MultiGrid

Grid Interconnection protocols for largely dispersed minigrids/microgrids for electrification of rural India

Interconnection Protocols for Minigrids

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About MultiGrid

Minigrids are heterogeneous in nature since they can include different type of energy sources and generators technologies. Hence, their dynamic operational characteristics varies from one another, for example, a mini-grid with power electronic converter interfaced RES will behave differently compared with a mini-grid with rotating generators for the same transient disturbance or change in operating condition. The integration of two heterogeneous mini-grids is a challenging task especially if each of the two mini-grids is serving appreciable number of local loads. Hence, it is critical to define protocols for connecting and disconnecting minigrids without affecting the stability and voltage quality of the grid.

In MultiGrid project, synchronization strategies will be drafted for multiple minigrids by carefully driving the relevant synchronization criteria. A reference controller will be selected in the beginning of the project from the range of controller schemes available in the literature. Furthermore, in this project, the developed interconnection protocols and controllers will be validated numerically and experimentally.

Partners

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Executive Summary

Interconnection of minigrids to the main grid in the developing world is for most part a fairly recent phenomenon, and the development of best practices is still a work in progress. No international group has yet produced an agreed upon set of standard policies and procedures for interconnection. The closest interconnection standard is the IEEE 1547 family of standards which has been used as reference to prepare guidelines and recommended practices in most countries. In this report interconnection standards, recommended practices and network codes are reviewed from different regions of the world investigating their applicability for minigrids. There is no guideline document for interconnection of multiple minigrids and existing documents for interconnection of minigrids to the main grid are not comprehensive.

1 Introduction

In India there exist solar, mini/micro-hydro plants, wind, diesel based minigrids. Some companies are also integrating biomass/ biogas based minigrids to provide continuous load demand, as shown in Figure 1.1. When the main grid arrives in the vicinity of rural minigrids or when another minigrids in the neighbourhood need to connect, a comprehensive synchronization process needs to be in place. The synchronization controller shall orchestrate the process of organizing synchronous generators, induction generators, inverter-based generators, controllable loads and storage systems within the minigrids.

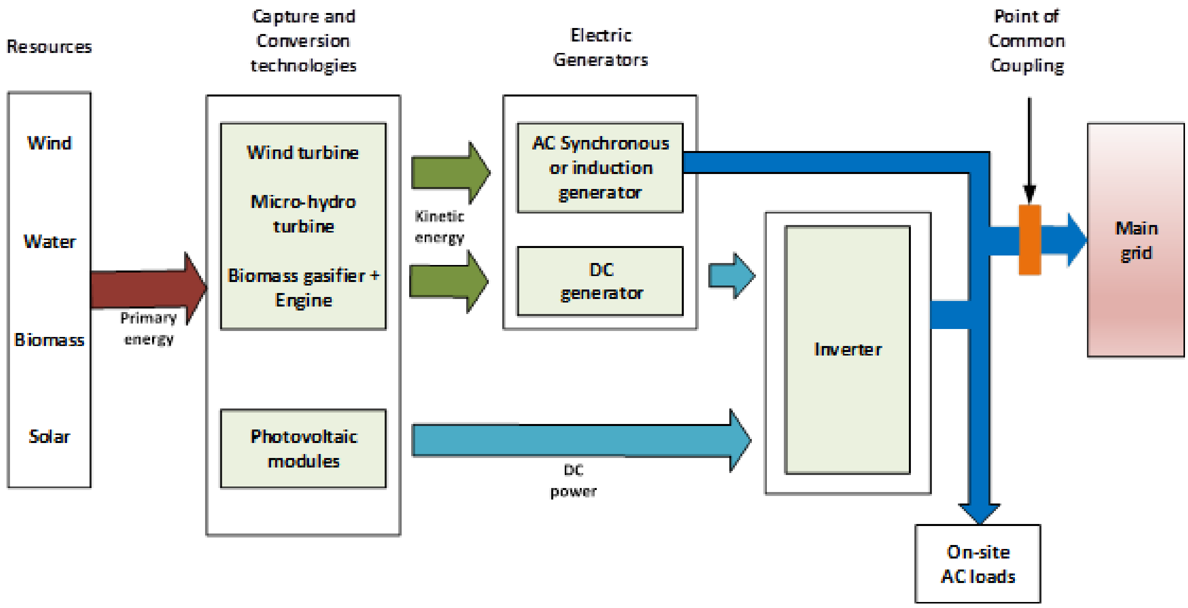


Figure 1.1 - Different types of generators connected in a renewable power minigrid [1]

In the recent days, interconnection of minigrids to the main grid is being explored and the protocols/standards that are in general agreed by all technical groups are yet to be established [1]. However, the interconnection standard, IEEE 1547 and its family of standards, guides and recommended practices are being adopted/adapted in different countries. The standard is essentially developed for the interconnection of distributed energy resources (DRs) with the main power grid.

For purpose of clarity the following terms are defined with reference to [2]:

Protocol: It is the mandatory set of decision-making rules/instructions/standards based on best practice (Guidelines) specific to the Practice.

Standard (Requirements): Acceptable level of quality or attainment. It is quantifiable Low Level Mandatory Controls

Procedure: A series of detailed steps to accomplish an end. It is a step-by-step instructions for implementation

Guideline: A piece of advice on how to act in a given situation. It is recommended but Non- Mandatory Control

In this report set of relevant standards and requirements are reviewed for their applicability to the minigrids-to-main grid interconnection as well as minigrids-to-minigrid interconnection. Section 2 briefly introduces different national/international interconnection Standards/Protocols along with their applicability, limitations and specific contributions. More detailed discussion on the specific standards like, IEEE 1547, interconnection requirements in Norway and India are discussed in Section 3. Comparison of different standards for various parameters is discussed in Section 4. Summary of the standards along with the limitations of the available standards is discussed along conclusions in Section 5 of this report.

2 State of the art in interconnection protocols

Different national/international state of the art interconnection Standards/Protocols are investigated and a brief review of these protocols is presented here in the

. This table included the Standard number, Publisher along with its country of origin, Publication year, scope, applicability along with relevant remarks.

Standard No.	Title of Standard	Publication/ Country of origin	Scope	Capacity	Network	Year of Publication	Remarks
IEEE 1547-2018/IEEE 1547. a-2020 [2]	IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces	The Institute of Electrical and Electronics Engineers (IEEE), USA	DR can be synchronous machine, induction machine, or power inverter/converter	10 MVA or less at the PCC	Primary/Secondary Distribution Network 0.12-161 kV	Revised multiple times from 2003, R2008, 2011, amendment IEEE 1547a-2014, 2018 is active, Amended in 2020	**R1**
IEEE 929-2000 [3]	IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) Systems	The Institute of Electrical and Electronics Engineers, USA	PV- Inverter Systems	10 KW or less	Distribution Network	2000	**R2**
Norway/EU [4]	Network code on requirements for grid connection of generators	Commission Regulation (EU)	All power generating modules	Varies from 0.8 kW to 15 MW	< 110 KV	2016	**R3**
Central Electricity Authority Regulations [5]	Technical Standard for Connectivity to the Grid	Central Electricity Authority- India	Any generating facility whose electrical plant is connected to the grid	All bulk generators ≥ 10 MW	≥ 33 KV	2006 amended in 2010, 2013, 2019	**R4**
Central Electricity Authority Regulations [6]	Technical Standards for Connectivity of the Distributed Generation Resources	Central Electricity Authority- India	Distributed generation resources, charging stations, prosumers	Small Capacity Generators	< 33 kV	2013, amended in 2019	**R5**
Draft Standard of MNRE, GoI. [7]	Technical requirements for Solar Photovoltaics Grid Tie inverters	The Ministry of New and Renewable Energy (MNRE), Govt. of India	PV- Grid Tie Inverter Systems		This standard applies to interconnection with the LV & MV utility distribution system.	Draft, April, 2020	**R6**

Standard No.	Title of Standard	Publication/ Country of origin	Scope	Capacity	Network	Year of Publication	Remarks
JEAC 9701-2012 [8]	Grid interconnected Code	Japan	1-Φ or 3- Φ power sources can be connected.	Up to 2000 KW	LV/HV Distribution network	2012	**R7**
KEPCO Technical Guideline [9]	Korea Electric Power Corporation Technical Guideline for integrating DRs with the grid	Korea	DR	Up to 3000 KW	LV/UHV	2018	**R8**
CNS 15382 [10]	Photovoltaic (PV) systems — Characteristics of the utility interface	The Bureau of Standards, Metrology and Inspection (BSMI), National Standards of the Republic of China (CNS) in Taiwan	PV	10 KVA or less	LV	2018	**R9**
AS/NZS4777 [11][12][13]	Grid connection of energy systems via inverters	Standards Australia- Australia/ New Zealand	DRs with Inverter interfaces	≤ 200kVA	LV	2015 & 2016	**R10**
RD 1663/2000 [14]	Interconnection of PV installations to the LV grid	Spain	PV	≤ 100 kVA	LV	September, 2009	**R11**
VDE-AR-N 4105 [15]	Power Generating Plants Connected to the LV Grid	VDE VERLAG GMBH- Germany	PV power generating plants connected to the low-voltage grid and block heating and generating plants (BHKW), hydroelectric power plants, small wind turbines and fuel cells.	30 KVA	LV Distribution network	April/September 2019 (Last updated)	**R12**

Standard No.	Title of Standard	Publication/ Country of origin	Scope	Capacity	Network	Year of Publication	Remarks
Engineering Recommendation G83-EREC G83	Recommendations for the Connection of Type Tested Small-scale Embedded Generators	Energy Networks Association, UK	Generating unit (or the aggregation of generating units with capacity of 16A per phase or less. Domestic CHP, PV, FC, Hydro, Wind, Storage Device	≤ 11.04 kW for 3-Φ and ≤ 3.68kW for 1-Φ	LV	December, 2014	**R13**
Engineering Recommendation G59-EREC G59	Recommendations for the Connection of Generating Plant to the Distribution Systems of Licensed Distribution Network Operators	Energy Networks Association, UK	Generating unit (or the aggregation of generating units with capacity of 16A per phase or less.	< 50 kW for 3-Φ and < 17kW for 1-Φ	LV	December, 2014	**R14**
IEC 61727 [16]	Photovoltaic (PV) Systems - Characteristics of the Utility Interface	IEC- Switzerland	PV	≤ 10 KVA, 1-Φ or 3-Φ systems	LV	2004	**R15**
CSA C22.3 No. 9-2020 [17]	Interconnection of Distributed Energy Resources and Electricity Supply Systems	Canadian Standards Association-National Standard of Canada	All DRs	Maximum capacity is not defined	≤ 50 kV	2020	**R16**
Electric Rule 21 [18]	Rule 21 Interconnection	California Public Utilities Commission	Any generation/ storage facilities that are being connected to a utility's distribution system			2016	**R17**

IEEE: Institute of Electrical and Electronics Engineers (IEEE), IEC: International Electrotechnical Commission; DR: Distributed Resource; DER: Distributed Energy Resource

Table 2-1 - International Standards/Guidelines for Integrating DRs with Power Grids and their Scope.

R1. Deals with the technical specifications for the interconnection and interoperability between utility electric power systems and DRs. Provides requirements relevant to the performance, operation, testing, safety considerations, and maintenance of the interconnection, including general requirements, response to abnormal conditions, power quality, islanding, installation evaluation, commissioning, and periodic tests.

R2. Deals with equipment and functions necessary to ensure compatible operation of PV systems that are connected in parallel with the electric utility. It includes factors related to personnel safety, equipment protection, power quality, utility system operation, Operation of PV system under islanding conditions, techniques to avoid unintentional islanding.

R3. The maximum limit varies from 0.8 kW to 15 MW based on the location, like Continental Europe, Great Britain, Nordic, Baltic, Ireland and Northern Ireland.

R4. Mainly for bulk generation plants.

R5. For Interconnection of distributed generators to the grid. All necessary studies have to be conducted prior to interconnection to assess the impact, including protection and safety studies.

R6. Applicable for interconnection of PV systems/inverters to the utility distribution system, operating in parallel using non-islanding inverters.

R7. Inverter based power sources can be connected at LV of 100/200V. 3-Φ rotating machine or inverter based generators can be connected at HV of 6.6 KV-33 KV. Generators rated at less than 50 kW, 50 to less than 2,000 kW, or not less than 2,000 kW can connect with a low-voltage (100/200V), medium-voltage (6.6kV), or extra-high-voltage (22/33kV and above) distribution network respectively. Anti-islanding is required.

R8. 20 kW or less capacity DRs are connected at LV. 3000 kW or less capacity DRs are connected at ultrahigh voltage (UHV)

R9. The objective of this standard is to minimize the feeder voltage issues and are expected to address through real and reactive power control of inverter.

R10. AS/NZS 4777.1: 2016 - Grid connection of energy systems via inverters – Installation requirements, AS/NZS 4777.2:2015 - Grid connection of energy systems via inverters Part 2: Inverter requirements.

R11. For PV systems with less than 100 kVA capacity and are to be connected to less than 1 kV line. Not in Use.

R12. This Code of Practice insists on accumulators for behavior like power generating plants in the discharging process. It also insists for dynamic network support including LVRT & HVRT and encourages reactive power control from DRs as well as active power regulation under frequency disturbances.

R13. 3-Φ generators with < 11.04 kW will be connected at 400V, 1-Φ generators with < 3.68kW will be connected at 230V. Applicable to generator(s) connected to the distribution network in a single premise.

R14. A guide for connecting generation to the distribution network in a single premise for capacities of < 50 kW, 3-Φ and < 17kW, 1-Φ.

R15. Applicable to utility-interconnected PV systems with (solid-state) non-islanding inverters. No discussion on EMC or protection mechanisms against islanding. With the inclusion of storages or PV systems are controlled from utility the requirements may vary.

R16. Includes distribution system characteristics regarding abnormal voltage and frequency operating conditions, requirements for the interconnection system regarding, identifying DR grades based on their capabilities, active and reactive power control, voltage ride, intentional islanding protection, production and type testing, advanced inverter functionality, safety of persons, protection of property.

R17. It is a tariff that describes the interconnection, operating and metering requirements for generation/storage facilities to be connected to a utility's distribution system while protecting the safety and reliability of the distribution and transmission systems at the local and system levels. Under revision.

3 IEEE, Norway-EU, CEA and MNRE Standards/Protocols

The prominent international standards/Protocols viz. IEEE 1547, Norway-European Protocols along with Central Electricity Authority Regulations and Ministry of New and Renewable Energy (MNRE) Regulations of India are discussed in this section for different technical parameters along with their significance.

3.1 IEEE standard 1547

The Institute of Electrical and Electronics Engineers (IEEE) Standard 1547 has been a foundational document for the interconnection of distributed resources (DRs) with the electric power system or the grid. It is the only American National Standard addressing the DR interconnection with the grid at system level. It also influences the energy industry business and its future operations. This standard has been instrumental in integration of distributed energy resources, especially renewable energy technologies and storages. While providing the mandatory technical requirements and specifications, it allows flexibility as well as choices with respect the equipment and different operations. The functions/operations of different equipment/devices, including the software, have to be met as per the specifications given in this standard, irrespective of their location in the system as well as type of device, like synchronous machines, induction machines or static power converters.

Different interconnection requirements are broadly classified as shown in the following Figure 3.1.

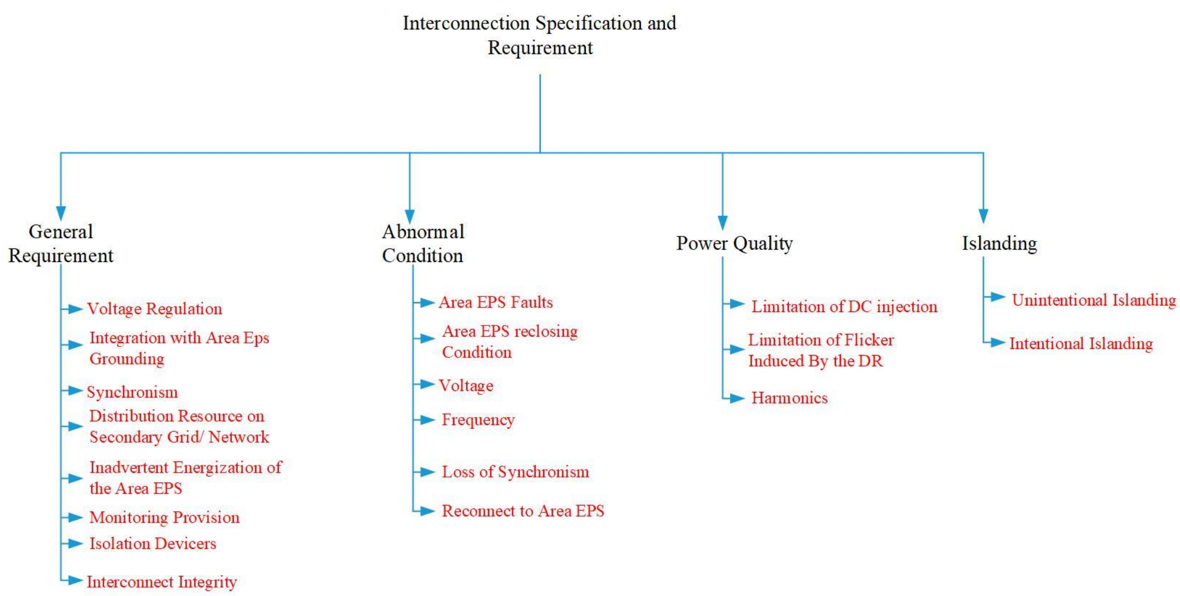


Figure 3.1 - Broad Classification of Interconnection Requirements and Specifications.

3.1.1 Voltage Regulation

An illustrative Area Electric Power System (Areas EPS) with its relationships is shown in Figure 3.2. The recent revision of IEEE 1547-2018 standard reversed the 2003 standard by requiring that all DERs have certain levels of voltage regulation capability. For this, DER is separated into two Normal Operating

Performance Categories as: (i) 'A' category specifies minimum performance capabilities needed and are in general attainable by all DERs, applicable in case of DER output does not have frequent large variations and penetration in the distribution system is lower (ii) 'B' category specifies additional capabilities needed for DERs whose output is subjected to frequent large variations with higher level of DER penetration as in Table 3-1. The **Error! Reference source not found.** gives the requirements of reactive power capabilities for DERs with respect to their category. The Voltage-Reactive power settings under normal operations are given Table 3-3, while the Real-Reactive power settings are described in Table 3-4 and Voltage-Active power settings are given in Table 3.5.

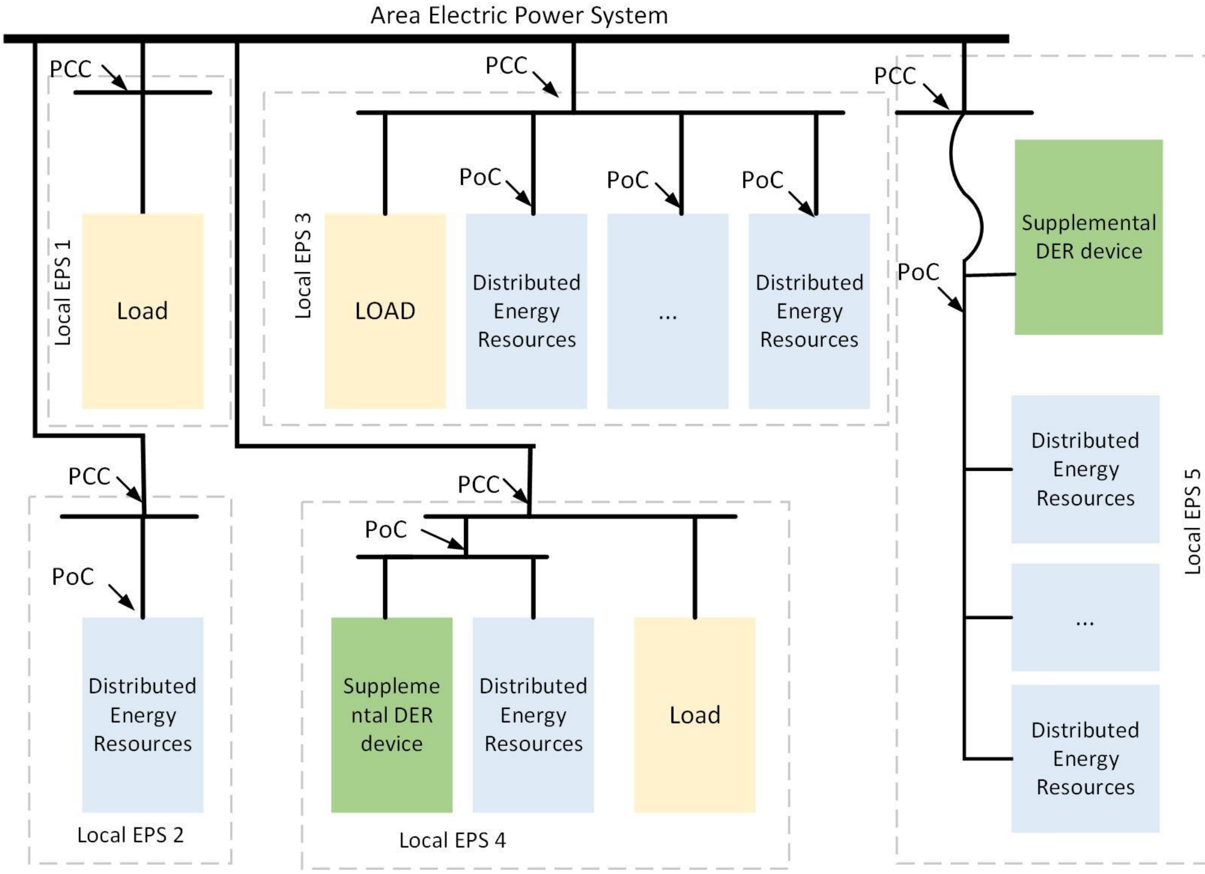


Figure 3.2 - A representative Area Electric Power System with DRs. [2] [1547-2018]

DER category	Category A	Category B
Voltage regulation by reactive power control		
Constant power factor mode	Mandatory	Mandatory
Voltage – reactive power mode[1]	Mandatory	Mandatory
Active power – reactive power mode[2]	Not required	Mandatory
Constant reactive power mode	Mandatory	Mandatory
Voltage and active power control		
Voltage – active power (volt-watt) mode	Not required	Mandatory

[1] Voltage-reactive power mode may also be commonly referred to as "volt-var" mode.
[2] Active power-reactive power mode may be commonly referred to as "watt-var" mode.

Table 3-1 - Voltage and reactive/active power control function requirements for DER normal operating performance categories [2]

Category	Injection capability as % of nameplate apparent power (kVA) rating	Absorption capability as % of nameplate apparent power (kVa) rating
A (at DER rated voltage)	44	25
B (over the full extent of ANSI C84.1 range A)	44	44

Table 3-2 - Reactive power injection/absorption capability requirements [2]

Voltage reactive power parameters	Default settings		Ranges of allowable settings	
	Category A	Category B	Minimum	Maximum
V_{Ref}	V_N	V_N	0.95 V_N	1.05 V_N
V_2	V_N	V_{Ref} – 0.02 V_N	Category A: V_{Ref} Category B: V_{Ref} – 0.03 V_N	V_{Ref}[3]
Q_2	0	0	100% of nameplate reactive power capability, absorption	100% of nameplate reactive power capability, injection
V_3	V_N	V_{Ref} + 0.02 V_N	V_{Ref}[3]	Category A: V_{Ref} Category B: V_{Ref} + 0.03 V_N
Q_3	0	0	100% of nameplate reactive power capability, absorption	100% of nameplate reactive power capability, injection
V_1	0.9 V_N	V_{Ref} - 0.08 V_N	V_{Ref} - 0.18 V_N	V_2 - 0.02 V_N[3]
Q_1[a]	25% of nameplate apparent power rating, injection	44% of nameplate apparent power rating, injection	0	100% of nameplate reactive power capability, injection[2]
V_4	1.1 V_N	V_{Ref} + 0.08 V_N	V_3 + 0.02 V_N[3]	V_{Ref} + 0.18 V_N
Q_4	25% of nameplate apparent power rating, absorption	44% of nameplate apparent power rating, absorption	100% of nameplate reactive power capability, absorption	0
Open loop response time	10 s	5 s	1 s	90 s

1 The DER reactive power capability may be reduced at lower voltage.
2 If needed DER may reduce active power output to meet this requirement.
3 Improper selection of these values may cause system instability.

Table 3-3 - Voltage reactive power settings for normal operating performance [2]

Active power – reactive power parameters	Default settings		Ranges of allowable settings	
	Category A	Category B	Minimum	Maximum
P_3	P_{rated}		$P_2 + 0.1\ P_{rated}$	P_{rated}
P_2	$0.5\ P_{rated}$		$0.4\ P_{rated}$	$0.8\ P_{rated}$
P_1	The greater of $0.2\ P_{rated}$ and P_{min}		P_{min}	$P_2 - 0.1\ P_{rated}$
P'_1	The lesser of $0.2 \times P'_{rated}$ and P'_{min}		$P'_2 - 0.1\ P'_{rated}$	P'_{min}
P'_2	$0.5\ P'_{rated}$		$0.8\ P'_{rated}$	$0.4\ P'_{rated}$
P'_3	P'_{rated}		P'_{rated}	$P'_2 + 0.1\ P'_{rated}$
Q_3	25% of nameplate apparent power rating, absorption	44% of nameplate apparent power rating, absorption	100% of nameplate reactive power absorption capability	100% of nameplate reactive power injection capability
Q_2	0			
Q_1	0			
Q'_1	0			
Q'_2	0			
Q'_3	44% of nameplate apparent power rating, injection			
NOTE - P_{rated} is the nameplate active power rating of the DER. P'_{rated} is the maximum active power that the DER can absorb. P_{min} is the minimum active power output of the DER. P'_{min} is the minimum, in amplitude, active power that the DER can absorb. P' parameters are negative in value.				

Table 3-4 - Active power reactive power settings for normal operating performance [2]

Voltage-active power parameters	Default settings	Ranges of allowable settings	
		Minimum	Maximum
V_1	$1.06\ V_N$	$1.05\ V_N$	$1.09\ V_N$
P_1	P_{rated}	N/A	N/A
V_2	$1.1\ V_N$	$V_1 + 0.01\ V_N$	$1.10\ V_N$
P_2 (applicable to DER that can only generate active power)	The lesser of $0.2\ P_{rated}$ or P_{min}[1]	P_{min}	P_{rated}
P'_2 (applicable to DER that can generate and absorb active power)	0[2]	0	P'_{rated}
Open Loop Response Time	10 s[3]	0.5 s	60 s

1 P_{min} is the minimum active power output in p.u. of the DER rating (i.e., 1.0 p.u.).
2 P'_{rated} is the maximum amount of active power that can be absorbed by DER. ESS operating in the negative real power half plane, through charging, shall follow this curve as long as available energy storage capacity permits this operation.
3 Any settings for the open loop response time of less than 3 s shall be approved by the Area EPS operator with due consideration of system dynamic oscillatory behavior.

Table 3-5 - Voltage active power settings [2]

3.1.2 Grounding

The grounding of DR should be done such a way that it shall not cause any over voltages beyond the rating of the equipment that is interconnected with area EPS. In addition, it shall not disrupt the ground fault protection coordination of area EPS.

3.1.3 Synchronization

The DR shall not result in voltage fluctuations greater than ±5% of the prevailing voltage level at PCC of area EPS while meeting flicker requirements of IEEE 1547-2003.

3.1.4 DR on distribution secondary grid and spot networks

The PCC applications are intended for DR units interconnected with radial primary or secondary distribution circuits, which is the most common distribution configuration. However, in large cities a LV distribution networks are employed. These networks can be of two subtypes: (i) Secondary grid networks, like street networks or area network or grid network which serves multiple locations or different city blocks, and (ii) spot network which serves only single location, like a building or part of it.

Distribution secondary spot networks

- Unless tested as per applicable standards, network protectors shall not be used to as a breaker, even as back-up breaker, to isolate the network from DER.
- The DER connection is allowed only when the area EPS bus is energised with more than 50% of capacity of existing network protectors.
- The network equipment loading and fault interrupting capacity shall not be exceeded with the addition of DR.

3.1.5 Monitoring provisions

In case of DERs with capacity, single unit or aggregated DER capacity, 250 kVA or more shall have interconnection monitoring provisions, such as voltage, real and reactive powers. If the DER is size is less than load connected at PCC, a remote monitoring system may exist.

3.1.6 Interconnect integrity

Protection from electromagnetic interference

The EMI shall not interfere in the protection of operation of interconnection system and shall comply with IEEE Std C37.90.2™-2004.

Surge withstand performance

With respect to voltage and current surges the interconnection system shall comply with IEEE Std C62.41.2™-2002 or IEEE Std C37.90.1™-2002 as applicable.

3.1.7 Response to area EPS abnormal conditions

During the abnormal conditions the Area EPS requires a response from the connected DR in order to protect personnel and equipment including the DER. The specifications in the following sub-cluses shall be at PCC otherwise mentioned. The operating performance under abnormal conditions is defined in three categories as:

- *Category* I is based on essential *bulk power system* (BPS) stability/reliability needs. It shall be attainable by all the DERs in general.
- *Category* II covers all BPS stability/reliability needs and is coordinated with existing reliability standards in order to prevent wider range of disturbances
- *Category* III covers both BPS stability/reliability and distribution system reliability/power quality needs, in case of high penetration of DER.

Area EPS faults

For the faults detected by Area EPS protection systems, the DER unit shall cease to energize or trip, unless specified otherwise by operator. The tripping has to be done in case of open phase faults within 2.0s.

Inadvertent energization of the Area EPS

The DR shall cease to energize the Area EPS prior to reclosure by the Area EPS, otherwise transients may damage the system if the area EPS breaker should reclose when the area EPS and the island of DER are out of phase.

Voltage

For Category I the mandatory response under faults is described in Table 3-6 and Figure 3.3, while the requirements for Category II and Category III are specified in Table 3-7, Figure 3.4, Table 3-8, and Figure 3.5.

Shall trip – Category I				
Shall trip function	Default settings		Range of allowable settings	
	Voltage (p.u. of nominal voltage)	Clearing time (s)	Voltage (p.u. of nominal voltage)	Clearing time (s)
OV2	1.20	0.16	fixed at 1.20	fixed at 0.16
OV1	1.10	2.0	1.10-1.20	1.0-13.0
UV1	0.70	2.0	0.0-0.88	2.0-21.0
UV2	0.45	0.16	0.0-0.50	0.16-2.0

Table 3-6 - DER response (shall trip to abnormal voltages for DER of abnormal operating performance Category I (see Figure 3.3) [2].

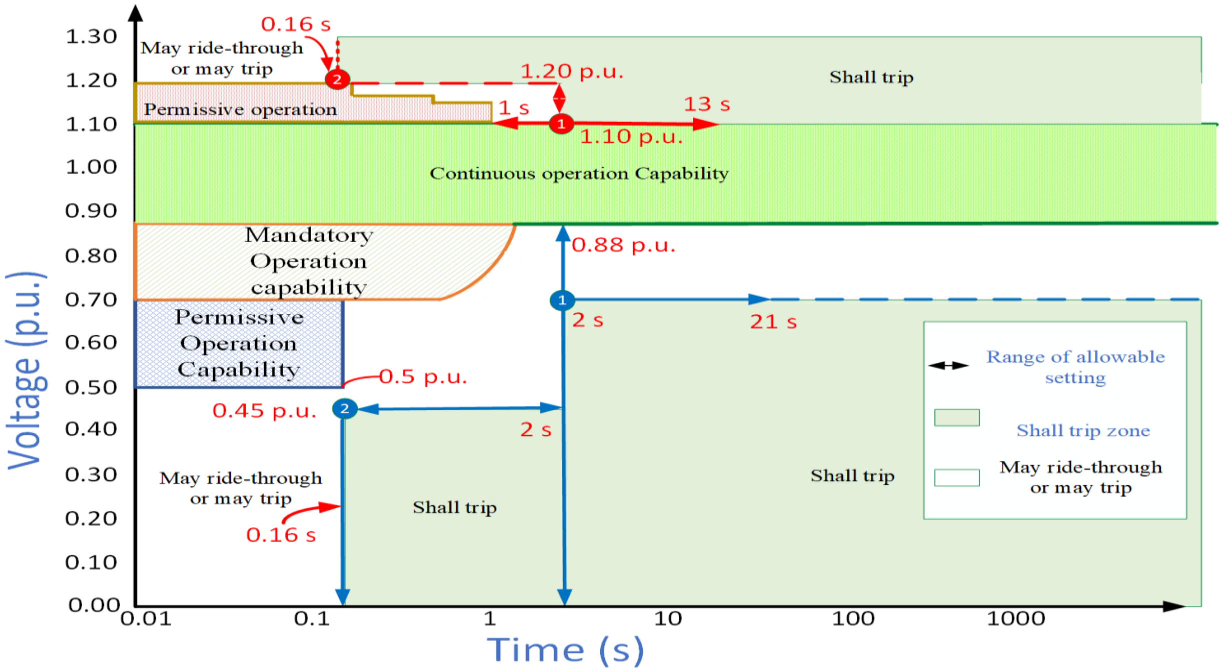


Figure 3.3 - DER response to abnormal voltages and voltage ride-through requirement for DER of abnormal operating performance Category I. [2]

Shall trip – Category II				
Shall trip function	Default settings		Range of allowable settings	
	Voltage (p.u. of nominal voltage)	Clearing time (s)	Voltage (p.u. of nominal voltage)	Clearing time (s)
OV2	1.20	0.16	fixed at 1.20	fixed at 0.16
OV1	1.10	2.0	1.10-1.20	1.0-13.0
UV1	0.70	10.0	0.0-0.88	2.0-21.0
UV2	0.45	0.16	0.0-0.50	0.16-2.0

Table 3-7 - DER response (shall trip) to abnormal voltages for DER of abnormal operating performance Category II (see Figure 3.4) [2]

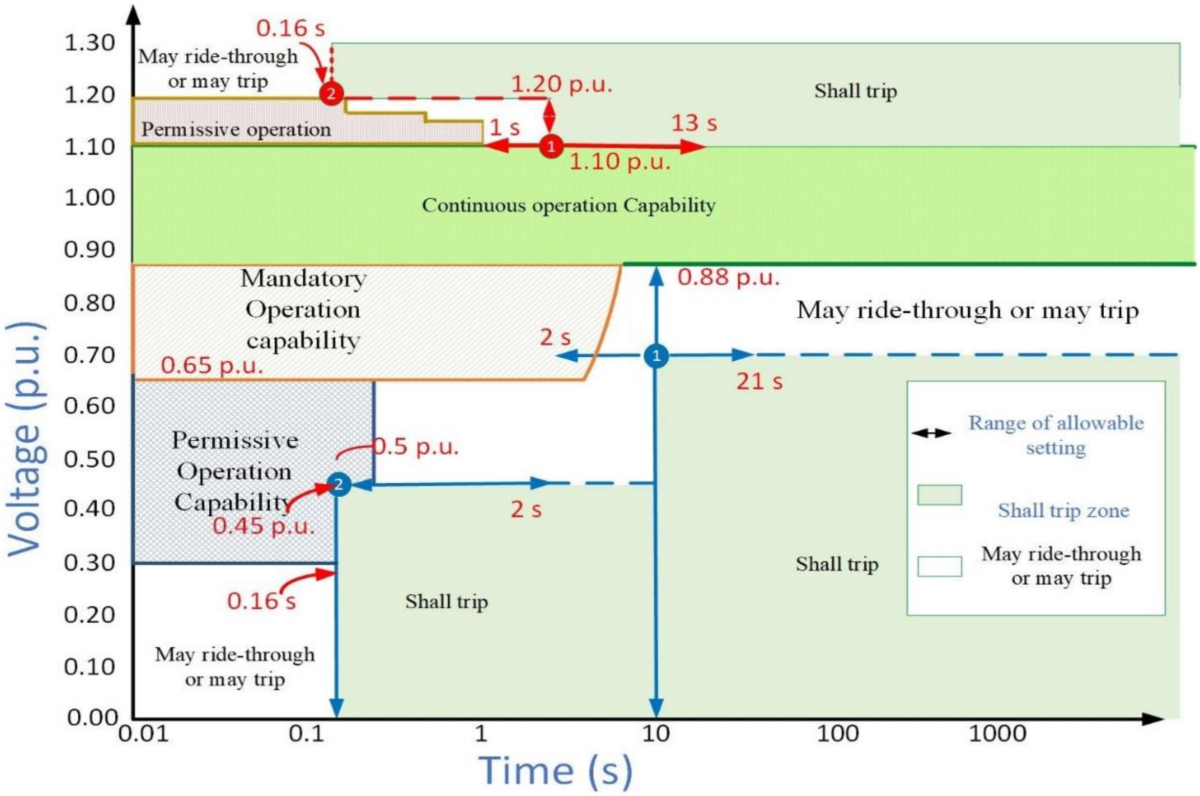


Figure 3.4 - DER response to abnormal voltages and voltage ride-through requirements for DER of abnormal operating performance Category II. [2]

Shall trip – Category III				
Shall trip function	**Default settings**		**Range of allowable settings**	
	Voltage (p.u. of nominal voltage)	**Clearing time (s)**	**Voltage (p.u. of nominal voltage)**	**Clearing time (s)**
OV2	1.20	0.16	fixed at 1.20	fixed at 0.16
OV1	1.10	13.0	1.10-1.20	1.0-13.0
UV1	0.88	21.0	0.0-0.88	21.0-50.0
UV2	0.50	2.0	0.0-0.50	2.0-21.0

Table 3-8 - DER response (shall trip) to abnormal voltages for DER of abnormal operating performance Category III (see Figure 3.5) [2]

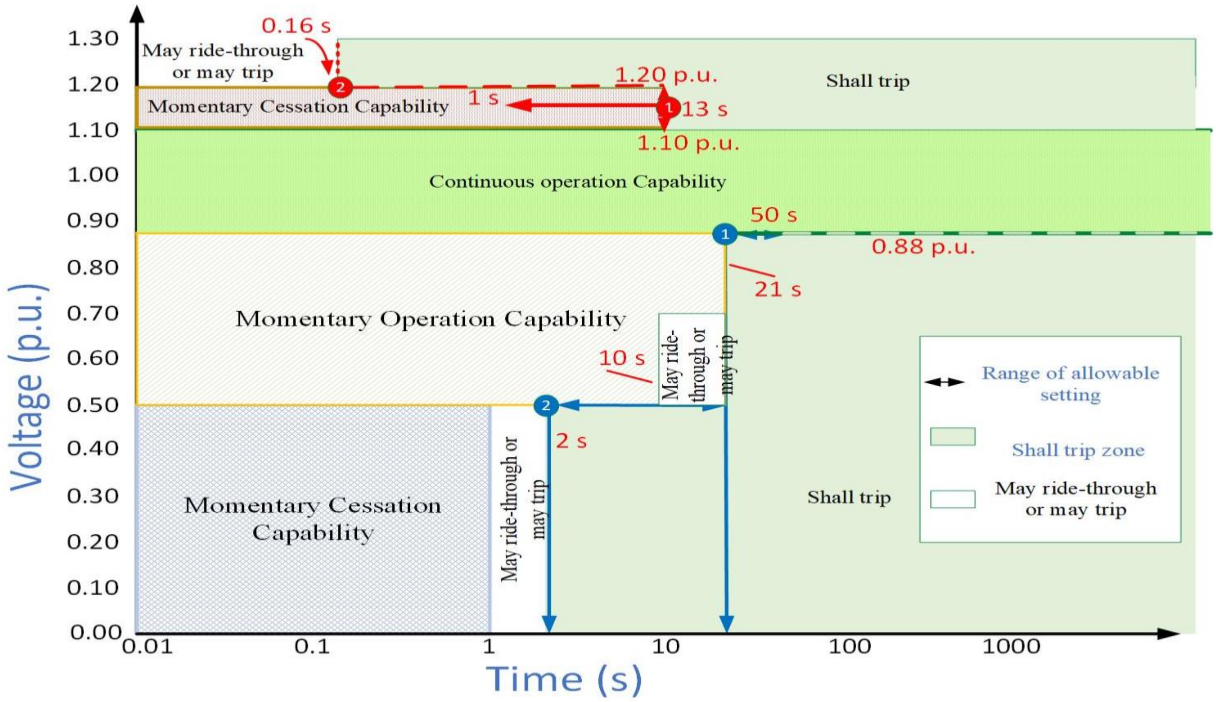


Figure 3.5 - DER response to abnormal voltages and voltage ride-through requirements for DER of abnormal operating performance Category III. [2]

The voltage-ride-through requirements for low as well as high voltages are specified in the following Table 3-9 to Table 3-11, whereas the above Figure 3.3 to Figure 3.5 depicted the voltage ride-through requirements also.

Voltage range (p.u.)	Operating mode/response	Minimum ride-through time (s) (design criteria)	Maximum response time (s) (design criteria)
$V > 1.20$	Cease to Energize[1]	N/A	0.16
$1.175 < V \leq 1.20$	Permissive Operation	0.2	N/A
$1.15 < V \leq 1.175$	Permissive Operation	0.5	N/A
$1.10 < V \leq 1.15$	Permissive Operation	1	N/A
$0.88 \leq V \leq 1.10$	Continuous Operation	Infinite	N/A
$0.70 \leq V < 0.88$	Mandatory Operation	Linear slope of 4 s/1 p.u. voltage starting at 0.7 s @ 0.7 p.u.: $T_{VRT} = 0.7\,s + \frac{4\,s}{1\,p.u.}(V - 0.7\,p.u.)$	N/A
$0.50 \leq V < 0.70$	Permissive Operation	0.16	N/A
$V < 0.50$	Cease to Energize[1]	N/A	0.16

[1] Cessation of current exchange of DER with Area EPS in not more than the maximum specified time and with no intentional delay. This does not necessarily imply disconnection, isolation, or a trip of the DER. This may include momentary cessation trip.

Table 3-9 - Voltage ride-through requirements for DER for abnormal operating performance Category I (see Figure 3.3) [2]

Voltage range (p.u.)	Operating mode/response	Minimum ride-through time (s) (design criteria)	Maximum response time (s) (design criteria)
$V > 1.20$	Cease to Energize[1]	N/A	0.16
$1.175 < V \leq 1.20$	Permissive Operation	0.2	N/A
$1.15 < V \leq 1.175$	Permissive Operation	0.5	N/A
$1.10 < V \leq 1.15$	Permissive Operation	1	N/A
$0.88 \leq V \leq 1.10$	Continuous Operation	Infinite	N/A
$0.65 \leq V < 0.88$	Mandatory Operation	Linear slope of 8.7 s/1 p.u. voltage starting at 3 s @ 0.65 p.u.: $T_{VRT} = 3\,s + \frac{8.7\,s}{1\,p.u.}(V - 0.65\,p.u.)$	N/A
$0.45 \leq V < 0.65$	Permissive Operation	0.32	N/A
$0.30 \leq V < 0.45$	Permissive Operation	0.16	N/A
$V < 0.30$	Cease to Energize[1]	N/A	0.16

[1] Cessation of current exchange of DER with Area EPS in not more than the maximum specified time and with no intentional delay. This does not necessarily imply disconnection, isolation, or a trip of the DER. This may include momentary cessation trip.

Table 3-10 - Voltage ride-through requirements for DER for abnormal operating performance Category II (see Figure 3.4).

Voltage range (p.u.)	Operating mode/response	Minimum ride-through time (s) (design criteria)	Maximum response time (s) (design criteria)
$V > 1.20$	Cease to Energize[1]	N/A	0.16
$1.10 < V \leq 1.20$	Momentary Cessation[2]	12	0.083
$0.88 \leq V \leq 1.10$	Continuous Operation	Infinite	N/A
$0.70 \leq V < 0.88$	Mandatory Operation	20	N/A
0.50[3] $\leq V < 0.70$	Mandatory Operation	10	N/A
$V < 0.50$[3]	Momentary Cessation[2]	1	0.083

[1] Cessation of current exchange of DER with Area EPS in not more than the maximum specified time and with no intentional delay. This does not necessarily imply disconnection, isolation, or a trip of the DER. This may include momentary cessation or trip.
[2] Temporarily cease to energize an EPS, while connected to the Area EPS, in response to a disturbance of the applicable voltages or the system frequency, with the capability of immediate restore output of operation when the applicable voltages and the system frequency return to within defined ranges.
[3] The voltage threshold between mandatory operation and momentary operation may be changed by mutual agreement between the Area EPS operator and DER operator, for example to allow the DER to provide Dynamic Voltage Support below 0.5 p.u.

Table 3-11 - Voltage ride-through requirements for DER for abnormal operating performance Category III (see Figure 3.5) [2]

Voltage-ride-through requirements for temporary voltage disturbances resulted from unsuccessful reclosing for DER is specified in the following Table. 3.12.

Col. 1	Col. 2	Col. 3	Col. 4
Category	Maximum number of ride-through disturbance sets	Minimum time between successive disturbance sets (s)	Time window for new count of disturbance sets (min)
I	2	20.0	60
II	2	10.0	60
III	3	5.0	20

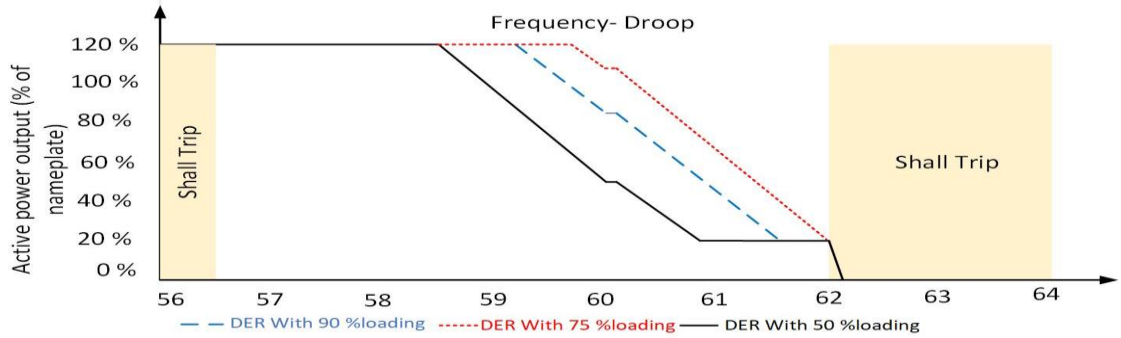
Table 3-12 - Voltage ride-through requirements for consecutive temporary voltage disturbances caused by unsuccessful reclosing for DER of abnormal operating performance Category I, Category II and Category III [2]

Frequency

The normal operating range of frequency is given in the following Table 3.13, while the Table 3.14 describes the specifications under abnormal operating conditions, mandatory power output requirements during frequency-ride-through are given in Table. 3.15.

Frequency range (Hz)	Operating mode	Minimum time (s) (design criteria)
$f > 62.0$	No ride-through requirements apply to this range	
$61.2 < f \leq 61.8$	Mandatory Operation	299
$58.8 \leq f \leq 61.2$	Continuous Operation	Infinite
$57.0 \leq f < 58.8$	Mandatory Operation	299
$f < 57.0$	No ride-through requirements apply to this range	

Table 3-13 - Frequency ride-through requirements for DER of abnormal operating performance Category I, Category II and Category III

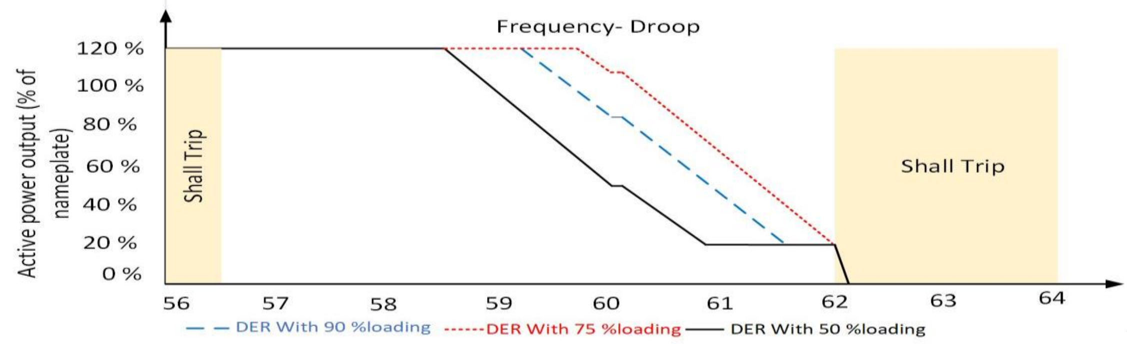
(see 

) [2]

Adjustable underfrequency trip settings shall be coordinated with Area EPS operations.

Shall trip function	Default setting		Range of allowable settings	
	Frequency (Hz)	Clearing time (s)	Frequency (Hz)	Clearing time (s)
OF2	62.0	0.16	61.8-66.0	0.16-1 000.0
OF1	61.2	300.0	61.0-66.0	180.0-1 000.0
UF1	58.5	300.0[3]	50.0-59.0	180.0-1 000
UF2	56.5	0.16	50.0-57.0	0.16-1 000

Table 3-14 - DER response (shall trip) to abnormal frequencies for DER of abnormal operating performance Category I, Category II and Category III (see



) [2]

lowing

describes the frequency (ride-through) response requirement of DER, while Figure 3.7 shows an example case of Frequency droop characteristics under varying frequencies, as specified.

Category	Active power output capability
I	80% of nameplate active power rating or the pre-disturbance active power output whichever is less
II and III	Pre-disturbance active power output

NOTE – Per 6.1, this requirement is limited to *available active power*.

Table 3-15 - Frequency ride-through requirements for active power output capability for abnormal operating performance Category I, Category II and Category III [2]

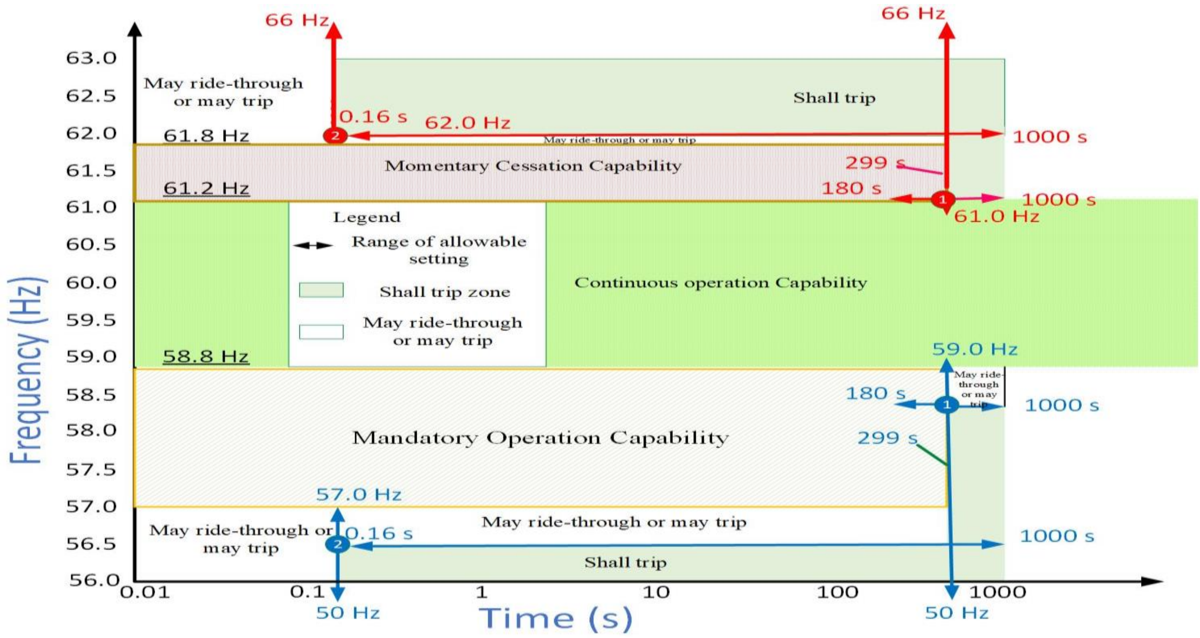
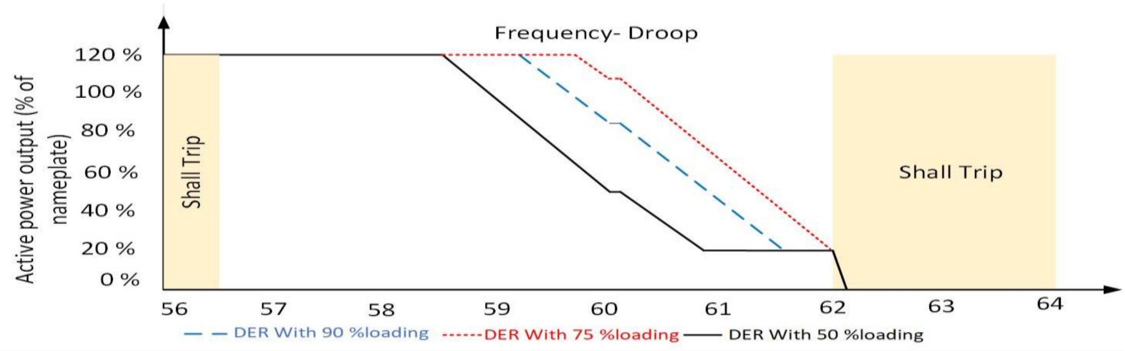


Figure 3.6 - DER default response to abnormal frequencies and frequency ride-through requirements for DER of abnormal operating performance Category I, Category II and Category III. [2]



NOTE – A DER response during low-frequency conditions may be subject to *available active power* and the pre-disturbance dispatch level**.**

Figure 3.7 - Example of a three frequency-droop function curves with a 5% droop, 36 mHz deadband, and 20% minimum active power output for DER operating at different pre-disturbance levels of nameplate rating (50%, 75% and 90%). [2]

Connection/Reconnection to area EPS

The voltage and frequency limits for a DER to energise the area EPS are specified in the Table 3-16 for all the three categories of DERs. In addition, the Table 3-17 specifies the synchronization parameters limits for synchronizing with an energised EPS.

Enter service criteria		**Default settings**	**Ranges of allowable settings**
Permit service		**Enabled**	**Enabled/Disabled**
Applicable voltage within range	Minimum value	≥ 0.917 p.u.[1]	0.88 p.u. to 0.95 p.u.
	Maximum value	≤ 1.05 p.u	1.05 p.u. to 1.06 p.u.
Frequency within range	Minimum value	≥ 59.5 Hz	59.0 Hz to 59.9 Hz
	Maximum value	≤ 60.1 Hz	60.1 Hz to 61.0 Hz

[1] This corresponds to the Range B of ANSI C84.1, Table 1, column for service voltage of 120-600 V.

Table 3-16 - Enter service criteria for DER of Category I, Category II and Category III [2]

Aggregate rating of DER units (kVA)	**Frequency difference (Δf, Hz)**	**Voltage difference (ΔV, %)**	**Phase angle difference ($\Delta\Phi$, °)**
0-500	0.3	10	20
>500-1 500	0.2	5	15
>1 500	0.1	3	10

Table 3-17 - Synchronization parameter limits for synchronous interconnection to an EPS or an energized Local EPS to an energized Area EPS [2]

3.1.8 Power quality

Limitation of dc injection

The DC current injections by the DER along with its interconnection system shall be limited to 0.5% of the rated output current of DER at PCC.

Limitation of Rapid Voltage Changes (RVCs) and flickers induced by the DER

RVC and flicker limits are specified in the following Tables 3.18 and 3.19

Number of changes (*n*)	**$\Delta V_{max}/V$ (%)**	
	≤ 35 kV	**> 35 kV**
$n \leq 4$ per day	5-6	3-5
$n \leq 2$ per hour and > 4 per day	4	3
$2 < n \leq 10$ per hour	3	2.5

Table 3-18 - System design planning level for RVCs (IEEE Std 1453)

E_{Pst}	**E_{Plt}**
0.35	0.25

[1] 95% probability value should not exceed the emission limit based on a one week measurement period.

Table 3-19 - Minimum individual DER flicker emission limits1

Harmonics

When the DR is serving balanced linear loads, harmonic current injection into the Area EPS at the PCC shall not exceed the limits stated below in the **Error! Reference source not found.** and

Table 3-21 respectively for odd and even harmonics. The terminology Total Harmonic Distortion has been replaced with Total Rated Current Distortion in the recent revision.

Individual odd harmonic order *h*	$h < 11$	$11 \le h < 17$	$17 \le h < 23$	$23 \le h < 35$	$35 \le h < 50$	Total rated current distortion (TRD)
Percent (%)	4.0	2.0	1.5	0.6	0.3	5.0

[1] I_{rated} = the DER unit rated current capacity (transformed to the RPA when a transformer exists between the DER unit and RPA).

Table 3-20 - Maximum odd harmonic current distortion in percent of rated current (I_{rated})[1]

Individual even harmonic order *h*	$h = 2$	$h = 4$	$h = 6$	$8 \le h < 50$
Percent (%)				Associated range specified in Table 26

[1] I_{rated} = the DER unit rated current capacity (transformed to the RPA when a transformer exists between the DER unit and the RPA).

Table 3-21 - Maximum even harmonic current distortion in percent of rated current (I_{rated})[1]

3.1.9 Unintentional islanding

The DER shall detect the island and cease to energise the Area EPS which (may be in part) is being energised by DER within 2 s and this is applicable to station bus island, substation island, and an adjacent circuit island.

3.1.10 Cyber security requirements

This standard does not mandate specific cyber security requirements at the DER interface and is beyond the scope of this standard.

3.2 Interconnection requirements in Norway/Europe

The European Network Code Requirements for Generators [4] has entered into force in April 2019. Even though the RfG NC regulation is mandatory to be implemented in Member states, it gives room for national specifications to specific extent. In this section, brief overview of the regulation will be presented followed by specific requirements in Norway.

3.2.1 European Network Code Requirements for Generators (RfG NC)

The Commission Regulation (EU) 2016/631 of 14 April 2016 established a network code on requirements for grid connection of generators with the aim of:

- Providing a clear legal framework for grid connections.
- Facilitate European union-wide trade in electricity.
- Ensure system security.
- Facilitate the integration of renewable electricity sources.
- Increase competition and allow more efficient use of the network and resources, for the benefit of consumers.

New Power Generating Modules (PGM) connected to ENTSO's synchronous areas fall into four categories of significance A, B, C and D as presented in Table 3-22.

Synchronous areas	**Limit for maximum capacity threshold from which a PGM is of:**			
	Type A	**Type B**	**Type C**	**Type D**
Continental Europe	0.8 kW	1 MW	50 MW	75 MW
Great Britain	0.8 kW	1 MW	50 MW	75 MW
Nordic	0.8 kW	1.5 MW	10 MW	30 MW
Ireland & Northern Ireland	0.8 kW	0.1 MW	5 MW	10 MW
Baltic	0.8 kW	0.5 MW	10 MW	15 MW
Connection point voltage	*<110 kV*	*<110 kV*	*<110 kV*	*≥110 kV*

Table 3-22 - Limits for thresholds for type B, C and D power-generating modules.

For type D power generating modules synchronization shall be possible at frequencies within the ranges set out in Table 3-23. Also, power-generating module shall be capable of remaining connected to the network and operate within the frequency ranges and time periods specified in the Table.

Synchronous Area	**Frequency Range**	**Time Period for operation**
Continental Europe	47.5 Hz-48.5 Hz	To be specified by each TSO, but not less than 30 minutes
	48.5Hz -49 Hz	To be specified by each TSO, but not less than period for 47.5Hz-48.5 Hz.
	49.0 Hz – 51 Hz	Unlimited
	51 Hz – 51.5 Hz	30 minutes
Nordic	47.5 Hz-48.5 Hz	30 minutes
	48.5Hz -49 Hz	To be specified by each TSO, but not less than period for 47.5Hz-48.5 Hz.
	49.0 Hz – 51 Hz	Unlimited
	51 Hz – 51.5 Hz	30 minutes

Table 3-23 - Minimum time periods for which a power-generating module has to be capable of operating on different frequencies, deviating from a nominal value, without disconnecting from the network [19]

The RfG NC regulation stipulates also that the relevant system operator and the power-generating facility owner shall agree on the settings of synchronisation devices to be concluded prior to operation of the power-generating module. This agreement shall cover:

- voltage;
- frequency;
- phase angle range;
- phase sequence;

- deviation of voltage and frequency.

The relevant TSO shall also specify admissible active power reduction from maximum output with falling frequency in its control area as a rate of reduction falling within the boundaries, illustrated by the full lines in Figure 3.8.

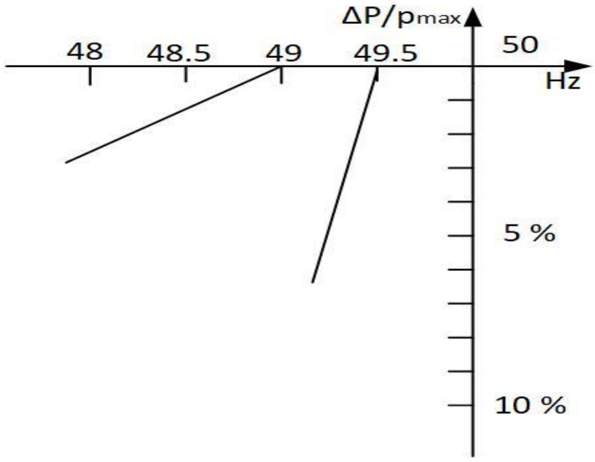


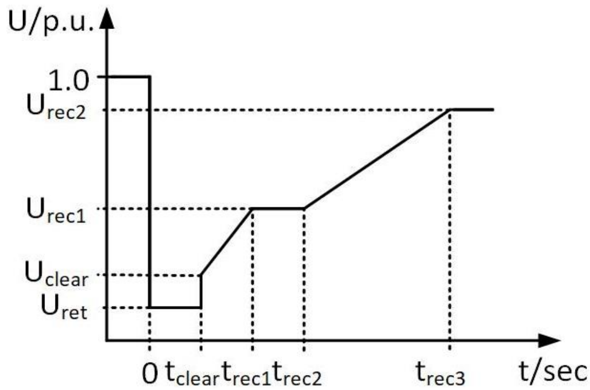
Figure 3.8 - Maximum power capability reduction with falling frequency. [4]

Rate Of Change Of Frequency (ROCOF) withstand capability

A power-generating module shall be capable of staying connected to the network and operate at rates of change of frequency up to a value specified by the relevant TSO. It Commonly fixed at 2 Hz/s for continental Europe with minor differences in measurement period.

Fault Ride through Requirements

Although member state TSOs will specify the specific requirements, ranges of parameters are provided in Table 3.24 and in Table 3.25 as given by RfG NC, with reference to Fig. 3.9.



U_{ret} = Retained voltage at the connection point during a fault
U_{clear} = The instant when the fault has been cleared
U_{rec1} = Voltage recovery after fault clearance
U_{rec2} = Voltage recovery after fault clearance
U_{rec3} = Voltage recovery after fault clearance

Figure 3.9 - Fault ride through curve for abnormal operation. [4]

Voltage Parameter (in p.u)		Time Parameter (in seconds)	
$\mathbf{U_{ret}}$	0.05-0.3	t_{clear}	0.14-0.15(0.14-0.25 if system protection and secure operation so require)
$\mathbf{U_{clear}}$	0.7-0.9	t_{rec1}	t_{clear}
$\mathbf{U_{rec1}}$	U_{clear}	t_{rec2}	$t_{rec1} - 0.7$
$\mathbf{U_{rec2}}$	$0.85 - 0.9 \geq U_{clear}$	t_{rec3}	$t_{rec2} - 1.5$

Table 3-24 - Parameters for fault ride through capability of synchronous power generating module.

Voltage Parameter (in p.u)		Time Parameter (in seconds)	
$\mathbf{U_{ret}}$	0.05-0.15	t_{clear}	0.14-0.15(0.14-0.25 if system protection and secure operation so require)
$\mathbf{U_{clear}}$	$U_{ret} - 0.15$	t_{rec2}	t_{clear}
$\mathbf{U_{rec1}}$	U_{clear}	t_{rec2}	t_{rec1}
$\mathbf{U_{rec2}}$	0.85	t_{rec3}	1.5-3

Table 3-25 - Parameters for fault ride through capability of synchronous power park modules

3.2.2 Norwegian Requirements for Grid Connection of Generators

In Norway there are many small-scale hydropower generation units connected in the distribution network. In 2017, the Norwegian Water Resources and Energy Directorate (NVE) asked the transmission system operator in Norway, Statnett, to review the Commission Regulation (EU) 2016/631 of 14 April 2016 (RfG NC). The final grid code implementation in Norway is still under discussion after the RfG NC entered into force in April 2019. The currently working grid code is published in 2012 (Funksjonskrav i kraftsystemet (FIKS)) [20]. In this document referring the currently working FIKS 2012, the EU RfG NC and the document prepared by Statnett for NVE [21], selected example requirements are discussed. According to review document prepared by Statnett on RfG NC, modified categories of generating unit types are presented in Table 3.26 specific for Nordic countries. Type A generating unit has maximum capacity of 0.8 kW.

	Type B	Type C	Type D
Sweden	1.5 MW	10 MW	30 MW
Norway	1.5 MW	10 MW	30 MW
Finland	1.0 MW	10 MW	30 MW
Denmark	0.1 MW	1 MW	25 MW
EU regulation Specified for Nordic countries	1.5 MW	10 MW	30 MW

Table 3-26 - Proposals for maximum capacity thresholds for types B, C and D from EU and revised versions for specific Nordic countries.

Also, since Norway is not a member of the EU, RfG (Requirements for Grid Connection of Generators), DCC and HVDC do not apply in Norway until the regulations have been included in the EEA agreement and implemented in Norwegian law. Hence, the EEA relevant document applicable to Norway is explicitly indicated by 'Text with EEA relevance' [22]. The EU network code implementation process in Norway is illustrated in Figure 3.10.

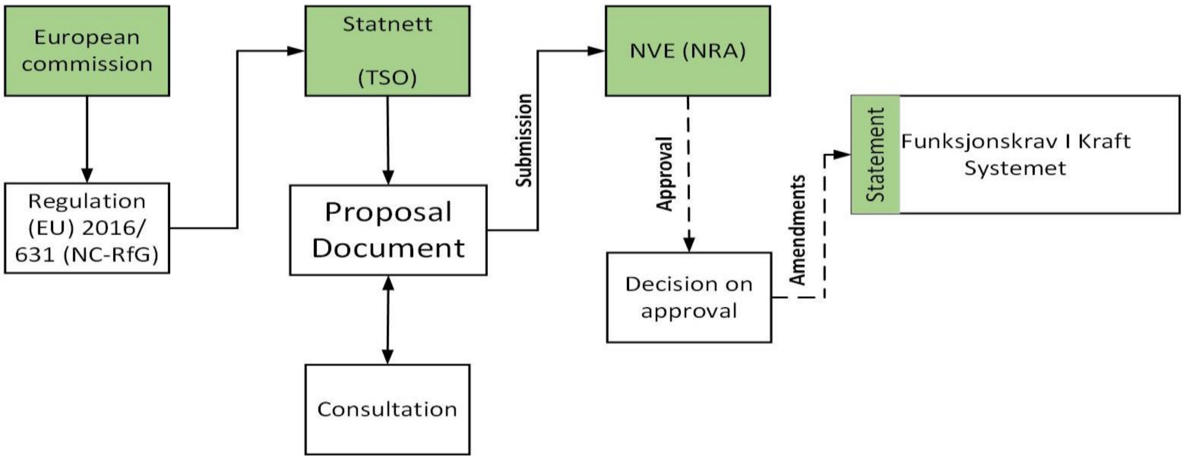


Figure 3.10 - Implementation process in Norway (Ali, M., E., C., & Y., February – 2021).

For the Nordic system minimum time periods for which a power-generating module has to be capable of operating on different frequencies, deviating from a nominal value, without disconnecting from the network is presented in Table 3.27.

Frequency range [Hz]	Voltage [pu]	Time period for operation
45.0 – 47.5	0.90 – 1.05	30 > 20 s
47.5 – 49.0	0.90 – 1.05	> 30 min
49.0 – 52.0	0.90 – 1.05	Continuous
52.0 – 53.0	0.90 – 1.05	> 30 min
53.0 – 55.0	0.90 – 1.05	> 20 s
55.0 – 57.0	0.90 – 1.05	> 10 s

Table 3-27 - Combinations of frequency and voltage that hydropower plants should be able to freely operate within without disconnecting. Ref. FIKS 2012.

Voltage variations withstand capability of generating units depends on the voltage level at which the generating units are connecting. In Table 3-28, Nordic region's requirement for power-generating module to be able to operate for voltages deviating from the reference 1 pu value at the connection point and the base voltage for peruint is 110 kV to 300 kV.

Voltage range	Time period for operation
0,90 pu-1,05 pu	Unlimited
1,05 pu-1,10 pu	60 minutes

Table 3-28 - Requirements relating to voltage stability for Type D generation units.

Robust FRT requirement, illustrated in Figure 3.11 is proposed in the RfG NC review document prepared by Statnett for type B generating units.

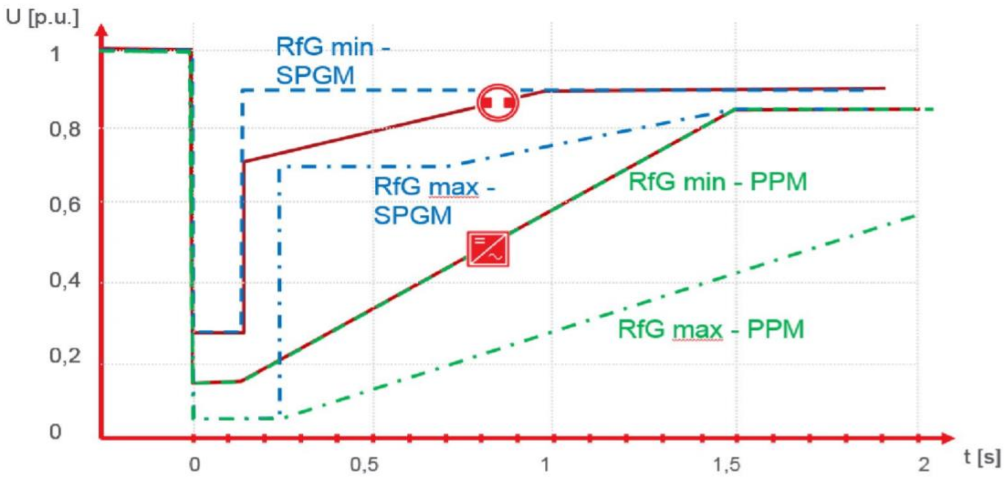


Figure 3.11 - Voltage-time-profile for generation units of type B for synchronous (SPGM) and power park modules (PPM). Maximum and minimum limits in NC-RfG illustrated for synchronous production units (blue) and power-park units (green) Ref Statnett Reviewed RfG NC. [4]

Although most of the requirements will follow the RfG NC, some deviations are expected which parameters are tuned to the Norwegian specific conditions. For example, For Synchronous Power Generating Modules, the maximum time to complete activation, which is 300 seconds for type D generators and 500 seconds for type C hydraulic SPGMs with a droop of 12%.

REN guidelines

With regards to protection system guidelines are provided by REN1 (a company which prepares and disseminates knowledge and guidelines for Norwegian grid companies) as industries best practices are presented in Table 3-29 for over/under voltage protection and in Table 3-30 and Table 3-31 for frequency response.

Voltage range in % of nominal voltage	Maximum disconnection time (Second)
U>>115	0.2
U>110	3
U<90	3
U<<85	0.2

Table 3-29 - Requirements for protection response in case of over- or under-voltage in the connection point.

Frequency range	Maximum disconnection time (Second)
f >52	0.5
f <47.5	0.5

Table 3-30 - Requirements for protection response at abnormal frequency in the measuring point

[1] https://www.ren.no/

Parameter	Allowed reconnection after: [s]
Frequency level	50.2 Hz
Reduction of production	2.4%
Time delay	0 s

Table 3-31 - Requirements for frequency response settings over frequency

The PV unit shall be capable of activating the active frequency response at a given frequency level. The range of the frequency response is 50.2-50.5 Hz. Production should be reduced between 2-12%. This depends on the input active power when the frequency reaches 50.2 Hz.

Harmonic Distortions

In terms of harmonic distortions, the standard is as follows in Table 3.32.

Odd harmonics				Even harmonics	
Not multiple of 3		Multiple of 3			
Order h	U_h (in %)	Order h	U_h (in %)	Order h	U_h (in %)
5	6.5	3	5.0	2	2.0
7	5.0	9	1.5	4	1.0
11	3.5	>9	0.5	>4	0.5
13	3.0				
17	2.0				
19, 23, 25	1.5				
>25	1.0				

Table 3-32 - Maximum allowable injected harmonics current to the grid system

3.3 Technical Standard for Connectivity to the Grid by Central Electricity Authority- India

These standards are applicable to any generating facility whose electrical plant is connected to the grid at voltage level 33 kV and above. Published first in 2006 amended in 2010, 2013 and 2019. Applicable for all types of bulk generating plants.

3.3.1 Connectivity Standards applicable to the Generating Stations other than wind and generating stations using inverters

A brief of this standard is presented here with respect to droops, protection, short circuit ratio, power factor operations.

Protection System

The protection system of generating units shall protect the units from internal faults, also from faults within station as well as from faults in connected lines. Generation plants of 100 MW rating and above shall have Automatic Voltage Regulator (AVR) with digital control and two separate channels having independent inputs and automatic changeover and these AVRs shall include Power System Stabilizer (PSS).

Similarly, these plants shall have two independent sets of protections, including trip coils and DC supplies. The protection system shall include Local Breaker Back-up (LBB) protection.

The Short Circuit Ratio (SCR) for generators shall be as per IDC-34.

Frequency Regulation

All generating machines should participate in frequency regulation. The governor droop for the thermal units shall be 3 to 6% and for hydro units it shall be 0 to 10%.

Power Factor Operation

The Operational Capability of Generator for Power Factor shall be ranging between 0.85 lagging (over-excited) and 0.95 leading (under-excited), 0.9 lagging and 0.95 leading, respectively located near and far from load centres. The operating power factor shall not deviate by more than 0.05 on either side from unity for distribution system and bulk consumer.

Voltage and Frequency Tolerance

The voltage variation shall not be more than ± 5% of nominal, **frequency variation** shall be within + 3% and -5%. The limit for combined voltage and frequency variation shall be ±5%. In case of Gas based plants the specified range of power factor operation shall be achieved for voltage variation of ±5%.

Frequency Response

For Short duration, the coal and lignite based units shall be capable of generating up to 105% of Maximum Continuous Rating to furnish the frequency response. The hydro generating units shall be capable of generating up to 110% of rated capacity on continuous basis. All the hydro generators with capacity of 50 MW or higher shall operate in lagging power factor, wherever feasible. All hydro generators shall be capable of black start. Diesel generators may be used to meet the auxiliary services to facilitate black start.

Back-Energization

One of the critical requirements is that there should not be any back-energization of the system by the consumer without such specific request from utility.

3.3.2 Connectivity standards applicable to the wind generating stations, generating stations using inverters, wind - solar photovoltaic hybrid systems and energy storage systems

This Subsection describe the standards for interconnection of generating stations that use PV and Wind as driving sources and employ inverters.

Active Power Control and Frequency Response

The generating stations with installed capacity not less than 10 MW and up to 500 MW, interfaced at voltage not less than 33 kV shall be capable of controlling the active power injection as desired by the load dispatch centre. These stations shall have governors or frequency controllers with a droop of 3 to 6%, however, the dead band shall not be greater than ±0.03 Hz.

In case, if the frequency deviates beyond 0.3 Hz, the station shall respond immediately (within 1 second) to provide real power support of at least 10% of maximum AC real power capacity.

If desired, the station shall provide the regulation over 10% to 100% of its capacity as frequency response, corresponding to solar insolation and wind speed, whatever is applicable.

During the process of regulation, power change rate shall not be more than ± 10% per minute.

The generating station shall deliver the rated output power, if the frequency is varying by ± 0.5 Hz and shall be capable of operating without disconnection in the frequency range of 47.5 Hz to 52 Hz.

If the frequency is below 49.90 Hz and above 50.05 Hz, the station shall be capable of regulating the output as desired for frequency response.

In addition, the generating unit shall be capable of maintaining its performance as mentioned above even with voltage variation of up to + 5%, however, subject to availability of sufficient wind speed and solar insolation, whatever may be the case.

In case of stations over and above 500 MW capacity shall vary its real and reactive power as desired by load dispatch centres.

Harmonics-Power Quality

The voltage and current harmonics injections on to the grid at PCC should be as per IEEE 519 standard. Voltage THD at the PCC shall not be more than 5%, however, any individual harmonic shall be limited within 3%. For current the THD shall be limited to 5%.

Voltage unbalance shall not be more than 3.0% for nominal voltages of 33KV and above.

The permissible limit of voltage fluctuation for repetitive step changes is 1.5%, for occasional fluctuations other than step changes the limit is 3%. The DC current injections shall not be more than 0.5%, flicker shall be limited as in IEC 61000-4-30 Class A.

As per IEC standard, compatibility level for short term flicker (P_{st}) is 1.0 where for long term flicker the compatibility level (P_{lt}) stands at 0.8.

where P_{st} is a value that characterizes the likelihood of perceptible light flicker that would have resulted from voltage fluctuations. A value of 1.0 is designed to represent that level of flicker for which 50% of people would perceive flicker in a 60W incandescent bulb. P_{lt} is derived from 2 hours of P_{st} values (12 values combined in cubic relationship)

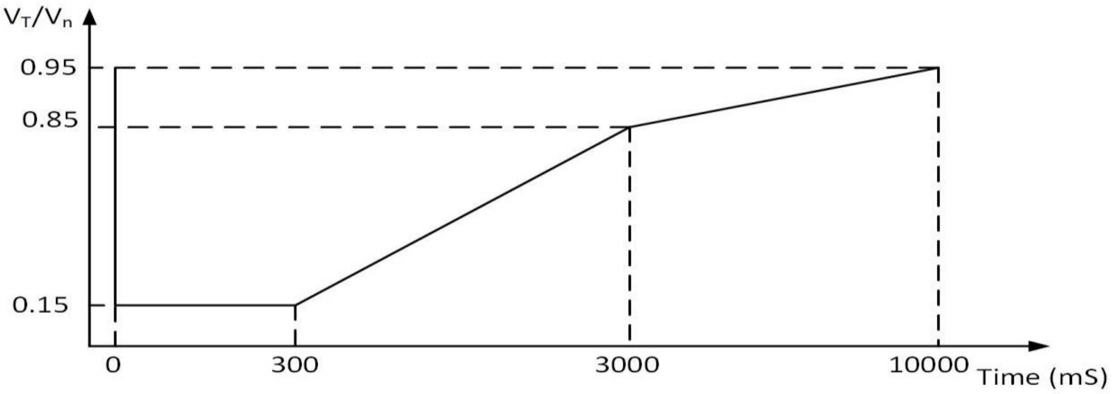
The deployment and activation of under frequency and rate of change of frequency with time (df/dt) relays shall be done as per the decision of Regional Power Committee.

The operating power factor of the station shall be within 0.95 lagging to 0.95 leading, accordingly the reactive power support shall be varied dynamically.

Though, much detailed ***standards are formulated for power quality in the recent revisions of IEEE Standards, they are yet to be adopted by CEA.***

***Fault*-Ride-Through**

The generating station shall not disconnect, unless the voltage at interconnection point dips below the thick line in the following Figure 3.12. This limit is applicable to any or all the phase voltages.



V_T : Actual Voltage; V_n: Nominal Voltage

Figure 3.12 - LVRT operating region. [5]

During the voltage dips, the reactive power has to be supplied on priority over real power, however, it is preferred to maintain the active power supply as well. Active power shall be restored to at least 90% of pre-fault value within 1 second of voltage restoration.

In case of over voltages, the generating station shall remain connected to the grid if the voltage is less than or equal to 110%. For other over voltages the operation shall be followed as describe in the following Table 3-33. This is applicable to any or all phases, including symmetrical/asymmetrical operations.

Voltage(pu)	Maximum time to remain connected (Seconds)
V < 1.1	continuous
1.1 < V ≤ 1.2	2 sec
1.2 < V ≤1.3	0.2 sec
V > 1.3	0 sec

Table 3-33 - High voltage ride through during abnormal condition

Short Circuit Ratio

The SCR at the interconnection point of generating station and the rest of the system shall not be less than 5.

Cyber Security

The station as well as the operator shall comply with cyber security guidelines issued by the Central Government, from time to time. No further ***details are specified in this regard.***

3.3.3 Technical standards for Connectivity of Distributed generators to the Grid by CEA, INDIA

General Connectivity Conditions

Prior to the interconnection, studies have to be conducted to determine the point of inter-connection, modifications required on the existing system, required interconnection facilities, maximum net capacity of the generating unit (1-Φ or 3- Φ) and associated imbalance in power flows, service quality to all the stake holders and the safety of equipment and personnel.

This particular set of standards is for interconnection of generating stations at a voltage level of below 33 kV.

All the equipment including overhead lines and cables shall comply with the relevant Indian standards issued by Bureau of Indian Standards (BIS). In case, if it not issued by BIS, equivalent standard of IEC or of British Standards or of American National Standards Institute (ANSI) or any other International Standard shall be followed in that order.

The aforementioned, adaption shall be in terms of conditions in India, including nominal frequency, nominal voltage, prevailing ambient temperature, humidity and other, as governed by CEA.

Safety

As per the CEA (Measures Relating to Safety and Electricity Supply) Regulations, 2010.

Sub-station Grounding

As per IS 3043, issued by BIS.

Metering

Meters shall be provided as specified in the CEA (Installation and Operation of Meters) Regulations, 2006. For interconnections at 11 kV or above power quality meters shall be installed and the recorded data (harmonic, voltage sag, swell, flicker, disruptions) shall be shared with the distribution licensee periodically, as decided by Electricity Regulatory Commission.

Synchronization

All the interconnecting resources shall have automatic synchronisation device, while the induction generators (other than self-excited induction generators) and resources with inverter (with inherent synchronization mechanism) shall not require this.

Paralleling device of DG shall withstand 220% of the nominal voltage at the interconnection point. The synchronization process shall not cause voltage fluctuations beyond ± 5%.

For higher capacities of DGs, a manually operated isolation switch shall be provided while following other technical and visual requirements.

Protection

In case of fault in the system with which the distributed generator (DG) or DR is connected, it shall cease to energise the circuit. The energization shall happen only when the voltage and frequency come within the prescribed limits and are stable for at least 60 seconds. Any unintended islanding shall be prevented.

The safety and reliability of the system shall not be compromised potentially due to failure of any single device or component in the connecting DG system.

3.3.4 Standards for charging station, prosumer, or a person connected or seeking connectivity to the electricity system

Same as 3.3.3

3.3.5 MNRE's Technical requirements for Solar Photovoltaics Grid Tie Inverters (Draft-April, 2020)

Solar PV inverters need to comply with standards as drafted by MNRE which cover the safety requirements as per IS 16221-Part II and islanding prevention measures tests for utility inter-connected photovoltaic inverters as per IS 16169.

These two standards are adopted from IEC.

DC Injection

The DC current injection by PV system at PCC shall not be greater than 0.5 % of the continuous maximum rated inverter output current. Moreover, it has to be validated at 0.25pu, 0.5pu 0.75pu and 1pu of rated output power. However, this requirement can be relaxed if the inverter of the PV system is interfaced through a line frequency isolation transformer.

Harmonics

Total harmonic distortion/Total Rated Current distortion (TRD) in the output current of the inverter shall be limited to 5% of rated inverter Output, while limits on individual harmonic shall be as in Table 3.34. Harmonic analysis shall be done at 0.25pu, 0.5pu 0.75pu and 1pu of rated output power and up to 50th harmonic.

Odd Harmonic	
Harmonic	**Distortion limit**
3^{rd} through 9^{th}	Less than 4.0 %
11^{th} through 15^{th}	Less than 2.0 %
15^{th} through 21^{th}	Less than 1.5 %
23^{rd} through 33^{th}	Less than 0.6 %
35^{th} through 49^{th}	Less than 0.3 %
Even Harmonic	
2^{nd} through 8^{th}	Less than 1.0 %
10^{th} through 14^{th}	Less than 0.5 %
14^{th} through 20^{th}	Less than 0.38 %
22^{nd} through 32^{nd}	Less than 0.15 %
34^{th} through 48^{th}	Less than 0.08 %

Table 3-34 - Maximum allowable injected harmonic current to the grid system

Flicker

Should meet the IEC 61000-3-3, IEC 61000-3-5 and IEC 61000-3-11 standard for Inverters with rated Current of ≤ 16 A, ≤ 75 A and > 75A, respectively. For inverters connected at medium voltage utility, IEC 61000-3-7 standard has to be followed.

Protection against abnormal voltage and frequency

Inverter will remain connected the utility irrespective of power flow, however, it will be disconnected during maintenance or any other service. Indicating that the control circuits remain connected to monitor the operating conditions of utility.

Low Voltage Ride-Through and High Voltage Ride-Through

The LVRT and HVRT functions to be derived from solar photovoltaic (SPV) inverters shall comply with operations described in Table 3-35.

Voltage(pu)	Mode of operation	Ride Through	Maximum Response time
V< 0.5	LVRT	1.7 s	1.8 s
0.5 =< V< 0.85	LVRT	3 s	3.1 s
0.85 =< V < 1.1	Continuous		
1.1 =< V < 1.2	HVRT	2 s	2.1 s
1.2 =< V < 1.3	HVRT	0.2 s	0.3 s
V > 1.3	HVRT		0.05 s

Table 3-35 - Voltage ride through limit for DGs integrated with grid

LVRT and HVRT are same as that of CEA Standard 2019, as depicted in Figure 3.13. The priorities among real and reactive power and the required power level after restoration are same that of CEA regulation

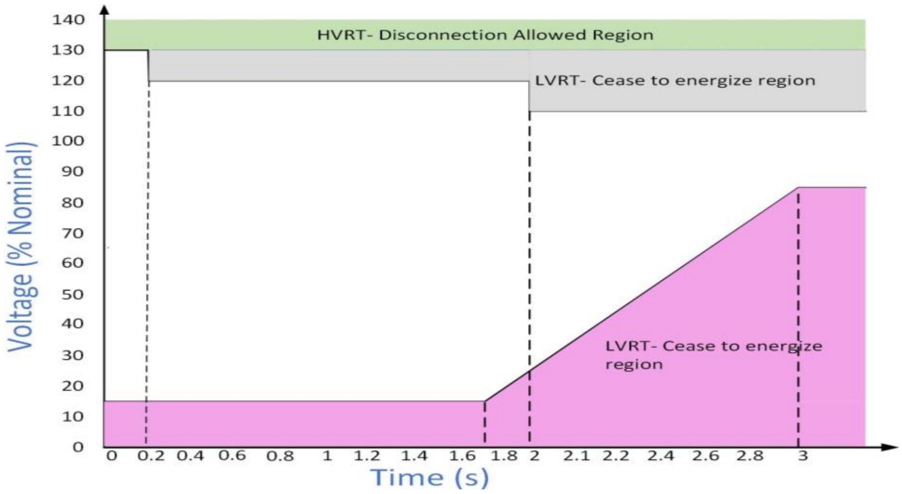


Figure 3.13 - Voltage ride through limit (X-axis values are as per CEA standard mentioned earlier). [7]

Frequency Ride-Though

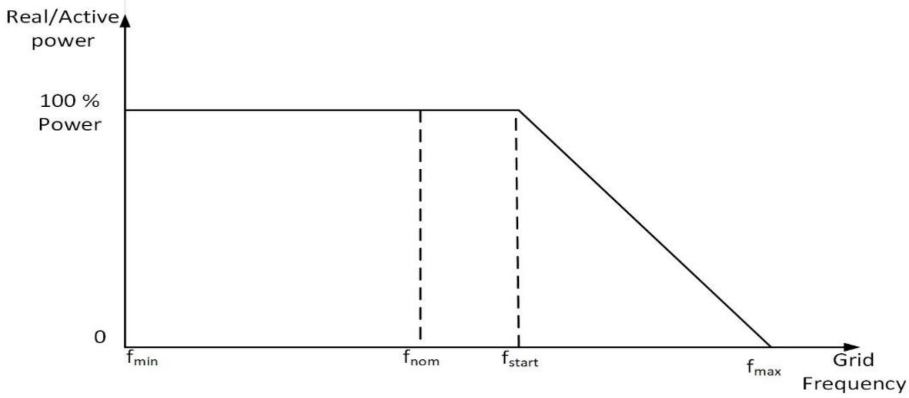
For frequency deviations, the range 47.5Hz to 52Hz shall be treated as continuous operation range. If the frequency deviates from this range, the non-islanding inverter shall cease to energize the utility interface within 0.2 s. Once the voltage and frequency have come back to the range of 0.85pu to 1.1pu and 49.5Hz to 50.5Hz, respectively, PV system shall energize the utility only after an adjustable time delay of 20 seconds to 300 seconds. In any case, once the island is formed, the PV system shall energize the line only after 2s.

No description of time bounds for specified continuous operation range.

Active Power Control

The SPV power output shall not change, if the power being supplied is less than the given request. On the other hand, if the request is for reduction of power below 0.1pu of nominal power, PV may get disconnected. For other cases, the required power shall be attained within a minute and with an accuracy of ± 5% nominal value.

The default setting of frequency is 50.6 HZ and shall be adjustable from 50.5 Hz to 52 Hz. When the frequency starts going beyond the f_{start} (= 50.6 Hz by default), real power output shall reduce by 0.4pu per Hz, as shown in Figure 3.14. If frequency exceeds 52 Hz, the inverter is permitted to disconnect within 0.2 s and resumes operations only when frequency is less than f_{start}. This resumption shall not happen with a rate more than 0.1pu per minute.



fnom: Nominal Frequency, fmax: Maximum Over Frequency

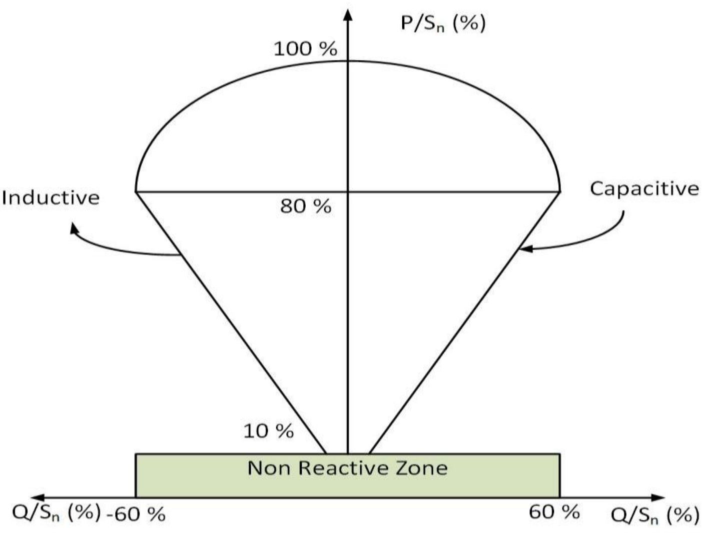
Figure 3.14 - Active power response for frequency deviation [7]

Power factor

The SPV inverter shall be capable of operating at any power factor between 0.8 lag to 0.8 lead with tolerance
of ± 0.01.

Fixed reactive power

The inverter shall be capable to supply a reactive power of 0.6pu inductive as well as capacitive to the utility line as described in the following Figure 3.15.



P: Active power; Q: Reactive Power; Sn: Maximum apparent Power of the inverter

Figure 3.15 - Real-Reactive power limits [7]

4 Comparison of Different Standards/Protocols on Different Technical Parameters

The prominent International standard/Protocol IEEE 1547, Norway-European Protocols along with Central Electricity Authority Regulations are reviewed and compared on different technical parameters in this Section as in the following Table 4.36.

Sl no	Parameters	IEEE	CEA	EU
1	THD or TRD Limit	5%	5%	8% and 5%, averaged over ten minutes and one week Voltage level: 230 V to 35 kV
2	DC injection Limit	0.5%	0.5%	0.5%
3	Generating Unit continuous Operating frequency	58.8 Hz to 61.2 Hz	49.5 Hz to 50.5 Hz	49 Hz to 51 Hz
4	Generator frequency Ride-through	57 Hz to 61.8 Hz	47.5Hz to 51.5 Hz	47.5Hz to 52 Hz
5	Generating Unit continuous Operating voltage	$0.95 \leq V_{pu} \leq 1.05$	$0.95 \leq V_{pu} \leq 1.05$	$0.95 \leq V_{pu} \leq 1.05$
6	Generator Voltage Ride-through	$0.45\ (0) \leq V_{pu} \leq 1.2$	$0.15 \leq V_{pu} \leq 1.3$	$0.05 \leq V_{pu} \leq 1.15$
7	Synchronization/connection /reconnection range	$0.917 \leq V_{pu} \leq 1.05$ 59.5 Hz $\leq f \leq$ 60.1 Hz	$0.85 \leq V_{pu} \leq 1.1$	----
8	Maximum Voltage fluctuation at PCC	5%	5%	10%
9	Allowed Droop for Power-Frequency response	5%	3% to 6%	----
10	Allowed Power Factor Operation	100 % of name plate capability	0.85 lag to 0.95 lead	----
11	Minimum Withstanding voltage of Paralleling Device	220% of the interconnection system rated voltage	220% of the interconnection system rated voltage	-----
12	Detection time and ceases of Area EPS when Unintentional islanding occurs	2 second	2 second	----
13	Compatibility level for short term flicker (P_{st})	1.0	1.0	1.2 if 0.23 kV ≤ UN ≤ 35 kV 1.0 if 35 kV < UN
14	Compatibility level for short term flicker (P_{lt})	0.8	0.8	1.0 if 0.23 kV ≤ UN ≤ 35 kV 0.8 if 35 kV < UN
15	Sub-station grounding	According to IEEE Std 1547-2003 4.1.2	According to IS 3043	----

Table 4-36 - Comparison of Different Standards/Protocols

5 Summary

Different protocols/standards for interconnection of generating sources, with a focus on DERs/DRs/DGs are investigated and reported in this document. A brief of the various standards across the globe is presented in Section 2 and more detailed discussion of IEEE 1547, Norway/European and Indian standards is reported Section 3.

All these standards are defined earlier and are getting revised time to time, as mentioned in Section 2, for example real and reactive power controls under normal and abnormal operating conditions. It is observed that IEEE 1547 is having much detailed specifications/protocols for different parameters for interconnection of different generating sources, including DERs.

Indian standards defined by CEA or MNRE (draft) have considered the different operating conditions prevailing in India. Certain specifications/parameters of Indian Standards are adapted/adopted from international standards like, IEEE and IEC. The recent revisions in IEEE/IEC standards are yet to be adopted/adapted in CEA standards

The European standards are defined for different countries in different way considering the local operating conditions and in general, these European countries are allowed to set their respective standards subjected to ranges specified. In case of Norway, these standards are yet to take final shape.

From investigation of CEA standards, it is understood that the capability of DERs can further better be utilized by relieving the limits up to the capacities of DERs. In addition, CEA standards are referring to IEEE 519; However, BIS Recognized labs or ISO 17025 labs in India are not accredited to conduct Harmonic test as per this standard; hence respective IEC standard may be referred.

Altogether, it is understood that the exiting standards are either not defined or not clearly defined for certain aspects of interconnection of DERs/Microgrids/Minigrids. To name,

- The available standards have not considered the interconnection of different Microgrids/Minigrids, though the standards are defined for interconnection of DERs/DRs/DGs with the EPS/Grid/rest of the system.
- The applicability of the exiting standards for interconnection of autonomous systems with two or more heterogeneous sources needs further investigation.
- Though the Fault ride through requirements are defined, their implementations needs further explorations.
- The applicability of interconnection standards for single phase systems is not clear, as the standards considered three phase systems in general.
- The load sharing control and the parameters to be met for systems in distributed networks (relatively small X/R ratio) are not clearly defined.
- LVRT/HVRTs for unbalanced systems or systems with Single Phase DERs have to be defined.

- Importantly, as the future grid is going to be smarter, it is inevitable to define the standards/protocols for security of Cyber Physical Systems in Smart Grid.

In addition, though some upper limits for rate of change of power with change in frequency considering the stability as prime focus, these limits may be needed to be relooked considering the capability of higher droops of inertia free interconnecting devices.

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