Generic functional requirements and parameter ranges for HVDC building blocks based on existing literature and references

DA.3 Background report

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Shaping power transmission

SuperGrid Institute SAS – 23 Rue Cyprian, CS 50289, 69628 Villeurbanne Cedex – France

+33 4 28 01 23 23 - accueil@supergrid-institute.com - www.supergrid-institute.com

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0. Executive summary

The North Sea Wind Power Hub (NSWPH) consortium is responsible for planning and pre-developing a series of hub-and-spoke projects that will enable large-scale North Sea offshore wind deployment and its integration in the energy system. The hub-and-spoke concept is based on elementary block types used in association to build the distributed hub scenarios. The NSWPH methodology to develop the concept is structured in three phases: pre-feasibility (2020-2021), feasibility (2021-2022) and pre-FEED (2022-2023). The study performed by SuperGrid Institute focuses on the pre-FEED phase and aims to assess from a transmission system operator (TSO) perspective how to derive and specify functional requirements.

The study is divided into two Scopes of Works (SoW). The first, SoW A aims to provide a thorough assessment and to propose typical parameter ranges of functional requirements to be applied for the modular HVDC building blocks based on a review of existing references. In this regard, any shortfalls and gaps of the existing functional requirements that need to be addressed will be identified and studied within SoW B. The second, SoW B focuses on the development of simplistic test benchmarks that are used to define and refine the functional requirements and parameter ranges for HVDC building blocks considering a stepwise increase of complexity of the use cases.

This report summarizes the generic functional requirements and parameter ranges available in existing literature and references. In particular, the CENELEC reports, Part 1: Guidelines and Part 2: Parameter Lists, are considered as the backbone in this assessment. The CENELEC reports describe the requirements in a generic and technology-independent manner and, hence, do not address the project-specific aspects (e.g. integration of offshore wind power parks), nor provide any specific values or typical ranges of parameters. Therefore, the scope of this assessment is primarily given to the requirements relevant to the context of the project under consideration: the innovative hub-and-spoke concept based on the modular elementary blocks of HVDC 2 GW ±525 kV DC bipolar converter station proposed by NSWPH consortium. Each of the identified functional requirements is concisely summarized and complemented by various references (e.g. CIGRE technical brochures, European and national grid codes). Recommendations including the necessary adaptations and the need for further discussions that were identified through the assessment are also summarized. This report is intended to support the descriptions of functional requirements and parameter ranges to be specified in the deliverable “Tendering material for HVDC building blocks for MTDC grids”. A systematic approach has been applied to identify functional requirements and parameter ranges for HVDC building block. For this purpose, four main functional groups have been defined: (i) HVDC system control; (ii) HVDC system protection; (iii) HVDC ancillary services and (iv) HVDC grid operational regimes. A fifth general functional group is also defined to consider HVDC system characteristics. Based on the literature review and considering the focus of the project on the definition of tendering material for the HVDC building blocks, the following functional requirements have been identified to be insufficiently specified in current literature and will be further investigated in SoW B.

→ HVDC system control

- Investigation on the fixed DC voltage control mode parameters.
- Clarification of the implication of the droop gain on the static and dynamic behavior of DC voltage for disturbance management, and proposal of a systematic selection method.
- Active power response in each control mode (setpoint tracking and post-fault recovery).
- Quantitative evaluation of the influence of the DC reactors on voltage stability and post-fault active

power requirements.

- Secondary DC voltage control, demonstration of feasibility and proposal on specifications.

→ HVDC Protection functional group:

- Refinement of active power Temporary Stop duration taking into account AC system frequency stability requirements.
- Definition of converter blocking criteria in terms of overcurrent from a DC system point of view.
- DC over- and undervoltage Fault Ride Through profile.
- Parameter ranges during fault clearing process (i.e. DC reactor requirements, DCCB operating times, fault current suppression times and energy absorption).
- Investigation of DBS operation requirements.

→ HVDC grid operational modes functional group:

- Coordination of DC connection modes, in particular the transition between degraded modes such as: disconnection of a spoke, disconnection of an interconnector (from MTDC to PtP operation), handling of DMR fault/disconnection, transition from bipole to asymmetric monopole and vice versa, transition from open to closed ring grid.
- Analysis of few possible start-up sequences: start-up of the whole HVDC grid, start-up of the grid as individual point-to-points and then connection as an MTDC, start-up of the HVDC grid considering that some of the onshore AC converters are unavailable and that some onshore stations must be energized from the DC side.
- Preliminary definition of functional requirement and parameter ranges for the main switching station switchgears

→ DC ancillary service functional group:

- Analysis of functional requirement and parameter ranges related to energization of DC subsystem: cable energization by means of a pre-insertion resistor and MMC energization from a controlled DC grid by means of a pre-insertion resistor.
- Energy balance by means of DBS (addressed within protection functional group studies)

1. Introduction

The Paris Agreement defined a goal of net zero greenhouse gas emissions by 2050. Offshore wind energy is one of the main renewable energy sources to achieve this goal, as reflected in the 2050 capacity target of 300 GW set by the European Commission (EC). This large-scale offshore wind deployment and its integration in the energy system needs international coordination, long-term policy targets and a robust regulatory framework.

The North Sea Wind Power Hub (NSWPH) consortium was created in 2017 to cope with those challenges. It consists of main actors in the North Sea: Energinet, Gasunie and TenneT. The Project Scoping workstream is responsible for planning and pre-developing a series of hub-and-spoke projects, which are based on the innovation solutions proposed by the NSWPH to ensure a cost-effective and step-by-step deployment. Pre-feasibility studies started in 2019 and the definition of preferred configuration is foreseen for 2023. The project construction is expected to start in 2025 with a provisional commissioning of the first hub-and-spoke which is estimated for 2035.

The NSWPH methodology to develop the concept is structured in three phases: pre-feasibility (2020-2021), feasibility (2021-2022) and pre-FEED (2022-2023). In each step, the range of the considered project configurations shrinks and the level of detail in studies increases. The pre-feasibility phase aimed to perform a screening of 10-20 alternative hub configurations. The Feasibility phase focused on a techno-economic assessment of the best selected configurations, considering the technical feasibility in term of topology and protection.

The main objective of the pre-FEED phase is to assess from a transmission system operator (TSO) perspective how to derive and specify the functional requirements as well as the parameter ranges for radial and meshed multi-terminal HVDC systems and their associated modular HVDC building blocks. The work is intended to be carried out in the sense of preparing a specification for the FEED phase.

2. Objectives

This report summarizes the generic functional requirements and the parameter ranges available in the existing literature and references. In particular, the CENELEC reports, Part 1: Guidelines [1] and Part 2: Parameter Lists [2], are considered as the backbone in this assessment. However, for the sake of generality, the CENELEC reports describe the requirements in a generic- and technology-independent manner and, hence, do not address project-specific aspects (e.g. integration of offshore wind power parks), nor provide any specific values or typical ranges of parameters. Therefore, the scope of this assessment is primarily given to the requirements relevant to the context of the project under consideration: the innovative hub-and-spoke concept to collect offshore wind energy by means of interconnectors and the modular elementary blocks of HVDC 2 GW ±525 kV DC converter station proposed by the NSWPH consortium. Each of the identified functional requirements is concisely summarized and complemented by various references (e.g. CIGRE technical brochures, European and national grid codes). Recommendations including the necessary adaptations and the need for further discussions that were identified through the assessment are also summarized.

This report is intended to support the descriptions of the functional requirements and the parameter ranges to be specified in the deliverable DA.4 “Tendering material for HVDC building blocks for MTDC grids” (Excel file). The relevant discussions and arguments that lead to the specifications of the functional requirements and the parameter ranges in the proposed tendering material are presented in a way that can be identified by a unique identifier (ID) assigned to each functional requirement in the tendering material.

2.1. Building blocks

In the NSWPH methodology, the main components of the MT-HVDC grid system, the so-called modular HVDC building blocks, are defined as follows:

- → Offshore HVDC converters
- → Onshore HVDC converters
- → Offshore DC switching stations

Furthermore, it was agreed to consider the **DC grid control** as an additional building block.

In Deliverable DA.4, the identified functional requirements are arranged according to the abovementioned definition of the building blocks.

2.2. Functional groups

The following four functional groups have been defined.

- → HVDC grid system control
- → HVDC grid protection
- → HVDC grid operational modes
- → Ancillary services

In addition, the generic system characteristics which do not fall into the above four functional groups are categorized as

- → HVDC grid system characteristics

In the present report, the functional requirements are arranged as follows:

Chapter 4: Functional group: HVDC grid system characteristics

Chapter 5: Functional group: HVDC grid system control

Chapter 6: Functional group: HVDC grid protection

Chapter 7: Functional group: HVDC grid operational modes

Chapter 8: Functional group: Ancillary services

2.3. Functional requirement records structure

This section briefly outlines the generic structure of information records for each functional requirement. This applies when deemed appropriate.

- → Title of functional requirement
- → Corresponding CENELEC description

    - Description: c.f. Part 1
    - Relevant parameters: c.f. Part 2
- Corresponding grid code description
- Descriptions in existing literature
    - Existing HVDC project
    - Other literature (e.g. CIGRE TB)
- Testing procedure in existing literature
- Applicability to the building blocks
- Corresponding functional requirement ID in tendering material
- Discussions

3. Acronyms

ACCB: AC Circuit Breaker

DBS: Dynamic Braking System

DCCB: DC Circuit Breaker

DCR: DC Reactor

DMR: Dedicated Metallic Return

FCR: Frequency Containment Reserve

FCS: Fault clearing Strategy

FPGA: Field-Programmable Gate Array

FRR: Frequency Restoration Reserve

FS-FCS: Full-Selective FCS

II: Internal Interconnector

LOI: Loss Of Infeed

MMC: Modular Multilevel Converter

PIR: Pre-Insertion Resistor

PtP: Point to Point

4. Functional group: HVDC system characteristics

4.1. General

The basic characteristics and attributes commonly applied to individual components in HVDC grid systems are mainly described in Section 5 HVDC Grid System Characteristics of the CENELEC report [1].

4.2. DC voltage

In Section 5.4 of the CENELEC report [1], the DC voltage specifications are defined in three parts:

- → Nominal DC system voltage
- → Steady-state DC voltage
- → Temporary DC voltage

Furthermore, it suggests that attention should be drawn to the fact that the terminal-to-neutral and terminal-to-earth voltages can differ depending on the topology and the operating conditions of the DC grid, such as the presence of the dedicated metallic return or the adopted earthing method of the system. Therefore, the abovementioned specifications must state whether the reference is taken at the neutral and/or the ground point.

4.2.1. Nominal DC system voltage

According to IEC 60038, the nominal DC system voltage is defined as a suitable approximate value used to designate or identify the system. The nominal DC system voltage shall be appropriately selected according to the required power transmission capacity as well as various economical and technical aspects.

4.2.1.1. CENELEC description

The relevant description can be found in Section 5.4.2 Nominal DC system voltage in [2] [1].

Table 1 lists the relevant parameters to be specified. The report explicitly mentions that the nominal DC system voltage is defined as the DC voltage between HV pole and earth.

Table 1 Nominal DC system voltage ([2]Table 19 in [2]).

Symbol	**Parameter**	**Characteristic**	**Value**	**Unit**
UDCpole_rat_pos	DC voltage to earth	nominal value of the positive DC pole voltage with respect to earth		kV
UDCpole_rat_neg	DC voltage to earth	nominal value of the negative DC pole voltage with respect to earth		kV

4.2.1.2. Applicability to the building blocks

Applicable to all the building blocks.

4.2.1.3. Corresponding functional requirement ID in tendering material

Functional requirement ID	Functional requirement title
General1	Nominal DC voltage

4.2.1.4. Discussions

For the NSWPH project, the nominal voltage of +/- 525 kV bipolar system configuration with metallic return has already been specified. No further detail is required as the nominal DC voltage is used to designate or identify the system.

4.2.2. Steady-State DC Voltage

In a DC system in no-load condition, all the nodes throughout the grid share the same DC voltage. However, in a loaded condition with a current flow, the voltage at each node differs due to resistive voltage drops in the transmission lines and cables. Current flows from nodes with higher voltage to those with a lower voltage. Thus, the load flow condition and the grid resistance result in a characteristic DC voltage profile [3]. The steady-state DC voltage shall be specified as a range within which all the performance requirements of the system apply without degradation of the performance quality.

4.2.2.1. CENELEC description

The relevant description of steady-state DC voltage can be found in Section 5.4.3 Steady-State DC Voltage. The report states that the steady-state voltage band shall be wide enough to cover all target operating points of the system. It also mentions that it must be specified for the neutral bus, DMR conductors and electrodes.

Table 2 gives the relevant parameters and their definitions in [2] [2].

Table 2 DC voltage range parameters – stead-state ([2]Table 20 in [2]).

Symbol	**Parameter**	**Characteristic**	**Value**	**Unit**
UDCpole_max	DC voltage to earth	upper level of the normal DC pole operating voltage range		kV
UDCpole_min	DC voltage to earth	lower level of the normal DC pole operating voltage range, including reduced DC voltage operating level, if any		kV
UXDCneutral_max	DC voltage to earth	maximum value of the neutral bus or the return path at a station, a station being identified by X = A, B, …Z		kV

4.2.2.2. Grid code

No mention of this functional requirement was found in DE, NL, DK national grid codes or in NC-HVDC.

4.2.2.3. Existing projects and literature

Table 3 provides the relevant parameters found in the literature.

Table 3 The parameters ranges related to steady-state DC voltage available in literature.

Ref	Symbol	Parameter	Value	Unit	Note
CIGRE TB 684 [4]	UDCpole_max/ UDCpole_min	DC voltage to earth	+/- 0.025 ~0.05 around the nominal voltage	p.u.	The operating range, defined as the range between the maximum and minimum continuous operating voltage, is stated as 5 to 10%. Note that the harmonics and voltage ripples are excluded from this range.
TGS report "Active Power Control of Wind Hub" [5]	UDCpole_max/ UDCpole_min	DC voltage to earth	+/- 0.05 around the nominal voltage	p.u.	Project title: North Sea Wind Power Hub - Dynamic Stability Studies Offshore Grid
Best Paths [6]	UDCpole_max/ UDCpole_min	DC voltage to earth	+/- 0.05 around the nominal voltage	p.u.	C.f. Section 5.4.4
PhD Dissertation R. Irnawan [7]	UDCpole_max/ UDCpole_min	DC voltage to earth	+/- 0.03 around the nominal voltage	p.u.	It is stated that the same data was used as for the COBRAcable project.
PROMOTioN D2.4 [8]	UDCpole_min	DC voltage to earth		N/A	In Section 3.1.1, it refers to the relation between the lower level of the normal DC pole operating voltage range and the minimum DC voltage required for normal operation of half-bridge MMC.
From SGI internal resource	UXDCneutral_max	DC voltage to earth	+/- 0.05 of the nominal voltage	p.u.	

4.2.2.4. Testing procedure

In CIGRE TB 563 [9] Section 4.2 Power flow for system adequacy studies, the steady-state under/over-voltages are categorized as performance parameters, subject to study in the pre-specification phase. Steady-state power flow studies using load flow calculation program would be suitable for this type of study.

Table 4 summarizes other approaches in the literature.

Table 4 The testing procedure related to steady-state DC voltage available in literature.

Ref	Section	Description
TGS report "Active Power Control of Wind Hub" [5]		Preliminary evaluation considering only the resistances of the DC cables, the power infeed modeled as an ideal power source, and converter modeled as a voltage source with droop. Detailed validation using PSCAD model.
PhD Dissertation R. Irnawan [7]		A step-by-step analysis using analytical expressions to estimate the operating range of the DC voltages is proposed. However, the proposed approach seems to be limited to applications to radial networks.

4.2.2.5. Applicability to the building blocks

Applicable to all building blocks. For the DC grid controller, this requirement must be taken into account in converter scheduling as well as the executions of certain functionalities, e.g. secondary DC voltage control. See Section 5.6.1 Secondary DC voltage control for more details.

4.2.2.6. Corresponding functional requirement ID in tendering material

Functional requirement ID	Functional requirement title
General2	Steady-state DC voltage
General3	DC volage range

4.2.2.7. Discussions

It is important to note that several different definitions exist for maximum and minimum continuous DC voltage. For example, CIGRE TB 684 [4] additionally mentions ***Maximum continuous voltage including harmonics, ripples, measuring tolerance***, which is deemed to be specifically related to cable design [8].

In PROMOTioN D2.4 Section 3.1.1 [8], the impact factors on the specification of the minimum DC voltage requirement are discussed. The required minimum DC voltage for nominal operation influences the design of the converter, in particular half-bridge MMCs. The relation between the DC pole-to-pole voltage and the AC phase-to-phase rms voltage is often expressed in terms of the so-called modulation index M:

$$M = \frac{\sqrt{2}V_{acLLrms}}{\sqrt{3}\frac{U_{dc}}{2}}$$

When the DC voltage drops and the modulation index exceeds one, the MMC may deviate from the linear operating region and degrade its operational performance, with for example an increase in THD. Note that the above expression changes if third harmonic injection to the phase voltage is adopted.

According to the description in [9], the steady-state voltage range is deemed to be part of the performance parameters to be addressed in the system adequacy studies in the pre-specification phase using a steady-state analysis tool, such as power flow program.

In addition, CIGRE TB 657 [10] lists several aspects to be considered in specifying the steady-state DC voltage range as follows:

- → the extension of the DC Grid
- → the maximum power to be transferred and all foreseeable power flows within the DC Grid
- → possible compensation of the resistive voltage drops by DC/DC converters (for large grids)
- → measuring errors, equipment and control tolerances
- → sufficient margins in order to allow flexibility in the choice of DC voltage set-points
- → minimum steady-state voltage required for operation of active subsystems

According to the clients, the maximum steady-state DC voltage is set to 525 kV. On the other hand, the steady-state voltage range must be specified so that all power flow conditions fall within that range. The voltage drops in transmission lines and cables are caused by current flow and, hence, depend on the power flow condition and the configuration of the system. Therefore, a non-generic study procedure in the pre-specification phase is required.

When specifying this steady-state voltage range, only steady-state conditions matter. So once a steady-state representation of the system is obtained, the voltage at each node of the system can be estimated for a given power flow. In other words, the dynamic component can be neglected. The voltage ranges shall be specified in terms of pole-to-earth voltages. Therefore, it is necessary to consider the effects of the grounding method as well as DMR return conductors. Moreover, the specification of the steady-state voltage range should take into account the expected future evolution of the DC grid.

The minimum DC voltage level shall be set above the theoretical minimum DC voltage required for normal operation of half-bridge MMCs. The theoretical limit should be determined according to the operational AC voltage range stipulated in the relevant grid code as well. In addition, as it has been widely accepted in practice, injection of third harmonics should be considered when determining this theoretical minimum DC voltage.

4.2.3. Temporary DC voltage

4.2.3.1. CENELEC description

The CENELEC report refers to [10] for the specification of temporary DC voltages. The different regimes with indicative amplitudes and time spans are shown in Figure 1. Beyond these profiles the subsystem would be allowed to reduce its operational performance, to block or to disconnect safely from the DC system.

Temporary DC voltages are sub-divided into transient DC voltages, dynamic operation and load flow operation.

For each DC voltage level within the HVDC grid system, including HVDC poles, lines and neutral points as well as return conductors, if any, the following voltage levels shall be defined. These levels should be coordinated throughout the HVDC Grid System. The levels describing the temporary DC pole-to-earth voltage profiles are illustrated in Figure 1.

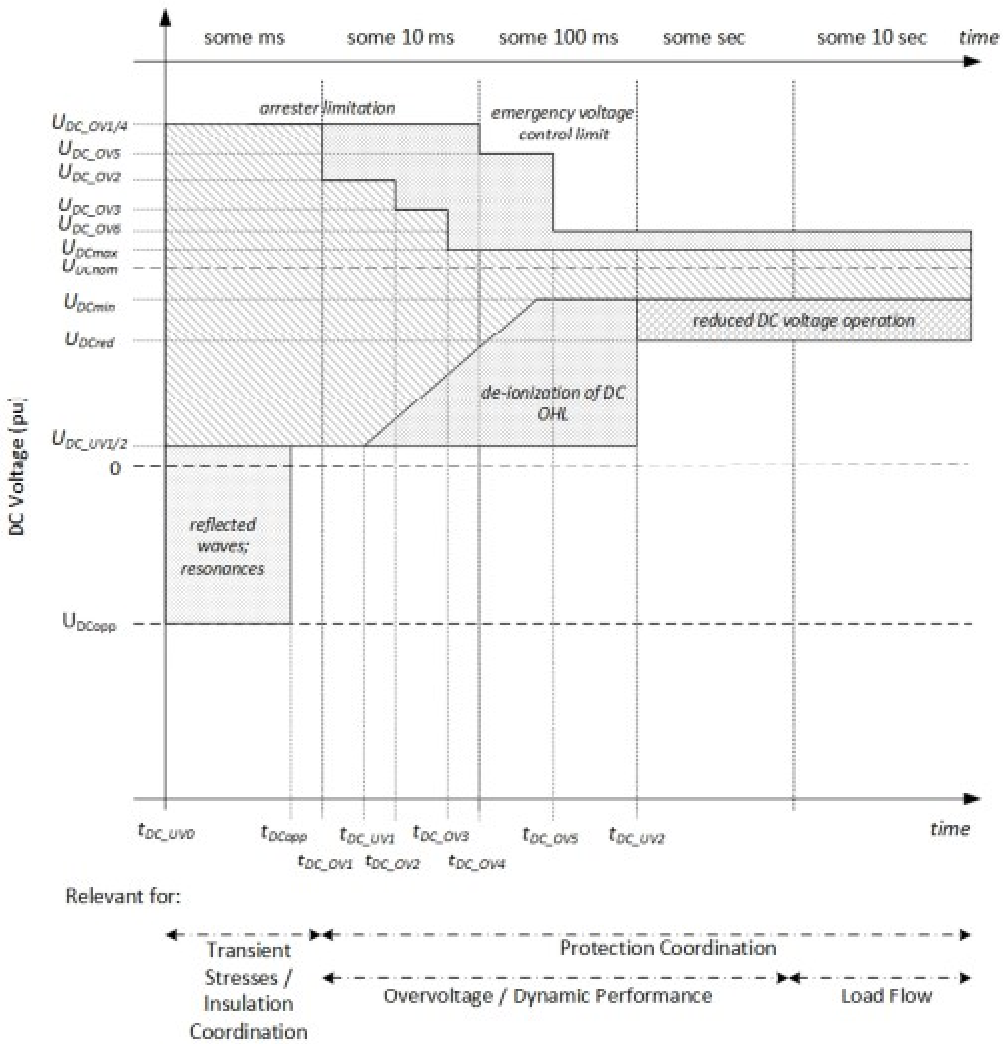


Figure 1 Temporary DC pole-to-ground voltage profiles in DC Grids. The time and voltage limits depend on topology and technology of the grid.

The following parameters should be specified.

Table 5 DC voltage range parameters - temporary undervoltages.

Symbol	Parameter	Characteristic	Value	Unit
UDC_UV1	DC voltage to earth	minimum Retained DC voltage during a DC fault		kV
tDC_UV0	Time	Fault inception time		s
tDC_UV1	Fault duration	Measured from fault inception		s
tDC_UV2	Time	Specifies a point of lower limits of DC voltage recovery		s

Table 6 DC voltage range parameters - temporary voltages.

Symbol	Parameter	Characteristic	Value	Unit
UDC_OV1	DC voltage to earth	Overvoltage level 1		kV
UDC_OV2	DC voltage to earth	Overvoltage level 2		kV
UDC_OV3	DC voltage to earth	Overvoltage level 3		kV
UDC_OV4	DC voltage to earth	Overvoltage level 4		kV
…				
UDCopp	DC voltage to earth	Transient DC voltage in opposite polarity		kV
tDC_OV0	Time	Fault inception time		s
tDC_OV1	Fault duration	UDC_OV1 overvoltage during tDC_OV1 – tDC_OV0		s
tDC_OV2	Time	UDC_OV2 overvoltage during tDC_OV2 – tDC_OV1		s
tDC_OV3	Time	UDC_OV3 overvoltage during tDC_OV3 – tDC_OV2		s
tDC_OV4	Time	UDC_OV4 overvoltage during tDC_OV4 – tDC_OV3		s
…				
tDCopp	Time	time of opposite DC voltage polarity		s

4.2.3.2. Grid code

No mention of this functional requirement was found in DE, NL, DK national grid codes or in NC-HVDC.

4.2.3.3. Existing projects and literature

CENELEC refers to [11] where a similar figure for temporary voltages is presented with indicative values in per unit with reference to the nominal DC system voltage. The following functional requirements are defined:

- → The equipment shall withstand those excursions and fluctuations without damage, and active elements shall operate safely and contribute to a damping of these excursions and fluctuations.
- → Trips of converter stations should be avoided as they may result in even more severe excursions and fluctuations.
- → Converter stations should have the right to disconnect in case of unsafe operation or potential equipment damages.

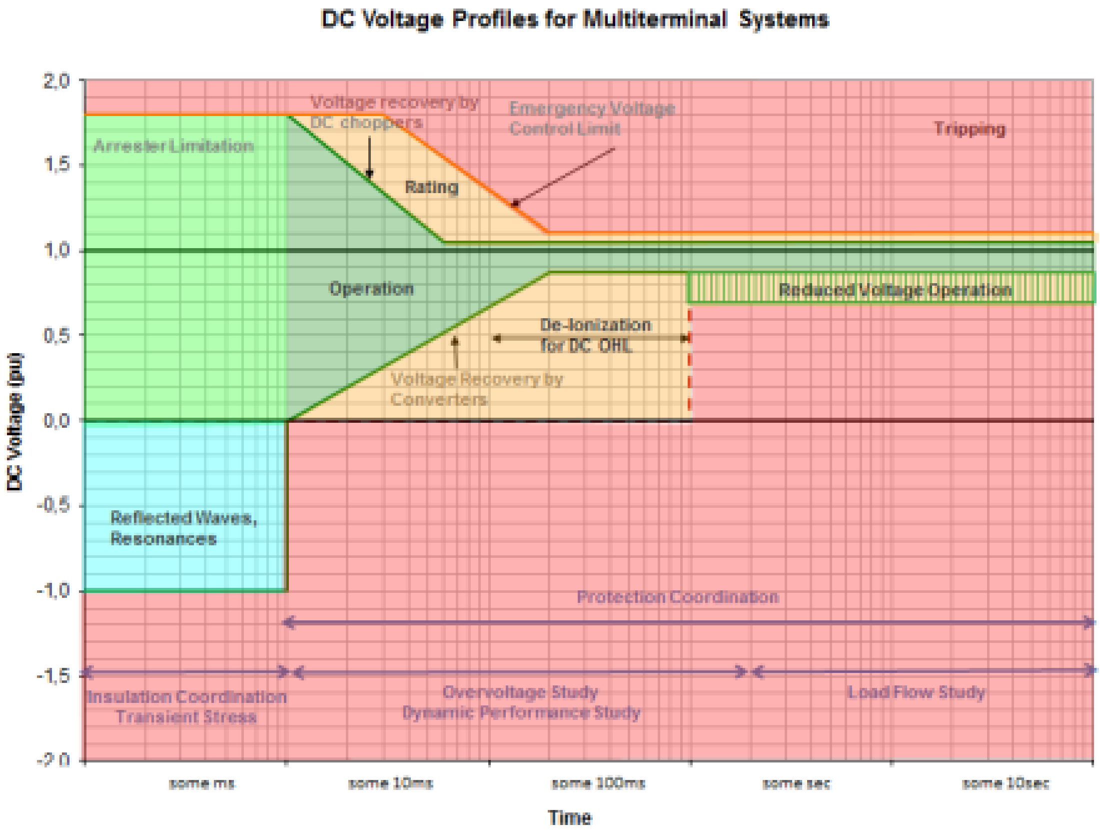


Figure 2 Temporary DC pole-to-ground voltage profiles in MTDC Grids [11].

4.2.3.4. Testing procedure

The testing procedure for insulation-coordination studies are described in CIGRE TB 563 as shown in Table 7.

Table 7 Summary of inputs and outputs for insulation co-ordination study.

Target of the study	**Tool**	**Key inputs**		**Key outputs**
		System data requirements (basic approach + special issues to be addressed)	HVDC model requirements (basic approach + special issues to be addressed)	
Establishment of the appropriate protective levels, clearance and creepage of station equipment	EMT simulation program	The short-circuit levels of AC network, AC network voltage ranges, grounding arrangements of AC substation, DC OHL/cable parameters, insulation coordination practices on AC substation	Preliminary values of converter transformers and DC side equipment from main scheme parameters study	Protective levels of station surge arresters, equipment BIL/BSL and creepages and clearances on the DC side of the converter transformer.

BIL: Basic Insulation Level (also known as Lightning Impulse Withstand Voltage (LIWV))

BSL: Basic Surge Withstand Level (also known as Switching Impulse Withstand Voltage (SIWV))

4.2.3.5. Applicability to the building blocks

Applicable to all building blocks except the DC grid controller. In fact, the sub-components of each building blocks must be designed such that the temporary over- and undervoltage curves are supported without disconnection. This implies that the protection equipment (DC Circuit Breakers, fault current limiting devices, DBS, DC switchgear) but also the control functions of the converter units have a sufficiently good performance to keep the voltage in the specified bandwidth during faults or other disturbances.

4.2.3.6. Corresponding functional requirement ID

Functional requirement ID	Functional requirement title
General3	DC voltage range
General49	Temporary DC system voltage

4.2.3.7. Discussion

Temporary DC voltages indicate the under- and overvoltage limits that need to be withstood by all components in the DC grid. Furthermore, active components must remain connected while the voltage is within the limits. However, active components must also actively support the DC voltage so that disconnection is avoided. This is an essential part of the DC protection design (for fault isolation and restoration) and converter control design for DC voltage restoration. Therefore, the parameters of this section are directly linked to “HVDC grid system protection”, “insulation coordination” and “DC system restoration”.

4.2.4. Neutral bus voltage

The neutral bus voltage specification will have impacts on the design of the neutral bus and any connected equipment. The neutral bus voltage shall be specified considering the topology of the network and the adopted neutral return path option. For the NSWPH project, neutral path using a dedicated metallic return conductor is given as the premise.

4.2.4.1. CENELEC description

The description of neutral bus voltages found in Section 5.4.5 in the report [1] is relatively short, and it is expected that it will be described in detail in a future version of the report.

The report briefly mentions that, for temporary voltage profiles, it is necessary to consider DC switches connected to the neutral, such as MRTS, ERTS, NBS, NBGS, for all relevant DC system configuration and reconfiguration sequences.

The only relevant parameter explicitly mentioned is the maximum neutral bus in Table 2 (Table 20 in [2]).

4.2.4.2. Grid code

No mention of this functional requirement was found in DE, NL, DK national grid codes or in NC-HVDC.

4.2.4.3. Existing projects and literature

No relevant information was found.

4.2.4.4. Testing procedure

The specification and validation procedure related to the neutral bus voltage shall be performed in conjunction with the insulation coordination.

4.2.4.5. Applicability to the building blocks

Applicable to all building blocks in the HVDC grid, except for the DC grid controller.

4.2.4.6. Corresponding functional requirement ID in tendering material

Functional requirement ID	Functional requirement title
General4	Neutral DC volage range

4.2.4.7. Discussions

In the current version of the CENELEC, only one relevant parameter can be found. In practice, however, it may be necessary to have a more detailed specification design that takes into account the temporary voltage profile (See CIGRE TB 675 General guidelines for HVDC electrode design [12]).

The steady-state voltage of the neutral bus is driven by the current through the return paths, e.g. DMRs. Therefore, the studies shall be incorporated into the non-generic specification procedure of the temporal DC voltage.

On the other hand, the temporary voltage profile requires consideration of all relevant fault scenarios and the transfers between DC connection modes. The design of HVDC equipment requires defining appropriate protection and withstand voltage levels, which need to be coordinated across the grid.

4.3. Insulation coordination

4.3.1.1. CENELEC description

For each DC voltage level within the HVDC Grid System, including HVDC poles, lines and neutral points as well as return conductors, if any, the following insulation levels shall be defined. These levels should be coordinated throughout the HVDC Grid System [2].

Tableau 1 Insulation coordination parameters according to CENELEC.

Symbol	Parameter	Characteristic	Value	Unit
UDC_SIWL	insulation level	switching impulse withstand voltage		kVcrest
UDC_SIres_i1	residual voltage	residual voltage at current i1		kVcrest
UDC_SIres_i2	residual voltage	residual voltage at current i2		kVcrest
UDC_LIWL	insulation level	lightning impulse withstand voltage		kVcrest

4.3.1.2. Grid code

No mention of this functional requirement was found in DE, NL, DK national grid codes or in NC-HVDC.

4.3.1.3. Existing projects and literature

Reference [13] provides specifications on insulation coordination testing for mechanical DC Circuit Breakers related to the Zhangbei Project (535kV) with reference to relevant IEC standards.

The purpose of insulation tests is to verify the insulation withstand capacity of each branch, power supply transformer and insulated support platform. The determination of each test parameter considers the operating conditions, safety factors and atmospheric conditions. At the same time, it also refers to the IEC standards of AC circuit breaker and VSC-HVDC valve. All the test items are listed in Table 8 [13].

Table 8 DCCB insulation test items [13].

<table>
<tr><th>Voltage applied to</th><th>Test items</th><th>Test value</th><th>Test frequency</th><th>Reference standards</th></tr>
<tr><td rowspan="3">DCCB to earth</td><td>DC withstand voltage and partial discharge measurement</td><td>±856kV</td><td></td><td rowspan="9">IEC 60270
IEC 62271-100
IEC 60700
IEC 60060-1:2010
IEC 62501:2014
IEC/TR CISPR 18-2:2010</td></tr>
<tr><td>Lightning impulse</td><td>1425kV</td><td>/</td></tr>
<tr><td>Switching impulse</td><td>920kV</td><td></td></tr>
<tr><td rowspan="2">Between terminals</td><td>DC withstand voltage</td><td></td><td></td></tr>
<tr><td>Switching impulse</td><td></td><td></td></tr>
<tr><td rowspan="2">Main branch and power supply transformer</td><td>Radio interference voltage test</td><td>±588kV</td><td>1MHz</td></tr>
<tr><td>Lightning impulse</td><td></td><td></td></tr>
<tr><td>Transfer branch</td><td>Switching impulse</td><td></td><td></td></tr>
</table>

4.3.1.4. Applicability to the building blocks

Applicable to all building blocks and sub-components.

4.3.1.5. Corresponding functional requirement ID

Functional requirement ID	Functional requirement title
General47	DC voltage insulation coordination

4.4. Short-circuit characteristics

4.4.1.1. CENELEC description

In the CENELEC report, it is stated that the short-circuit current depends on various parameters such as grid configuration, grounding, and discharge of passive elements. However, the standard approximation function proposed (see Figure 3) is a first-order response, which by nature cannot represents such a complex system in an accurate way. The standard approximation function and the related parameters are not directly applicable to MTDC grids because many influencing factors as well as many contributors determine the DC fault current evolution. In fact, adjacent cables and converters contribute to the fault, which makes the fault current evolution too complex to be approximated by a first-order differential equation. No reference that confirms the CENELEC approach could be found in literature, which underlines that this is not directly applicable to evolving MTDC grids. The description of DC fault current will be a fundamental subject in SoW B.

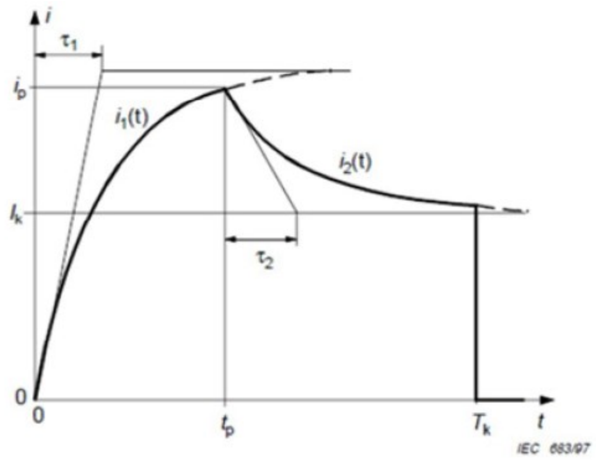


Figure 5 — Standard approximation function according EN 61660-1:1997

Figure 3 Standard approximation function according EN 61660-1:1997 ([2] – Table 5).

Table 9 Short-circuit current parameters ([2] – Table 27).

Symbol	Parameter	Characteristic	Value	Unit
i Xp	instantaneous current	peak current in case of a short-circuit		kA
t Xp	time to peak	related to the peak current		ms
I Xk	steady-state current	after decaying of all oscillations		kA
T Xk	duration	short circuit duration		ms
X1	time constant	rise-time constant		s
X2	time constant	decay-time constant		s

4.4.1.2. Grid code

No mention of this functional requirement was found in DE, NL, DK national grid codes or in NC-HVDC.

4.4.1.3. Existing literature and projects

In literature, there are no generic and/or pre-standardized ways to calculate the DC fault current evolution.

Cigré TB 739: “Protection and local control of HVDC grids” [14] lists a couple of influencing factors (see Section 5.4.3) which is similar to CENELEC.

4.4.1.4. Applicability to the building blocks

Applicable to all building blocks except the master controller. The short-circuit current contribution may vary significantly between different building blocks and dedicated grid configurations. Therefore, short-circuit characteristics must be specified independently for each building block.

4.4.1.5. Corresponding functional requirement ID

Functional requirement ID	Functional requirement title
General48	Short-circuit current design requirements

4.4.1.6. Discussion

The short-circuit current evolution in MTDC grids is a highly transient event with many interactions. Several influencing factors are listed in the CENELEC report (see Section 5.5) and in Cigré TB 739.

Other influencing factors include the DC voltage level, the number of adjacent lines and converters, the converter blocking criterion for onshore and offshore stations, the converter rating and potentially the converter control.

However, when it comes to clearing of DC faults, the protection strategy and in particular the protection equipment but also the fault limiting devices have a direct impact on the time of fault clearing and the peak current to be cleared. This results in a bi-directional dependency between the protection design and the short-circuit characteristics. Only if AC and DC constraints as well as the protection design are well defined, can the question of generic short-circuit characteristics be investigated. This is one of the major tasks in SoW B. The parameters proposed in Table 9 are not directly applicable because the fault current response in MTDC grids cannot be described by a first-order response function. For now, only i_Xp and t_Xp will be used in the tendering material and more appropriate values will be investigated during SoW B.

4.5. Steady-state voltage and current distortions

While voltage and current distortion limits for AC systems have been well-established today, clear definitions and limits are yet to be defined for HVDC grid systems.

4.5.1. Voltage and current distortion limits

4.5.1.1. CENELEC description

Corresponding chapters in the CENELEC report [1]	5.7.1 Voltage and Current Distortion Limits

In [1], an empirical approach to determine THD limits for HVDC systems is recommended.

- → Define a Point of Connection-DC (PoC-DC)
- → Measure or simulate pre-existing voltage distortions at PoC-DC
- → Evaluate the HVDC Grid System impedances as seen from the PoC-DC of the unit to be connected (define and consider different grid conditions/states)
- → Define the headroom of voltage distortions for each frequency (bandwidth) and dedicate it to the installation
- → Assess the magnitude of the pre-existing voltage distortion and additional contribution to the disturbance by connecting a new installation

4.5.1.2. Grid code

In DE grid code [15], the total harmonic distortion (THD) as a result of all voltage harmonics is set to 3% at any connection point (from the context, it is presumed that this refers to PoC-AC) and any time. Any measures for reducing harmonics, such as implementation of filters, are subject to consent of the relevant system operator.

4.5.1.3. Existing projects and literature

Harmonic propagation through the elements of the HVDC grid is only discussed to a rather limited extent in the existing literature. The study in [16] highlights the importance of appropriate cable modeling for the estimation of the potential harmonic propagation the impact on HVDC cable insulation.

4.5.1.4. Applicability to the building blocks

Applicable to onshore and offshore converter units.

4.5.1.5. Discussion

While there are established methods for AC systems, the voltage and current distortion limits of HVDC systems are still unclear. Further investigation is needed for generalization and scalability of the method for MTDC grid application.

4.6. Power loss and restauration

4.6.1.1. CENELEC description

Related discussions can be found in Section 4.4.3.2 Network conditions and power flow requirements and 7.4.1 HVDC Grid system protection zones of [1].

In case of an AC or DC fault, the active and reactive power transmission will be impacted. After a DC fault, the lost power will depend on the type of the employed fault separation concept (temporary stop P, Q, permanent stop P, Q, or continued operation). From the AC system point of view, the maximum loss and the duration of power should be defined to maintain AC and DC system stability.

The maximum loss of power transmitted to the AC system due to a system outage should be specified, with different values depending on the frequency of events. The maximum duration of the power interruption should be specified for both active and reactive power, with respect to some predefined target.

4.6.1.2. Grid code

The maximum instantaneous power loss in CE is a loss of 3 GW.

The maximum permanent loss of infeed considered by different TSO is given in Table 10 [17].

Table 10 Maximum loss of infeed for different TSOs.

TSO	Maximum loss of infeed (MW)
Tennet NL	1000
Tennet DE	1400
Energinet DK1	700
National grid	1800

The maximum instantaneous frequency deviation is $\pm 800\ \mathrm{mHz}$ in CE.

4.6.1.3. Existing projects and literature

The relation between DC grid contingencies and AC stability was studied in [18]. The impact of a pre-defined power profile (see Figure 4) due to HVDC outage is studied, considering the resulting maximum rate of change of frequency (ROCOF) and minimum reached frequency (Nadir). The duration and amplitude of the HVDC loss, as well as the AC system inertia, are varied. A combination of low inertia, large loss and long restoration can lead to unacceptable ROCOF and Nadir.

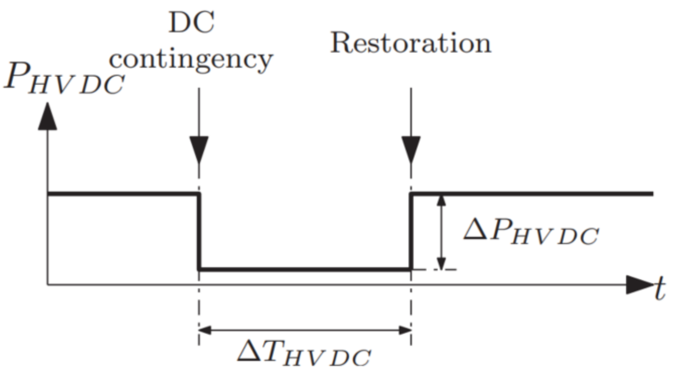


Figure 4 Total active power imbalance profile applied to the AC system.

The author underlines that the actual grid codes focus on permanent loss of infeed, which may not be appropriate for AC/DC grid as fast power restoration can increase the nadir after a contingency. Instead, different power infeed loss levels are proposed with different associated durations, as depicted in Figure 5. Indicative ranges for t_1, and t_2 are less than one cycle and hundreds of ms, respectively.

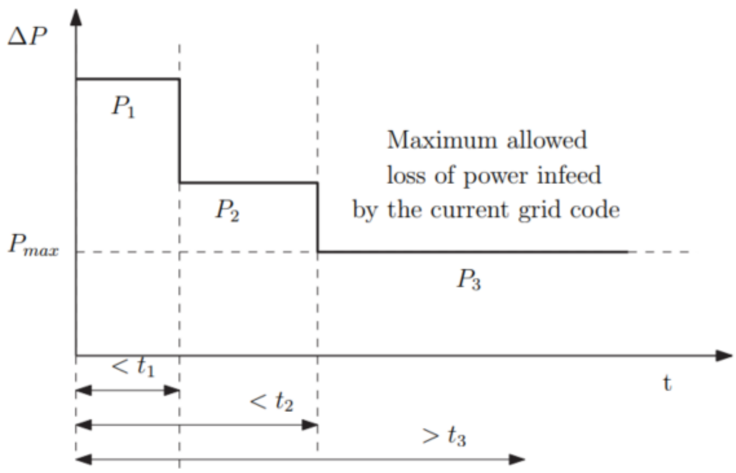


Figure 5 Possible future AC grid code: loss of power infeed and duration.

4.6.1.4. Testing procedure

N/A

4.6.1.5. Applicability to building blocks

The permanent and temporary stop characteristics apply to the HVDC grid as a whole and should be in line with the DC protection design.

4.6.1.6. Corresponding functional requirement ID

Functional requirement title	Functional requirement ID
General53	Time requirements Temporary faults
General60	Maximum loss of active power
General61	Post-fault active power recovery

4.6.1.7. Discussion

N/A

4.7. HVDC grid topology

4.7.1. HVDC circuit topologies

4.7.1.1. CENELEC description

The following attributes apply to the entire HVDC system or to a converter station, as specified in CENELEC Section 5.1.

Table 11 Nomenclature of HVDC circuit topologies (Table 1 in [2]).

Attributes	**Applicable to**	**Available options**	**Corresponding nomenclature**
Number of HV poles	HVDC systems or sub-systems	One pole: monopole Two poles: bipole	
DC Circuit earthing		Effectively earthed Not effectively earthed	“e” “z”
Connection to HVDC poles	Converter station	Connected to HV pole1, Connected to HV pole 2 Connected to both poles.	“1” “2” “B”
Neutral return path		DMR; HV pole used as MR; Earth or sea electrode; No return path	“R” “R” “E” “O”
Station Earthing		Direct earthing Impedance earthing No connection to earth	“E” “Z” “O”

The combination of the 5 attributes lead to the full definition of the HVDC circuit topology and AC/DC converter station characteristics.

4.7.1.2. Existing projects and literature

Different grounding options are investigated for bipolar and symmetrical and asymmetrical monopoles in [19]. The suitability of low and high grounding impedance for the different configurations are compared, in particular in terms of fault current and voltage stresses. High impedance grounding for bipole and asymmetric monopole can lead to a high overvoltage (up to the nominal voltage) on the metallic return after a pole-to-ground fault, which limits the advantage of a low rated metallic return. The possibility to have a bipolar grid with asymmetric monopole extension is mentioned.

4.7.1.3. Applicability to the building blocks

Applicable to all building blocks.

4.7.1.4. Corresponding functional requirement ID in tendering material

Functional requirement title	Functional requirement ID
General29	HVDC grid system installation topology
General59	HVDC system grounding

4.7.1.5. Discussions

N/A

4.8. Communication System

This section presents information regarding communication system for the DC grid control that SuperGrid Institute was able to procure from a subcontractor to prepare Interopera project.

- → There are no technical barriers to build an offshore communication system based on Fiber Optic (FO)
- → Signal processing delay
  - \> 100ms and even 10-20ms can be achieved by means of a reasonably priced hardware (e.g by means of a classic real-time operating system)
  - \> A signal processing with delay < 10ms could still be achievable by means of FPGA
- → The master control could implement a communication system with a signal processing delay of 100ms-1s for tasks requiring a slow response and even 10ms for tasks requiring a fast response
- → Protection relay could implement a communication system with a signal processing delay < 10ms

4.9. AC voltage

4.9.1. AC voltage range

This section deals with the range of AC voltage at the connection point, within which an HVDC converter station shall be capable of staying connected to the network and capable of operating at the HVDC system maximum current.

4.9.1.1. CENELEC description

Section 8.4.3.1 : AC Voltages

The AC/DC converter station shall meet the requirements of the corresponding grid code valid for the AC grid regarding normal steady-state AC operating voltage range as well as temporary and transient voltages.

Table 12 Voltage range capability parameters (Table 22 in [2]).

Symbol	Parameter	Characteristic	Value	Unit
U_{XACmax_ss}		maximum steady-state voltage at each station defined at the PoCAC, a station being identified by X = A, B, …Z		kV
U_{XACmin_ss}		minimum steady-state voltage at each station defined at the PoCAC, a station being identified by X = A, B, …Z		kV

Section 4.4.3.3 AC Voltage Control Related Services

Table 13 Voltage range capability parameters (Table 12 in [2]).

Symbol	Parameter	Characteristic	Value	Unit
U_{ACrat}	rated AC voltage	rated AC voltage		kVrms
$[U_{\min}; U_{\max}]$	normal AC voltage operating range	normal voltage range for continuous operation		kVrms
$[U_{\mathrm{min\_tmp}}; U_{\mathrm{max\_tmp}}]$	Temporary AC voltage operating range	extended voltage operating range for limited time period		kVrms
$t_{U_{tmp}}$	time for extended voltage operating range	time period for temporary operation defined for each range		s

4.9.1.2. Grid code

The following provides a summary of the relevant information in the current grid codes. The requirements on onshore HVDC converter stations and offshore converter stations are presented separately. For either type of converter stations, the voltage range boundaries given in per unit differs depending on whether the nominal voltage is above or below 300 kV, and whether the continental Europe or the Nordic grid is considered.

Onshore HVDC

Voltage range: $110\ \mathrm{kV} \leq U_n < 300\ \mathrm{kV}$

Continental European grid

Voltage range/kV	EU (continental) [20]	DE [15]	NL [21]	DK (Continental Europe) [22]
Values of Un /kV	N/A	110, 220	110, 150, 220	152, 220
0.85 pu – 1.118 pu	Unlimited	Unlimited	Unlimited	Unlimited
1.118 pu – 1.15 pu	≥ 20 min	20 min	20 min	20 min

Nordic grid

Voltage range/kV	EU (Nordic) [20]	DK (Nordic) [22]
Values of Un /kV	N/A	138, 234
0.90 pu – 1.05 pu	Unlimited	Unlimited
1.05 pu – 1.10 pu	60 min	60 min

Voltage range: $300\ \mathrm{kV} \leq U_n \leq 400\ \mathrm{kV}$

Continental European grid

Voltage range/kV	EU (continental) [20]	DE [15]	NL [21]	DK (Continental Europe) [22]
Values of Un /kV	N/A	380	300, 400	400
0.85 pu – 1.05 pu	Unlimited	Unlimited	Unlimited	Unlimited
1.05 pu – 1.0875 pu	≥ 60 min	60 min	60 min	60 min
1.0875 pu – 1.10 pu	60 min	60 min	60 min	60 min

Nordic grid

Voltage range/kV	EU (Nordic) [20]	DK [22]
Values of Un /kV	N/A	400
0.90 pu – 1.05 pu	Unlimited	Unlimited
1.05 pu – 1.10 pu	≥ 60 min	60 min

Note: The German grid code is given in SI units, not per unit. The nominal network voltage is given as 380 kV, with voltage ranges and requirements based on this value. However, for consistency with the grid codes of other countries, the base voltage of 400 kV was used here for conversion to per-unit values.

Offshore HVDC

Voltage range: $U_n < 110\ \mathrm{kV}$

Voltage range/kV	DE [23]	DK [24]
Values of Un /kV	66	50, 60, etc.
0.85 pu – 0.90 pu	60 minutes	10 s
0.90 pu – 1.10 pu	Unlimited* (1.098, instead of 1.1 for 66 kV)	Unlimited
1.10 pu – 1.15 pu	30 minutes	60 s

Note that for DK, the voltage range for wind power plants are defined without distinguishing onshore from offshore stations. Regardless of the categories defined based on the rated total power, the voltage range for normal operation is uniformly set at ±10%. Above or below this range, the requirements are associated with protection setting and defined differently for each category (See section 6 of [24] for more details).

Voltage range: $110\ \mathrm{kV} \leq U_n < 300\ \mathrm{kV}$

Voltage range/kV	EU (continental) [20]	DE [15]	NL [21]	DK (Continental Europe) [22]
Values of Un /kV	N/A	110, 150 220	110, 150, 220	152, 220
0.85 pu – 0.90 pu	60 min	60 min	Unlimited	Unlimited
0.90 pu – 1.10 pu	Unlimited	Unlimited	Unlimited	Unlimited
1.10 pu – 1.12 pu	Unlimited, unless specified otherwise by the relevant TSO	Unlimited	Unlimited	Unlimited
1.12 pu – 1.15 pu	To be specified by the relevant TSO	30 min	30 min	60 min

Voltage range: $300\ \mathrm{kV} \leq U_n \leq 400\ \mathrm{kV}$

Voltage range/kV	EU (continental) [20]	NL [21]	DK [22]
Values of Un /kV	N/A	300, 400	400
0.85 pu – 0.90 pu	60 minutes	Unlimited	Unlimited
0.90 pu – 1.05 pu	Unlimited	Unlimited	Unlimited
1.05 pu – 1.15 pu	To be specified by the relevant system operator, in coordination with the relevant TSO.	60 min	60 min

4.9.1.3. Existing projects and literature

PROMOTioN: D1.7 [25] provides the same as the EU regulation.

4.9.1.4. Testing procedure

Ref	Section	Description
CIGRE TB 563 [9]	4.2 Power flow for system adequacy studies	The target values set for voltage levels are met and the transmission system is capable of receiving or delivering the power transferred via a HVDC connection throughout all the operating and switching conditions related to normal operation or operation under relevant contingencies and disturbances.
CIGRE TB 832 [26]	3.3 Planning stage – feasibility and specification studies	Determination of AC system equivalent: Preliminary studies can help to understand the size of the AC network that should be considered when performing the studies. Analysis of overvoltages: The overvoltage and insulation coordination studies are usually performed by the converter manufacturer during the design phase.
CIGRE TB 832 [26]	3.4.2 Temporary overvoltage and undervoltage profiles	For the design of the VSC converter, the voltage fluctuations during normal operation and after faults are extremely large. Consequentially, an exact definition of the over- and undervoltage-profile, including the expectations of the HVDC system behavior during such events, is beneficial for the customer as well as the manufacturer
CIGRE TB 832 [26]	3.5 Implementation stage - Final design studies	3.5.1 AC overvoltage study (if applicable) Study objective: Calculation of AC overvoltage in weak or converter dominated networks; The controls and configuration of the existing generators and converters is to be considered

4.9.1.5. Applicability to the building blocks

Applicable to all HVDC converter stations in the MTDC grid.

4.9.1.6. Corresponding functional requirement ID in tendering material

Functional requirement ID	Functional requirement title
General5	AC voltage range

4.9.1.7. Discussions

As shown in the tables, the grid codes of the three countries under consideration (DE, NL and DK) show very few differences in terms of the duration of staying connected within the different AC voltage ranges expressed in per unit.

However, the different values of the nominal voltage between the three countries may raise concerns. In particular, the German grid code specifies all the voltage ranges in kV. For consistency with the grid codes of the other countries and the EU regulation, the base voltages of 110, 220 or 400 kV have to be used here for conversion to per-unit value. Therefore, the countries involved should reach an agreement on the choice of the nominal voltage value, especially for the case where an AC connecting point is the properties of multiple countries (e.g. offshore converter stations) and is thus subject to their grid codes.

4.10. Active and reactive power characteristics

4.10.1. Steady-state active and reactive power capabilities

This section deals with the active and reactive power capabilities of HVDC converter in normal operation, i.e. the active and reactive power that a converter is capable of transferring in steady state. Given the dependency of P and Q on the voltage U, their capabilities are usually given in diagrams where all the three variables are involved.

During low or high voltage operation and during faults for which fault-ride-through capability is required, it must be specified whether active power contribution or reactive power contribution shall have priority, as well as the dynamic voltage control requirements that must be fulfilled. See Sections 5.7.2 and 8.3.3 of the current document for the detailed discussions on the requirements during abnormal conditions.

4.10.1.1. CENELEC description

In Section 4.3, the steady-state active and reactive power capabilities of an AC/DC converter station are described by the maximum and minimum active vs. reactive power exchange capability charts depending on the AC voltage at the PoC-AC (UAC) of each station as shown in Figure 6.

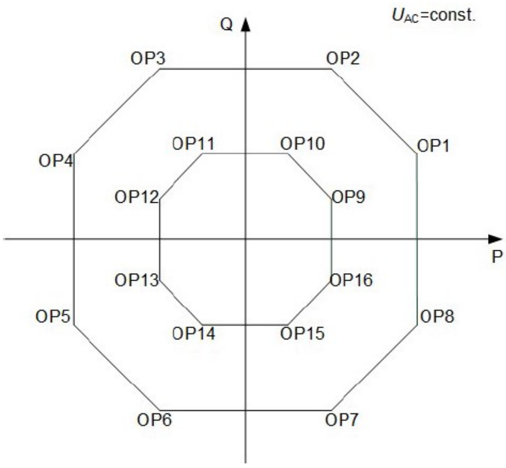


Figure 6 Example of a PQ diagram showing maximum and minimum active vs reactive power exchange capability of an AC/DC converter station for a given AC voltage level (Figure 4 in [1]).

The convention is defined so that power exchange of converter station operating in rectification mode (rectifier) is counted positive.

The following table summarizes the relevant parameters.

Table 14 Active and Reactive Power Characteristics for a Given AC System Voltage Operating Range (part of Table 2 in [2]).

Symbol	Parameter	Characteristic	Value	Unit
$P_{XAC_{\text{max\_ss}}}$	maximum active power	maximum steady-state active power exchange between AC and DC network at each station defined at the PoC-AC, a station being identified by X = A, B, …Z[1]		MW
$P_{XAC_{\text{min\_ss}}}$	minimum active power	minimum steady-state active power exchange between AC and DC network at each station defined at the PoC-AC, a station being identified by X = A, B, …Z[2]		MW
$P_{X\text{loss\_rat}}$	Power losses of station X	power losses function[3]		
$Q_{XAC_{\text{max\_ss}}}(\cdot)$	maximum reactive power	maximum steady-state reactive power exchange capability chart (inductive and capacitive) depending on active power and voltage (P_{XAC}, U_{XAC}) at the PoC-AC of each station, a station being identified by identified by X = A, B, …Z		Mvar
$Q_{XAC_{\text{min\_ss}}}(\cdot)$	minimum reactive power	minimum steady-state reactive power exchange capability chart (inductive and capacitive) depending on active power and voltage (P_{XAC}, U_{XAC}) at the PoC-AC of each station, a station being identified by identified by X = A, B, …Z		Mvar
T_{AMB_min}	Minimum ambient temerature	minimum ambient temperature at the station over which the real and reactive power capability must be met		°C
T_{AMB_max}	Maximum ambient temerature	maximum ambient temperature at the station over which the real and reactive power capability must be met		°C

[1] Instead of $P_{XAC_{\text{max\_ss}}}$, the rated active power $P_{XDC_{\text{max\_ss}}}$ may be defined at the PoC-DC.

[2] Instead of $P_{XAC_{\text{min\_ss}}}$, the rated active power $P_{XDC_{\text{min\_ss}}}$ may be defined at the PoC-DC.

[3] Instead of $P_{X\text{loss\_rat}}$, power losses $P_{X\text{loss\_}OP}$ at various operating points OP may be given.

4.10.1.2. Grid code

EU grid code [20]

The **reactive power capability** at the connection points is specified through a U-Q/Pmax profile that must lie within the boundary as specified in Figure 7. Indicative values of the inner envelope in different synchronous zones are provided in Table 15. The HVDC system must be able to move from one operating point to another in time scales specified by the TSO. Example of limits of U-Q/Pmax profile for different asynchronous zones are provided in Figure 7.

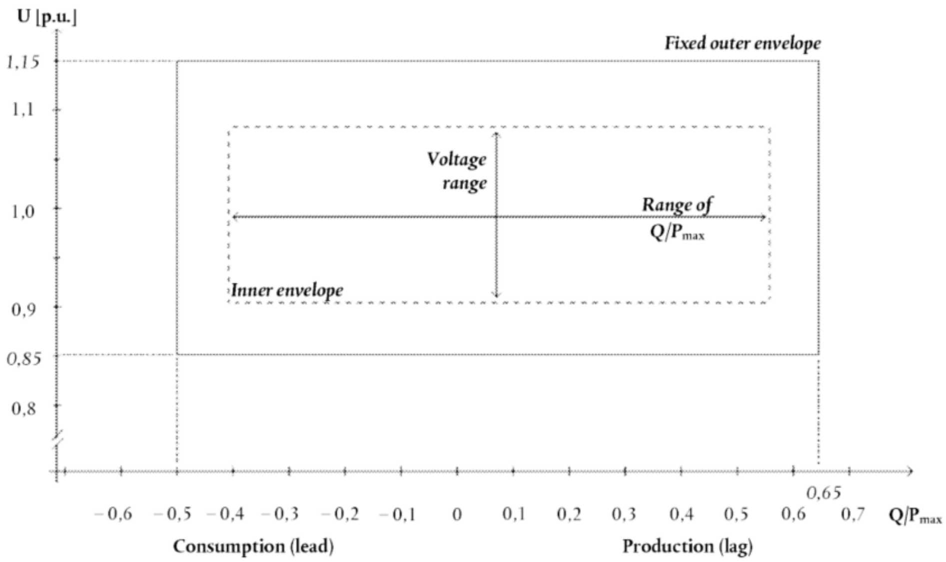


Figure 7 Requirements or U-Q/Pmax profile (Figure 5 in [20]).

Table 15 Parameters for the inner envelope of U-Q/Pmax profile (Table 6 in [20]).

Synchronous Area	Maximum range of Q/Pmax	Maximum range of steady state voltage level in PU
Continental Europe	0.95	0.225
Nordic	0.95	0.15
Great Britain	0.95	0.225
Ireland and Northern Ireland	1.08	0.218
Baltic States	1.0	0.220

Reactive power requirements must also be expressed in P-Q diagram, as presented in Figure 8 for different grid codes [27].

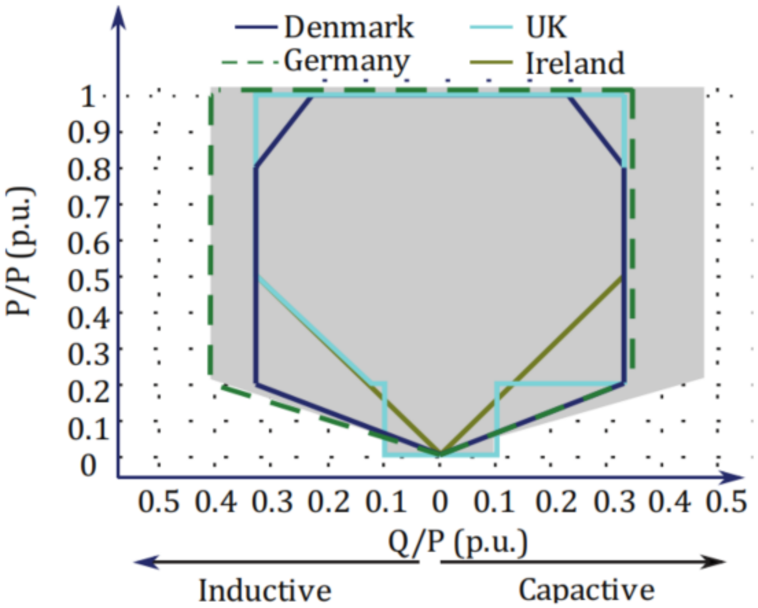
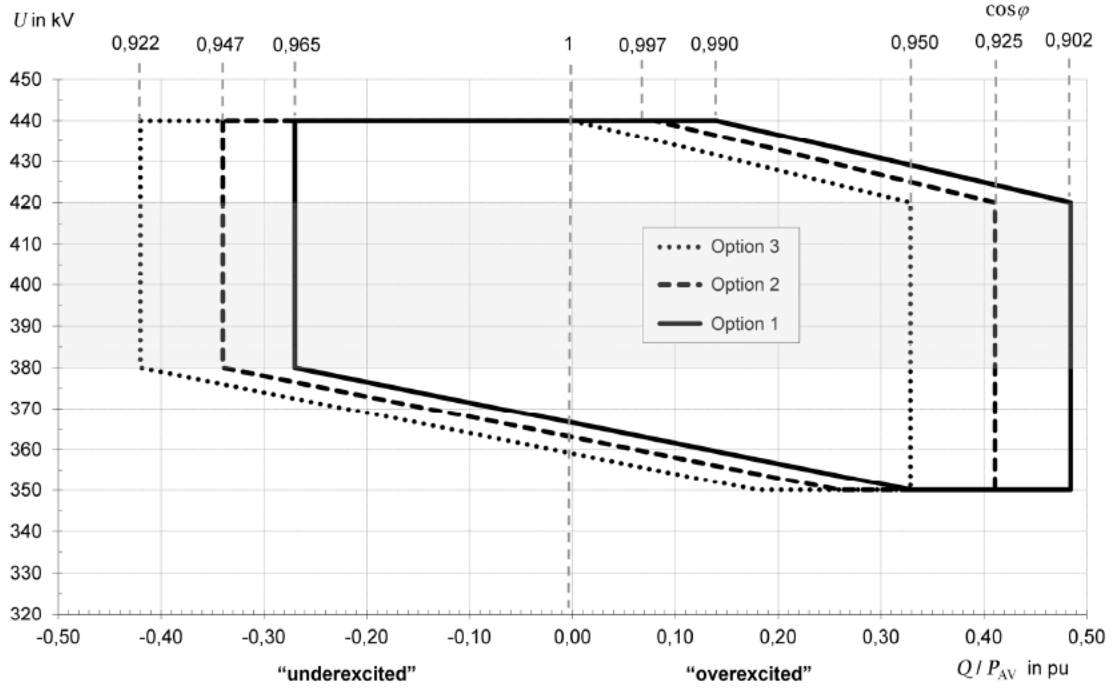


Figure 8 Reactive power requirements of various grid codes (Figure 14 in [27]).

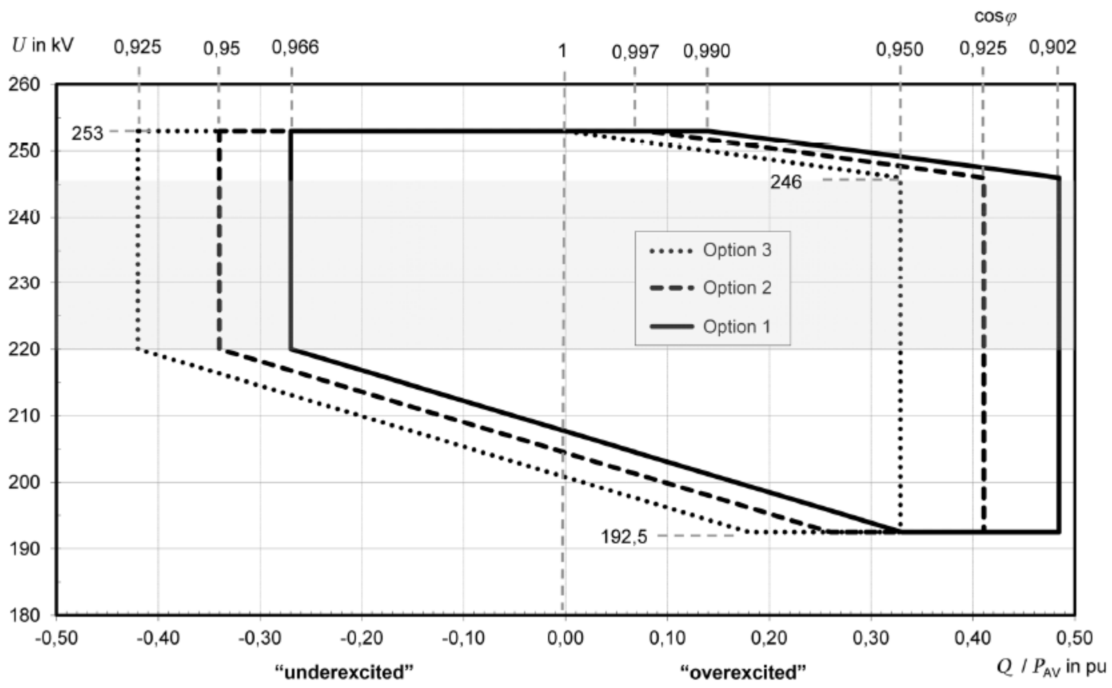
DE grid code [15]

Section 10.1.10 deals with reactive power provision for HVDC systems. The basic requirements regarding the capability of reactive power output as a function of the voltage at the connection point are given for 380 kV, 220 kV and 110 kV.



Option: 380 kV

Figure 9 Option 380 kV of reactive power provision by an HVDC system (part of Figure 7 in [15])



Option: 220 kV

Figure 10 Option 220 kV of reactive power provision by an HVDC system (part of Figure 7 in [15])

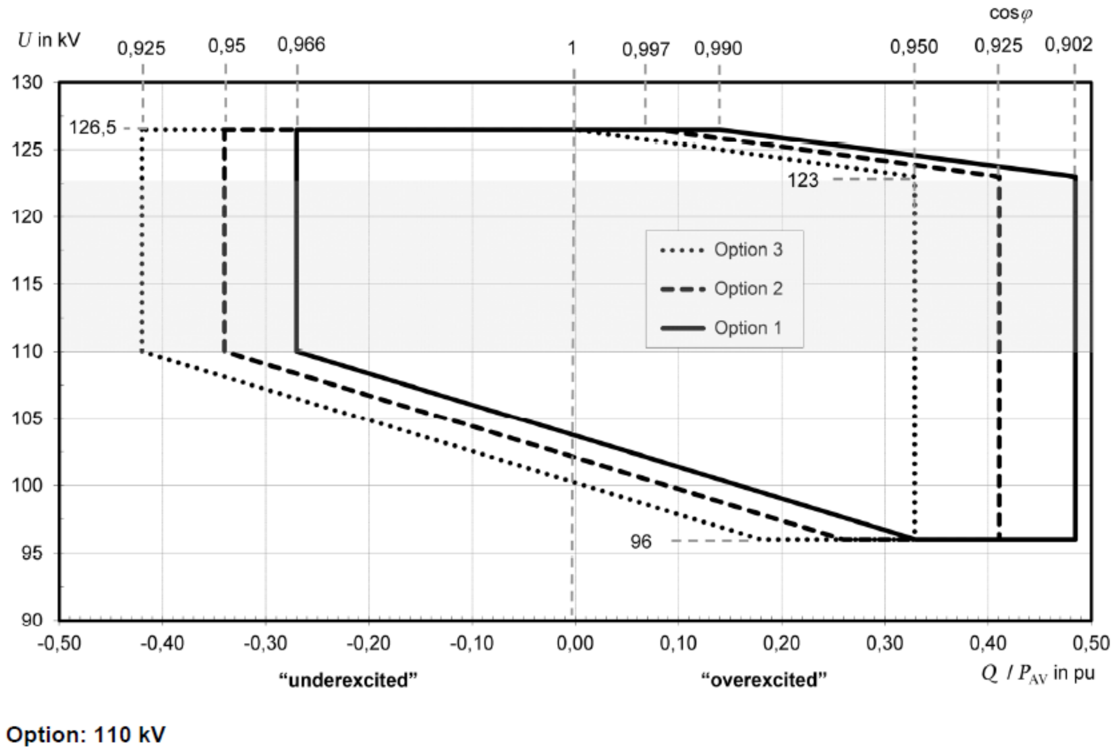


Figure 11 Option 110 kV of reactive power provision by an HVDC system (part of Figure 7 in [15])

On the other hand, Section 10.3.3.2 details the reactive power supply for offshore HVDC converter stations.

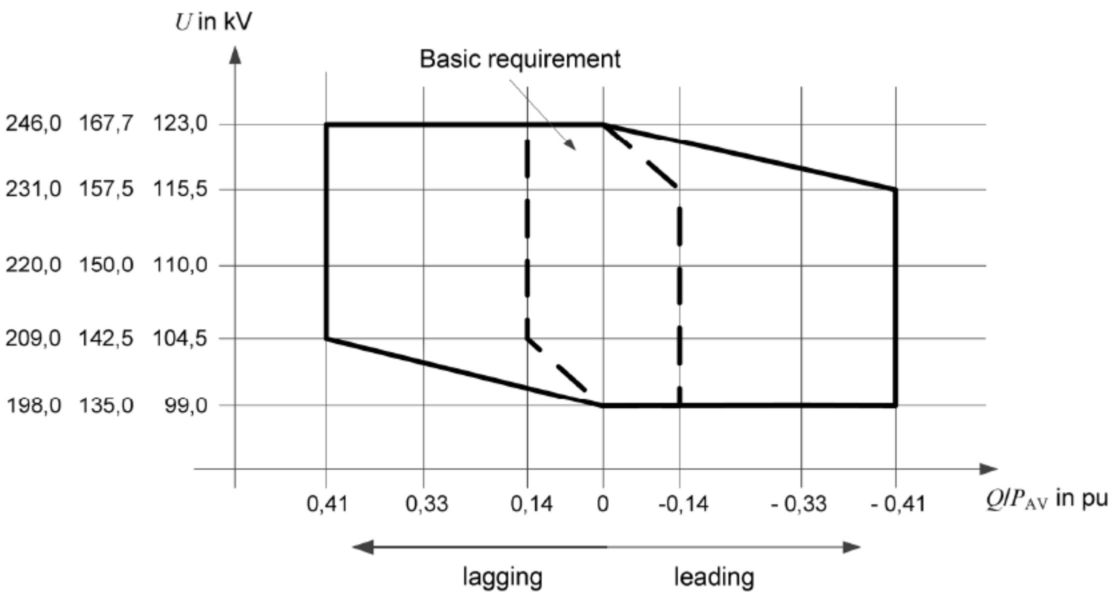


Figure 12 Basic requirements and outer envelope as an additional requirement for defining an U-Q/P_{AV} profile (Figure 14 in [15])

Besides, Section 10.1.11 stipulates the constraints on the AC voltage change resulting from a change in the reactive power. It states that the voltage change caused by a step change of the reactive power shall not exceed $\Delta u = 2\%$ as compared to the pre-change voltage value.

NL grid code

Section 4.2.1 Reactive power capability in [28] mentions Articles 6.9 and 6.10 of the Dutch grid code [21]:

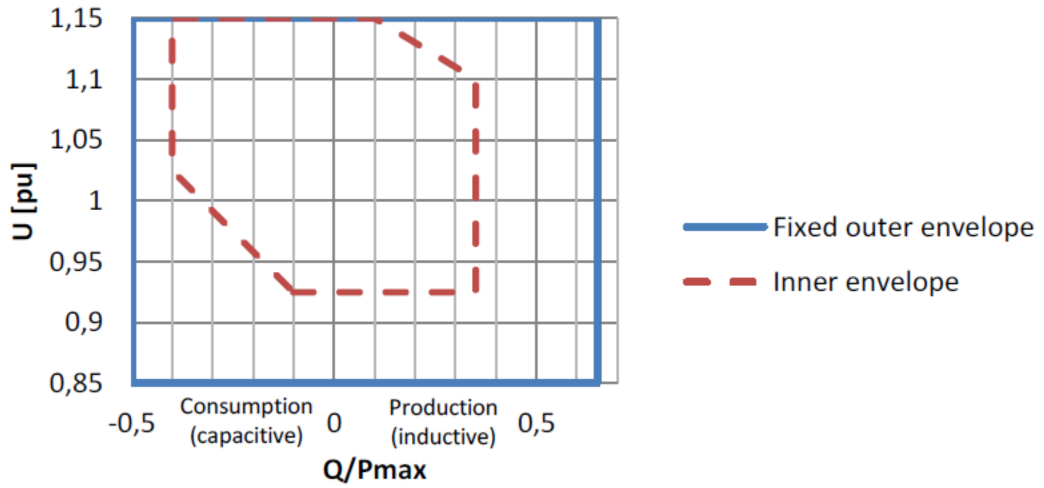


Figure 13 U-Q/Pmax-profile of an HVDC-system (Unom < 300kV) [28].

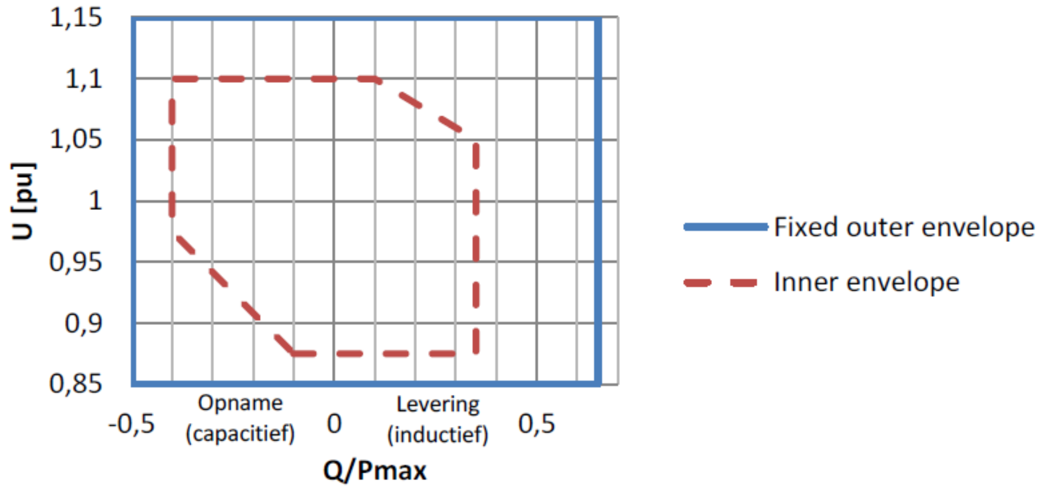


Figure 14 U-Q/Pmax-profile of an HVDC-system (Unom > 300kV) [28]

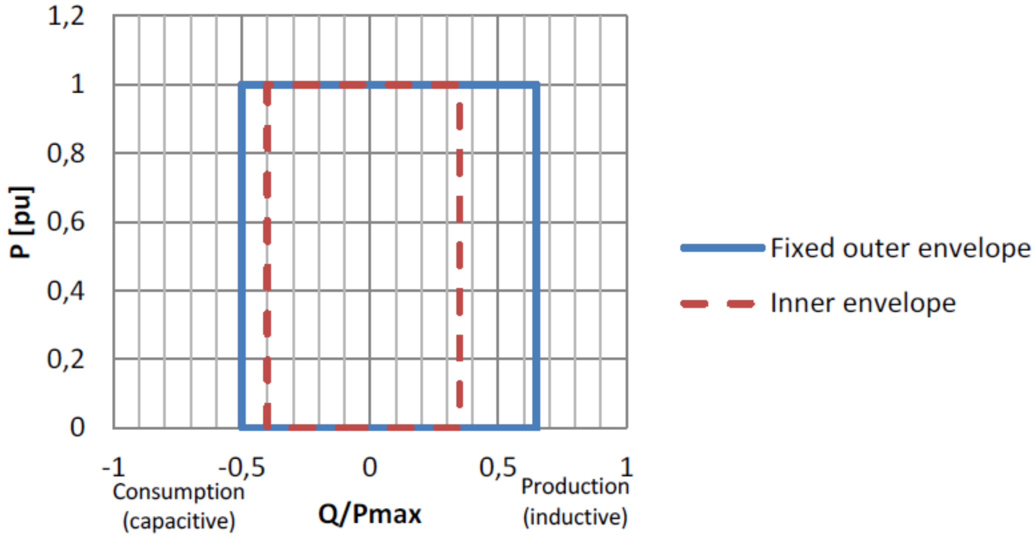


Figure 15 P-Q/Pmax-profile of an HVDC-system [28]

Danish grid code [22]

Annex D of the Danish grid code gives the diagram of the reactive power requirement of HVDC facilities, for two bidding zones, DK1 and DK2.

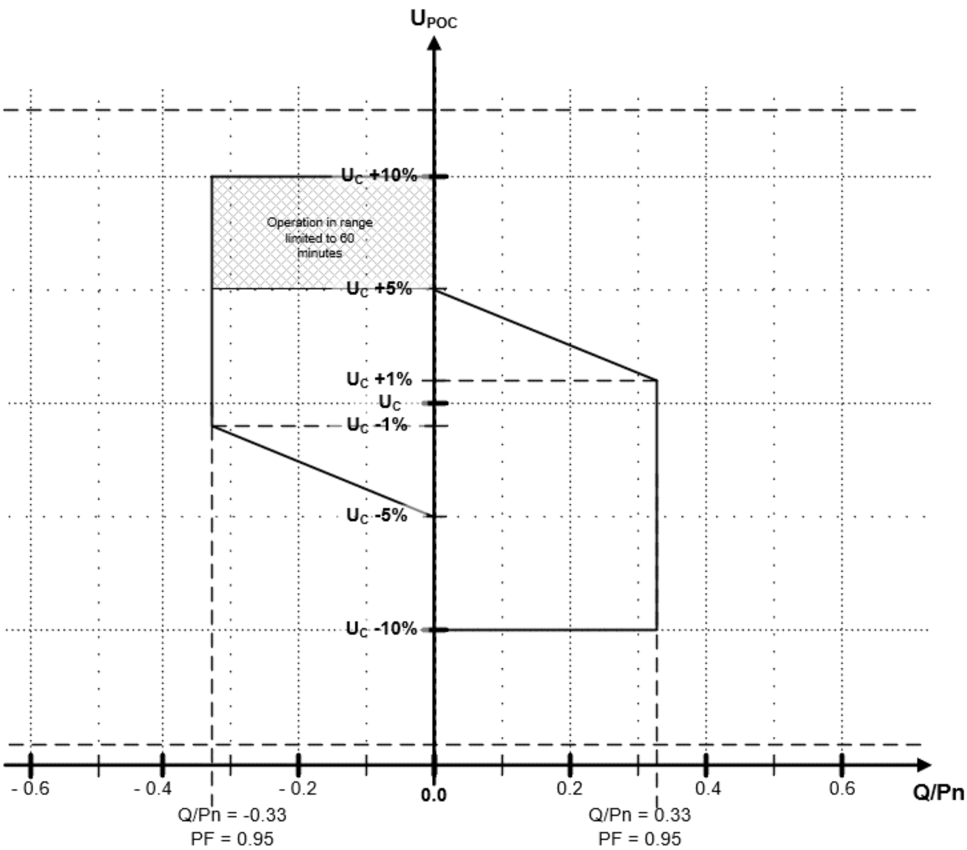


Figure 16 U/Q-Pmax requirements for HVDC facilities, DK1.

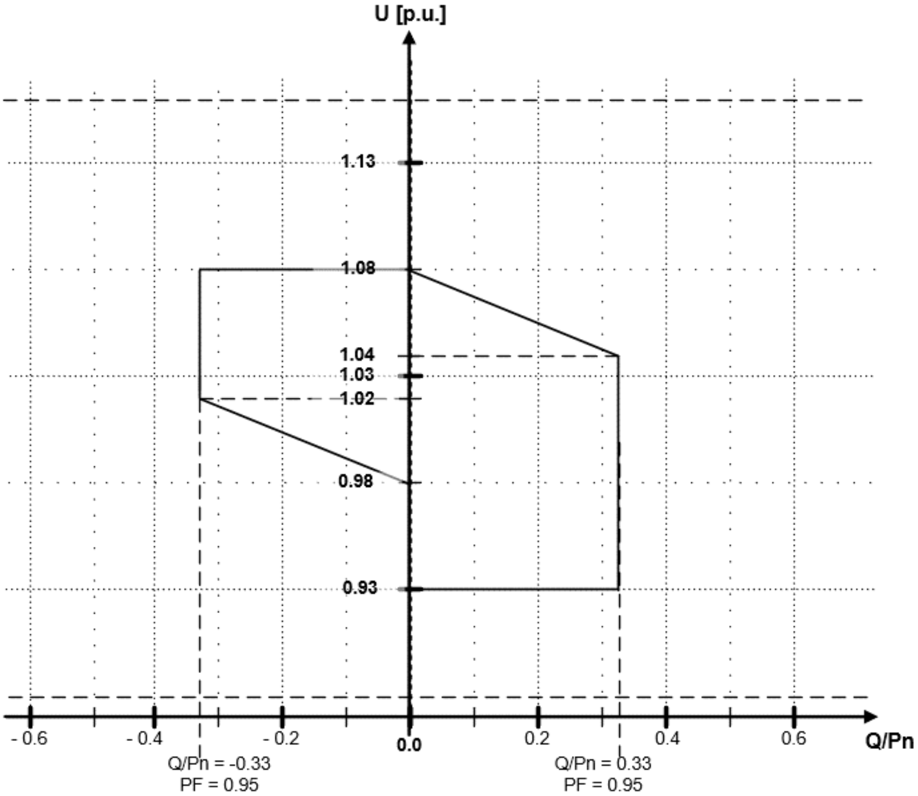


Figure 17 U/Q-Pmax requirements for HVDC facilities, DK2.

4.10.1.3. Existing projects and literature

PROMOTioN D1.7 [25] defines in Section 3.2.2.2 the reactive power capability for onshore AC as summarized in Table 16.

Table 16 Parameters for the inner envelope [20].

Synchronous area	Maximum range of Q/ Pmax	Maximum range of steady – state voltage **level U in pu**
Continental Europe	0.95	0.225
Nordic	0.95	0.15

4.10.1.4. Testing procedure

Ref	Section	Description
BestPaths [6]	5.9 Dynamic performance validation	Generic dynamic performance validation for a step change no larger than 5% of Vn according to the dynamic performance criteria with the parameters defined.
CIGRE TB 563 [9]	3.1 Steady state power flow & 4.2 power flow for system adequacy studies	Maximum reactive power support range to AC system and voltage can be studied using steady-state power flow tools. Such studies are conducted at the planning stage.
CIGRE TB 832 [26]	3.6.1 Dynamic Performance Study/Dynamic Performance Test	Verification of dynamic performance by utilizing EMT type tools.
CIGRE TB 832 [26]	4.2 Setpoint changes and load rejections	Some examples of relevant events to consider in offline EMT tools are listed below: -Fast power setpoint changes (such as run-up and run-back) -For bipolar of parallel links, fast automatic power dispatch in case one system trip -Fast power reversals -Sudden change in AC voltage (trip or connection of AC equipment near the HVDC converter station)

4.10.1.5. Corresponding functional requirement ID in tendering material

Functional requirement ID	Functional requirement title
General6	Steady-state active and reactive power capabilities
General7	Temporary active and reactive power capabilities
General39	Reactive power capability
General28	Priority to active power or reactive power contributions

4.10.1.6. Discussions

The CENELEC report gives an example (not an obligation) of the P-Q diagram for a given AC voltage, while the EU regulations and the national grid codes of DE, NL and DK discuss in terms of Q/Pmax – U diagram. The German and Dutch grid codes both give Q/Pmax – U diagrams for different voltage levels, while the Danish grid code refers to the EU regulation.

4.11. AC Fault Ride Through (FRT) capability

The fault ride through (FRT) is the capability of HVDC converters stations to stay connected in short periods of lower or higher electric network voltage.

4.11.1.1. CENELEC description

Section 4.4.3.3. describes with AC Low-Voltage Ride Through Capability (LVRT) and AC Over-Voltage Ride Through (OVRT) with the figure shown below.

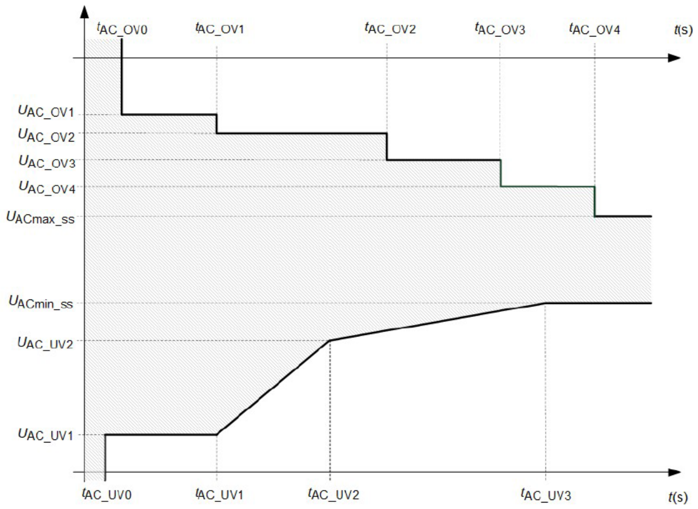


Figure 18 Exemplary generic AC Over- and Under Voltage Ride Through profile of an AC/DC converter station (Figure 5 in [1]).

The tables below given in Section 8.4.3.1.2 summarizes the associated parameters to be specified.

Table 17 AC Under Voltage Ride Through Requirements (Table 8 in [2]).

Symbol	Parameter	Characteristic	Value	Unit
U_{XAC_UVt}	Voltage level	voltage level defining the retained AC under voltage during a fault at the PoC-AC of a station at the time defined by t_{XAC_UVt}, a station being identified by X = A, B, …Z		kVrms
t_{XAC_UVt}	Time	time defining the maximum duration of the voltage level U_{XAC_UVt}		s
n_{XAC_UVt}	Number	number of consecutive undervoltage events		N/A

Table 18 AC Over Voltage Ride Through Requirements (Table 9 in [2]).

Symbol	Parameter	Characteristic	Value	Unit
U_{XAC_OVt}	Voltage level	voltage level defining one supporting point of the AC over voltage at the PoC-AC of a station at the time defined by t_{XAC_OVt}, a station being identified by X = A, B, …Z		kVrms
t_{XAC_OVt}	Time	time defining the maximum duration of the voltage level U_{XAC_OVt}		s
n_{XAC_OVt}	Number	number of consecutive overvoltage events		N/A

4.11.1.2. Grid code

Onshore HVDC

Low-Voltage Ride Through Capability (LVRT)

The German and Dutch grid codes ([15], [21]) are given with respect to Figure 19:

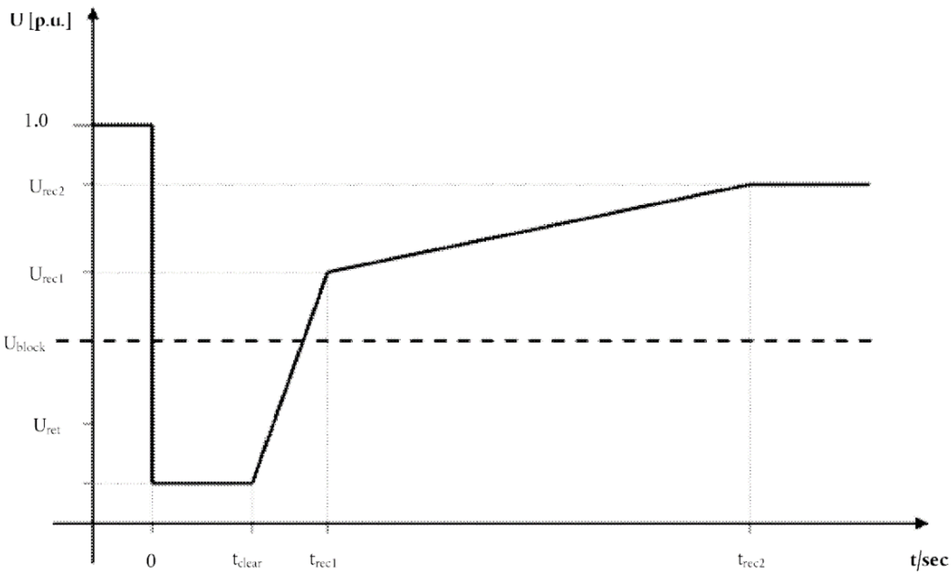


Figure 19 Fault-ride-through profile of an HVDC converter station [20]. The diagram represents the lower limit of a voltage-against-time profile at the connection point, expressed by the ratio of its actual value and its reference 1 pu value in per unit before, during and after a fault. U_{ret} is the retained voltage at the connection point during a fault, t_{clear} is the instant when the fault has been cleared, Urec1 and trec1 specify a point of lower limits of voltage recovery following fault clearance. U_{block} is the blocking voltage at the connection point. The time values referred to are measured from t_{fault}.

Table 19 Parameter values of LVRT profile in the German and Dutch grid codes.

	DE 3-phase fault [15]	DE 2-phase fault [15]	NL [21]
U_{ret} (pu)	0	0	0
U_{rec1} (pu)	0.85	0.75	0.425
U_{rec2} (pu)	N/A	0.85	0.85
t_{clear} (s)	0.15	0.22	0.25
t_{rec1} (s)	3	3	1.625
t_{rec2} (s)	N/A	5	3.0

Note: The German grid code is given in SI units, not per unit. The nominal network voltage is given as 380 kV, with voltage ranges and requirements based on this value. However, for consistency with the grid codes of other countries, the base voltage of 400 kV was used here for conversion to per unit.

The Danish grid code [22] is given with respect to Figure 20.

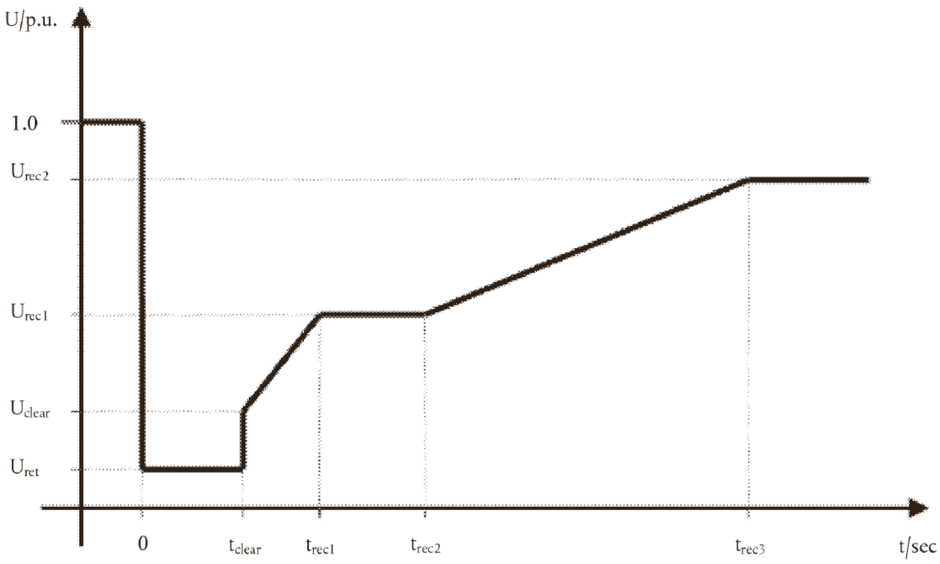


Figure 20 Fault-ride-through profile of a power-generating module [29].

Table 20 Parameter values of LVRT profile in the Danish grid code.

	DK (Continental Europe) [22]	DK (Nordic) [22]
U_{ret} (pu)	0	0
U_{clear} (pu)	0	0
U_{rec1} (pu)	0.8	0.8
U_{rec2} (pu)	0.85	0.9
t_{clear} (s)	0.15	0.15
t_{rec1} (s)	0.15	0.15
t_{rec2} (s)	2	2
t_{rec3} (s)	10	10

The German grid code [15] imposes no disconnection under a single-phase fault, while the Dutch and Danish grid codes [21], [22] require the same FRT capacity for asymmetrical faults as for symmetrical faults.

Over-Voltage Ride Through Capability (OVRT)

Only the German grid code [15] mentions OVRT capability. Figure 21 shows both the LVRT and the OVRT limit for Un=110 kV.

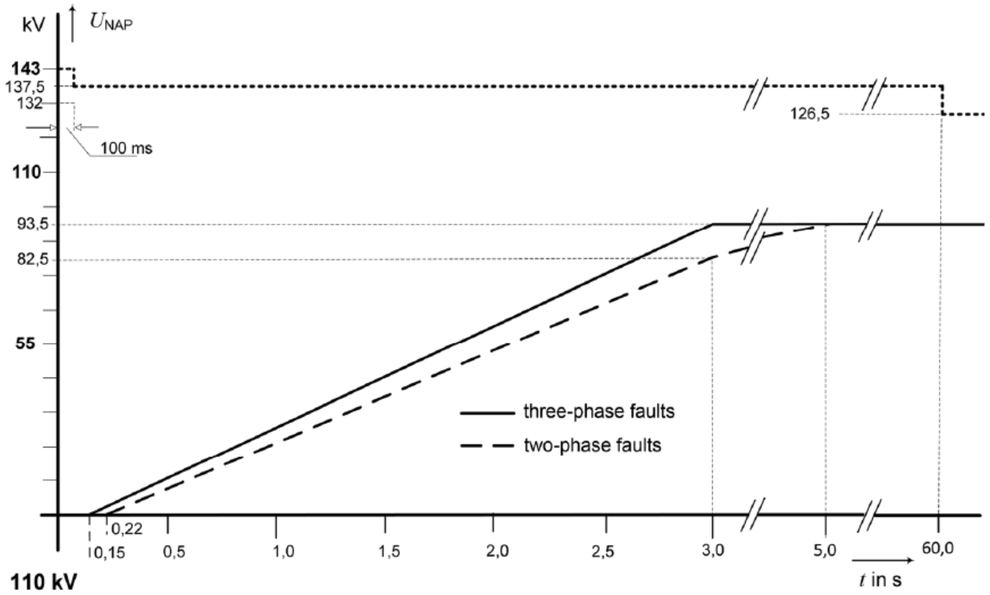


Figure 21 FRT profile in the German grid code [15].

In particular, the OVRT profile for Un=110kV is defined in [15] as:

→ 143 kV (or 1.3 pu) between 0 and 100 ms

→ 137,5 kV (or 1.25 pu) between 100 ms and 60 s

→ 132 kV (or 1.2 pu) after 60 s

The OVRT profiles for Un=220kV and 380kV are defined in [15] with exactly the same voltage levels in pu and step changing instants. But, as before, for Un=380 kV, the base voltage is 400 kV instead of 380 kV. For example, 0.85 pu corresponds to 0.85 * 400 = 340 kV.

Offshore HVDC

The German grid code [15] specifies the LVRT and OVRT capability requirements for offshore HDVC converter stations.

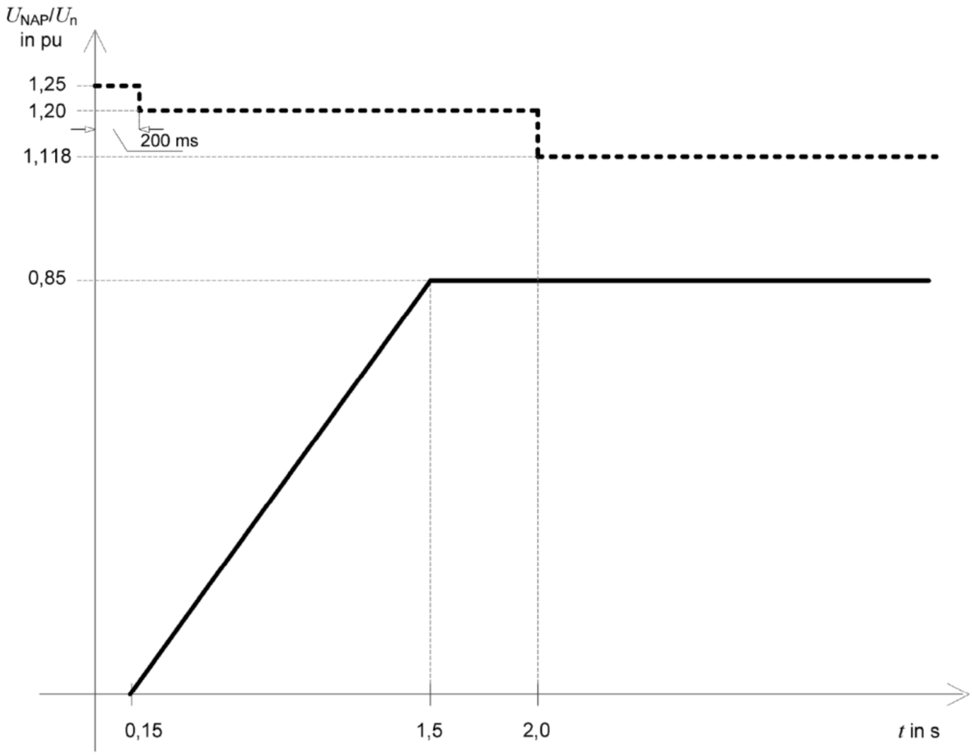


Figure 22 Fault-Ride-Through (FRT) limit curve for the voltage curve at the connection point [15].

The Danish grid code [15] specifies the LVRT and OVRT capability requirements for offshore HDVC converter stations in Article 26.

In the event of short-circuit conditions > 3.5 seconds:

→ The converter must be able to supply 90% of the active power level prior to the fault within 200 ms (t_a) after voltage in the point of connection has been restored to 90% of the level prior to the fault on the rectifier side and within 300 ms (t_b) on the inverter side, without continuous oscillation.

→ Continuous oscillation is defined as maximum 5% oscillation of effective power.

→ Maximum overshoot during restoration of the AC grid due to fault(s) must not exceed 10% of target power level.

In the event of short-circuit conditions < 3.5 seconds, the facility manufacturer must state t_a and t_b.

The Dutch grid code [21] specify the LVRT for a type of DC PPM connected at or above 110 kV:

- → 0 voltage during 0.25s
- → 0.85 pu after 3s

4.11.1.3. Existing projects and literature

PROMOTioN: D1.7 [25], Section 3.2.3.1 Fault ride through capability for onshore AC

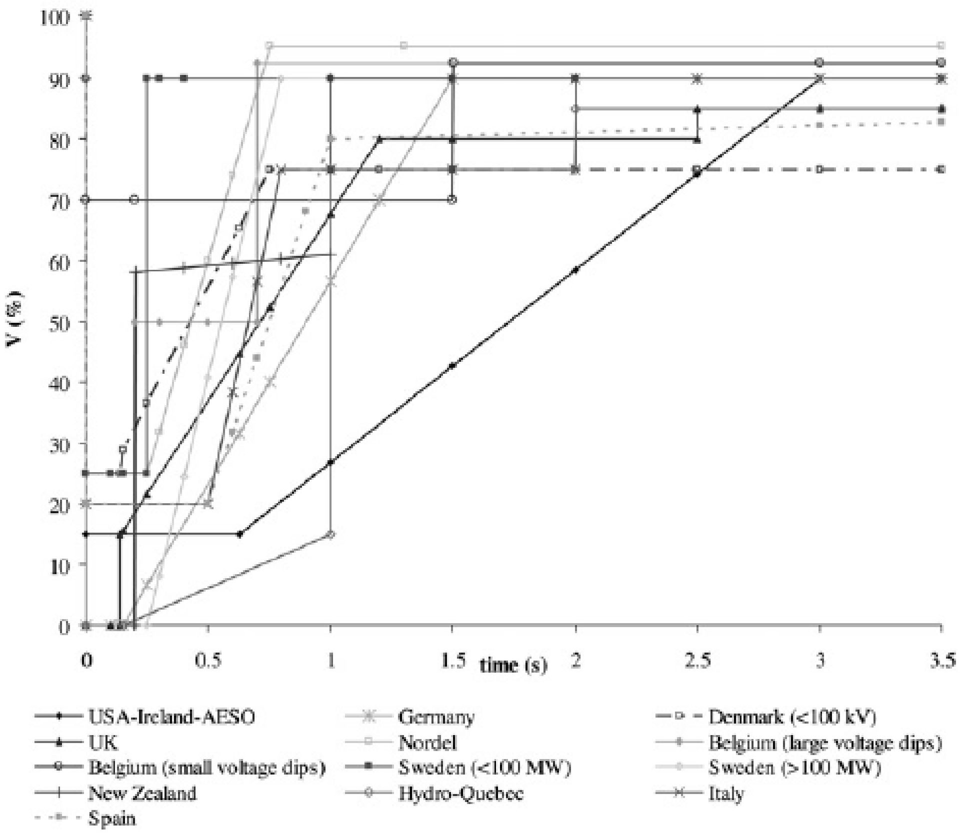


Figure 23 LVRT requirements of various grid codes [30].

Table 21 Characteristics of fault ride through curves of various grid codes [30].

Grid code	Fault duration (ms)	Fault duration (cycles)	Min voltage level (% of Vnom)	Voltage restoration (s)
Germany	150	7.5	0	1.5
Denmark (<100 kV)	140	7	25	0.75
Denmark (>100 kV)	100	5	0	10

PROMOTioN: D1.7 [25], Section 4.1.2.1 AC fault ride through for OWFs

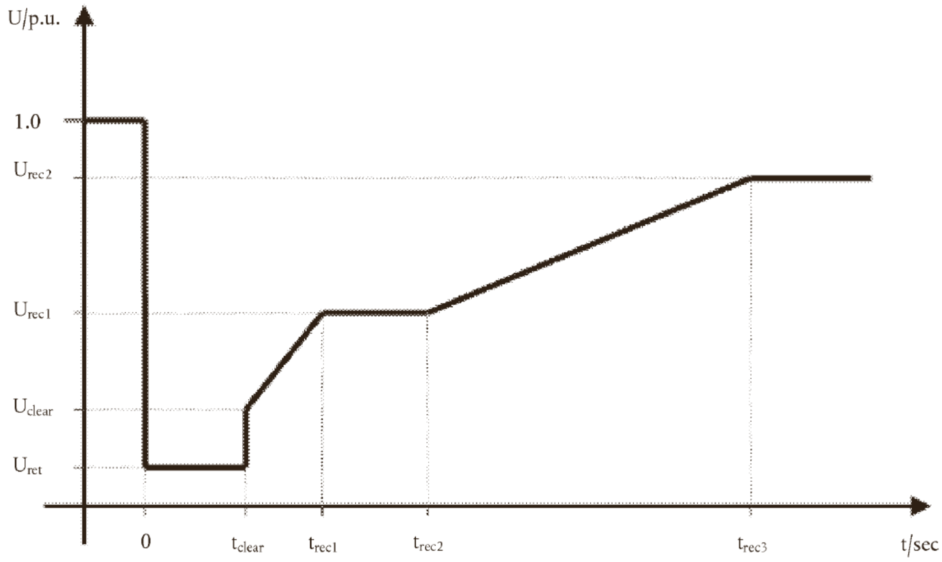


Figure 24 Fault-ride-through profile of a power-generating module [29].

Table 22 Parameters for Figure 24for fault ride through capability of power park modules [29].

Voltage parameters (pu)		Time parameters (seconds)	
U_{ret}	0.05-0.15	t_{clear}	0.14 – 0.15 (or 0.14 – 0.25 if system protection and secure operation so require)
U_{clear}	$U_{ret} - 0.15$	t_{rec1}	t_{clear}
U_{rec1}	U_{clear}	t_{rec2}	t_{rec1}
U_{rec2}	0.85	t_{rec3}	1.5-3.0

PROMOTioN: D1.7 [25], Section 4.2.3.1 AC fault ride through for offshore converters

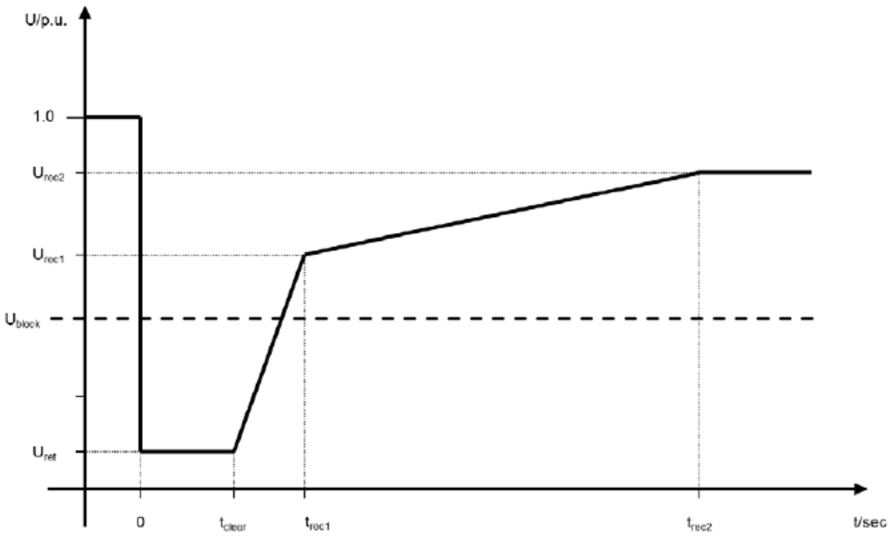


Figure 25 Fault ride through capability curve for an HVDC converter station at the connection point [29].

Table 23 Parameter range for the fault ride through capability for an HVDC converter station at the connection point [29].

Voltage parameters (pu)		Time parameters (seconds)	
U_{ret}	0.00 – 0.30	t_{clear}	0.14 – 0.25
U_{rec1}	0.25 – 0.85	t_{rec1}	1.5 – 2.5
U_{rec2}	0.85 – 0.90	t_{rec2}	$t_{rec1} - 10.0$

4.11.1.4. Testing procedure

Section 4.2.14 of [28] describes in great detail the testing procedure for the Dutch requirements.

4.11.1.5. Applicability to the building blocks

Applicable to all HVDC converters.

4.11.1.6. Corresponding functional requirement ID in the tendering material

Functional requirement ID	Functional requirement title
General8	AC fault ride through capability

4.11.1.7. Discussions

The CENELEC report only gives a general description of the definition of FRT capability.

The German grid code gives FRT profiles for different volage levels, with a distinction between onshore and offshore converters, while the Dutch and Danish grid codes specify the parameter values of the FRT profiles given in the EU regulation.

4.12. AC frequency

4.12.1. AC frequency range

An HVDC system shall be capable of staying connected to the network and remaining operable within the specified frequency range defined together with respective time periods.

4.12.1.1. CENELEC description

Surprisingly, no mention regarding the frequency range in the CENELEC report was found.

4.12.1.2. Grid code

In general, each grid code defines a ranges of stead-state frequency deviations from nominal frequency with corresponding time periods for operation.

Table 24 summarizes the frequency ranges and minimum time periods specified in the respective grid codes.

Table 24 Minimum connection time for specific frequency ranges for HVDC system according to selected example requirements [31].

	DC-connected PPM		HVDC system			
Frequency range (Hz)	EU [32] (Article 39)	DE [15] (c.f. 10.2.1)	EU [32] (Article 11)	DE [15] (c.f. 10.1.1)	DK [22] (c.f. 10.1)	NL [21] (c.f. 6.1)
47.0 – 47.5	20 s	20 s	60 s	60 s	≥60 s	60 s
47.0 – 48.5	90min	90min	90min	90min	≥90min	90min
48.5 – 49.0	90min	90min	90min	90min	≥90min	90min
49.0 – 51.0	unlimited	unlimited	unlimited	unlimited	unlimited	unlimited
51.0 – 51.5	90min	90min	90min	90min	≥90min	90min
51.5 – 52.0	15min	15min	15min	15min	≥60min	15min

4.12.1.3. Testing procedure

Compliance testing should be incorporated into the dynamic performance study using EMT-type models that accurately represent actual C&P system.

The project specific C&P hardware should be then validated by the factory acceptance test.

4.12.1.4. Applicability to the building blocks

Applicable to all HVDC converter stations.

4.12.1.5. Corresponding functional requirement ID in the tendering material

Functional requirement ID	Functional requirement title
General9	Frequency range

4.12.1.6. Discussions

It should be noted that the frequency range specifications involve a certain discretion of the relevant respective TSOs. Furthermore, it is worth noting that the frequency ranges applicable to HVDC systems are, in general, different from those applicable to DC-connected power park modules. Harmonizing the frequency range of offshore AC collection networks would be an ideal solution for eliminating differences in converter station specifications. On the other hand, however, it is conceivable that some minor differences in specifications of the frequency ranges would not pose significant problem.

4.12.2. Rate of Change of Frequency (RoCoF)

The HVDC system shall be capable of staying connected to the network and operable when the rate of change of frequency does not exceed the specified value.

4.12.2.1. CENELEC description

No relevant description is found.

4.12.2.2. Grid code

Table 25 summarizes the minimum RoCoF requirements found in the literature.

Table 25 Minimum RoCoF requirements [31].

Applicable units	EU [32]	DE [15]	NL [21]	DK [22]
HVDC system	± 2.5 Hz/s (Article 12)	± 2.5 Hz/s (c.f. 10.1.2)	N/A	± 2.5 Hz/s (Article 12)
DC-connected power park modules	± 2.0 Hz/s (Article 39)	± 2.0 Hz/s (c.f. 10.2.2)	N/A	± 2.0 Hz/s (Article 39)

NC-HVDC [32] specifies that RoCoF shall be measured at any point in time as an average of the rate of change of frequency for the previous 1 s. This “1s” is understood as the moving average time window for the measurement of the RoCoF.

The ENTSO-E guidance document on RoCoF withstand capability [33] gives an elaborated discussion. The rationale behind the difference of RoCoF withstand capability requirements between HVDC systems and power generation modules is to ensure that HVDC systems will disconnect last to enable other units to contribute to the stability as long as possible. It also mentions that, based on stakeholder survey results, wind turbines can continue the stable operation even if df/dt goes as high as 4 Hz/s whereas it is more challenging for the synchronous power generating modules (especially gas turbines) to continue the stable operation at such a high RoCoF.

4.12.2.3. Testing procedure

Although intended for power generating modules, the ENTSO-E guidance document on RoCoF withstand capability [33] proposes that the relevant TSO define the withstand capability compliance test as a set of frequency-against-time profiles. They shall express lower limits for under-frequency and upper limits for over-frequency of the actual course of the frequency deviation in the network as a function of time before, during and after the frequency event. Such profile should include:

- → frequency nadir/zenith
- → steady-state frequency offset
- → the duration for which the user has to stay connected
- → and consecutive df/dt ramps

4.12.2.4. Applicability to the building blocks

Applicable to all HVDC converter stations.

4.12.2.5. Corresponding functional requirement ID in the tendering material

Functional requirement ID	Functional requirement title
General10	Rate of change of frequency

4.12.2.6. Discussions

In general, the main issues of large RoCoF in thermal power generation modules, such as instability and reduced asset life (electrical and mechanical) due to wear and tear, do not apply to HVDC systems.

RoCoF is indeed an important issue that can have a significant impact on the stability of the entire AC system, but it is the RoCoF of those synchronous machines that is the main constraining factor.

4.13. Conclusions & next steps in SoW B

For the compliance requirements at PoC-AC, there are already sufficiently detailed specifications. On the other hand, there is still insufficient discussion on DC voltage level specifications. In SoW B, the following aspects are further investigated:

- Investigation on specification of steady-state DC voltage range for use case models
- Dynamic and temporarily over- and under-voltage profiles

5. Functional group: HVDC grid system control

5.1. General

In the CENELEC report [1], the basic information regarding the HVDC grid system control can be found in Section 6 HVDC Grid System Control.

5.2. HVDC system control hierarchy

In the CENELEC report, the hierarchical control scheme is introduced in the sections describing the **closed-loop control functions**, i.e. Section 6.1 Closed-Loop Control Functions, 6.2 Control Hierarchy, and 6.3 Propagation of information. It is defined as a closed loop in the sense that each of defined control layer represents a feedback loop, cascaded in such a way that setpoints are sent by an upper layer to a lower layer.

On the other hand, the coordination of operational sequences and connection modes of the installations in the HVDC grid system are collectively referred to as **open-loop control functions**, which are discussed in detail in Chapter 6 "Functional Groups: Operational regimes".

In the CENELEC report, the HVDC grid closed-loop control functions are divided into:

- → Core control functions: functions essential for HVDC grid system operation, based on local information locally available to the controlling devices, i.e. AC/DC converter stations
- → Coordinating control functions: functions that allow for optimizing the HVDC grid system operation regarding various aspects, which often rely on remote information through communication.

Those functions are further structured into different control layers in a hierarchical manner.

Figure 26 depicts the general control hierarchy of the HVDC grid closed-loop functions, each with a typical response time.

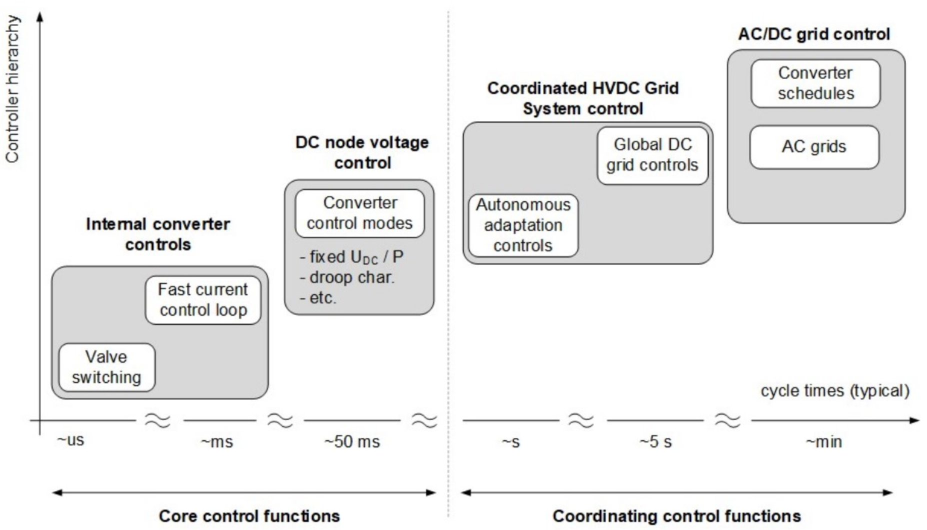


Figure 26 General controller hierarchy with typical time ranges of operation (Figure 13 in [1]).

Four different functional layers are defined:

- → Internal converter control
- → DC node voltage control
- → Coordinated HVDC grid system control
  - > Autonomous adaptation controls
  - > Global DC grid controls
- → AC/DC grid control

Note that autonomous adaptation controls belong to the HVDC stations themselves, although they conceptually belong to the coordinated HVDC grid system controls.

The hierarchy of the control layers as well as their functions are defined according to

- → Time range in which control actions should be done
- → Priority of operation during normal and abnormal operations
- → Available data (e.g. local or global measurements)
- → Actuator (e.g. local, distributed or centralized devices)

It is important to note that the timescale of the dynamics of the functional layers are carefully defined so that they do not overlap with each other, in order to ensure closed-loop control system stability.

The hierarchical control structure presented clearly defines the exchange of information between layers as depicted in Figure 27.

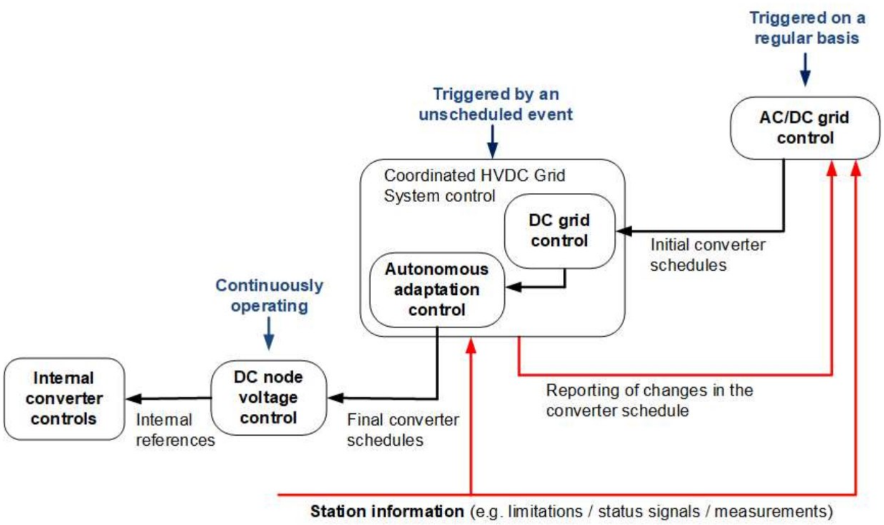


Figure 27 Generation of final converter schedules including converter control modes and its parameters (Figure 15 in [1]).

In the top-down direction, the propagation of the information is organized in terms of "**converter schedules**". These schedules include:

- Control modes (to be precise, converter control mode)
- Additional control-mode parameters (if any)
- Active power reference values (i.e. operating point in terms of active power and DC voltage)

This implies that, in the report, a converter control mode is to be defined as a mode for the DC node voltage control layer. See Section 6.2.3 of the CENELEC report for more detail.

The initial converter schedules are calculated at the top level of the AC/DC grid control hierarchy and periodically dispatched (typically every few minutes). If no contingencies are detected and that the initial converter schedules have been realized by the HVDC grid, these schedules are simply propagated to the DC node voltage controls in the HVDC stations. In case of disturbances or unscheduled events, the coordinated HVDC grid system control layer modifies and adapts the converter schedules to meet the optimization criteria while keeping operational margins. The final converter schedule received by the DC node voltage control of each converter station is then realized by the internal converter controls.

Any modifications made on the initial converter schedules need to be reported back to the upper layer, namely, the DC grid control and the AC/DC grid control layers in a bottom-up manner. This is necessary in order to allow for the AC/DC grid control to take into account the actual situation of the grid as well as for adapting the schedule in the next dispatch cycle. In a similar manner, status, measurements, and limitations from the core control functions are collected at the HVDC station level and propagated bottom-up by means of “station information” data.

Additionally, the CENELEC report recommends the use of standardized communication protocols wherever possible for the information exchange between the layers. For example, standards as EN 61850 and the GOOSE (Generic Object Oriented Substation Events) framework described herein could be the basis for this.

5.2.1. Control interface requirement (Receiving)

5.2.1.1. CENELEC description

Sections 6.1, 6.2, and 6.3 of [1] discuss the interfaces required for **closed-loop control functions** in HVDC grid system control.

The definition of the “converter schedule” is given in Table 26. It should be noted that this table is introduced as the <u>minimum set of information</u> that is required for control functions in the individual control layer. Therefore, additional interface should be added as needed.

Table 26 Definition of "Initial Converter Schedule" (Table 35 in [2]).

Symbol	Parameter	Characteristic	Value	Unit
P_DCref	active power reference	desired active power to be regulated by this DC node (for the remainder of this control cycle). This may either be provided directly by the "AC/DC Grid Control" layer or will be derived by the "DC Grid Control" layer based on the desired active and reactive power orders.	N/A	MW
U_DCref	DC reference voltage	desired DC voltage to be respected by this DC node (for the remainder of this control cycle). This may either be provided directly by the "AC/DC Grid Control" layer or will be derived by the "DC Grid Control" layer based on the desired active and reactive power orders.	N/A	kV
Q_ref	reactive power reference	desired reactive power to be provided by this DC node at its AC terminals (for the remainder of this control cycle).	N/A	Mvar
U_ACref	AC reference voltage	AC voltage to be assumed and regulated by this DC node at its AC terminals (for the remainder of this control cycle).	N/A	kV
no symbol	control Mode	control mode of this DC node (for the remainder of this control cycle). Each mode is specified by an integer number that has to be fixed, consistent and known among all vendors within the HVDC grid system	N/A	integer
no symbol	parameters for CM	additional parameters for the chosen control mode (for the remainder of this control cycle). Depending on the type of control mode there may be zero (e.g. constant DC voltage control) or more parameters required (e.g. configurable droop characteristics).	N/A	various, real-valued
ΔP_ramp	active power ramp rate	speed of implementing the desired active power reference value at the given converter.	N/A	MW/s
ΔQ_ramp	reactive power ramp rate	speed of implementing the desired reactive power reference value at the given converter.	N/A	Mvar/s

Section 6.2.4.2 of [1] describes the role of the autonomous adaptation control. The autonomous adaptation control is a sub-layer to be implemented in each HVDC station. This layer is in charge of detecting alert or emergency states based on local measurements (but does not prohibit more elaborate rules defined by communication when remote measurements are available) and provides fast countermeasures according to a

set of predefined rules. These rules consist of detection criteria, related countermeasures to be triggered, and priority level, respectively defined in a specific format.

Some similarities can be found between the role of autonomous adaptive control and defense plans of existing AC systems. The ENTSO-E report [34] provides the guideline for special protection scheme implementation. A defense plan may consist of both a set of event-based specific protection schemes (e.g. in case of loss of specific line) and response-based actions (e.g. triggered by violation of certain voltage thresholds). Both intends to preserve system integrity rather than the protection of specific equipment by fast predetermined automatic actions. However, unintended operation or malfunction of special protective devices can have a adverse impact on the system, so the design of autonomous adaptive control as well requires appropriate preliminary studies and setting of reliability and dependability levels.

Table 27 summarizes the general parameters of any rules implemented for the autonomous adaptation control layer at a converter station.

Table 27 General parameters for autonomous adaption control rules (Interface List) (Table 31 in [2]).

Symbol	Parameter	Characteristic	Value	Unit
no symbol	operational status	status of the autonomous adaptation controls at each converter	N/A	Boolean
no symbol	rule ID	unique identifier of a rule	N/A	integer
no symbol	priority	priority of a rule, i.e. the active rule with highest priority is the only one being effective	N/A	integer
no symbol	observation ID	unique identifier of the observation (single variable/threshold comparison or set of observation criteria) which corresponds to the rule	N/A	integer
t_hold	holding time	duration for which values defined by the corresponding observation (single value or pattern) have to exceed the defined thresholds in order to activate the respective countermeasure(s)	N/A	s
no symbol	counter-measure ID(s)	one or more unique identifiers for all countermeasures that will be triggered according to this rule	N/A	integer (s)
no symbol	comment	possibility to name and describe the purpose / context of a rule	N/A	string

A rule is triggered based on one or more observation criteria. Table 28 defines the parameters necessary to define observations for rule detection and/or identification.

Table 28 Parameters defining an observation / threshold combination (Interface List) ([2] Table 32).

Symbol	Parameter	Characteristic	Value	Unit
no symbol	observation ID	unique identifier of the corresponding observation	N/A	integer
no symbol	observation variable(s)	list of (at least one) physical quantity to be compared against threshold parameters defined in this observation (e.g. measurement signals)	N/A	integer
no symbol	threshold parameter(s)	threshold parameters (e.g. upper/lower tolerance values) for each variable to be observed. Violation of these thresholds by its corresponding observation will trigger a counter that is compared with the related "holding time" (see Table 31)	N/A	various, real values

Each rule is associated with at least one countermeasure action. Table 29 defines the parameters that characterize the corresponding countermeasure action.

Table 29 Parameters defining countermeasures activated by Autonomous Adaptation Control rules (Interface List) (Table 33 in [2]).

Symbol	Parameter	Characteristic	Value	Unit
no symbol	countermeasure ID	unique identifier of the corresponding countermeasure action	N/A	integer
no symbol	converter ID	ID of the addressed converter station in the HVDC grid system where this rule is to be implemented	N/A	integer
no symbol	parameter	DC node voltage control parameter that will be modified by this rule (i.e. set point value, droop parameter, etc.)	N/A	string
no symbol	modification type	type of modification that is performed on the respective parameter (e.g. replacement, addition of "delta" value, multiplication by a gain etc.)	N/A	various
no symbol	modification value	value of the implemented modification (its effect depends on the type of modification)	N/A	real valued

The table shows that a typical countermeasure action is to change the parameters of each control mode defined in the DC node control layer.

Section 6.2.4.3 of [1] gives a brief description of the DC grid control interfaces, i.e. the signals that should be exchanged with the converter stations.

The following is the output signals of the DC grid control:

- → relevant and accessible nodes in the HVDC grid system:
  - > commands to DC switching devices (open / close)
- → converter stations:
  - > orders for converter control mode

- orders for set points (DC voltage, DC current, DC power)
- restrictions for operational limits (due to external effects)

5.2.1.2. Grid code

Grid code specifies the specifications of the automatic controller that should be installed in each HVDC converter unit to receive instructions from the relevant grid operator. Table 30 summarizes the required signals to be received by the automatic controller. The NL grid code does not contain this information.

Table 30 Summary of specifications of the automatic controller for receiving signals.

Signals	EU [20] (c.f. Article 51)	DE [15] (c.f. 10.4.3)	DK [22] (c.f. Article 51.3)
Operational signals			
Start-up command	✓	✓	✓
Active power setpoints	✓	✓	✓
FSM settings	✓	✓	✓
Reactive power, voltage or similar setpoints;	✓	✓	✓
Reactive power control modes	✓	✓	✓
Power oscillation damping control	✓	✓ (Activation and deactivation)	✓
Synthetic inertia	✓	✓	✓
Alarm signals			
Emergency blocking command	✓	✓	✓
Ramp blocking command	✓	✓*	✓
Active power flow direction	✓	✓*	✓
Fast active power reversal command	✓	✓*	✓
Cancellation of the alarm signal(s)	NA	✓	NA

It also states that "*the quality specifications for each signal to be provided shall be agreed between the connection owner and the relevant system operator*."

DE grid code [15]

The German grid code elaborates in Section 10.4.3 the specifications for alarm signals regarding the ramp blocking command, active power direction, and fast active reversal commands as follows:

- → ramp blocking command with a predefined power flow direction or a predefined tripping range;
- → change of the transmitted power by ΔP;
- → change of the transmitted power to P_{SET};
- → change of the gradient at ramping $\Delta P/\Delta t$, for the aforementioned alarm signals. It shall be possible to receive an adjustable tripping range $P1 < P_{HVDC} < P2$ and at least the power flow direction for the respective alarm signal;
- → blocking the tripping of active power reversal or blocking the tripping with a power flow direction for (holding) times between two/multiple consecutive signals for the fast change of the operating point of the HVDC;
- → tripping of an alarm signal for operating along any predefined active power pattern within the operating range;

5.2.1.3. Applicability to the building blocks

Applicable to all the HVDC converters. The DC grid controller must have appropriate interface accordingly.

5.2.1.4. Corresponding functional requirement ID in the tendering material

Functional requirement ID	Functional requirement title
General15	Control interface requirement (receiving)

5.2.1.5. Discussions

Table 31 summarizes the correspondence between the definitions in CENELEC and the descriptions in the existing grid codes.

Table 31 Summary of the correspondence between the receiving interface specifications in CENELEC and the existing grid codes.

Signals	CENELEC categorization
Operational signals	
Start-up command	Related to Open-loop control
Active power setpoints	Converter schedule (including associated parameters for ancillary services)
FSM settings	
Reactive power, voltage or similar setpoints;	
Reactive power control modes	
Power oscillation damping control	
Synthetic inertia	
Alarm signals	
Emergency blocking command	NA
Ramp blocking command	NA
Active power flow direction	NA
Fast active power reversal command	NA
Cancellation of the alarm signal(s)	NA

According to this observation, the operating signals specified in the existing grid code fit well within the definition of the converter schedule in the CENELEC report, but other types of signals, especially those related to alarm signals, were found to be missing.

The interface needed for the open-loop function and protection of the DC grid needs to be added. Furthermore, since autonomous adaptation control is a supplemental layer proposed for coordination of HVDC grid operation, relevant signal interfaces must be added.

From the above information, the following conclusions can be drawn:

The HVDC converter unit of an HVDC system must be equipped with an automatic controller capable of receiving set points and commands from the DC grid controller, including:

- → operational signals, receiving at least the following:
  - > Converter schedule including the required parameters for ancillary services
  - > Autonomous adaptation control rules
  - > Signals related open-loop control command

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- Signals related to DC grid protection, if any

→ alarm signals, receiving at least the following:

- Emergency blocking command
- Ramp blocking command
- Active power flow direction
- Fast active power reversal command
- Cancellation of the alarm signal(s)

5.2.2. Control interface requirement (Sending)

Similar to the capability of receiving signals, the automatic control device to be installed in each converter station must be capable of sending the specified set of signals to the upper control layer.

5.2.2.1. CENELEC description

Table 32 shows the essential state variables and equipment status signals that must be communicated continuously for proper coordination within the HVDC grid system.

Table 32 System state variables and equipment status signals (Interface List) (Table 30 in [2])

Symbol	Parameter	Characteristic	Value	Unit
no symbol	switches status	status messages (opened/closed) of switches related to all nodes connected to the HVDC Grid System	N/A	Boolean
I_DCmeas	DC line currents	measured DC current through all transmission lines	N/A	kA
U_DCmeas	DC node voltage	measured DC voltage at all electrical nodes	N/A	kV

In addition, the converter station must inform upper control layers of the status, measurements and limitations in bottom-up direction by means of “station information” data. In addition, the final converter schedules, in other words, any modifications made on the converter schedules, need to be reported back to the upper-control layers (DC grid control and AC/DC grid control). This is necessary in order to take the actual operating conditions and status into account the schedule for the next dispatch cycle.

Table 33 provides the definition of the station information.

Table 33 Definition of "Station Information" (Interface List) (Table 36 in [2]).

Symbol	Parameter	Characteristic	Value	Unit
P meas	measured active power	actually measured active power at this converter station. Since this is propagated to the higher-levels of the HVDC system controls, this will typically refer to DC power.	N/A	MW
U DCmeas	measured DC voltage	actually measured DC voltage at this converter station.	N/A	kV
Q meas	measured reactive power	actually measured reactive power at this converter station.	N/A	Mvar
U ACmeas	measured AC voltage	actually measured AC voltage at this converter station.	N/A	kV
no symbol	active control mode	active control mode of this converter station.	N/A	integer
no symbol	parameters for active CM	all required parameters for the currently active control mode of this converter station.	N/A	various, real-valued
P_max / _P min	power limitations	limitations for the active power capability of this converter station. These may be different from the actual rating due to external influences and internal design parameters (e.g. state of cooling system, power electronics etc.) refer to Table 2	N/A	MW
Q_max / _Q min	Reactive power limits	Limits for the reactive power capability of the converter station	N/A	Mvar
U_DCmax_ctrl , U_DCmin	DC voltage profile(s)	tolerable maximum and minimum values for the DC and allowed durations, may be different for each grid node depending on type of connected HVDC line (e.g. submarine cable), has to account for manufacturer's transient over-voltage specifications (refer to Table 21 and Table 22, respectively, for the definition of voltage profiles)	N/A	list of tuples: kV / s
T_s	DC voltage settling time	time required for DC node voltages to settle to a new reference value after sudden changes, typically defined for a precision within x% absolute distance to new reference value	N/A	s
no symbol	Limitation strategy	Priority of power limitation strategy, i.e. if active or reactive power will be limited first (see Table 54)	N/A	integer
no symbol	State of limitation	Indication whether limitation is currently active in the AC/DC converter station. If active, the result of the limitation can be observed by	N/A	Boolean

		comparing the reference values (Table 35) to the max/min values (signalled by this Table 36)		
no symbol	Status information	Indication if autonomous adaptation controls are enabled and/or active.	N/A	Boolean
no symbol	Active autonomous adaptation control rule	ID of the currently active rule (if any) of the autonomous adaptation controls of the AC/DC converter station. The set of rule IDs shall be consistent throughout the HVDC Grid System.	N/A	integer

Section 6.2.4.3 of [1] also briefly describes the required interface of the DC grid control, i.e. the signals that should be sent by the converter stations.

The following is the input signals of the DC grid control:

- relevant and accessible nodes in the HVDC grid system:
  - voltage of DC nodes
  - currents of DC lines
  - status of DC switching devices
- converter stations:
  - operational status
  - active converter control mode
  - active set points (DC voltage, DC current, DC power)
  - limitations / remaining capabilities (active/reactive power)
  - measurements (DC voltage, DC current, DC power)

5.2.2.2. Grid code

The grid code also specifies the signals to be sent by the automatic control unit that should be installed in each HVDC converter unit. Table 34 summarizes the required signaled to be sent by the automatic controller.

Table 34 Summary of specifications of the automatic controller for sending signals.

Signals	EU [20] (c.f. Article 51)	DE [15] (c.f. 10.4.3)	NL [21] (c.f. Article 13.28)	DK [22] (c.f. Article 51.2)
Operational signals				
Start-up signals	✓	✓	✓	✓
AC and DC voltage measurements	✓	✓	✓	✓
AC and DC current measurements	✓	✓	✓	✓
active power and reactive power measurements on the AC side	✓	✓	✓	✓
DC power measurements	✓	✓	✓	✓
HVDC converter unit level operation in a multi-phase type HVDC converter	✓	✓	✓	✓
elements and topology status	✓	✓	✓	✓
FSM, LFSM-O and LFSM-U active power ranges	✓	✓	✓	✓
Alarm signals				
Emergency blocking	✓	✓	✓	✓
Ramp blocking	✓	✓*	✓	✓
Fast active power reversal	✓	✓*	✓	✓
Cancellation of the alarm signal	NA	✓	NA	NA

DE grid code [15]

The German grid code elaborates in Section 10.4.3 the specifications for sending signals for ramp blocking, active power direction, and fast active reversal commands as follows:

- → ramp blocking with a predefined power flow direction or a predefined tripping range;
- → change of the transmitted power by ΔP;
- → change of the transmitted power to P_{SET};
- → change of the gradient at ramping $\Delta P/\Delta t$,
- → adjustable tripping range $P1 < P < P2$ of the respective alarm signal, at least specification of a power flow direction;
- → blocking the tripping of the active power reversion or blocking the tripping of the alarm signal with a freely adjustable power flow direction;
- → tripping of an alarm signal for operating along any predefined active power pattern within the operating range;

It also states that "*the quality specifications for each signal to be provided shall be agreed between the connection owner and the relevant system operator*."

5.2.2.3. Applicability to the building blocks

Applicable to all the HVDC converters. The DC grid controller must have appropriate interface accordingly.

5.2.2.4. Corresponding functional requirement ID in the tendering material

Functional requirement ID	Functional requirement title
General16	Control interface requirement (sending)

5.2.2.5. Discussions

Table 35 summarizes the correspondence between the definitions in CENELEC and the descriptions in the existing grid codes.

Table 35 Summary of the correspondence between the receiving interface specifications in CENELEC and the existing grid codes.

Signals	EU [20] (c.f. Article 51)
Operational signals	
Start-up signals	NA
AC and DC voltage measurements	Station information
AC and DC current measurements	
active power and reactive power measurements on the AC side	
DC power measurements	
HVDC converter unit level operation in a multi-phase type HVDC converter	
elements and topology status	System state variables and equipment status signals
FSM, LFSM-O and LFSM-U active power ranges	NA
Alarm signals	
Emergency blocking	NA
Ramp blocking	NA
Fast active power reversal	NA
Cancellation of the alarm signal	NA

While most of the operational signals are included in the definition of the station information in the CENELEC report, there is no mention of active power range for respective ancillary services, i.e. FSM, LFSM-O and U. Furthermore, similarly to the receiving signal requirements, there is no mention of the specifications related to alarm signals in the CENELEC report.

From the above information, the following conclusions can be drawn:

The HVDC converter unit of an HVDC system must be equipped with an automatic controller capable of sending set points and commands to the DC grid controller and AC/DC grid controller, including:

- operational signals, receiving at least the following:
    - final converter schedule
    - Station information
    - Signals related to Open-loop control functions

- Signals related to coordination of ancillary services

- alarm signals, providing at least the following:
  - emergency blocking
  - ramp blocking
  - fast active power reversal command
  - Cancellation of the alarm signal(s)

5.3. Converter Control Modes

5.3.1. Control mode specifications

5.3.1.1. CENELEC description

The description related to the specifications of control mode is dispersed in many sections in the CENELEC report.

In Section 4.4 of [1], a general categorization of converter operational functions is provided. They are categorized into:

- Basic operation functions during normal operating states (c.f. 4.4.2)
- Basic operation functions during abnormal operation states (c.f. 4.4.3)
- Ancillary services (c.f. 4.4.4)

In general, converter control has two fundamental degrees of freedom: active power exchange and reactive power exchange.

For active power exchange, the reference values can be given for Active power control, AC frequency control, and DC voltage control. It is emphasized that they cannot be reached independently from one another. For the controls of AC frequency and DC voltage, the basic operational requirements are specified with droop characteristics. Considering the extreme cases, the classification of the basic active power exchange-related control modes is illustrated in Figure 28.

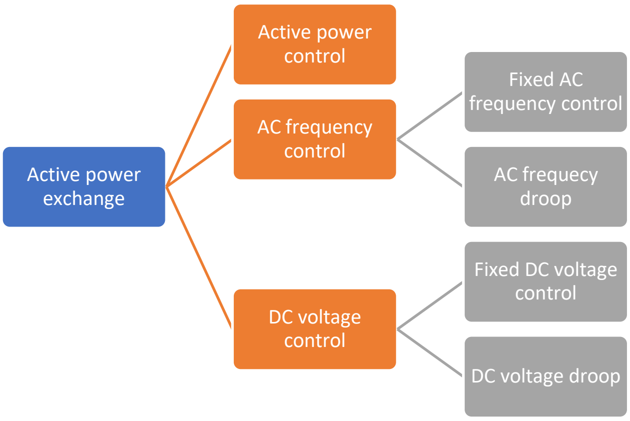


Figure 28 the classification of the basic active power exchange-related control modes.

On the other hand, for reactive power exchange, the two reference values can be given, one for reactive power control and the other for AC voltage magnitude. In addition, during an AC fault, the converter must provide fault current contribution according to the specification with respect to the voltage. Figure 29 depicts the classification of the basic control mode related to reactive power exchange. Note that the control modes related to reactive power exchange are classified as ancillary services.

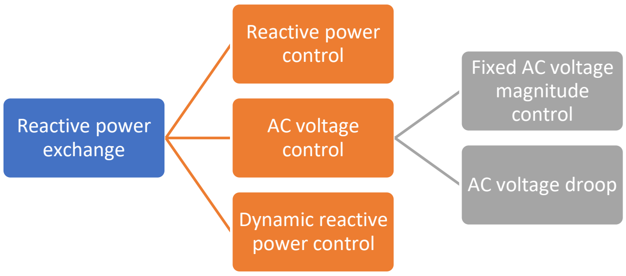


Figure 29 the classification of the basic reactive power exchange-related control modes.

Besides, certain types of ancillary services are also elaborated. It clearly states that the operational functions of ancillary services are optional. They can be activated to improve or support the power system but are not mandatory for the operation of the system. Ancillary services are first categorized into:

- → AC frequency control related services
- → AC voltage control related services
- → Power oscillation damping services
- → System restoration services

The details of each operational function of the Ancillary Services are described in the section "Functional Groups: Ancillary Services".

In Section 6.2.3 of [1], it is stated that each mode is specified by an integer number that must be fixed, consistent and known among all vendors within the HVDC grid system.

The following gives an extract of the description in the section introduced as a typical example:

> *Depending on the desired target of control or combinations thereof, the following converter control modes can apply. They can be identified by integer numbers (1 – 5).*

1. *fixed DC voltage control:*
2. *fixed AC power, DC power or DC current control:*
3. *DC voltage/AC power, DC voltage/DC power or DC voltage/DC current droop control:*
4. *fixed AC frequency control:*
5. *AC frequency / power droop control*

Section 8.3.1 of [1] mentions the capability of changing control modes over time by either manual or automatic means in coordination with the whole HVDC Grid System.

Section 8.5.3 of [1], while referring to 6.2.3 "DC Node Voltage Control" for the specification of individual control mode, also mentions that in addition to the active power related control modes, different target options may be available for the control of reactive power.

Table 36 outlines how the possible control modes that can be provided by an AC/DC converter station should be indicated. Availability of options may therefore be indicated by checkboxes.

Table 36 Parameters for the available control modes of AC/DC converter stations (Table 53 in [2]).

Symbol	Parameter	Characteristic	Value	Unit
no symbol	Active power control modes	This information defines a list of (core) control modes related to active power regulation at the converter stations PoC-AC or PoC-DC. These modes may comprise: - Constant DC voltage - Constant DC current - Constant DC power - Constant AC active power - DC voltage / current droop - DC voltage / power droop - DC voltage / AC active power droop - Constant AC frequency - AC active power / frequency droop	N/A	Booleans
no symbol	Reactive power control modes	This information defines a list of (core) control modes for regulation of reactive power at the PoC-AC of the station. These modes may comprise: - Constant AC reactive power (Q) - Constant power factor ("cos phi") - AC reactive power / voltage droop	N/A	Booleans
no symbol	Supporting Controls	Information on availability of controls supporting the coordination within the HVDC Grid System (e.g. for damping functions): - "Delta P" modulation (active power) - "Delta Q" modulation (reactive power)	N/A	Booleans

5.3.1.2. Existing projects and literature

Table 37 and

Table 38 list the identified control modes and their sources.

Table 37 List of control mode related to active power exchange.

Control mode	**Comment**	**CENELEC** [1]	**ENTSO-E** [35]
Fixed active power control mode (Pac, Pdc, or Idc)		4.4.2, etc.	3.2.1
Fixed DC voltage control mode		4.4.2, etc.	
DC voltage droop mode (Vdc/Pac, Vdc/Pdc, or Vdc/Idc)		4.4.2, etc.	
Fixed AC frequency control mode (connection of WF)		4.4.2, etc.	
AC frequency droop mode	Possibly combined with FSM	4.4.2, etc.	3.3.1
Frequency sensitive mode (FSM)		4.4.4.2.2	3.3.1
Limited frequency sensitive mode (LFSM-O, LFSM-U)		N/A	
Synthetic inertia (Differential Frequency Control)		4.4.4.2.1	3.3.4
POD-P		4.4.4.4	3.3.5
AC line emulation		N/A	3.3.1.1.2
EPC-P		N/A	3.3.3

Table 38 List of control mode related to reactive power exchange.

Control mode	Comment	CENELEC	ENTSO-E
Fixed reactive power control mode		4.4.2, etc.	3.3.2.1
Fixed AC voltage magnitude control mode		4.4.2, etc.	
AC voltage droop mode		4.4.4.3	3.3.2.1
Power factor control mode		8.5.3	3.3.2.1
POD-Q		6.2.3, etc.	
EPC-Q		6.2.3, etc.	3.3.3
Dynamic reactive power control*			3.3.2.2

5.3.1.3. Applicability to the building blocks

Applicable to all HVDC converters. The DC grid controller must be capable of assigning appropriate control modes and provides required parameters.

5.3.1.4. Corresponding functional requirement ID in the tendering material

Functional requirement ID	Functional requirement title
General18	Control mode specification
General19	Changes to protection and control schemes and settings

5.3.1.5. Discussions

In the CENELEC report, the control modes are defined as that of **the DC node voltage control layer**. The converter control mode is governed by the converter schedule as propagated through the higher-order control layers. The chosen control mode can be changed over time by either manual or automatic means in coordination with the whole HVDC grid system.

In addition to the active power related control modes, different target options may be available for the control of reactive power.

According to the definition in the CENELEC report, each mode shall be specified by an integer number that has to be fixed, consistent and known among all vendors within the HVDC grid system. This seems problematic because when control modes are defined exclusively, only one control mode is allowed to be activated at any moment. In other words, converters in a DC grid are usually expected to contribute to DC voltage regulation by activation the DC voltage droop control mode, if possible. However, if AC frequency droop mode is defined as another control mode for providing a frequency containment reserve, it may not be possible to activate the DC voltage droop control mode and the AC frequency droop mode at the same time.

To avoid this problem, two options are conceivable:

Option 1: The simplest option is to define each possible combination of control modes as a control mode. For example, the combination of DC voltage droop mode and AC frequency droop mode is defined as a new control mode. Although there is no problem as long as the number of control modes to be combined is small, when considering a wide variety of ancillary services, the number of possible combinations may become enormous.

Option 2: The alternative option is to develop the description in Section 8.5.3 Control Modes & Support of Coordination, by classifying the control modes into "core control mode" and "supporting control modes", and assuming that the exclusive definition by integer and activation restriction apply only to the core control mode. In this case, the specifications described in the CENELEC can be applied as basic control functions defined as core control mode. On the other hand, for control modes mostly related to ancillary services defined as supporting control modes, it is necessary to introduce dedicated new specifications.

Whichever option is to be adopted, it is necessary to consider which combination of control modes are feasible, and the necessary conditions for them.

5.4. Active power control

5.4.1. Controllability of active power

An HVDC terminal should be capable of regulating the active power up to the value in the active power control range. The maximum and minimum power step size as well as maximum and minimum active power ramp speed for adjusting the set-points for the active power exchange shall be specified. These values shall be adjustable during operation upon instruction by the relevant TSOs.

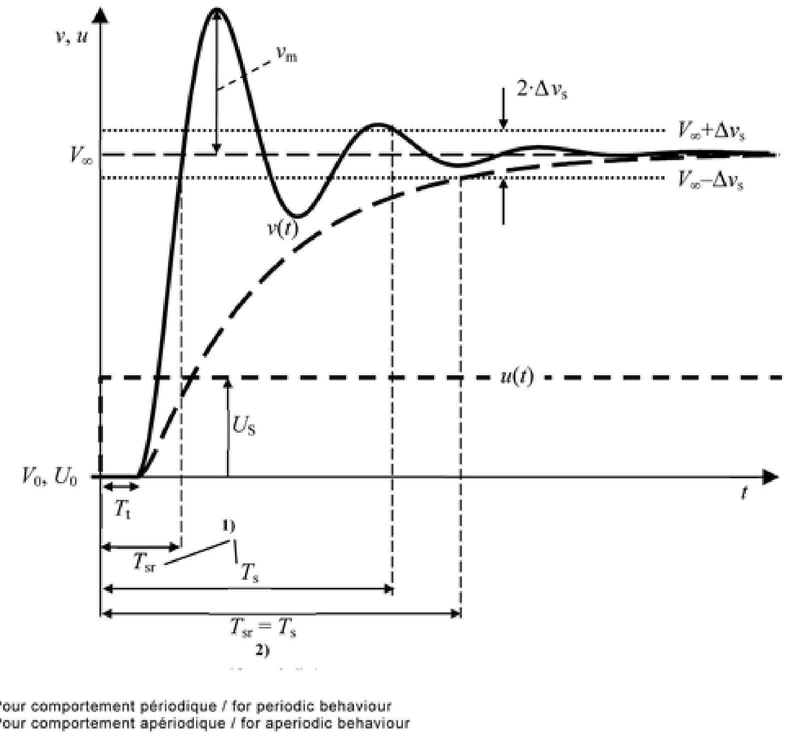
The maximum initial delay of the HVDC system when adjusting the active power transmission upon the reception of a triggering signal from the relevant transmission system operator shall be kept to a minimum and not exceed the specified value, unless justified technical proof is provided to the relevant transmission system operator.

5.4.1.1. CENELEC description

Section 8.3.3 of [1] states that for active power reversal, the type (i.e. by voltage reversal or current reversal), sequence and time shall be specified for active power reversal.

On the other hand, in Section 8.5.6, it is stated that the AC/DC converter stations shall fulfil certain requirements on sudden changes in reference values in order to demonstrate stability and smoothness of the underlying controls, and the definition of step responses shall be specified according to the definition in IEV 351-45-27.

The following is an excerpt from IEV 351-45-27: Step response [36].



u	Variable d'entrée	Input variable
U_0	Valeur initiale de la variable d'entrée	Initial value of the input variable
U_S	Hauteur de l'échelon de la variable d'entrée	Step height of the input variable
v	Variable de sortie	Output variable
V_0, V_∞	Valeurs en régime établi, avant et après application de l'échelon	Steady-state values before and after application of the step
v_m	Taux de dépassement (déviation transitoire maximale à partir de la valeur en régime établi final)	Overshoot (maximum transient deviation from the final steady-state value)
$2{\cdot}\Delta v_s$	Limite de tolérance spécifiée	Specified tolerance limit
T_{sr}	Temps de réponse à un échelon	Step response time
T_s	Durée d'établissement	Settling time
T_t	Temps mort	Dead time

Figure 30 Typical step responses of a system.

5.4.1.2. Grid code

EU grid code [32] **:**

Article 13 states that, regarding the capability of controlling the transmitted active power, the relevant TSO:

- → may specify a maximum and minimum power step size
- → may specify a minimum HVDC active power transmission capacity for each direction, below which active power transmission capability is not requested
- → shall specify the maximum delay within which the HVDC system shall be capable of adjusting the transmitted active power upon receipt of request from the relevant TSO.

The maximum initial delay of the HVDC system for adjusting the transmitted active power in case of disturbances upon reception of a triggering signal from the relevant transmission system operator for the respective situations shall be 10 ms, unless justified.

The HVDC system shall be capable to reverse the power flow as fast as technically feasible. It shall take less than 2s, unless justified.

HVDC systems shall be capable of adjusting the ramping rate of active power variations within their technical capabilities according to the instructions sent by the relevant transmission system operators. In case of modification of active power upon reception of a triggering signal or at fast power reversal, there shall be no adjustment of the ramping rate.

HVDC systems linking various control areas or synchronous areas shall be equipped with control functions enabling the relevant transmission system operator to modify the transmitted active power for the purpose of cross-border balancing.

DE grid code [15] **:**

In addition to what is specified in the EU grid code [32], Section 10.1.3 in DE grid code specifies the maximum initial delay the HVDC system for adjusting the transmitted active power upon reception of a triggering signal from the relevant TSO as 100 ms, unless justified.

NL grid code [28]**:**

Section 4.2.9 specifies the requirements to be verified as:

- the minimum power step size is 1 MW; the maximum power step size is twice the maximum HVDC transmission capacity.
- the minimum HVDC active power transmission capacity for each direction, below which active power transmission capability is not requested, is 0 MW, unless another value has been agreed and recorded in the Connection Agreement.
- the maximum delay within which the HVDC system shall be capable of adjusting the transmitted active power upon receipt of request is 100 ms;

DK grid code [22]

Article 13.1 specifies the requirements as follows:

- The minimum active power step size for adjusting the transmitted active power is 1MW.
- Dynamic performance requirements of active power tracking are:
    - Maximum processing time: 0.5s;
    - Command/set points: 0.25s;
    - Events exceeding data filter: 0.5s;
    - Cyclic measurement: 1–60s.

5.4.1.3. Testing procedure

Ref	Section	Description
NC-HVDC [32]	Article 71.9	With regards to the active power controllability, the HVDC system shall demonstrate its technical capability to continuously modulate active power over the full operating range according to Article 13(1)(a) and (d);
VDE [15]	Section 11.5.9 Active power controllability test	

5.4.1.4. Applicability to the building blocks

Applicable to all HVDC converters. The DC grid controller must assign

Building blocks	Applicability	Note
Onshore HVDC Converters	Yes	
Offshore HVDC Converters	Yes	
Offshore DC Switching stations	No	
Offshore DC Switching stations	No	
Global DC grid controller	Yes	

5.4.1.5. Corresponding functional requirement ID in the tendering material

Functional requirement ID	Functional requirement title
General20	Active power controllability

5.4.1.6. Discussions

Even though the CENELC report states that the dynamic requirements for active power control shall be defined by the step response based on IEV 357-45-27, the relevant specifications found in the current grid code are only about the maximum initial delay and ramp speed.

While the mention of “triggering signals from the relevant TSO” mainly refer to the signals sent by the defined protection scheme of the TSO, for MTDC grid application, they shall include the signals sent via the DC grid controller.

5.4.2. Active power ramp rate

According to the client, DK standard for the active power ramp rates are set as: 999 MW/min for normal power orders. 999 MW/s for emergency power control.

5.4.2.1. Testing procedure

Ref	Section	Description
NC-HVDC [32]	Article 71.10	With regard to the ramping rate modification test, the HVDC system shall demonstrate its technical capability to adjust the ramping rate according to Article 13(2);
VDE [15]	Section 11.5.10 Ramping rate modification test	
NL Grid code [28]	4.2.10 Ramping rate modification	Details the requirements to be verified and testing procedure

5.4.2.2. Corresponding functional requirement ID in the tendering material

Functional requirement ID	Functional requirement title
General21	Ramping rate of active power change

5.5. DC voltage control

5.5.1. DC voltage droop

When operating in DC voltage droop mode, the converter shall be capable of responding to DC voltage deviations in the connected DC network by adjusting the active power injection/extraction according to the specified DC voltage droop constant(s). The adjustment of the active power response shall be limited by the maximum HVDC active power transmission capacity of the converter or otherwise specified (in each direction).

5.5.1.1. CENELEC description

Relevant discussions can be found in Section 4.4.2.3 and 6.2.3 of [1].

The DC voltage by a DC voltage / DC power droop (s_{P_UDC}) describes the change of active power in response to a deviation of the DC voltage from its reference value.

$$s_{P\_UDC} = (\Delta U_{DC}/U_{DCnom}) / (\Delta P/Pn)$$

Similarly, the DC voltage by a DC voltage / DC current droop (s_{IDC_UDC}) describes the change of DC current in response to a deviation of the DC voltage from its reference value. It is defined by

$$s_{IDC\_UDC} = (\Delta U_{DC} / U_{DCnom}) / (\Delta I_{DC} / I_{DCnom})$$

The CENELEC report describes that the above droop characteristics are the most common, but there could be others along with all other control modes where the droop constants could be a function of active power, DC voltage, etc. Several droop constants s(P) could be used to model dead bands, etc.

Table 39 Parameter list for DC voltage / DC power droop (Table 5 in [2]).

Symbol	Parameter	Characteristic	Value	Unit
UXDCrat	DC voltage	rated DC voltage at each station defined at the PoC-DC, a station being identified by X = A, B, … Z		kV
sP_UDC	DC voltage / DC power droop	defines the change of active power reference in response to a deviation of the DC voltage from its reference value		N/A
sIDC_UDC	DC voltage / DC current droop	defines the change of DC current reference in response to a deviation of the DC voltage from its reference value.		N/A

In the CENELEC report, the DC voltage droop control appears as one of the converter control modes in the DC node voltage control layer. The essential function of this control layer are:

- → to achieve the desired power flow in the HVDC Grid
- → to maintain the DC voltage within its operational limits throughout the HVDC Grid

This layer operates continuously not only under normal grid conditions but also when the grid is disturbed. As outputs, it provides reference values to the subordinate layer, the internal converter control.

The definition of droop control is slightly expanded here, mentioning that having one or more sections with droop gain per section, or even continuously changing the droop.

An illustration of a typical converter control mode characteristic is shown in Figure 31.

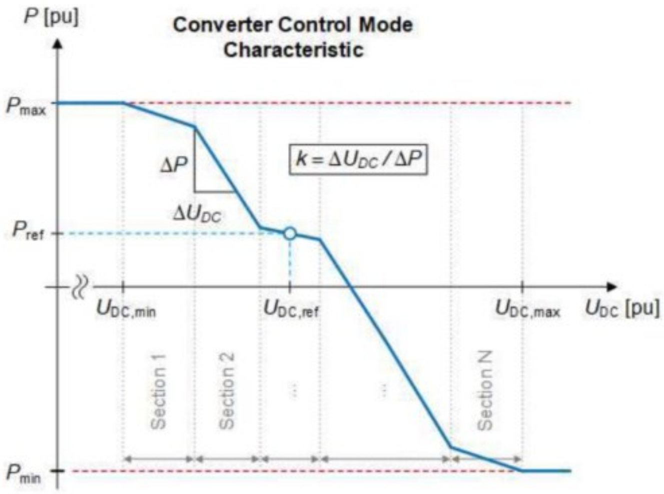


Figure 31 Typical DC node voltage control mode (Figure 14 in [2]).

It states that the setting for control modes and related parameters (if any) are incorporated in the converter schedule. It is noteworthy that the droop characteristic is mentioned as an example of the control mode-related parameters to be dispatched as initial converter schedule (C.f; Table 40 in [2].). This implies that droop parameters are considered as configurable parameters and can be adjusted according to the system needs.

Apart from the above, no further detail is provided in the current version of the CENELEC report Part 2 [2].

Presumably, from the description,

- the parameters defining the sections,
- the droop parameter for each section,
- the maximum and minimum DC voltage levels to deactivate the droop action and enter the constant power mode,
- the power set point values for each, and
- Parameters that specify required dynamic characteristics are required.

5.5.1.2. Grid code

No mention of this functional requirement was found in DE, NL, DK national grid codes or in NC-HVDC.

5.5.1.3. Existing projects and literature

Symbol	Parameter	Value	Unit	Ref	Description
SP_UDC	DC voltage/ DC power droop	0.05–0.5	p.u./p.u. (V/P)	BestPaths [6]	Originally mentioned as 0.032-0.32 kV/MW Characterized by $V'_{dc\_ref}=V_{dc\_ref}+V_{dc\_droop} \times (P_{ac}-P_{ac\_ref})$ Mentions the possibility of a dead band around the DC voltage setpoint (0-10% Vn).
SP_UDC	DC voltage/ DC current droop	0.02-0.05	p.u./p.u. (V/Idc)	TSG [37]	

Beside, BestPaths D9.3 [6] describes the DC voltage droop control mode specification as follows:

Symbol	Parameter	Value	Unit	Description
TR	Rising time	20	ms	
TS	Settling time	100	ms	
VR	Threshold for the rising time	0.9	p.u.	90% of the change
ΔvS	Tolerance limit around the reference value	0.005	p.u.	0.5 % of the nominal voltage The total deadband = 2 ΔvS
Vm	Overshoot	0.075	p.u.	

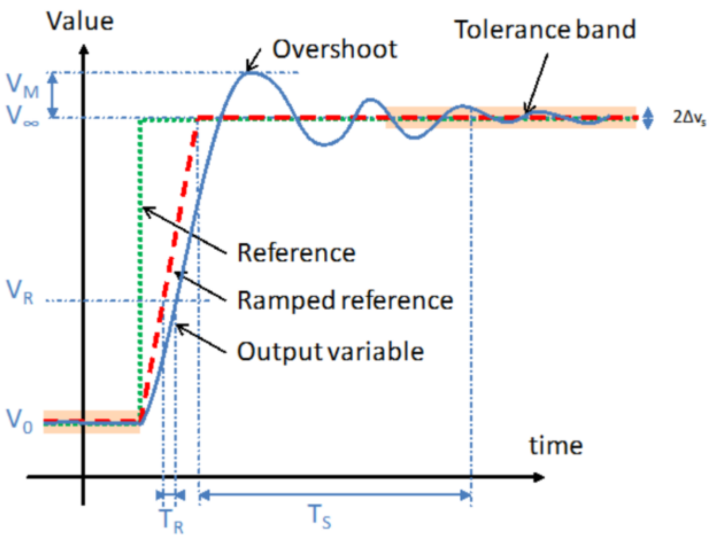


Figure 32 Validation profile of the dynamic performances of a control mode ([6] Figure 29).

It also mentions the presence or absence of dead-bands.

Symbol	Parameter	Value	Unit	Description
Vdc_db	Dead band around Vdc_ref where the active power is not adjusted	0.0 – 0.1	p.u.	0 –10 % of Vn

5.5.1.4. Testing procedure

Ref	Section	Description
CIGRE TB 563 [9]	4.2 Power flow for system adequacy studies	The target values set for voltage levels are met and the transmission system is capable of receiving or delivering the power transferred via a HVDC connection throughout all the operating and switching conditions related to normal operation or operation under relevant contingencies and disturbances.
CIGRE TB 563 [9]	4.4 Preliminary analysis of dynamic stability	Preliminary evaluation of the system stability and reliability is the second part of the system adequacy study in the pre-specification phase.
BestPaths [6]	5.9 Dynamic performance validation	Generic dynamic performance validation for a step change no larger than 5% of Vn according to the dynamic performance criteria with the parameters defined as
CIGRE TB 832 [26]	3.4.4. Preliminary dynamic performance study (if required)	A preliminary dynamic performance study for the validation of a reduced set of non-steady-state events based on preliminary control parameters can be conducted as part of the bid process. The study requires a preliminary detailed converter model with an appropriate control system representation and a Thevenin equivalent representation of the AC system.
TB 832 [26]	3.6.1 Dynamic Performance Study/Dynamic Performance Test	Verification of dynamic performance by utilizing EMT type tools
TB 832 [26]	4.2 Setpoint changes and load rejections	Some examples of relevant events to consider in offline EMT tools are listed below: -Fast power setpoint changes (such as run-up and run-back) -For bipolar of parallel links, fast automatic power dispatch in case one system trip -Fast power reversals -Sudden change in AC voltage (trip or connection of AC equipment near the HVDC converter station)

5.5.1.5. Applicability to the building blocks

In principle, this applies only to onshore HVDC converter stations.

5.5.1.6. Corresponding functional requirement ID in the tendering material

Functional requirement ID	Functional requirement title
General23	DC voltage droop mode
General24	DC voltage droop mode parameterization

5.5.1.7. Discussions

Specification phase:

Although CIGRE TB 563 [9] does not address directly the MTDC grids, the definition of control modes and performance parameters is the subject of the studies in the pre-specification phase, so the specification of the DC voltage droop control is deemed to be covered during this stage.

Trade-off in droop parameter selection

In general, as droop decreases, the converter will contribute greater power for a given voltage deviation. Therefore, DC voltage deviation after disturbance becomes smaller. On the other hand, as the droop decreases, it becomes more sensitive to voltage drops in the grid and any sensor gain errors, which result in less accurate power distribution.

Variants in control solution

Although the CENELEC defines the DC voltage/DC power droop as "the change of active power reference in response to a deviation of the DC voltage from its reference value", many variants in implementation can be found in the literature, and the consensus has yet to be reached. Figure 33 shows five typical DC voltage droop implementations available in the literature.

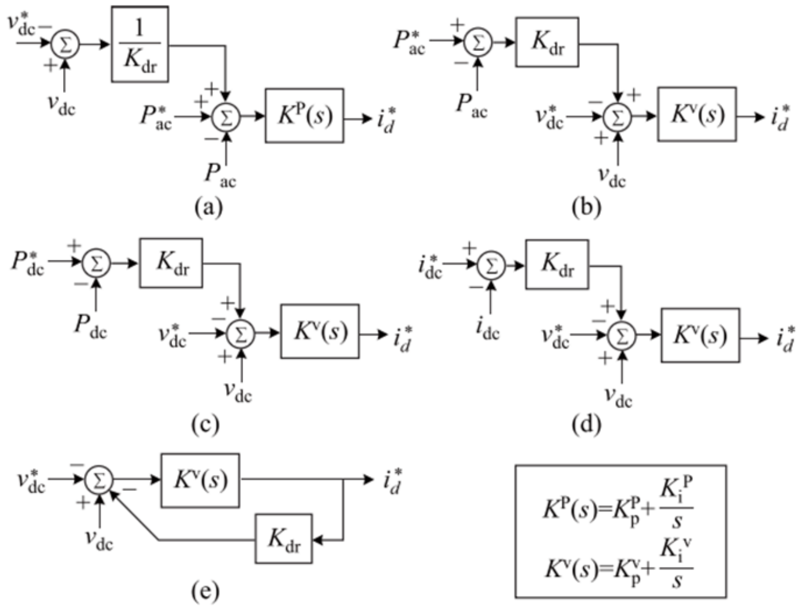


Figure 33 Five types of dc voltage droop control implementations. (a) Type 1: V-P_{ac} droop A; (b) Type 2: V-P_{ac} droop B; (c) Type 3: V-P_{dc} droop; (d) Type 4: V-I_{dc} droop; (e) Type 5: V-i_d droop. [38].

Parameters to be determined

Unlike the description in the grid code for the FSM, which is the counterpart in the AC systems, the only parameter mentioned in CENELEC for the specification of DC voltage droop control is the droop characteristic. For comparative purposes, the parameters specified for the FSM in the German grid code [15] are given in Table 40 and Table 41.

Table 40 Parameters for the active power frequency response in the FSM [15].

Parameters	**Ranges**
Dead band $\lvert\Delta f_{tot}\rvert$	$0\ldots200$ mHz
Droop s_1	≥ 0.1 %
Droop s_2	≥ 0.1 %
Permissible tolerance $\Delta f_{toleranz}$	≤ 30 mHz

Table 41 Parameters for full activation of the active power frequency step response [15].

Parameters	**Ranges**
Initial time delay $\lvert t_1\rvert$	≤ 0.5 s
Time for full activation $\lvert t_2\rvert$	≤ 30 s

It can be seen from the tables that the specification of the FSM is not only the droop gains, but also the dynamic response requirements for full activation of the agreed active power reserve.

Impact on the connected AC systems:

The ability of the DC voltage droop control is influenced by the available headroom capability of the converters and restricted to the allowable changes in active power import/export of the connected AC systems.

Network power voltage characteristic

For a given power imbalance in a DC grid, the post-contingency steady-state DC voltage deviation can be approximated by the network power voltage characteristic, which is defined in [39] as:

$$\frac{\Delta P_{dis}}{\Delta V_{dc}} \approx \lambda_{v_{dc}} = \frac{1}{U_{DCpole\_n}} \left(\frac{P_{ACrat1}}{s_{P_{U\_DC1}}} + \frac{P_{ACrat2}}{s_{P_{U\_DC2}}} + \cdots + \frac{P_{ACrat2}}{s_{P_{U\_DC2}}} \right)$$

Converters in a grid do not necessarily have the same rating. Therefore, it is necessary to consider the effect of the droop parameters on the system characteristics, taking into account the rating of each converter.

The effective power contribution of each converter can approximately be determined by the ratio of the assigned droop parameter to the network power voltage characteristic.

Combination with DBS:

In presence of smaller flexible power inputs, such as generation from offshore wind station, when one of the exporting stations is lost, the overall power input may exceed the total capacity of the withdrawable power. In this case, the containment of DC voltage rise by the droop control is no longer possible. Therefore, DBS is essential to cope with overvoltage that cannot be handled by the DC voltage droop [10].

Specification and validation procedure

The primal importance of the DC voltage droop control is to contain the DC voltage excursion and meet the target values set for the DC voltage as well as the allowable change in the active power of the connected AC systems in post-contingency state for any credible contingencies and disturbances. Specifying DC voltage droop control-related parameters requires a holistic analysis. Therefore, they could first be distinguished between the aspects related to the system as a whole and requirements for individual building blocks.

Since the droop parameter is a major factor in determining the static HVDC grid characteristic, a non-generic testing procedure should be carried out in order to determine the appropriate droop parameter range, considering the entire DC grid topology, cable/line impedance, converter power rating, as well as the future grid extension. Such studies shall be carried out by the system owner in the pre-specification phase.

The main target of this study is to define the appropriate range of the droop gain. As an input, predefined temporary DC voltage profile will be needed. In line with the studies performed in [5], the static representation of the target system can be employed. Furthermore, as concluded in [5], in a bipolar system, disturbances of power at a given pole are compensated by converters of the same polarity. Therefore, when specifying the droop parameter range, the symmetry of positive and negative poles can be exploited, and only one of the two priorities need to be represented. Finally, the determination of this range requires an arbitrary decision about the trade-off between power sharing accuracy and voltage variation range.

On the other hand, the dynamic response of the converters under the DC voltage droop control should be fulfilled through the definitions of appropriate dynamic performance criteria by the owner in order to avoid interoperability issues due to the inconsistencies among the vendor specific control solutions. While the BestPaths project specifies the dynamic response requirement in terms of DC voltage, the dynamic requirements of the FSM in AC systems are defined in terms of the initial activation delay and the time for full activation of the agreed power.

From above discussion, the minimum performance requirements can be defined by the following:

- → The HVDC converter station in DC voltage droop control mode shall be capable activating a power DC voltage response within a specified initial delay t_1
- → At a DC voltage change, the HVDC converter shall be capable of adjusting the active power in according to the specified characteristic curve defined in terms of the time for full activation t_2 and agreed active power change ΔP

5.5.2. Fixed DC volage control (Master control in Master/Slave method)

In a point-to-point HVDC system, one converter station acts as the slack bus by taking the responsibility for maintaining the DC voltage constant whilst the other station only controls power. This method, the so-called Master/Slave method, can be applied to MTDC grids. In the Master/Slave method, the station in the fixed DC voltage control is called Master, while the other converter stations called Slave operate at constant power.

5.5.2.1. CENELEC description

In the CENELEC report [1], the Master and Slave controls are described as two extreme cases of the DC voltage droop characteristics. The fixed DC voltage control is described as an extreme case, where

$$s_{P\_UDC} = 0, \quad s_{IDC\_UDC} = 0.$$

This can be represented by a horizontal curve in the P-V or I-V plane. In this case, the converter station will exchange the power needed to keep the DC voltage at its terminal constant.

Additionally, the fixed power control is described as

$$s_{P\_UDC} = \infty, \quad s_{IDC\_UDC} = \infty.$$

Apart from the above information, no specific mention on the fixed DC voltage control was found.

5.5.2.2. Grid code

No mention of this functional requirement was found in DE, NL, DK national grid codes or in NC-HVDC.

5.5.2.3. Existing projects and literature

BestPaths [6]

BestPaths describes the DC voltage control mode specifications as follows:

Symbol	Parameter	Value	Unit	Description
TR	Rising time	20	ms	
TS	Settling time	100	ms	
VR	Threshold for the rising time	0.9	p.u.	90% of the change
ΔvS	Tolerance limit around the reference value	0.005	p.u.	0.5 % of the nominal voltage The total deadband = 2 ΔvS
Vm	Overshoot	0.075	p.u.	

It also precisely states that *"... at nominal DC voltage level, following any active power change (including power flow reversal), the DC voltage shall remain between boundaries of ±5% around the nominal DC voltage provided that the PQ capability diagram limits are not exceeded."*

CIGRE TB 832 [40]: **5.4.2.2 Three-Phase-to-Ground Fault at the Rectifier Station**

In case that the Master station loses control, for example due to a three-phase ground fault on the AC side bus, the Master station can no longer control the DC voltage, but the Slave stations will continue to try to maintain power flow.

It describes two feasible options:

→ With interstation communication enabled, the inverter could receive an order to reduce the active power output and thereby stabilize or even control the DC voltage.

→ When no communication is considered such as in this case, a droop characteristic in the active power control mode is used to decrease the active power setpoint depending on the DC voltage. This stabilizes the DC voltage after around 100 ms and the DC current decreases to zero.

It also addresses an important aspect of the control design. "It should be noted that, for half-bridge MMC, the DC voltage must always be higher than the AC converter-side peak voltage in order to keep control of the converter. Therefore, it needs to be ensured that the DC voltage drop during the fault remains within acceptable limits. After the fault is cleared, a transient AC overvoltage can be observed as well as a transient peak in the AC current. Especially, the current peak should be prevented by the control, even if no critical valve currents are reached in this case. "

Other literature

Symbol	Parameter	Value	Unit	Ref	Type	Description
N/A	Response time	100	ms	Saad 2015 [41]	Article	
N/A	Response time	100	ms	Freytes 2017 [42]	Article	

5.5.2.4. Testing procedure

Ref	Section	Description
BestPaths [6]	5.9 Dyynamic perfoamnce validation	Generic dynamic performance validation for a step change no larger than 5% of Vn according to the dynamic performance criteria with the parameters defined as
TB 832 [40]	3.6.1 Dynamic Performance Study/Dynamic Performance Test	Verification of dynamic performance by utilizing EMT type tools
TB 832 [40]	4.2 Setpoint changes and load rejections	Some examples of relevant events to consider in offline EMT tools are listed below: -Fast power setpoint changes (such as run-up and run-back) -For bipolar of parallel links, fast automatic power dispatch in case one system trip -Fast power reversals -Sudden change in AC voltage (trip or connection of AC equipment near the HVDC converter station)

5.5.2.5. Applicability to the building blocks

Only applicable to onshore HVDC station.

5.5.2.6. Corresponding functional requirement ID in the tendering material

Functional requirement ID	Functional requirement title
General22	Fixed DC voltage control mode

5.5.2.7. Discussions

Dependence of the settling time on the grid configuration

Since the DC voltage control loop includes not only the controller but also the DC system equivalent capacitance, the settling time will be affected by the actual system configuration, e.g. the number of converters connected at that time. Figure 34 shows the influence of the DC system equivalent capacitance on the DC voltage dynamics [7]. As seen, although the rise time does not change significantly, the settling time of the 1-terminal case is around 40 ms, and that of the 4-terminal equivalent case is around 100 ms slower.

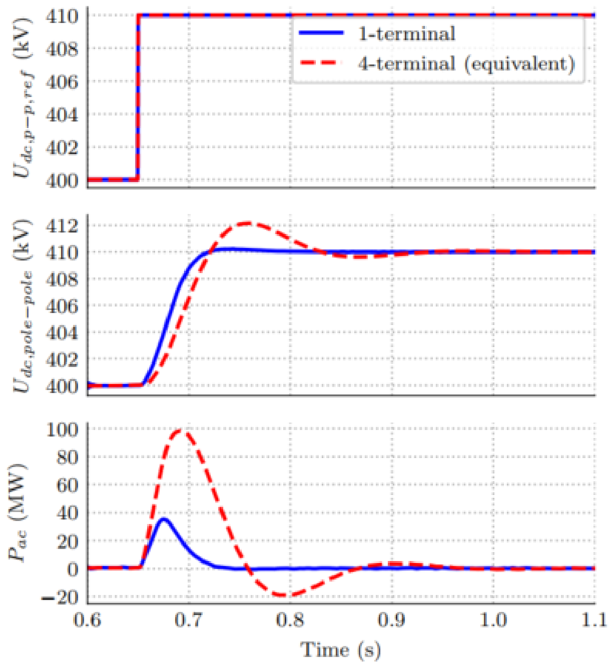


Figure 34 DC voltage step response comparison when only one and 4 converters are active [7].

As a solution to meeting the same control requirements regardless of the DC grid configuration, Roni proposed in [7] a cascaded compensation structure. The lead-lag phase compensator is tuned by the gain-schedule method. The gain parameters are set from a look-up table previously calculated by EMT simulations using the project specific vender-developed models, according to the binarized actual grid conditions informed by the centralized control unit. This approach allows adjustment of the settling time without the information of the venders' control structure and signal processing methods, which are usually not provided due to IP issues.

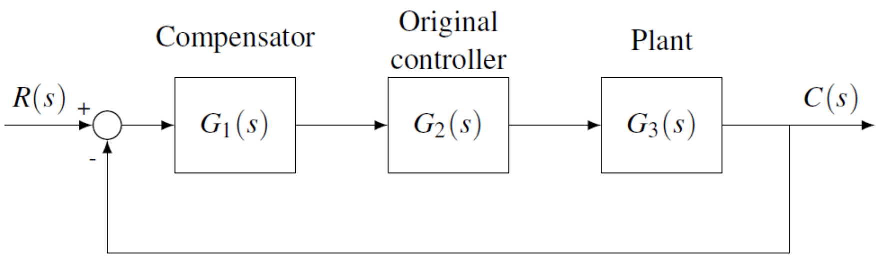


Figure 35 The cascade compensation structure. The input reference is denoted as $R(s)$, while the output of the system is given as $C(s)$. Each block diagram represents the transfer function in frequency domain of the compensator, original controller, and plant [7].

5.6. Global DC grid control requirements

5.6.1. Secondary DC voltage control

Secondary DC voltage control is considered as one of the desired functions of the DC grid control layer. Its principal role is to adjust the converter power schedule from the initial order from the AC/DC grid control in order to ensure all constraints in the DC grid are met, and to dispatch the new power flow setpoint and DC voltage reference to each converter station.

The operation of an HVDC grid system requires balancing the active power exchange with the connected AC grids; the balance of the active power of the DC grid is represented by the stability of the DC voltage. When a disturbance occurs and the power flow in the DC grid changes, the primary DC voltage control will contain the voltage excursion and find a new equilibrium point different from the initial operating states. This implies that, although the post-contingency DC voltage remains within the acceptable range, the security margin of the DC voltage is reduced and may not be sufficient to cope with another contingency. Moreover, unexpected disturbances and the subsequent primary DC voltage regulation will lead to changes in the power flow profile different from what was initially scheduled as the expected operating points. In this state, often called alert state, the secondary DC voltage control is activated and brings back the voltage to the desired level and adjusts the power flow setpoints. Secondary regulation requires a modification of the import/export capacities of one or several stations, hence the need of a close joint operation with the interconnected AC system operators.

5.6.1.1. CENELEC description

Relevant discussion can be found in section 6.2.4.3 DC Grid Control of [1].

Secondary DC voltage control is defined here as a composite of the main functional requirements specified for the Global DC grid control within the CENELEC report, as listed below.

→ Continuous processing of initial converter schedules dispatched by the AC/DC Grid

→ Managing the control modes of all converter stations in the DC node voltage control layer ensuring a secure steady-state operation of the HVDC Grid System within defined safety limits (e.g. consistency checks, set value modifications)

→ Optimizing DC network operation (e.g. after an unscheduled event) and reacting to deviations from the anticipated power exchange with new converter control mode and/or settings

→ Provision of operational simplifications for the HVDC grid system by “default scenarios” (e.g. predefined energization sequences, response to usual/frequent contingencies)

→ Supporting the dispatch process to set up a consistent power schedule for the HVDC grid system (e.g. by pre-computed information for the AC/DC grid control)

While the initial converter schedules are calculated at the top level of the hierarch and periodically dispatched by the so-called AC/DC grid control, the role of the DC grid control layer is to generate the final converter schedules according to desired optimization targets. In case of a disturbance or another unscheduled event, these schedules are modified adequately in order to properly respond to the changing external conditions while keeping operational margins. The typical timescale of operation at the DC grid controller layer is mentioned to be less than 5 s in the report, but only indicatively.

Figure 36 from the report illustrates the propagation of information between the layers.

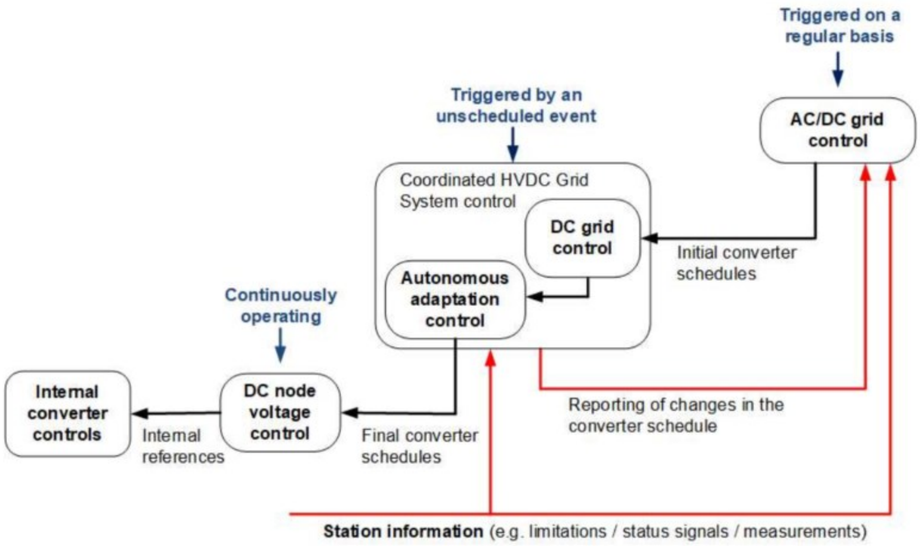


Figure 36 Generation of final converter schedules including converter control modes and its parameters (Figure 15 in [1]).

5.6.1.2. Grid code

No mention of this functional requirement was found in DE, NL, DK national grid codes or in NC-HVDC.

5.6.1.3. Existing projects and literature

CIGRE TB 657 [10]

There is a dedicated section 3.4 “DC grid secondary control” in the brochure, which describes its principal role as

“*When a disturbance causes a change of the power flow in the DC Grid, the primary control will find a new stable operating point, but it will differ from the desired DC voltage profile. The DC Grid controller should then measure the new post-disturbance power flow and adjust the DC voltage profile to be within the acceptable steady state range and also make necessary adjustments to the power flow in order to avoid exceeding thermal limits of the DC Grid. The operator will be notified about the disturbance and can then enter a new dispatch, if desired.* “

It also clearly states that the DC grid secondary control will be performed by the DC grid controller using communication to each converter station. Three main purposes for the communication are:

- → To communicate a desired power flow dispatch from the operation center
- → To check that all constraints in the DC grid are fulfilled
- → To send new power orders and DC voltage references to each converter station in a synchronized manner

CIGRE TB 699 [43]

Section 6.1 of [43] describes the secondary DC voltage control by analogy with secondary frequency control in AC systems.

A coordinated system control is required to enable returning to the original DC voltage level and dispatches new power set-points following a distribution agreed between involved transmission operators. The new setpoints must ensure sufficient margin to enable the control to operate without exceeding security limits. To this end, before sending references and control parameters to local controllers or changing control modes, they must be checked and verified whether if it fulfils a stable operation within the limits regardless of the event which may occur in the HVDC grid.

Section 6.3 of [43] elaborates the necessary considerations in changing or updating the set-points and control parameters of the converter stations. To minimize disturbances when changing set-points, there shall be a coordinated ramp rate limits to allow smooth changes, expected in emergency situations. When transitioning from one control mode to the other, a contingency may occur during the transition. Hence, the procedure for the control mode transition must consider such a contingency during the transition as well as a possibility that one or several converters might not transition to the new control mode. For DC voltage regulation, this means that at least one (but normally several) station must control DC voltage to ensure the DC grid energy balance and maintain the DC voltage within the specified operational limits

In general, the coordinating control system takes some time to detect an abnormal situation, calculate a new operating point, and transmit a new reference. In case of a credible contingency, the system must stay within limits. This duty is carried out by the DC node voltage control without relying on the intervention of the coordinated control during the transient. However, in the post-contingency state, the system may not have enough margins for the second contingency. Moreover, power exchange between the AC and DC grids may not satisfy the scheduled power flow. In such a state, the set-points need to be changed to be prepared for another possible contingency, and later, changed back to normal operation.

Section 6.4 of [43] elaborates typical methods for set-points calculation. The set-points must fulfill the desired power exchange between the interconnected AC systems and ensure the DC voltage security. A power flow analysis calculates the steady-state voltages and the power flows within the network. Power flow equations are non-linear and are solved iteratively, using algorithms such as Newton-Raphson method.

Power flow algorithms should be revised to meet the specific demands of the operator. In each of the application case listed below, the inputs required for the algorithm can be different.

- → Standard DC system power flow
- → Power flow schedule errors are compensated by the selected slack bus station
- → DC system power flow with droop
- → DC system power flow with power sharing
- → The power schedule error is shared among the stations according to the user-defined coefficients
- → AC/DC power flow

Section 6.6 of [43] gives a suggestion on communication speed for the secondary DC voltage control.

The European grid code specifies that the secondary AC frequency control must start no later than 30 seconds after the event and the control action must be completed as quickly as possible. To meet this requirement, the secondary DC voltage control must accomplish the restoration of the power flow sufficiently fast in order to avoid unnecessary activation of the frequency restoration reserves. In order to achieve this, all the necessary data to comprehend the actual grid situation must be collected and based on these data, new settings and ramp rates must be calculated and transferred to the converters and other equipment, and they must be realized by the local control system.

Other existing literature

Some advanced solutions that employ Model Predictive Control (MPC) can be found in the literature, e.g. [44]. A power flow algorithm inherently requires the knowledge of the system admittance. However, the conductor resistance of a cable can changes with temperature, and this can introduce a non-negligible difference between the expected and actual power flow. Unlike a power flow algorithm, a feedback solution such as MPC can offer the possibility of limiting the errors that can be caused by uncertain disturbances.

5.6.1.4. Testing procedure

Ref		Description
Sanchez [44]		Step increase in wind generation
Sanchez [44]		Converter trip
Sanchez [44]		Turbulent wind-power conditions

5.6.1.5. Applicability to the building blocks

Only applicable to the DC grid controller.

5.6.1.6. Corresponding functional requirement ID in the tendering material

Functional requirement ID	Functional requirement title
General26	Priority ranking of protection and settings
Master_Control1	Connection modes coordination
Master_Control2	Control interface requirement (receiving)
Master_Control3	Control interface requirement (reporting)
Master_Control4	Converter schedule processing
Master_Control5	Converter control mode management
Master_Control7	Secondary DC voltage control
Master_Control8	Monitoring of HVDC grid

5.6.1.7. Discussions

The primary role of the secondary DC voltage control is analog to that of secondary AC frequency control in AC systems. In other words, after an unscheduled event occurs in the DC grid, the secondary DC voltage control seeks to re-establish the AC/DC system power flow as close as the original schedule by determining the actual DC grid state from the collected data, calculating the new set-points and associated parameters based on the collected data, and then dispatching them to the corresponding converter stations and other equipment in the grid.

The above-mentioned power flow algorithms are typically employed to calculate the set-points.

When an unscheduled event occurs in an HVDC grid with a relatively small number of terminals, it is often impossible to re-establish the same power flow to the one before the accident due to capacity constraints. In that case, it is necessary to formulate a constrained optimization problem and solve it to derive a unique solution. Reference [45] proposed a three-step process to solve such problem. Step 1: if there is no constraint violation, the set-points are calculated so that the net power exchange of each bipolar station is the same as before. This means that the change of power in one pole is compensated by the unaffected pole. Step 2: If there is a constraint violation in Step 1, the set-points are calculated to nullify the net power exchange of the AC area. Step 3: if there is a constraint violation in Step 2, the set-points are calculated to minimize the change in the net power exchange of AC areas.

5.7. Prioritization

Corresponding chapters in the CENELEC report	6.2.4.2 Autonomous Adaptation Control
	8.5.4 Limitation Strategies

The HVDC control scheme consists of the management and activation of different control modes, including the calculation and assignment of parameters. These are coordinated according to agreed priority raking and the control and protection system must be implemented in compliance with it.

5.7.1. Priority Ranking

5.7.1.1. CENELEC description

The autonomous adaptation control is a rule-based local control layer to be implemented at each converter station. See Section 5.2.1 of the present report for more information.

5.7.1.2. Grid codes

Grid codes stipulate the priority ranking of protection and control systems listed in decreasing order of importance.

EU grid code [32]

European grid code [32] stipulates the priority ranking in Article 35 as follows:

→ network system and HVDC system protection

→ active power control for emergency assistance

- → synthetic inertia, if applicable
- → automatic remedial actions as specified in Article 13(3)[4]
- → LFSM
- → FSM and frequency control
- → power gradient constraint.

DE grid code

DE grid code [15] stipulates the priority ranking in Section 10.1.25 in a more elaborated manner as follows:

- → Protection of the network and HVDC system
- → capability of damping subsynchronous torsional interaction
- → Dynamic voltage control
- → active power control in the event of faults in one or more of the connected AC networks following reception of a triggering signal
- → dynamic frequency/active power behavior
- → capability of implementing automation systems
- → capability of power oscillation damping
- → active power control in the limited frequency sensitive mode
- → reactive power control
- → active power control in the frequency sensitive mode
- → frequency control
- → active power control with power gradient limitation after a fault
- → active power control in normal operation
- → black-start capability
- → capability of participating in island operation

5.7.1.3. Testing procedure

So far, no relevant information was found.

[4] Article 13(3) stipulates that if specified by a relevant TSOs, the system shall be capable of taking automatic remedial actions including, but not limited to, stopping the ramping and blocking FSM, LFSM, etc.

5.7.1.4. Applicability to the building blocks

The priority ranking applies to all the layers of the control and protection system, and their implementations must be organized in compliance with it.

5.7.1.5. Corresponding functional requirement ID in the tendering material

Functional requirement ID	Functional requirement title
General26	Priority ranking of protection and settings

5.7.1.6. Discussions

The existing grid code does not mention the priority of DC voltage control.

5.7.2. Active and reactive power limitation strategies

If the set values for active and reactive power exceed the actual capacity of the AC/DC converter station, an appropriate compromise must be made.

5.7.2.1. CENELEC description: 8.5.4 Limitation Strategies

In the case where the set values for active and reactive power contributions exceed the actual capability of the AC/DC converter station, the following strategies can be applied:

- limiting the last set value change
- limiting active power while fulfilling the requirements for reactive power (Q priority)
- limiting reactive power while fulfilling the requirements for active power (P priority)
- limiting active as well as reactive power symmetrically or unsymmetrically.

Criteria for setting and leaving a specific strategy shall be specified as well.

Table 42 gives an example of the specifications.

Table 42 Limitation Strategies (Table 35 in [2]).

Symbol	Parameter	Characteristic	Value	Unit

No symbol	Priority mode	- Limiting the last set value change
		- Limiting active power while fulfilling the requirements for reactive power (Q priority)
		- Limiting reactive power while fulfilling the requirements for active power (P priority)
		- Limiting active as well as reactive:
		  - symmetrical: constant cos(ϕ).
		  - unsymmetrical: weighting factors
			N/A	N/A

No symbol	criteria	Applicable criteria for entering and leaving the limiting strategy.	N/A	N/A

5.7.2.2. Applicability to the building blocks

Only applicable to HVDC converter station.

5.7.2.3. Corresponding functional requirement ID in the tendering material

Functional requirement ID	Functional requirement title
General27	Autonomous adaptation control
General28	Priority to active power or reactive power contributions
General39	Reactive power capability

5.7.2.4. Discussions

The existing grid code does not mention the priority of DC voltage control.

5.8. Conclusions & next steps in SoW B

The extensive survey of the existing literature on the functional requirements for HVDC grid control revealed that there are still several options available for the definition of each functional requirement, and that there is no framework or standardization for determining the range of parameters to be defined. For the adequacy of the parameter range, it is indispensable to take into account not only the design of the control, but also the parameters of the system, e.g. the size of the DCR. In SoW B, we will attempt to clarify the influence of the parameters associated to the principal control modes as well as the external parameters e.g. DCR size, on their performance. In addition, the feasibility of selected global DC voltage controller functionalities will be demonstrated. More specifically, the following points are investigated in SoW B:

- → Investigation on the fixed DC voltage control mode parameters, and quantitative evaluation of the influence of the parameters on dynamic system behavior under the presence of DC reactors.
- → Clarification of the implication of the droop gain on the static and dynamic behavior of DC voltage for disturbance management, and proposal of a systematic selection method
- → Active power response in each control mode (setpoint tracking and post-fault recovery).
- → Secondary DC voltage control, demonstration of feasibility and proposal on specifications

Therefore, in SoW B, we first evaluate the principal converter control mode, namely active power control, fixed DC voltage control mode, DC voltage droop mode, and clarifies the influence of the associated parameters on each control mode as well as the external parameters e.g. DCR size, on their performance. Furthermore, we will demonstrate the feasibility of secondary DC voltage, which is an important function of global DC grid control.

6. Functional group: HVDC grid protection

Figure 37 provides an overview of protection related sections in the CENELEC document. Its section 5 is related to HVDC system characteristics, which was described in Section 4 of this report. Section 7 of the CENELEC report focuses on the global DC protection design and interacts with specific building blocks, namely AC/DC converter stations (Section 8) and switching station (Section 9).

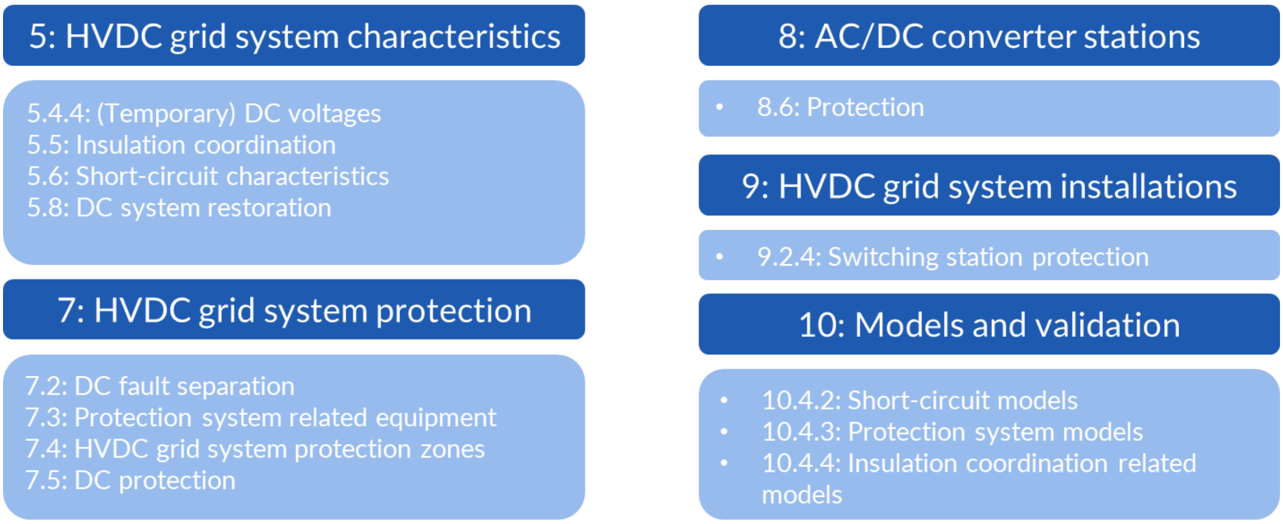


Figure 37 Overview on protection related sections in CENELEC report.

6.1. DC fault separation

6.1.1.1. CENELEC description

In the CENELEC document, the DC side fault separation is described in two steps:

1. Time between fault inception and fault separation
2. Time between fault separation and power flow recovery in the operational part of the grid

The first part focuses on the switchgear operation in order to clear the fault, whereas the second part includes Post DC fault recovery and hence potential control functions of converters to sustain the DC voltage. The related parameter is the fault separation time t_sep as specified in Figure 38.

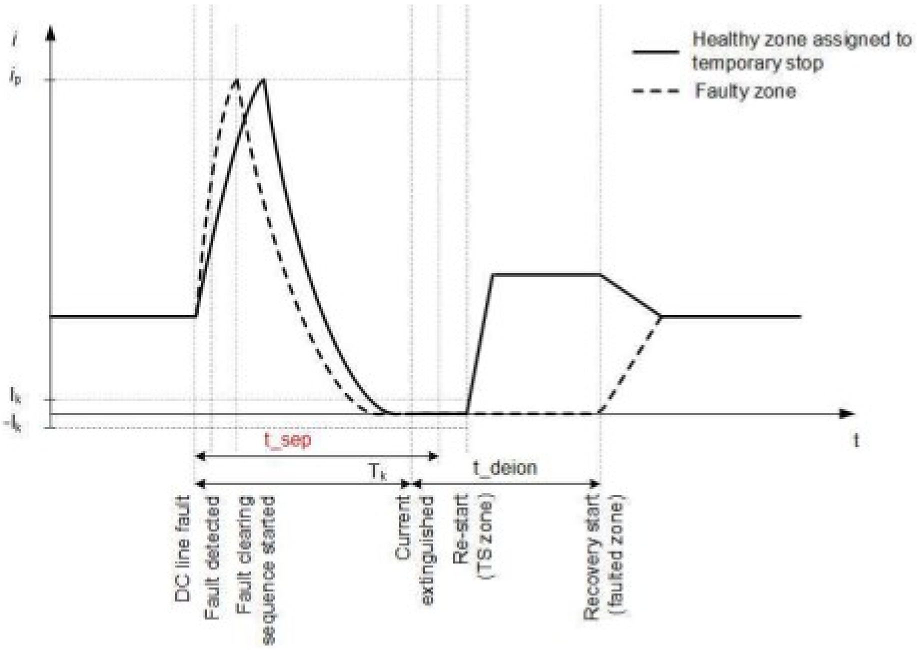


Figure 38 Fault separation time for TS-P (Figure 19 in [1]).

6.1.1.2. Grid code

No mention of this functional requirement was found in DE, NL, DK national grid codes or in NC-HVDC.

6.1.1.3. Existing projects and literature

The Cigré TB 683: “Technical requirements and specifications of state-of-the-art HVDC switching equipment” provides a clear terminology on the different steps from fault inception and current zero. The terminology is chosen such that it is independent from the DCCB technology. The corresponding terms are shown in Figure 39.

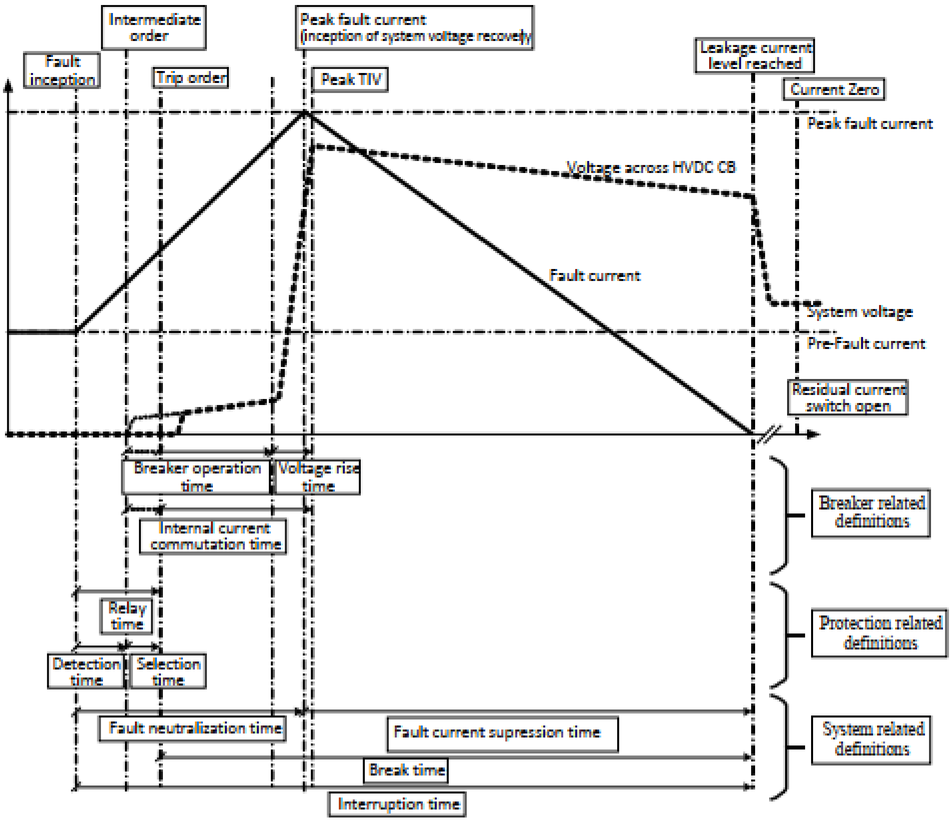


Figure 39 Timing for fault current interruption process [46].

6.1.1.4. Applicability to the building blocks

Applicable to all building blocks with DC switchgear with DC current breaking capability.

6.1.1.5. Corresponding functional requirement ID

Functional requirement ID	Functional requirement title
General51	DC fault detection and identification concept
General52	DC fault seperation devices

6.1.1.6. Discussion

The CENELEC document proposes a single parameter regarding fault current separation, which is the time from fault inception to fault current extinction. For the protection concept, intermediate moments such as fault neutralization time as proposed in [46] are more relevant. In fact, once the DCCB holds the TIV, the voltage recovery of the DC grid starts and the remote converters can establish a post-fault power flow. The fault neutralization time parameter is added to the tendering material document.

6.2. HVDC Grid System protection strategy

6.2.1.1. CENELEC description

Different from other references, the CENELEC document describes a protection concept based on protection zones and not based on protection strategies[5]. Multiple protection zones can be defined according to Figure 40. Different fault separation devices such as AC Circuit Breakers (ACCB), DCCBs, fault separating converter stations, or a mix of them can be used to clear a fault in a protection zone. For bipolar configuration, the protection zones of positive and negative poles are identical but separated since one pole should remain operational in case of a single-pole fault. Complementary to the figure, converter unit protection zones and DC switchyard protection zones can be defined. AC system protection zone and transformer protection zone include standard protections normally used together with HVDC converters or in AC substations. Therefore, they are not described any further in the CENELEC document.

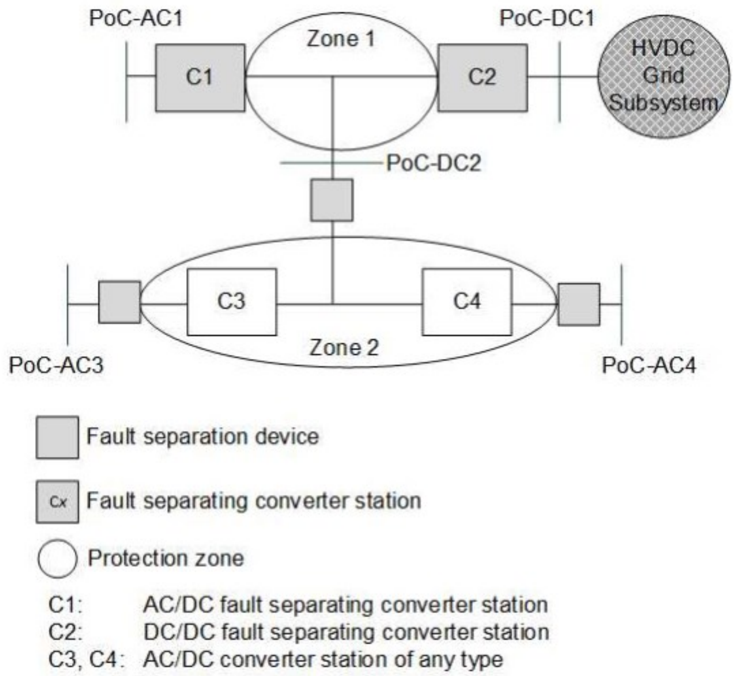


Figure 40 Example illustrating the concept of protection zones in HVDC Grid Systems (Figure 17 in [1]).

The point of coupling (PoC) of a protection zone can be located either on the AC side (PoC-AC) or on the DC side (PoC-DC). Fault separation devices should be chosen in order to be compliant with the FRT behavior at the dedicated PoC. Depending on the capabilities of converters and other equipment in the grid, five concepts

[5] Disclaimer: The CENELEC document describes the protection zones in two sections (7.4 and 8.6). In this document, they are jointly described in order to facilitate the structure.

for the behavior at a PoC during faults are to be considered (see Table 43). The fault separation device (e.g. a breaker, a disconnector or a converter) can be located:

- → In an AC/DC converter station on the AC or DC side
- → In a DC/DC converter station
- → In a DC switching station

For faults in each of these zones, the fault behavior of the transmission system at all PoC-AC and PoC-DC shall be specified. The fault behavior shall be specified by a protection zone matrix including the zones and the PoCs on its axis (see Table 44).

Table 43 DC fault separation concepts of HVDC Grid Systems or parts of them defined at a PoC-AC or PoC-DC respectively.

Fault separation concepts	**Definition of the concept**
Continued operation	The exchange of active and reactive power remains controllable all time during the fault and the fault separation.
Temporary stop P	The exchange of active power can be temporarily interrupted while reactive power remains controllable all time during the fault and fault separation. The interruption of active power is short enough to prevent the transmission system from entering into alert, emergency or blackout state.
Temporary stop PQ	The exchange of active and reactive power can be temporarily interrupted during the fault and fault separation. The interruption is short enough to prevent the transmission system from entering into alert, emergency or blackout state.
Permanent stop P	The exchange of active power can be interrupted due to the fault. The transmission system can enter into alert, emergency or blackout state.
Permanent stop PQ	The exchange of active and reactive power can be interrupted due to the fault. The transmission system can enter into alert, emergency or blackout state.

Table 44 Protection zone matrix.

Faults in:	**PoC-AC1**	**PoC-AC3**	**PoC-AC4**	**PoC-DC1**	**PoC-DC2**
Zone 1	PS-P	CO	CO	PS-P	PS-P
Zone 2	TS-P	CO	CO	TS-P*	TS-P
Zone 3	TS-P	CO	CO	PS-P	TS-P
Zone 4	CO	PS-PQ	PS-PQ	CO	PS-P

6.2.1.2. Grid code

No mention of this functional requirement was found in DE, NL, DK national grid codes or in NC-HVDC.

6.2.1.3. Existing literature and projects

Cigré TB 739: "Protection and local control of HVDC grids"

Other references propose a DC protection strategy related approach. In Cigré TB 739 [14] (see also [47]), it is stated that the fault clearing philosophy must match with the constraints of a specific grid structure, which are maximum loss of infeed and transient stability constraints. The following fault clearing philosophies are identified:

- Non-selective fault clearing
- Partially selective fault clearing
- Fully selective fault clearing

However, it is not excluded that more than one protection philosophy exists in a single meshed HVDC grid.

Taking the non-selective fault clearing as example (see Figure 41), different fault clearing principles can be applied:

a) AC breaker opening
b) DC converter fault clearing
c) Open DC circuit breakers at DC terminals

A fundamental difference from what is proposed in CENELEC is that all PoC of a protection zone are expected to behave identically when running through a fault. No protection zone matrix, where the operational performance of each PoC is defined, is described.

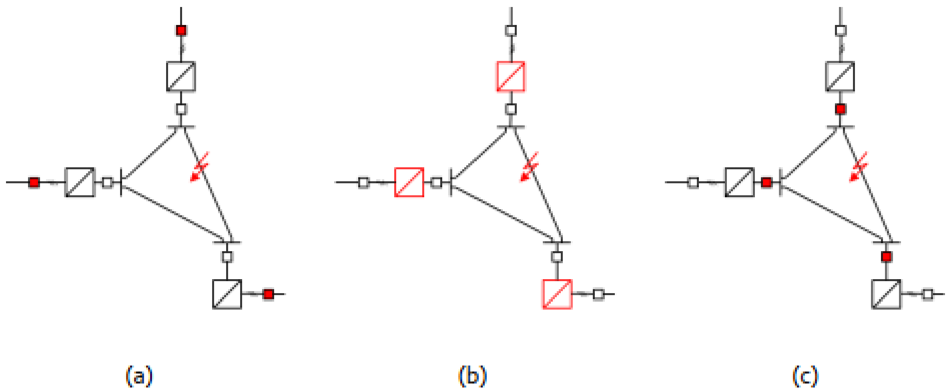


Figure 41 Non-selective fault clearing methods for DC systems. (a) AC breaker opening, (b) DC converter blocking and (c) opening HVDC circuit breakers at converter terminals (elements involved).

Cigré TB 713: "Designing HVDC grids for optimal reliability and availability performance"

In Cigré TB 713, an overview on different fault clearing philosophies and associated fault clearing times is provided (see Table 45).

Table 45 Overview on protection philosophies.

Protection philosophy	Fully selective	Partially selective	Non-selective			
Fault Clearing Strategy	Line or zone	Grid-Splitting	AC circuit breaker	with fault blocking converters	with HVDC circuit breakers at converters	Open Grid
HVDC grid protection zones	Lines and converters as separate zones	Small parts of the grids as zones	Entire HVDC grid as one zone	Entire HVDC grid as one zone	Entire HVDC grid as one zone	No protection zones are defined for fault clearing
Faulted zone isolation method[1]	HVDC circuit breakers	HVDC circuit breakers, DC/DC converters	AC circuit breakers	Fault blocking converters	HVDC circuit breakers at converter terminals	HVDC circuit breakers at line ends
Fault clearing time	5 – 10 msec	Depends on fault clearing method (see non-selective methods)	~60 – 80 msec	~5 – 10 msec	~5 – 10 msec	~5-10 msec
HVDC line switching equipment	HVDC circuit breakers or HVDC switches	HVDC circuit breakers, and/or DC/DC converters and HVDC switches	HVDC switches	HVDC switches	HVDC switches or HVDC circuit breakers	HVDC Circuit Breakers or HVDC switches

6.2.1.4. Applicability to the building blocks

The protection concept must be specified at each PoC-AC and PoC-DC and is therefore applicable to each building block except the master controller.

6.2.1.5. Corresponding functional requirement ID

Functional requirement ID	Functional requirement title
General50	DC fault seperation concept
General53	Time requirements Temporary faults
General55	DC fault recovery
General60	Maximum loss of active power
General61	Post-fault active power recovery
General62	Fast recovery from DC fault
General63	HVDC terminal response to DC grid faults

6.2.1.6. Discussion

The CENELEC document provides a systematic approach to developing a protection concept for HVDC grids. It takes into consideration the constraints on the AC side and on the DC side by proposing operational modes for each PoC according to the system constraints. In this way, a modular grid planning with different technologies is possible and a dedicated protection concept can be specified. Therefore, the CENELEC approach should be used.

6.3. Functional requirements for HVDC protection zones

The CENELEC document proposes minimum functional requirements for the detection and elimination of converter unit protection zone faults and DC line protection zone faults (see CENELEC Section 8.6). The specifications for the DC switching station zone faults are provided in CENELEC Section 9.2.

6.3.1. Converter Unit protection zone:

6.3.1.1. CENELEC description

In addition to the protection zones that are defined in an HVDC grid structure (see section 6.2), other protection zones should be specified in order to cover internal faults (e.g. internal converter faults). For the protection system of the AC/DC converter station, the following protection zones are defined:

- AC switch yard protection zone
- converter transformer protection zone
- converter unit protection zone
- DC switching station protection zone
- DC line protection zone

It is stated that not all protection zones are necessary. In fact, a DC switchyard protection zone is not mandatory if only one converter unit is connected because the converter unit protection zone already covers the protection aspects.

The following internal faults shall be detected:

- internal valve or submodule faults
- phase-to-phase or phase-to-earth short-circuit at the AC connection of the converter transformer valve side
- faults to earth at the DC circuit
- abnormal AC system conditions (e.g. abnormal AC voltages or frequencies beyond specified limits)
- inadvertent opening of circuit breakers feeding the AC/DC converter unit
- DC side abnormal voltages

The following failures shall be detected by the overall protection system, control or specific protections associated to that equipment:

→ elements inside the converter
→ converter control circuits including the identification of failed devices
→ auxiliary systems

For faults on Neutral Bus and DC switches, CENELEC report states the following. It should be noted that DC switches and neutral bus can be located at the switching station. In that case, the identification of such failures should be done by the switching station and communicated to the local converter station if relevant. This applies also for the protection functions listed hereunder.

→ DC switch failure, if any
→ open circuit fault of the neutral, if any
→ current at the station earth, if any

Protection functions:

→ differential protections
→ overcurrent protections (can include equipment from other protection zones)
→ DC-side abnormal voltages protection
→ AC-side abnormal voltages protection
→ special equipment protection, if any
→ neutral DC bus overvoltage protection
→ DC switch protection

CENELEC report further proposes several fault separation strategies related to internal converter faults:

→ Inhibit de-block
→ Trip AC circuit breaker
→ Converter block
→ Converter/pole isolation
→ Current limit
→ Close neutral bus grounding switch
→ Re-close the DC switch or HVDC breaker
→ Transfer trip to DC grid protection

6.3.1.2. Grid code

N/A

6.3.1.3. Existing literature and projects

In the Zhangbei project [48], the converter station protection zones are specified as shown in Figure 42. It is stated that the DC line protection and metallic return protection are independently arranged in the DC line protection host, ensuring that they can be switched on/off separately without mutual interference.

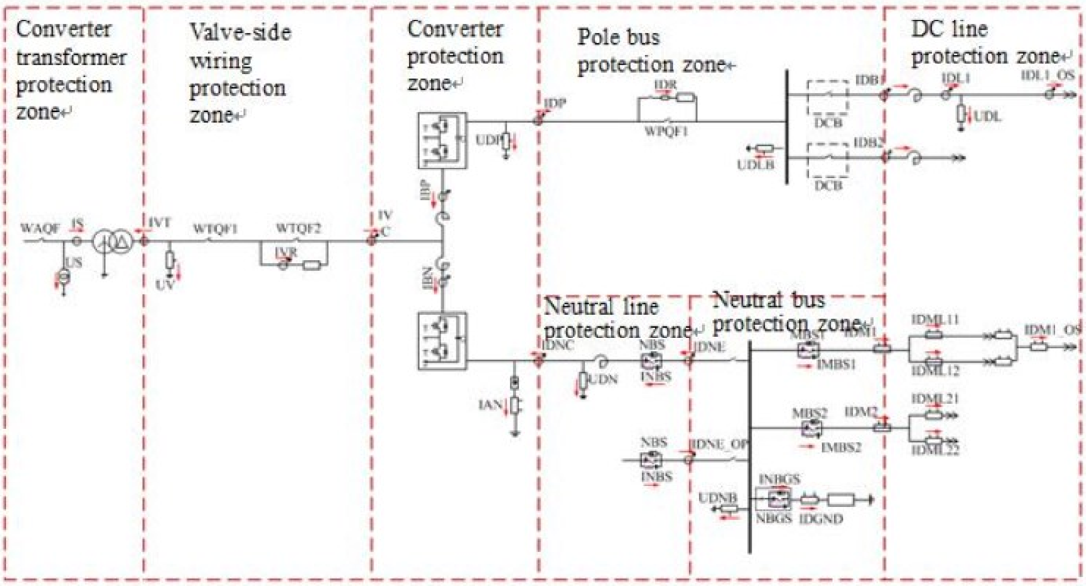


Figure 42 Converter station protection zones in Zhangbei project.

6.3.1.4. Applicability to the building blocks

Applicable to onshore and offshore converter units.

6.3.1.5. Corresponding functional requirement ID

Functional requirement ID	Functional requirement title
General64	AC/DC converter protection functions
On_ACDC_Con5	Converter protection zones
On_ACDC_Con6	Converter unit protection zone
On_ACDC_Con7	DC line protection zone
On_ACDC_Con8	DC switching station protection zone

On_ACDC_Con9	Coordination of DC protection with HVDC system
Off_ACDC_Con7	Converter protection zones
Off_ACDC_Con8	Converter unit protection zone
Off_ACDC_Con9	DC line protection zone
Off_ACDC_Con10	DC switching station protection zone
Off_ACDC_Con11	Coordination of DC protection with HVDC system

6.3.2. DC switching station protection zone

6.3.2.1. CENELEC description

According to CENELEC report, the following faults within the DC switching station protection zone shall be detected:

- faults to earth or neutral (pole-to-earth fault)
- faults between two poles (pole-to-pole fault with and without earth connection)

The following faults affecting the neutral bus and the DC switches operated on-load, if any, shall be detected:

- DC switch failure, if any
- open circuit fault of the neutral, if any
- current at the station earth, if any
- faults in the HV pole line, if configured as metallic return

The following protection functions are typically provided:

- differential protections
- overcurrent protections (can include equipment from other protection zones)
- neutral DC bus overvoltage protection
- DC switch protection

The following failures shall be detected by the overall protection system, control or specific protections associated to that equipment, if applicable:

- auxiliary systems
- status of switchgear

6.3.2.2. Applicability to the building blocks

Applicable to the switching station.

6.3.2.3. Corresponding functional requirement ID

Functional requirement ID	Functional requirement title
Off_SS1	Fault current interruption
Off_SS2	Switching station protection zones
Off_SS3	Switchgear failure detection
Off_SS4	DC line fault detection

6.3.3. DC line protection zone

The DC line protection zone shall detect the following faults:

- faults to earth or neutral (pole-to-earth fault)
- faults between two poles (pole-to-pole fault with and without earth connection)

For the neutral line, if any, the DC line protection zone shall detect the following faults:

- open circuit fault of the neutral line
- neutral line to earth fault

6.4. Coordination of the DC protection with the HVDC Grid system

6.4.1.1. CENELEC description

According to the CENELEC report, the protection coordination between the different protection zones must be specified for primary and backup protection and for each zone individually. Therefore, it is proposed to define detection requirements and relevant communications.

Table 46 shows the proposed concept of protection coordination for primary and backup protection.

Table 46 Protection coordination of an AC/DC converter station and the HVDC grid system (Table 56 in [2]).

Faulted zone	PoC-AC1				PoC-DC1			
	Main		Backup		Main		Backup	
	Sep. concept (Sep. device)	Detection requirement	Sep. concept (Sep. device)	Detection requirement	Sep. concept (Sep. device)	Detection requirement	Sep. concept (Sep. device)	Detection requirement
Zone 1								
Zone 2								
...								
Zone *n*								

The CENELEC report does not impose a protection scheme without communication (single ended) for selective fault clearing, but it can be seen as a recommendation in order to avoid a communication delay. Hence, a column could be added to Table 46 with specification of fault detection time and fault identification time.

6.4.1.2. Grid code

N/A

6.4.1.3. Existing projects and literature

Cigré TB 713: "Designing HVDC grids for optimal reliability and availability performance"

Cigré TB 713 provides additional elements in terms of reliability and redundancy requirements for DC protection systems.

Protection system reliability:

→ The system must operate in the presence of a fault within its zone of protection. This facet of protection system reliability is commonly referred to as dependability.

→ It must refrain from operating unnecessarily for faults outside its protective zone or in the absence of a fault. This facet of protection system reliability is commonly referred to as security.

Protection system redundancy:

The duplication of the main protection system achieves a level of redundancy that ensures correct operation of the protection system in the event of a failure of a single component i.e. satisfying N-1 planning criteria. In case where protection equipment is located offshore, it may take a number of weeks to have the faulty equipment replaced. In these cases, it may be worth considering triplication of the main protection system, allowing for 2 simultaneous contingencies. This would have a positive effect on the dependability of the overall grid protection system. However, there would inevitably be some level of reduction of the security of the protection system, since duplication of components increases the risk of unwanted operation.

One method that could be used to optimize both the security and dependability of the protection system is to triplicate the protection system, and configure the tripping logic as a 2-out-of-3 system. This allows for correct operation following the failure of a single component, while also being less sensitive to unwanted operation because at least two systems need to issue a trip command. It is noted that converter protection schemes have previously used 3-out-of-4 voting schemes. This also allows for correct operation following the failure of one component, while assuring a very high security against unwanted tripping, as three protection systems must issue a trip command before the command is issued to the breaker.

6.4.1.4. Applicability to the building blocks

Applicable to all building blocks. The DC protection coordination must be specified at a local level and interfaces with the master controller must be specified.

6.4.1.5. Corresponding functional requirement ID

Functional requirement ID	Functional requirement title
General56	Communication
General57	Protection equipment redundancy
General58	Protection system measuring equipment

6.4.1.6. Discussions

In addition to what is proposed in the CENELEC report, it should also be specified how to distinguish between internal and external faults. The Cigré TB 713 gives a better overview on the terms security and dependability but no related functional requirements are defined. The fault detection time should be specified for each separation concept in Table 46.

6.5. DC fault current limiting devices

The DC fault current can be limited by either DC reactors or Superconducting Fault Current Limiters (SFCL) [49]. In this section, the focus is on DC reactors as they are considered in the CENELEC report and in other relevant references.

It should be noted that the DC fault current is dependent on many aspects as listed in Section 4.3.1.4. This should be considered to the DC reactor design. Therefore, all values are for reference purpose only as they are related to a specific grid structure and the dedicated design parameters. No generic values could be found in literature.

6.5.1.1. CENELEC description

The DC fault current limiting device is one of many influencing factors on the short circuit characteristics (see Section 4.3.1.4, CENELEC Section 5.6). In the parameters section, a DC reactor value should be specified.

Table 47 DC line reactor data (Table 25 in [2]).

Symbol	Parameter	Characteristic	Value	Unit
L_XR	inductance			mH

6.5.1.2. Grid code

N/A

6.5.1.3. Existing projects and literature

The NSWPH technical requirements, SoW A (Supergrid) [50]

Table 48 DCR sizing result for 2 GW block type.

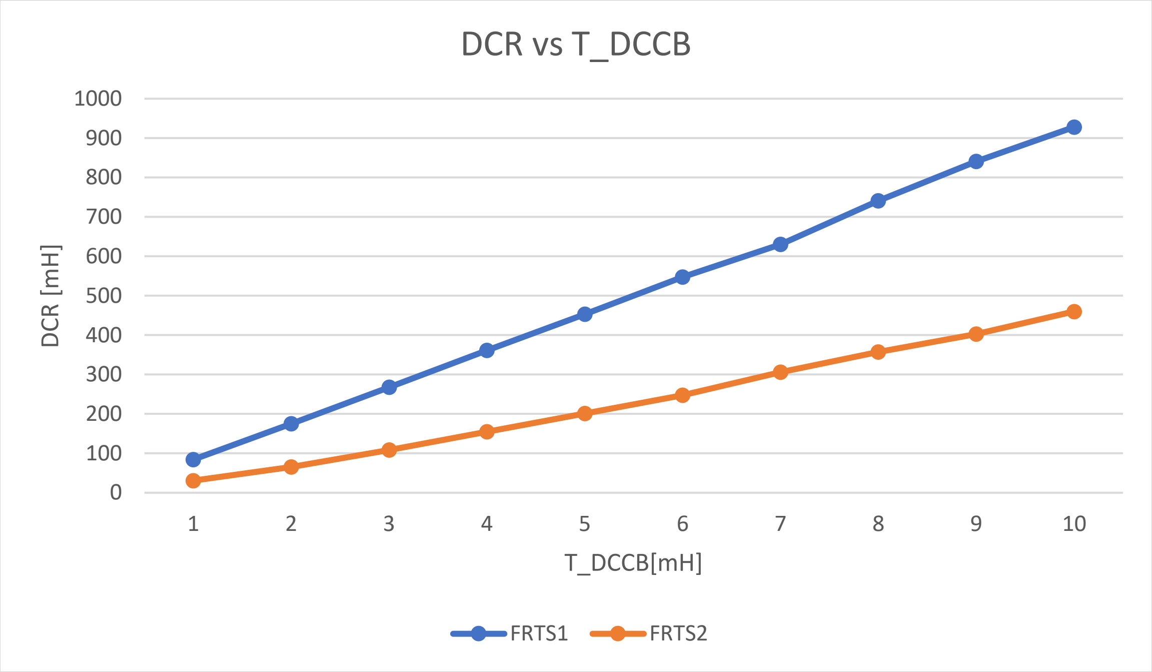
WF	150 mH
Spoke	250 mH
Left (II)	150 mH
Right (II)	150 mH

Table 49 DCR sizing result for 3 GW block type (switching station).

Spoke	180 mH
II	180 mH
II with two lines in parallel	180x2 mH (at each cable end)

Systematic Approach to HVDC Circuit Breaker Sizing [51] [52]

DCR[mH]\T_DCCB[ms]	1	2	3	4	5	6	7	8	9	10
FRTS1	84	176	268	361	454	548	631	741	841	928
FRTS2	31	66	108	155	201	247	306	357	403	460



Conditions	
Grid configuration	5-terminal symmetrical monopolar
Rated voltage	320kV
Rated converter power	400-1000MW
Converter overcurrent threshold	2
DCR placement	Only at line end
Blocking criteria	2pu DC current
	FRTS1 : No converter blocking
	FRTS2 : Local converter allowed to block
	FRTS3: All converters allowed to block
Conductor type	Cable
Cable length	150-250km
Fault detection time	0.3ms

PROMOTioN D4.2 [47]

T_DCCB [ms]	2	8
DCR [mH]	50	100

Conditions	
Grid configuration	4-terminal symmetrical monopolar (Pole-to-pole fault)
Rated voltage	320kV
Rated converter power	1200MW
Converter overcurrent threshold	2 pu DC current
DCR placement	At line end & at converter output
Blocking criteria	No blocking
Conductor type	Cable
Cable length	100-350km
Fault detection time	0.5ms

Zhangbei project] [53]

	Reference	Beijing	Fengning	Kangbao	Zhangbei
Arm reactor	[54]	75	100	100	75
	[55]	40	75	75	40
	[56]	50	100	100	50
DC reactor at line end	[54], [56]	150	150	150	150
Neutral reactor	[54] , [56]	300	300	300	300

Table 1. The main equipment parameters of converter station.

Equipment	Beijing	Fengning	Kangbao	Zhangbei
Sub-module capacitance (mF)	15	8	8	15
Number of sub-modules	244	244	244	244
IGBT parameter	4.5kV/3kA	4.5kV/2kA	4.5kV/2kA	4.5kV/3kA
Converter station capacity (MW)	3000	1500	1500	3000
Bridge arm reactor (mH)	75	100	100	75
Polar reactor (mH)	150	150	150	150
Neutral wire reactor (mH)	300	300	300	300

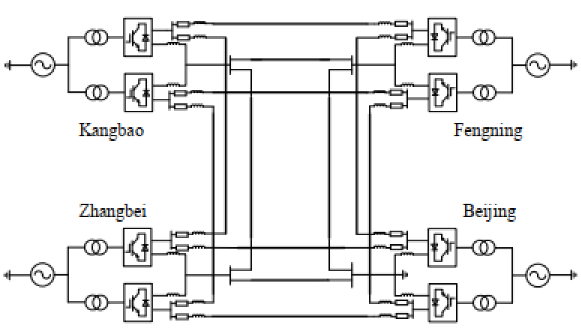


Figure 1. Four-terminal flexible grid topology.

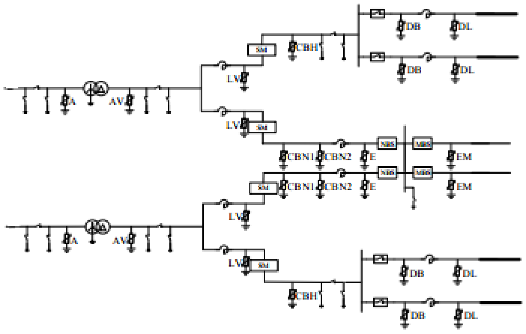


Figure 2. Typical structure diagram of converter station.

Figure 43 Zhangbei grid topology and converter parameters.

Cigré TB 739 (Chapter 5.4.3) [49]

Factors to consider:

→ Transmission line type

→ The characteristic impedance of overhead lines is larger than that of cables, which causes current waves to be smaller in amplitude. The traveling wave speed of overhead lines is about the speed of light, whereas for cables this is half to 2/3 the speed of light.

→ Fault resistance

→ An increasing fault resistance leads to a smaller prospective steady-state fault current.

→ DC side inductance

→ Increasing the DC side inductance decreases the rate of rise of the current but does not impact the prospective steady-state fault current.

→ DC side capacitance

→ A DC side capacitance (e.g. the one used in two-level topologies) initially provides a large discharge current.

→ Converter blocking instant

→ The converter blocking instant determines the amount of discharge of submodule capacitors. Delaying the converter blocking instant increases the capacitor discharge.

- AC system strength
- The AC system strength mainly determines the value of the prospective steady-state current. An increased AC system strength leads to an increased value of the prospective steady-state current, only limited by the short-circuit impedance of the connecting equipment such as transformers.
- System earthing
- Converter topology

6.5.1.4. Applicability to the building blocks

The requirements on fault current limiting devices should be investigated for each building block while considering the overall protection concept. DC reactors may also be required to match the fault detection and fault identification in the specified protection zones as they provide additional electrical distance.

6.5.1.5. Corresponding functional requirement ID

Functional requirement ID	Functional requirement title
General65	DC fault current limiting

6.6. Neutral Grounding

This section focuses on existing FR that can be found in literature regarding the grounding of the neutral point of the bipolar converter station.

6.6.1.1. CENELEC description

CENELEC proposes two main definitions:

- → DC circuit earthing
- → Station earthing

DC circuit earthing

The DC circuit earthing regards the connection of the neutral points in the HVDC Grid or subsystem to the earth. It is mainly dependent by the change of the DC voltage of a non-faulty conductor with respect to earth due to an undisturbed steady-state fault current, i.e. assuming there were no countermeasures limiting the DC fault current. The decisive parameter is the ratio of the non-faulty conductor's DC voltage to earth during the fault to the nominal DC voltage to earth of the same conductor. DC circuits having a DC voltage displacement lower or equal to a pre-defined level are defined as effectively earthed. DC circuits having higher DC voltage displacement are defined not effectively earthed. The characteristics of possible DC circuit earthing are depicted in Table 50. The NSWPH project only focuses on effectively earthed DC circuit.

Table 50 DC circuit earthing characteristics.

	DC circuit earthing principle	
	Effectively earthed	Not Effectively Earthed
Stresses during DC pole to earth fault	High DC fault current stresses Low voltage stress	Temporary over voltages Low DC fault current stresses
Examples	Bipole with DMR Rigid Bipole Asymmetric Monopole	Symmetric Monopole

Station Earthing

In a bipolar configuration the station earthing is referred to the neutral grounding, that is the earthing of the neutral point of the MMC station. The options for the station earthing are:

- → Direct Earthing (solid connection)
- → Impedance Earthing (Z impedance, combination of R,L,C components or SA)
- → No connection to Earth (very high impedance)

Illustration of station earthing are shown in Figure 44, a switch (Sw) can be used to change the grounding configuration, for example from direct earthing to earthing through a SA.

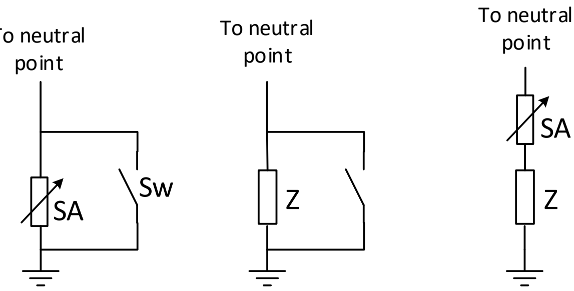


Figure 44: Example of station earthing options.

6.6.1.2. Existing projects and literature

This section covers the literature review for neutral grounding of HVDC grid in bipolar system. A focus is made for Zhangbei HVDC grid, 500kV MMC half-bridge HVDC grid in bipolar configuration with DMR and OHL, see Figure 45 [57].

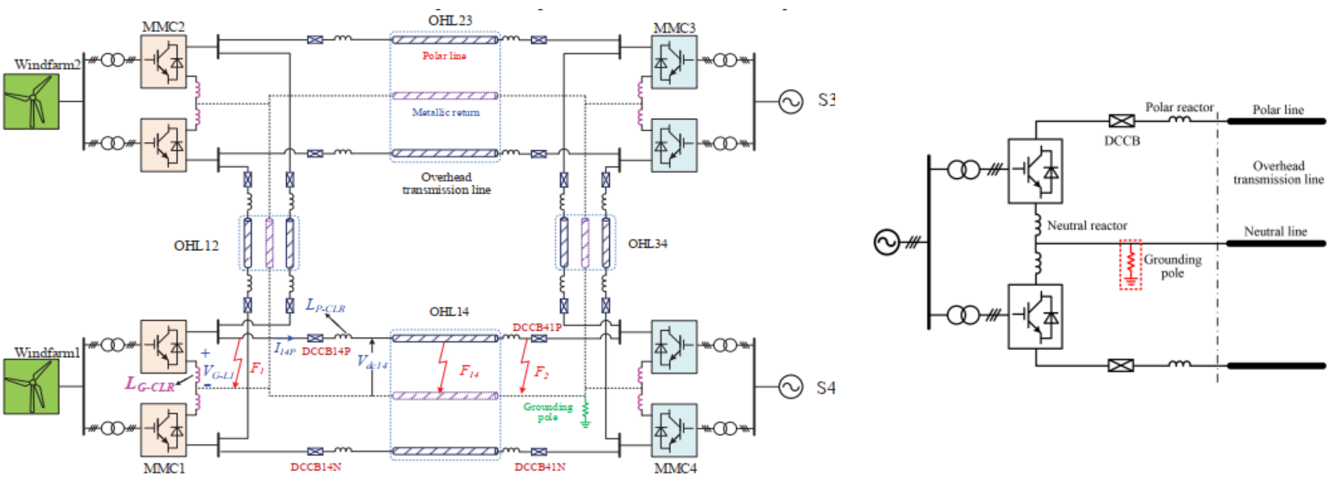


Figure 45: Zhangbei HVDC grid.

Based on the literature review, the following characteristics are identified:

→ **Neutral grounding**

> Beijing station (MMC4), see Figure 45, has a neutral earthing resistance Rg of 15 Ω [58].

> All other stations have neutral grounded through a SA, probably with a clamping voltage around 200 kV [53]. During pole to ground fault on a line (eg. at middle of a line), due to coupling effects, an overvoltage (max around 360 kV) will appear at the DMR (eg at middle of the DMR) as shown in paper [59]. Note that in a cable configuration the mutual coupling between poles and DMR are negligeable and the maximum overvoltages at the DMR would appear only at line end.

> It should be noted that the Rg has no impact on the design parameter for the DCCB (short circuit current) because the DCCB has to be designed to clear pole-to-ground, pole-to-DMR and pole-to-pole faults. Indeed, during a pole-to-pole fault the majority of current flows through the poles and the neutrals point of the stations, without involving the grounding resistance.

→ **DCR at neutral point**

> All MMC stations have the neutral conductors connected to the DMR through a neutral reactor of 300 mH [58]. This reactor has the same function of DC fault current limiting Reactors (DCR) placed at the positive or negative poles of the MMC. Indeed, in [60] it is mentioned that for HVDC grids with high operation voltage and transmission power, the current limiting reactors could be split between the HVDC pole lines and the neutral connections to minimize the reactor size and ease the dielectric design of the current limiting reactors.

→ Grounding resistance and SPG fault at valve side

> The aim of the grounding resistor Rg is probably to avoid non-zero current crossing at the AC grid side during a Single Pole to Ground (SPG) fault occurring at AC valve side [61], [62], see Figure 46. During a SPG fault, the MMC is blocked and a trip signal is sent to the AC breaker installed at the AC grid side. The SPG fault can entails non-zero current crossing at the AC grid side and thus damage the AC breaker during its operation. The grounding resistance allows to accelerate the decay of the DC current component and avoid the non-zero crossing during the operation of the AC breaker. To our knowledge, the designing principles of the grounding resistance for Zhangbei system are not described in literature.
It is worth noting that for Skagerrak 4 HVDC project (bipolar configuration) another solution is adopted to avoid the phenomenon of non-zero crossing during SPG fault [63], Figure 47. An AC circuit breaker phase-to-ground has been installed at the transformer grid side which is closed after a SPG fault. This produces a new three-phase to ground fault and add a symmetrical current component that ensures zero crossing.

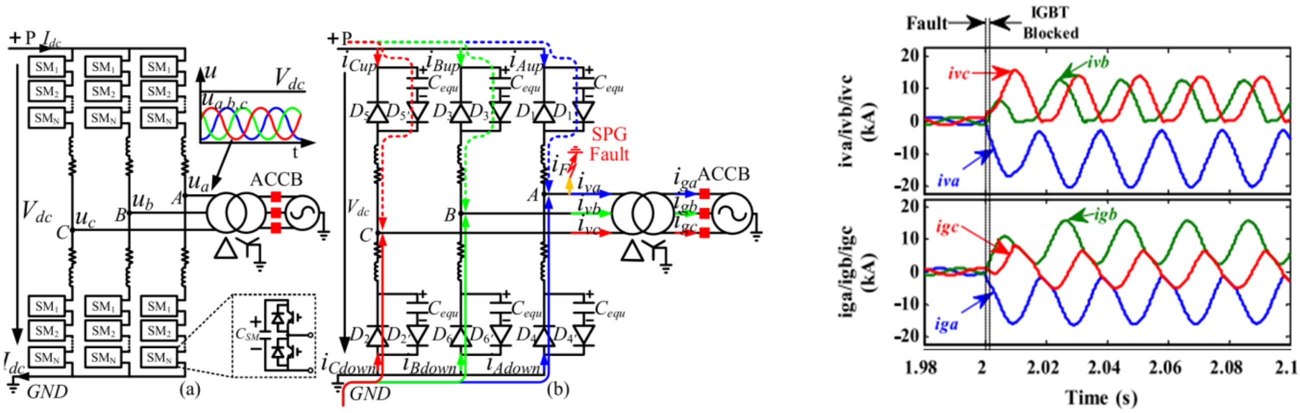


Figure 46: SPG valve side fault entailing a non-current zero crossing for AC currents.

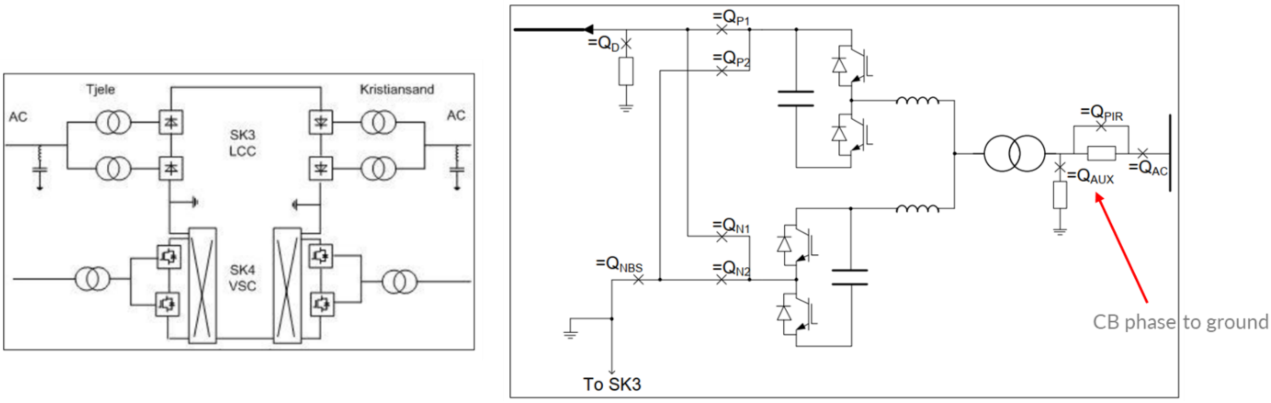


Figure 47: Solution proposed in Skagerrak 4 to avoid non-current zero crossing using phase to ground AC breaker.

→ **Other Neutral grounding**

> The TB 471 [64] mentions that the DMR is grounded at only one point (usually the neutral of one of the converters) while the neutral of the other converters are left floating but protected by an arrester or a combination of an arrester and a surge capacitor, see Figure 48. The capacitor in parallel of the SA is probably useful to reduce SA energy requirement.

> In case of DMR based on OHL, the management of the neutral grounding is more complex because the risk of DMR to ground fault is much higher due to lightning impulses [65]. This subject is out of scope within the present study.

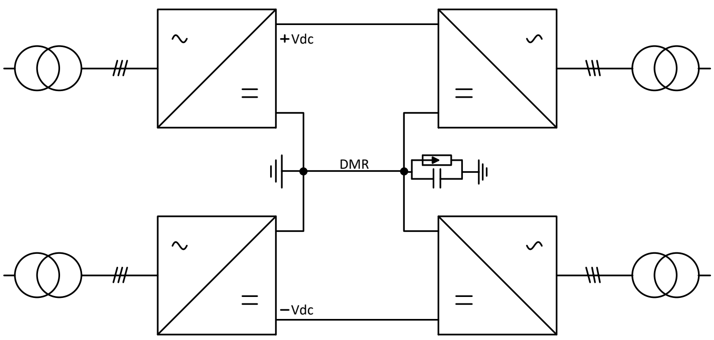


Figure 48: Example of grounding by means of SA in parallel with a capacitor.

6.6.1.3. Applicability to the building blocks

The requirements for neutral grounding are applicable to each building block.

6.6.1.4. Corresponding functional requirements

Functional requirement ID	Functional requirement title	Requirement
General 79	Neutral voltage reference	The grounding of neutral shall provide a reference voltage for the neutral of the stations. At least one station shall be solidly grounded or grounded through a grounding resistance. The grounding scheme of the whole grid shall allow the redundancy of the solidly grounded station and shall allow extensibility of the grid.
General 80	Neutral overvoltages	The grounding of neutral shall limit the overvoltages at the neutral of the station.
General 81	Current though the neutral grounding	The grounding of the neutral shall not allow flowing current through the earth during normal operation.

6.6.1.5. Discussions

Based on the literature review presented in the previous sections the following assumptions are taken as a starting point for SoW B and for the definition of FR and PR for neutral grounding.

- In steady state, only one station can have the neutral grounding solidly connected to earth. Note that if in steady state two station are solidly grounded, the unbalanced current would flow through the earth instead of the DMR.
  - The steady state (>2s) current should not exceed 5 A (the current technical status is that the unbalance earth current can be controlled below 2A, also for LCC bi-pole links).
- Temporarily, two stations can have the neutral grounding solidly connected to earth.
  - Load current 2 kA is allowed for 2 seconds.
- The solidly grounded station can have a grounding resistance in the order of 10-20 ohm to avoid the problem of non-zero current crossing at the AC side grid during a SPG fault at valve side.
- All N-1 stations that are not solidly grounded have the neutral point grounded through a SA to limit overvoltages in case of faults. Note that the neutral surge arrester shall be designed to ensure limited steady state current through the earth during unbalance operation and to limit overvoltages during faults.
- To allow redundancy, all stations can switch from solidly grounded neutral to a neutral point grounded through a SA.
- Grounding options that include combinations of RLC components are not taken into account within SoW B.

6.7. Surplus power absorption

6.7.1.1. CENELEC description

The energy dissipation/absorption capability is stated as an optional requirement that can be integrated into an AC/DC converter station (see CENELEC Section 8.4.1.4) and/or a DC switching station (see CENELEC Section 9.2.2.1.5).

Minimum requirements for such a device are:

- → power vs. time characteristics $P = f(t)$ (MW)
- → repetition (number of events)
- → minimum time between consecutive events (min)

6.7.1.2. Grid code

6.7.1.3. Existing projects and literature

In Zhangbei project, AC choppers on the production side are used to absorb the surplus of energy [48]. The following reasoning is stated:

If the converter station connecting renewable energy sources employs VF control mode, the input power of converters is out of control and thus the following problems occur,

- → In the case where the receiving-end converter station is blocked and switched off or its power is limited due to the fault, the sending-end converter station remains at the original output power level, which results in excess power in the DC grid, DC voltage rise, and blocking and shutdown of the DC grid.
- → In the case where a single pole of the sending-end converter station is blocked and switched off or its power is limited due to the fault, the power of wind farm is transferred to the healthy pole. During the power transfer, overcurrent will occur on the converter valve bridge arm of the healthy pole, leading to expansion of the fault range.

In Zhangbei project, energy-consuming resistors are provided on the AC side of the sending-end converter station. Under island operation mode, in the case where single or both poles at the sending end are blocked due to fault, the energy-consuming resistors would be switched on based on the pre-fault power; and in the case where the DC voltage rises due to the fault at the receiving end, the energy-consuming resistors would be switched on based on the DC voltage and pre-fault power [48].

6.7.1.4. Applicability to the building blocks

Applicable to all building blocks where an energy absorption device (i.e. DBS) is installed.

6.7.1.5. Corresponding functional requirement ID

Functional requirement ID	Functional requirement title
General54	Surplus power absorption

6.7.1.6. Discussion

An energy dissipation device must ensure that voltage bands on the AC side and on the DC side are not violated, and that unwanted disconnections due to such violations must be avoided. In existing PtP links, choppers are located on the DC side onshore. This allows to absorb a surplus of energy in case of onshore converter outage and lower the footprint on the offshore side. However, an offshore AC chopper has the advantage of absorbing the offshore wind power in case of temporary offshore converter blocking and reconfiguration of the busbar (e.g. during busbar fault). Thus, wind farm disconnection could be avoided. There is a tradeoff between installation costs and availability.

6.8. Conclusions & next steps in SoW B

The CENELEC report covers different protection strategies and DC fault separation concept on a very high level. Taking into account several boundary conditions such as maximum loss of infeed, converter blocking constraints, most likely offshore hub topologies as described in the use case scenarios and the ability to extend the DC grid in a modular way some technical choices on the protection design can be made. These technical choices allow to provide a more detailed investigation of protection aspects in SoW B and to develop generic models in this context. In SoW B the following aspects will be investigated:

- Refinement of Temporary stop and Permanent stop as this is not sufficiently specified in the CENELEC standard.
- Converter blocking specifications in terms of overcurrent and undervoltage. The blocking constraints of the converter must be incorporated in the protection design in order to respect limits in terms of maximum loss of infeed.
- A DC over- and undervoltage ride through profile is proposed in CENELEC but voltage levels and times are not specified. Relevant dimensioning events are investigated in SoW B.
- Parameter ranges during fault clearing process (i.e. DC reactor requirements, DCCB operating times, fault current suppression times and energy absorption) are further specified in SoW B).
- DBS operation requirements will be further investigated.

7. Functional group: HVDC grid operational modes

7.1. General

The functional group “HVDC grid operational modes” gathers different functional requirements related to the open-loop controls of the DC system (including start-up and shut down), the operating states, and the connection modes.

Section in present report	Corresponding chapters in the CENELEC report I
Connection modes	5.2 Connection modes
Operating states	5.3 Grid Operating States
Operating states	5.8 DC System Restoration
Open-loop controls & Operating sequences	6.4 Open loop controls
Connection modes	8.4 Main Circuit Design
Open-loop controls & Operating sequences	8.5 Controls
Connection modes	8.6.6 Coordination of the DC Protection with the HVDC Grid System
Connection modes	9.2.2.2 DC Switching Station – DC Connection

7.2. Open loop controls and operating sequences

7.2.1.1. CENELEC description

Open-loop controls, in opposition to closed-loop controls, cover the following control objectives

- → Start-up and shut down of the DC system or DC subsystems through proper operating sequences, which is the focus of this section.
- → Connection modes of high voltage poles, neutral conductor, and system earthing. This is further detailed in Section 7.4

The start-up and shut down sequences are described in Figure 49 and may apply to either the entire HVDC grid system or sub-systems, including converter stations. The operating sequences for an AC/DC converter station are further detailed in Section 8.5.5.

The complete start up process comprises the steps from “Preparing to energize” to “Connecting” while the shutdown process comprises the steps from “Stopping Synchronization” to “Shutting down”.

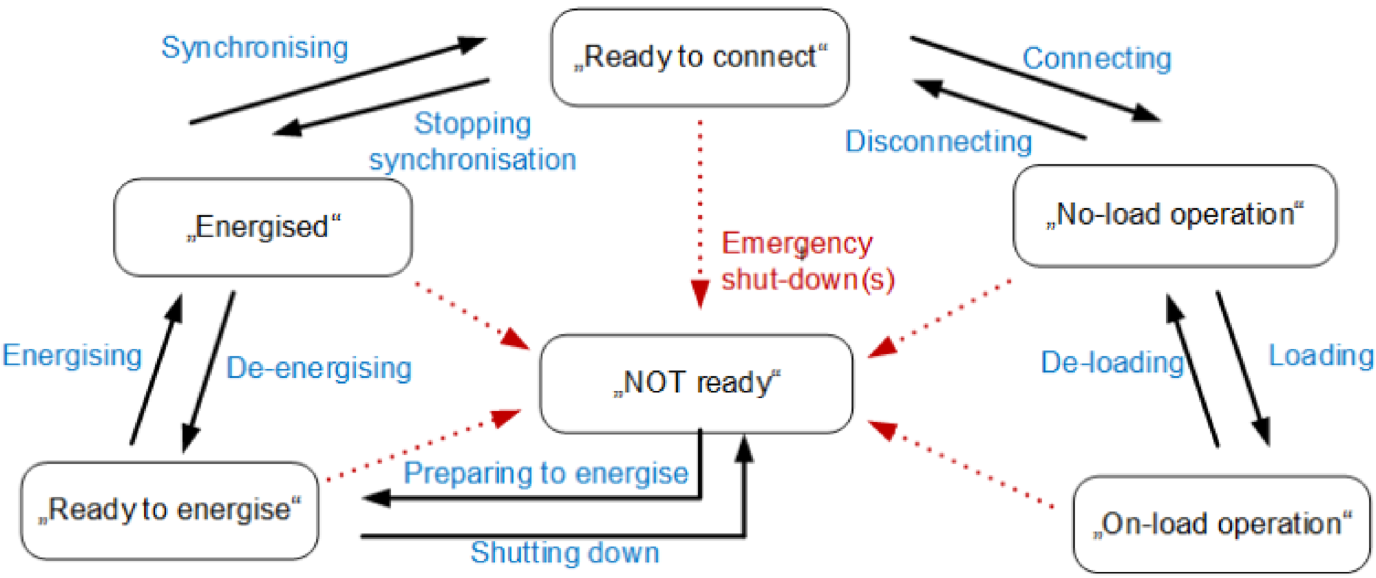


Figure 49 Start-up and Shut down sequences for converter stations and DC grid (Figure 16 in [1]).

The applicability of the operating sequences to the different components of the DC grid is further specified in Table 51.

Table 51 Functions changing operating states.

	AC/DC interface	**HVDC Grid System Installation**			
Function	AC/DC converter station	DC switching station	transmission line and transition stations	DC/DC converter station	DC line power flow controller
Preparation for energisation / shut down	yes	yes	n.a.	yes	yes
Energisation / de-energisation	yes	optional	n.a.	yes	optional
Synchronisation / stop synchronisation	yes	optional	n.a.	yes	yes
Connection / disconnection	yes	yes	n.a.	yes	yes
Loading AC side / de-loading AC side	yes	n.a	n.a.	n.a.	n.a.
Loading DC side / de-loading DC side	yes	optional	n.a.	yes	yes

7.2.1.2. Grid code description

It is stated in [20] that during energization and synchronization, HVDC converter station shall be able to limit any voltage changes to a steady-state level. This level should be less than 5% of the pre-synchronization voltage.

7.2.1.3. Description in existing literature

In CIGRE TB 697 [66], the following “operating states” are defined for a converter and are mutually exclusive

- → Earthed: converter is earthed on DC and AC sides, for maintenance work.
- → Stopped/Isolated: Converter is isolated on AC and AC sides.
- → Standby/De-energised: Converter is not transmitted power but all auxiliary circuits are operational.
- → Blocked: Converter is fully energized but not receiving control commands.
- → Deblocked: Converter is fully energized and receiving control commands.
- → STATCOM: Converter is fully energized and receiving control commands, but DC side is isolated or configured such that no active power is transmitted. The DC bus voltage can be controlled.
- → Islanded / DC connected: The converter connected to an islanded AC network is able to control the AC voltage and frequency.
- → Transmission mode: Converter is deblocked and fully energised and linked to other converters through DC links. Active and reactive power can be controlled.

It is noteworthy that the operating states from [66] do not entirely match the ones from CENELEC.

Different possible start-up sequences for an offshore MTDC grid are investigated in [67]. The four different sequences are summarized in Table 52. The system under study is a 4-terminal HVDC grid with one offshore wind farm and three onshore terminals. One offshore converter is operating in voltage control mode and the remaining onshore terminals are in power control mode. For sequences 3 and 4 (valid sequences), the start-up of the whole system takes slightly less than 30s.

Table 52 Four different proposed start-up sequences for MTDC grid.

	Principle	Assessment
Seq. 1	Simultaneous start-up of all HVDC terminals and OWF	Not valid as the PWF cannot be started when its terminal voltage has not been established.
Seq. 2	Sequential start-up of the HVDC terminals, starting with the power control terminal, OWF is energized afterwards	Not valid for the MTDC as the power control terminal should not start up prior to the voltage control terminal.
Seq. 3	Sequential start-up of the HVDC terminals, starting with the voltage control terminal, OWF is energized afterwards	Valid for both the MTDC and OWF.
Seq. 4	Sequential start-up of some of the HVDC terminals, including voltage control terminal and OWF connected station, OWF is energized and the remaining terminals are energized last.	Valid for both the MTDC and OWF. Performances are slightly improved compared to seq. 3 (voltage and current surges).

In [68], the start-up of a 4 terminal DC grid based on Zhangbei project is investigated. The proposed start-up sequence is summarized in Figure 50.

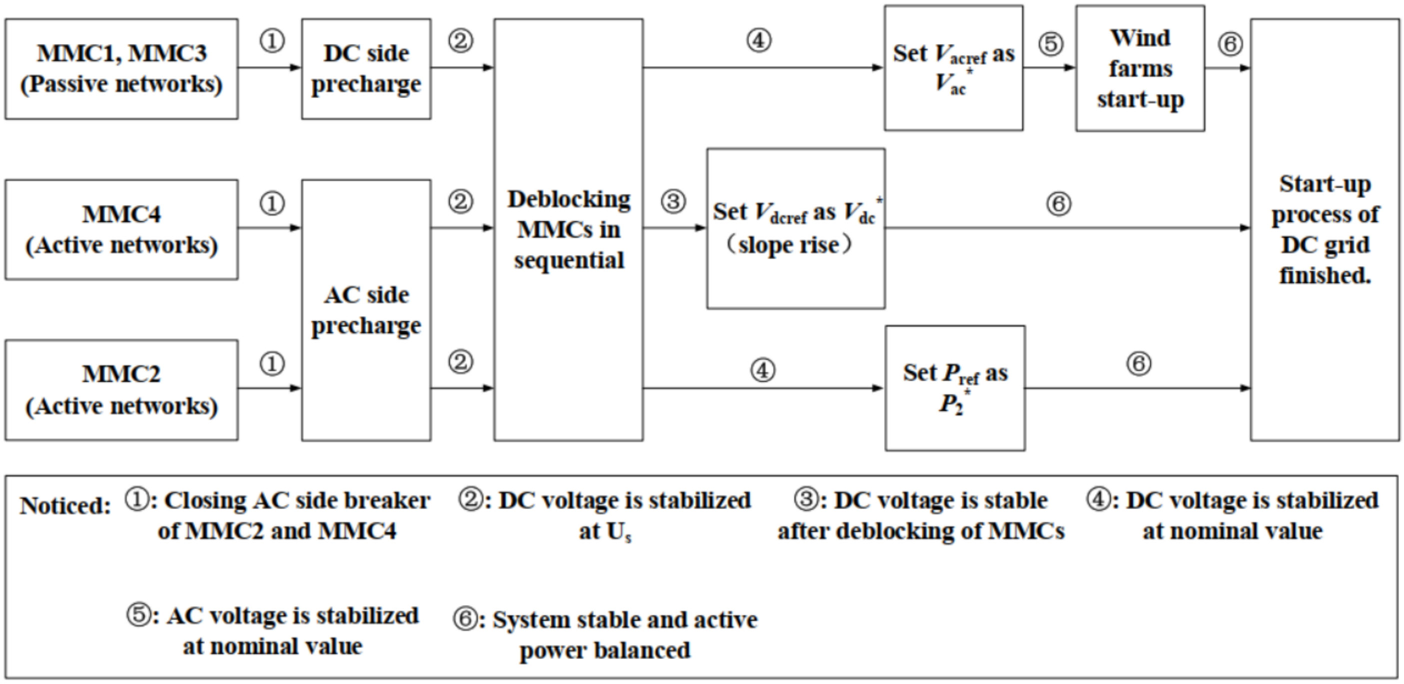


Figure 50 Coordinated start-up scheme of DC grid.

Three different operation modes are also studied where disconnected converters (e.g. due to maintenance) are reconnected to the DC grid

- → One onshore converter is reconnected to the three-terminal DC grid. The voltage difference at the output of the disconnected converter can be reduced as this converter can be energized from the AC grid.
- → One offshore converter is reconnected to the three-terminal DC grid. In order to reduce the surge current due to the voltage difference at the output of the disconnected offshore converter, DC side current limiting resistors should be inserted properly.
- → One onshore and one offshore converter are reconnected to the point-to-point DC link. In this case, the two disconnected stations are first operated separately as an independent PtP, before being reconnected to the third one.

7.2.1.4. Testing procedure

When the HVDC Grid System or HVDC or subparts of it are to be energized (or de-energized), from a converter or switching station, equivalent circuit diagram must be specified for all systems to be energized, including cables, overhead lines, and converter stations. Equivalent impedances of all relevant components shall also be provided [1].

Demonstration of normal start-up and shut down can be performed, if required, during the bid-process through Dynamic Performance Study [9]. Check of start-up, shut down, and all automatic sequences is performed during Factory Acceptance Test.

7.2.1.5. Applicability to the building blocks

As mentioned in the CENELEC reports, the open-loop controls apply both to the HVDC subsystems and to the HVDC grid as a whole.

7.2.1.6. Related FR and PR

Functional requirement ID	Functional requirement title
General32	Energisation
General33	Startup of DC grid
General34	Operating sequences
Off_ACDC_Con5	Offshore AC grid start-up

7.2.1.7. Discussion

The CENELEC reports indicate that operating sequences and operating states, as presented in Figure 49 and The applicability of the operating sequences to the different components of the DC grid is further specified in Table 51.

Table 51, can apply to AC/DC converter stations, DC switching stations, and the DC grid. However, the start-up process of the entire DC grid is not detailed. As stated in [25], the start-up of the DC grid should rely on some specific terminals that should then be clearly identified. Assuming that

- Any particular HVDC grid may be operated as several independent point-to-point links, for which independent start-up should be available.
- The start-up of the DC grid requires a source of active power, whose availability cannot be guaranteed at the offshore stations

It seems then relevant that all onshore stations should be able to perform the necessary actions in order to energize the DC grid, while this requirement is pointless for offshore stations.

Overall,

→ The operating states are rather well described from the individual HVDC installation perspective. The introduced operating states could however be better described, making for instance a distinction between energization from AC and DC sides.

→ The coordination of the operating states and sequences in an HVDC grid is not well established. The start-up sequence of the entire HVDC grid is thus not investigated.

Those two points require further elaboration and will be investigated with SoW B.

7.3. Operating states

7.3.1.1. CENELEC description

As depicted in Figure 51, the operating states of the HVDC grid are

- → Normal: within operational security limit
- → Alert: within operational security limit but a contingency has been detected
- → Emergency: one or more security limits are violated
- → Blackout: part or all transmission system has stopped
- → Restoration: activities to bring the system back to the normal state

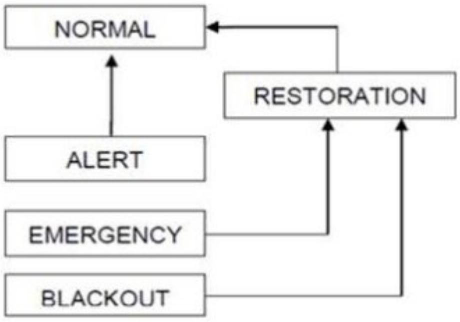


Figure 51 Operating states.

7.3.1.2. Grid code description

N/A

7.3.1.3. Description in existing literature

A similar description of grid operating states is provided in [11], see Figure 52. The (n-k) rule is introduced to differentiate between normal state (n-0) and alert state (n-1). Emergency state is characterized by the violation of operational limits, interruption of supply/transits or loss of stability, though the specific meaning of those concepts remains vague. While the DC grid controller may take several actions to bring the system from alert or emergency state back to normal state, system restoration refers specifically to the recovery from black-out state, which differs from the CENELEC description.

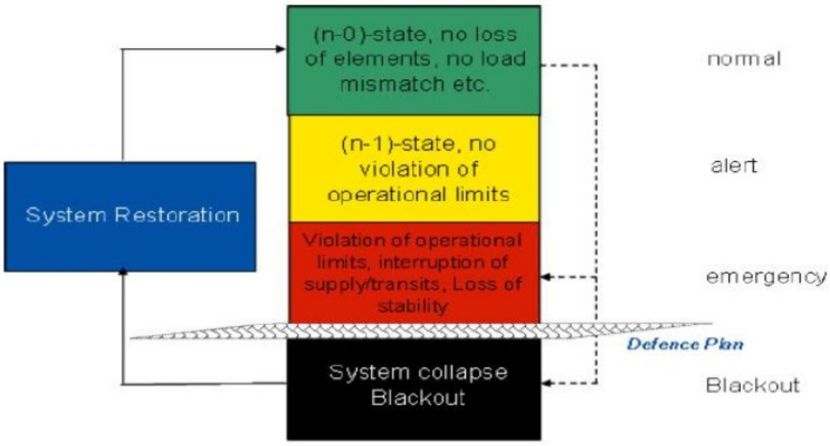


Figure 52 Operation states and codes.

7.3.1.4. Testing procedure

N/A

7.3.1.5. Applicability to the building blocks

The operating states apply to the DC system as a whole and should be identifiable by the DC grid controller.

7.3.1.6. Related FR and PR

N/A.

7.3.1.7. Discussion

Distinction should be made between:

- Post DC fault recovery, which comprises all the protection actions to be taken after a DC fault, including
  - Fault detection
  - Fault localization
  - Fault clearing
  - Reconfiguration of part of the DC grid
- DC System restoration from black-out, also known as SRAS-DC (System Restoration Ancillary Services). This service is further detailed in Section 8.5.

The subject of operating states is broadly described and the literature, but is very much related to operational aspects that go beyond the scope of this study. Apart from SRAS-DC, which is partially addressed in SoW B through a black-start energization sequence, operating states are not further investigated.

7.4. Connection modes

7.4.1.1. CENELEC description

The connection modes are defined

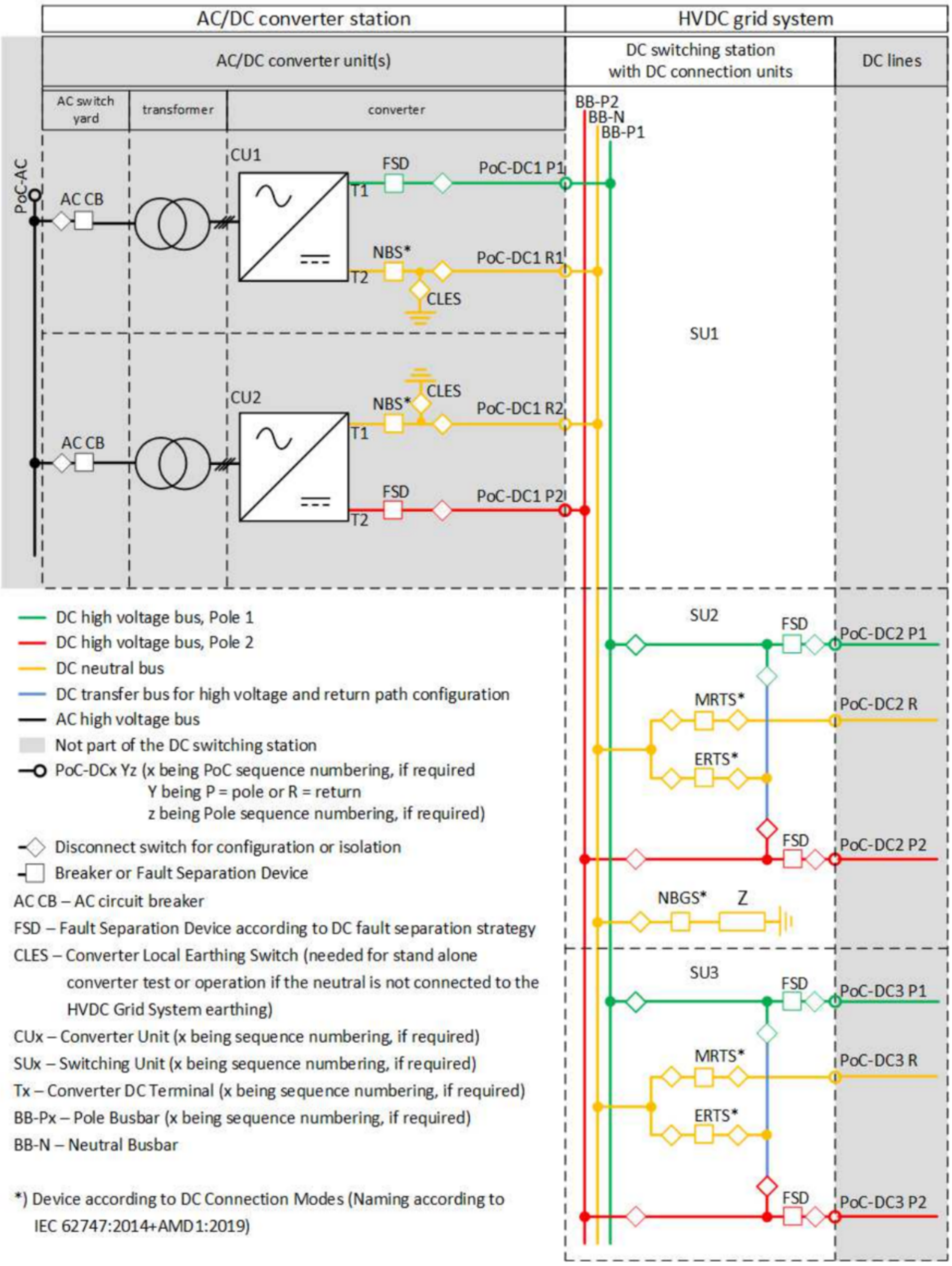
→ For a converter station as the possible connection between the terminals of the converter units (CUxTy) and its PoC-DC. Examples of connection modes for a converter station is provided in Table 53. The transition time between any mode when a direct transition is possible should be less than some maximum transition time $t_{\max}$.

Table 53 DC Connection Modes of an AC/DC Converter Station.

	Connection Mode	CU1T1	CU1T2	CU2T1	CU2T2
Mode 1	“coupled”	PoC-DC1 P1	PoC-DC1 R1	PoC-DC1 R2	PoC-DC1 P2
Mode 2	CU2 “DC decoupled”	PoC-DC1 P1	PoC-DC1 R1		
Mode 3	CU1 “DC decoupled”			PoC-DC1 R2	PoC-DC1 P2
Mode 4	CU1, CU2 “DC decoupled”				

→ For a switching unit as the possible connection between busbar of the DC switching station and the PoC DC of any DC system, may it be a converter unit or a DC transmission line. Examples of connection modes for a switching station and a converter unit is provided in Table 54. The transition between mode i and j when directly possible is associated to a maximum transition time $t_{\max,ij}$.

Though the connection modes are defined at a local level (switching unit or converter unit), they should be **coordinated at the HVDC grid level** to ensure compatibility between different connection modes. In particular, the earthing of the grid must be maintained at all times. Table 55 provides an example of how connection modes between a switching unit and transmission line can be associated to connection modes of a converter station.



The DC switching station connects exemplarily two bipolar transmission circuits with DMR and a converter station of bipolar topology.

Figure 53 Example of an AC/DC converter unit and connected DC switching station.

Table 54 Connection modes of an exemplary bipolar DC switching unit connecting x-th PoC-DC of an HVDC transmission line.

Connection Mode \ Busbar		BB-P1	BB-N	BB-P2
Mode 1	Bipolar with return path	PoC-DCx P1	PoC-DCx R	PoC-DCx P2
Mode 2	Bipolar without return path ("rigid bipolar")	PoC-DCx P1		PoC-DCx P2
Mode 3	Monopolar pole 1	PoC-DCx P1	PoC-DCx R	
Mode 4	Monopolar pole 2		PoC-DCx R	PoC-DCx P2
Mode 5	Monopolar pole 1 with HV parallel return	PoC-DCx P1	PoC-DCx R PoC-DCx P2	
Mode 6	Monopolar pole 2 with HV parallel return		PoC-DCx R PoC-DCx P1	PoC-DCx P2
Mode 7	Monopolar pole 1 with HV return	PoC-DCx P1	PoC-DCx P2	
Mode 8	Monopolar pole 2 with HV return		PoC-DCx P1	PoC-DCx P2

Table 55 Connection modes of an exemplary bipolar DC switching unit connecting a PoC*DC of an AC/DC converter station.

Connection Mode \ Busbar		BB-P1	BB-N	BB-P2
Mode 1, 2	Bipolar	PoC-DCx P1	PoC-DCx R1 PoC-DCx R2	PoC-DCx P2
Mode 3, 5, 7	Monopolar pole 1 (DC decoupled pole 2)	PoC-DCx P1	PoC-DCx R1	
Mode 4, 6, 8	Monopolar pole 2 (DC decoupled pole 1)		PoC-DCx R2	PoC-DCx P2
Mode 9	DC decoupled pole 1 and pole 2			

7.4.1.2. Grid code description

N/A

7.4.1.3. Description in existing literature

The literature that focuses on connection modes is rather scarce. The CIGRE TB 683 “Technical requirements and specifications of state-of-the-art HVDC switching equipment” gives detailed information on switching gears and HVDC station arrangement. A thorough description of switching equipment, including ratings and existing installations, is provided. An example of arrangement of an HVDC substation is presented in Figure 54. Though this arrangement corresponds to the context of a PtP link and that the switching station is not differentiated from the converter station, it matches well the CENELEC diagram. We propose to enrich the CENELEC diagram with the nomenclature from Figure 54 so that switches and disconnectors can be specifically referred to.

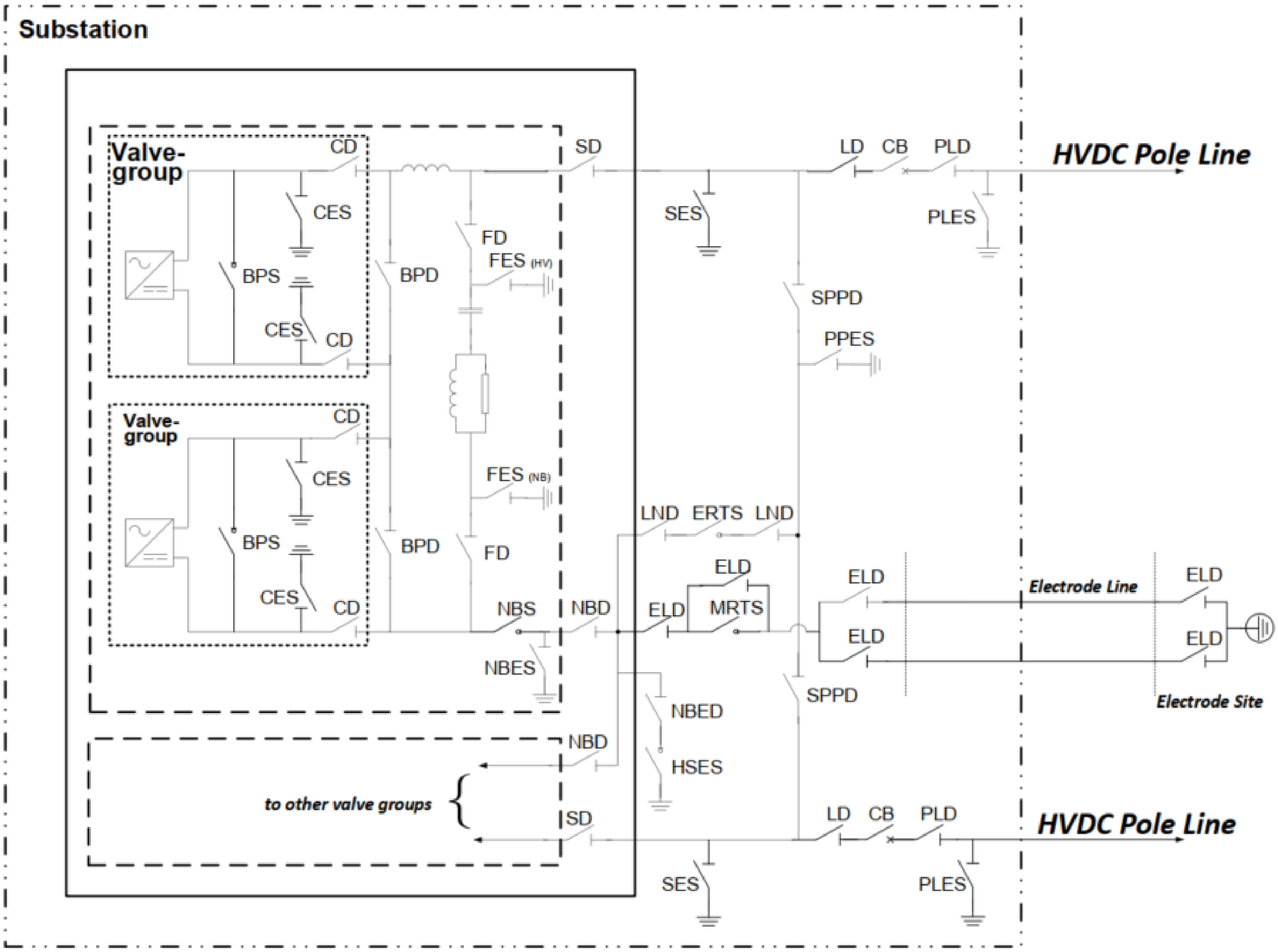


Figure 54 Example of HVDC side switchgear arrangement for one pole in an HVDC substation.

Main differences between the two documents are listed in the following table, along with the proposed choices.

CENELEC	CIGRE	Proposed choice
Neutral conductor referred to as Metallic return	Neutral conductor referred to as Electrode Line	Metallic return
Fault Separation Device	Circuit Breaker	Circuit Breaker
Neutral Bus Grounding Switch at switching station and Converter Local Earthing Switch at converter unit	High Speed Earthing Switch at the switching station and Neutral Bus Earthing Switch at the converter unit	High Speed Earthing Switch at the switching station and Converter Local Earthing Switch at converter unit

The possibility to operate a grid with "mixed topologies" is mentioned in [69] (with bipole, asymmetric monopole and symmetric monopole) as a possible result of a step-by-step expansion.

The combination of multiple converter station connection modes in an MTDC is envisaged in [25]. In Figure 55 for instance, bipolar configuration is combined with asymmetric and symmetric monopoles. In this configuration, Converter 2 would operate at twice the rated voltage of the other converters.

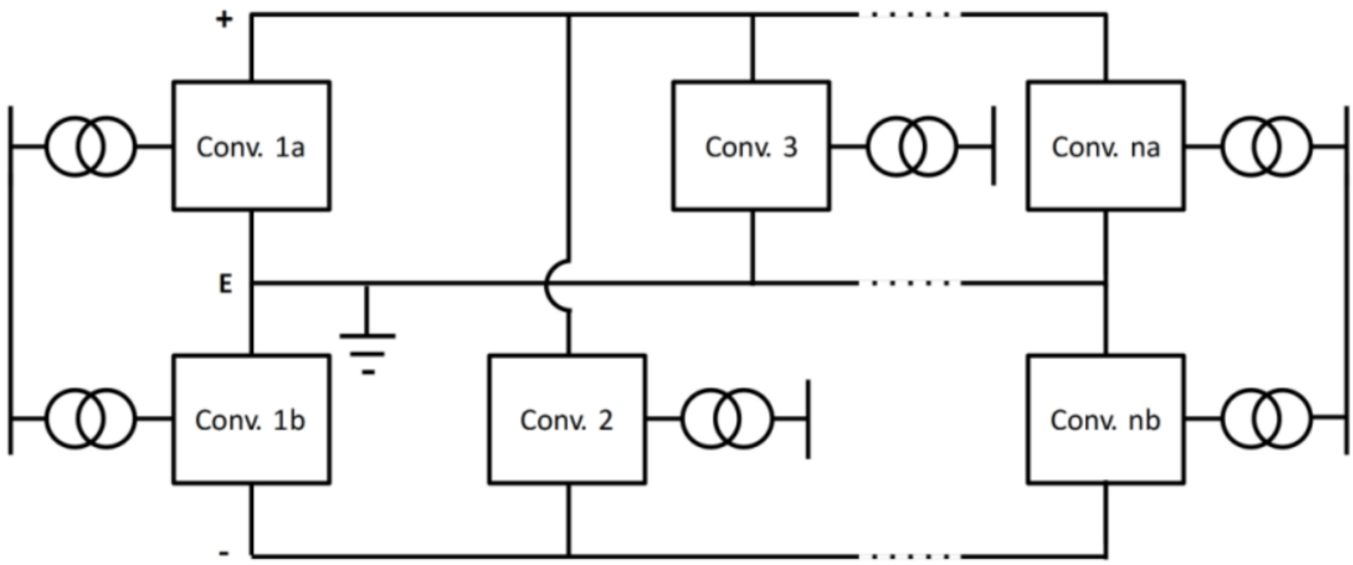


Figure 55 Bipole configuration with asymmetric and symmetrical monopole tappings.

For a PtP bipolar connection with an offshore wind farm, [70] presents the following connection modes, which can apply to one or both poles:

- Bipole with DMR
- Bipole without DMR, i.e. rigid bipole
- Asymmetrical monopole
- STATCOM coupled, in which the converter in STATCOM mode is still connected to a pole, though this pole is disconnected at the remote end and no current can flow through it. In this configuration,

the DMR is disconnected on both sides, meaning the STATCOM converter is grounded. The interest of such a connection mode is however not detailed.

→ STATCOM decoupled

→ Shutdown

Examples of transition sequences from different connection modes are provided, in particular for the transition between bipole (BPD) to rigid bipole (BPND) after a DMR fault, see Figure 56.

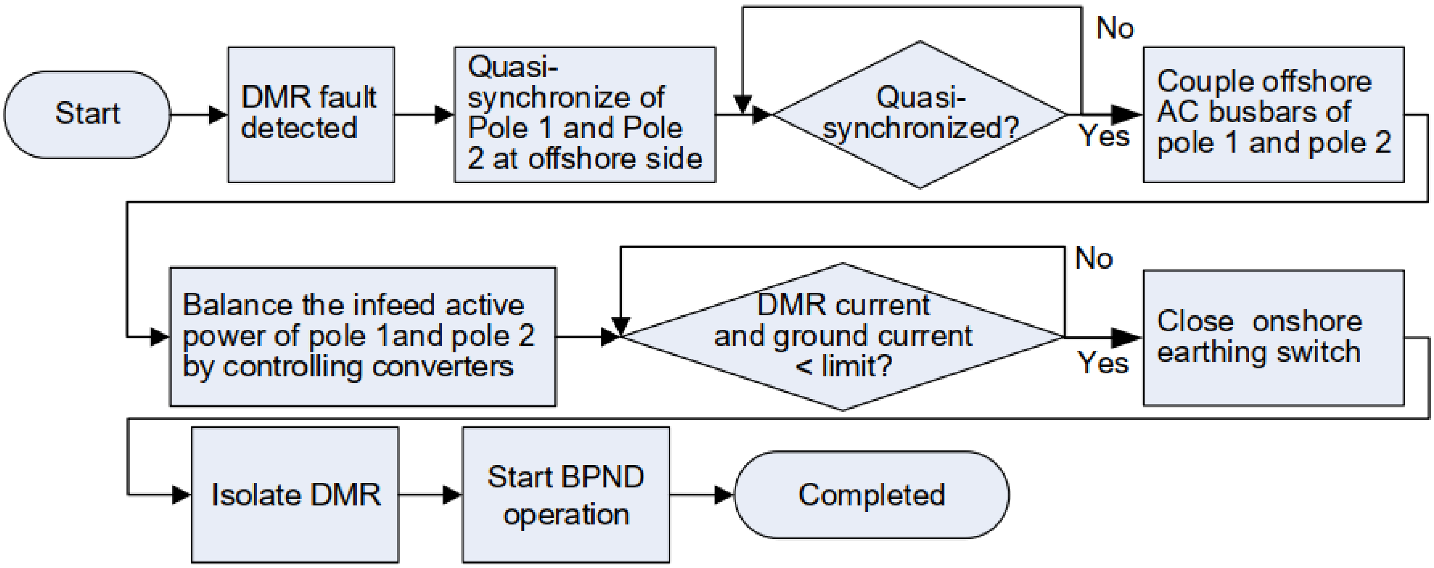


Figure 56 Fault-related transition sequence from bipole (BPD) to rigid bipole (BPND) [70]

7.4.1.4. Testing procedure

N/A

7.4.1.5. Applicability to the building blocks

As mentioned before, the connection modes are defined for each converter station and switching station. They must be coordinated by the DC grid control to ensure compatibility between the different modes. The applicability of different functions of grid operation to the different HVDC grid system installations is further specified in Table 56, where the functions “reconfiguration” and “earthing” are particularly relevant for connection modes.

Table 56 Functions of grid operation.

	AC/DC Interface	**HVDC Grid System Installation**			
Function *(relevant aspects)*	AC/DC converter station	DC switching station	transmission line and transition stations	DC/DC converter station	DC line power flow controller
Operation on-load *(withstand voltage, current stresses)*	yes	yes	yes	yes	yes
Measuring *(DC and AC voltages and currents, active and reactive power)*	yes	yes	optional	yes	yes
Energy balancing *(Maintaining the average DC grid voltage)*	optional	optional	n.a.	optional	optional
Reconfiguration *(DC circuit, e.g. connection of lines, bipolar to monopolar, DMR to earth return)*	optional	yes	n.a.	yes	optional
Discharge *(DC circuit)*	yes	optional	n.a.	yes	n.a.
Earthing *(Providing earth reference, functional earthing)*	yes	yes	n.a.	yes	optional
Interconnection *(Connecting different DC voltage levels)*	n.a.	n.a.	n.a.	yes	n.a.

7.4.1.6. Related FR and PR

Functional requirement ID	Functional requirement title
General30	HVDC grid system installation connection modes
General31	DC Circuit reconfiguration
Master_Control10	Coordination of HVDC grid earthing
Master_Control11	Coordination of neutral bus switches
Master_Control1	Connection modes coordination

7.4.1.7. Discussion

The CENELEC reports state that the transition sequence from one connection mode to another must be specified from no-load operation to on-load operation. This raises a number of questions

- → Is it always possible to enforce the no-load condition, in any line or part of the DC grid? Such a requirement could impose additional installation of power flow controllers.
- → What level of residual currents is acceptable? For switching stations / converter stations that are not equipped with DCCB in particular (typically onshore), switches and disconnectors such as line disconnectors (LD) must be properly sized so that they can interrupt this residual current.

The coordination of different connections throughout the DC grid is of prior importance but not thoroughly detailed. Some points of relevance are

- → How to define the connection modes between a converter station and a switching station comprising several switching units (in contrast to what is presented in Table 55 where a single switching unit is assumed)?
- → The connection modes at the two ends of the same transmission line should be compatible
- → The nomenclature proposed in CENELEC reports (e.g. 2DCe-BR for an effectively earthed bipole with metallic return) cannot describe a grid with multiple connection modes. It could however be defined for each transmission line.

The subjects of coordination and compatibility of multiple connection modes will be further investigated within SoW B. The sizing of DC switchgear will also be addressed through specific examples of transition sequences between different operation modes.

7.5. Conclusions & next steps in SoW B

Regarding HVDC grid operating sequences functional group, the following aspects have been identified for further investigation within SoW B:

- → Coordination of DC connection modes, in particular the transition between degraded modes such as: disconnection of a spoke, disconnection of an interconnector (from MTDC to PtP operation), handling of DMR fault/disconnection, transition from bipole to asymmetric monopole and vice versa, transition from open to closed ring grid.
- → Analysis of few possible start-up sequences: start-up of the whole HVDC grid, start-up of the grid as individual point-to-points and then connection as an MTDC, start-up of the HVDC grid considering that some of the onshore AC converters are unavailable and that some onshore stations must be energized from the DC side.
- → Preliminary definition of functional requirement and parameter ranges for the main switching station switchgears.

8. Functional group: ancillary services

8.1. General

According to the CENELEC reports, “ancillary services comprise **operation functions that are optional**, i.e. that can be activated in order to improve or support the rest of power system, but they are not mandatory for the operation of the power system”.

According to [71], “ancillary service” means a “service necessary for the operation of a transmission or distribution system, including balancing and non-frequency ancillary services, but not including congestion management”. Non-frequency services include

- Steady-state voltage control
- Fast reactive current injections
- Inertia for local grid stability
- Short-circuit current
- Black-start capability
- Island operation capability

Corresponding chapters in the CENELEC report I	4.4.2 Basic operation functions – converter normal operation state
	8.4.2.7 System restoration DC Side
	8.4.3 AC Side
	4.4.4 Ancillary services
	4.4.4.5 System restoration services

A list of implemented functions in existing HVDC systems is provided in Table 57, taken from [35].

Table 57 List of implemented ancillary services in existing HVDC systems.

	BritNed	EWIC	INELFE	IFA 2000	Skagerrak 34	NorNed	KONTEK	KF CGS	SAPEI	SACOI
Market based scheduling (chapter 3)	x	x		Special optimisation based on market schedule	x	x	x	Combined with fluctuating wind	X	X
Ramp rate (chapter 3)	x			x	x		x	x	Fast (ms) and slow power reversal	Fast (ms) and slow power reversal
AC line emulation (chapter 3.1.2) in MS2)			x							
Dynamic frequency response (chapter 3)									X	X
Special protection scheme – runback/run up (chapter 3)	x		x	x	x		x	x		
Special protection scheme dynamic Q/U support			x		x					
Operation with special DC side topology (chapter 3)			Single-link and multi-link operation	Automatic set point reallocation when one bipole trips	Automatic topology change to reverse polarity (without impact on power transmission) + run with metallic return				Monopolar and bipolar	
Frequency control (chapter 3)		Frequency containment and restoration reserve	Frequency containment reserve (in case of system split)	Frequency containment reserve	Frequency containment reserve, Frequency restoration reserve (including communication with power plants). Automatic imbalance netting			Frequency containment reserve	Frequency containment reserve and Frequency restoration reserve	Frequency containment reserve
Island detection			a) Monitorin					a) Monitorin	b) Angle differenc	b) Angle differenc

	BritNed	EWIC	INELFE	IFA 2000	Skagerrak 34	NorNed	KONTEK	KF CGS	SAPEI	SACOI
(3 ways)			g tie-line breakers b) Angle difference exceeds limit c) Triggered by operator					g tie-line breakers b) Angle difference exceeds limit c) Triggered by operator	e exceeds limit	e exceeds limit
Black start (chapter 3)		x	x		Skagerrak 4 (including re-synchronisation)			x		
Restoration support									x	x
Static Q/U-support (chapter 3)			x		x			x		
POD (chapter 3)			POD-P and POD-Q-mode							
SPS – Emergency Power control (chapter 3)	x			x	EPC-P and EPC-Q (higher priority for Q)		EPC-P	EPC-P and EPC-Q (higher priority for Q)	Included in the defence system	Included in the defence system
DC loop flow (chapter 3)					x		x	x		
Automatic system operation								a) Capacity calculation b) P and UAC online set point adaptation c) Identification and trigger of counter-trade		

8.2. Frequency services

8.2.1.1. CENELEC description

Frequency services mentioned in CENELEC standards can be divided into

- → Synthetic Inertia, for which no standards are specified
- → Frequency Containment Reserve (FCR)
- → Frequency Restoration Reserve (FRR)
- → Replacement Reserve (RR)

The latter two, also known as secondary and tertiary reserves, are achieved through a change in the controller setpoints through a master controller, in a time scale of several minutes.

FCR is a service that consists in the fast supply of active power in case of frequency deviation. This supply can rely on different control mode, one of them being the Frequency Sensitive Mode (FSM). FSM characteristic is specified in Figure 57 (note that no deadband is represented, though it can be specified).

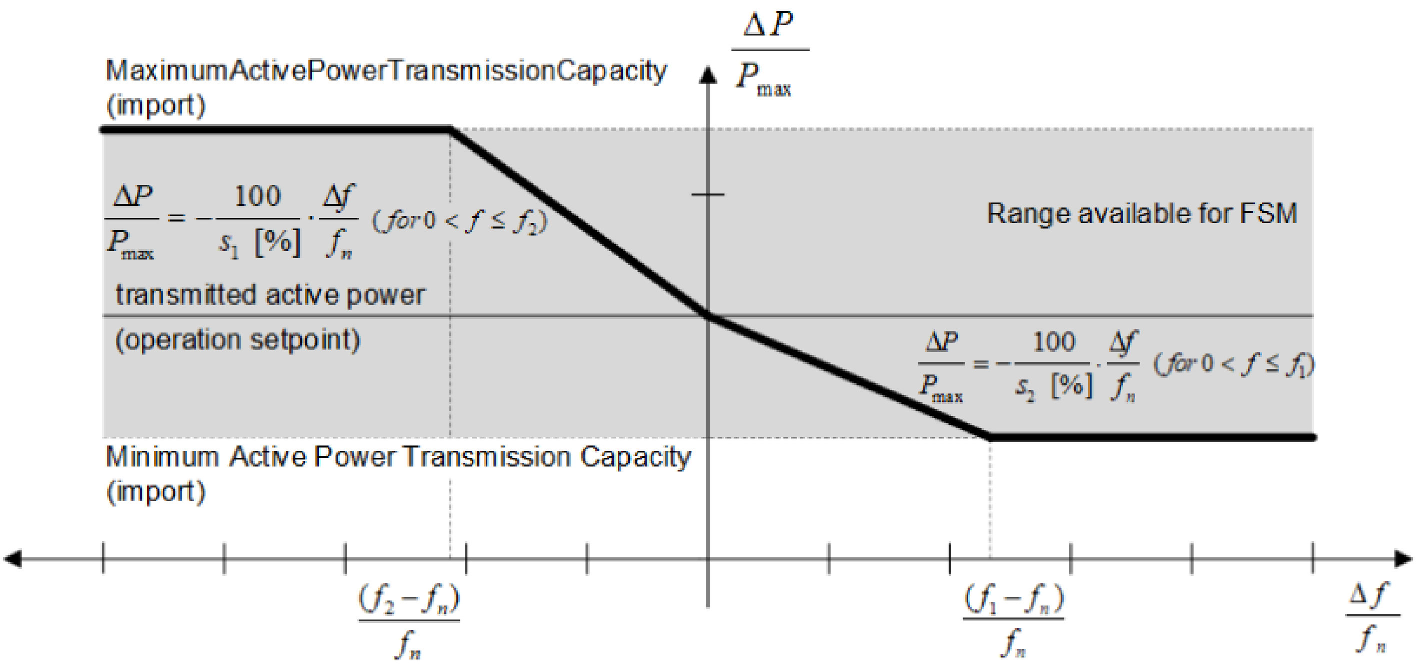


Figure 57 Frequency Sensitive Mode (FSM) characteristic of an AC/DC converter station, according to CENELEC standards.

In the case where more than two synchronous areas are connected, the dispatch of power between the receiving and sending areas must be determined through FCR distribution coefficients. The provision of FCR between areas connected through multiple converters (i.e. an MTDC grid) is however not covered. This point is further addressed in the discussion section.

8.2.1.2. Grid code description

In [20], the supply of frequency support is specified through the Frequency Sensitive Mode (FSM), Limited FSM over-frequency (LFSM-O) and Limited FSM under-frequency (LFSM-U). The characteristics of Figure 57 corresponds to FSM mode with 0 deadband. Parameters and ranges for FSM from [20] and [27] are provided in Table 58.

Table 58 Parameter ranges for FSM and LFSM for CE and GB.

Parameter	**European Code**	**GB grid code**
Frequency response deadband	0+- 500mHz	0 Hz
FSM Droop s1 (upward)	Min 0.1%, 2-12%	3-5%
FSM Droop s2 (downward)	Min 0.1%, 2-12%	3-5%
FSM Available capacity (%Pmax)	1.5-10%	10%
Frequency response insensitivity	10 - 30 mHz	
LFSM-O threshold value	50.2 – 50.5 Hz	50.4 Hz
LFSM-O droop value	2-12%	10%
LFSM-U threshold value	49.5 – 49.8 Hz	10%
LFSM-U droop value	2-12%	49.5 Hz

The time response of FSM after a frequency step is represented in Figure 58 with a maximum admissible delay t1 being 0.5 s and full activation time t2 being 30s (10s for GB). This places FSM as a way to provide an FCR service.

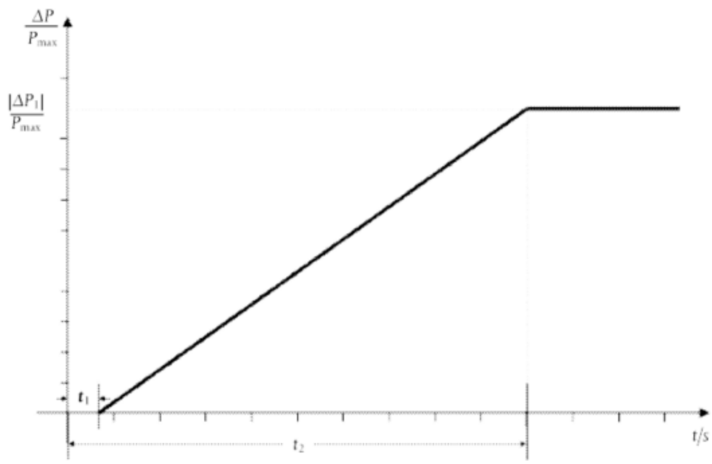


Figure 58 Active power frequency response of an HVDC system triggered by a step change in frequency.

The frequency response of LFSM-U and LFSM-O are provided in Figure 59 and Figure 60. Though the LFSM mode should be “as fast as inherently technically feasible”, no specific numbers are provided regarding the time response, contrary to FSM mode.

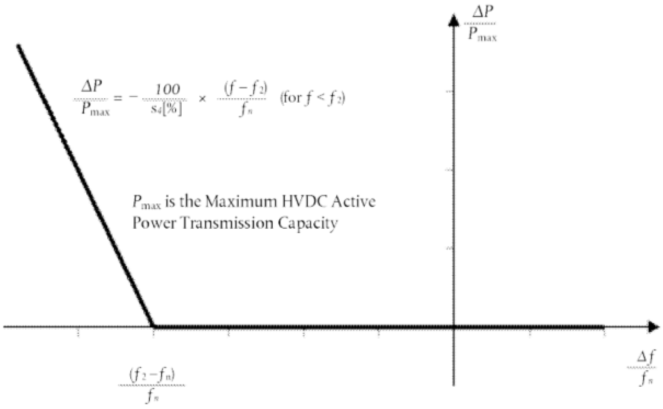


Figure 59 Active power frequency response capability of HVDC systems in LFSM-U.

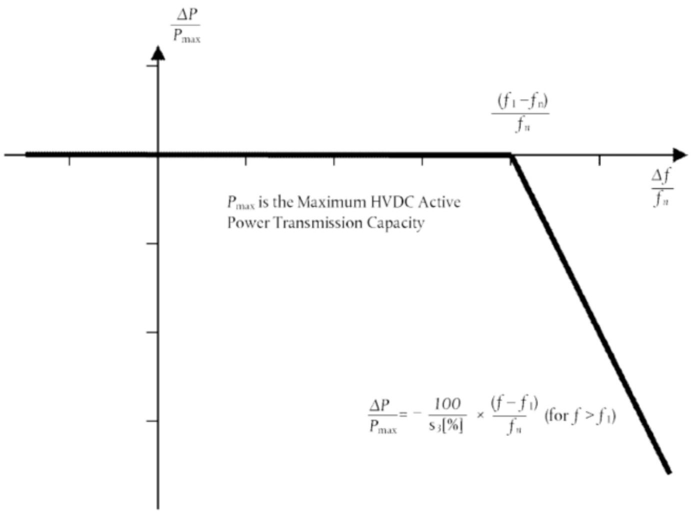


Figure 60 Active power frequency response capability of HVDC systems in LFSM-O.

8.2.1.3. Description in existing literature

Though not specified in the CENELEC reports, frequency services faster than FCR are emerging in HVDC systems, such as Fast Frequency Response (FFR), Emergency Power Control (EPC), and Synthetic Inertia (SI). We elaborate further those different services, though it should be noted that how to provide such services through an MTDC grid remains an open topic. Going from HVDC PtP to MTDC specifications face similar challenges as for FCR service with respect to dispatch of power between different AC areas and multiple converters connected to the same area.

Fast Frequency Response

Fast Frequency Response can be defined as an ancillary service that delivers a fast power change to mitigate the effect of reduced inertial response, so that frequency stability can be maintained [72]. Different FFR services exist but they all share a short activation time, typically between 0.25s and 2s. Some examples of FFR product and their parameters are provided in Table 59.

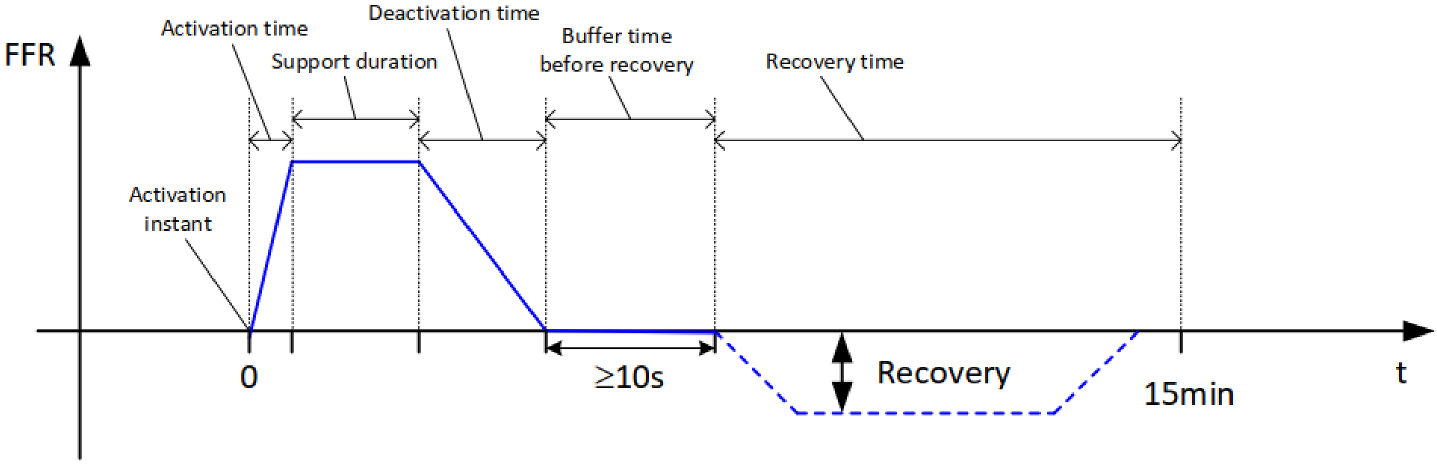


Figure 61 Typical parameters that characterize an FFR product.

Table 59 Examples of considered FFR products and associated parameters.

FFR Product	Trigger	Activation time	Ramp rate	Duration	Source
Emergency Power Control (EPC)	f < 49.6 Hz f < 49.5 Hz f < 49.4 Hz	0.5 s 0.5 s 0.5 s	100 MW/s 100 MW/s 100 MW/s		Nordic countries [72]
Dynamic containment Dynamic moderation	Deadband: ±0.015 Hz	1 s 1 s	See profile in Figure 62		National Grid [6]
FFR	f < 49.7 Hz f < 49.6 Hz f < 49.5 Hz	1.3 s (full activation time) 1 s (full activation time) 0.7 s (full activation time)		5s (short) 30s (long)	Nordic countries [73]

[6] https://www.nationalgrideso.com/electricity-transmission/balancing-services/frequency-response-services/dynamic-containment and https://www.nationalgrideso.com/electricity-transmission/industry-information/balancing-services/Frequency-Response-Services/Dynamic-Moderation/Technical-Requirements

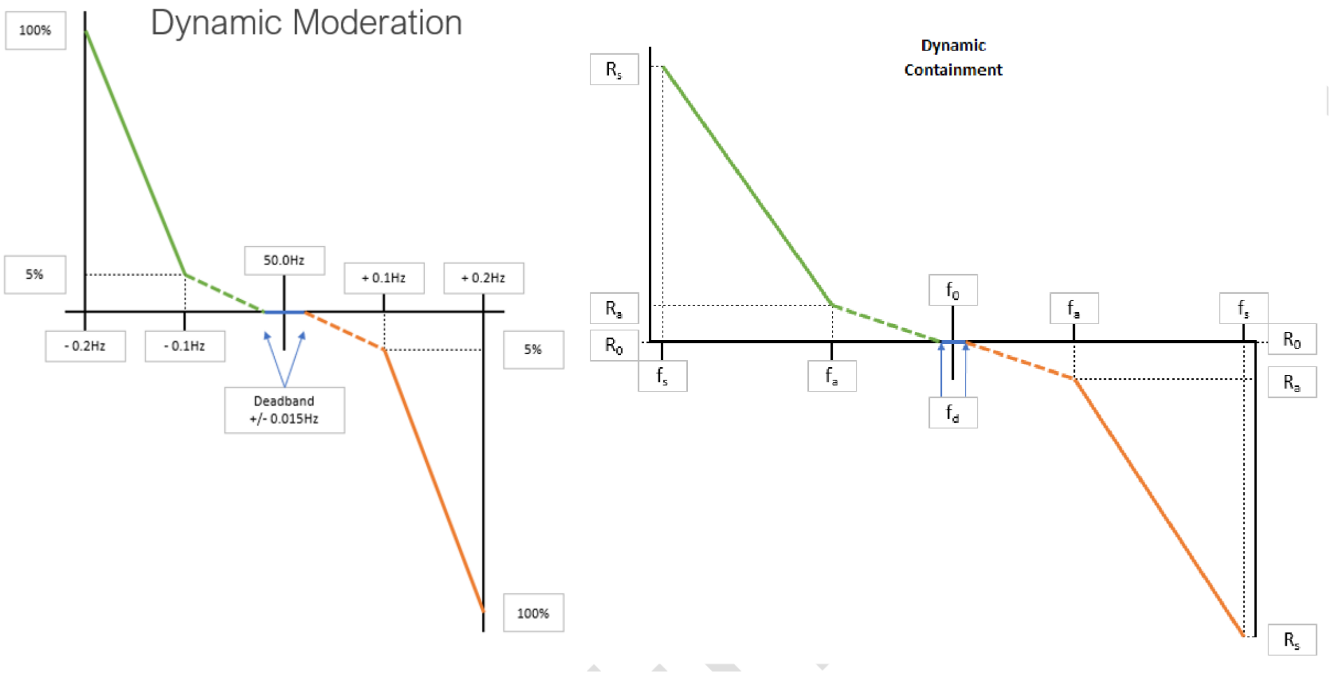


Figure 62 Dynamic moderation (left) and dynamic containment (right) products, as implemented by National Grid.

HVDC Interconnectors

In the context of HVDC interconnectors between two asynchronous areas, frequency support can be achieved through frequency coupling [74]. Frequency coupling services can be static services (stepwise activated) or dynamic services (continuously activated). Such dynamic services include

- → FCR exchange: in case of a frequency deviation in one zone, the other zone would provide frequency support, irrespective of its own frequency.
- → Frequency netting (FN): process whereby FCR is reduced when frequency deviations have opposite signs in the considered synchronous zones.
- → Frequency optimization (FO): process that optimizes the overall frequency deviations of the connected zones. The sum of the absolute frequency deviation is thus minimized.

The capabilities of the different coupling services between a zone with frequency f_1 and a zone with frequency f_2 are illustrated in Figure 63.

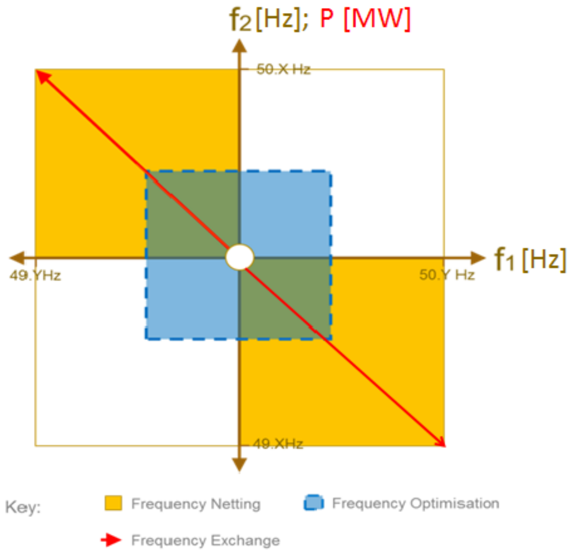


Figure 63 Illustration of the different frequency coupling classes and how they relate to the frequencies of the synchronous areas. For frequency exchange, the x-axis (f1 [Hz]) relates to the frequency of the receiving SA, whereas the y-axis (P[MW]) relates to the power shifted from providing to receiving SA.

Application to MTDC grids

In [75], the provision of FCR by an MTDC grid connected to multiple asynchronous zones was investigated through three different control solutions

- Frequency droop implemented locally at each converter
- Frequency droop implemented locally with a common time-varying frequency reference signal. This allows to reflect the overall asynchronous zones dynamics while limiting the interactions with the DC voltage droop.
- Distributed control for each pair of AC grids. This solution resembles some primary frequency control scheme used for HVDC lines as well as virtual link concept for rotor-angle stability improvement. This solution limits the use of communication (compared to solution 2). Another advantage is that controller can be designed based on bilateral contract between a pair of grids.

Simulation results show that the third solution leads to an actual FCR contribution much closer the expected contribution than the two other solutions. However, this approach only considers the case where a single converter is connected to each AC zone.

8.2.1.4. Testing procedure

According to CIGRE TB 563 [9], fast power response of the HVDC system, such as EPC, can be studied using transient stability tools.

Detailed models of AC components that affect the electro-mechanical behavior must be employed, including rotor turbine inertia, exciter and turbine governor control. For the HVDC model, key control system parameters must be provided, such as Voltage Dependent Current Limit, recovery ramp rates, and high-level control functionalities.

Such studies can be performed in a preliminary dynamic stability analysis to evaluate the capability of the HVDC system to support the AC grid. Study cases considered as the most difficult are used to conduct the studies. Interaction studies conducted during the bid process then demonstrate the stability and frequency behavior of the converter stations.

8.2.1.5. Applicability to the building blocks

Regarding the applicability of ancillary services to the different building blocks, in the CENELEC reports [1], no distinction is made between onshore and offshore converter stations. By contrast, PROMOTIoN deliverable D1.7 [20] presents that most ancillary services apply to onshore converter stations, while only a few of them apply to offshore converters. Finally, the HVDC grid code specifies that frequency control requirements (FSM, LFSM) apply to offshore converters as well as onshore converters.

In case of frequency services between asynchronous zones (MTDC seen as interconnector), the offshore converter stations are not involved. In the case where the power variation with the onshore system results from a power variation of the PPM, the control of the PPM is involved. If frequency services are implemented between pairs of converters (as proposed in [75]), the involvement of the DC grid control may not be required. More centralized approach would however rely on the DC grid control, in particular to ensure active power balance throughout the grid.

8.2.1.6. Related FR and PR

Functional requirement ID	Functional requirement title
General35	Frequency sensitive mode
General36	Limited Frequency Sensitive Mode – Overfrequency (LFSM-O)
General37	Limited Frequency Sensitive Mode – Underfrequency (LFSM-U)
General38	Synthetic inertia
Master_Control9	Ancillary service coordination

8.2.1.7. Discussion

We elaborate here further on how frequency services such as FCR and FFR can be extended to MTDC grid connecting at least two asynchronous zones, or one synchronous zone and a source of active power. The CENELEC reports provide a framework for the provision of frequency services between more than two AC zones through the “K matrix”, though how to choose and specify the coefficients is not detailed. Various studies have proposed appropriate methodologies to compute these parameters, but it is generally assumed that each zone is only connected through one converter. By contrast, how to dispatch the frequency provision among multiple converters connected *to the same zone* remains rather uncharted.

In the spirit of the K matrix introduced in [1], the power dispatch between multiple converters connected to the same AC zone can be defined through S and R matrices:

$$\Delta P = S \cdot K \cdot R \cdot \Delta P$$

The receiving coefficient $R_{i,j}$ defines the contribution of converter j to AC zone i, and the sending coefficient $S_{i,j}$ defines the contribution of AC zone j to converter i. The power dispatch between the different zones is still given by the K matrix. It should be noted that the sum of each column of S should be one, as well as the sum of each row of R.

Consider the case of three AC zones, namely the CE, Nordic, and GB, connected through an MTDC grid of five converters. An example of the S, K, and R matrices is

$$\begin{bmatrix} \Delta P_1 \\ \Delta P_2 \\ \Delta P_3 \\ \Delta P_4 \\ \Delta P_5 \end{bmatrix} = \underbrace{\begin{bmatrix} 1 & 0 & 0 \\ 0 & 0.5 & 0 \\ 0 & 0.5 & 0 \\ 0 & 0 & 0.3 \\ 0 & 0 & 0.7 \end{bmatrix}}_{=S} \begin{bmatrix} K_{1,1} & K_{1,2} & K_{1,3} \\ K_{2,1} & K_{2,2} & K_{2,3} \\ K_{3,1} & K_{3,2} & K_{3,3} \end{bmatrix} \underbrace{\begin{bmatrix} 1 & 0 & 0 & 0 & 0 \\ 0 & 1 & 1 & 0 & 0 \\ 0 & 0 & 0 & 1 & 1 \end{bmatrix}}_{=R} \begin{bmatrix} \Delta P_1 \\ \Delta P_2 \\ \Delta P_3 \\ \Delta P_4 \\ \Delta P_5 \end{bmatrix}$$

Matrix R represents the connection of the different converters to each AC zone

→ Converter 1 is connected to zone 1, hence $R_{1,1} = 1$

→ Converters 2 and 3 are connected to zone 2, hence $R_{2,2} = 1$ and $R_{2,3} = 1$

→ Converters 4 and 5 are connected to zone 3, hence $R_{3,4} = 1$ and $R_{3,5} = 1$

Matrix K represents the active power contribution between the different asynchronous zones (as in CENELEC reports)

Matrix S represents the dispatch of the power between the different connected converters.

Though such an approach allows to clarify the power dispatch through an MTDC grid

- It does not address how to define the active power change of each converter (e.g. by droop, or predefined power step)
- The feasibility of the power flow is not ensured and should be checked.

8.3. Reactive power control modes

8.3.1. Classification of the reactive power control mode

8.3.1.1. CENELEC description

C.f. Part 1: Section 4.4.2 says that AC voltage magnitude control can be one of the two control objectives when determining the reference values of the reactive power exchange.

C.f. Part 1: Section 4.4.4.3. says that AC Voltage control related services can be

- either AC voltage magnitude control
- or reactive power provision as a function of AC voltage magnitude, either manually or automatically.

8.3.1.2. Grid code

German grid code

Reactive power control modes are addressed in the following article:

10.1.9 Dynamic voltage control: for details, see the part on “Voltage control mode or reactive power/voltage characteristic mode”.

10.1.9.2 Dynamic voltage control without reactive current specification

10.1.9.3 Dynamic voltage control with reactive current specification

10.1.12 Reactive power control mode (for slow voltage change)

Which corresponds to 3 control modes:

- Reactive power/voltage characteristic
- Reactive power control
- Power factor control

The step response time for a step change of the setpoint (Annex C, Figure C.1) for the purpose of reaching the reactive power setpoint shall be adjustable to between 0,1 s and 10 s by the HVDC converter station. Unless any concrete value has been specified by the relevant system operator, a value of 5 s shall apply. The settling time for reaching the reactive power setpoint shall be specified by the relevant system operator within the range of 1 s to 60 s. Unless any concrete value has been specified by the relevant system operator, a value of 30 s shall apply. The tolerance for steady-state reactive power output shall not exceed 5 % of the maximum reactive power supply.

Dutch grid code

N/A.

Danish grid code

The reactive power control commands must be possible to execute independently in any of the converter stations. From local (OWS) and remote it must be possible to select.

- → Voltage Control mode (Q= (V-Vref)*a)
- → Reactive Power Control mode (Q = Q_ref)
- → Power Factor Control mode (cos φ = const.)

8.3.1.3. Existing projects and literature

The operation in STATCOM mode is mentioned in BestPath [6]: Section 5.5 Control modes and performance requirements under normal conditions. Requirements in terms of dynamics are identical that those presented for fixed reactive power control mode and AC voltage control mode. Requirements in terms of amplitude correspond to the green and orange areas in the UQ diagram (see Section 4.10.1.3). Moreover, in this control mode, each converter station shall be able to control the DC voltage at its terminals with the same requirements as those of the DC voltage control mode.

8.3.1.4. Testing procedure

This section gathers all testing procedures that relate to the different reactive power control modes, in addition to reactive power capability testing procedures.

Based on [9], in the post award phase, reactive power studies must determine the steady state and dynamic range of reactive power needs to satisfy the required AC voltage control levels. Interaction studies are also needed to demonstrate the dynamic performance of the control methodology and parameters. Such studies are performed using EMT programs and/or RTS.

8.3.1.5. Applicability to the building blocks

This section gathers the applicability to the building blocks that relate to the different reactive power control modes. No distinction is done between onshore and offshore converter stations in CENELEC standards. By contrast, PROMOTIoN deliverable D1.7 [20] presents that very few requirements apply to offshore converters. Finally, the HVDC grid code [32] specifies that reactive power control mode requirements apply to offshore converters as well as onshore converters.

Reactive power requirements applies to both onshore and offshore converter stations. Contrary to frequency control services, the involvement of the DC grid controller is only required for the attribution of the control modes and priority to the different stations.

8.3.1.6. Related FR and PR

Functional requirement ID	Functional requirement title
General41	Reactive power control modes
Off_ACDC_Con4	AC grid voltage control
General28	Priority to active power or reactive power contributions

8.3.1.7. Discussions

The CENELEC report only mentions briefly the different reactive power control modes.

The German grid code presents different category:

For fast/dynamic voltage control:

→ Dynamic voltage control (Section 10.1.9), which should be activated for faults with residual voltages $U_1 < 15\ \% \ U_n$. HVDC should be capable of feeding into each conductor a current I of at least 100 % of the rated current

→ Dynamic voltage control without reactive current specification: basic requirement

→ Dynamic voltage control with reactive current specification: the proportional nature between the additional consumed reactive current and the voltage deviation, the value range of the proportional gain, and the dynamics performances are specified.

For slow voltage change (Section 10.1.12):

→ Reactive power/voltage characteristic: $Q = f(U)$

→ Reactive power control: Q_{ref} = const.

→ Power factor control: cos ϕ_{ref} = const

Three reactive power control mods are presented in the Danish grid code:

→ Voltage Control mode: $Q = \left(V - V_{ref}\right) * a$

→ Reactive Power Control mode: $Q\ = Q_{ref}$

→ Power Factor Control mode: $\cos\varphi = \text{const}$

Figures and numerical values are given for each control mode, with a concise description.

8.3.2. Fixed reactive power control mode

8.3.2.1. CENELEC description

N/A

8.3.2.2. Grid code

German grid code

→ 10.1.12 Reactive power control mode (for slow voltage change)

The step response time for a step change of the setpoint (Annex C, Figure C.1) for the purpose of reaching the reactive power setpoint shall be adjustable to between 0.1 s and 10 s by the HVDC converter station. Unless any concrete value has been specified by the relevant system operator, a value of 5 s shall apply. The settling time for reaching the reactive power setpoint shall be specified by the relevant system operator within the range of 1 s to 60 s. Unless any concrete value has been specified by the relevant system operator, a value of 30 s shall apply. The tolerance for steady-state reactive power output shall not exceed 5 % of the maximum reactive power supply.

→ 10.1.12.3 Reactive power control (for slow voltage change)

The setpoint Q_{ref} shall be specified by the relevant system operator with maximum setting steps of 10 Mvar. Unless indicated by the relevant system operator, a setpoint of 0 Mvar shall be used as the basic value.

Dutch grid code

→ 4.2.3 Reactive power control mode

The same as in §4.2.2 voltage control mode

7. The HVDC system is capable of setting the reactive power setpoint anywhere in the reactive power range, specified by NC HVDC Article 20, with setting steps no greater than 5 Mvar or 5% (whichever is smaller) of full reactive power, controlling the reactive power at the connection point to an accuracy within plus or minus 5 Mvar or plus or minus 5% (whichever is smaller) of the full reactive power

Danish grid code

The Reactive Power control mode must keep a fixed reactive power exchange Qo with the grid unless the voltage at the POC/voltage reference point is outside the selected Umin,Umax for Qo upon which the RPC must support the voltage with a droop control to restore the voltage, when the voltage is restored within Umin, Umax, the RPC will “automatically' return to Qo.

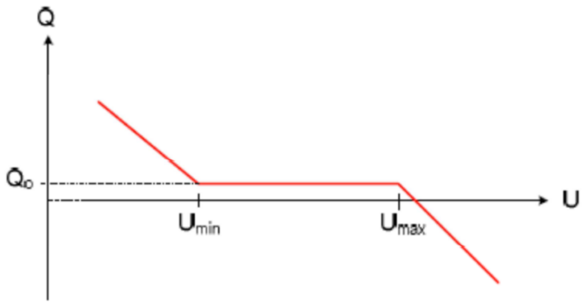
The Reactive Power control mode must

→ Keep a fixed reactive power exchange Qo with the grid within a specified Umin and Umax.

→ If the voltage at the POC/voltage reference point is outside the specified Umin, Umax for Qo the RPC must support the voltage with a droop control to restore the voltage

→ When the voltage is restored i.e. within Umin, Umax, the RPC will “automatically' return to operate with a fixed reactive power exchange Qo

→ Change from the currently active set-point to a new target set-point must be done with the defined ramp Qramp speed.



Normal control characteristic for reactive power control mode

Figure 64 Normal control characteristics for reactive power control mode.

The set-points for the station must be adjustable between:

→ Qo = between 0 and +/- the maximum converter reactive power rating

→ Qramp speed = between 1-30 Mvar/min (speed of set point reference change)

→ Droop = between 1-10%, different values must be selectable for voltages below Umin and above Umax

8.3.2.3. Existing projects and literature

Requirements for reactive power control mode are given in PROMOTioN: D1.7 [25], Section 3.2.2.4 Reactive power control mode for onshore AC, and reproduced in Table 60Table 60 Parameters related to the reactive power control mode .

Table 60 Parameters related to the reactive power control mode [20].

	Value range NC HVDC	Example values
Setpoint	As specified by relevant onshore TSO, using HVDC capabilities	0.41 pu ind. – 0.41 pu cap.
Setting step	As specified by relevant onshore TSO, using HVDC capabilities	Max. 5 MVAr or 5% (the lower value is valid)
Accuracy	As specified by relevant onshore TSO, using HVDC capabilities	As specified by relevant onshore TSO, using HVDC capabilities

Dynamic performance requirements for fixed reactive power control mode after a change in the setpoint are given in BestPath: Section 5.5 Control modes and performance requirements under normal conditions, and reproduced in Table 61. TR is the rising time to reach the threshold VR, TS is the settling time to reach the steady state with a tolerance band ΔvS. VM is the tolerable overshoot.

Table 61 Dynamic performance requirements for a change in reactive power setpoint.

Parameter	TR	TS	VR	ΔvS	VM
Value	20 ms	100 ms	90% of the change	1 Mvar	10 Mvar

8.3.2.4. Testing procedure

See Section 8.3.1.4.

8.3.2.5. Applicability to the building blocks

See Section 8.3.1.58.3.1.4.

8.3.2.6. Related FR and PR

Functional requirement ID	Functional requirement title
General44	Fixed Reactive power control mode

8.3.2.7. Discussions

The national grid codes, PROMOTioN and BestPath specifies specify various criteria of the tracking performance: response time, settling time, tolerance (accuracy), setting step, deadband. In addition, the Danish grid code also mentions the Q-U droop control when U is out of the range [Umin, Umax].

8.3.3. Voltage control mode or reactive power/voltage characteristic mode

8.3.3.1. CENELEC description

The CENELEC document only briefly mentions the characteristics of the AC voltage / reactive power control mode. The shape of the Q(U_ac) function in particular is not specified.

8.3.3.2. Grid code

German grid code

→ 10.1.9 Dynamic voltage control:

The continuous dynamic voltage control for fast voltage changes and the reactive power control required according to 10.1.12 for slow voltage changes shall be permanently and simultaneously activated.

During dynamic voltage control, HVDC systems shall be capable of feeding into each conductor a current I of at least 100 % of the rated current (converter side) of the HVDC converter station.

The specified upper limit value of the voltage band or the FRT profile shall not be impaired at any time by impact of the HVDC system, not even during the predefined settling time in order to prevent the HVDC system from conducting a protective disconnection.

For faults with residual voltages $U_1 < 15\ \%\ U_n$ (positive-sequence system) at the connection point, dynamic voltage control is conducted, for example, based on the last reliably measured network frequency or voltage angle.

→ 10.1.9.2 Dynamic voltage control without reactive current specification

As a basic requirement, HVDC systems shall, within their rated limits, be capable of activating dynamic voltage control without any reactive current specification. The objective of dynamic voltage control without any reactive current specification is to counteract a short-term change of the fundamental component amplitude of positive-sequence and negative-sequence systems thereby contributing to the limitation of the voltage change.

This requirement is subject to project-specific substantiation in agreement with the relevant system operator.

Unless specified otherwise by the relevant system operator, dynamic voltage control without reactive current specification in the positive-sequence system is to be conducted without deadband. Subject to agreement with the relevant system operator, a deadband of 2 % to 10 % of the nominal network voltage Un or complete deactivation of the control may be applied in the negative-sequence system.

→ 10.1.9.3 Dynamic voltage control with reactive current specification

The additional consumed reactive current should be proportional to the voltage deviation, with the proportional gain being between 2 and 6 for the positive-sequence system and the same gain or 0 for the negative-sequence system, with a step adjustment of 0.5.

The dynamic requirements given below shall apply to the transient behavior for reaching the additional current (step response):

Step response time: $T_{an\_90\%} \leq 50$ ms

Settling time: $T_{ein\_\Delta x} \ \leq 80$ ms

Overshoot: $\Delta x_{\max}$

Settling tolerance: $-5\ \% < \Delta x < +15\ \%$

→ 10.1.12.2 Reactive power/voltage characteristic (for slow voltage change)

The objective of this method is the reactive power exchange between the HVDC converter station and the network at the connection point subject to the actual operating voltage of the extra-high voltage network ($Q = f(U)$).

For this purpose, the relevant system operator shall specify the reference voltage U_{ref}, a reference reactive power Q_{ref} and the increase and, if applicable, a deadband. The value of the reactive power to be exchanged by the HVDC converter station at the connection point results from the voltage actually measured at the connection point and the parameters of the characteristic curve.

The deadband is adjustable within a selectable range of zero to ±5 % of the reference value of 1 pu of the network voltage in maximum steps of 0,5 %.

Dutch grid code

From HVDC compliance verification [28]:

4.2.2 Voltage control mode: Netcode elektriciteit article: 6.12.3 – 6.12.6 (HVDC systems); article 3.26, paragraphs 5, 7 and 10 (DC-connected PPM's)

(b) the voltage control may be operated with or without a deadband around the setpoint selectable in a range from zero to +/– 5 % of reference 1 pu network voltage. The deadband shall be adjustable in steps as specified by the relevant system operator in coordination with the relevant TSO;

(c) following a step change in voltage, the HVDC converter station shall be capable of:

(i) achieving 90 % of the change in reactive power output within a time t_1 specified by the relevant system operator in coordination with the relevant TSO. The time t_1 shall be in the range of 0,1-10 seconds; and

(ii) settling at the value specified by the operating slope within a time t_2 specified by the relevant system operator in coordination with the relevant TSO. The time t_2 shall be in the range of 1-60 seconds, with a specified steady- state tolerance given in % of the maximum reactive power.

3. The voltage control deadband shall be adjustable in steps of 0,5% of the 1 pu reference voltage;

4. The value of time t_1 for achieving 90% of the change in reactive power output, shall be agreed between the RSO in consultation with the TSO and the Connected Party and will be recorded in the Connection Agreement;

5. The value of time t_2, in the range of 1 to 60 seconds, for achieving 99% of the change in reactive power output, shall be agreed between the RSO in consultation with the TSO and the Connected Party and will be recorded in the Connection Agreement;

Danish grid code

Voltage Control Mode must:

- → Be possible to select Voltage Control as the default control mode that is automatically activated in case of an outage of the DC cable or the other Converter Station.
- → If the voltage set point is to be changed, such change must be commenced immediately after receipt of an order to change the set point.
- → The HVDC station must be able to perform the control within its dynamic range and voltage limit with the droop configured. In this context, droop is the voltage change (p.u.) caused by a change in reactive power (p.u.).

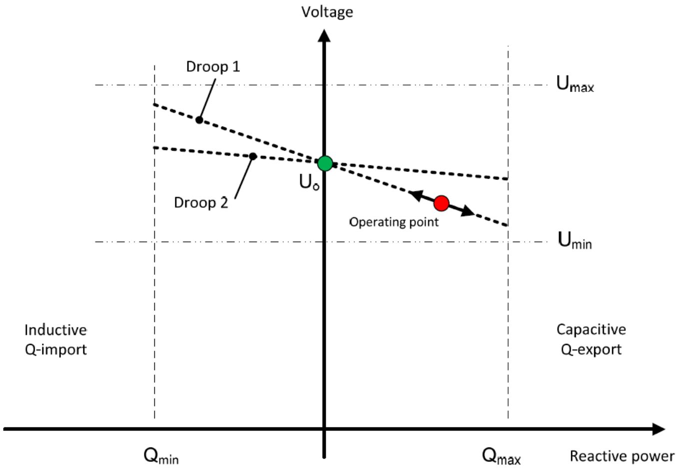


Figure 65 Illustration of reactive power - voltage droop control mode.

U0 = range within minimum to maximum voltage, with an accuracy of 1 kV.

Qmin = Between 0 and - the maximum converter reactive power rating

Qmax = Between 0 and + the maximum converter reactive power rating

Droop = between 1-10%, different values must be selectable for voltages below Qmin and above Qmax

All set points must be adjustable from local and remote.

8.3.3.3. Existing projects and literature

From PROMOTioN: D1.7 [25], Section 3.2.2.4 Reactive power control mode for onshore AC. The three control modes (voltage, reactive power, and power factor) are mentioned. Main parameters related to those modes are indicated in Table 60.

Table 62 Parameters related to the voltage control mode [20].

	Value range NC HVDC	Example values
Setpoint voltage	As specified by relevant onshore TSO	0.9 – 1.1 pu
Setpoint voltage step size	As specified by relevant onshore TSO	Max 1 %
Deadband	0 - ± 5%	± 5%
Deadband step size	As specified by relevant onshore TSO	Max 0.5 %
Slope	As specified by relevant onshore TSO	2 – 7 % (6% default value)
Slope step size	As specified by relevant onshore TSO	0.5 %
Rise time	0.1 s – 10 s	1 – 5 s

In BestPath [6]: Section 5.5 Control modes and performance requirements under normal conditions, the AC voltage control mode is defined as

$$U_{ac} + \frac{Q_{ac}}{U_{ac\_droop}} = U_{ac\_ref} + \frac{Q_{ac\_ref}}{U_{ac\_droop}}$$

Control modes and performance requirements under normal conditions and reproduced in Table 61 and Table 64. TR is the rising time to reach the threshold VR, TS is the settling time to reach the steady state with a tolerance band ΔvS. VM is the tolerable overshoot.

Table 63: Step response requirements for voltage control mode under normal condition.

Parameter	TR	TS	VR	ΔvS	VM
Value	200 ms	1 s	90% of the change	0.5% of Un	5% of Un

Table 64: AC voltage / reactive power control mode characteristics.

Signal	Description	Unit	Range
Uac_ref	AC voltage setpoint	[kV]	85% to 105% Un
Uac_droop	Slope of the voltage control	[Mvar/kV]	300 Mvar for a deviation of 7% of Un to 300 Mvar for a deviation of 2% of Un
Qac_ref	Reactive power setpoint when the voltage measurement value equals the voltage setpoint	[Mvar]	[Qmin ; Qmax]

BestPath [6]: Section 5.6.3 describes the reactive current support during abnormal AC voltage. The reference reactive current in this mode is given by

$$I_{q\_ac\_ref} = \Delta I_q + I_{q\_ac\_0} = I_{q\_ac\_coef} * \frac{U_{ac} - U_{ac_{db}}}{U_n} * \frac{P_{max}}{\sqrt{3} * U_n} + I_{q\_ac\_0}$$

Where $U_{ac_{db}}$ is the voltage threshold on the normal operating range, $I_{q\_ac\_0}$ is the pre-fault reactive current.

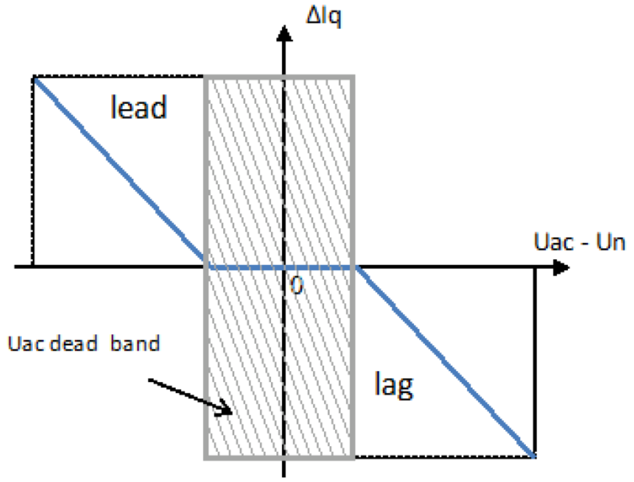


Figure 66 Example of reactive current support for abnormal AC voltage.

Control modes and performance requirements under normal conditions and reproduced in Table 65 and Table 66. TR is the rising time to reach the threshold VR, TS is the settling time to reach the steady state with a tolerance band ΔvS. VM is the tolerable overshoot.

Table 65: Step response requirements for voltage control mode under abnormal condition.

Parameter	TR	TS	VR	ΔvS	VM
Value	10 ms	20 ms	50% of the change	15A	150A

Table 66: AC voltage / reactive current for abnormal voltage control mode tuning parameters.

Description	range	Unit	Description
Iq_supp_max	Upper DC current limit for reactive current support (maximal DC current injection)	[0 – 2000]	A
Iq_supp_min	Lower DC current limit for reactive current support (maximal DC current absorption)	[-2000 – 0]	A
Iq_supp_coef	Contribution factor for reactive current support	[0 – 4]	-
Iq_supp_Uac_l	Low DC voltage threshold: lower limit of the dead band for the activation of reactive current support	[0 – 400]	kV
Iq_supp_Uac_h	High DC voltage threshold: upper limit of the dead band for the activation of reactive current support	[400 – 440]	kV

8.3.3.4. Testing procedure

See Section 8.3.1.4.

8.3.3.5. Applicability to the building blocks

See Section 8.3.1.58.3.1.4.

8.3.3.6. Related FR and PR

Functional requirement ID	Functional requirement title
General42	Steady state AC voltage droop mode
General43	Dynamic AC voltage droop mode

8.3.3.7. Discussions

NL: The compliance verification [28] (in English) is better organized than the Dutch grid code [21] (in Dutch). Therefore, the former is extracted here. In addition, there seems to be some discrepancies between the two, e.g. some references in the compliance verification in English do not correspond to the articles in the Dutch grid code. The NL grid code mentions rather various criteria of the tracking performance, which are also shared by the paragraph on the reactive power control.

DK: The Q setpoint follows a droop depending on the voltage.

PROMOTioN: various criteria of the tracking performance for voltage control.

BestPath: The various criteria of the tracking performance for voltage control are given in two situations: normal operation, and during disturbance. For the former case, the expression of Q setpoint is given, while for the latter case, that of the reactive current setpoint is given.

Though not mentioned in the CENELEC report, a distinction between slow and fast voltage control modes appears in several document, in particular the German grid code and the best paths project. This distinction seems relevant as the two modes pursue different objectives, two different functional requirements are thus proposed accordingly

- → Steady-state reactive power / AC voltage control capability addresses the AC voltage tuning for small deviations around the nominal voltage with response time above 100ms.
- → Dynamic reactive power / AC voltage control capability addresses the control of AC voltage following large AC voltage disturbances, with response time of less than 100ms. If enabled, the dynamic reactive power support should have priority over other control objectives which are then frozen until the AC voltage returns to the dynamic reactive power support deadband.

8.3.4. Constant power factor control mode

8.3.4.1. CENELEC description

N/A

8.3.4.2. Grid code

German grid code

10.1.12.4 Power factor control (for slow voltage change)

$\cos \phi_{ref}$ = const

The power factor setpoint $\cos \phi_{ref}$ shall be predefined within a range as shown in the diagram of AC voltage range. The value shall be predefined with minimum steps of $\Delta\cos\phi$ = 0,005.

The relevant system operator shall predefine a power factor setpoint. Unless indicated by the relevant system operator, a setpoint of $\cos \phi_{ref}$ = 1 shall be used as the basic value.

Dutch grid code

HVDC compliance verification [28]:

4.2.4 Power factor control mode

The same as in §4.2.3 reactive power control mode

8. The target power factor minimum steps size shall be no greater than 0.005.

Danish grid code

The following requirements for Power Factor control mode are

- → Power Factor control mode can be enabled and disabled from operator level (OWS) independently at each station
- → The actual measured active power is used as input of the Power Factor Controller
- → The operator can input a desired power factor target value in the range between minimum and maximum PF value with a resolution of 0.001.
- → Besides the absolute value for the Power Factor, the inductive or capacitive characteristic is to be selected by operator.
- → Power factor target ramping speed must also be possible.
- → At any time during the ramp the operator can initiate “ramp stop” to stop the power factor ramp and hold at the actual power factor target level.
- → Initiating “ramp release” resumes the already defined ramp with the same destination, if no interim changes were made to the settings
- → The power factor order ramping process is stopped as soon as the desired power factor target order finally reached the new power factor target set-point.
- → The power order calculation of the power factor controller is permanent, i.e. even when the controller is disabled, it calculates a potential order, but it is not contributed. In case of enabling of the power factor controller the calculated order is immediately used for reactive power control. But for bumpless transition the actual calculated order is also added to the Q-controller with opposite sign.
- →

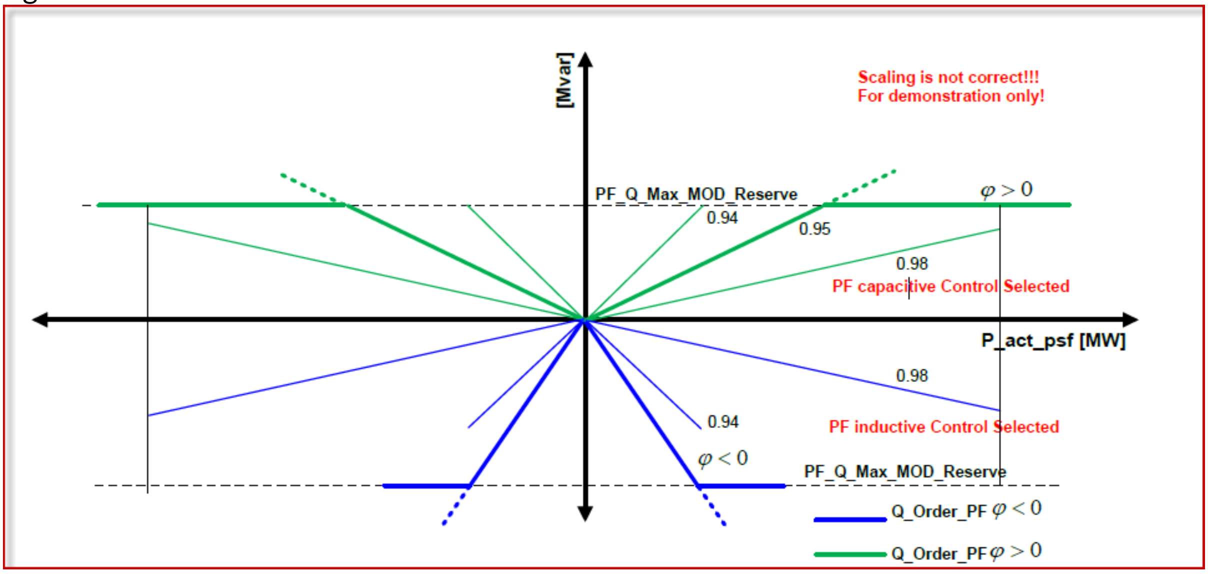


Figure 67 Principle of power factor control mode.

8.3.4.3. Existing projects and literature

PROMOTioN: D1.7 [25], Section 3.2.2.4 Reactive power control mode for onshore AC provides the following parameters for PF control mode, see Table 67.

Table 67 Parameters related to the power factor control mode [20].

	Value range NC HVDC	Example values
PF range	With respect to NC HVDC articles 20 and 21 [20]	0.925 ind. – 0.925 cap.
PF step size	As specified by relevant onshore TSO	0.005
Dynamic		Setting time max 4 min
Tolerance	-	-

8.3.4.4. Testing procedure

See Section 8.3.1.4.

8.3.4.5. Applicability to the building blocks

See Section 8.3.1.58.3.1.4.

8.3.4.6. Related FR and PR

Functional requirement ID	Functional requirement title
General45	Power factor control mode

8.3.4.7. Discussions

The 3 national grid codes, PROMOTioN and BestPath gives some requirements on various criteria of the tracking performance.

8.4. Power oscillation damping service

8.4.1.1. CENELEC description

Power Oscillation Damping is a control function that can provide damping of low frequency oscillations, typically in the range of [0.1 - 2] Hz through modulation of active or reactive power. In case of active power modulation, the active power can be provided from

- → A small energy storage at the converter level
- → A neighboring synchronous area (e.g. interconnector case)
- → The same synchronous area through the DC grid (e.g. embedded HVDC link case)

HVDC control loops can themselves induce sub-synchronous oscillations, including torsional interactions (SSTI) when operating in the vicinity of large synchronous generators.

8.4.1.2. Grid code description

POD is the subject of “Article 30 - Power oscillation damping capability”, where only the frequency range of oscillations that must be damped is mentioned, with an indicative range of [0.1 -2] Hz. POD function can manually be enabled or disabled.

8.4.1.3. Description in existing literature

Existing POD in HVDC point-to-point systems

As mentioned in Table 57, a POD is implemented in the INELFE interconnector, an embedded HVDC link between France and Spain. An angle difference control has been implemented[7], the active power is modulated as

$$\Delta P = K_\theta \Delta\theta$$

where $\Delta\theta$ is the angle difference between the two ends of the HVDC link.

An alternative control, the Dynamic Virtual Admittance Control (DVAC), has been proposed in the RITSE project by SuperGrid Institute[8].

Another example of implemented POD is the DC Pacific Intertie in the US Wester Interconnection [76]. The control law is

$$\Delta P = K_f \Delta f$$

where Δf is the frequency difference between the two ends of the HVDC link, based on PMUs measurements and an appropriate derivative filter.

Note that in both cases, the control relies on distant PMU measurements, which induces some delay τ for communication.

Extension of POD to MTDC systems

The extension of the POD capability to an MTDC grid is not straightforward. The requirement that the active power of the MTDC grid is always balanced gives many possibilities on how to share the active power. In addition, an MTDC can interconnect multiples areas of the same synchronous zone, and asynchronous zones.

The extension of power oscillation damping capabilities to an MTDC grid connecting to asynchronous zones is investigated in [77]. A decoupling controller, achieved through proportional control, is beneficial as it allows to decouple the oscillation modes of the two AC zones. The propagation of oscillation modes from one zone to the other is then avoided.

Oscillation damping by an embedded MTDC is studied in [78]. A weighted average frequency is used as the frequency reference for all converters. The choice of the weights is proposed based on the relative ratings of the different converters but also influences the priority given to the different modes to be damped. Each converter then modulates its active & reactive power based on the difference between its local frequency and the average frequency. The proposed approach is effectively able to damp oscillations for a 3-terminal HVDC

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[7] https://innodc.org/wp-content/uploads/2020/10/Inelfe_REE_LuisCoronado_20201019.pdf

[8] https://www.ree.es/en/sustainability/anticipating-change-and-taking-action/grid2030-programme

system embedded in the Nordic32A test system. The case of an MTDC connected multiple asynchronous zones was however not studied.

It is shown in [79] that the preferred choice for damping inter-area oscillations with embedded MTDC is to couple pairs of converters so that the sum of their active power modulation is null. This conclusion stands also for MTDC connected multiple asynchronous areas. The choice of pairing is then crucial. The comparison of the electrical distances (through the reactance) and inertias of the different areas connected to the MTDC indicates which areas should be paired to provide the best damping. Adequate gain can also be derived based on the inertias and reactances of the network. The communication between the paired converters is performed through wide area control system.

8.4.1.4. Testing procedure

According to CIGRE TB 563 [9], power oscillation damping studies can be performed by transient analysis tools. Detailed models of AC components that affect the electro-mechanical behavior must be employed, including rotor turbine inertia, exciter and turbine governor control. For the HVDC model, key control system parameters must be provided, such as Voltage Dependent Current Limit, recovery ramp rates, and high-level control functionalities.

Such studies can be performed in a preliminary dynamic stability analysis to evaluate the capability of the HVDC system to support the AC grid. Study cases considered as the most difficult are used to conduct the studies. Interaction studies conducted during the bid process then demonstrate the stability and frequency behavior of the converter stations.

8.4.1.5. Applicability to the building blocks

As electro-mechanical oscillations affect the entire AC synchronous area, the ability to damp such oscillations apply to all the onshore stations connected to the same AC zone. POD should thus not be seen as the ability of a single converter but rather as an ability of the entire DC grid, or at least of a part of it (for instance a pair of converter stations connected to the same AC area).

The offshore converters should also be able to damp oscillations in their respective offshore AC network.

8.4.1.6. Related FR and PR

Functional requirement ID	Functional requirement title
On_ACDC_Con1	Power oscillation damping capability
On_ACDC_Con2	Sub-synchronous torsional interaction damping capability
Off_ACDC_Con6	Oscillation damping capability
Master_Control9	Ancillary service coordination

8.4.1.7. Discussion

The requirements for the damping capability of a MTDC grid should address the following questions

- Is the MTDC embedded within one AC zone or connecting multiple AC zones? In the latter case, how to avoid the propagation of oscillations between the asynchronous zones?
- How to define the frequency deviation to be minimized by each converter, in particular what frequency reference should be used?

8.5. System restoration services

8.5.1.1. CENELEC description

Distinction should be made between

Energization process, which includes the start-up of AC/DC converter from connected AC system, DC system or internal power. It is not an ancillary service and is further detailed in Section 7.2 operating sequences and open-loop controls.

System Recovery Ancillary Service DC (SRAS-DC): ability of a converter to provide services for the restoration of the DC system, which includes

→ Earthing reference for DC grid
→ Active power demand of connected loads
→ Charging DC circuit and equipment to be energized
→ Provide short circuit current for DC protection

AC system restoration from black-out: ability of a converter to provide services for the restoration of the AC system, which includes

→ Black-start: Energization of relevant AC/DC converter from remote or asynchronous operational AC system via DC connection
→ SRAS: Energization of the black, connected AC system. AC/DC converter must be able to maintain the AC voltage and frequency at its PoC-AC.

8.5.1.2. Grid code description

DC system restoration services: N/A

AC system restoration is addressed in [80], and in [20], [81] regarding the participation of DC connected PPM and HVDC systems.

Difference is made between:

→ Top-down re-energization strategy, where the assistance of other TSOs is required to re-energize part of the system of a TSO.

- → Bottom-up re-energization strategy, where part of the system of a TSO can be re-energized without the assistance from other TSOs.

Inter-TSO assistance can be performed through HVDC interconnector, and assistance includes

- → Manual power flow regulation to bring frequency within frequency operational security limits
- → Automatic control of active power
- → Automatic frequency control in case of islanded operation
- → Voltage and reactive power control

In [20], black-start capability is not mandatory for HVDC system. If applicable, an HVDC system with black-start capability should be able to energize, from one energized station, a remote converter station and its connected AC busbar.

8.5.1.3. Description in existing literature

DC system restoration

The CIGRE Brochure [11] focuses on ancillary services for the DC system.

DC black-start capability is then defined by National Grid as "the procedure to recover from a total or partial shutdown of the transmission system which has caused an extensive loss of supplies. This entails isolated power stations being started individually and gradually being reconnected to each other in order to form an interconnected system again".

The black-start capability may be available

- → At one converter connected to an AC system
- → At several converters connected to the same AC system
- → At several converters connected to independent AC systems
- → Independently from the AC grid, based on independent generation unit.

AC system restoration [35]

Participation of HVDC systems in strategies for AC system restoration are further detailed in [35].

- → Top-down strategy

The top-down strategy is based on external voltage sources connected through AC lines. HVDC converters with grid forming capability can create an independent restoration path. Alternatively, HVDC converters can be used as STATCOM in such a strategy to control voltage and reactive power. This feature is today implemented in KF CGS, INELFE, and Skagerrak 4.

- → Bottom-up strategy

HVDC system can be used in a "bottom-up" restoration strategy, working as target group with a large regulation capacity, see Figure 68.

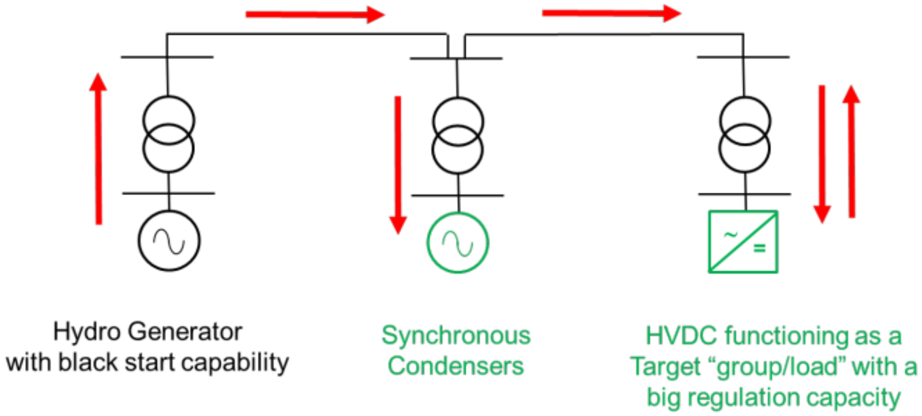

Figure 68 Restoration based on a bottom-up strategy including HVDC [35].

The following HVDC functionalities can contribute to AC restoration

- Black-start capability of the converter, without the need for power supply from the AC grid affected by the black-out.
- AC side voltage ramp-up, from 0 to 0.9 pu
- STATCOM – reactive power / voltage control
- Primary frequency regulation
- Synchronization, which relies on the islanding mode capability of the converter stations

8.5.1.4. Testing procedure

The performance criteria for the HVDC system defined in the planning stage should include possible black-start and islanding network operation [9].

According to CIGRE TB 832 [26], system restoration and black-start study/test are performed during implementation stage.

System restoration and black-start tests are performed using EMT type tools (real-time or offline) and a generic representation of the connected system. Their goal is to verify the capabilities during black-start and system restoration using different switching events and faults. The simplified network representation typically comprises one local bus and one remote end bus.

System restoration and black-start studies are performed using EMT tools (real-time or offline) with the full C&P system and a detailed representation of the system part involved in the restauration scenario. Their goal is to provide a detailed verification of the system behavior during specific black-start and restoration sequences.

8.5.1.5. Applicability to the building blocks

SRAS-DC capability can be available at one/several converter stations of the HVDC grid. Switching stations can also provide some of the features required in SRAS-DC (e.g. DC grid earthing).

SRAS-AC requirements specifically apply to onshore converter stations. The black-start capability of the converter however can rely on the energization of the DC grid and thus on other converter stations.

8.5.1.6. Related FR and PR

Functional requirement ID	Functional requirement title
General46	System Restoration DC Side
On_ACDC_Con3	Black start
On_ACDC_Con4	System Restoration AC Side

8.5.1.7. Discussion

N/A

8.6. Other ancillary services

We list here a list of additional ancillary services that are mentioned in reference documents, though less relevant to the study. None of those are extensively describe in the CENELEC reports.

→ **Island operation capability**, which can be defined as one of the possible control modes of a converter, along with DC voltage and power control. It can be used when the converter is connected to a small islanded network on the AC side. Typical applications are an islanded wind farm and the black-start of an AC network [11]. It is thus understood that islanding is a type of grid-forming capability. A converter operating in islanded mode, or U-f control, cannot contribute to DC voltage regulation.

→ **AC Short-circuit current (overload capability).** The contribution of HVDC system during AC fault is mentioned in Article 19 of European NC. Requirements can be specified by the TSO regarding the voltage deviation, characteristics of the provided fault current, and the timing and accuracy of the fault current.

8.7. Conclusions & next steps in SoW B

The topic of AC ancillary services is globally well covered in existing literature and grid codes. The extension of AC ancillary services to MTDC grids may not be straightforward, for instance regarding frequency services. The investigation of such functionality however requires a rather detailed representation of AC side elements and constraints. As the focus of this project is more on the DC PoC, it was decided not to further investigate AC ancillary services within SoW B. The following subjects of DC ancillary services are addressed within the SoW B

→ Analysis of functional requirement and parameter ranges related to energization of DC subsystem: cable energization by means of a pre-insertion resistor and MMC energization from a controlled DC grid by means of a pre-insertion resistor.

→ Energy balance by means of DBS (addressed within protection functional group studies).

9. Conclusions

This background report provides an overview on functional requirements for future multi-terminal DC grids based on relevant literature. The CENELEC report can be seen as an important reference for the pre-standardization. It gives a good overview on design aspects to be considered and is a good starting point. However, it remains very general in terms of DC grid architecture and technology. As a consequence, the functional specifications are formulated in a very general way such that project-related specifications for preferred topologies of the NSWPH project are not sufficiently covered (i.e. bipolar, offshore/onshore requirements, fully selective protection scheme, …). Another limitation is the lack of parameter ranges in the CENELEC guideline.

10. Next Steps

The background report can be seen as a good starting point for the SoW B, where the identified limitations will be addressed and further investigated in order to provide more specific functional requirements according to the NSWPH project needs. The development of simplistic test benchmarks for the building blocks and the validation by the use cases will allow to narrow down the parameter ranges.

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