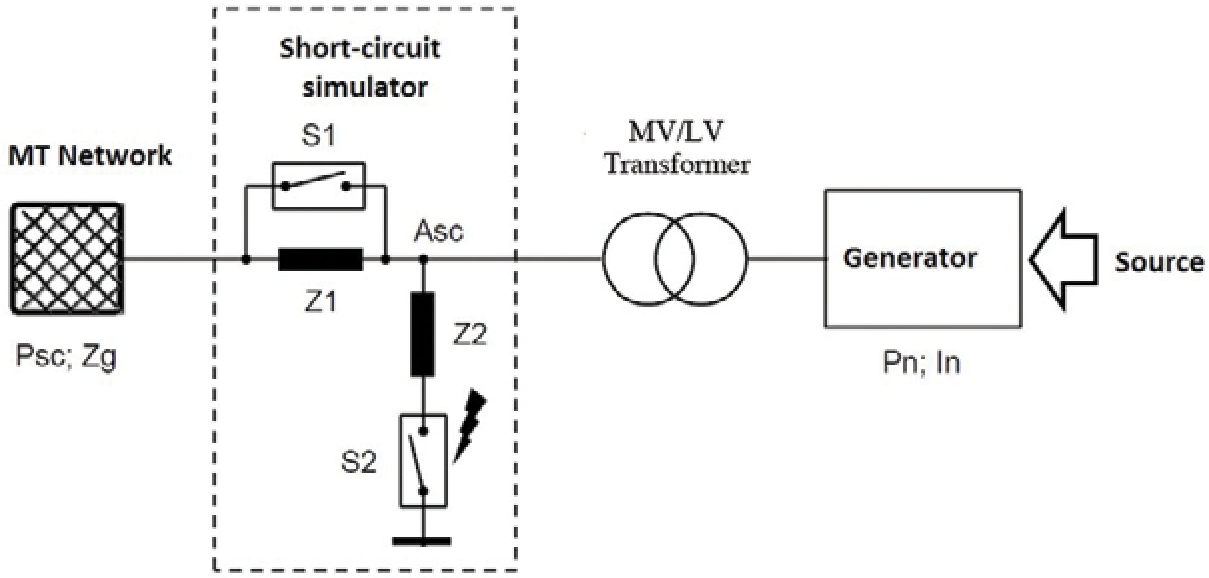


Figure D26 - Example of test circuit for simulating the temporary voltage dips

For the sizing of the test circuit, the following considerations apply:

For the sizing of the test circuit, the following considerations apply:

- The impedance Z1 is used to limit the effect of the short circuit on the power grid that feeds the test circuit. The sizing of Z1 must therefore allow all the test sequences, limiting the maximum short-circuit current drawn from the grid to values that do not cause excessive reductions in the upstream voltage (particularly in the worst case, i.e. with residual voltage 5% Vn). Considering at most an acceptable reduction in mains voltage of 5% during the test performance, the minimum value of Z1 must be at least 20 × Zg, where Zg is the short-circuit impedance of the network measured at the point of connection of the test circuit;

- in order to make this test realistic it is however necessary that the available apparent short-circuit power at the generator connection node (Ssc), or at Z2 terminals, is at least equal to 3 × Pn, where Pn is the nominal power of the generator (value minimum Ssc > 3 Pn, recommended Ssc = 5÷6 × Pn). This means that during the execution of the short-circuit test, the contribution of the current from the network has to prevail on that injected by the generator, assuming that the latter is limited to nominal current In (plausible hypothesis for static converters of PV type). For example with Z1 such that Ssc = 5 × Pn, the contribution to the current in Z2 from the inverter is at most equal to 1/5 of the contribution from the network through Z1. Thus the current that, if it is the case, the generator injects in Z2 for the duration of the voltage drop does not produce a significant increase in the voltage at its ends, thus maintaining the voltage - time profile in line with that measured with no load. It is also appropriate that the impedances Z1 and Z2, of inductive nature, are characterized by a ratio X / R at least equal to 3, this in order to reproduce the typical minimum values of X / R detected on HV power lines but also in MV.

- the two previous conditions define the minimum and maximum limits that Z1 can assume based on the short- circuit power available from the network (Psc) and the size of the generator. The two conditions combined together define the limit criteria for the choice of the network infrastructure suitable for the execution of the tests with use of impedances. Considering a typical value of Z1 such that Ssc = 5 × Pn and a reduction in voltage during the more severe sequence (tests 1s and 1a in Table D22), equal to 5%, the point of connection of the circuit must have an effective short-circuit power Psc at least equal to 100 × Pn (minimum value 60 × Pn in limiting case of Ssc = 3 × Pn);

- A bypass switch S1 is usually employed to avoid the overheating of the series impedance Z1 before and after the execution of each sequence;

- The voltage drop is created by connecting the impedance Z2 to the ground or to another phase, via the switch S2. The value of Z2 must be calculated to produce a voltage at its terminals equal to the values of residual voltage specified in Table D22 (no load conditions);

- The values of the series impedances (Z1) and short-circuit (Z2) used in the measurements campaign and the related ratio X / R must be specified in the test report, along with the description of the circuit. In addition, the short-circuit power of the network, made available at the voltage level at which the test is performed, must be documented;

- As to the AC network, it has to be intended a three-phase medium voltage network. Laboratories are not allowed to connect directly to a public LV network. Hence, the testing laboratory shall be provided with a MV connection, with a short-circuit power sufficient to safely perform the tests in accordance with these guidelines and compliance with the requirements imposed by DEWA. If a MV / LV transformer of suitable size is available, it is possible to perform the tests by connecting the simulation circuit on the LV side of the transformer. In this case, the characteristics of the transformer have to be taken into account for the calculation of the impedance;

- The closing and the opening of switch S2 determines the duration of the events of voltage drop, therefore its control must be accurate in simulations of both two-phase and three-phase faults. The switch can be for example an electromechanical device or a controlled electronic device based on solid state components, provided with switching characteristics similar to a MV switch;

- In the absence of the generator, the test circuit must ensure that the envelope of the voltage during the simulation corresponds to the graph of Figure D27. The duration of the transient voltage drop must be measured from the instant of closure to that of reopening of switch S2. The tolerances dashed in Figure D27 take into account the deviations and delays in opening and closing of S2 and the gradient of voltage drop and rise. Any deviations from the graph shown below should be adequately documented and justified in the test report.

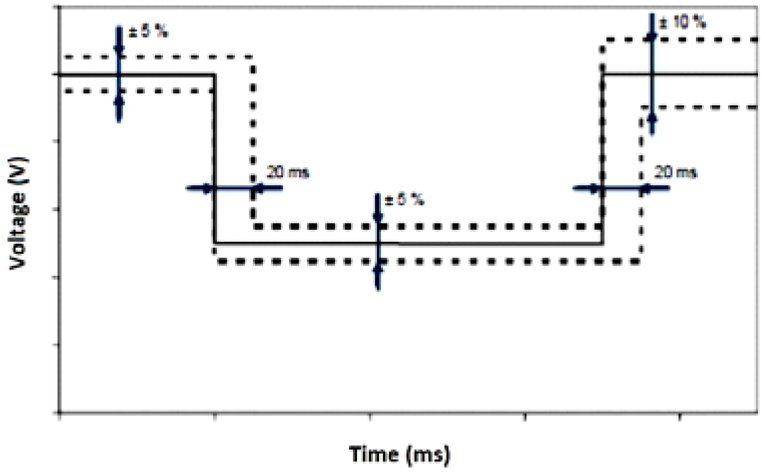


Figure D27 - Tolerances of amplitude and time for the test sequences of mains voltage drop (LVRT Test) (Source: IEC 61400-21)

NOTE: When performing measurements by means of the use of the short circuit simulator based on the voltage divider, it must be borne in mind that this latter represents a significant load for both the generator and especially for the network. Therefore, it is necessary to adopt all the necessary provisions to include appropriate protective devices on both the network and the generator side. If the test requires the use of a significant percentage of short circuit power Psc available at the point of connection (> 5% Psc), it is suggested to agree in advance with DEWA both the test schedule (time slots, minimum interval between a sequence and the next, etc.), and the protective circuit and devices to be adopted.

D.4.8.2.2 Alternative test methods - network simulator

The test circuit suggested by IEC 61400-21, sec. 6.5 and 7.5 for the simulation of faults on the network and the resulting transient voltage dips is provided by way of example, as other circuit topologies are eligible, provided they are able to reproduce the voltage steps provided in Table D22 at the generator terminals.

Indeed, in principle, even considering that the circuit described in paragraph D.4.8.2.1 faithfully simulates the behaviour of the network during a two-phase or three-phase fault, what is relevant for the purposes of this standard is to verify the impact the transients have on the generator under test, not on the power grid.

Therefore, circuits or devices are allowed as an alternative to short-circuit simulator reported in IEC 61400-21 based on the principle of the voltage divider, provided:

- They reproduce these voltage drops both in shape and duration with the characteristics listed in Table D22, in particular as regards the rapidity of the voltage rise and drop edges, as shown in Figure D27 (comparable to those of medium voltage circuit breakers);
- The behaviour of the three phase triple during the application of the simulated fault can be modelled with the same accuracy;
- The edges of the voltage transients are independent of the phase angle of the network voltage;
- Since the faults on the electrical network typically involve a phase jump of voltage vectors, in addition to the effect of reduction in amplitude during the transient, it is necessary that the alternative simulation system used is also capable of generating phase jumps during the application of the voltage steps ([4]).

The availability of alternative methods which fulfil the above requirements may be exploited in particular for the verification of static generators for photovoltaic applications, since the use of photovoltaic modules as the primary source is not an essential requirement to ensure the reliability of the test results, being able to use in such cases simulated DC sources provided the power is at least equal to the rated power of the generator under test.

In particular, alternative test circuits are allowed based on the use of network simulators, as represented in Figure D28.

These are composed basically of a voltage source with low internal resistance combined with broadband amplifiers (either linear or forced commutation ones) able to reliably reproduce three sinusoidal voltages with a controlled harmonic content, with amplitude, fundamental frequency and phase relationship adjustable within wide ranges.

Particular versions of the so called "regenerative" type exist, based on bidirectional switching topologies, thus able to handle active and reactive power flows both incoming and outgoing from output terminals. These models are typically connected to the mains being able to deliver or absorb power at different voltages and frequencies (DUT - Device Under Test- side in Figure D28), while maintaining an absorption or supply as an input to the 50Hz network with unity power factor and low harmonic content.

If use of a network simulator is made, provided its rated power is at least equal to 0.9 × Sn, the latter must:

1. ensure the possibility of independent control of the amplitude and phase angle of the three voltages;

2. be built with adjustable impedances Z1, Z2 and Z3, ZN in order to reproduce the resistive and inductive components of the typical short-circuit impedance of the network.

3. be able to reproduce the phase voltages and relative phase angles similar to those produced on the LV side of a MV/LV transformer because of the vector group (typically Dy), in presence of asymmetric two-phase faults on the MV side (public network side).

4 Refer to calculation of amplitude/phase values of the three voltages during steps application

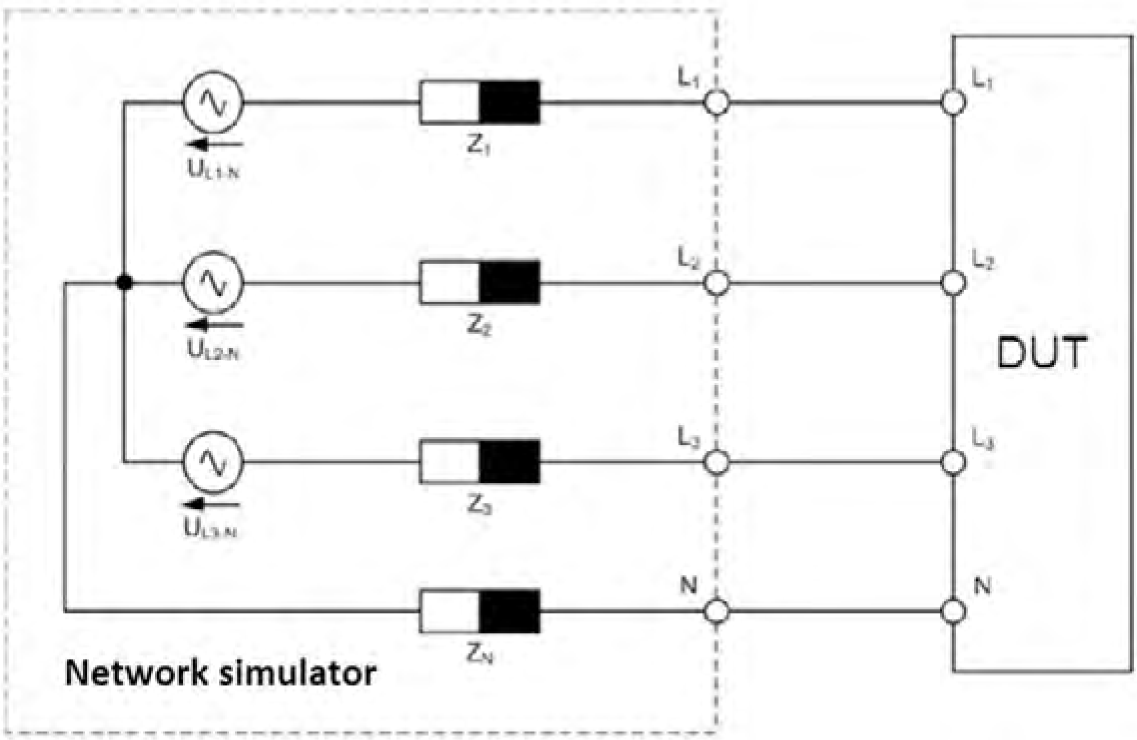


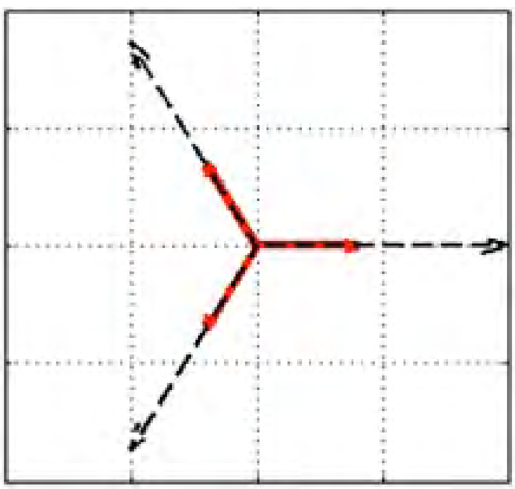
Figure D28 - Network simulator

As regards the electrical supply of the generator / device under test, a source able to simulate the input of the system

/ technology under test, such as a DC for photovoltaic conversion systems, can be used, provided this is able to guarantee the adequate level of power during each individual test. In particular, the source will have to reproduce both the simulated steady-state conditions and the dynamic ones necessary to ensure the compliance of the test to the actual operating conditions of the generator.

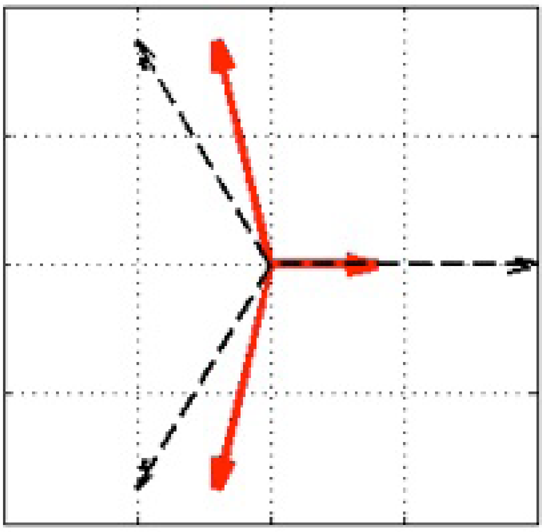
With reference to the list of tests in Table D22, the voltage drops here tested are actually caused by faults on the distribution line. The types of fault considered are two:

1. three-phase symmetrical fault (Table D22, Tests No. 1s, 2s, 3s, 4s, 5s)



2. phase-to-phase (2-phase) asymmetrical fault (Table D22, Tests No. 1a, 2a, 3a, 4a, 5a)

A MV fault, which causes a change in LV on both amplitude and phase relationship between voltages (the case considered foresees the presence of a Dy transformer for connecting the generator to the MV line or to the secondary substation).



During the phase-to-phase asymmetrical fault, the residual amplitude of the 3 voltages and the shifts between phases must comply with the values in Table D23.

Table D23 - Phasors on the LV side of a transformer Dy in the presence of two-phase asymmetric faults on the MV primary side

Test N.	V/Vnominal (MV side)	Phase to ground Voltage			Phase angles		
		u1/u1n	u2/u2n	u3 / u3n	φu1	φu2	φu3
1a	0.05 ± 0.05	0.86 ± 0.05	0.86 ± 0.05	0.05 ± 0.05	28 °	-148 °	120 °
2a	0.25 ± 0.05	0.88 ± 0.05	0.88 ± 0.05	0.25 ± 0.05	22 °	-142 °	120 °
3a	0.50 ± 0.05	0.90 ± 0.05	0.90 ± 0.05	0.50 ± 0.05	14 °	-134 °	120 °
4a	0.75 ± 0.05	0.94 ± 0.05	0.94 ± 0.05	0.75 ± 0.05	7 °	- 127 °	120 °
Nom. Cond.	1	1	1	1	0 °	-120 °	120 °

These voltage variations propagate on the low voltage side of the transformer with amplitude of individual voltages and phase angles that are dependent on the characteristics of the transformer used to connect the generation system to the network, in particular the vector group and the impedance. However, the more frequent case in real applications is considered here, since the transformers adopted are generally those of normalized size and type with vector group Dy (or similar to this group due to the characteristics of phase shift). Therefore it was deemed appropriate specifying both the amplitudes of the phase relationships of the 3 voltages to be set in the simulator for execution of the tests related to asymmetric two-phase faults (sequences 1a/2a/3a/4a/5a in Table D22) in order to provide a set of unique and repeatable conditions for cases in which the use of a test circuit with the simulator is envisaged.

Laboratories accredited to perform this test at their premises, will be allowed to test at the manufacturer's premises, with their own measurement equipment. In case the Manufacturer owns the equipment for the execution of the test, it will be the accredited laboratories responsibility to check the compliance of the equipment with standard requirements..

D.5 - Simulations and Testing

The connection of a RRGP to DEWA network raises important technical issues for network operation and can sometimes represent a limit to the use of renewable energy sources and the integration of DRRG within electricity networks. In order to mitigate possible negative implications, DEWA has developed a DRRG Network Connection Assessment (NCA) which evaluates the RRGP impact on the operation of the distribution network it is connected to. The methodology is based on technical criteria which pay attention to thermal ratings of network components, short circuit contribution and resulting fault level, voltage regulation, power quality, etc.. The RRGP connection is granted only if no negative impact is observed.

As far as power quality and harmonics assessment are concerned and with MV connected RRGPs, within NCA, an emission limit is fixed for each RRGP, based on network harmonics background, MV distribution network capacity and distorting equipment (other DRRG and/or loads) already connected or planned to be connected to the MV distribution network the RRGP is connected to. The assessment is then performed through simulations on a computer model with information on RRGP current spectrum and network impedance model. If the harmonics assessment deems the RRGP impact on network harmonics as negative, DEWA has then two possibilities:

- grant a conditional permission to proceed with the connection process, deferring the final decision of acceptance after actual harmonics measurements have assessed that the impact of RRGP on harmonics is within the limits. This is the typical case when the RRGP NCA points out emissions just beyond the limits; in this case, the limits excess may not be directly attributed to RRGP high emissions level but more to the intrinsic limitations of simulation modelling and it is therefore possible to defer acceptance after measurements, when proper provisions, if needed, may be better defined (e.g. power reduction).

- Ask the customer for remedial measures to be taken unless more precise harmonic studies, performed by the customer, show that the admissible harmonic voltages in the network are not exceeded. This is the typical case when the RRGP NCA puts in evidence emissions far beyond the limits fixed by DEWA. In this case, even if intrinsic limitations of simulation modelling are unlikely to explain the excess, DEWA offers customers the opportunity to carry out more detailed harmonic studies to demonstrate the fulfilment within the limits. Also the effectiveness of the adopted remedial solutions must be demonstrated through simulation studies and validated by DEWA.

RRGP harmonic studies performed by the customer must be based on a simulation model showing the interrelationship of the customer and the local network, enabling the effects of the RRGP harmonic sources to be computer modelled. The simulation model shall be in accordance to the model described below and represented in the following figure:

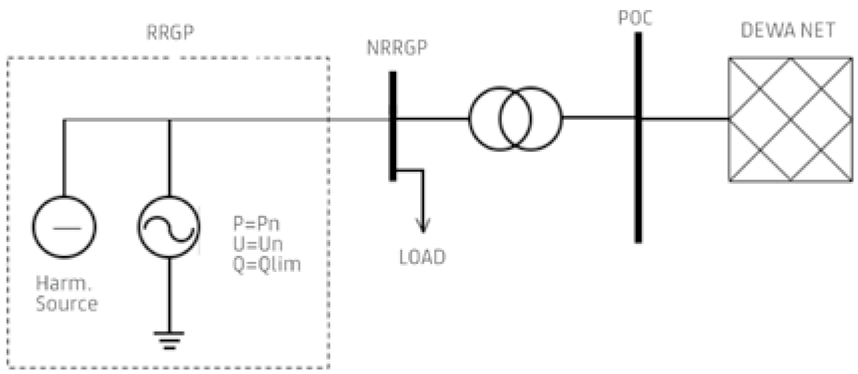


Figure D29 – Simulation model to be provided

- The node "POC" shall represent the connection point of the RRGP. For particular connection situations (such as the unit and its step-up transformer delivering power to the grid through a single cable), this POC may be different from the Connection Point to the grid. DEWA will specify the node to be taken into account and any supplementary element to be added in the test grid between the POC and the step-up transformer.

- The NRRGP-POC transformer models the step-up transformer which connects the RRGUs to the grid; the actual transformation ratio shall be used.

- LOAD represents the active and reactive consumption at customer premises. An R-X parallel model shall be used to represent this load.

- DEWA NET is an equivalent feeder to represent the short circuit power of the upstream network at the point of connection. The minimum value of the short circuit power shall be used as provided by DEWA.

- The feeder shall also represent the background harmonic voltages as measured at the point of connection without the contribution of the RRGP.

- The voltage at POC will be fixed into the feeder so as to obtain the normal operating voltage at the connection node.

- If the RRGP has several RRGUs, the simulation model must be built by assembling the different RRGU models and the plant internal network. The RRGU model must especially reproduce the RRGU current emission spectrum as declared and communicated by RRGU manufacturer. The remedial provisions used to compensate the initial RRGP high harmonic emissions must also be included into the RRGP/RRGU models.

The simulations must be performed in order to provide at PoC the RRGP voltage harmonic emission for different ranges of RRGP active power: 0-25, 25-50, 50-75 and 75-100% of RRGP rated power. These emissions values shall then be compared with the RRGP allowed limits provided by DEWA.

D.5.1 - On-site testing (and inspection) of a RRGP

The following on-site testing (and inspection) activities shall be performed on the RRGU or RRGP before and after connection to the distribution network:

- Testing (and inspection) without interconnection to the network to check the consistency of the system (tests at Mechanical Completion for plants with P_{MC} ≥ 100 kW and /or at Inspection stage);
- Testing (and inspection) with interconnection to the network for the verification of the features and the functionalities of the system (tests carried out by the Applicant for plants P_{MC} < 100kW and Performance Tests for plants with P_{MC} ≥ 100 kW).

DEWA may supervise the above Inspections and Tests, except those checks that may involve the concerned Authority (i.e. Dubai Municipality, Trakhees, etc.).

The above activities are described in the document "Inspection and Testing Guidelines for Renewable Resources Generators connected to Medium and Low Voltage Distribution Network" available on DEWA website www.dewa.gov.ae.

The generalities and an itemized list of the checks envisaged are summarized hereinafter.

D.5.1.1 – General Requirements for on-site tests

1. Timing of the tests:
   a) DEWA shall specify the preferred time frame (moment of the day) for the tests.
   b) DEWA shall give its approval before starting the tests and is entitled to suspend or cancel the tests at any time.
   c) DEWA shall ensure enough reserve is available to prevent consequences of a forced outage.
   d) Before starting the tests, the control centre of DEWA shall simulate in the EMS (Energy Management System) the various actions taken and make sure the operational security criteria are met.

2. Monitoring of the tests
   a) DEWA shall take care of measurements at the connection point. Where necessary, measuring equipment might be added for the tests (and even longer).
   b) DEWA and the Producer shall agree on the minimum set of measurements to be recorded by this latter. These measurements have to be provided to DEWA on request.
   c) Checklists with additional information and operating instructions will be made available to prepare the test and provide templates for reporting. A Test Report will be issued by the test operator, for it to be included in the technical dossier of the RRGU/RRGP..

D.5.1.2 - Testing without interconnection to the network to check the consistency of the system

This paragraph lists the tests to check the consistency of the photovoltaic RRGU / RRGP.

The tests have to assess the correspondence to the drawings and design documents, regarding the amount, type, sizing, installation and integrity of components and materials. A list of the tests envisaged is given below.

More details are provided in the document "Inspection and Testing Guidelines for Renewable Resources Generators connected to Medium and Low Voltage Distribution Network" available on DEWA website www.dewa.gov.ae..

D.5.1.2.1 Visual and Mechanical Inspection

The following inspection and tests are required for RRGPs.

1. General assessment of RRGU / RRGP. The following subgroups of tests / checks can be considered.

   a) Layout and total number of PV modules.

b) Substations and main cable connections (if already finished). Internal roads. Fences or any other barriers required for segregation of hazardous areas. Warning signs.

c) Availability of documents and drawings inside substations (if already finished) (PV modules/strings layout, single line diagrams, detailed diagrams, etc.).

2. Civil works (*).

3. Support Structures (*).

4. Photovoltaic modules. The following subgroups of tests can be considered.

   a) Visual inspection of PV modules.
   b) Quality of cabling.
   c) Modules identification (on a sample basis)

5. Electrical equipment

6. Protection of assembled components (e.g. IP degree)

7. Visual inspection of string combiner boxes (DC - string connections and AC – auxiliary services)

8. Visual inspection of electrical power connections in the substations and electrical rooms

9. Bonding and earthing system

10. Connections of metallic structures and equipment to earthing system

(*) Tests and Inspections listed from 1. to 4. are required as a separate preliminary inspection. Inspections marked by a (*) may involve the concerned Authority

D.5.1.2.2 Electrical Tests and Measurements

11. Insulation of LV DC and AC connections

    a) Test performed by applying between live conductors and earth (structures) a test voltage 1000 VDC for 1 minute. Limit value for acceptance of insulation resistance: 1 MΩ.

12. Voltage and current measures on photovoltaic strings

    a) Measure each single string voltage VOC and string current ISC (inverter switched off).

    b) Measures related to strings belonging to same switchboard to be made in rapid sequence to minimize effects due to variations of solar radiation.

    c) Check average Voltage and Current of strings from the same switchboard: in case of strings with deviations higher than ± 5%, verify the continuity of the related circuits and recheck strings voltage/current.

13. String insulation to earth

    a) Measure each single string in short-circuit and earth connected (other strings are open). Apply between short- circuit and earthing system a test voltage (1000 VDC for 1 minute). Disconnect surge arresters prior to do the test. Limit value of insulation resistance for acceptance of each string is 5 MΩ in dry conditions (2MΩ in wet conditions).

14. Calibration of protections (Interface Protection). Checking/adjusting thresholds of equipment and protective devices, through simulated tests of intervention where possible (blank tests).

.D.5.1.3 - Testing with interconnection to the network for the verification of the features and the functionalities of the system.

This paragraph lists the tests to check the functionalities and the power characteristics of the photovoltaic RRGU / RRGP.

More details are provided in the document "Inspection and Testing Guidelines for Distributed Renewable Resources Generators connected to the Distribution Network" available on DEWA website www.dewa.gov.ae.

1. Connection to grid and start-up of RRGU/RRGP

2. Parallel with the grid.

3. Start-up tests on inverters. Tests performed separately on each inverter and progressively throughout the whole RRGU/RRGP

4. Verification of connection of energy meters.

    a) Detect nameplate data of all voltage and current transducers.
    b) Check connection of meters to voltage/current transducers, and transformation settings.
    c) Check compliance off meter calibration certificates.

5. Alarms and messages. Check the correct operation of alarms and messages through simulated tests of intervention (blank tests)

6. Measurements. Check correspondence and degree of accuracy of measurements.

7. RRGU/RRGP Monitoring system. Check system operation, reliability of measures, and correspondence with requirements.

    a) Check calibration and certification of meteorological sensors.
    b) Remote monitoring functions

8. Operation of electrical systems in each cabin.

9. Security system. Checking installation operation of security system (if any)

10. Technical dossier prepared by the Contractor.

    a) The dossier contains as-built design documents; and
    b) The certifications relevant to the system and its installation.
    c) Assure the adequacy of such documentation in terms of both document availability; and
    d) Availability of the required information.

The following tests and a post-connection inspection are required only in case of RRGPs with maximum capacity $P_{MC} \geq 100$ kW.

The Performance Test is divided into Energy Performance Test, Power Performance Test and Harmonic Emissions Performance Test.

11. Energy Performance Test. The test is performed for the whole plant, involving the following measurement.

    a) Read active energy as measured by the production meter.

    b) Measurements of the solar irradiance from a reference solar cell or pyranometer connected to a data logger in order to store them in the performance test time span.

    c) Measurements of the PV module temperature by means of a temperature sensor located on the back surface. Values to be sent to the data logger.

The energy which may be produced by the modules is compared with the energy measured by the meter, in order to calculate the Energy Performance Ratio.

12. Power Performance Test. The test is performed for each inverter and related strings of PV modules.

    a) Measure power input to inverter by DC wattmeter (including voltage and current).

    b) Measure power output from inverter by AC wattmeter (single or three-phase electrical quantities) connected to inverter busbar.

    c) DC and AC measures must be synchronized. Measurements shall be carried simultaneously or in fast sequence, for each subsection (inverter) of RRGU.

    d) Measures of solar radiation from a reference solar cell or pyranometer.

    e) Measurements of the PV module temperature by means of a temperature sensor located on the back surface.

Power performance parameters are eventually calculated to evaluate the performance of the plant.

The aim of the Energy and Power Performance Tests is to demonstrate the performance of the RRGP. If performance is not according to the design data, the Applicant shall recheck and retest the RRGP until the performance is as close as possible to the expected rates.

13. Harmonic Emissions measurements. The measurements shall demonstrate that the harmonic emissions generating from the plant are within acceptable limits, do not generate disturbances to the grid and result in a voltage power quality in line with the requirements reported in the present Standards.

    a) In principle, the tests are performed for the whole power plant at POC. If the RRGP has different POCs, the tests must be performed at each POC

    b) The tests may be performed indifferently using one of the following measurements methods:

        i) Taking advantage of the functionalities of the Smart Meter (if it is compliant with the above measurements requirements), by retrieving the measurements on a suitable time period.

        ii) Installing and making use of specific instrumentation, compliant with the above requirements, to perform a dedicated test campaign.

c) The tests results and the measured values shall be clearly presented in tables for their analysis by DEWA engineers and their confrontation with DEWA planning levels or limits. In case some limits are exceeded, DEWA is entitled to ask the customer for additional measurements on current harmonics emissions in order to check the actual RRGP current emission spectrum and investigate whether the causes of such limits violations are to be attributed to the RRGP or to the interaction with other RRGPs.

14. Post-Connection Inspection. The Post-Connection site inspection is aimed to:

a) Make the final checks on the installation, if necessary;

b) Verify the proper behaviour of the meters, if necessary;

c) Supervise the Power Performance Tests if repeated by the Applicant, on explicit request of DEWA, if considered necessary; and

i) Obtain the reading of the meters in order to begin to consider the exports and net metering.

No checklist or Inspection Report is envisaged for such Post Connection Inspection, but the previously used checklists may be reviewed.

Endnotes

For any further queries and clarifications on the DRRG Standards, please contact **DRRG.**

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