CHAPTER 1

ACCESS TO THE NATIONAL TRANSMISSION GRID

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SECTION 1C - TECHNICAL CONNECTION RULES FOR NEW PLANTS UNDER THE TERMS OF EU REGULATIONS 2016/631, 2016/1388 AND 2017/1447

1C.1 SUBJECT

This section 1C governs the technical conditions for regulated access to the **grid** for the plants described in paragraph 1C.2, in order to guarantee correct operation and safety of the National Electricity System (Sistema elettrico nazionale - **SEN**).

The following aspects are covered by the technical **connection** rules (hereinafter “Technical Rules”):

a) functional and performance characteristics of the **NTG** at **connection** sites;

b) the essential requirements in terms of design and operation, particularly regarding functional design criteria and operational characteristics of **production plants**, **grids with third-party connection obligations**, **plants** representing **consumption units**, **other electricity grids** and **high-voltage** direct-current systems (**HVDC systems**).

1C.2 SCOPE OF APPLICATION

The Technical Rules apply to plants falling within the scope of application of the European Connection Codes (Reg. EU 2016/631-Requirements for Generators, RfG, Reg. EU 2016/1388-Demand Connection Code, DCC and

Reg. EU 2016/1447-High Voltage Direct Current HVDC) and are represented by the following types:

a) **Production plants**[1], including pumped-storage generation plants (paragraph 1C.5 and paragraph 1C.5.BIS);
b) Plants corresponding to **consumption units**[2] (paragraph 1C.6);
c) Plants corresponding to **grids with third-party connection obligations** (paragraph 1C.6);
d) Plants corresponding to **other electricity grids** (paragraph 1C.6);
e) **HVDC systems** and power parks connected via **HVDC systems** (paragraph 1C.7).

With reference to the scope of application of European Connection Codes, as detailed in **ARERA** (Italian Regulatory Authority for Energy, Networks and Environment) resolutions 592/2018 and 149/2019 for the RfG Code and 82/2019 for the DCC Code and HVDC code, it is noted that the technical rules as per section 1C of this Chapter of the Grid Code apply to:

- new plants, i.e. plants that:
  - are not connected at the date of entry in force of the relative European Connection Code[3]; or
  - for which the **User** has not signed a definitive and binding contract for the purchase of the main equipment within twenty-four months of the date of entry into force of the relative European Grid Code on

[1] In compliance with the provisions of the RfG Code, the technical rules in this Chapter 1C.5 do not apply to: a) synchronous plants on the Sardinian **grid**; b) **production plants** installed to provide reserve energy and operate in parallel with the **grid** for less than five minutes per month while the **SEN** is operating under **normal conditions**; c) **production plants** that do not have a permanent **connection point** and are used by **grid operators** to temporarily provide power when the normal system capacity is partially or completely unavailable; d) type A plants classified by the **Authority** as emerging technology.

[2] In line with the provisions of the DCC Code, the technical rules in this Chapter 1C.6 do not apply: a) to plants corresponding to **consumption units** and plants corresponding to **grids** with or without connection obligations on the Sardinian **grid**; b) electricity storage devices.

[3] 17 May 2016 for the RfG Code, 7 September 2016 for the DCC Code and 28 September 2016 for the HVDC Code.

connection[4]. In such cases, the **User**, in order to obtain classification as an existing plant, must communicate successful establishment of a contract to the **Operator** according to the methods defined by the same and published on the website of the **Operator**. As defined in **Authority** resolutions, this communication is not necessary for plants in operation on 13 July 2018 in the case of **production plants** and on 6 March 2019 in the case of plants classified within the types set out under the previous points b), c), d) and e).

- existing plants, in the case of significant changes or partial or total overhaul of the plant[5].

For plants falling within the categories indicated in the previous points a), b), c), d), e) and that do not fall within the scope of application of the European Connection Codes, section 1B of this Chapter of the Grid Code applies.

To allow the **Operator** to evaluate the significance of a change or overhaul, the **User** must ensure prior notification to the **Operator** of the planned work. For changes not already classified in this paragraph as significant changes, within 60 days from receipt of the notification, the **Operator** verifies the impact of upgrading on technical performance and then evaluates the significance. After this period, in the absence of communication from the **Operator**, the change is considered insignificant.

Cases in which it is necessary to update the **connection contract** are to be considered significant changes, with consequent application of the technical connection rules in this section 1C. Furthermore, as an example, below is a list of other changes also to be considered significant:

4 17 May 2018 for the RfG Code, 7 September 2018 for the DCC Code and 28 September 2018 for the HVDC Code.

5 For **production plants**, application to existing plants in case of upgrading or overhaul is applicable only over a certain size/voltage level. Specifically, it applies only to groups classified according to the criteria of paragraph 1C.2.1 below as type C and D.

1. For synchronous **generator groups**:
   - substitution of the alternator;
   - renewal of **voltage regulation** and/or **frequency** regulation systems;
   - renewal of plant control and **protection** systems;
   - modification/replacement of components involved in the thermal or hydraulic cycle (e.g. burners, boiler parts, hydraulic piping, turbines, etc.).

2. For power parks:
   - replacement of a number of wind turbines or power inverters corresponding to at least 10% of the **nominal power of the plant**;
   - renewal of plant control and protection systems.

3. For **HVDC** systems:
   - Modification of system **transport capacity**;
   - Modification of system technology;
   - Modification of system configuration (monopolar, bipolar).

In such cases, the Technical Rules set out in this section 1C apply:

- fully in relation only to the parts of the plant being replaced,
- partially, limited only to provisions that do not presuppose replacement, in relation to the remaining parts of the plant .

1C.2.1 Classification of production plants

With reference to **production plants**, it is specified that the Technical Rules set out in section 1C of Chapter 1 of the Grid Code apply to all **generator groups**: both to synchronous **generator groups** and to power park modules including offshore systems, and are differentiated on the basis of the voltage

level of the connection point and the **efficient power**[6] of the **generator group**. For this purpose, the **generator groups** are classified according to the following categories:

- Type A **Generator group**: connection point < 110 kV and **efficient power** greater than or equal to 0.8 kW lower than or equal to 11.08 kW;

- Type B **Generator group**: connection point < 110 kV and **efficient power** greater than 11.08 kW lower than or equal to 6 MW;

- Type C **Generator group**: connection point < 110 kV and **efficient power** greater than 6 MW lower than 10 MW;

- Type D **Generator group**: connection point < 110 kV and **efficient power** equal to or greater than 10 MW or connection point ≥ 110 kV independent of power.

The Technical Rules of **generator groups** are further subdivided into those applicable to type C **generator groups directly connected to the NTG** and type D, **directly** and **indirectly connected to the NTG**, defined in paragraph 1C.5, and those applicable in all other cases indicated in paragraph 1C.5.BIS.

[6] Corresponding to the definition of maximum capacity of RfG Code.

1C.3 CHARACTERISTICS AND PERFORMANCE OF THE NTG AT CONNECTION SITES

The characteristics of the **NTG** at **connection** sites are those indicated in paragraph 1B.3.

1C.4 TECHNICAL RULES COMMON TO ALL PLANT CATEGORIES

The Technical Rules common to all categories of **plants directly connected to the NTG** and to type D **generator groups indirectly connected to the NTG** are those indicated in paragraph 1B.4, with the exception of paragraph 1B.4.12. With reference to the system services provided by **production plants** the table indicated references to chapters of the Grid Code and to the attached documents that provide details of technical requirements and characteristics of plants that provide the indicated system services.

Service	**Mandatory/optional nature of service provision**	**Technical requirements and characteristics**
Resolution of congestion at planning phase	Mandatory for **PUs** suitable and enabled for provision of the service on the Dispatching Services Market (MSD)	Para. 4.4.1
Primary frequency regulation	Mandatory for **generator groups** suitable for the service	Para. 1C.5.3.4; Para. 1C.5.3.3; Para. 4.4.2; Annex A.6; Annex A.15
Secondary frequency/power regulation	Mandatory for **PUs** suitable and enabled for provision of the service on the MSD	Para. 1C.5.3.5; Para. 4.4.3; Annex A.15; Annex A.23

Tertiary power regulation	Mandatory for **PUs** suitable and enabled for provision of the service on the MSD	Para. 4.4.4
Balancing	Mandatory for **PUs** suitable and enabled for provision of the service on the MSD	Para. 4.4.5; Annex A.23
Group primary voltage regulation	Mandatory for **generator groups** suitable for the service	Para. 1C.5.4.2; Para. 4.4.7; Annex A.6; Annex A.14
Power plant primary voltage regulation	Mandatory for **power plants** with at least one group suitable for the service	Para. 1C.5.4.3; Para. 4.4.7; Annex A.6; Annex A.14; Annex A.16
Secondary voltage regulation	Mandatory for **power plants** with at least one group suitable for the service	Para. 1C.5.4.3; Para. 4.4.8; Annex A.6; Annex A.14; Annex A.16
Load rejection	Mandatory for type D thermoelectric **generator groups**	Para. 1C.5.5; Para. 4.4.9
Participation in the restoration of the Electricity System	Mandatory for significant **PUs** indicated in Annex A.10	Para. 1C.5.5; Para. 4.4.10; Annex A.10
Remote disconnection	Mandatory for all wind power and photovoltaic plants and for all significant **PUs** enabled on the MSD located in limited production hubs and in other cases on request of the **Operator**.	Para. 1C.5.5.4; Para. 4.4.11; Annex A.9; Annex A.17; Annex A.68.

"Note: the **Operator** has the right to set additional requirements and services for needs linked to SEN security"

1C.5 SPECIFIC TECHNICAL RULES FOR PRODUCTION PLANTS CONNECTED DIRECTLY TO THE NTG AND FOR TYPE D GENERATOR GROUPS

The contents of this paragraph apply to **generator groups**, i.e. synchronous **generator groups** and power park modules, including offshore installations, of type C **directly connected to the NTG** and type D **directly** and **indirectly connected to the NTG**, including **generator groups** that are located within **simple production and consumption systems**. The requirements set out in this paragraph also apply to **generator groups** with pumped storage.

For power park modules, relative to wind-power and solar installations Annexes A.17 "Wind power stations - General conditions for connection to HV grids - Protection, regulation and control systems" and A.68 "Photovoltaic power stations - General conditions for connection to HV grids - Protection, regulation and control systems" apply respectively, included under Appendix A to this Chapter and paragraph 1C.5.7 relative to **plant** compliance.

It follows that the rules defined in the subsequent paragraphs refer only to type C synchronous **generator groups directly connected to the NTG** and type D groups **directly** and **indirectly connected to the NTG**, with the exception of paragraph 1C.5.7 that applies both to synchronous **generator groups** and to power park modules.

1C.5.1 Frequency and voltage operating ranges

Synchronous **generator groups** must be designed, built and operated to remain in parallel not only under **normal grid operating conditions** but also under **emergency** and **recovery conditions**.

Specifically, synchronous **generator groups** must be capable of remaining connected to the grid and operating without limits on time with frequency and voltage values at the connection point (CP) within the following ranges:

- 47.5 Hz ≤ f ≤ 51.5 Hz
- 85%Vn ≤ V ≤ 115%Vn if the CP has nominal voltage (Vn) lower than 300 kV
- 85%Vn ≤ V ≤ 110%Vn if the CP has Vn greater than or equal to 300 kV

The **Producer** must not in any case voluntarily limit the operating range of the group to the aforementioned values; instead, where the build characteristics allow it, the **Producer** must notify the **Operator** of any broader limits on operation, the effective use of which will be agreed with the **Operator** during the **connection application** phase and defined in the **Operating Regulations**.

Within the ranges indicated above, the control system of the synchronous **generator group** must guarantee:

- stable operation with any **load** between the auxiliary services **load** and its **efficient power**;
- issue of scheduled **active power**;
- possible participation in **frequency regulation**, depending on the characteristics of the group;
- possible participation in **voltage regulation**, depending on the characteristics of the group.

Furthermore, the synchronous **generator group** must operate within the areas and time frames indicated in Figure 1, in line with the conditions established by technical standard IEC 60034-1 on rotating electrical machines. Specifically, in areas B and C indicated in the figure, the **generator group** must operate in line with its stated nominal performance specifications for a minimum period of 15 minutes; after 15 minutes, the **generator group** must remain connected, although a reduction in its performance is permitted.

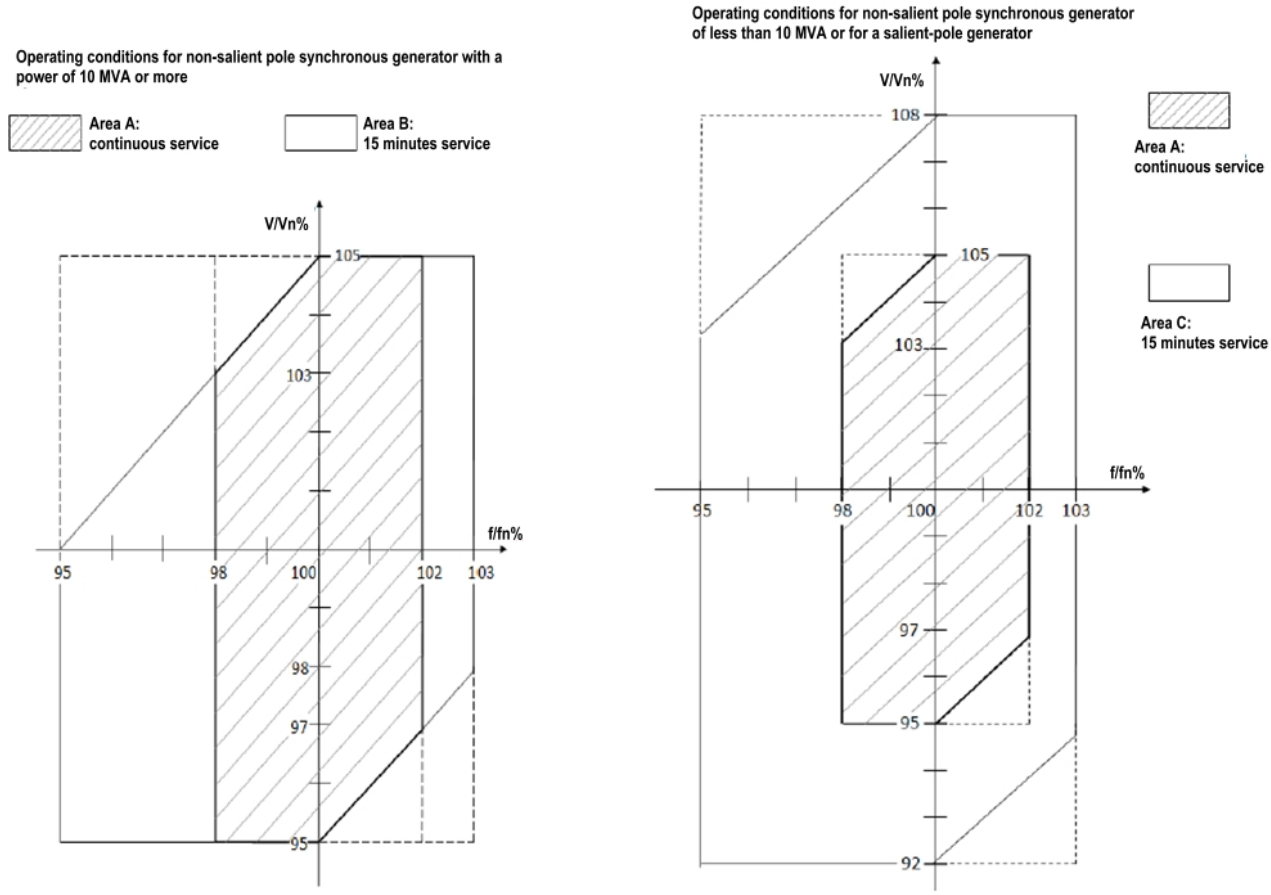


Figure 1: Operating states of generator groups. The x-axis indicates frequency, the y-axis indicates voltage at generator terminals. Both values are expressed as percentages of the relative nominal values.

Outside the above frequency range, the regulator must guarantee that it remains connected for very limited time frames, i.e.:

- At least 4s for 46.5 Hz < f < 47.5 Hz
- At least 1s for 51.5Hz < f < 52.5Hz
- At least 0.1s for f < 46.5 Hz or f > 52.5 Hz

The **Producer** is responsible for the **protection** of its own machinery and equipment against damage caused by any frequency and/or voltage outside the range defined for fluctuation under emergency or **grid** recovery conditions. Methods for separation from the **grid** with frequency and/or voltage regimes outside the limits defined and methods for return to normal operation are agreed with the **Operator** in the **Operating Regulations**.

1C.5.2 Immunity to grid disturbances

1C.5.2.1 Resistance to rate-of-change of frequency

Synchronous **generator groups** must be designed to be able to operate in parallel with the **grid** without disconnection, and with rate-of-change of frequency at up to at least 2.5 Hz/s on at least five cycles (100 ms).

Calculation of rate-of-change of frequency must be possible with a variable window that can be set between 100 ms and 1 s (the variable window is selected based on the value of the frequency ROCOF to calculate, generally increasing with a decreasing ROCOF value).

1C.5.2.2 Insensitivity to voltage disturbances

In the event of voltage transients due to cleared **faults** on the **grid** (**voltage dips**), the synchronous **generator groups** must be capable of remaining connected to the grid and continuing stable operation if the voltage at the connection point (hereinafter CP) remains above a **fault-ride-through** (**FRT**) voltage/time profile.

The profile indicates the lower limit of the real development in phase-phase voltage compared to **grid** voltage at the CP during a symmetrical or asymmetrical **fault**, based on the time before, during or after the **fault** and defines the zones where disconnection is permitted and not-permitted. The

area above the **FRT** represents the minimum zone in which the **generator group** must guarantee connection to the grid.

Within the zone where disconnection is not permitted, i.e. above the **fault-ride-through** profile, the synchronous **generator groups** must guarantee the capability to remain connected to the **grid** and offer stable operation.

Within the zone where disconnection is permitted, i.e. below the **fault-ride-through** profile, disconnection of the synchronous **generator groups** is acceptable via intervention of the **generator group protection** system, as described in paragraph 1C.5.6.3. Installation of **protection systems** with ad-hoc minimum voltage that implement the minimum curve described is not permitted. Specifically, the under-voltage **protection**, where requested and/or necessary, is set up by the **Producer** based on the technical limits of the **group**, unless the **Operator** requests more restrictive settings.

The requirement is completely separate from actions for disconnection from the **grid** defined by operational and/or **grid protection** needs and those implemented via equipment and relative parameters defined by the **Operator** (e.g. **protection systems**). In relation to these actions, disconnection from the **grid** may be requested for **generator groups** with time/voltage conditions within the disconnection-not-permitted range.

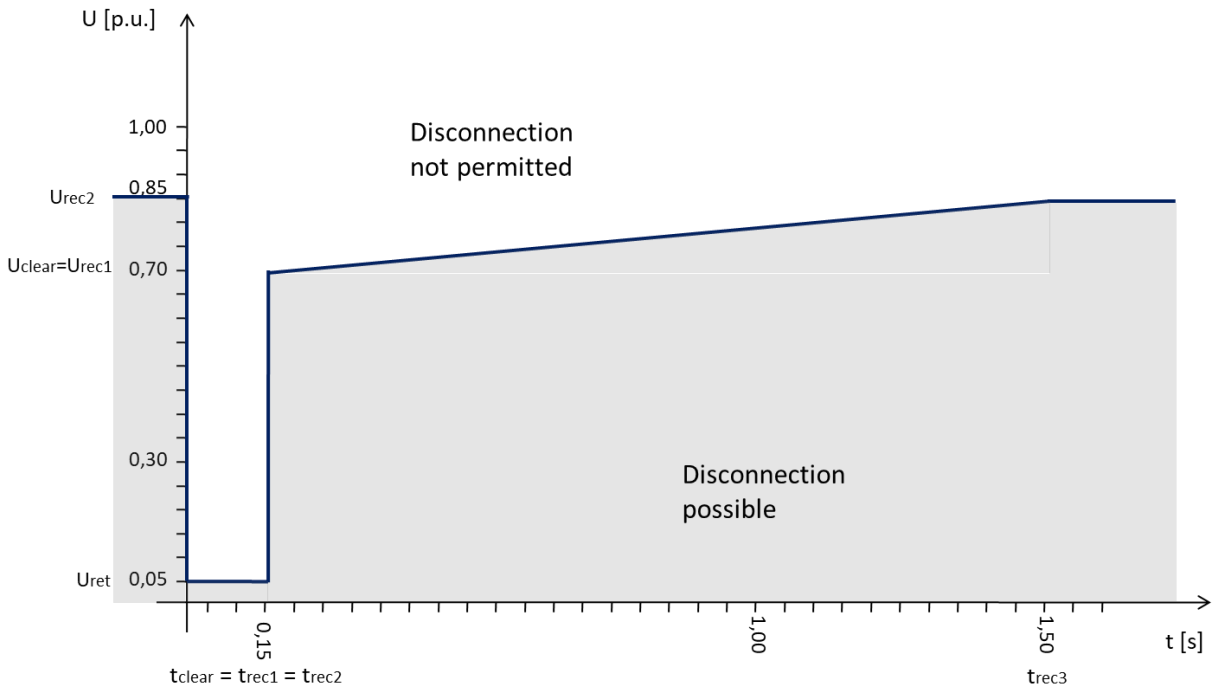
Observance of the **fault-ride-through** profile must be checked for each **short-circuit-power** value pre-fault and post-fault between the minimum and maximum values of the **short-circuit power** expected at the CP. In this regard, reference may be made to minimum and maximum **short-circuit-power** values that the **Operator** publishes annually on its website for all **NTG** hubs. The criteria used to determine these values are compliant with applicable technical standards and are indicated in Annex A.8 “Short-circuit currents and fault clearance times for plants of grids running at voltages equal to or greater than 120 kV” included under Appendix A to this Chapter.

For type C synchronous **generator groups**, the parameters of the **fault-ride-through** voltage profile are indicated in Table 1; Figure 2 presents the resulting profile. For these **generator groups**, the disconnection logic must be of the one-out-of-three type: it may be activated both for symmetrical and asymmetrical **faults** when one of the three voltage levels exceeds the permitted **voltage dips** in terms of depth and duration.

Table 1: Parameters for fault-ride-through capability of type C synchronous generators

U_{ret}	0.05 [p.u.]	T_{clear}	0.15 s
U_{clear}	0.7 [p.u.]	T_{rec1}	0.15 s
U_{rec1}	0.7 [p.u.]	T_{rec2}	0.15 s
U_{rec2}	0.85 [p.u.]	T_{rec3}	1.5 s

Figure 2: Fault-ride-through profile for type C synchronous generators



For type D synchronous **generator groups**, the parameters of the fault-ride-through voltage profile are indicated in:

- Table 2 for symmetrical faults: Figure 3 represents the resulting profile;
- Table 3 for asymmetrical faults: Figure 4 represents the resulting profile.

Table 2: Parameters for fault-ride-through capability of type D synchronous generators for symmetrical faults

U_{ret}	0 [p.u.]	T_{clear}	0.2 s
U_{clear}	0.25 [p.u.]	T_{rec1}	0.45 s
U_{rec1}	0.5 [p.u.]	T_{rec2}	0.7 s
U_{rec2}	0.85 [p.u.]	T_{rec3}	1.5 s

Figure 3: Fault-ride-through profile for type D synchronous generators for symmetrical faults

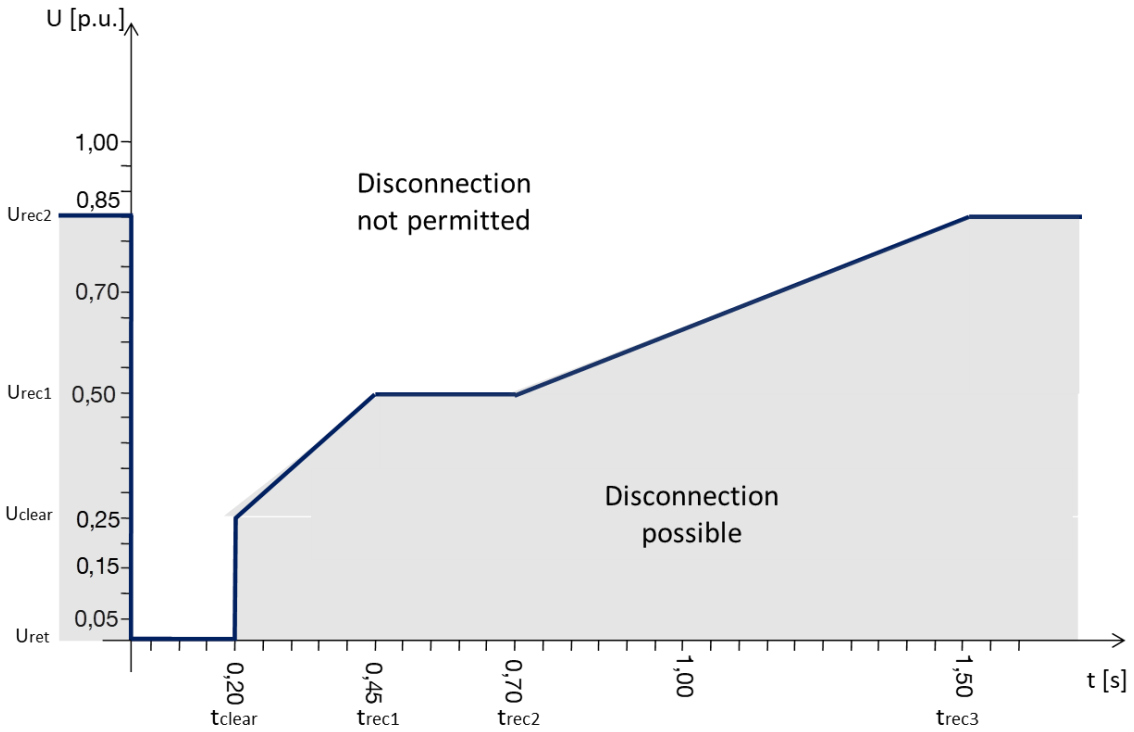
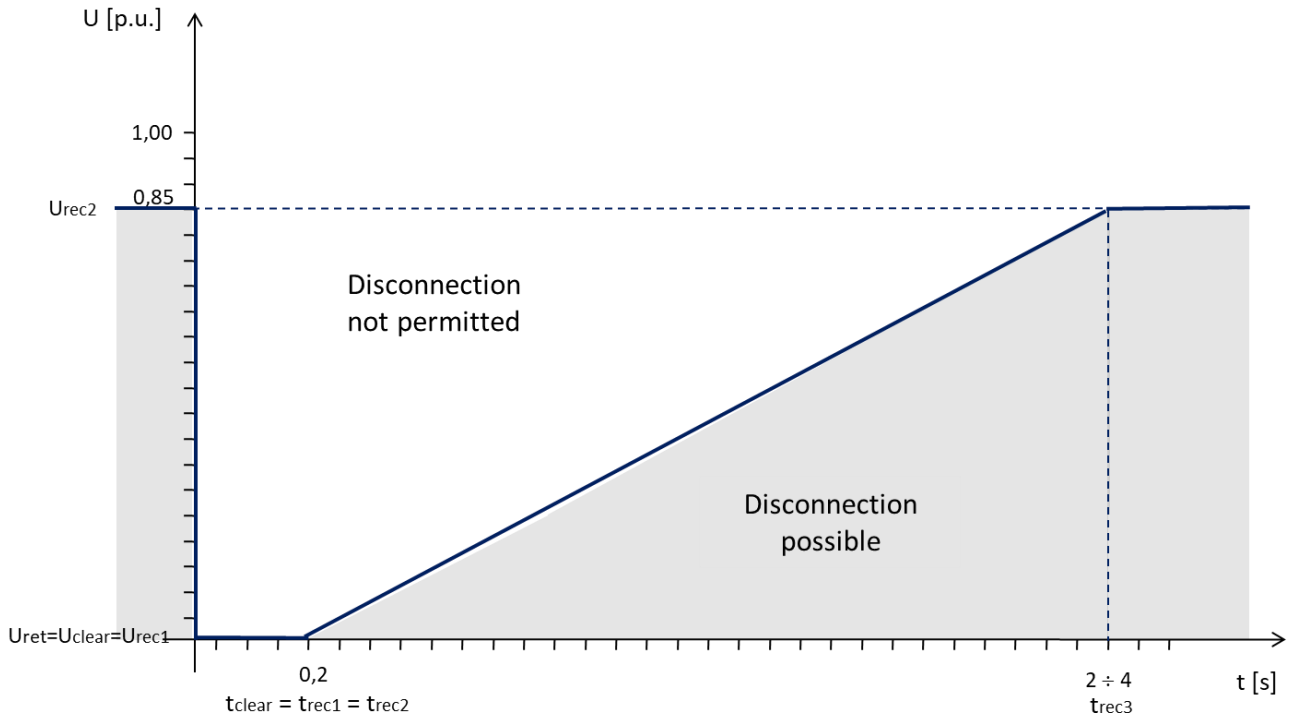


Table 3: Parameters for fault-ride-through capability of type D synchronous generators for asymmetrical faults

U_{ret}	0	T_{clear}	0.2 s
U_{clear}	0	T_{rec1}	0.2 s
U_{rec1}	0	T_{rec2}	0.2 s
U_{rec2}	0.85 [p.u.]	T_{rec3}	2.0 s ($V_n \leq 150$ kV) 2.8 s (150 kV $< V_n \leq$ 220 kV) 4.0 s ($V_n >$ 220 kV)

Figure 4: Fault-ride-through profile for type D synchronous generators for asymmetrical faults



1C.5.3 Frequency stability requirements

1C.5.3.1 Control of target active power

Synchronous **generator groups** must be capable of continuous maintenance of a constant input of **active power** at any target value within the technical minimum declared and the **efficient power**, with the exception of the variations required on the basis of **frequency regulation** or the **LFSM-O**, **LFSM-U**, **FSM** and **ILF** modes described in paragraphs 1C.5.3.3, 1C.5.3.4, 1C.5.3.5 and 1C.5.3.6.

Under normal operating conditions, i.e. when the reference signal is constant, the control system must maintain the **active power** of the **generator group**[7] around the target value, with a tolerance of:

- ±2% of the **nominal power** of the group for type C **generator groups** connected to the **NTG**;

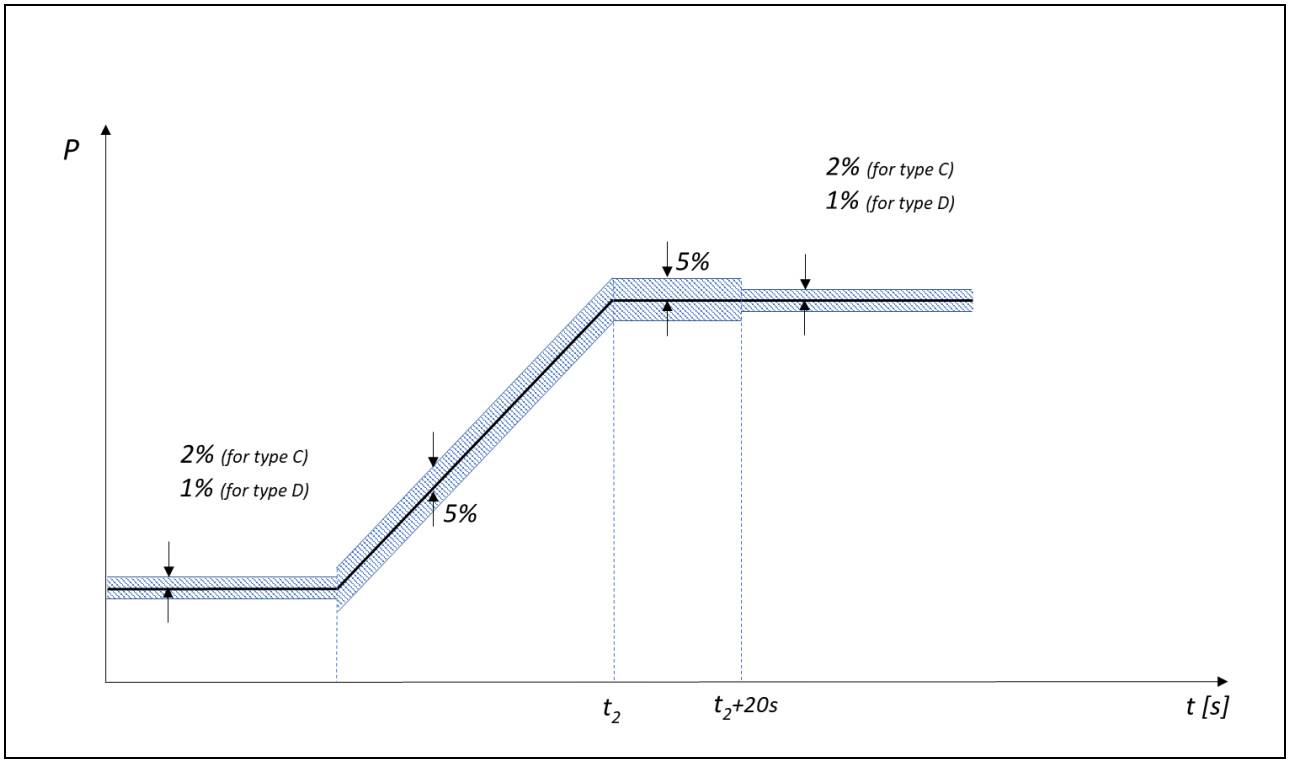
[7] In the case of combined cycle **generation plants**, this requirement must be met by the overall output from steam and gas turbines.

- ±1% of the **nominal power** of the group for type D **generator groups**.

For the purposes of checking observance of the maximum error threshold, the **active power** must be measured as an average per second. The provision is considered to have been met when 95% of readings observe the indicated tolerance limit.

In the case of variation of the reference signal (variation of the target value), during transitory variation of the signal a maximum control tolerance of ±5% of the **nominal power** of the **generator group** is permitted. Within 20 s from the end of the transitory variation of the reference signal, the control error must return to below the standard-operation tolerance value as illustrated in Figure 5.
These control tolerance values are not applicable to specific **grid** services (e.g. **frequency regulation**) in the case that other tolerance values are specified.

Figure 5: Representation of tolerance for difference between group active power measured as average per second and reference value



1C.5.3.2 Reduction of maximum active power with under-frequency conditions

When a synchronous **generator group** is operating with under-frequency conditions, and where justified for technical reasons, a reduction is permitted in the maximum **active power** issuable compared to the **efficient power** value declared to the **Operator**. The curves in figure 6 represent the maximum percentage reduction permitted in **active power** and therefore define the lower limit above which the maximum **active power** issuable by the **group** must always be maintained.

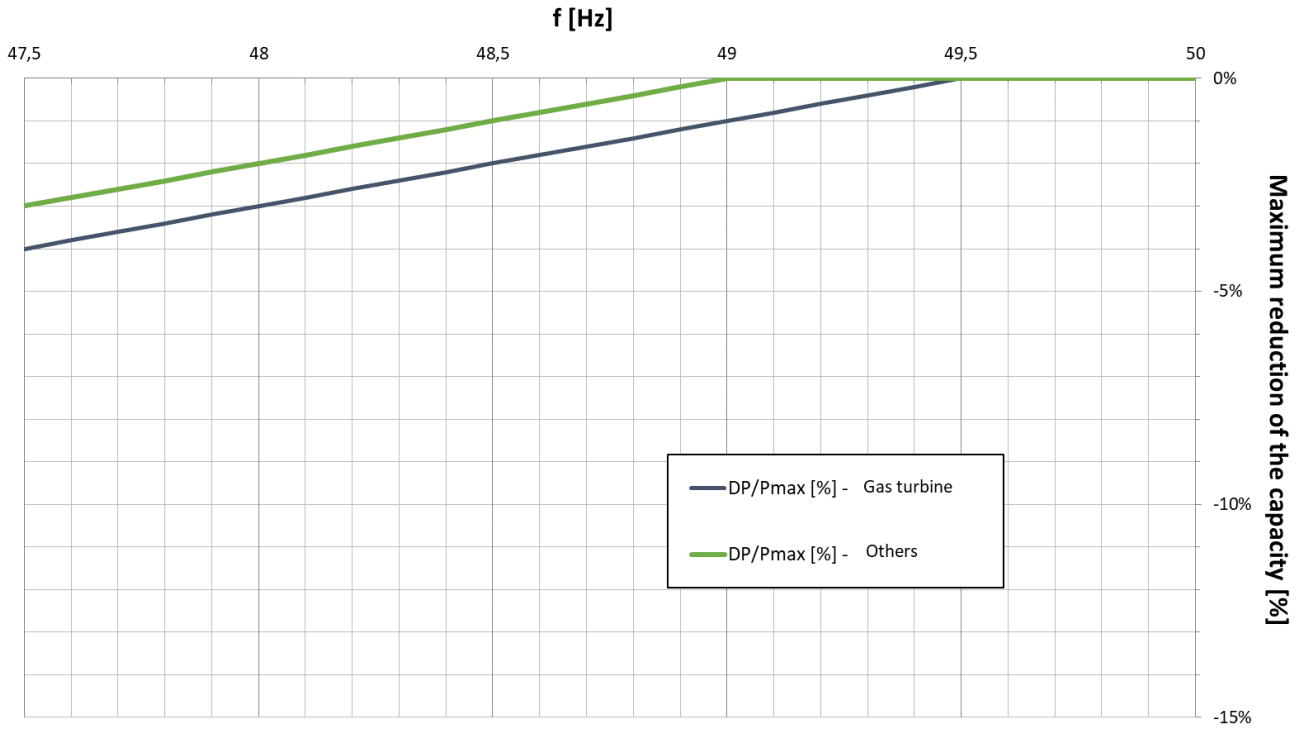
The parameters characterising these curves are:

- for all synchronous **generator groups** other than gas-turbine systems, the reduction in maximum **active power** issuable by the group must not be greater than 2% for each 1 Hz of drop in frequency for values lower than 49 Hz independent of ambient conditions;
- for gas-turbine (or combined cycle) **generator groups**, the reduction in maximum **active power** issuable by the **group**, must not be greater than 2% for each 1 Hz of drop in frequency for values below 49.5 Hz

and for temperatures lower than 0°C; for temperatures greater than or equal to 0°C a gradual increase is permitted in reduction of maximum **active power** issuable with variation of frequency, up to a maximum of 4.5% for each 1 Hz of drop in frequency below 49.5 Hz.

The percentage value of the reduction is relative to the **efficient power** of the **group**. If the **efficient power** is in turn influenced by environmental conditions, the curve should be understood as relative to the **efficient power** corresponding to ambient operating conditions.

Figure 6: Curve of maximum reduction in power capability with decreasing frequency



1C.5.3.3 Response to frequency variation in LFSM mode

The synchronous **generator groups** must regulate the exchange of **active power** with the **grid** compared to the scheduled value (target **active power**)

in response to large frequency variations on the **grid** with over and under-frequency, with the **LFSM-O** and **LFSM-U** modes.

This functionality is not required for **generator groups** that can demonstrate to be without regulation capacity by nature.

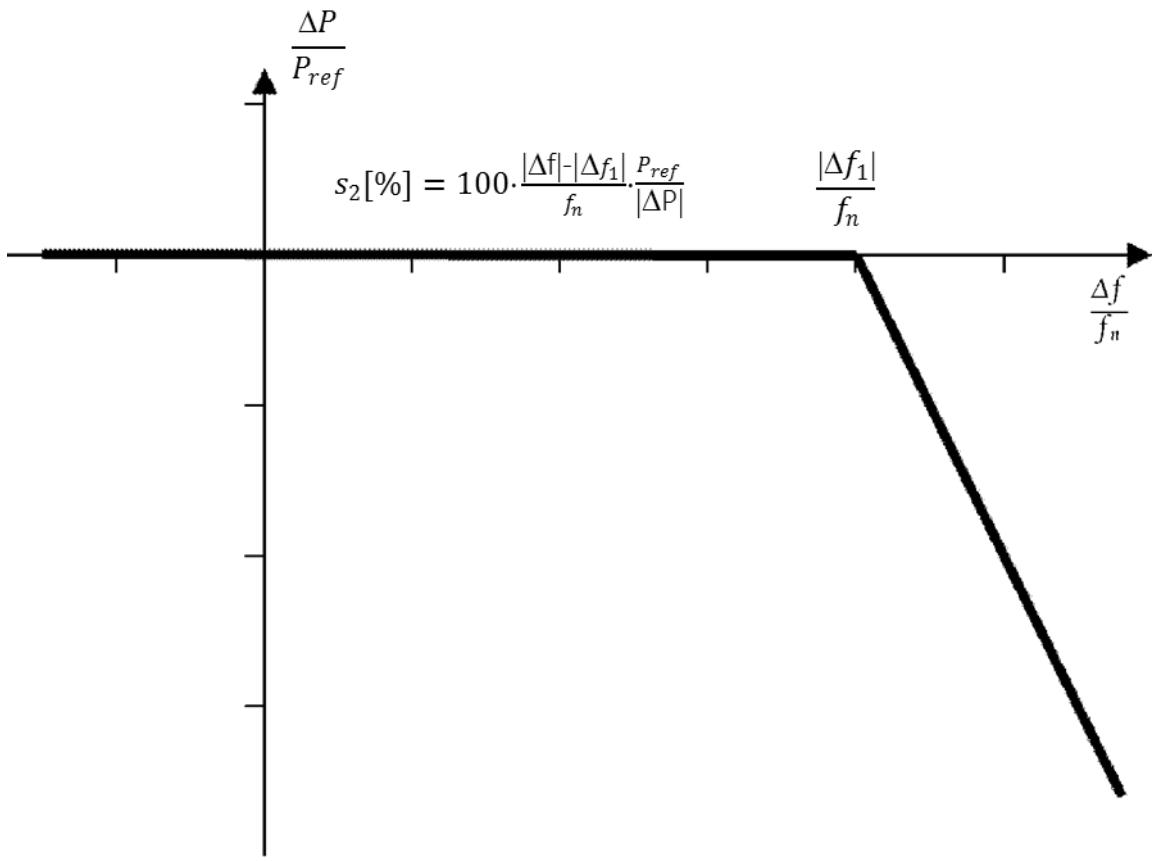
The operating principles of **LFSM-O** and **LFSM-U** modes are indicated in Figure 7 and Figure 8 with the following parameters and specifications:

- the accuracy of frequency measurement must be compliant with the applicable industrial standard and in any case no greater than 10 mHz;
- power P_{ref} represented by the **efficient power** of the synchronous **generator group**;
- the frequency threshold for activation of **LFSM-O** must be settable within the range 50.2-50.5 Hz with a default value of 50.2 Hz, except in the event of communication otherwise from the **Operator**;
- the frequency threshold for activation of **LFSM-U** must be settable within the range 49.5-49.8Hz with a default value of 49.8Hz, except in the event of communication otherwise from the **Operator**;
- the droop of each of the modes **LFSM-O** and **LFSM-U** must be settable independently within the range 2-12%;
    - the droop of both modes **LFSM-O** and **LFSM-U** must be set by default at 4% for hydroelectric **generator groups**, except in the event of communication otherwise from the **Operator**;
    - the droop of both modes **LFSM-O** and **LFSM-U** must be set by default at 5% for thermoelectric **generator groups**, except in the event of communication otherwise by the **Operator**. This also applies for each combined cycle **section**, independent of the regulation capacity of the steam unit;
- activation of **LFSM-O** or **LFSM-U** response shall occur with minimal initial delay. If this delay is greater than two seconds, the **Producer** is

required to provide justification for this, with technical supporting data, to the **Operator**;

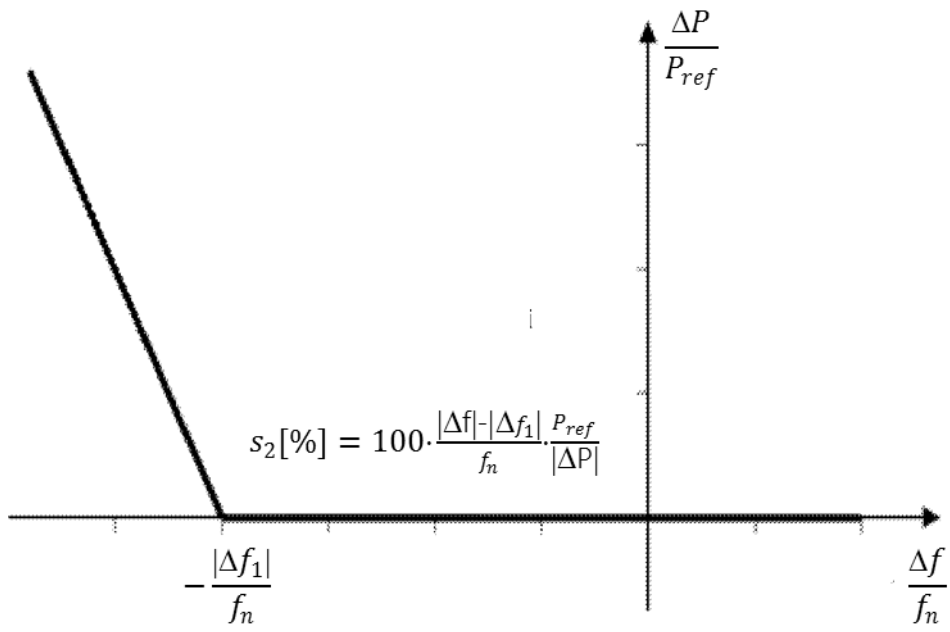
- power variation must be performed with the maximum admissible gradient for continuous operation of the synchronous **generator group** (or the plant, depending on the case), i.e. the maximum gradient that does not compromise continuous operation of the fuel, thermal and electromechanical cycle of the group (or plant). Specifically, the following provisions must be observed:
  - for conventional steam **generator groups**, the maximum gradient must be such that:
    - it guarantees continuous operation of the group and therefore avoids blocking/tripping of the boiler/turbine system,
    - it does not compromise the success of any **load rejection** action, if required (paragraph 1C.5.5)
  - for gas-turbine **generator groups** (or combined cycle), the maximum gradient must not be lower than 13%/min of the **efficient power** of the **group**;
  - for all other types of **generator groups**, the gradient must be significantly greater than 3% Pn/min of the **efficient power** of the **group**.
- In **LFSM-O** and **LFSM-U** modes, the **generator groups**, if required by the degree of frequency variation, must issue the whole available power margin until the relative minimum or maximum power **operational limits** are reached, taking into account the possible limitations described in paragraph 1C.5.3.2;
- The **generator group** must be capable of stable operation in both **LFSM-O** and **LFSM-U** modes.

Figure 7: Frequency/active power response of generator groups in LFSM-O mode



P_{ref} is the reference active power to which ΔP is related and *corresponds to the efficient power of the synchronous generator group. ΔP is the change in active power output from the generator group. f_n is the nominal frequency (50 Hz) on the grid Δf is the frequency change on the grid. At overfrequencies where Δf is above Δf_1, the generator group has to provide a negative active power output change according to the droop S_2.*

Figure 8: Frequency/active power response of generator groups in LFSM-U mode



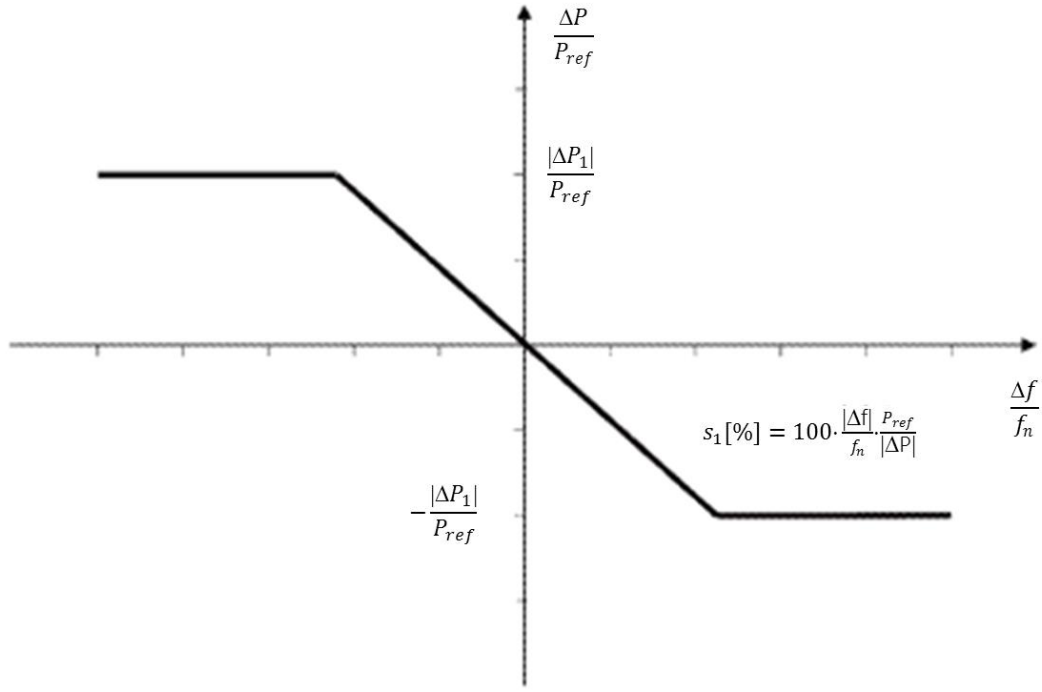
Pref is the reference active power to which ΔP is related and *corresponds to the efficient power of the synchronous generator group. ΔP is the change in active power output from the generator group. fn is the nominal frequency (50 Hz) on the grid Δf is the frequency change on the grid. At underfrequencies where Δf is below Δf1, the generator group has to provide a positive active power output increase according to the droop S2.*

1C.5.3.4 Power regulation in FSM mode

Synchronous **generator groups** must be capable of operating in **FSM** mode, which determines a variation in **active power** output compared to the scheduled value (target **active power**) in response to variations limited variations in **grid** frequency. **FSM** mode is used, together with **LFSM-O** and **LFSM-U**, described in paragraph 1C.5.3.3, for the **primary frequency regulation** service.

This functionality is not required for **generator groups** that can demonstrate to be without regulation capacity by nature.

Figure 9: Frequency/active power response capability of generator groups in FSM mode illustrating the case of zero deadband and insensitivity



Pref is the reference active power to which ΔP is related and *corresponds to the efficient power of the synchronous generator group. ΔP is the change in active power output from the generator group. fn is the nominal frequency (50 Hz) on the grid Δf is the frequency change on the grid.*

The operating principle of **FSM** mode are indicated in Figure 9 with the following parameters and specifications:

- the accuracy of frequency measurement must be compliant with the applicable industrial standard and in any case no greater than 10 mHz;
- power P_{ref} is the **efficient power**of the **group** if not otherwise specified by the **Operator**;
- the maximum insensitivity of regulators, i.e. the technological limit of the regulators themselves, must not exceed ±10 mHz;
- the power variation required by **FSM** mode is proportional to the frequency error according to the set droop. The droop must be settable

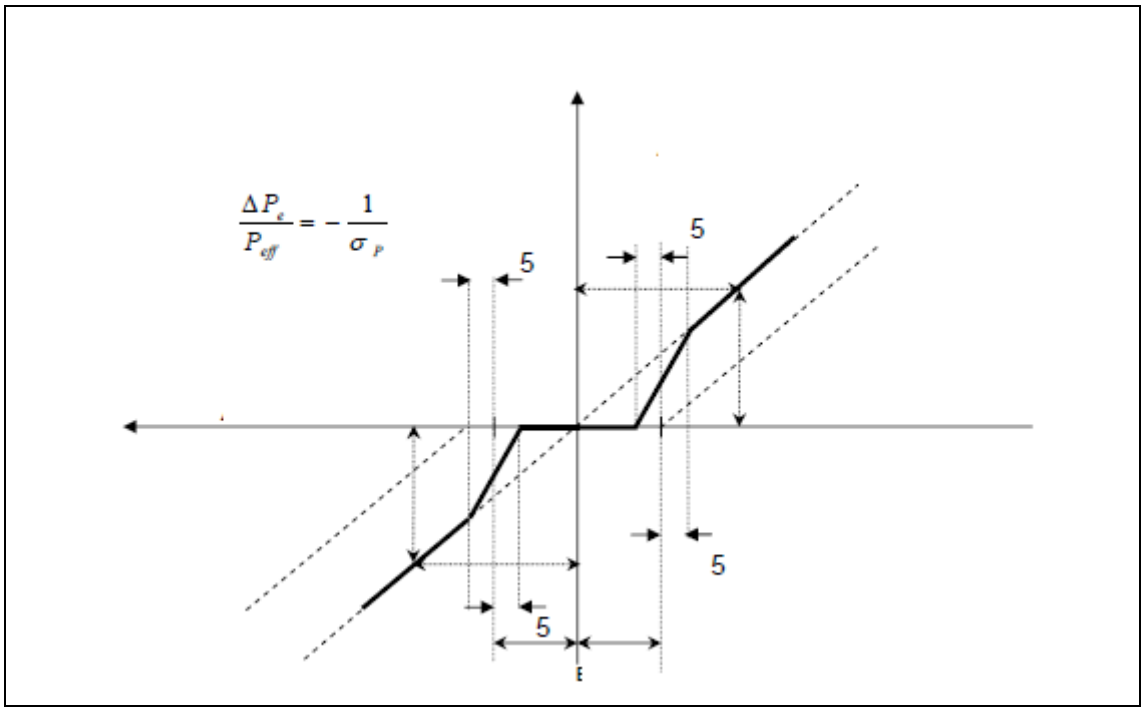
within a range of 2-12% and, unless otherwise communicated by the Operator, must observe the following limits:

- the droop must not be greater than 4% for hydroelectric **generator groups**;
- the droop must not be greater than 5% for thermoelectric **generator groups**. All sections of combined cycle installations must also observe this limit, independent of the regulation capacity of the steam unit;

- presence of an intentional deadband is permitted, settable in the range 0-500 mHz. If not otherwise communicated by the **Operator**, it must observe the following provisions:
  - the intentional deadband must not generally exceed ±10 mHz for conventional steam **generator groups** and hydroelectric **generator groups**;
  - the intentional deadband must not generally exceed ±20 mHz for gas-turbine **generator groups** and steam **generator groups** of combined-cycle installations;

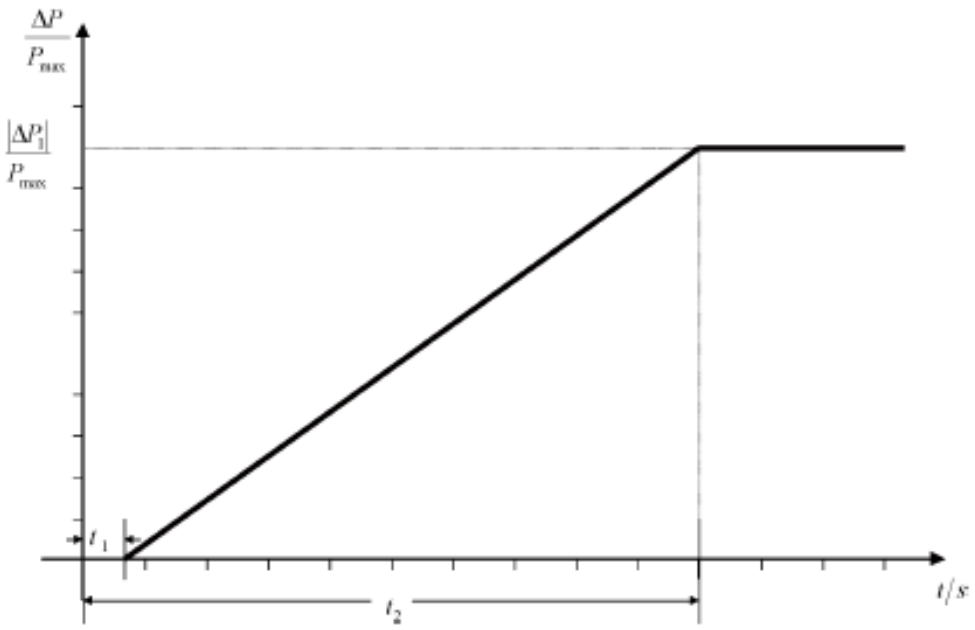
  In the event of frequency variation above the deadband, the contribution not provided must be recovered according to a similar scheme, e.g. as indicated in Figure 10;
- For power levels between the minimum and maximum issuable, the power variation required by **FSM** mode must not be limited in its degree unless the **FSM** limits indicated in Table 4 are reached, or the minimum or maximum power **operational limits**, taking into account the possible limitations described in paragraph 1C.5.3.2.

Figure 10: Regulation methods for compensation of regulator deadband



In the case of frequency step change, the power response in **FSM** must be activated by the **group** with a curve above or at least corresponding to the line presented in Figure 11, in accordance with parameters specified in Table 4. Once the power variation has been launched, the **generator group** must continue stable issue of the new power value for at least 30 minutes consecutively in the absence of further frequency changes. In the event of further frequency changes, the **group** must continue to increase or decrease the power issued on the basis of the frequency error and droop set.

Figure 11: Method for issuing frequency/power response of FSM mode



ΔP is the change in active power output from the generator group. The generator group shall provide active power output ΔP up to the point ΔP1 in accordance with the maximum times t1 and t2. t1 is the maximum initial delay. t2 is the maximum time for full activation.

Table 4: Parameters for FSM frequency response

	Hydroelectric generator group	**Thermoelectric generator group**
Initial delay admissible t1 in Figure 11	2s	2s
Response level (|ΔP1|/Pmax)	10%	8%
Maximum full activation time t2 in Figure 11	30s	30s

1C.5.3.5 Control of frequency restoration

Synchronous **generator groups** enabled for provision of the **secondary frequency regulation** service must be capable of participating in control of frequency restoration (**secondary frequency/power regulation**) according to the provisions defined by the service. The conditions for enabling and

methods for issue of the service are regulated by Chapter 4 of the Grid Code and Annex A.15 “Participation in the regulation of frequency and frequency/power” included under Appendix A of this Chapter.

1C.5.3.6 Local full frequency regulation (ILF)

Synchronous **generator groups** must be capable of operating in **Local Full Frequency Regulation** (**ILF**) mode to contribute to nominal frequency restoration. Detailed specifications of **ILF** methods are provided in Annex A.15 “Participation in the regulation of frequency and frequency/power” included under Appendix A of this Chapter.

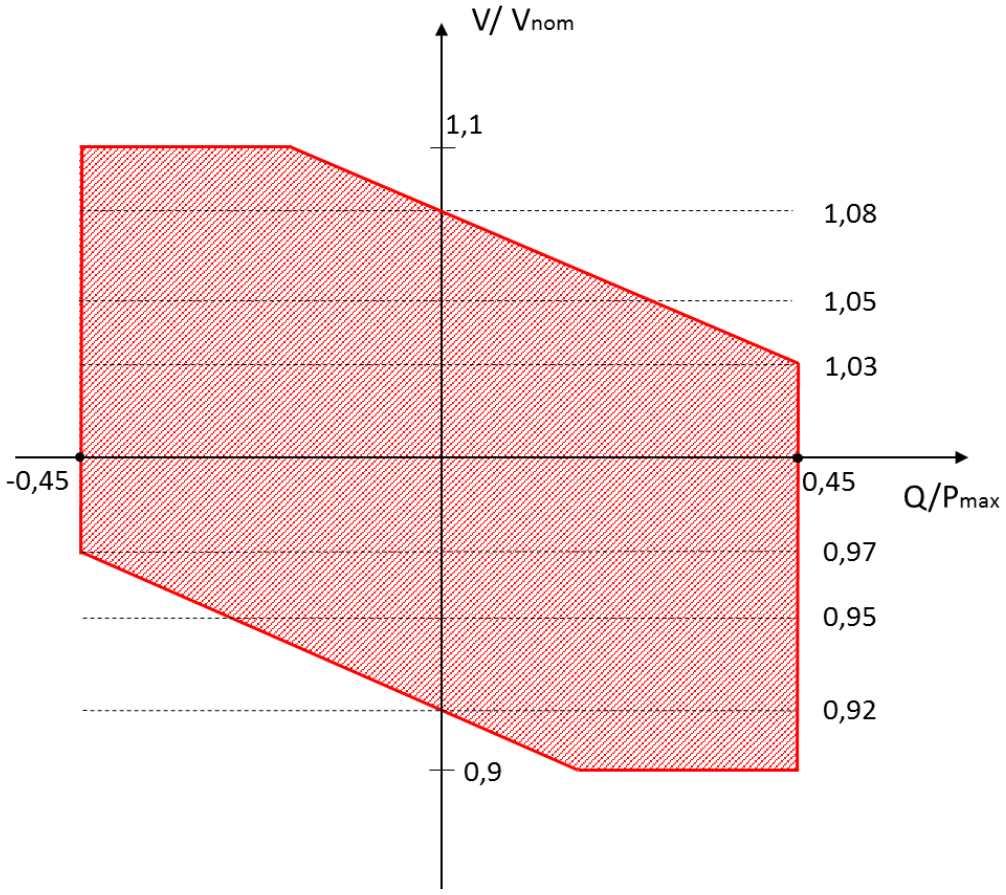
1C.5.4 Voltage stability requirements

1C.5.4.1 Reactive power capability

A type C synchronous **generator group** connected to the **grid** must be capable of operating at **efficient power** Pmax of the **group** with any power factor at the connection point between 0.98 input and 0.80 output of **reactive power**.

A type D synchronous **generator group** must be capable of operating at **efficient power capacity** Pmax at any point within the envelope of the U-Q/Pmax profile presented in Figure 12. The profile indicated the minimum **reactive power** interval expected at the CP on the basis of the voltage at the connection point. The **generator group** must also be capable of moving in an appropriate time frame from any point on the surface to another.

Figure 12: U-Q/Pmax profile of a type D synchronous generator group



When operating at an **active power** between **max capacity** (P < Pmax) and the declared technical minimum, synchronous **generator groups** must be capable of operating at any point of the P-Q capability diagram communicated to the **Operator** during the initial **plant connection** phase. The documentation must be updated by the **Producer** for each subsequent change that leads to a variation in the reactive power capability compared to that previously communicated. This P-Q diagram must not significantly limit the effective capability of the alternator.

Finally, where a line or connection cable exists between the CP of the synchronous **generator group** and the **HV** terminals of the step-up transformer, where requested by the **Operator**, the **Producer** must provide for compensation of **reactive power** demand for the line or cable.

1C.5.4.2 Voltage control system

Synchronous **generator groups** must contribute to **primary voltage regulation** that consists in **voltage regulation** at the terminals of each **group**. Therefore, they must be equipped with an (**AVR** or **RAT**) automatic control system for excitation compliant with the technical requirements contained in Annex A.14 “Participation in voltage regulation” included under Appendix A of this Chapter.

Generator groups with power greater than or equal to 50 MW must also have power system stabilizers (PSS) installed for damping power oscillations that observe the provisions set out in Annex A.9 “Defence plan of the electricity system” included under Appendix A of this Chapter. The calibration values of PSSs are agreed with the **Operator**. For **stability** requirements of the **SEN**, the **Operator** may request installation of a PSS also for smaller type D **generator groups**.

1C.5.4.3 SART functionality

Synchronous **generator plants** with at least one **generator group** that exceeds 100 MVA must provide **reactive power** resources for **power plant primary voltage regulation** and for **secondary voltage regulation**, unless otherwise indicated by the **Operator**. This requirement means that the **power station** must be equipped with SART functionality with the characteristics detailed in Annex A.16 “Automatic system for regulating voltage (SART) for electricity production plants” included under Appendix A of this Chapter.

The **Operator** reserves the right to request SART functionality also for **plants** with single **groups** below 100 MVA, where they hold particular importance for **voltage regulation** purposes.

The methods for **regulation** requested (for **group** or **HV** or EHV busbars), any voltage profiles to follow or schedules for issue of **reactive power** to be implemented are defined in the **Operating Regulations**. The **Operator**

sends the **Producer** the reference levels of voltage or **reactive power** to adopt with the methods indicated in Annex A.6 “Criteria of data acquisition for remote control” or via the Command System described in Annex A.34 “Command System: message format” included under Appendix A of this Chapter or equivalent systems for **groups** (or PUs) that are not enabled.

1C.5.5 Requirements regarding emergency management

1C.5.5.1 System black-start

On the basis of **NTG** requirements and according to the procedures established in the Dispatching Regulations (Chapter 4 of the Grid Code), a synchronous **generator group** may be selected by the **Operator** for participation in the recovery of the electricity system with the **black-start** service. Identification of the choice of groups is performed on the basis of their location on the **grid** and their technical specifications (current or potential through upgrading):

- significance of power for the individual group and the plant to which it belongs;
- rapid start-up capacity with absence of external power;
- capacity for synchronisation across a broad range of frequencies and voltages;
- capacity to operate in parallel with other **generator groups** using an island configuration[8];
- levels of reactive power **capability curves**;
- frequency regulation capacity on separate **grid** within strict variability limits and with connection of significant **loads** compared to the size of the group;
- voltage regulation capacity within strict variability limits and with connection of significant reactive **loads** compared to the group capability,

[8] Isolated portion of **NTG** generally characterised by low short-circuit power

which generate sudden voltage changes and capacity to launch voltage on **power restoration** lines.

The technical requirements of **power stations**/**groups** with **black-start** capability (initial power **restoration**) and the methods for provision of the service are described in Annex A.10 “Repowering and restoration plan of the national electricity system” included under Appendix A of this Chapter. The methods for testing the service are indicated in Annex A.19 “Prescriptions for verifying performance of production units for restarting the electricity system” included under Appendix A of this Chapter.

1C.5.5.2 Load rejection and re-synchronisation following disconnection from the grid

In the event of disconnection from the **grid**, synchronous **generator groups** must be capable of re-synchronisation in line with the **protection** strategy agreed between **Operator** and **Producer** and defined in the **Operating Regulations**.

If the re-synchronisation time of the **generator group** is greater than 15 minutes[9] or, in any case, if the generator group is a type D thermoelectric group, it must be capable of providing **load rejection** operation from any operating point on the P-Q capability diagram, i.e. it must guarantee stable operating conditions with disconnection of the **generator group** from the **grid**, supplying its own auxiliary services from respective unit transformers.

Identification of **load rejection** operation must not be based exclusively on position signals of the system operator's switching equipment.

Specifically, type D thermoelectric **generator groups** must be capable of continuing **load rejection** operation for a minimum of 12 hours, regardless of any auxiliary **connection** to the external grid.

[9] The 15 minute minimum re-synchronisation time is to be understood as the minimum time necessary for a **generator group** to re-synchronise with the **NTG** once power has been restored at the **CP**.

The minimum **load rejection** time may be subject to review based on the results of compliance testing and **restoration** implementation requirements.

1C.5.5.3 Participation in load shedding plan

Synchronous **generator groups** operating with **load**, including pumped-storage hydroelectric plants, must disconnect their **load**, with the exception of auxiliary services, with under-frequency conditions.

Under-frequency thresholds are communicated by the **Operator** and indicated in the plant **Operating Regulations**. The criteria and thresholds to be implemented are identified by the **Operator** on the basis of considerations regarding possible **grid** transient scenarios and are indicated in Annex A.12 “Calibration criteria for electricity system frequency relays” included under Appendix A of this Chapter.

1C.5.5.4 Remote disconnection

The **Operator** may request that one or more remote-control and/or remote-command devices are installed on the **Producer’s** plant, dedicated to specific remote disconnection and/or remote control of **generator groups** and/or disconnection of **load** and sending and receiving of data. The use of machinery dedicated to individual functions (e.g. remote disconnection), the installation of which is the responsibility of the **Producer**, may be requested to fall within the safety requirements and implementation times for commands and reporting, relative to Annex A.9 “Defence plan of the electricity system” included under Appendix A of this Chapter.

Annexes A.52 “Peripheral units of the defence and monitoring system. Functional and communication specifications” and A.69 “Criteria for connection of production plants to Terna defence systems” included under

Appendix A of this Chapter, describe the technical and functional characteristics of the DMPU equipment and methods for **connection** to the defence system.

1C.5.5.5 Functionality for stimulation of hydroelectric plants

Speed controllers of hydroelectric **generator groups** must be capable of receiving a stimulation signal directly from the **Operator's** control rooms, or from relative transmission points. Details of operation are provided in Annex A.15 "Participation in the regulation of frequency and frequency/power" included under Appendix A of this Chapter.

1C.5.6 System management requirements

1C.5.6.1 Energisation and (re)connection

The conditions for energisation of a **generator group** following an intentional stop or following intervention of the group protection system are agreed between the **Operator** and the **Producer** and are indicated in the **Operating Regulations**.

As a general rule, energisation is permitted only following receipt of explicit consent from the **Operator**, and with the **grid** within the voltage and frequency operating range indicated in paragraph 1C.5.1. In any case, the **Operator** may refuse energisation of the **group**, also in the presence of voltage and frequency values within the ranges indicated above, if the **grid** conditions are unsuitable for the parallel operation (**grid** disturbances, **outages**, etc.).

Where specifically indicated by the **Operating Regulations**, automatic management of energisation is permitted, i.e. without explicit consent from

the **Operator**, subject to the following checks on **grid** conditions by the automation system:

- voltage at the connection point (hereinafter CP) must remain between 90-110% of **nominal voltage**;
- the CP frequency must not exceed an adjustable value between 50 and 51 Hz with 0.05 Hz increments. The value is set by default at 50.2 Hz, unless otherwise indicated by the **Operator**;
- voltage and frequency conditions at the above CP must be verified for a minimum time settable between 0 s and 900 s with step of no greater than 5 s. The default minimum time is 30 s, unless otherwise indicated by the **Operator**.

During switching for energisation of the group, the closure of the parallel switch must be managed by a synchro-check device capable of blocking execution of switching if the module and phase voltage difference or slip relative to the **grid** exceed set limits. Threshold setting must be compliant with those used for the **grid** devices indicated in Annex A.11 “General criteria for calibration of protection devices on grids running at voltage equal to or greater than 110 kV” included under Appendix A of this Chapter.

Once connected to the **grid**, the **generator group** may gradually increase its power up to the scheduled value (target value) according to the gradient agreed with the **Operator**, which cannot exceed 20% per minute of the **max capacity**.

1C.5.6.2 Ramping limit

Upward and downward variation in target **active power** as set out in paragraph 1C.5.3.1 must be subject to ramping limits. The ramping value must be agreed with the **Operator**, typically within the range of 1-20%/minute of **nominal power** of the **generator group**, taking into account the specific

characteristics of the **generator group** and in particular the technology of the primary motor and primary energy source.

These ramping limitations for **active power** variation of **generator groups** meet the operating requirements of the **SEN** to avoid **active power** variations that are too rapid or too slow lowering the quality of the **frequency regulation** service.

The above ramping limitations do not apply in cases where it is the **Operator** to specifically request a **load** variation with ramping other than that agreed previously or to **grid** services (mandatory or optional) that require **load** variations with ramping outside the aforementioned range.

1C.5.6.3 Protection system

The protection system of a **generator group** has precedence over operational controls, taking into account the security of the system as well as the health and safety of personnel and of citizens and containing damage to the **generator group**.

The provisions in this paragraph are supplementary to the general requirements on **protection systems** already described in paragraph 1C.4.

1C5.6.3.1 Protection against internal faults

The list of minimum **protection systems** to be adopted for **protection** of each individual **generator group** is composed as follows:

Electrical protection systems:

(a) differential protection for **generator groups** with power alternators equal to or greater than 10 MVA;

(b) minimum impedance with power oscillation protection device for **generator groups** with power alternators equal to or greater than 20 MVA;
(c) stator earth;
(d) rotor earth;
(e) under excitation and/or loss of excitation;
(f) maximum voltage;
(g) directional protection for **active power** for thermoelectric **generator groups**;
(h) maximum flow for **generator groups** with power alternators equal to or greater than 50 MVA;
(i) protection against loss of synchronism for **generator groups** with power alternators equal to or greater than 100 MVA;
(j) step-up transformer or total differential protection for **generator groups** with power alternators equal to or greater than 10 MVA;
(k) distance **protection** on **HV** or **EHV** side of step-up transformer with measurement zone facing the transformer, for **generator groups** with power alternators equal to or greater than 200 MVA;
(l) maximum current protection on **HV** or **EHV** side of the step-up transformer, for **generator groups** with power alternator lower than 200 MVA, combined with a minimum voltage protection device;
(m) **group** circuit breaker opening failure protection for **generator groups** with power alternators equal to or greater than 20 MVA.

Non-electrical protection systems:
(a) maximum speed;
(b) maximum temperature of active parts and/or cooling fluid.

The **protection devices** for “under-excitation and or loss of excitation”, “maximum voltage”, “directional protection for active power” and “loss of synchronism” are sensitive to **grid** disturbances (including **faults** and electromechanical fluctuations) as well as **emergency conditions** and

restoration conditions of the **grid** itself. Calibration of these **protection devices** must therefore be agreed with the **Operator**.

The **group** circuit breaker opening failure **protection device** may send an opening command to circuit breakers installed in the **delivery station** or in a bordering station(s) via remote tripping.

Protection devices against internal faults must command blocking of the **generator group**.

1C5.6.3.2 Protection devices against external faults

A synchronous **generator group** must be equipped with a system of **protection devices** capable of separating it from the **grid** in the event of **faults** on the **grid** that cannot be correctly cleared by **grid protection devices**. The schemes and calibration settings must be coordinated with those of the **grid protection devices** and are therefore established by the **Operator** based on the criteria indicated in Annexes A.4 “General criteria for protection of grids running at voltage equal to or greater than 110 kV” and A.11 “General criteria for calibration of protection devices on grids running at voltage equal to or greater than 110 kV” as per Appendix of this Chapter. In relation to the requirements of the electricity system to which the **group** is connected, calibration may also be different from that indicated in Annex A.11 “General criteria for calibration of protection devices on grids running at voltage equal to or greater than 110 kV” included under Appendix A of this Chapter.

Specifically, the **Producer's** plant connected directly, or via a line, to a delivery station equipped with **protection** against failed opening of relative circuit breakers, must be set-up to receive an opening command to be forwarded to its circuit breakers. Specifically, this requirement arises in the event that the **Producer’s** plant is connected to the **delivery station** via connection without circuit breaker on the station side.

Other **protection devices** sensitive to grid events other than those indicated in Annexes A.4 “General criteria for protection of grids running at voltage equal to or greater than 110 kV” and A.11 “General criteria for calibration of protection devices on grids running at voltage equal to or greater than 110 kV”, included under Appendix A of this Chapter, must be declared by the **Producer** and relative calibration settings agreed with the **Operator** in order to guarantee coordination with calibration of **grid protection devices**.

Protection devices against external **faults** must be limited to opening of the **HV** or **EHV** circuit breaker of the **group**, in order to separate the generator and step-up transformer from the **grid**. Furthermore, where defined and in line with the provisions of paragraph 1C.5.5.2, the **generator group** must be kept operational in terms of its auxiliary services, ready for recovery of parallel operation with the **grid**.

1C.5.6.4 Control system

The schemes and settings of a **generator group** control system are agreed between **Producer** and **Operator** on the basis of the documentation provided by the **Producer** for preparation of the **Operating Regulations** in the context of the **connection** procedure as per section 1A of this Chapter. The settings of the control system must also be provided to the **Operator** according to the provisions of Annex A.65 “Structural Technical Data” as per Appendix of this Chapter.

Any changes to the schemes and/or settings subsequent to the initial **connection** phase must always first be agreed with the **Operator**.

1C.5.6.5 Control and protection action priorities

The **Producer** organises the **protection** and control devices of the plant with the following order of priority (decreasing):

i) **protection** of the **grid** and the **generator group**;

ii) synthetic inertia, where applicable;

iii) frequency control (**active power regulation**);

iv) power limitation;

v) power ramping limitation.

1C.5.6.6 Monitoring and exchange of information

Below is a list of the types of information that each **Producer** must send to the **Operator**. The detailed list and methods for exchanges of information are established, for each **generation plant**, in the **Operating Regulations**. For any requirement connected to security of the **SEN**, the **Operator** reserves the right to request further information.

1C.5.6.6.1 Real-time remote control

A **generator group** must be equipped with an **RTU** for transmission of remote metering and remote signals required for real-time **grid** operation, particularly for the following processes:

- remote control;
- remote **monitoring**;
- remote operation, with exclusive reference to remote disconnection operations;
- remote regulation.

Detailed specifications of the **RTU**, remote signals and remote metering to exchange, minimum performance requirements and interfacing methods with the **Operator's** systems are described in paragraph 1C.4 of this Chapter and in Annexes A.6 “Criteria of data acquisition for remote control” and A.13

"Criteria for connection to Terna's control system" included under Appendix A of this Chapter and indicated in the **Operating Regulations.**

Regarding real-time monitoring of the **FSM** operating mode, **generation plants** must exchange a dataset including at least the following remote measurements with the **Operator** via the **RTU**:

- **Active power** of the **generator group** (or of the Production Unit, where necessary for the provision of a grid service) - 4'' (set between 1 and 4 s)
- Power reference [10] - 4'' (between 1 and 4 s)
- Frequency from the channel of the speed controller of **generator groups** - 4'' (settable between 1 and 4 s)
- **Grid** frequency - 4'' (settable between 1 and 4 s)

For detailed specifications of remote metering for **FSM** monitoring, the indications of Annex A.73 apply: "Technical specifications for the verification and evaluation of the service of primary frequency regulation" included under Appendix A of this Chapter.

Furthermore, **generator groups** larger than or equal to 50 MVA must install a PMU (Phasor Measurement Unit) at the **HV** busbars of the **delivery station**, the detailed specifications of which are to be agreed with the **Operator**. The PMU must be integrated with **Operator** control systems.

1C.5.6.6.2 Fault monitoring systems

The **monitoring** systems for the purpose of Analysis of Disturbances that must be installed by the **Producer** are specified in Annex A.7 "Monitoring systems of the disruption of electrical grids with voltage equal to or greater than 50 kV", included under Appendix A to this Chapter.

[10] Corresponds to the gross power set on the load regulator of the **group**, minus any **primary regulation** contribution but including any **secondary regulation** contribution downstream of the final plant gradient limiter.

Specifically, **generator groups** connected to the **grid** with **nominal power** equal to or greater than 50 MVA, or **production plants** with total **nominal power** equal to or greater than 50 MVA, provided that the relative production is attributable to a single **injection point** and to the same **Producer**, must be equipped with a **disturbance recorder** to identify electromechanical disturbances within them and the relative behaviour of **protection** devices. This classification includes step-up transformers associated with **production units**.

Generator groups larger than or equal to 50 MVA must also be equipped with a further continuous **monitoring** system, named a generator-group perturbograph (*PErturbografo per Gruppi di GEnerazione - PEGGE*), capable of recording significant values of the **generator** and the generation process during electromechanical transients considered significant for the integrity of the **electricity system**. Recordings made by the PEGGE system are fundamental for performance of analysis for reconstructing events, for analysis of dynamic system safety and for continuous improvement of control strategies for the **grid** under **emergency conditions**.

The specific characteristics of the systems indicated above and the values to monitor must be agreed with the **Operator** on the basis of the information contained in Annex A.7 “Monitoring systems of the disruption of electrical grids with voltage equal to or greater than 50 kV”, included under Appendix A to this Chapter.

1C.5.6.6.3 Information for rapid restoration of service

Following an outage, the **Producer** must promptly notify the **Operator** regarding:

- availability of the **Group** (or the **plant**) excluded during the outage, the causes leading to the exclusion and those impeding resumption;
- the time frame required for resumption.

Data from **chronological event recorders** (**CER**), at the **Producer's** plant, limited to the border between **NTG** and plant, must be provided to the **Operator** within 10 seconds of the event.

1C.5.6.6.4 Information for reconstruction of outages

In line with the obligations set out in Annex A.7 “Monitoring systems of the disruption of electrical grids with voltage equal to or greater than 50 kV”, included under Appendix A to this Chapter, for reconstruction of outages, the **Producer** shall make the following available to the **Operator**:

- records from **disturbance recorders** (regarding instantaneous current and voltage values, logic signals regarding operation of **protection** systems, etc.);
- complete chronological event records (**CER**);
- records of electromechanical transients;
- local notifications.

Following a **fault**, **disturbance recorder** data, at least that relating to **HV** bays bordering with the **NTG**, must be provided automatically to the **Operator** within 10 minutes of the event.

1C.5.6.7 Simulation models

Provision of **generator group** simulation models is required with an appropriate level of detail to simulate the behaviour of the plant under:

- Steady-state conditions
- Electromechanical conditions (RMS) also considering behaviour in unbalanced mode
- Electromagnetic conditions (EMT)

The model must contain the individual synchronous generator, the internal **MV grid** and the **MV**/**HV** transformer(s) and must provide responses aligned with the real response of the **group** faced with **load** steps, voltage steps, frequency transients and symmetrical and asymmetrical **short circuits**, and compliance testing as per paragraphs 1C.5.7.2 and/or 1C.5.7.3The results of the comparison may be provided in free format.

All static and dynamic models must be provided, along with definition of parameters and limitations, as described below. In any case, the **Operator** reserves the right to request further information:

- **primary and secondary regulation** of **frequency** and **voltage**;
- model of frequency, voltage and loss-of-synchronism **protection** systems;
- models of turbine, thermal cycle and penstock;
- P/Q capability models on the basis of **generator group** voltage;
- PSS model, if present.

The models may be supplied in free format, i.e. Excel files (or text files), block diagrams (without black box) with indication of parameters used, transfer functions and equations employed. The **Operator** may in any case request the complete dynamic models used in standard format for commonly used simulation software.

1C.5.6.8 Power quality

Under **normal grid operating conditions**, the connection of a **generator group** must not lower **grid** performance specifications, at the connection point, beyond the disturbance levels subsequently defined by the **Operator**, including the contribution from the new plant.

To assess impacts of the new **generator group** on the **grid**, the **Producer** provides, upon submission of the **connection application**, all design data

regarding emission of disturbances. On the basis of this data, the **Operator** evaluates the effects on the **grid**, under minimum **short-circuit power** conditions on the **grid** itself.

The maximum disturbance emission levels associated with the individual **generator group**, which connects to the grid or intends to make significant changes to the existing system, are set by the **Operator**, taking into account the planning values adopted, the **short-circuit power** at the connection point (hereinafter CP) of the **group**, the **group** specifications and the parameters of the **grid** at the hub, the emissions of other **Users** already connected to the same **grid**, emission transferred from the rest of the **grid** and future emissions of new **Users** that have already launched the **connection application** procedure.

For **grid** portions with disturbance levels close to planning limits, connection of new plants that causes disturbances is permitted following implementation of measures required to observe planning limits.

On the basis of the **connection site** and the **grid** conditions, the **Operator** in any case reserves the right to request that the **Producer**, during a subsequent phase, installs further compensation systems in order to guarantee **NTG** quality standards.

The criteria for evaluation of emission limits regard:

i) Current asymmetry

In the absence of a **grid fault** or phase **interruptions**, injection of negative sequence current from a **generator group** must be such that the **degree of voltage asymmetry** at the **CP** remains below 1% for **grids** with **nominal voltage** below or equal to 150 kV and below 0.8% for **grids** with voltage greater than or equal to 220 kV.

Furthermore, in the case of connection in a **hub** of the **NTG** with a **short-circuit power** 500 times lower than the **efficient power** of the **generator group**, the maximum negative sequence current that can be injected at the **CP** must be lower than:

$$I_{2p.u.} = E_{ui} \cdot \frac{S_{cc}}{P_n}$$

where $I_{2p.u.}$ is the maximum negative sequence current in p.u. of the **generator group**, E_{ui} the assigned emission limit, S_{sc} the minimum three-phase **short-circuit** power at the **connection hub**, and P_n the **nominal power** of the **generator group**.

The parameter E_{ui} is defined by the **Operator** on the basis of the **grid** specifications at the **Connection Point**:

$$E_{ui} = \max\left[0.002, L \cdot \sqrt[1.4]{\frac{k_{uE} \cdot P_n}{S_t}}\right]$$

where k_{uE} is generally equal to 0.7.

The parameter *L* is equal to 0.008 for **plants** connected to the 220 kV or 380 kV **grid** and equal to 0.01 for **plants** connected to **grids** with voltage lower than or equal to 150 kV.

The parameter S_t is equal to:

- 50 MVA for **grids** with **nominal voltage** lower than 110 kV;
- 225 MVA for **grids** with **nominal voltage** greater than or equal to 110 kV and lower than 220 kV;
- 350 MVA for **grids** with **nominal voltage** of 220 kV;
- 1000 MVA for **grids** with **nominal voltage** of 380 kV.

ii) <u>Harmonic current distortion</u>

Emissions of harmonic currents must be such that the maximum level of **total harmonic distortion** of current (THD_I) calculated up to the 50th harmonic and the individual harmonic currents, considering the nominal current of the **generator group** as a base, do not exceed the values indicated in the Tables[11] below at the CP.

Harmonic order [12]						
I_{SC}/I_L [13]	3 ≤ h < 11	11 ≤ h < 17	17 ≤ h < 23	23 ≤ h < 35	35 ≤ h ≤ 50	THD_I
<20	2	1	0.75	0.3	0.15	2.5
<20<50	3.5	1.75	1.25	0.5	0.25	4
50<100	5	2.25	2	0.75	0.35	6
100<1000	6	2.75	2.5	1	0.5	7.5
≥1000	7.5	3.5	3	1.25	0.7	10
Maximum harmonic current distortion in percent of I_L [14]						

Table 5: Harmonic current limits for systems with nominal voltage lower than or equal to 110 kV.

Harmonic order [11] in addition to the above						
I_{SC}/I_L [12]	3 ≤ h < 11	11 ≤ h < 17	17 ≤ h < 23	23 ≤ h < 35	35 ≤ h ≤ 50	THD_I
<25	1	0.5	0.38	0.15	0.1	1.5
<25<50	2	1	0.75	0.3	0.15	2.5
≥50	3	1.5	1.15	0.45	0.22	3.75
Maximum harmonic current distortion in percent of I_L [13]						

Table 6: Harmonic current limits for systems with nominal voltage greater than 110 kV.

iii) Harmonic voltage distortion

11 The tables are established on the basis of standard IEEE 519 [42] and are applicable to current harmonics with frequencies that are integer multiples of the power frequency (50 Hz).

12 Presence of a direct-current component is not permitted.

13 I_{SC} is the maximum **short-circuit current** at the connection point of the **generator group** (or power park module).

14 I_L is the nominal current of the **generator group** (or of the power park module) connected at the connection point.

Harmonic emissions of a **generator group** must be such that the maximum level of **total harmonic distortion** (THDv) of the voltage (calculated up to the 50th harmonic) at the connection point, also considering the contribution from the new group itself, does not exceed the following values:

- THDv ≤ 2.5% for **grids** with **nominal voltage** lower than 220 kV;
- THDv ≤ 1.5% for **grids** with **nominal voltage** greater than or equal to 220 kV.

During evaluation of emissions limits of a **generator group**, the following alternatives are possible:

- emissions of the **group** in terms of current distortion are compliant with the above limits and such that the voltage distortion limits are not exceeded. In this case the **group** may be connected without further measures;
- emissions of the **group** in terms of current distortion exceed the above limits or are such that the voltage distortion limits are exceeded. In this case **connection** is conditional on further compensation such as to return within the planning limits.

iv) Flicker

Regarding the flicker effect, the values adopted for **NTG** planning of the **short-term flicker severity ratio (P_{st})** and the **long-term flicker severity ratio (P_{lt})** are kept within the following thresholds:

Voltage level (kV)	P_{st}	P_{lt}
220 – 380	0.70	0.50
132 – 150	0.85	0.62

v) Rapid Voltage Change

Furthermore, rapid voltage changes induced by variations in **power** exchanged with the **grid** must not exceed the thresholds indicated in the table below (IEC/TR 61000-3-7):

Number of changes n	$\Delta U/U_N$ %	
	MV	HV/EHV
n ≤ 4 per day	5-6	3-5
n ≤ 2 per hour and > 4 per day	4	3
2 < n ≤ 10 per hour	3	2,5

1C.5.7 Plant compliance

The **Producer** must ensure that every **generator group** (synchronous or power park module) is compliant with the Technical Rules introduced in section 1C of this Chapter for the entire lifetime of the **plant** and must inform the **Operator** in the event of changes and or incidents/**faults** that may have repercussions on compliance with the Technical Rules.

The **Operator** evaluates compliance of **generator groups** with the Technical Rules introduced in section 1C of this Chapter for the entire lifetime of the plant (as well as during the **connection** phase) and informs the **Producer** on the outcome of evaluations performed on the basis of:

- Information, documents and data provided by the **Producer** during the **connection** process as per section 1A of this Chapter (or following changes) or subsequently as requested by the **Operator** (paragraph 1C.5.7.1);
- Verifications/tests performed by the **Operator** or by the **Producer** on request of the **Operator** also via self-certification (paragraph 1C.5.7.2);
- **Monitoring** in real time and during **faults** (paragraph 1C.5.6.6);

- Simulations of **generator group** performance performed by the **Producer** on request of the **Operator** or performed directly by the **Operator** (paragraph 1C.5.7.3).

1C.5.7.2 *Information and documents that the Producer is required to provide to the Operator*

The **Producers** must provide the **Operator** with information and documents that describe the specifications of their systems for each individual **generator group**. The data declared must correspond with **operational** performance. Where the **Producer** fails to provide the requested data, the **Operator** shall notify the **Authority**.

Data must be provided upon submission of the **connection application** or following changes to the technical specification of **generator groups** due to modifications of technical capacity or operating incidents or **faults**, or when requested by the **Operator**.

Generally, documents and information useful for evaluation of compliance are included amongst documents and information requested during the **connection** process, as per section 1A of this Chapter, and regard (non-exhaustive list):

- general information regarding plant type;
- type of process and primary sources;
- constraints associated with the process, limiting the typical performance specifications of the relative type, and any environmental constraints;
- key features relative to identification of **operational** flexibility, as indicated in Chapter 4;
- the features of the generator group and the plant described in Annex A.65 “Structural Technical Data”, included under Appendix A of this Chapter, required for definition of the electrical behaviour of the plant. More specifically, this regards features required for execution of calculations

with steady-state and dynamic conditions, such as **short-circuit** values, load flow and electromechanical transients;

- the specifications of regulators and capability curves for definition of capability to provide system services;
- data regarding **fault** rates. Where such data is not made available by the **Producers**, the **Operator** will adopt, for its assessments, values based on historical data for the same type of plant or data available in technical documentation;
- **production plant** yield values;
- capability to power isolated **transmission-grid** portions and/or **own loads**;
- capability to withstand **load rejection**;
- capability to provide **restoration** services.

1C.5.7.2 Checks

The **Operator** defines the procedures for checks regarding:

(a) control level and control functions of **active** and **reactive power** issued to the **grid**;
(b) automatic disconnection functions of **generator groups** on identification of pre-established grid conditions;
(c) implementation of **load rejection** actions (see paragraph 1C.5.5.2);
(d) implementation of actions envisaged during phases for restoration of the electricity service following **outages**;
(e) functionality of **protection systems** subject to coordination actions with **protection devices** installed on the **NTG**.

The checks described under points c) and d) are preparatory for more complex checks on procedures for **restoration** of the electricity system and must be repeated periodically. These must consider the functionality of plants used for preparation of power **restoration** lines with reference to:

(a) **load rejection** tests on thermoelectric **groups**;

(b) tests on disconnection from the **grid** of **primary-restoration power stations**, or simple start-up following scheduled shut-down, with restarting under **black-start-up** conditions.

The **Operator** defines the procedures for evaluating compliance of plants to establish the accuracy of declarations issued by **Producers** and the technical parameters described in **GAUDÌ** and, specifically, to verify the following aspects:

- Technical connection requirements and performance of control systems (Annex A.18 “Verification of compliance of generation units with Operator technical requirements” included under Appendix A of this Chapter):
  - performance of systems for **frequency regulation**;
  - contribution to frequency transients under **emergency conditions**;
  - performance of systems for **voltage regulation**.

- Performance of production units for **restoration** of the **electricity system** (Annex A.19 “Prescriptions for verifying performance of production units for restarting the electricity system” included under Appendix A of this Chapter).

The **Operator** reserves the right to perform tests on plant functionality at any time, both using its own personnel or external consultants.

It is mandatory for parties involved in the tests described in this paragraph to participate and cooperate with the **Operator** for their performance.

Finally, with reference to the tests performed directly and autonomously by the **Producer** via self-certification, it is clarified that these tests regard:

- plants with at least one **PU** with no less than 50 MVA. For these plants, the **Producer** must periodically perform compliance testing according to the indications of Annex A.18 “Verification of compliance of generation units with Operator technical requirements” included under Appendix A of this Chapter;
- plants that provide **load rejection** and **black-start** services according to Annex A.19 “Prescriptions for verifying performance of production units for restarting the electricity system” included under Appendix A of this Chapter.

1C.5.7.3 Compliance simulations

To demonstrate compliance of **generator groups** with the Technical Rules as per section 1C of this Chapter, the **Operator** may request **Producers** to perform certain compliance simulations, to be performed with the mathematical models described in paragraph 1C.5.6.7 provided by the **Producers** themselves. The **Operator** provides the **Producer** with the technical data and **grid** simulation model, as required for performance of the required simulations.

Generally, the simulations required regard verification of requisites that are difficult to check via compliance testing, i.e.:

- Operation of **LFSM-O** and **LFSM-U** modes;
- Operation of **FSM** mode;
- **Fault-Ride-Through** capability;
- Restoration of **active power** after a **fault**;
- Island operation;
- **Reactive power** capability;
- Correct attenuation of power oscillations.

The **Operator** may in any case request that the **Producer** perform a series of supplementary or additional simulations where the information provided in

relation to the simulations described above is not sufficient to demonstrate compliance with the Technical Rules as per section 1C of this Chapter.

For evaluation of **generator group** compliance, the **Operator** also performs its own simulations on the basis of the simulations performed by the **Producer** indicated above, the simulation models described in paragraph 1C.5.6.7, checks and compliance testing as per paragraph 1C.5.7.2.

1C.5.BIS SPECIFIC TECHNICAL RULES FOR PRODUCTION PLANTS INDIRECTLY CONNECTED TO THE NTG

For the connection requirements of type A, B and C **generator groups** not connected to the **NTG**, please consult the following IEC standards:

- Standard IEC 0-21, *"Technical rules of reference for connection of active and passive users to LV grids of electricity distributors"*
- Standard IEC 0-16, *"Technical rules of reference for connection of active and passive users to HV and MV grids of electricity distributors"*

These standards were updated by IEC in implementation of Regulation (EU) 2016/631 and technical regulations for adoption of the same prepared by the **Operator**.

For **generator groups** connected to the MV grid, Annex A.72 "Procedure for the reduction of distributed generation under emergency conditions of the national electricity system (RDG)" is applicable included under Appendix A of this Chapter.

With reference to the exchange of data with the Operator, it is specified that production plants falling within the scope of application of Annex A.6 must provide the **Operator** directly or indirectly via the **grid operator** to which they are connected, with the data indicated in Annex A.6, according to the methods therein.

1C.6 SPECIFIC TECHNICAL RULES FOR DEMAND FACILITIES, DISTRIBUTION FACILITIES AND DISTRIBUTION SYSTEMS

The requirements in this paragraph are additional to the general requirements defined in paragraph 1C.4 and apply to:

- Plants corresponding to **consumption units directly connected to the NTG**, with simple or multiple connections (multi-site connections), including the loads of plants where both generation and consumption of electricity take place;
- Plants corresponding to **grids with third-party connection obligation directly connected to the NTG** via simple or multiple connections (multi-site connections)**;**
- Plants corresponding to **other electricity grids directly connected to the NTG** via simple or multiple connections (multi-site connections).

Considering the configuration of the **NTG** at 150 or 132 kV, there is a strong need for **interoperability** between the **NTG** and **grids with third-party connection obligations**. Here is the reason for this:

- 132 and 150 kV distribution islands must be observable by the **Operator's Control System**, as indicated in Annex A.6 “Criteria of data acquisition for remote control”, included under Appendix A of this Chapter, and according to the criteria for **connection** to the **Operator's Control System** indicated in A.13 “Criteria for connection to Terna’s control system”, included under Appendix A of this Chapter;
- **protection systems** on stretches composing islands must be strictly coordinated with those on the **NTG**, as per the indications of Annexes A.4 “General criteria for protection of grids running at voltage equal to or greater than 110 kV” and A.11 “General criteria for calibration of protection devices on grids running at voltage equal to or greater than 110 kV” as per Appendix of this Chapter.

For **grids with third-party connection obligations** and **other electricity grids** connected directly to **NTG** plants, the **grid** operator must adopt technical **connection** rules in relation to third parties that are aligned with those adopted by the **Operator** for **plants connected directly to the NTG**.

1C.6.1 Frequency and voltage operating ranges

Plants corresponding to**consumption units**, **grids with third-party connection obligations** and **other electricity grids directly connected to the NTG** must be designed, built and operated to remain parallel not only under **normal operating conditions** of the **SEN** but also under **emergency** and **restoration conditions**. Specifically, this means that they must be capable of remaining connected to the **NTG** and functioning for an unlimited period of time when

- the frequency is in the range 47.5 – 51.5 Hz,
- the voltage at the **connection point** is within the ranges specified in Table 7. The interval is expressed as a ratio between voltage at the **connection point** and reference voltage.

Owners of demand facilities, operators of **grids with third-party connection obligations** or operators of **other electricity grids** must not in any case voluntarily limit the scope of operation of their plants or **distribution grids** to the values indicated above. Instead, where the build specifications allow it, they should declare to the **Operator** any broader ranges (with relative time frames), the use of which will be agreed with the **Operator** during the **connection application** phase and defined in the **Operating Regulations**.

Table 7: Voltage ranges

Nominal voltage at CP (kV)	**Voltage range (p.u.)**	**Reference voltage 1 p.u.**
380 kV	0.9-1.1	400 kV
220 kV	0.9-1.15	220 kV
150 kV		150 kV
132[15] kV		132 kV
132[16] kV		120 kV
70 kV		70 kV
66 kV		66 kV
60 kV		60 kV
50 kV		50 kV
36 kV	0.9-1.1	36 kV

1C.6.2 Immunity to grid disturbances

1C.6.2.1 Resistance to short-circuit current

Plants corresponding to **consumption units**, **grids with third-party connection obligations** and **other electricity grids directly connected to the NTG** must be designed to withstand **short-circuit** currents with values up to the nominal **short-circuit** power of the circuit breakers installed on the **NTG**, indicated in paragraph 1C.4.

1C.6.2.2 ***Notifications regarding short-circuit current***

Notifications regarding temporary changes to the **NTG** or to plants corresponding to **consumption units**, grids with **third-party connection obligations** or **other electricity grids** that may lead to variations in the

[15] Valle d'Aosta, Piedmont, Liguria, Lombardy, Trentino-Alto Adige, Veneto, Friuli-Venezia Giulia, Emilia-Romagna, Tuscany

[16] Marche, Umbria, Lazio (small portion), Abruzzo (small portion)

maximum and minimum short-circuit current values will be managed according to the methods defined in the **Operating Regulations**.

1C.6.3Requirements regarding voltage stability

1C.6.3.1 Reactive power capability

Plants corresponding to **consumption units**, **grids with third-party connection obligations** and **other electricity grids directly connected to the NTG** must guarantee exchange of power with an inductive power factor between 0.9 and 1. Exchange of power with a capacitive power factor is not permitted.

In order to limit **reactive power** transients, the **Operator** may also request, from the moment of connection or if the need arises, that owners of **plants** corresponding to **consumption units**, operators of **grids with third-party connection obligations** and operators of **other electricity grids** adopt **reactive-power** compensation measures (such as shunt capacitors or reactors) ensuring the most effective location.

The timings for activation/deactivation of **reactive power** compensation measures, both those requested by the **Operator** (as per the previous point) and those installed for their own needs by owners of **plants** representing **consumption units** or by operators of **grids**, must be agreed with the **Operator**.

For **NTG** security reasons, the **Operator** may also require operators of **grids with third-party connection obligations** and operators of **other electricity grids** to maintain a specific power factor at exchange points, set within the range indicated above.

1C.6.3.2 Voltage control system

For **grids with third-party connection obligations** and **other electricity grids directly connected to the NTG**, **voltage regulation** performed via variation of the transformation ratio of **EHV**/**MV**or **HV**/**MV** transformers must be coordinated with the **Operator's** actions, and the **Operator** has the right to request controls on on-load voltage regulators of transformers in the case of **operating** conditions close to voltage collapse.

Furthermore, for the purposes of controlling the voltage of the **NTG**, the **Operator** may request that operators of **grids with third-party connection obligations** and operators of **other electricity grids** implement systems, on their own behalf, for **secondary voltage regulation**, also using plants **indirectly connected to the NTG** for the **grid** under their responsibility.

1C.6.4 Requirements regarding emergency management

1C.6.4.1 Load disconnection

The possibility to disconnect a portion of the electrical **load** from the **grid** is one of the measures set out by the **Defence Plan** prepared by the **Operator** (see Annex A.9 “Defence plan of the electricity system”, included under Appendix A of this Chapter). Load shedding is performed via:

- devices installed in **electrical stations** of **grids with third-party connection obligations** or **other electricity grids** (local mode);
- centralised devices (remote disconnection) of the **Operator** that act on circuit breakers of **grids with third-party connection obligations** or **other electricity grids**, directly or indirectly, via the **control system** of the **grid** operator;
- devices installed in **plants** corresponding to **consumption units directly** and **indirectly connected to the NTG** controlled by the **Operator’s** centralised system.

Local-mode load shedding is performed in the event of variations in frequency and/or voltage, in order to ensure the selective disconnection of the minimum **load** (in MW) required to restore **grid** conditions.
On the **Operator's** request, for **grids with third-party connection obligations**, **other electricity grids** or **plants** corresponding to **consumption units**, the **Owner** must therefore install load balancing equipment compliant with the specifications of Annexes A.12 "Calibration criteria for electricity system frequency relays" and A.53 "Technical and functional characteristics of the load balancing equipment" included under Appendix A of this Chapter. The logic and thresholds for activation of the devices are defined by the **Operator** and indicated in the **Operating Regulations**.

Owners of **plants** corresponding to **consumption units**, operators of **grids with third-party connection obligations** and operators of **other electricity grids** are responsible for maintenance of the aforementioned devices installed on their plants and must also notify the **Operator** of any significant changes in the disconnectable **load**.

Load shedding performed with centralised devices is subject to the rules indicated in paragraph 1C.4. The **Operator** may request that one or more remote control and/or remote-command devices are installed on the plants of owners with **plants** corresponding to **consumption units**, operators of **grids with third-party connection obligations** and operators of **other electricity grids**, dedicated to specific functions such as **load** disconnection. Use of machinery dedicated to individual functions, the installation of which is the responsibility of the Owners of **plants** representing **consumption units**, operators of **grids with third-party connection obligations** or operators of **other electricity grids**, may be requested to observe the security requirements and implementation times of commands and notifications relative to Annex A.9 "Defence plan of the electricity system"

included under Appendix A of this Chapter. The technical specifications, in terms of functionality and performance of the devices indicated in Annex A.52 “Peripheral units of the defence and monitoring system. Functional and communication specifications” included under Appendix A to this Chapter and the methods for integration with the **Operator’s** defence systems are indicated in Annex A.69 “Criteria for connection of production plants to Terna defence systems” included under Appendix A of this Chapter.

In any case, apparatus serving the **Operator's Defence Plan**, settings and re-connection and/or re-synchronisation methods following activation, are agreed with the **Operator** and indicated in the **Operating Regulations**.

1C.6.4.2 Disconnection of distributed generation (DG)

For **SEN** reasons, the **Operator** may require operators of **grids with third-party connection obligations** and/or operators of **other electricity grids** to reduce the distributed generation connected to **MV** electricity **grids** via the methods indicated in Annex A.72 “Procedure for the reduction of distributed generation under emergency conditions of the national electricity system (RDG)” included under Appendix A of this Chapter.

1C.6.4.3 On-load tap changer blocking

On **grids with third-party connection obligations** and **other electricity grids**, installation is required of equipment for blocking on-load tap changer of **HV**/**MT** transformers. Such equipment must be capable of blocking both for minimum voltage and maximum voltage.
It must be possible for the block to be activated both automatically and manually on request of the **Operator**, according to the methods described in Annex A.9 “Defence plan of the electricity system” included under Appendix A of this Chapter. The schemes and parameters for automatic activation are agreed with the **Operator**.

1C.6.4.4 Procedure for restart and restoration

Following extended outages, operators of **grids with third-party connection obligations** and **other electricity grids** must participate in **restart** procedures, preparing their plants as established by the **Operator** in Chapters 4 and 10 of this Grid Code.

1C.6.5 System management requirements

1C.6.5.1 Protection system

The schemes and settings of the **protection system** of plants corresponding to **consumption units**, of **grids with third-party connection obligations** or of **other electricity grids** are agreed with the **Operator** and indicated in the **Operating Regulations**.

The general principles of the **protection systems** for plants corresponding to **consumption units**, **grids with third-party connection obligations** or **other electricity grids** are common for all **NTG User** categories and are described in paragraphs 1C.3 and 1C.4. The provisions of Annex A.4 “General criteria for protection of grids running at voltage equal to or greater than 110 kV” also apply for **plants** corresponding to **consumption units**, and the provisions of Annexes A.4 “General criteria for protection of grids running at voltage equal to or greater than 110 kV” and A.11 “General criteria for calibration of protection devices on grids running at voltage equal to or greater than 110 kV”, included under Appendix A of this Chapter, for **grids with third-party connection obligations** and **other electricity grids**.

Finally, systems for **protection** of **plants** corresponding to **consumption units**, **grids with third-party connection obligations** or **other electricity grids directly connected to the NTG** have precedence over operational

controls, considering system security and the health and safety of personnel and citizens.

1C.6.5.2 Control system

The schemes and settings of control systems for plants corresponding to **consumption units**, **grids with third-party connection obligations** or **other electricity grids** are agreed between the Owner of the plant or the operator of the **grid** and the **Operator**, and are indicated in the **Operating Regulations**.

Furthermore, **Operator** control and remote operation centres must be able to issue instructions to the **User** Control Rooms regarding operation of plants, both under **normal conditions** and under **emergency conditions**. In this context, if requested by the **Operator**, owners of **plants** representing **consumption units** operators of **grids with third-party connection obligations**, and operators of **other electricity grids** must provide a dedicated telephone line. The functional specifications of required equipment are defined by the **Operator**.

1C.6.5.3 Monitoring and exchange of information

1C.6.5.3.1 Real-time monitoring

Plants corresponding to **consumption units grids with third-party connection obligations** and **other electricity grids** must be integrated with the **Operator's** control and operation systems according to the provisions of paragraph 1C.4. For normal **operation** of the **NTG**, the following readings and measurements must be taken:

(a) identification of status of command devices;

(b) voltage measurements;

(c) measurements of **active power**, **reactive power** and line currents, if requested by the **Operator.**

Measurements of **active power** and **reactive power** shall be provided separately for each plant element.

Details of the readings and measurements exchanged is contained in Annex A.6 of the Grid Code and is indicated in the **Operating Regulations**.

1C.6.5.3.2 Fault monitoring systems

In **plants** corresponding to **consumption units**, **grids with third-party connection obligations** and **other electricity grids**, installation is required of **monitoring** systems involving **disturbance recorder**, **fault** locator and chronological event recording, according to the applicability criteria and functional specifications contained in Annex A.7 “Monitoring systems of distruption of electrical grids with voltage equal to or greater than 50 kV” included under Appendix A to this Chapter.

In the event of **faults** or outages, the owner of the **plant** corresponding to a **consumption unit**, operator of a **grid with third-party connection obligations** or operator of **other electricity grids** is required to automatically make local notifications and records of the above **monitoring** equipment available to the **Operator** (as applicable).

Furthermore, if requested by the **Operator**, operators of **grids with third-party connection obligations** and **other electricity grids** must provide all information, including data regarding grids outside the scope of observability of the **Operator**, useful for reconstructing the outage event.

All information must be synchronised between them via GPS or another equivalent system.

1C.6.5.4 Simulation models

Owners of plants corresponding to **consumption units**, operators of **grids with third-party connection obligations** and operators of **other electricity grids** must provide a simulation model of their plants that corresponds with the real situation. Simulation models must have a sufficient level of detail so as to simulate the behaviour of the plant or the **grid** in:

- Steady-state conditions;
- Dynamic electromechanical conditions (RMS) also considering behaviour in unbalanced mode;
- Electromagnetic conditions (EMT);
- Harmonic conditions, only for plants causing distortion, to assess input to the **grid** of harmonics at different frequencies.

Plant models must be provided with sub-models and/or equivalent information regarding:

- transformer connected to the **Connection Point**;
- busbar connected to the secondary of the transformer;
- the different types of consumption, i.e. the electro-technical characteristics of loads;
- voltage control;
- **protection** system;
- power control (where present);
- converters (where present).

The models may be supplied in free format, i.e. Excel files (or text files), block diagrams (without black box) with indication of parameters used, transfer functions and equations employed. The **Operator** may in any case request the complete dynamic models used in standard format for commonly used simulation software.

1C.6.5.5 Power quality

Under **normal grid operating conditions**, the connection of plants corresponding to **consumption units**, **grids with third-party connection obligations** or **other electricity grids** must not lower **NTG** performance specifications, at the **connection point**, beyond the disturbance levels subsequently defined by the **Operator**, including the contribution from the new plant.

To assess impacts on the **grid**, Owners of plants corresponding to **consumption units**, operators of **grids with third-party connection obligations** or operators of **other electricity grids** provide, upon submission of the **connection application**, all design data regarding emission of disturbances. On the basis of this data, the **Operator** evaluates the effects on the **grid**, under minimum **short-circuit power** conditions on the **grid** itself.

The maximum disturbance emissions levels associated with individual plants corresponding to **consumption units** and with **grids with third-party connection obligations** and **other electricity grids**, which connect to the **grid** or intend to make significant changes to the existing system, are set by the **Operator**, taking into account the planning values adopted by the **Operator**, the **short-circuit power** at the **connection point (hereinafter CP)**, the emissions of other Users already connected to the same **grid**, emission transferred from the rest of the **grid** and future emissions of new **Users** that have already launched the **connection application** procedure.

For **grid** portions with disturbance levels close to planning limits, connection of new **plants** that cause disturbances is permitted following implementation of measures required to observe planning limits.

Depending on the **connection site** and **NTG** conditions, the **Operator** in any case reserves the right to request in a later phase that owners of **plants**

corresponding to **consumption units**, operators of **grids with third-party connection obligations** and operators of **other electricity grids** install further compensation systems to guarantee **NTG** quality standards.
The indications included in the following paragraphs refer to the voltage of the Delivery Point.
The criteria for evaluation of emission limits regard:

i) Current asymmetry

In the absence of **faults** on the **grid** or phase **interruptions**, injection of negative sequence current from a plant corresponding to **consumption unit**, from a **grid with third-party connection obligation** or from **other electricity grids** must be such that the **degree of voltage asymmetry** at the **connection point**, remains below 1% for **connection points** with **nominal voltage** below or equal to 150 kV and below 0.8% for **connection points** with voltage greater than or equal to 220 kV.

Furthermore, in the case of **connection** in a **hub** of the **NTG** with a **short-circuit power** 500 times lower than the maximum power of the **plant**, the maximum negative sequence current that can be injected at the **connection point** must be lower than:

$$I_{2p.u.} = E_{ui} \cdot \frac{S_{cc}}{P_n}$$

where $I_{2p.u.}$ is the maximum negative sequence current in p.u. of the **plant**, E_{ui} the assigned emission limit, S_{sc} the minimum three-phase **short-circuit power** at the **connection hub**, P_n the **nominal power** of the plant corresponding to a **consumption unit** or **grid with third-party connection obligation** or **other electricity grid**.

The parameter E_{ui} is defined by the **Operator** on the basis of the **NTG** specifications at the **connection point**:

$$E_{ui} = \max\left[0.002, L \cdot \sqrt[1.4]{\frac{k_{uE} \cdot P_n}{S_t}}\right]$$

where k_{uE} is generally equal to 0.7.

The parameter *L* is equal to 0.008 for **plants** connected to the 220 kV or 380 kV **grid** and equal to 0.01 for **plants** connected to **grids** with voltage lower than or equal to 150 kV.

The parameter S_t is equal to:

- 50 MVA for **connections** to **connection point** with **nominal voltage** below 110 kV;
- 225 MVA for **connections** to **connection point** with**nominal voltage** greater than or equal to 110 kV and below 220 kV;
- 350 MVA for **connections** to **connection point** with **nominal voltage** of 220 kV;
- 1000 MVA for **connections** to **connection point** with **nominal voltage** of 380 kV.

Where the owner of a plant provides a public service, in order to guarantee continuity of service in emergency situations for the owner of the connection, unbalanced energy withdrawals are permitted for short periods. The methods for application of these criteria shall be defined during the **connection** phase and indicated in the **Operating Regulations**.

ii) Harmonic current distortion

Emissions of harmonic currents must be such that the maximum level of **total harmonic distortion** of current (THDi) calculated up to the 50th harmonic and the individual harmonic currents, considering the nominal current of the **plant** at the **connection point** as a base, do not exceed the values indicated in the Tables[17] below at the CP.

[17] The tables are established on the basis of standard IEEE 519 [42] and are applicable to current harmonics with frequencies that are integer multiples of the power frequency (50 Hz).

Harmonic order [18]						
I_{sc}/I_L [19]	3 ≤ h < 11	11 ≤ h < 17	17 ≤ h < 23	23 ≤ h < 35	35 ≤ h ≤ 50	THD_I
<20	2	1	0.75	0.3	0.15	2.5
<20<50	3.5	1.75	1.25	0.5	0.25	4
50<100	5	2.25	2	0.75	0.35	6
100<1000	6	2.75	2.5	1	0.5	7.5
≥1000	7.5	3.5	3	1.25	0.7	10
Maximum harmonic current distortion in percent of I_L [20]						

Table 8: Harmonic current limits for systems with nominal voltage lower than or equal to 110 kV.

Harmonic order [17] in addition to the above						
I_{sc}/I_L [18]	3 ≤ h < 11	11 ≤ h < 17	17 ≤ h < 23	23 ≤ h < 35	35 ≤ h ≤ 50	THD_I
<25	1	0.5	0.38	0.15	0.1	1.5
<25<50	2	1	0.75	0.3	0.15	2.5
≥50	3	1.5	1.15	0.45	0.22	3.75
Maximum harmonic current distortion in percent of I_L [19]						

Table 9: Harmonic current limits for systems with nominal voltage greater than 110 kV.

iii) Harmonic voltage distortion

Harmonic emissions of plants corresponding to **consumption units**, **grids with third-party connection obligations** or **other electricity grids** must be such that the maximum level of **total harmonic distortion** (THDv) of the voltage (calculated up to the 50th harmonic), also considering the contribution from the new plant itself, does not exceed the following values at the **connection point**:

- THDv ≤ 2.5% for **grids** with **nominal voltage** lower than 220 kV;
- THDv ≤ 1.5% for **grids** with **nominal voltage** greater than or equal to 220 kV.

18 Presence of a direct-current component is not permitted.

19 I_{sc} is the maximum **short-circuit** current at the **connection point** of the **plant** representing a **consumption unit, the plant**representing **grids with connection obligations**or **other grids**.

20 I_L is the nominal current of the **plant** representing a **consumption unit,** the **plant** representing **grids with connection obligations** or **other grids** connected at the **Connection Point**.

During evaluation of the emissions limits of a **plant** corresponding to **consumption units**, **grids with third-party connection obligations** or **other electricity grids** the following alternatives are possible:

- emissions in terms of current distortion are compliant with the above limits and such that the voltage distortion limits are not exceeded. In this case the **User** may be connected without further measures;
- emissions of the plant in terms of current distortion exceed the above limits or are such that the voltage distortion limits are exceeded. In this case **connection** is conditional on further compensation such as to return within the planning limits.

iv) Flicker

Regarding the flicker effect, the values adopted for **grid** planning of the **short-term flicker severity ratio (P_{st})** and the **long-term flicker severity ratio (P_{lt})** are kept within the following thresholds:

Voltage level (kV)	P_{st}	P_{lt}
220 – 380	0.70	0.50
132 – 150	0.85	0.62

v) Rapid Voltage Change

Furthermore, rapid voltage changes induced by variations in **power** exchanged with the **grid** must not exceed the thresholds indicated in the table below (IEC/TR 61000-3-7):

Number of changes n	$\Delta U/U_N$ %	
	MV	HV/EHV
n ≤ 4 per day	5-6	3-5
n ≤ 2 per hour and > 4 per day	4	3
2 < n ≤ 10 per hour	3	2,5

1C.6.6 Plant compliance

Owners of plants corresponding to **consumption units**, operators of **grids with third-party connection obligations** and operators of **other electricity grids** must guarantee long-term compliance of their plants with the Technical Rules described in section 1C of this Chapter.

The **Operator** evaluates the compliance of plants corresponding to **consumption units**, **grids with third-party connection obligations** and **other electricity grids** with the Technical Rules described in section 1C of this Chapter and informs owners of **plants** corresponding to **consumption units** and operators of **grids** of the outcome of these evaluations.

The **Operator's** evaluations are performed on the basis of:

- Information, documents and data provided by owners of **plants** corresponding to **consumption units**, operators of **grids with third-party connection obligations** and operators of **other electricity grids** during the **connection** process as per section 1A of this Chapter (or following subsequent changes) or upon request of the **Operator**;
- Inspections/tests performed by the **Operator** to establish the accuracy of declarations issued by owners of **plants** corresponding to **consumption units**, operators of **grids with third-party connection obligations** and operators of **other electricity grids**. The methods for execution of these inspections and/or tests shall be agreed between the

Operator and the **Owner** of the **plant** corresponding to **consumption unit** or operator of a **grid**, on the basis of standard procedures where applicable[21]. Specifically, compliance testing involves:

- verification of the disconnection and reconnection requirements under paragraph 1C.6.4.1[22];
- verification of the information exchange requirements under paragraph 1C.6.5.3;

- **Monitoring** in real time and during **faults** in line with the provisions of paragraph 1C.6.5.3;
- Compliance simulations performed by owners of plants corresponding to **consumption units**, operators of **grids with third-party connection obligations** and operators of **other electricity grids** on request of the **Operator** or performed directly by the **Operator**. Compliance simulations are performed with the simulation models provided by the owners of plants corresponding to **consumption units**, operators of **grids with third-party connection obligations** and operators of **other electricity grids** and in any case have the main objective of verifying the capability requirements as per paragraph 1C.6.3.

1C.7 SPECIFIC TECHNICAL RULES FOR DIRECT CURRENT (HVDC) TRANSMISSION SYSTEMS AND POWER PARK MODULES CONNECTION VIA HVDC SYSTEMS

The provisions contained in this paragraph, together with the general requirements already defined in paragraph 1C.4, apply to all high-voltage, direct current interconnection circuits, both simple and multiple (multi-site

21 For example, verification of remote disconnection capability will be performed on the basis of document DREPX02005, “Verification procedure for installation of Peripheral Load Shedding Units”, available in the section “Electricity System, Technical Documentation” [29] of the **Operator’s** website.

22 As an alternative to compliance testing for disconnection requirements, provision of certificates of conformity is permitted for equipment created on the basis of the specifications indicated in Annex A 53.

connection) of the **NTG** with **other electricity grids** or those within the **NTG**[23].

Specifically, the requirements of this paragraph apply not only to **HVDC systems** that connect the **NTG** with nearby countries in the same **synchronous area** but also to **HVDC systems** that connect power park modules to the **NTG**.

1C.7.1 Frequency and voltage operating ranges of HVDC connections

An **HVDC system** must be designed, built and operated to remain connected to the **NTG** not only under **normal grid operating conditions** but also under **emergency** and **recovery conditions**. Specifically, this means that it must be capable of remaining connected to the **NTG** and operating when the frequency and voltage at the **connection point** are within the ranges and have a minimum period as per Table 10 and Table 11, respectively.

In table 11, the voltage range is expressed as the relationship between voltage at the **connection point** and reference voltage indicated in the same table. Any changes in relation to the reference voltage indicated in Table 11 shall be defined during the **connection application** phase and indicated in the **Operating Regulations**.

The ranges specified in Table 10 and Table 11 refer to operation of the **NTG** with **short-circuit power** at the **connection point** (hereinafter **CP**) between the expected minimum and maximum values. In this regard, reference may be made to minimum and maximum **short-circuit-power** values that the **Operator** publishes annually on its website for all **NTG** hubs. The criteria used to determine these values are compliant with applicable technical standards and are indicated in Annex A.8 “Short-circuit currents and fault

[23] With the exception of those connected to the Sardinian grid.

clearance times for plants of grids running at voltages equal to or greater than 120 kV" included under Appendix A to this Chapter.

The Owner of the HVDC converter station must not in any case voluntarily limit the operating range of the station to the aforementioned values; instead, where the build characteristics allow it, the Owner must notify the **Operator** of any broader ranges (with indication of relative durations), the effective use of which will be agreed with the **Operator** during the **connection application** phase and defined in the **Operating Regulations**.

Table 10: Frequency range

Frequency range (Hz)	**Minimum operating period**
46.5 – 47 Hz	Fraction of second
47 – 47.5 Hz	60 seconds
47.5 – 51.5 Hz	Unlimited
51.5 – 52 Hz	30 minutes

Table 11: Voltage ranges

Nominal voltage at CP (kV)	Reference voltage 1 p.u.	Voltage range (p.u.)	Minimum operating period
380 kV	400 kV	0.85 – 1.0875	Unlimited
		1.0875 – 1.1	60 minutes[24]
220 kV	220 kV	0.85-1.15	Unlimited
150 kV	150 kV		Unlimited
132[25] kV	132 kV		Unlimited
132[26] kV	120 kV		Unlimited
70 kV	70 kV	0.9-1.1	Unlimited
66 kV	66 kV		Unlimited
60 kV	60 kV		Unlimited
50 kV	50 kV		Unlimited

1C.7.2 Immunity of HVDC connections to grid disturbances

1C.7.2.1 Resistance to rate-of-change of frequency

HVDC systems must be designed to be capable of operating in parallel with the **NTG** without disconnection with rate-of-change of frequency at the **connection points** between -2.5 and +2.5 Hz/s (measured at any moment as the average ROCOF for the previous second).

1C.7.2.2 Insensitivity to voltage disturbances

In the event of voltage transients due to cleared **faults** on the **NTG** (**voltage dips**), HVDC converter stations must be capable of remaining connected to the **NTG** and continuing stable operation if the voltage at the **connection**

[24] Beyond 60 minutes, the station must in any case remain connected but a reduction in performance is permitted. The **Owner** must in any case declare and document the degree to which performance is reduced and the reasons for such reduction.

[25] Valle d'Aosta, Piedmont, Liguria, Lombardy, Trentino-Alto Adige, Veneto, Friuli-Venezia Giulia, Emilia-Romagna, Tuscany

[26] Marche, Umbria, Lazio (small portion), Abruzzo (small portion)

point (hereinafter **CP**) remains above a **fault-ride-through (FRT)** voltage/time profile.

The profile indicates the lower limit of the variation over time in phase-phase voltage compared to **grid** voltage at the **CP** prior to, during and after a **fault**, and defines the zones where disconnection is permitted and not-permitted. The disconnection logic must be of the one-out-of-three type: it may be activated both for symmetrical and asymmetrical **faults** when one of the three voltage levels at the **CP** exceeds the permitted **voltage dip** in terms of depth and duration.

Within the zone for which disconnection is not permitted, the HVDC converter station must guarantee the capability to remain connected to the **NTG**.

Within the zone for which disconnection is permitted, disconnection of the HVDC converter station is acceptable due to intervention of the station's **protection** system as per paragraph 1C.7.6.2. Installation of **protection systems** with ad-hoc minimum voltage that implement the minimum curve described is not permitted. Specifically, the live **protection system**, where requested and/or necessary, is set up by the Owner of the HVDC converter station based on the technical limits of the station, unless the **Operator** requests more restrictive settings.

The requirement is completely separate from actions for disconnection from the **NTG** defined by **operational** and/or **NTG protection** needs and those implemented via equipment and relative parameters defined by the Operator (e.g. **protection systems**). In relation to these actions, disconnection from the **NTG** may be requested for HVDC converter stations with time/voltage conditions within the disconnection-not-permitted range.

Observance of the **fault-ride-through** profile must be checked for each **short-circuit-power** value pre-fault and post-fault between the minimum and

maximum values of the **short-circuit power** expected at the **CP**. In this regard, reference may be made to minimum and maximum **short-circuit-power** values that the **Operator** publishes annually on its website for all **NTG** hubs. The criteria used to determine these values are compliant with applicable technical standards and are indicated in Annex A.8 “Short-circuit currents and fault clearance times for plants of grids running at voltages equal to or greater than 120 kV” included under Appendix A to this Chapter.

The parameters of the **fault-ride-through** voltage profile are indicated in Table 12; Figure 13 presents the resulting profile.

Furthermore, to deal with voltage increases accompanying the clearance of a **fault**, HVDC converter stations must also guarantee maintenance of the **connection** to the **grid** for overvoltages during voltage transient, as represented by the curve **OVRT (**Overvoltage Ride Through**)** in Figure 13:

- For the first 100 ms, the upper limit of the **OVRT** feature is defined by the manufacturer, but in any case should not be lower than 1.3 p.u. of the reference voltage.
- For the section from 100 ms up to 1 s, the upper limit of the **OVRT** feature must be at least equal to 1.2 p.u. of the reference voltage.
- For transients with a duration above 1 s, maintenance of **connection** to the **grid** must be guaranteed for voltage of at least
    - 1.1 p.u. of the reference voltage for voltage levels below 300 kV and
    - 1.15 p.u. of the reference voltage for voltage levels between 300 kV and 400 kV.

In any case, upon re-stabilisation of the normal operating conditions as per paragraph 1C.7, the values for **active** and **reactive** power issued to the **grid** should return to the pre-fault value within 200 ms and accurate to within ±10%.

Figure 13: Overvoltage Ride Through and Undervoltage Ride Through of an HVDC converter station

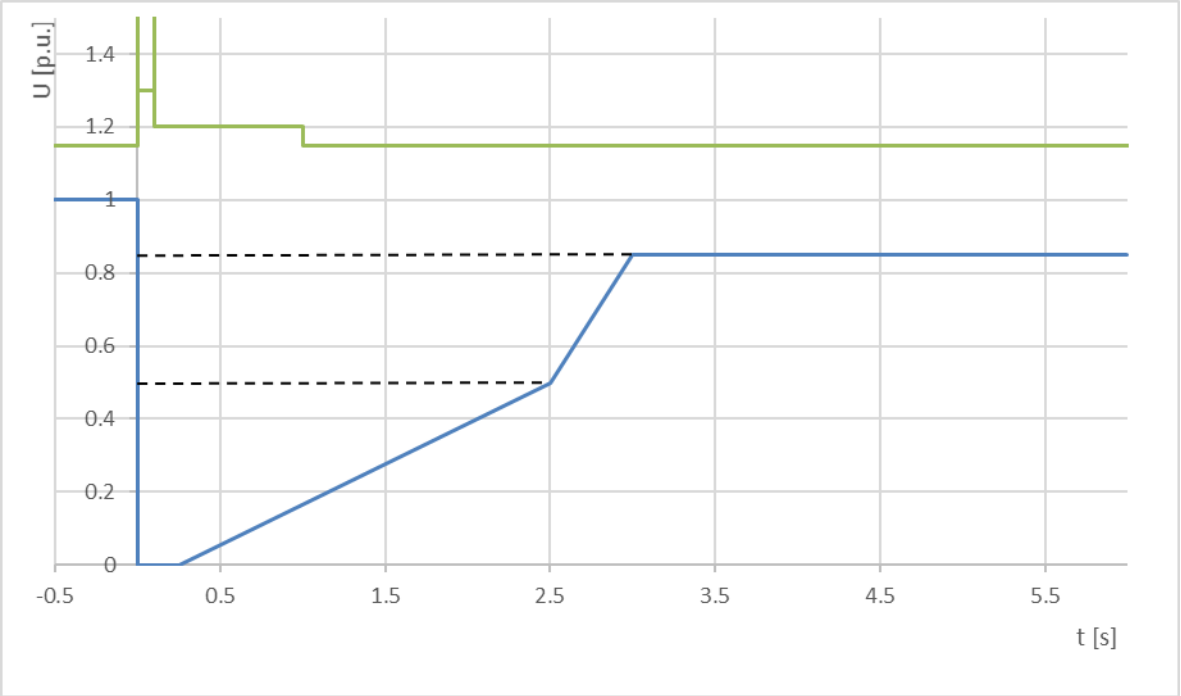


Table 12: Parameters for fault-ride-through capability of type C synchronous generators

U_{ret}	0.05 [p.u.]	T_{clear}	0.25 s
U_{rec1}	0.5 [p.u.]	T_{rec1}	2.5 s
U_{rec2}	0.85 [p.u.]	T_{rec2}	6 s

1C.7.2.3 Rapid recovery following faults on DC side

HVDC systems, including DC overhead power lines, must be capable of rapid recovery following transient **faults** in the **HVDC system**. Details of this capability are subject to coordination and agreement on schemes and settings of the **protection** system as per paragraph 1C.7.6.2.

1C.7.3HVDC connection requirements regarding frequency stability

1C.7.3.1 Control of target active power

HVDC systems must be capable of regulating the flow of **active power** in each direction at a target value communicated by the **Operator** (reference). The detailed technical specification for control of **active power** shall be defined during the **connection application** phase for the **HVDC system** and subsequently formalised in the **Operating Regulations**. Below is an example of certain elements that may be requested and specified:

- minimum **active power** values for each direction of flow of the **HVDC system** below which **active power** transmission capability is not required;
- maximum and minimum values of the power step that may be requested in relation to the reference value;
- overload capability of the system and HVDC converter stations;
- gradient of the change in **active power**;
- division of **active power** flowing between the different HVDC converter station (if applicable);
- expected operation in the event of disturbances at the **connection point** of one or more HVDC **connection** stations;
- possibility of rapid inversion of **active power** flow with relative logic, conditions and activation times. Specifically, the **Operator** may request activation of rapid power inversion on frequency thresholds (typically in the region of 400 mHz);
- maximum time[27] within which the **HVDC system** must react and begin variation of **active power** following a change in the reference power by the **Operator**;
- criteria for activation/shutdown of **frequency regulation** as per paragraph 1C.7.3.

1C.7.3.2 Reduction of maximum active power with under-frequency conditions

[27] Not greater than 100 ms

No reduction is permitted in **transport capacity** of an **HVDC system** due to under-frequency at one or more **Connection Points** of the **HVDC system**.

1C.7.3.3 Maximum loss of active power

Configuration of an **HVDC system** must be such that the loss of **active power** issued to the **NTG** is limited to a value specified by the **Operator**. This value will be communicated to the **Owner** during the **connection application** phase and will be determined on the basis of the **stability limits** of the **SEN** faced with a single situation that involves the **HVDC system**, and the number and location of the **HVDC system Connection Points**.

1C.7.3.4 Synthetic inertia

In order to limit frequency creep during certain frequency transients, the **Operator** may request that an **HVDC system** implement a control for provision of synthetic inertia. In the event that this capability is requested, during the **connection application** phase, the **Operator** will provide the Owner of the **HVDC system** with detailed specifications regarding the control schemes to be implemented and parameters and the relative requirements shall subsequently be formalised in the **HVDC system Operating Regulations**.

1C.7.3.5 Response to frequency variation in LFSM mode

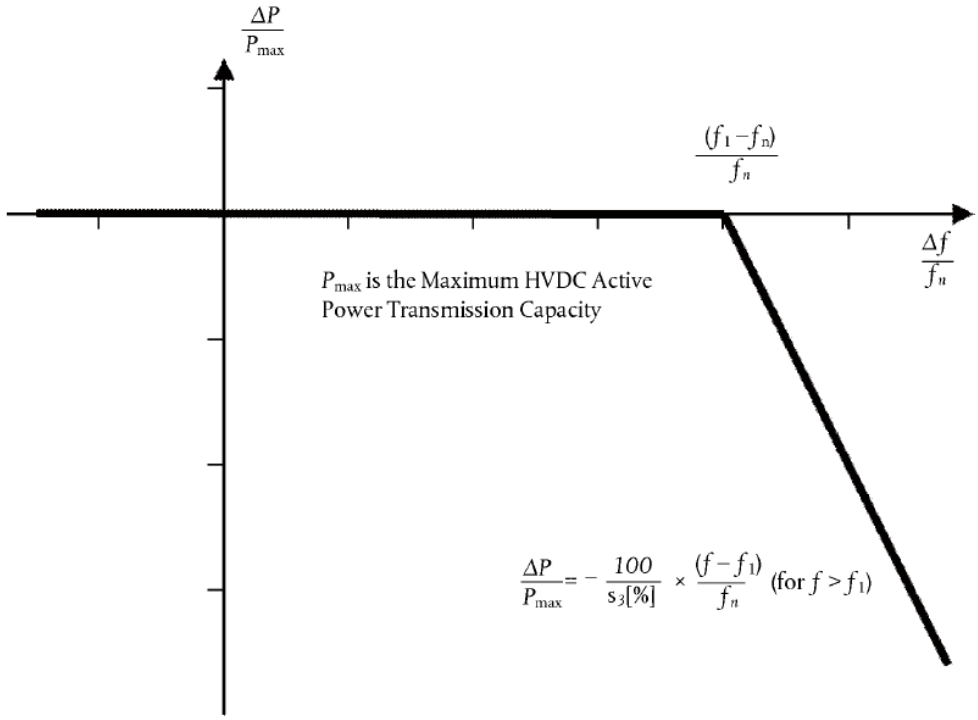
On request of the **Operator**, an **HVDC system** must implement two operating modes, called **LFSM-O** and **LFSM-U**, that allow adjustment of the exchange of **active power** with the **NTG** compared to the scheduled value (target **active power**) in response to wide variations in **NTG** frequency. The logics and conditions for activation of the aforementioned modes shall be specified by the **Operator** (via coordination with other relevant TSOs) during the

connection application phase, and the relative requirements shall be formalised in the **Operating Regulations**.

The operating principles of **LFSM-O** and **LFSM-U** modes are indicated in Figure 14 and Figure 15 with the following parameters and specifications:

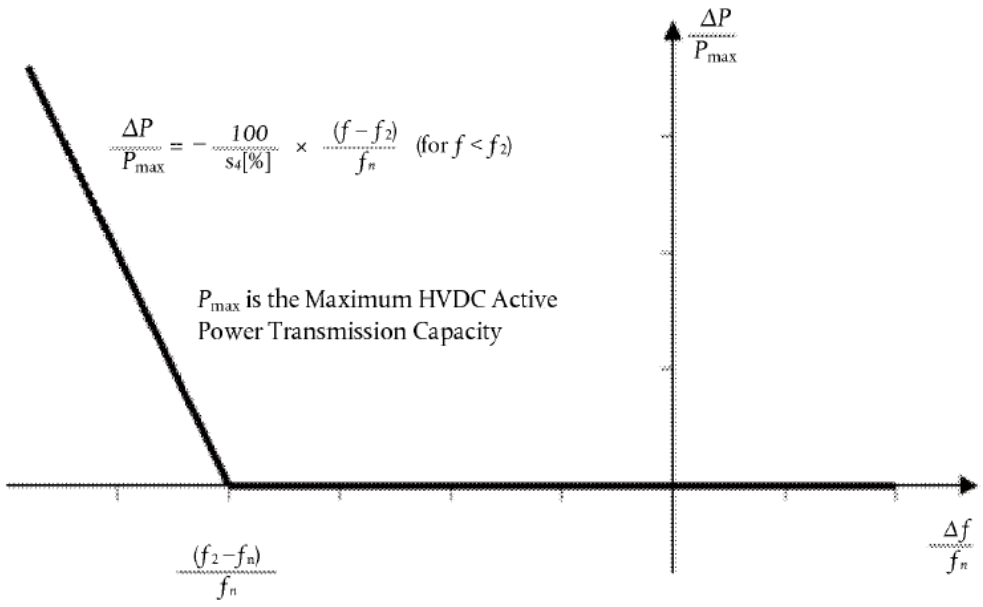
- The **LFSM-U** and **LFSM-O** modes must be capable of functioning independently of the direction of flow of **active power** in the **HVDC system**;
- power P_{max} represents the maximum **active power** flow of the **HVDC system**;
- the frequency threshold for activation of **LFSM-O** must be settable within the range 50.2-50.5 Hz with a default value of 50.2 Hz, except in the event of communication otherwise from the **Operator**;
- the frequency threshold for activation of **LFSM-U** must be settable within the range 49.5-49.8Hz with a default value of 49.8Hz, except in the event of communication otherwise from the **Operator**;
- the droop of **LFSM-O** and **LFSM-U** modes must be settable independently for each mode with a minimum value of 0.1% and a default value of 0.8%, unless otherwise communicated by the **Operator**;
- activation of the **LFSM-O** or **LFSM-U** response must occur as quickly as possible and must not take longer than 100 ms;
- the power variation required by activation of the **LFSM-O** or **LFSM-U** modes must be provided with the maximum speed permitted by the **HVDC system** specifications and performed within 2 s;
- The power variation required by activation of the **LFSM-O** or **LFSM-U** modes must not be limited, with the exception of reaching the **operating limits** of maximum or minimum **transmission power of the HVDC system**;

Figure 14: Frequency/active power response capability of HVDC systems in LFSM-O mode



ΔP is the change in active power output from the HVDC system, i.e. depending on the operating conditions a decrease of import power or an increase of export power. f_n is the nominal frequency in the AC network or networks the HVDC system is connected to and Δf is the frequency change in the AC network or networks the HVDC is connected to. In the event of overfrequencies where f is greater than f_1, the HVDC system reduces active power output according to droop s_3.

Figure 15: Frequency/active power response capability of HVDC systems in LFSM-U mode



ΔP is the change in active power output from the HVDC system, i.e. depending on the operating conditions a decrease of import power or an increase of export power. fn is the nominal frequency in the AC network or networks the HVDC system is connected to and Δf is the frequency change in the AC network or networks the HVDC is connected to. In the event of underfrequencies where f is greater than f2, the HVDC system increases active power output according to droop s4.

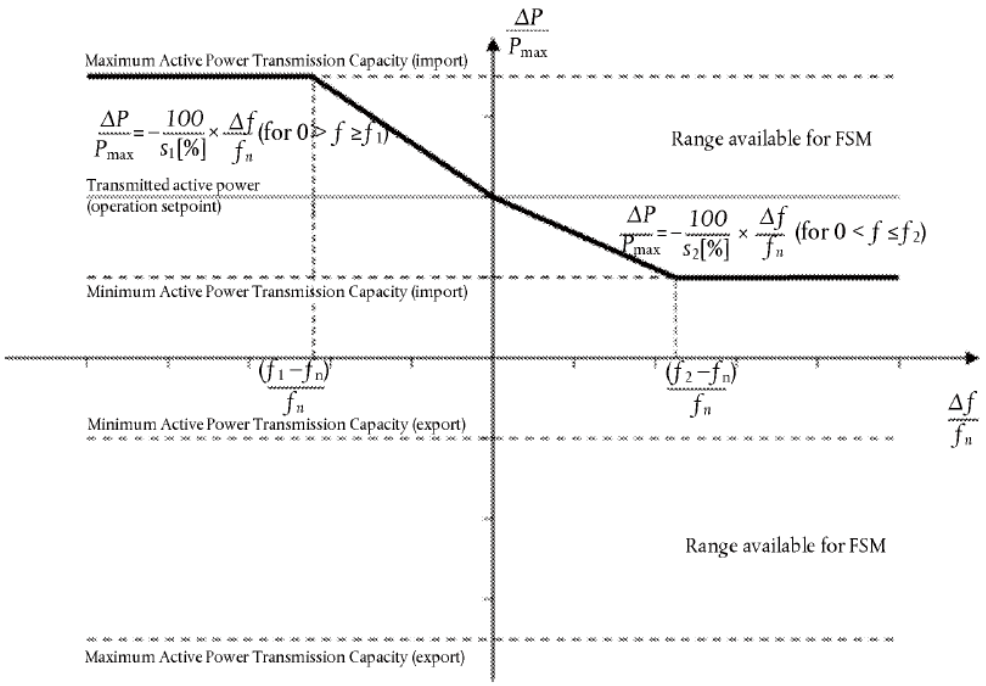
1C.7.3.6 Response to frequency variation in FSM mode

On request of the **Operator**, an **HVDC system** must implement an operating mode called **FSM**, which determines a change in **active power** flow compared to the scheduled value (target **active power**) in response to limited variations in **NTG** frequency. The logics and conditions for activation of the aforementioned **FSM** mode shall be specified by the **Operator** (via coordination with other relevant TSOs) during the **connection application** phase, and the relative requirements shall be formalised in the **Operating Regulations**.

The operating principle of **FSM** mode are indicated in Figure 15 with the following specifications:

- The **FSM** mode must be capable of functioning independently of the direction of flow of **active power** in the **HVDC system**;
- the accuracy of frequency measurement must be compliant with the applicable industrial standard and in any case no greater than 10 mHz;
- power P_{max} represents the maximum **active power** flow of the **HVDC system**;
- the changes in power required by the **FSM** mode is proportional to the frequency error, according to the s1 and s2 droop values set. The s1 and s2 droop values must be independently settable with a minimum value of 0.1%;
- in the implementation scheme of the **FSM** mode, it must be possible to set an intentional deadband at any value in the range 0 - ±500 mHz;
- the insensitivity of **regulation** of the **FSM** mode must be better than ±30 mHz;
- the change in power requested by the **FSM** mode must be limited to a value that can be adjusted according to the **operating** situation (**regulation** band) and/or by reaching the **operating limits** of maximum and minimum power flow of the **HVDC system**;

Figure 16: Frequency/active power response capability of an HVDC system in FSM mode

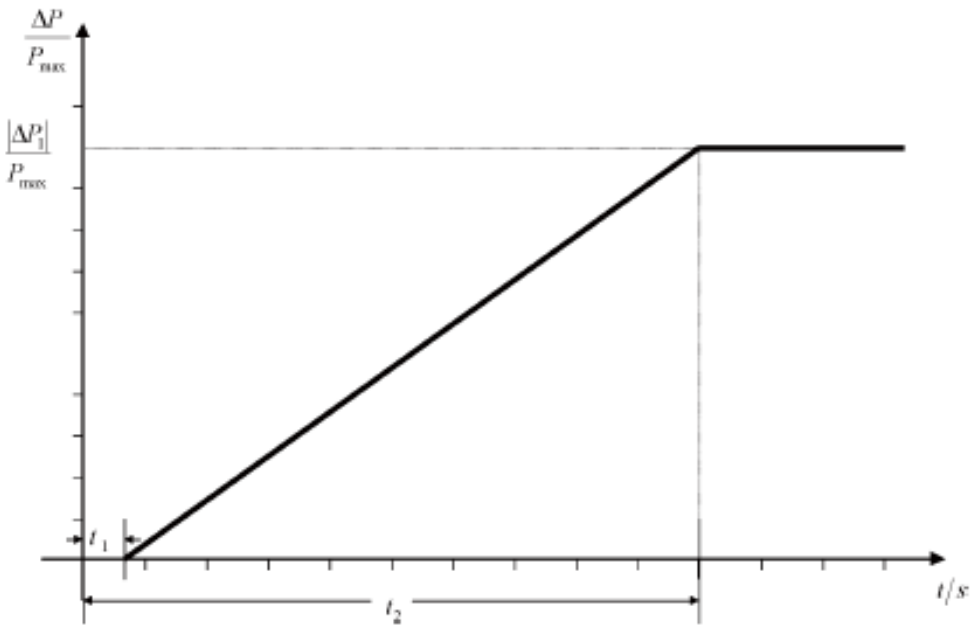


ΔP is the change in active power output from the HVDC system. fn is the target frequency in the AC network where the FSM service is provided and Δf is the frequency deviation in the AC network where the FSM service is provided.

In the event of frequency step change, the response of the **FSM** mode must be activated by the **HVDC system** according to a curve corresponding to or above the solid line shown in Figure 17. The maximum initial delay must be lower than 100 milliseconds (t_1) while the change in power must be completed within 2 seconds of activation (t_2).

Once the power variation has been launched, the **HVDC system** must maintain power flow stable at the new value in the absence of further frequency changes. In the event of further frequency changes, the **HVDC system** must adjust the flow of **active power** on the basis of the frequency error and droop set.

Figure 17: Frequency/power response capability of an HVDC system due to FSM mode



ΔP is the change in active power output from the generator group. The generator group must provide production of active power ΔP up to the point ΔP_1 observing the time limits t_1 and t_2.
t_1 is the initial delay limit. t_2 is the limit for complete activation.

1C.7.3.7 Additional frequency control

On request of the **Operator**, an **HVDC system** must implement an independent control mode that allows adaptation of the flow of power in the **HVDC system** and exchange of **active power** of the **HVDC converter stations** on the basis of frequencies at all **connection points** of the **HVDC system**, in order to maintain a stable system frequency.

If requested, the operating principle, associated parameters for performance and activation criteria of the control will be provided by the Owner of the **HVDC system** in the **connection application** phase and the requirements will be formalised in the **Operating Regulations** of the **HVDC system**.

1C.7.4HVDC connection requirements regarding voltage stability

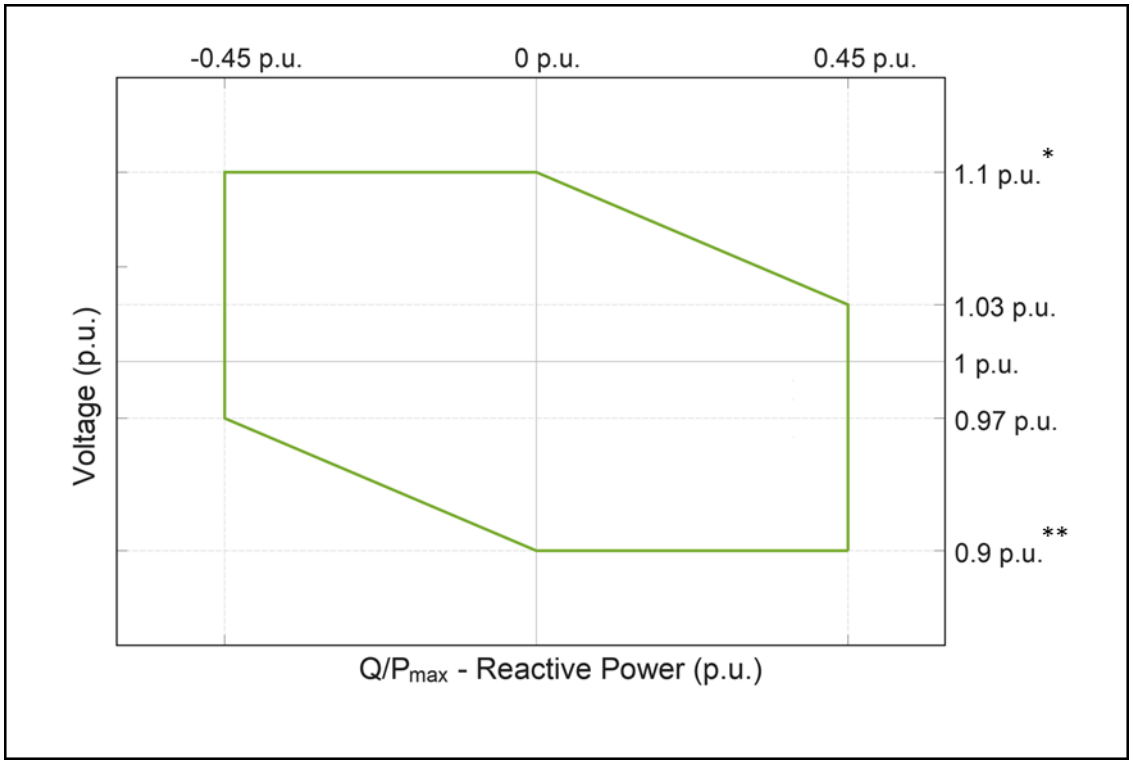
1C.7.4.1 Reactive power capability

HVDC converter stations must be capable of operating at any point within the envelope of the U-Q/P_{max} profile indicated in Figure 18 and for any exchanged **active power** value between the minimum and maximum declared. The profile in Figure 18 represents the minimum **reactive power** interval expected at the **connection point** (hereinafter **CP**) on the basis of the voltage at the **CP**.

HVDC converter stations must also be capable of moving from any operating point within the envelope to another within time limits compliant with the active control mode, as described in paragraph 1C.7.4.2.

The Owner of the HVDC converter station must not in any case voluntarily limit the operating range of the station to the aforementioned profile; instead, where the build characteristics allow it, the Owner must notify the **Operator** of any broader ranges, the effective use of which will be agreed with the **Operator** during the **connection application** phase and defined in the **Operating Regulations**.

Figure 18: U-Q/Pmax profile of an HVDC converter station



**The voltage is equal to 1.1125 p.u. for voltage levels below 300kV and 1.1 p.u. for voltage levels between 300kV and 400kV*
*** The voltage is equal to 0.8875 for voltage levels below 300kV and 0.9 p.u. for voltage levels between 300kV and 400kV*

Due to **operating** requirements of the **NTG**, an **HVDC converter station** must also be capable of further limiting exchange of reactive power with the **NTG** relative to the profile in Figure 18 to values communicated on one or more occasions by the **Operator** in line with the communication methods indicated in paragraph 1C.7.6.4.

Finally, where technology allows it, **HVDC converter stations** must also be capable of STATCOM operation, i.e. guaranteeing the U-Q/Pmax profile of Figure 18 also when the DC connection is out of service.

1C.7.4.2 Voltage control system

Where specifications of the technology allow it, **HVDC converter stations** must implement the following three control modes:

- A voltage control mode that controls the **reactive power** at the **connection point** (hereinafter **CP**) at a **reactive power** value that depends on the voltage at the **CP**;
- A **reactive power** control mode that maintains the exchange of **reactive power** at the **CP** constant at the set reference value, independent of voltage;
- A power factor control mode that maintains the exchange of power factor at the **CP** constant at the set reference value, independent of voltage.

The control mode to be used during **operation** will be communicated on one or more occasions by the **Operator**, on the basis of **NTG operating** requirements. The communication methods will be agreed with the **Owner of the HVDC system** and indicated in the **Operating Regulations**.

The following paragraphs provide further details on operation of the three main control modes.

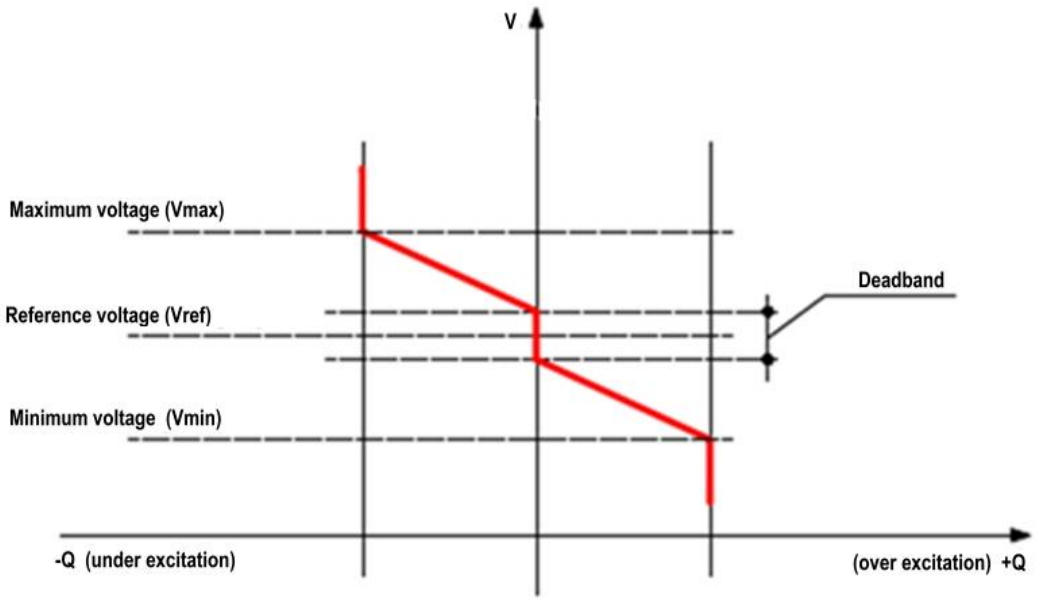
1C.7.4.2.1 Voltage control mode

The static characteristics of the voltage control mode are indicated in Figure 19, and the following considerations apply:

- The reference voltage (Vref) must be adjustable within the range of 90-110% of **nominal voltage** Vn at the **connection point** (hereinafter **CP**), with a resolution greater than 0.1 kV;
- The maximum voltage (Vmax) must be adjustable within the range of 100-110% of **nominal voltage** Vn at the **CP** with a resolution greater than 0.1 kV;

- The minimum voltage (Vmin) must be adjustable at least within the range of 90-100% of **nominal voltage** Vn at the **CP**, with a resolution greater than 0.1 kV;
- The deadband must be selectable between zero and ±5% of the **nominal voltage** Vn at the **CP** and with a resolution greater than 0.1% of the Vn;
- The speed of change of the reference voltage (kV/min) must be settable in the range specified by the **Operator** during the **connection application** phase;
- The Qmax value must correspond to the **reactive power** capability indicated in paragraph 1C.7.4 or to any value within the diagram provided by the **Operator** during **operation**.
- following a voltage step change, the change in **reactive power** must reach 90% of the standard value within 1 s and settle at the standard value within 5 seconds of the step;

Figure 19: Operating principle of voltage control mode



1C.7.4.2.2 Reactive power control mode

The characteristics of the **reactive power** regulator must be compliant with the following requirements:

- The reference **reactive power** (Qref) must be adjustable between 100% of the Qmin and 100% of the Qmax, with a resolution greater than 1% or 1 MVAr;
- The Qmin and Qmax values must correspond to the **reactive power** capability indicated in paragraph 1C.7.4 or to any value within the diagram provided by the **Operator** during **operation**;
- The speed of change of the reference **reactive power** (in MVAr/s or %/s) must be settable in the range specified by the **Operator** during the **connection application** phase;
- In the presence of a step change in the reference **reactive power**, the effective change in **reactive power** must settle at the new standard value within 5 seconds of the step.

1C.7.4.2.3 Methods for controlling the power factor

The characteristics of the power factor regulator must be compliant with the following requirements:

- The reference power factor must be settable between 0 and 1 with a resolution of 0.01;
- The speed of change of the reference value (in p.u./s) must be settable in the range specified by the **Operator** during the **connection application** phase;
- In the presence of a step change in the reference value, the regulator response time, i.e. the time taken for the **reactive power** to reach its new standard value, must be to 5 seconds.

1C.7.4.2.4 SART functionality

On request of the **Operator**, two new control modes must be implemented, named BVR (busbar voltage regulator) and RVR (regional voltage regulator), the functional specifications of which are indicated in Annex A.16 “Automatic system for regulating voltage (SART) for electricity production plants” included under Appendix A of this Chapter.

1C.7.4.2.5 Voltage support during a short circuit

Where technical specifications of the technology allow it, HVDC converter stations must provide **fast fault current** in the event of three-phase symmetrical **faults**. The logics and conditions for activation of **fast fault current** provision and its priority compared to other control will be specified by the **Operator** during the **connection application** phase, and the relative requirements shall be formalised in the **Operating Regulations**.

1C.7.5 HVDC connection requirements regarding emergency management

1C.7.5.1 System black-start

Where specifications of the technology allow it, **HVDC systems** must offer **black-start** functionality. This functionality consists in the capability of energising the AC busbar of the substation of an HVDC converter station starting from another live HVDC converter station (also AC) of the same **HVDC system**.

The interval between stoppage of an HVDC converter station and its restart shall generally not be below 15 minutes.

1C.7.5.2 Remote disconnection

For the purposes of participation in the electricity system **Defence Plan**, the **Operator** may request that one or more remote control/remote command devices are installed on one or more HVDC converter stations of the Owner of an **HVDC system**, dedicated to specific functions such as remote disconnection and remote control of the converter stations and the **HVDC system** and to data transmission and receipt. The use of machinery dedicated to individual functions (e.g. remote disconnection), the installation and maintenance of which is the responsibility of the Owner of the HVDC converter station or **HVDC system**, may be requested to fall within the safety requirements and implementation times for commands and reporting, described in Annex A.9 “Defence plan of the electricity system” included under Appendix A of this Chapter.

The technical specifications, in terms of functionality and performance of the devices indicated in Annex A.52 “Peripheral units of the defence and monitoring system. Functional and communication specifications” and the methods for integration with the **Operator’s** defence systems are indicated in Annex A.69 “Criteria for connection of production plants to Terna defence systems” included under Appendix A of this Chapter.

1C.7.6 HVDC connection requirements for system management

1C.7.6.1 Energisation and synchronisation of HVDC converter stations

Energisation of an **HVDC converter station** or its synchronisation with the AC **grid** or **connection** of an energised **HVDC converter station** to an **HVDC system** must be performed so as to limit disturbances generated at the **Connection Point**.

The detailed specifications will be defined during the **connection application** phase and the relative requirements will be formalised in the **Operating Regulations**.

1C.7.6.2 Protection system

The provisions in this paragraph are supplementary to the general requirements for **protection systems** valid for all **NTG Users** already described in paragraph 1C.4.

The **protection systems** of an **HVDC system** and its converter stations take precedence over operational controls, taking into account the security of the **SEN** as well as the health and safety of personnel and citizens.

The **protection system** of an **HVDC system** must be organised according to the following categories:

- **protection** against internal **faults** as described in paragraph 1C.7.6.1;
- **grid protection** as described in paragraph 1C.7.6.2.2;
- specific supplementary **protection systems** as described in paragraph 1C.7.6.2.3:

Any changes to **protection** systems (schemes and/or settings) are subject to prior agreement with the **Operator**. The procedures for changing **protection** schemes are specified in the **Operating Regulations**.

1C.7.6.2.1 Protection against internal faults

All **HVDC system** machinery must be protected against stress due to **faults** that are not cleared by **NTG protection systems** or not covered by them.

Every component, subsystem, **HVDC converter station** and **HVDC system** as a whole, must be protected with **protection systems** coordinated

between one another, capable of supporting and working against all abnormal operating conditions and any **fault** event, in order to guarantee the security of personnel, minimum damage to components and maximum availability of the **HVDC system**. Specifically, the security of the installation must also be ensured in the case of faults involving the **telecommunications system**.

Development and design of the **protection** system must be based on complete duplication of the equipment. Redundancy must include metering circuits, at least from the transducer side, signal pick-up systems, output circuits, the **telecommunications system**, main processing units and all elements associated with **protection** equipment.

The duplication of **protection** systems must be performed using devices with a different detection principle and/or intervention algorithm where possible.

If possible a secondary redundancy **protection** system should be activated in addition to primary **protection** systems. Longer intervention times and lower selectivity are permitted for the secondary system.

For all duplicated or redundancy systems, a monitoring and diagnostics system must be provided that allows both automatic and manual passage from the active system to the stand-by system, that must always be ready for activation. Passage from one protection system to the other must be possible and occur when anomalous operating conditions are identified on the active system. Intervention must be possible under secure conditions without disturbing the rest of the system. When one of the systems has a **fault** or is subject to forced deactivation, the automatic monitoring system must not switch from the current active system to the system that is not functioning.

Appropriate build measures must guarantee that any **protection** system **faults** do not propagate to the other **protection** system.

Every **HVDC converter station** must have a blocking device, that can normally be set both manually and locally, and in exceptional cases also remotely. This must be active in the event of a **fault**, identified by **protection devices**, which requires shutdown of the system and inspection and verification of one or more components.

The block triggered by intervention of the **protection device** must only regard the HVDC converter unit involved and must not normally be propagated to the other units of the same converter station. The **HVDC converter unit** block must impede control actions until manual reset.

Depending on the type of intervention by the **protection device**, the action may be a temporary shutdown of the individual **pole of the HVDC system**, followed by a restart attempt, or passage to the RFO (Ready For Operation), RFE (Ready For Energisation) and DIS (Disconnected) operating states, with possible activation of the blocking device.

Where a portion of system redundancy presents a **fault**, the relative **protection device** must proceed with isolation of the faulty component, where possible without **interruption**, continue to operate using the back-up component. The **protection** system must be designed with microprocessor technology and must be equipped with an in-line self-diagnostics system. This system must be capable of avoiding all incorrect actions in the event of problems within the **protection** system and should activate a specific alarm for the problem identified.

All non-conformities between information of the primary and secondary systems must be communicated to the monitoring system via specific alarms for each problem identified.

The **protection** system of the **HVDC system** must guarantee:

- maximum selectivity, at least with the primary **protection** system;
- that each **fault** is cleared within the maximum **fault** removal time by at least two **protection devices**.

1C.7.6.2.2 Protection systems on AC grid side

HVDC systems and relative substations and **HVDC** converter units must be equipped with a **protection** system capable of separating them from the **NTG** in the case of **faults** on the **NTG** that are not correctly cleared or to safeguard **SEN** stability. The schemes and calibration settings must be coordinated with those of the **NTG protection devices** and are therefore established by the **Operator** based on the criteria indicated in Annexes A.4 “General criteria for protection of grids running at voltage equal to or greater than 110 kV” and A.11 “General criteria for calibration of protection devices on grids running at voltage equal to or greater than 110 kV” as per Appendix of this Chapter. In relation to the requirements of the electricity system to which the **HVDC system** is connected, calibration may also differ from that indicated in Annex A.11 “General criteria for calibration of protection devices on grids running at voltage equal to or greater than 110 kV” included under Appendix A of this Chapter.

During the **connection application** phase for an **HVDC system**, the **Operator** verifies correspondence of the **protection** system proposed with the general requirements contained in Annex A.4 “General criteria for protection of grids running at voltage equal to or greater than 110 kV” included under Appendix A of this Chapter and agrees the detailed schemes and calibration with the Owner of the **HVDC system**.

1C.7.6.2.3 Other specific protection devices

The following are also required for HVDC converter stations:

- **protection devices** against fluctuations in power that cannot be controlled by the **HVDC system**;
- **protection devices** against **grid** losses: a **protection system** must be designed that verifies the effective presence of the **NTG**. This **protection system** must be based on power, voltage and current measurements and, where necessary, the status of the station. The **protection system** must prevent activation of the **HVDC system** if the correct conditions are not present and its disconnection in the case of opening of the last line that connects the plant to the **NTG**. The **protection system** may be located in the box on the conversion busbar connections in the **grid** substation or within the **protection** system that must therefore pick up all necessary signals. The manufacturer/owner is responsible for specifying the type and specification of the interface with the substation for exchange of signals;
- **protection** from harmonic distortion. If the **HVDC system** injects an excessive quantity of harmonics into the **grid**, an alarm will be generated;
- **protection** from **grid** voltage asymmetry: HVDC converter stations must be disconnected when the asymmetry limits indicated in paragraph 1C.7.6.6 are reached. Calibration of the **protection system** must be agreed with the **Operator** to avoid, for the purpose of safeguarding **NTG** availability requirements, exclusion of an HVDC converter station in transient state before effectively necessary.

1C.7.6.3 Control system

HVDC systems must be equipped with a control system capable of coordinated management and control of all **HVDC** converter units of the system.

During the **connection application** phase, the hierarchy and structure of the control system shall be agreed with the **Operator** and the relative

requirements shall be formalised in the **Operating Regulations** of the **HVDC System**.

The schemes and settings of the **HVDC system** are agreed between **Owner** of the system and **Operator** on the basis of the principles indicated in the following paragraphs, in the context of the **connection** procedure as per section 1A of this Chapter. Any changes to the schemes and/or settings subsequent to the initial **connection** phase must always first be agreed with the **Operator**.

1C.7.6.3.1 Automation, control and regulation criteria

Hierarchical structure of the control system

For each pole of the HVDC[28] system and for each HVDC converter station, the functional structure of the control system must be organised in the following way[29]:

- "converter control" that includes the majority of fast and internal control functions of conversion bridges of **HVDC** converter units, including control of the firing angle of thyristors, converter current and voltage control loops, limiter functions of angles of flow, start-stop logics, etc. The "converter logics" generate low-level logic functions for automation and separate management of the converter;
- the "terminal control" allows management of **HVDC** converter units in the absence of telecommunications between the **HVDC** converter units of the same pole, with local commands. Coordination of functions shall not be automatic but obtained manually and guaranteed by operators. The "terminal logics", generate high-level logic functions for automation

[28] A pole of the HVDC system is understood as the part of an HVDC system composed of two or more converter stations connected to one another via AC cables or transmission lines. In the AC section, the polarity of the voltage is the same for all common system parts of the pole.

[29] In compliance with standard IEC 60633:1998 "Terminology for high-voltage direct current (HVDC) transmission",

and management of **HVDC** converter units, in the absence of telecommunications;

- the “connection control”, which via the **telecommunications system** between the HVDC converter stations of a pole, operates symmetrically and coordinates with the relative block at the other end of the pole. In this way, complete automatic coordination is achieved of the entire pole, implementing the slower control functions such as constant power transfer or **frequency regulation** in one of the two **grids**. The “connection logics”, in the presence of telecommunications with analogue block at the other station, generate high-level logic functions, for automation and management of the pole, and generate interfacing for remote operation.

For each HVDC converter station, the control system structure may also include the following functions:

- “station control” allowing coordinated management of the HVDC converter station, coordinating control functions of HVDC converter units of individual poles in the absence of telecommunications with the other HVDC converter stations;
- “two-pole network control” generates high-level logic functions for coordinated automation and management of both poles, coordinating connection or terminal control function in the presence of telecommunications.

Control-system redundancy

Development and design of the HVDC converter station control systems must be based on complete duplication of the equipment. Redundancy must include metering circuits, at least from the transducer side, signal pick-up systems, output circuits, the **telecommunications system**, main processing units and all elements associated with command, control and **protection** equipment of converter stations. Duplication must extend up to the level of conversion bridges, also including the level of valves and relative cooling

system. Equipment designed with redundancy shall be considered as duplicated.

For all duplicated or redundancy systems, a monitoring and diagnostics system must be provided that allows both automatic and manual passage from the active system to the stand-by system, that must always be ready for activation. Passage from one system to the other must be possible and occur when anomalous operating conditions are identified on the active system. Intervention must be possible under secure conditions without disturbing the rest of the **HVDC system**. When a system has a **fault** or is subject to forced deactivation, the automatic monitoring system must not switch from the current active system.

There must be a guarantee of the principle that any **faults** on duplicated equipment do not propagate to relative redundancy equipment.

Order of priority of protection and control

The Owner of an **HVDC system** organises their **protection systems** and control devices on the basis of the following order of priority (decreasing), unless otherwise indicated by the **Operator**:

- **protection of the grid** and the **HVDC system**;
- control of **active power** for emergency assistance;
- synthetic inertia, where applicable;
- any corrective actions consisting in automatic block of load ramps and/or activation/blocking of frequency control (**LFSM-U**, **LFSM-O** and **FSM** modes);
- **LFSM** mode;
- **FSM** mode and frequency control and
- power ramping limitation.

Possible changes or additions to the order of priority indicated above may be provided by the **Operator** during the **connection application** phase and indicated in the **Operating Regulations**.

1C.7.6.3.2 Functional requirements of the control system

The control system of an **HVDC system** must implement all indispensable command, control and **protection** functions of HVDC converter stations, interfaces necessary for operators to manage all defined operating modes and fundamental configurations for control of the connection. Furthermore, for activities involved in entry into service of the **HVDC system**, a mode most be provided for the control of current alone that can also be used in the event of outages of the telecommunications system used for coordination of the units and converter stations of the **HVDC system**.

The control system of the HVDC converter stations must include various control functions that can be generically divided into three groups:

- Primary control functions: power or synchronous current control, **grid** frequency control (with associated quick inversion of the direction of power transmission), voltage control on the connection, and control of on-load transformer. The synchronous control set-ups must be equipped with adequate reserve functions, to manage the **operating** conditions under which the telecommunications system is temporarily unavailable.
- Secondary control functions: control of **reactive power** absorbed by the **grid** (logics for reduction of impact of actions on AC filters), current limitation in the event of overload, current limitation on the basis of the current/voltage characteristics, rapid recovery of the system in the event of **grid faults** management of test set-up with open line (used in “Manual” mode to verify the integrity of isolation of DC circuit components).
- Additional control functions: **grid** voltage control, damping of electromechanical oscillations and dampening of subsynchronous oscillations, fast variation of power transmitted with run-back and run-up.

Operating mode

The control system of HVDC converter stations and the **HVDC system** must at least offer the possibility of operation in each of the following modes.

- "Automatic Connection" operating mode (ALM), which is operated locally (control room) or remotely (remote-operation centre). This standard and permanent operating mode requires that the telecommunications system is operational to automatically manage transitions between the various operating states (Ready for Energisation - RFE, Ready for Operation - RFO, Connection in Operation - POW) and control (Power/frequency control, Synchronous current control) of the **HVDC system** or of the individual poles composing it. The command, control and protection sequences must be coordinated and synchronised automatically between the HVDC converter stations, beginning with local commands from the control room or remote commands from the remote-operation centre. According to the **operating** set-up (bipolar or monopolar), this operating mode is divided into:
  - "Bipolar Automatic Connection";
  - "Monopolar Automatic Connection".
- "Automatic Terminal" (ATM) operating mode, which is only operated locally (control room). This special, temporary operating mode must be available for manual selection by both operators that will manage coordination, via telecommunications, of transitions between the various operating states (Terminal Disconnected, Terminal Ready for Energisation, Terminal Ready for Operation, Terminal in Operation) and control (Control of Asynchronous Current) of both poles (with bipolar set-up) or of one pole (with monopolar set-up) of the same HVDC converter station. The command, control and protection sequences must be coordinated via telecommunications between the HVDC converter stations, beginning with local commands from the control room. According to the **operating** set-up (bipolar or monopolar), this operating mode is divided into:

- “Bipolar Automatic Terminal”;
- “Monopolar Automatic Terminal”.

- “Manual” (MAN) operating mode, which is only operated locally (control room). This special, temporary operating mode must be available for manual selection by both operators that will manage, by telephone, without the support of any automatic operation sequences (with the sole exception of hardware interlocks that shall always remain active), coordination of transitions between the various operating states (Pole Disconnected, Pole Ready for Energisation, Pole Ready for Operation, Pole in Operation) and control (Control of Asynchronous Current) of the poles separately, (both with bipolar or monopolar set-up) of the same HVDC converter station. Control actions must be coordinated by telephone between the HVDC converter stations, beginning with local commands of the control room.

Master or slave operation

In “automatic connection” mode, the MASTER HVDC converter station will be that with the highest priority and its operator will completely control the **HVDC system** or the individual poles composing it. The other HVDC converter station will be allocated as SLAVE and will automatically perform the actions requested by the MASTER station.

The definition of which station is MASTER and which is SLAVE shall be performed prior both to unblocking of the connection and issue of the order for entry into service. The MASTER function may in any case be transferred without **interruption** of service.

Both stations must be may be selected as MASTER station.

All orders in “Automatic Connection” mode, e.g. orders for set power, shall be defined in the MASTER station, which shall transmit the necessary information to the SLAVE station.

Operating states

The control system of the HVDC converter stations must at least provide for the following different operating states of the **HVDC System** (if the system is operated in “Automatic Connection” mode) or of the **HVDC** converter units (if the system is operated in “Automatic Terminal” mode), which are characterised by clearly defined identification criteria:

- converter unit disconnected (DIS): this operating state requires open DC switches, open AC circuit breaker and switch, and locked valves (visually identifiable system condition prior to maintenance).
- converter unit ready for energisation (RFE): this operating state requires closed DC switches, open AC circuit breaker and switch, and locked valves (in this system state, the transformers are ready for entry into service).
- converter unit ready for operation (RFO): this operating state requires closed DC switches, closed AC circuit breaker and switch, and locked valves (with this system status, the filters are ready for entry into service).
- converter unit under power transmission conditions (POW): this operating state requires closed DC switches, closed AC circuit breaker and switch, and unlocked valves (in this system state, power is transferred between the terminals).

The individual pole adopts states with the same names (Connection Ready for Energisation, Connection Ready for Operation, Connection Under Power Transmission Conditions) when the converter units have reached the corresponding operating states, with the sole exception of the disconnected state, which can only be reached at converter-unit level.

The **HVDC system** adopts operating states with the same names when the poles have reached the corresponding operating states.

1C.7.6.4 Monitoring and exchange of information

1C.7.6.4.1 Real-time monitoring

For the purpose of real-time **operation** of the **NTG**, installation is required within **HVDC** converter stations of one or more **RTUs** for integration of an **HVDC system** and its converter stations with the **Operator's** control and command systems. The integration methods are indicated in paragraph 1C.4.

The instructions regarding quantity and type of information and updating time frames required for each individual data unit/measurement are defined by the **Operator** in the **connection application** phase of the **HVDC system** and indicated in the **Operating Regulations**.

1C.7.6.4.2 Fault monitoring systems

All HVDC converter stations must be equipped with a system for recording events (**CER** – **Chronological Event Recording**) and **faults** (**TFR** - **Transient Fault Recorder & Analyser**):

- The **CER** collects all status signals and variations in them for the various systems, and all commands and **protection** actions and stores them, both under **standard** conditions and in the presence of disturbances.
- The **TFR** records and analyses the analogue and digital values of the system during disturbances.

It must also be possible to acquire and analyse the harmonic distortion (from the 2nd to the 50th harmonic) and the components of the current injected into the **grid** and the voltage at the **connection point**.

Furthermore, a sufficient number of configurations must be available, and easily accessible, making it possible to record transients expected during the testing phases and select events involved.

The **CER** and **TFR** systems shall be used and managed through operator workstations and remote workstations.

All events and transients will use the same synchronisation signal (GPS) to label events or records.

The **CER** function should store all events. Recent events and all faults or alarm statuses still present shall be immediately accessible. It shall be possible to bring up specific categories of events using appropriate filters and search algorithms. The events will be divided by degree of severity.

It must be possible to activate the **TFR** both manually and automatically for violations of thresholds set by the operator. The duration of recording shall be at least 3 seconds and shall terminate when all conditions have returned within expected values.

Records shall include both wave form and RMS values calculated by the system itself. All records of subsystems shall be comparable and superimposable.

The resolution, of both signal and records, shall be such as to allow reconstruction of the event and may vary depending on the underlying phenomenon.

Records shall be stored and easily available for operators to locate/view and print. It shall also be possible to add notes and comments.

It shall be possible to export the data to other systems for off-line analysis of the event.

1C.7.6.5 Simulation models

The Owner of an **HVDC system** must provide an **HVDC system** simulation model that mirrors the real behaviour of the system and allows simulation with a sufficient level of detail of behaviour under steady-state conditions, dynamic electromechanical conditions (RMS), electromagnetism (EMT) and harmonic conditions (with evaluation of input to the **grid** of harmonics at different frequencies).

The simulation model must be provided with sub-models and/or equivalent information regarding:

- models of **HVDC** converter units;
- models of AC components;
- models of DC **grid**;
- voltage, frequency and power control system;
- special control features such as dampening of power oscillations and control of dampening for sub-synchronous torsional interaction (where applicable);
- control with multiple terminals, where applicable;
- **protection** models of the **HVDC system**.

Further submodels may be requested on the basis of the **HVDC system** specifications and/or its **connection** scheme with the **NTG**.

The simulation models may be supplied in free format, i.e. Excel files (or text files), block diagrams (without black box) with indication of parameters used, transfer functions and equations employed. The **Operator** may in any case request the complete dynamic models in standard format for commonly used simulation software.

In addition to simulations performed in the context of the compliance process as per paragraph 1C.7.9, the models provided may also be used for execution of verification analyses, such as:

- Transient overvoltages;
- **Stability** with small changes (**transient stability**);
- Sub-synchronous torsional interaction;
- Interaction between **HVDC systems** or other plants and equipment that is located in close electrical proximity;
- Loss of an **HVDC converter station**.

1C.7.6.6 Power quality

Under **normal grid operating conditions**, the connection of an **HVDC system** must not lower **NTG** performance specifications, at the **connection point**, beyond the disturbance levels subsequently defined by the **Operator**, including the contribution from the new plant.

To assess impacts on the **grid**, the Owner of an **HVDC system** provides, upon submission of the **connection application**, all design data regarding emission of disturbances. On the basis of this data, the **Operator** evaluates the effects on the **grid**, under minimum **short-circuit power** conditions on the **grid** itself.

The maximum disturbance emission levels associated with the individual **HVDC system** and its converter stations are set by the **Operator**, taking into account the planning values adopted by the **Operator**, the **short-circuit power** at the **connection point** (hereinafter **CP**), specifications data of the **HVDC system**, the emissions of other **Users** already connected to the same **grid**, emission transferred from the rest of the **grid** and future emissions of new **Users** that have already launched the **connection application** procedure.

For **grid** portions with disturbance levels close to planning limits, connection of new plants that cause disturbances is permitted following implementation of measures required to observe planning limits.

On the basis of the **NTG** conditions at the **CPs**, the **Operator** in any case reserves the right to request that the owner of the **HVDC system**, during a subsequent phase, installs further compensation systems in order to guarantee **NTG** quality standards.

The criteria for evaluation of emission limits regard:

i) Current asymmetry

Injection of negative sequence current from an **HVDC converter station** must be such that the **degree of voltage asymmetry** at the **CP**, in the absence of phase **interruptions**, remains below 1% for **grids** with **nominal voltage** below or equal to 150 kV and below 0.8% for **grids** with voltage greater than or equal to 220 kV.

Furthermore, in the case of **connection** of an **HVDC converter station** in a **hub** of the **NTG** with a **short-circuit power** 500 times lower than the max power of the HVDC converter station, the maximum negative sequence current that can be injected at the **CP** must be lower than:

$$I_{2p.u.} = E_{ui} \cdot \frac{S_{cc}}{P_n}$$

where $I_{2p.u.}$is the maximum negative sequence current in p.u. of the HVDC converter station, E_{ui} the assigned emission limit, $S_{sc}$the minimum three-phase **short-circuit** power at the **connection hub**, and P_n the **nominal power** of the HVDC converter station.

The parameter E_{ui} is defined by the **Operator** on the basis of the **grid** specifications at the **connection point**:

$$E_{ui} = \max\left[0.002, L \cdot \sqrt[1.4]{\frac{k_{uE} \cdot P_n}{S_t}}\right]$$

where k_{uE} is generally equal to 0.7.

The parameter *L* is equal to 0.008 for plants connected to the 220 kV or 380 kV **grid** and equal to 0.01 for plants connected to **grids** with voltage lower than or equal to 150 kV.

The parameter S_t is equal to:

- 50 MVA for **grids** with **nominal voltage** lower than 110 kV;
- 225 MVA for **grids** with **nominal voltage** greater than or equal to 110 kV and lower than 220 kV;
- 350 MVA for **grids** with **nominal voltage** of 220 kV;
- 1000 MVA for **grids** with **nominal voltage** of 380 kV.

ii) Harmonic current distortion

Emissions of harmonic currents of an HVDC converter station must be such that the maximum level of **total harmonic distortion** of current (THD_I) calculated up to the 50th harmonic and considering the nominal current of the HVDC converter station as a base, do not exceed the values indicated in the Tables[30] below at the CP.

Harmonic order (31)						
I_{sc}/I_L (32)	3 ≤ h < 11	11 ≤ h < 17	17 ≤ h < 23	23 ≤ h < 35	35 ≤ h ≤ 50	THD_I
<20	2	1	0.75	0.3	0.15	2.5
<20<50	3.5	1.75	1.25	0.5	0.25	4
50<100	5	2.25	2	0.75	0.35	6
100<1000	6	2.75	2.5	1	0.5	7.5
≥1000	7.5	3.5	3	1.25	0.7	10
Maximum harmonic current distortion in percent of I_L (33)						

Table 13: Harmonic current limits for systems with nominal voltage lower than or equal to 110 kV.

30 The tables are established on the basis of standard IEEE 519 [42] and are applicable to current harmonics with frequencies that are integer multiples of the power frequency (50 Hz).

31 Presence of a direct-current component is not permitted.

32 **I_{sc} is the maximum short-circuit current at the connection point of the HVDC system.**

33 I_L is the nominal current of the HVDC converter station at the Connection Point.

Harmonic order [30] in addition to the above						
I_{sc}/I_L [31]	3 ≤ h < 11	11 ≤ h < 17	17 ≤ h < 23	23 ≤ h < 35	35 ≤ h ≤ 50	THD_I
<25	1	0.5	0.38	0.15	0.1	1.5
<25<50	2	1	0.75	0.3	0.15	2.5
≥50	3	1.5	1.15	0.45	0.22	3.75
Maximum harmonic current distortion in percent of I_L [32]						

Table 14: Harmonic current limits for systems with nominal voltage greater than 110 kV.

iii) Harmonic voltage distortion

Harmonic emissions of An HVDC converter station must be such that the maximum level of **total harmonic distortion** (THDv) of the voltage (calculated up to the 50th harmonic) at the **connection point**, also considering the contribution from the new system itself, does not exceed the following values:

- THDv ≤ 2.5% for **grids** with **nominal voltage** lower than 220 kV;
- THDv ≤ 1.5% for **grids** with **nominal voltage** greater than or equal to 220 kV.

During evaluation of emissions limits of an **HVDC System**, the following alternatives are possible:

- emissions of the **HVDC system** in terms of current distortion are compliant with the above limits and such that the voltage distortion limits are not exceeded. In this case the **HVDC system** may be connected without further measures;
- emissions of the **HVDC system** in terms of current distortion exceed the above limits or are such that the voltage distortion limits are exceeded. In this case **connection** is conditional on further compensation such as to return within the planning limits.

iv) Flicker

Regarding the flicker effect, the values adopted for **grid** planning of the **short-term flicker severity ratio (P_{st})** and the **long-term flicker severity ratio (P_{lt})** are kept within the following thresholds:

Voltage level (kV)	P_{st}	P_{lt}
220 – 380	0.70	0.50
132 – 150	0.85	0.62

v) Rapid Voltage Change

Furthermore, rapid voltage changes induced by variations in **power** exchanged with the **grid** must not exceed the thresholds indicated in the table below (IEC/TR 61000-3-7):

Number of changes n	$\Delta U/U_N$ %	
	MV	HV/EHV
n ≤ 4 per day	5-6	3-5
n ≤ 2 per hour and > 4 per day	4	3
2 < n ≤ 10 per hour	3	2,5

1C.7.6.7 Power system stabilizers

An **HVDC system** must be capable of contributing to dampening of power oscillations in AC **grids** to which it is connected. The detailed specifications of PSS systems and relative calibration parameters shall be agreed during the **connection** phase and indicated in the **Operating Regulations**.

1C.7.6.8 Resilience of the HVDC system

HVDC systems must be capable of identifying stable operating points with minimal changes in the flow of **active power** and voltage level, during and after any scheduled or unscheduled changes to the **HVDC system** or the AC **grid** to which it is connected. Detailed information are provided by the **Operator** during the **connection application** phase on the basis of **HVDC system** and **Connection Point** data.

An example list of minimum conditions under which the **stability** of the **HVDC system** must be verified is provided below:

- opening and closing of **grid** elements bordering the connection;
- energisation and tripping of filters;
- energisation of transformers in proximity of the **station** or of another **pole** of the same connection;
- change in overvoltage and undervoltage due to **faults**;
- loss of **grid** portions;
- longitudinal **grid faults**.

1C.7.7 Additional requirements for remote-end HVDC converter stations

The remote-end converter station[34] of an **HVDC system** must be designed so as to guarantee, at the HVDC interface point[35], the frequency and voltage ranges and durations indicated in Table 15 and Table 16, respectively.

If, following agreement with the **Operator**, a nominal frequency other than 50 Hz is adopted or a variable project frequency or a reference voltage other than that indicated in the table, the **Operator** will agree with the **Owner**,

[34] The “remote end” refers to the converter station of an **HVDC system** connected to an AC **grid** where the AC power park module is present.

[35] “HVDC interface point” refers to a point, defined by the **Operator**, at which HVDC equipment is connected to an AC network, at which technical specifications affecting the performance of the equipment can be prescribed.

during the **connection application** phase, all frequency and/or voltage ranges and durations applicable and the relative requirements shall be formalised in the **Operating Regulations**.

Where the build characteristics allow it, the **Owner** the owner of the remote-end converter station must declare any limits of longer operating durations, the use of which will be agreed with the **Operator** during the **connection application** phase and defined in the **Operating Regulations**.

Table 15: Frequency ranges of the converter station

Frequency range (Hz)	**Minimum operating period**
46.5 – 47 Hz	Fraction of second
47 – 47.5 Hz	60 seconds
47.5 – 51.5 Hz	Unlimited
51.5 – 52 Hz	30 minutes

Table 16: Voltage ranges of the converter station

Reference voltage for 1 p.u. at the CP	**Voltage range (p.u.)**	**Minimum operating period**
≤400 kV and >300 kV	0.85 – 0.9	60 minutes
	0.9 – 1.05	Unlimited
	1.05 – 1.15	60 minutes
≥110 kV and ≤ 300 kV	0.85 – 0.9	60 minutes
	0.9 – 1.12	Unlimited
	1.12 – 1.15	60 minutes

The requirements regarding **reactive power** capability of remote-end **HVDC converter stations** shall be agreed with the **Operator** during the **connection application** phase and the relative requirements shall be formalised in the **Operating Regulations**.

1C.7.8 Additional requirements for DC-connected power park modules

A DC-connected wind-power **power park module** must be designed on the basis of the requirements set out in Annex A.17, included under Appendix A of this Chapter, applicable at the interface point of the wind-power facility.

The detailed specification is defined by the **Operator** during the **connection application** phase and on the basis of preliminary design information, particularly regarding reference voltage and frequency at the interface point of the wind-power facility. All relative requirements shall be formalised in the **Operating Regulations**.

In any case, it is hereby specified that the requirements regarding frequency regulation (FSM, LFSM-O and LFSM-U modes, as per Annex A.17) are applicable to frequency (and its measurement) at the **connection point** of the power park module to the **NTG**.

1C.7.9 Plant compliance

For DC-connected power park modules, the same provisions apply as for AC-connected power park modules and indicated in paragraph 1C.5.7.

For **HVDC systems**, the **Owner** must ensure that its system is compliant with the requirements of this Chapter for the entire useful life of the plant.

The **Operator** evaluated compliance of the **HVDC system** with the requirements of this Chapter for the entire useful life of the plant and updates the **HVDC system Owner** on the results of evaluations performed on the basis of:

- Information, documents and data provided to the **Operator** by the **HVDC system Owner** during the **connection** application phase as per Chapter 1A or subsequently;

- Inspections/tests performed by the **Operator** to establish the accuracy of declarations issued by **Owners of HVDC systems**. The methods for execution of these inspections and/or tests shall be agreed between the **Operator** and the **HVDC system Owner** on the basis of standard procedures where present. Compliance testing specifically regards:
  - verification of the frequency **stability** requirements under paragraph 1C.7.3;
  - verification of the voltage **stability** requirements under paragraph 1C.7.4;
  - verification of the emergency management requirements under paragraph 1C.7.5;
- **Monitoring** in real time and during **faults** using information exchange as per paragraph 1C.7.6.4;
- Simulations of performance of **HVDC systems** performed by owners on request of the **Operator** (or directly by the **Operator**) on the basis of the simulation models described in paragraph 1C.7.6.5;

The **Operator** may in any case request that the **HVDC system Owner** perform a series of supplementary or additional simulations where the information provided in relation to the simulations described above is not sufficient to demonstrate compliance with the Technical Rules as per section 1C of this Chapter.

1C.8 FUNCTIONAL SEPARATION OF TRANSMISSION ACTIVITY FROM OTHER ELECTRICAL ACTIVITY

The general principles for management of functional separation points of **transmission activity** from other electrical activity are defined in paragraph 1B.9.

APPENDICES

A REFERENCE DOCUMENTATION

As a supplement to the contents of this Chapter, below are listed the reference documents which constitute the Annexes to this Grid Code:

A.4 "General criteria for protection of grids running at voltage equal to or greater than 110 kV";

A.6 "Criteria of data acquisition for remote control";

A.7 "Monitoring systems of the disruption of electrical grids with voltage equal to or greater than 50 kV";

A.8 "Short-circuit currents and fault clearance times for plants of grids running at voltages equal to or greater than 120 kV";

A.9 "Defence plan of the electricity system";

A.10 "Repowering and restoration plan of the national electricity system";

A.11 "General criteria for calibration of protection devices on grids running at voltage equal to or greater than 110 kV";

A.12 "Calibration criteria for electricity system frequency relays";

A.13 "Criteria for connection to Terna's control system";

A.14 "Participation in voltage regulation";

A.15 “Participation in the regulation of frequency and frequency/power”;

A.16 “Automatic system for regulating voltage (SART) for electricity production plants”;

A.17 “Wind power stations - General conditions for connection to HV grids - Protection, regulation and control systems”;

A.18 “Verification of compliance of generation units with Operator technical requirements”;

A.19 “Prescriptions for verifying performance of production units for restarting the electricity system”;

A.23 “Procedure for selecting resources in the balancing market”;

A.34 “Command System: message format”;

A.52 “Peripheral units of the defence and monitoring system. Functional and communication specifications”;

A.53 “Technical and functional characteristics of the load balancing equipment”;

A.65 “Structural Technical Data”;

A.68 “Photovoltaic power stations - General conditions for connection to HV grids - Protection, regulation and control systems”;

A.69 “Criteria for connection of production plants to Terna defence systems”;

A.72 “Procedure for the reduction of distributed generation under emergency conditions of the national electricity system (RDG)”;

A.73 “Technical specifications for the verification and evaluation of the service of primary frequency regulation”;

A.79 “Plants with electrochemical storage systems - General conditions for connection to the EHV and HV networks - Regulation and control protection systems”