Functional requirements for HVDC grid systems and subsystems

InterOPERA
Enabling multi-vendor HVDC grids

ABOUT INTEROPERA:

The InterOPERA project will define technical frameworks and standards for electricity transmission and accelerate the integration of renewable energy. Ensuring that HVDC systems, HVDC transmission systems or HVDC components from different suppliers can work together – making them "interoperable"- is a top priority to accelerate Europe's energy transition.

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1. Abbreviations and definitions

AC/DC	alternating current / direct current
CBC	Current Breaking Capability
DCGC	DC grid controller
DCR	DC Reactor
DCSS	DC Switching Station
DCVLM	DC Voltage Limiting mode
DCVSM	DC Voltage Sensitive mode
DMR	Dedicated Metallic Return
ERTS	Earth Return Transfer Switch
FCLD	Fault Current Limiting Device
FSD	Fault Separation Device
FIZ	Fault Isolation Zone
FRR	Frequency Restoration Reserve
FRT	Fault-Ride-Through
FSZ	Fault Separation Zone
HV	High Voltage
MV	Medium Voltage
LDCVSM-O/U	Limited DC Voltage Sensitive Mode-Overvoltage/Undervoltage
LVRT	Low Voltage Ride Through
OVRT	Over Voltage Ride Through
MRTS	Metallic Return Transfer Switch
MT	Multi Terminal
PCS	Peak Current Suppression
PLES	Pole local earthing switch
PLM	Power Limiting Mode
PoC	Point Of Connection
PPM	power park modules

PtG/PtP	Pole-to-Ground/ Pole-to-Pole
RCS	Residual current Switch
SU	Switching Unit
TIV	Transient Interruption Voltage
TSO	Transmission System Operator
ZDD	Zone Distinction Device

2. Executive summary

The European target of installing more than 300GW of offshore wind power in the North Sea by 2050 urges for an increasing need of HVDC systems. So far, only turnkey solutions provided by a single vendor have been installed. Considering an expandable multi-terminal HVDC grid with multi-purpose interconnectors would significantly improve the power exchange flexibility, the wind power transfer and the global system cost efficiency.

This deliverable intends to provide a guideline for the definition of functional requirements in HVDC systems considering a multi-terminal multi-vendor context. The functional framework shall ensure expandability and interoperability of HVDC systems by specifying connection requirements at the DC Point of Connection. The functional framework should be described in an inclusive and technology-agnostic way. It should allow different technical solutions to cohabitate in an HVDC grid and avoid excluding any technical solutions without justification. The functional requirements shall be purpose oriented, generic, solution-open and justified. They should provide a clear functional split between subsystems to maximise interoperability by design.

Section 4 provides an overview on the functional aggregation of the following subsystems: AC/DC converter station, DC switching station, energy absorber, Power Park Module (PPM) and AC switching station. The subsystems are aggregated based on their primary functional purpose. The AC/DC converter station is a power exchange device. Energy storage and energy absorption are functions covered by functionally independent subsystems, further denoted as energy storage device and energy absorption device. A DC switching station includes all relevant DC switchgear and automation functions to ensure connection and disconnection operations for planned and unplanned events. All subsystems are monitored and coordinated with vertical communication interfaces with a DC grid controller and AC/DC dispatch centre. A major result of the functional aggregation is the generic and technology-agnostic definition of the switching unit. The switchgear of a switching unit depends on assigned functionalities. In addition, different switching functions (e.g. fault/load current interruption or energization) and fault detection functions (e.g. for different fault types, primary/backup protection) can be assigned to the switching unit. The aggregation of switchgear is a design choice of the vendor if the functional requirements associated to the switching unit are fulfilled.

The functional requirements at the DC side address multi-disciplinary subjects. To ensure the work progress in a structured way, the following functional groups have been formed: Sequential control, Continuous control, DC grid protection. The main outcomes of each functional group will be outlined in the following.

Sequential control

Within a given HVDC system topology, different DC connection modes are possible. The DC connection modes describe the connection between the individual units within the HVDC system at their DC-PoC. The sequential control describes all actions that allow the HVDC system to switch from one connection mode to another. The main operational modes and transitions are captured in flowchart diagrams. Such transitions may be triggered automatically, or manually by an operator, or a combination of both.

The main states of a switching unit are either "open" or "closed". The transition sequence depends on conditions of surrounding units which are verifiable at switching unit level based on voltage and current quantities. A transition from "open to "closed" state may be carried out by an aggregation sequence (connection of two discharged units), an energization sequence (connection of one charged and one discharged unit) or a synchronization sequence (connection of two charged units). From close to open the transition sequence is characterized by the presence or not of current. Depending on whether fault, load or residual current is observed, the performed sequence and applicable requirements for the switching unit are different.

Finally, a list of functional requirements is provided including the following functions: Command routing, interlocking, aggregation, energization, synchronization, disconnection, separation, isolation, discharge, auto-reclosing, earthing, reconfiguration.

Continuous control

HVDC systems must deliver scheduled power while ensuring their own security and reliability to guarantee continuous operation. It is imperative to prevent power flows and DC voltages that exceed the physical capabilities of system components. Disturbances in the system can disrupt the balance of power, resulting in fluctuations in DC voltages. In such instances, the AC/DC converters within the system must promptly and collectively restore system energy equilibrium to prevent violations of system limits.

The functional group continuous control addresses the overarching control architecture of HVDC systems by defining roles and responsibilities allocated to each layer. Boundary conditions from surrounding AC grids and physical constraints are introduced. These conditions serve as a basis for the functional description of static and dynamic requirements for primary DC voltage control.

A deviation of DC system voltage is an indicator of an imbalance in power flow from the initial load flow, which was originally at equilibrium. The primary DC voltage control plays a crucial role in preventing this imbalance and reaching an equilibrium point of the system. In order to achieve improved security while achieving the maximum exploitation, the multi-segment droop characteristic for primary DC voltage control is defined as a distinct set of control capabilities, each with specific operational requirements.

The stability of the system is determined by the dynamic response of each AC/DC converter and their interactions through the network. In a multi-vendor and multi-terminal DC grid, each converter controller would likely be unique to each vendor, reflecting different dynamic control design concepts. Therefore, the established static requirements for the primary DC voltage control are complemented by appropriate dynamic primary DC voltage control requirements. The AC/DC converter station shall comply with several characteristic values such as step response time, overshoot, and damping coefficient to be specified by the TSO. First considerations for the performance evaluation in a standalone test environment are made.

Finally, a list of functional requirements is provided including the following functions: Element status analysis, System topology analysis, Element limitation analysis, DC power flow optimization, Secondary DC voltage control, Ramp rate coordination, Offshore power curtailment, Control mode management, primary DC voltage control related modes.

DC grid protection

The protection of DC systems should follow the same objectives as in AC systems: Ensuring a reliable and secure HVDC system operation during contingencies including DC faults and component failures. In a large scale HVDC system the shutdown of the entire system is not compliant with power system criteria which imposes a limited impact for a single event. This implies a need for fault separation in the HVDC system. The fault separation zones on the DC side need to be defined such that the maximum loss of power of surrounding AC grids is respected. AC/DC Converter stations outside of the fault separation zone shall ensure post fault active power recovery. The DC-Fault Ride Through (DC-FRT) capability of converters shall be specified such that any unexpected disconnection of the converters from the grid is avoided.

The functional group DC grid protection defines the system states (normal, alert, emergency, blackout) and associates them to ordinary and extraordinary contingencies. Requirements for fault detection and fault current suppression are defined on DC switching station level and a DC-FRT profile for AC/DC converter stations is defined with the objective of a clear functional split between AC/DC converter station and DC switching station.

The DC-FRT profile ensures that the AC/DC converter station has sufficient withstand capability to ride through a DC fault while the primary protection operates avoiding any unplanned disconnection. The functional group DC grid protection has investigated different ways to define DC-FRT requirements, mainly distinguishing between a generic and design-based approach and between DC voltage and DC current profiles. To leave freedom to the vendors for different converter design strategies, only a DC-FRT profile based on DC voltage quantities is defined, and no overcurrent capabilities are prescribed. The actual fault current level in the converter is left unspecified and then depends on the design strategy of the converter's vendor. The definition and evaluation of alternative DC-FRT profiles is provided in the appendix section. The assessment of converter grid serving requirements during DC-FRT will be added to the final version of the deliverable.

Finally, a list of functional requirements is provided including the following functions: DC-FRT (connection requirement, operational requirement), Fault separation, Fault isolation, Fault detection/discrimination (fault separation & fault isolation), Tele-communication, Protective auto-reclosing, Monitoring.

3. Introduction

This deliverable is listing basic functional requirements for the building blocks of multi-vendor HVDC grids ensuring interoperability by design.

The building blocks of HVDC grids include the following subsystems: AC/DC converter stations; DC switching stations; coordinated DC grid control; power park modules connected to the offshore AC system. Functional requirements are defined for a bipolar configuration with Dedicated Metallic Return (DMR) as a full set while considering rigid bipolar and asymmetrical monopolar configurations covered as sub-sets. It should be noted that requirements for symmetrical monopolar configurations may not be fully represented in this deliverable.

The main functions of a multi-vendor HVDC grids (continuous control, sequential control, DC grid protection) have been analysed, divided and assigned to the subsystems. This leads to the definition of basic functional requirements for each subsystem. Those basic functional requirements are defined to be verifiable at subsystem level with standalone compliance tests and dedicated simple models.

Interoperability by design is a success if the standalone compliance of individual subsystems is enough to ensure the desired integrated DC grid system performance and behaviour.

Interoperability will be tested through the Demonstrator of InterOPERA. The integration tests and interaction studies may lead to the discovery of interoperability issues. Solving those issues should ideally be possible through a refinement of the subsystems' basic functional requirements. This learning process will reinforce the basic functional requirements and their capability to ensure interoperability by design.

Some control and protection functions belong to the grid level and others at subsystem or component level. Functions at subsystem-level, implemented by several different vendors, are the most susceptible to cause adverse interactions. Therefore, in this current version of this deliverable, special attention has been paid to the formulation of functional requirements at subsystem level and at the DC points of connection. For grid operation functions, it was first assumed that there is only one instance of grid-level operation in the system, so they are less prone to adverse interactions. A second version of this deliverable may further elaborate on the functional requirements for grid-level functions implemented in DC grid controllers, possibly considering distributed architectures for this control layer, in a multi-operator context.

Functional requirements shall be described in a technology agnostic and purpose-oriented way. The basic functional requirements are intended to open the market for different technical solutions and to foster innovation while addressing and fulfilling the relevant requirements for a stable MT MV HVDC network. Any restrictions are to be justified by technical efficiency gains. Functional requirements shall be formulated in a generic manner and as independent from a specific design or topology as possible. The basic functional requirements are still subject to screening for identification of patents that may relate to them. The evaluation of patent relevance or essentiality will then be organized. This may lead to revisit the functional requirements or to include a reference to a patented item, granted that the right licensing conditions are secured.: Section 4 describes the aggregation of the subsystems by defining the terminology, boundaries and interfaces. Sections 5-7 define functional requirements and provide reasoning for different functional groups. The section 5 provides an overview of global and local sequences in an HVDC system. In this context states of subsystems, transitions and relevant communication interfaces are defined. The section 6 provides an overview on functional requirements related to continuous control. In the first part, a clarification on different functional levels and responsibilities is provided by distinguishing between operational level, converter station-level and converter unit level. In the second part, main sections deal with static and dynamic control concepts and define relevant functional requirements. Section 7 provides an overview on functional requirements related to DC grid protection. In the first part, a relation between system states and DC grid contingencies is defined leading to DC grid protection coordination requirements. The second part focusses on DC-Fault Ride Through (FRT) requirements for converter stations on the one hand and fault separation requirements on the other hand. At the end of each section a list of functional requirements and associated parameters are provided.

Deliverable 2.1 consists of two versions. This first version describes the functional framework and basic functional requirements while some sections are expected to be filled for the second release of the deliverable. Furthermore, the second version will incorporate updated functional requirements based on a refinement process including lessons learned from subsystem standalone compliance tests and performance verification at HVDC system level.

4. Functional subsystem definition

In this section, the aggregation of subsystems in a multi-terminal HVDC system are defined such that connection requirements can be assigned at the DC-Point of Connection in an independent and verifiable way while ensuring a clear split of interfaces and functional responsibilities[1]. The following functional levels are defined.

HVDC system

Means an electrical power system which transfers energy in the form of high-voltage direct current between two or more alternating current (AC) buses and comprises at least two HVDC converter stations with DC transmission lines or cables between the HVDC converter stations.

DC grid control layer (DCGC)

Represents an interface for getting information on the power flow conditions and accessing all electrical nodes in the HVDC grid. It continuously receives and transmits status and command messages to and from any high voltage equipment necessary for HVDC power transmission. Based on this information, the HVDC grid control provides modifications on the dispatched converter schedules in order to properly respond to changing external conditions according to desired optimization targets.

DC switching station (DCSS)

Part of an HVDC system with the primary purpose to establish electrical connections between functional elements in the HVDC system. It is composed of:

- **Switching unit:** Set of all switchgears that ensures the connection between one external unit (transmission or converter) and a busbar of the switching station [1]. Some switching units may also ensure connection between busbars of the same switching station. The switching unit corresponds to an aggregation of all switchgear for a given pole, and a given feeder. A switching unit comprises both the primary equipment, as well as the secondary equipment needed for automation and monitoring of the switchgear including fault detection and discrimination functions. Switching unit may comprise fault separation device (FSD) or not.
- **Busbar unit:** Including secondary equipment for busbar related fault detection and discrimination functions.
- **Grounding unit:** The grounding unit is located in the DC switching station. It is a passive device ensuring the system grounding which is configured by a switching unit.
- Measurement device required for the automation of the switching unit and switching station control.

AC/DC converter station

[1] Disclaimer: It should be noted that no techno-economical assessment has been made which might, for individual functionalities and subsystem aggregations, come with a certain cost of oversizing or redundancy.

Part of an HVDC system which consists of one or more HVDC converter units installed in a single location together with transformers, reactors, filters, reactive power devices, control, monitoring, protective, measuring and auxiliary equipment. While system relevant switching functions are located in DC switching stations, switchgear required for the self-protection may still be part of the converter station. This in particular includes ACCB and NBS.

- **Converter units**[2]: An AC/DC converter unit is a power exchange device with the ability to transfer power from/to an AC network from/to a DC network. It is defined per pole on the DC side, so that a bipolar converter station comprises two converter units with opposite polarity. It comprises switching, earthing and protective devices relevant for the internal functioning of the converter. Switching capabilities that are relevant for the entire HVDC system are however not part of the converter unit. A Converter unit would typically comprise an AC circuit breaker for self-protection whereas DC fault separation device would be part of DCSS. Additional AC switchgears relevant for system operation would be part of AC switching stations, and not converter stations.

Transmission line

- **Transmission units**: A transmission unit is passive component with the ability to transmit DC current, assuming it is connected on both sides. The capability of a transmission unit to earth itself, *e.g.*, for maintenance purposes is delegated to a neighboring switching unit. Transmission units are defined per pole (HV poles, medium voltage pole/DMR) and may be grouped to form a transmission line.

Energy absorber

Devices to absorb dynamically excessive energy in case of contingency scenarios to limit overvoltage within the HVDC system. Typically, these devices are triggered by over-voltage conditions arising from such contingencies.

FIGURE 1 provides an overview on the functional aggregation of the subsystems (primary equipment) with a focus on DC grid components and relevant AC components in direct relation with the HVDC system such as Power Park Modules (PPM) at the AC side offshore and AC switchyards.

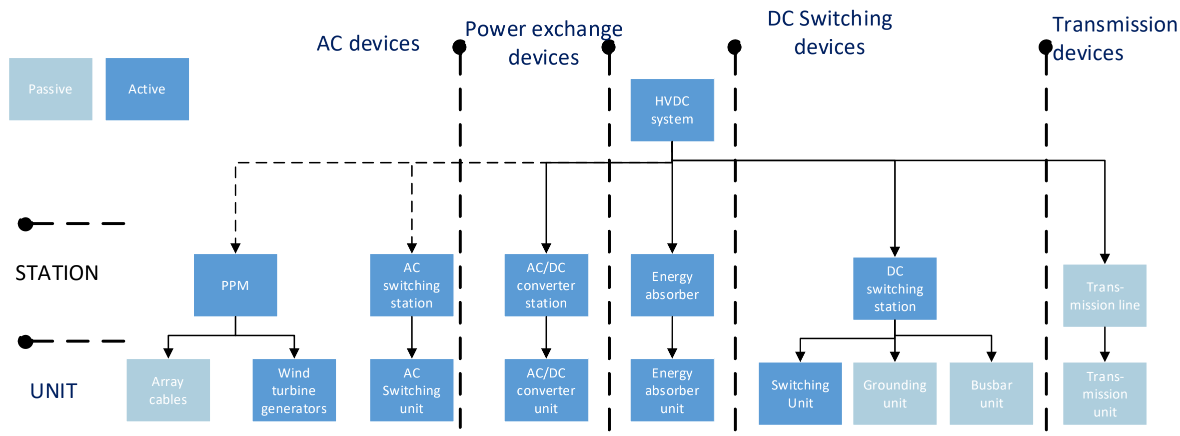

FIGURE 1: Functional aggregation of subsystems and sub-units related to an HVDC system with focus on primary equipment

[2] The proposed definition follows and further specifies the one from COMMISSION REGULATION (EU) 2016/1447: "means a unit comprising one or more converter bridges, together with one or more converter transformers, reactors, converter unit control equipment, essential protective and switching devices and auxiliaries, if any, used for the conversion."

4.1 DC switching station

The primary purpose of a DC Switching Station (DCSS) is to establish electrical connections between functional elements in the HVDC system. Therefore, the functional aggregation is such that all DC switchgear with system functionalities is located in the DCSS including fault separation devices (FSD). Sub-units of a DC switching station are DC busbars (passive), earthing unit and switching unit (see **FIGURE 3**).

A switching unit is the functional block that contains all switching functions associated to one point of connection of the DC switching station. This point of connection can be for example towards a transmission unit or towards a converter unit. In case the DC switching station comprises only two points of connection per pole, a switching unit may directly link these two points of connection. Otherwise, the switching unit typically connect the point of connection to a busbar. A switching unit can for instance connect a busbar (per pole) and a transmission unit, or a converter unit (per pole) and a busbar. It is intended that all switching functions relevant for DC system level operations, and hence all switching units, are hosted in DC switching stations[3]. Note that the number and capabilities of the different switchgears comprises in a switching unit will vary from one switching unit to another, depending on the individual functional requirements that are assigned to the specific switching unit. The individual switchgear shall be designed such that all functional are satisfied.

An illustrative functional single line diagram of a switching unit connecting two units (unit A and unit B) at high voltage level is provided in **FIGURE 2**. The switchgear of a switching unit depends on the desired functionalities. In addition, different switching functions (e.g. fault/load current interruption or energization) and fault detection functions (e.g. for different fault types, primary/backup protection) could be embedded in a single device. The realisation of the function and the aggregation of switchgear is subject to the vendor as long as the functional requirements associated to the switching unit are fulfilled. The possibility of the switching unit to have access to the earth is represented (for instance to discharge unit A or unit B). It should be noted that a switching unit may have more than two connection points (i.e. a third internal connection to a low voltage connection point).

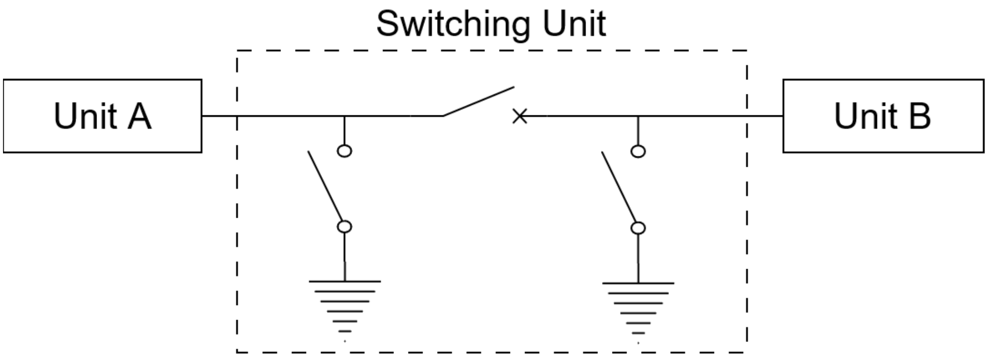

FIGURE 2: Exemplary functional diagram of a switching unit connecting two other units (e.g., converter unit, transmission unit…). The circuit breaker symbol is indicative only as not all switching units may have fault separation capabilities. The switching unit may have access to earth itself for maintenance purposes, or to earth the neighboring unit (A or B) if they are passive ones, such as cables.

[3] A disconnected converter station may still have a local earthing point to respond to AC side statcom requirements. It should be noted that this is an exception which is not considered as a DC system level function.

A switching unit having two connection points, assuming it is not earthed, can either be in open or closed state. An earthed state can be introduced for maintenance purposes.

The functional behavior of a switching unit for a close and open commands is further specified in section 5 in flowchart diagrams. While the close/open commands are always initiated outside the switching unit (e.g. by operator, DC grid controller, protection relay), the remaining of the sequence is executed based on local information only. In fact, the switching unit consists not only of primary equipment (DC switchgear and hardware components) but also of secondary equipment (automation, measurements, monitoring) in order to execute open and close commands based on local information[4].

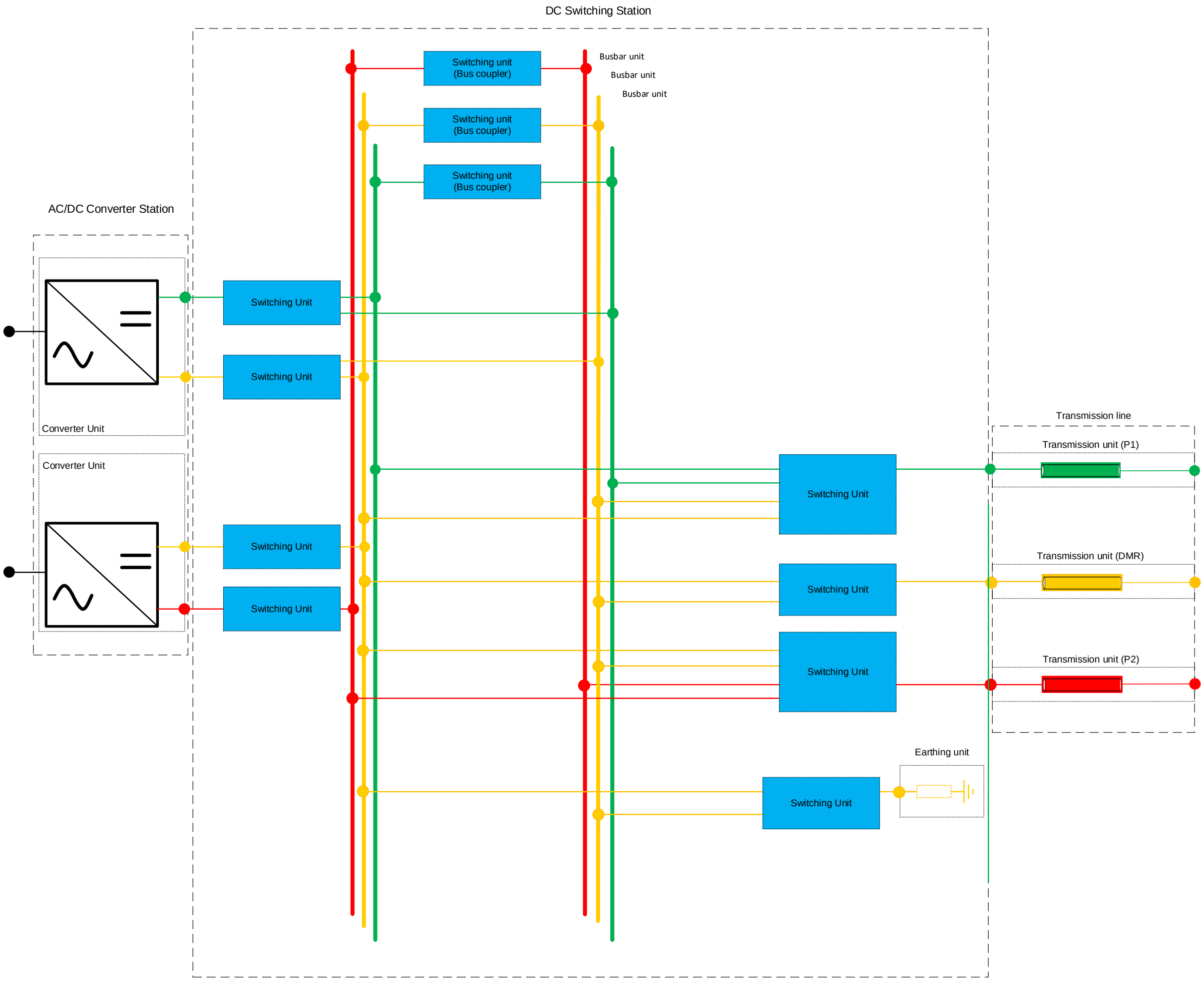

FIGURE 3: Example of a switching station layout connecting one converter station to one transmission line. The station includes two busbars connected by switching units (bus couplers) and an earth reference connected to the neutral busbar through a switching unit. Other layouts are possible such as having a single switching unit connecting the two neutral point of the two converter units.

[4] It should be noted that some secondary equipment and automation functions for coordinated switching unit operations inside a DCSS can be located at central automation level of the DCSS.

4.2 AC/DC converter station

The primary purpose of the AC/DC converter station is to exchange power between the AC grid and the DC grid. Considering this, primarily control functions are assigned to the AC/DC converter stations, whereas AC and DC switching functions are assigned respectively to the AC switchyard and the DCSS with the exception of internal switchgears for self-protection and local earthing of the converter. This in particular includes ACCB and NBS.

4.3 Energy absorber

The primary purpose of the energy absorber is to absorb dynamically excessive energy in case of contingency scenarios to limit overvoltage within the HVDC system. Typically, these devices are triggered by over-voltage conditions arising from such contingencies. The Energy absorber is considered as a separate subsystem because of its functional independence to the AC/DC converter station or the DCSS. Due to the functional independence the physical placement is not limited to close vicinity of the AC/DC converter station.

4.4 AC switching station

All AC switching elements are placed in the AC switching station. Physically, they are part of the AC grid. However, some functionalities are also relevant for the protection or coordination of the DC grid. From a functional perspective they can be activated due to both DC and AC events. It should be noted that in case of activation due DC contingencies, the AC Circuit Breaker can be activated by protection relays located at the DC side or by AC/DC converter stations according to the DC-FRT definition. More information is provided in section 7. Note that a detailed functional description of the AC switching station is not in the scope of this deliverable.

4.5 Power Park Modules

The PPMs are power generating modules consisting of multiple wind turbines, which are power park units connected to the AC offshore grid. Due to the direct connection to offshore converters they are functionally related to the HVDC system and may have direct or indirect control and communication interfaces with the DCGC or other DC grid subsystems. For instance, in case of a DC contingency depleting power export reserves, wind turbine curtailment needs to be coordinated throughout offshore connection points and PPMs.

4.6 DC Point of Connection (DC-PoC)

DC-Point Of Connection (DC-PoC) means a point at which HVDC equipment is connected on the DC side, at which technical specifications affecting the performance of the equipment can be prescribed. The -DC-PoC should be accessible for converter stations and other subsystems to ensure and verify conform operation. Voltage and current measurements shall be accessible without telecommunication. **FIGURE 4** provides an overview on the DC-PoC for the AC/DC converter station and for the DCSS. It should be noted that the AC/DC converter station is connected to an AC-PoC and a DC-PoC, whereas the DCSS is connected to at least two DC-PoCs.

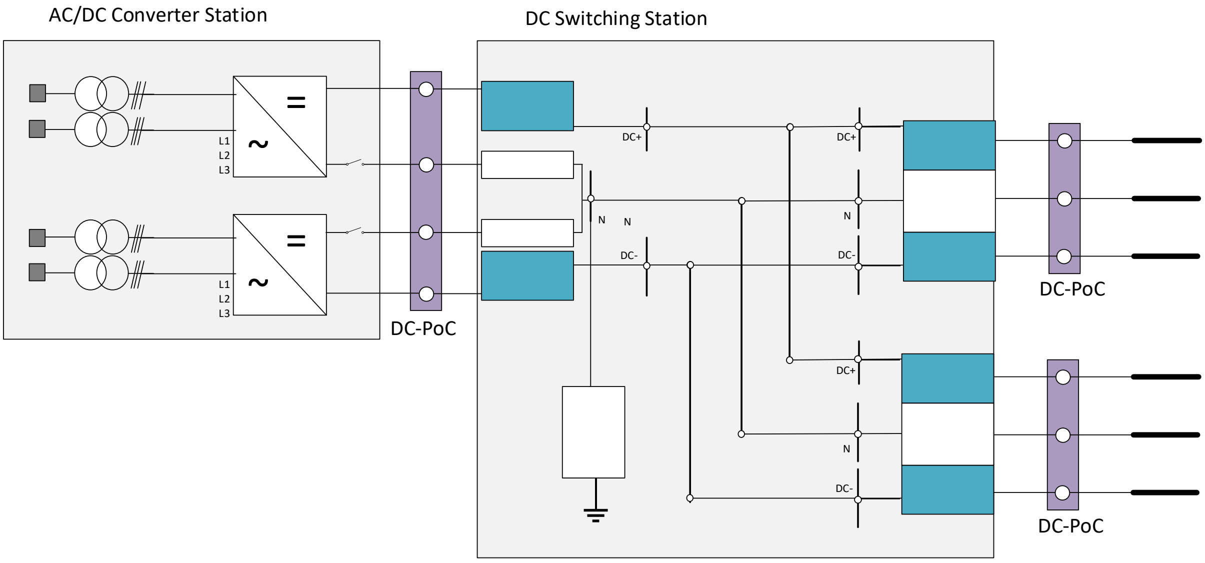

FIGURE 4 Indication of DC- Point of Connection (DC-PoC) for AC/DC converter station and DC switching station

4.7 AC-Point of connection (AC-PoC)

'**Connection point**' means the AC interface at a synchronous area at which the power-generating module, demand facility, distribution system or HVDC system is connected to a transmission system, offshore network, distribution system, including closed distribution systems, or HVDC system, as identified in the connection agreement. The connection point is also typically referred to as the point of connection (PoC) [2].

5. Sequential Control

Within a given HVDC system topology, different DC connection modes are possible. The DC connection modes describe the connection between the individual units within the HVDC system at their DC-PoC. Those connection modes are determined by the individual states of all the switching devices within the grid. Given the large number of such devices, all connection modes may hardly be described exhaustively. The sequential control describes all planned actions that allow the HVDC system to go from one connection mode to another. Such actions may be triggered automatically, or by an operator, or a combination of both. Change of connection modes after protection action, *e.g.*, line disconnection, are not seen as sequential control actions but rather a protection actions.

On one hand, the handling of large number aggregated connection modes on a multiterminal HVDC system level is not practical, due to the very large number of possible combinations. On the other hand, the control of each individual switch by an operator or DC grid controller is also unsuitable. As such, the main purpose of this workstream is to define the appropriate granularity to manipulate the switching devices within the grid. It is proposed that the set of switches connecting two DC units (i.e. for one pole) is a relevant aggregated level, called a switching unit. A switching unit may hence connect a converter unit to a busbar (per pole), a busbar to the ground, a HV conductor to a busbar, etc. While some switching units may have many more capabilities than others, they can all be described as a state machine being open or closed. The opening and closing of switching units will induce changes in other units throughout the grid, for instance the energization of converter or transmission units. The concepts defined in this section significantly differ from the ones introduced in [3], where an aggregation per feeder is adopted. As already introduced in Section 4, all switchgears relevant for the HVDC system operation have also been grouped in the switching station, whereas they may be part of converter stations in [3]. Those two modifications are deemed to facilitate interoperability and compatibility between the different functional sub-systems, as well as between HVDC systems with different topologies (bipolar with and without metallic return and asymmetric monopole).

An overview of the control structure for sequential control is first presented in Section 5.1.The main units constituting an HVDC grid and their states are then defined in Section 5.2. A functional definition of a switching unit is provided in Section 5.3, including the transition from closed to open and from open to closed.

5.1 Control structure for sequential control

An overview of the control hierarchy for sequential control of an HVDC system is depicted in **FIGURE 5**. For sequential control purposes, the change of states of the units within the HVDC system or a network of HVDC stations and switching stations connected on DC side may be directly controlled by a DC grid controller, or similarly may be directly controlled by a national dispatch centre where software with similar functionality exists. If necessary, local control of switchgear at the switching station level shall be possible. States of the HVDC system or a network of AC/DC converter stations and switching stations may also be controlled more locally for other purposes (*e.g.*, protection). In the context of sequential control, the functionality of the DC grid controller or relevant software being part of the TSOs national dispatch centre may be:

- To propose operational simplification of default scenarios for planned reconfiguration. While the exhaustive description of all connection modes of the grid and the transition between them shall be defined by the relevant TSO in coordination with adjacent TSOs (if applicable) the macro-sequence that allows to perform planned reconfiguration actions can still be coordinated by the DC grid controller. Such usual actions for instance include: start-up and shut-down of the DC network, connection or disconnection of a transmission line, or of a converter, and change of the system earthing point location. The proposed macro-sequences can then be activated step-by-step by an operator, or automatically. In all cases, the abortion of the sequence must be possible.
- To be able to respond to unscheduled events, when required. Unscheduled events such as faults are primarily handled by protection, ensuring the security of the HVDC system or the network of HVDC converters stations. Sequential control actions can then be performed to improve the reliability of the power system. Such actions may be included to the DC grid controller as "operational simplification" described above, or may be triggered automatically and locally if a faster action is beneficial. Examples of unscheduled events that may benefit from automatic reconfigurations are:
- Recovery procedure after fault isolation in order to reconnect the part of the fault separation zone that is healthy. Such a reconfiguration may also be performed locally as an auto-reclosing attempt, known as "protective auto-reclosing".
- Busbar reconfiguration after a busbar fault, for instance in case of double busbar single breaker scheme.

For any of such sequences, the commands will consist of open and close commands sent to switching units. For convenience, such commands would be sent to the switching station automation, which will in turn re-dispatch them to the switching units. However, the switching station has not been identified as a relevant functional level for sequential control and may hence only pass the open and close commands to the appropriate switching unit. In return, the switching units report their status to the DC grid controller, through the switching station. In addition, a switching station may implement interlocks between switching units to prevent non-suitable switching operation (*e.g.*, closing onto an earthed unit, or controlling an out of service unit). The DCSS will only issue a command to the switching unit if necessary, interlock checks are satisfied.

As depicted in **FIGURE 5**, all interfaces for sequential control are deemed vertical. No horizontal communication between different switching units, converter units, or switching stations and converter stations are envisaged. Exceptions to this principle may be considered, if functionally required. If needed, the DCGC can act as a communication bus to provide information to the relevant unit. However, this approach would unlikely satisfy ultra-fast communication needs. In sequential control, no such functionalities requiring fast horizontal communication have been identified yet.

Other functional devices may be present in switching stations, in particular protection relays for protection purposes.

Beyond sequential control, many reconfigurations of the grid would also involve continuous control actions, for instance for the dispatch of new power flow references. Such actions may be part of the planned connection / disconnection of a converter or transmission unit or can also be used in a post-fault recovery process.

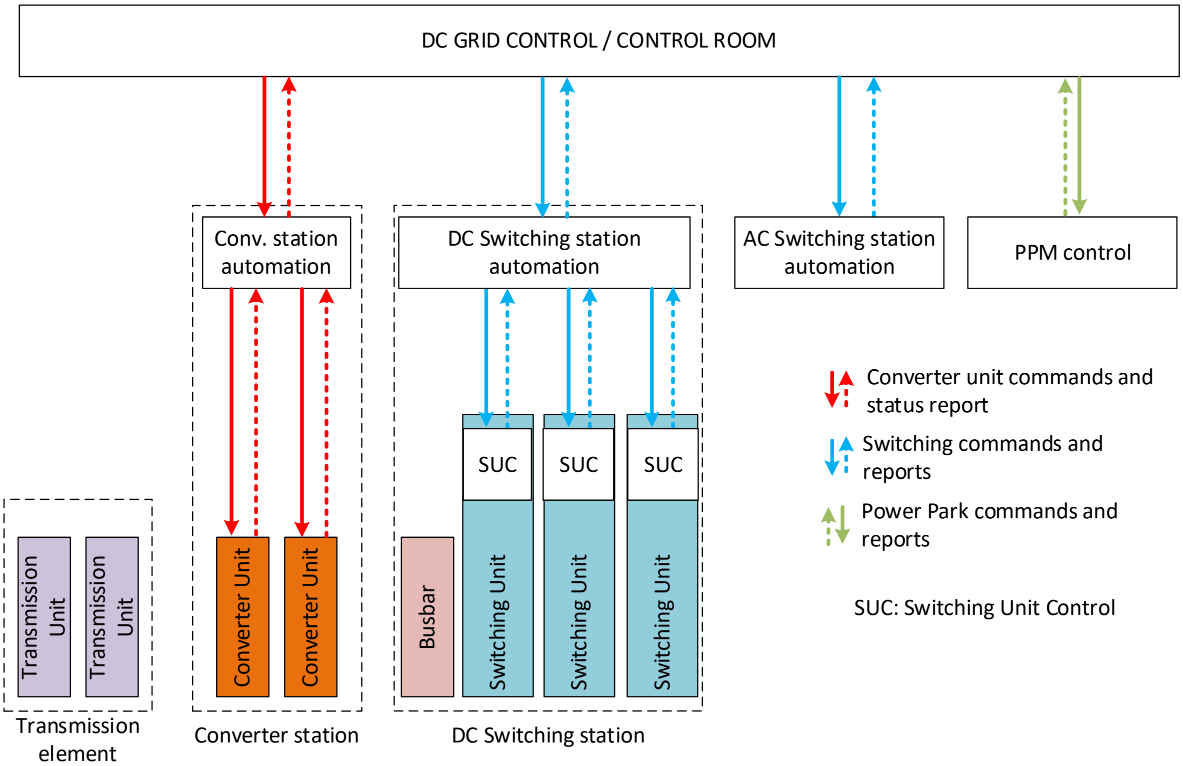

FIGURE 5: Sequential control architecture of an HVDC system: channels between the DC grid controller and the converter or switching stations are an aggregation of the commands sent to the unit layer. Interactions with AC side equipment such as PPM and AC switchyard are also included, though not detailed in this chapter. Note that relays can also be included in switching stations, controlling one or multiple switching units for protection purposes, see Section 7.4 for further details.

5.2 Interface and state of the main units

This section provides the main interfaces for the sequential control of the units within an HVDC system. Based on those interfaces, state diagrams are proposed to illustrate the behaviour of the units. In [3], state representation based on a three-pole aggregation (2 HV poles and neutral) is proposed, linking "connection modes" of the AC/DC converter stations (bipole, monopole…) with the ones of the switching station. By contrast, the functional scope split presented in Section 4 leads to a single pole (HV or neutral) description of the connection states within the system. The proposed approach allows a clear definition of the behaviour of the functional units of the grid, without the complexity of states of combined units that would depend on specific topologies and configurations.

5.2.1 Switching station

As discussed in Section 5.1, the switching station is not deemed a relevant functional layer for sequential control. Its main role is to transmit commands from the upper layer (e.g. DC Grid Control) to switching units, and to report feedback the other way around. In addition, it may implement interlocks between switching units to prevent unsecure switching operations, such as closing onto an earthed subsystem. An overview of the switching station interfaces is provided in **TABLE 1**.

TABLE 1: Interface of the DC Switching Station with DCGC and DC Switching Units

Top layer interface : Between DC grid control and DC switching stations	
From DCGC to DCSS	Commands for switching units: open, close, discharge (if applicable), auto-reclose attempt enabled (if applicable), maintenance & earthing (if applicable).
From DCSS to DCCG	- Feedback on switching unit status (open, closed, maintenance…) - Continuous measurements (V, I) - Failure of switching unit functionality (e.g. FSD function unavailable) - Protection information: fault zone (from protection relay), and trip command issued
Bottom layer interface: Between DC switching stations and switching units	
From DCSS to Switching Unit	Commands for switching units: open, close, discharge (if applicable), auto-reclose attempt enabled (if applicable), maintenance & earthing (if applicable).
From Switching Unit to DCSS	- Feedback on switching unit status (open, closed, maintenance) - Continuous measurements (V, I) - Failure of switching unit functionality (e.g. FSD function unavailable) - Trip report (following trip issued from protection relay)

5.2.2 Switching unit

A switching unit is defined as the switchgear that forms a connection path per pole between two units. A functional view of a switching unit connecting two other units is provided in **FIGURE 6**. It may be composed of one or more switching devices depending on the functionalities available. It is controlled by the switching unit automation who is responsible for the control of each switching device within the unit. Switching units can for instance be used

- between a HV transmission unit (cable) and a HV busbar
- between a converter unit and a HV busbar
- between a neutral transmission unit (cable) and a neutral busbar
- between a converter unit and a neutral busbar
- between a neutral busbar and the ground, to provide the ground reference for the network. Electrical components associated with the ground reference (surge arresters, resistance…) are gathered in the "grounding unit".

The main role of the switching unit is to open or close the connection path. The corresponding close and open commands are received from the DC Grid Controller for planned operation but can also be issued by IEDs for protection purposes (i.e. trip). Optional functionalities of a switching unit include the ability to discharge one of the connected units (e.g. a cable), and to attempt to auto-reclose after a trip. In addition, a switching unit can be earthed for maintenance purposes. In this state, all relevant earthing switches are closed.

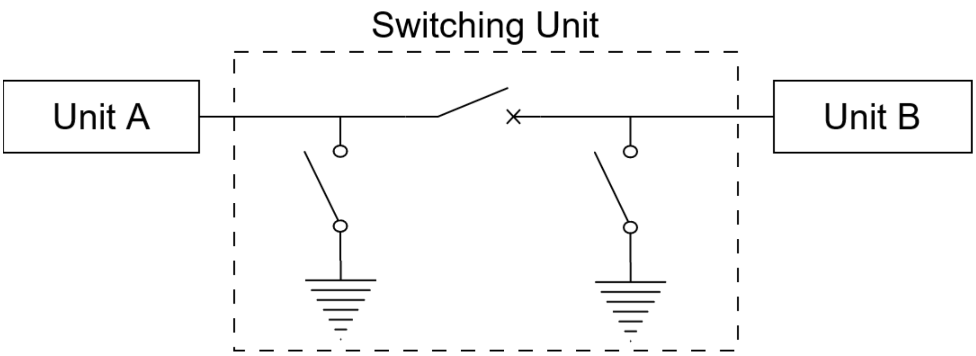

FIGURE 6 Functional view of a switching unit connecting two units. The circuit breaker symbol is indicative only as not all switching units may have fault separation capabilities.

When connecting passive units, such as busbars or cables, a switching unit can have the duty to earth those units for maintenance purposes. Though it is those passive units that are in a maintenance state, the commands are given to the switching unit. Additional commands and states are hence introduced to account for such cases. When connecting an active unit such as a converter, this maintenance functionality would typically not apply.

The interfaces of a switching unit are summarized in **TABLE 2**, and a corresponding state machine is proposed in **FIGURE 7**. In case of a failure of an internal component of the switching unit, the switching unit can be stuck in an intermediate state, which is reported to the DC grid controller (see detailed flowcharts in Sections 5.3.2 and 5.3.3 for further details).

In some cases, a switching unit may have the possibility to connect more than two units (*e.g.* a HV transmission unit may either be connected to a HV busbar, or to a MV busbar). In such cases, the close/open state shall be supplemented with the relevant units, see Section 5.3.5 for more details.

TABLE 2: Interface of the switching unit automation for sequential control. It is assumed the switching unit reports to the switching station the status of each action.

Switching Unit inputs	Short description	Mandatory/Optional
Go to maintenance	The switching unit will go to a maintenance state where all earthing switches are closed.	Mandatory
Prepare to connect	The switching unit will go from the maintenance state to the open state and is ready to close.	Mandatory
Open	The switching unit will open.	Mandatory
Close	The switching unit will close.	Mandatory
Auto-reclose	After a trip, the switching unit will attempt to auto-reclose.	Optional
Discharge transmission unit A (or B)	When open, the switching unit can discharge one of the neighbouring transmission units. After discharging, the switching unit remains open and the neighbouring unit (A or B) are not earthed.	Optional

Switching Unit inputs	Short description	Mandatory/Optional
Earth transmission unit A (or B)	If open, the switching unit can provide maintenance earthing for the neighbouring transmission units.	Optional
Remove earthing of transmission unit A (or B)	Removing the connection to ground from one of the neighbouring transmission unit.	Optional

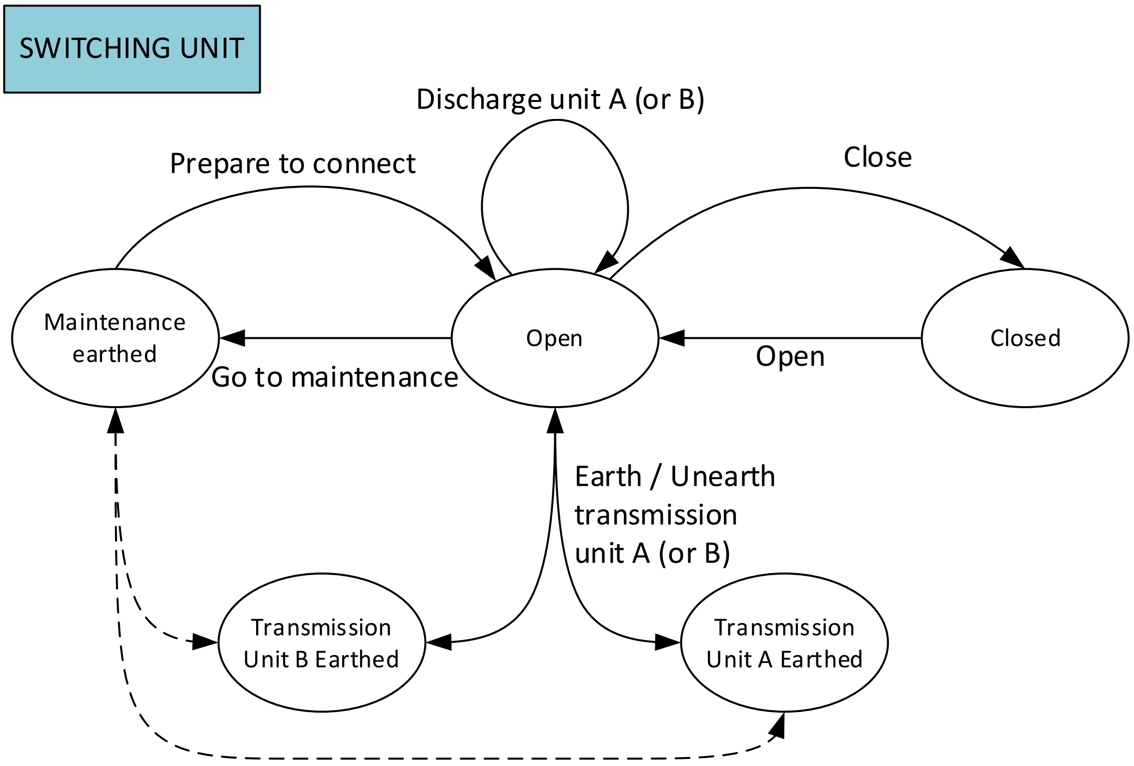

FIGURE 7: State diagram for the switching unit, including the discharge and earthing commands. Switching units have the ability of earthing neighbouring passive units (busbars or cables). It is assumed that earthing of both neighbouring transmission units is equivalent to the switching unit being earthed itself (dashed-lines).

5.2.3 Transmission unit

A transmission unit typically refers to subsea/underground cables and overhead transmission lines. A transmission unit consists of a single pole conductor, which may either be HV or MV (for neutral path). A busbar can also be considered as a special case of transmission unit, being particularly short and having typically more than two connection points. Within the HVDC System, the neutral path shall be connected to the ground to provide reference to the neutral path for the entire grid. Such reference is typically established within a switching station by the closing of a dedicated switching unit between the neutral busbar and the ground.

Transmission units are passive components and do not include any switchgear, assuming they are earthed through the neighbouring switching units when they are out of service. As such, no control interface is associated with such units. A state machine can still be established to model the behaviour of a transmission unit, but all transitions will only depend on other units within the grid. Thus, states of a transmission unit depend on the number of connected units as well as whether DC voltage has been established:

- It is considered the "ready to connect" state assumes residual voltage has been reached. It is thus mandatory when going from "Energized" to "ready to connect" to use the "open & discharge" command of the switching unit. In "ready to connect", all earthing switches are open.
- After the closing of a single DC switching unit, the transmission unit is connected to another DC unit but cannot transmit power. Depending on whether the connected unit is itself energized, the transmission unit may either be energized, or only connected.
- A transmission unit connected to at least two DC switching units is either "aggregated" or "ready to transmit" depending on whether the connected units are energized and also connected to other DC systems.
- A busbar can be connected to more than two DC switching units and remains in "ready to transmit" state if energized, or in "aggregated" state if not energized.

The state diagram for a DC transmission unit is pictured in **FIGURE 8**.

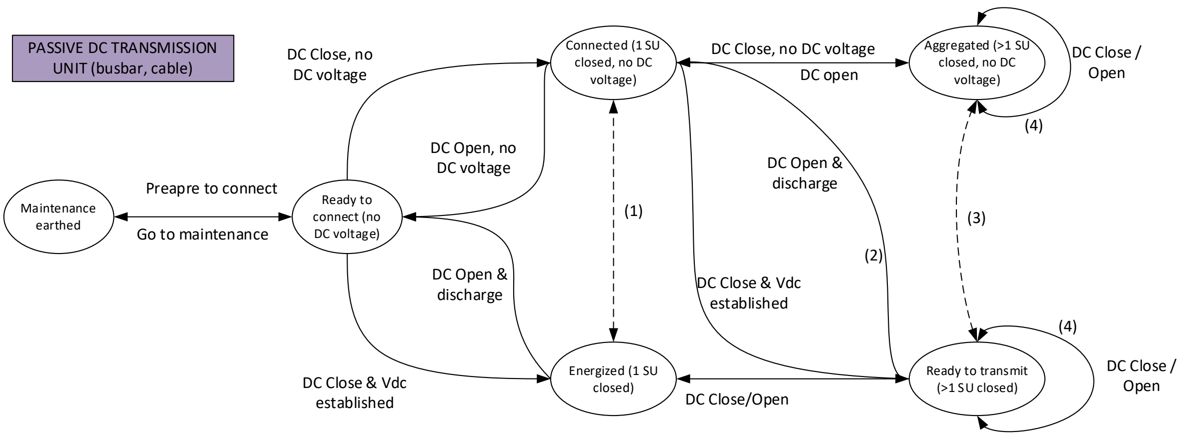

FIGURE 8: State diagram of a transmission unit. All transitions are induced by the actions of the switching units (SU) connecting the unit to the rest of the grid. States are further distinguished depending on whether DC voltage is established or not. Transitions in dashed (1) and (3) are caused by operation of remote units. The energization of multiple DC units already aggregated can for instance be due to a single unit closing. Going from "Ready to transmit" to "connected" (2) using a DC open and discharge command should be carefully considered as the remaining closed unit should not be connected to a live DC grid. For busbars, it is possible to be connected to more than two other units (4).

5.2.4 Converter station and unit

From a sequential control perspective, a converter station only consists in one converter unit (monopole) or the aggregation of two converter units of opposite polarity (bipole). Only the interfaces of the converter unit are thus further detailed. In addition to the inputs listed in **TABLE 3**, the converter unit shall report the corresponding status (*e.g.* "ready to energize") after completion of a command. Those status shall be communicated to the DC grid control or any equivalent upper layer control. It should be emphasized that the connection of the converter to the DC grid is determined by the closing of the relevant switching units, which are not part of the converter stations. Any converter unit may still include relevant switchgear for protection purposes, including an AC breaker.

TABLE 3: Sequential control interfaces of the converter unit. In addition, the converter unit reports whenever the commands have been executed.

Converter Unit inputs	Short description
Go to maintenance	The converter unit will go to a maintenance state where all earthing switches are closed. The submodules are discharging.
Prepare for energization	The converter unit will go from the maintenance state to a "ready to connect" state. The energization may either come from the AC or DC side.
Close AC side	The converter will close the ACCB within the converter area (additional ACCB can be located further on the AC switching unit).
Open AC side	The converter will open the ACCB within the converter area.
Close local earth reference	Closing of the local earthing switch to provide neutral reference. Typically used for STATCOM operation.
Open local earth reference	Opening of the local earthing switch.

The states of a converter unit depend on whether it is connected on the AC and/or DC side, as well as on the presence of voltage or not (energization). A state diagram of a converter unit is provided here in Figure 9.

The proposed states can be modified by the converter itself through the following commands:

- Prepare for energization: this step is a prerequisite to any connection to the HVDC system, and comprises multiple actions such as opening of the maintenance switches, preparation of internal controls, establishing a DC reference to ground
- Prepare for maintenance.
- AC Close and AC open, as this action controls the AC side breaker of the converter. Note that operation of more AC breakers may be required to effectively connect the converter to an AC bus.

By contrast, DC side connections are established through the closing and opening of DC Switching Units, included in DC Switching Stations and not in the converter station. As the converter may be connected to dead subsystems (so called "aggregated" state), the energization may be induced by the closing of remote units in the system.

The converter unit can either be energized from AC or DC side, leading to the "ready to STATCOM" or "ready to be islanded" modes, respectively. When connected on both sides and energized, the converter is "ready to transmit".

Closed loop controls concepts are intentionally not specified as sequential states. As such, blocked or deblocked state as well as control modes (STATCOM, islanded…) do not appear in **FIGURE 9**.

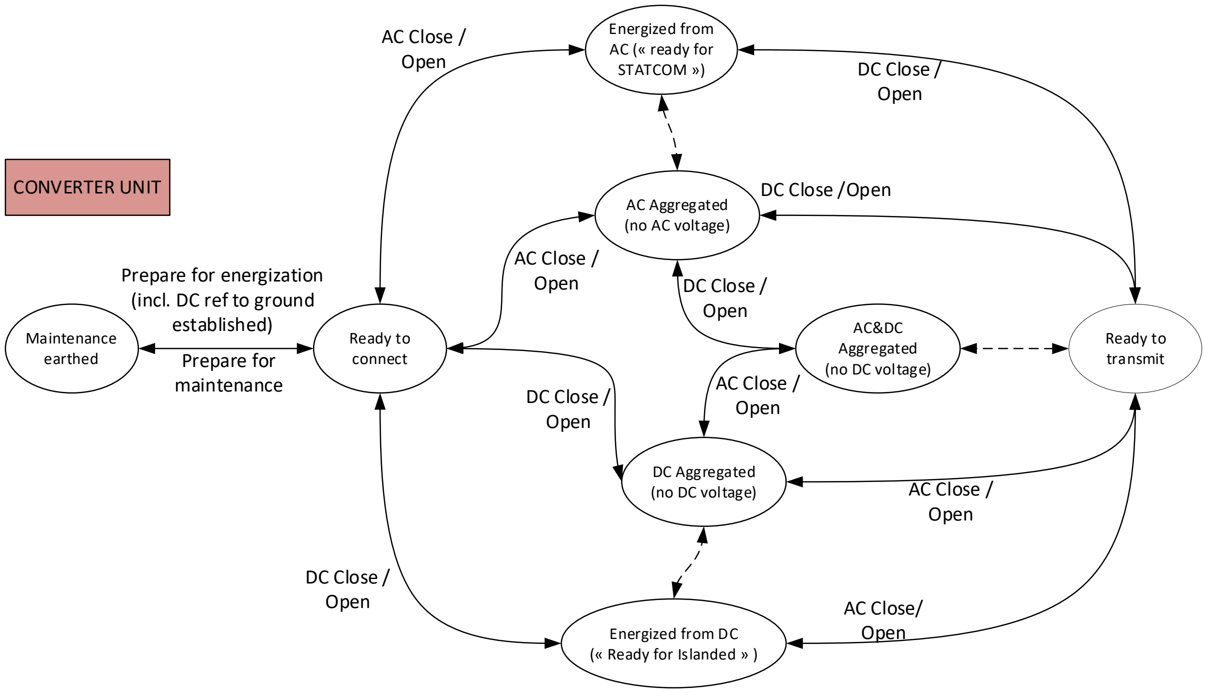

FIGURE 9: State diagram of a converter unit. Plain arrows indicate transitions due to the switching units at the PoC of the converter, while dashed arrow transition may be due to remote switching units within the grid. The only transitions handled locally at the converter unit are between "maintenance earthed" state and "ready to connect" and to open & close the AC side.

5.3 Detailed specification of the switching unit

5.3.1 Switching unit connecting two units

A **switching unit** may comprise one or more switches, depending on the desired functionalities. An exemplary overview of a switchgear arrangement is provided in **FIGURE 10** of a switching unit with full capabilities (fault separation, energization, discharge, earthing…). It is reminded a switching unit may comprise much less switchgear if less functionalities are needed. In addition, the arrangement presented in **FIGURE 10** is indicative only, and the same functionality may be satisfied with different set-ups. For instance, if it is required to bypass the entire switching unit during maintenance, all the SU switchgear shall be within disconnectors.

Those switches are further specified in **TABLE 4**, from a functional point of view. It is assumed that the residual current switch (RCS) also embeds the making current capability.

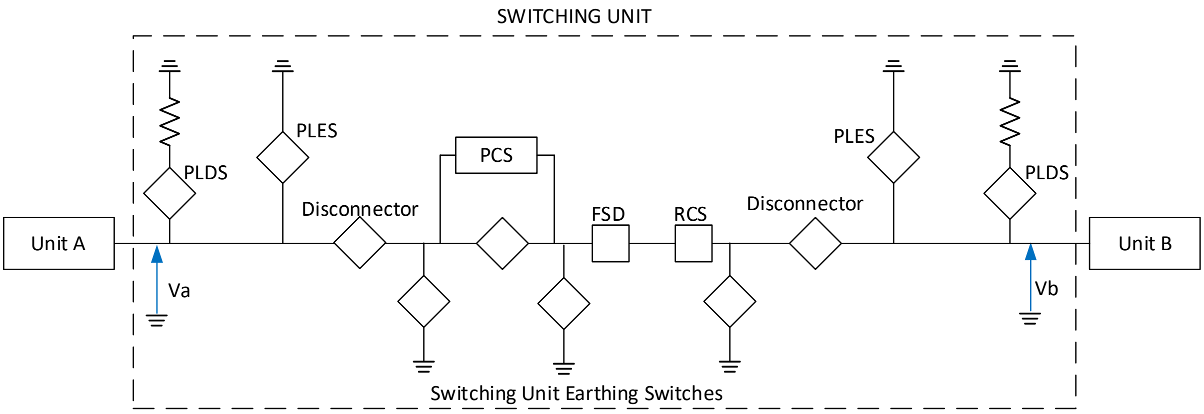

FIGURE 10: Detailed functional description of a switching unit with full capabilities. The number of switches and their arrangement is only indicative for illustration purposes. Additional energy dissipation devices can be embedded whenever relevant, in particular within the FSD or the PCS.

TABLE 4: List of devices that can be included in a switching unit.

Full name	Acronym	Functionality
Disconnectors		Switches with no current making nor interrupting capability. In the absence of an RCS, the disconnectors embed the aggregation and disconnection capabilities of the switching unit.
Residual current switch	RCS	Switch with ability to break small amount of current (typ. residual current) and with making current capability.
Fault Separation Device	FSD	Active device able to suppress fault current by producing a counter voltage. Within switching units, such devices are typically DCCB. FSD can be "activated" (fault current suppressed) or deactivated (normal onload operation). By extension, this device is able to suppress load current are denoted as FSD with smaller capabilities.
Peak Current Suppression	PCS	Component that limits the inrush current at the closing of the RCS, for instance a pre-insertion resistor (PIR). The PCS can be inserted or bypassed by controlling the relevant switches.
Pole Local Discharge Switch	PLDS	Switch connected to the earth with the ability to discharge an element (typically a cable) connected to the switching unit, after the opening of the switching unit.
Pole Local Earthing Switch	PLES	Switch to the earth to permanently earth the transmission line for maintenance.
Switching Unit Earthing Switch	SUES	Internal earthing switches for maintenance of the switching unit itself.

A switching unit having two connection points, assuming it is not earthed, can either be in open or closed state. Those two states are further specified in the table below, depending on the specific switchgear that composes the switching unit.

TABLE 5: Definition of the closed and open states for the switching unit. (*) In the specific case where a switching unit does not include an RCS, the disconnectors should be open in the open state.

State	Short description
Maintenance	All disconnectors are open, as well as residual current switches, if any. If available, fault separation devices are deactivated (e.g. DCCB are not tripped). All earthing switches are closed.
Open state	All disconnectors are closed (*). Residual current switch is open. If available, fault separation devices are deactivated (e.g. DCCB are not tripped). All earthing switches are open.
Closed state	All disconnectors are closed, as well as residual current switches, if any. If available, fault separation device and peak current suppression device are deactivated.

The functional behaviour of a switching unit for a close and open commands are further specified using flowcharts. While the close/open command are always initiated outside the switching unit (e.g. by operator, DC grid controller, protection relay), the remaining of the sequence is executed based on local information only.

5.3.2 The close command

The transition sequence for a switching unit going from open to closed state is detailed in **FIGURE 11**. The closing of a switching unit connecting two DC units may involve three different functionalities:

- "Aggregation" of two units. This situation is characterized by the absence of voltage on both sides of the switching unit (first check). The use of disconnectors is sufficient to handle this function.
- "Energization" of one unit through the other one. This situation is characterized by the presence of voltage on only one side of the switching unit. The inrush current resulting from the energization typically requires the activation of a PCS.
- "Synchronization" of two live HVDC subsystems. This situation is characterized by the presence of voltage on both sides of the switching unit. A convergence of the voltages at the two sides of the switching unit is typically expected before the switching unit is closed (check $\Delta V < V\mathrm{sync}$). If a load current is scheduled between the two subsystems, a voltage drop between the two sides of the switching unit will be observed.

Some of the failure modes are considered, whenever a component may fail or if one of the conditions required for the proceeding of the sequence is not met (e.g., $\Delta V > V\mathrm{sync}$). Such conditions are associated to a timeout to avoid the switching unit being stuck in an intermediate step. Failure modes are handled such that, as much as possible, the switching unit gets back to a stable closed or open state. This may not be always possible however. It may for instance happen that a switching unit is closing onto a fault, or more generally onto an earthed unit. This will result in a persistent current after the closing of the RCS. Depending on the availability of an FSD at this switching unit, the switching unit may be able to get back to a stable open state or may end up in a faulty state "closed onto fault". In the latter case, it is recommended to deactivate the PCS to 1) avoid damage to the equipment, and 2) increase the current so that the abnormal behaviour can be detected and handled by other protection equipment.

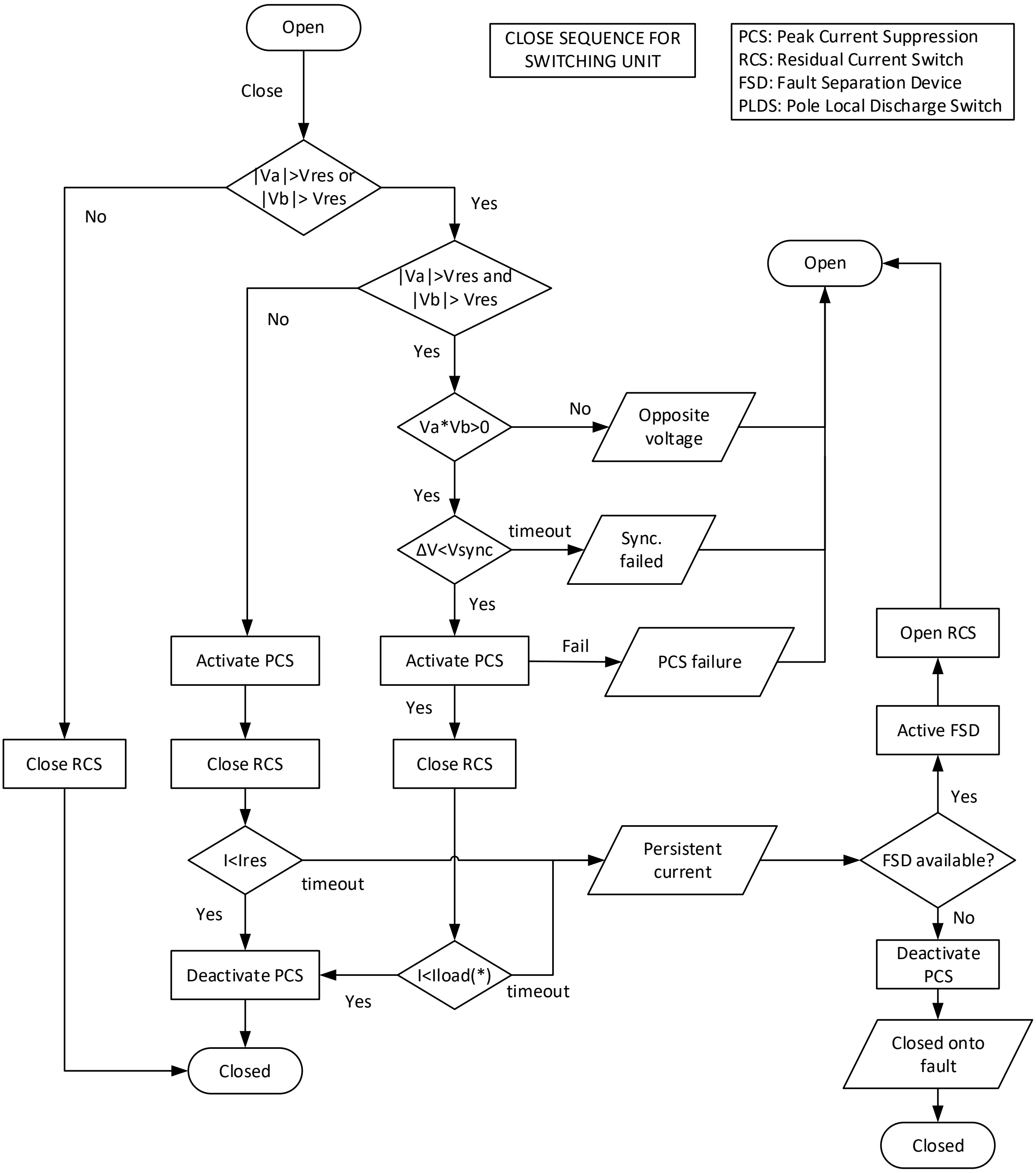

FIGURE 11: Transition sequence of a switching unit for the close command. (*)The threshold used to detect persistent current after the connection of two live sub-grids may be lower than the load current Iload.

5.3.3 The open command

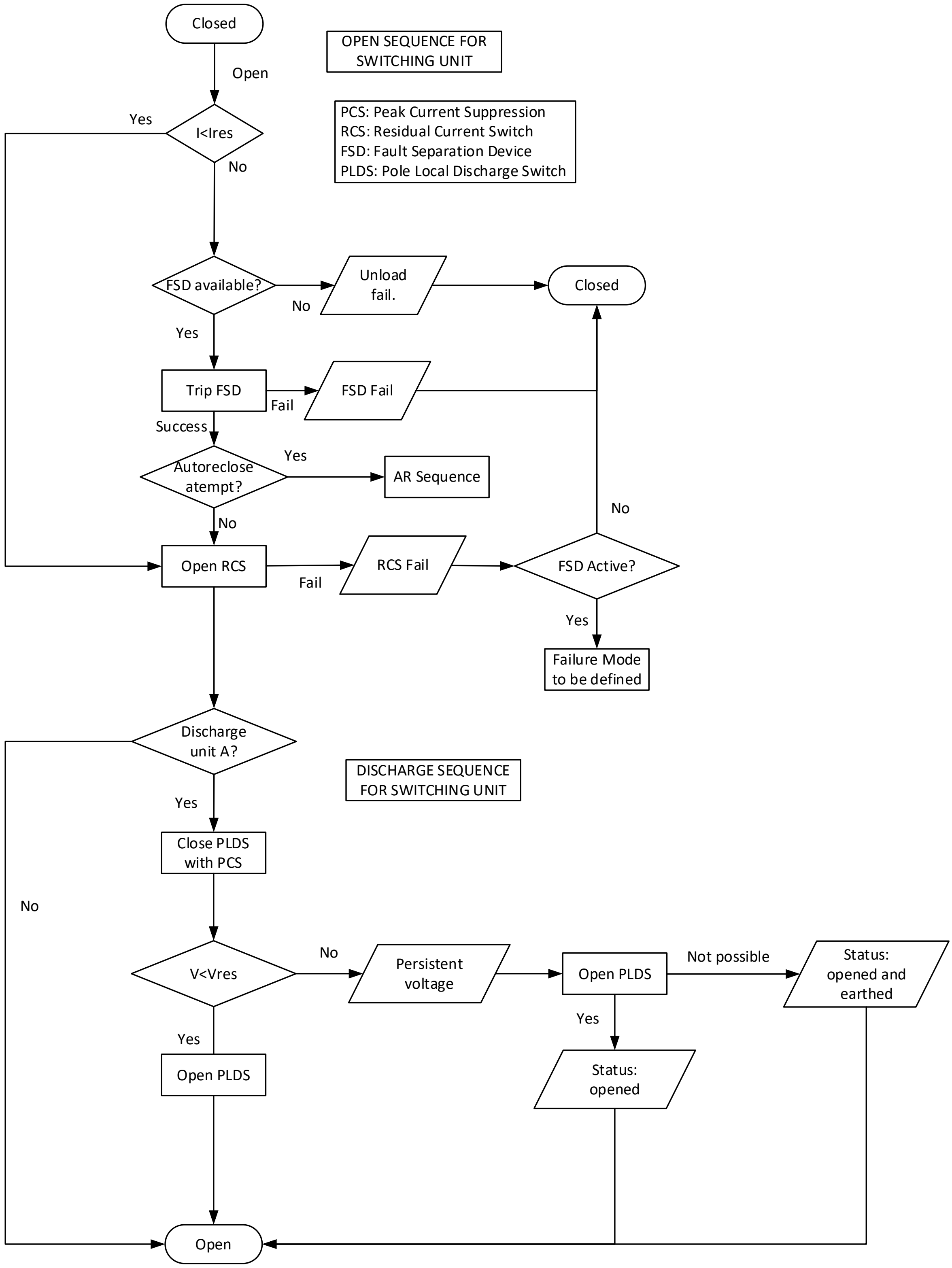

FIGURE 12: Transition sequence of a switching unit for the open command and discharge commands.

The transition sequence for a switching unit going from closed to open state is detailed in **FIGURE 12**. This transition is typically performed after the switching unit has received an open request from the switching station control. Though protection trips are typically issued by protection relays, they can functionally be described within the "open" command framework. As for the close command, the open command may involve two different functions:

- "Fault/Load separation" if the current is above residual current, in which case the activation of a FSD is required. This function may also be used to disconnect a unit with load current.
- "Fault isolation" if the current is below residual current. This function is also used to disconnect a unit with residual current only.

In a protection context, a trip command may comprise an auto-reclose request. Auto-reclosing can be performed in either an automatic way, or in a coordinated way:

- Protective auto-reclosing is considered as a protection action. It assumes that the fault has been cleared in some predefined time.
- Recovery procedure relies on the DC grid control to send the reclosing command, after the fault isolation has been confirmed.

In addition to the open command, the ability of the switching unit to discharge the unit it is disconnected from is also considered. If such an action is desired, the open command should be supplemented with the discharge command, specifying which unit should be discharged (e.g., open and discharge unit A). The discharge command does not include the permanent earthing of the unit A (or B), which is controlled by the corresponding earthing commands, as specified in **TABLE 2**.

5.3.4 Main functions of a switching unit

The specification of the behaviour of the switching unit for the close and open commands allows to identify the main functions that can be embedded in a switching unit. Those functions are defined in **TABLE 6**. Which specific functions (as well as the corresponding ratings) must be chosen for a specific switching unit is a design choice, *e.g.*, some switching units will provide only aggregation and separation functions, while others may provide synchronization and isolation functions. More complex functions may imply more basic functions, for instance a switching unit with the synchronization ability will have the energization ability, and similarly the energization function includes the aggregation function.

TABLE 6: Main functions that may be embedded in a switching unit, associated with the open and close commands.

Command	Function	Short description
Close	Aggregation	Connection of two units without significant voltage.
	Energization	Connection of one unit without voltage to a unit with established DC voltage. The inrush current during the charging shall be limited to acceptable level.
	Synchronization	Connection of two units with significant DC voltage. The inrush current during the discharge shall be limited to acceptable level. The current oscillation during synchronisation shall be sufficiently damped.
Open	Disconnection	Opening of the switching unit without significant current nor voltage.
	Separation	Opening of the switching unit under fault or load current, including suppression of the fault/load current.
	Isolation	Opening of the switching unit under residual current and isolation of the two units.
Discharge unit A (or B)	Discharge	Discharge of one of the units connected to the switching unit, after the opening. The discharge current during the discharge shall be limited to acceptable level.
Earth Unit A (or B)	Earthing	Earthing for maintenance purposes one of the units connected to the switching unit, assuming the unit has already been discharged.

The proposed function names are intended to help visualize the main use cases of the functions. It does not correspond to an exhaustive description of what the functions can be used for. For instance, "isolation" may be used in both the context of fault isolation, or in the context of a planned line disconnection.

5.3.5 Switching unit connecting more than two units

It may happen that a switching unit has the ability to connect to more than two units. In general, it is considered that a switching unit, within a switching station, can only connect to one unit external to the switching station (eg converter unit or transmission unit), but can connect to several connection points within the switching station (eg busbar).

Two examples of such cases are:

- Switching unit connecting on one side a HV transmission unit with the ability to connect on the other side either to a HV bus or to a MV bus, as depicted in **FIGURE 13**. Such a scheme allows the use of the HV transmission unit as a backup or parallel MV path.
- Switching unit connecting on one side a transmission unit with the ability to connect on the other side to two different busbars. Such a scheme allows the use of double busbar configuration.

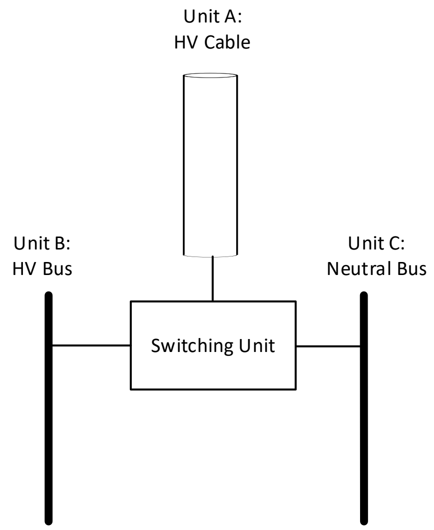

FIGURE 13: Exemplary scheme where a switching unit connect a HV cable to either a HV or a MV busbar.

For such units, the close command remains valid, but shall be specified with respect to which units are to be considered. A close command shall for instance specify "close between unit A and unit B". On the opposite, the open command implies an opening with respect to all DC-PoC or only one of them.

The functional specification of such switching units should allow for different functionalities being associated to the different current paths. A connection matrix can be used to specify such functions. An exemplary connection matrix is provided in Table 7. It can be interpreted as the possible specification of a switching unit connecting a HV transmission cable (unit A), a HV busbar (unit B), and a neutral busbar (unit C). When connecting the HV path, the unit has the separation functionality, as well as the synchronization ability. By contrast, the MV current path is limited to isolation and aggregation functions. The discharge and earthing function, as it relates to a unit rather than to a connection path, is expressed on the diagonal, when included. By construction, the matrix is symmetric.

TABLE 7: Exemplary connection matrix of a switching unit connecting three units

	Unit A (e.g. HV cable)	Unit B (e.g. HV busbar)	Unit C (e.g. MV busbar)
Unit A (e.g. HV cable)	Discharge & earthing	Separation, isolation, synchronization	Isolation, Aggregation
Unit B (e.g. HV busbar)		Discharge & earthing	Not allowed
Unit C (e.g. MV busbar)			Discharge & earthing

The choice of specifying an architecture using such multi-terminal SU must be compared to a specification using multiple two-terminal SU. The latter should be preferred whenever the use of multi-terminal SU makes the design too complex.

5.4 Functional requirements & parameter list

This section provides a summary of the functional requirements related to sequential control as well as associated parameters.

TABLE 8: List of functional requirements and associated parameters for sequential control.

FR	Short description	Associated parameters	Subsystem
Command routing	A switching station shall be able to receive and redispatch commands to the appropriate switching unit.	N/A	Switching Station
Interlocking	A switching station shall be able to block commands that lead to a non-safe operation of the grid.	N/A	Switching Station
Aggregation	A switching unit shall be able to connect two units without significant current nor voltage.	No-load current and no-load voltage.	Switching unit
Energization	A switching unit may be able to connect one unit without voltage to a unit with established DC voltage while limiting the inrush current.	Maximum inrush current. Energy to be dissipated.	Switching unit
Synchronization	A switching unit may be able to connect two units with significant DC voltage while limiting the inrush current.	Maximum current. Synchronization time.	Switching unit
Disconnection	A switching unit shall be able to disconnect two units without significant voltage nor current.	Disconnector characteristics	Switching unit
Separation	A switching unit may be able to suppress a fault or load current.	FSD characteristics, cf Protection WS	Switching unit
Isolation	A switching unit may be able to suppress of residual current and isolation of the two units.	Residual DC current to be interrupted (Ires). Isolation Time.	Switching unit
Discharge	Ability to discharge one of the units connected to the switching unit, after the opening. The inrush current during the discharge shall be limited to acceptable level.	Discharge time. Maximum peak current.	Switching unit

Auto-reclose	After activation of an FSD, the switching unit may attempt to auto-reclose based on local information only, assuming the fault has been cleared.	O-C-O cycle time	Switching unit
Earthing	Ability to earth for maintenance purposes one of the units connected to the switching unit, assuming the unit has already been discharged.	N/A	Switching unit
Reconfiguration sequence	The DC Grid controller may provide operational simplifications to perform a reconfiguration sequence of the HVDC system.	Reconfiguration time.	DCGC

6. Continuous control

The HVDC systems should deliver scheduled power while ensuring the security and reliability of the HVDC systems themselves to guarantee their continuous operation. It is imperative to prevent power flows and DC voltages that exceed the physical capabilities of system components. Disturbances in the system can disrupt the balance of power, resulting in fluctuations in DC voltages. In such instances, the AC/DC converters within the system must promptly and collectively restore system energy equilibrium to prevent violations of system limits.

In order to ensure both the scheduled power transmission and reliable, continuous system operation, the overarching control architecture of HVDC systems is hierarchically structured, with defined roles and responsibilities allocated to each layer and secure exchange and propagation of essential information between each layer.

This chapter first delineates the physical and operational constraints that HVDC systems must consistently satisfy, along with providing definitions of system-level operational DC voltage ranges and system states in terms of DC voltage. It then elucidates the expected roles and responsibilities of each control layer within the control hierarchy, considering the delineated constraints and limitations. Based on those, the fundamental principles of DC grid voltage control, classified into primary and secondary DC voltage controls analogous to the AC system frequency framework, are described. Finally, comprehensive continuous control functional requirements for each subsystem are summarized.

6.1 HVDC System Physical and Operational Constraints

This section presents the pertinent physical constraints of the HVDC system that shall be ensured by continuous control. Subsequently, it provides the definitions of system-level operational DC voltage ranges and the system states in terms of DC voltage level.

6.1.1 Physical Constraints on the DC side of System Components

All components in the HVDC systems shall be designed to operate within the defined physical capabilities. The continuous control of the HVDC systems shall be designed to ensure continuous operation without violating those physical limits. The following outlines pertinent physical constraints to be considered in the design of continuous control.

> **AC/DC Converters:** AC/DC converters have limited physical capabilities regarding over and under voltages, both in terms of terminal-to-ground and terminal-neutral voltages. While the network code for HVDC systems [4] clearly stipulates the AC voltage and frequency ranges as well as associated time within which the HVDC converter station must remain connected, extending those statements to DC voltage in HVDC systems is deemed appropriate. Thus, AC/DC converters shall be capable of staying connected to the DC network and capable of operating within the DC voltage ranges for the time periods specified by the relevant system operator, in coordination with the

relevant TSOs[5]. The required operational performance and allowed protective measures must be consistent with the specified DC-FRT profile (see Section 7 for more details). The HVDC system owner and the relevant system operator, in coordination with the relevant TSO may agree on wider or narrower voltage ranges and associated period of time for operational capability of individual AC/DC converter stations in order to ensure the best use of the technical capabilities if needed, especially in case of radial and sparse DC network. Additionally, AC/DC converters are subject to rated current equivalent to maximum current capabilities within which their secure operation shall be ensured. The maximum current may change over time depending on the constraints on the converter unit (e.g. problems with the cooling system).

- **High Voltage transmission lines/units:** They shall be designed to withstand the temporary and continuous DC voltage profile within the specified DC insulation capabilities. Additionally, they shall be designed to have sufficient thermal capability to continuously carry the rated current. Temporary overcurrent is possible due to the thermal capacity of the conductor, it depends on the environment and external conditions (e.g. temperature), according to IEC 62067 [5].

- **Neutral transmission lines/units:** Neutral transmission lines and units, here referring to return conductors such as DMRs, typically operate at much lower voltages relative to the ground and shall be designed with adequate DC insulation capabilities. Furthermore, like high voltage conductors, they shall be designed to possess sufficient thermal capability to continuously accommodate the rated current.

6.1.2 Operational Constraints at AC Connection Points

In addition to the physical capabilities, HVDC systems are required to comply with the functional requirements at each point of connection with the AC systems in accordance with [4]. In other words, the AC/DC converters that interface with AC systems must meet the specified operational constraints. They are broadly classified into those pertaining to transmission capability and those related to functional requirements. The following introduces the essential transmission capabilities.

- **AC active power exchange capacity:** the maximum AC active power transmission capacity, denoted by P_{max}, shall be defined at the AC side connection point (AC-PoC) for steady-state condition. P_{max} means the maximum continuous active power which an HVDC system can exchange with the AC network at each AC-PoC as specified in the connection agreement or as agreed between the relevant system operator and the HVDC system owner. In the case of a bipolar AC/DC converter station, this must be defined separately for bipolar operation and monopolar operation, where one of converter units is out of service. Unless otherwise specified, the AC active power transmission capacity shall be defined for each direction of power.

- **Reactive power exchange capacity**: the AC/DC converter station or unit shall possess the constructive ability of injecting or absorbing reactive power at the AC-PoC within the U-Q/Pmax profile specified by the relevant system operator, in coordination with the relevant TSO. Additionally, when operating at an active power output below its maximum AC transmission

[5] For instance, NC-HVDC Article 18 stipulates the minimum time periods an HVDC system shall be capable of operating for AC voltages deviating from the reference 1 p.u. value at the connection points without disconnecting from the network.

capacity, the AC/DC converter station shall be capable of operating in every possible operating point, as specified by the relevant system operator, in coordination with the relevant TSO and in accordance with the reactive power capability set out by the U-Q/Pmax profile specified. During operation, the relevant TSO might reduce the reactive power capability by defining operating reactive power range. For offshore converter stations, this may require coordination with the connected PPM. Those limits can be defined independently for each direction.

6.1.3 Functional requirements at AC connection points:

The functional requirements that the HVDC system and each of AC/DC converter station or unit within the system must satisfy are comprehensively stipulated in [4]. For the sake of self-containment, please see Appendix 9.1 for a concise summary of these requirements.

6.2 Definition of System-Level DC Voltage Ranges

The system-level DC voltage ranges are one of the most important parameters for achieving secure and reliable operation of the HVDC system. **The system operator shall aim to maintain voltages at all nodes in the system within these voltage ranges.** They must be carefully established so as not to violate the rated design constraints of the components in the system in the event of credible and dimensioning disturbances. This ensures the proper operation of the DC grid and desired power flow while also respecting the compliance with the operational requirements at each of the AC-PoCs.

The system operator shall aim to maintain voltages at all nodes in the system within these ranges.

They shall serve as the basis for monitoring the system's condition and for coordination of specific requirements for individual equipment.

It should be noted that terminal-to-neutral and terminal-to-ground voltages may vary depending on the topology of the HVDC system and operating conditions. Therefore, the definition of DC voltage ranges must be specified, indicating which voltage they refer to. In the context of continuous control, the DC voltage specifically refers to the pole-to-neutral voltage, unless stated otherwise. This is because pole-to-neutral voltage is relevant for most control considerations. On the other hand, the pole-to-ground voltage is considered pertinent for aspects related to design and protection, as well as insulation coordination.

The behaviour of DC voltage in HVDC systems can broadly be categorized into three ranges with respect to time: transient, dynamic, and steady state.

The **transient time range** is primarily characterized by fast electromagnetic stress induced typically by a fault or switching event in the system. The relevant voltage levels and envelopes should be determined within the protection design, accounting for transient stress and insulation coordination, and it is thus not part of the continuous control. The behaviour and withstand capability of the system during transient phenomena is discussed in Section 7.3.

The time range following this is defined as the **dynamic time range**, where the speed at which the system reaches a steady state is predominantly determined by the controller performances. To the extent possible, overshoot and undershoot of the dynamic response related to an event shall not exceed the dynamic voltage range in order to guarantee continued operation of the system and avoid triggering unintended protective actions. Additionally, the system should exhibit sufficient damping to achieve a new steady-state within the desired settling time.

In the **steady-state time range**, voltage profiles are predominantly determined by the load flow and DC system resistance. In this state, the DC voltage of each node shall fall within a specified range, ensuring the entire system is capable of operating permanently without violating physical capabilities. It's important to note that security margins may be different depending on pre-contingency operating conditions. Thus, the system operator shall strive to maximize the safety margins in steady-state operation to be prepared for realistic incidents that might happen.

FIGURE 14 presents the conceptual illustration of the system-level DC voltage profile, indicating also the parameters essential for this definition.

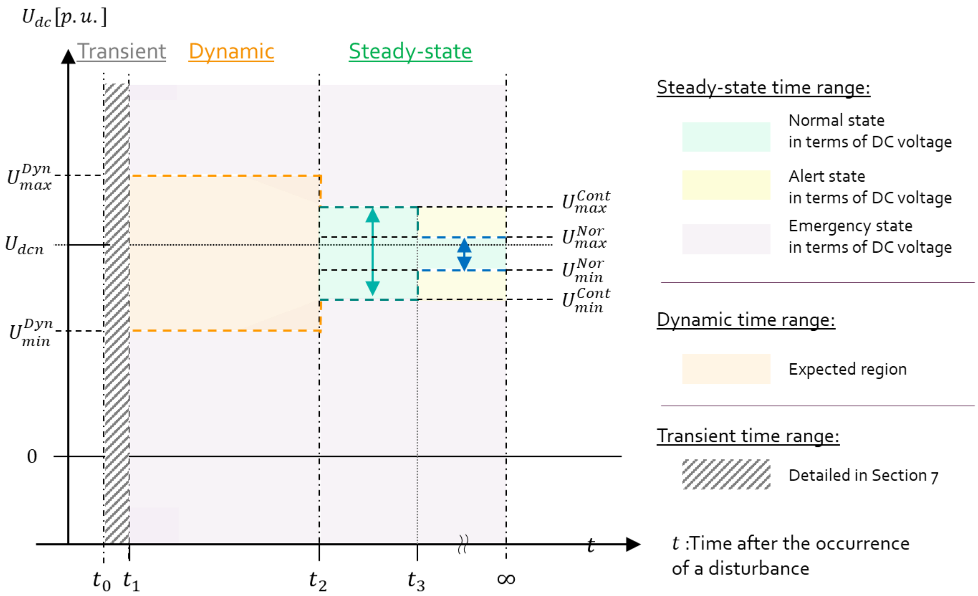

FIGURE 14: General illustration of system-level DC voltage profile.

The parameters are defined as follows:

Voltages	$U_{max}^{Dyn}, U_{max}^{Dyn}$	Maximum/Minimum dynamic DC voltage limits
	$U_{max}^{Cont}, U_{min}^{Cont}$	Maximum/Minimum continuous DC voltage limits
	$U_{max}^{Nor}, U_{min}^{Nor}$	Maximum/Minimum normal operating DC voltage limits
Time	$t_1 \leq T_{max}^{Rec} - t_0$	T_{max}^{Rec} here denotes the maximum time for full voltage recovery time to dynamic voltage range (see Section 7.3.2)
	$T_{max}^{Dyn} = t_2 - t_1$	Maximum settling time
	$T_{Alert} = t_3 - t_2$	Alert-state triggering time in terms of steady-state DC voltage

Furthermore, the system's security is characterized by various other voltage levels, including, but not limited to, the energy absorber unit activation voltage and converter blocking undervoltage. Therefore, the parameters delineating this profile should be specified by the system operator by comprehensively considering all relevant factors, with particular emphasis on the worst-case scenario, i.e. potentially identified dimensioning incidents.

In the following, the detailed definitions of the DC voltage ranges characterized by the introduced parameters within the respective time ranges are presented, focusing on steady-state and dynamic time ranges, along with their implications in terms of HVDC system operation and the expected functionality of the equipment within the system.

6.2.1 Static DC voltage range in Steady-State time range

- **Normal Operating DC Voltage Range** $[U_{min}^{Nor}, U_{max}^{Nor}]$: This range is defined as an interval around the nominal DC voltage between specific upper and lower voltage levels, i.e. $U_{min}^{Nor}, U_{max}^{Nor}$. This range does not have to be symmetrical. It is expected that the voltage at any point within the system falls within this range under normal operating conditions. Therefore, this range shall be established to encompass all foreseeable power flow condition and network configuration. This means that the voltage setpoints of any converter station or unit must fall within this range.

- **Continuous Operating DC Voltage Range** $[U_{min}^{Cont}, U_{max}^{Cont}]$: This range refers to a designated voltage range $[U_{min}^{Cont}, U_{max}^{Cont}]$ within which voltages shall be contained in case of ordinary contingencies, provided that such contingencies do not exceed the overall capability of the system. All equipment shall be capable of continuously operating within this range without compromising its security. In the event of contingency, the DC voltages of the node within the HVDC system may deviate beyond the normal operating DC voltage range, but in steady state, they are expected to remain within this continuous operating DC voltage range. The relevant system operator is thus responsible for determining the appropriate primary DC voltage control parameters of each converter station/unit, ensuring that the voltages of all nodes within the system remain within this range in steady state in the event of all credible contingency scenarios.

  The continuous operating voltage range inherently encompasses the normal operating voltage range, however, in cases where voltages fall within this range but outside of the normal operating DC voltage range, it is deemed undesirable due to the reduced security margin. Therefore, remedial control action, such as secondary DC voltage control, shall be taken within the specified time frame to bring the voltage back into the normal operating DC voltage range.

- **Abnormal over/undervoltage ranges** $[-\infty, U_{min}^{Cont}]$ and $[U_{max}^{Cont}, \infty]$: These ranges are defined as the range outside the continuous operating DC voltage range. In the event of a disturbance in the HVDC system leading to an overvoltage or an undervoltage and exceeding the continuous operating DC voltage range, it is imperative to promptly take appropriate discrete countermeasures.

6.2.2 Dynamic DC voltage range in Dynamic time range

- **Dynamic DC voltage range** $[U_{min}^{Dyn}, U_{max}^{Dyn}]$: This range is defined by the maximum and minimum dynamic DC voltage levels, $[U_{min}^{Dyn}, U_{max}^{Dyn}]$. In the event of a disturbance, it is expected that the primary DC voltage control (See Section 6.5) contains peak DC voltage overshoots and undershoots within this range, to the extent possible given the physical and operational capabilities. The primary DC voltage control shall be designed to contain the voltages within these ranges considering the credible and dimensioning disturbances.

  Additionally, after any disturbance, it is expected that voltage oscillations are damped and falls within the continuous operating DC voltage range within the specified maximum settling time T_{max}^{Dyn}.The system operator is responsible for ensuring those limits. To achieve these objectives, the system operator, in coordination with the relevant TSOs, must specify the dynamic behaviour required for each converter.

6.2.3 Transient DC voltage range in Transient time range

Transient voltages are highly location-dependent phenomena and are not considered as the representation of the system state. They are associated with local protective measures and the DC-FRT requirements of AC/DC converter units. For further details on the functional requirements pertinent to transient time range, please refer to DC-FRT requirements of converters defined in section 7.3.

6.3 Definition of System States in terms of Steady-State DC Voltage

Continuous monitoring of the system condition through gathered measurements and relevant information is essential for ensuring the reliable operation. Following the AC system convention clearly delineated in Article 18 of SOGL [6], the system state shall be categorized into "*normal*," "*alert*," and "*emergency*" states according to the defined criteria. Then, for each state detected, predefined actions shall be taken.

The states of the systems are typically defined by multifaceted factors. In AC systems, these factors include AC voltage levels, power flows, frequency deviations, and the availability of both active and reactive power reserves to withstand contingencies in the established contingency list.

Concerning HVDC systems, it is crucial to establish the relationship between the voltage ranges defined in the previous section and the DC voltages observed in a steady state. The following outlines the criteria for distinguishing between the system states from the observed DC voltages. It is important to note that these criteria shall be complemented by other conditions with disjunctive relationship. The applicability of the following definitions is, hence, limited to the observable DC voltages. For additional definitions related to contingencies, please refer to Section 7.2.1.

6.3.1 Normal state in terms of DC voltage:

In terms of DC voltage, the HVDC system shall be in normal state when the following conditions are fulfilled:

- the voltages of all the nodes in the system are within the normal operating DC voltage range; and
- the conditions established for the alert and emergency state are not fulfilled.

The normal state in terms of DC voltage is associated to the normal operating DC voltage range. The overall HVDC system is expected to ensure sufficient margins to keep the system within the continuous DC voltage range in case of ordinary contingency, provided that such contingency does not exceed the overall capability of the system. The system thus shall strive to maintain or always restore the systems' voltage back to this normal operating range by the secondary DC control by the DC grid controller during operation.

6.3.2 Alert state in terms of DC voltage:

In terms of DC voltage, the HVDC system shall be in alert state when:

- All nodes are within the continuous operating DC voltage range, but one or more nodes are outside the normal operating DC voltage range for a period longer than the alert-state trigger time.

The alert state means that even though the voltages at all nodes in the system stay within the continuous operating range and meet the security requirements in terms of DC voltage, the operation in a state of reduced security margin persists. This condition indicates a state of alert due to potential issues with the remedial action scheme and the need for promptly re-establishing the necessary security margins.

6.3.3 Emergency state in terms of DC voltage:

In terms of DC voltage, the HVDC system shall be in emergency state when:

- The voltages do not meet the criteria for the normal state and for the alert state defined above.

6.4 Continuous Control Architecture

IEC TS 63291 [3] presents the general continuous control architecture, which consists of four distinct control layers. Each layer is associated with an indicative typical cycle time for actions. The purpose of this hierarchy is to provide clarity regarding the scope of responsibility, the priority of actions (which must be higher as the layer goes down), the availability of data, and the actuators involved. For more details regarding the IEC definitions of the continuous control hierarchy and the defined information propagation through the control layers, please refer [3].

6.4.1 General Continuous Control Hierarchy

While ensuring the consistency with the definitions in [3], **FIGURE 15** depicts the assignment of the functional hierarchy to the subsystems defined in Section 4.

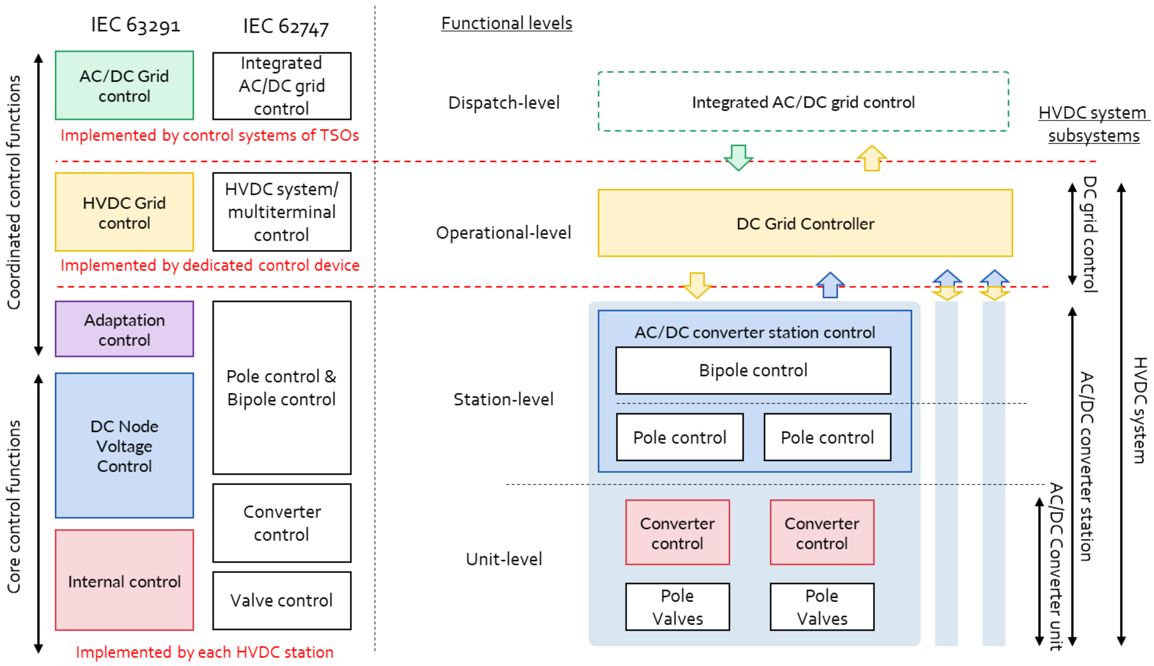

FIGURE 15: General continuous control hierarchy. Additional communication interfaces may be required, though not explicitly depicted explicitly in the figure, particularly for the coordination with PPMs.

The following sections outline the expected roles of the subsystem(s) corresponding to each level in the continuous control architecture as well as the generic description of each function.

6.4.2 Dispatch-Level

The dispatch-level, introduced as the highest layer in the continuous control architecture in [3] and is designated as "Integrated AC/DC system control" in IEC 62747 [7], conceptually represents a control system that governs the integrated operation of AC and HVDC systems in a power system.

From the perspective of an HVDC system, this is an **external** control system that serves as the only interface through which the DC grid controller receives all necessary set-points and instructions essential for ensuring the stable operation. It is envisaged that no other interface bypassing this is in place unless there are no communication issues, although in future different design concepts may evolve depending on special design need of the TSOs or HVDC project owners.

This level shall provide the DC grid controller with the active power transmission order for the upcoming dispatch cycle as well as all the other setpoints at the AC and DC connection point (such as but not limited to reactive power set-points, constraints, and any other operational instructions as specified by the relevant TSOs). These inputs, although not strictly limited, may regularly be updated in conjunction with the dispatch program schedule, as specified by the relevant TSO in coordination with adjacent TSOs and hence, may be updated alongside any other generation units in the grid. Therefore, in accordance with the IEC standard, these set of input values for a given time period are hereinafter referred to as **converter schedule**.

6.4.3 Operational-Level

The operational-level in the hierarchical continuous control architecture directly corresponds to the DC grid controller, which is an interface for obtaining information on the power flow conditions and accessing all electrical nodes in the HVDC system. The primary objective of the DC grid controller is to achieve the converter schedules set by the dispatch-level while ensuring compliance with all the security constraints within the HVDC system, as specified by the relevant TSO. During operation, internal and external system conditions may change. Thus, the DC grid controller shall be capable of taking appropriate measures to prevent overloading and overvoltage of any equipment and to achieve the Normal Operating DC voltage ranges as specified in Section 6.2.1, even though it may result in deviation from the initial converter schedules received. The DC grid controller shall ensure that this deviation is both reasonable and justifiable to all stakeholders involved, and then report to the higher control hierarchy, i.e., the dispatch-level.

6.4.3.1 HVDC System state analysis

Like the state estimation commonly conducted in existing AC systems, the DC grid controller shall be aware of the actual conditions of the HVDC system. The system's state is determined based on available real-time measurement. The minimum set of information required for the system state analysis is specified in [3] and categorized as status signal and physical quantities. The system state analysis can be categorized into three main components for convenience:

- **Element status analysis:** The DC grid controller shall comprehend the real-time status of every element within the HVDC system. This involves gathering continuously communicated essential system state variables and equipment state, defined as "station Information", from the AC/DC converter, AC and DC switching stations, Energy absorption devices, as well as PPMs.

- **System topology analysis:** Based on the element status analysis, the DC grid controller shall identify the actual grid topology. In general, contingencies can result in the outage of different grid components such as cables or converters that may lead to new grid topologies, such as a system split.

- **Element limitation analysis:** A particular emphasis is given to the importance of comprehending the actual capabilities of converter stations. While the tolerable maximum and minimum values for the DC voltage are typically determined by the design of the component, the limitation regarding active power, as well as reactive power capabilities of an AC/DC converter station may deviate from the rated values during operation due to the state of the cooling system and power electronic devices.

6.4.3.2 DC power flow optimization

One of the essential functionalities expected from the DC grid controller is to establish an adequate DC power flow by sending out appropriate set-points to the AC/DC converter stations. This includes a verification of the received converter schedules and an assessment of its feasibility in accordance with the actual state of the system.

Under changing grid conditions, including deviations in offshore wind generation from forecasted levels or limitation on the transmission capacity due to disturbances, the DC grid controller must accordingly determine the optimal DC power flow while ensuring all the security constraints of the system described in Section 6.1. These constraints encompass the voltages of all nodes, including the neutral voltages, the physical and operational constraints of the AC/DC converter units, and the current capacity of conductors including DMRs.

The objective function for the optimal power flow calculation shall be the operational discretion of the relevant TSOs. Potential factors to be considered, though not exhaustive, include:

- Loss minimization
- Security margin
- Minimization of deviation between pre- and post-contingency situation at each PoC-AC
- Adherence to repartition factor (pre-defined power sharing ratio between control areas)

The parameters required for DC power flow optimization depend on the selected optimization criteria, which shall be left to the discretion of the system operator. It is imperative that the operator identifies these essential parameters beforehand and adequately provides them as input to the DC grid controller.

6.4.3.3 Secondary DC voltage control

Analogue to the hierarchical structure of frequency control in AC systems, which is divided into primary, secondary, and tertiary frequency control, the DC voltage control in DC grids shall also be composed of a hierarchical manner. While the primary DC voltage control is a local control mechanism and thus implemented at each AC/DC converter station, the secondary DC voltage control is an overall HVDC grid control scheme.

Details of the required functions are provided in detail in the dedicated section: Section 6.6.

6.4.3.4 Ramp rate coordination

In general, an abrupt change in power can stress and threaten the AC system stability and, thus, should be avoided. The power set points are usually associated with ramp rate limits. In practice, there are various instances where the power set-point change shall be limited by the specified ramp rate, and typical ramp rate depends on the situation.

The power transmission order for an HVDC system can potentially change significantly from one to the next market time unit[6]. In order to ensure the interconnected AC systems' stability, restrictions are imposed on the ramp rate for power flow change. Such ramp rate limitations shall be predetermined by the relevant TSOs through the assessment of the frequency stability and voltage sensitivity and are normally in the order of minutes. Therefore, for each change of market time unit, an adequate ramp rate must be applied to the set-points to be sent out to the AC/DC converter stations.

DC voltage and power restoration through the secondary DC voltage control following an unscheduled event requires a substantially faster timeframe than the typical dispatch operation.

In addition, for AC ancillary services, such as Emergency Power Control (EPC) and automatic Frequency Restoration Reserve (aFRR), ramp speed specifications are determined by the relevant TSOs of both the

[6] "Market time unit" means the period for which the market price is established [24].

receiving and supplying sides for each service, respectively. For instance, in the case of EPC, an automatic reduction or increase of power pursuant to an instruction from the applicable TSO, which may also involve power reversal, the ramp rate limitations or requirements are typically in the order of seconds, e.g. up to 999 MW/s.

It is also imperative to acknowledge the distinction between onshore and offshore stations connected to PPMs. The technical specifications on the feasible ramp speed of the connected PPMs must be considered.

Moreover, applying the same ramp rate limitation across all stations, while power step orders differ among them, can lead to potential power imbalances during the ramping process, seen as a disturbance to the HVDC system. Thus, it is desired that the ramp rate limitations are coordinated within the technical specifications and assigned to each AC/DC converter station differently in line with the power step orders such that secure transition of operating points can be ensured.

Consequently, given the significant differences in expected ramp rates for dispatch, re-dispatch following unscheduled events in the HVDC system, and potentially AC ancillary services, the DC grid controller shall be capable of adequately coordinating the ramp rate of individual converter stations to ensure the power balance during the ramping process.

6.4.3.5 Offshore power curtailment

Offshore power curtailment refers here to the intentional reduction of power generation of offshore PPMs below their maximum potential production. This measure may be required to prevent congestion within the DC grid and must be done in accordance with the regulatory agreements. While such considerations shall be taken into account in the DC power flow optimization process, as detailed in Section 6.4.3.2, this section places particular emphasis on the interface requirement of the DC grid controller and the offshore power curtailment in emergency scenarios.

In the event of a disturbance in a DC grid, the primary DC voltage control of AC/DC converter stations handle the power imbalance and contains the DC voltage excursion. However, it is crucial to acknowledge that the power limitations of converter stations inherently impose constraints on their ability to contain such disturbances.

Consider a scenario where the incoming power from PPMs exceeds the total export capability of the HVDC system, due to power limits of the onshore AC/DC converter stations, or a fault on AC side of an onshore station or in an interconnector cable. When the total power injection exceeds the maximum export capacity of the HVDC system, it will result in a persistent increase in DC voltages. It is imperative that this surplus energy must be dissipated by immediate activation of the energy absorber units upon detection of overvoltage exceeding a predefined voltage threshold. However, since the energy absorber unit can dissipate energy only for a brief duration, the wind power curtailment process must be initiated before exceeding the time constraint of the energy absorber units.

To achieve this, various technical options are possible. One such option involves a direct communication channel between the DC grid controller and the PPM controllers. Upon detection of the fault or activation of energy absorber unit, the DC grid controller dispatches a new power limit with a specified ramp-down rate to each of the relevant PPM controllers in order to initiate their offshore power curtailment, which then can limit the PPM output power accordingly. Alternatively, communication from the DC grid controller to offshore AC/DC converter station is also a viable option. In this scenario, the offshore converter station would take the necessary measures to curtail the wind power. This could be achieved either by communicating with the PPM controllers of the connected wind turbines or by modulating the electrical signals that are detected by the wind turbines, prompting them to adjust their output [2].

Moreover, in case of an AC grid experiencing congestion, upon receipt of a request from the responsible AC system TSO, sending a curtailment order to the PPM is also envisioned as a role of the DC grid controller.

6.4.3.6 Converter control mode coordination

Prior to operation, the HVDC system operator, in coordination with the relevant TSO, is responsible for predefining the control mode and the associated parameters of each converter unit, within the parameter range specified. Frequent modifications and update of control parameters are not anticipated, expect perhaps on a seasonal basis, or in certain situations like modification to another grid configuration or change in network constraints. The appropriate parameters associated with any control modes values should be selected in accordance with the parameters and parameter ranges specified during planning and testing phases as outlined in [8]. Prior to actual operation, those values shall be thoroughly assessed for various load flow conditions and a set of contingencies. Through this process, all pertinent stakeholders shall agree on the criteria for selecting control modes and associated parameters for each converter unit across various operational situations.

The DC grid controller should be responsible for setting the control modes and their associated parameter. During the operation, the DC grid controller shall oversee the coordination of the control modes and their associated parameter, making necessary adjustment to meet requirements, all while adhering with predefined criteria.

6.4.4 Station-Level

The station-level encompass high-level control systems responsible for the control, monitoring, and protection functions within an AC/DC converter station. It shall receive the comprehensive converter schedule from the DC grid controller, which shall include at least the valid set-points for active power and DC voltage for each converter unit in the station.

Furthermore, given that this level has access to all the information within the AC/DC converter station, it shall possess the capability of continuously sending the specified set of signals to the DC grid controller. This shall include essential state variables and equipment status signals and those defined as *station information* in [3], as well as any additional signals specified by the relevant TSOs.

Additionally, in case of a bipolar configuration, control systems are divided into bipolar and pole controls, in alignment with IEC 62747 [7]. Note that bipolar control is defined as a control that necessitates the state variables from both the positive and negative converter units, whereas pole control shall rely exclusively on the pole quantities, independent of the counterpart.

6.4.4.1 Bipole Control

In bipolar configuration, an AC/DC converter station comprises positive and negative AC/DC converter units. It is essential that the functional requirements at the AC PoC are fulfilled, either by the station as a whole or individually by each converter unit, in alignment with the specifications set by the relevant TSO[7].

In the case of bipolar configuration with DMR, from the perspective of the DC connection point and DC functional requirements, a bipolar AC/DC converter station possesses two distinct fundamental degrees of freedom: positive and negative AC/DC converter units, yet the physical configuration to which the station is interconnected consists of three conductors: positive, negative, and DMR, as shown in **FIGURE 16**. Therefore, this configuration inherently entails a degree of flexibility in associating the control capabilities of the two converter units within the station with the systems' variables that are subject to the regulation via selectable control parameters. Depending on how the control capabilities are associated with the system's variables, a control function can be classified either as bipolar control or pole control.

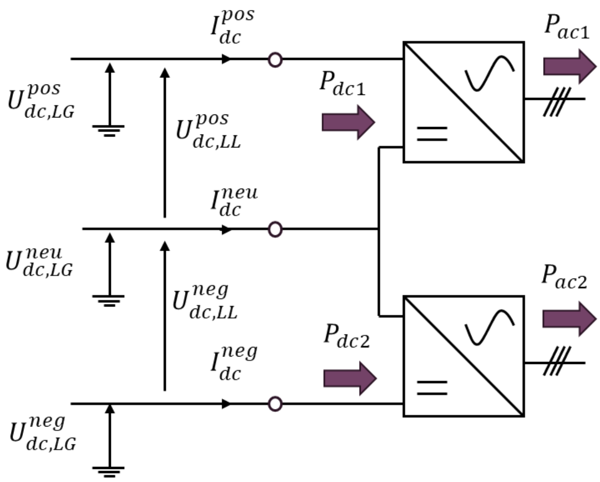

FIGURE 16: Conceptual illustration of DC variables in a bipolar configuration.

One option is to directly correlate the operational capabilities of each converter unit with the physical quantities of its respective pole. This ensures a clear distinction of the responsibilities and independent control over the positive and negative poles. The DC voltage droop control (detailed in Section 6.5) can be understood as controlling the interrelation between voltage and power (or current) in each pole in accordance with the specified characteristic with no consideration for other pole. It is important to note that in scenarios involving changes in the system's configuration, especially the loss of the DMR connection, the independence among the positive and negative pole variables changes. Such changes in the system must be detected and appropriate measures should be taken by the DC grid controller. It can also be considered that, as shown in **FIGURE 17**, a backup function implemented locally at the station-level, be in place to take the necessary action to regulate/limit neutral quantities when communication with the DC grid controller is lost.

[7] Unless otherwise specified, specific features of the AC system may be implemented at the station level or at the unit level, at the vendor's discretion.

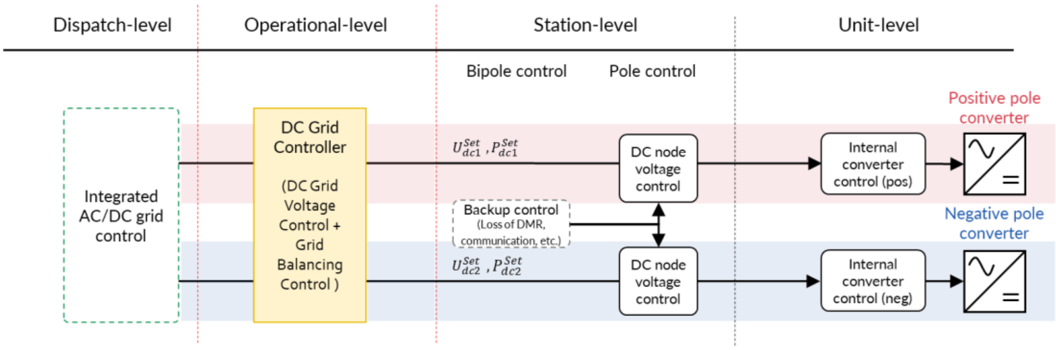

FIGURE 17: Conceptual illustration of the option ensuring independent control over the positive and negative poles, alongside bipolar level control reconfiguration is mentioned. Only the signals relevant are displayed.

Nonetheless, under normal operational conditions, these controls are pole independent controls that do not depend on the quantities of the other pole option; and hence, categorized as pole control. However, it can be noted that this option does not inherently provide any mechanism for controlling the quantities associated with the neutral (or metallic return) conductor.

To address this concern, two innovative solutions have been proposed, summarized as follows.

Option 1, as introduced in [1], originates from the traditional symmetrical components transformation (Fortescue) used for 3 phase AC systems and extends this methodology to DC systems. This approach involves relating the quantities of each pole, specifically, pole voltages and currents, through predefined coupling matrices, deriving balanced and residual mode voltages and currents. By considering the derived quantities as control variables and adopting a similar approach to the set-points for the AC/DC converter station, the positive and negative AC/DC converter units are linearly transformed into two decoupled subsystems in the balanced and residual components. **FIGURE 18** shows the conceptual illustration of this option.

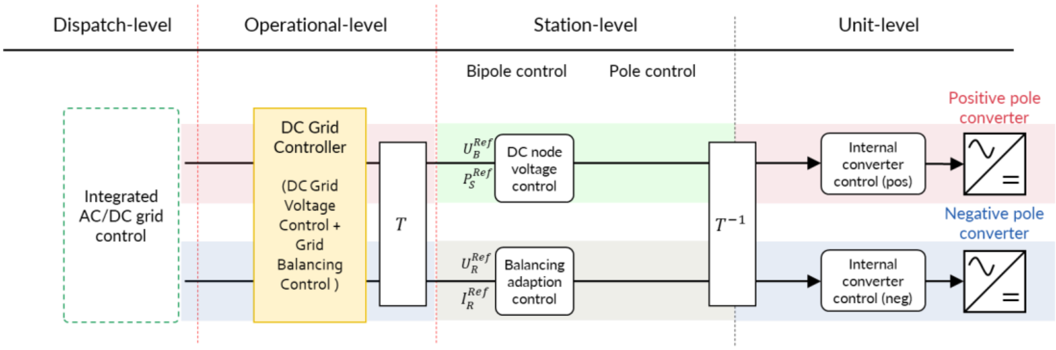

FIGURE 18: Conceptual illustration of Option 1, within which only the signals relevant are shown.

Option 2, on the other hand, maintains the fundamental independencies between the positive and negative poles while introducing supplemental control measure over the neutral quantity. This approach leverages the inherent and intuitive separation of the poles, while employing the supplemental measure aimed at neutral quantity to manage the issue arising from the asymmetrical power flow conditions. **FIGURE 19** provides a conceptual depiction of this option.

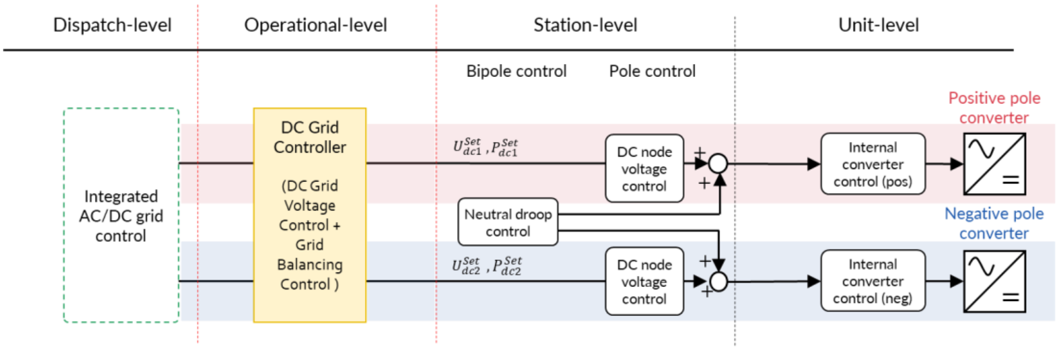

FIGURE 19: Conceptual illustration of Option 2, within which only the signals relevant are shown.

The comparative performances of these solutions have been demonstrated by their respective entities proposing the solutions. In addition, both have been thoroughly investigated analytically. While they are significantly different in terms of the operating principles and associated design space, they share a certain commonality in terms of the regulation over the neutral quantities, which necessitates, in both, coordination in measurement and actions from both the positive and negative converter units.

As delineated in Section 6.1, while it is imperative to ensure all the physical and operational constraints during operation, the bipolar control shall be capable of managing the following operational conditions of the station:

1. Normal operation of the station: This assumes an ideal bipolar operation with the presence of a DMR connection, where the identical functioning of the positive and negative pole units would be expected.
2. Operation in the event of disconnection with the neutral (DMR connection loss)
3. Asymmetric monopolar operation due to the loss of the converter unit of a pole or a pole conductor
4. Asymmetric operating set-points of power between positive and negative units: This situation arises when there's a difference in power injection between the positive and negative poles, which might occur due to decoupled AC busbars in offshore stations connected to PPMs, maintenance activities on one of the pole converter units, or the loss of a pole conductor connecting a station. Different operating set-points between the positive and negative units also implies a difference in the available headroom capacity between the units.
5. Asymmetric power capability: This involves scenarios where there is a problem, such as in an AC transformer in one of the units, affecting the converter unit's power capability and necessitating asymmetric operation.

Ultimately, it falls upon the system operator's responsibility to clearly define the functional specifications and interface signals between operational level and station level, considering all relevant factors and potential operational conditions. Nonetheless, the actual implementation of the solution is at the discretion of the vendor, provided it complies with all the defined functional specifications.

Neutral Current/Voltage control:

> [Filled in final version]

6.4.4.2 Pole Control

Pole control, as defined in accordance with [7], refers to the control system dedicated to the management of each converter pole within an AC/DC converter station. The pole control shall be implemented and managed individually for the positive and negative poles. The functional requirements for the pole control shall be defined for the behaviour of that pole, independent of the counterpart pole.

6.4.5 Unit-level

The unit level includes the internal converter control and the valve control of each converter unit. This level represents the lower most part in the continuous control hierarchy and is highly specific to the technology and the proprietary designs of each vendor.

Regarding converter control, there are two distinct control schemes: Grid Following (GFL) and Grid Forming (GFM). These schemes differ in the fundamental design principles, leading to differences in the withstand capability and dynamic performance requirements that can be fulfilled. For a detailed definition and the required performances of GFM, please refer [2].

The converter control must be designed and tuned such that all the functional requirements and performance requirements specified by the system operator and the relevant TSO are met.

6.5 Primary DC Voltage Control

This section first recalls the conventional control modes, namely fixed DC voltage control mode and fixed active power control mode. It then focuses on primary DC voltage control based on the principle of droop. Formal definitions of the droop and relevant terminology are provided. Subsequently, it outlines their functional specifications, first focusing on the static aspects. Then, initial considerations on how to specify and evaluate the dynamic performance requirements are presented.

6.5.1 Definitions of conventional control modes

The fixed DC voltage control is an extension of the conventional master/slave control method in traditional point-to-point systems. In this setup, only one station in the grid is responsible for maintaining the DC voltages of the system constant, while the other track the active power set-points. The following provides the brief description of the two conventional control modes.

6.5.1.1 Fixed DC voltage control mode

When operating the fixed DC voltage control mode, the AC/DC converter station or unit shall be capable to maintain the DC voltage of its DC-PoCs at the reference specified by the system operator or the DC grid controller by adjusting active power injection/absorption according to the specification set by the system operator. 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).

6.5.1.2 Fixed active power control mode

When operating the fixed active power control mode, the AC/DC converter station or unit shall be capable of regulate its active power following the specifications set by the system operator, in coordination with the relevant TSOs, according to NC-HVDC Article 13 [4].

6.5.2 Definitions of DC Voltage Droop

The concept of the primary DC voltage control based on DC voltage droop control is well recognized today: however, existing literature presents notable discrepancies in definitions of DC voltage droop. IEC describes in [3] the DC voltage/DC power droop as the change of active power in response to a deviation of the DC voltage from its reference value, while CIGRE TB699 [9] mentions that the droop value "*is the inverse of the proportional controller gain used in the actual implementation*." In the context of the former research initiatives like PROMOTioN and BestPaths projects, droop is introduced as the parameter defining the characteristic of the droop control mode, determining the reference values for active power [10] or the DC voltage [11], from implementation focused perspectives, rather than providing a functional, quantifiable definition.

In light of varying interpretations existing in the literature, and referring to the definition of droop in AC system formulated in RfG Article 2 (23) [12], we suggest the definition of the DC voltage droop as follows:

The "DC voltage droop" refers to the ratio of a steady-state deviation of DC voltage to the steady-state change in active power output.

It is noteworthy to state that this definition is universal, not excluding or prescribing any specific implementation methods.

In accordance with the above definition, the ratio, k, can be mathematically expressed as follows:

$$k = \frac{\frac{\Delta U_{dc}}{U_{dcn}}}{\frac{\Delta P}{P_n}} \text{ [p.u.]}$$

where

Steady-state deviation of DC voltage:	$\Delta U_{dc} = U_{dc} - U_{dc}^{Set}$
Steady-state deviation of active power:	$\Delta P = P - P^{set}$

and

U_{dcn}	Nominal voltage of the DC network
P_n	Nominal power
U_{dc}^{Set}	DC voltage setpoint
P^{set}	Power setpoint
U_{dc}	DC voltage measurement
P	Power measurement

While the droop is formally defined as the ratio of two variables: the numerator being DC voltage deviation and denominator as active power output, a more precise clarity in the interpretation of these variables is required to ensure the consistency among the AC/DC converter stations or units in the system.

Convention of power flow direction

In accordance with IEC 62747 [7], the power flow through the AC/DC converter flowing from the DC-PoC into the converter and further on from the converter into the AC-PoC is designated by positive sign. This definition is illustratively represented in the figure below.

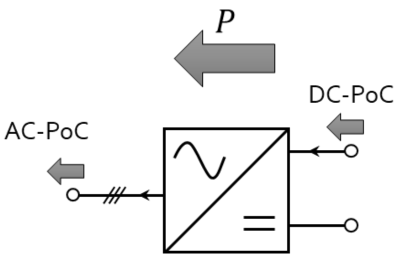

FIGURE 20: Representation of the convention of power flow direction as defined in IEC 62747 [7].

Definition of numerator and denominator variables

Concerning the numerator variable of the droop, the definition of DC voltage presents some ambiguity. DC voltage could be interpreted as the pole-to-ground voltage, pole-to-neutral voltage, or other forms such as balance or residual mode DC voltages, as proposed in [1]. An imprecise definition of DC voltage could lead to different interpretations of the numerator variable in the droop, resulting in inconsistent behaviour among the AC/DC converter stations within the system. It is essential that a consistent definition is uniformly applied across the system. The system operator should make this selection with careful consideration, as altering them at a later stage could introduce significant challenges. For compatibility with symmetrical monopolar configurations, it is recommended that this DC voltage to be defined as the pole-to-neural voltage.

Similarly, the denominator variable in the droop, termed active power output, is acknowledged that it encompasses the possibility of being defined as either AC active power or DC power, and either converter unit’s power or bipolar station power.

General implication of DC voltage droop

FIGURE 21 illustrates the implication of varying droop. Drawing an analogy to frequency droop in AC systems, the value of the DC voltage droop can be understood as the change in DC voltage causing the converter to change its power by 1 p.u. in steady state. For instance, a 0.05 p.u. DC voltage droop implies that a 0.05 p.u. deviation in voltage leads to a 1 p.u. change in power output of the AC/DC converter in steady state.

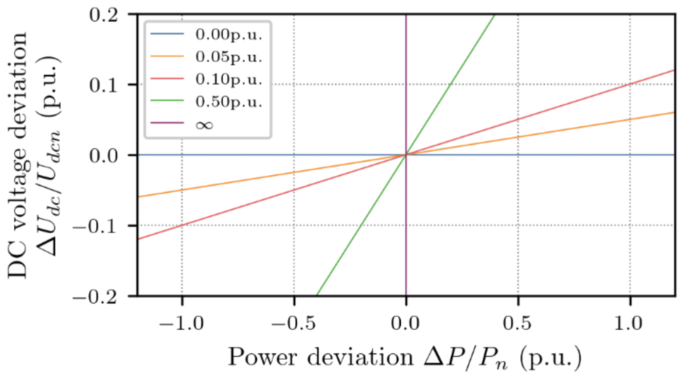

FIGURE 21: Example of characteristics in different droop.

To summarize, with a larger droop, the power output is less sensitive to changes in DC voltages, leading to a smaller contribution to DC voltage regulation. Conversely, with a smaller droop value, the power becomes more sensitive to fluctuations in DC voltage, resulting in a greater contribution to DC voltage regulation.

6.5.2.1 DC Voltage Droop Characteristics

For an intuitive representation of the steady-state behaviour of an AC/DC converter, including the factors like set-points and maximum power constraints, it is a common practice to plot it as a continuous linear or piecewise linear function on a Cartesian plane, with the vertical and horizontal axes corresponding to the numerator and denominator variables of the DC voltage droop. This representation is hereinafter referred to as "DC voltage droop characteristic", and is formally defined as follows:

The "DC voltage droop characteristic" is defined for each converter station or unit as a representation of a desired static performance.

Neglecting the maximum power constraints, a typical DC voltage droop characteristic with an indicative droop of 0.05 p.u. is depicted in **FIGURE 22**. The dot in the figure represents the set-point assigned to the converter, i.e. $[P^{Set}, U^{Set}] = [0.0\text{ p.u.}, 1.0\text{ p.u.}]$.

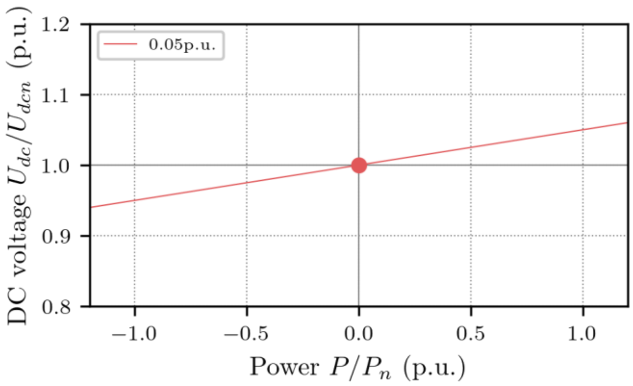

FIGURE 22: Typical DC voltage droop characteristic with a DC voltage droop of 0.05 p.u.

The DC voltage droop characteristic is derived directly from the droop. Following the definition of DC voltage droop, a mathematical manipulation results in two identical equations:

- Voltage form:

$$U_{dc} = k\frac{P - P^{set}}{P_n}U_{dcn} + U_{dc}^{Set}$$

- Power form:

$$P = \frac{U_{dc} - U_{dc}^{Set}}{k}\frac{P_n}{U_{dcn}} + P^{set}$$

As mentioned in CIGRE TB699 [9], if the DC voltage droop characteristics are plotted on a plane that is different from the chosen definitions of the numerator and denominator of the droop, the resulting characteristic will appear as a nonlinear function. This underscores the importance of adhering to the defined numerator and denominator in subsequent discussions or analyses.

The position of the DC voltage droop characteristics on the plane is determined by the assigned set-points, as can be inferred from the equations above. **FIGURE 23** and **FIGURE 24** show the droop characteristics employing the same droop, with **FIGURE 23** demonstrating the effect of changing the voltage-setpoint and **FIGURE 24** depicting the impact of modifying the power-setpoint, respectively. As observed, adjusting the DC voltage set-point results in a vertical shift of the characteristic, whereas modifying the power set-point results in a horizontal shift in the characteristic.

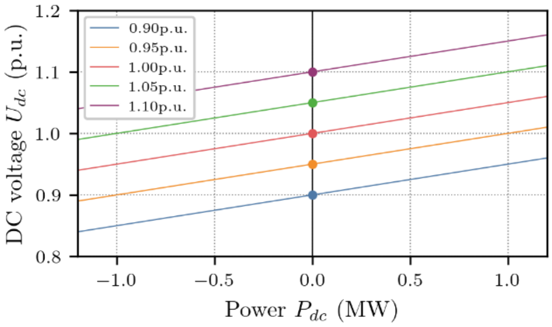

FIGURE 23: DC voltage droop characteristics with different DC voltage set-point U_{dc}^{Set}, (with $\frac{P^{set}}{P_n} = 0\ \text{p.u.}, k = 0.05\ \text{p.u.}$)

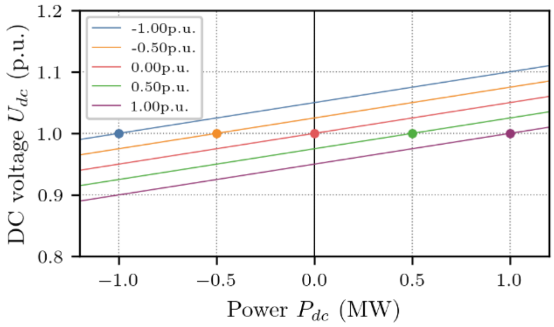

FIGURE 24: DC voltage droop characteristics with different power set-point P^{set}, (with $\frac{U_{dc}^{Set}}{U_{dcn}} = 1\ \text{p.u.}, k = 0.05\ \text{p.u.}$)

Equivalent representations of conventional control modes
[To be filled in the final version]

6.5.3 Static requirements for Primary DC voltage control related control modes

In order to achieve improved security while achieving the maximum exploitation of the DC grid operation by overcoming the limitations of the single section droop characteristic, the implementation of multi-segment droop characteristic is essential. In the context of multi-vendor, multi-terminal DC grid, ensuring interoperability between AC/DC converter stations supplied by different vendors requires the establishment of precise definitions and functional requirement for each segment, as well as comprehensive clarification of all essential parameters necessary to be specified.

The primary DC voltage control is defined as the control capability of an AC/DC converter station or unit in which the active power output changes proportionally to a change in system DC voltage, in such a way that it prevents power imbalance in the DC grid and supports reaching an equilibrium point of the system.

To achieve efficient DC voltage regulation and ensure steady-state voltages remain within the continuous operating DC voltage range established in Section 6.2.1, the primary DC voltage control is divided into at least three distinct operating modes, each defined with specific operational requirements:

1. **DC Voltage Sensitive Mode**: or DCVSM means an operating mode that primarily focuses on the behavior within the normal operating DC voltage range.

2. **Limited DC Voltage Sensitive Mode-Overvoltage**: or "LDCVSM-O" means an operating mode that is activated when the voltage exceeds the upper limit of the normal operating DC voltage range up to the maximum continuous operating DC voltage value.

3. **Limited DC Voltage Sensitive Mode-Undervoltage**: or "LDCVSM-U" means an operating mode that is activated activated when the voltage exceeds the lower limit of the normal operating DC voltage down to the minimum continuous operating DC voltage value.

In addition to the above modes, the following two supplemental operating modes are relevant to the primary DC voltage control in order to enhance the security of the system.

4. **DC Voltage Limiting Mode**: or "DCVLM" means a supplemental operating mode that is activated when the voltage is outside the continuous operating range, provided that the full active power headroom was not yet reached[8].

5. **Power Limiting Mode**: or "PLM" means a supplemental operating mode that aims to limit the active power output to the maximum and minimum power capability.

FIGURE 25 illustrates an example of the operational implication of each mode.

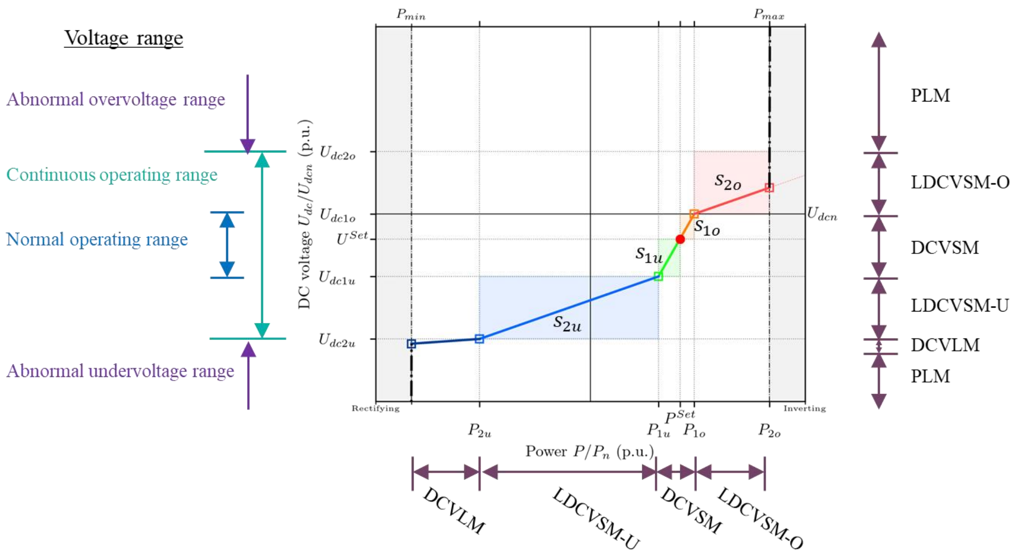

FIGURE 25: Example depiction of typical droop characteristic of an AC/DC converter station or unit in each primary DC voltage control related mode.

Each of these modes shall be defined with specific performance and capability requirements associated with specific parameters.

6.5.3.1 DC Voltage Sensitive Mode (DCVSM)

When operating in DCVSM, the AC/DC converter station or unit shall be capable of responding to DC voltage deviation in the connected HVDC system as indicated in **FIGURE 26** and in accordance with the parameters detailed in **TABLE 9** and **TABLE 10**. These parameters shall be specified by the system operator within the ranges predefined for each parameter.

[8] The DCVLM serves as a security backup, and depending on other mode parameter selections (e.g., LDCVSM setting reaching the power limit before reaching the voltage limit), it cannot be activated, and thus does not appear in the multi-segment droop characteristic.

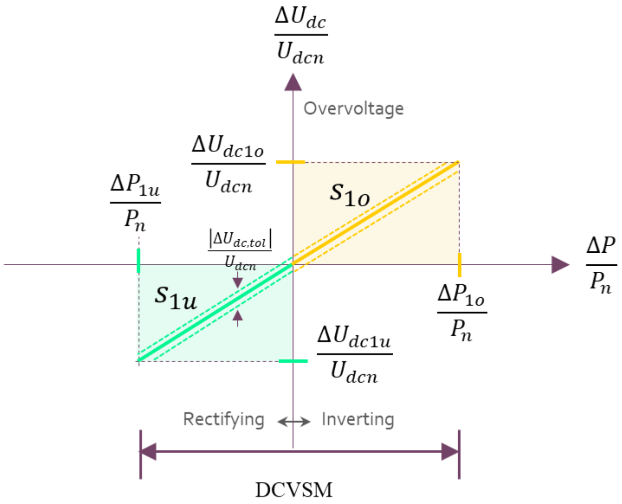

FIGURE 26: Droop capability of an AC/DC converter station or unit in DCVSM.

TABLE 9: Definitions of basic parameters and variables used for defining active power voltage response in DCVSM.

Variables	Definitions	Unit
U_{dcn}	nominal voltage of the DC network for which the DCVSM service is provided	kV
P_n	nominal active power	MW
P_{max}	agreed maximum power defined for the connection point of the converter station or unit	MW
P_{min}	agreed minimum power defined for the connection point the converter station or unit	MW
U_{dc}^{Set}	DC voltage set-point	kV
P^{Set}	active power set-point	MW
U_{dc1u}	undervoltage threshold value	kV
U_{dc1o}	overvoltage threshold value	kV
ΔP	change in active power by the AC/DC converter station or unit with respect to the present operating point	$\Delta P = P - P^{Set}$
ΔU_{dc}	voltage deviation of the DC network for which the DCVSM service is provided[9]	$\Delta U_{dc} = U_{dc} - U_{dc}^{Set}$

[9] In AC systems, the frequency is a global variable. This means that any frequency deviation Δf is formally defined as the deviation from the nominal frequency f_n, i.e. $\Delta f = f - f_n$. In a steady state, the frequency deviation is the same at all local measurements throughout the system. Conversely, the voltage in DC system is not a universal variable. Instead, in steady-state, the voltage at each node varies due to line

TABLE 10: Parameters for active power voltage response in DCVSM

Variables	Definitions	Unit
ΔP_{1u}	agreed power change at reaching the voltage threshold value ΔU_{dc1u}	MW
ΔP_{1o}	agreed power change at reaching the voltage threshold value ΔU_{dc1o}	MW
s_{1u}	droop at undervoltage	$\mathrm{p.u.}$
s_{1o}	droop at overvoltage	$\mathrm{p.u.}$
ΔU_{dc1u}	undervoltage deviation threshold value	$\Delta U_{dc1u} = U_{dc1u} - U_{dc}^{Set}$
ΔU_{dc1o}	overvoltage deviation threshold value	$\Delta U_{dc1o} = U_{dc1o} - U_{dc}^{Set}$
$\Delta U_{dc,\,db}$	deadband of the power voltage response	kV
$\Delta U_{dc,\,tol}$	voltage response insensitivity (permissible tolerance)	%

The following provides a detailed description of the definition of each parameter.

Maximum and Minimum power limits P_{max} & P_{min}

The maximum and minimum power limits, denoted by P_{max} & P_{min}, are defined for the connection point of each converter station or unit by the relevant system operator.

Those values shall be the maximum and minimum continuous active power which the AC/DC converter station or unit can exchange with the AC network at each AC-PoC as specified in the connection agreement or as agreed with the relevant TSO. It shall not be obligatory for the AC/DC converter station or unit to provide active power beyond those values limits. Therefore, if, as a result of the active power voltage response in DCVSM the maximum and minimum power limits are reached, the maximum and minimum power limits reached shall be maintained.

Undervoltage/Overvoltage threshold values U_{dc1u} & U_{dc1o}

The undervoltage and overvoltage threshold values, denoted by U_{dc1u} & U_{dc1o}, are defined as the system level values consistent for all AC/DC converter stations or units within the DC grid. Within the voltage range defined by those two values, the AC/DC converter station or unit in DCVSM must fulfil the functional requirement in accordance with the parameters specified by the system operator.

It is recommended to establish the system level common under and over DC voltage threshold values U_{dc1u} & U_{dc1o}, which are consistent across all AC/DC converter units and do not change depending on the

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resistance and other factors causing voltage drops. As a result, the DC voltage deviation measured at any given converter unit must be relative to the converter's own DC voltage set-point, i.e. $\Delta U_{dc} = U_{dc} - U_{dc}^{Set}$. When a converter under droop control is operating without any deviation of power, i.e. $\Delta P = 0$, it implies a condition where the voltage deviation equals zero ($\Delta U_{dc} = U_{dc} - U_{dc}^{Set} = 0$).

power flow conditions [10]. This approach allows to standardize the response to voltage deviations, ensuring a consistent and predictable operational framework for the entire grid. Then, the DC voltage deviation threshold values are defined with respect to the system level DC voltage threshold values as follows:

- $\Delta U_{dc1o} = U_{dc1o} - U_{dc}^{Set}$ is the upper DC voltage deviation threshold below which the AC/DC converter station or converter unit must provide the DCVSM response according to the parameters specified for overvoltage, and
- $\Delta U_{dc1u} = U_{dc1u} - U_{dc}^{Set}$ is the lower DC voltage deviation threshold above which the AC/DC converter station or converter unit must provide the DCVSM response according to the parameters specified for under voltage.

The implications of the above definitions in the DC voltage droop characteristic plane are illustrated in the **FIGURE 27**.

From a technical standpoint, those voltage threshold values can be established independently of the static DC voltage ranges defined in Section 6.2.1. However, it is a common practice in AC systems to align the FSM and LFSM threshold frequencies with the maximum steady-state frequency deviation of the system[11]. Therefore, in accordance with the customary practice of AC systems, it is advisable to align those voltage thresholds values with the voltage levels that define the static DC voltage range. This suggests that $[U_{dc1u}, U_{dc1o}] = [U_{min}^{Nor}, U_{max}^{Nor}]$. Consequently, the range of DC voltage within which the DCVSM is required to provide specified responses corresponds directly to the Normal Operating DC voltage range.

It shall be noted, however, that in a sparse and/or radial DC grid, particularly with long-distance transmission lines, there may be instances where the same voltage thresholds cannot be applied to all converter stations, necessitating the definition of specific voltage threshold levels for particular stations. As the DC grid evolves and becomes more developed and meshed in the future, the need for such specific voltage thresholds may decrease.

[10] The droop characteristic of a given converter varies vertically in accordance with the designated U_{dc}^{Set}, which can vary during the operation depending on the power flow condition. Therefore, from the TSO's point of view, if DCVSM thresholds are specified with respect to "deviation", it means that each converter will transition the control modes at different grid voltage levels, depending on its pre-contingency power flow condition. To circumvent this and ensure uniformity across the grid, establishing the system level common under and over DC voltage threshold values U_{dc1u} & U_{dc1o} is recommended such that it is consistent across all AC/DC converter stations or units and do not change depending on the power flow conditions.

[11] Article 15 of SOGL [5] specifies the maximum steady-state frequency deviation of the synchronous areas. According to ENTSO-E guideline document [23], droop for FSM should be calculated to make sure the reserve power capacity could be fully deployed for the synchronous area reference frequency deviation (i.e 200 mHz for CE, 500 mHz for GB).

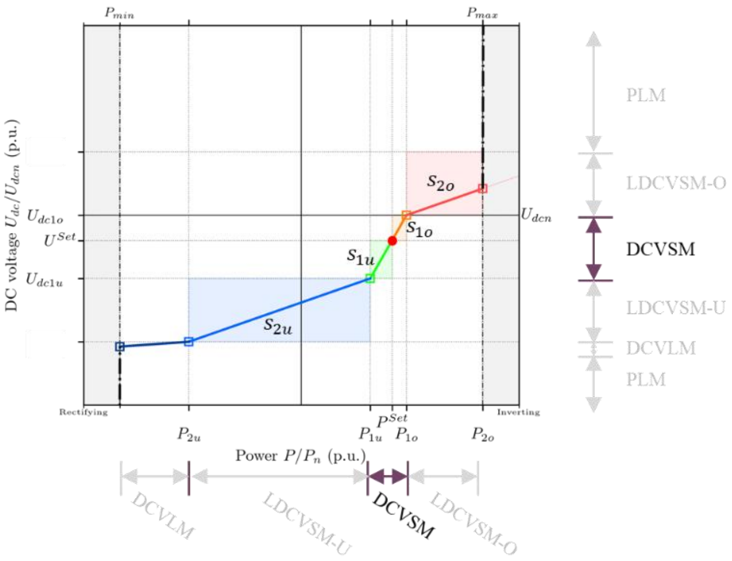


FIGURE 27: Illustration of the implications of the definitions of undervoltage and overvoltage DC voltage threshold values in the DC voltage droop characteristic.

Droop s_{1u} & s_{1o}

AC/DC converter stations or units should have the capability of implementing the droop settings for DCVSM.

The droop s_{1u} & s_{1o} are parameters specifying the expected characteristic in the DCVSM. Selecting the appropriate droop parameter is at the discretion of the system operator. It is indispensable that AC/DC converter stations or units possess the capability of implementing the droop setting for DCVSM. Nevertheless, the application of this capability can vary significantly depending on the operational context of the system as evidenced in the practice of AC systems[12]. The following further elucidates the implication of these different contexts with recommendation.

Neglecting the deadband, the droop for overvoltage can be expressed by:

$$s_{1o} = \frac{\frac{\Delta U_{dc1o}}{U_{dcn}}}{\frac{\Delta P_{1o}}{P_n}} \; [\mathrm{p.u.}]$$

[12] For Frequency Sensitive Mode (FSM), the AC system counterpart of the DCVSM, NC-HVDC Annex II.1.1.(c) [3] stipulates that HVDC systems must possess the capability of adjusting the droop for upward and downward upon an instruction from the relevant TSO. In practice, whether the droop for FSM is fixed over its entire exploitation period or changed regularly depend on the operational context, and both are prevailing practice. For the former, the droop is determined in the initial contractual agreement and remains fixed until this contractual agreement is renewed. In the latter case, the droop is considered as a variable that ensures the provision of FCR (Frequency Containment Reserve) services. For a practical example, please refer to [25]. Thus, the droop setting is regularly adjusted based on the portfolio of the balance responsible party and the outcomes of FCR market auctions. Theoretically, this means that the actual droop could potentially be modified every dispatch cycle.

Here, ΔU_{dc1o} is the overvoltage threshold value, s_{1o}, is the droop for overvoltage, and ΔP_{1o} is the agreed power deviation at reaching the voltage threshold value. The equation indicates that only two of the parameters ΔU_{dc1o}, s_{1o}, and ΔP_{1o} can be independently chosen, as the remaining parameter is determined as a consequence of other two. **FIGURE 28** illustrates the relation between the three parameters.

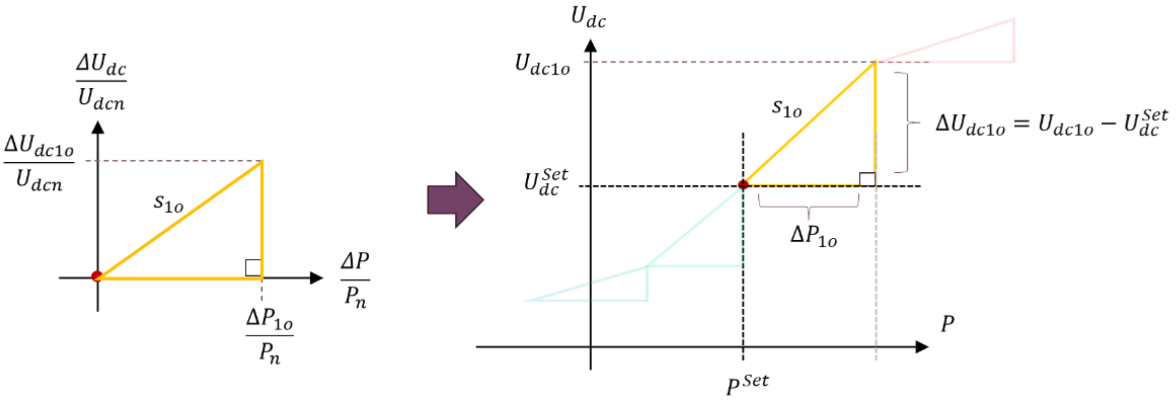


FIGURE 28: Inherent relationship between the parameters.

Given that ΔU_{dc1o} is determined by the system level DC voltage deviation threshold value, the different operational contexts can be effectively reduced to prioritizing either droop s_{1o} or power deviation ΔP_{1o}.

From the above reflection, two distinct operational contexts for the DCVSM are possible within the functional framework, namely, basic and advanced options. The choice between the basic and advanced options should be made by the system operator, considering factors such as the size of the grid and the number of converter units within the system, as well as the impact on the interconnected AC systems.

Basic option: In this option, priority is given to the droop. The droop for each AC/DC converter station or unit is fixed and is not frequently adjusted, even when operating set-points change. The droop values determine the distribution of disturbance power between converters in steady state, which shall be agreed upon and may be updated (e.g., seasonally) to reflect the changing conditions of the connected AC grids. The trade-off for this option is that the power deviation at reaching the DC voltage threshold values is no longer specifiable.

Advanced Option: In this option, the power deviation at reaching the voltage threshold is prioritized over droop. Here, the assigned quantity of power is considered a specifiable attribute for the overall system management, analogue to FCR service provision in AC systems. The droop settings of each unit are adjusted to ensure the provision of the agreed power. The droop can be theoretically updated every dispatch cycle.

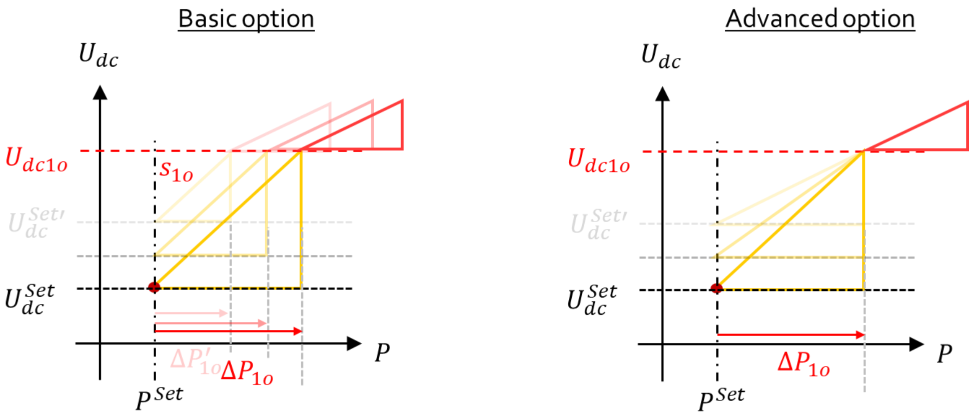


FIGURE 29: Illustrative representation contrasting the basic and advanced options, highlighting their respective impacts of the change in DC voltage setpoint and active power setpoint.

FIGURE 29 illustratively depicts the relationship between droop and the power deviation at reaching the voltage threshold in each option, highlighting their distinct impacts those options have on the change in DC voltage setpoint. In the basic option, the amount of power contribution at reaching the voltage threshold U_{dc1o} is determined by the voltage setpoint and the specified droop gain, indicating that the extent of the contribution of the AC/DC converter station or unit to maintaining the voltage within the normal operating range varies depending on the DC voltage setpoint. Conversely, in the advanced solution, the droop settings are adjusted to ensure the provision of the agreed-upon active power contribution when reaching U_{dc1o}. Ultimately, the selection between the basic and advanced options depends on the operator's assessment of the grid's needs. The primary advantage of the basic option lies in its simplicity, coupled with reduced communication and reliability issues. This benefit holds true irrespective of the grid's size. While the advanced option may allow for a more flexible system operation, it requires more sophisticated management and control systems capable of handling frequent droop adjustments.

Deadband & Insensitivity

The HVDC system owner and the relevant system operator, in coordination with the relevant TSO may agree on the implementation of deadband for DCVSM in the AC/DC converter stations or units and the capability of adjusting the deadband settings for DCVSM. The insensitivity of active power voltage response for DCVSM should be less than the value specified by the system operator.

Definitions:

Deadband: refers to an interval centred around the set-point. This is used intentionally to make the DC voltage control unresponsive.

Insensitivity: refers to an inherent feature of control system specified as the minimum change in the DC voltage or input signal that results in a change of output power or output signal.

If implemented, the deadband should be adjustable according to the operator's needs. While no stringent technical considerations mandating the implementation of the deadband have been identified, the deadband may be viewed as a mean to provide additional flexibility for the system operator, potentially used to prevent undesirable interactions. It is important for the system operator to ensure that not every converter station in the system is set to operate with a deadband, since it is essential that at least one converter in the system must regulate the DC voltage.

Concerning insensitivity, this unintentional characteristic typically arises from the measurement accuracy. The system operator shall specify the reasonable upper limit for sensor accuracy requirements, while ensuring consistency with other functional specifications.

6.5.3.2 Limited DC Voltage Sensitive Mode-Overvoltage (LDCVSM-O)

In addition to the requirements of DCVSM, the following shall apply with regard to LDCVSM-O. The AC/DC converter station or unit shall be capable of responding to DC voltage deviation in the connected DC grid according to **FIGURE 30** and the parameters detailed in **TABLE 9** and **TABLE 11**. These parameters shall be specified by the system operator within the ranges defined for each parameter.

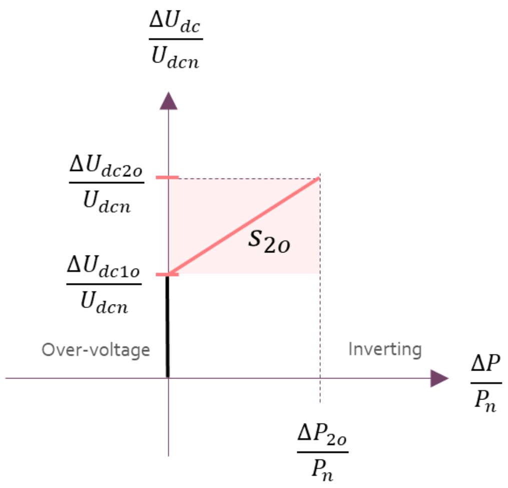


FIGURE 30: Droop capability of an AC/DC converter station or unit in LDCVSM-O.

TABLE 11: Parameters for active power voltage response in LDCVSM-O.

Variables	Definitions	Unit
ΔP_{2o}	agreed power change at reaching the voltage threshold value ΔU_{dc2}	MW
s_{2o}	droop at overvoltage	$\mathrm{p.u.}$
U_{dc1o}	overvoltage threshold value that triggers LDCVSM-O	kV
U_{dc2o}	overvoltage level below which the AC/DC converter or unit shall adjust the active power according to the parameters specified for LDCVSM-O	kV

Overvoltage level U_{dc2o}

The overvoltage level, denoted by U_{dc2o}, is defined as the DC voltage value consistent for all AC/DC converter stations or units within the DC grid. Below this level, the AC/DC converter station or unit in

LDCVSM-O must fulfil the functional requirement in accordance with the parameters specified by the system operator.

The parameters specified for LDCVSM-O applies the voltage range defined by this U_{dc2o} and the previously established overvoltage threshold value U_{dc1o}. The LDCVSM-O is triggered upon detecting an overvoltage that surpasses the threshold U_{dc1o} and is required to provide active power adjustment up to ΔP_{2o} or the specified maximum power limit. This shall be executed up to the voltage level U_{dc2o}.

Similarly to the DCVSM, this voltage level can be established independently from those defining the static DC voltage ranges defined in Section 6.2.1. However, following the convention in AC systems, it is recommended that this voltage level to be aligned with the maximum continuous DC voltage limit, i.e. $[U_{dc20}] = [U_{max}^{Cont}]$. This implies that the AC/DC converter station or unit in LDCVSM-O shall provide the specified response up to the maximum limit of the Continuous Operating DC voltage range.

Droop s_{2o}

AC/DC converter stations or units should have the capability of implementing the droop settings for LDCVSM-O.

The droop for LVSM-O can be mathematically expressed in a slightly different form compared to the case with DCVSM:

$$s_{2o} = \frac{\frac{\Delta U_{dc2o} - \Delta U_{dc1o}}{U_{dcn}}}{\frac{\Delta P_{2o}}{P_n}} = \frac{U_{dc2o} - U_{dc1o}}{\Delta P_{2o}} \frac{P_n}{U_{dcn}} \ [\text{p.u.}]$$

Here, $U_{dc2o} - U_{dc1o}$ is the difference between the system level overvoltage threshold value for LDCVSM-O and that of DCVSM, s_{2o}, is the droop in LDCVSM-O, and ΔP_{2o} is the power deviation at reaching the voltage threshold value for the LDCVSM-O. The equation above indicates that, owing to the previously established system level voltage threshold values, the degree of freedom in selecting parameters in the LDCVSM-O is governed by a more stringent triangulation relationship. This relationship differs from the case in the DCVSM, where the influence of the voltage setpoint remains unavoidable. By the principle of droop, only two of the parameters $U_{dc2o} - U_{dc1o}$, s_{2o}, and ΔP_{2o} can be independently chosen, as the remaining parameter is determined as a consequence of the other two.

Given that U_{dc2o} is to be determined as the system level DC voltage, and thus $U_{dc2o} - U_{dc1o}$ is a fixed value, two different operational contexts namely, basic, and advanced option can be considered, as previously introduced.

Basic option: In this option, priority is given to the droop over the power level. The droop for each AC/DC converter station or unit is fixed and is not frequently adjusted. The trade-off for this option is that the power deviation at reaching the overvoltage level ΔP_{2o}, which is indeed subject to the limitation of the available converter headroom, cannot be considered as a specifiable parameter.

Advanced Option: In this option, the power deviation at reaching the voltage threshold is prioritized over droop. Here, the assigned quantity of power designated for the LDCVSM-O is considered as a specifiable parameter. Subject to the constraint by the available headroom capacity of the converter, the system operator can adjust the desired power deviation at reaching the overvoltage level, ΔP_{2o}, to ensure the DC voltage security of the HVDC system, as well as the AC system security, especially when there is a congestion. The droop can be theoretically updated every dispatch cycle.

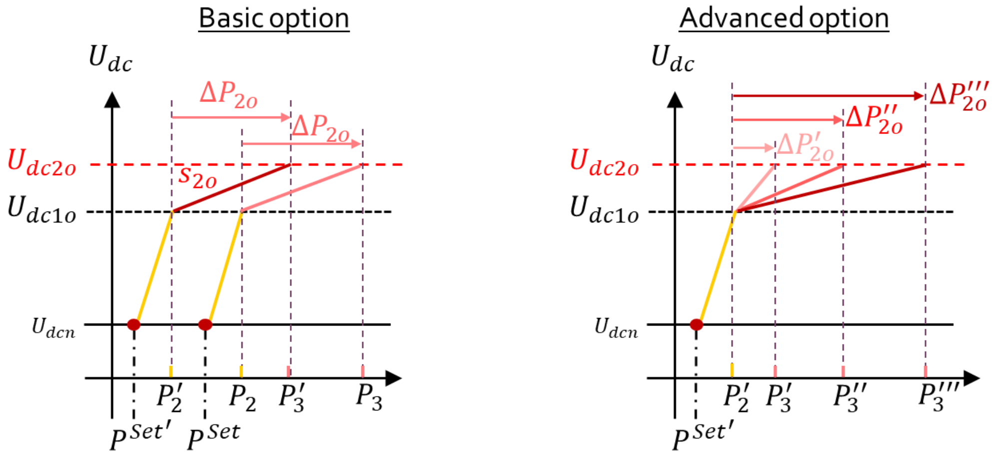


FIGURE 31: Illustrative representation contrasting the basic and advanced options in LDCVSM-O.

FIGURE 31 illustratively shows the implication associated with the two options. In the basic option, where the droop is fixed, there is no degree of freedom, and as long as it remains within the available headroom capacity, its droop contribution before reaching the voltage level U_{dc2o} is always fixed at the value determined by the assigned droop for LDCVSM. Therefore, the droop must be meticulously chosen to ensure the capability of coping with any ordinary contingencies when operating at any possible operating power set-point. In contrast, in the advanced option, the droop is determined in order to adjust the amount of contribution of the power at reaching the voltage level U_{dc2o} within the availability of the headroom capacity. Again, ultimately, the selection between the basic and advanced options depends on the operator's assessment of the grid's needs.

6.5.3.3 Limited DC Voltage Sensitive Mode Undervoltage (LDCVSM-U)

In addition to the requirements of DCVSM and LDCVSM-O, the following shall apply with regard to LDCVSM-U. The AC/DC converter station or unit shall be capable of responding to DC voltage deviation in the connected DC grid according to **FIGURE 32** and the parameters detailed in **TABLE 9** and **TABLE 12**. These parameters shall be specified by the system operator within the ranges defined for each parameter.

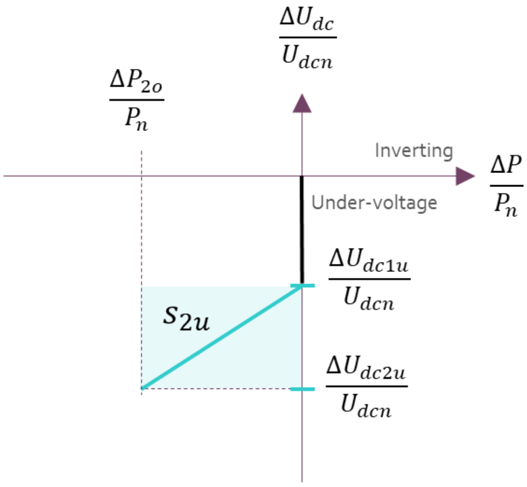


FIGURE 32: Droop capability of an AC/DC converter station or unit in LDCVSM-U.

TABLE 12: Parameters for active power voltage response in LDCVSM-U

Variables	Definitions	Unit
ΔP_{2u}	agreed power change at reaching the voltage level ΔU_{dc2u}	MW
s_{2u}	droop at undervoltage	$\mathrm{p.u.}$
U_{dc1u}	undervoltage threshold value that triggers LDCVSM-U	kV
U_{dc2u}	undervoltage level above which the AC/DC converter or unit shall adjust the active power according to the parameters specified for LDCVSM-U	kV

Undervoltage level U_{dc2u}

The undervoltage level, denoted by U_{dc2u}, is defined as the system level value consistent for all AC/DC converter stations or units within the DC grid. Above this level and below U_{dc1u}, the AC/DC converter station or unit in LDCVSM-U must fulfil the functional requirement in accordance with the parameters specified by the system operator.

The parameters specified for LDCVSM-U applies the voltage range defined by this U_{dc2u} and the previously established under threshold value U_{dc1u}.

The LDCVSM-U is triggered upon detecting an undervoltage that surpasses the threshold U_{dc1u} and is required to provide active power adjustment down to the specified maximum power limit.

Similarly to the LDCVSM-O, it is recommended that this voltage level to be aligned with the minimum continuous DC voltage limit, i.e. $[U_{dc2u}] = [U_{min}^{Cont}]$. This implies that the AC/DC converter station or unit in LDCVSM-U shall provide the specified response down to the minimum limit of the Continuous Operating DC voltage range.

Droop s_{2u}

AC/DC converter station or units should have the capability of implementing the droop settings for LDCVSM-U.

Similarly, to LDCVSM-O, the droop for LDCVSM-U can be mathematically expressed as:

$$s_{2u} = \frac{\frac{\Delta U_{dc1u} - \Delta U_{dc2u}}{U_{dcn}}}{\frac{\Delta P_{2u}}{P_n}} = \frac{U_{dc1u} - U_{dc2u}}{\Delta P_{2u}} \frac{P_n}{U_{dcn}} \text{ [p.u.]}$$

Here, $U_{dc1u} - U_{dc2u}$ is the difference between the system level under threshold value and the LDCVSM-U undervoltage level, s_{2u} is the droop for LDCVSM-U, and ΔP_{2u} is the power deviation at reaching the voltage threshold value for the LDCVSM-U. Since U_{dc2u} is to be determined as the system level DC voltage, and thus $U_{dc1u} - U_{dc2u}$, the same, basic, and advanced options can also be considered, as previously introduced.

6.5.3.4 DC Voltage Limiting Mode (DCVLM)

In addition to the requirements of DCVSM, LDCVSM-O, and LDCVSM-U, the following shall apply with regard to DCVLM. The AC/DC converter station or unit shall be capable of responding to DC voltage deviation in the connected DC grid according to **FIGURE 33** and the parameters detailed in **TABLE 9** and **TABLE 13**. These parameters shall be specified by the system operator within the ranges defined for each parameter.

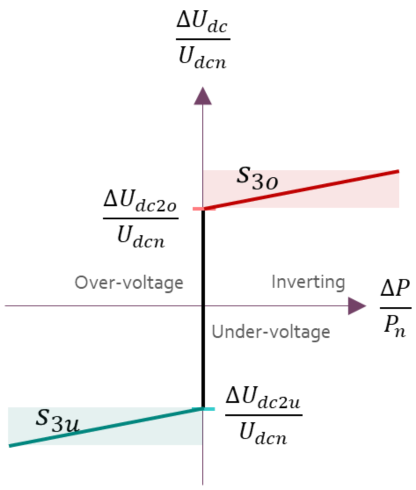


FIGURE 33: Droop capability of an AC/DC converter station or unit in DCVLM.

TABLE 13: Parameters for active power voltage response in DCVLM.

Variables	Definitions	Unit
s_{3o}	droop at overvoltage	p.u.
s_{3u}	droop at undervoltage	p.u.
U_{dc2o}	overvoltage threshold value that triggers DCVLM	kV
U_{dc2u}	undervoltage threshold value that triggers DCVLM	kV

Activation of DC Voltage Limiting Mode

DC Voltage Limiting Droop Mode shall be activated when detecting the voltage exceeding the overvoltage level U_{dc2o} and similarly below the undervoltage level U_{dc2u}.

The parameters specified for DCVLM applies the abnormal voltage range above the previously defined overvoltage level U_{dc2o} and below undervoltage level U_{dc2u}.

The DCVLM is triggered upon detecting an overvoltage that surpasses the threshold U_{dc2o} or an undervoltage below U_{dc2u}.

Expected roles of DC Voltage Limiting Mode

This mode is activated following the full engagement of the LDCVSM-O or -U. Whether the entire reserve capacity is depleted before exceeding U_{dc2o} or U_{dc2u} depends on the selected parameters and the pre-contingency operating conditions. The DCVLM becomes relevant only in the scenarios where the LDCVSM-O or -U of an AC/DC converter station or unit does not deplete all available headroom capacity before reaching the voltage threshold values, implying the potential to evacuate or inject more power.

When the excursions of the DC voltages surpass the thresholds, U_{dc2o} or U_{dc2u}, the AC/DC converter stations or units with available capacity are expected to contribute up to their maximum or minimum power limits. In instances where more than one converter is capable of additional power injection/evacuation, a power sharing mechanism is needed to prevent conflicts arising from simultaneous voltage control by multiple converters (Such as multiple converters in Fixed DC voltage control mode inadvertently work against each other.)

DCVLM is designated to address such situations. Upon activation, an AC/DC converter station or unit is expected to contribute to the voltage containment until it exhausts its maximum or minimum capability in accordance with the specified parameters.

Droop of DC Voltage Limiting Mode

Given that the primary objective of this mode is to contain abnormal voltage excursion that falls outside of the continuous operating range, the droop of this mode is naturally set to be low.

As this mode serves as an emergency measure for the system operation, it should be designed to provide a robust and reliable response. Therefore, altering the control configuration related to this mode after commissioning should not be considered.

6.5.3.5 Power Limiting Mode (PLM)

In addition to the requirements of DCVSM, LDCVSM-O, LDCVSM-U, and DCVLM, the following shall apply with regard to PLM. The AC/DC converter station or unit shall be capable of protecting itself from reaching its capability limits during transient and limiting the power to the maximum and minimum power limits P_{max} & P_{min} in steady state.

Expected roles of Power Limiting Mode

P_{max} & P_{min} are the maximum and minimum active power which the AC/DC converter station or unit can continuously exchange with the network at each connection point as specified in the connection agreement or as agreed with the relevant system operator. On the other hand, power capability limits are design parameters dependent on the manufacturer.

In steady state, power should be confined within P_{max} & P_{min}. During transient operation, power should not reach the capability limits of the converter.

The implementation of the scheme and the dynamic characteristics of this mode are subject to the discretion of the converter manufacturer.

6.5.4 Dynamic requirements for Primary DC voltage control related control modes

In the previous section, specifications for the primary DC voltage control related control modes, which determine their static bahavior were presented. In the event of a disturbance, the parameters specifying those static behavioral characteristics uniquely determine the post-contingency equilibrium state. However, they neither determine the dynamic bahavior of the system nor guarantee the system stability.

The stability of the system is determined by the dynamic response of each AC/DC converter and their interactions through the network. In a multi-vendor and multi-terminal DC grid, each converter controller would likely be unique to each vendor, reflecting different control design concepts. Moreover, the complexity of converter controller, especially those involving IP-sensitive solutions, challenges the application of conventional control design procedures in a single vendor system. Therefore, the established static requirements for the primary DC voltage control must be complemented by appropriate dynamic requirements such that the risk of interoperability issues in a multi-vendor HVDC systems can be minimized.

In this section, the implementation of DC voltage droop controller, the crucial element that characterize the system dynamics is first discussed. Then, the principal determinant factors that shall be considered in specifying the dynamic performance requirements are discussed.

Following them, a preliminary discussion for a general framework for the dynamic performance requirements and evaluation procedure for multi-vendor, multi-terminal HVDC systems is presented, acknowledging that this may require further refinement.

6.5.4.1 DC Voltage Droop Controller Implementation

First, recall that the DC voltage droop is formally defined as the ratio between the steady-state DC voltage deviation to the steady-state change in the active power of the converter, which can be mathematically expressed by

$$k = \frac{\Delta U_{dc}}{\Delta P} = \frac{U_{dc} - U_{dc}^{Set}}{P - P^{Set}}.$$

However, the actual implementation of droop controller is subject to arbitrary manipulation due to the fact that this equation is complete, determined by the specified droop, k, set-points received from the DC grid controller, U_{dc}^{Set} and P^{Set}, and local measurement, U_{dc} and P. This gives a rise to a flexibility in the derivation of different control laws from the same definition in the above equation.

In **FIGURE 34**, the proportional action by droop acts on the mismatch between the DC voltage setpoint and the measured DC voltage, modifying the active power reference which interfaces with the subordinate control layer. Assuming the power reference tracking capability of the AC power controller in steady state, the control law of this option can be expressed by:

$$P^{Ref} = \frac{1}{k}\left(U_{dc} - U_{dc}^{Set}\right) + P_{ac}^{Set} \Rightarrow P_{ac}$$

In Figure 35, on the other hand, the proportional action of droop acts on the mismatch between the active power setpoint and the measured value, modifying the DC voltage reference which is interfaced with the subordinate control layer. Assuming this time the DC voltage reference tracking capability in steady-state, the control law for this configuration can be given by

$$U_{dc}^{Ref} = k(P - P^{Set}) + U_{dc}^{Set} \Rightarrow U_{dc}$$

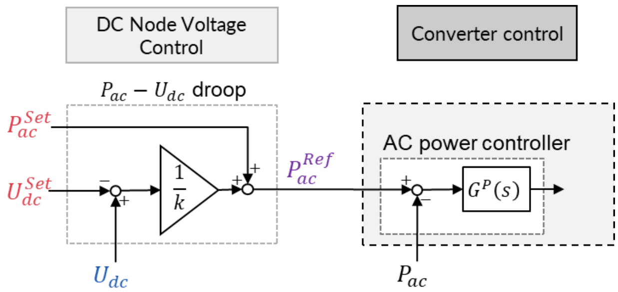


FIGURE 34: Droop implementation option 1.

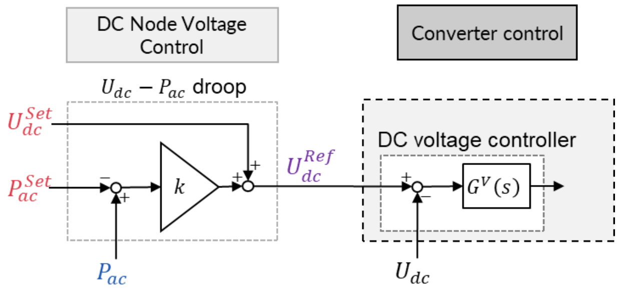


FIGURE 35: Droop implementation option 2.

The aforementioned examples theoretically demonstrate that two implementation options can both comply with the static behavioural requirement and will behave similarly in the static sense. However, the underlining difference of the cause-effect relation between the DC voltage and power could result in possible discrepancies when dynamic aspects are considered.

One such example is the implication of the droop gain as both a steady-state indicator and control parameter that impacts the dynamic response of the converter. **FIGURE 36** illustrates a use case of a three terminal DC system comprising the two DC voltage droop implementations described (Station 1 operating with option 1 and Station 2 operating with option 2), while Station 3 operates in constant power mode. The response, depicted in **FIGURE 37**, shows that the two implementations can co-exist in one DC grid in stable manner and that both lead to the same steady-state response (with the same droop gain for both stations, the two stations equally share the contribution to the primary DC voltage control). Nevertheless, due to the different implementation, the dynamic response of power for the two stations are different.

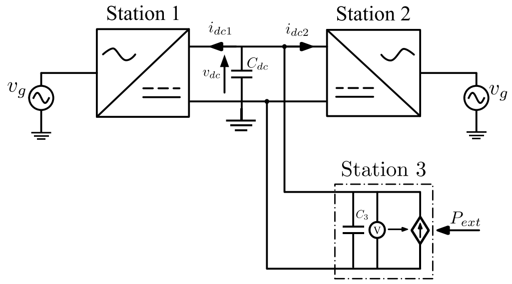


FIGURE 36: An exemplary three-terminal DC grid with Station 1 in Droop control option 1, Station 2 in Droop control option 2, and Station 3 in Constant active power control.

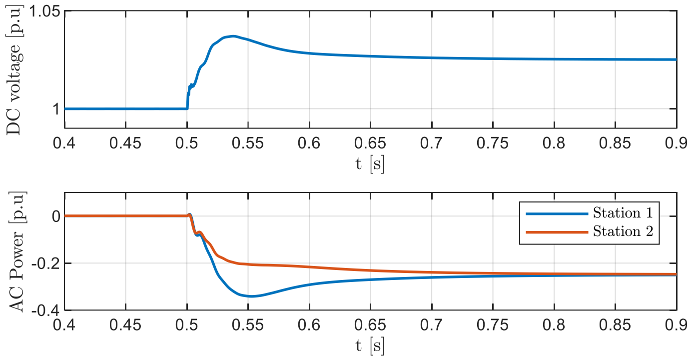


FIGURE 37: DC voltage (top) and AC power (bottom) response to a disturbance of a DC system comprising two droop implementation options.

In different scenarios, including additional analyses not detailed here, both options have demonstrated comparative performance. Despite the necessity for more in-depth exploration, particularly concerning different converter control schemes such as GFL and GFM, the evidence gathered thus far provided **no clear rational for excluding either and rather support retention of both options until and unless further analysis potentially reveals decisive factors.**

6.5.4.2 Determinant factors for system dynamics

Droop gain

From the above section, it was shown that the implication of the droop gain from a dynamic perspective is dependent on the respective controller implementation. This raises the question of the minimum and maximum feasible droop gain. In fact, referring to the control block diagrams in **FIGURE 34** and **FIGURE 35** an extremely low value of droop gain for option 1 could lead to high gain instability as the active power reference becomes more sensitive to variations in the DC voltage. Similarly, a risk of high-gain instability for option 2 comes when a high droop gain is employed, since the DC voltage reference signal becomes more sensitive to variations in the active power, rendering the controller incompatible. An example of high gain instability for option 1 is shown in **FIGURE 39**, where a four terminal DC grid (shown in **FIGURE 38**) is simulated. In the MTDC grid, two stations operate in DC voltage droop mode and the other two stations operate in constant active power control. A disturbance from station 4 is introduced to the system at $t = 2s$. A droop gain of 0.002 pu is used in the station operating with droop control option 1 which renders the system unstable.

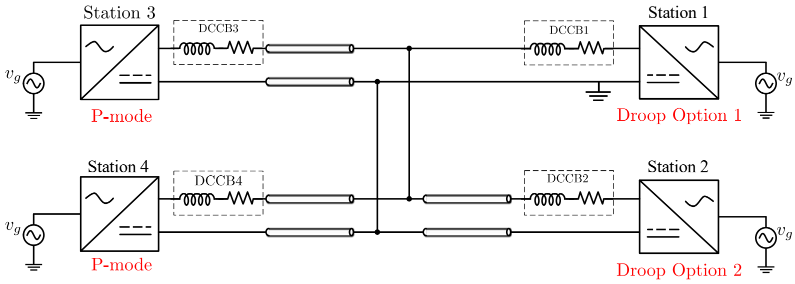


FIGURE 38: An example four terminal DC grid under study.

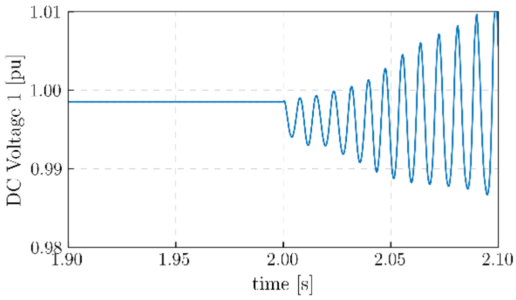


FIGURE 39: DC voltage response of a station operation with Droop option 1 at k_d = 0.002 pu.

DC reactor size

The sizing of DC reactors (DCRs) in a DC grid is commonly based on fault currents limiting considerations. However, the effect of DCRs on continuous control operation and the system response to disturbances needs to be further analysed. In **FIGURE 40** a comparison between the DC voltage response in the same DC grid depicted in **FIGURE 38** with respect to different DCR sizes is highlighted. It is clear that the DCR has a negative effect on the damping of the DC voltage. This impact should be considered in the design requirements of the DCR and the dynamic performance requirement for the primary DC voltage control.

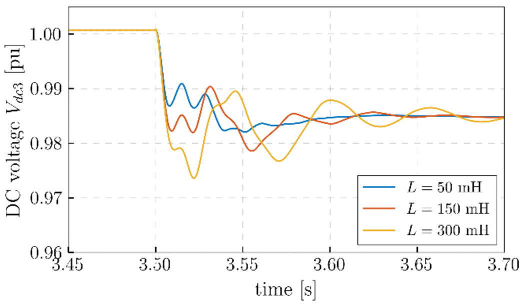


FIGURE 40: DC voltage response for different DCR values.

The negative effect of the DCR on the DC voltage damping is different for different power flow conditions. This is demonstrated in **FIGURE 41**, where two different initial power flow scenarios are compared with the same disturbance and the same system parameters. The difference between PF1 and PF2 lies in the direction of the power flow. In PF1, Fixed P control mode (P-mode) stations supply power to the DC grid, while DC voltage droop mode stations evacuate the injected power. This is inverted in PF2, where P-mode stations evacuate power from the DC grid.

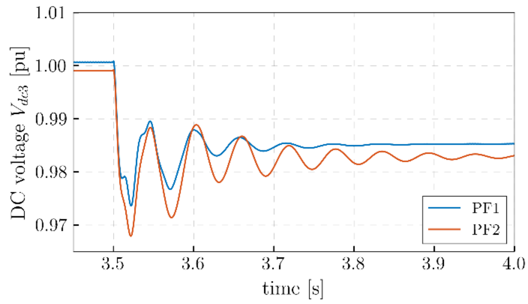


FIGURE 41: Effect of the initial power flow on the system response to disturbances. PF1: P-mode stations inject power to the DC system. PF2: P-mode stations evacuate power from the DC system.

From the above result, the negative effect of the DCR size on the damping of the DC voltage is augmented when P-mode stations operate in inverter mode. The so-called negative impedance instability of constant power loads is clearly visible. Different power flow scenarios should be included in the interaction studies of the system as well as in the compliance testing process to determine the worst case at which an MTDC could operate. If necessary, dedicated active damping controllers should be implemented.

Other determinant factors

As has been mentioned in this section, the dynamic response of the DC network is a function of both the physical elements of the grid and the active control provided by converter stations. The above two subsections demonstrated by simulation the implications of the droop gain and the DCR size on the grid's dynamic performance. However, other system constraints participate in shaping the dynamic response. These constraints include the AC grid strength alongside the internal controls of the respective converter stations.

6.5.4.3 Design space of droop

The previous section can be seen as an initial step in identifying the determinant factors that affect the system dynamic performance. A second step is to obtain a range of feasible control parameters that would satisfy both the static and dynamic requirements of the DC grid. Figure 42 illustrates that, depending on how droop control is implemented, there is either a minimum or a maximum droop gain that ensures stability[13]. By considering conservative upper and lower limits for droop gains, both implementation options can coexist in the same DC grid, ensuring a satisfactory dynamic response.

[13] In Option 1, an infinite droop gain means the system operates in a constant active power mode, while a droop gain of zero leads to high-gain instability, making Vdc-mode control unfeasible regardless of the droop gain value. Option 2, on the other hand, allows for Vdc-mode control with a zero-droop gain. A high droop gain in this case makes the system unstable, rendering the P-mode unfeasible.

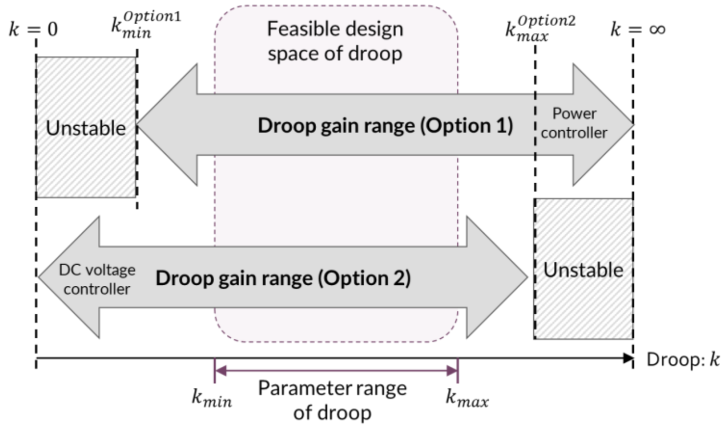


FIGURE 42: Example design space for droop gain based on the two droop implementation options.

6.5.4.4 Performance evaluation & verification procedure

In the context of multi-vendor multi-terminal HVDC systems, the applicable methods, required inputs, and constraints for conducting preliminary design studies would be significantly different from those of turnkey PtoP HVDC projects delivered by a single vendor. In such a system, although it is ultimately imperative to assess the overall system security and guarantee the absence of interoperability issues through the comprehensive system-level tests in integrated testing environment –incorporating all C&P systems together with detailed representation of the entire HVDC system equipment and adjacent AC systems in a real-time simulation framework– it is equally important to facilitate the integration process and minimize the interoperability risks by establishing the standardized DC side dynamic performance requirements upfront. In fact, this also implies setting clear expectations for the performance of each AC/DC converter station. Achieving this, however, requires several challenges to be addressed.

In the following, the consensus among the TSOs concerning the general system expectations in relation to the primary DC voltage control are outlined. Following this, the elements that have been identified as currently missing but essential are discussed, along with the necessary considerations for them.

General System Expectations/Needs for Primary DC voltage Control
The consensus on the general expectations among TSOs for the primary DC voltage control and the corresponding definition of the system-level DC voltage ranges are outlined below:

In the event of the identified worst-case scenario (for instance, the maximum sudden loss of infeed or load), the DC voltage at any node within the system shall be maintained within the predefined system-level DC voltage parameters outlined in Section 6.2, which entails:

a) Ensuring that the post-contingency steady-state voltages at any system node remain within the continuous operating DC voltage range,
b) Limiting the dynamic voltage overshoot exceeding the continuous operating DC voltage range to no more than the value specified as a percentage of the nominal voltage,
c) Ensuring that any oscillations to be settled within T_{max}^{Dyn}, and
d) Preventing the primary DC voltage control from triggering any unintentional protective actions of any equipment during such events.

In addition,

e) Converters with the same droop parameter equally contribute dynamically to the extent feasible, provided they are equidistant electrically from the source of the event and connected to AC networks with respective similar grid strength.
f) The primary DC voltage control shall not render the system unstable in any circumstance.
g) Accessibility to all related parameters to ensure the system stability considering expandability.

The relevant TSO bears the responsibility for selecting all static parameters as detailed in Section 6.2.1, which theoretically define the "***Static***" characteristics of the system for a given disturbance in the system. However, as illustrated in Section 6.5.4.1, even though having identical droop settings, two converter stations differing in droop control implementations can differ in their dynamics. This demonstrates that droop alone do not dictate the dynamic response of the converter, and consequently, the overall system dynamics. This implies that the dynamic characteristics of the overall system cannot be ascertained until the integrated testing environment is established, once that incorporates the actual and identical control solution of each vendor altogether. As a first mitigation step, it is imperative for the system operator to establish standardized "dynamic performance requirements for individual AC/DC converter stations" upfront, to which each converter manufacturer must adhere in their controller design. In addition, this should entail: 1) **Defined performance evaluation testbenches**, 2) **Definition of dynamic performance criteria**, and 3) **Specific test scenarios**.

In the following, although each topic necessitates further investigation and examination of feasibility, the plausible options and requisite considerations are outlined.

Performance evaluation testbenches

The conceptual general illustration of the performance evaluation testbench is shown in **FIGURE 43**. The AC/DC converter station or unit subject to evaluation is required to be interfaced with appropriate representation of both AC and DC system equivalent on both sides. They shall be specified by the system operator upfront and standardized for all vendors.

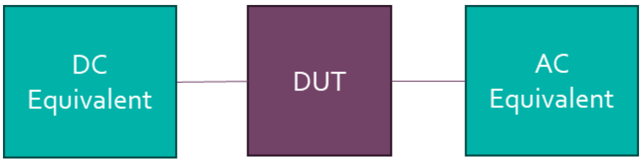


FIGURE 43: Generic illustration of device under test (DUT) connected to AC and DC grid equivalent.

Currently, there exists no standardized model for the DC grid equivalent. It is understandable that the appropriate DC grid equivalent may vary depending on whether a new converter station is to be connected into an existing system or constitutes a new system. Furthermore, any specificities in the HVDC system to be interconnected shall also be taken into consideration.

The appropriate equivalent representations may also differ depending on the type of test, the frequency range of interest, and other relevant factors. The system operator shall distinctly specify the testbench for each test scenario to be conducted.

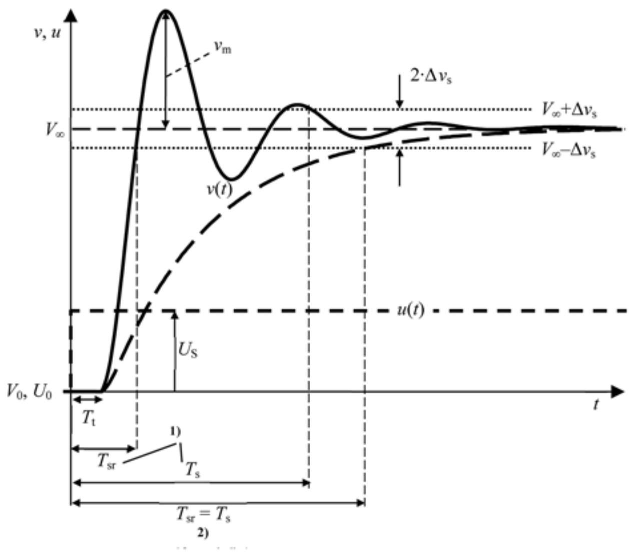
Equally important is the appropriate AC grid equivalent, which is particularly important to properly simulate the interaction between the GFL or GFM control with the DC side.

Dynamic performance criteria

The system operator should establish a comprehensive specification with which the dynamic response of the AC/DC converter station or unit must comply. A viable approach is to adhere to established formal definitions, such as those provided by IEC for step response and ramp response.

For instance, the step response, as defined by IEV 351-45-27 and depicted in **FIGURE 44**, defines the set of parameters that describes the dynamic response of a system, triggered by the application of a step function to one of the input variables. Alignment to such formal definitions could offer a fundamental basis for evaluating dynamic performance.

While the evaluation based on step or ramp responses are applicable for changes in the control inputs, e.g. reference tracking, it's equally important to assess the dynamic response to exogenous events, such as a disturbance. Additionally, incorporating the assessment of damping characteristic in the assessment can provide a more comprehensive understanding of the dynamic characteristic of the DUT.



1) Pour comportement périodique / for periodic behaviour
2) Pour comportement apériodique / for aperiodic behaviour

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 44: Definition of typical step responses of a system in IEV 351-45-27 [13].

Specific test scenarios

The appropriate system equivalents and evaluation criteria depend on the specific dynamic performance to be tested. This means that for each test scenario, the system operator shall define and specify the corresponding testbench and evaluation criteria.

Furthermore, these test scenarios should examine a range of relevant parameters, like variation of SCR value for AC system equivalent, accounting in the DC system equivalent for changes in the DC grid impedance due to a change in grid configuration and influence of the DCRs. Additionally, as suggested in Section 6.5.4.2, it is necessary to ensure the specified dynamic performance for any droop within the range predefined by the system operator.

Assessing various control configurations, including GFM mode, is also crucial for comprehensive evaluation.

While different perspectives from TSOs may be possible, compliance tests should be, in general, conducted and reported by each vendor, with the system operator provision.

6.6 Secondary DC Voltage Control

Like the primary AC frequency control, the primary DC voltage is concerned with containment of DC voltage excursions. Therefore, when a disturbance occurs in a DC grid, the primary DC voltage control will find a new equilibrium point, but it will be different from the pre-contingency DC voltage profile and power flow.

Similar to how secondary frequency control in AC systems corrects the area control error and restore the frequency to the nominal value after the primary frequency control action, the principal objectives of the secondary DC voltage control are [14]:

- To correct and maintain the active power interchange over the DC grid.
- To maintain or restore the power flow and DC node voltages within the specified limits.

It is imperative to acknowledge the fundamental difference between AC and DC systems. While the frequency serves as a global variable that reflects the generation and demand balance of the whole system, it is not the case in a DC grid as the DC voltage at each node varies due to the voltage drop across the cables and depends on the load flow conditions [15]. Consequently, unlike secondary frequency control, which dispatches power references to generators, secondary DC voltage control must transmit not only the appropriate power set-points but also the DC voltage set-points to the converter stations.

According to the optimal set-points calculated by the dedicated optimal DC power flow calculation algorithm, which takes into account the security constraints and objective function, the secondary DC voltage control ensures that the converter stations effectively track these set-points while respecting all the constraints [16].

6.7 Continuous Control Functional Requirements of Subsystems & Parameter Lists

This section provides a comprehensive summary of the functional requirements and associated parameters related to the continuous control that subsystems must comply with, in addition to those stipulated in the NC HVDC [4].

FR	Short description	Associated parameters	Subsystem
Element status analysis	The DC grid controller shall be capable to ascertain the real-time status of every element within the HVDC system.	N/A	DC grid controller
System topology analysis	The DC grid controller shall be capable of accurately determining the actual configuration of the grid topology	N/A	DC grid controller
Element limitation analysis	The DC grid controller shall be able to comprehend the actual capabilities of each converter station within the system.	N/A	DC grid controller
DC power flow optimization	The DC gird controller shall be able to calculate the optimal DC power flow, adhering to the objective function specified by the relevant TSO.		DC grid controller
Secondary DC voltage control	See Section 6.6		DC grid controller
Ramp rate coordination	The DC grid controller shall be capable of adequately coordinating the ramp rate of individual converter stations or unit to ensure the power balance during the ramping process.	N/A	DC grid controller
Offshore power curtailment	See Section 6.4.3.5		DC grid controller
Control mode management	The DC grid controller shall oversee the coordination of the control modes and their associated parameter when there is a need, such as a change of topology, according to predefined criteria.	N/A	DC grid controller
Fixed DC voltage control mode	See Section 6.5.1.1		AC/DC converter station or unit
Fixed active power control mode	See Section 6.5.1.2		AC/DC converter station or unit
DCVSM	See Section 6.5.3.1	Table 9, Table 10	AC/DC converter station or unit
LDCVSM-O	See Section 6.5.3.2	Table 9, Table 11	AC/DC converter station or unit
LDCVSM-U	See Section 6.5.3.3	Table 9, Table 12	AC/DC converter station or unit
DCVLM	See Section 6.5.3.4	Table 9, Table 13	AC/DC converter station or unit
PLM	See Section 6.5.3.5	P_{Max} & P_{Min}	AC/DC converter station or unit

7. DC grid protection

The protection of DC systems should follow the same objectives as in AC systems: Ensuring a reliable and secure HVDC system operation during contingencies and component failures. The deployment of a multi-terminal multi-vendor HVDC system protection presents new challenges compared to Point-to-Point HVDC systems where protection measures are turnkey solutions at the boundary of the HVDC system.

In a large scale HVDC system the shutdown of the entire system is not compliant with power system criteria which imposes the use of DC-FSDs in order to limit the impact for a single contingency event. In a multi-vendor context different subsystems need to work seamlessly together. For instance, different fault separation concepts and devices at DCSS level need to be compliant with FRT concepts of AC/DC converter stations in order to avoid unexpected loss of power. The functional framework should provide a guideline that allows different technical solutions to connect to an evolving HVDC system while ensuring a reliable and secure DC grid protection with respect to constraints at both AC and DC points of connection.

The outline of this section is as follows. The first sub-section 7.1 defines relevant terms in the context of DC grid protection. Sub-section 7.2 defines overarching protection system level requirements and system states ensuring a coordinated DC grid protection design while respecting AC and DC system boundary conditions. Sub-section 7.3 defines converter station DC-FRT requirements. DCSS fault separation requirements are defined in sub-section 7.4. Sub-section 7.7 provides an overview on functional requirements related to DC grid protection with assignment to the subsystems as defined chapter 4.

7.1 Terminology

7.1.1 DC grid protection function definition

- **Protection :** The provisions for detecting faults or other ordinary contingencies in a power system for enabling fault clearance, for terminating ordinary contingencies and for initializing signals or indications.
- **DC grid protection scheme :** The objective of a DC protection scheme is to keep the power system stable by isolating only the components under fault, whilst leaving remaining part as possible in operation and preventing the system from blackout, it includes the DC grid main protection and the backup protection to ensure a safe and reliable operation of the DC grid.
- **DC grid main protection (addressing the functions of several subsystems):** The primary or main protection is designed to immediately sense and respond to faults in order to isolate the faulty part of the system from the healthy part. The DC grid is divided into fault separation zones (see FSZ below). For each zone there is a specific protective scheme. When a fault occurs in an FSZ, it is the duty of the primary or main relays and protection components to detect the fault and take inherent action to isolate the faulty element.
- **DC grid backup protection (addressing the functions of several subsystems):** The backup protection provides the backup to the DC main protection whenever it fails to operate, or it is out of service for maintenance. Different types of backup protections exist:

1. Remote backup protection: Primary and backup protection are executed at different locations.
2. Local backup protection: The backup protection is performed locally by triggering adjacent switching units located at the same DC switching station.
3. Relay backup protection: Primary and backup protection relays are connected to the same switching unit. Backup protection is activated when primary protection fails to detect the fault.

> **Fault separation zone (FSZ):** A FSZ defines a zone in which a fault current can be suppressed by operation of FSD at the borders of the FSZ. Two different types of FSZ exist (for illustration, see single-line diagram in **FIGURE 45**:

> **Selective FSZ**: Comprises a single fault isolation zone which is equal to the FSZ (see **FIGURE 45**, FSZ2 and FSZ3). Fault separation function and fault isolation function are within the same switching unit. The fault discrimination functions are redundant as they cover the same zone. After fault isolation, no reconfiguration is possible.

> **Partially selective FSZ**: Comprises several fault isolation zones which are unequal to the FSZ but included within (see **FIGURE 45**, FSZ1 including FIZ1.1 and 1.2). Fault separation function and fault isolation function may or may not be in the same switching unit. The fault discrimination functions are not redundant as they do not cover the same zone. After fault isolation, a reconfiguration is possible and reclosing of the healthy part can be considered.

> **Fault isolation zone (FIZ):** A fault isolation zone defines a zone in which a fault can be isolated by operation of an RCS at the border of the FIZ.

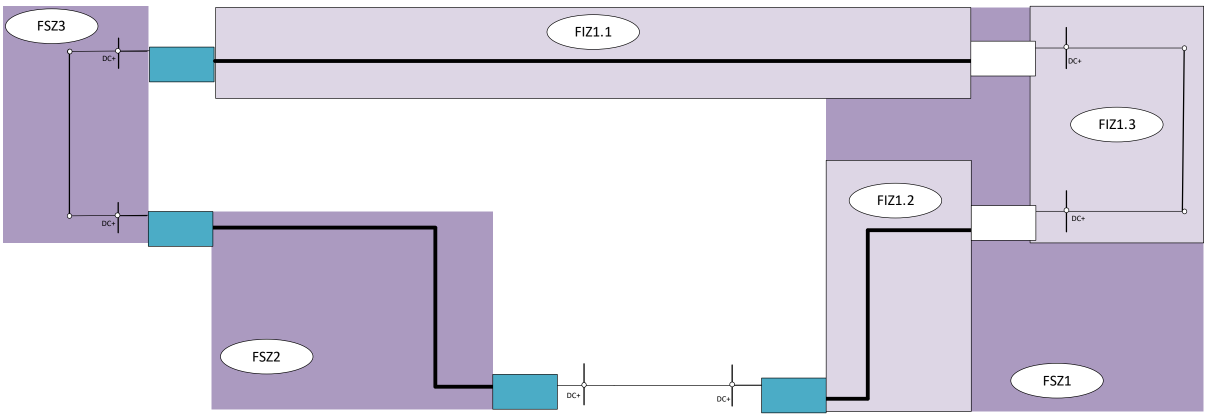


FIGURE 45 Illustration of selective FSZ (FSZ2, FSZ3), partially-selective FSZ1 including three FIZ 1.1, 1.2 and 1.3 (single pole representation)

> **DC Fault-ride-through (DC-FRT) :** Defining the required withstand capability of a converter station to remain connected during protection actions related to DC contingencies including faults, disturbances and dynamic responses.

7.1.2 Protection component definition

The following devices are of relevance for protection function executions and are part of the switching unit as defined in section 5.3.

- **Fault separation device (FSD)[14]:** Subsystem component with fault neutralization and fault current suppression capability
- **Passive fault current limiting:** Fault current limiting by passive devices, e.g. DC reactors or Superconducting Fault Current Limiters (SFCL).
- **Zone distinction device (ZDD)** [1]**:** Physical device that enables non-unit fault discrimination within a protection zone, e.g. DC reactor.
- **Residual Current Switch (RCS):** Switch with ability to break small amount of current (typically residual current) and with making current capability.

7.1.3 Switching unit protection function definition

The following protection function definitions consider a simplified FSD system level representation with ideal ON/OFF operation as shown in **FIGURE 46**. Note that the FSD is part of the switching unit. The terminology and associated times are illustrated in **FIGURE 47**.

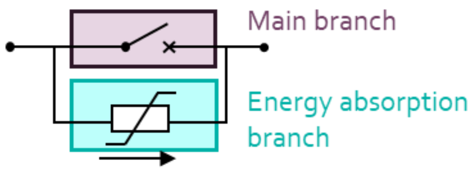


FIGURE 46 FSD system level representation consisting of main branch and energy absorption branch [17]

- **Fault detection:** Functionality to detect a fault based on local measurements of the protection relay located at unit level.
- **Fault discrimination:** Functionality to distinguish between faults inside and outside of the protection zone (located at unit level) based on local measurements only (non-unit based) or with remote end telecommunication (unit based).
- **Fault neutralization:** Fault neutralization describes the moment when the peak fault current is reached. In case of a FSD this implies that the transient interruption voltage (TIV) is sufficiently established.
- **Fault neutralization time:** The time interval between fault arrival and the instant when the fault current starts to decrease (peak fault current). Due to the TIV created by the FSD the fault is effectively neutralized and the system voltage for the healthy part of the system can start to recover [18]. The fault neutralization time includes the relay time for fault discrimination and internal current commutation time.
- **Relay time:** Time interval comprising fault detection and fault discrimination time. The relay time starts with the fault arrival and ends with the reception of the trip order at the FSD [18].
- **Internal current commutation time:** Time interval between the reception of the trip order and the reach of peak TIV.
- **Fault current suppression:** Fault current suppression describes the moment when a residual current is reached.
- **Fault current suppression time:** This is the time interval between fault neutralization and the instant when the current has been lowered to residual current level (or below) [18]

[14] For the first set of definitions a simple framework with focus on the main system-level functionality of the FSD is assumed (operating in ON/OFF mode)

> **Fault current interruption time :** Time from fault arrival until reaching residual current level.
> **Fault isolation:** Physical disconnection leading to a current zero (suppression of residual current). It should be noted that galvanic disconnection is achieved by a RCS, additional opening of disconnector switch is optional.

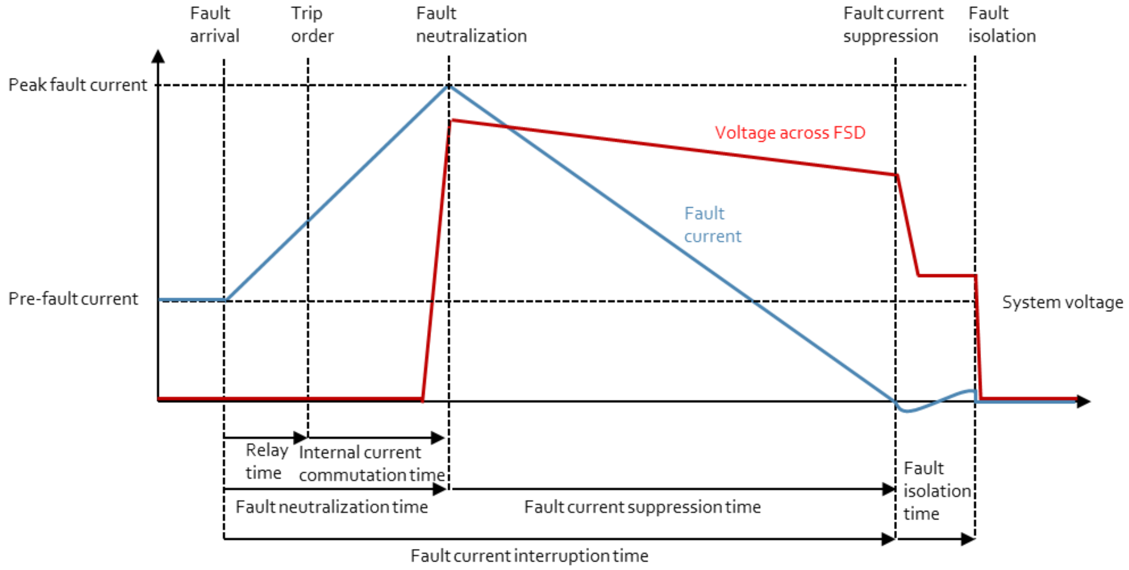


FIGURE 47 Fault current interruption process; main system functionalities of an FSD

7.2 DC system level requirements

7.2.1 Grid operating states during contingencies

The IEC TS 63291 distinguishes between normal operation, alert state, emergency state and blackout state [3]. **TABLE 14** provides a grid operating state description and provides high level examples of DC grid contingency scenarios and dedicated countermeasures and remediation actions.

> **Countermeasures** are all planned actions which react on all contingencies with the primary objective to keep the system within operational limits: Two baselines can be distinguished:
> Planned local protection actions when encountering ordinary contingency from the list of ordinary contingencies
> Local primary control actions releasing available reserves
> **Remediation actions** are additional actions which are activated when countermeasures have not prevented the system to enter emergency or blackout state. If in emergency state, remediation actions shall bring the system back to normal state before it enters black-out state. Examples are activation of energy absorber units and curtailment of PPMs.

TABLE 14 Grid operating states during DC contingencies, countermeasures and remediation actions

	Grid operating state description	DC grid contingency scenarios	Counter measures / Remediation actions
Normal state	Normal state means a situation in which the system is within operational security limits (no voltages or currents exceed operational limits).	Small deviations from scheduled load flow due to mismatch between scheduled and actual wind power production or ordinary contingencies without violation of operational limits.	Primary control provides local actions to avoid any violation of operational limits.
Alert state	Alert state means a situation in which the system is within operational security limits, but an ordinary contingency has been detected leading to major deviations compared to the initial power flow schedule. In alert state the system may not have sufficient primary reserves to encounter a second contingency. Remediation actions are foreseen to bring the system back to a normal operating state	All DC grid ordinary contingency scenarios (faults, unavailability of devices) including dedicated primary and backup protection sequences considering sufficient primary reserve.	Counter measures are foreseen to keep the system within operational limits (e.g. primary control ensures within the available reserves that operational voltage limits are not exceeded. Remediation actions are necessary to bring the system back to normal state (e.g. send out a new optimal operating point for the degraded system (see section 6.6, Secondary control).
Emergency state	Emergency state means a state in which one or more operational security limits are violated.	All extraordinary contingencies or ordinary contingencies if available reserves are depleted.	In emergency state, countermeasures are depleted. Immediate remediation actions may be required to avoid blackout state and to bring all system components back into operational limits. Coordinated protection actions may be necessary to avoid blackout state. Coordinated reconfiguration/ restoration towards a safe operating state may be necessary.
Blackout state	Blackout state means the state where the operation of part or all the transmission system has stopped.		Start-up of remaining DC grid

The classification of DC faults as ordinary contingencies is subject to TSO investigation of likelihood and risk assessment. The DC grid protection and other counter measures and remediation actions shall be designed such that for all ordinary contingencies both AC and DC systems do not run into emergency or blackout state. Note that the association of DC contingencies to either ordinary or extraordinary is not in the scope of this report as this is a question of power reliability impact, acceptable maximum loss of infeed and desired availability which needs to be carefully coordinated by system operators. A classification into ordinary and extraordinary contingencies for the InterOPERA demonstrator topology has been provided in [19].

Disturbances classified as extraordinary contingencies can cause the system to enter emergency or blackout state (see **TABLE** 15). In small DC grids with limited primary reserves intermediate remediation actions may be necessary if primary reserves are depleted (e.g. Energy absorber unit activation and PPM curtailment). As blackout state should be avoided, coordinated remediation actions may be necessary[15]. The protection design shall be coordinated in a way that it responds to the boundary conditions imposed by the system operators by eliminating unsafe conditions and prevent collateral damage in a safe and selective way. For this purpose, individual protection requirements need to be coordinated with each other. This concerns in particular the DC-FRT requirements of converters and the fault separation requirements of the DC switching station.

TABLE 15 System state after ordinary and extraordinary contingency and counter measures

	Ordinary contingencies	Extraordinary contingencies
System state	May result system in a system alert state (No violation of operational limits in post-fault operation) or in emergency state if countermeasures are depleted.	May result in a system emergency or blackout state (Violation of operational limits in post-fault operation)
Counter measures/	Protection sequence is foreseen, protection equipment is rated for fault separation. Primary control actions are activated (see section 6.5).	No dedicated protection sequence foreseen. Primary control actions are activated (see section 6.5).
Remediation action	If primary reserves are depleted, remediation actions such as energy absorber unit activation and PPM curtailment may be activated.	Remediation actions may be required, some active network elements may enter into limited mode (primary reserves exhausted) or disconnection (individual converters may disconnect due to DC-FRT violation).

7.2.1.1 Boundary conditions at AC side offshore

The state of the art for AC offshore grids is, that the offshore converter is operated in V/f control mode while PPMs operate in grid following mode. In case of offshore converter disconnection or blocking, both frequency and voltage are uncontrolled and may exceed operational limits as specified in [4]. In case of an overvoltage event, PPMs may disconnect according to AC OVRT specifications [20]. A disconnection of PPMs requires a time-consuming manual restoration sequence. Therefore, disconnection of PPMs must be considered as a permanent loss of active power. For this reason, the DC-FRT behaviour of the offshore

[15] The definition and classification of extraordinary contingencies is not in the scope of this report.

converter shall not provoke a disconnection of the PPMs by exceeding the specified OVRT limits during DC faults. Two cases must be distinguished for DC-FRT considerations:

- The converter remains in continuous operation and provides continuously a V/f-reference to the PPMs.
- The converter temporarily blocks during DC fault transients and deblocks after DC voltage recovery. When temporarily blocked, the offshore converter behaves as an uncontrolled diode rectifier and does not provide a V/f reference to the PPMs[16]. An overview of the macro-sequence is provided by **FIGURE 48**. From converter blocking to DC fault neutralization the DC voltage drop leads to a voltage drop on the AC side. After fault neutralization, DC voltage recovers leading to an overvoltage ride-through event on the AC side which persists until deblocking of converter.

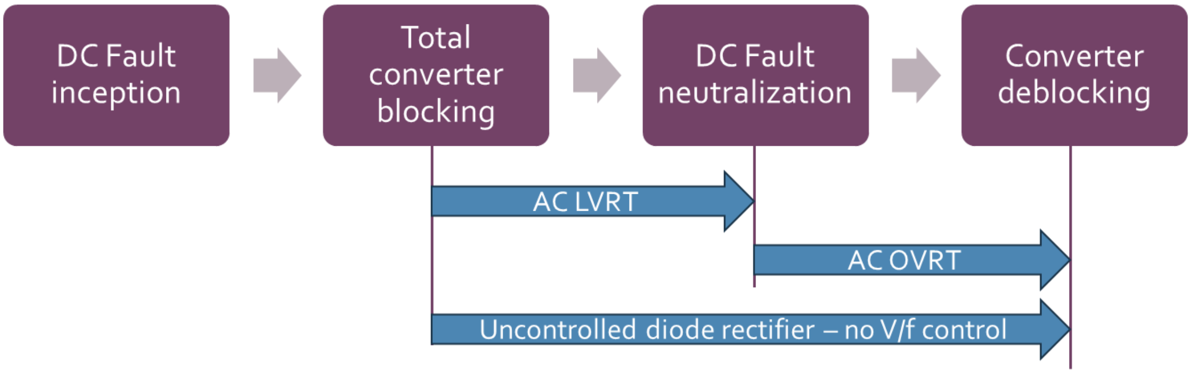


FIGURE 48 Perception of DC-FRT by PPMs in case of temporary blocking of offshore converter in V/f control

Note that in D2.2 the term "temporary islanding" is used to address DC-FRT requirements during temporary blocking of the offshore converter. In addition, alternative grid forming control concepts for PPMs have been proposed to facilitate a DC-FRT with temporary offshore converter blocking [2].

The temporary blocking of the offshore converter during DC fault transients is compliant as long as voltage and frequency ranges at the AC side do not lead to a disconnection of PPMs. To ensure this, an alignment between OVRT requirements of PPMs and DC-FRT requirements of the converter station is needed. A coordinated requirement is subject to further investigation and will be addressed in the final version of this report. Applicable AC requirements for offshore PPMs such as OVRT profiles and frequency deviation limits as well as other limits (e.g. loss of synchronization due to phase jumps) shall be considered and carefully assessed.

7.2.1.2 Boundary conditions at AC side onshore

HVDC power loss characteristics should at least comply with existing AC requirements. Any power loss in the DC grid should be less than the maximum loss of infeed for the considered AC zone. The permanent loss of active power shall comply with the Frequency Restoration Reserve (FRR) of the corresponding bidding zone (see exemplary values in **TABLE 16**). It should be noted that respecting those limits is a planning issue which depends on boundary conditions and reliabilities assumed on AC and DC side (e.g.

[16] Considering decoupled operation of positive and negative pole at the offshore side. Note that in case of coupled operation during a PtG fault, the V/f control would be ensured by the healthy pole converter.

classification of ordinary and extraordinary contingencies according to availability data and risk assessment of the relevant TSO). More explicitly, ordinary contingencies on the DC side shall respect the maximum loss of active power of surrounding AC grids and existing requirements at the AC-PoC as stipulated in [4].

TABLE 16 Boundary conditions in surrounding AC grids

Related AC parameter	Value
Maximum loss of infeed	UCTE: 3 GW Nordic grid: 1,4 GW
FRR per bidding zone	Dependent on country

7.2.2 DC grid protection coordination

As part of DC grid protection coordination, fault separation zones (FSZ) shall be defined such that all ordinary contingencies are isolated while respecting AC boundaries as defined above. The FSZ shall in particular respect the maximum loss of infeed constraints from surrounding AC grids and ensure stable DC grid operation after fault separation.

The switching units at the boundaries of FSZs shall be equipped with FSDs which are capable of separating all ordinary contingencies within a maximum fault neutralization time $T_{N,max}$.

Converters outside a fault separation zone will remain connected to the DC grid and are expected to recover and operate after fault separation[17]. The main purpose of the DC-FRT profile at the PoC of the converter is to ensure:

- Converter connection during fault separation
- Converter operation after fault recovery
- Safe disconnection of the converter in case of protection failure

FIGURE 49 provides an illustrative example on FSZ definition and operational expectations after fault separation. Faults in FSZ1 and FSZ2 are expected to be separated by associated switching units with DC current breaking capability (blue color). The converter station is outside FSZ1 and FSZ2 and is therefore expected to be operational after fault separation which is ensured by a DC-FRT profile as introduced in section 7.3. For faults in a FSZ3 the fault separation sequence involves the activation of both FSD on the DC side and the ACCB on the AC side of the converter. The activation of the ACCB is ensured by a dedicated fault detection and discrimination function for FSZ3. The example underlines the following points:

- **Converter station inside FSZ:** The DC-FRT profile does not apply for ordinary contingencies in protection zones which involve AC Circuit Breaker (ACCB) operation.

[17] Note that all elements inside a FSZ including converters are separated from the DC grid and out of operation after fault separation. In this case, the triggering of the ACCB is part of the protection sequence and shall not be confound with triggering when exceeding the DC-FRT profile which is due to protection failure

- **Converter station outside FSZ:** The converter station is expected to operate after fault separation. This involves to respect on the one hand the DC-FRT requirements and on the other hand relevant AC side requirements[18]

The following sections 7.3 and 7.4 define respectively DC-FRT requirements for AC/DC converter station and fault separation requirements for DCSS.

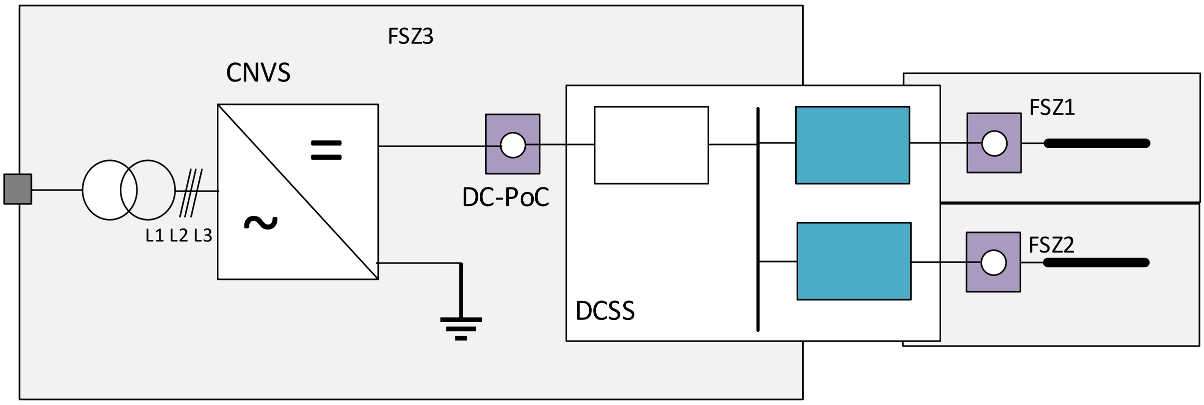


FIGURE 49 Illustrative example on fault separation zone definition and DC-FRT profile application at DC-PoC; blue and white boxes inside a DCSS indicate respectively switching units with and without FSD

7.3 DC-FRT requirements of converters

Disclaimer: To ensure a certain degree of technological openness, this deliverable describes all possible ways of riding through DC faults. The relevant TSO decides whether functions such as "temporary blocking" can be used as a protective function in the event of DC faults. Especially as continuous operation in the healthy protection zones has a very high priority for the TSOs and the impact on the AC grids (offshore and onshore) shall be as small as possible in order to guarantee the overall system stability. To provide a sufficient basis for such decisions, detailed information on the behavior of the converters and the resulting effects – including the impact on the AC grid – will be presented in the later version of this deliverable. Further investigations shall be focused for example on whether all phases are or only individual phases are blocked, how long the blocking process takes, how long it take to reach the pre-fault operating point (or the new operating point as adjusted by the grid controller) and in particular, how many converters could be affected and what is the impact for the AC on- and offshore grids.

In the AC grid code, the FRT requirement serves as a means to define the capability of the converter to stay connected during low voltage conditions. Based on this, a disconnection of generating or power exchanging units during protection action is avoided when outside the protection zone. The AC-FRT description is generic in the sense that it is not topology dependent and does not consider the specific performance of the AC switchgear. It neither distinguishes between a FRT curve for primary or backup protection nor between individual FRT curves for each protection zone in the AC grid. There is one single

[18] Requirements may be different depending on onshore or offshore grid connection

FRT curve ensuring a clear functional split between withstand capability of the generating / power exchanging unit and fault clearing of AC switchgear [4].

In the IEC TS 63291, a design / topology dependent approach for the converter DC-FRT definition has been chosen following a protection zone matrix approach. Different operational concepts for each PoC-AC and each PoC DC are defined: Continued operation (CO), Temporary stop (TS) and permanent stop (PS). For each converter in the HVDC system a protection coordination matrix is established which defines the operational behaviour requirement for each fault separation zone and each protection sequence (primary/backup) individually. Hence, the converter FRT requirement changes depending on the location of the fault and the associated protection sequence. With such a design / topology dependent approach, a DC-FRT curve would need to be defined for each operational concept and each protection sequence with a dependability between converter FRT and fault clearing. In addition, the temporary stop in the same DC grid may lead to a different state of the AC grid depending on AC system characteristics (e.g. network strength, clearing times, onshore or offshore connection).

FIGURE 50 shows an example following the design / topology dependent approach proposed by the IEC TS 63291. A converter unit is inside FSZ3 and connected to FSZ1 and FSZ2 via a DC switching station. The converter has an individual FRT requirement for each FSZ. It should remain in continued operation (CO) for FSZ1, temporary stop (TS) is allowed for FSZ2 and a permanent stop (PS) is foreseen for FSZ3. Focusing first on FSZ1 and FSZ2, the converter FRT compliance cannot be ensured by the converter unit itself. It rather depends on the design of the individual switching unit connection FSZ1 and FSZ2. In fact, with this approach a strong coordination between the converter design constraints (e.g. overcurrent capabilities) and the switching unit design constraints (FSD operating time, fault current limiting device) is unavoidable. For a busbar fault (inside FSZ3), the converter unit is in permanent stop, meaning permanent disconnection on both AC and DC side. The definition of FSZ3 and the assignment of a converter behaviour is an example of how in a topology / design dependent approach fault separation and converter FRT definition are interdependent. A converter FRT definition for a FSZ covering the converter itself is obsolete since fault separation is handled by converter protection actions.

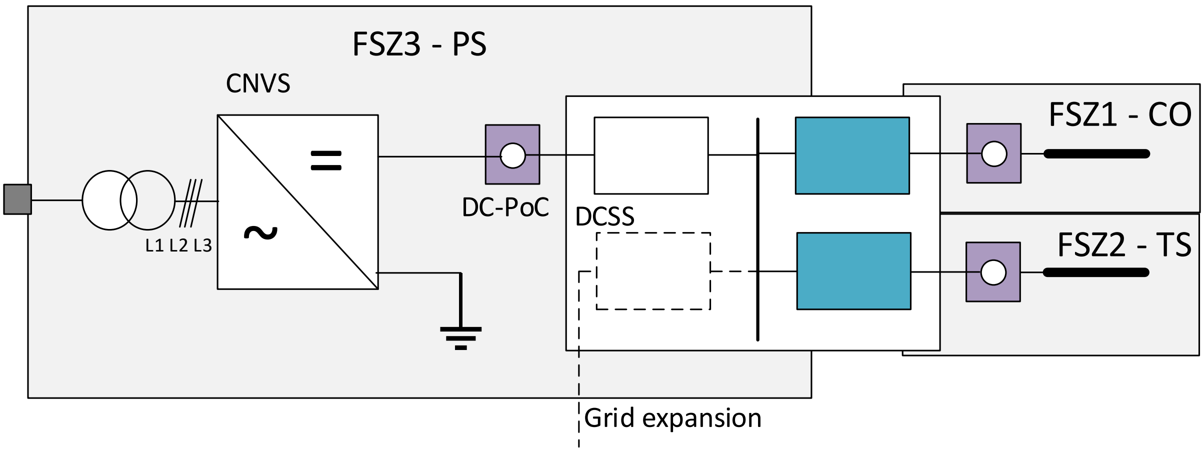


FIGURE 50 Example of design / topology dependent DC-FRT description (based on [3])

Extending this example further, a future grid expansion consisting of an additional converter connection to the same busbar as indicated by the dashed line in a design dependent approach reveals the question of inclusive grid design. To which extent does the initial design of the first converter unit (e.g. overcurrent capabilities) and the switching units (e.g. fault neutralization time, fault current limiting device and current breaking capability) restrict other subsystems with lower performance to connect at a later stage?

A design-based approach is tentative for small MTDC grid configurations as it potentially leads to an optimized design for a given sub-grid or node and connected converter stations and DC switching stations. However, a design-based approach implies a strong coordination of key design parameters between subsystem vendors. For instance, the fault current limiting devices (e.g. DC reactors, SFCL, ...) need to be coordinated between DCSS and converter station such that it corresponds to the transient withstand capabilities of the converter (e.g. overcurrent limit, energy limit, ...) with respect to the fault neutralization time of the FSD and the respective current breaking capability. Any advanced FRT functionality such as temporary blocking or energy-based control would need to be assessed individually.

Different approaches of defining DC-FRT capabilities have been discussed within the DC grid protection workstream. They differ mainly in terms of genericity (generic or design / topology dependent) and the quantity they are expressed in (DC voltage or DC current). An evaluation of different DC-FRT profiles based on the following criteria is provided in appendix 9.3. The following sub-sections describe the resulting DC-FRT profile and relevant parameters.

- **Technological agnostic:** Are the functional requirements permitting different technological solutions or are they restricting, excluding certain technologies?
- **Functional split:** Are functional description and design of subsystems independent? How to split functional responsibilities?
- **Oversizing :** Does the decoupling of subsystem requirements and the genericity / system independence generate an oversizing?
- **Standardization:** Is the DC-FRT description subsystem-dependent or generic? Do several DC-FRT profiles co-exist?
- **Verifiability :** Can the DC-FRT profile be specified at the DC-PoC based on local measurements?

The functional requirements apply at the DC-PoC of the converter station. All parameters that are defined in the following refer to verifications at the DC-PoC, DC voltage specifications are pole-to-ground voltages (see $U_{DC\text{-}FRT}$, **FIGURE 51**).

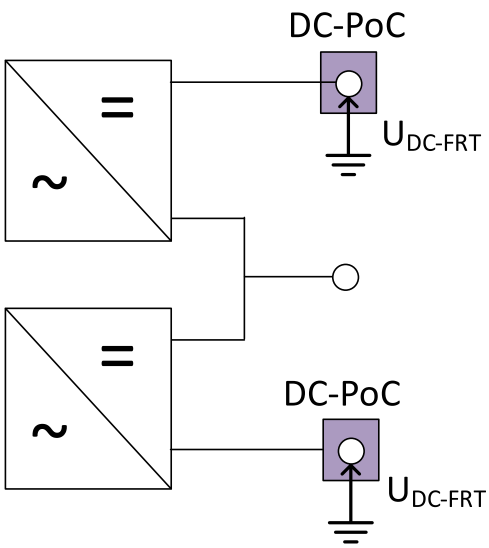


FIGURE 51 AC/DC converter station - illustration of reference point for DC-FRT definition

7.3.1 Low voltage ride-through (LVRT) requirements

Disclaimer: Different approaches of defining DC-FRT profiles have been discussed within the DC grid protection workstream. Appendix 9.3 shall be seen as a complementary section providing background information on alternative descriptions highlighting the main differences and outlining advantages and drawbacks of each DC-FRT profile. This annex documents the author's interpretation of the current status of ongoing technical discussions with regards to DC-FRT. A final assessment of the presented options must be based on technical and economical evaluations which cannot be fully concluded in the scope of InterOPERA.

To leave freedom to the vendors to come up with different design strategies, only a DC-LVRT profile is described, and no overcurrent capabilities are prescribed. The actual fault current level in the converter is left unspecified and then depends on the design strategy of the converter's vendor. It can be the result of converter control or of its protection. Converter control requirements for DC grid voltage stability may somehow frame the converter's fault current contribution during a voltage dip. But different technical solutions for converter protection may exist and lead to differentiated fault current contributions. The IGBT components are highly sensitive to overcurrents, and limits may vary depending on the vendor. To protect them, different solutions to limit the increase of converter fault current during DC faults exist:

- The limitation of current increase can be adjusted by means of fault current limiting devices such as DC reactors.
- Some sub-module topologies (e.g. full-bridge) allow to control fault currents.
- For half-bridge topology, innovative temporary blocking can further avoid damage of IGBTs by taking them out of the circuit during transients while ensuring stable operation after DC voltage recovery.

The LVRT profile that the converter shall withstand is meant to be an outer envelope including all realistic undervoltages related to faults in a DC system that do not depend on the converter fault current contribution which is vendor specific and depending on the individual technical solution. This can be at the cost of oversizing.

Connection requirement (CR): The primary requirement of the converter station during a DC-FRT is to stay connected from fault arrival to fault current suppression and to ensure stable operation after DC grid recovery. Hence, any disconnection that leads to permanent loss of active power as for instance the triggering on an ACCB shall be avoided. The connection requirement is ensured by a DC voltage FRT profile which defines a conservative outer envelope related to DC fault transients (see **FIGURE 51**, solid line). Characteristic values are listed in **TABLE 17**. Further reasoning on the determination is provided in the following sub-sections.

Operational requirement (OR): DC faults lead to transients with significant undervoltages at the DC-PoC of the converter. From fault arrival until DC voltage recovery, the converter station is mainly exposed to the fault transients with limited controllability of active power. Imposing continued operation with full controllability would impose major design constraints on the converter even though the purpose is not clear. **Therefore, the operational requirement is limited to the definition of the converter operation after DC voltage recovery: The converter shall continue stable operation after the power system has recovered following fault clearance.** The way the converter respects those requirements is a technical solution, not a requirement[19]. CO, TS or any other intermediate solution is authorized from fault arrival to

[19] It should be noted that the technical solution shall be compliant with requirements that apply at both AC-PoC and DC-PoC.

DC voltage recovery as long as a trip/disconnection on AC or DC side is avoided and stable operation after voltage recovery is guaranteed.

The operational requirement is represented by the dashed lines in **FIGURE 52**. $U_{UV4\text{-}1}$ is a blocking limit under which the converter is allowed to block if no grid serving requirement until fault neutralization is prescribed (see section 7.3.5). $U_{UV4\text{-}2}$ is a voltage limit at which the converter shall be able to deblock[20]. $U_{UV4\text{-}1}$ and $U_{UV4\text{-}2}$ shall be aligned with the dynamic voltage control bands that are defined in section 6.2.2 and the diode rectifier voltage level after fault separation in case of small DC grids. In extended DC grids $U_{UV4\text{-}2}$ is linked to dynamic voltage bands. The diode rectifier voltage condition applies for small DC grids as a worst-case assumption considering temporary blocking of all converters. Note that the number of simultaneously blocking converters can be limited by applying a firewall functionality to individual switching units to ensure limited voltage drop in adjacent sub-grids. The maximum number of simultaneously blocked converters depends on the grid design and risk assessment of the relevant TSO. The necessity of such a requirement will be assessed in the final version of the deliverable.

It is evident that the converter shall be capable of controlling voltage and current quantities inside dynamic voltage bands and ensure stable operation with absence of blocking. Whenever the converter blocks during a DC-FRT within the CR, deblocking shall be ensured after DC voltage recovery to dynamic voltage bands within a maximum deblocking time ΔT_{dblk}. For the specification of ΔT_{dblk}, maximum fault current suppression times and converter process times for deblocking shall be considered.

Outside of dynamic voltage bands, the converter can ride through the fault by different means: CO, TS or any other intermediate solution is authorized as long as a trip/disconnection on AC or DC side is avoided and stable operation after voltage recovery is guaranteed.

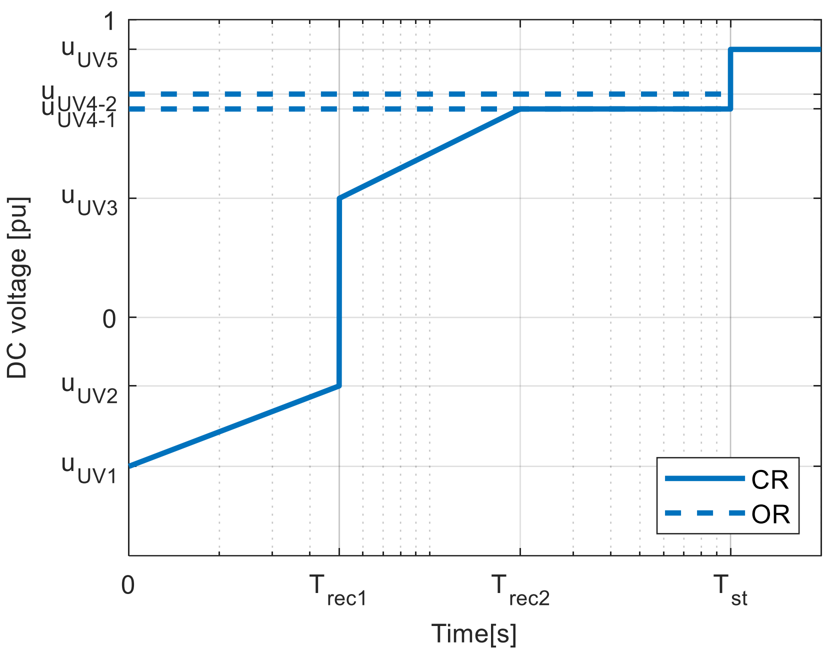


FIGURE 52 DC undervoltage FRT profile at DC-PoC for connection requirement definition, Pole-to-Ground voltages

[20] It should be noted that the blocking limit $U_{UV4\text{-}1}$ is optional, the converter may or may not block during DC fault transients. This depends on the technical solution and capability of the individual converter. However, if blocked the deblocking above $U_{UV4\text{-}2}$ is mandatory within ΔT_{dblk}.

TABLE 17 Characteristic parameters related to DC-FRT

Parameter	Require-ment	Description	Parameter definition
U_{UV1}	CR	Worst-case undervoltage related to fault arrival considering traveling wave reflection at inductive terminations. k_{TW} is an adjustment factor.	$U_{UV1} = k_{TW}\, UV_{max}$
U_{UV2}	CR	Worst-case undervoltage related to fault arrival considering traveling wave reflection at inductive terminations for distant faults considering cable damping by adjustment factor d_c.	$U_{UV2} = k_{TW}\, d_c\, UV_{max}$
U_{UV3}	CR	Partial instantaneous recovery voltage level after fault neutralization	
U_{UV4-1}	CR & OR	Optional undervoltage blocking limit outside minimum dynamic voltage bands U_{min}^{Dyn} considering a security margin k^{Dyn}. In the transient region, the converter is allowed to block below this limit.	$U_{UV4-1} = k^{Dyn}\, U_{min}^{Dyn}$
U_{UV4-2}	OR	Deblocking threshold after full system voltage recovery to minimum dynamic voltage bands U_{min}^{Dyn}. If the converter is blocked in the transient region, the converter shall deblock above this voltage limit. The deblocking shall be ensured within a maximum deblocking time ΔT_{dblk}.	$U_{UV4-2} = U_{min}^{Dyn}$
U_{UV5}	CR	Full voltage recovery to minimum static voltage bands[21] U_{min}^{Cont} considering a security margin k^{Cont} to avoid unwanted and irreversible converter disconnections.	$U_{UV5} = k^{Cont}\, U_{min}^{Cont}$
T_{rec1}	CR	Maximum partial voltage recovery time related to fault neutralization time[22] $T_{N,max}$ considering a security margin T_b (buffer time). Note: The maximum fault neutralization time may include backup protection. In case of backup protection T_{rec1} would be at least two times the maximum fault neutralization time of the FSD	$T_{rec1} = T_{N,max} + T_b$

[21] Static voltage bands to be aligned with static voltage control bands, see section 6.2.
[22] Fault neutralization time includes both relay time and Internal current commutation time [17]

T_{rec2}	CR	Maximum full voltage recovery time to dynamic voltage bands	/
T_{st}	CR & OR	Maximum full voltage recovery time to static voltage bands	/
ΔT_{dblk}	OR	Maximum deblocking time after system voltage at DC-PoC reaches dynamic voltage bands. For the specification of ΔT_{dblk}, maximum fault current suppression times and converter process times for deblocking shall be considered.	/

Exceptions

There are exceptions where the DC-FRT profile does not apply, mainly when the activation of the ACCB is part of the protection sequence and a dedicated fault detection and discrimination function is foreseen to immediately trigger the ACCB.

- **Converter station inside FSZ:** The DC-FRT profile does not apply for ordinary contingencies in protection zones which involve ACCB operation. For such faults there shall be dedicated detection function → Immediate trip (see illustrative example in **FIGURE 49**).
- **Internal converter station faults:** The DC-FRT profile does not apply → Immediate trip
- **Backup protection sequences** which lead to an isolation of the converter unit

7.3.2 LVRT parameter description

7.3.2.1 From fault arrival to fault neutralization

This sub-section focusses on characteristic parameters during transients and more precisely from fault arrival to fault neutralization.

T_{rec1}

The maximum fault neutralization time $T_{N,max}$ characterizes the maximum time between fault arrival and full establishment of the Transient Interruption Voltage (TIV) of the FSD including the relay time for fault discrimination. T_{rec1} shall be defined such that no FSD solutions are excluded due to operating time constraints while considering a sufficient relay time for fault discrimination and sufficient security margin to avoid any unnecessary trip of converters which could lead to a higher loss of active power than planned. For the definition of T_{rec1} the following points shall be considered:

- Maximum fault neutralization time of a FSD for primary protection
- Maximum fault neutralization time of a FSD for backup protection (if applicable)
- Buffer time (Security margin)

U_{UV1} & U_{UV2}

The LVRT profile should represent an outer envelope including all realistic undervoltages related to faults in a DC system that the converter shall withstand without depending on the specific converter fault current contribution which is vendor specific and without depending on the individual technical solution[23]. The DC-LVRT profile is described based on undervoltages related to fault transients. Considering a DC fault, the most severe voltage drop is not caused by the closest fault but by a fault on a conductor due to traveling wave reflection at the terminal [21]. **FIGURE 53** compares voltage and current evolution for a fault at the cable termination and a distant fault on the cable. The distant fault provokes a voltage reversal at the cable termination which leads to a temporarily steeper increase of fault current.

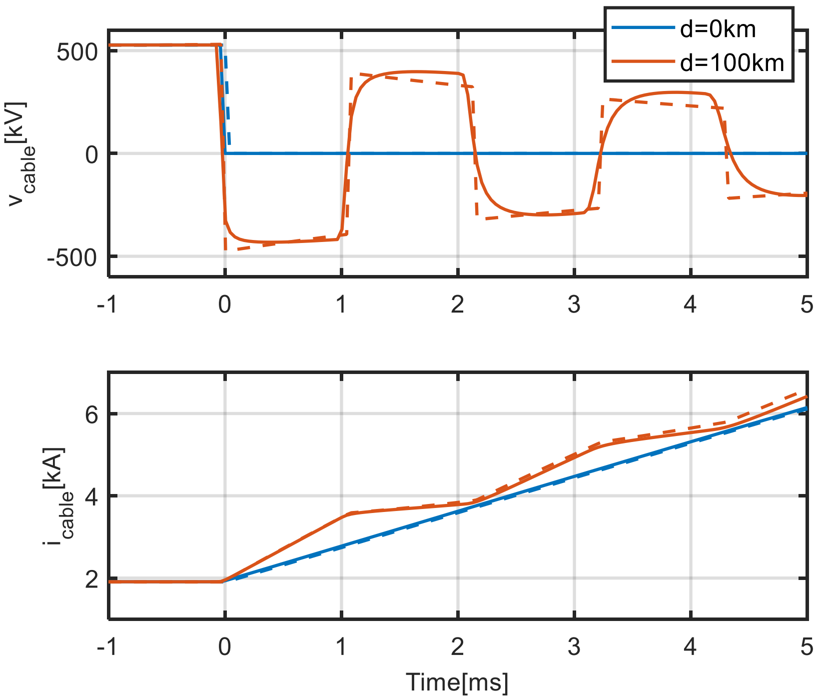


FIGURE 53 Comparison between close fault (blue) and distant cable fault (red); Voltage drop at cable termination (top), DC current evolution (bottom); solid line: frequency dependent cable model, dashed line: traveling wave approximation [21]

Theoretically, the traveling wave reflection at a conductor termination may lead to severe voltage drops of up to 2pu. This gives a first boundary for a conservative outer voltage envelope at the DC-PoC[24] from fault arrival to fault neutralization. It should be noted that a minimum impedance between the DC-PoC of the converter and the fault is not specified. This is mainly due to the fact that the main requirement of the DCSS is to separate the fault in a given time $T_{N,max}$ but a specific device to limit the increase of fault current is not imposed (e.g. a DC reactor). At this stage, it would not be appropriate to restrict the fault current limiting to a specific device or value. With this in mind, the outer voltage band due to fault transients at the cable termination shall be considered as a withstand requirement at the converter DC-PoC. The outer voltage envelope has been assessed by using a simplified traveling wave generating model for various fault distances as shown in **FIGURE 54** for $T_{N,max}$=5ms (more information on the model is provided in [21]). Even though the approach is simplified, and the values have pure illustrative purposes, it shows how

[23] Connection requirement and associated withstand capabilities mean to avoid any disconnection, the operation itself during fault transients is not specified. For instance, temporary blocking, fault current control or any other mean to withstand the fault transients are allowed.
[24] A requirement on a specific fault current limiting device (type and minimum value) is not defined at DCSS level.

an outer voltage envelope for the DC-PoC of the converter can be defined between fault arrival and fault neutralization independently from the converter type. The converter type, rating or control may or may not have an influence on the actual voltage at the DC-PoC but this does not change the outer envelope related to DC fault transients. This outer envelope related to fault transients is represented in the DC-FRT profile shown in **FIGURE 55**. For this example, the buffer time was assumed to be zero, hence $T_{rec1}=T_{N,max}$.

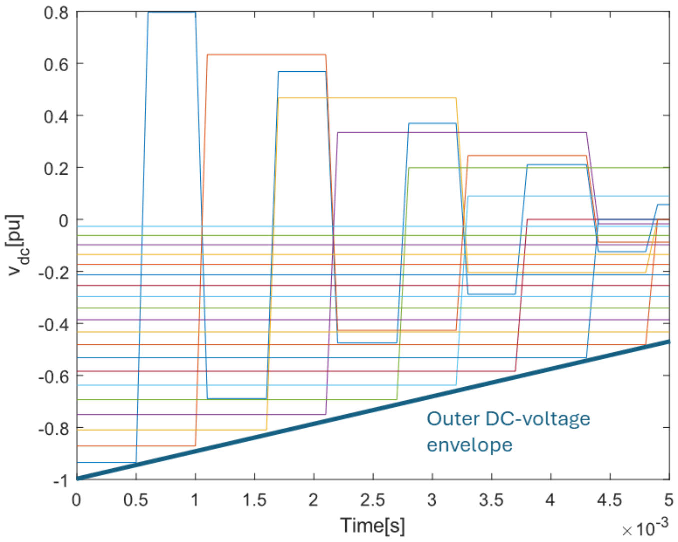


FIGURE 54 Investigation on outer DC voltage envelope using a simplified traveling wave generating model with variation of fault distance for $T_{N,max}$=5ms (example)

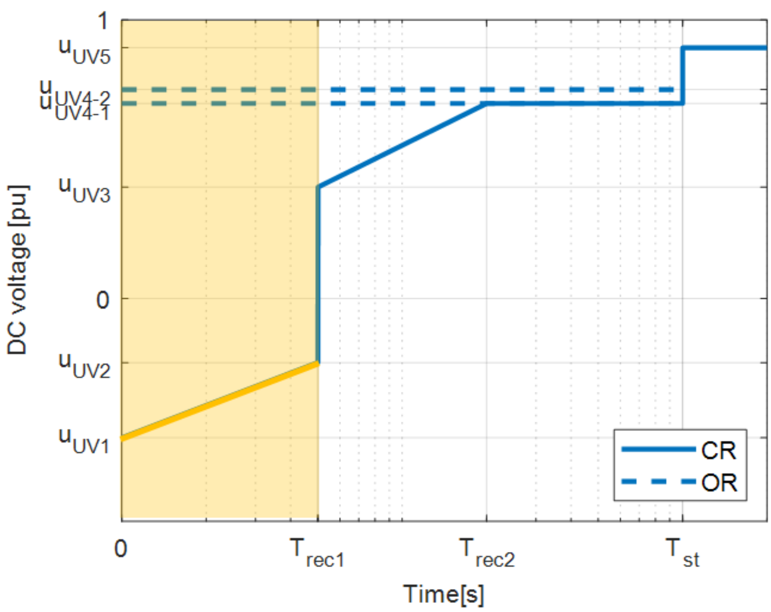


FIGURE 55 Outer voltage envelope defining the converter withstand capability at the DC-PoC from fault arrival to T_{rec1}

Minimum impedances or other considerations which lead to a narrower voltage band during fault transients for $U_{UV1}$and U_{UV2} may be considered by an adjustment factor $k_{TW} < 1$. For U_{UV2} a damping coefficient of the cable d_c shall be considered. The adjustment factor k_{TW} shall ensure that U_{UV1} and U_{UV2} provide a realistic outer envelope for DC system undervoltages before fault neutralization.

$$U_{UV1} = k_{TW}\, UV_{max}$$

$$U_{UV2} = k_{TW}\, d_c(T_{Nmax})\, UV_{max}$$

7.3.2.2 Maximum recovery time to dynamic and static voltage bands

DC voltage recovery starts with the full establishment of the TIV. For converters in close vicinity of the fault the imposed TIV leads to an instantaneous increase of voltage at the DC-PoC. For distant converters the voltage drop is likely to be less severe, but the voltage recovery time is longer. The DC-FRT profile shall provide an envelope for both cases, avoiding unnecessary disconnections of converters.

The DC voltage recovery process is specified by the following parameters:

- **U_{UV3} (T_{rec1}):** Minimum voltage recovery level at fault neutralization. In order to keep the voltage FRT profile as simple as possible, there is no time frame associated leading to a vertical representation.
- **$U_{UV4\text{-}1}$**: Optional undervoltage blocking limit outside dynamic voltage bands (see dynamic control bands, section 6.2.2) considering a security margin k^{Dyn}. In the transient region, the converter is allowed to block below this limit.

$$U_{UV4-1} = k^{Dyn}\, U_{min}^{Dyn}$$

- **$U_{UV4\text{-}2}$ (T_{rec2}):** Deblocking threshold after full system voltage recovery to dynamic voltage bands (see dynamic control bands, section 6.2.2). If the converter is blocked in the transient region, the converter shall deblock above this voltage limit. The deblocking shall be ensured within a maximum deblocking time ΔT_{dblk}. (see dynamic control bands, section 6.2.2).

$$U_{UV4-2} = U_{min}^{Dyn}$$

- **U_{UV5} (T_{st}):** Voltage recovery to static voltage bands (see static voltage band ranges, section 6.2.1). A security margin according to the static voltage band can be applied by k^{Cont} to avoid unwanted converter disconnections.

$$U_{UV5} = k^{Cont}\, U_{min}^{Cont}$$

7.3.2.3 Post-fault power recovery

After DC voltage recovery to dynamic voltage bands, a new post-contingency operational set-point is defined by the P-Vdc characteristic (see section 6.5). Requirements related to post-fault power recovery will be assessed in the final version of the report.

7.3.3 Converter compliance testing for DC-FRT

The converter shall demonstrate compliance with the LVRT requirements in a standalone test circuit while being connected to an AC and DC grid equivalent as shown in **FIGURE 56**. Similar to an AC Thevenin voltage source, the DC grid equivalent shall represent the DC grid behaviour in a simplified and conservative way while being sufficiently independent from actual DC grid topologies. This section is intended to provide an initial hypothesis for a DC grid equivalent for DC-FRT compliance testing of converter stations.

FIGURE 56 Generic illustration of device under test (DUT) connected to an AC and a DC grid equivalent

The converter connection requirement and operation requirement shall be respected independently from the actual grid topology. The worst-case topology for the converter in terms of fault current increase and DC voltage drop is when adjacent lines and converters are disconnected, for example due to maintenance (see **FIGURE 57**).

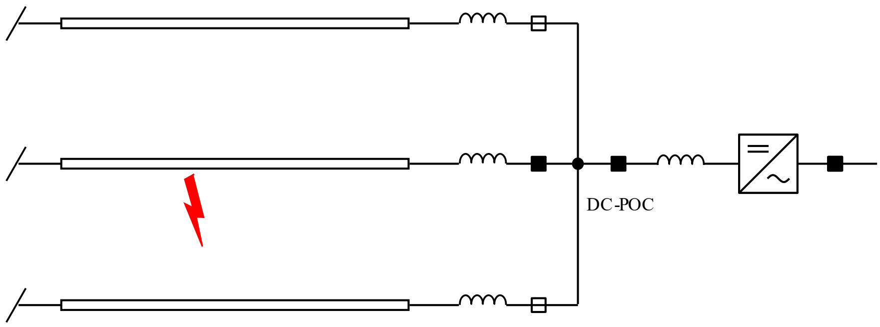


FIGURE 57 Worst case assumptions: No adjacent lines and converters connected, highest voltage drop at DC-PoC of converter station

Considering this, a preliminary minimum test circuit for DC-FRT compliance testing can be defined (see **FIGURE 58**). On the AC side, the system strength and short-circuit ratio shall be represented by an AC Thevenin source. On the DC side a controlled voltage source in series with an impedance shall emulate an outer undervoltage envelope drop due to DC fault profiles while considering both a solid fault and voltage reversals due traveling wave propagation while considering appropriate damping factors of DC cables and the maximum fault neutralization time[25].

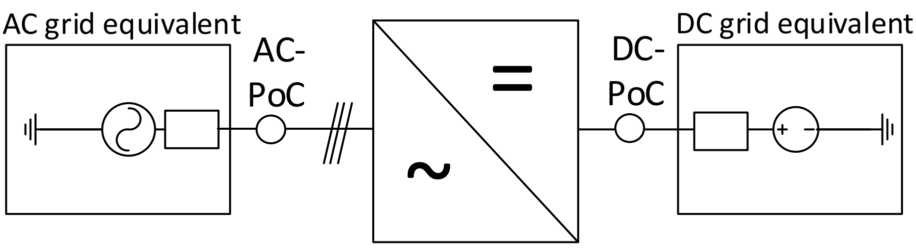


FIGURE 58 Minimum test circuit for converter FRT compliance testing at DC-PoC

[25] Note that the DC grid impedance may be considered equal to zero.

An illustrative converter LVRT compliance test profile applicable to the voltage source of the DC grid equivalent is shown in **FIGURE 59**. It consists of two main parts:

1. Undervoltage transients representing the outer envelope of undervoltage from fault arrival (T_0) to T_{rec1}: The test profile parameters shall be aligned with LVRT profile, in particular with parameters U_{UV1}, U_{UV2} and $T_{N,max}$.
2. DC voltage recovery due to fault neutralization: The test profile considers the TIV imposed by the FSD during fault current suppression. Besides the LVRT profile (blue) a specified maximum TIV shall be tested (green)

The overall goal of the DC-LVRT compliance test is to prove compliance with both the connection requirement and the operational requirement, meaning no trip of ACCB and stable operation after DC voltage recovery.

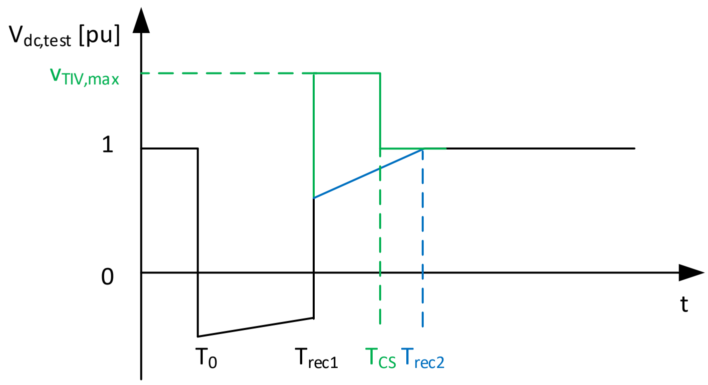


FIGURE 59 Indicative converter LVRT compliance test profiles

Compliance examples considering different technical solutions

The overall goal of the DC-FRT definition is to describe the requirements in a most inclusive and technology-agnostic way. The following examples as listed in **TABLE 18** illustrate at a high level how different technical converter solutions (non-exhaustive) meet the requirements.

TABLE 18 Different technical solutions for converter stations

Converter Technical solution	1	2	3
Temporary blocking function	No	No	Yes
Fault current control function (e.g. Full-bridge topology)	No	Yes	No

Converter 1 has no temporary blocking function and no fault current control function.

The requirement of staying connected and ensuring stable operation after fault neutralization can be achieved by proper sizing of the converter DC inductance L_{MMC} such that the overcurrent is kept below the IGBT overcurrent capabilities (vendor specific).

Converter 2 has no temporary blocking function but can control fault currents (e.g. due to full-bridge topology).
Due to this functionality, the requirement of remaining connected and ensuring stable operation can be ensured without a specific fault current limiting device and AC side controllability is ensured as well.

Converter 3 has a functionality of temporary blocking, meaning fast deblocking of blocked sub-modules after fault neutralization.
The converter can ensure to continue stable operation after the DC-FRT and fulfils requirements at AC-PoC.

7.3.4 OVRT requirements

Similar to the LVRT definition, the overvoltage ride through (OVRT) requirements are intended to provide a framework of converter withstand capabilities. An outer envelope of overvoltage levels and time frames related to all critical but planned events in a DC grid shall be specified at the DC-PoC of the converter (see Figure **51**). The converter shall withstand the OVRT specifications while remaining connected and ensure stable operation during the OVRT-event.

All overvoltage levels are defined with reference to ground but not all pole-to-ground overvoltages lead to higher stresses of the converter unit itself. In fact, the actual converter unit voltages stresses are measured with reference to the neutral. This is illustrated by the following non-exhaustive list of critical events for transient and dynamic overvoltage level determination.

Overvoltage on healthy pole during a PtG fault: A PtG fault leads to an inherent increase of the fault current in the faulty pole. The earth return current leads to a conduction of the neutral-to-ground arresters. The voltage level in the neutral rises to the arrester clamping voltage. The offset on the neutral is directly reflected to the healthy pole resulting in an overvoltage with an offset of the arrester clamping voltage. The overvoltage persists until fault current suppression. Note that the pole-to-neutral voltage of the converter unit is not affected by this event.

Overvoltage during fault current/load current suppression: The fault current suppression by an FSD requires to impose a TIV which is higher than the rated DC voltage provoking a decrease of fault current. In case of load current suppression, the conductor under load at the remote end of the FSD imposes an offset to the TIV of the FSD. The voltage across a fault current limiting device (FCLD) such as a DC reactor needs to be considered when assessing realistic overvoltages during current suppression. Further investigation will be included in the final version of the report. It should be noted that this event affects both pole-to-ground and pole-to neutral voltage stresses.

Loss of load: An unexpected loss of load leads to an inherent mismatch between power infeed and export. The imbalance is compensated by reserves of adjacent converter stations and energy absorption devices if reserves are depleted. The converter stations are exposed to dynamic overvoltages during such a loss of load event. It should be noted that this event affects both pole-to-ground and pole-to neutral voltage stresses.

Operation after contingency: After fault separation, the operational voltages may be different to pre-fault set-points which is mainly due to droop adjustments. The converter station is expected to operate in the specified voltage ranges until secondary voltage control frees-up the voltage reserves (see static voltage bands, section 6.2).

The OVRT profile is shown in **FIGURE 60** and characteristic values are given in **TABLE 19**. It should be noted that the parameter definition will be assessed in the final version of this document.

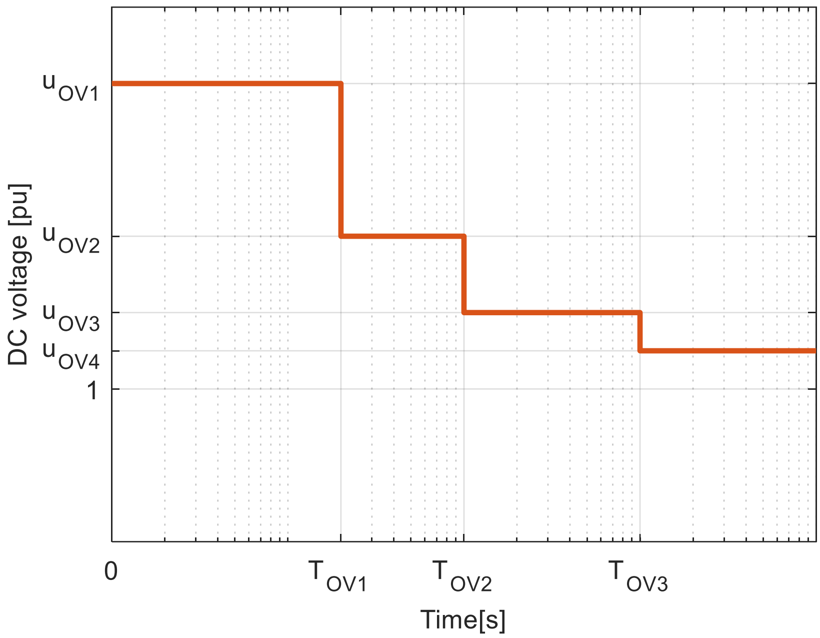


FIGURE 60 OVRT profile for the AC/DC converter station at the DC-PoC (indicative – assessed in final version)

TABLE 19 OVRT parameter description for the AC/DC converter station at the DC-PoC (indicative – assessed in final version)

Parameter	Description	Parameter definition
U_{OV4}	Overvoltage withstand capability related to static voltage bands (see section 6.2)	Assessed in final version
U_{OV3}	Overvoltage withstand capability related to static continuous voltage bands (see section 6.2)	Assessed in final version
U_{OV2}	Overvoltage withstand capability related to dynamic voltage bands	Assessed in final version
U_{OV1}	Overvoltage withstand capability related to transient overvoltages	Assessed in final version
T_{OV1}	Time frame related to transient overvoltage events	Assessed in final version

T_{OV2}	Time frame related to dynamic overvoltage events	Assessed in final version
T_{OV3}	Time frame related to static overvoltage events (Primary control → secondary control)	Assessed in final version

As stated above, the OVRT profile is a mean to specify overvoltage withstand capabilities of the converter. However, the definition of protective actions when exceeding the OVRT is less evident compared to LVRT, where an inherent action is to trip the ACCB to suppress the fault current. The trip of the ACCB in case of OVRT may not be an effective action since the overvoltage on the DC side will persist. Hence, the overvoltage protection shall be foreseen on the DC side. It should be noted that the assignment of such a functionality requires further investigation and will be described in the final version of this document.

7.3.4.1 On-site application of DC-FRT profile

On-site, the DC-FRT profile is a means for the converter to detect abnormal DC fault transients that are outside the specified times and amplitudes in which the DC grid protection is supposed to operate. This section is intending to clarify on the application and verification of the DC-FRT profile in an MTDC system.

A fault or a contingency in the DC grid results in a voltage deviation at the DC-PoC of the converter. This will determine the triggering time t_0. **FIGURE 61** shows an illustrative undervoltage event of oscillatory behaviour, where multiple transitions between undervoltage and normal voltage bands occur. If not specified, different interpretations for the triggering and reset of an undervoltage event in case of oscillatory behaviour are possible.

- **Trigger voltage level:** Defined as the voltage level at which an undervoltage event is detected by the converter and from which measurements at the DC-PoC are verified against the DC-FRT-profile. The trigger voltage level shall be equal to the highest undervoltage threshold (in this case U_UV5).
- The **reset level** is defined as the minimum voltage recovery level after a LVRT event and associated minimum time from which a new DC-FRT event is considered to occur.
- The **reset time** shall allow to clearly distinguish between a new LVRT event and for instance oscillatory behaviour. An example of possible recurrent LVRT events in a short time frame is a tentative of reclosing after an overhead line fault considering a de-ionisation time of several hundreds of milliseconds. In case of a persistent fault, the reset time shall allow to consider the sub-sequent LVRT event as an independent event.
- The **maximum number of recurrent ride through events** shall be specified and coordinated at least with the number of reclosing tentatives of FSDs.

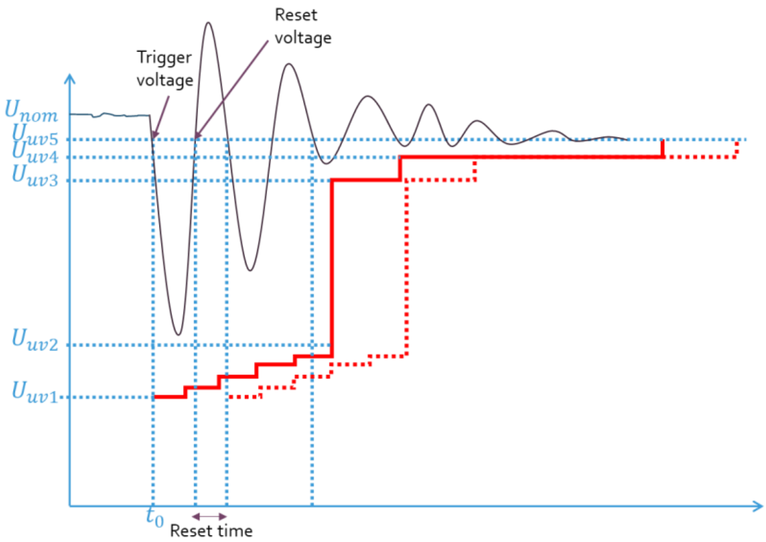


FIGURE 61 Illustration of trigger voltage level, reset voltage and reset time for on-site DC-FRT verification; in this example, the LVRT profile is shown in a discretised format

7.3.5 Grid-serving requirements

Grid-serving requirements describe converter functionalities which support the DC grid during a transient event before fault neutralization. In AC, such functions are specifically designed for the event of a fault (such as reactive current injection for voltage support). Grid-serving requirements may also exist during the DC FRT of a converter, which would require a certain level of controllability during a DC fault. The need for grid serving requirements and possible definitions will be assessed in the final version of the deliverable.

7.4 Fault separation requirements (DCSS)

7.4.1 Software requirements

Protection relays are defined per protected section or zone and not per feeder, they can have access to multiple local current and voltage measurements of multiple switching units. DC fault detection and discrimination functions are defined at unit level. The DC fault detection and discrimination functions shall cover all ordinary contingencies as specified by the relevant TSO. Fault detection and discrimination shall be ensued within a relay time which, together with the FSD operation time, does not exceed the maximum fault neutralization time. If a minimum time between detection (pre-activation) and discrimination is required, this needs to be specified. If the border of a FSZ is on the AC side (e.g. ACCB) or at converter level, a fault detection and discrimination shall be foreseen to activate the fault separation function of such devices.

An overview on communication interfaces related to DC grid protection is provided in **FIGURE 62**. It should be noted that this is a functional view which does not represent the individual system component deployment which might be different. Fault detection and discrimination is located at unit level (i.e. switching unit or busbar unit) whereas (tele-) communication interfaces between sub-systems are at station level (e.g. between two DCSS). In practical application, different protection relays may require access to measurement of several devices at field level. For example, protection relays in busbar units will request tripping of the relevant switching units. A switching unit shall be able to send status updates to the DC switching station. If remote information or measurements are needed for the purpose of backup protection, additional fast (tele-) communications with remote end switching stations shall be foreseen.

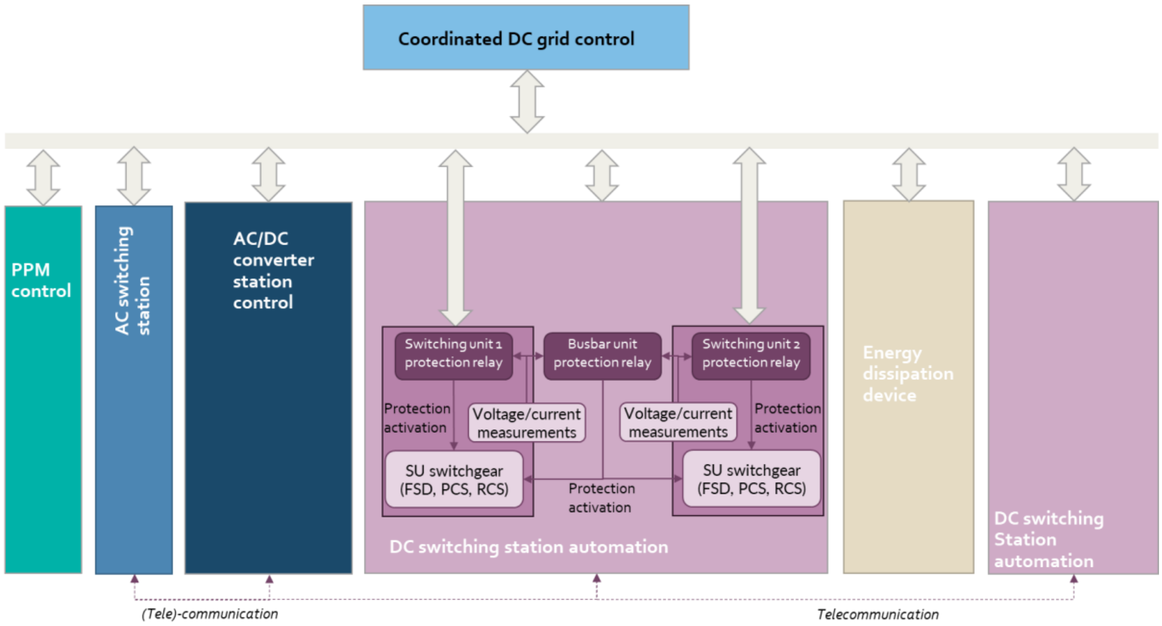


FIGURE 62 Communication interfaces between functional levels for DC grid protection; fault detection/discrimination at unit level, (Tele-)communication between subsystems at station level

7.4.1.1 DC fault detection and discrimination

HV pole

The objective of fault discrimination is to distinguish between a fault inside or outside a specified part of an HVDC grid either for fault separation or for fault isolation. A fault separation zone (FSZ) defines a zone in which a fault current can be suppressed by operation of the FSD at the borders of the FSZ. Two different types of FSZ exist: Selective and partially selective (see definitions in section 7.1).

When defining functional requirements related to fault discrimination, the existence of different protection zones shall be considered. It shall be further distinguished between fault discrimination requirements for fault separation and fault isolation as they are not equally critical.

Primary protection for fault separation shall be based on non-unit algorithms whenever technically feasible in order to reduce the relay time. Zone distinction devices (ZDD), e.g. DC reactors, shall be designed accordingly. Non-unit fault discrimination shall be considered as a design criterion for protection zoning. Possible exceptions are an FSZ with several local measurements (e.g. DC busbar), primary protection during maintenance (aggregation of two primary protection zones) and fault isolation.

Backup protection sequences for fault separation at remote ends without telecommunication[26] are technically challenging. For the time being the option of having communication is maintained but

[26] The term telecommunication is only used for remote-end communication, unit-based algorithms at a busbar are considered local

communication delays shall be as small as technically possible (e.g. telecommunication via fibre optic link). An overview is provided by **TABLE 20**.

Non-unit fault discrimination is not mandatory for fault isolation because it is less time critical and may be technically challenging. However, whenever technically feasible non-unit fault discrimination shall be prioritized in order to limit horizontal telecommunication interfaces between subsystems.

The method of fault discrimination (non-unit, unit) shall be specified for all relevant protection zones according to the list of ordinary contingencies (including primary and backup protection).

TABLE 20 Authorization of telecommunication for fault discrimination; X: Not allowed, (X): if non-unit protection not technically feasible (intertripping), O: Allowed

	Fault separation	Fault isolation
Primary protection (local)	X	(X)
Backup protection	(X)	O

DMR

The detection and discrimination of DMR faults is less time-critical compared to HV pole faults. A DMR fault may result in a ground return current but the overall system operation is ensured. Therefore, the fault detection and discrimination shall be ensured but in a less restrictive time frame compared to HV pole faults. A unit-based principle relying on communication may be used considering the fact that the detection of DMR faults may be more challenging compared to HV pole faults. This is mainly due to the limited voltage drop in the neutral system which might result in small or even no increase of currents in case of a fault[27].

7.4.1.2 Auto-reclosing

A reclosing after fault current suppression[28] supposes that the faulty element has been isolated and that parts of the FSZ are healthy. Two main reclosing sequences can be distinguished: Auto-reclosing and coordinated reclosing (see **FIGURE 63**). The preferred reclosing sequence shall be specified for each fault separation zone.

The term auto-reclosing is defined as an autonomous reclosing sequence by the switching unit. Dedicated timers for protective auto-reclosing shall be specified and backup actions for the case of auto-reclosure on a fault shall be specified. The maximum number of protective auto-reclosing attempts shall be specified and the energy rating of relevant components (e.g. surge arresters) shall be designed accordingly. The FSD shall be designed for a dedicated reopening sequence in case of persistent fault.

Coordinated reclosing sequences (e.g. for partially selective FSZ) shall be specified at DC grid control level.

[27] A fault on an unloaded DMR may lead to zero fault current.
[28] Note that auto-reclosing is not limited to overhead line faults but could also be required in cable based grids (e.g. in case of partially selective FSZ)

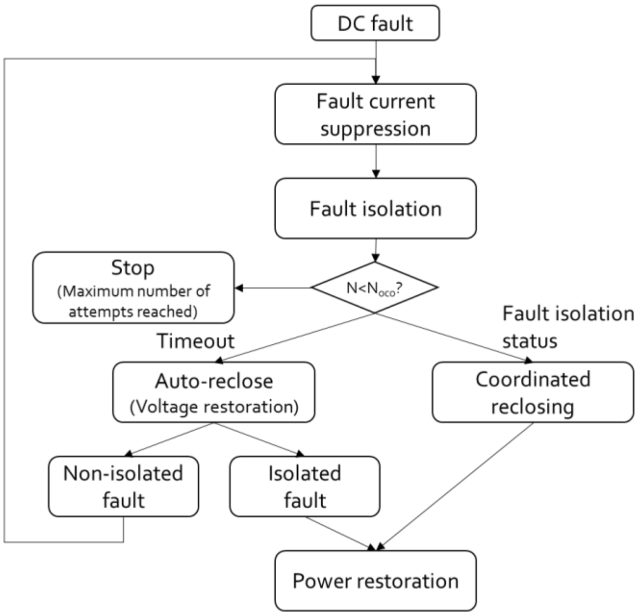


FIGURE 63 Example of reclosing sequences after fault current suppression

7.4.1.3 Monitoring and status for DC grid protection

The FSD is part of a switching unit. The FSD may be triggered due to a local request by a protection relay or by a global request from the DCGC (corresponding to an open command, as defined in Section 5.3.3). If the FSD trip is issued by a local protection relay, this information is reported to the DCSS and DCGC layers. Beside of the close open and close status, an intermediate state "status closed – FSD activated" is defined for protection sequences. Open commands are distinguished from trip commands such that FSD technologies may apply fault current separation or load current separation sequences (with reduced TIV if applicable).

- Status closed – FSD not activated
- Status closed – FSD activated: Activation of FSD is an intermediate step which lead to fault current separation without galvanic isolation (RCS closed). Possibility to go back to status "closed – FSD not activated" if an auto-reclosing is performed (e.g. in case of an Open-Close-Open sequence (OCO)).
- Status open: Achieved once the RCS has successfully opened providing a galvanic isolation.[29]

Converter operational states to be reported to the DCGC:

- Blocked state[30]
- ACCB activation / trip
- Normal operation

7.4.2 Hardware requirements

[29] Note that an operation of RCS might be required for certain FSD solutions to proceed to auto-reclosure.
[30] For the reporting of a blocked state permanent blocking and temporary blocking shall be distinguished. For temporary blocking no particular action from the DCGC is expected since the converter deblocking is based on local measurements.

7.4.2.1 DC fault separation

The fault current evolution due to a DC fault is highly transient and has various influencing factors such as topology, converter ratings and the type of transmission line. In addition, the presence and sizing of DC reactors or other fault current limiting devices has an important impact on the evolution of fault currents. The DC reactor can be seen as a multi-purpose device ensuring both protection zone distinction and fault current limiting. The choice of fault current limiting devices shall be compliant with the performance of the FSD in terms of current breaking capability and operating time.

The switching unit and more precisely the FSD shall be rated such that it can neutralize all fault currents related to ordinary contingencies as specified by the relevant TSO within the maximum time $T_{N,max}$. Note that $T_{N,max}$ may be specified for both primary and backup protection sequences[31]. The Transient Interruption Voltage (TIV) of the FSD shall be within specified ranges $v_{TIV,min}$ and $v_{TIV,max}$. The FSD shall be equipped with a sufficient energy rating to absorb the maximum energy due to faults. The number of OCO sequences N_{OCO} as specified by the TSO shall be considered for energy absorption rating. If $N_{OCO}>1$, the maximum reclosing time shall be respected. Due to the high interdependencies of fault neutralization time, fault limiting device and current breaking capability, it is recommended to design them in a coordinated way ensuring fault current interruption for all relevant ordinary contingencies[32]. Note that the device for fault current limiting is not specified in order to ensure an inclusive and technology-agnostic description of the functional requirements according to the system needs. From a protection perspective several combinations of protection equipment ratings are possible. However, the impact on the DC grid controllability should be thoroughly investigated to ensure stable operation. Relevant parameters should be specified in a coordinated and compatible way. Functional requirements related to fault separation shall be specified at switching unit level.

7.4.2.2 DC fault isolation

DC fault isolation describes the sequence of physical isolation of the faulty device by operating the RCS after fault current suppression. With the opening of the RCS, the fault current decreases from residual current level to zero current.

Functional requirements regarding residual current breaking capabilities in terms of amplitude and time shall be specified.

7.4.2.3 Auto-reclosing

Hardware requirements related to auto-reclosing shall be specified at switching unit level. The maximum number of auto-reclosing attempts shall be specified. Relevant switchgear and pre-insertion devices shall be designed accordingly.

7.4.3 Compliance test for DC fault interruption

[31] Note that $T_{N,max}$ imposes both hardware and software requirements on the FSD as it includes the relay time for fault detection and discrimination. More information is provided in the relevant section.

[32] This deviates from IEC TS 61291 where a separate specification of fault current limiters and FSD capabilities is proposed.

The obvious requirement for switching units inside a DC switching station with fault current breaking capability is to achieve fault current suppression for all associated DC faults considered as ordinary contingencies as specified by the relevant TSO. The DCSS has several DC-PoCs. In case of a fault, at least one PoC is connected to the faulty part of the system whereas the remaining PoCs are connected to the healthy parts of the DC grid. In an expandable DC grid the detailed characteristics of each of the feeders might not be known in a planning stage. As a worst-case assumption in terms of fault current contributions, the healthy part of the DC grid can be represented by an ideal DC voltage source of rated value.

In **FIGURE 64** the faulty part is represented by a voltage source $V_{dc,test}$ whereas healthy part connections are represented by ideal DC voltage sources $v_{dc,r}$ behind a potential DC grid impedance representing the worst case scenario for fault current increase. For simplification only one pole is represented while considering a Pole-to-Ground (PtG) fault. The test voltage source emulates a voltage profile that corresponds to the worst-case. The worst case shall be specified including voltage reversals due to traveling wave reflection. An illustrative wave shape is shown in **FIGURE 65**.

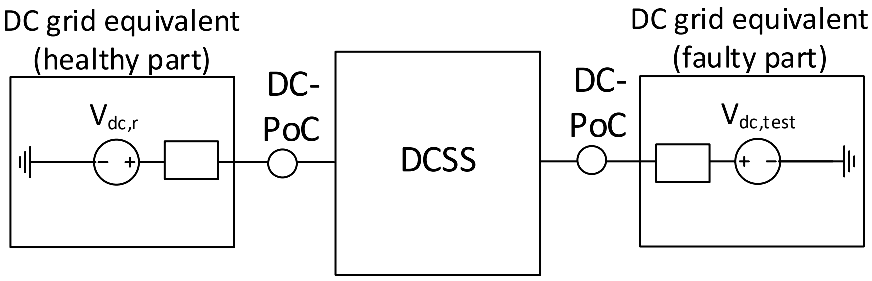


FIGURE 64 Standalone compliance test circuit for a DC switching station (DCSS) connected to two DC-PoCs: Single pole representation, Pole-to-Ground faults

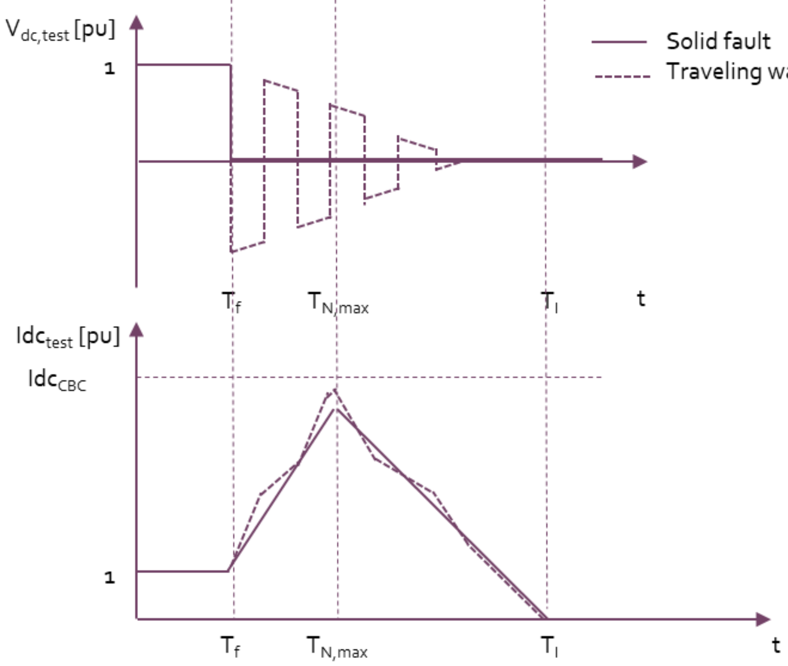


FIGURE 65 Illustrative wave shape of voltage $V_{dc,test}$ and current I_{dctest} for DC switching station compliance testing

7.5 DC system grounding

[Filled in final version]

7.6 Insulation coordination

[Filled in final version]

7.7 DC grid protection Functional Requirements of Subsystems & Parameter Lists

Functional requirement	Short description	Associated parameters	Subsystem
DC-FRT connection requirement	The AC/DC converter station shall stay connected during DC fault separation according to DC-LVRT profile	DC-FRT profile: U_{UV1}, U_{UV2}, U_{UV3}, $U_{UV4\text{-}1}$, $U_{UV4\text{-}2}$, U_{UV5}, T_{rec1}, T_{rec2}, T_{st} Trigger voltage level, reset voltage level, reset time, maximum number of successive events	AC/DC converter station
DC-FRT operational requirement	The converter shall continue stable operation after the power system has recovered following fault separation.	DC-FRT profile: $U_{UV4\text{-}1}$, $U_{UV4\text{-}2}$, ΔT_{blk}	AC/DC converter station
DC-OVRT requirement	The AC/DC converter station the converter station shall stay connected during overvoltage events defined by the DC-OVRT profile	DC-OVRT profile (assessed in final version)	AC/DC converter station
Fault separation HV & neutral	The switching units at the boundaries of HV FSZs shall be equipped with an FSD which is capable of interrupting DC fault current related to all ordinary contingencies within a maximum fault neutralization time $T_{N,max}$.	$v_{TIV,min}$, $v_{TIV,max}$, $T_{N,max}$	Switching unit
Fault separation AC/DC converter station	AC/DC converter stations at the boundary of a FSZ shall ensure fault separation by its own means or by activation of the adjacent ACCB.		AC/DC converter station
Fault isolation HV & neutral	The switching units at the boundaries of an FIZs shall be able to isolate all ordinary contingencies within a maximum fault isolation time.	Residual current interruption level, Fault isolation time	Switching unit

Fault discrimination FSZ – primary	Each subsystem at the border of a FSZ shall ensure fault discrimination for fault separation based on local measurements without telecommunication, ZDDs shall be designed accordingly. The relay time shall be coordinated with the internal commutation time of the related FSD to comply with the maximum fault neutralization time for main protection.	$T_{N,max}$ (T_{relay}, T_{op})	Switching station / switching unit, AC/DC converter station
Fault discrimination FSZ – backup	Each subsystem at the border of a FSZ shall ensure fault discrimination for fault separation which shall be based on local measurements if technically feasible. The relay time shall be coordinated with the internal commutation time of the related FSD to comply with the maximum fault neutralization time for backup protection.	$T_{N,max}$ (T_{relay}, T_{op})	Switching station / switching unit
Fault discrimination FIZ	Fault discrimination for fault isolation shall be ensured with or without telecommunication.	$T_{N,max}$ (T_{relay}, T_{op})	Switching station / switching unit
Fault discrimination neutral path	Fault discrimination on the DMR pole shall be ensured with or without telecommunication within the specified time.		Switching station / switching unit
Tele-communication	In case of unit-based fault discrimination, a telecommunication interface with remote-end subsystems shall be provided. Signals and communication protocol shall be coordinated.		Switching station / switching unit
Protective auto-reclosing	In case the switching unit is required to have the ability to re-energize the healthy part of the FSZ, the number of OCO sequences N_{OCO} and associated maximum reclosing time shall be respected in case of a persistent fault. The energy absorption rating shall be designed accordingly.	N_{OCO}, T_C	switching unit
Coordinated reclosing	Communication interfaces for coordinated reclosing of several subsystems shall be provided. Switching units shall be able to receive reclosing commands.		Switching station / switching unit
Monitoring	States related to protection sequences shall be reported to the DCGC	converter station: Blocked state, ACCB activation DCSS: FSD activation / deactivation	Switching station AC/DC converter station

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9. Appendix

9.1 Functional Requirements at AC connection point

The functional requirements that the HVDC system and each of AC/DC converter station or unit within the system must satisfy are comprehensively stipulated in [20]. The following provides a concise summary of these requirements, with references indicated.

Active Power Controllability (Article 13): The AC/DC converter shall be capable of regulating the active power up to the value in the active power control range in compliance with the performance requirements specified by the relevant TSO.

Ramping Rate of Active Power Change (Article 13): The AC/DC converter station shall be capable of adjusting the ramping rate of active power variations within their technical capabilities according to the instructions sent by the relevant TSO.

Frequency Sensitive Mode (FSM) (Article 15): The HVDC system shall be capable of responding to frequency deviations in each connected AC network by adjusting the active power transmission in accordance with the parameters specified by each TSO within the ranges specified.

Limited Frequency Sensitive Mode – Overfrequency (LFSM-O): In addition to the requirements specified for FSM, when operating in LFMSM-U, the HVDC terminal shall be capable of adjusting active power frequency response to the AC network or networks according to the parameters specified for LFSM-U by the relevant TSO.

Limited Frequency Sensitive Mode – Underfrequency (LFSM-U): In addition to the requirements specified for FSM, when operating in LFMSM-U, the HVDC terminal shall be capable of adjusting active power frequency response to the AC network or networks according to the parameters specified for LFSM-O by the relevant TSO.

Short Circuit Contribution during AC Faults (Article 19): If specified by the relevant system operator, the AC/DC converter shall have the capability to provide fast fault current at the AC side connection point in case of symmetrical faults in accordance with the specified requirements.

Reactive Power Control Mode (Article 22): The AC/DC converter station shall be equipped with different reactive power control modes, as specified by the relevant system operator in coordination with the relevant TSO.

AC Voltage Droop Control Mode (Article 22): When operating in the AC voltage droop control mode, the AC/DC converter station shall be capable of contributing to voltage control according to the parameters specified by the relevant TSO.

Dynamic AC voltage control (VDE-AR-N Section 10.1.9): In case of large AC voltage deviation, the AC/DC converter station must be capable of contributing to voltage control by rapidly injecting reactive power, as specified by the relevant system operator in coordination with the relevant TSO.

Frequency Control (Article 16): If specified by the relevant TSO, the AC/DC converter shall be equipped with an independent control mode to modulate the active power output depending on the frequencies in order to maintain stable system frequencies.

Priority to Active or Reactive Power Contribution (Article 23): The AC/DC converter station or unit shall be equipped with a control function logic to prioritize either active or reactive power contribution during low or high voltage operation and during faults for which fault-ride-through capability is required. If priority is given to active power contribution, its provision must be established within a time from the fault inception as specified by relevant onshore TSO.

Post fault active power recovery (Article 26): The AC/DC converter station shall be capable of restoring active power after a fault in AC network in compliance with the allowed time and levels of AC voltage and active power recovery specified by relevant TSO(s).

AC Fault Ride Through Capability (Article 25): The AC/DC converter station or unit shall remain connected and continue stable operation when its connection point voltage stays within the specified voltage-time series profile.

Priority Ranking of Protection and Control (Article 35): The control scheme of protections and control devices consisting of different control modes, including settings of the specific parameters, shall be organized in compliance with the following priority ranking, listed in decreasing order of importance:

- Connected AC network system and HVDC system protection; (interpreted as this includes DC voltage droop mode)
- active power control for emergency assistance;
- synthetic inertia, if applicable;
- automatic remedial actions, including blocking FSM, LFSM-O, LFSM-U
- LFSM;
- FSM and frequency control; and
- power gradient constraint

Power Oscillation Damping Capability (Article 30): The HVDC system shall be capable of contributing to the damping of power oscillations in connected AC networks. The control system of the HVDC system shall not reduce the damping of power oscillations.

9.2 Examples and Justifications of Multi-Segment Droop Characteristics with Varying Power Setpoints

The following illustrates several multi-segment droop characteristics based on the functional specifications established in Section 6.5. Note that the selection of these parameters depends on the system and is subject to the discretion of the system operator. Thus, the values utilized in the following demonstration are only indicative.

First, the influence of the power set-point on the multi-segment droop characteristic is demonstrated. The following figures illustrate how variation in set-point, specifically [+1.0, +0.5, 0, -0.5, -1.0] p.u, affects the shape of the droop characteristic. All associated parameters, such as the voltage levels and droops, are summarized on top of each figure and remain consistent across all figures.

The power set-point plays a crucial role in determining the available headroom capacity in each direction. When the set-point is close to the maximum or minimum power limit, power voltage response along the given droop may soon exceed the power transmission capability. As mentioned in the functional requirements for each mode, namely, DCVSM, LDCVSM, and DCVLM, the active power shall be constrained by the maximum and minimum active power transmission capacity. Consequently, the droop characteristics of those mode shall cease its progression when reaching these maximum and minimum power limits.

Main

Param	Value
U_{dcn}	525kV
P_n	1000MW
P^{Set}	1.0
U^{Set}	0.98
P_{max}	1.0
P_{min}	-1.0

DCVSM

Param	Value
U_{1o}	1.00
U_{1u}	0.95
s_{1o}	0.15
s_{1u}	0.15
dP_{1o}	0.00
dP_{1u}	-0.20
dU_{Do}	0
dU_{Du}	0

LDCVSM

Param	Value
U_{2o}	1.05
U_{2u}	0.90
s_{2o}	0.05
s_{2u}	0.05
dP_{2o}	0.00
dP_{2u}	-1.00

DCVLM

Param	Value
U_{2o}	1.05
U_{2u}	0.90
s_{3o}	0.01
s_{3u}	0.01

PLM

Param	Value
P_{max}	1.0
P_{min}	-1.0
	N/A
	N/A

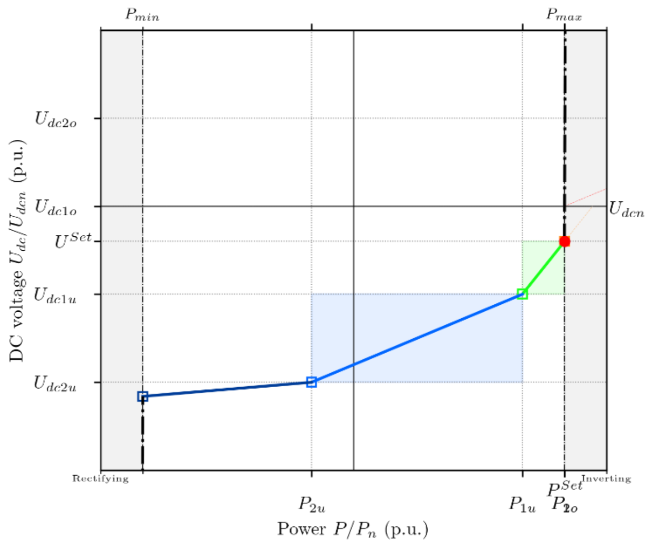


FIGURE 66: Multi-Segment Droop Characteristics Illustration with Setpoint [P^{Set}, U^{Set}] = [+1.0, 0.98].

An observation across the figures indicates that certain slopes associated with the droop of specific modes may not appear depending on the power set-point. Each droop characteristic determines the power deviation associated with the respective section. Consequently, if these deviations accumulate to the extent that reach the maximum or minimum power transmission capacity, there is no capacity available to accommodate certain modes.

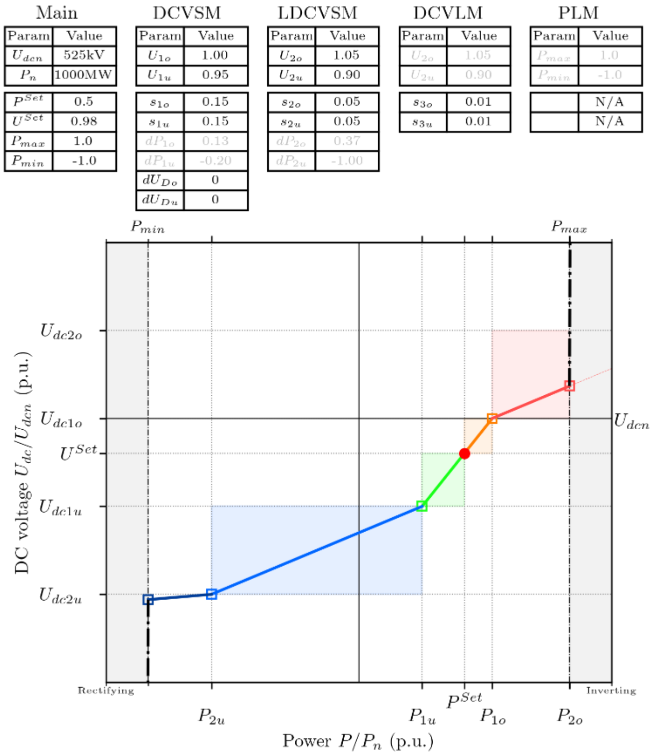


FIGURE 67: Multi-Segment Droop Characteristics Illustration with Setpoint [P^{Set}, U^{Set}] = [+0.5, 0.98].

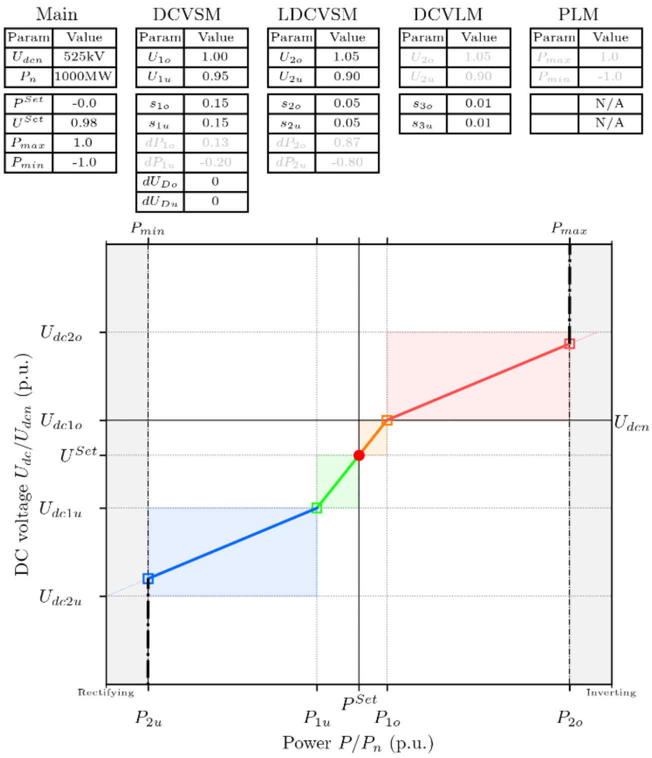
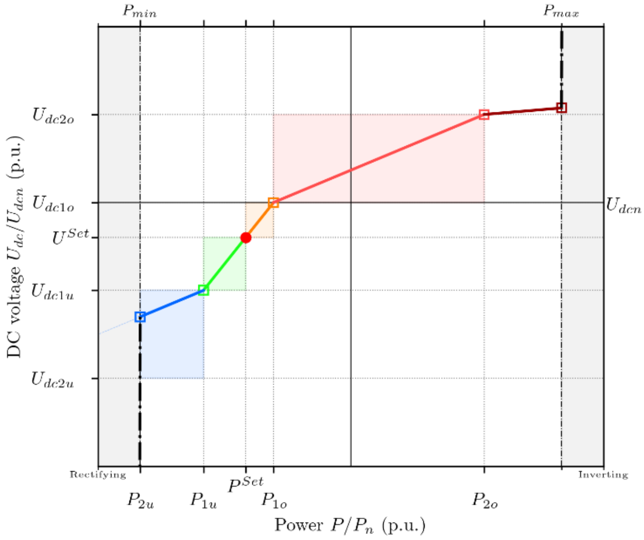


FIGURE 68: Multi-Segment Droop Characteristics Illustration with Setpoint [P^{Set}, U^{Set}] = [0.0, 0.98].

A noticeable difference can be observed between **FIGURE 68** and **FIGURE 69**. In **FIGURE 68**, the maximum transmission capacity is fully exploited before the multi-segment droop characteristic reaches the overvoltage level Udc2o. However, in **FIGURE 69**, the full power capacity is not exhausted at Udc2o, where power reaches P2o. This suggests that in case where a large headroom capacity is available, depending on the selected droops, the full power capacity may not be fully utilized before reaching Udc2o.

Given that exploiting the full power capacity is not stipulated as mandate condition for LDCVSM-O and -U, a countermeasure is necessary to immediately utilize the available capacity once Udc2o is exceeded. This is the role of DCVLM.



Param	Value
U_{dcn}	525kV
P_n	1000MW
P^{Set}	-0.5
U^{Set}	0.98
P_{max}	1.0
P_{min}	-1.0

Param	Value
U_{1o}	1.00
U_{1u}	0.95
s_{1o}	0.15
s_{1u}	0.15
dP_{1o}	0.13
dP_{1u}	-0.20
dU_{Do}	0
dU_{Du}	0

Param	Value
U_{2o}	1.05
U_{2u}	0.90
s_{2o}	0.05
s_{2u}	0.05
dP_{2o}	1.00
dP_{2u}	-0.30

Param	Value
U_{2o}	1.05
U_{2u}	0.90
s_{3o}	0.01
s_{3u}	0.01

Param	Value
P_{max}	1.0
P_{min}	-1.0
	N/A
	N/A

FIGURE 69: Multi-Segment Droop Characteristics Illustration with Setpoint [P^{Set}, U^{Set}] = [-0.5, 0.98].

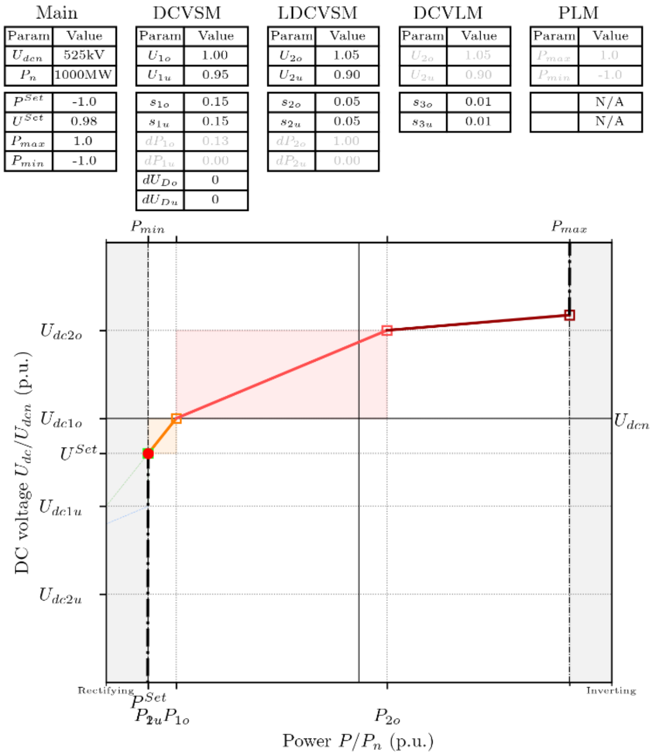


FIGURE 70: Multi-Segment Droop Characteristics Illustration with Setpoint $[P^{Set}, U^{Set}] = [-1.0, 0.98]$.

9.3 Alternative DC-FRT profiles and evaluation

Different approaches of defining DC-FRT capabilities have been discussed within the DC grid protection workstream. This section shall be seen as a complement to section 7.3 with the objective to provide background information on the evaluation process highlighting the main differences and outlining advantages and drawbacks of each of the solutions. It should be noted that a final assessment of the presented options must be based on technical and economical evaluations which cannot be fully concluded in the scope of InterOPERA.

TABLE 21 summarizes the different approaches of how a DC-FRT could be described. They differ mainly in terms of genericity and the quantity they are expressed in.

TABLE 21 Different categories for DC-FRT definitions

Option	Description	Quantity
1	Design / topology dependent	DC Current based
2	Design / topology dependent	DC Voltage based
3	Generic	DC Current based
4 (see section 7.3)	Generic	DC Voltage based

Evaluation criteria

- **Technological agnostic:** Are the functional requirements permitting different technological solutions or are they restricting, excluding certain technologies?
- **Functional split:** Are functional description and design of subsystems independent? How to split functional responsibilities?
- **Oversizing :** Does the decoupling of subsystem requirements and the genericity / system independence generate an oversizing?
- **Standardization:** Is the DC-FRT description subsystem-dependent or generic? Do several DC-FRT profiles co-exist?
- **Verifiability :** Can the DC-FRT profile be specified at the DC-PoC based on local measurements?

9.3.1 Generic vs design / topology dependent approach

Considering a design / topology dependent DC-FRT description, the following questions arise and reveal potential drawbacks. For each of the identified drawbacks, the advantages of a generic DC-FRT description as defined in section 7.3 are expressed.

Functional split: Are functional description and design of subsystems independent? How to split functional responsibilities?

Standardization: Is the DC-FRT description subsystem-dependent or generic? Do several DC-FRT profiles co-exist?

- ➔ For a design / topology dependent approach as proposed in the IEC TS 63291, a DC-FRT curve would need to be defined for each operational concept and each protection sequence with a dependability between converter FRT and fault clearing. The current response and overcurrent limits depend on the specific sub-system design.

- ➔ The DC-FRT voltage profile as described in section 7.3 defines an outer envelope which is valid for all fault transients at the DC-PoC of the converter independently from the converter type. This approach has been evaluated in EMT simulations based on a reference system. Functional requirements and subsystem compliance standalone tests are generic and non-project, non-station specific.

Technological agnostic: Are the functional requirements permitting different technological solutions or are they restricting, excluding certain technologies?

- ➔ The DC-FRT requirements as defined in section 7.3 do not distinguish between CO and TS. The overall objective is to ensure stable operation after fault separation. It is well understood that converter IGBT components are highly sensitive to overcurrents and dedicated limits must be respected to avoid any damage. However, it must be acknowledged that several different technical solutions exist to limit the increase of converter fault current during DC faults and that the functional description shall not impose one of them. For instance, some sub-module topologies (e.g. full-bridge) allow to control fault currents. In case of half-bridge topology, the actual converter overcurrent capability may vary depending on the IGBT design. The limitation of current increase by means of fault current limiting devices such as DC reactors.

- ➔ For half-bridge topology innovative control solutions such as temporary blocking can further avoid damage of IGBTs by taking them out of the circuit during transients while ensuring stable operation after DC voltage recovery. From a technical perspective on the DC side, the performance of a temporary blocking converter is not by default worse than a converter in continued operation.

Continued operation comes with costs, especially due to increased requirements on converter overcurrent capabilities and increased size of DC reactor. Those can be significantly reduced with a temporary blocking function and the impact need to be thoroughly assessed. The deblocking can be done quasi-instantaneous once DC voltage and current recovered to operational range leading to a temporary blocking time range of several ms to few tens of ms.

The DC-LVRT profile is therefore described independently from the actual converter fault current contribution without distinguishing between continued operation and temporary blocking.

Functional split: Are functional description and design of subsystems independent? How to split functional responsibilities?

➔ The protection zone matrix approach from the IEC TS 63291 defines converter FRT requirements for each protection zone creating an interdependence between protection zoning and converter FRT requirements.
A protection zone shall not be confounded with converter FRT requirements. A converter outside a protection zone shall by definition avoid permanent stop and ensure operation after fault separation. The DC-FRT requirement as defined in section 7.3 defines an outer envelope ensuring that converter units have enough withstand capability to allow DC grid protection actions for fault separation. The fault separation requirements are specified separately in section 7.2.2 and section 7.4.

Verifiability : Can the DC-FRT profile be specified at the DC-PoC based on local measurements?

➔ The design / topology dependent approach from the IEC TS 63291 defines operational requirements to the converter for each FSZ independently. It remains unclear how such superposed requirements can be verified at the DC-PoC of the converter.
The DC-FRT requirements as defined in section 7.3 provide a clear split between converter unit and switching unit functional requirements.

9.3.2 Alternative DC-FRT profiles

The DC-FRT requirements can be expressed either in DC voltage or DC current quantities, they can be either generic or design-based leading to four options as listed in **TABLE 22**. Considering that the generic voltage-based approach (option 4) has been described in section 7.3 as the preferred option, two current based options (design based (1) and generic (3)) and one design-based voltage option (2) are described and evaluated in the following.

TABLE 22 Comparison of functional requirement definition for different DC-FRT descriptions

Functional requirement	Option 1 DC Current quantities (design based-CO)	Option 2 DC voltage quantities (design based-CO)	Option 3 DC current quantities (generic)	Option 4 DC Voltage quantities (generic)
1 Converter-Connection requirement	converter station must withstand a predetermined converter-specific short-circuit current profile and remain connected	converter station must withstand a predetermined voltage profile (conservative outer envelope) and remain connected	converter station must withstand a predetermined short-circuit current profile (conservative outer envelope) and remain connected	converter station must withstand a predetermined voltage profile (conservative outer envelope) and remain connected
2 Converter-Operational requirement)	converter station must remain in continued operation	converter station must remain in continued operation	converter station must deblock after a certain time if blocked after voltage recovery	converter station must deblock after a certain time if blocked after voltage recovery

All DC-FRT curves need to be defined in a way that enough withstand capability of the converter is ensured to ride through the fault according to the same fault transients. A minimum circuit can be derived under the assumption that adjacent lines are disconnected leading to the highest current contribution of the converter (no voltage support from adjacent lines leading to the most severe voltage drop at the converter DC-PoC). The simplified circuit is depicted in **FIGURE 71**. It consists of the following elements:

- L_{DCSS}: DC inductance of the DC switching station
- L_{MMC}: Equivalent DC inductance of converter unit
- U_{dc}: Rated converter DC voltage represented by an ideal voltage source
- U_{TW}: Controlled voltage source emulating DC fault transients including traveling wave phenomena
- $L_{sum}=L_{dc}+L_{MMC}$

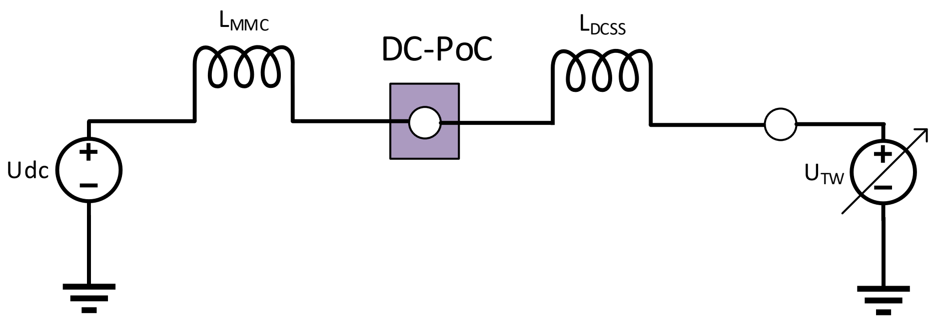


FIGURE 71 Simplified circuit to determine equivalent DC inductance to ensure DC-FRT requirements

FIGURE 72 shows an example of DC voltage evolutions for different fault distances emulated by the controlled voltage source U_{TW} from fault arrival (T=0s) to fault neutralization (T_N=5ms). The controlled voltage source considers cable losses by a simplified damping factor and ideal reflection coefficient equal to two. This is a worst-case approximation considering an inductive cable termination. This profile represents an outer envelope for DC fault transients independently from the converter type. The converter type, rating or control may or may not have an influence on the actual voltage at the DC-PoC but this does not change the outer envelope related to DC fault transients.

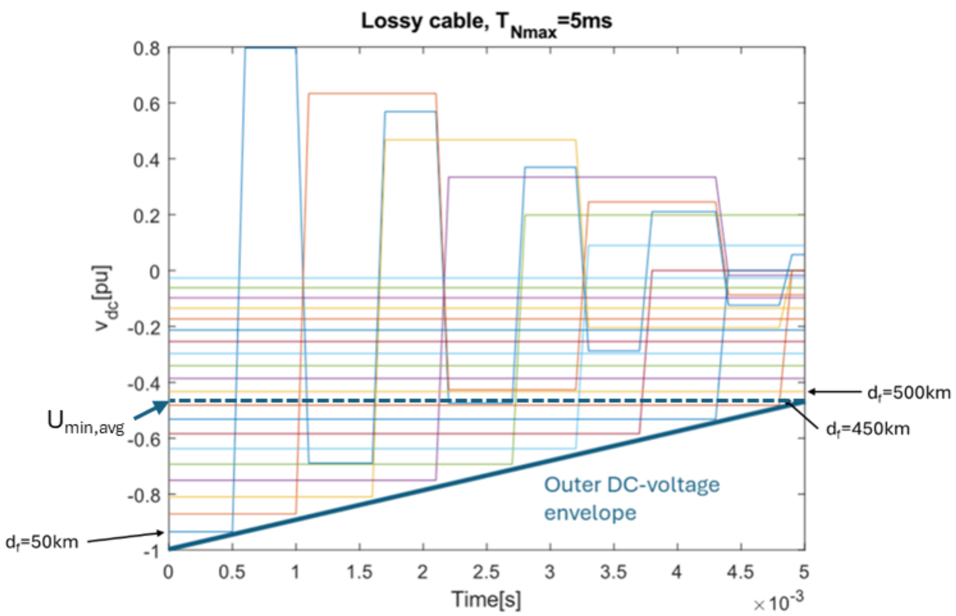


FIGURE 72 Possible DC voltage transients at cable termination depending on fault distance (d_f=50…1000km) for a fault neutralization time of 5ms (for illustration purpose); $U_{min,avg}$: Minimum average undervoltage during fault neutralization

For both design-based solutions an illustrative calculation example DC inductor sizes will be provided in the dedicated section considering hypothetical boundary conditions (design constraints, see **TABLE 23**) for converter station and switching station according to the simplified circuit shown in **FIGURE 72**.

TABLE 23 Example parameters for equivalent DC inductance determination

Subsystem	Design parameter description	Parameter	Value
DC system	Rated DC voltage	U_{dc}	525kV
	Maximum fault neutralization time	$T_{N,max}$	5ms
Converter station	DC overcurrent limit for CO	$Idc_{Max,CO}$	4kA (2pu)
DC switching station	Maximum DC current breaking capability	I_{cbc}	20kA

9.3.2.1 Option 1: Design based solution based on current for continued operation

The current based approach defines the DC-FRT based on overcurrent capabilities that the converter station needs to withstand during fault neutralization while remaining in continued operation. It should be noted that the approach focusses on primary protection and continued operation. Different DC-FRT profiles are expected to be defined for backup protection and temporary stop (temporary blocking).

FIGURE 73 shows two concepts of DC-FRT profiles based on DC overcurrent. For both concepts it is assumed that the TSO defines the following key parameters for an MTDC grid or a zone thereof:

- $Idc_{Max,CO}$: DC overcurrent capability requirements of converter stations
- $E_{max,CO}$ / $\Delta Q_{max,CO}$: Energy rating or charge of the converter station to remain in CO
- $T_{N,max}$: Maximum fault neutralization time (indirectly defined by $Idc_{Max,CO}$ and max di/dt in concept (a), explicitly specified in concept (b))

Concept (a) additionally defines maximum and minimum di/dt values:

- Max di/dt: Maximum increase of DC fault current
- Min di/dt: Minimum decrease of DC current during fault current suppression

For concept (b) the following design based approach has been proposed:

- Specify converter parameters: $\Delta Q_{max,CO}$ and $Idc_{Max,CO}$
- Specify fault separation related switching unit parameters: $T_{N,max}$, ICBC (current breaking capability)
- Specify inductances L_{DCSS} and L_{MMC}

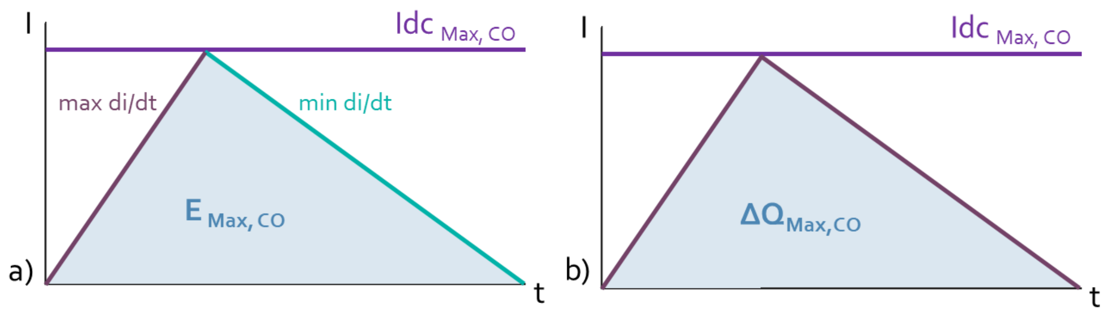


FIGURE 73 Design based DC-FRT profile based on DC overcurrent; With and without specification of maximum and minimum di/dt respectively represented by concept (a) and concept (b)

In concept (a), to ensure that min di/dt ≤ di/dt ≤ max di/dt the grid operator needs to choose the equivalent DC inductance accordingly. This involves coordinating the DC inductance between the converter station and the DCSS as the increase of the fault current is directly dependent on the design of both subsystems as shown by the simplified circuit in **FIGURE 71**. The equivalent DC inductance is the sum of L_{DCSS} inside the DCSS and L_{MMC} inside the converter station assuming an ideal voltage source as a worst case. The maximum di/dt represents an average current increase from fault arrival to fault neutralization ($T_{N,max}$). It should be noted that it can be temporarily higher (e.g. for close faults during voltage reversal). This should be considered for the final definition of the design-based DC-FRT curve based on current as a temporarily higher increase of current while remaining below the absolute current threshold shall not lead to a disconnection of the converter. Simplified equations to determine minimum inductances to keep the converter in continued operation are provided in the following, where $U_{min,avg}$=-0.46 U_{dc} and Idc_r=2kA correspond respectively to the minimum average undervoltage as indicated in **FIGURE 72** and the rated converter DC current in this example.

$$L_{sum} = L_{MMC} = \frac{U_{dc} - U_{min,avg}}{Idc_{Max,CO} - Idc_r} T_{N,max}$$

$$L_{DCSS} = \frac{U_{dc} - U_{min,avg}}{I_{cbc} - Idc_r} T_N$$

Applying the example based on parameters listed in **TABLE 23**, a minimum total inductance of 1916mH would be needed to ensure continued operation. The minimum inductance design for the DCSS would be of 212mH. After coordination between DCSS vendor and converter station vendor, an optimized design of 212mH for the switching station and 1704mH for the converter station is possible.

Technological solutions: The current-based approach is a pragmatic solution limiting the design space due to pre-defined technical choices which directly defines converter functional requirements with overcurrent capabilities which is understood to be the most critical design constraint. On the other hand, overcurrent limits risk to exclude some converters with low overcurrent capabilities. Different from the DC voltage FRT definition, where the transient part corresponds to an outer envelope of DC fault undervoltages, the overcurrent is a response to undervoltage which depends on the technical solution. Advanced technical solutions such as temporary blocking or fault current control (ex: full-bridge) are penalized if the short-circuit level is chosen to make all vendors able to comply. In fact, for those advanced solutions, similar performance could be achieved with significantly lower requirements on both the equivalent DC inductance and the converter requirements.

Interoperability-by-design: If the current response and overcurrent limit is tailor made, the response according to faults is predictable. Further investigation is required to verify to which extend different design concepts may coexist in an MTDC grid.

Standardization: Functional requirements and subsystem compliance standalone tests depend on the specific project and/or station inside a project, they are project and/or station specific. By now it is not clear how several DC-FRT curves may co-exist in this design-based approach (e.g. DC-FRT curve for CO, TS, primary, backup). Application of several DC-FRT curves may add complexity.

Oversizing: The DC inductance design is tailor made with low overdesign for a pre-defined overcurrent limit. However, the overcurrent limit could be seen as arbitrary since the primary purpose is to ride through DC fault transients represented by a voltage drop. Imposing an overcurrent might lead to oversizing restricting advanced technical solutions for converters (e.g. temporary blocking, energy-based control, fault current control).

9.3.2.2 Option 2: Design based solution based on voltage for continued operation

The voltage-based approach defines the DC-FRT based on a voltage profile that the converter station needs to withstand during fault neutralization while remaining in continued operation considering the DC switching station design between DC fault location and converter station resulting in the simplified circuit as shown in **FIGURE 71**. It should be noted that the approach focusses on primary protection and continued operation. Different DC-FRT profiles are expected to be defined for backup protection and temporary stop (temporary blocking).

The functional requirements and design constraints are formulated in the following:

Functional requirement

A worst-case retained voltage profile **UV1** (see outer envelope, **FIGURE 72**) at the DC-PoC of the DCSS, for which the DCSS must be able to interrupt the consequential current.

A minimum equivalent converter inductance $\mathbf{L_{MMC,min}}$ that the converter must provide. This, for example, can be obtained by consensus amongst vendors.

A minimum equivalent DCSS inductance $\mathbf{L_{DCSS,min}}$ that the DCSS must provide and a maximum neutralisation time $\mathbf{T_{N,max}}$.

DCSS vendor design

The DCSS vendor chooses a $\mathbf{L_{DCSS}}$, which must be no less than $L_{DCSS,min}$, based on UV1, $L_{MMC,min}$, their FSD's T_N and $I_{FSD,max}$, assuming maximum DC system voltage behind the $L_{MMC,min}$ inductance.

Converter vendor design

The converter vendor chooses a $\mathbf{L_{MMC}}$, which must be no less than $L_{MMC,min}$, based on UV1, the $L_{DCSS,min}$, $T_{N,max}$ and their converter's overcurrent capability $Idc_{Max,CO}$.

Applying the example based on parameters listed in **TABLE 23**, a minimum total inductance of 1916mH would be needed to ensure continued operation. The minimum inductance design for the DCSS would be of 212mH. No co-ordination between the converter station vendor and the DCSS vendor is needed because the two are decoupled by the $L_{MMC,min}$ and $L_{DCSS,min}$, at the cost of potential oversizing of inductors.

Technological solutions: The voltage-based approach is a pragmatic solution which does not impose an overcurrent capability which is understood to be the most critical design constraint. The converter vendor can adjust the design in a way that continued operation is ensured, for example by adjusting the DC inductance. This DC-FRT is limited to continued operation but can be extended to cover temporary blocking functionalities and backup protection.

Interoperability-by-design: Further investigation is required to verify to which extend different design concepts may coexist in an MTDC grid.

Standardization: The DC-FRT specifications in terms of DC voltage are specified at the DC-PoC of the DC switching station with a certain dependence on the DC switching station design. By now it is not clear how several DC-FRT curves may co-exist in this design-based approach (e.g. DC-FRT curve for CO, TS, primary, backup). Application of several DC-FRT curves may add complexity.

Oversizing: The DC inductance design is tailor made with low overdesign for a pre-defined undervoltage profile.

9.3.2.3 Option 3: Generic DC-FRT profile based on current

A generic description should result in a single DC-FRT curve based on DC current independent from specific converter designs and DC grid topologies. Considering this, the DC-current envelope should be valid for both continued operation and temporary stop (including advanced solutions such as temporary blocking). Generic outer envelope for operational current limit and total overcurrent limit needs to be specified. The operational limit needs to correspond to overcurrent in unblocked state, total overcurrent limit need to be specified for blocked state. It seems challenging to determine a generic envelope for the rate of rise of fault current for both converter states. To cover all cases in a generic manner, the outer envelope may lead very high short circuit currents (e.g. diode-rectifier fault current with strong AC grid).

9.3.2.4 Option 4: Generic DC-FRT profile based on voltage

See DC-FRT requirements of converters, section 7.3.