Detailed Functional Specifications

PUBLIC

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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Detailed Functional Specifications - Overall Demonstrator Definition

DELIVERABLE 3.3(B)

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Table of Contents

VERSION CONTROL

Version	Date	Created/modified by	Comments
2.2	16.09.2025	P. Düllmann (Siemens Energy)	After stakeholder review
2.1	04.08.2025	P. Düllmann (Siemens Energy)	First D3.3b issue for review
2.0	07.07.2025	P. Düllmann (Siemens Energy)	Modifications for D3.3b
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1. Executive summary

The InterOPERA project is divided into two consecutive phases with different focus:

- Phase 1: development of functional frameworks and preparation of simulation environments
- Phase 2: real-time physical demonstrator and offline simulations

Task 3.3 "Drafting detailed functional specifications" is located at the transition of the two project phases. It shall apply the functional framework from Phase 1 to the specific InterOPERA demonstrator project allowing the project vendors to develop their models for Phase 2.

Hence, this document is to be seen as an interim detailed functional specification based on the basic system design studies performed in phase 1 of the InterOPERA project. As part of phase 2, the functional specifications will be reviewed and may be subject to future amendments and updates – depending on the results of the integration real time tests and demonstrator simulations in phase 2.

The result of task 3.3 is split in two parts acknowledging the need for gradual development and potential refinement:

- Deliverable D3.3 (a): Preliminary Functional Specifications (April 2025)
- **Deliverable D3.3 (b): Detailed Functional Specifications (this document and its annexes)**

The task was subdivided into subtasks associated with the different demonstrator building blocks as listed in **Table 1-1** below. Each subtask was asked to produce a self-contained specification comprising the information required for the model development of the corresponding subsystem. To avoid redundancy and potential inconsistencies, references are made among the subsystem specifications and towards this overall demonstrator definition.

Table 1-1: Structure of task 3.3. and deliverable D3.3

Subtask	Subtask Definition	Subtask Lead	Subtask Result
T3.3.1	Overall Demonstrator Definition	Siemens Energy	This document
Task force	Demonstrator Use Cases and Features	SuperGrid	Annex 01
Task force	DC Cable Data	RTE / TU Delft	Annex 02
T3.3.2	DC Grid Controller	SuperGrid	Annex 3.3.2
T3.3.3	AC/DC Converter Station (onshore/offshore)	Siemens Energy	Annex 3.3.3
T3.3.4	DC Switching Station	SciBreak	Annex 3.3.4
T3.3.5	AC Onshore Testbench	Energinet	Annex 3.3.5
T3.3.6	Power Park Modules + AC Offshore Testbench	Wind Europe / Orsted	Annex 3.3.6

It shall be noted that all specifications in this deliverable are focusing on interoperability requirements related to multi-terminal / multi-vendor aspects assuming that general compliance with established industry standards and grid codes is given. All specifications are functional in their nature, meaning that prescription of a certain solution is avoided as far as possible. They are however specific in all aspects that are mandatory to ensure proper operation of the InterOPERA demonstrator system. As such, the specifications establish one exemplary way to implement the general functional framework defined in interOPERA. However, as parts of the specifications have been limited to the scope of the InterOPERA demonstrator, they can only be a starting point, but not a complete blueprint for all future multi-terminal / multi-vendor schemes. Further work is required, and the specifications will be reviewed based on the outcomes of the demonstrator studies conducted within InterOPERA.

The distinction between Preliminary Specifications (D3.3a) and Detailed Specifications (D3.3b) is made based on the form of the demonstrator system, i.e. HVDC grid size and topology, and the functional scope. This will be further detailed in the course of this document in chapter 4 "Demonstrator System Context". Corresponding to the specifications, a staged delivery of demonstrator models is planned:

- Stage 1: Model delivery based on Preliminary Functional Specifications (both online / offline)
- Stage 2: Model delivery based on Detailed Functional Specifications (both online / offline)

Requirements on the modelling itself for online and offline simulation platforms have been developed in WP1 deliverables D1.1 [01] and D1.2 [02] and will not be repeated here in the provided specifications.

The development and integration of demonstrator models is coordinated in the bundled tasks T3.4 / T3.5 "[…] Control and protection development towards system integration in multi-vendor environment". Progress and feedback from the model development has been taken into account for drafting these Detailed Functional Specifications (D3.3b).

2. General Input Clarification

The specifications presented in this document and its annexes are mainly based on the functional framework developed in WP2 and the preparational or accompanying design tasks in WP3:

- Deliverable D2.1 "Functional Requirements for HVDC Grid systems and subsystems" [03]
- Deliverable D2.2 "Requirements for Grid Forming Controls [...]" [04]
- Deliverable D3.1 "Demonstrator project definition and system design studies" [05]
- Deliverable D3.2 "Subsystem pre-design phase process and outcomes" [06]
- Deliverable D3.8 "Demonstrator HVDC Grid System Design Studies" [07]

The WP2 framework [03][04] provides functional requirements for HVDC Grid systems summarizing the latest state of technical discussions and supporting investigations throughout Phase 1. Translating the general framework into specific requirements for the InterOPERA demonstrator system, also considering time constraints for the model delivery, can be described as one of the main challenges in task 3.3.

Throughout WP3, use cases and features of the demonstrator system have been aligned among the different stakeholder groups. The outcome is documented in Annex 01 and forms an agreed baseline for the overall demonstrator scope which is an important input to the specifications. In addition, results from preparational deliverables D3.1 [05] and D3.2 [06] are considered and partly revised, if needed.

The specifications cannot remain purely functional, meaning that specific electrical values or parameter ranges must be provided further detailing functional requirements. For this purpose, design studies on HVDC Grid level are conducted in a new task T3.6 leading to deliverable D3.8 [07]. The outcomes of these HVDC grid-level design studies are taken into consideration for the provision of quantitative values for the detailed functional specifications in this document.

3. Demonstrator System Architecture

3.1. General definition of demonstrator subsystems

The InterOPERA demonstrator is based on the functional subsystem breakdown presented in D2.1 [03] with the only difference that the DC Energy Absorber Unit is an integrated part of the AC/DC Onshore Converter Station and not a stand-alone HVDC subsystem. This decision was motivated in D3.1 [05] to balance project scope and implementation efforts. The resulting hierarchy of HVDC subsystems within the multi-terminal HVDC system for the demonstrator is presented in **Figure 3-1**. The HVDC Grid Controller and Grid Communication System is shown in addition to the HVDC primary system at the interface of the station level elements.

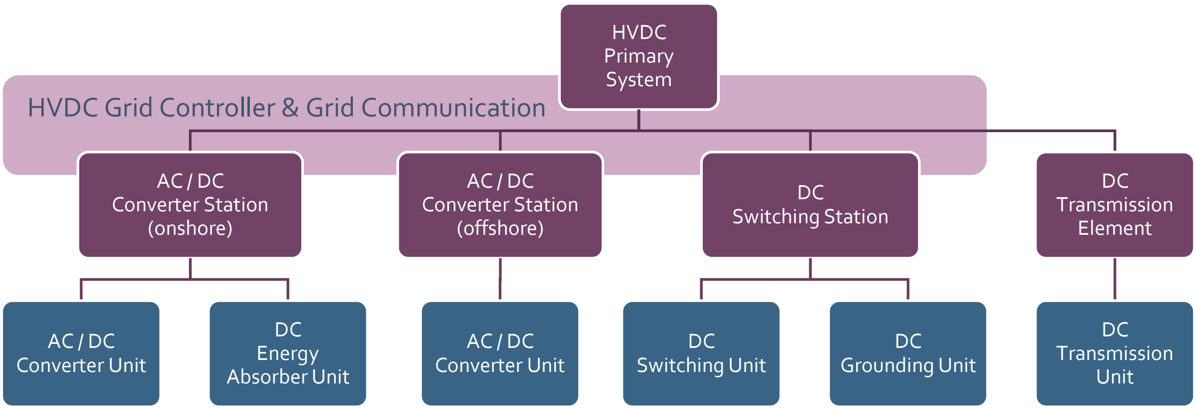


Figure 3-1: Definition of HVDC subsystems for the InterOPERA demonstrator / HVDC system

A formal definition of the HVDC subsystems and a general assignment of functions can be taken from [03]. The Overall Demonstrator Definition (this document) and the associated demonstrator subsystem specifications (its annexes) will apply this functional breakdown to the defined demonstrator project and shall motivate deviations, if any, from the general understanding in the project specific context.

In addition to the HVDC subsystems, the demonstrator project consists of two additional AC subsystems due to its nature of being a real project inspired **test system** with additional degrees of freedom [06]:

- AC Onshore Testbench
- Power Park Modules + AC Offshore Testbench

All of the above-mentioned subsystems, both AC and DC, form the building blocks from which the demonstrator and its variants are assembled. The agreed demonstrator system will be further elaborated in this document providing system level requirements which cannot be assigned to a single subsystem or which are relevant for the design of all subsystems.

This includes information about the system context and the required behavior at its AC boundaries as well as environmental data like the definition of **the InterOPERA DC cable** assumed as homologated DC Transmission Element for the design of the demonstrator.

3.2. HVDC System States

Relevant operating states of the demonstrator on HVDC system level are defined following the System Operation Guideline (SOGL) [08]. It shall be noted that the definitions from SOGL, in particular for NORMAL and ALERT state, differ from IEC TS 63291 [09].

Normal State

"Normal State means a situation in which the system is within Operational Security Limits in the N-situation and after the occurrence of any Contingency from the Contingency list, taking into account the effect of the available Remedial Actions." [08]

Interpretation for the InterOPERA HVDC System:

The system is within Operational Security Limits for the current N-situation and is also N-1 secure, after effect of the available Remedial Actions, for any Contingency from the Contingency List. The current situation does not imply that all subsystems are available as planned as the normal state is only based on security aspects. It can be in a degraded state because one or more subsystems are not available.

→ **No action is required.**

Alert State

"Alert State means the system state in which the system is within Operational Security Limits, but a contingency from the contingency list has been detected and in case of its occurrence the available remedial actions are not sufficient to keep the Normal State." [08]

Interpretation for the InterOPERA HVDC System:

The system is within Operational Security Limits for the current situation, but contingency analysis identified that it is not N-1 secure, even after effect of the available Remedial Actions (e.g., primary control – cf. listed actions for normal state in **Table 4-6**), for at least one Contingency from the Contingency List. It is recommended to bring the system back to Normal (Secure) State.

While the above statement is generally valid, in the InterOPERA demonstrator, "Alert State" shall be exclusively identified by the quasi-stationary DC voltage leaving a pre-defined N-1 secure "Normal voltage range" for the respective test scenario.

→ **Action is required but not immediately.**

Emergency State

"Emergency State means the system state in which one or more operational security limits are violated." [o8]

Interpretation for the HVDC System:

The system is outside Operational Security Limits which, without being resolved in a given time frame, can lead to cascading effects and finally to Blackout State.

→ Immediate restoration action required to avoid Blackout State.

Blackout State

"Blackout State means the system state in which the operation of part or all of the transmission system is terminated." [o8]

Interpretation for the InterOPERA HVDC System:

Load flow in parts or all of the HVDC System cannot be resumed as parts or all of the HVDC System are permanently disconnected from the DC side, from the AC side or both. In the context of the InterOPERA demonstrator, this state is not relevant in so far that the network size does not allow a reasonable definition of sub-grids in Blackout State.

→ Restoration action required but not immediately.

Restoration State

"Restoration State means the system state in which the objective of all activities in the transmission system is to re-establish the system operation and maintain operational security after the Blackout State or the Emergency State." [o8]

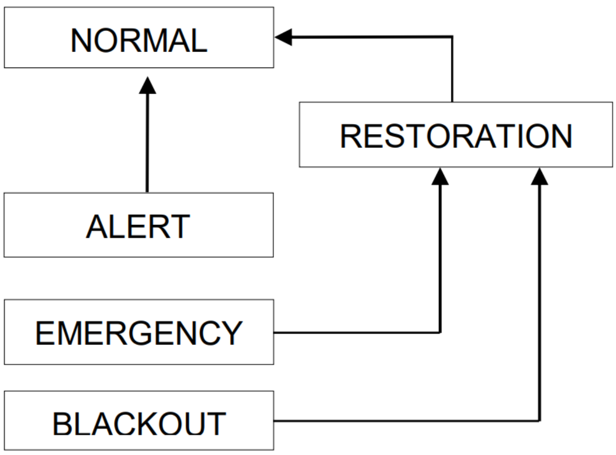


Figure 3-2: HVDC System Operating States [o8]

3.3. General HVDC control & protection strategy

3.3.1. Control architecture

The InterOPERA demonstrator control architecture shall follow a hierarchical structure schematically depicted in **Figure 3-3**. The dispatch level is not included in the scope of the InterOPERA demonstrator. Any input and signal that is required on operation level or the station level – and that in a real system would originate from the dispatch level – will be manually entered in the individual subsystem's Human-Machine-Interface (HMI).

The operation level in InterOPERA is realized by a DC Grid Controller. The DC Grid Controller governs the overall HVDC system by issuing commands to and collecting status information from the individual subsystems in the station level[1]. For the InterOPERA demonstrator, it was decided that the communication between the operation level and the station level shall be realized according to the principles of IEC 61850 protocol. As part of the demonstration, it shall be evaluated if the IEC 61850 protocol and its engineering processes can also be applied in real infrastructure projects including long-distance communication needs. Further information on the DC Grid Controller and the DC Grid Communication System can be found in the corresponding subsystem specification.

The communication between the station and unit level is subject to the individual vendor's solution and will be further detailed in the subsystem specifications. Please note that direct exchange of information between stations/elements at station level, or units at unit level, is not foreseen in **Figure 3-3** but also not explicitly excluded if e.g. interlocking or protection requirements cannot be reliably realized by an exchange of information via the DC Grid Controller on operation level.

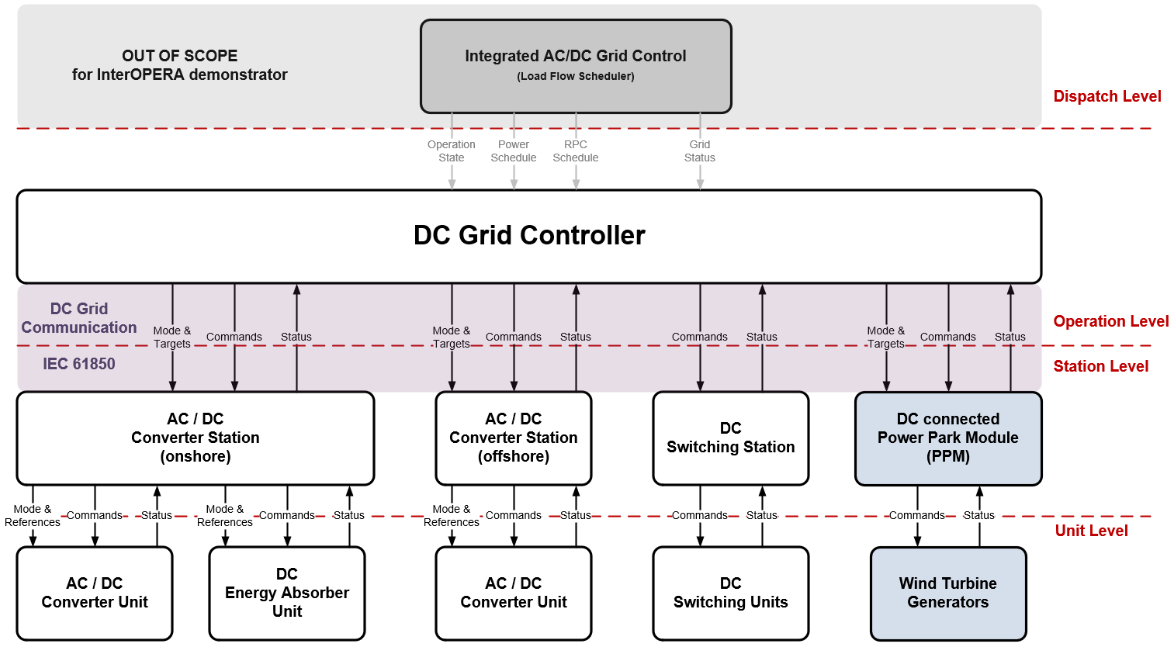


Figure 3-3: General control hierarchy for the InterOPERA demonstrator[2]

[1] As shown in **Figure 3-1**, transmission elements are also part of the station/element level. As they do not communicate to the DCGC (labelled as "passive" in D2.1 [03], Fig. 2), they are omitted here. In case communication from cable segmentation/transmission stations is required on operation level, these would have to be added on station level.
[2] The direct communication between the DC Grid Controller and the Power Park Modules is a specific decision made for the InterOPERA demonstrator to reduce the coordination effort for offshore wind power curtailment. This is motivated and further elaborated together with alternative schemes in deliverable D3.1 [05] and D2.1 [03].

3.3.2. Control principles

Sequential Controls

Sequential controls refer to any planned action that allows modification of the HVDC system topology by changing the connection status of the different units within the HVDC system. Following subsystem definitions in D2.1 [03], in the context of sequential controls, a **functional unit** is understood as a subsystem that can have its own independent and unambiguous unit state[3].

The following definition of connection states shall be used throughout the InterOPERA demonstrator. Detailed description of the states is provided in the subsystem specifications.

Table 3-1: Definition of HVDC unit states used in the InterOPERA demonstrator

Unit	State	Description
DC Switching Unit	Maintenance Earthed	Unit is out of operation and not available.
	Transmission Unit Earthed[4]	Adjacent transmission unit is earthed.
	Open	PoC-DC and DC busbar are not connected.
	Closed	PoC-DC and DC busbar are connected.
AC/DC Converter Unit	Maintenance earthed	Unit is out of operation and not available.
	Ready to connect	Earthing removed, internal disconnectors closed; auxiliary systems available to allow connection to AC or DC side
	AC aggregated (not utilized)	Unit connected to PoC-AC but no AC voltage applied
	DC aggregated	Unit connected to PoC-DC but no DC voltage applied between unit terminals
	AC/DC aggregated (not utilized)	Unit connected to PoC-AC and to PoC-DC but no AC voltage and no DC voltage applied
	Energized from DC	Unit connected to PoC-DC but not to PoC-AC; Unit energized and deblocked
	Energized from AC	Unit connected to PoC-AC but not to PoC-DC; Unit energized and deblocked
	Ready to transmit	Unit connected to PoC-AC and to PoC-DC; Unit ready to transmit active power

[3] Please note that the InterOPERA definition of a **functional unit** differs from IEC TS 63291 (10 / 2023) and leads to different aggregation levels, in particular for DC Switching Units. In IEC TS 63291, a DC Switching Unit comprises both HV poles and the neutral system in one logical element whereas; in InterOPERA, this would be defined as three separate functional units.

[4] only relevant for DC switching units connecting to an external transmission unit (i.e. DC cable)

Table 3-2: Definition of PPM unit states used in the InterOPERA demonstrator

Unit	State	Description
Power Park Module	Not available	PPM is not available for power generation.
	Ready to generate	PPM is connected and operational. Power can be ramped up.

For the InterOPERA demonstrator, the sequential controls include handling of the following actions:

- Planned connection and disconnection of transmission units
  (see UC01-01 / UC01-03 in Annex 01)
- Planned connection and disconnection of AC/DC converter units
  (see UC01-01 / UC01-03 in Annex 01)
- Planned split or merge of two live sub-grids
  (see UC01-081 / UC01-082 Annex 01, and also sections 6.3.3 and 6.3.5 of D3.2 [06]))

Those actions involve the control of DC switching units (open / close) and of AC/DC converter units (energization / shut down…). The different reconfigurations may be executed according to two main different approaches:

A. "Manual" mode: all unit commands are issued and coordinated by the human operator.
B. "Automated" mode: in response to an operator trigger, the DCGC automatically issues the commands to complete the overall sequence.

Combination of both modes shall be envisaged, considering that complex reconfigurations can only be partly automated, or to allow the operator to proceed in a step-by-step manner.

Continuous Controls

IEC TS 63291 [09] introduces a continuous control hierarchy which is also considered and further elaborated in D2.1 [03]. The InterOPERA demonstrator generally builds upon the same continuous control structure with the difference that:

- **no dispatch level (AC/DC grid control)** is implemented
- **no autonomous adaptation control** is considered [5]

The resulting continuous control hierarchy for the InterOPERA demonstrator is shown in **Figure 3-4**.

For continuous control, the DC Grid Controller in the operational level shall be non-essential for system stability. This means that the stability of the HVDC system shall be maintained by the DC node voltage control in the station and unit level making use of available primary power and voltage reserves. The DC Grid Controller and its role in the continuous controls is described in this section and in the subsystem specification Annex 3.3.2. Requirements on the DC node voltage control and its implementation are further detailed in this section and in the subsystem specifications Annex 3.3.3.

The internal controls are supposed to remain within the individual vendor's responsibility. The internal controls will therefore not be specified in detail. Settling times of the internal controls shall be sufficiently low to not interfere with the tasks of the upper-level controls which will be further detailed in subsystem specification Annex 3.3.3.

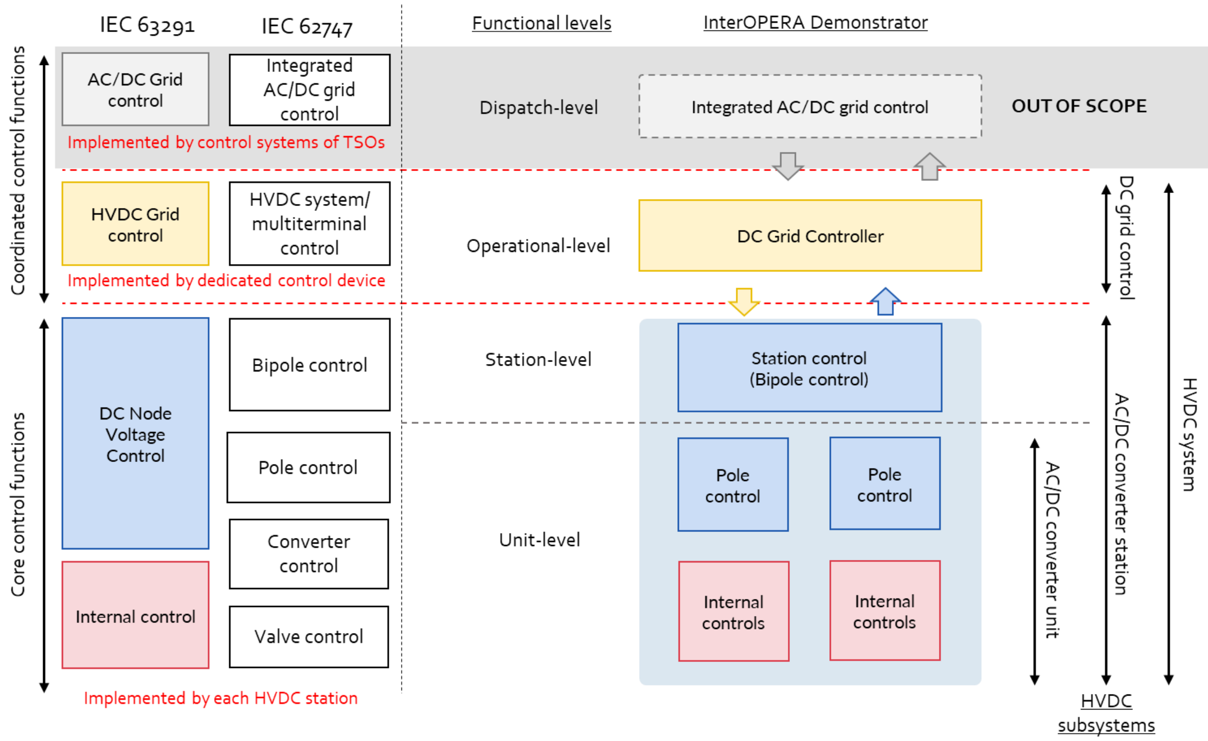


Figure 3-4: Overview of the continuous control hierarchy for the InterOPERA demonstrator (adapted from [03])

[5] Based on the use cases (Annex 01), there was no need identified for control functions which could be reasonably interpreted as autonomous adaptation control in the sense of IEC TS 63291.

There are several ways to control a bipolar HVDC network which are described in D2.1 [03]. For the InterOPERA demonstrator, it was decided to control the two HV poles separately in the basic use cases. This means the DC node voltage control is fully implemented on pole control level. The station control (bipole control) shall only serve as a router providing the setpoints received from the DC Grid Controller to the corresponding pole controls. With this control strategy, use of power reserves between the poles and limitation of neutral system quantities in case of asymmetric operation can only be realized by coordinated control functions on operational-level. Please refer to **Figure 3-5** for a conceptual illustration of this control concept. The different types of DC node voltage control applied in the InterOPERA demonstrator are further explained in this chapter and the subsystem specifications Annex 3.3.3.

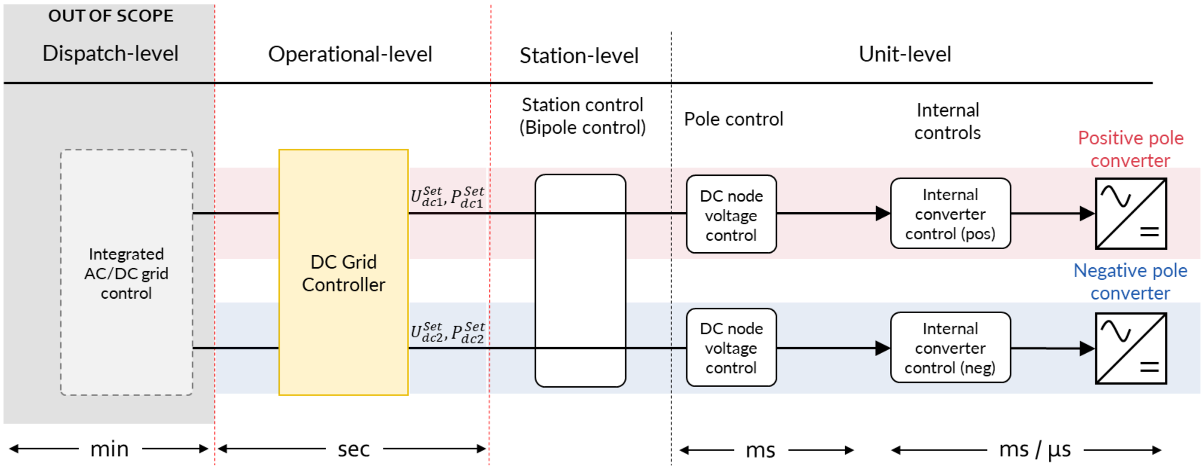


Figure 3-5: Conceptual illustration of independent control over positive and negative poles (adapted from [03])

Primary Control

The DC Node Voltage Control shall form an essential part of the HVDC system's primary reaction to both power and voltage disturbances. Its response shall be solely based on local measurements at the HVDC subsystem's point of connection. According to D2.1 [03], the following DC side control modes can be distinguished representing different levels of contribution to DC voltage stability:

i. Fixed DC voltage control mode

ii. DC voltage droop control mode

iii. Fixed active power control mode[6]

In the InterOPERA demonstrator, these control modes shall be realized on unit-level by the AC/DC converter stations when in unit state "Ready to transmit". The DC side control modes listed in **Table 3-3** are required. Change of the DC node voltage control mode shall be initiated by the DC Grid Controller or at the local AC/DC converter unit HMI. This will be further elaborated in subsystem specifications Annex 3.3.2 and Annex 3.3.3.

Table 3-3: DC node voltage control modes

DC node voltage control modes	Onshore AC/DC converter unit	Offshore AC/DC converter unit
Fixed DC voltage control mode	X	
DC voltage droop control mode (DC voltage and active power)	X	
Fixed active power control mode[5]		X (associated with V/f control)

[6] From the perspective of DC node voltage control, this mode maintains its active power exchange at PoC-DC regardless of the DC voltage level, thereby not contributing to the DC voltage containment in steady-state.

Secondary Control

Secondary DC voltage and power controls are implemented on operation level which shall be realized by the DC Grid Controller in the InterOPERA demonstrator. According to D2.1 [03], their task is:

(1) To correct and maintain the active power interchange over the DC grid.

(2) To maintain or restore the power flow and DC node voltages within the specified limits.

Deviations from the initial active power and DC voltage targets typically occur in connection with variation of offshore wind power generation. For the InterOPERA demonstrator, it was decided that fluctuations of the operating point within a pre-defined N-1 secure "Normal voltage range" will not lead to any automatic reaction from the DC Grid Controller. In this case, the operator is free to provide new active power and/or DC voltage references if deemed necessary.

After ordinary contingencies, primary control - in connection with sufficient voltage and power reserves - is expected to keep the HVDC system within Operational Security Limits. If the new equilibrium after primary control response is not N-1 secure, the HVDC system is entering "Alert state" (refer to section 3.2). In this case, the secondary controls of the DC Grid Controller shall be triggered to:

- Provide new active power setpoints while satisfying additional load flow constraints.
- Provide new DC voltage setpoints to bring back the HVDC system voltage within the N-1 secure "Normal voltage range" for the actual scenario and hence restore "Normal State".

Both aspects shall be handled in the DC Grid Controller by means of Optimal Power Flow (OPF) computation and provision of adequate voltage and power setpoints together with associated ramp-rates. More details can be found in section 4.2.7 "Remedial Actions" and Annex 3.3.2.

Extreme events leading to a persistent violation of Operational Security Limits, i.e. the HVDC system is entering "Emergency State", shall be taken care of by coordinated control schemes specifically defined for the InterOPERA demonstrator in "Overvoltage Power Control Scheme (OVPC)".

3.3.3. Protection principles

Protection principles of HV-MTDC systems follow similar principles as in AC systems and are supposed to ensure reliable and secure system operation. This includes avoiding fault propagation from AC to DC side and vice versa and avoiding shutdown of the entire system in case of local DC faults. A description of a general terminology and definition of system wide requirements has already been implemented in chapter 7 of D2.1 [03]. From the framework described in D2.1, it was decided to take the following general principles and assumptions into account for the protection design of the InterOPERA demonstrator:

i. zoning concept for DC grid planning distinguishing between **Fault Separation Zones (FSZ)** and **Fault Isolation Zones (FIZ)**

ii. formulation of **DC fault separation requirements** for individual HVDC sub-grids[7] characterized by different fault neutralization times

iii. formulation of undervoltage **DC fault-ride-through (DC FRT) compliance test profiles for** AC/DC **converter stations** in individual HVDC sub-grids

iv. allowance of **temporary blocking of AC/DC converter stations as one option[8] to** ride through the **DC FRT compliance** test profile in line with the descriptions in chapter 7 of D2.1 [03].

v. **limitation to main protection**. Back-up protection, i.e. malfunction of a protection device is not considered in the design and will not be tested (refer to Use Case 03-03 in Annex 01).

These principles will be applied in chapter 5 where the InterOPERA demonstrator design is described.

The preliminary specifications from D3.3a formulated a reduced set of requirements for protection design, which intended to allow adequate primary system design of all subsystems. In particular, the requirements for AC/DC converter stations (cf. section 5.1.3 and section 5.2.2) have been limited to ensuring that converter stations do not trip until the maximum DC fault neutralization time specified in the DC FRT profile. These preliminary specifications have been taken into account for the design studies in T3.6 / D3.8 [07]. For the detailed functional specifications (this document and its annexes), the DC FRT profile is further detailed, quantified, and connected to the dynamic DC voltage ranges – in particular to describe the behaviour after DC fault neutralization, and the requirements for de-blocking in case the AC/DC converter station has blocked (but not tripped) to ride through the low DC voltage at its PoC-DC.

Disclaimer: While the DC FRT specification until fault neutralization – and the standalone DC FRT test for AC/DC converter stations which is explicitly designed to cover this time frame – has been proven to lead to the expected DC protection performance on a system level in T3.6 transient studies (cf. [07]), the updated DC FRT specification including DC voltage recovery after fault neutralization and converter de-blocking has not been tested in any generic HVDC grid study. Hence, a special focus during the demonstrator studies (UC03-01, UC03-021, and UC04-051 in Annex 01) shall be put on the evaluation of the system behaviour achieved with all AC/DC converter stations fulfilling the D3.3b DC FRT requirements.

[7] Following D2.1 [03] definition, a **sub-grid** is characterized by a set of functional requirements (here: fault separation requirements) and can be connected to other sub-grids with different functional requirements at one or several connection points. For the InterOPERA demonstrator, two sub-grids with different DC fault separation requirements are considered as outlined in section 5.2.2.

[8] for the InterOPERA demonstrator, it is considered that the *temporary* blocking functionality is allowed and available. In practice, the relevant TSO determines whether and to which extent such functions may be used in the event of a DC fault.

4. Demonstrator System Context

4.1. Demonstrator Use Cases and Features

The InterOPERA demonstrator use cases are described in Annex 01 and listed in **Table 4-1**. These use cases shall be referenced and connected to the functional requirements in this document and its annexes, the subsystem specifications.

Classification of a Use Case is based on its maturity and its relevance for the achievement of InterOPERA's project objectives. Use Cases defined as **B**asic form the minimum scope of the demonstrator project. **O**ptional Use Cases might require further investigation and iterations in the demonstration or cannot be fully developed by all vendors in the time frame of InterOPERA.

Table 4-1: Demonstrator Use Cases assigned to the Detailed Specifications (from Annex 01)

F01	Grid Operation and Reconfiguration	Basic Optional
UC01-01	Start-up from 1 onshore station and shut-down	B
UC01-021	Transition from one power flow schedule to another (only set points)	B
UC01-022	Transition to new control modes and control parameters	B
UC01-03	Basic switching operations and grid reconfiguration sequences	B
UC01-04	Secondary control - automatic transition to a new power flow schedule after a severe contingency	B
UC01-081	Planned subgrids merge - on load switching	O
UC01-082	Planned grid split - on load switching	O
F02	**Continuous Controls**	Basic Optional
UC02-01	Power disturbance with 1 converter station in Vdc control mode, the others in power control mode	B
UC02-02	Power disturbance with converter stations in Vdc-droop control modes	B
UC02-031	Asymmetrical pole operation due to one transmission pole outage	B
UC02-032	Asymmetrical pole operation due to difference in power injection in positive and negative poles	B
UC02-04	Vdc-droop converters connected to the same DC-bus, to the same DC switching station	O

F03	DC Protection	Basic Optional
UC03-01	DC fault within all selective fault separation zones	stage 1: O stage 2: B
UC03-021	DC fault within the fault separation zone including non-selective zones	stage 1: O stage 2: B
F04	**Offshore AC Performance**	Basic Optional
UC04-01	Offshore grid energization from 1 offshore HVDC station ("soft start")	B
UC04-02	PPMs from two different vendors directly connected to the same busbar (steady-state small-signal operation validation)	B
UC04-03	Re-energization of tripped PPM after HVDC transformer fault by closing busbar coupler ("hard start")	B
UC04-051	Ride through offshore HVDC converter temporary blocking with WTGs in GFL control mode	stage 1: O stage 2: B
UC04-07	DC-side contingency leading, after energy absorber activation, to a coordinated emergency offshore wind ramp-down or curtailment	B
UC04-081	Offshore AC fault ride through capability with GFL WTGs - Post fault active power recovery	B
UC04-111	HVDC converter permanent blocking with WTGs in GFL control mode	B
F05	**Onshore AC Performance**	Basic Optional
UC05-01	Onshore AC fault ride through capability and post fault active power recovery	B
UC05-02	Reactive power support under weak grid conditions	B
UC05-03	Grid forming active power support to the onshore AC grid	B
UC05-12	Exploration of HVDC system stability and interoperability with interconnected AC areas (no design requirements)	O

4.2. System boundaries / System context

4.2.1. Demonstrator DC side topologies

The **full scope** of the demonstrator DC-side topology is depicted in Figure 4-1. It was originally agreed in D3.1 [05] and further refined in D3.8 [07] avoiding variations on the DC side in order to:

a) use only one set of signal definitions with a unique assignment of subsystems to DC connection points for the interaction between operation level and station level controls

b) reduce risk for ambiguity in technical discussions throughout the project

As the hardware setup of the demonstrator is limited to three AC/DC converter stations (one per vendor), it was decided to define a subset of the full extent as a so-called **base case** and make this a minimum scope of delivery. The system studies performed in Task T3.6 "HVDC Grid System Design Studies" focused on the base case to create a robust study approach. The base case DC side topology is shown in **Figure 4-2**. The detailed set of functional specifications, i.e. this document and its annexes, shall take both the full scope DC-side topology and the base case into account. For some subsystem specifications, the DC side topology might be irrelevant (e.g. AC Onshore Testbench) or it might be beneficial to already consider the full scope respectively parts thereof (e.g. DC Grid Controller). In this case, the individual demonstrator scope considered shall be further detailed in the corresponding annexes.

The AC/DC converter stations (AC/DC #1-5) shown in the overviews can be either onshore or offshore type depending on the study scenario. Each vendor is supposed to deliver one onshore design and one offshore design for an AC/DC converter station. The grid level requirements on each design are further described in section 5, the detailed subsystem specification is provided in Annex 3.3.3.

The DC switching stations (DCSS #1-5) are illustrated by bus sections and generic DC switching units. For DCSS #3 and #4, only one DC cable connection is foreseen. Another DC cable connection is indicated in dashed lines to allow the same DCSS typical in location #1, #2, #3 and #4. Grid level requirements and associated functionalities of the DC switching units (e.g. for fault separation) are described in section 5, the detailed subsystem specification is provided in Annex 3.3.4.

The AC connection details are not shown in **Figure 4-1** and **Figure 4-2** as they might differ based on the study scenario and the AC/DC converter station type being onshore or offshore. General AC connection requirements for both types are described in the next section 4.2.3. The detailed subsystem specification of the AC Onshore Testbench is provided in Annex 3.3.5, for the AC Offshore Testbench incl. Power Park Modules in annex Annex 3.3.6.

Detailed data of the DC cable connections shown in the overviews is provided in section 4.3.1.

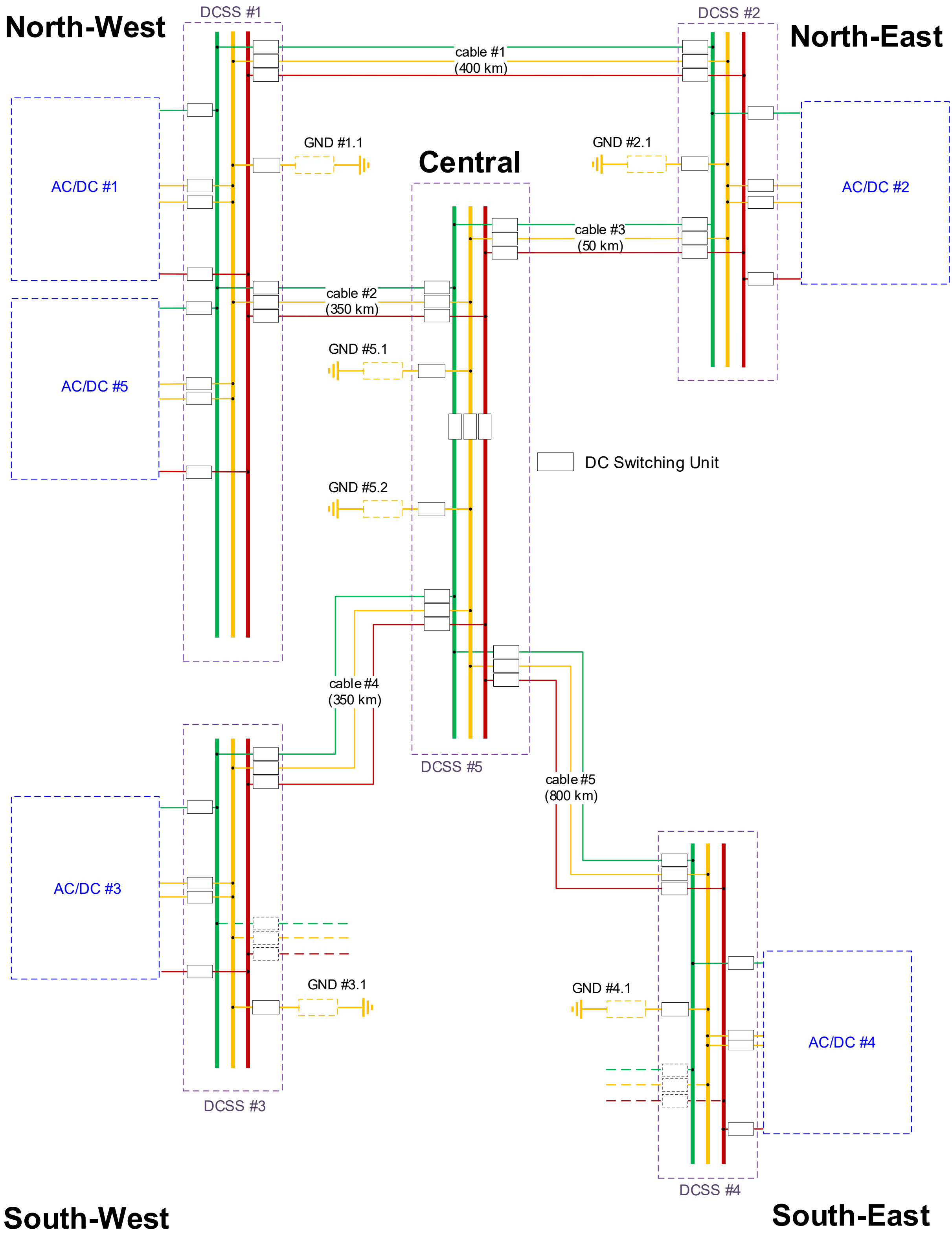


Figure 4-1: Demonstrator DC side topology; full scope

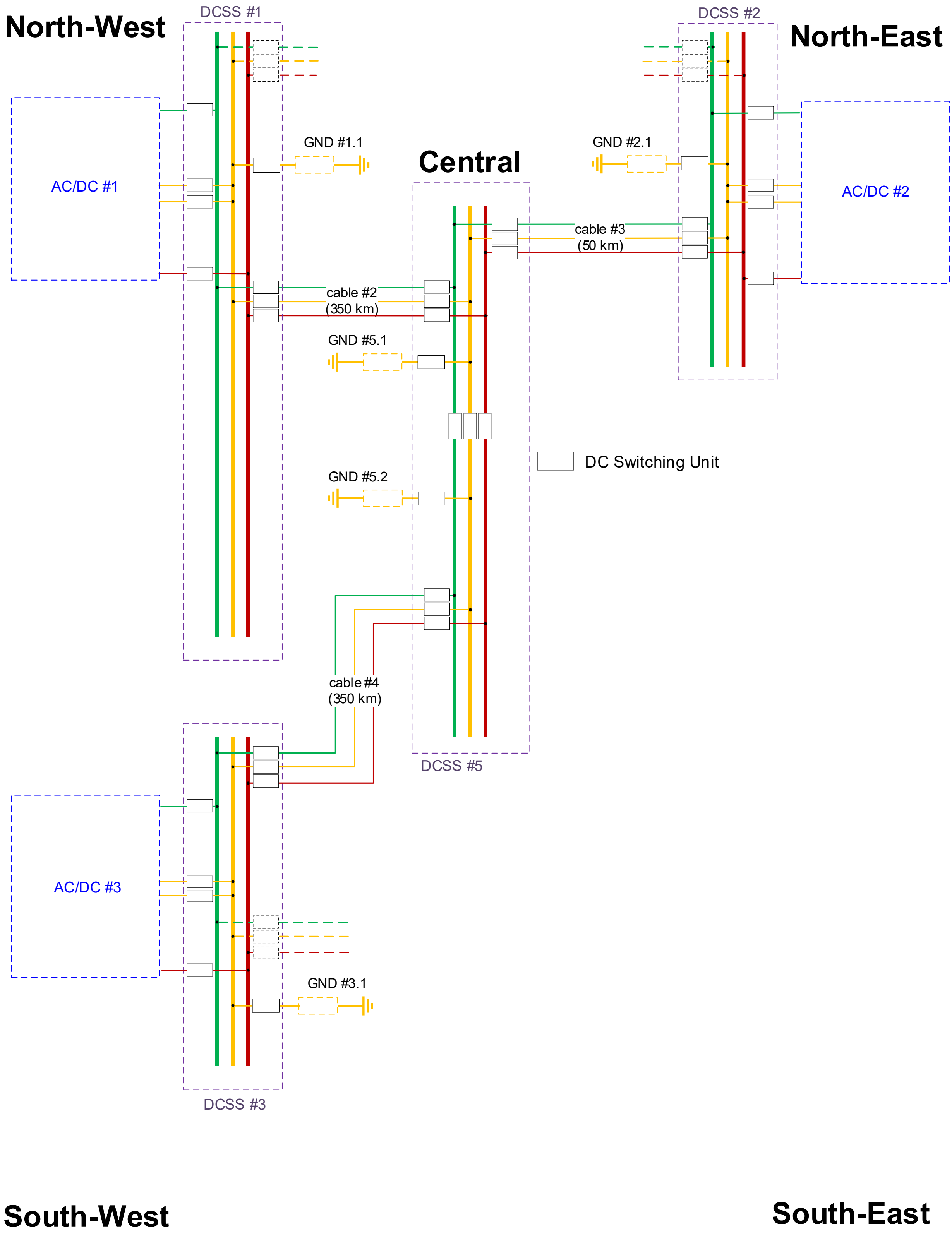


Figure 4-2: Demonstrator DC side topology; base case

4.2.2. Reference Designation for Points of Connection (DC and AC)

In accordance with IEC TS 63291 [09], the point of connection DC (PoC-DC) is defined as the electrical interface point at DC voltage; the point of connection AC (PoC-AC) is defined as electrical interface point at AC voltage. The technical specification from IEC also offers a reference designation system that shall be applied to the InterOPERA demonstrator as depicted in **Figure 4-3** (for DC Switching Station) and **Figure 4-4** (for AC/DC Converter Station). The point of connection of the power park modules to the offshore AC system shall be designated as shown in **Figure 4-5**.

All HVDC subsystem specifications shall follow this naming convention. Functional requirements shall refer to the PoC-DC and the PoC-AC to which they apply.

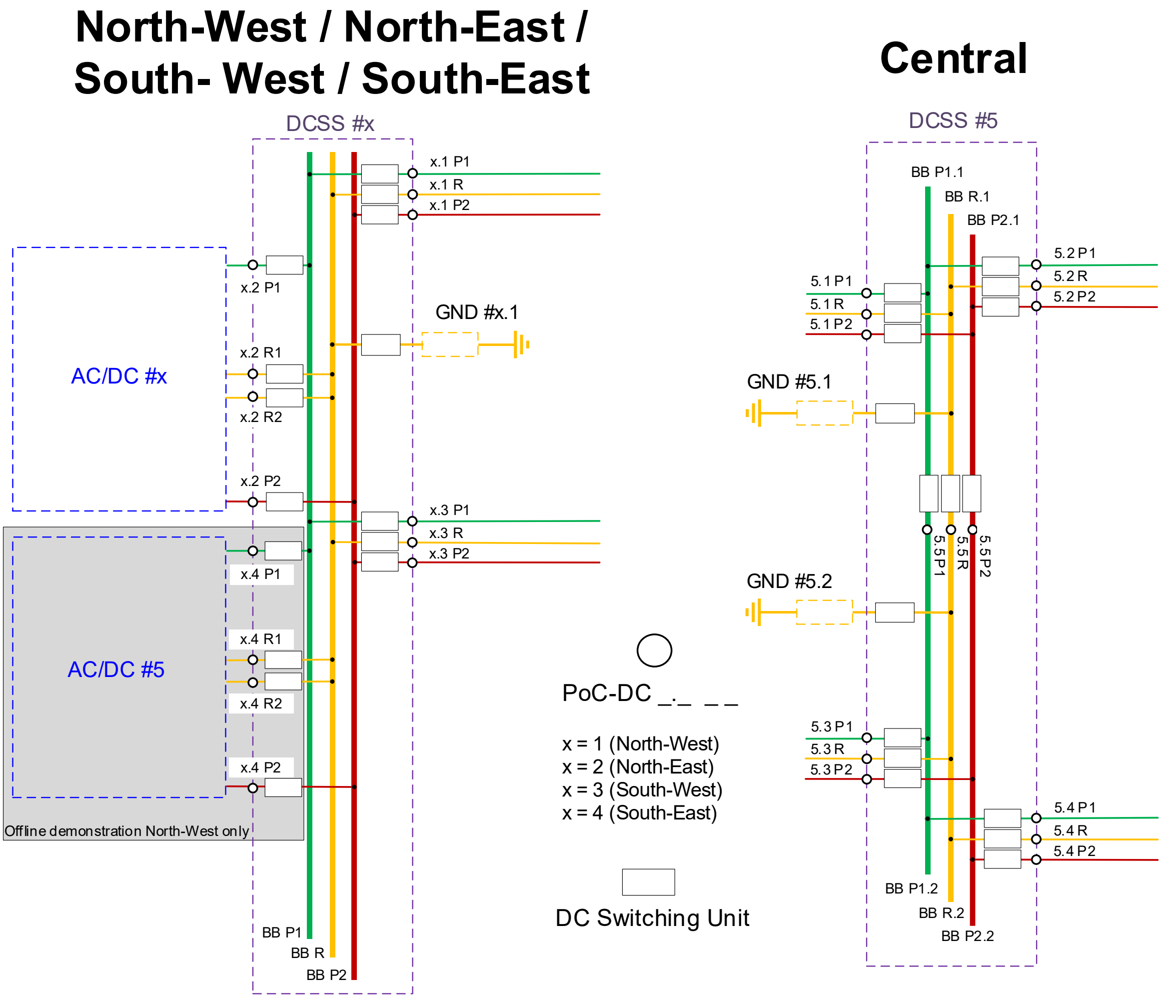


Figure 4-3: Demonstrator reference designation of PoC-DC for DC Switching Stations

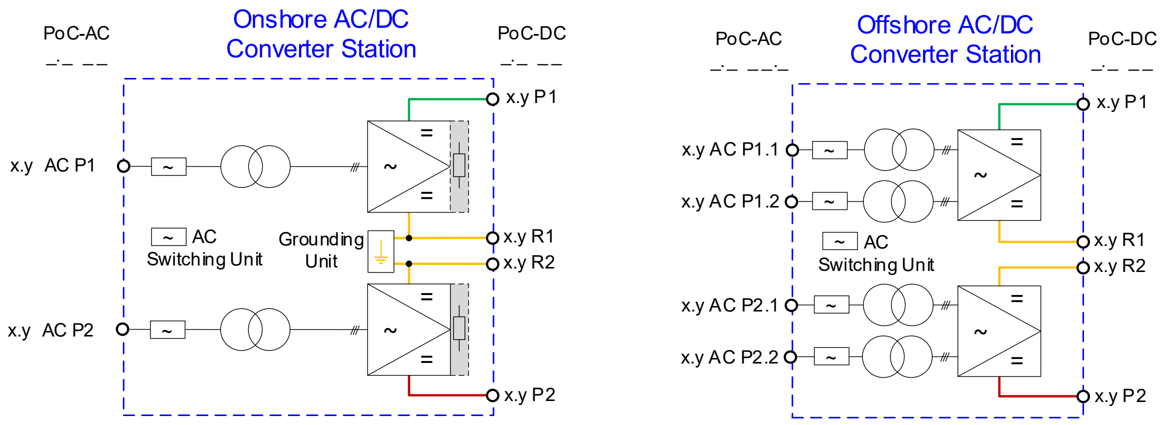


Figure 4-4: Demonstrator reference designation of PoC-AC and PoC-DC for AC/DC Converter Stations

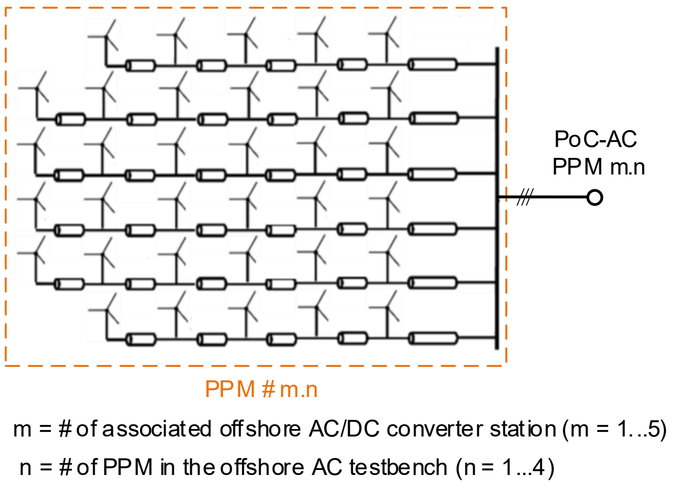


Figure 4-5: Demonstrator reference designation of PoC-AC for offshore PPM

4.2.3. Sign Convention

As different station level elements are communicating and sharing measured values with the DC Grid Controller (refer to section 3.3.1), a consistent sign convention shall be used throughout the demonstrator.

For the InterOPERA demonstrator, it was decided that all currents flowing "into the DC grid" are counted as positive. By this approach, a switch-over of reference values in the DC Grid Controller from DC side to AC side does not require changes in the signing.

For the demonstrator subsystems, the following sign conventions shall be used at the connection points:

U_A = Voltage to ground at Point A

U_B = Voltage to ground at Point B

U_AB = Voltage between Point A and Point B with $U\_AB = U\_A - U\_B$

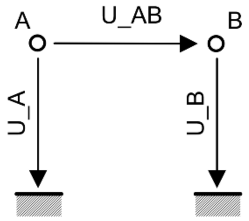


Figure 4-6: Example for definition of voltage phasor in this document

AC/DC Converter Station

Refer to Figure 4-7:

- DC side: Generator sign convention for active power and DC currents
- AC side: Load sign convention for active and reactive* power

*This implies that: inductive reactive power (lagging current) is counted as positive (+)
capacitive reactive power (leading current) is counted as negative (-)

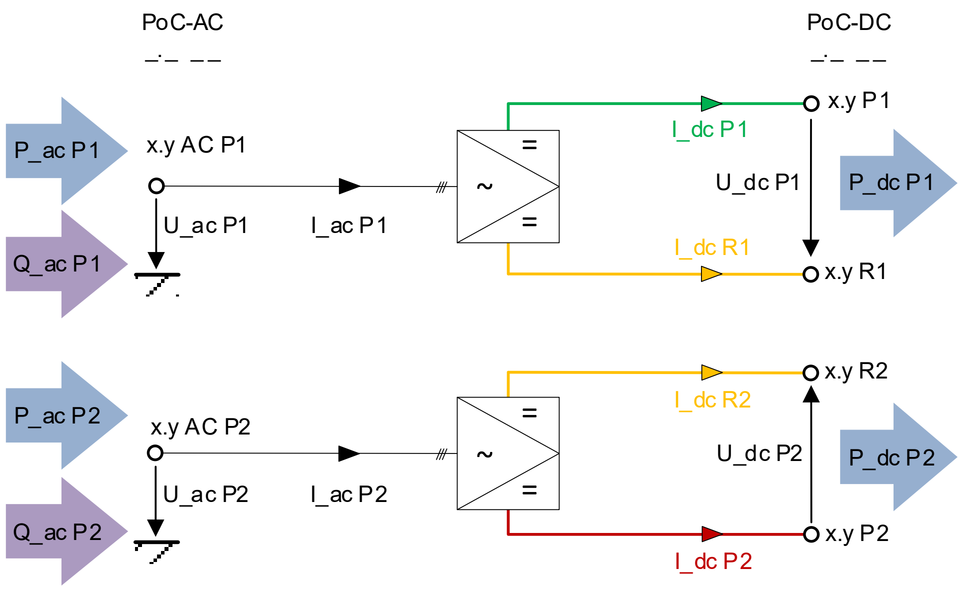


Figure 4-7: Demonstrator sign convention for AC/DC converter station

Offshore PPM

Refer to Figure 4-8:

- AC side: Generator sign convention for active and reactive* power

  *This implies that: inductive reactive power (lagging current) is counted as negative (-) capacitive reactive power (leading current) is counted as positive (+)

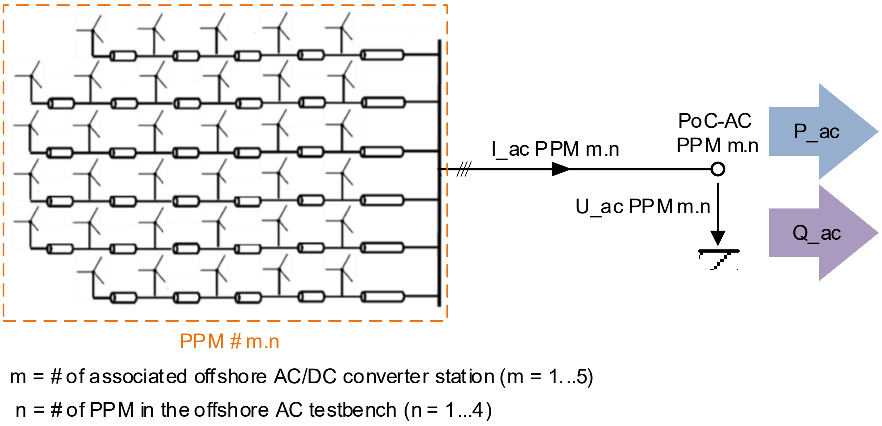


Figure 4-8: Demonstrator sign convention for offshore PPM

DC Switching Station

Refer to Figure 4-9:

- DC side: Load sign convention for active power and DC currents

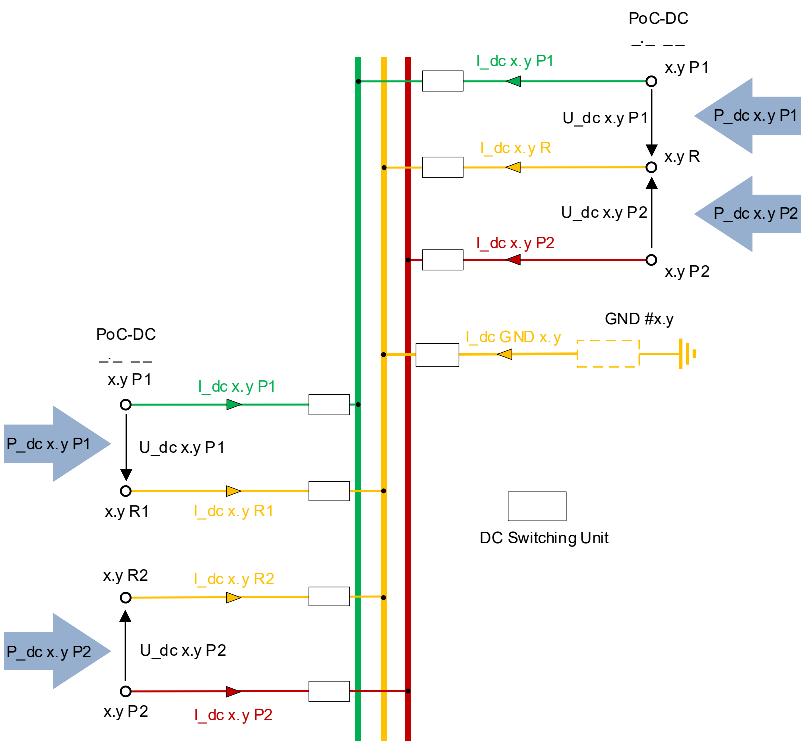


Figure 4-9: Demonstrator sign convention for DC Switching Station

4.2.4. AC connection requirements

Depending on the study scenario, AC/DC converter stations can be connected to different AC systems:

1) integrated AC onshore system
(see subsystem specification Annex 3.3.5 "AC Onshore Testbench")

2) isolated AC offshore system
(see subsystem specification Annex 3.3.6 "Power Park Modules + AC Offshore Testbench")

The type of the AC/DC converter station being onshore or offshore would change according to the study scenario. Both AC/DC converter station types shall be described in subsystem specification Annex 3.3.3 "AC/DC Converter Station (onshore/offshore) + DBS".

General compliance with established network codes is assumed but will not be validated in detail by the demonstration. The applicable grid code for the InterOPERA demonstrator shall be the NC HVDC [10]. The national implementation VDE-AR-N 4131:2019-03 [11] shall apply in case more exhaustive parameters are needed but not provided in the NC HVDC. Further details on the AC connection requirements can be found in the subsystem specifications Annex 3.3.5 and Annex 3.3.6.

Depending on the use case (refer to section 4.1 and Annex 01), different general AC control behaviours are expected at the Point of Connection AC (PoC-AC) which are:

'Grid Following (GFL) control' (adapted from D2.2 [04]; refer to D3.2 [06] for control concept)

Grid-following (GFL) control refers to conventional strategy or non-grid-forming control behavior of an AC/DC converter unit or DC-connected PPM, where active (P) and reactive (Q) power exchange with the AC grid are regulated directly through controlling the active and reactive currents using current controllers. In PQ control, the subsystem acts as controlled current source in parallel to an impedance and does not provide a notable inherent response to changes in the phase, frequency, and voltage amplitude. Any support of the AC grid during such disturbances in PQ mode can only be provided by changing the setpoints based on measurement values.

'V/f control' (adapted from D2.2 [04]; refer to D3.2 [06] for control concept)

V/f control behavior refers to the case where the HVDC converter station is the single component in an isolated AC network for generating, controlling and maintaining the AC voltage and frequency. In the InterOPERA demonstrator context of DC-connected PPMs, this control mode is used for offshore stations, where demonstrator the wind turbines are in conventional GFL control (see definition of GFL control).

'Grid Forming (GFM) control' (adapted from D2.2 [04]; refer to D3.2 [06] for control concept)

GFM functionality is defined as the functional behavior of an AC/DC converter unit or DC-connected PPM as a controlled voltage source behind an impedance, following the definition of the ENTSO-E technical group work HPoPEIPS [12]. The voltage source behavior at the AC connection point of an AC/DC converter unit or DC-connected PPM shall be maintained as long as the HVDC system or the PPM is within the operating limits. This voltage-source behavior means that the HVDC converter station and/or the PPM shall maintain its internal voltage phasor nearly constant (can slowly change) in the first instance following a disturbance. GFM control can also be used to realize V/f control behavior (see definition of V/f control).

GFM control is a mandatory requirement for the onshore AC/DC converter units delivered in the second stage. It can however still be delivered in the first stage upon individual vendor's choice based on the GFM solution availability. The corresponding assignment of AC node control concepts to the AC/DC converter units for the detailed functional specifications is given in **Table 4-2**.

Table 4-2: AC node control concept assignment

AC node control concepts	Onshore AC/DC converter unit	Offshore AC/DC converter unit
Grid Following (GFL)	*optional*	
V/f		X
Grid Forming (GFM)	X	*optional (with V/f behaviour)*

Following D3.2 [06], base functions have been described, selected and assigned to the AC node control concepts (refer to **Table 4-3**). The requirements on the functions shall be in line with the chosen reference AC grid code unless otherwise specified in the subsystem specifications (Annex 3.3.5 and Annex 3.3.6). Control modes and setpoints for AC node control are sent by the DC Grid Controller to the individual AC/DC converter units and PPMs.

Table 4-3: AC node control function assignment for AC/DC converter units

AC node control function	Grid Following Onshore	V/f Offshore	Grid Forming Onshore
Active Power Control[9] (incl. power ramping)			
Reactive Power Control	X		X
Priority to active or reactive power contribution	X		X
AC Voltage Control		X	
AC Voltage Control with reactive power droop	X		X
Frequency Control	*optional*	X	*optional*
AC fault ride through	X	X	X
Dynamic voltage support	X		X (inherent reactive power capability)
Post fault active power recovery	X		X
Inertial active power capability (Grid forming only)			X

[9] Active power setpoints and control are part of the droop-based DC node voltage control, cf. **Table 3-3**. No constant power control without DC voltage sensitivity is foreseen.

4.2.5. List of Contingencies

Definitions according to System Operation Guideline (SOGL) [08]:

Ordinary Contingency
means the occurrence of a contingency of a single branch or injection.

Exceptional Contingency
means the simultaneous occurrence of multiple contingencies with a common cause.

Out-of-range Contingency
means the simultaneous occurrence of multiple contingencies without a common cause, or a loss of power generating modules with a total loss of generation capacity exceeding the reference incident.

For InterOPERA, the following List of Contingencies was defined for the electrical circuit on the DC side. Any contingency listed below shall be considered in the design of the InterOPERA demonstrator though not all contingencies will be tested (see also section 4.2.6 "DC Fault Locations"). Contingencies not listed below are considered as "Out-of-Range Contingencies". Cumulation of contingencies (N-2) of any kind in the electrical system is not considered in the design of InterOPERA. AC side contingencies are not explicitly defined. General compliance with the AC grid code chosen for InterOPERA shall be assumed (refer to section 4.2.3).

Table 4-4: List of Contingencies for the InterOPERA demonstrator (DC side)

Ordinary Contingency	**Additional comments**
Outage of single AC/DC converter unit	%
Outage of single DC switching unit	%
Outage of single HV busbar unit	Depending on the topology under test, the impact of this scenario can be different (disconnection of one or more converter units, system split,...)
Outage of single HV cable unit	%
Exceptional Contingency	**Additional comments**
Outage of complete DC cable element for offshore connections (HV poles + DMR)	The InterOPERA DC Cable is assumed to be laid in bundles independent from whether it represents an onshore or an offshore connection in the demonstrator topology under test. Bundled conductors are exposed to external faults such as anchor drags or building works likely to take the whole cable system out (=common cause).

4.2.6. DC Fault Types and Locations

Application of DC faults and the subsequent fault handling is a mandatory requirement for the final model delivery and the demonstrator studies.

The design of all subsystems shall take into account the detailed functional specifications on DC fault handling and DC FRT (see also section 3.3.3 "Protection Principles"), as well as the DC fault types and locations listed in **Table 4-5**. For DC FRT considerations, the worst case of a solid fault with negligible resistance to ground shall be considered.

Note for the InterOPERA demonstrator studies: In case temporary blocking is used for DC fault handling, the de-blocking requirements are only mandatory for the offline simulations, but optional[10] for the online/HIL simulations.

Table 4-5: List of DC fault types and locations for the InterOPERA demonstrator

DC Fault Type	DC Fault Location	Additional comments
Single HV pole to ground fault	along DC cable	The requirements apply to any fault location along the cable. The demonstrator test shall include tests with faults at various locations on the cable, at least at the beginning, end, and middle. Additional locations – e.g., every 50km – may be studied as well.
	between AC/DC converter unit and DC switching unit	%
	at DC switching station busbar (resp. busbar section)	%

[10] In case de-blocking is not implemented by the respective OEM for online / HiL simulations, converters shall remain in blocked state but shall not trip.

4.2.7. Remedial Actions

For the InterOPERA demonstrator, the following **Remedial Actions** are foreseen.

Remedial Actions applied to stay within Operational Security Limits and/or to re-establish N-1 security:

- Primary Controls (voltage limiting mode and power limiting mode)
- Secondary Controls
- Re-establish reference to ground in all subnetworks after HVDC system split[11]

Remedial Actions applied to re-establish Operational Security Limits:

- Temporary energy dissipation by Dynamic Braking System (DBS)
- Wind park curtailment as action triggered by the DCGC (refer to section 3.3.2)

➔ Both actions and their coordination described below in "Overvoltage Power Control Scheme (OVPC)".

Deviation from the initial power and voltage targets typically occur after small disturbances such as wind power variation or after bigger disturbances like subsystem outages and faults. Any incident that leads to a power disturbance will also lead to a DC voltage deviation. The different remedial actions considered in the InterOPERA demonstrator depend on the resulting system state as summarized in **Table 4-6**. For the InterOPERA demonstrator, the system state is derived from the (quasi) steady-state DC voltage following the disturbance.

Table 4-6: Overview of remedial actions undertaken depending on the system state

Steady-state DC voltage	Associated system state	Remedial action
Within OSL* + within N-1 secure "Normal range"	Normal	Primary controls
Within OSL* + outside N-1 secure "Normal range"	Alert	Primary + Secondary controls
Outside OSL*	Emergency	Primary + Secondary controls; DBS activation & OVPC

*OSL = Operational Security Limits (refer to section 5.1.1)

[11] It should be noted that in the InterOPERA demonstrator, it is not a mandatory requirement that this action is executed automatically. As outlined in UC01-082, The DCGC does not perform this action automatically. It should be requested by a grid operator after the system split.

Overvoltage Power Control Scheme (OVPC)

This section relates to the UC04-07 "DC-side contingency leading, after energy absorber activation, to a coordinated emergency offshore wind ramp-down or curtailment" (refer to Annex 01). The objective is to align the behaviour of the different subsystems involved in the handling of such an event, namely the converter stations (including DBS as described in D3.2 [06]), the PPM, and the DC Grid Control.

After an over-voltage disturbance or contingency (e.g. onshore converter blocking), the excess of power generation will induce an increase of the DC voltage[12]. If the available primary reserves are not sufficient to absorb the power imbalance, the excess power will eventually make the system enter the abnormal operating range and trigger the activation of the DBS at V_DBS_trig. The DBS will allow the system to achieve power balance for a limited time, due to DBS limited energy absorption capabilities. Requirements on the DBS are described in Annex 3.3.3.

The DBS activation, or the voltage entering pre-defined abnormal range, shall trigger the Over-Voltage Power Control (OVPC) scheme within the DCGC. This scheme shall ensure that – in case a state of persistent power imbalance is identified[13] – the power imbalance within the HVDC system is resorbed, in particular using coordinated PPM curtailment, and shall bring back the voltage into the desired operating range. The DCGC shall issue new maximum wind farm powers to the offshore PPMs and control setpoints to the AC/DC converter stations corresponding to the new load flow to be reached, as well as associated ramp-rates. An overview of the main signals exchanged between the different subsystems is pictured in **Figure 4-10**.

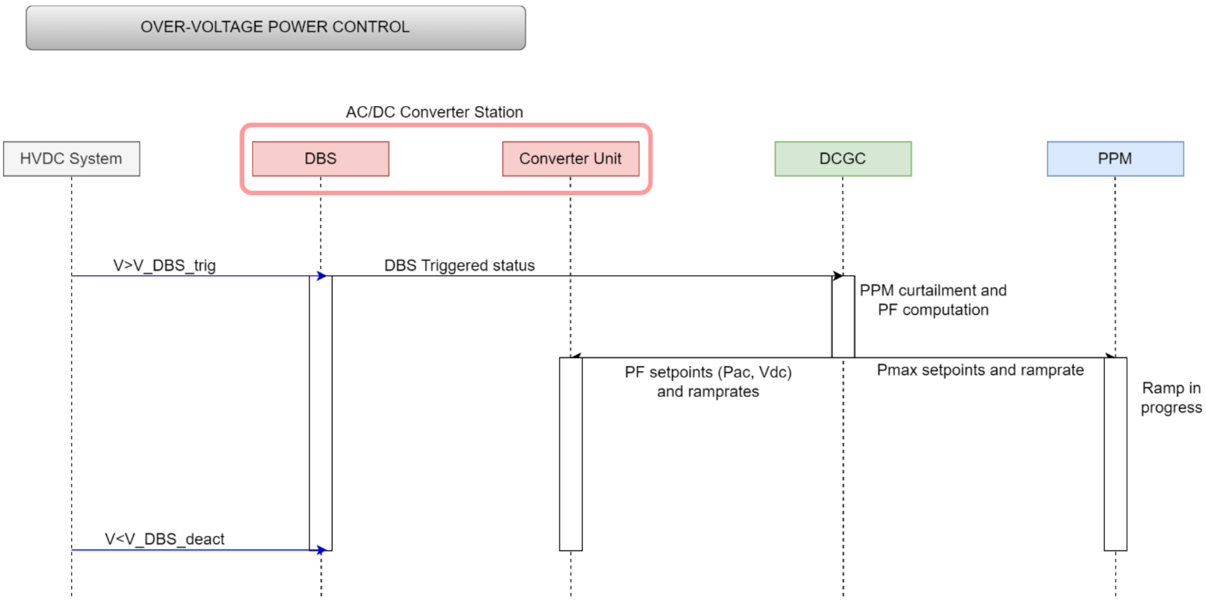


Figure 4-10: Functional overview of the Over-Voltage Power Control concept

[12] The 3 terminal set-up with 2 onshore stations cannot reproduce such an event. A 3T with 2 offshore stations could have such an event due to excessive wind infeed. A more realistic set-up is a 4T system, or the 5T demonstrator with 3 offshore stations.
[13] The OVPC scheme may use different methods to avoid PPM curtailment in case of self-healing overload situations, e.g. under AC-FRT conditions.

To further illustrate the overall chain of event that occurs in the HVDC system and its subsystems after such an event, **Figure 4-11** presents:

1) A simplified evolution of the DC voltage across the HVDC system (top):
After a transient response following the event, the primary response of the converters is expecting to cause a first order like voltage response. As the primary voltage response of AC/DC converter stations saturate, the voltage exceeds the DBS activation threshold. The voltage will remain at this high level until it decreases due to the PPM ramp down and onshore stations new voltage setpoints. The deactivation threshold should be less than the maximum operational voltage to ensure it is not deactivated before the excess power in the system is fully resorbed.

2) A simplified evolution of the HVDC powers, comprising onshore AC/DC converter station powers, offshore PPM powers, and DBS power (middle):
The primary response of the onshore AC/DC converter stations compensate only partially for the loss of export capabilities, and the remaining excess power is eventually dissipated in the DBS. The latter will dissipate less and less power as the PPM ramp down progresses.

3) A time diagram with the main actions undertaken by the HVDC stations (including DBS), the DCGC and offshore PPM (bottom).

All times are indicative only and do not account for any specific performances of any of the subsystems. The option depicted in the diagram assumes ramp rates of PPM and converters are adjusted such that the new operating point is reached at the same time for all subsystems.

Disclaimer: The specification for DBS (cf. Annex 3.3.3, section 2.3.6) foresees a hysteresis-based control with V_DBS_trig (in some documents also titled V_DBS_act) and V_DBS_deact threshold values. Although different concepts of DBS coordination and control have been described as examples in D3.2 [06] and studied in a simplified case in D3.8 [07], the functional specification is yet limited to the existence of both thresholds which can be defined by the OEM responsible for the respective AC/DC onshore converter station.

It is expected that – depending on the chosen threshold values by each OEM, and the implementation of the DBS control – there is a need for additional DBS coordination (e.g., adapting thresholds as defined in D3.2 and tested in D3.8) whenever there are two or more DBSs in one HVDC system. This coordination – along with potential adaptions to the DBS specification – is to be performed during the demonstrator studies, and it may not only affect the DBS thresholds and the DBS control, but also the DCGC and the implementation of the OVPC scheme. A signal exchange between DBS and DCGC may be required, cf. also optional signals listed in Annex 3.3.2.

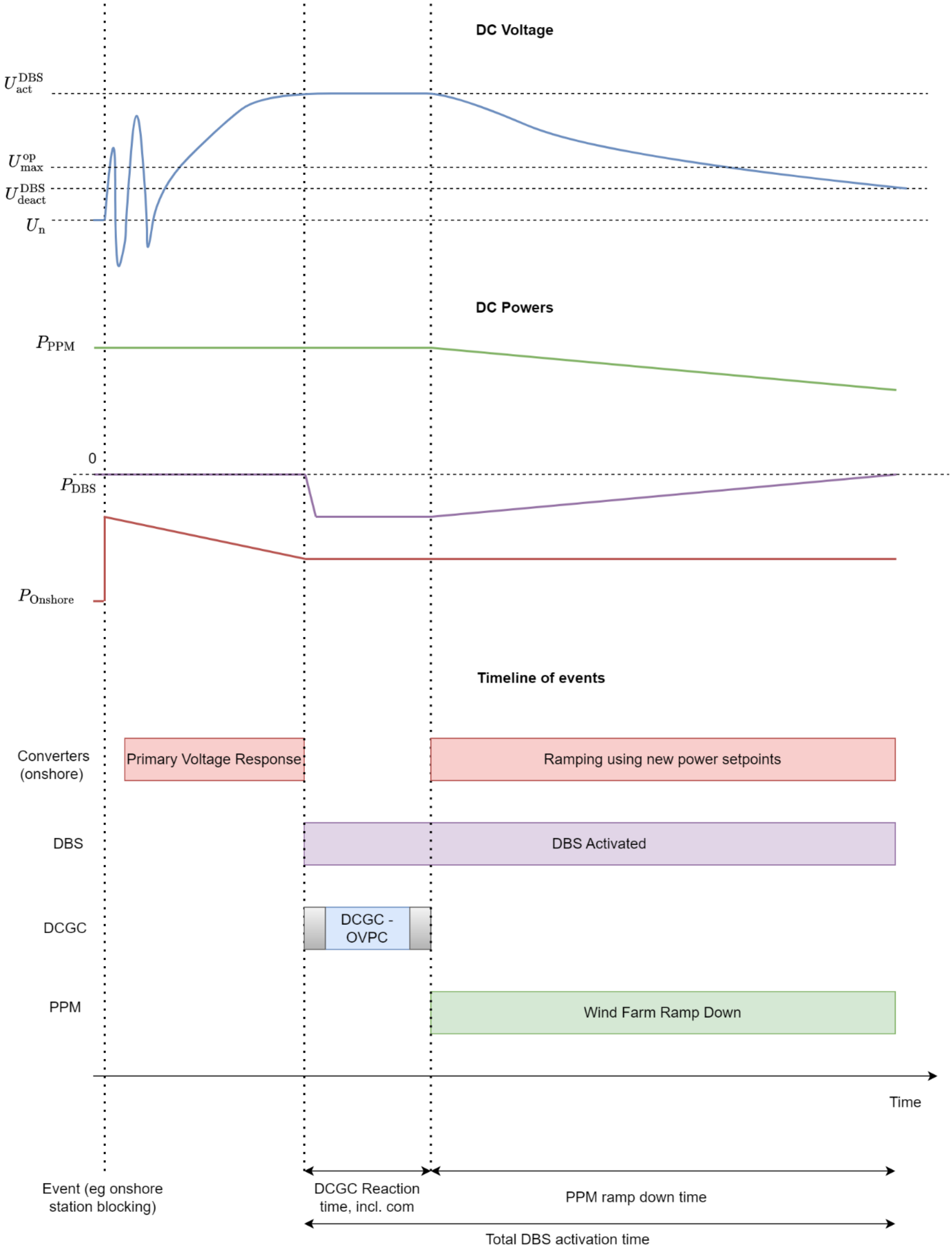


Figure 4-11: Overview of the chain of events occurring after a loss of export capability Top: simplified evolution of DC voltage ; middle: simplified evolution of DC powers; bottom : main actions undertaken by HVDC system

4.3. Environmental data / constraints

4.3.1. DC Cable Data

For the InterOPERA demonstrator, it was decided to continue all studies and simulation works consistently using only one DC cable type (= **the InterOPERA DC Cable**) independent from the location of the transmission element in the demonstrator e.g. being onshore or offshore. This does not imply that the same DC cable model is used in all study types and simulations, but the cable data shall be taken from a consistent and agreed "data sheet". The main data of **the InterOPERA DC Cable** and its relevant limits, both for pole cables as well as for the dedicated metallic return (DMR), are provided in this section. Detailed data for cable modelling is based on [13] and provided in Annex 02: DC Cable Data.

As DC cables are ground-connected, **all voltage values provided in this section are pole-to-ground**.

Table 4-7: DC cable main circuit data (P1/P2 and R)

AC node control concepts	High voltage conductor (P1 / P2)	Dedicated Metallic Return (R)
Core material	copper	copper
Core metal section	2500 mm²	2500 mm²
Core temperature in operation	70°C	20°C
Insulation material	XLPE	XLPE
Resistance @ 0 Hz	8.63 mΩ/km	7.21 mΩ/km
Inductance @ 10 kHz	0.144 mH/km	0.087 mH/km
Capacitance	0.224 µF/km	0.452 µF/km

Table 4-8: DC cable voltage and current rating (P1/P2 and R)

	High voltage conductor (P1 / P2)	Dedicated Metallic Return (R)
Rated voltage	525 kV*	52 kV (RMS)**
Temporary overvoltage	see TOV profile (see **Figure 4-12**)	95 kV (RMS)**
SIWL	1050 kV (peak)	
LIWL	1050 kV (peak)	250 kV (peak)**
Short Circuit Current - peak - 100 ms	40 kA (peak) 25 kA (RMS)	40 kA (peak) 25 kA (RMS)

*rated voltage U_0 as per CIGRÉ TB 852 [14]

**values taken from IEC 60071-1 [15] for AC systems

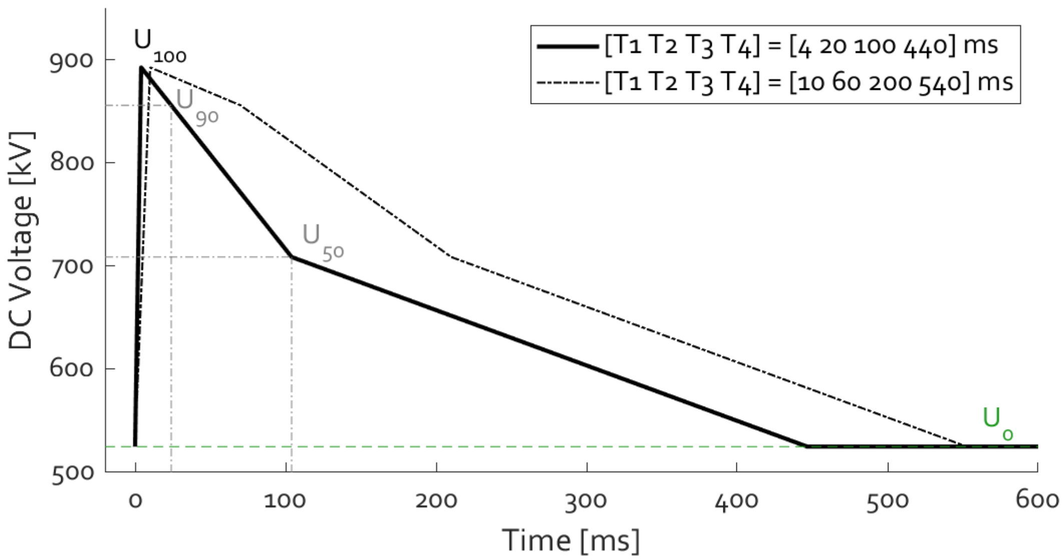


Figure 4-12: High voltage DC cable overvoltage profile (P1/P2) adapted from D3.1 [05]

Table 4-9: Voltage and time values for high voltage DC cable overvoltage profile (P1/P2) from D3.1 [05]

	Unit	Value	Comment
U_o	kV	525	Rated voltage U_o as per CIGRÉ TB 852 [14]
U_{100}	kV (peak)	893	$U_{100} = 1.7 * U_o$
$T_1 = t_1 - t_o$	ms	4-10	Time to reach U_{100} (with $t_o = 0$ ms)
U_{90}	kV (peak)	856	$U_{90} = U_o + [0.9 * (U_{100} - U_o)]$
$T_2 = t_2 - t_1$	ms	20-60	Time to reach U_{90}
U_{50}	kV (peak)	709	$U_{50} = U_o + [0.5 * (U_{100} - U_o)]$
$T_3 = t_3 - t_1$	ms	100-200	Time to reach U_{50}
$T_4 = t_4 - t_1$	ms	440 - 540	Time to reach U_o

5. Demonstrator Network Planning Results

5.1. Planning results

5.1.1. Operational Security Limits

For the InterOPERA demonstrator, the operational security limits (OSL) of the HVDC Grid for steady-state operation, i.e. after settling of transients and dynamics, are based on currently available ratings of AC/DC converter stations and DC transmission elements in 525 kV / 2GW systems.

All values provided in **Table 5-1** refer to the PoC-DC of the subsystems. Please note that these values are HVDC Grid system level parameters and do not constitute the maximum capabilities of the subsystems which are supposed to include additional design margins and reserves. They can be exceeded within an HVDC subsystem (e.g. busbars currents in the central DC switching station) or might need to be adapted (e.g. in case of an offshore connection only capable of operating in one power direction). Specific subsystem requirements are formulated in the corresponding annexes.

For the InterOPERA demonstrator, these values shall be interpreted as the operational limits within which the demonstrator system and all its subsystems can be operated continuously without taking any damage.

Table 5-1: Operational Security Limits for the InterOPERA demonstrator

	Base Unit	Upper Operational Security Limit	Lower Operational Security Limit
DC Voltage (HV+ pole to neutral)	500 kV 1 pu	525 kV 1.05 pu	475 kV 0.95 pu
DC Voltage (HV- pole to neutral)	- 500 kV - 1 pu	- 475 kV - 0.95 pu	- 525 kV - 1.05 pu
DC Current (HV poles and DMR)	2000A 1 pu	2030 A 1.015 pu	-2030 A - 1.015 pu
Active Power (at HV pole PoC-DC)	1 GW 1 pu	1 GW 1 pu	- 1 GW - 1 pu

Please note that all operational voltages are provided as HV pole-to-neutral voltages as this is the only quantity relevant for DC load flows and operation of AC/DC converter units controlling the DC voltage. Limitations on continuous operating voltages from equipment connected to ground, e.g. DC cables in case of asymmetrical operation, shall be taken care of by an adequate choice, and eventual re-dispatch, of load flow targets and control parameter settings.

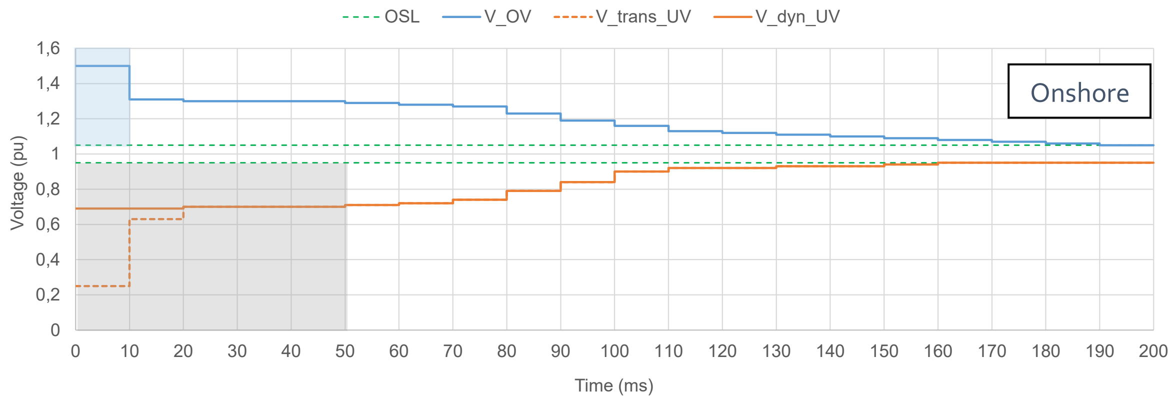
5.1.2. Dynamic Limits

A first set of dynamic studies has been conducted in Task 3.6 [07] providing insights in the dynamic voltage excursions following different types of disturbances. An envelope has been created around all cases where the equipment is supposed to be fully operational, i.e. no blocking is allowed. Due to the different control modes applied in onshore and offshore AC/DC converter units, different response to disturbances can be observed. This is illustrated in **Figure 5-1**. The data is provided in **Table 5-2** and **Table 5-3**.

Each AC/DC converter unit shall be able to ride through, at least, dynamic voltage excursions within the envelopes specified in **Table 5-2** and **Table 5-3** without blocking. During – or at least following such excursions – the AC/DC converter shall be able to control its active power contributing to the primary control (cf. Section 3.3.2). In addition, all systems are required to withstand stresses imposed by their own blocking or de-blocking which is not considered in the envelope depicted below.

Note: The shown values represent an envelope, not an individual physically measured voltage trajectory. Depending on the converter design, values at the lower end of the envelope may lead to short periods of overmodulation – but must not lead to protective blocking of the converter.

The dotted lines in **Figure 5-1**, corresponding to values in paratheses in **Table 5-2** and **Table 5-3**, do <u>not</u> constitute a binding specification for the dynamic time frame. However, they indicate an envelope around the lowest temporary DC voltages observed in the generic studies conducted in T3.6 of InterOPERA at non-blocked converters as a reaction to short circuit DC faults. These values are provided for reference, and fall within the time range relevant for DC FRT (marked grey specified in section 5.1.3 / 5.2.2.The highest temporary DC voltages specified in **Figure 5-1**, **Table 5-2** and **Table 5-3** refer to dynamic overvoltages and shall not be mistaken with values relevant for insulation coordination (cf. section 5.3.2).



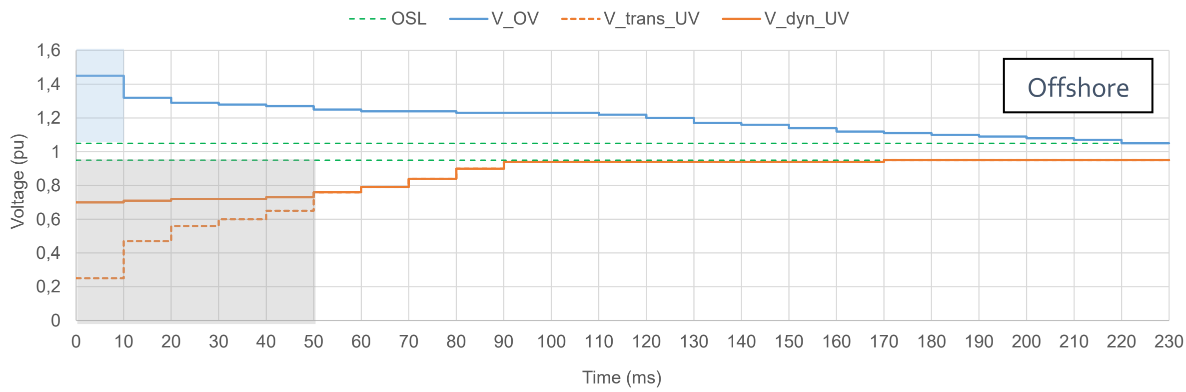


Figure 5-1: Observed DC voltage dynamic ranges at PoC-DC. Onshore (Top), Offshore (Bottom)

Table 5-2: Envelopes of the observed DC voltage dynamic ranges at PoC-DC (Onshore); Numbers in brackets represent transient excursions observed in T3.6.4 / D3.8 DC fault investigations.

Time (ms)	10	20	30	40	50	60	70	80	90	100
Onshore	1.5	1.31	1.30	1.30	1.30	1.29	1.28	1.27	1.23	1.19
	0.69 (0.25)	0.69 (0.63)	0.70	0.70	0.70	0.71	0.72	0.74	0.79	0.84

Time (ms)	110	120	130	140	150	160	170	180	190	200
Onshore	1.16	1.13	1.12	1.11	1.10	1.09	1.08	1.07	1.06	1.05
	0.90	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95

Table 5-3: Envelopes of the observed DC voltage dynamic ranges at PoC-DC (Offshore); Numbers in brackets represent transient excursions observed in T3.6.4 / D3.8 DC fault investigations.

Time (ms)	10	20	30	40	50	60	70	80	90	100
Offshore	1.45	1.32	1.29	1.28	1.27	1.25	1.24	1.24	1.23	1.23
	0.70 (0.25)	0.71 (0.47)	0.72 (0.56)	0.72 (0.6)	0.73 (0.65)	0.76	0.79	0.84	0.90	0.94

Time (ms)	110	120	130	140	150	160	170	180	190	200	210	220	230
Offshore	1.23	1.22	1.20	1.17	1.16	1.14	1.12	1.11	1.10	1.09	1.08	1.07	1.05
	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.95	0.95	0.95	0.95	0.95	0.95

Disclaimer: The dynamic voltage ranges are observed based on generic models in GFL control mode. While in general, it is expected that vendor-specific controls will outperform the generic converter controls and hence lead to narrower voltage bands, there is a possibility of greater subsystem-level stresses (and hence wider ranges) under GFM operation compared to GFL.

5.1.3. Transient Limits

DC undervoltage

As described in section 3.3.3, the zoning concept and the DC FRT compliance test profiles from D2.1 [03] shall be applied to the InterOPERA demonstrator. The general undervoltage DC FRT profile is depicted in **Figure 5-2**. There is no requirement on maximum short circuit currents except for the DC cable current limitations (refer to section 4.3.1). The general framework distinguishes between:

a) **Operational Requirements (OR) - dashed lines**
   All subsystems participating in the DC load flow shall stay fully operational; no blocking allowed.
b) **Connection Requirements (CR) - solid lines**
   For DC voltage excursions above the shown DC FRT profile, all subsystems participating in the DC load flow shall stay connected but are allowed to block their operation if required. After successful fault handling, all subsystems in the healthy network zones shall resume operation.

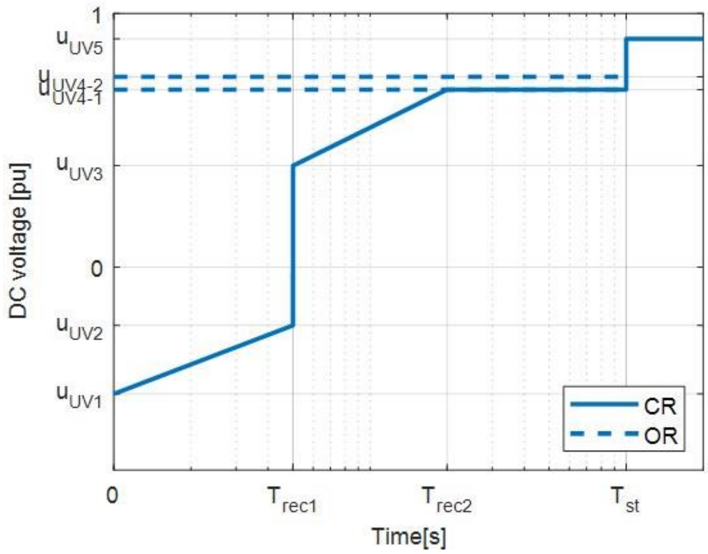


Figure 5-2: General DC undervoltage FRT profile to define OR and CR for PoC-DC P1 (from D2.1 [03])

The **OR requirement** – with the parameter U_UV4-1 defining a requirement for operational converters to remain operational – is to be interpreted as an amendment to the dynamic voltage ranges given in section 5.1.2. In line with D2.1 [03], it is an "undervoltage blocking limit outside minimum dynamic voltage bands [...] considering a security margin". To cover the dynamic limits defined in **Table 5-2** and **Table 5-3**, U_UV4-1 is defined to 0.7 p.u. (350kv) for a conservative duration of T_st = 150 ms. The parameter U_UV5 is identical to the minimum static voltage (0.95 p.u.– cf. **Table 5-1**). Values are summarized in **Table 5-4**.

Table 5-4: InterOPERA demonstrator parameters for DC undervoltage FRT profile at PoC-DC – Part 1: Parameters for the operational requirement (OR) for non-blocked, operational converters

Parameter	Value	Comment
U_UV4-1	350 kV (0.7 p.u.)	Based on **Table 5-2** + **Table 5-3** / D3.8 [07]
U_UV5	475 kV (0.95 p.u.)	Vdc_op_min (Vdc_2U) / **Table 5-1**
T_st	150 ms	Based on **Table 5-2** + **Table 5-3** / D3.8 [07]

The **CR requirement** is subject to the individual HVDC sub-grid characteristics. The complete parameters are therefore provided in 5.2.2 in connection with the network zoning for fault handling.

For compliance testing, the general DC FRT profile shown in **Figure 5-2** shall be broken down into individual subsystem requirements as described in D2.1 [03]. Hence, the DC FRT undervoltage profile is further detailed in the subsystem specifications of AC/DC converter stations (Annex 3.3.3) and DC Switching Stations (Annex 3.3.4).

Disclaimer: For the DC undervoltage specification, it is considered that the *temporary* blocking functionality is available and tolerable from an AC grid perspective. In practice, the relevant TSO determines whether such functions may be used for DC-FRT / DC undervoltage FRT. For changed CR requirements (e.g., not allowing temporary blocking), other parametrisations of the DC-FRT voltage profile may be required. A direct transfer of the values described in this document to different protection concepts with different DC-FRT requirements is not recommended.

DC overvoltage

No additional transient DC overvoltage requirements are specified beyond the dynamic DC overvoltage requirements (cf. section 5.1.2) as well as the DC cable transient overvoltage limitations (refer to section 4.3.1). Transient overvoltages shall be evaluated as part of the overall insulation coordination (refer to section 5.3.2).

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

As outlined in D2.1: 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.

5.2. Network zoning

5.2.1. Energization

An energization zone is defined as an aggregation of subsystems which are energized together. At least one switching unit (AC or DC) at the boundary of an energization zone must provide adequate making capability and peak current suppression functionality [03].

For the InterOPERA demonstrator, it was decided to equip all DC switching units with making capability and peak current suppression to allow individual DC energization of each subsystem from all directions. The resulting energization zones on the DC side for the 3T base case are depicted in **Figure 5-3**.

All onshore AC/DC converter stations shall additionally be equipped to allow for energization from AC.

Energization zones can be aggregated up to the following maximum extent which shall be considered for the design of the switching units (AC and DC) and the respective devices therein:

- 1 x AC/DC Converter Station
- 2 x DC Switching Station (only busbars → negligible)
- 1 x DC Transmission Element (max. 800 km; see Annex 02 for DC cable data)

The initial start-up of the InterOPERA demonstrator shall always be done via <u>one</u> AC/DC converter station acting as onshore station. To avoid reconfiguration of the reference to ground in the neutral system during initial energization, the following units shall be **aggregated in the neutral system before energization**:

1) AC/DC converter unit in the onshore station performing the energization from AC
2) Neutral bus unit in the DC switching station adjacent to the onshore AC/DC converter station
3) Neutral conductor unit (DMR) of the DC transmission element connected to the DC switching stations (i.e., the DCSS connected to the respective AC/DC converter station, and DCSS #5)
4) Neutral bus unit in the central DC switching station #5
5) Grounding unit in the central DC switching station #5

This approach is indicated in **Figure 5-4** for the 3T base case and for the example of an AC energization initiated from AC/DC converter station #2 acting as onshore station. It differs from D3.1 [05] by not allowing initial energization without inclusion of the central DC switching station #5 in the neutral system. The initial single reference to ground (refer to section 4.2.1) can be established at the central DC switching station #5 by default. The subsequent energization of the high voltage units can be performed individually or by an aggregation up to the maximum extent described above.

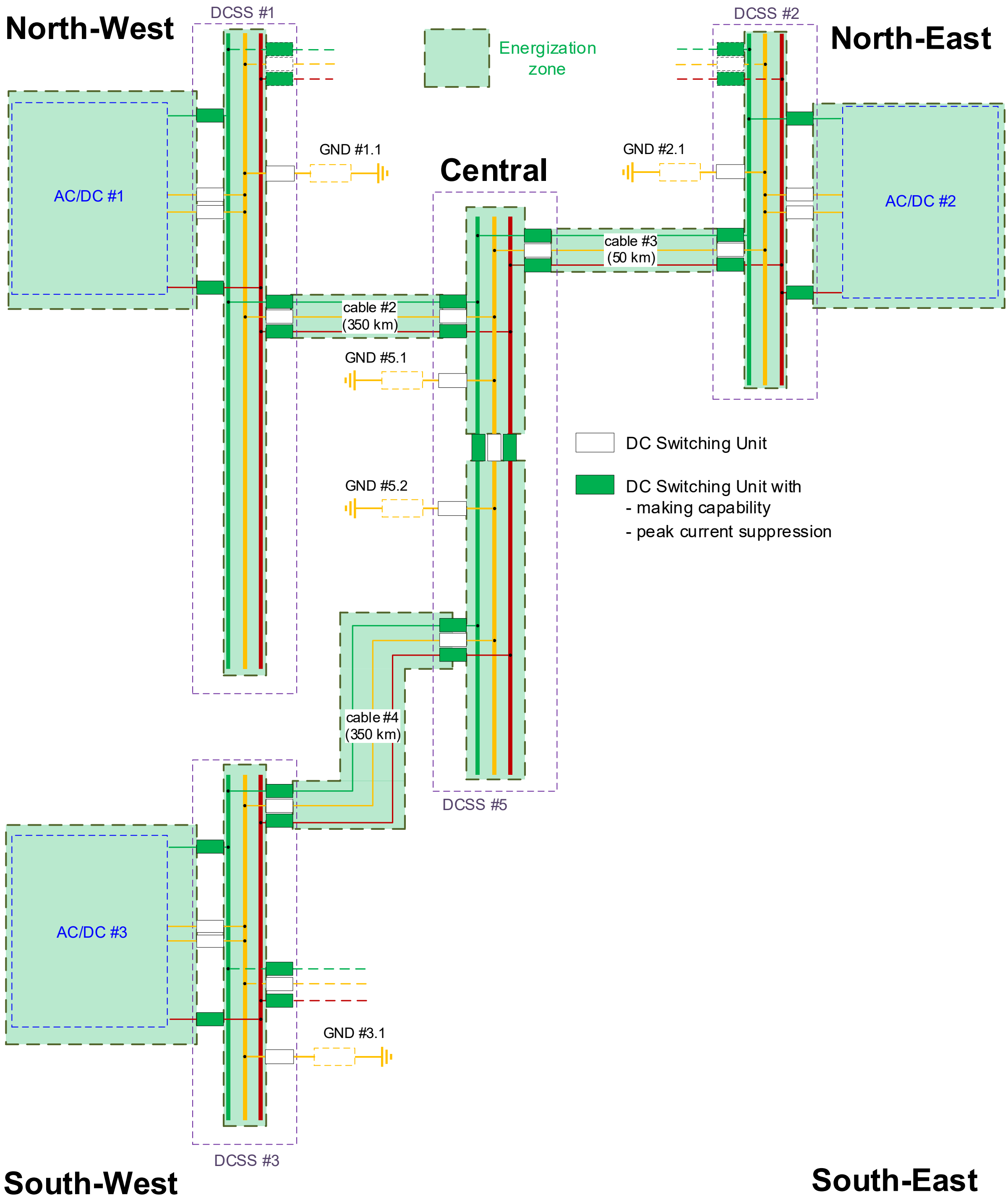


Figure 5-3: Indication of energization zones in 3T base case

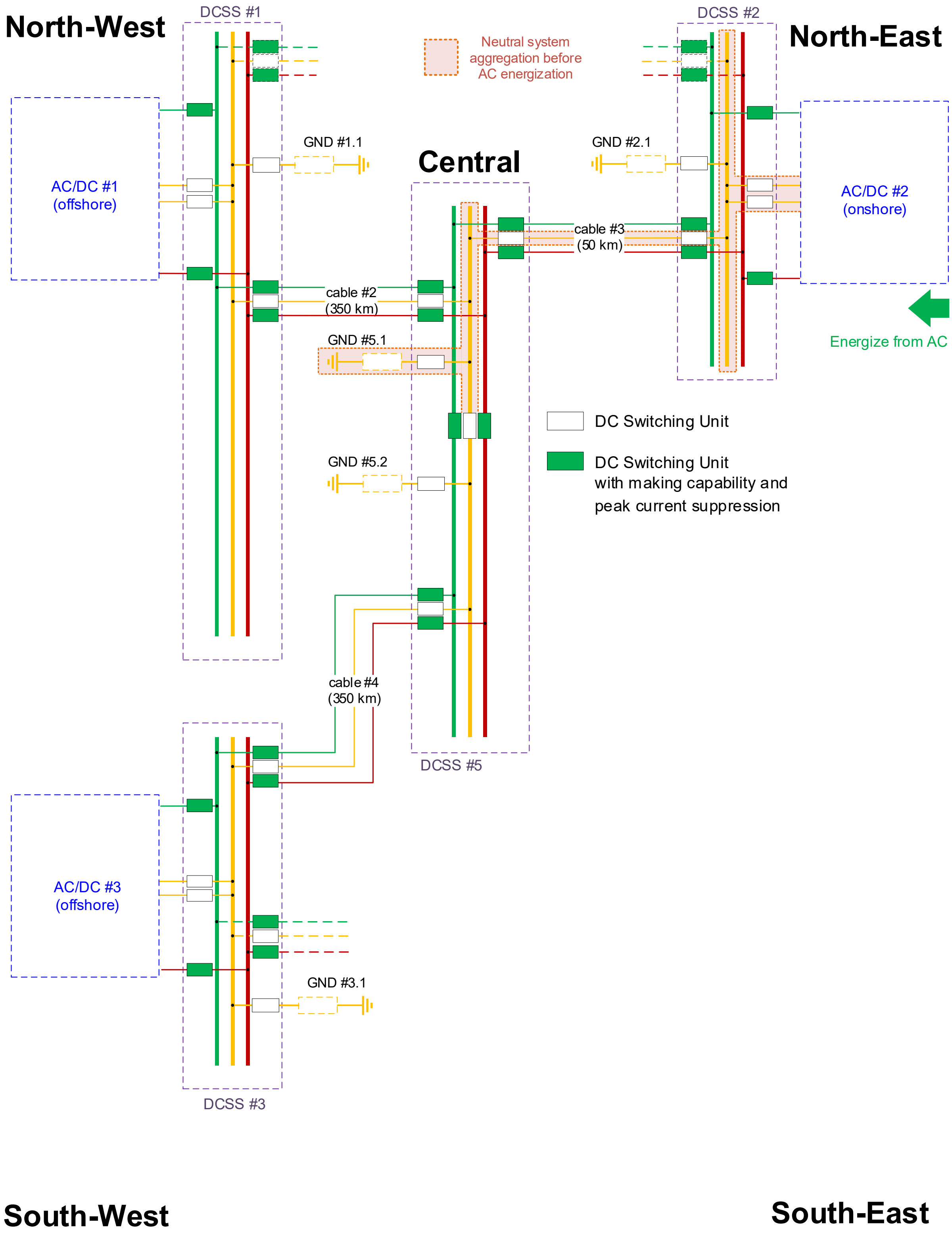


Figure 5-4: Neutral system aggregation before initial energization from AC (example for AC/DC #2)

5.2.2. Fault Handling

For the InterOPERA demonstrator, the primary goal is the demonstration of multi-vendor interoperability. The placement of FSDs thus is a result of the different vendor commitments to deliver fault separation devices in their DC switching units (refer to overview in D3.1 [05]).

Two types of solutions have been identified for the InterOPERA demonstrator with different maximum fault neutralization times being assumed as the sum of protection relay time and the fault separation device's internal current commutation time (**Table 5-5**).

Table 5-5: Variants of maximum fault neutralization times in the InterOPERA demonstrator ($T_{N,\,max}$)

	$T_{N,\,max}$ [ms]
Fault Separation Device (FSD) Type A	2.5
Fault Separation Device (FSD) Type B [14]	8

The fault neutralization times are directly connected to the DC undervoltage duration experienced at the PoC-DC of AC/DC converter units in healthy fault separation zones – and thus to the parameterization of the DC FRT compliance test profile described in section 5.1.3 – in particular the value of T_rec1.

Due to the significant difference in the fault neutralization times and partial incompatibility with capabilities of available AC/DC converter units, it was decided to not apply a global set of DC FRT parameters for the InterOPERA demonstrator. Instead, the HVDC system is divided into sub-grids characterized by different voltage recovery times (T_rec1 as defined in the DC FRT profile in **Figure 5-2**).

Sub-grid Definition and Fault Separation Zones

For both the 3T (cf. **Figure 5-5**) and the 5T topology (cf. **Figure 5-6**), two sub-grids are defined: A and B. Applying the two FSD types to the demonstrator 3 terminal base case topology, considering the individual vendor's planned scope of delivery, leads to distinctive Fault Separation Zones (FSZ) shown in **Figure 5-5**. The FSDs in the DC Switching units are numbered according to the reference designation in chapter 4.2.2. The FSZ numbering is already anticipating the 5 terminal full topology which is why some numbers are skipped in the 3 terminal base case topology. For information, the 5 terminal full scope topology is shown in **Figure 5-6**.

The following requirements and definitions are formulated for the subsystems in each sub-grid:

- Subsystems located in Fault Separation Zones with Trec1a = 2.5 ms (i.e. FSZ#4, #8, and #9; blue) shall comply with "Subgrid A" parameters in **Table 5-6**.
- Subsystems located in Fault Separation Zones with Trec1b = 8 ms (i.e. FSZ #1,#2, #3, #5, #6, and #7; red) shall comply with "Subgrid B" parameters in **Table 5-6**. FSZ#3 and #7 are explicitly included in the red sub-grid to anticipate the 5-terminal full scope (refer to **Figure 5-6**).

[14] The value of $T_{N,max}$ consists of both the relay time (which depends on the fault location and protection algorithm) and the breaker opening time (which is dependent on the specific breaker technology). This value was chosen as a conservative assumption, representing a worst-case scenario for which selectivity and robustness can still be ensured for remote faults, rather than reflecting a specific vendor capability. It is experience-based to already incorporate the future 5T setup and additional fault cases and thereby to reduce the expected workload during stage 2. In a 3T system with defined fault cases, lower fault neutralization times can be anticipated, especially for faults near the DCCB.

Note: FSZ #7 and FSZ #3 were arbitrarily assigned to Subgrid B (red) to create a single sub-grid boundary in both the 3T and the 5T topology. Further, this choice is illustrating that faster DCCB technologies can be accommodated within a given sub-grid: Trec1 defines only a minimum performance requirement (i.e., a maximum allowable TN such that $T_{N,Max,i} \leq T_{rec1,k}$). Here, all DCSUs connected to the central DCSS#5 are assumed to be the same – such that their TN is defined by the sub-grid with the strictest requirement. In principle, FSZ #3 could also have been assigned to sub-grid A (blue). In the 3T topology, this would directly lead to FSZ7/NE converter being sub-grid A as well. However, in the 5T topology, FSZ7/NE would remain part of sub-grid B (red) due to the connection of cable #1. Hence, there would be no system-level benefit of forcing FSZ3 to be part of sub-grid B – as the converter NE needs to pass a DCFRT test with Trec1a (8ms) either way. Rather, selecting FSZ3 and FSZ7/NE as sub-grid A in 3T would limit expandability.

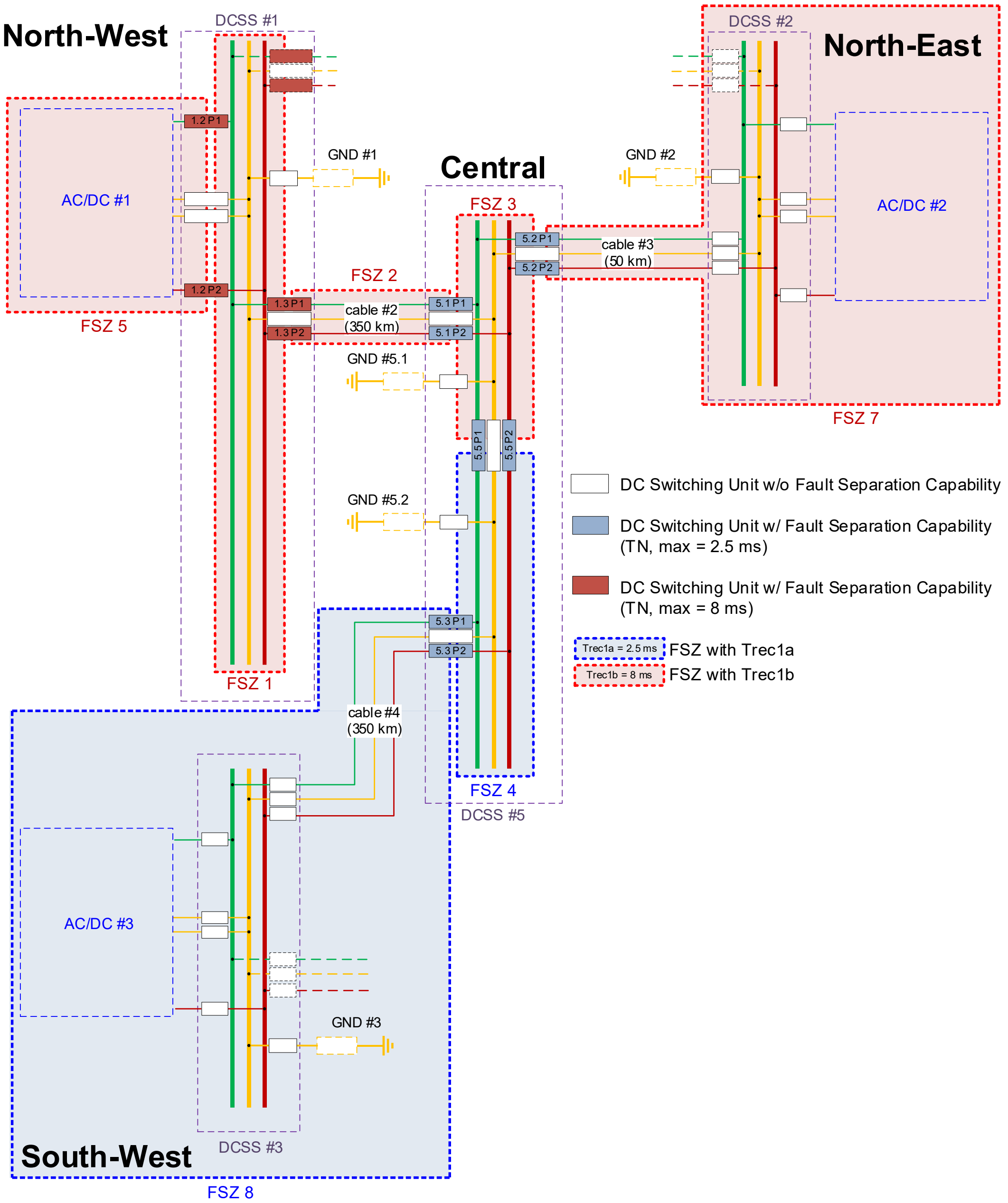


Figure 5-5: Fault separation zones for the InterOPERA demonstrator; 3T base case

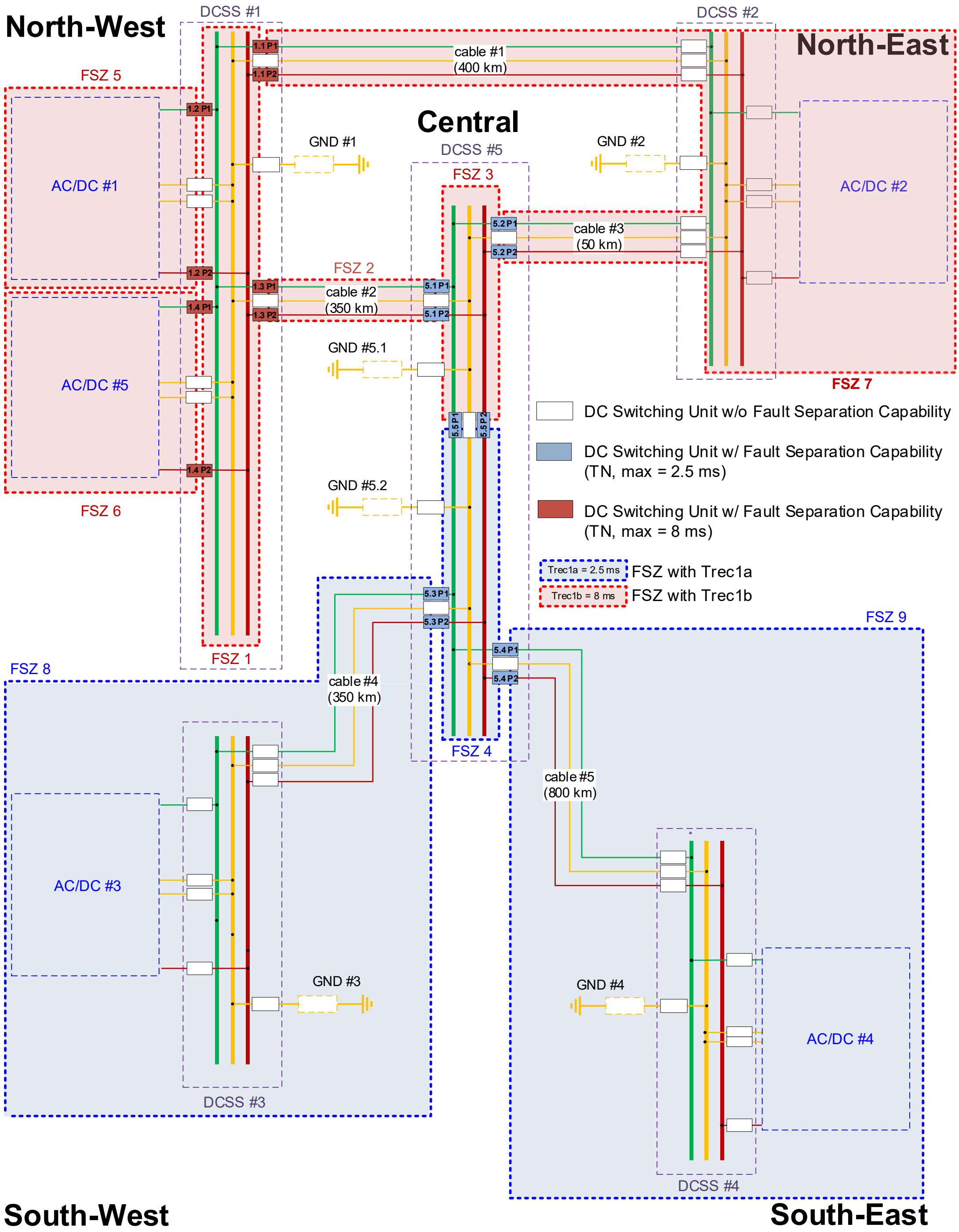


Figure 5-6: Fault separation zones for the InterOPERA demonstrator; 5T full scope

Referring to section 5.1.3, and considering the two sub-grids A and B defined above, the values for the DC FRT profile are provided in **Table 5-6**. For better readability and direct reference for all values provided in the table, the DC FRT profile is repeated in **Figure 5-7**.

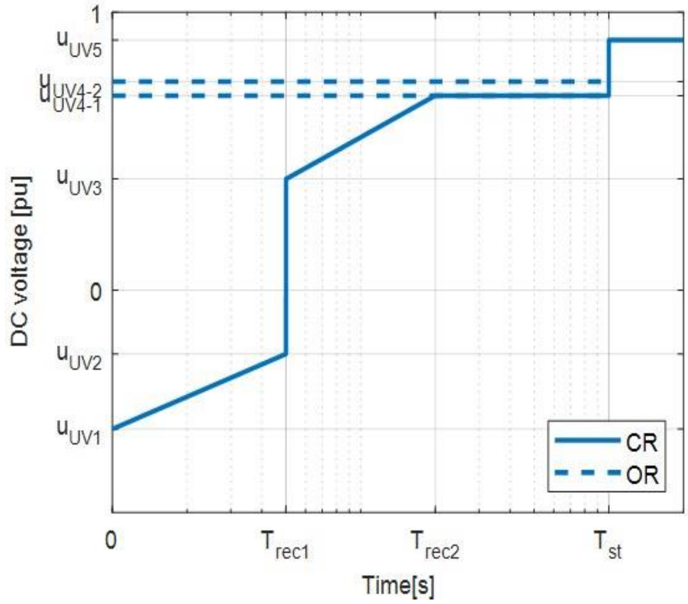


Figure 5-7: DC undervoltage FRT profile for OR/CR definition at PoC-DC P1 (from D2.1 [03])

Table 5-6: InterOPERA demonstrator parameters for DC undervoltage FRT profile at PoC-DC P1

Parameter	Subgrid A	Subgrid B	Comment
T_rec1	T_rec1a = 2.5 ms	T_rec1b = 8 ms	$T_{N,\,max}$ from **Table 5-5**; no additional buffer
T_rec2	30 ms		Value based on D3.8 [07]
T_st	150 ms		Value based on D3.8 [07]
U_UV1	-500 kV (- 1 pu)		Assume full voltage reversal as worst case for primary design.
U_UV2	U_UV2a = -350 kV (-0.7 pu)	U_UV2b = -100 kV (-0.2 pu)	Values corresponding to Trec1 (refer to D2.1 [03])
U_UV3	125 kV (0.25 pu)		Based on voltage ranges observed in results of D3.8 [07]. Note: The definition of U_UV3 indirectly defines a minimum inductance in between sub-grids.
U_UV4-1	350 kV (0.7 p.u.)		Minimum voltage for OR. Based on voltage ranges observed in D3.8 [07]
U_UV4-2	350 kV (0.7 p.u.)		Lower boundary of de-blocking requirement as explained below. Based on voltage ranges observed in D3.8 [07].
U_UV5	475 kV (0.95 p.u.)		Vdc_op_min (Vdc_2U)

In contrast to D2.1 [03], **all voltages for DC FRT are provided as HV pole-to-neutral voltages at PoC-DC.** It shall be assumed that the equivalent average voltages in the DC FRT compliance tests are applied between the AC/DC converter unit terminals (P1, R1). The required compliance tests for DC FRT will be further detailed in the subsystem specifications of AC/DC converter stations (Annex 3.3.3).

Further explanations to the connection requirement (CR)

As outlined in D2.1, the connection requirement is to be interpreted in a way that "outside of dynamic voltage bands, the converter can ride through the fault by different means: CO, [temporary blocking], 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".

Importantly, the CR curve in **Figure 5-7** is an outer envelope of different DC voltage shapes caused by different faults – and neither a physical trajectory nor an average undervoltage to be directly tested at the PoC-DC. The values of UV3 at T_rec1 and U_UV4-1 at T_rec2 describe the worst-case conditions observed in D3.8 [07] – which occur under different conditions than the worst-case voltage sags considered for U_UV1 and U_UV2. It is not expected that a voltage dip down to U_UV1 will occur for the same DC faults that lead to a slow DC voltage recovery back to only U_UV3 until T_rec1, and U_UV4-1 until T_rec2.

Notably, the standalone "minimum test circuit for AC/DC converter unit FRT compliance testing" (cf. Annex 3.3.3) is testing whether converters do not trip for a defined worst-case average DC undervoltage until the time T_rec1 – which considers the above explanations[15]. In T3.6.4 / D3.8 [07], it was shown that fulfillment of the standalone DC FRT test as defined in Annex 3.3.3 ensures that converters do not trip for a variety of realistic DC fault scenarios.

Requirements for blocked converters to return to operation / Converter de-blocking

In case a converter fulfills the CR via temporary blocking[16], there is a requirement for temporarily blocked converters to become operational again within defined boundary conditions. Note for InterOPERA: This requirement is mandatory for offline simulations, but optional for online/HiL simulations[17].

If the DC voltage at the PoC-DC of a blocked converter returns to values equal or higher **U_UV4-2** before the CR trajectory is exceeded, blocked converters must de-block and resume normal operation within a defined timeframe. Until reaching **T_st**, they must be able to de-block and control their PoC-DC voltage to values within the static band defined by **U_UV5**. There is no explicit specification of a deblocking time T_dblk (cf. definition in D2.1 [03]) made in D3.3b. It is left to each OEM how fast exactly de-blocking is executed once U_UV4-2 is reached, as long as a stable and controlled operation is re-gained within T_st.

This definition of de-blocking is taking into account that the realization of blocking and de-blocking is part of the converter internal, vendor-specific control and protection system, and is likely to be based on the internal arm current measurements. It is expected that de-blocking requires the arm current to decay to

[15] The standalone test is utilizing that cables in between the FSD and the converter PoC-DC not only slow down the DC voltage recovery (up to T_rec2 in the worst case), but also limit the initial depth of the voltage drop until T_rec1.
[16] For the InterOPERA demonstrator, it is considered that the *temporary* blocking functionality is available. In practice, the relevant TSO determines whether such functions may be used in the event of a DC fault
[17]In case de-blocking is not implemented for online / HiL, converters shall remain in blocked state but not trip.

values below a vendor-specific threshold. As a voltage-based DC FRT specification has been chosen within interOPERA, the provided voltage level and recovery time definitions intend to mimic the worst-case conditions under which a vendor has to ensure that the internal arm currents decay below the respective blocking reset value. The definition allows for different implementations of de-blocking, and margins to react to possible interactions and/or oscillations upon de-blocking of multiple converters. A slower but controlled de-blocking may lead to an overall faster recovery towards a stable DC grid operation (and active power exchange with the AC-PoCs) compared to a de-blocking as fast as possible.

For the realization of de-blocking, it should be noted that there are different conditions under which blocked converters may have to de-block:

1) The converter to be de-blocked is connected to a DC system in which at least one converter is still operational and controlling the DC voltage: The recovery to U_UV4-2 and above is defined by other converters (within the dynamic voltage bands) and inductances placed in the DCSS.
2) The converter to be de-blocked is islanded on the DC-side. Hence, the DC voltage recovery defined by the converter itself, at it is driven by a current flow through the converter in blocked mode (B6 rectification). Two sub-conditions are considered:
    a. The converter is only connected to a busbar: Instantaneous recovery to U_UV4-2 or even above (depending on converter secondary-side transformer voltage).
    b. The converter is connected to a cable which is disconnected at the other end (especially relevant for the 3T case, cf. D3.8 studies): A delayed recovery to U_UV4-2 is expected, as the blocked converter's current needs to re-charge the cable to restore the voltage.
3) The converter to be de-blocked is connected to a DC system in which all other remaining converters are also in blocked state. This case can be considered similar to case 2, at least in terms of DC voltage recovery. For this case, adverse interactions between multiple de-blocking converters shall be avoided.

With regard to case 1 and 3, it shall be noted that number of simultaneously blocked converters in the defined DC fault scenarios studied in the demonstrator can be limited by keeping the DC voltage in some FSZs above U_UV4-1, e.g. by sufficient inductance in series with an individual FSD at the FSZ boundary and/or at the sub-grid boundary.

All the aforementioned conditions relate to the descriptions in section 7.3.1 of D2.1 ([03]), where it is stated that the de-blocking voltage U_UV4-2 "shall be aligned with the dynamic voltage control bands […] and the diode rectifier voltage level after fault separation in case of small DC grids […] as a worst-case assumption considering temporary blocking of all converters".

Additional explanations for multiple sub-grids: Selection of U_UV_3 in Table 5-6

In **Table 5-6**, it is stated that "The definition of U_UV3 indirectly defines a minimum inductance in between sub-grids". Selecting a certain U_UV3 for the sub-grid with the lowest T_rec1 (here: sub-grid A with 2.5ms) that is higher than the value of U_UV2 associated with the adjacent sub-grid with a larger T_rec (here: sub-grid B, 8ms) is an indirect definition of the minimum inductance in between those sub-grids. More specifically, this defines the sum of a) the inductance of the FSDs / DCSUs at the sub-grid boundary and b) the inductance of the slowest FSD / DCSU in the sub-grid with the larger T_rec1 (here: sub-grid B). This is explained in **Figure 5-8** – where it can be seen that in the InterOPERA use case, the fact that all FSDs of DCSS#5 have the same TN,max (here: 2.5ms) relaxes the implications.

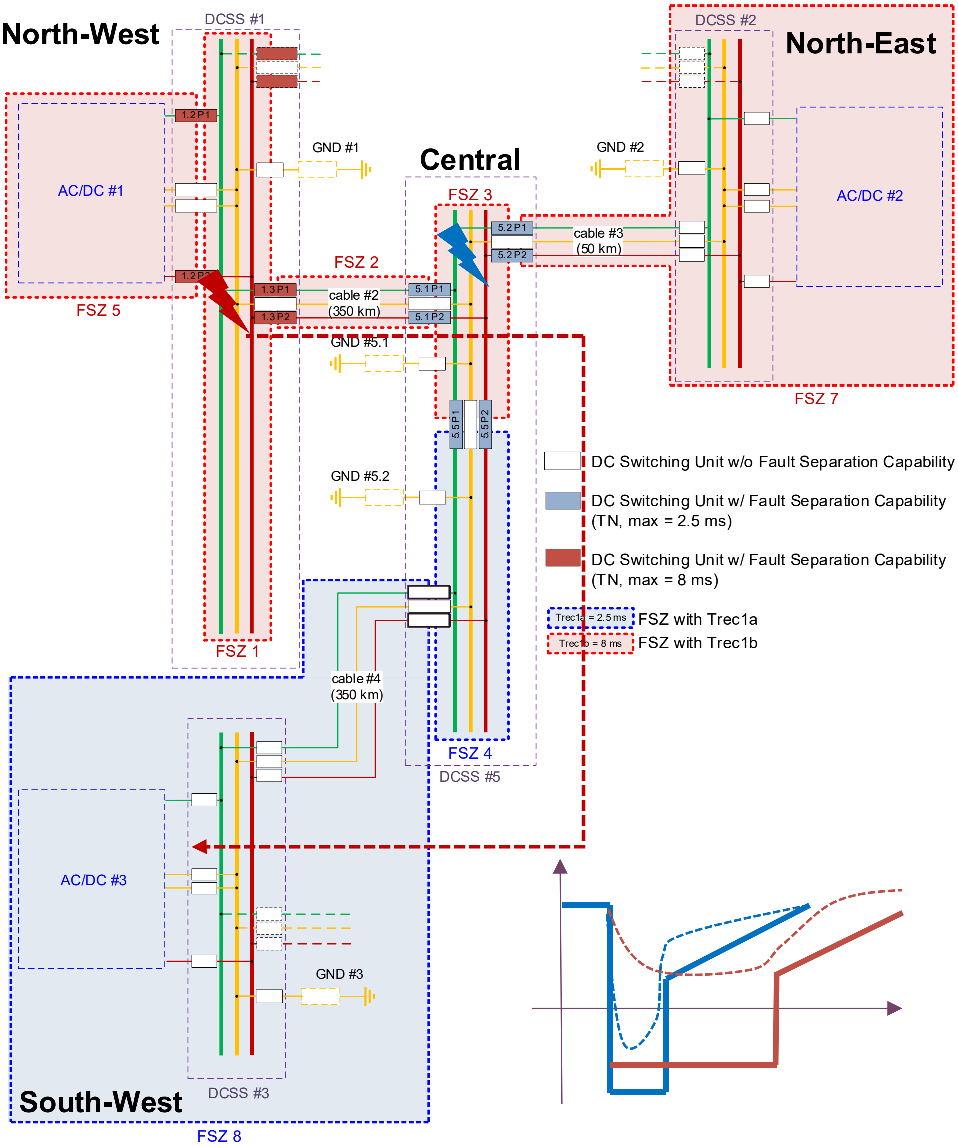


Figure 5-8: InterOPERA 3T demonstrator topology with explanation for minimum inductance imposed by U_UV3 definition in adjacent sub-grids with different values of Trec1. Solid blue curve: DCFRT profile for #SW; Solid red curve: DCFRT profile for #NW and #NE. Blue dotted curve: Qualitative sketch of SW converter DC voltage for a fault cleared via a FSD of sub-grid A ; Red dotted curve: Qualitative sketch of SW converter DC voltage for a fault cleared via a FSD of sub-grid B.

Fault Isolation Zones

The InterOPERA demonstrator shall be fully selective in terms of fault isolation which implies that all DC switching units are providing residual current breaking capabilities. Applying this approach to the demonstrator 3 terminal base case topology leads to Fault Isolation Zones (FIZ) as shown in **Figure 5-9**. The FIZ numbering is already anticipating the 5 terminal full topology which is why some numbers are skipped in the 3 terminal base case topology. For information, the 5 terminal full scope topology is shown in **Figure 5-10**.

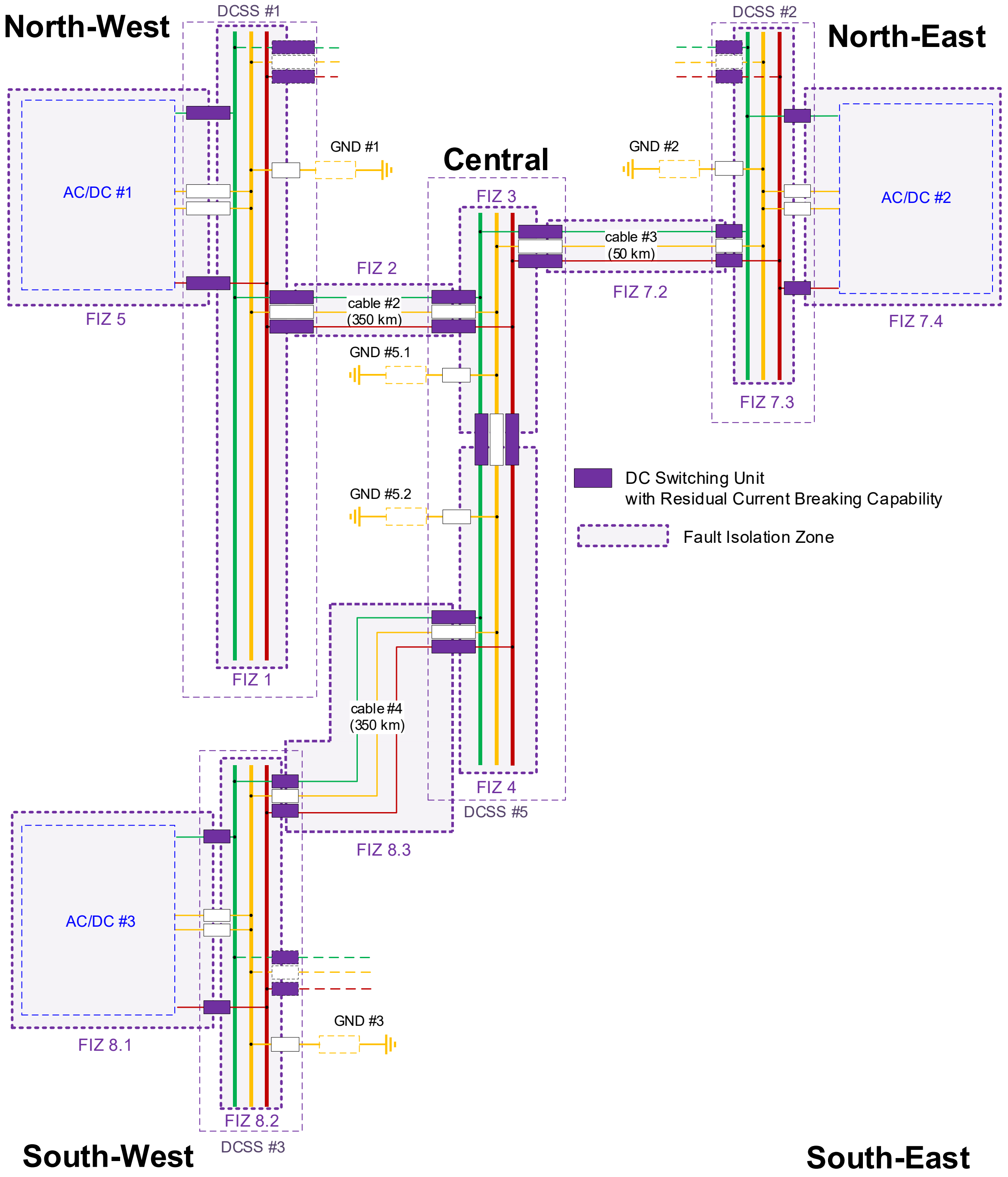


Figure 5-9: Fault isolation zones for the InterOPERA demonstrator; 3T base case

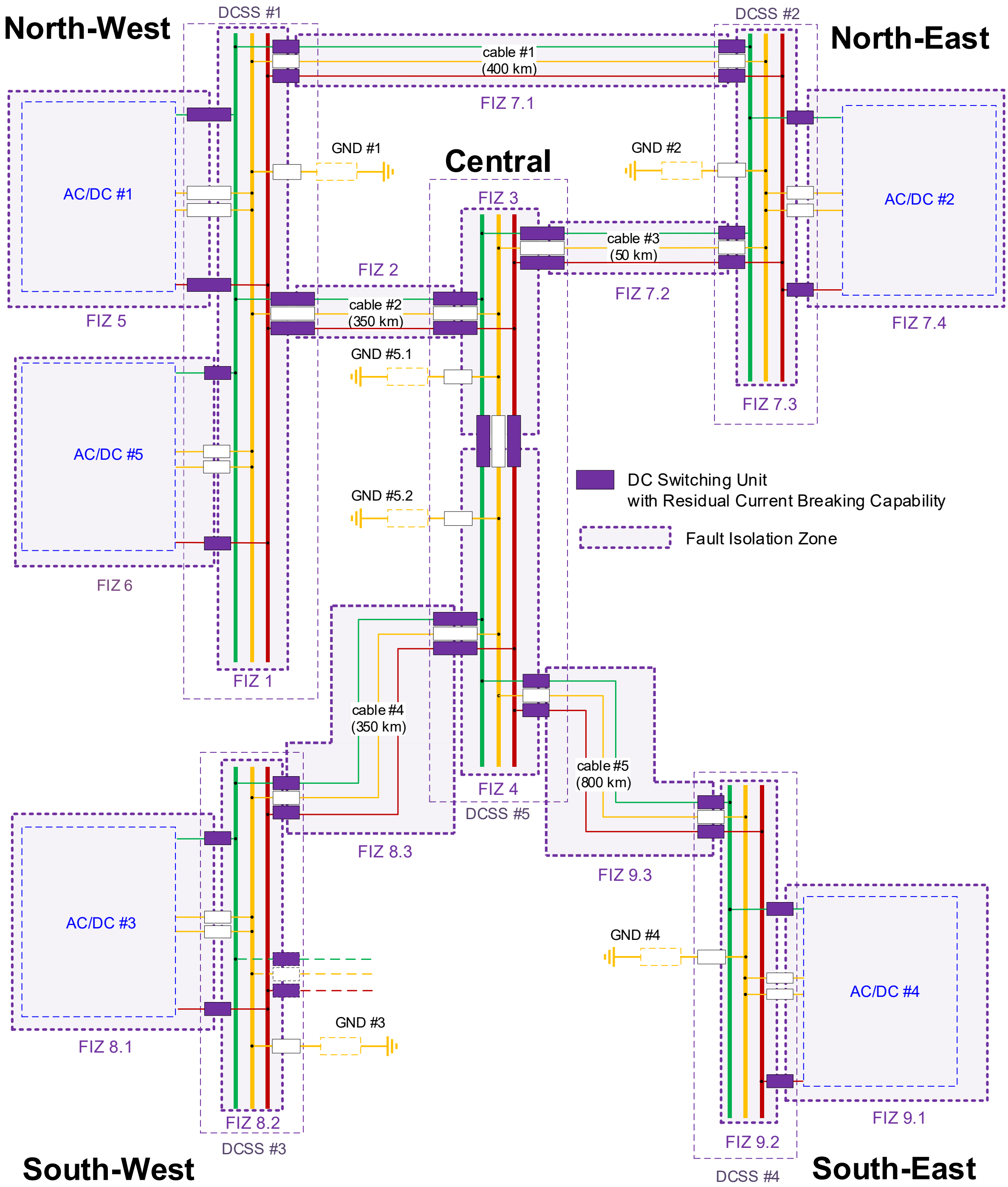


Figure 5-10: Fault isolation zones for the InterOPERA demonstrator; 5T full scope

Please note that the term "fault isolation" is used in InterOPERA for the operation of residual current switches in the process of fault handling. Other definitions (e.g. IEC TS 63291) refer to "fault clearing" instead and use "fault isolation" for the operation of slow disconnectors. As there was no consensus reached and corresponding standards are under maintenance, both definitions might be used in the InterOPERA demonstrator.

5.3. Specific Connection Requirements

This section provides specific connection requirements for different demonstrator subsystems which need to be defined holistically for the overall InterOPERA demonstrator but cannot be formulated on a purely functional basis.

5.3.1. Reference to Ground

The reference to ground in the neutral system must be coordinated throughout the DC system. For the InterOPERA demonstrator, all DC Switching Stations are supposed to include a grounding unit providing a reference to ground. The default location for neutral system reference to ground after start-up is the central DC Switching Station #5 (refer to section 5.2.1). Any change of the reference to ground shall be coordinated by the DC Grid Controller.

As a specific connection requirement, all grounding units shall provide an ohmic resistance of **10 Ohms.** Further information about the requirements on grounding units are provided in Annex 3.3.4.

5.3.2. Insulation Coordination

According to the IEC 60071-11:2022 [16] standard, the main objective of the insulation coordination is "[…] the determination of withstand voltages to achieve the desired reliability" of the system. Another important objective is the determination of surge arrester requirements, as "the insulation level of the HVDC system is directly determined by the characteristics and arrangement of the arrester". Although both parts play a crucial role during insulation coordination, it should be pointed out, that arrester ratings are usually design specific and shall be adapted by the vendors, as long, as the predefined voltage withstand levels are met.

In an HVDC grid, the HV transmission cables may be regarded as the most sensitive components when it comes to protection against overvoltages, as the cable characteristic itself can hardly be changed. While the internal components of converters are also sensitive to overvoltages, they are partly decoupled from incoming surges by the series reactors connected between the converter arms and the switching station or cable (whichever would be connected to the converter station, via a switching unit). Together with the fixed cable parameters, it may thereby be reasoned that the cable ratings should be used as a basis for determining the required switching and lightning impulse withstand levels of the system, as these will translate into the most stringent requirements for the surge arrester I-V characteristics.

Following the withstand capabilities of the DC cable in section 4.3.1, the switching and lightning impulse withstand levels (SIWL and LIWL, respectively) for each PoC-DC in the InterOPERA demonstrator shall be considered as given in **Table 5-7**. As the surge arrester rating is design specific and thereby in the scope of each vendor separately, arrester design and protective levels (switching impulse protective level (SIPL) and lightning impulse protective level (LIPL)) are not in the scope of this specification. Corresponding safety factors are taken from Table 3 in IEC 60071-11 [16] for equipment on the DC side.

Table 5-7: Parameters for DC grid insulation coordination

Parameter	High-voltage DC system (P1 / P2)	Neutral DC system (R)
SIWL	1050 kV	
Safety factor	1.15	
LIWL	1050 kV	250 kV
Safety factor	1.20	1.20

By this scope demarcation each subsystem owner should ensure that overvoltages at the PoC-DC of each subsystem meet the defined withstand voltages with the defined margins. In addition to the standard impulse levels, specific requirements (e.g. DC cable TOV limits from section 4.3.1 – which may be project specific in reality, with cable testing still being under development) shall also be considered.

5.3.3. Power Curtailment

Following the overvoltage power control scheme described in chapter 4.2.7, a specific connection requirement for the InterOPERA demonstrator is formulated as this information is relevant for the design of different subsystems.

All Power Park Modules shall be able to ramp down their power generation following a ramp rate within a given range (between zero and a maximum ramp rate) – which is for example requested by the DC grid controller. The maximum ramp rate is defined as[18] **0.25 p.u. / second**.

It is recommended to specify a maximum acceptable latency — for example, 100 ms — between signal reception at the PPM interface and the initiation of curtailment / ramp down.

More details on PPM power curtailment can be found in Annex 3.3.6.

[18] PPMs may be capable of ramping down power with a faster ramp rate, but its application needs to be coordinated with the DCGC and accepted by the entity responsible for system operation.

6. References

Table 6-1: List of references

Ref. No.	Title
01	InterOPERA D1.1 (PUBLIC) "Functional requirements for HVDC grid systems and subsystems"
02	InterOPERA D1.2 (PUBLIC) "Minimum technical requirements for EMT offline, SIL and HIL simulations platforms and models to perform interaction studies"
03	InterOPERA D2.1 (PUBLIC) "Functional requirements for HVDC grid systems and subsystems"
04	InterOPERA D2.2 (PUBLIC) Grid-Forming Functional Requirements for HVDC Converter Stations and DC-Connected PPMs in Multi-terminal Multi-vendor HVDC systems
05	InterOPERA D3.1 (PUBLIC) "Demonstrator project definition and system design studies"
06	InterOPERA D3.2 (SENSITIVE) "Subsystems pre-design phase process and outcomes"
07	InterOPERA D3.8 (SENSITIVE) "Demonstrator HVDC Grid System Design Studies"
08	Commission Regulation (EU) 2017/1485
09	IEC TS 63291 High voltage direct current (HVDC) grid systems and connected converter stations – Guideline and parameter lists for functional specifications
10	ENTSO-E Network Code HVDC
11	VDE-AR-N 4131:2019-03 Technical requirements for grid connection of high voltage direct current systems and direct current-connected power park modules (TAR HVDC)
12	ENTSO-E Technical Group, 2020 High Penetration of Power Electronic Interfaced Power Sources (PEIPS) and the Potential Contribution of Grid Forming Converters
13	CIGRE Science & Engineering (CSE) N°36, February 2025 Enhanced Modelling and Parameter Determination of HVDC Cables Using Practice-Oriented Methodology

14	CIGRÉ B1 – Technical Brochure 562 Recommendations for testing DC extruded cable systems for power transmission at a rated voltage up to and including 800 kV
15	IEC IEC 60071-1:2019 Insulation co-ordination - Part 1: Definitions, principles and rules
16	IEC 60071-11:2022 Insulation co-ordination - Part 11: Definitions, principles and rules for HVDC system

Annex 01: Demonstrator Use Cases and Features

WP3

Multi-vendor / Multi-terminal demonstrator project

Deliverable 3.3(b)

Detailed Functional Specifications

Annex 01

Demonstrator’s use cases and features

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.

Co-funded by
the European Union

DISCLAIMER:

PROJECT DETAILS:

Duration: 1 January 2023 – 30 April 2027
Grant agreement: 101095874 — InterOPERA — HORIZON-CL5-2022-D3-01

Detailed Functional Specifications

DEMONSTRATOR’S USE CASES AND FEATURES

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Table of Contents

VERSION CONTROL

Version	Date	Created/modified by	Comments
1.0	06.02.2025	S. Silvant (SuperGrid Institute)	DUCF incorporation with D3.3 initial release for internal review
1.1	05.03.2025	S. Silvant (SuperGrid Institute)	Update after internal review
2.0	18.03.2025	S. Silvant (SuperGrid Institute)	Second issue (clean) for consensus review
2.1	19.09.2025	S. Silvant (SuperGrid Institute)	Third issue (clean) for consensus review D3.3b

1. Introduction

1.1. Context and objective: the scoping of InterOPERA's Demonstrator from operational and functional perspectives.

The global objective of InterOPERA is to de-risk the multi-vendor multi-terminal HVDC technology with grid forming capability, to pave the way to the first real-life projects in Europe and to enable the development of the European HVDC grid for offshore wind energy integration.

The overall concept underpinning InterOPERA is to achieve interoperability of multi-vendor HVDC grids by developing all relevant frameworks and performing the full scope of necessary activities concurring to the implementation of a real-time physical demonstrator.

InterOPERA's Demonstrator grid topology has already been defined. D3.1 [01] outlined a fully flexible Demonstrator grid topology but left many functional and operational aspects quite open.

The relevant subsystems have been described in D3.2 [02] from a functional perspective while leaving generally open the field of possibilities. In other words, some functional scope choices were already made through the description of the relevant subsystems, but many topics are still open, and certain functional scope and operational rules decisions left to be made.

To enter the more concrete activities of system design and studies, of subsystem detailed specification (T3.3) and subsequent Control & Protection development by the different vendors, it was necessary to agree on an operational and functional scope for InterOPERA's Demonstrator.

This document aims at structuring its definition and the underlying collective decision-making process through the description and categorization of Use Cases.

The Use Cases will also serve as an input to T2.2 supporting the derivation of the Demonstrator test strategy.

InterOPERA's consortium collectively agrees on the Demonstrator's operational and functional scope. Every decision made is a compromise between the interest for enabling and de-risking multi-terminal multi-vendor HVDC grids with grid forming capability, and the effort and risk taken in terms of design, development and testing

InterOPERA's partners have been consulted as stakeholder groups, namely the TSOs, the offshore developers, the HVDC or WTG vendors, to simplify the process considering that the needs and the constraints of their respective members shall be aligned for the most part. The resulting feedback has been processed to consolidate a list of Use Cases. When a decision had to be made, the final word for prioritization has often been left to the HVDC and WTG vendors, considering the TSOs and offshore developers' expectations.

1.2. What is a Use Case

1.2.1. Process of specifying Use Cases (UCs)

D3.2 [02] proposed to use the general methodology of specifying Use Cases (UCs) as described in IEC 62559-2. The process starts by identifying the objectives, i.e., InterOPERA objectives, and the associated required features as described schematically in Figure 1-1. Following that each feature is analyzed to identify the possible use cases (UCs) of the feature as relevant to the system users (aka actors), as shown by the diagram in Figure 1-2: Process of specifying the Use Cases.

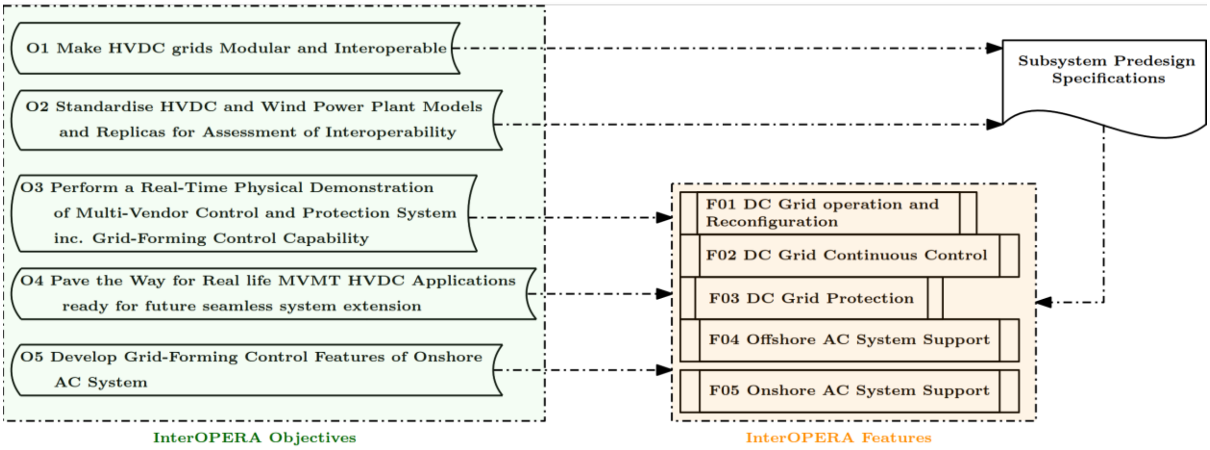

Figure 1-1: Features in correlation to InterOPERA objectives.

A UC is a triggered event that impacts how the system is used. A UC can be connected to more than one system feature, where a feature in this deliverable refers to a Demonstrator feature. For simplicity, each UC is described in relation to a single feature.

The demonstrator features have been identified to satisfy InterOPERA's technical project objectives as described in the Grant Agreement.

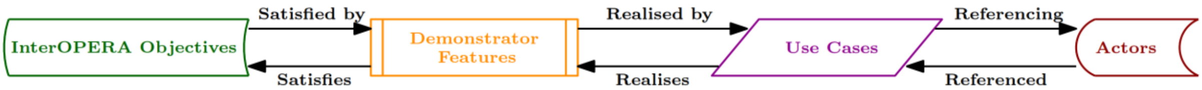

Figure 1-2: Process of specifying the Use Cases

1.2.2. Use case description template

Main category	F01 - DC Grid operation and reconfiguration F02 – DC Grid continuous control F03 – DC Grid protection F04 – Offshore AC F05 – Onshore AC
Priority rating	**Basic** **Optional -** means that after each of those steps (system design/studies, development and testing), we can pivot and decide to not proceed with the next step for this UC. There is no obligation of successful results. **Excluded**
Preliminary or final specs	The result of task 3.3 is split in two parts acknowledging the need for gradual development and potential refinement: • Deliverable D3.3 (a): Preliminary Functional Specifications (this document and its annexes) • Deliverable D3.3 (b): Detailed Functional Specifications A UC may already be considered when deriving the preliminary specs (= "preliminary") or may be only considered in a second step when deriving the final specs (="final").
Description	Simple description of the UCs, containing as much as possible references to relevant sections from other InterOPERA's deliverables.
Min. required grid topology, config or equipment	An indication of the minimum required grid topology, configuration or equipment for the UC to be applicable. This will help with the design of a progressive Demonstrator test protocol. This minimum required grid topology is often misleading and misunderstood; it is not about stating that the UC will be limited to that topology, it is about stating that with a less rich/complex topology than the one mentioned, this UC is not relevant or not applicable.
Min. D3.1 subset	Same as the line above but a direct reference to the Demonstrator subsets defined in D3.1
Simu. environment (testing method)	It can be HIL, Offline, Offline + HIL, resp. Offline+HIL or Offline only if respectively two min. required grid topologies are proposed. Is it enough to demonstrate the use-case or feature offline, or shall it be implemented in hardware and tested in HIL? Considering the Grant Agreement compliance (i.e. TRL6), but also the partners expectation and the fact the HIL setup is limited to 3 terminals
Pre-condition (grid configuration, control modes, state...)	What is the initial system state, grid configuration, actual power flow… What are the control modes of the different subsystems

Trigger	The trigger is a discrete event like an operator command, a fault, a disturbance…
Post-condition	What is the expected final system state
Primary flow	What is the expected flow of actions
Alternative flow	
Failure flow	
Actors / inv. subsystems	The subsystems AC/DC CNVS, DCSS, PPM, Offshore AC, Onshore AC, Energy absorber, DCGC, can be primary actor(s), secondary actor(s) or not concerned. The primary actor is the actor that responds first to the UC trigger. A secondary actor is an actor that provides a secondary response to the UC trigger or the primary actor.

2. Use cases

List overview

F01	**Grid Operation and Reconfiguration**	**B**asic **O**ptional **Ex**cluded	**Preliminary** Specs (Dec 24)	**Final** Specs (Jun 25)
UC01-01	Start-up from 1 onshore station and shut-down	B	X	
UC01-021	Transition from one power flow schedule to another (only set points)	B	X	
UC01-022	Transition to new control modes and control parameters	B	X	
UC01-03	Basic switching operations and grid reconfiguration sequences	B	X	
UC01-04	Secondary control - automatic transition to a new power flow schedule after a severe contingency	B	X	
UC01-07	More advanced switching operations and grid reconfiguration sequences involving (unloading) control actions	Excl.		
UC01-081	Planned subgrids merge - on load switching	O		(X)
UC01-082	Planned grid split - on load switching	O		(X)
UC01-09	Black start capabilities from one synchronous zone to another	Excl.		
F02	**Continuous Controls**	**B**asic **O**ptional **Ex**cluded	**Preliminary** Specs (Dec 24)	**Final** Specs (Jun 25)
UC02-01	Power disturbance with 1 converter station in Vdc control mode, the others in power control mode	B	X	
UC02-02	Power disturbance with converter stations in Vdc-droop control modes	B	X	
UC02-031	Asymmetrical pole operation due to one transmission pole outage	B	X	
UC02-032	Asymmetrical pole operation due to difference in power injection in positive and negative poles	B	X	
UC02-04	Vdc-droop converters connected to the same DC-bus, to the same DC switching station	O		X

F03	**DC Protection**	**B**asic **O**ptional **E**xcluded	**Preliminary** Specs (Dec 24)	**Final** Specs (Jun 25)
UC03-01	DC fault within all selective fault separation zones	B	(X)	X
UC03-021	DC fault within the fault separation zone including non-selective zones	B	(X)	X
UC03-022	Reclosing of healthy part of non-selective FSZ after fault isolation	Excl.		
UC03-03	Back-up protection	Excl.		
F04	**Offshore AC Performance**	**B**asic **O**ptional **E**xcluded	**Preliminary** Specs (Dec 24)	**Final** Specs (Jun 25)
UC04-01	Offshore grid energization from 1 offshore HVDC station ("soft start")	B	X	
UC04-02	PPMs from two different vendors directly connected to the same busbar (steady-state small-signal operation validation)	B	X	
UC04-03	Re-energization of tripped PPM after HVDC transformer fault by closing busbar coupler ("hard start")	B	X	
UC04-04	PPMs from two different vendors connected to two coupled HVDC poles including testing of converter pole faults and PPMs power curtailment	Excl.		
UC04-051	Ride through offshore HVDC converter temporary blocking with WTGs in GFL control mode	B	(X)	X
UC04-052	Ride through offshore HVDC converter temporary blocking with WTGs in GFM control mode	O		
UC04-06	Ride through offshore HVDC converter temporary blocking with shared parallel GFM between two AC interconnected remote-end HVDC converter stations	Excl.		
UC04-07	DC-side contingency leading, after energy absorber activation, to a coordinated emergency offshore wind ramp-down or curtailment	B	X	
UC04-081	Offshore AC fault ride through capability with GFL WTGs - Post fault active power recovery	B	X	
UC04-082	Offshore AC fault ride through capability with GFM WTGs - Post fault active power recovery	O		
UC04-09	Offshore AC interconnection - AC/DC circular interactions	Excl.		

UC04-10	PPMs enabling the remote-end HVDC capability to control the DC-voltage in droop control mode	Excl.		
UC04-111	HVDC converter permanent blocking with WTGs in GFL control mode	B	X	
UC04-112	HVDC converter permanent blocking with WTGs in GFM control mode	O		
F05	**Onshore AC Performance**	**B**asic **O**ptional **Ex**cluded	**Preliminary** Specs (Dec 24)	**Final** Specs (Jun 25)
UC05-01	Onshore AC fault ride through capability and post fault active power recovery	B	X	
UC05-02	Reactive power control under extreme grid conditions	B		X
UC05-03	Grid forming active power support to the onshore AC grid	B		X
UC05-04	Grid forming active power support to the onshore AC grid including support from offshore WTGs	O		
UC05-10	SSTI	Excl.		
UC05-11	POD-P	Excl.		
UC05-12	Exploration of HVDC system stability and interoperability with interconnected AC areas	O	(X)	

1

2.1. F01 - DC Grid operation and reconfiguration

UC01-01 - Start-up from 1 onshore station and shut-down

Main category	F01 - DC Grid operation and reconfiguration
Priority rating	**Basic**
Preliminary or final specs	**Preliminary**
Description	- It shall be possible to start up the HVDC grid from an onshore converter station. - It shall also be possible to carry out the reverse sequence for a shutdown of the HVDC grid. See D1.3 chapter 6 (Energization and de-energization)
Min. required grid topology, config or equipment	3T only onshore - radial only
Min. D3.1 subset	Subset 1 - (P2P – integration of standalone DCSS) - cable 1 opened (radial)
Simulation environment (testing method)	Offline + HIL
Pre-condition (grid configuration, control modes, state...)	All equipment is shut down, de-energized. Telecom is available
Trigger	Operator
Post-condition	DC Voltage is controlled and stable. No power flow is implemented.
Primary flow	After an initial request from the operator, the DCGC proposes a standard start-up or shut down sequence. The sequence can be executed at once or step-by-step by the operator.
Alternative flow	The operator controls himself the relevant operations (switching unit closing, control mode setting…)
Failure flow	
Actors / inv. subsystems	
AC/DC CNVS	Primary actor
DCSS	Primary actor
PPM	Primary actor
Offshore AC	
Onshore AC	
Energy absorber	
DCGC	Primary actor

UC01-021 - Transition from one power flow schedule to another (only set points)

Main category	F01 - DC Grid operation and reconfiguration
	F02 - DC Continuous control
Priority rating	**Basic**
Preliminary or final specs	**Preliminary**
Description	It shall be possible to schedule and implement new power flow set points without interrupting the operation of the HVDC grid. Accurate DC power flow (DC power and voltage references) shall be computed based on initial AC/DC schedule (AC power references). This includes going from/to no-load operation and the coordination of power ramp-up and ramp-down rates between converters and wind farms. see NC-HVDC Article 13 see D3.2 section 3.4.1 (Power flow computation and implementation) see D3.2 section 8.3.5.2 (PPC external interfaces)
Min. required grid topology, config or equipment	3T only onshore- radial only
Min. D3.1 subset	Subset 2 (3 MT - base topology) - cable 1 opened (radial)
Simu. environment (testing method)	Offline + HIL
Pre-condition (grid configuration, control modes, state…)	All subsystems are available and ready for power operation. DC voltage is controlled and stable. AC offshore voltage is controlled and stable.
Trigger	Operator provides a new AC power schedule for all converter stations / units.
Post-condition	The power flow operating point transfers into the new scheduled operating point. The operation is stable.
Primary flow	- DCGC receives a command for a schedule change. - DCGC calculates new set points associated with the new schedule. - DCGC computes appropriate ramp rates for all converter stations and PPM. - DCGC issues new set points for converter units and PPM. - Converter stations and PPMs set points are updated
Alternative flow	The operator sends the new set points directly to the stations
Failure flow	- DCGC fails to compute the PF due to constraints being impossible to satisfy given operator's request.

	- DCGC fails to send the appropriate setpoints due to interoperability issues - The new power flow is not reached with a satisfactory precision
Actors / inv. subsystems	
AC/DC CNVS	Primary actor
DCSS	Primary actor
PPM	Primary actor
Offshore AC	Not concerned
Onshore AC	Not concerned
Energy absorber	Not concerned
DCGC	Primary actor

UC01-022 - Transition to new control modes and control parameters

Main category	F01 - DC Grid operation and reconfiguration
Priority rating	**Basic**
Preliminary or final specs	**Preliminary**
Description	It shall be possible to communicate and implement new control modes and associated control settings, while ensuring the DC voltage controllability (e.g. with interlocking control modes) see D3.2 section 4.8.2.2 (DC node outer controllers) see D3.2 section 3.4.4 (Voltage security assessment) Assumption: focus on DC side control modes and control parameters; Most usual control modes (Pdc, droop and Vdc) shall be included as "basic" whereas transitions from/to GFM control mode are considered as "optional". No differentiated pole control modes.
Min. required grid topology, config or equipment	3T only onshore- radial only
Min. D3.1 subset	Subset 2 (3 MT - base topology) - cable 1 opened (radial)
Simu. environment (testing method)	Offline + HIL
Pre-condition (grid configuration, control modes, state...)	All subsystems are available and ready for power operation. DC voltage is controlled and stable. AC offshore voltage is controlled and stable.
Trigger	Operator provides new control modes and new control settings

Post-condition	The converter stations and PPMs have updated their control modes and settings; the system is stable.
Primary flow	- DCGC receives a command for control modes and settings updates - DCGC checks the DC voltage controllability. - DCGC issues new control modes and settings for converter units and PPM. - Converter stations and PPMs control modes and settings are updated
Alternative flow	The operator sends the new control modes and settings directly to the stations
Failure flow	- DC voltage control is not coordinated - DCGC fails to send the appropriate control modes and settings due to interoperability issue
Actors / inv. subsystems	
AC/DC CNVS	Primary actor
DCSS	Primary actor
PPM	Primary actor
Offshore AC	Not concerned
Onshore AC	Not concerned
Energy absorber	Not concerned
DCGC	Primary actor

UC01-03 - Basic switching operations and grid reconfiguration sequences

Main category	F01 - DC Grid operation and reconfiguration
Priority rating	**Basic**
Preliminary or final specs	**Preliminary**
Description	Connection and disconnection of individual units (one single transmission pole or one converter unit) or elements (one converter station or one entire transmission line). This includes - Planned operation – no-load switching, de-loading managed by the dispatch - Possible on-load switching of the meshed part - Connection and energization of an offshore converter station to a live DC grid See D3.2 section 3.4.3 (Reconfiguration sequence)

	"Basic" seen from Grid Control: only based on switching order, no automatic unloading or any other means of synchronization across the switches
Min. required grid topology, config or equipment	3T only onshore
Min. D3.1 subset	Subset 2 (3 MT - base topology) - cable 1 opened (radial) Meshed 3T
Simu. environment (testing method)	Offline + HIL
Pre-condition (grid configuration, control modes, state...)	The HVDC grid is in normal state and stable
Trigger	Operator
Post-condition	The HVDC grid is in normal state and stable after the reconfiguration
Primary flow	After an initial request from the operator, the DCGC will propose a sequence composed of multiple switching operations. The operator must validate the sequence before it is executed by the DCGC. For sequences that can be broken down into smaller ones, the operator can proceed step-by-step through the sequence. In case of on-load switching, inrush current needs to be limited either through DC Switching Unit Peak Current Suppression capability.
Alternative flow	The operator controls himself the relevant operations (DC Switching Unit closing/opening).
Failure flow	
Actors / inv. subsystems	
AC/DC CNVS	Secondary actor
DCSS	Primary actor
PPM	Secondary actor
Offshore AC	Secondary actor
Onshore AC	Not concerned
Energy absorber	Not concerned
DCGC	Primary actor

UC01-04 - Secondary control - automatic transition to a new power flow schedule after a severe contingency

Main category	F01 - DC Grid operation and reconfiguration
Priority rating	**Basic**

Preliminary or final specs	**Preliminary**
Description	Following a contingency, assuming the post-fault state is within the continuous operating range, the power flow can be modified to - re-establish voltage within the normal range - ~~restore power margins~~ ~~- to respect dc cable current limits~~ see D3.2 section 3.4.2 (Coordinated wind farm curtailment & Secondary Voltage Control) Clarification: This Use Case does not include wind power curtailment
Min. required grid topology, config or equipment	3T
Min. D3.1 subset	
Simu. environment (testing method)	Offline + HIL
Pre-condition (grid configuration, control modes, state...)	The DC voltage is stable within the continuous operating range following the primary voltage response.
Trigger	The HVDC grid is in alert state after a contingency.
Post-condition	The DC voltage is established within the normal range.
Primary flow	Alert state is detected by DCGC due to voltage exceeding normal range after a certain duration. DCGC computes new Power Flow based on actual AC power, but with DC voltage within the normal range.
Alternative flow	
Failure flow	
Actors / inv. subsystems	
AC/DC CNVS	Secondary actor
DCSS	
PPM	Secondary actor
Offshore AC	
Onshore AC	
Energy absorber	
DCGC	Primary actor

UC01-07 - More advanced switching operations and grid reconfiguration sequences involving dynamic (unloading) control actions

Main category	F01 - DC Grid operation and reconfiguration
Priority rating	**Excluded**
Preliminary or final specs	N/A
Description	Power flow modification can be wished to unload a unit before disconnection. Modification of control modes can be required to ensure voltage controllability. The ability to automate power flow and control mode changes in reconfiguration sequences is seen as one of the most challenging actions for both vendors and TSOs. See D3.2 section 3.4.3 (Reconfiguration sequence)
Min. required grid topology, config or equipment	3T - meshed required?
Min. D3.1 subset	
Simu. environment (testing method)	
Pre-condition **(grid configuration, control modes, state..)**	Stable operating point, normal state.
Trigger	Operator
Post-condition	Disconnected parallel cable
Primary flow	The DCGC unloads parallel cable before sending a disconnection order
Alternative flow	The operator controls himself the sequence
Failure flow	Switching unit capability exceeded?
Actors / inv. subsystems	
AC/DC CNVS	Secondary actor
DCSS	Secondary actor
PPM	
Offshore AC	
Onshore AC	
Energy absorber	
DCGC	Primary actor

UC01-081 - Planned subgrids merge

Main category	F01 - DC Grid operation and reconfiguration
Priority rating	**Optional**
Preliminary or final specs	**Final**
Description	Connection of two live HVDC subgrids with/out power flows. Neutral system could be connected beforehand or not. Only the central DC switching station is capable of splitting or merging the grid as this limits and simplifies the engineering effort See D3.2 section 6.3.4 (DC Synchronization) See D2.1 (DC switching unit) To ensure no-load switching, it is assumed that the prerequisite is that there must be the same voltage in the sub-sections of the central station just before the merger. Whether or not the DCGC will enable the operator to manually adjust the average voltage of both subgrids is to be confirmed, so the equalization of the voltages at the two sides of the switching unit seems difficult to guarantee. An alternative way is to equip the DC Switching Unit with Peak Current Suppression capability. The DC switching station will anyway be responsible for switching without creating undesirable over voltages for the system. The planning of the merger goes beyond the question of power flow; it also includes the management of grounding and control modes. The DCGC will probably not include automatic change of control modes, nor automatic change of grounding points (no automation of the overall process). It is assumed to be Ok to have two different simultaneous grounding points for a while.
Min. required grid topology, config or equipment	5T
Min. D3.1 subset	
Simu. environment (testing method)	Offline
Pre-condition (grid configuration, control modes, state…)	Both subgrids are: - DC Voltage controlled - Earthed - All stations in droop?
Trigger	Operator
Post-condition	HVDC system is in normal operation, with stable voltage, 1 earthing point
Primary flow	Following an operator request, the DCGC autonomously - Check compatibility of control modes

	- Connect neutral system and handle system earthing - Electrically connect the sub grids
Alternative flow	The operator controls himself the merge sequence
Failure flow	
Actors / inv. subsystems	
AC/DC CNVS	Secondary actor
DCSS	Primary actor
PPM	Secondary actor
Offshore AC	
Onshore AC	
Energy absorber	
DCGC	Primary actor

UC01-082 - Planned grid split - on load switching

Main category	F01 - DC Grid operation and reconfiguration
Priority rating	**Optional**
Preliminary or final specs	**Final**
Description	Separation of a DC grid into two electrically disconnected subgrids. Only the central DC switching station is capable of splitting or merging the grid as this limits and simplifies the engineering effort see D3.2 section 6.3.6 (System split) <u>If planned for no-load switching:</u> The two electrically disconnected subgrids shall be grounded and DC-voltage controlled. The DCGC will not include automatic change of control modes, nor automatic change of grounding points (no automation of the overall process). It is assumed to be Ok to have two different simultaneous grounding points for a while. The need to plan the merger could also include the question of power flow scheduling to ensure that there is no power flowing in the central station before the split to ensure a no-load DCSU operation. <u>For the flexibility to split without planning, relying on load switching capability:</u> To provide the operator with the flexibility to trigger a split without significant planning and preliminary actions, this may require: - the two sides of the central DCSU are grounded by default even in closed position?

	- the two subgrids include DC-voltage droop controlled onshore converter stations before the split? - Load-switching capability for the central DCSU
Min. required grid topology, config or equipment	5T
Min. D3.1 subset	
Simu. environment (testing method)	Offline
Pre-condition (grid configuration, control modes, state…)	Stable operating point, normal state. Neutral system could be disconnected beforehand or not.
Trigger	Operator
Post-condition	HVDC system is split into two electrically disconnected subgrids that are stable
Primary flow	Following an operator request, the DCGC autonomously - Check compatibility of control modes - Separate neutral system and handle system earthing - Electrically disconnect the sub grids
Alternative flow	The operator controls himself the split sequence
Failure flow	Undesirable overvoltages created Maximum DCSU current switching capability exceeded
Actors / inv. subsystems	
AC/DC CNVS	Secondary actor
DCSS	Primary actor
PPM	Secondary actor
Offshore AC	
Onshore AC	
Energy absorber	
DCGC	Primary actor

UC01-09 - Black start capabilities from one synchronous zone to another

Main category	F01 - DC Grid operation and reconfiguration
Priority rating	**Excluded**
Preliminary or final specs	N/A
Description	
Min. required grid topology, config or equipment	3T variant 2
Min. D3.1 subset	
Simu. environment (testing method)	HIL?
Actors / inv. subsystems	

2.2. F02 - DC Continuous control

UC02-01 - Power disturbance with 1 converter station in fixed Vdc control mode, the others in power control mode

Main category	F02 - DC Continuous control
Priority rating	**Basic**
Preliminary or final specs	**Preliminary**
Description	Power disturbances and contingency's management / reaction see D3.2 section 4.8.2.2 (DC node outer controllers) The exact test cases (initial conditions, power step magnitude…) will be defined in T2.2 test protocols.
Min. required grid topology, config or equipment	3T
Min. D3.1 subset	Subset 2 (3 MT - base topology) - cable 1 opened
Simu. environment (testing method)	Offline + HIL
Pre-condition (grid configuration, control modes, state...)	The HVDC grid DC voltage is established at all bus bars within the normal operating range and the power flow is stable
Trigger	Perturbation (power step).
Post-condition	The HVDC grid DC voltage is established at all bus bars within the continuous operating range and the power flow is stable
Primary flow	The CNVS controls act to stabilize the DC voltage
Alternative flow	
Failure flow	
Actors / inv. subsystems	
AC/DC CNVS	Primary actor
DCSS	
PPM	
Offshore AC	
Onshore AC	
Energy absorber	
DCGC	

UC02-02 - Power disturbance with converter stations in Vdc-droop control modes

Main category	F02 - DC Continuous control
Priority rating	**Basic**
Preliminary or final specs	**Preliminary**
Description	Power disturbances and contingency management / reaction Scope limited to onshore converter stations providing Vdc droop control, the offshore converter stations are not supporting the DC voltage. See D3.2 section 4.8.2.2 (DC node outer controllers) Carefully test the interaction risks that may occur when Vdc droop controls are operating close to the knee points of the multi-segment droop Emulate EPC or LFSM stresses by applying a large disturbance to the power flow that crosses the knee points of the DC voltage droop control characteristics (converter blocking would be more severe but only downwards and would entail full loss, might want to be upwards as well and with a less big step). The exact test cases (initial conditions, power step magnitude…) will be defined in T2.2 test protocols.
Min. required grid topology, config or equipment	3T (onshore only, or with 2 stations onshore)
Min. D3.1 subset	Subset 2 (3 MT base topology - variant 2) Subset 3 or 4 (4MT long DC tap)
Simu. environment (testing method)	Offline + HIL
Pre-condition (grid configuration, control modes, state...)	The HVDC grid DC voltage is established at all bus bars within the normal operating range and the power flow is stable. The power flows should be adjusted in a way such that the post disturbance not only crosses the points but also operates very close to the limit to really provoke any adverse interactions.
Trigger	Perturbation (if subset 3 or 4: power step - spurious trip of an offshore converter station, if 3T only onshore: power step can also lead to overvoltage perturbation)
Post-condition	The HVDC grid DC voltage is established at all bus bars within the continuous operating range and the power flow is stable
Primary flow	The CNVS controls act to stabilize the DC voltage
Alternative flow	
Failure flow	- not have sufficient power reserves to deal with ordinary contingencies

	- adverse control interactions, insufficient damping
Actors / inv. subsystems	
AC/DC CNVS	Primary actor
DCSS	
PPM	
Offshore AC	
Onshore AC	
Energy absorber	
DCGC	

UC02-031 - Asymmetrical pole operation due to one transmission pole outage

Main category	F02 - DC Continuous control
Priority rating	**Basic**
Preliminary or final specs	**Preliminary**
Description	Planned outage of one HV feeder in the radial configuration, leading to large power flow pole asymmetries, up to 1000MW. *Subsequent local CNVS bipole reconfiguration and dynamic rebalancing control to exploit overcurrent capability of the remaining transmission pole are not considered.* The exact test cases (initial conditions, delta power unbalance between the two poles…) will be defined in T2.2 test protocols.
Min. required grid topology, config or equipment	3T
Min. D3.1 subset	Subset 2 (3 MT base topology)
Simu. environment (testing method)	Offline + HIL
Pre-condition (grid configuration, control modes, state..)	The HVDC grid DC voltage is established at all bus bars within the normal operating range and the power flow is stable
Trigger	1 radial transmission pole outage
Post-condition	The HVDC grid DC voltage is established at all bus bars within the normal operating range and the power flow is stable. Optionally, the disconnected converter units are in STATCOM mode.
Primary flow	The CNVS controls act to stabilize the DC voltage.

	Optional: automatic transition to STATCOM mode when a converter unit is disconnected from the DC side.
Alternative flow	
Failure flow	Different approaches to station level controls may result in interoperability issues
Actors / inv. subsystems	
AC/DC CNVS	Primary actor
DCSS	
PPM	Secondary actor
Offshore AC	
Onshore AC	
Energy absorber	
DCGC	

UC02-032 - Asymmetrical pole operation due to difference in power injection in positive and negative poles

Main category	F02 - DC Continuous control
Priority rating	**Basic**
Preliminary or final specs	**Preliminary**
Description	It shall be possible to operate the bi-polar HVDC grid within an unbalanced power flow case. Power flow pole asymmetries are in this use case relatively small (e.g. 10% <=100MW). Poles are control separately; any new pole balancing would be managed by the DCGC. see D3.2 section 4.8.2.3 (Pole Balancing)-→ balancing control is not required since the DMR are full rated. *Emulation of a non-full-rated DMR, or complete loss of DMR (rigid bipole operation) are not considered. This would have allowed to test pole balancing controls, and to check the capability to mutualize reserves from the 2 poles.* The exact test cases (initial conditions, delta power unbalance between the two poles…) will be defined in T2.2 test protocols.
Min. required grid topology, config or equipment	3T
Min. D3.1 subset	Subset 2 (3 MT base topology)

Simu. environment (testing method)	Offline + HIL
Pre-condition (grid configuration, control modes, state..)	The HVDC grid DC voltage is established at all bus bars within the normal operating range and the power flow is stable. Split bus connected PPMs
Trigger	Diverging power generation between PPMs
Post-condition	The HVDC grid DC voltage is established at all bus bars within the normal operating range and the power flow is stable
Primary flow	The CNVS controls act to stabilize the DC voltage
Alternative flow	
Failure flow	Different approaches to station level controls may result in interoperability issues
Actors / inv. subsystems	
AC/DC CNVS	Primary actor
DCSS	
PPM	Secondary actor
Offshore AC	
Onshore AC	
Energy absorber	
DCGC	

UC02-04 - Vdc-droop converters connected to the same DC-bus, to the same DC switching station

Main category	F02 - DC Continuous control
Priority rating	**Optional** – exploration stress test, with no specific design actions beforehand (no dedicated system studies)
Preliminary or final specs	**Final**
Description	Power disturbances and contingency management / reaction see D3.2 section 4.8.2.2 (DC node outer controllers)
Min. required grid topology, config or equipment	5T variant 2
Min. D3.1 subset	Full extent - 5T variant 2
Simu. environment (testing method)	Offline
Pre-condition (grid configuration, control modes, state..)	

Trigger	
Post-condition	
Primary flow	
Alternative flow	
Failure flow	
Actors / inv. subsystems	
AC/DC CNVS	Primary actor
DCSS	Secondary actor
PPM	
Offshore AC	
Onshore AC	
Energy absober	
DCGC	

2.3. F03 - DC protection

UC03-01 - DC fault within all selective fault separation zones (primary sequence including voltage and power restoration, open-loop relays) based on DC-FRT requirements for converter stations

Main category	F03 - DC protection
Priority rating	**Basic** – but with a second stage model delivery, with a technology disclaimer. Temporary blocking of AC/DC converter stations shall be provided in offline simulations but is optional in online simulations.
Preliminary or final specs	**(Preliminary)** - FSDs might not be available in stage 1 delivery for all vendors but design spec should include requirements as much as possible based on available data, in order to avoid design changes between preliminary and final specs (If possible, converter stations shall anticipate DC-FRT capabilities and all future DC reactors, including those part of DC Switching Units with expected fault separation capability, shall already be present in the preliminary design with their anticipated final value.)
Description	The protection equipment design is holistic at all DC Switching Stations and all converter stations in the 3/5-terminal system. This includes the application of the DC-FRT profile as defined in T2.1 to all converters. All switching units need to be designed to fulfil fault neutralization requirements for the pre-defined list of ordinary contingencies. see D3.2 section 6.5.1 (Protection zones and FSDs) see D3.3.1 section 5.2.2 (updated protection zones and FSDs) Relays can be emulated (no real detection algorithm)
Min. required grid topology, config or equipment	3T with DCCBs
Min. D3.1 subset	
Simu. environment (testing method)	Offline + HIL Due to specific vendors expected deliveries (Converter stations DC-FRT capabilities, provision of FSDs or not), the vendors position will be fixed in the HIL setup. Additional vendors might provide FSDs for the offline setup, opening for different positions and combinations.
Pre-condition (grid configuration, control modes, state…)	The HVDC grid is in operation and stable. The DC grid has sufficient reserves to encounter the contingency without remediation actions such as wind farm curtailment.
Trigger	DC fault within the fault separation zone (cable #2), relevant FSDs are tripped based on open loop signals, no fault discrimination algorithms are foreseen.

Post-condition	The fault is isolated. All converters outside the FSZ remain connected. A new stable power flow case is established.
Primary flow	- Fault occurrence - Fault detection - Fault neutralization - Post fault power recovery
Alternative flow	
Failure flow	- The contingency leads to a disconnection or a non-recovery of the converter station after blocking OR the FSD does not succeed in interrupting the fault current OR RCB cannot interrupt the residual current. - In the 3T system, there is still the question of DC voltage controllability if all 3 converter stations block → it is a question of DC-FRT profile parametrization. But also a question of initial control modes?
Actors / inv. subsystems	
AC/DC CNVS	Secondary actor
DCSS	Primary actor
PPM	
Offshore AC	
Onshore AC	
Energy absorber	
DCGC	

UC03-021 - DC fault within the fault separation zone including non-selective zones

Main category	F03 - DC protection
Priority rating	**Basic** – but with a second stage model delivery, with a technology disclaimer. Temporary blocking of AC/DC converter stations shall be provided in offline simulations but is optional in online simulations.
Preliminary or final specs	**(Preliminary)** - FSDs might not be available in stage 1 delivery for all vendors but design spec should include requirements as much as possible based on available data, in order to avoid design changes between preliminary and final specs (If possible, converter stations shall anticipate DC-FRT capabilities and all future DC reactors, including those part of DC Switching Units with expected fault separation capability,

	shall already be present in the preliminary design with their anticipated final value.)
Description	See description UC03-01. + Demonstrator activated all protection zones including non-selective ones (primary sequence including restoration, open-loop relays) based on DC-FRT requirements for converter stations + For non-selective protection zones, additional functionalities are tested: Trip of ACCB as boundary of FSZ and fault isolation at different location to fault separation. + Pole-to-ground or pole-to-pole faults considered as ordinary contingencies see D3.2 section 6.5.1 (Protection zones and FSDs) see D3.3.1 section 5.2.2 (updated protection zones and FSDs)
Min. required grid topology, config or equipment	3T meshed variant 2 or 5T - with DCCBs
Min. D3.1 subset	Subset 2 (3 MT base topology) or Full extent - 5T
Simu. environment (testing method)	Offline + HIL Due to specific vendors expected deliveries (Converter stations DC-FRT capabilities, provision of FSDs or not), the vendors position will be fixed in the HIL setup. Additional vendors might provide FSDs for the offline setup, opening for different positions and combinations.
Pre-condition **(grid configuration, control modes, state.,.)**	The HVDC grid is in operation and stable. The DC grid has sufficient reserves to encounter the contingency without remediation actions such as wind farm curtailment.
Trigger	See UC03-01 plus trip of ACCB at the boundary of non-selective FSZ and fault isolation inside FSZ
Post-condition	The fault is isolated. All converters outside the FSZ remain connected. A new stable power flow case is established.
Primary flow	- Fault occurrence - Fault detection (open-loop signal) - Fault neutralization - Post fault power recovery
Alternative flow	

Failure flow	- The contingency leads to a disconnection or a non-recovery of the converter station after blocking OR the FSD does not succeed in interrupting the fault current OR RCB cannot interrupt the residual current. - In the 3T system, there is still the question of DC voltage controllability if all 3 converter stations blocks → it is a question of DC-FRT profile parametrization. But also a question of initial control modes? D2.1 key investigations showed that a DC grid designed around AD/DC converter stations with temporary blocking capability recovers the DC voltage and power flow faster, even when multiple stations are blocking, than if the DC grid was designed around AD/DC converter stations without temporary blocking (mainly due to smaller DC reactors)
Actors / inv. subsystems	
AC/DC CNVS	Secondary actor
DCSS	Primary actor
PPM	
Offshore AC	
Onshore AC	
Energy absorber	
DCGC	

UC03-022 - Reclosing of healthy part of non-selective FSZ after fault isolation

Main category	F03 - DC protection
Priority rating	**Excluded -**

UC03-03 - Back-up protection

Main category	F03 - DC protection
Priority rating	**Excluded**

2.4. F04 - Offshore AC

UC04-01 - Offshore grid energization from 1 offshore HVDC station ("soft start")

Main category	F04 - Offshore AC
Priority rating	**Basic**
Preliminary or final specs	**Preliminary**
Description	see D1.3 section 6.1.6x, scenario a (Synchronized PPMs and HVDC offshore system energization) Offshore AC voltage can be ramped-up without causing any inrush transients. Define energization sequence and voltage ramp rate for HVDC converters. Base work on established grid codes.
Min. required grid topology, config or equipment	3T
Min. D3.1 subset	Subset 2 (3 MT base topology)
Simu. environment (testing method)	Offline + HIL
Pre-condition (grid configuration, control modes, state...)	Offshore AC system is de-energized D2.2 control chain concept #1
Trigger	Operator
Post-condition	Successful energization. In case of sudden shut-down, HVDC converter should be able to withstand load disturbance corresponding to disconnection of one or two OWFs.
Primary flow	Synchronized PPM and HVDC offshore system energization: It is expected that inside the parks, the transmission lines and all transformers are always connected and not switched with live voltage. The gradual start of the offshore HVDC stations will provide simultaneous energization of these components in a soft manner. Also, the start-up sequence of the turbines is achieved through pre-charge resistors and the filters are pre-loaded. As such, no major inrush currents are expected. Some special considerations can be made for especially long cables due to resonances and/or waveform travelling time, but this should equally be addressed by HVDC station soft-start. Traditional energization approach of an offshore wind farm, i.e., string by string, WTG by WTG, considering both PPMs.
Alternative flow	

Failure flow	Trips or component stresses outside design ranges. WTG from 2 different PPMs starting with adverse interactions
Actors / inv. subsystems	
AC/DC CNVS	Secondary actor
DCSS	Secondary actor
PPM	Secondary actor
Offshore AC	Secondary actor
Onshore AC	
Energy absorber	
DCGC	Primary actor

UC04-02 - PPMs from two different vendors directly connected to the same busbar (steady-state small-signal operation validation)

Main category	F04 - Offshore AC
Priority rating	**Basic** – mostly a matter of testing
Preliminary or final specs	**Preliminary -** control modes and setpoints are defined but no direct design requirements to small signal behaviour (no exchange of small-signal model expected in the first place). In case of adverse interactions, design requirements might be issued
Description	see D3.2 section 7.3.3.1 (pole coupler normally open), section 7.4.3 (related interactions) and section 7.6.3 (related recommendation for this option - alternative 1) 2 PPMs measuring and controlling the voltage at the same bus bar This UC requires the pre-definition of control modes - voltage, reactive power, power factor - and setpoints for the PPM's PPC so that they can operate harmonically. Since the different PPCs will be measuring and controlling quantities at the same electrical point, it is recommended not to adopt direct voltage control to avoid control hunting. Reactive power mode for PPMs is recommended, and its range should be defined through existing TSO documents. TenneT and Energinet documents (VDE-AR-N_4131_2019-03, Updated technical requirements for HVDC-connected power park modules and HVDC converters (draft)) were used as references. Operational voltage specifications should also be defined based on the TSO documents. In T.3.3.6, specifications for reactive power and voltage ranges are defined, but control mode and setpoint definitions should be decided in T3.5. Since the offshore AC/DC Converter Station is the one forming the Offshore AC Grid, then specifications for voltage, reactive power and frequency should also be defined for this subsystem.

Min. required grid topology, config or equipment	Connection between two AC busbars of the same pole.
Min. D3.1 subset	Subset 2 (3 MT base topology)
Simu. environment (testing method)	Offline + HIL
Pre-condition (grid configuration, control modes, state..)	D2.2 control chain concept #1 2 PPMs to be connected to the same busbar, not only the same HVDC pole (example in case of outage of one of the two transformers, or in case of outage of 1 pole, leading to closing of respectively the busbar or the pole coupler)
Trigger	Small power perturbations from the wind farms (+/- 3-5 % ramps), or even faults
Post-condition	WTG from different vendors must operate without adverse control interactions both at WTG and PPC levels.
Primary flow	
Alternative flow	
Failure flow	
Actors / inv. subsystems	
AC/DC CNVS	Primary actor
DCSS	
PPM	Primary actor
Offshore AC	Secondary actor
Onshore AC	
Energy absorber	
DCGC	

UC04-03 - Re-energization of tripped PPM after HVDC transformer fault by closing busbar coupler ("hard start")

Main category	F04 - Offshore AC
Priority rating	**Basic**
Preliminary or final specs	**Preliminary**
Description	see D1.3 section 6.1.6x, scenario b (OWF energization with fully operational HVDC) Considering that the PPM would be energized string by string, or feeder by feeder, no CNVS design constraints are anticipated (even more if Point-On-Wave switches are installed). Nonetheless, energization tests

	are to be performed during the interaction studies to check potential interaction with vendor's control and protection.
Min. required grid topology, config or equipment	3T
Min. D3.1 subset	Subset 2 (3 MT base topology)
Simu. environment (testing method)	Offline only (energization string by string is required, which is only possible if you duplicate the vendor's WTG models at different aggregation levels)
Pre-condition (grid configuration, control modes, state..)	D2.2 control chain concept #1 2 vendor PPMs connected to the same busbar
Trigger	Operator to initiate the defined sequence
Post-condition	Successful energization without trips and with component stresses within design ranges. WTG from 2 different PPMs starting without adverse interactions.
Primary flow	OWF energization with fully operational HVDC: in such scenario –like any wind park connection without HVDC system– although the closure of switches might energize further cables and transformers, but it is not yet a concern for meaningful inrush current and overvoltage. As per design the whole park is divided into several strings and each equipped with CB, and the energization of each takes effect only after last one is fully energized. The recommended distance between wind turbines –a design factor based on different aspects such as blade span–, constrained to other factors such as maximum allowed/recommended section of collector cable (e.g., max 1000mm2) defines the number of wind turbines per string and thus the total length of cable per string. The typical number of WTGs per string is less than 10 and the power normally doesn't exceed 100MW. For instance, the 66kV platforms are designed withing inter-array strings of 5~6 WTGs of 15MW. Hence energization driven overvoltage in OWF is not a risk, even with fully operative offshore station.
Alternative flow	
Failure flow	Operation of the offshore AC switchyard (open/close) with live voltage could result in inrush currents.
Actors / inv. subsystems	
AC/DC CNVS	Secondary actor
DCSS	
PPM	Secondary actor
Offshore AC	Primary actor
Onshore AC	

Energy absorber	
DCGC	

UC04-04 - PPMs from two different vendors connected to two coupled HVDC poles including testing of converter pole faults and PPMs power curtailment

Main category	F04 - Offshore AC
Priority rating	**Excluded**

UC04-051 – Ride through offshore HVDC converter temporary blocking with WTGs in GFL control mode

Main category	F04 - Offshore AC
Priority rating	**Basic** – related to UC3-01 and UC03-21 (second stage model delivery, with a technology disclaimer, proof of concept)
Preliminary or final specs	**(Preliminary)** - Temporary blocking function might not be available in stage 1 delivery, but design spec should include requirements as much as possible based on available data
Description	see D3.2 section 8.3.5.3 .4 (HVDC temporary blocking ride through capability) see D2.2 control chain concept #1 see D2.1 key investigations – sections 10.6 and 10.7 Duration of temporary blocking: the Demonstrator tests should evaluate and recommend the maximum allowable duration for temporary blocking necessary to ride through a DC fault in a multi-terminal, multi-vendor HVDC system. Furthermore, the Demonstrator should evaluate whether this proposed duration is technically viable for the PPM. If not technically viable in the first place, there should be attempts or recommendations to make this viable (either by reducing the duration of temporary blocking, or by increasing the capability of the PPM to ride-through such event, for example with GFM WTG or any other solution, like HVDC converter smooth resynchronisation). This UC requires the pre-definition of functional specifications for PPMs based on GFL WTGs to be capable of riding through the temporary blocking of the HVDC converter. According to studies carried out in WP2 DC Protection workstream and T.3.3.6, it is recommended to assess whether and how the PPMs based on GFL WTGs can be capable of

	limiting the frequency excursion and the overvoltages that could lead to their tripping according to protective measures. It is also important to identify possible ways to detect and/or communicate the islanding condition for the control actions. Finally, synchronization methods must be considered to avoid critical transients after the deblocking of the HVDC converter. The re-synchronization is a functional specification imposed to the HVDC vendors.
Min. required grid topology, config or equipment	3T
Min. D3.1 subset	Subset 2 (3 MT base topology)
Simu. environment (testing method)	Offline + HIL
Pre-condition (grid configuration, control modes, state..)	D2.2 control chain concept #1 PPMs are with Pmax operation (this would allow assessment of permanent trips, if occuring.)
Trigger	DC fault and offshore HVDC converter temporary blocking
Post-condition	WTGs from both OWFs must be capable of riding through the HVDC temporary blocking.
Primary flow	- DC fault inception - converter blocking - DC fault neutralization - converter deblocking
Alternative flow	
Failure flow	During temporary blocking WTGs, adverse control interactions and/or offshore grid quantities outside acceptable limits. Some PPM's internal protections might be triggered
Actors / inv. subsystems	
AC/DC CNVS	Primary actor
DCSS	
PPM	Primary actor
Offshore AC	
Onshore AC	
Energy absorber	
DCGC	

UC04-052 - Ride through offshore HVDC converter temporary blocking with WTGs in GFM control mode

Main category	F04 - Offshore AC
Priority rating	**Optional -** The demonstration of GFM WTGs and their advantages could be an interesting outcome of InterOPERA even though this technology might not be fundamental for the proper operation of basic MTDC grids, which should be the focus of InterOPERA. Optional Use Case if it can be proven that GFL WTGs are capable of riding through HVDC temporary blocking. Update: at best one WTG vendor only, the other having already confirmed non-delivery of GFM WTGs
Preliminary or final specs	No deep technical investigations and collective alignment process could be secured. As a result, no detailed specifications were issued. Despite this, the vendors can still provide their own interpretation of what is required and their own solution for testing and exploration.
Description	see D3.2 section 8.3.5.3 .4 (HVDC temporary blocking ride through capability) Duration of temporary blocking: 150ms is the minimum requirement based on the German VDE 4131 and see if it is possible to achieve 300ms.
Min. required grid topology, config or equipment	3T
Min. D3.1 subset	Subset 2 (3 MT base topology)
Simu. environment (testing method)	Offline
Pre-condition (grid configuration, control modes, state..)	Exact control mode configuration of the offshore HVDC converter to be clarified (can be D2.2 control chain concept #4: PPMs GFM and HVDC reduced GFM with Vdc droop control)
Trigger	DC fault and offshore HVDC converter temporary blocking
Post-condition	WTGs from both OWFs must be capable of riding through the HVDC temporary blocking.
Primary flow	- DC fault inception - converter blocking - DC fault neutralization - converter deblocking
Alternative flow	
Failure flow	During temporary blocking WTGs, adverse control interactions and/or offshore grid quantities outside acceptable limits.
Actors / inv. subsystems	

AC/DC CNVS	Primary actor
DCSS	
PPM	Primary actor
Offshore AC	
Onshore AC	
Energy absorber	
DCGC	

UC04-06 - Ride through offshore HVDC converter temporary blocking with shared parallel GFM between two AC interconnected remote-end HVDC converter stations

Main category	F04 - Offshore AC
Priority rating	**Excluded -** AC Interconnection between two offshore AC/DC Converter Stations is neglected in InterOPERA due to high complexity and low priority.
Preliminary or final specs	N/A
Description	see D2.2 control chain concept #1 with AC inter-bipole interconnector
Min. required grid topology, config or equipment	Inter-bipole interconnector
Min. D3.1 subset	
Simu. environment (testing method)	
Pre-condition (grid configuration, control modes, state..)	D2.2 control chain concept #1 with AC inter-bipole interconnector
Trigger	DC fault and offshore HVDC converter temporary blocking
Post-condition	WTGs from both OWFs must be capable of riding through the HVDC temporary blocking.
Primary flow	- DC fault inception - converter blocking - DC fault neutralization - converter deblocking
Alternative flow	
Failure flow	During temporary blocking WTGs, adverse control interactions and/or offshore grid quantities outside acceptable limits.

Actors / inv. subsystems	
AC/DC CNVS	Primary actor
DCSS	
PPM	Primary actor
Offshore AC	
Onshore AC	
Energy absorber	
DCGC	

UC04-07 - DC-side contingency leading, after energy absorber activation, to a coordinated emergency offshore wind ramp-down or curtailment

Main category	F04 - Offshore AC
Priority rating	**Basic**
Preliminary or final specs	**Preliminary** – though this UC will mostly be relevant for the 5T configuration
Description	Following a fault decreasing the power export capability to the onshore grid, it may be required to curtail offshore power. Essential functionality for the safe operation of the HVDC grid that requires coordination between the PPM's PPC, the DCGC and the DBSs. This UC requires definition of Emergency Power Control and Special Protection Scheme requirements for the PPMs considering, among others, communication delay and ramp-down speed. TenneT and Energinet documents are adopted as references. The functional specifications regarding communication between the PPCs and the DCGC must also be defined considering a signal list. see D3.2 section 8.3.5.3.1 (Power curtailment, Coordination based on communication.) and section 8.4.2.2 (Requirements for fast curtailment) see D3.2 section 3.4.2 (Coordinated wind farm curtailment & Secondary Voltage Control) Coordination of Over Voltage Power Curtailment (OVPC), triggered by the violation of operational security limits or DBS activation (see Figure 3 8). This functionality is included in the basic DCGC and requires new direct communication channel between PPCs and DCGC see D3.2 section 5 (DBS operating characteristics during FRT and energy dissipation capability, DBS control...)

Min. required grid topology, config or equipment	a priori relevant only in offline 5T (a DC fault with a radial 3T system leads to a point-to-point configuration, and a DC fault with a meshed 3T can leads to 3T radial configuration. In all cases, the rated powers and the remaining export capability in the post-fault configuration can accommodate the new power flow, hence no need for energy absorption and curtailment) Will DBSs be part of the HIL setup? D3.1 states only Hitachi Energy in HIL
Min. D3.1 subset	
Simu. environment (testing method)	Offline
Pre-condition (grid configuration, control modes, state..)	Stable operating point, normal state.
Trigger	Fault leading to DBS activation
Post-condition	Offshore power has been curtailed to avoid DBS saturation. Voltage is stabilized at least in alert state.
Primary flow	- Primary voltage response of converters, insufficient to absorb the offshore power. - DC Overvoltage leads to DBS activation, which stabilizes the voltage. - DCGC detects the OV / DBS activation. The need of curtailment power is computed based on the actual operating point. A new PF considering the curtailed power is sent out to converters and PPM. The WTGs must react curtailing their active power outputs according to methodology (communication) and specs to be agreed.
Alternative flow	Converters trip their connected wind farms
Failure flow	Converters blocking
Actors / inv. subsystems	
AC/DC CNVS	
DCSS	
PPM	Secondary actor
Offshore AC	
Onshore AC	
Energy absorber	Primary actor
DCGC	Primary actor

UC04-081 - Offshore AC fault ride through capability with GFL WTGs - Post fault active power recovery

Main category	F04 - Offshore AC
Priority rating	**Basic**
Preliminary or final specs	**Preliminary**
Description	see D3.2 section 8.3.3.1 (WTG transient handling capabilities - FRT) to test offshore AC faults in different locations and how these faults could be isolated while maintaining the remaining parts of the offshore AC system connected. For example, if there is a fault in the array system of a given PPM, this fault should be isolated (likely to be permanent one) and both the HVDC and the other PPM should be able to remain online and back to normal operation after the fault is cleared. This UC requires definition of FRT curves, fault-current contribution requirements as well as post fault active power recovery requirements. All these specifications can be obtained through existing TSO documents. Offshore AC faults also impose ride through specifications to the offshore AC/DC Converter Stations.
Min. required grid topology, config or equipment	PPMs connected to point-to-point HVDC link
Min. D3.1 subset	Subset 0
Simu. environment (testing method)	Offline + HIL
Pre-condition (grid configuration, control modes, state..)	
Trigger	test offshore AC faults in different locations
Post-condition	maintaining the remaining parts of the offshore AC system connected
Primary flow	faults to be isolated
Alternative flow	
Failure flow	
Actors / inv. subsystems	
AC/DC CNVS	Primary actor
DCSS	
PPM	Primary actor
Offshore AC	
Onshore AC	
Energy absorber	
DCGC	

UC04-082 - Offshore AC fault ride through capability with GFM WTGs - Post fault active power recovery

Main category	F04 - Offshore AC
Priority rating	**Optional -** at best one WTG vendor only, the other having already confirmed non-delivery of GFM WTGs
Preliminary or final specs	No deep technical investigations and collective alignment process could be secured. As a result, no detailed specifications were issued. Despite this, the vendors can still provide their own interpretation of what is required and their own solution for testing and exploration.
Description	see D3.2 section 8.3.3.1 (WTG transient handling capabilities - FRT) to test offshore AC faults in different locations and how these faults could be isolated while maintaining the remaining parts of the offshore AC system connected. For example, if there is a fault in the array system of a given PPM, this fault should be isolated (likely to be permanent one) and both the HVDC and the other PPM should be able to remain online and back to normal operation after the fault is cleared. GFM WTGs might present new challenges to ride through certain AC faults while supporting the grid operation.
Min. required grid topology, config or equipment	PPMs connected to point-to-point HVDC link
Min. D3.1 subset	Subset 0
Simu. environment (testing method)	Offline + HIL
Pre-condition (grid configuration, control modes, state..)	Probably the case is only interesting if GFM controls are employed - preferably decoupled and not interconnected on the AC side D2.2 control chain concept #4: PPMs GFM and HVDC reduced GFM with Vdc droop control? New control concept #5??
Trigger	test offshore AC faults in different locations
Post-condition	maintaining the remaining parts of the offshore AC system connected
Primary flow	faults to be isolated
Alternative flow	
Failure flow	
Actors / inv. subsystems	
AC/DC CNVS	Primary actor
DCSS	
PPM	Primary actor

Offshore AC	
Onshore AC	
Energy absorber	
DCGC	

UC04-09 - Offshore AC interconnection - AC/DC circular interactions

Main category	F04 - Offshore AC
Priority rating	**Excluded**
Preliminary or final specs	N/A
Description	see D3.2 section 7.3.4 (bipole coupler) and section 7.6.4 (related recommendation for this option) - "GFM control with frequency droop would have to be applied to all the HVDC converters to share the forming of the AC grid, considering different eventual implementations from different HVDC 4 vendors – Extra control interactions would potentially occur due to the more complex system including power oscillations between the HVDC converters connected nearby but with different electrical distances between some of them. - Option 3 also allows to test steady-state, small-signal control interactions between two PPMs using technologies from different WTG vendors, between two different AC/DC Converters using technologies from different HVDC vendors, and between these PPMs and these HVDC converters. Due to the coupling of HVDC converters at their AC and DC sides at the same time, complex “circular interactions” between them can potentially occur, which could be investigated through Option 3."
Min. required grid topology, config or equipment	Inter-bipole interconnectors
Min. D3.1 subset	
Simu. environment (testing method)	
Pre-condition **(grid configuration, control modes, state..)**	
Trigger	
Post-condition	
Primary flow	
Alternative flow	

Failure flow	
Actors / inv. subsystems	
AC/DC CNVS	Primary actor
DCSS	
PPM	Primary actor
Offshore AC	Secondary actor
Onshore AC	
Energy absorber	
DCGC	

UC04-10 - PPMs enabling the remote-end HVDC capability to control the DC-voltage in droop control mode

Main category	F04 - Offshore AC
Priority rating	**Excluded** since energy storage would be required on the offshore AC side.
Preliminary or final specs	N/A
Description	see D2.2 control chain concept #3

UC04-111 - HVDC converter permanent blocking with WTGs in GFL control mode

Main category	F04 - Offshore AC
Priority rating	**Basic** – related to UC04-051
Preliminary or final specs	**Preliminary**
Description	The permanent blocking of the HVDC converter can lead to overvoltages that can damage the offshore AC grid equipment. This problem can be more challenging when different PPMs with different controls are islanded together offshore (connected nearby), which is a new characteristic of the InterOPERA demonstrator. WTGs are requested to be capable of identifying the islanding situation and of tripping without causing overvoltages in case of the permanent blocking of the HVDC converter. This UC requires the pre-definition of functional specifications for the GFL WTGs to be capable of handling the permanent blocking of the HVDC converter without damaging equipment. Typically, the PPMs would have to be capable to identify the islanding situation and to trip

	while keeping voltages within limits. TenneT's existing document VDE-AR-N_4131_2019-03 covers this requirement. It is important to highlight that this must be achieved at a PPM level by eventually relying on devices like energy dissipation devices and not necessarily relying only on the wind-turbine converter control.
Min. required grid topology, config or equipment	PPMs connected to point-to-point HVDC link
Min. D3.1 subset	Subset 0
Simu. environment (testing method)	Offline + HIL
Pre-condition (grid configuration, control modes, state..)	
Trigger	test offshore AC faults in different locations
Post-condition	maintaining the remaining parts of the offshore AC system connected
Primary flow	faults to be isolated
Alternative flow	
Failure flow	
Actors / inv. subsystems	
AC/DC CNVS	Primary actor
DCSS	
PPM	Primary actor
Offshore AC	
Onshore AC	
Energy absorber	
DCGC	

UC04-112 - HVDC converter permanent blocking with WTGs in GFM control mode

Main category	F04 - Offshore AC
Priority rating	**Optional** – related to UC04-052 - at best one WTG vendor only, the other having already confirmed non-delivery of GFM WTGs
Preliminary or final specs	No deep technical investigations and collective alignment process could be secured. As a result, no detailed specifications were issued. Despite this, the vendors can still provide their own interpretation of what is required and their own solution for testing and exploration.

Description	The demonstration of GFM WTGs and their advantages could be an interesting outcome of InterOPERA even though this technology might not be fundamental for the proper operation of basic MTDC grids, which should be the focus of InterOPERA. Optional Use Case if it can be proven that GFL WTGs are capable of detecting islanding and tripping without causing overvoltages at the offshore AC grid. WTGs are requested to be capable of identifying the islanding situation and of tripping without causing overvoltages in case of the permanent blocking of the HVDC converter.
Min. required grid topology, config or equipment	PPMs connected to point-to-point HVDC link
Min. D3.1 subset	Subset 0
Simu. environment (testing method)	Offline + HIL
Pre-condition (grid configuration, control modes, state..)	
Trigger	test offshore AC faults in different locations
Post-condition	maintaining the remaining parts of the offshore AC system connected
Primary flow	faults to be isolated
Alternative flow	
Failure flow	
Actors / inv. subsystems	
AC/DC CNVS	Primary actor
DCSS	
PPM	Primary actor
Offshore AC	
Onshore AC	
Energy absorber	
DCGC	

2.5. F05 - Onshore AC

UC05-01 - Onshore AC fault ride through capability and post fault active power recovery

Main category	F05 - Onshore AC
Priority rating	**Basic**
Preliminary or final specs	**Preliminary**
Description	**Scope:** Demonstration of AC fault ride through capability as per NC-HVDC Article 25. Onshore HVDC shall perform AC fault ride through whilst maintaining the same mode of operation as before the fault. As per NC-HVDC Article 26 regarding post fault active power recovery, 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. **Priority of reactive or active power during faults:** As per NC-HVDC Article 23 the HVDC converter station 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 the time from the fault inception. **Onshore topology:** According to T3.3.5 – Onshore AC test bench (link) **Applicable member-state grid-code:** VDE-AR-N 4131 and TenneT NAR Annex B.300 as specified in T3.3.5 – Onshore AC test bench (link)
Min. required grid topology, config or equipment	3T Variant 2 **HVDC system control configuration:** This use case is repeated for both GFL and GFM control of the onshore HVDC converter stations: **Stage 1 - GFL control configuration:** AC/DC #1 (Offshore converter station): V/f control mode AC/DC #2 (Onshore converter station): GFL control with either Vdc fixed or Vdc droop control mode AC/DC #4 (Onshore converter station): GFM control mode with either APC, Vdc fixed or Vdc droop control dependent on the HVDC vendor solution **Stage 2 - GFM control configuration:** AC/DC #1 (Offshore converter station): V/f control mode

	AC/DC #2 (Onshore converter station): Vdc droop – GFM control mode AC/DC #4 (Onshore converter station): Vdc droop – GFM control mode
Min. D3.1 subset	Subset 1 and 2
Simu. environment (testing method)	Offline + HIL
Pre-condition (grid configuration, control modes, state..)	**AC/DC #2 (Onshore converter station):** - Nordic grid-equivalent - SCLmin **AC/DC #4(Onshore converter station):** - Continental Europe grid-equivalent - SCLmin **Conditions:** The HVDC grid is energized. The onshore AC system voltage level is within the normal condition boundaries. It is assumed that the DBS is healthy and ready to be triggered. The AC/DC converter station is stably operating and equipped with overcurrent protection and voltage support functions
Trigger	**AC fault simulation** The voltage is within the required FRT withstand requirements. Therefore, the HVDC converter shall not block and is able to inject reactive and active currents into the AC grid during fault. **Fault locations** Faults are to be simulated at both HVDC converter stations (not simultanously): • AC/DC #2 (Onshore converter station) • AC/DC #4 (Onshore converter station) **Fault cases:** According to T3.3.5 – Onshore AC test bench (link) 1. Single phase to ground fault at the connection point a. Fault duration: 150 ms, residual voltage: 0.1 p.u. 2. Two phase fault at the connection point a. Fault duration: 150 ms, residual voltage: 0.1 p.u 3. Two phase to ground fault at the connection point a. Fault duration: 150 ms, residual voltage: 0.1 p.u 4. Three phase to ground fault at the connection point a. Fault duration: 150 ms, residual voltage: 0.1 p.u.
Post-condition	The AC voltage and active power stably recovered their operating conditions. - The DC voltage recovers in normal condition band.

	- DBS off.
Primary flow	Fault occurs. - The DC voltage increases due to the offshore overpower leading to triggering of the DBS. - The AC/DC converter close to the AC faults, limit the current and prioritize the reactive power injection to support the AC voltage.
Alternative flow	
Failure flow	
Actors / inv. subsystems	
AC/DC CNVS	Primary actor
DCSS	
PPM	
Offshore AC	
Onshore AC	
Energy absorber	Secondary actor
DCGC	

UC05-02 - Reactive power support under extreme grid conditions

Main category	F05 - Onshore AC
Priority rating	**Basic**
Preliminary or final specs	**Final**
Description	**Scope:** Demonstration of inherent reactive power capability and voltage control mode (Q-v droop) during extreme weak grid and extreme strong grid operation. The onshore AC/DC converter shall perform stably in very weak and very strong AC grid conditions and provide reactive power support. The use case is done only with GFM control on the onshore HVDC converter stations, and not GFL control. The test case is done in two iterations: 1. In GFM mode with Q-v droop control deactivated to see the pure inherent reactive power response from the GFM control. 2. In GFM mode with Q-v droop control activated to assess the performance of the reactive power control. Voltage control mode is specified in NC HVDC 22, while D3.2 section 4.8.2.1 provides functional description for GFM HVDC converter stations.

	Inherent reactive power capability of GFM converters detailed in InterOPERA D2.2 and D3.2 Section 4.8.1.2 **Onshore topology:** According to T3.3.5 – Onshore AC test bench (link) **Applicable member-state grid-code:** VDE-AR-N 4131 and TenneT NAR Annex B.300 as specified in T3.3.5 – Onshore AC test bench (link)
Min. required grid topology, config or equipment	3T Variant 2 **HVDC system control configuration:** This use case is to be done only with GFM control mode of the onshore HVDC converter stations: AC/DC #1 (Offshore converter station): V/f control mode AC/DC #2 (Onshore converter station): Vdc droop – GFM control mode AC/DC #4 (Onshore converter station): Vdc droop – GFM control mode
Min. D3.1 subset	Subset 1 and 2
Simu. environment (testing method)	Offline + HIL
Pre-condition (grid configuration, control modes, state..)	**AC/DC #2 (Onshore converter station):** - Nordic grid-equivalent - SCLmin and SCLmax (repeated in both cases) **AC/DC #4 (Onshore converter station):** - Continental Europe grid-equivalent - SCLmin and SCLmax (repeated in both cases) The use case is repeated in two itterations: **Step 1: Conditions for assessment of inherent reactive power capability:** - The AC/DC converter operating in GFM with reactive power control modes deactivated in order to assess the purely inherent GFM response. **Step 2: Conditions for assesment of voltage control mode:** - The AC/DC converter operating in GFM with AC voltage control (Q-v droop) activated **General conditions:** - The HVDC grid is healthy.
Trigger	**Evaluation of inherent reactive power capability and voltage control with Q-v droop:** **Voltage step tests as specified in T3.3.5 – Onshore AC test bench (link):** 1. Voltage step of phase-to-phase positive sequence voltage magnitude from 1 p.u. to 0.95 p.u., AC system frequency before disturbance: 50 Hz

	2. Voltage step of phase-to-phase positive sequence voltage magnitude from 1 p.u. to 0.85 p.u., AC system frequency before disturbance: 50 Hz 3. Voltage step of phase-to-phase positive sequence voltage magnitude from 1 p.u. to 1.05 p.u., AC system frequency before disturbance: 50 Hz 4. Voltage step of phase-to-phase positive sequence voltage magnitude from 1 p.u. to 1.10 p.u., AC system frequency before disturbance: 50 Hz **Robust voltage control during step changes in short circuit power as specified in T3.3.5 – Onshore AC test bench (link):** **Extreme low SCL operation:** 1. Step reduction in short-circuit power: a. Operation at SCL= 6 GVA and reduction to SCLmin as specified in Chapter 3 and Chapter 4 for CE and Nordic grid areas respectively. 2. Step increase in short-circuit power: a. Operation at SCLmin and increase to SCL = 6 GVA **Extreme high SCL operation:** 1. Step increase in short-circuit power a. Operation at SCL = 10 GVA and increase to SCLmax as specified in Chapter 3 and Chapter 4 for CE and Nordic grid areas respectively.
Post-condition	Stable operation under very weak grid conditions (Stable operation without tripping, providing dynamic voltage support, reduced harmonic oscillations during the faults and smooth transition to post-fault system operation.)
Primary flow	
Alternative flow	
Failure flow	Phase over-currents and risks of tripping.
Actors / inv. subsystems	
AC/DC CNVS	Primary actor
DCSS	
PPM	
Offshore AC	
Onshore AC	
Energy absorber	
DCGC	

UC05-03 – Grid forming active power support to the onshore AC grid

Main category	F05 - Onshore AC
Priority rating	**Basic**
Preliminary or final specs	**Final**
Description	**Scope:** Demonstration of grid-forming capabilities related to active power contribution associated with slow changing voltage source behind an impedance behaviour as specified in InterOPERA D2.2. - Demonstration of phase jump active power capability - Demonstration of inertial active power capability The use case is repeated for two different operating points of the GFM HVDC converter station. One time where there is sufficient active power margin for the GFM action (P=0.5 p.u.), and one time where there is no active power margin to verify that the system is robust when entering withstand mode (P=1 p.u.) **Onshore topology:** According to T3.3.5 – Onshore AC test bench (link) **Applicable member-state grid-code:** Grid-forming not yet covered by the NC HVDC (amended in V2.0). Qualitative functional requirements as per InterOPERA D2.2 Test cases and modified dynamic performance requirements based on VDE FNN guideline and TenneT NAR Annex B.409 as specified in T3.3.5 – Onshore AC test bench (link) **Note:** As the use case involves a control concept where HVDC converter stations have combined Vdc droop control duty and GFM functionality, the inertial active power capability and phase jump active power capabilities are expected to be low due to the priority of the DC voltage control and stability as described and discussed in D2.2. However, it is deemed that it is more realistic and relevant for real project implementation to demonstrate GFM capability using this control concept compared to a control concept where one AC grid area always supports another.
Min. required grid topology, config or equipment	3T Variant 2 **HVDC system control configuration:** AC/DC #1 (Offshore converter station): V/f or GFM control mode (no Vdc droop control duty) AC/DC #2 (Onshore converter station): Vdc droop – GFM control mode AC/DC #4 (Onshore converter station): Vdc droop – GFM control mode

	PPMs connected to AC/DC #1: GFL or GFM (indifferent) **Fall back modification of the use case:** Should the demonstration project and the progress of WP3 experience issues related to implementing combined Vdc droop and GFM control mode on HVDC converter stations, the following control concept can be consired as a fall back solution to complete Objective 5 of the InterOPERA project: AC/DC #1 (Offshore converter station): V/f control mode AC/DC #2 (Onshore converter station): Pac – GFM control AC/DC #4 (Onshore converter station): Vdc (direct voltage control) – GFL control mode
Min. D3.1 subset	Subset 1 and 2
Simu. environment (testing method)	Offline + HIL
Pre-condition **(grid configuration, control modes, state..)**	**GFM converter station operating point:** Repeated in two iterations: P = 0.5 p.u. Q = 0 p.u. And P = 1 p.u. (to see dynamic response when exceeding limits) Q = 0 p.u. **AC/DC #2 (Onshore converter station):** - Nordic grid-equivalent - SCLmin and SCLmax (repeated in both cases) - The onshore AC system is a frequency dependent model **AC/DC #4(Onshore converter station):** - Continental Europe grid-equivalent - SCLmin and SCLmax (repeated in both cases) - The onshore AC system is a frequency dependent model **Conditions:** The overall HVDC system is healthy. The AC/DC converter station stably operating
Trigger	Test cases as specified in Task 3.3.5 – Onshore AC test bench (link) **Trigger 1: Phase jump active power evaluation:** Change in the voltage angle of the positive sequence: $\Delta\phi 1$ = -10° **Trigger 2: Inertial active power evaluation:**

	High RoCoF: Rate of Change of Frequency (RoCoF): -2 Hz/s from 50 Hz to 47,5 Hz. **Trigger 3: Inertia constant approximation:** Low RoCoF (used for inertia constant approximation): Rate of Change of Frequency (RoCoF): -0.3 Hz/s from 50 Hz to 47,5 Hz.
Post-condition	The AC/DC converter reaches its equilibrium point after the disturbance while prioritizing DC voltage control/stability
Primary flow	A phase jump or frequency change is applied on the onshore AC grid. The AC/DC converter station injects active power to support the AC system
Alternative flow	
Failure flow	
Actors / inv. subsystems	
AC/DC CNVS	Primary actor
DCSS	
PPM	
Offshore AC	
Onshore AC	
Energy absorber	
DCGC	

UC05-04 – Grid forming active power support to the onshore AC grid including support from offshore WTGs

Main category	F05 - Onshore AC
Priority rating	**Excluded**

UC05-12 – Exploration of HVDC system stability and interoperability with interconnected AC areas

Main category	F05 - Onshore AC
Priority rating	**Optional**
Preliminary or final specs	no performance requirements for subsystem design, exploration tests
Description	**Scope:** Explore stability and interaction risks when interconnecting AC areas of onshore HVDC converter stations with both HVDC converter stations being in grid forming control mode.

	- Assessment of large-signal stability during transients such as faults and trip of converter stations
	    o Check the AC fault ride through responses with choppers coordination
	    o Check potential GFM concurrent behaviour
	- Assessment of small-signal stability related to potential interactions between the converter stations.
	    o Check potential GFM concurrent behaviour
	
	Limitation:
	
	- The case is solely for explorative/investigative purposes, and no performance evaluation will be done based on the case.
	- Upon experience of adverse interactions and stability issues a sensitivity variation of the interconnecting line impedance as specified in Task 3.3.5 – Onshore AC test bench (link) can be performed as the converter controls will not have been designed with multi-infeed studies

Min. required grid topology, config or equipment	3T variant 2 D2.2 control chain concept #2 **HVDC system control configuration:** AC/DC #2 (Onshore converter station): Vdc droop + GFM control AC/DC #4 (Onshore converter station): Vdc droop + GFM control **Equivalent line between onshore Area 1 and Area 2:** - The equivalent line parameters specified in Task 3.3.5 must be applied
Min. D3.1 subset	Subset 1 and 2
Simu. environment (testing method)	Offline + HIL
Pre-condition (grid configuration, control modes, state..)	**Note:** The two AC areas can be represented with Nordic and CE parameters respectively as stated in Task 3.3.5. However, they must be assumed to be synchronized in the simulation for the purpose of the test case. **AC/DC #2 (Onshore converter station):** - Nordic grid-equivalent - SCLmin - The onshore AC system is a frequency dependent model **AC/DC #4 (Onshore converter station):** - Continental Europe grid-equivalent - SCLmin - The onshore AC system is a frequency dependent model

	Conditions: The overall HVDC system is healthy. The AC/DC converter station stably operating
Trigger	**Small-signal stability analysis:** 1. Initialization of steady-state conditions 2. Change power flow from Area 1 to Area 2 3. Detection of any oscillations in active power and/or voltage in the combined (interconnected) onshore AC system **4.** If oscillations identified: Apply small-signal analysis (See Task 2.2 small-signal sub-group) **Large-signal stability analysis:** (conditions that the system is steady-state stable in pre-fault and post-fault conditions (see small-signal stability analysis step). 1. Three phase to ground fault at the connection point of the HVDC converter station: Fault duration: 150ms, residual voltage: 0.0p.u. 2. Spontaneous (no fault) trip of a. Single HVDC converter unit (1 pole) b. Full HVDC converter station (both poles)
Post-condition	
Primary flow	
Alternative flow	
Failure flow	
Actors / inv. subsystems	
AC/DC CNVS	
DCSS	
PPM	
Offshore AC	
Onshore AC	
Energy absorber	
DCGC	

3. References

Table 3-1: List of references

Ref. No.	Title
01	InterOPERA D3.1 (PUBLIC) "Demonstrator project definition and system design studies"
02	InterOPERA D3.2 (SENSITIVE) "Subsystems pre-design phase process and outcomes"

Annex 02: DC Cable Data

Parameters (based on [13])			
Pole conductor (P1 / P2)	Core radius	mm	30
	Core resistivity	Ω.m	2,44E-08
	Thickness semicon	mm	2
	Thickness insulation	mm	26
	Insulation permittivity		2,4
	Thickness semicon	mm	1,8
	Thickness sheath	mm	3,2
	Sheath resistivity	Ω.m	2,14E-07
	Thickness PE-sheath	mm	5
	PE-sheath permittivity		2,4
	Thickness armor	mm	6
	Armor resistivity	Ω.m	1,80E-07
	Armor permeability		10
	Thickness outer serving	mm	6,5
	Loss factor		0,0001
	R (@ 0Hz ; 70°C)	mΩ/km	8,63
	L (@ 10kHz)	mH/km	0,144
	C	µF/km	0,224

Parameters			
DMR conductor (R)	Core radius	mm	30
	Core resistivity	Ω.m	2,04E-08
	Thickness semicon	mm	2
	Thickness insulation	mm	11
	Insulation permittivity		2,4
	Thickness semicon	mm	1,8
	Thickness sheath	mm	3,2
	Sheath resistivity	Ω.m	2,14E-07
	Thickness PE-sheath	mm	5,0000
	PE-sheath permittivity		2,4
	Thickness armor	mm	6
	Armor resistivity	Ω.m	1,80E-07
	Armor permeability		10
	Thickness outer serving	mm	6,5
	Loss factor		0,0001
	R (@ 0Hz ; 70°C)	mΩ/km	7,21
	L (@10kHz)	mH/km	0,087
	C	µF/km	0,452

Please note that DC cable models based on the data above have been created for different simulation environment (EMTP, PSCAD, RSCAD) in Work Package 1 and are available for every project partner. DC cable data is based on [13].

Annex 03: Subsystem Specifications

Annex 3.3.2: DC Grid Controller

WP3

Multi-vendor / Multi-terminal demonstrator project

Deliverable 3.3(b)

Detailed Functional Specifications

Subtask 3.3.2

DC Grid Control, Interfaces and Communication

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.

Co-funded by the European Union

DISCLAIMER:

PROJECT DETAILS:

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Detailed Functional Specifications

DC GRID CONTROL, INTERFACES & COMMUNICATION

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Table of Contents

VERSION CONTROL

Version	Date	Created/modified by	Comments
0.1	06.02.2025	P.Verrax (SuperGrid Institute)	Preliminary Version
0.2	14.03.2025	P.Verrax (SuperGrid Institute)	Preliminary Version after review
1.0	04.07.2025	H. Farias (SuperGrid Institute)	Detailed specifications – First version
2.0	29.08.2025	H. Farias (SuperGrid Institute)	Detailed specifications after Consortium review

1. Functionalities overview

The functionalities of the DCGC have first been determined through an alignment process, from November 2023 to January 2024. This process allowed to gather inputs and feedbacks from TSOs and vendors. The alignment process as well as the motivation behind the choices of the functionalities are detailed in the document *DCGC Functional scope* [04]. Those functionalities have been further described in InterOPERA D3.2 [02]. The list of functionalities is reminded in **Table 1** and linked to the associated demonstrator use cases (UC), which are further described in Annex 01. Those use cases are specifically supported by some DCGC functionalities (along with other subsystems), but the DCGC may still play a minor role in other use cases.

Table 1: DC Grid Control functionalities and related demonstrator use cases

DCGC Functionality		Related use case	Link to relevant section
Continuous control	Power flow computation and implementation	UC01-021 (Transition from one power flow schedule to another)	Section 2.1
	Over-voltage power control - Coordinated wind farm curtailment	UC04-07 (DC-side contingency leading, after energy absorber activation, to a coordinated emergency offshore wind ramp-down or curtailment)	Section 2.3
	Secondary Voltage Control	UC01-04 (Secondary control - automatic transition to a new power flow schedule after a severe contingency)	Section 2.2
	Control mode management	UC01-22 (Transition to new control modes and control parameters)	Section 2.4
Sequential control	Reconfiguration sequence	UC01-01 (Start-up from 1 onshore station and shut-down) UC01-03 (Basic switching operations and grid reconfiguration sequences) UC01-81 (Merge) UC01-82 (Split and on load switching)	Section 3

The DCGC functionalities aforementioned are further discussed in next 2 sections: Continuous control (grouping first 4 functionalities) and Sequential control (for the last functionality).

Disclaimer: The DCGC specifications described in this deliverable correspond to a specific implementation within the InterOPERA demonstrator, serving as a proof of concept for demonstration purposes. In real-life projects, constraints related to market regulations and standardization may require adaptations or modifications to certain functionalities of this subsystem.

2. Continuous control

2.1. Planned power dispatch

Planned power dispatch refers to the situation where all the grid nodes are within Operational Security Limits. Note planned power dispatch might interfere with automatic secondary voltage control in the case voltages are outside of normal voltage range, see **Figure 2**. The operator is providing AC side power references for all converter units (i.e. per pole), including offshore ones, corresponding to a wind power forecast. The main related use case is UC01-21 "Transition from one power flow schedule to another".

In case of AC side coupled converters, only the total AC power for both poles shall be provided by the operator. In addition to those AC power references, the operator may provide additional inputs to tune the power flow dispatch and implementation according to the system needs. Such tuning inputs are summarized in the **Table 2**.

Table 2 : Main inputs that can be provided by the operator to tune the Power Flow dispatch

Name	Description
AC Power references	AC power references for all converter units, or converter stations when AC side is coupled.
AC Power tolerance	Acceptable deviation from the AC power references used in the OPF.
Max/min current	Maximum and minimum currents allowed in each transmission unit.
Max/min voltage	Maximum and minimum pole-to-neutral voltage considered at DC busbars in the OPF.
Objective function choice and tuning	- Choice of the average voltage - Relative weighing of converter units/stations in power reference setpoints accuracy
Neutral current control	Possibility to further limit the current in the neutral path, and associated tolerance.
PF implementation time	Transition time used in the ramp rates computation

The DCGC solves an Optimal Power Flow (OPF) problem based on the provided inputs. The OPF formulation considers typical constraints regarding DC power flow equations and also operational limitations, such as maximum current in transmission units. The DCGC shall support the transition from the actual operating point (including no-load conditions in case of start-up) and the target power flow, providing setpoints for relevant subsystems, as listed below:

- To all the converter stations:
  - New setpoints of DC voltage reference and respective ramp rate
  - New setpoints of DC power reference and respective ramp rate
- To all Power Park Modules (PPM):
  - New setpoints of AC maximum power reference and respective ramp rate

The sending of the PF setpoints to the converters and maximum power for wind farms is coordinated such that:

- The setpoints for power and voltage ramp rates shall be sent by the DCGC to all subsystems within a DCGC time cycle;
- The setpoints for power and voltage reference shall be sent by the DCGC to all subsystems within a DCGC time cycle;

The objective is that all subsystems can implement their power or voltage ramp roughly simultaneously (start and end). The DCGC shall adapt the ramp rates for each subsystem to ensure that the transition to a new operating point is completed within the same overall duration across all subsystems, assuming all subsystems start the PF transition simultaneously. The duration of the implementation of the PF shall be configurable within the DCGC, but also limited by ramp rate maximum values of each subsystem.

The overall process for planned power dispatch is depicted in **Figure 1**. The modification of the PPM max power is relevant in case of PPM wind curtailment either initiated by the operator, or after start-up to ramp-up the power. The specific communication mechanism for the sending of new power flow setpoints and associated ramp rates is further detailed in Section 5.1.

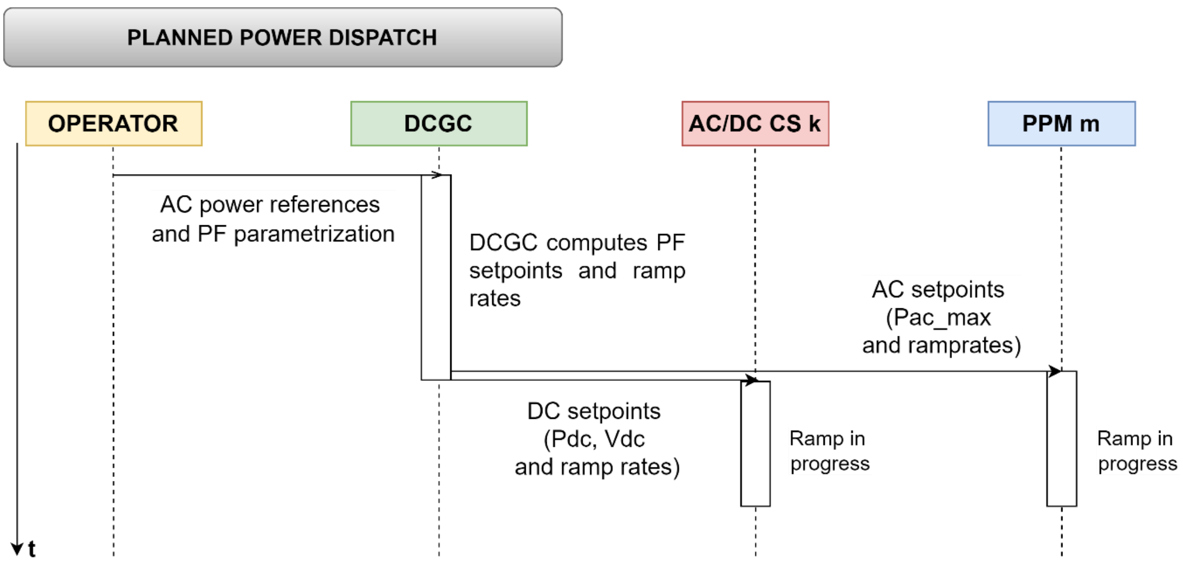

Figure 1: Overview of the planned power dispatch process.

The setpoints sent to all converter stations will include both active power and DC voltage references, independent from the control mode they actually apply. Some of the setpoints may hence not be used by the converter.

2.2. Secondary voltage control

Following InterOPERA D2.1 [01], the principal objectives of the secondary DC voltage control (SVC) are:

- 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.

For the demonstrator, a secondary voltage control is implemented within the DCGC, in response to a disturbance or contingency after which the steady-state voltage remains within the Operational Security Limits but exceeds the N-1 secure voltage range (see **Figure 2**). Note the N-1 secure voltage range corresponds to the Normal voltage range. The corresponding use case is UC01-04 "Secondary control - automatic transition to a new power flow schedule after a severe contingency".

All converters, after the action of the primary response, reach an operating point in steady-state $(V_i^{\mathrm{DC}}, P_i^{\mathrm{DC}})$. The DCGC shall automatically trigger the SVC function if at least one of the PoC DC voltage exceeds the N-1 secure voltage range in steady-state during an activation time indicated in Section 4, tuned in accordance with primary control response time. The activation time for the DCGC shall be configurable by the operator. The DCGC shall automatically correct the power flow setpoints so all voltages setpoints at PoC DC are within the N-1 secure voltage range after completion of the SVC function.

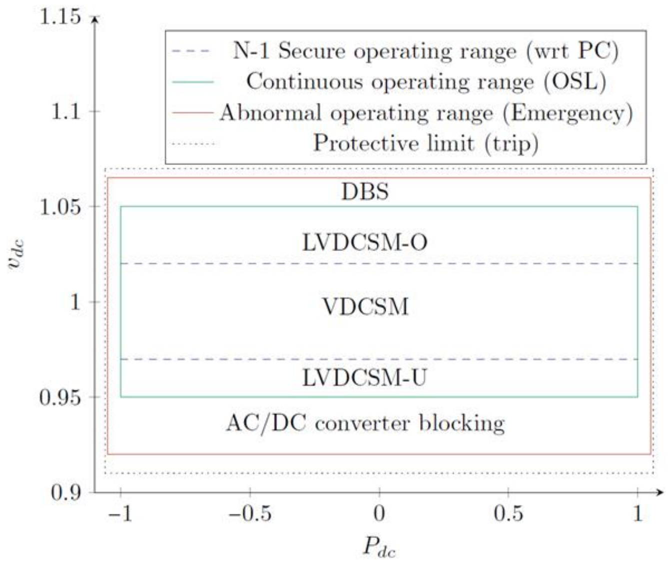

Figure 2: Preliminary definition of different operating ranges: N-1 secure operating range (also referred to as N-1 secure normal voltage range), continuous operating voltage range (also referred to as Operational Security Limits), and abnormal operating voltage range, from InterOPERA D3.8 – DC Load Flow Study.

Note in practice the operation of the HVDC system within continuous operating voltage range is not limited in time by any hardware constraint, but there might be operational limitations from the AC side that can also constrain the reaction time of the SVC. Such AC constraints are not considered in the demonstrator.

The objective of SVC is to restore the DC voltages across the system within the N-1 secure voltage range. The SVC will hence compute an OPF:

$$(V_1^{\mathrm{set}}, \ldots, V_n^{\mathrm{set}}) = \arg\min f(x) \text{ such that } V_{\mathrm{inf}}^{N-1} \leq V_i^{\mathrm{set}} \leq V_{\mathrm{sup}}^{N-1}$$

As previously mentioned, this OPF also considers usual constraints regarding DC power flow equations and other operational limitations. Active power set-points $P_i^{\mathrm{DC,set}}$ are then derived based on the obtained setpoints and grid characteristics.

The DCGC SVC function shall restore voltage margins only; it shall not restore additional power margins. Power setpoints may differ from the previous setpoints depending on power flow constraints and on the actual state of the HVDC system. The impact distribution across stations shall be configurable within the DCGC. The main steps of the SVC are depicted in **Figure 3**.

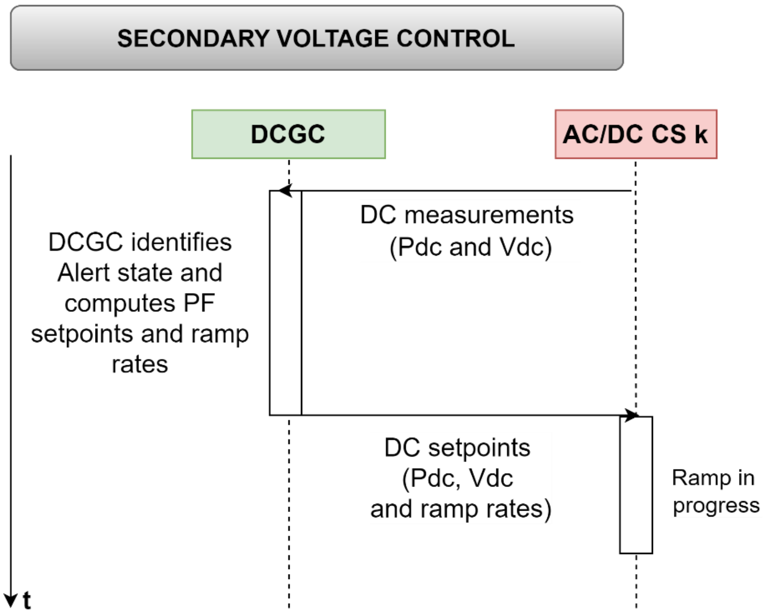

Figure 3: Overview of the Secondary Voltage Control concept

2.3. Over-Voltage Power Control

As the OVPC function involves the coordination of multiple sub-systems of the HVDC system, it has been included in the Main document describing the overall system definition.

2.4. Control mode management

The relevant control modes applicable to a converter unit are listed below.

- The control strategy reference, referring to either:
  - V/f control
  - Grid Following Control
  - Grid Forming Control
- The DC node control modes, referring to either:
  - Constant DC voltage
  - Voltage droop control
  - Dedicated DC node control mode for V/f control strategy (referred also as V/f DC node control mode)
- The AC node control modes, being either:
  - Constant reactive power
  - AC voltage with reactive power droop (Q-U)
  - Dedicated AC voltage control for V/f control strategy (referred also as V/f AC node control mode)

The management of control modes by the DCGC include the sending of appropriate commands following an operator request to change one or several control modes within the HVDC system. The DCGC shall be able to change DC control parameters of outer loops of converter stations controlled in Voltage droop control, namely droop slopes coefficients for different voltage sensitive modes ranges.

The DCGC shall implement a transition between different control modes and control parameters (including DC droop slopes and voltage limits) exclusively on demand of the operator.

Nevertheless, the DCGC shall prevent the operator to lead the HVDC system to unsafe DC control modes combinations across different converter units connected to a same pole. For one HVDC system, at least one converter station shall control the DC voltage (either Constant DC voltage or Voltage droop control), and no more than one station can be in Constant DC voltage control mode. Unsafe combinations of DC node control modes, such as two stations operating in Vdc control mode and connected to the same grid or no stations at all contributing to the voltage regulation, are thus avoided by the DCGC through an interlocking mechanism.

Note the specific control modes to be used in the 3T demonstrator system are further specified for each station in the main document, specifying which modes are required for onshore or offshore converter stations.

In addition to the effective control modes described above, each converter may apply a "default" or "standby" control mode following energization. This control mode is determined locally for each converter and does not follow a DCGC command. As soon as a converter is energized, it shall follow the DCGC control modes references.

3. Sequential control

3.1. Overview

The DCGC's sequential control provides operational simplifications in the management of reconfiguration sequences in the HVDC grid. It does so by automating the operation of switching devices, such as AC breakers and DC switching units, as well as AC/DC converters. The DCGC delivers sequential commands to relevant controllers and use feedback signals to confirm their reception, delaying or adjusting subsequent instructions as needed. It is important to note that the DCGC's capabilities for sequential control are determined by its logical interface with remote controllers (available inputs and outputs).

Reconfiguration sequences managed by the DCGC are organized into two possible categories based on the scope of the reconfiguration process:

- Local sequences: The reconfiguration is limited to a small functional zone or subsystem, e.g.:
  - The connection and disconnection of transmission units (HV or neutral pole).
  - The opening and closing of grounding units.
  - The connection and disconnection of converter units.
- High-level sequences: The reconfiguration process involves the entire HVDC grid, such as the grid start-up and shut-down.

The DCGC also implements additional safety mechanisms, particularly to prevent critical failures during the reconfiguration process, including short-circuits, and to avoid sequences that could create unsafe grid configurations, for example, an HVDC grid operating without a neutral ground reference. It also provides tolerance for the unresponsiveness of target systems following a sequential command and the ability to automatically trigger corrective sequences in response to grid reconfiguration driven by external systems, which cannot be directly prevented by the DCGC.

By contrast, the DCGC does not handle malfunctions of remote controllers or underlying equipment. In such cases, the DCGC's sequential control can be operated in a "manual" mode (unautomated) upon request. This enables operators to bypass internal control functions and manually set the values of sequential commands through the HMI.

The core functionalities of the DCGC's sequential control are detailed in the sections below.

3.2. Local sequences

Local reconfiguration sequences are used to change the operation of grid equipment within the same functional zone or subsystem. With a limited scope, they represent the most basic level of operational simplification available to grid operators. In general, these sequences are designed to prevent the occurrence of short-circuits or other system failures during the reconfiguration process by delaying and adjusting commands based on feedback from remote controllers.

Local reconfiguration sequences managed by the DCGC are organized into three groups based on the primary equipment involved in the corresponding reconfiguration process:

- Transmission units. This group includes DMR's and HV cables.
- Standalone DC switching units. This includes HV and neutral busbar coupling units in the central DC switching station and grounding units.
- Converter units.

The following subsections describe the sequences available in each group. The focus is on outlining required steps and relevant signals exchanged between the DCGC and other controllers.

3.2.1. Transmission unit

For each transmission unit in the HVDC grid, i.e., DMRs and HV cables, the DCGC shall be able to manage an automated **connection** and **disconnection** sequence. The scope of control operations is formed by the pair of DC switching units at both ends of the target transmission unit. The corresponding control architecture is illustrated in **Figure 4** for a generic system.

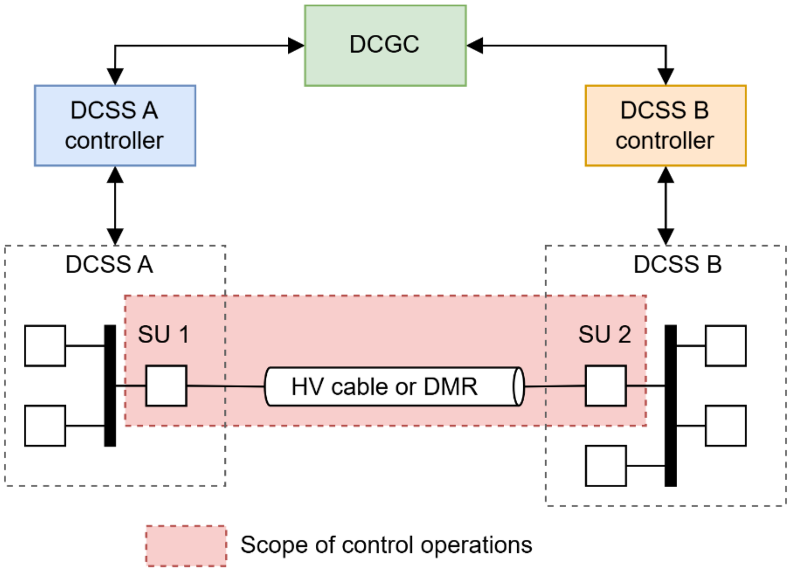

Figure 4: Control architecture for the management of local sequences involving a transmission unit.

Connection of a transmission unit

The steps involved in the connection of a transmission unit are shown in **Figure 5**. At the beginning of the sequence, DC switching units at both ends of the target transmission units are in the state "transmission unit earthed". When the sequence is initiated, the DCGC first reconfigures them to the "maintenance earthed" state, followed by the "open" state. If these steps succeed, the DCGC attempts to close both switching units following a predefined order determined by grid operators, either simultaneously or sequentially. Once the sequence is completed, the target transmission unit is connected to DC busbars on both sides. This state serves as the starting point of the disconnection sequence for the same transmission unit.

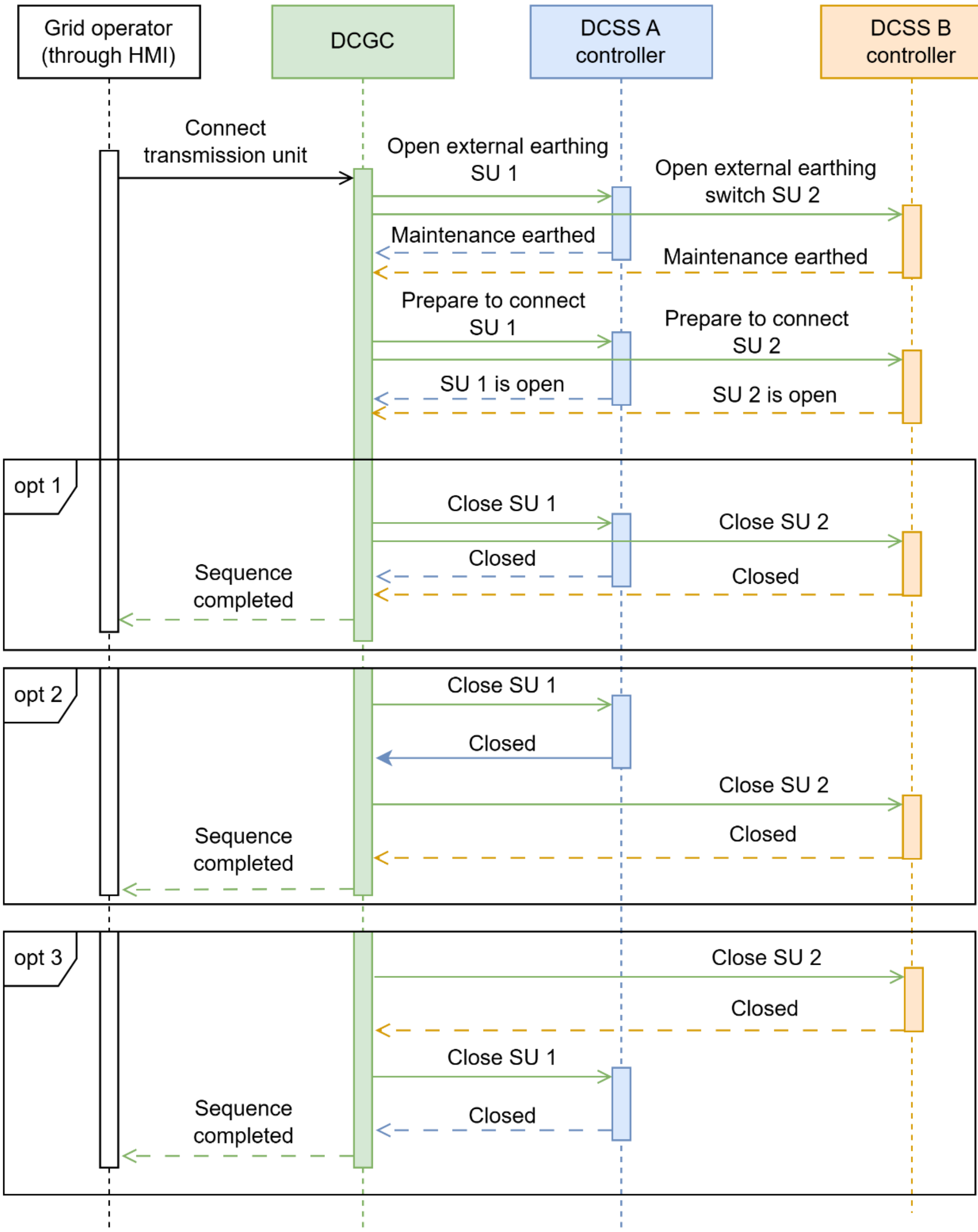

Figure 5: Transmission unit connection sequence.

Disconnection of a transmission unit

The steps involved in the disconnection of a transmission unit are shown in **Figure 6**. At the start of the sequence, DC switching units at both ends of the target transmission units are closed. When the sequence is initiated, the DCGC first opens both switching units simultaneously, followed by a reconfiguration to the "maintenance earthed" state for both. If these steps are successful, the DCGC reconfigures the DC switching units to the state "transmission unit earthed". Once the sequence is completed, the transmission unit is discharged and grounded at both ends. This operational state serves as the starting point of the connection sequence for the same transmission unit.

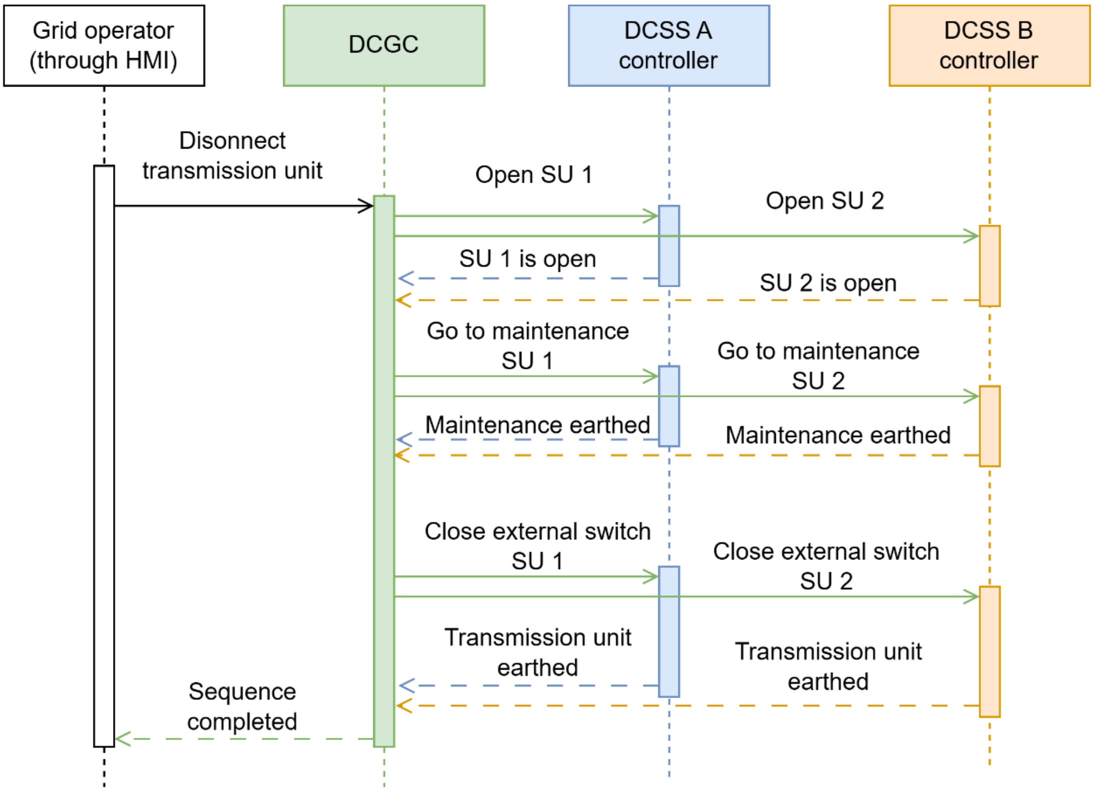

Figure 6:Transmission unit disconnection sequence.

3.2.2. Standalone switching units

Standalone switching units are those typically operated individually within the same pole during grid reconfiguration. This category includes grounding units and DC switching units used for busbar aggregation in the central switching station. For each of these devices, the DCGC can automate a **closing (connection)** and an **opening (disconnection)** sequence. Therefore, the scope of control operations is limited to a single DC switching unit.

Closing (connection) of a standalone switching unit

The closing sequence of a standalone switching unit is shown in **Figure 7**. At the sequence's starting point, the controlled unit is in the state "maintenance-earthed". Once the sequence is initiated, the DCGC attempts to reconfigure it to the state "open" and finally to the state "closed".

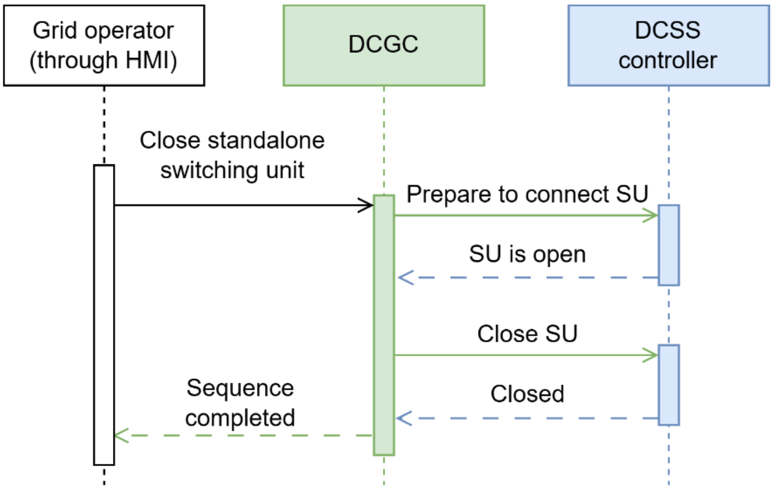

Figure 7: Standalone switching unit closing (connection) sequence.

Opening (disconnection) of a standalone switching unit

The opening sequence of a standalone switching unit is shown in **Figure 8**. The controlled unit is initially in the state "closed". Once the sequence starts, the DCGC attempts to reconfigure it to the state "open" and finally to the state "maintenance-earthed".

Although the "maintenance-earthed" state may vary depending on the solution of the DC switching unit's vendor, it must be at least emulated by its corresponding controller.

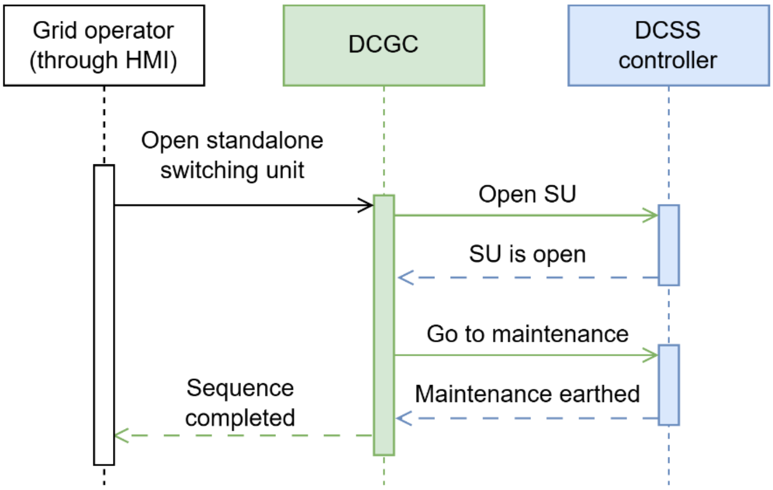

Figure 8: Standalone switching unit opening (disconnection) sequence.

3.2.3. Converter units

For each converter unit in the HVDC grid, the DCGC shall be able to manage an automated **connection** and **disconnection** sequence. In all sequences, the scope of control operations is formed by one AC/DC converter at one pole of a converter station and switching devices used to connect it to AC and DC sides. The corresponding control architecture is shown in **Figure 9** for a generic converter unit.

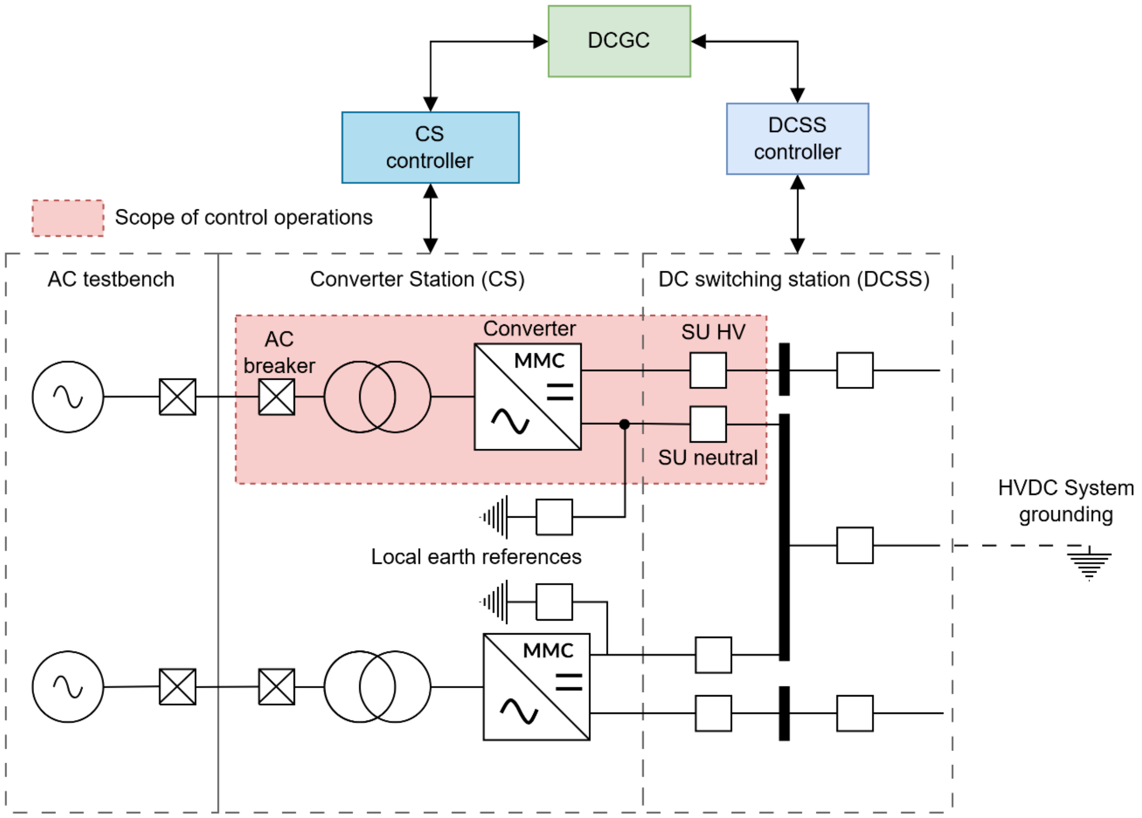

Figure 9: Control architecture for the management of local sequences involving a converter unit.

Connection of a converter unit

The DCGC shall manage the connection of a converter unit to adjacent AC and DC grids using one of the following energization methods:

- Energization from the AC side followed by the connection to the DC side, typically used for onshore stations.
- Energization from the DC side followed by the connection to the AC side, used for both offshore and onshore stations.

The choice of energization method is determined by grid operators and be changed dynamically prior to the sequence's request. For both cases, the starting point is defined as follows:

- The converter unit is in the "Maintenance earthed" state and is therefore disconnected from the PoC-AC and the PoC-DC.
- The DC Switching units between the target converter unit and the neighbouring DC busbar are in the "Maintenance earthed" state. Although the implementation of this state may vary depending on specific vendor's solution, it must be at least emulated in the corresponding remote controller.
- The local neutral ground reference in the converter station is disconnected.
- The neighbouring charging network used as source for the converter's energization is also energized (AC grid if energization from the AC, DC grid if energization from DC side).
- The DC grid is configured such that a neutral ground reference is established at the neighbouring DC busbar.

The connection sequence is illustrated in **Figure 10**. The control operations involved in the reconfiguration process are described below. They are the same in both energization methods with the difference being in the order of their execution.

(A) Using the "Prepare to connect" commands, the DCGC reconfigures both the **neutral and HV** DC switching units from the "Maintenance earthed" state to the "Open" state.

(B) The DCGC delivers the "Prepare for energization" command to reconfigure the converter unit from the "Maintenance earthed" to state to the "Ready to connect" state. This action initiates internal converter operations such as removing earthing points to set the converter ready for energization.

(C) Using the "Close" command, the DCGC reconfigures the **neutral** DC switching unit from the "Open" state to the "Closed" state, thereby connecting the converter to the **neutral** PoC-DC. This operation creates a path between the AC/DC converter to a reference ground established somewhere in the DC grid.

(D) The DCGC requests the closing of AC breaker(s) to connect the converter unit to the PoC-AC. This operation may trigger the passive energization of the AC/DC converter (step E) if the energization from AC side connection method is being used. Otherwise, it completes the connection sequence.

(E) After a passive energization, the AC/DC converter is autonomously deblocked (i.e. without any further command from DCGC) and becomes actively controlled. The converter unit reports a feedback signal to the DCGC based on the source of energization, either "Energized from AC" or "Energized from DC".

(F) Using the "Close" command, the DCGC reconfigures the **HV** DC switching unit from the "Open" state to the "Closed" state, thereby connecting the converter to the **HV** PoC-DC. This operation may trigger the passive energization of the AC/DC converter (step E) if the energization from DC side connection method is being used. Otherwise, it completes the connection sequence.

Regardless of the chosen energization method, the connection sequence is completed when the target converter unit is in the state "Ready to transmit", where it is connected to its PoC-AC and PoC-DC. This operational state serves as the starting point of the disconnection sequence for the same converter unit.

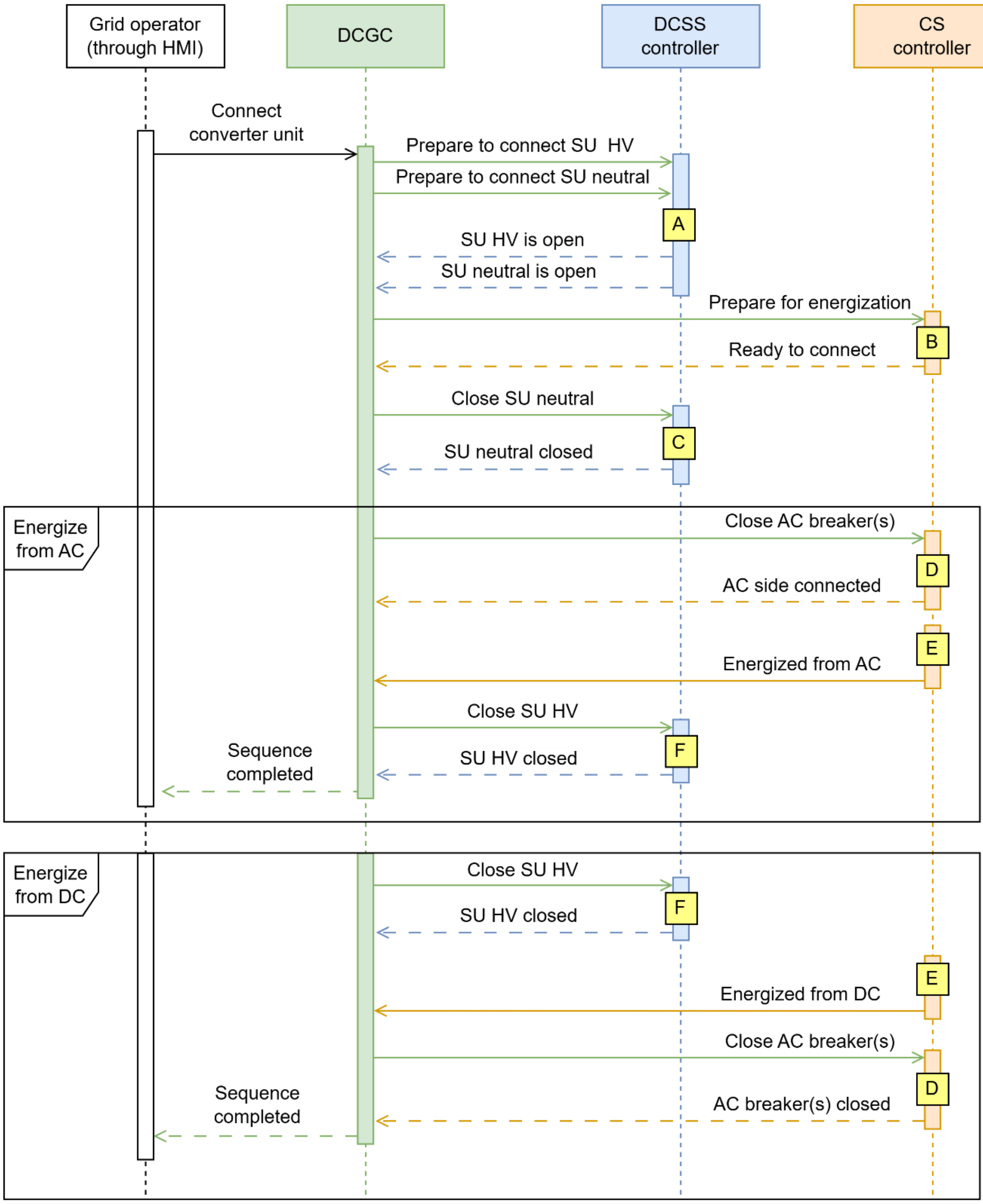

Figure 10: Converter unit connection sequence.

Disconnection of a converter unit

Contrary to the connection sequence, the DCGC shall manage only one variant of disconnection sequence for converter units. This sequence is applicable to both onshore and offshore converter units. Its starting point is described as follows:

- The converter unit is in the "Ready to transmit" state and is therefore connected to the PoC-AC and the PoC-DC through AC breakers and DC switching units respectively.

- The converter unit is operational and controllable. If the converter unit is in an offshore station, PPMs connected to it are shut down.
- Any load flow through the unit has been previously suppressed by control means.
- Any required change of control modes in the HVDC system to cope with the disconnection of the unit has been performed.

The disconnection sequence is illustrated in **Figure 11**. It aims to bring the converter unit to the "Maintenance earthed". The steps are detailed below:

1. The DCGC delivers the "Prepare to shutdown" command to prepare the converter unit for an upcoming disconnection. This step is deemed relevant so that the converter can undertake any relevant internal steps, particularly to control modes.
2. The DCGC requests the opening of AC breaker(s) to disconnect the converter unit from the PoC-AC.
3. The DCGC requests the opening of the **HV** switching unit to disconnect the **HV** pole of the converter unit from the PoC-DC. The converter unit is still connected to the neutral pole of the DC grid.
4. The DCGC requests the opening of the **neutral** switching unit to disconnect the **neutral** pole of the converter unit from the PoC-DC. At this stage, the converter unit is in the state "Ready to connect", therefore it is disconnected from the PoC-AC and the PoC-DC. **Because the STATCOM operation is outside the DCGC's scope, it does not manage the connection of local neutral ground references in the converter station during the disconnection sequence.**
5. Using the "Go to maintenance" command, the DCGC reconfigures the converter unit from the "Ready to connect" state to the "Maintenance earthed" state.
6. Finally, the DCGC delivers the "Go to maintenance" command to both HV and neutral switching units, thereby completing the disconnection sequence.

The operational state reached by the converter unit after the completion of the disconnection sequence serves as the starting point of the connection sequence.

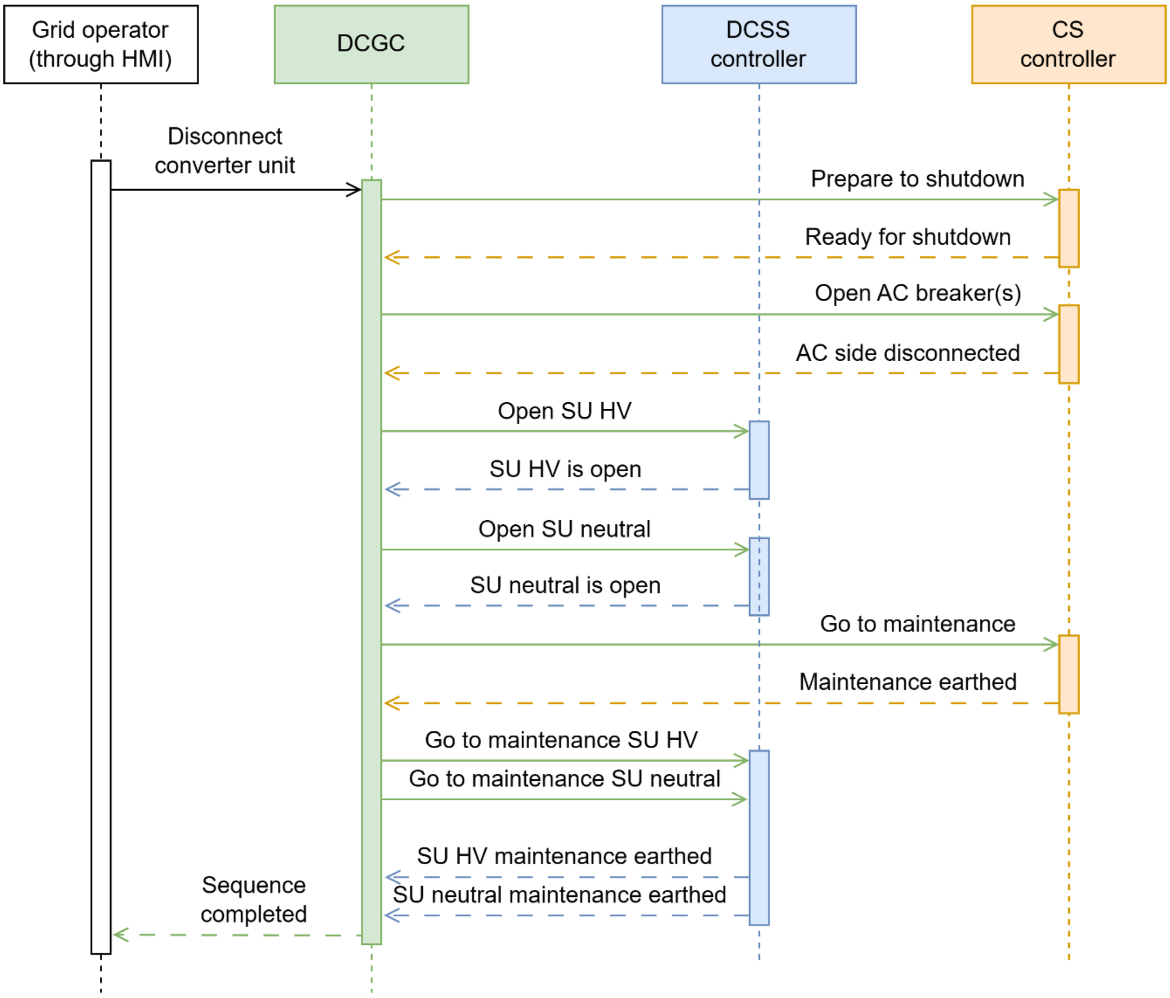

Figure 11: Converter unit disconnection sequence.

3.2.4. Additional remarks

Sequence failure and control deadlocks

Local interlocking mechanisms may be implemented based on information that is not available to the DCGC. Therefore, it is possible to initiate a local sequence with steps that would violate such interlocks. Then, the following cases may apply:

- **Sequence failure**: The design of the reconfiguration sequence includes a timeout logic to detect the lack of feedback after a sequential command is delivered. In such cases, the sequence is aborted and replaced by an automated fallback procedure which attempts to make target devices return to their original states which define the sequence's starting point. Therefore, the aborted sequence is considered to have failed. This tolerance for the lack of feedback and the execution of a fallback procedure is intended for early stages of local sequences.
- **Control deadlock**: The design of the reconfiguration sequence lacks a timeout logic to detect the absence of feedback. This situation typically arises in advanced sequence stages or during the execution of a fallback procedure, where standard fallback logic cannot be defined, or the

likelihood of sequential commands from the DCGC being rejected is low. Such cases are treated as system malfunctions, resulting in a permanent block of the DCGC's sequential control (control deadlock). In these circumstances, the grid operator can proceed with the reconfiguration process by switching to the manual mode of the DCGC's sequential control, manually setting individual values of command signals sent to remote controllers.

Corrective grid reconfiguration

The HVDC grid is subject to unexpected events which may cause its reconfiguration without the DCGC's participation. For instance, local protection mechanisms may trigger opening sequences of DC switching units or AC breakers. This could cause abnormal grid configurations, where converter units or HV cables would be partially disconnected from the rest of the grid or floating. From the DCGC's perspective, such configurations are undesirable for the following reasons:

- They are incompatible with the expected starting points of control sequences managed by the DCGC. Therefore, the safety of control operations could no longer be guaranteed, and the risk of control deadlock in future sequences would be increased.
- They interfere with grid-level interlocking mechanisms, which require the HVDC grid to operate in a predefined set of safe configurations.

As an operational simplification to grid operators, the DCGC can automatically trigger a local sequence to reconfigure underlying subsystems back into a safe operational state following unexpected events. This is a corrective reconfiguration mechanism which enables the DCGC to adapt to changing conditions while maintaining its core abilities.

For safety measures, only disconnection (converter units and transmission units) and opening (standalone switching units) sequences can be autonomously triggered by the DCGC as they lead target systems into a de-energized operational state. Subsequent connection or closing sequences can then be requested by the grid operator if needed.

The autonomous triggering of corrective reconfiguration sequences is subject to a timing logic which can be adapted and disabled based on control parameters. By default, the time required to initiate the corrective sequence should be long enough so as not to interfere with other control and protection systems.

3.3. High-level sequences

High-level reconfiguration sequences aim to change the global operational state of the HVDC grid by arranging local sequences according to a common goal. Following UC01-011, the DCGC shall be able to manage two types of high-level sequences for the HVDC grid:

- Grid start-up from an onshore converter station.
- Grid shut-down, equivalent to the reverse of the start-up procedure.

The high-level sequences managed by the DCGC are described in the following subsections. They follow a standard, **fully automated** procedure. Should grid operators wish to have greater control over the timing of individual steps or modify their order according to a different strategy, they can request individual local reconfiguration sequences managed by the DCGC.

It is important to note that any interaction with PPMs is beyond the scope of the high-level sequences. Consequently, to ensure that relevant systems in the grid comply with their expected starting points, grid operators may need to perform direct control actions on these systems before requesting the HVDC grid start-up or shut-down sequences from the DCGC.

3.3.1. Grid start-up

The starting point of the automated start-up procedure is as follows:

- The AC network adjacent to the charging converter station is energized.
- All converter units are in the "Maintenance earthed" state.
- All DC switching units between converter units and DC busbars are in the "Maintenance earthed" state.
- All converter units are disconnected from their local earth references.
- DC switching units at the ends of transmission units are in the state "Transmission unit earthed".
- Remaining DC switching units, used for DC busbar coupling and as grounding units, are in the "Maintenance earthed" state.

The start-up sequence will then follow the procedure below:

1. Establishment of a neutral ground reference in the central DC switching station.
2. Sequential aggregation of neutral busbars of DC switching stations.
3. Connection and energization from the AC side of an onshore converter station.
4. Sequential connection and energization of HV transmission units according to the zoning limitations specified in the overall demonstrator definition.
5. Sequential connection and energization from the DC side of remaining converter units according to the zoning limitations specified in the overall demonstrator definition.

The ending point of the start-up sequence is then a fully energized and operational HVDC system with controlled DC voltage and all converter units connected to their corresponding AC and DC sides ("Ready to transmit"). In particular, the states reached by controlled systems after the grid start-up also define the starting point of the grid shut-down sequence.

3.3.2. Grid shut-down

The starting point of the automated shut-down procedure is as follows:

- PPMs are shut down.
- Any load flow in the grid has been previously suppressed.
- All converter units are in the "Ready to transmit" state.
- The DC grid is fully aggregated at the HV and neutral poles:
    - All transmission units (HV cables and DMRs) are connected to DC busbars at their ends
    - There is no split bus configuration in the central DC switching station.
- A neutral ground reference is established at the central DC switching station through a predetermined grounding unit.

The shut-down sequence will proceed as follows:

1. Sequential disconnection of converter units.
2. Sequential disconnection of HV transmission units and separation of HV busbars in the central DC switching station.
3. Sequential disconnection of neutral transmission units (DMRs) and separation of neutral busbars in the central DC switching station.

4. Removal of the neutral ground reference in the central DC switching station.

Overall, the grid shut-down sequence follows the reversed procedure used for the grid start-up. The ending point of the sequence is then a fully unloaded and discharged HVDC grid. In particular, the states reached by controlled systems after the grid shut-down is over serve as the starting point of the grid start-up sequence.

3.3.3. Additional remarks

Sequence failure and control deadlocks

As explained in Section 3.2, local interlocking mechanisms invisible to the DCGC could cause a reconfiguration sequence to fail or block if an expected feedback signal is not received. Knowing that high-level sequences are an arrangement of local sequences, they are also impacted by local interlocks. Therefore, if the lack of feedback occurs while a local reconfiguration sequence is being executed as part of a high-level sequence, the following cases may apply:

- **Sequence failure**: The local reconfiguration sequence completes by following a fallback procedure. In such case, the high-level sequence is aborted as soon as the fallback procedure is completed, and no further action is taken by the DCGC to return the grid to its original operational state. The grid operator can then continue the reconfiguration process manually or by requesting other local sequences.
- **Control deadlock**: The local reconfiguration sequence is blocked because the ongoing sequence does not include a timeout logic to detect the lack of feedback. Under such circumstances, the high-level sequence is also blocked, and the grid operator must continue the reconfiguration process by manually setting individual values of command signals sent to remote controllers.

3.4. Sequence interlocks

The DCGC shall implement logical interlocks to prevent the execution of control sequences that could lead the HVDC grid into a dangerous configuration or are incompatible with the current operational state of underlying equipment. The following rules apply:

- **Sequence initiation:** A control sequence can only be initiated if its starting point is confirmed by the DCGC. This rule is implemented using feedback received before the sequence request.
- **Parallel execution:**
    - A high-level sequence and a low-level sequence cannot be executed simultaneously; initiating one prevents the execution of the other.
    - At most one high-level sequence can be executed at any time.
- **Neutral ground reference protection:** Any sequence that would create a configuration containing a converter unit in the state "Ready to transmit" without a neutral ground reference is prohibited. The following local sequences may be disabled by this interlock:
    - Opening (disconnection) of grounding units.
    - Disconnection of transmission units.
    - Connection of converter units.

    To support ground reconfiguration while preventing a floating neutral pole in the DC grid, the DCGC tolerates the establishment of multiple grounding points.

4. Monitoring

For some of the DC grid control functions, certain information (measurements and feedbacks from subsystems) retrieving from the HVDC grid needs to be processed further to be exploitable.

In this regard, the Monitoring function has the following objectives:

- Process the data from subsystems and to provide some additional information that are required by other functions, such as Power flow control functions.
- Monitor the constraints and identify the disturbance events

For monitoring the DC voltage constraints of all converter units, this function will provide the ongoing state of the HVDC system - Normal, Alert, or Emergency, as described in the Overall Demonstrator Definition and reminded in **Figure 2**.

- All three states are determined by the DC voltage measurement being within (or outside) a voltage band for a given period.
- Relevant parameters are provided in **Table 3** based on InterOPERA D3.8 [03] for a 3T system with two onshore station and one offshore station.

Table 3: Operational states of the HVDC system monitored by the DCGC and associated static voltage range (specific values for 3T version).

HVDC system state	Normal (N-1 secure)	Alert (Operational Security Range)	Emergency
Lower voltage bound/range	$\geq$0.975 p.u.	[0.95; 0.975) p.u.	<0.95 p.u.
Upper voltage bound	$\leq$1.01 p.u.	(1.01; 1.05] p.u.	>1.05 p.u.
Time	N/A	1000 ms	250 ms

- The appropriate time intervals for the detection of alert and emergency states shall allow the robust and fast detection of quasi-static overvoltage and undervoltage conditions, while ignoring faster transients.
    - The activation time for Emergency state (250 ms) is consistent with Section 3.3.2 of the AC/DC Converter Station Specification, which defines a return to DC voltage OSLs within 230 ms when specifying the Dynamic DC voltage range for the offshore station (worst case), as supported by dynamic studies conducted in T3.6 (see InterOPERA D3.8 [03]).
    - The activation time for Alert state (1s) intends to provide sufficient margin to ensure that all relevant dynamics associated with the disturbance and the deployment of remedial actions (here limited to primary control) have fully settled.
- The alert/emergency detection is done for all converter units. In case of at least one converter unit having an out-of-normal-range DC voltage measurement after a given period, the global HVDC system status will be accordingly triggered to alert/emergency status. It allows the DCGC to be sensitive to any abnormal behavior on an operating converter unit.

- The DC voltage limits as well as the acceptance time intervals are defined as DCGC parameters. Therefore, the values proposed in **Table 3** are not intended to be unchangeable and can be adapted for different grid topologies.

The HVDC system status is sent to Power Flow function (details are in Section 2) for its operation and to the HMI level for monitoring

- In normal cases, this function is expected to send the Normal state. No Power flow control function is activated.
- In case of alert/emergency, the relevant grid status is sent to the Power Flow control, at which the corrective actions will be triggered automatically upon these Alert/Emergency state to coordinate power and voltage controls.
    - Alert state: Activation of Secondary Voltage Control (SVC)
    - Emergency state (upper voltage range): Activation of Over-Voltage Power Control (OVPC)

5. Interfaces and communication

The list of signals exchanged between the DCGC and the other controllers (PPM, AC/DC converter units, DC Switching Units) are provided in a separate excel document named "InterOPERA_Task_3.3.2_interface_signal_list". The version "v1_7" was reviewed by the partners simultaneously to this document. Note the Interface signal list excel is not part of the functional specifications. The objective of this document is two-fold:

- From a functional point-of-view, define the inputs and outputs of the DCGC. To foster the shared understanding on the signals and the associated behaviour, various sequence diagrams have also been drafted, as presented throughout the document.
- From a protocol point-of-view, prepare all required information for the implementation of the signals within the IEC 61850 norm.

A screenshot of the signal list file is depicted in Figure 12 as an illustrative example. The signals shown in this figure are an example of signals sent from the DCGC to ACDC Converter Stations controllers. The list includes the signal name, a brief description, data type, units, acquisition rate, data model and reference to IEC 61850 standard. The description of these signal attributes is deemed to support also HIL simulations.

Category	#	Signal name	Max value	Min value	Description	DC grid equipment	Data type	Unit	Acquisition rate
DC voltage	1	ref_Udc_CS_k_CU_A	1,00E+03	0	Pole-to-neutral DC voltage set-point at DC-PoC.	CS k CU A/B	float	kV	trigger be set to data-change or data-update
	2	ref_Udc_CS_k_CU_B	0,00E+00	-1,00E+03			float	kV	trigger be set to data-change or data-update
	3	init_Udc_CS_k_CU_A	-	-	Initiate signal for Udc set-point	CS k CU A/B	boolean	-	trigger be set to data-change or data-update
	4	init_Udc_CS_k_CU_B	-	-			boolean	-	trigger be set to data-change or data-update
	5	ref_Udc_ramprate_CS_k_CU_A	1,00E+04	-1,00E+04	DC voltage ramp rate reference	CS k CU A/B	float	kV/s	trigger be set to data-change or data-update
	6	ref_Udc_ramprate_CS_k_CU_B	1,00E+04	-1,00E+04			float	kV/s	trigger be set to data-change or data-update
	7	init_Udc_ramprate_CS_k_CU_A	-	-	Initiate signal for Udc ramp rate reference	CS k CU A/B	boolean	-	trigger be set to data-change or data-update
	8	init_Udc_ramprate_CS_k_CU_B	-	-			boolean	-	trigger be set to data-change or data-update

Figure 12: Screenshot of Interface signal list excel file. Example of signals sent from the DCGC to ACDC Converter Stations controllers.

5.1. Procedure for modification of continuous control references

It has been decided that the sending of many continuous control commands to a converter station or to a power park module shall follow a specific mechanism, where two different signals are sent from DCGC to the subsystem:

- The new setpoint value (e.g. reactive power, DC voltage, active power ramp-rate…)
- An "initiate" signal that indicates the new setpoint has changed and should be taken into account. This additional signal allows to avoid misinterpretation of the setpoint signal in case of undesired change of the reference value, e.g. related to noise.

The two signals shall be sent at the same time from DCGC, i.e., have identical time-stamps, so that the receiving subsystem is able to link the two signals. The mechanism is displayed in Figure 13.

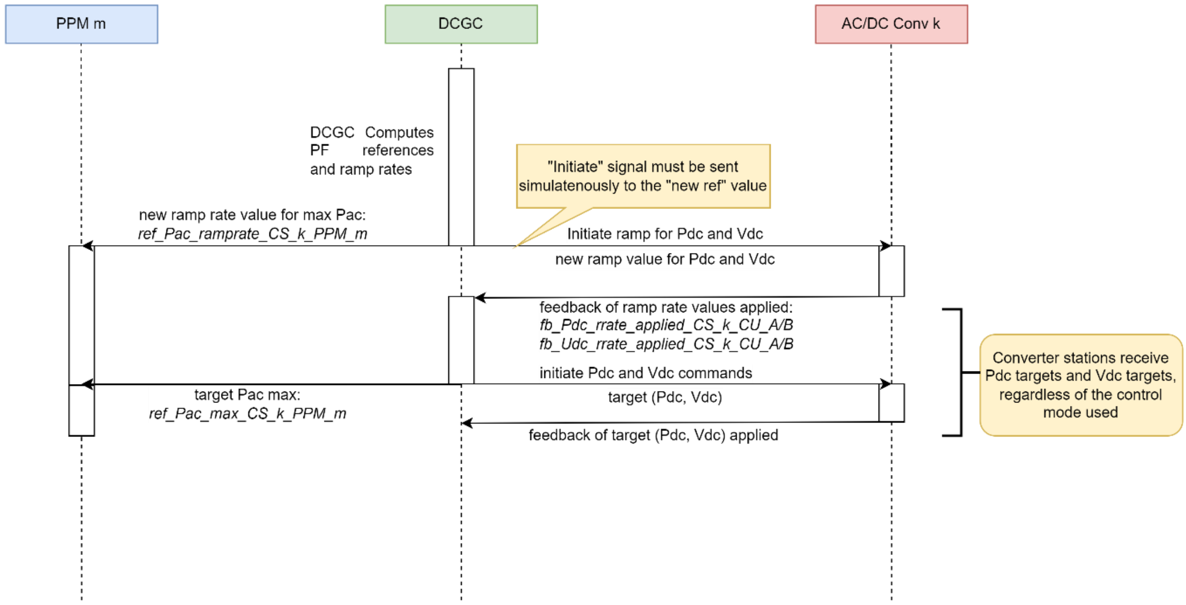

Figure 13: Signals exchanged for the sending of new power flow setpoints to a converter station and a PPM, following the "initiate" mechanism.

5.2. Network configuration

For the demonstration, in addition to the signal list and the used data models, the network configuration must be defined. The specification of the network configuration was done in the WP1 as a part of the labs HIL test benches preparation. The test of the network configuration and the 61850 communication layer between DCGC and the other controllers is the objective of the dry-run for the DCGC.

To specify this network configuration, two documents were provided[1]:

- HC DRY-RUN NETWORK: Hardware Controller dry-run network, SuperGrid/Worldgrid memo, Dec. 2024, v1.1 [05]. This document gives elements for the network configuration. The *Figure 14* gives an example of configuration in RTE lab.
- IP ADDRESS, IP address plan for dry-run network, SuperGrid/Worldgrid, Sep. 2024 [06]. This document lists the IP address to be used by each controller in each lab.

[1] InterOPERA - Documents\WP1\D1.3 & dry-run preparation\Telecom_architecture_IP_address_plan_reports\

During the phase 2 of InterOPERA, the two labs and all vendors will keep this communication architecture.

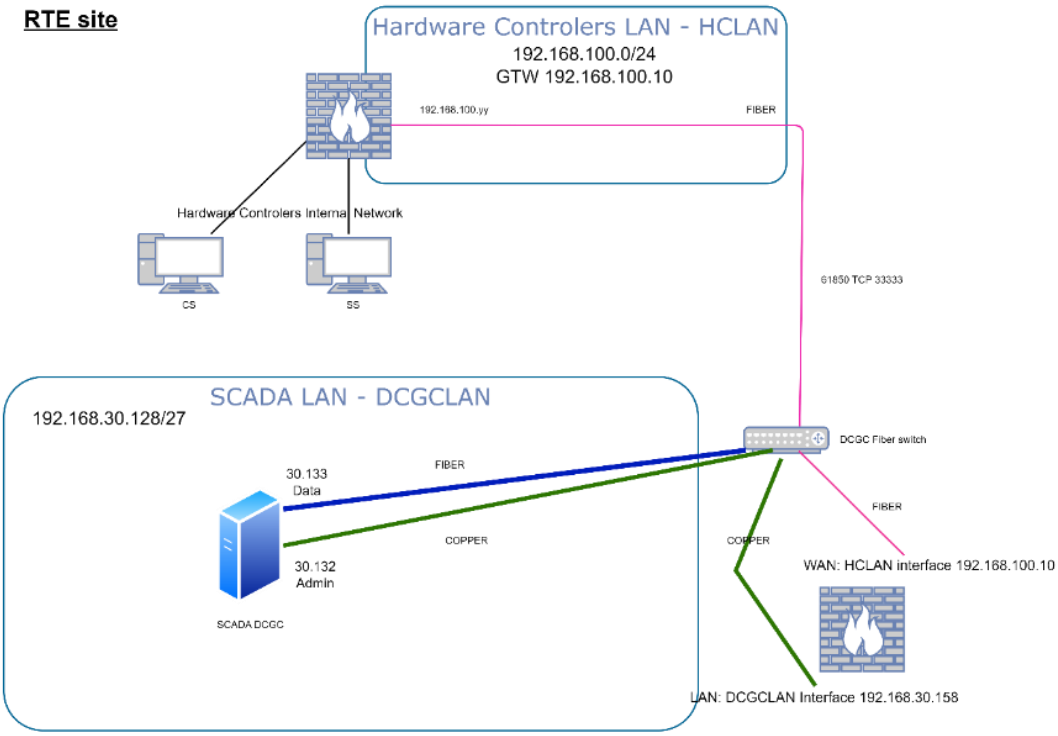

Figure 14: network architecture (RTE lab example)

6. References

Ref. No.	Title
01	InterOPERA D2.1 (PUBLIC) "Functional requirements for HVDC grid systems and subsystems"
02	InterOPERA D3.2 (SENSITIVE) "Subsystems pre-design phase process and outcomes"
03	InterOPERA D3.8 (SENSITIVE) "Demonstrator HVDC Grid System Design Studies"
04	SuperGrid Institute "DCGC Functional Scope", January 2024
05	SuperGrid Institute/Worldgrid – WP1 HC DRY-RUN NETWORK: Hardware Controller dry-run network, memo, December 2024, V1.1
06	SuperGrid Institute/Worldgrid – WP1 IP ADDRESS, IP address plan for dry-run network, September 2024.

Annex 3.3.3: AC/DC Converter Station (onshore / offshore)

WP3

Multi-vendor / Multi-terminal demonstrator project

Deliverable 3.3(b)

Detailed Functional Specifications

Subtask 3.3.3

AC/DC Converter Station (onshore / offshore)

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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PROJECT DETAILS:

Duration: 1 January 2023 – 30 April 2027
Grant agreement: 101095874 — InterOPERA — HORIZON-CL5-2022-D3-01

Detailed Functional Specifications

AC/DC CONVERTER STATION (ONSHORE/OFFSHORE)

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Table of Contents

VERSION CONTROL

Version	Date	Created/modified by	Comments
1.1	16.09.2025	P. Düllmann (Siemens Energy)	After stakeholder review
1.0	04.08.2025	P. Düllmann (Siemens Energy)	First issue for review

1. Executive summary

This specification provides functional requirements and specific design values for the AC/DC converter stations in the InterOPERA demonstrator (see **Figure 1-1**).

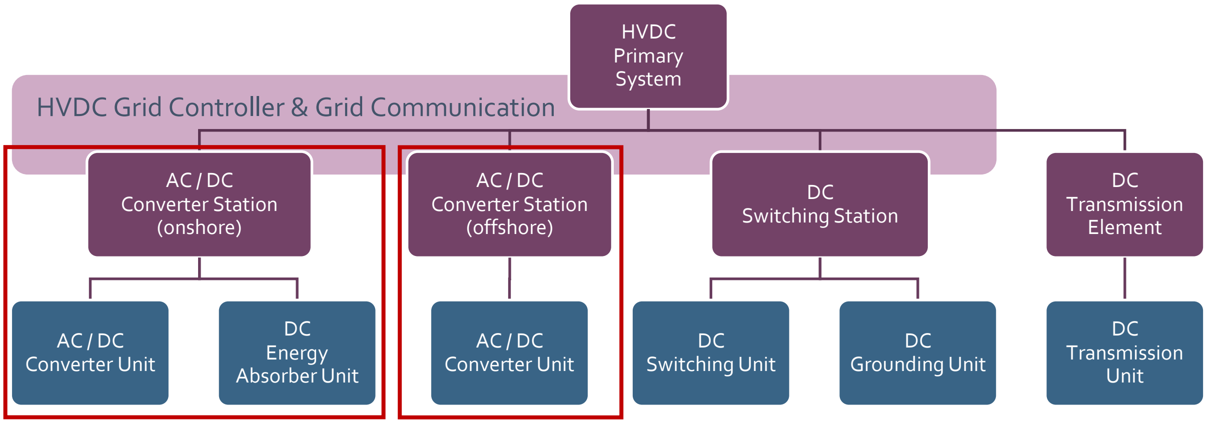


Figure 1-1: Definition of HVDC subsystems for the InterOPERA demonstrator

Each HVDC vendor has agreed to deliver one AC/DC converter station model for onshore connections and one AC/DC converter station model for offshore connections. Depending on the demonstrator test scenario, one or the other model will be connected to the system. It is the individual vendor's choice how the two different types are implemented.

The specification is structured in two chapters comprising one AC/DC converter station type each:

- chapter 2 "AC/DC Converter Station (onshore)"
- chapter 3 "AC/DC Converter Station (offshore)"

It shall be noted that all specifications in this document are focusing on interoperability requirements related to multi-terminal / multi-vendor aspects assuming that general compliance with established industry standards and AC grid codes is given. All specifications are functional in their nature, meaning that prescription of a certain solution is avoided as far as possible. They are, however, specific in all aspects that are mandatory to ensure proper operation of the InterOPERA demonstrator system.

As such, the specifications establish one exemplary way to implement the general functional framework defined in InterOPERA. However, as part of the specifications have been limited to the scope of the InterOPERA demonstrator, they can only be a starting point, but not a complete blueprint for all future multi-terminal / multi-vendor schemes. Further work is required.

2. AC/DC Converter Station (onshore)

2.1. Configuration

2.1.1. Topology

The onshore AC/DC converter station shall follow the functional topology of a bipolar system and the PoC reference designation as shown in **Figure 2-1** (refer to Overall Demonstrator definition for numbering).

The AC switching units associated with the PoC-AC (P_n) shall be delivered as part of the AC/DC converter station and shall be operated by the corresponding converter unit. Please note that the PoC-AC definition and the AC switching unit aggregate all three AC phases into one functional unit. Requirements for the AC switching unit are included in the following sections.

Each DC terminal of a converter unit is associated with a separate PoC-DC (P_n and R_n) to allow individual connection and disconnection of poles by the external DC switching units in the DC switching stations.

The onshore AC/DC converter station shall provide a grounding unit allowing a local reference to ground for the low voltage terminals of the converter units. In the InterOPERA demonstrator, this shall only be used for STATCOM operation when the converter unit is <u>not connected with the DC system</u>. As such, the design of the local grounding unit is subject to an individual vendor's solution and will not be further specified in this document.

Each onshore converter unit shall have a DC energy absorber unit realized as dynamic braking system (DBS) [03] to limit temporary overvoltage between the converter unit DC terminals by means of energy dissipation. Requirements for the DBS are included in the following sections.

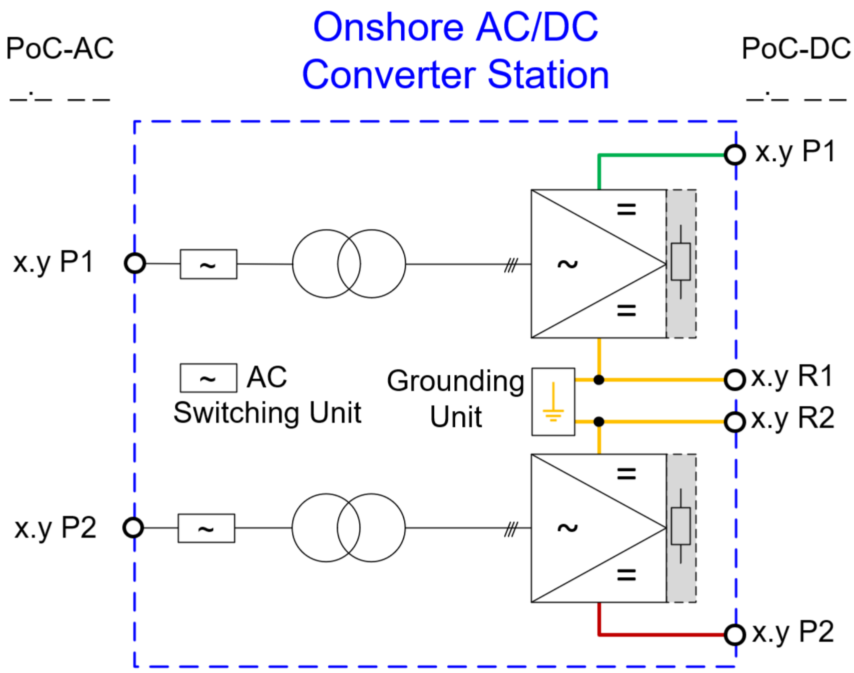


Figure 2-1: Onshore AC/DC converter station functional topology and PoC reference designation

2.1.2. Sequential controls

Following D2.1 [01] and D3.2 [03], each converter unit shall be designed to provide the unit states listed in **Table 2-1** and exchange information about its current unit state with the DC Grid Controller (refer to Annex 3.3.2). The corresponding state diagram is shown in **Figure 2-2** and further detailed in this section.

Please note that states can differ between the DC phases (P_n, R_n). Example: The neutral system (R_n) can be pre-configured to "DC aggregated" while the high-voltage terminal (P_n) is in state "Ready to connect".

Table 2-1: Converter Unit state definition (onshore AC/DC converter station)

Converter Unit State	PoC – AC (P_n) switching unit	AC Voltage @ PoC - AC	PoC – DC (P_n, R_n) switching unit	DC Voltage @ PoC - DC
Maintenance earthed	Open	Don't care	Open	Don't care
Ready to connect	Open	Don't care	Open	Don't care
AC aggregated (not utilized)	Closed	No	Open	Don't care
DC aggregated	Open	Don't care	Closed	No
AC/DC aggregated (not utilized)	Closed	No	Closed	No
Energized from DC	Open	Don't care	Closed	Yes
Energized from AC	Closed	Yes	Open	Don't care
Ready to transmit	Closed	Yes	Closed	Yes

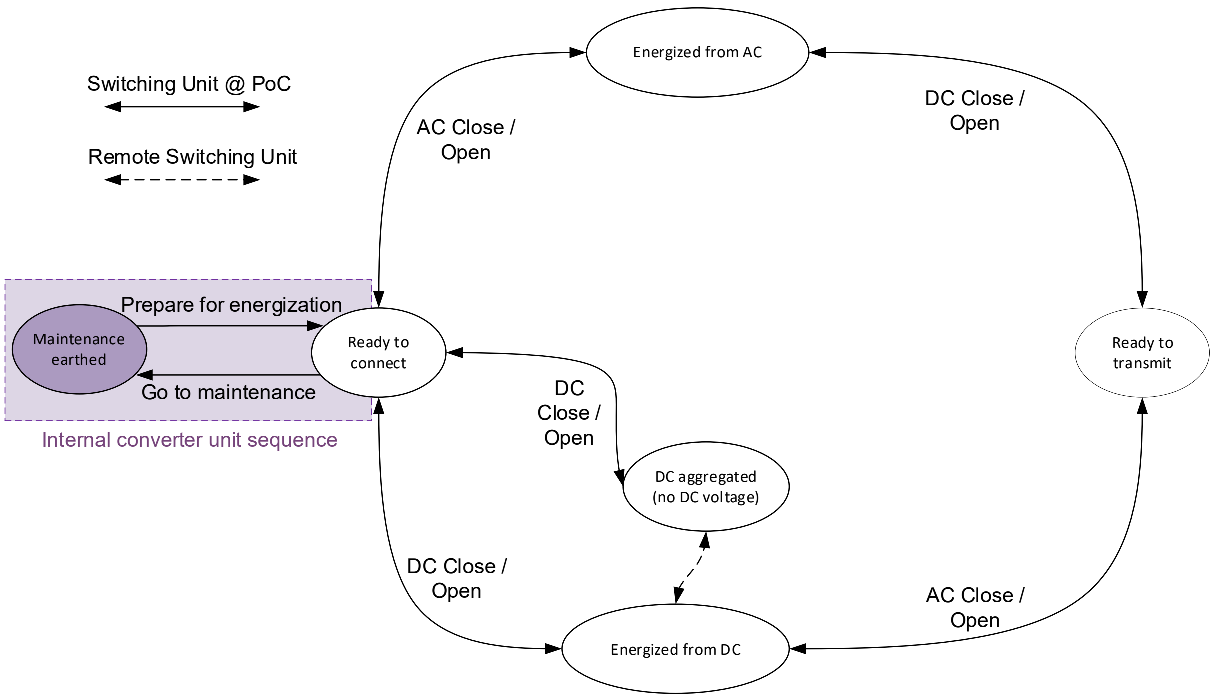


Figure 2-2: State diagram of a Converter Unit (onshore AC/DC converter station; adapted from [01])

Internal converter unit sequences include all procedures within the unit which do not change the status of the neighbouring units. In the InterOPERA demonstrator, this does only comprise the transition between the internal unit state “Maintenance earthed” and the externally relevant unit state “Ready to connect”. Internal unit states (“Maintenance earthed”) and internal converter unit sequences are subject to the individual vendor’s solution and will not be further detailed or specified in this document.

All other transitions between converter unit states shall be induced by the **actions of switching units** which can either be located at the converter unit’s points of connection (AC or DC) or at another remote point in the AC or DC system. For the InterOPERA demonstrator, the AC switching unit associated with the PoC-AC (P_n) shall be operated by the corresponding converter unit. The DC switching units associated with the PoC-DC (P_n, R_n) shall be independent functional units not operated by the converter unit. The converter unit shall be informed about the state of the DC switching units. In order to prepare the converter unit for an upcoming disconnection, a command “Prepare to shutdown” is sent in advance by the DC Grid Controller and shall be responded by a status signal “Ready to shutdown”.

For the InterOPERA demonstrator, energization of the DC circuit shall always be performed starting from converter unit status **“DC aggregated” in the neutral system** (refer to Overall Demonstrator Definition for energization zoning). Reference to ground in the neutral system shall always be established in one of the DC switching stations (default: Central DCSS #5) and not in the AC/DC converter stations.

The states connected to energization processes, “Energized from AC” and “Energized from DC”, include an automatic deblock of the AC/DC converter units after passive energization.

The grounding unit in the AC/DC converter station shall only be used for STATCOM operation when the converter unit is not connected with the DC system, i.e. all switching units at PoC-DC are in status “Open”. The information about whether the local reference to ground shall be established or removed for a state transition is not available at station level. A corresponding command shall therefore be issued by the DC grid controller on operation level requesting the converter unit to connect/disconnect its low voltage terminal (R_n) to/from the grounding unit in the AC/DC converter station.

As a summary, the AC/DC converter station shall be able to receive the following commands from the DC grid controller and forward them in a coordinated manner to the individual converter units (**Table 2-2**).

Table 2-2: Sequential control commands from DC grid controller to onshore AC/DC converter station

Sequential control command (referring to converter unit level)	Short description
Go to maintenance	The converter unit shall go to state "Maintenance earthed". This state is subject to individual vendor's solutions.
Prepare for energization	The converter unit shall go from state "Maintenance earthed" to state "Ready to connect" allowing energization from AC or DC.
Prepare for shut-down	The converter unit shall prepare internally for disconnection from the DC side and report the feedback "Ready to shut down".
Close AC switching unit	The converter unit shall close its associated AC switching unit.
Open AC switching unit	The converter unit shall open its associated AC switching unit.
Close local reference to ground (only used for STATCOM)	The converter unit shall connect its low voltage terminal to the local reference to ground via the station grounding unit.
Open local reference to ground (before connection to DC system)	The converter unit shall disconnect its low voltage terminal from the local reference to ground via the station grounding unit.

2.1.3. Sign Convention

The sign convention used for the onshore AC/DC converter station is following the Overall Demonstrator Definition (refer to Figure 2-3). In particular, all currents flowing "into the DC grid" are counted as positive.

- DC side: Generator sign convention for active power and DC currents
- AC side: Load sign convention for active and reactive* power

*This implies that: inductive reactive power (lagging current) is counted as positive (+)
capacitive reactive power (leading current) is counted as negative (-)

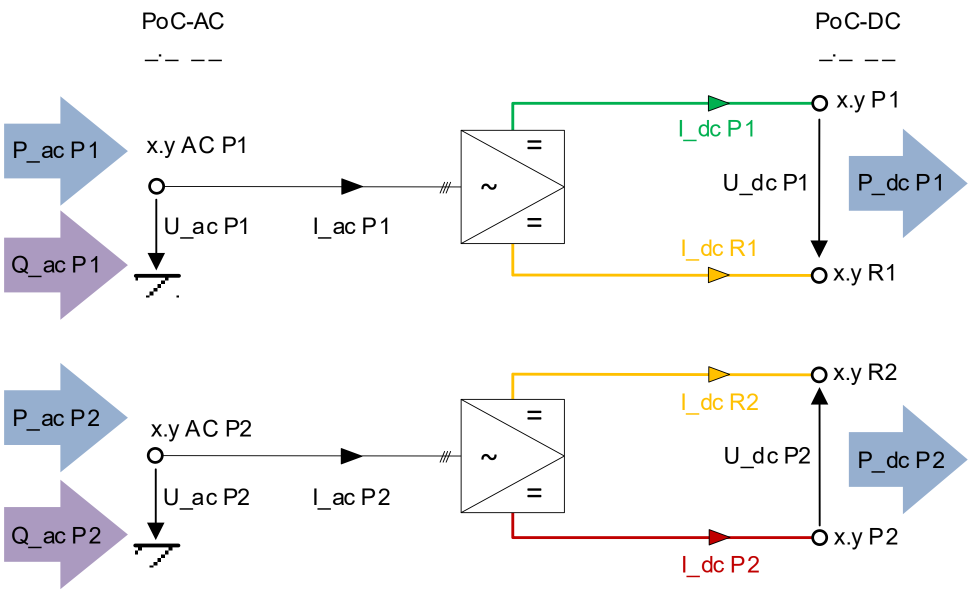


Figure 2-3: Demonstrator sign convention for onshore AC/DC converter station

2.2. Requirements at Point of Connection – AC

2.2.1. AC onshore system data

Please refer to Annex 3.3.5 for all information about the AC Onshore Testbench to which the AC/DC converter station shall be connected.

2.2.2. AC power rating

Active Power Requirements

The active power rating of an AC/DC converter unit is defined at the DC Point of Connection (PoC-DC) as detailed in section 2.3.3. The corresponding active power at the AC Point of Connection (PoC-AC) shall be available across the whole AC voltage range defined in Annex 3.3.5, i.e. there shall be no persistent limitation of active power due to steady-state AC voltage variations within the given voltage range.

Reactive Power Requirements

Please refer to Annex 3.3.5 for Reactive Power Requirements in the AC Onshore Testbench to which the AC/DC converter station shall be connected.

2.2.3. AC switching unit

Each onshore AC/DC converter unit shall comprise and control an AC switching unit connecting the converter unit to its associated PoC-AC. Each AC switching unit shall at least provide the following features:

- Making capability and peak current suppression for initial energization when connecting to PoC-AC
- Breaking capability for residual currents and load currents when disconnecting from PoC-AC
- Fault separation and isolation for AC side faults and DC side faults

Following the Overall Demonstrator Definition, each AC switching unit shall be designed to energize an aggregated zone up to the to the following maximum extent:

- 1 x AC/DC Converter Station
- 2 x DC Switching Station (only busbars → negligible)
- 1 x DC Transmission Element (max. 800 km; see Annex 02 for DC cable data)

The AC switching unit, respectively the AC/DC converter unit, shall be able to receive open / close commands from the DC Grid Controller via the AC/DC converter station level and report its current status (open / closed) via the same communication path. Please also refer to section 2.1.2 "Sequential controls".

Fault separation and isolation in the AC switching unit shall be initiated based on local information and trip signals from the AC/DC converter unit.

2.2.4. AC node control modes

Following the overall demonstrator definition, the following AC node control modes shall be realized by the onshore AC/DC converter station on unit level. Change of control modes can be requested by the DC

Grid Controller. The AC/DC Converter Unit shall communicate its current AC node control mode to the DC Grid Controller. If the AC/DC Converter Unit is not in one of the control modes listed below, e.g. "idle / standby / default" after energization, this shall also be communicated to the DC Grid Controller.

During energisation from DC (cf. **Table 2-1** and **Figure 2-2**), the AC-side control mode – and if required, also the synchronisation with the AC network – is to be handled by the vendor-specific control system. The node control modes/functions below apply to converters that reached the "ready to transmit" state.

Table 2-3: AC node control concept assignment

AC node control concepts	Onshore AC/DC converter unit
Grid Following (GFL)	*optional*
Grid Forming (GFM)	X

The requirements on the functions (refer to **Table 2-4**) shall be in line with the chosen reference AC grid code unless otherwise specified in the subsystem specifications (Annex 3.3.5).

Table 2-4: AC node control function assignment

AC node control function	Grid Following *(optional)* Onshore	*Grid Forming* *Onshore*
Active Power Control[1] (incl. power ramping)		
Reactive Power Control	X	X
Priority to active or reactive power contribution	X	X
AC Voltage Control with reactive power droop	X	X
AC fault ride through	X	X
Dynamic voltage support	X	X
Post fault active power recovery	X	X
Inherent Inertial Response		X

2.2.5. AC fault handling

For the InterOPERA demonstrator, there are no specific requirements to the AC fault handling that are going beyond the reference AC grid code (refer to Annex 3.3.5 "AC Onshore Testbench").

[1] Active power setpoints and control are part of the droop-based DC node voltage control (cf. section 2.3.4). No constant power control without DC voltage sensitivity is foreseen.

2.3. Requirements at Point of Connection – DC

2.3.1. DC network data

Please refer to the main document "Overall Demonstrator Definition" for information about the DC side topologies and related electrical data (e.g. DC Cable Data in Annex 02).

2.3.2. DC voltage ranges

The onshore AC/DC converter stations shall be able to be continuously operated for every pole-to-neutral DC voltage at the DC-PoC that lies within the operational security limits (OSL) defined for the demonstrator, cf. also Section 5.1.1 of the "Overall Demonstrator Definition". The relevant continuous pole-to-neutral voltage ranges are repeated in **Table 2-5**.

Continuous

Table 2-5: Operational Security Limits for the InterOPERA demonstrator

	Nominal	Upper Operational Security Limit	Lower Operational Security Limit
DC Voltage (HV+ pole to neutral)	500 kV 1 pu	525 kV 1.05 pu	475 kV 0.95 pu
DC Voltage (HV- pole to neutral)	- 500 kV - 1 pu	- 475 kV - 0.95 pu	- 525 kV - 1.05 pu

Temporary (Dynamic)

Following disturbances and/or contingencies, the DC-PoCs of the AC/DC converter units will be exposed to different temporary DC voltage excursions. Based on dynamic and transient studies[2] conducted in Task 3.6 ([04]), **Table 2-6** and **Figure 2-4** quantify an envelope around all cases for which an AC/DC converter unit shall remain operational (i.e., not blocked). All values are pole-to-neutral voltages in p.u. of the rated DC voltage. During – or at least after – any voltage excursions within the dynamic range, the AC/DC converter shall be able to control its active power contributing to the primary control. In addition, an AC/DC converter unit is required to withstand dynamics and stresses imposed by their own blocking or de-blocking which is not considered in the envelope depicted below.

Table 2-6: DC voltage dynamic ranges envelope at PoC-DC for onshore AC/DC converter unit

Time (ms)	10	20	30	40	50	60	70	80	90	100
Onshore	1.50	1.31	1.30	1.30	1.30	1.29	1.28	1.27	1.23	1.19
	0.69 (0.25)	0.69 (0.63)	0.70	0.70	0.70	0.71	0.72	0.74	0.79	0.84

Time (ms)	110	120	130	140	150	160	170	180	190	200
Onshore	1.16	1.13	1.12	1.11	1.10	1.09	1.08	1.07	1.06	1.05
	0.90	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95

[2] Here, transient studies refer to DC-side short circuit fault simulations which also lead to DC voltage excursions in the dynamic time range.

Note: The shown values represent an envelope, not an individual physically measured voltage trajectory. Depending on the converter design, values at the lower end of the envelope may lead to short periods of overmodulation – but must not lead to protective blocking of the converter.

For overvoltages, the values provided for a short time frame (time frame marked blue in **Figure 2-4**) are not to be interpreted as absolute maximum values. Short-term overvoltages – in particular to ground – are covered in section 2.4.2 under "insulation coordination".

For undervoltages, the transient values provided for a short time frame (values indicated in brackets or as a dashed line in **Figure 2-4** and **Table 2-6**) do not constitute a binding specification for the dynamic time frame. However, they indicate the lowest DC voltages observed in the generic studies of T3.6 / D3.8 at operational (i.e., non-blocked) converters as a reaction to short circuit DC faults. These values are provided for reference, and fall within the time range relevant for DC FRT (marked grey), for which the required behaviour of the AC/DC converter units is described in the DC-FRT functional specification in section 2.3.5, and in section 5.1.2 of the "Overall Demonstrator Definition".

Disclaimer: The dynamic voltage ranges are observed based on generic models in GFL control mode. While in general, it is expected that vendor-specific controls will outperform the generic converter controls and hence lead to narrower voltage bands, there is a possibility of greater subsystem-level stresses (and hence wider ranges) under GFM operation compared to GFL.

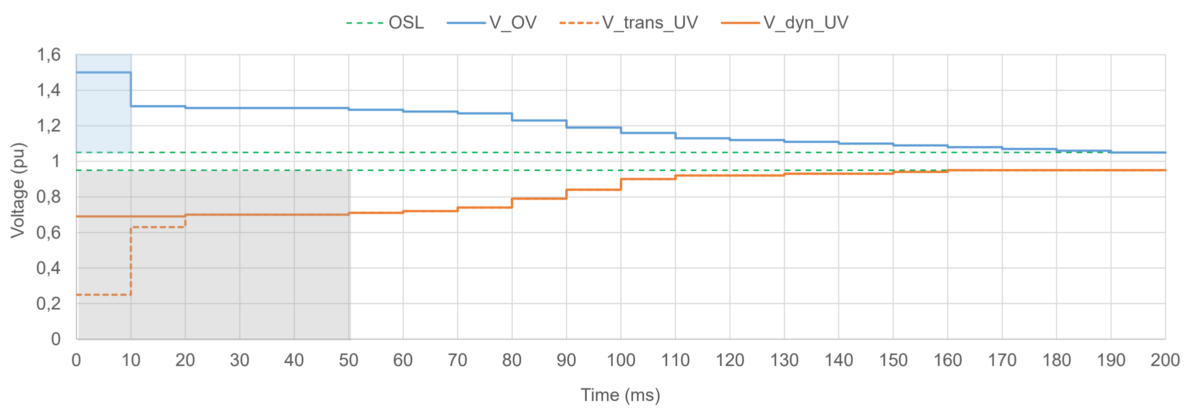


Figure 2-4: Observed DC voltage dynamic ranges at PoC-DC for onshore AC/DC converter unit; Grey marked time period marks overlap with DC-FRT specification / DC fault handling (cf. section 2.3.5)

2.3.3. DC power rating

Active Power Requirements

The maximum active power provided by an AC/DC converter unit for continuous operation shall be 1 GW defined at the DC Point of Connection (PoC-DC) for rectifier operation (= sending end).

For design purposes, the minimum active power in inverter operation (= receiving end) shall also be assumed as (-)1 GW defined at the DC Point of Connection (PoC-DC).

The maximum DC current for continuous operation shall be 2030 A for continuous operation for both rectifier and inverter mode. The resulting continuous operating range is shown in **Figure 2-5**.

The AC/DC converter unit continuous capabilities shall not limit the continuous operating range depicted in **Figure 2-5** at any point considering e.g. measuring accuracies, ripples or internal design constraints.

Table 2-7: Continuous values for active power and DC current for AC/DC converter unit (onshore)

	Nominal	Continuous operating values (receiving and sending end)
Active Power (at HV pole DC PoC)	1 GW 1 pu	+/- 1 GW +/- 1 pu
DC Current (HV poles and DMR)	2000A 1 pu	+/- 2030 A +/- 1.015 pu

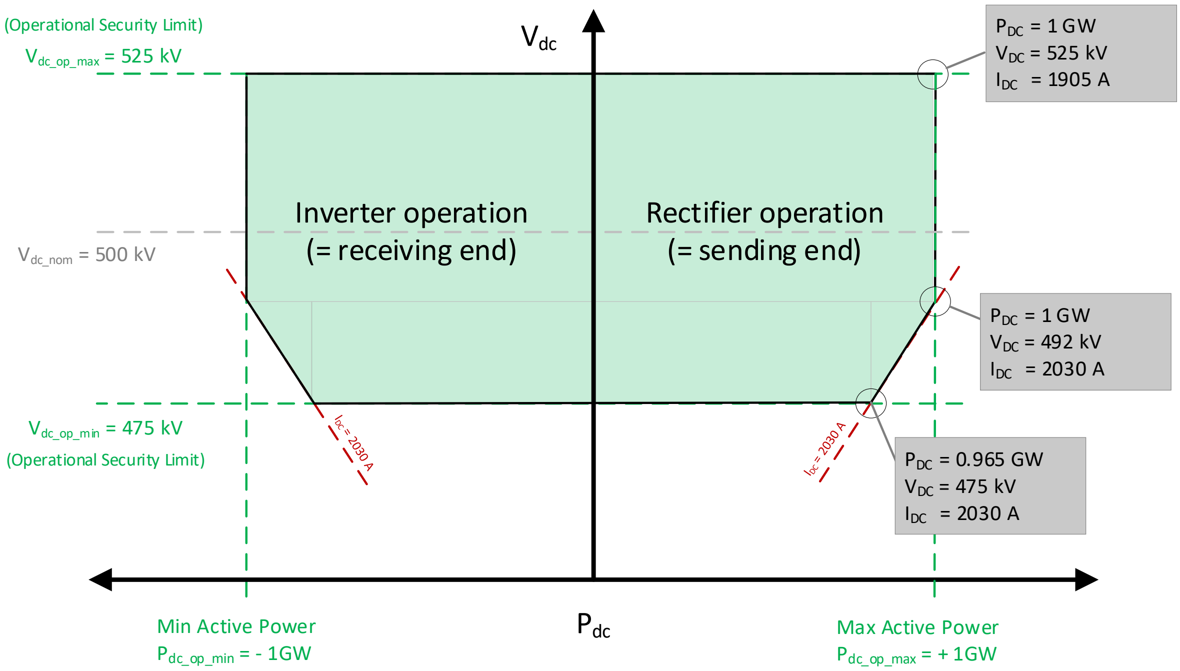


Figure 2-5: Continuous operating range for AC/DC converter unit (onshore)

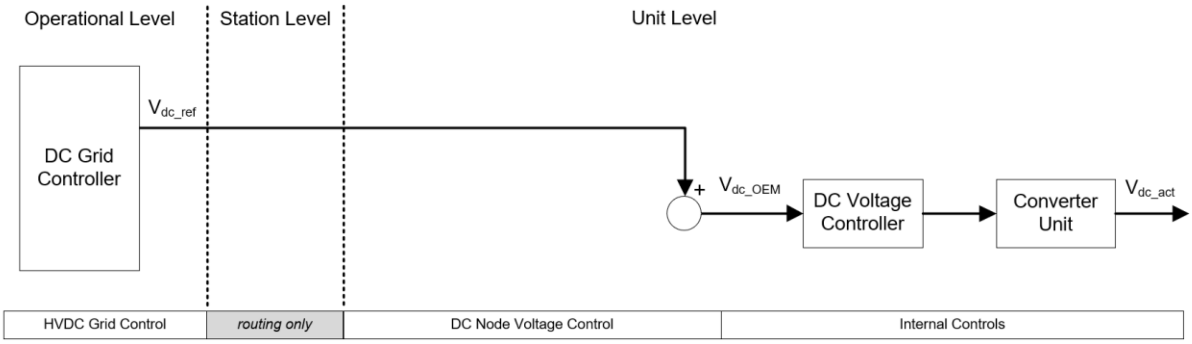
2.3.4. DC node voltage control

Following the overall demonstrator definition, the following DC node voltage control modes shall be realized by the onshore AC/DC converter station on unit level. Change of control modes can be requested by the DC Grid Controller. The AC/DC Converter Unit shall communicate its current DC node voltage control mode to the DC Grid Controller. If the AC/DC Converter Unit is not in one of the control modes listed below, e.g. "idle / standby / default" after DC energization (the state immediately after energisation can be defined and chosen by each vendor), this shall also be communicated to the DC Grid Controller.

Fixed DC voltage control mode

The AC/DC converter unit shall be capable to maintain the DC voltage between its DC-PoC terminals at the DC voltage reference requested by the DC Grid Controller within the defined operational limits. The required adjustment of the active power response shall be limited by the maximum active power rating (see also 2.3.3).

A functional block diagram for fixed DC voltage control is shown in **Figure 2-6**. The DC voltage setpoint is sent from the DC Grid Controller to the AC/DC converter station where it is routed to the DC node voltage control of the associated converter unit. The internal DC voltage controller shall then establish the requested DC voltage between its DC-PoC terminals.



Vdc_ref: DC voltage setpoint from DC Grid Controller to DC Node Voltage Control Level in AC/DC Converter Unit

Vdc_OEM: Internal DC voltage reference forwarded from DC Node Voltage Control Level to internal Controls

Vdc_act: Actual DC voltage set by the AC/DC Converter Unit

Figure 2-6: Schematic block diagram of fixed DC voltage control mode

The general principle of a fixed DC voltage control mode is illustrated in **Figure 2-7**. Parameters for the InterOPERA demonstrator are listed in **Table 2-8**. Within the demonstrator's Operational Security Limits, the AC/DC converter unit is supposed to keep the DC voltage fixed at the reference requested by the DC Grid Controller. The DC Grid Controller can request any value within the Operational Security Limits and shall send new DC voltage setpoints together with DC voltage ramp rates.

For the InterOPERA demonstrator, the behaviour in the grey zone outside the operating range limited by Operational Security Limits (OSL, green dashed lines) is not quantified. When the OSL power limit is reached, it is assumed that the AC/DC converter unit is, at least, limiting the power to this value within the OSL voltage limits. Internal power reserves shall be utilized, if possible.

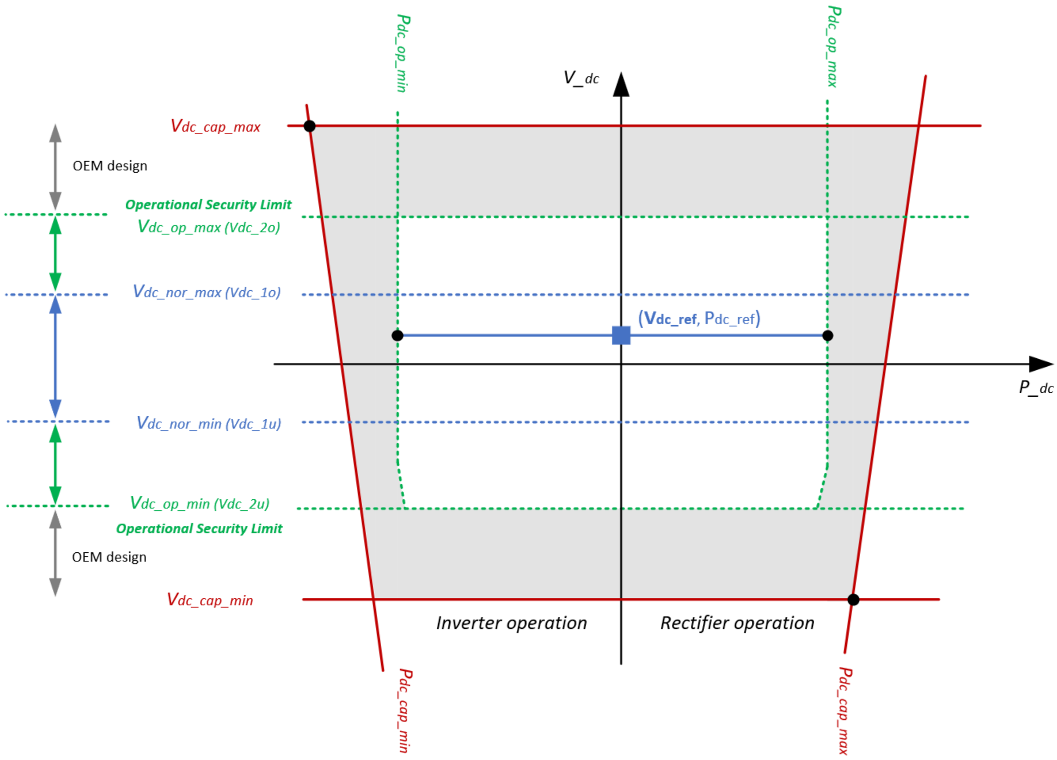


Figure 2-7: Illustration of fixed DC voltage control mode

Table 2-8: Parameters for fixed DC voltage control mode for AC/DC converter unit (onshore)

Parameter	InterOPERA Demonstrator
Vdc_cap_max	Chosen by OEM
Vdc_op_max (Vdc_2o)	525 kV (1.05 pu)
Vdc_nor_max (Vdc_1o)	setpoint from converter HMI *(Task 3.6: 1.01 - 1.025 pu)*
Vdc_ref	setpoint from DC Grid Controller or HMI
Vdc_nor_min (Vdc_1u)	setpoint from converter HMI (*Task 3.6:* 0.975 - 0.985 pu)
Vdc_op_min (Vdc_2u)	475 kV (0.95 pu)
Vdc_cap_min	Chosen by OEM

Parameter	InterOPERA Demonstrator
Pdc_cap_max	Chosen by OEM
Pdc_op_max	1 GW (also refer to **Figure 2-5**)
Pdc_ref (not used)	setpoint from DC Grid Controller or HMI
Pdc_op_min	-1 GW (also refer to **Figure 2-5**)
Pdc_cap_min	Chosen by OEM

Based on generic models, control dynamics have been evaluated in D3.8 [04] following stand-alone tests as described in D2.1 [01] under the assumption of GFL control mode. Thereby the indicative values are only relevant for the current implementation of GFL. The maximum values are provided in **Table 2-9** as reference. It is expected that the dynamic response of vendor models applied in the same equivalent test network is at least as good as the generic implementation. Based on the behaviour observed in the demonstrator system incl. all vendor models, optimization and potential standardization of performance requirements shall be discussed.

Table 2-9: Dynamic requirements for fixed DC voltage control for AC/DC converter unit (onshore)

DC voltage reference step – DC voltage response

Parameter	Maximum in 3T based equivalent
Settling time Ts [ms]	261.3
Step response time Tsr [ms]	54.2
Rise time Tr [ms]	49.8
Dead/reaction time Tt [ms]	0.8
Overshoot Vm [kV]	2.99

DC voltage reference step – DC power response

Parameter	Maximum in 3T based equivalent
Settling time Ts [ms]	204.9
Dead/reaction time Tt [ms]	4.3
Overshoot Vm [MW]	114.3

DC power disturbance – DC voltage response

Parameter	Maximum in 3T based equivalent
Settling time Ts [ms]	233.4
Overshoot Vm [kV]	5.32

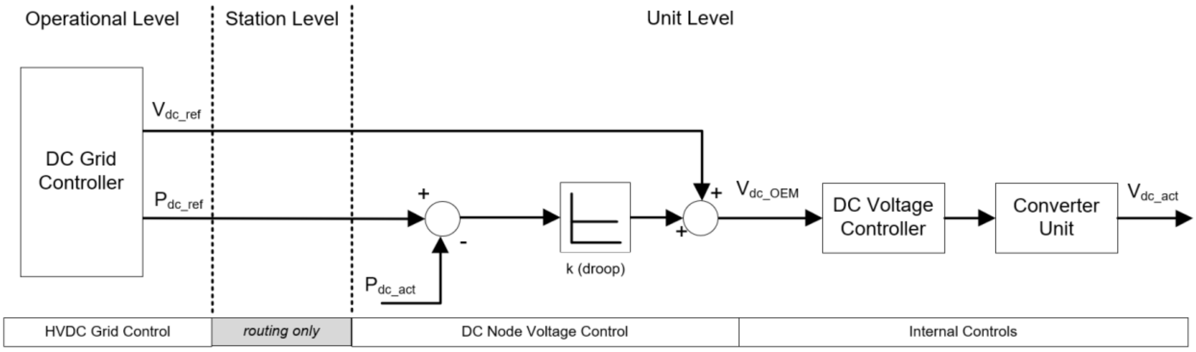
DC power disturbance – DC power response

Parameter	Maximum in 3T based equivalent
Settling time Ts [ms]	259.3
Step response time Tsr [ms]	51.2
Rise time Tr [ms]	48.7
Dead/reaction time Tt [ms]	13.6
Overshoot Vm [MW]	39.9

DC voltage droop control mode

The AC/DC converter unit shall be capable of adjusting the DC voltage between its DC-PoC terminals based on a DC voltage droop which refers to the ratio of a steady-state deviation of DC voltage to the steady-state change in active power output. Please refer to D2.1 [01] for more background information and discussion of alternative implementations of this control mode.

A functional block diagram for droop-based DC voltage control is shown in **Figure 2-8**. The DC voltage setpoint and the active power setpoint are sent from the DC Grid Controller to the AC/DC converter station where they are routed to the DC node voltage control of the associated converter unit. The DC node voltage control shall add an offset to the DC voltage setpoint that is proportional to the active power deviation. The resulting internal DC voltage reference is forwarded to the internal DC voltage controller which shall then establish the requested DC voltage between its DC-PoC terminals.



Vdc_ref: DC voltage setpoint from DC Grid Controller to DC Node Voltage Control Level in AC/DC Converter Unit

Pdc_ref: Active power reference from DC Grid Controller to DC Node Voltage Control Level in AC/DC Converter Unit

Pdc_act: Actual active power measured at DC-PoC of AC/DC Converter Unit

k_droop: proportional factor of multi-segment DC voltage droop characteristic expressed in [kV / MW]

Vdc_OEM: Internal DC voltage reference forwarded from DC Node Voltage Control Level to internal Controls

Vdc_act: Actual DC voltage set by the AC/DC Converter Unit

Figure 2-8: Schematic block diagram of DC voltage droop control mode

The droop constant k shall be derived from a multi-segment DC voltage droop characteristic as illustrated in **Figure 2-9**. Parameters for the InterOPERA demonstrator are listed in **Table 2-10**.

The DC Grid Controller can request any pair of DC voltage and power within the Operational Security Limits and shall send new setpoints together with ramp rates. The droop parameters for VSM (k_1), LVSM-O (k_{2o}) and LVSM-U (k_{2u}) shall be provided by the DC Grid Controller to the AC/DC converter unit in advance for the test scenario and shall not be changed during operation.

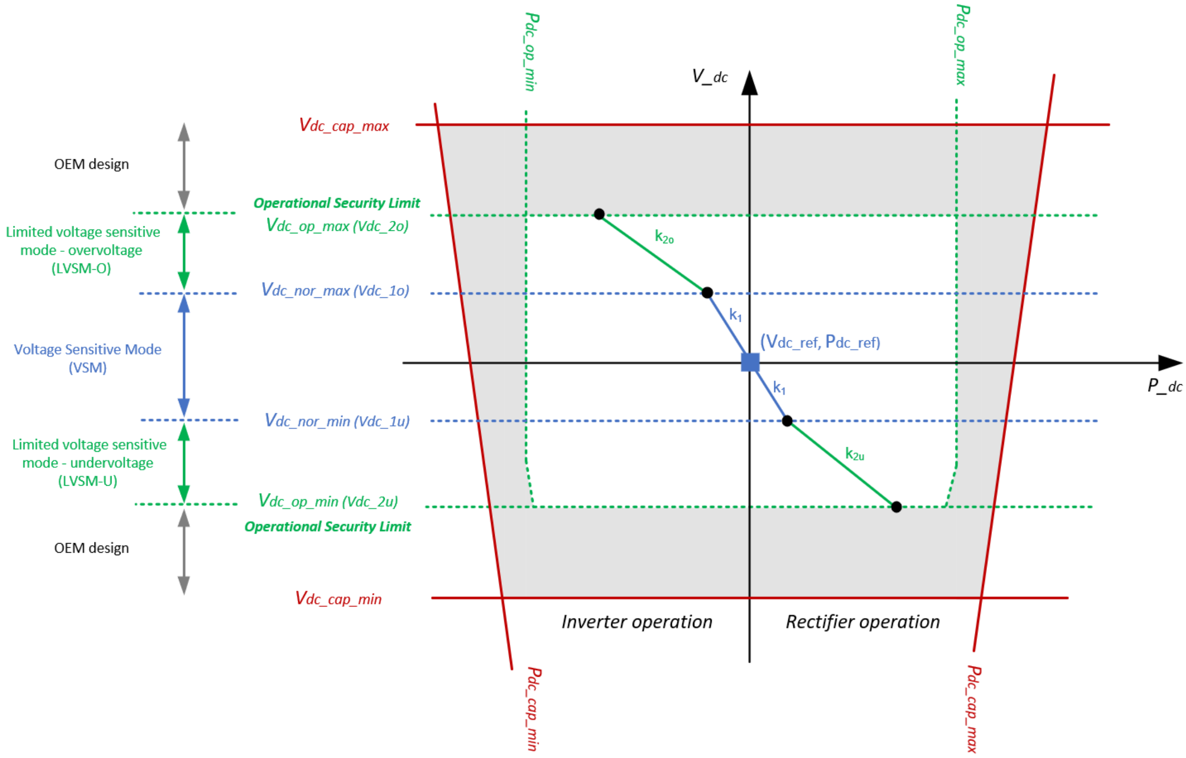


Figure 2-9: Illustration of DC voltage droop control mode

Table 2-10: Parameters for DC voltage droop control mode for AC/DC converter unit (onshore)

Parameter	InterOPERA Demonstrator
Vdc_cap_max	Chosen by OEM
Vdc_op_max (Vdc_2o)	525 kV (1.05 pu)
Vdc_nor_max (Vdc_1o)	setpoint from converter HMI *(Task 3.6: 1.01 - 1.025 pu)*
Vdc_ref	setpoint from DC Grid Controller or HMI
Vdc_nor_min (Vdc_1u)	setpoint from converter HMI (*Task 3.6:* 0.975 - 0.985 pu)
Vdc_op_min (Vdc_2u)	475 kV (0.95 pu)
Vdc_cap_min	Chosen by OEM

Parameter	InterOPERA Demonstrator
Pdc_cap_max	Chosen by OEM
Pdc_op_max	1 GW (also refer to **Figure 2-5**)
Pdc_ref	setpoint from DC Grid Controller or HMI
Pdc_op_min	-1 GW (also refer to **Figure 2-5**)
Pdc_cap_min	Chosen by OEM

Droop k_1, k_{2o}, k_{2u}	parameters from HMI or DC Grid Controller

For the InterOPERA demonstrator, it was decided that the knee-points of the multi-segment droop characteristic shall stay on the absolute voltage limits which are fixed for the HVDC grid scenario under test. When changing setpoints and/or droop parameters in the course of a new load flow dispatch, the knee-points are therefore "sliding" along the fixed voltage limits (Vdc_nor_max/min, Vdc_op_max/min) unless they are moving beyond the Operational Security Limits (green dashed lines).

This principle is illustrated in **Figure 2-10**.

For the InterOPERA demonstrator, the behaviour in the grey zone outside the operating range limited by Operational Security Limits (green dashed lines) is not quantified.

When the OSL power limit is reached, it is assumed that the AC/DC converter unit is, at least, limiting the power to this value within the OSL voltage limits. Internal power reserves shall be utilized, if possible.

When the OSL voltage limit is reached, it is assumed that the AC/DC converter unit keeps supporting the voltage containment as much as possible making use of internal voltage and power reserves. It can either stay on the LVSM droop or change to another droop segment corresponding with the DC Voltage Limiting Mode (DCVLM) described in D2.1 [01].

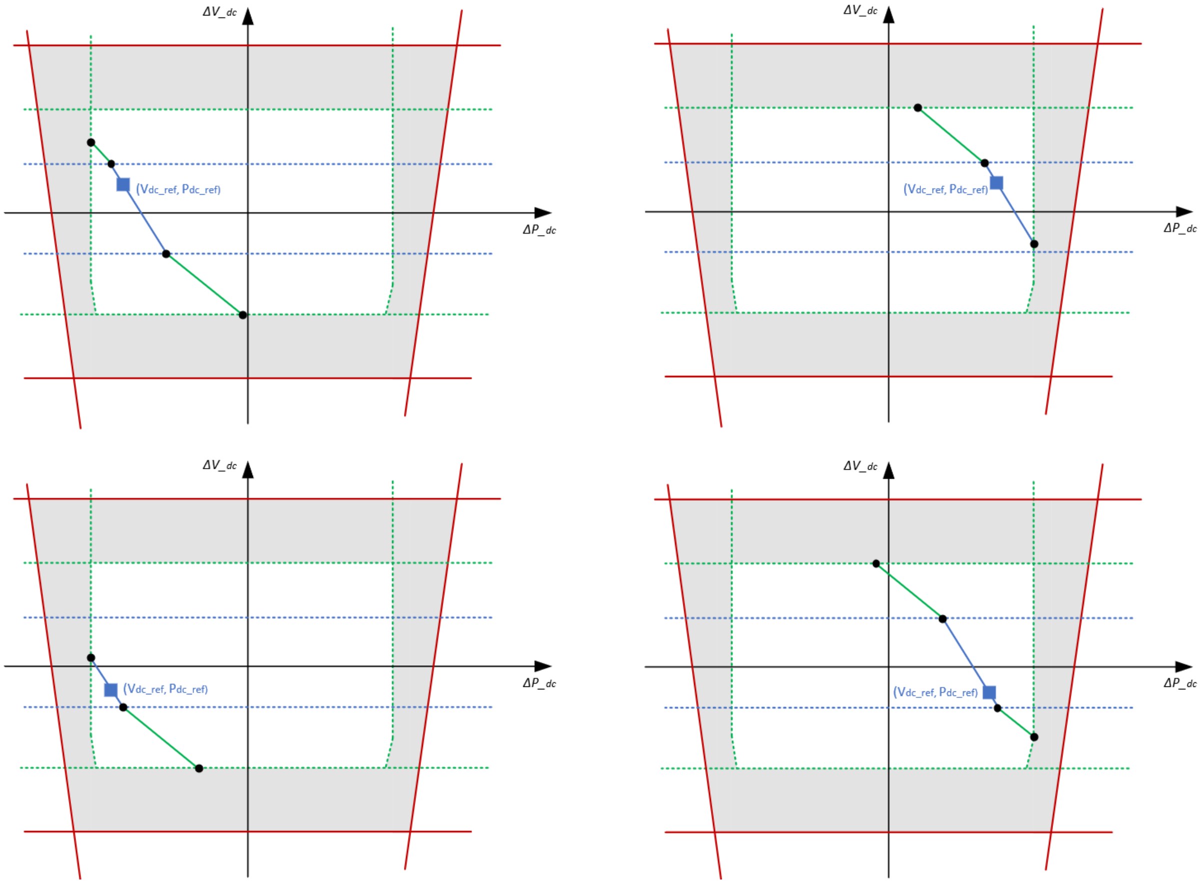


Figure 2-10: Illustration of knee-points fixed to absolute voltage limits for different operating points

Based on generic models, control dynamics have been evaluated in D3.8 [04] following the stand-alone tests as described in D2.1 [01] under the assumption of GFL control mode. Thereby the indicative values are only relevant for the current implementation of GFL. The maximum values are provided in **Table 2-11** as reference. It is expected that the dynamic response of vendor models applied in the same equivalent test network is at least as good as the generic implementation. Based on the behaviour observed in the demonstrator system incl. all vendor models, optimization and potential standardization of performance requirements shall be discussed.

Table 2-11: Dynamic requirements for DC voltage droop control for AC/DC converter unit (onshore)

DC voltage reference step – DC voltage response

Parameter	Maximum in 3T based equivalent
Settling time Ts [ms]	187.2
Step response time Tsr [ms]	174.5
Rise time Tr [ms]	84.4
Overshoot Vm [kV]	1.48

DC voltage reference step – DC power response

Parameter	Maximum in 3T based equivalent
Settling time Ts [ms]	156.5
Dead/reaction time Tt [ms]	4.0
Overshoot Vm [MW]	82.0

DC power reference step – DC voltage response

Parameter	Maximum in 3T based equivalent
Settling time Ts [ms]	144.0
Step response time Tsr [ms]	39.3
Overshoot Vm [kV]	0.3

DC power reference step – DC power response

Parameter	Maximum in 3T based equivalent
Settling time Ts [ms]	181.3
Step response time Tsr [ms]	181.3
Rise time Tr [ms]	137.8
Dead/reaction time Tt [ms]	25.8
Overshoot Vm [MW]	0.091

DC voltage disturbance – DC voltage response

Parameter	Maximum in 3T based equivalent
Settling time Ts [ms]	90.7
Step response time Tsr [ms]	36.9
Rise time Tr [ms]	31.3
Overshoot Vm [kV]	0.68

DC voltage disturbance – DC power response

Parameter	Maximum in 3T based equivalent
Settling time Ts [ms]	158.9
Step response time Tsr [ms]	158.9
Rise time Tr [ms]	35.7
Dead/reaction time Tt [ms]	4.8
Overshoot Vm [MW]	0.117

DC power disturbance – DC voltage response

Parameter	Maximum in 3T based equivalent
Settling time Ts [ms]	221.6
Step response time Tsr [ms]	54.3
Rise time Tr [ms]	49.6
Overshoot Vm [kV]	0.96

DC power disturbance – DC power response

Parameter	Maximum in 3T based equivalent
Settling time Ts [ms]	61.6
Step response time Tsr [ms]	61.6
Rise time Tr [ms]	56.1
Dead/reaction time Tt [ms]	13.7
Overshoot Vm [MW]	3.27

2.3.5. DC fault handling

The application of DC faults and the consequential fault handling (e.g., UC 03-01, UC03-021) is a mandatory requirement for the final model delivery and the demonstrator studies[3]. As outlined in the Overall Demonstrator Definition, it was agreed within interOPERA to apply the DC FRT undervoltage profile from D2.1 [01] and the corresponding stand-alone tests to evaluate its applicability in the demonstrator setup.

The test setup for DC FRT compliance testing of an AC/DC converter unit is shown in **Figure 2-11**. Following the zoning concept for fault separation described in the Overall Demonstrator Definition, the parameters for DC FRT compliance testing depend on the location of the AC/DC converter station in the 3T base case DC side topology and in the 5T full scope DC side topology – i.e., on the association of the AC/DC converter station with sub-grid A or sub-grid B as defined in section 5.2.2 of the Overall Demonstrator Definition.

The AC/DC converter unit is allowed to block for DC voltage profiles outside the dynamic voltage ranges defined in section 3.3.2. However, as defined for the "connection requirement" (CR) in Figure 5-2 of the Overall Demonstrator Definition, it is not allowed to trip – i.e., to enter into a state where blocking is irreversible and/or the ACCB is used to disconnect the AC/DC converter unit from the AC-side PoC. The standalone test in **Figure 2-11** recreates the worst-case overcurrents experienced for any voltage within the CR voltage profile via an averaging principle (i.e., the instantaneous voltage sag may exceed $V_{min,avg}$). The standalone test is passed when no internal converter limit is reached (i.e., the converter does not trip) as a response to the specified $V_{DC,test}$ voltage profile being applied at its DC-PoC.

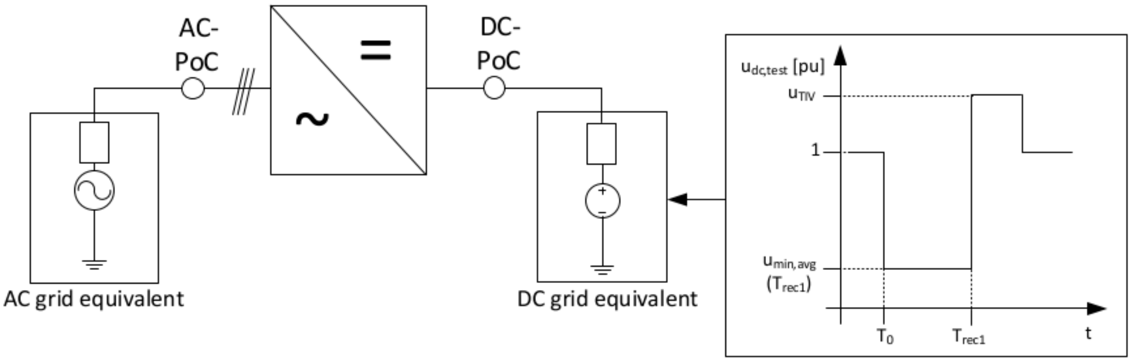


Figure 2-11: Minimum test circuit for AC/DC converter unit FRT compliance testing at DC-PoC (P1)

Table 2-12: Parameters for FRT compliance testing at DC-PoC (P1)

Parameter	AC/DC Converter Station Location #1 / #2	AC/DC Converter Station Location #3
Trec1	8 ms	2.5 ms
Vmin_avg	-100 kV (-0.2 pu)	-300 kV (-0.6 pu)
V_TIV	1 p.u.	1 p.u.

[3] In case temporary blocking is used for DC fault handling, the de-blocking requirement are only mandatory for the offline simulations, but optional for the online/HIL simulations.

In contrast to D2.1 [01], **all voltages for DC FRT are provided as HV pole-to-neutral voltages at DC-PoC.** It shall be assumed that the equivalent average voltages Vmin_avg in the DC FRT compliance tests are applied between the AC/DC converter unit terminals (P1, R1).

DC grid equivalent:

The DC grid equivalent consists of a controlled voltage source following the defined trajectory. The DC grid inductance – that would contribute to di/dt limiting – is equal to zero. As described in D2.1, the converter DC-FRT only applies for DC faults outside of the converter's own fault separation zone. Consequently, for every fault that is relevant for converter DC-FRT, there is a fault separation device in between the respective converter and the fault location. Depending on the fault current limitation device of the DCSU vendor there may be an inductance inside the DCSU that represents the DC grid impedance. In general, a minimum inductance could be specified by the system operator; for the InterOPERA demonstrator the minimum inductance is zero.

AC grid equivalent:

On the onshore AC side, the system strength and short-circuit ratio shall be represented by an AC Thevenin source. For the grid strength, maximum conditions (cf. Annex 3.3.5) shall be considered.

Setpoint and control modes:

The test is to be passed for rectification at full rated power (P_{ref} = 1000 MW) and maximum/minimum reactive power.

Requirements for de-blocking in case the CR is fulfilled using temporary blocking

In case an AC/DC converter unit fulfills the CR via temporary blocking, there is a requirement for temporarily blocked converters to become operational again within defined boundary conditions. In particular after DC voltage recovery above U_UV4-2 – cf. Table 5-6 in section 5.2.2 of the "Overall Demonstrator Definition" – it shall be possible for the AC/DC converter unit to deblock within the time period until T_st and resume operation after successful DC fault handling. For completeness, the key values for the transient DC undervoltage requirements – defining an envelope of all possible undervoltage shapes, not an average – are repeated below in **Figure 2-12** and **Table 2-13**.

The onshore AC/DC Converter Station shall be capable of smoothly resynchronizing with the Onshore AC Grid when de-blocking.

The definition of de-blocking is taking into account that the realization of blocking and de-blocking is part of the converter internal, vendor-specific control and protection system, and is likely to be based on the internal arm current measurements.

Disclaimer: The DC voltage recovery and the de-blocking behaviour are not explicitly covered by the minimum standalone test circuit for AC/DC converter unit FRT compliance testing.

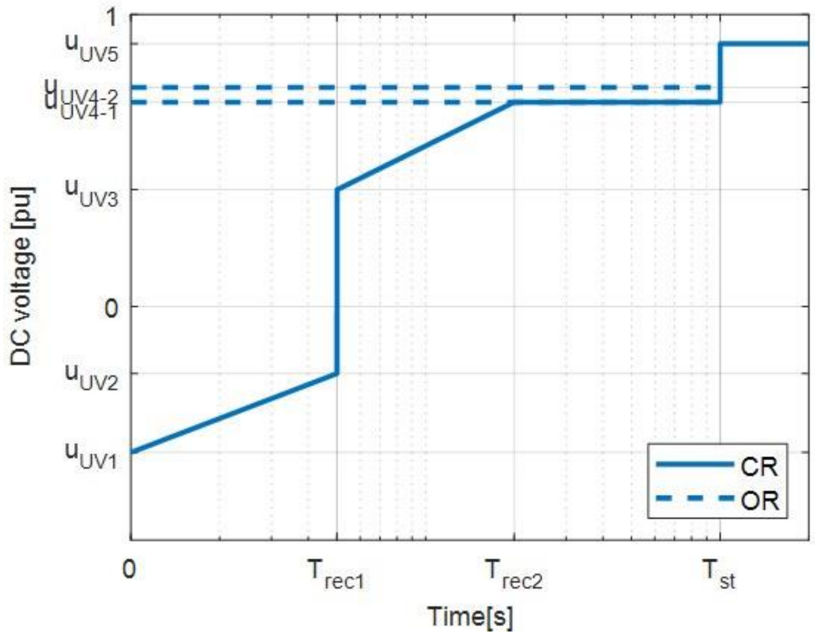


Figure 2-12: General DC undervoltage FRT profile to define OR and CR for DC-PoC P1 (from D2.1 [01])

Table 2-13: InterOPERA demonstrator parameters for DC undervoltage FRT profile at DC-PoC P1

Parameter	Subgrid A	Subgrid B	Comment
T_rec1	T_rec1a = 2.5 ms	T_rec1b = 8 ms	$T_{N,\ max}$ as per subgrid definition; no additional buffer
T_rec2	30 ms		Value based on D3.8 [04]
T_st	150 ms		Value based on D3.8 [04]
U_UV1	-500 kV (- 1 pu)		Assume full voltage reversal as worst case for primary design.
U_UV2	U_UV2a = -350 kV (-0.7 pu)	U_UV2b = -100 kV (-0.2 pu)	Values corresponding to Trec1 (refer to D2.1 [01])
U_UV3	125 kV (0.25 pu)		Based on voltage ranges observed in results of D3.8 [04] Note: The definition of U_UV3 indirectly defines a minimum inductance in between sub-grids A and B.
U_UV4-1	350 kV (0.7 p.u.)		Minimum voltage for OR. Based on voltage ranges observed in D3.8 [04]
U_UV4-2	350 kV (0.7 p.u.)		Lower boundary for de-blocking requirement. Based on voltage ranges observed in D3.8 [04]
U_UV5	475 kV (0.95 p.u.)		Vdc_op_min (Vdc_2U)

Note: As shown in **Figure 2-12**, parameters labelled with a "T" refer to total times after the fault event.

2.3.6. Dynamic Braking System (DBS)

Each converter unit in an onshore AC/DC converter station shall be equipped with a Dynamic Braking System (DBS) between its DC-PoC terminals. This requirement is mandatory for the offline simulation and optional for the online simulation. Please refer to D3.1 [02] for an overview on which vendor DBS delivery is foreseen in which simulation environment of the demonstrator.

Different DBS concepts and control designs are described in D3.2 [03]. The DBS controller shall continuously monitor the DC voltage, and in the event where predefined thresholds are exceeded, it shall dissipate power in the braking resistor. A rise in the DC voltage above a set maximum DC voltage point shall result in DBS operation to constrain the voltage to the maximum value. The DBS should contribute to maintaining stable DC voltage levels within the desired operating range during dynamic braking events.

For the InterOPERA demonstrator, each DBS unit shall be designed to absorb nominal power (1 GW) for up to 2 seconds. It was decided to operate the DBS with a simple hysteresis-based trigger mechanism as illustrated in **Figure 2-13**. The DBS unit shall be activated based on local voltage measurement between the AC/DC converter unit DC-PoC terminals when the DC voltage rises above a pre-defined threshold chosen by the DBS vendor (Vdc_DBS_act). When the DC voltage falls below the lower threshold (Vdc_DBS_deact) or when the DBS maximum energy rating is reached, the DBS unit shall be deactivated. It is not specified which control principle (e.g., activation with full power, active control of DC voltage, or other options) is to be applied in the activated state of the DBS.

Each DBS unit shall communicate its current status (activated / deactivated) to the DC Grid Controller via the AC/DC Converter Station level.

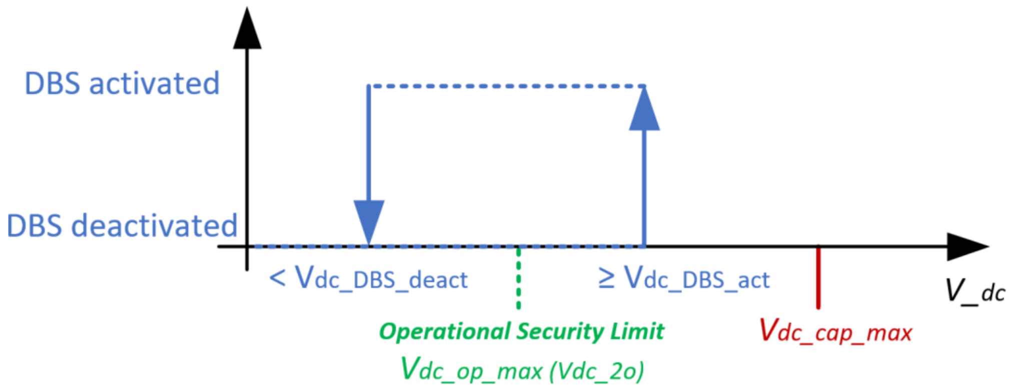


Figure 2-13: Illustration of DBS trigger mechanism

Table 2-14: Parameters for DBS operation for AC/DC converter unit (onshore)

Parameter	InterOPERA Demonstrator
Vdc_cap_max	Chosen by OEM
Vdc_op_max (Vdc_20)	525 kV (1.05 pu)
Vdc_DBS_act	fixed parameter chosen by DBS vendor
Vdc_DBS_deact	fixed parameter chosen by DBS vendor

With regard to the dynamic overvoltage requirements on the onshore AC/DC converter stations (cf. section 2.3.2), the specified range can be fulfilled with or without the use of the DBS. It is to be noted that – depending on the chopper thresholds chosen by the OEMs – the resulting dynamic overvoltages at both the onshore and the offshore AC/DC converter stations (cf. **Table 2-6** and **Table 3-6**) may be reduced as well. As a worst case, the values observed without any DBS operation are given.

Disclaimer: Depending on the chosen threshold values and control principles by each OEM, there may be a need for additional DBS coordination (e.g., adapting thresholds following concepts defined in D3.2 and tested in D3.8) to be performed during the (offline) demonstrator studies. This coordination may not only affect all DBS of the DC system, but also the DC Grid Controller (DCGC) and the implementation of the Overvoltage Power Control (OVPC) scheme. A signal exchange between DBS and DCGC – including a signal from DCGC to DBS, which is listed as optional in the InterOPERA signal list of the DCGC – may be required.

2.4. Primary Design requirements

2.4.1. Converter Transformer

In the onshore AC/DC converter units, converter transformers can be equipped with tap changers to achieve the required continuous operating range for active and reactive power.

2.4.2. AC/DC Converter Unit

Converter type

The converter systems of the onshore AC/DC converter units applied in the InterOPERA demonstrator shall be of half-bridge type.

Insulation Coordination

For the insulation coordination towards the DC grid, i.e. at PoC-DC, the following levels shall be used. In addition to the standard impulse levels, specific requirements (e.g. DC cable TOV limits from the Overall Demonstrator definition) shall also be considered.

Table 2-15: Parameters for DC grid insulation coordination

Parameter	High-voltage DC system (P1 / P2)	Neutral DC system (R)
SIWL	1050 kV	
Safety factor	1.15	
LIWL	1050 kV	250 kV
Safety factor	1.20	1.20

3. AC/DC Converter Station (offshore)

3.1. Configuration

3.1.1. Topology

The offshore AC/DC converter station shall follow the functional topology of a bipolar system and the PoC reference designation as shown in **Figure 3-1** (refer to Overall Demonstrator definition for numbering).

The AC switching units associated with the PoC-AC ($P_{n.n}$) shall be delivered as part of the AC/DC converter station and shall be operated by the corresponding converter unit. Please note that the PoC-AC definition and the AC switching unit aggregate all three AC phases into one functional unit. Requirements for the AC switching unit are included in the following sections.

Each DC terminal of a converter unit is associated with a separate PoC-DC (P_n and R_n) to allow individual connection and disconnection of poles by the external DC switching units in the DC switching stations.

As the offshore AC/DC converter station is not supposed to provide STATCOM operation, grounding units at the low voltage terminals of the converter units are not required. The offshore AC/DC converter stations are assumed to be always connected to the DC neutral system during operation.

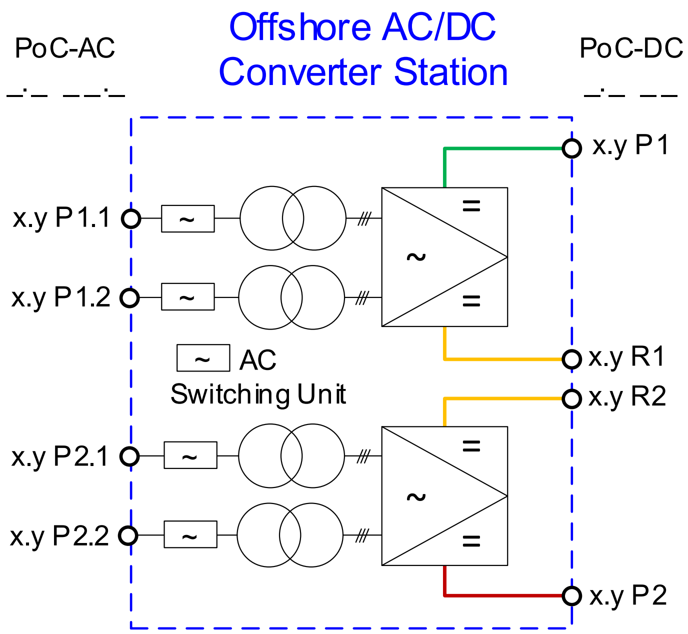


Figure 3-1: Demonstrator reference designation of PoC-AC and PoC-DC of AC/DC converter station

3.1.2. Sequential controls

Following D2.1 [01] and D3.2 [03], each converter unit shall be designed to provide the unit states listed in **Table 3-1** and exchange information about its current unit state with the DC Grid Controller (refer to Annex 3.3.2). The corresponding state diagram is shown in **Figure 3-2** and further detailed in this section.

Please note that states can differ between the DC phases (P_n, R_n). Example: The neutral system (R_n) can be pre-configured to "DC aggregated" while the high-voltage terminal (P_n) is in state "Ready to connect".

Table 3-1: Converter Unit state definition (offshore AC/DC converter station)

Converter Unit State	PoC – AC ($P_{n,m}$) switching unit	AC Voltage @ PoC - AC	PoC – DC (P_n, R_n) switching unit	DC Voltage @ PoC - DC
Maintenance earthed	Open	Don't care	Open	Don't care
Ready to connect	Open	Don't care	Open	Don't care
DC aggregated	Open	Don't care	Closed	No
Energized from DC	Open	Don't care	Closed	Yes
Ready to transmit	Closed	Yes	Closed	Yes

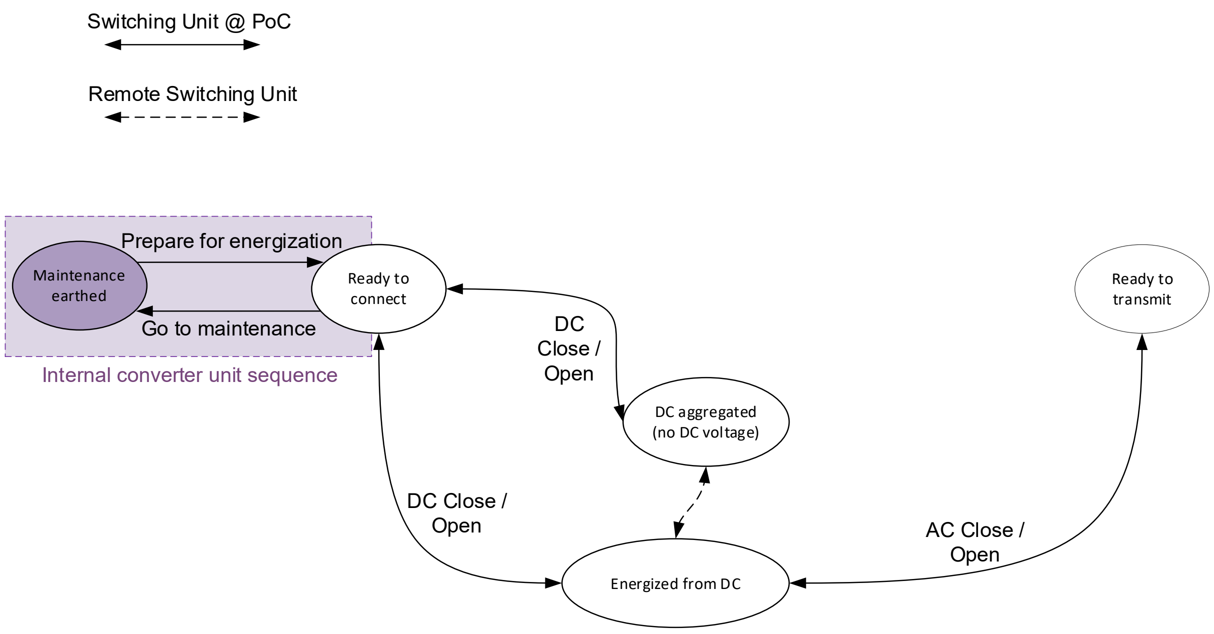


Figure 3-2: State diagram of a Converter Unit (offshore AC/DC converter station; adapted from [01])

Internal converter unit sequences include all procedures within the unit which do not change the status of the neighbouring units. In the InterOPERA demonstrator, this does only comprise the transition between the internal unit state “Maintenance earthed” and the externally relevant unit state “Ready to connect”. Internal unit states (“Maintenance earthed”) and internal converter unit sequences are subject to the individual vendor’s solution and will not be further detailed or specified in this document.

All other transitions between converter unit states shall be induced by the **actions of switching units** which can either be located at the converter unit’s points of connection (AC or DC) or at another remote point in the AC or DC system. For the InterOPERA demonstrator, the AC switching unit associated with a PoC-AC ($P_{n,m}$) shall be operated by the corresponding converter unit. The DC switching units associated with a PoC-DC (P_n, R_n) shall be independent functional units not operated by the converter unit. The converter unit shall be informed about the state of the DC switching units. In order to prepare the converter unit for an upcoming disconnection, a command “Prepare to shutdown” is sent in advance by the DC Grid Controller and shall be responded by a status signal “Ready-to-shutdown”.

For the InterOPERA demonstrator, energization of offshore AC/DC converter units shall always be performed from the DC side. There shall also be no off-voltage aggregation on the AC side prior to the DC energization. After successful DC energization and deblocking of the converter unit, i.e. state “Energized from DC” has been reached, AC voltage is established at the AC switching units which are still open. The next steps for the energization of the AC Offshore Testbench or parts thereof can then be performed according to the chosen scenario and use case (refer to UC04-01 “soft start” and UC04-03 “hard start”). When closing one of its AC switching units, the converter unit state changes to “Ready to transmit”.

As a summary, the AC/DC converter station shall be able to receive the following commands from the DC grid controller and forward them in a coordinated manner to the individual converter units (**Table 2-2**).

Table 3-2: Sequential control commands from DC grid controller to offshore AC/DC converter station

Sequential control command (referring to converter unit level)	Short description
Go to maintenance	The converter unit shall go to state “Maintenance earthed”. This state is subject to individual vendor’s solutions.
Prepare for energization	The converter unit shall go from state “Maintenance earthed” to state “Ready to connect” allowing energization from DC.
Prepare for shut-down	The converter unit shall prepare internally for disconnection from the DC side and report the feedback “Ready to shut down”.
Close AC switching unit	The converter unit shall close its associated AC switching unit.
Open AC switching unit	The converter unit shall open its associated AC switching unit.

3.1.3. Sign Convention

The sign convention used for the offshore AC/DC converter station is following the Overall Demonstrator Definition (refer to Figure 3-3).

- DC side: Generator sign convention for active power and DC currents
- AC side: Load sign convention for active and reactive* power

*This implies that: inductive reactive power (lagging current) is counted as positive (+)
capacitive reactive power (leading current) is counted as negative (-)

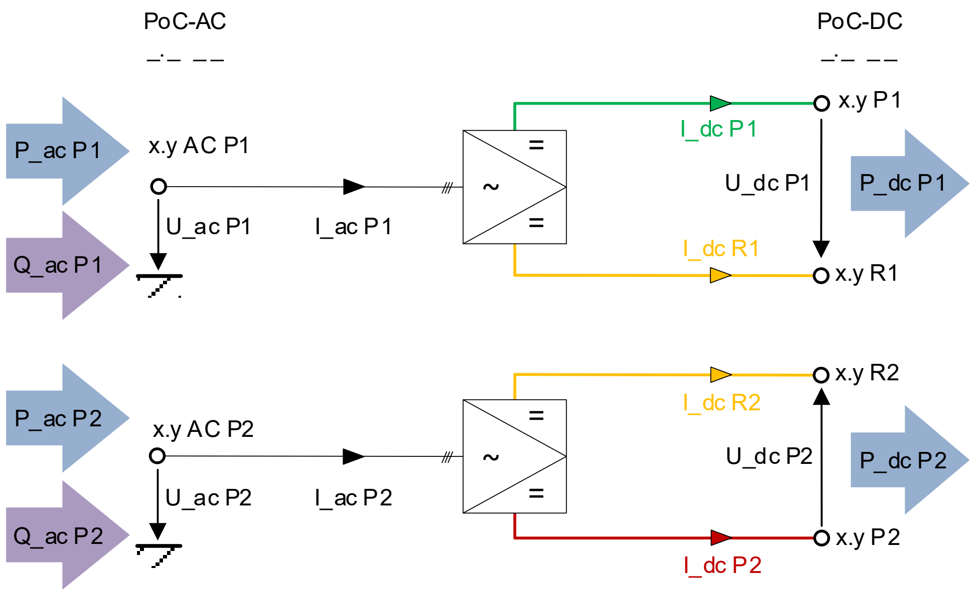


Figure 3-3: Demonstrator sign convention for offshore AC/DC converter station

3.2. Requirements at Point of Connection – AC

3.2.1. AC offshore system data

Please refer to Annex 3.3.6 for all information about the AC Offshore Testbench to which the AC/DC converter station shall be connected.

3.2.2. AC power rating

Active Power Requirements

The active power rating of an AC/DC converter unit is defined at the DC Point of Connection (PoC-DC) as detailed in section 3.3.3. The corresponding active power at the AC Point of Connection (PoC-AC) shall be available across the whole AC voltage range defined in Annex 3.3.6, i.e. there shall be no persistent limitation of active power due to steady-state AC voltage variations within the given voltage range.

Reactive Power Requirements

Please refer to Annex 3.3.6 for Reactive Power Requirements in the AC Offshore Testbench to which the AC/DC converter station shall be connected.

3.2.3. AC switching unit

Each offshore AC/DC converter unit shall comprise and control two AC switching units, one per converter transformer, connecting the converter unit and its transformers to the associated PoC-AC. Each AC switching unit shall at least provide the following features:

- Making capability when connecting to PoC-AC
  (no energization required from offshore AC/DC converter units)
- Breaking capability for residual currents and load currents when disconnecting from PoC-AC
- Fault separation and isolation for AC side faults and DC side faults

The AC switching unit, respectively the AC/DC converter unit, shall be able to receive open / close commands from the DC Grid Controller via the AC/DC converter station level and report its current status (open / closed) via the same communication path. Please also refer to section 3.1.2 "Sequential controls".

Fault separation and isolation in the AC switching unit shall be initiated based on local information and trip signals from the AC/DC converter unit.

3.2.4. AC node control modes

Following the overall demonstrator definition, the following AC node control modes shall be realized by the offshore AC/DC converter station on unit level. Change of control modes can be requested by the DC Grid Controller. The AC/DC converter unit shall communicate its current AC node control mode to the DC Grid Controller. If the AC/DC converter unit is not in one of the control modes listed below, e.g. "idle / standby / default" after AC energization, this shall also be communicated to the DC Grid Controller.

Table 3-3: AC node control concept assignment

AC node control concepts	Offshore AC/DC converter unit
V/f	X
Grid Forming (GFM)	*optional (with V/f behaviour)*

The requirements on the functions (refer to **Table 3-4**) shall be in line with the chosen reference AC grid code unless otherwise specified in the subsystem specifications (Annex 3.3.6).

Table 3-4: AC node control function assignment

AC node control function	V/f Offshore
AC Voltage Control	X
Frequency Control	X
AC fault ride through	X

3.2.5. AC fault handling

For the InterOPERA demonstrator, there are no specific requirements to the AC fault handling that are going beyond the reference AC grid code (refer to Annex 3.3.6 "PPM & AC Offshore Testbench").

3.3. Requirements at Point of Connection – DC

3.3.1. DC network data

Please refer to the main document "Overall Demonstrator Definition" for information about the DC side topologies and related electrical data (e.g. DC Cable Data in Annex 02).

3.3.2. DC voltage ranges

The offshore AC/DC converter stations shall be able to be continuously operated for every pole-to-neutral DC voltage at the DC-PoC that lies within the operational security limits (OSL) defined for the demonstrator, cf. also Section 5.1.1 of the "Overall Demonstrator Definition". The relevant continuous pole-to-neutral voltage ranges are repeated in **Table 3-5**.

Continuous

Table 3-5: Operational Security Limits for the InterOPERA demonstrator

	Nominal	Upper Operational Security Limit	Lower Operational Security Limit
DC Voltage (HV+ pole to neutral)	500 kV 1 pu	525 kV 1.05 pu	475 kV 0.95 pu
DC Voltage (HV- pole to neutral)	- 500 kV - 1 pu	- 475 kV - 0.95 pu	- 525 kV - 1.05 pu

Temporary (Dynamic)

Following disturbances and/or contingencies, the DC-PoCs of the AC/DC converter units will be exposed to different temporary DC voltage excursions. **Table 3-6** and **Figure 3-4** quantify an envelope of voltages for which an AC/DC converter unit shall remain operational (i.e., not blocked). The values are based on dynamic and transient studies[4] conducted in Task 3.6 ([04]), and are given as pole-to-neutral voltages in p.u.. During – or at least after – any voltage excursions within the dynamic range, the AC/DC converter shall be able to control its active power contributing to the primary control. In addition, an AC/DC converter unit is required to withstand dynamics and stresses imposed by their own blocking or de-blocking which is not considered in the envelope depicted below.

Table 3-6: DC voltage dynamic ranges envelope at PoC-DC for offshore AC/DC converter unit

Time (ms)	10	20	30	40	50	60	70	80	90	100
Offshore	1.45	1.32	1.29	1.28	1.27	1.25	1.24	1.24	1.23	1.23
	0.70 (0.25)	0.71 (0.47)	0.72 (0.56)	0.72 (0.6)	0.73 (0.65)	0.76	0.79	0.84	0.90	0.94

Time (ms)	110	120	130	140	150	160	170	180	190	200	210	220	230
Offshore	1.23	1.22	1.20	1.17	1.16	1.14	1.12	1.11	1.10	1.09	1.08	1.07	1.05
	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.95	0.95	0.95	0.95	0.95	0.95

[4] DC-side short circuit fault simulations which also lead to DC voltage excursions in the dynamic time range.

Note: The shown values represent an envelope, not an individual physically measured voltage trajectory. Depending on the converter design, values at the lower end of the envelope may lead to short periods of overmodulation – but must not lead to protective blocking of the converter.

For overvoltages, the values provided for a short time frame (time frame marked blue in **Figure 3-4**) are not to be interpreted as absolute maximum values. Short-term overvoltages – in particular to ground – are covered in section 2.4.2 under "insulation coordination".

For undervoltages, the transient values provided for a short time frame (values indicated in brackets or as a dashed line in **Figure 3-4** and **Table 3-6**) do <u>not</u> constitute a binding specification for the dynamic time frame . They are to be interpreted as values that were observed for operational converters in the transient and dynamic studies[5]. For such voltages outside the dynamic range (below the solid orange trajectory), the required behaviour of the AC/DC converter units is described in the DC-FRT functional specification / standalone test in section 3.3.5, as well as in section 5.1.2 of the "Overall Demonstrator Definition".

Disclaimer: The dynamic voltage ranges are observed based on generic models in GFL control mode. While in general, it is expected that vendor-specific controls will outperform the generic converter controls and hence lead to narrower voltage bands, there is a possibility of greater subsystem-level stresses (and hence wider ranges) under GFM operation compared to GFL.

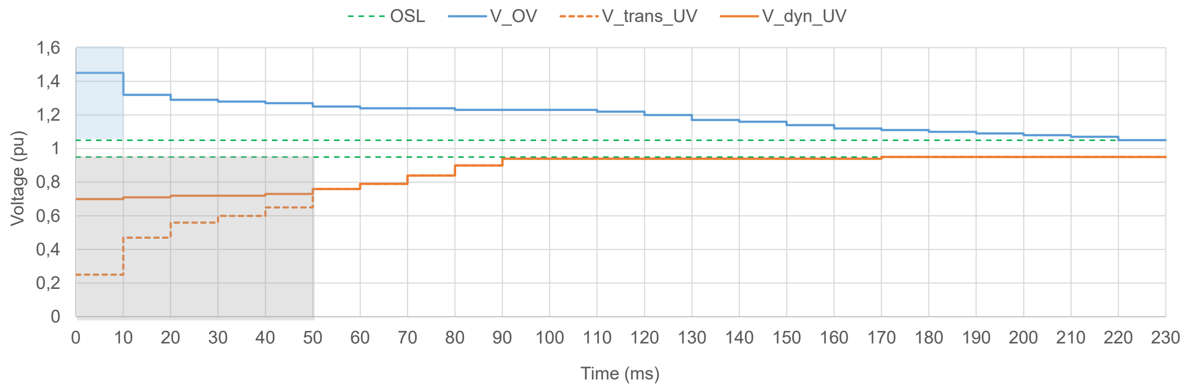


Figure 3-4: Observed DC voltage dynamic ranges at PoC-DC for offshore AC/DC converter unit

[5] The transient undervoltages from D3.8 ([04]) have been taken into account until a duration of 50ms, as converter de-blocking (not modelled in D3.8) is expected to transfer the voltage back into the dynamic range.

3.3.3. DC power ratings

Active Power Requirements

The maximum active power provided by an AC/DC converter unit for continuous operation shall be 1 GW defined at the DC Point of Connection (PoC-DC) for rectifier operation (= sending end).

For an offshore AC/DC converter unit, the minimum active power in inverter operation (= receiving end) shall be (-)0.1 GW defined at the DC Point of Connection (PoC-DC).

The maximum DC current for continuous operation shall be 2030 A for continuous operation for rectifier mode. The resulting continuous operating range is shown in **Figure 3-5**.

The AC/DC converter unit continuous capabilities shall not limit the continuous operating range depicted in **Figure 3-5** at any point considering e.g. measuring accuracies, ripples or internal design constraints.

Table 3-7: Continuous values for active power and DC current for AC/DC converter unit (offshore)

	Nominal	Continuous operating values
Active Power (at HV pole DC PoC)	1 GW 1 pu	+ 1 GW / -0.1 GW +1 pu / -0.1 pu
DC Current (HV poles and DMR)	2000A 1 pu	+/- 2030 A +/- 1.015 pu

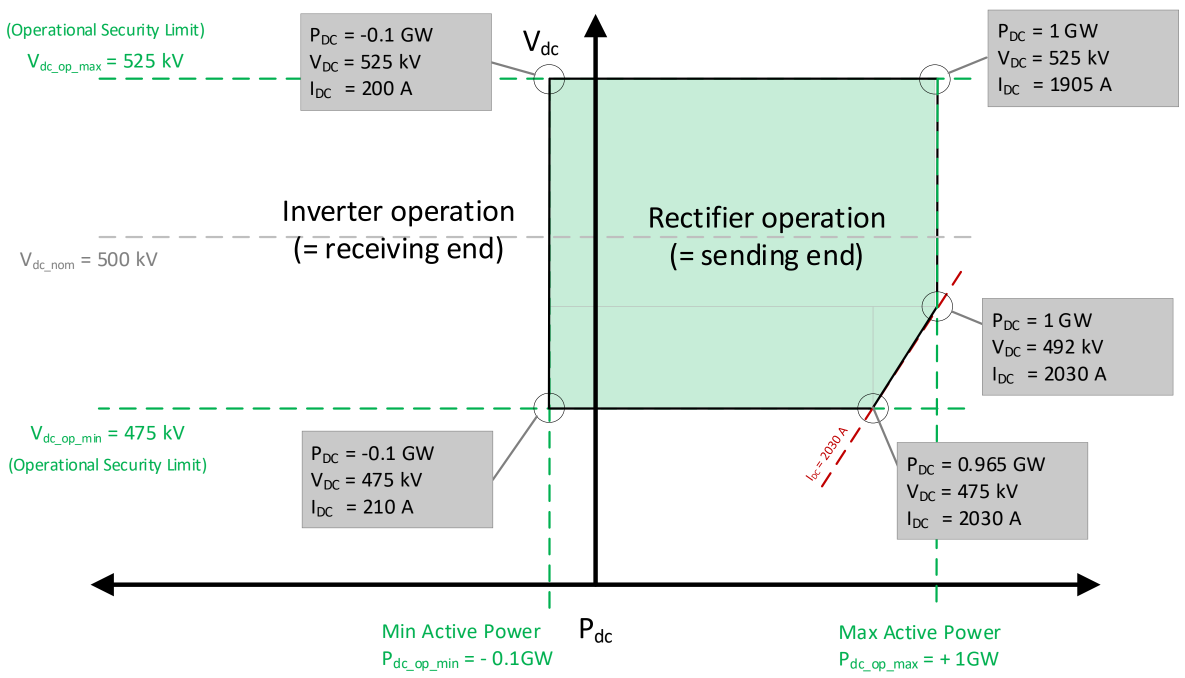


Figure 3-5: Continuous operating range for AC/DC converter unit (offshore)

3.3.4. DC node voltage control

Following the overall demonstrator definition, the offshore AC/DC converter station shall not participate in the DC node voltage control of the HVDC grid. Instead, it shall ensure frequency stability in the AC offshore system in V/f mode by regulating its active power exchange with the HVDC grid. This is further described as fixed active power control associated to V/f mode.

Fixed active power control mode (associated with V/f mode)

When operating in fixed active power control mode, the AC/DC converter station or unit shall be capable of regulating its active power exchange with the HVDC grid to the value required for local AC offshore frequency stability within the Operational Security Limits.

The DC Grid Controller is still issuing setpoints, interpreted only as target values, to the AC/DC converter station which shall be forwarded to the associated AC/DC converter unit. These target values are then adapted by the local offshore AC power duties following the volatile offshore wind power generation. The implementation of the connection between V/f mode and the DC node voltage control is deemed a vendor specific solution which is not further specified here. The actual values of Vdc and Pdc shall be communicated to the DC Grid Controller. In case of significant and persistent deviations from the target values (= forecast), the DC Grid Controller might update the setpoints in the next load flow dispatch cycle.

The general principle of fixed active power control mode is illustrated in **Figure 3-6**. Parameters for the InterOPERA demonstrator are listed in **Table 3-8**. Within the demonstrator's Operational Security Limits, the AC/DC converter unit is supposed to adapt its active power exchange to ensure frequency and voltage stability in the AC offshore system (local power tracking).

For the InterOPERA demonstrator, the behaviour in the grey zone outside the operating range limited by Operational Security Limits (green dashed lines) is not quantified. It is assumed that the AC/DC converter unit stays in the fixed active power control mode until an internal limitation is reached.

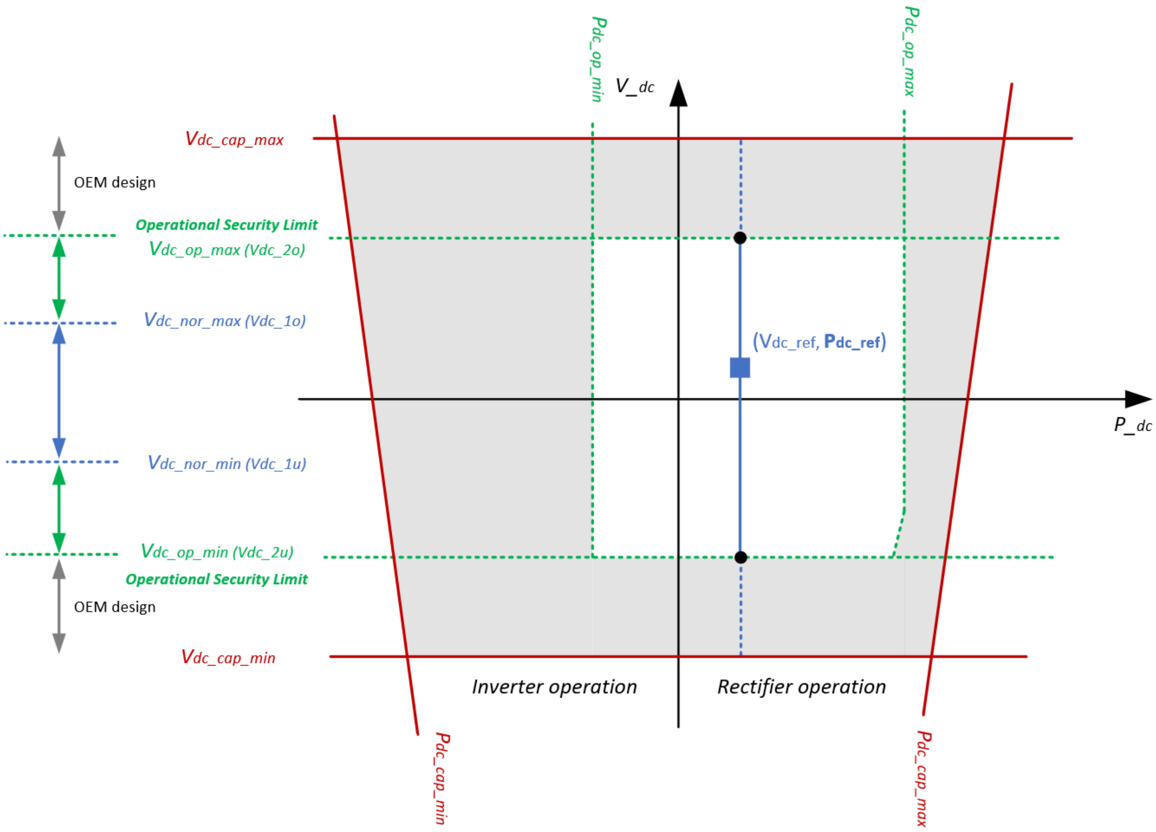


Figure 3-6: Illustration of fixed active power control mode

Table 3-8: Parameters for fixed active power control mode for AC/DC converter unit (offshore)

Parameter	InterOPERA Demonstrator
Vdc_cap_max	Chosen by OEM
Vdc_op_max (Vdc_2o)	525 kV (1.05 pu)
Vdc_nor_max (Vdc_1o)	setpoint from converter HMI *(Task 3.6: 1.01 - 1.025 pu)*
Vdc_ref (target value)	setpoint from DC Grid Controller or HMI
Vdc_nor_min (Vdc_1u)	setpoint from converter HMI (*Task 3.6:* 0.975 - 0.985 pu)
Vdc_op_min (Vdc_2u)	475 kV (0.95 pu)
Vdc_cap_min	Chosen by OEM

Parameter	InterOPERA Demonstrator
Pdc_cap_max	Chosen by OEM
Pdc_op_max	1 GW (also refer to **Figure 3-5**)
Pdc_ref (target value)	setpoint from DC Grid Controller or HMI
Pdc_op_min	-0.1 GW (also refer to **Figure 3-5**)
Pdc_cap_min	Chosen by OEM

Based on generic models, control dynamics have been evaluated in D3.8 [04] following the stand-alone tests as described in D2.1 [01]. The maximum values are provided in **Table 3-9** as reference. It is expected that the dynamic response of vendor models applied in the same equivalent test network is at least as good as the generic implementation. Based on the behaviour observed in the demonstrator system including all vendor models, optimization and potential standardization of performance requirements shall be discussed.

Table 3-9: Dynamic requirements for fixed active power control for AC/DC converter unit (offshore)

DC voltage disturbance – DC voltage response

Parameter	Maximum in 3T based equivalent
Settling time Ts [ms]	49.7
Step response time Tsr [ms]	21.9
Rise time Tr [ms]	18.8
Dead/reaction time Tt [ms]	1.7
Overshoot Vm [kV]	1.49

DC voltage disturbance – DC power response

Parameter	Maximum in 3T based equivalent
Settling time Ts [ms]	69.8
Dead/reaction time Tt [ms]	3.4
Overshoot Vm [MW]	65.9

3.3.5. DC fault handling

The application of DC faults and the consequential fault handling (e.g., UC 03-01, UC03-021) is a mandatory requirement for the final model delivery and the demonstrator studies. As outlined in the Overall Demonstrator Definition, it was agreed within interOPERA to apply the DC FRT undervoltage profile from D2.1 [01] and the corresponding stand-alone tests to evaluate its applicability in the demonstrator setup.

The test setup for DC FRT compliance testing of an AC/DC converter unit (cf. also T3.4 "Stand Alone Tests for HVDC Vendor's Models") is shown in **Figure 3-7**. Following the zoning concept for fault separation described in the Overall Demonstrator Definition, the parameters for DC FRT compliance testing depend on the location of the AC/DC converter station in the 3T base case DC side topology and in the 5T full scope DC side topology – i.e., on the association of the AC/DC converter station with sub-grid A or sub-grid B as defined in section 5.2.2 of the Overall Demonstrator Definition.

The AC/DC converter unit is allowed to block for DC voltage profiles outside the dynamic voltage ranges defined in section 3.3.2. However, as defined for the "connection requirement" (CR) in Figure 5-2 of the Overall Demonstrator Definition, it is not allowed to trip – i.e., to enter into a state where blocking is irreversible and/or the ACCB is used to disconnect the AC/DC converter unit from the AC-side PoC. This behaviour is tested with the setup shown in **Figure 3-7**.

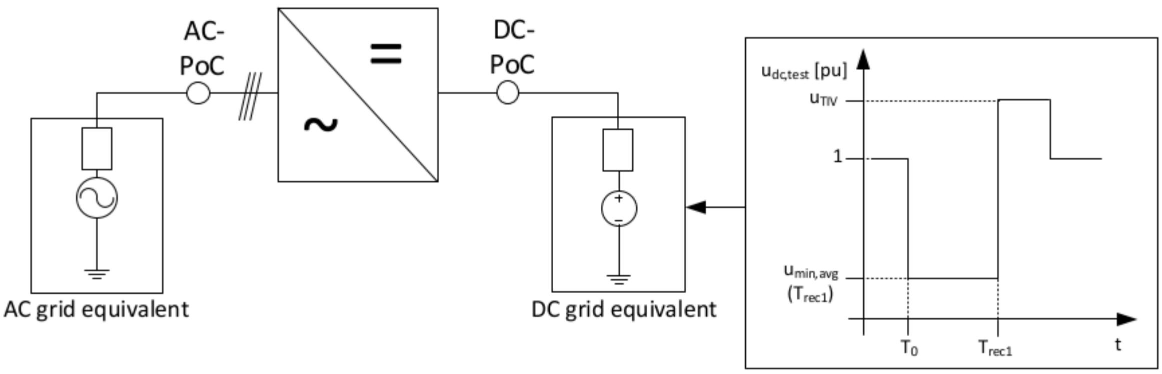


Figure 3-7: Minimum test circuit for AC/DC converter unit FRT compliance testing at DC-PoC (P1)

Table 3-10: Parameters for FRT compliance testing at DC-PoC (P1)

Parameter	AC/DC Converter Station Location #1 / #2	AC/DC Converter Station Location #3
Trec1	8 ms	2.5 ms
V_min_avg	-100 kV (-0.2 pu)	-300 kV (-0.6 pu)
V_TIV	1 p.u.	1 p.u.

In contrast to D2.1 [01], **all voltages for DC FRT are provided as HV pole-to-neutral voltages at DC-PoC.** It shall be assumed that the equivalent average voltages Vmin_avg in the DC FRT compliance tests are applied between the AC/DC converter unit terminals (P1, R1).

DC grid equivalent:

The DC grid equivalent consists of a controlled voltage source following the defined trajectory. The DC grid inductance is equal to zero. As described in D2.1, the converter DC-FRT only applies for DC faults outside of the converter's own fault separation zone. Consequently, for every fault that is relevant for converter DC-FRT, there is a fault separation device in between the respective converter and the fault location. Depending on the fault current limitation device of the DCSU vendor there may be an inductance inside the DCSU. In general, a minimum inductance could be specified by the system operator; for the InterOPERA demonstrator the minimum inductance is zero.

AC grid equivalent:

On the AC side, the system shall be represented by an applicable offshore wind farm model (cf. Annex 3.3.6) or an equivalent AC Thevenin source (conservative estimation of wind farm strength and short-circuit ratio).

Setpoint and control modes:

The test is to be passed for rectification at full rated power (P_{ref} = 1000 MW).

Requirements for de-blocking in case the CR is fulfilled using temporary blocking

In case an AC/DC converter unit fulfils the CR via temporary blocking, there is a requirement for temporarily blocked converters to become operational again within defined boundary conditions. In particular, after DC voltage recovery to values above U_UV4-2 – cf. Table 5-6 in section 5.2.2 of the Overall Demonstrator Definition – it shall be possible for the AC/DC converter unit to deblock within T_st and resume operation after successful DC fault handling. For completeness, the key values for the transient DC undervoltage requirements – defining an envelope of all possible undervoltage shapes, not an average – are repeated below in **Table 3-11**.

The offshore AC/DC Converter Station shall be capable of smoothly resynchronizing with the Offshore AC Grid when de-blocking. Section 4.2.2 of Annex 3.3.6 provides further information and examples for resynchronisation and power flow restoration.

The definition of de-blocking is taking into account that the realization of blocking and de-blocking is part of the converter internal, vendor-specific control and protection system, and is likely to be based on the internal arm current measurements.

Disclaimer: The DC voltage recovery and the de-blocking behaviour are not explicitly covered by the minimum test circuit for AC/DC converter unit FRT compliance testing.

Table 3-11: InterOPERA demonstrator parameters for DC undervoltage FRT profile at DC-PoC P1

Parameter	Subgrid A	Subgrid B	Comment
T_rec1	T_rec1a = 2.5 ms	T_rec1b = 8 ms	$T_{N, max}$ as per subgrid definition; no additional buffer
T_rec2	30 ms		Value based on D3.8 [04]
T_st	150 ms		Value based on D3.8 [04]
U_UV1	-500 kV (- 1 pu)		Assume full voltage reversal as worst case for primary design.
U_UV2	U_UV2a = -350 kV (-0.7 pu)	U_UV2b = -100 kV (-0.2 pu)	Values corresponding to Trec1 (refer to D2.1 [01])
U_UV3	125 kV (0.25 pu)		Based on voltage ranges observed in results of D3.8 [04]. Note: The definition of U_UV3 indirectly defines a minimum inductance in between sub-grids A and B.
U_UV4-1	350 kV (0.7 p.u.)		Minimum voltage for OR. Based on voltage ranges observed in D3.8 [04]
U_UV4-2	350 kV (0.7 p.u.)		Lower boundary for de-blocking requirement. Based on voltage ranges observed in D3.8 [04]
U_UV5	475 kV (0.95 p.u.)		Vdc_op_min (Vdc_2U)

3.4. Primary Design requirements

3.4.1. Converter Transformer

In the offshore AC/DC converter units, converter transformers shall not be equipped with tap changers.

3.4.2. AC/DC Converter Unit

Converter type

The converter systems of the onshore AC/DC converter units applied in the InterOPERA demonstrator shall be of half-bridge type.

Insulation Coordination

For the insulation coordination towards the DC grid, i.e. at PoC-DC, the following levels shall be used. In addition to the standard impulse levels, specific requirements (e.g. DC cable TOV limits from the Overall Demonstrator definition) shall also be considered.

Table 3-12: Parameters for DC grid insulation coordination

Parameter	High-voltage DC system (P1 / P2)	Neutral DC system (R)
SIWL	1050 kV	
Safety factor	1.15	
LIWL	1050 kV	250 kV
Safety factor	1.20	1.20

4. References

Table 4-1: List of references

Ref. No.	Title
01	InterOPERA D2.1 (PUBLIC) "Functional requirements for HVDC grid systems and subsystems"
02	InterOPERA D3.1 (PUBLIC) "Demonstrator project definition and system design studies"
03	InterOPERA D3.2 (SENSITIVE) "Subsystems pre-design phase process and outcomes"
04	InterOPERA D3.8 (SENSITIVE) "Demonstrator HVDC Grid System Design Studies"

Annex 3.3.4: DC Switching Station

WP3

Multi-vendor / Multi-terminal demonstrator project

Deliverable 3.3(b)

Detailed functional specifications

Subtask 3.3.4

DC Switching station
(Final)

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.

Co-funded by
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DISCLAIMER:

PROJECT DETAILS:

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Detailed Functional Specifications

DC SWITCHING STATIONS

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Table of Contents

VERSION CONTROL

Version	Date	Created/modified by	Comments
0.1	27.11.2024	Bence Hatsagi	Initial version
0.2	08.01.2025	Ben Rennings	Complete overhaul of the previous version
0.3	04.02.2025	Bence Hatsagi	Addition of DCCS#5 sections
0.4	06.02.2025	Bence Hatsagi	Cleaned-up version
0.5	06.02.2025	Bence Hatsagi	Minor stylistic edits
2.0	19.03.2025	Bence Hatsagi	Changes made based on reviewer comments
2.1	30.07.2025	Bence Hatsagi	Changes made based on reviewer comments
2.2	27.08.2025	Bence Hatsagi	Changes made based on stakeholder reviewer comments
2.3	08.10.2025	Bence Hatsagi	Changes to reflect the updated T3.4 document

1. Executive summary

This document is intended to serve as the description of functional requirements for DC switching stations (DCSSs) and DC switching units (DCSUs) for use in the framework of T3.3 of InterOPERA. The purpose of this description is to narrow down the more general functional specification of DCSSs and DCSUs as outlined in the D2.1 report [01]. It is also the goal of the document to make distinctions between different types of switching stations and switching units based on role in the demonstrator grid and to explicitly describe the different sets of requirements pertaining to these stations and units.

The aim is to gather functional specifications in a technology-agnostic way as to allow HVDC equipment vendors to implement their solutions; therefore, prescription of how a certain functionality shall be achieved is omitted. The implementation of functionality shall remain vendor specific.

2. General Input Clarification

The sequential control aspects of DC switching stations and the constituting DC switching units have been outlined in section 5 of the D2.1 report [01]. Section 5.3 of [01] describes a quite long list of functional requirements and a proposal of a switching unit model.

The protection control aspects of a DC switching station are detailed in subsection 7.4 of the D2.1 report [01].

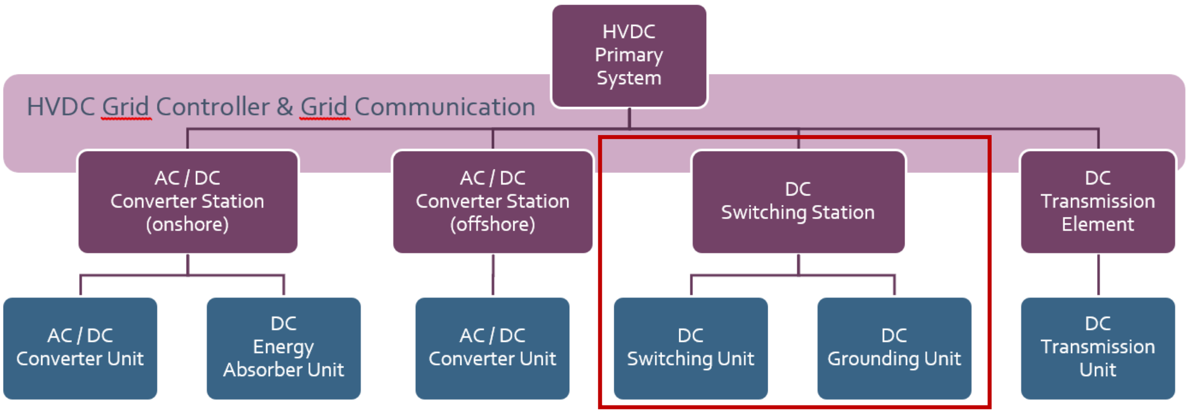


Figure 2-1: DC Switching Station and its components in the definition of HVDC subsystems for the InterOPERA demonstrator

2.1.1. Sign Convention

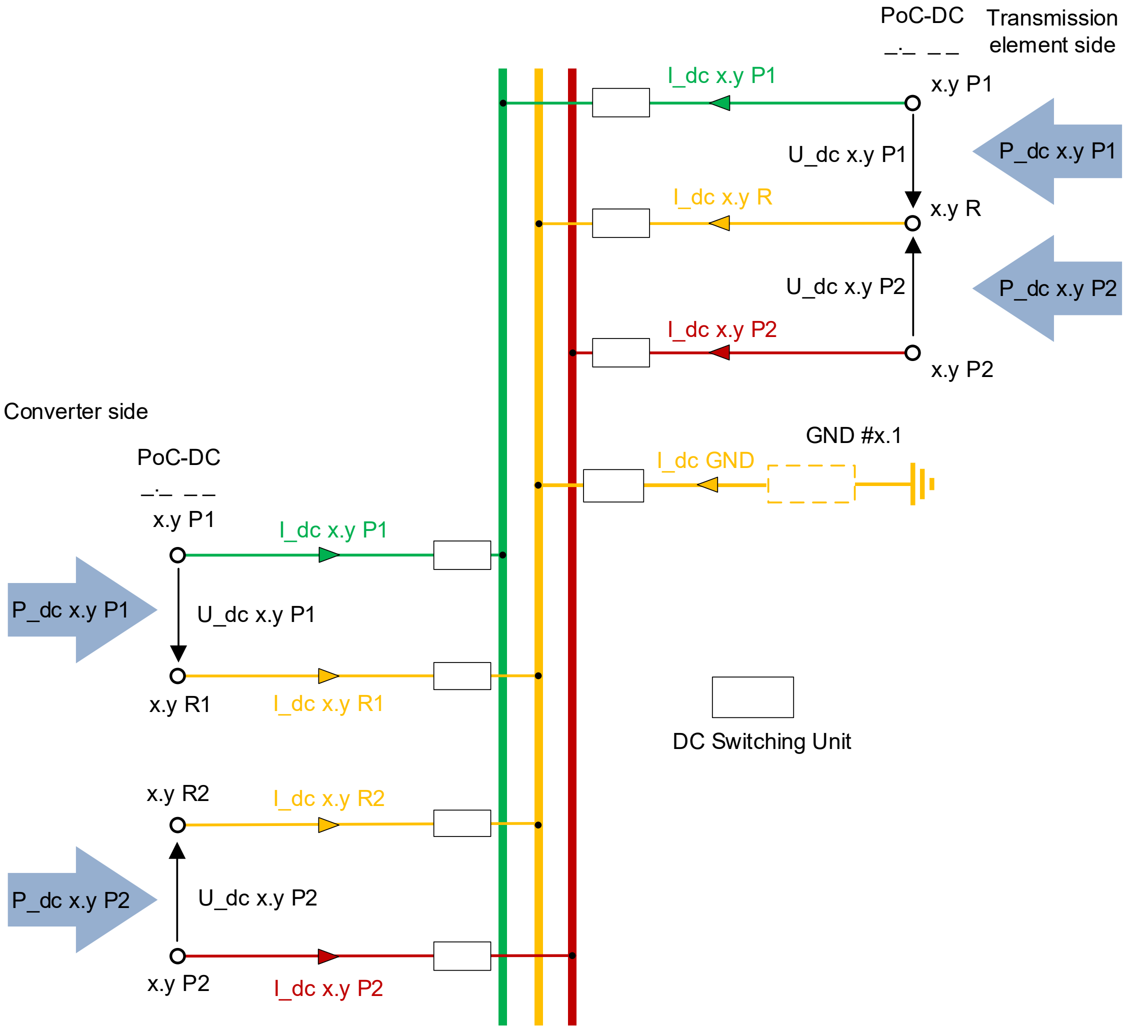


Figure 2-2: Demonstrator sign convention for DC Switching Stations

2.1.2. DC voltage range

Continuous

Table 2-1: Operational Security Limits for the InterOPERA demonstrator

	Nominal	Upper Operational Security Limit	Lower Operational Security Limit
DC Voltage (HV+ pole to neutral)	500 kV 1 pu	525 kV 1.05 pu	475 kV 0.95 pu
DC Voltage (HV- pole to neutral)	- 500 kV - 1 pu	- 475 kV - 0.95 pu	- 525 kV - 1.05 pu

Transient

Please refer to **Table 3-4** or **Table 4-4**.

3. DC Switching Station #1, #2, #3

3.1. Scope

The DC switching stations DCSS #1 (North-West), #2 (North-East) and #3 (South-West) shall include:

- 1 busbar per DC pole (P1, R, P2)
- 2 connections to DC cable transmission elements with dedicated metallic return, each connection consisting of 3 DC switching units, 1 per DC pole (P1, R, P2)
- 1 connection to a bipolar AC/DC converter station with individual neutral terminal per converter unit, each connection consisting of 4 DC switching units, 2 per AC/DC converter unit (P1, R1, R2, P2)
- 1 DC switching unit acting as Grounding Unit connecting the neutral bus to a local earth reference (grounding impedance specified in section 3.3.1)

The functional topology and the PoC reference designation are shown in **Figure 3-1**.

The described scope for this DCSS typical shall be delivered independent from the actual position of the DCSS in the InterOPERA demonstrator. This shall harmonize the delivery scope and allow exchangeability of vendor specific DCSS solutions in the demonstrator, at least for tests related to basic functionalities from feature group F01 “Grid Operation and Reconfiguration” (in section 4.1. of the Overall Demonstrator Definition).

Each DC busbar (BB P1, BB R, BB P2) in the DC switching stations shall be equipped with DC voltage measurement and the measured DC busbar voltage shall be provided to the DC Grid Controller. It is up to the DC switching station vendor to decide how this is realized and where the corresponding measurement is placed within the DC Switching Station. Apart from this, there are no requirements on the DC busbars.

Requirements on DC Switching Units and the DC Grounding Units are provided in the following chapters.

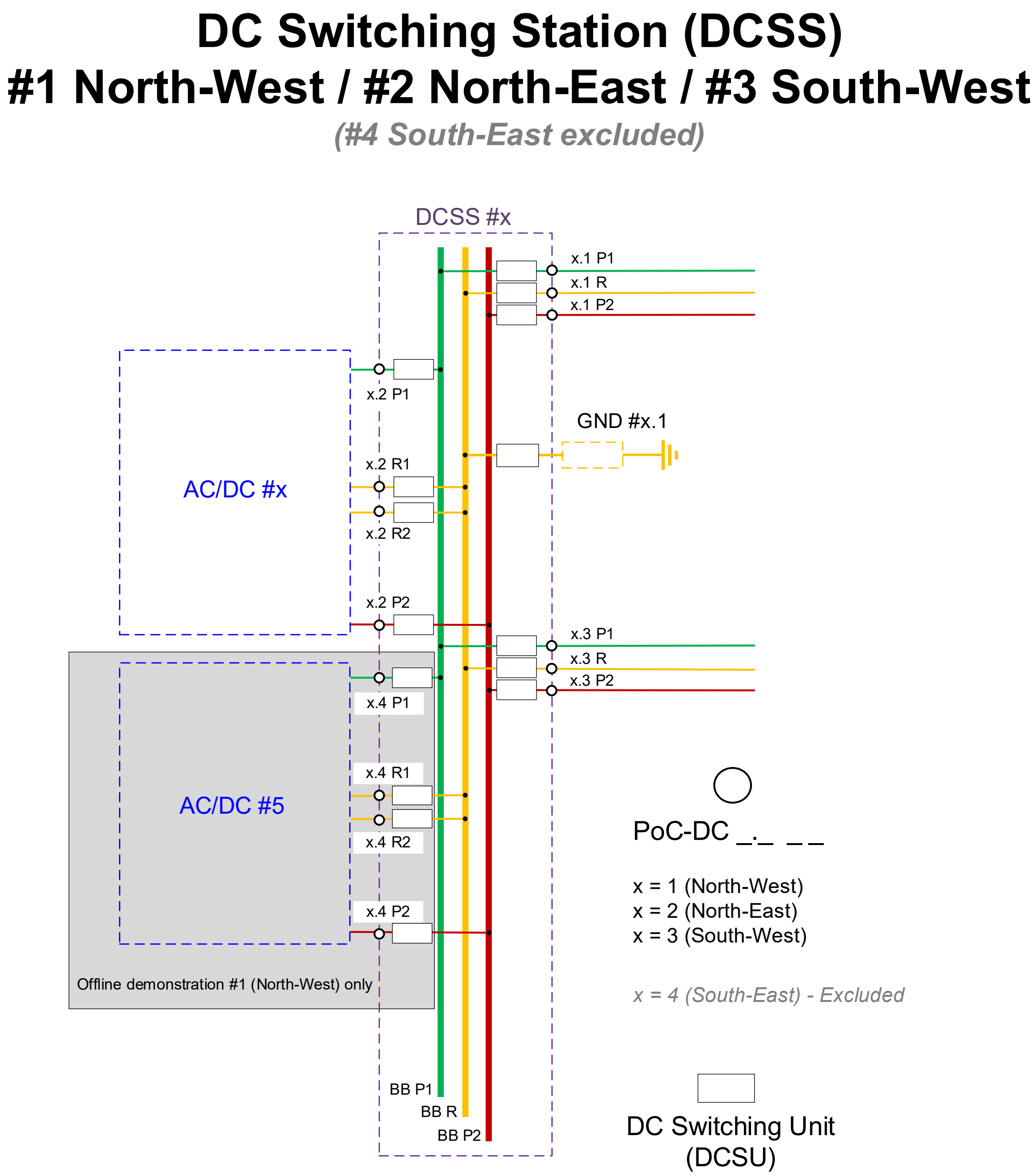


Figure 3-1: DC switching station (#1,#2, #3) functional topology and PoC reference designation

3.2. DC Switching Units

3.2.1. Functional requirements

Following the Overall Demonstrator Definition, the functions listed in **Table 3-1** shall be provided in all DC Switching Units connecting a DCSS busbars to the corresponding DC point of connection (PoC-DC). Functional requirements on certain functions will be provided in the following sections.

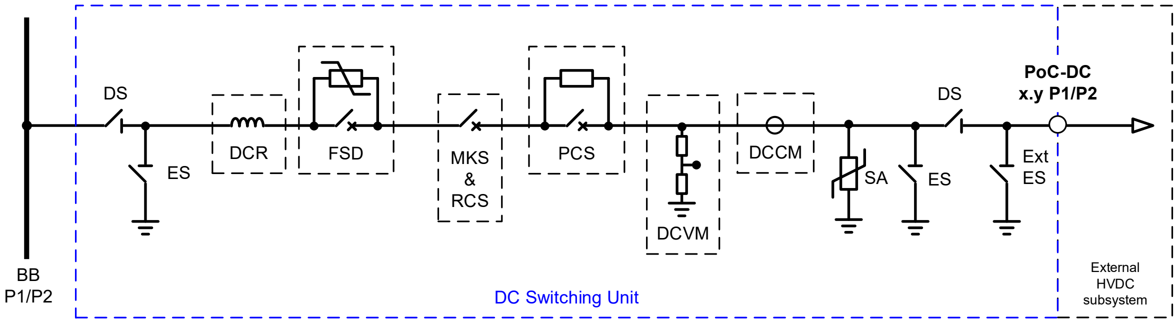
Table 3-1: DC switching unit functions

Item #	Function	High voltage DC system (P_n)	Neutral DC system (R_n)
1	Maintenance earthing* (inside DC switching unit)	X	X
2	Transmission unit earthed**	X	X
3	Voltage isolation	X	X
4	Current making	X	X
5	Peak current suppression	X	
6	Residual current breaking	X	X
7	Fault separation *only DCSS #1 (North-West);*	X	
8	DC voltage measurement	X	X
9	DC current measurement	X	X
10	Fault zone identification	X	

* For the InterOPERA demonstrator, being a simulator only, the maintenance earthing is not mandatory. The corresponding state "Maintenance earthed" (refer to section 3.2.2) can as well be emulated.

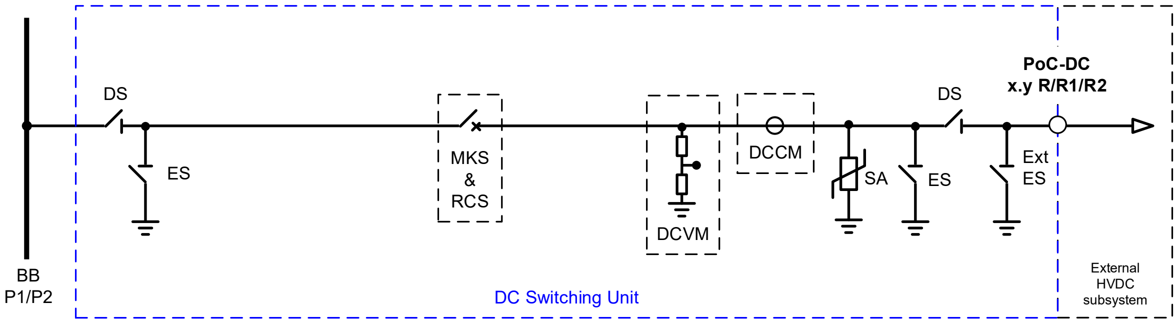
**only relevant for DC switching units connecting to an external transmission unit (i.e. DC cable)

Translating the assigned functions into a functional single line diagram is illustrated in **Figure 3-2** (high voltage DCSU) and **Figure 3-3** (neutral DCSU). This shall serve as reference for, and simplify the understanding of, functional descriptions in the following sections. Please note that the diagrams depict only one possible way of implementing a DCSU that complies with the functions above (e.g. fault separation capability and peak current suppression capability could be handled by one device). It shall not prescribe any specific implementation and or any specific arrangement of equipment within a DC switching unit. The implementation of requested functionality shall remain vendor specific.



Abbreviation	Definition	Relevant for function #
ES	Earthing Switch	(1)
Ext ES	External Earthing Switch (for DC cable)	(2)
DS	Disconnector Switch	(3)
MKS/RCS	Make Switch & Residual Current Switch	(4) (6)
PCS	Peak Current Suppression	(5)
FSD	Fault Separation Device	(7)
DCR	DC Reactor for current limitation and zone distinction	(7) (10)
DCVM	DC Voltage Measurement	(8) (10)
DCCM	DC Current Measurement	(9) (10)
SA	Surge Arrester (for insulation coordination)	

Figure 3-2: DC switching unit functional topology (high voltage DC system P1/P2)



Abbreviation	Definition	Relevant for function #
ES	Earthing Switch	(1)
Ext ES	External Earthing Switch (for DC cable)	(2)
DS	Disconnector Switch	(3)
MKS/RCS	Make Switch & Residual Current Switch	(4) (6)
DCVM	DC Voltage Measurement	(8)
DCCM	DC Current Measurement	(9)
SA	Surge Arrester (for insulation coordination)	

Figure 3-3: DC switching unit functional topology (neutral DC system R/R1/R2)

Transmission unit earthing

All DC switching units associated with a DC-PoC connected to a passive transmission unit (i.e. DC cable) shall include an earthing switch allowing to earth the external unit. As the coordination and interlocking of the earthing cannot be based on local information, a corresponding command shall be issued by the DC Grid Controller. The DC switching unit shall report the state of the earthing back.

For the InterOPERA demonstrator, being a simulator only, it shall be assumed that the external earthing switch can be closed independent from the actual DC cable voltage. As a result, waiting time for passive DC cable discharge or implementation of additional functionality for active discharge can be omitted.

Current making and peak current suppression (Energization)

The DC switching unit shall ensure that inrush currents to other parts of the HVDC grid do not cause the subsystems in question exceed their permissible current limits. Following the overall demonstrator definition, each DC switching unit shall be designed to energize an aggregated zone up to the following maximum extent:

- 1 x AC/DC Converter Station
- 2 x DC Switching Station (only busbars → negligible)
- 1 x DC Transmission Element (max. 800 km; see Annex 02 for DC cable data)

Residual current breaking and fault zone identification

Following the Overall Demonstrator Definition of fault isolation zones for the InterOPERA demonstrator, all DC switching units are supposed to provide residual current breaking. As such, each DC switching unit is associated with exactly two fault isolation zones.

Fault zone identification refers to the localization of a fault being in one or the other fault isolation zone (please refer to D3.3.1, section 3.3.3 and D2.1, section 7.4.1.1 for the definition of a fault isolation zone). This information shall be provided by each DC switching unit to the DC switching station and from there forwarded to the DC Grid Controller. The DC Grid Controller aggregates all information to decide upon which zone(s) to finally isolate from the healthy system.

Since a fault separation zone can comprise of several, disjunct fault isolation zones and the FSDs of the DC switching units that define a certain fault separation zone should interrupt the current ensuing the fault regardless of which fault isolation zone it is in, there are no specific requirements for the protection relays of the FSDs with respect to fault zone identification.

Fault separation (only for primary design in DCSS#1 – North West)

In line with the defined fault separation zones (cf. Overall Demonstrator Definition for the InterOPERA demonstrator), DCSUs are required to neutralize faults within a defined fault neutralisation time T_N – or faster.

To test this functional requirement, it was agreed to slightly modify the standalone test from D2.1 [01] (please refer also to D3.3.1, section 5.2.2) which represented the DC fault conditions via a DC FRT undervoltage profile for a fixed duration of $T_{N,max}$. Instead, the DC fault conditions are modelled by actual fault and cable models – the latter of which was used in D2.1 to derive the DC FRT undervoltage profile. The fault neutralisation time T_N of the DCSU under test is now an outcome of the test, and the test is considered successful if the measured fault neutralization time T_N is smaller than $T_{N,max}$ (with $T_{N,max}$ = 8 ms for DCSS #1).

The test setup for DC FRT compliance testing of a DC switching unit is shown in **Figure 3-4**. The voltage in both DC grid equivalents is set to the upper limit of the steady-state system voltage range, which is 525 kV for the demonstrator. According to D2.1, the equivalent inductance of both representations of the DC grid and parts thereof is zero. For the DCSS itself, an "internal" equivalent inductance L_{dc_eq} can be considered depending on the DCSS configuration and on the tested fault location – cf. **Figure 3-5**.

At least two fault locations are to be considered for the test – a nearby fault at the line terminal (which can also represent busbar faults) and a distant fault. The fault impedance shall be zero. The cable length can be varied to model different fault distances of "fault location 2". The minimum and maximum cable lengths are to be aligned with the DC network topology – in this case with the cable lengths defined for the demonstrator.

Further details for the parametrisation of the standalone test will be developed as part of task T3.4 of InterOPERA. These will be considered for the planned revision/update of the functional specifications once the demonstrator tests have been completed.

Following the zoning concept for fault separation described in the Overall Demonstrator Definition (sub-grids A and B), the parameters (cable lengths, equivalent inductance and target values such as $T_{N,max}$) for DC FRT compliance testing depend on the location of the DC switching station in the DC side topology.

Please note that a successful fault neutralization does not automatically imply a successful fault clearing. For the latter, the FSD must provide a countervoltage sufficiently large to drive the current through the DC switching unit to residual levels in a sufficiently short time so that the energy absorption branch of the FSD is not pushed beyond its designed limits.

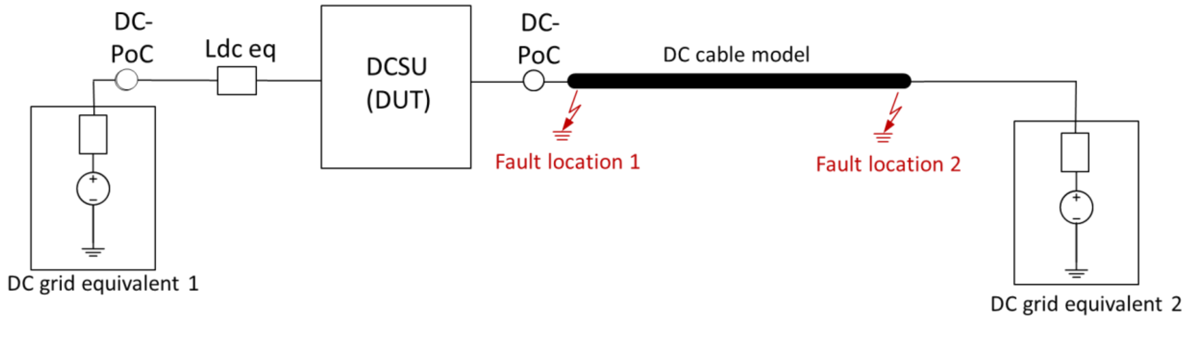


Figure 3-4: Standalone test circuit for fault current interruption for a DC switching unit as DUT.

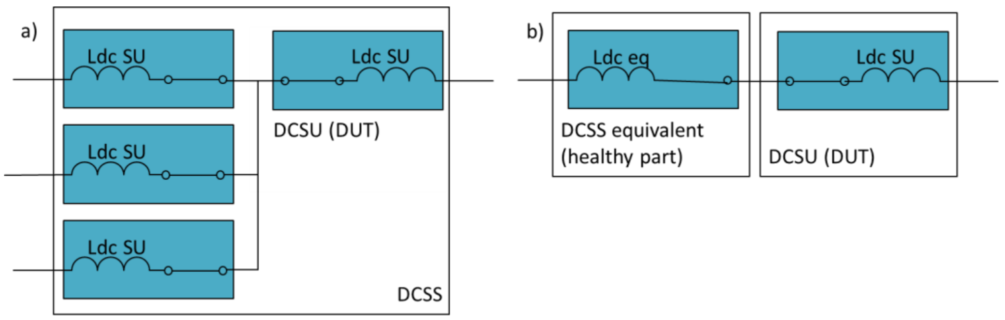
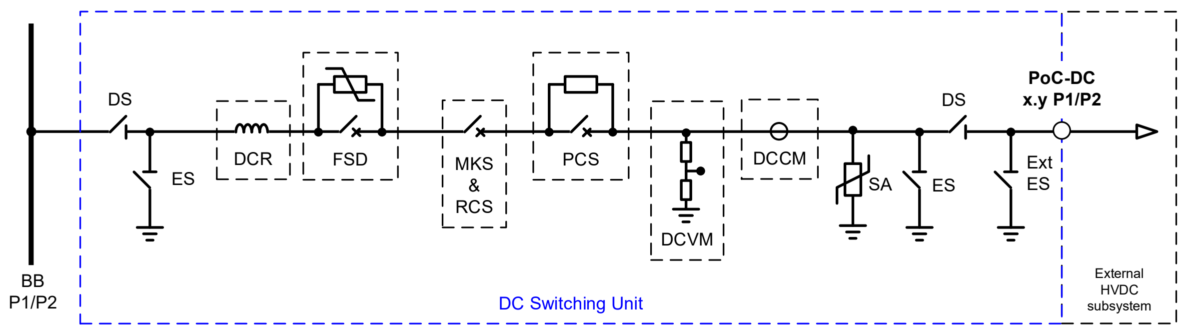


Figure 3-5: Options for selecting L_{dc_eq}.

3.2.2. Sequential controls

Following D2.1 [01] and D3.2 [03], each DC switching unit shall be designed to provide the unit states listed in **Table 3-2** and exchange information about its current unit state with the DC Switching Station from where the information is forwarded to the DC Grid Controller. The unit states are described using the illustration from the functional diagram presented in section 3.2.1 and repeated here for better readability (**Figure 3-6**). (Please note that the diagram depicts only one possible way of implementing a DCSU that complies with the functions listed in **Table 3-1** [e.g. fault separation capability and peak current suppression capability could be handled by one device]. It shall not prescribe any specific implementation or any specific arrangement of equipment within a DC switching unit. The implementation of requested functionality shall remain vendor specific.)

The corresponding state diagram is shown in **Figure 3-7** and further detailed in this section.



Abbreviation	Definition	Relevant for function #
ES	Earthing Switch	(1)
Ext ES	External Earthing Switch (for DC cable)	(2)
DS	Disconnector Switch	(3)
MKS/RCS	Make Switch & Residual Current Switch	(4) (6)
PCS	Peak Current Suppression	(5)
FSD	Fault Separation Device	(7)
DCR	DC Reactor for current limitation and zone distinction	(7) (10)
DCVM	DC Voltage Measurement	(8) (10)
DCCM	DC Current Measurement	(9) (10)
SA	Surge Arrester (for insulation coordination)	

Figure 3-6: DC switching unit functional topology (high voltage DC system P1/P2)

Table 3-2 : DC Switching Unit state definition

DC Switching Unit	ES	DS	MKS & RCS	PCS	FSD	External ES
Maintenance earthed	Closed*	Open	Don't care	Don't care	Don't care	Open
Transmission unit earthed **	Closed*	Open	Don't care	Don't care	Don't care	Closed
Open	Open	Closed	Open	Don't care	Don't care	Open
Closed	Open	Closed	Closed	Deactivated	Deactivated	Open

* For the InterOPERA demonstrator, being a simulator only, the maintenance earthing is not mandatory. The corresponding state "Maintenance earthed" can as well be emulated.

**only relevant for DC switching units connecting to an external transmission unit (i.e. DC cable)

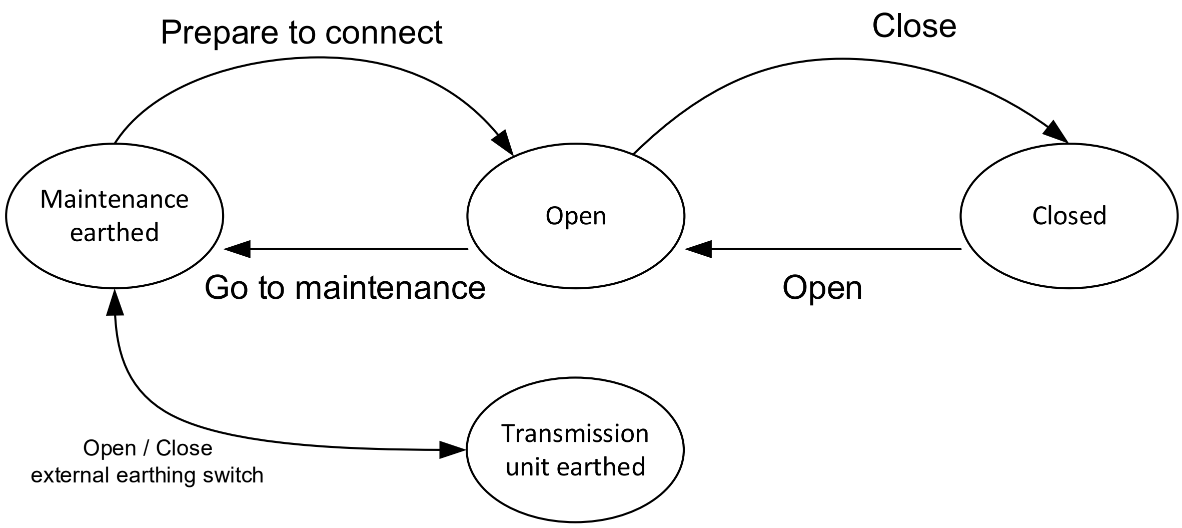


Figure 3-7: State diagram of a DC Switching Unit (for DCSS #1, #2, #3; adapted from [01])

Table 3-3 : Sequential control commands to DC switching unit (for DCSS #1, #2, #3)

Sequential control command	Short description
Go to maintenance	The DC switching unit shall go to state "Maintenance earthed". This state is subject to individual vendor's solutions.
Prepare to connect	The DC switching unit shall go from state "Maintenance earthed" to state "Open", allowing later connection by a "Close" command
Closed	The DC switching unit shall perform the closing sequence. Refer to **Figure 3-8**.
Open	The DC switching unit shall perform the opening sequence. Refer to **Figure 3-9**.

Close external earthing switch	The DC switching unit shall close the external earthing switch at the adjacent transmission unit (i.e. DC cable)
Open external earthing switch	The DC switching unit shall open the external earthing switch at the adjacent transmission unit (i.e. DC cable)

Closing Sequence

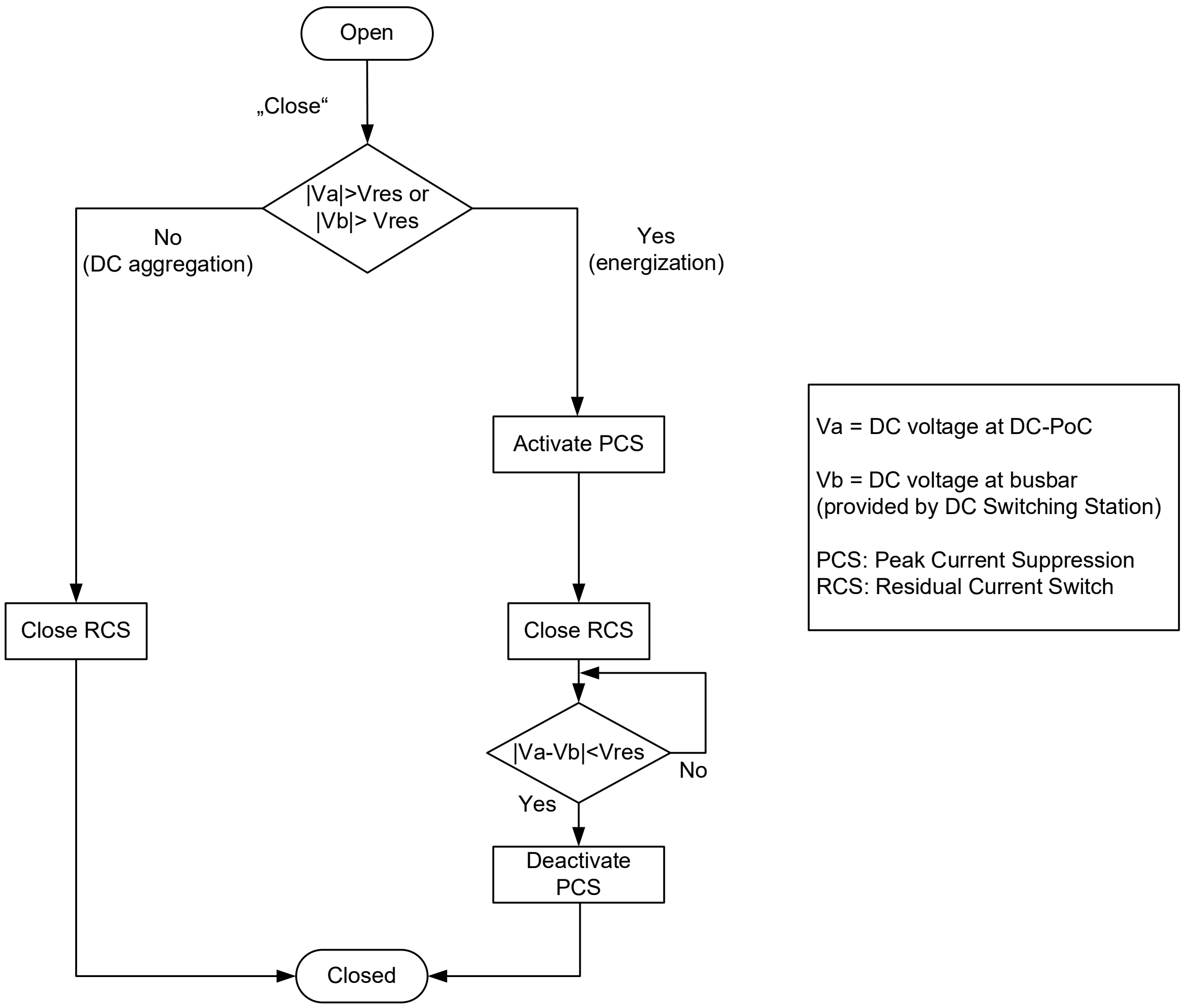


Figure 3-8: Transition sequence of a switching unit for the close command (adapted from [01])

Opening sequence

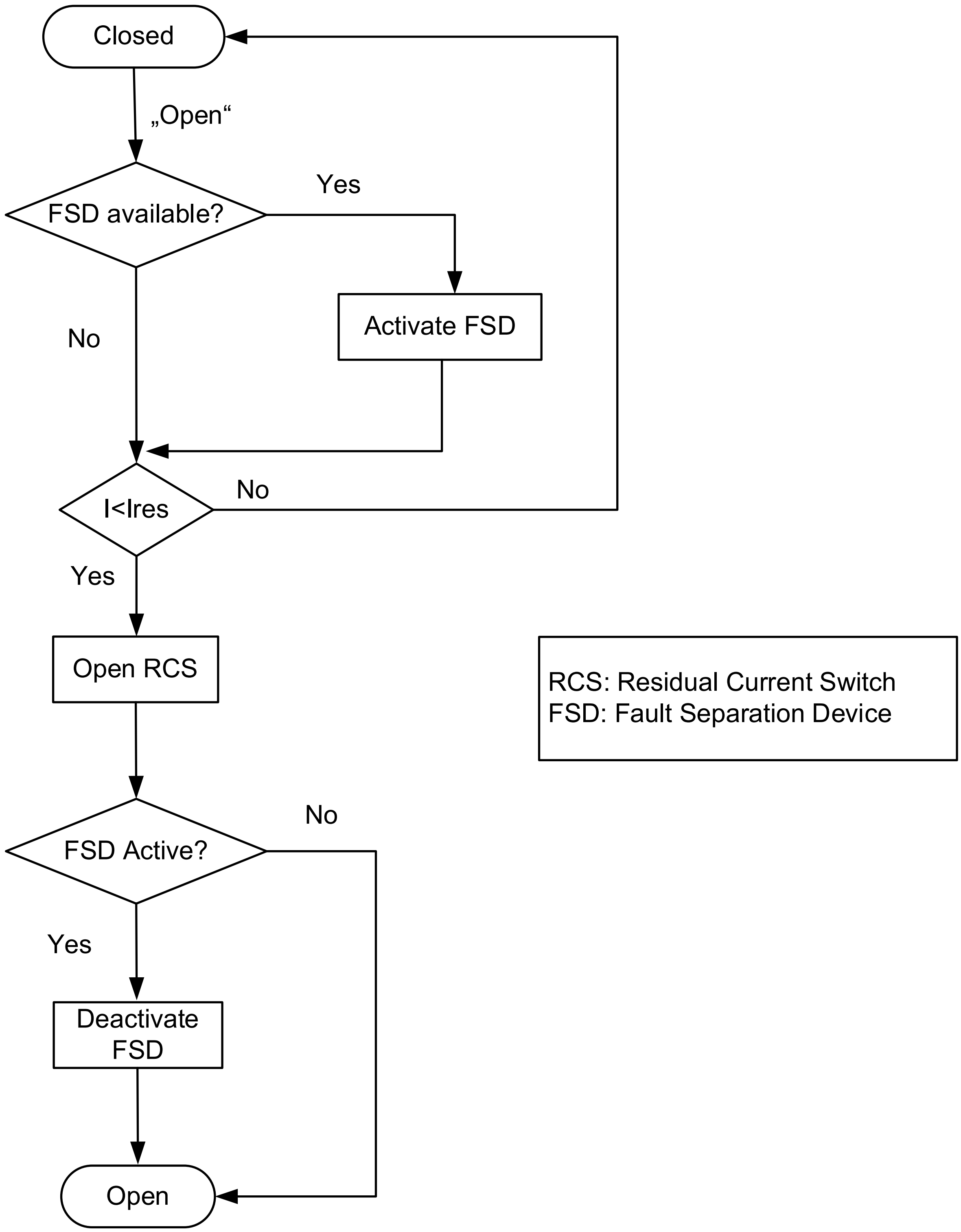


Figure 3-9: Transition sequence of a switching unit for the open command (adapted from [01])

3.2.3. Primary design requirements

For the insulation coordination towards the DC grid, i.e. at PoC-DC, the following levels shall be used. In addition to the standard impulse levels, specific requirements (e.g. DC cable TOV limits from the Overall Demonstrator Definition) shall also be considered.

Table 3-4: Parameters for DC grid insulation coordination

Parameter	High-voltage DC system (P1 / P2)	Neutral DC system (R)
SIWL	1050 kV	
Safety factor	1.15	
LIWL	1050 kV	250 kV
Safety factor	1.20	1.20

As the implementation of the surge arrester batteries is vendor specific, the LIPL level is not used for dimensioning the energy handling capabilities of a single arrester. Therefore, the LIPL can assume the same value as the SIPL in this case, as lightning strokes are not likely to directly hit the subsystems of the demonstrator.

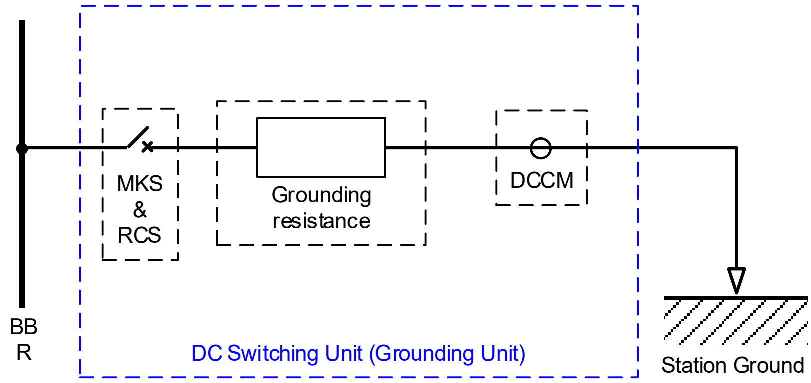
3.3. DC Grounding Unit

3.3.1. Functional requirements

The DC Grounding Unit is a special variant of a DC switching unit establishing a local reference to ground with a defined resistance for the whole DC part of the demonstrator grid. The grounding resistance used is a compromise that should take into consideration possible overvoltages appearing on healthy poles in case of fault scenarios in the DC grid (when using large grounding resistance) and lacking current zero-crossings on the AC side of converters in case of fault scenarios (when using small grounding resistance).

Figure 3-10 is showing a functional single line diagram. This shall serve as reference for, and simplify the understanding of, functional descriptions in this section. Please note that the diagram depicts only one possible way of implementing a DC grounding unit. It shall not prescribe any specific implementation and or any specific arrangement of equipment within a DC grounding unit. The implementation of requested functionality shall remain vendor specific.

However, due to its relevance for the whole HVDC system, the DC grounding resistance is explicitly specified following the Overall Demonstrator Definition and shall be 10 Ohm for DC Switching Stations #1, #2 and #3.



Abbreviation	Definition
MKS & RCS	Make Switch & Residual Current Switch
DCCM	DC Current Measurement

Figure 3-10: DC grounding unit functional topology

3.3.2. Sequential controls

In general, a DC grounding unit shall follow the same unit states and sequential controls as a regular DC switching unit described in section 3.2.2. Due to its much simpler structure, consisting of only one active switching device, the corresponding states must be aggregated as depicted in **Table 3-5**. Accordingly, sequential control commands "Open" and "Close" do not initiate sequences but simply operate the single switching device in the DC grounding unit.

Table 3-5: DC Grounding Unit state definition

DC Grounding Unit	MKS & RCS
Maintenance earthed	Open and not available
Ready to connect = Open	Open and available
Closed	Closed

4. Central DC Switching Station #5

4.1. Scope

The DC switching station DCSS #5 (Central) shall include:

- 2 busbar sections per DC pole (P1, R, P2)
- 4 connections to DC cable transmission elements with dedicated metallic return, each connection consisting of 3 DC switching units, 1 per DC pole (P1, R, P2)
- 2 DC switching unit acting as grounding unit, 1 per neutral bus section, connecting the neutral bus section to a local earth reference (grounding impedance specified in section 4.3)
- 1 bus sectionalizing unit, consisting of 3 DC switching unit, 1 per DC pole (P1, R, P2)

The functional topology and the PoC reference designation are shown in **Figure 4-1**.

Each DC busbar section (BB P1.n, BB R.n, BB P2.n) in the DC switching stations shall be equipped with DC voltage measurement and the measured DC busbar voltage shall be provided to the DC Grid Controller. It is up to the DC switching station vendor to decide how this is realized and where the corresponding measurement is placed within the DC Switching Station. Apart from this, there are no requirements on the DC busbar sections.

Requirements on DC Switching Units and the DC Grounding Units are provided in the following chapters.

DC Switching Station (DCSS)
#5 Central

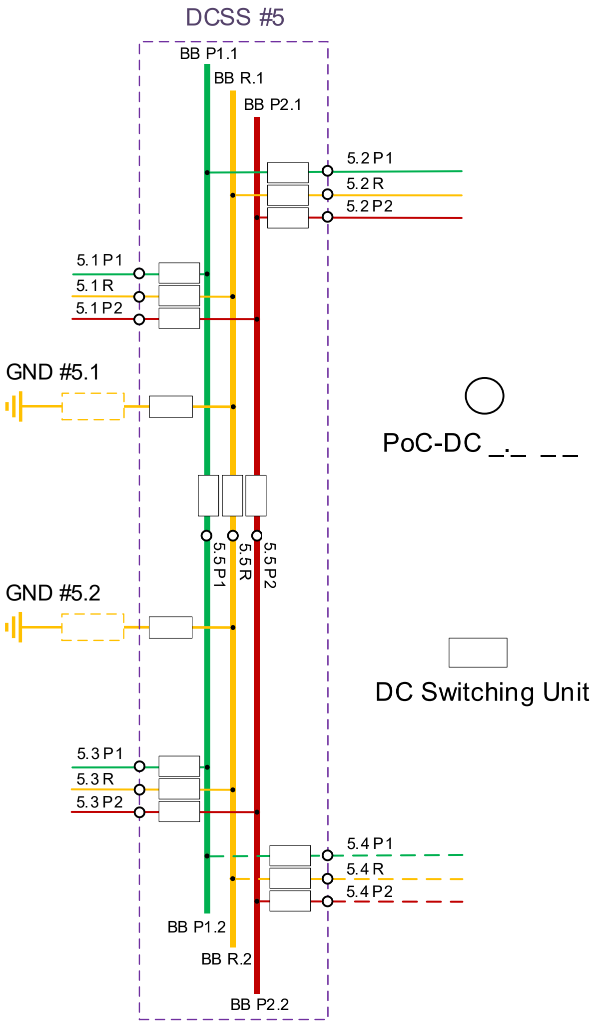


Figure 4-1: DC switching station (#5) functional topology and PoC reference designation

4.2. DC Switching Units

4.2.1. Functional requirements

Following the Overall Demonstrator Definition, the functions listed in **Table 4-1** shall be provided in all DC Switching Units connecting a DCSS busbars to the corresponding DC point of connection (PoC-DC). Functional requirements on certain functions will be provided in the following sections.

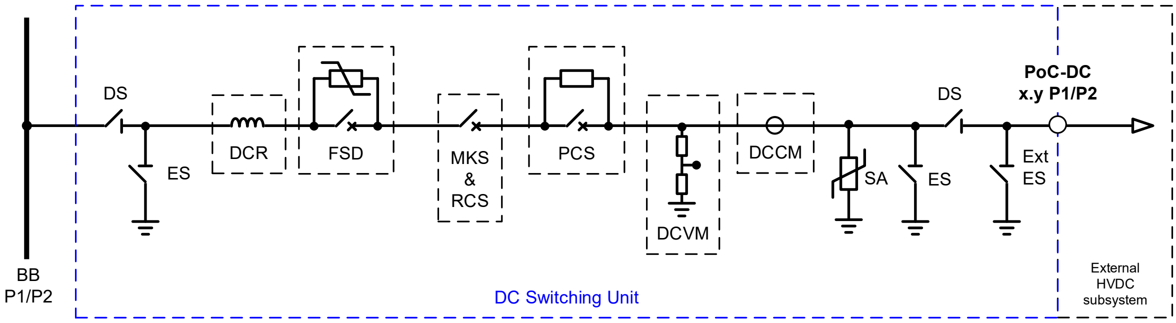
Table 4-1: DC switching unit functions

Item #	Function	High voltage DC system (P_n)	Neutral DC system (R_n)
1	Maintenance earthing*	X	X
2	Transmission unit earthed**	X	X
3	Voltage isolation	X	X
4	Current making	X	X
5	Peak current suppression	X	
6	Residual current breaking	X	X
7	Fault separation	X	
8	On-load switching	X	
9	DC voltage measurement	X	X
10	DC current measurement	X	X
11	Fault zone identification	X	

* For the InterOPERA demonstrator, being a simulator only, the maintenance earthing is not mandatory. The corresponding state "Maintenance earthed" (refer to section 4.2.2) can as well be emulated.

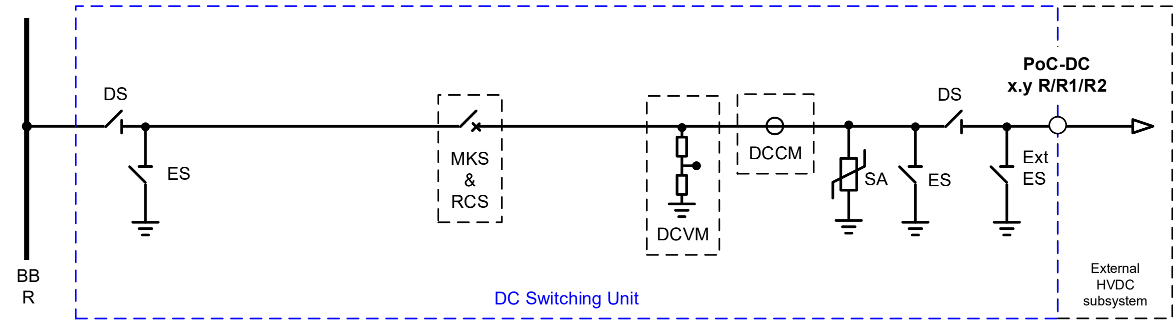
**not relevant for DC switching units acting as the bus sectionalizing breakers as they are not connecting to an external transmission unit (i.e. DC cable)

Translating the assigned functions into a functional single line diagram is illustrated in **Figure 4-2** (high voltage DCSU) and **Figure 4-3** (neutral DCSU). This shall serve as reference for, and simplify the understanding of, functional descriptions in the following sections. Please note that the diagrams depict only one possible way of implementing a DCSU that complies with the functions above (e.g. fault separation capability and peak current suppression capability could be handled by one device). It shall not prescribe any specific implementation and or any specific arrangement of equipment within a DC switching unit. The implementation of requested functionality shall remain vendor specific.



Abbreviation	Definition	Relevant for function #
ES	Earthing Switch	(1)
Ext ES	External Earthing Switch (for DC cable)	(2)
DS	Disconnector Switch	(3)
MKS/RCS	Make Switch & Residual Current Switch	(4) (6)
PCS	Peak Current Suppression	(5)
FSD	Fault Separation Device	(7)
DCR	DC Reactor for current limitation and zone distinction	(7) (10)
DCVM	DC Voltage Measurement	(8) (10)
DCCM	DC Current Measurement	(9) (10)
SA	Surge Arrester (for insulation coordination)	

Figure 4-2: DC switching unit functional topology (high voltage DC system P1/P2)



Abbreviation	Definition	Relevant for function #
ES	Earthing Switch	(1)
Ext ES	External Earthing Switch (for DC cable)	(2)
DS	Disconnector Switch	(3)
MKS/RCS	Make Switch & Residual Current Switch	(4) (6)
DCVM	DC Voltage Measurement	(8)
DCCM	DC Current Measurement	(9)
SA	Surge Arrester (for insulation coordination)	

Figure 4-3: DC switching unit functional topology (neutral DC system R/R1/R2)

Transmission unit earthing

All DC switching units associated with a DC-PoC connected to a passive transmission unit (i.e. DC cable) shall include an earthing switch allowing to earth the external unit. As the coordination and interlocking of the earthing cannot be based on local information, a corresponding command shall be issued by the DC Grid Controller. The DC switching unit shall report the state of the earthing back.

For the InterOPERA demonstrator, being a simulator only, it shall be assumed that the external earthing switch can be closed independent from the actual DC cable voltage. As a result, waiting time for passive DC cable discharge or implementation of additional functionality for active discharge can be omitted.

Current making and peak current suppression (Energization)

The DC switching unit shall ensure that inrush currents to other parts of the HVDC grid do not cause the subsystems in question exceed their permissible current limits. Following the overall demonstrator definition, each DC switching unit shall be designed to energize an aggregated zone up to the following maximum extent:

- 1 x AC/DC Converter Station
- 1 x DC Switching Station (only busbars → negligible)
- 1 x DC Transmission Element (max. 800 km; see Annex 02 for DC cable data)

Residual current breaking and fault zone identification

Following the Overall Demonstrator Definition of fault isolation zones for the InterOPERA demonstrator, all DC switching units are supposed to provide residual current breaking. As such, each DC switching unit is associated with exactly two fault isolation zones.

Fault zone identification refers to the localization of a fault being in one or the other fault isolation zone (please refer to D3.3.1, section 3.3.3 and D2.1, section 7.4.1.1 for the definition of a fault isolation zone). This information shall be provided by each DC switching unit to the DC switching station and from there forwarded to the DC Grid Controller. The DC Grid Controller aggregates all information to decide upon which zone(s) to finally isolate from the healthy system.

Fault separation

In line with the defined fault separation zones (cf. Overall Demonstrator Definition for the InterOPERA demonstrator), DCSUs are required to neutralize faults within a defined fault neutralisation time T_N – or faster.

To test this functional requirement, it was agreed to slightly modify the standalone test from D2.1 [01] (please refer also to D3.3.1, section 5.2.2) which represented the DC fault conditions by a DC FRT undervoltage profile for a fixed duration of $T_{N,max}$. Instead, the DC fault conditions are modelled by actual fault and cable models – the latter of which was used in D2.1 to derive the DC FRT undervoltage profile. The fault neutralisation time T_N of the DCSU under test is now an outcome of the test, and the test is considered successful if the measured fault neutralization time T_N is smaller than $T_{N,max}$ (with $T_{N,max}$ = 2.5ms for DCSS #5).

The test setup for DC FRT compliance testing of a DC switching unit is shown in **Figure 4-4**. The voltage in both DC grid equivalents is set to the upper limit of the steady-state system voltage range, which is 525 kV for the demonstrator. According to D2.1, the equivalent inductance of both representations of the DC grid and parts thereof is zero. For the DCSS itself, an "internal" equivalent inductance L_{dc_eq} can be considered depending on the DCSS configuration and on the tested fault location.

At least two fault locations are to be considered for the test – a nearby fault at the line terminal (which can also represent busbar faults) and a distant fault. The fault impedance shall be zero. The cable length can be varied to model different fault distances of "fault location 2". The minimum and maximum cable lengths are to be aligned with the DC network topology – in this case with the cable lengths defined for the demonstrator.

Further details for the parametrisation of the standalone test will be developed as part of task T3.4 of InterOPERA. These will be considered for the planned revision/update of the functional specifications once the demonstrator tests have been completed.

Following the zoning concept for fault separation described in the Overall Demonstrator Definition (sub-grids A and B), the parameters (cable lengths, equivalent inductance and target values such as $T_{N,max}$) for DC FRT compliance testing depend on the location of the DC switching station in the DC side topology.

Please note that a successful fault neutralization does not automatically imply a successful fault clearing. For the latter, the FSD must provide a countervoltage sufficiently large to drive the current through the DC switching unit to residual levels in a sufficiently short time so that the energy absorption branch of the FSD is not pushed beyond its designed limits.

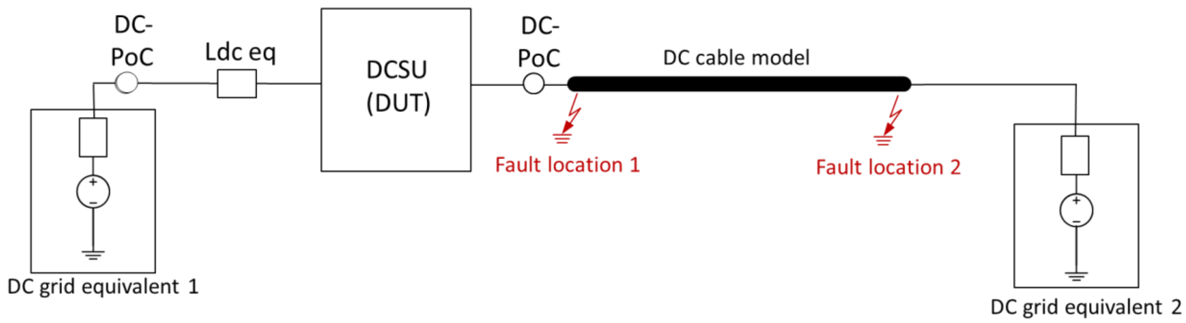


Figure 4-4: Standalone test circuit for fault current interruption for a DC switching unit as DUT.

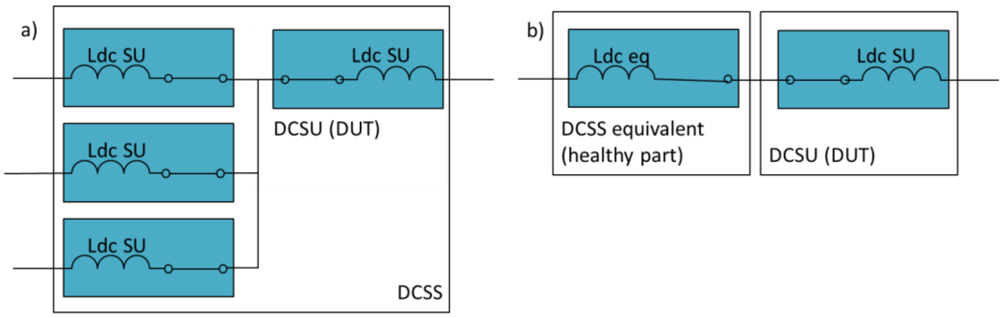


Figure 4-5: Options for selecting L_{dc_eq}.

On-load switching – planned subgrid merge

The switching units of the central switching station are required to perform on-load switching in addition to the function of energization.

In case of a planned merge of subgrids, the transient stresses on the components of the DCSU are not exceeding those experienced during a subgrid energization operation. In fact, the inrush currents through the switches of the DCSU and the energy dissipated in the PCS are considerably smaller.

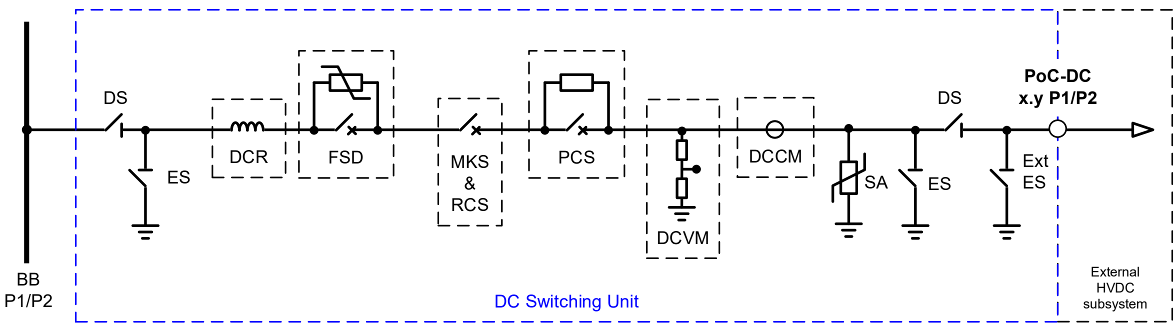
On-load switching – planned subgrid split

In case of a planned split of subgrids, in order not to exceed transient voltage limits, the FSDs of the switching units have to insert a partial counter voltage that suppresses the load current flowing through said FSDs to residual levels.

It is up to the vendor to decide what the partial counter voltage to be inserted is and how this insertion is implemented as long as the transient voltage stresses are not imposed on other components of the grid. For instance, the insertion of a single, predefined partial counter voltage may be acceptable, i.e., it is not needed to implement an adjustable range of the counter voltage values.

4.2.2. Sequential controls

Following D2.1 [01] and D3.2 [03], each DC switching unit shall be designed to provide the unit states listed in **Table 4-2** and exchange information about its current unit state with the DC Switching Station from where the information is forwarded to the DC Grid Controller. The unit states are described using the illustration from the functional diagram presented in section 4.2.1 and repeated here for better readability (**Figure 4-6**). (Please note that the diagram depicts only one possible way of implementing a DCSU that complies with the functions listed in **Table 4-1** [e.g. fault separation capability and peak current suppression capability could be handled by one device]. It shall not prescribe any specific implementation or any specific arrangement of equipment within a DC switching unit. The implementation of requested functionality shall remain vendor specific.) The corresponding state diagram is shown in **Figure 4-7** and further detailed in this section.



Abbreviation	Definition	Relevant for function #
ES	Earthing Switch	(1)
Ext ES	External Earthing Switch (for DC cable)	(2)
DS	Disconnector Switch	(3)
MKS/RCS	Make Switch & Residual Current Switch	(4) (6)
PCS	Peak Current Suppression	(5)
FSD	Fault Separation Device	(7)
DCR	DC Reactor for current limitation and zone distinction	(7) (10)
DCVM	DC Voltage Measurement	(8) (10)
DCCM	DC Current Measurement	(9) (10)
SA	Surge Arrester (for insulation coordination)	

Figure 4-6: DC switching unit functional topology (high voltage DC system P1/P2)

Table 4-2: DC Switching Unit state definition

DC Switching Unit	ES	DS	MKS & RCS	PCS	FSD	External ES
Maintenance earthed	Closed*	Open	Don't care	Don't care	Don't care	Open
Transmission unit earthed **	Closed*	Open	Don't care	Don't care	Don't care	Closed
Open	Open	Closed	Open	Don't care	Don't care	Open
Closed	Open	Closed	Closed	Deactivated	Deactivated	Open

* For the InterOPERA demonstrator, being a simulator only, the maintenance earthing is not mandatory. The corresponding state "Maintenance earthed" can as well be emulated.

**only relevant for DC switching units connecting to an external transmission unit (i.e. DC cable)

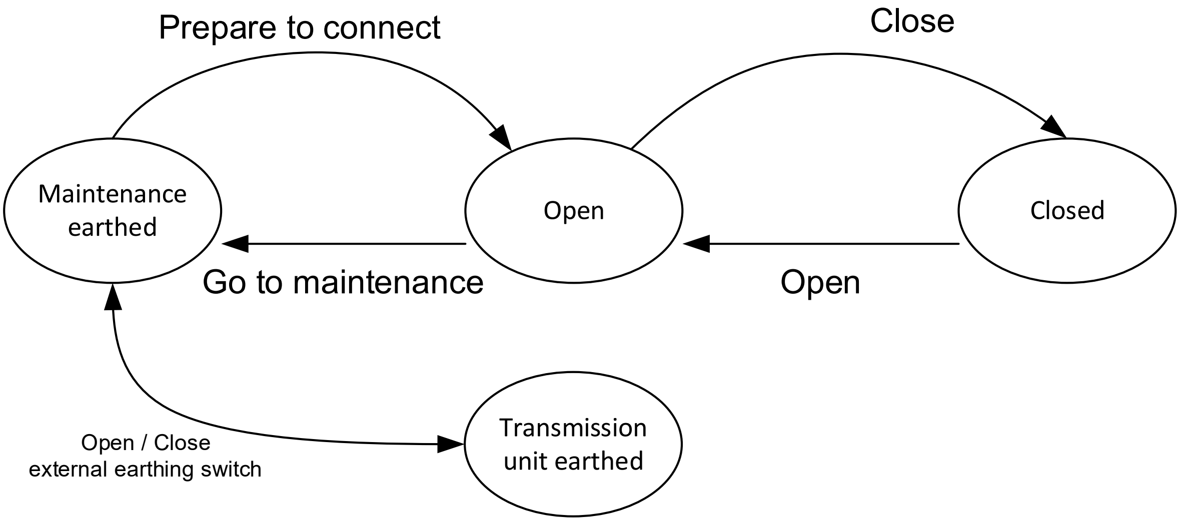


Figure 4-7: State diagram of a DC Switching Unit (for DCSS #5; adapted from [01])

Table 4-3: Sequential control commands to DC switching unit (in DCSS #5, where relevant)

Sequential control command	Short description
Go to maintenance	The DC switching unit shall go to state "Maintenance earthed". This state is subject to individual vendor's solutions.
Prepare to connect	The DC switching unit shall go from state "Maintenance earthed" to state "Open", allowing later connection by a "Close" command
Closed	The DC switching unit shall perform the closing sequence. Refer to **Figure 4-8**.
Open	The DC switching unit shall perform the opening sequence. Refer to **Figure 4-9**.

Close external earthing switch	The DC switching unit shall close the external earthing switch at the adjacent transmission unit (i.e. DC cable)
Open external earthing switch	The DC switching unit shall open the external earthing switch at the adjacent transmission unit (i.e. DC cable)

Closing Sequence

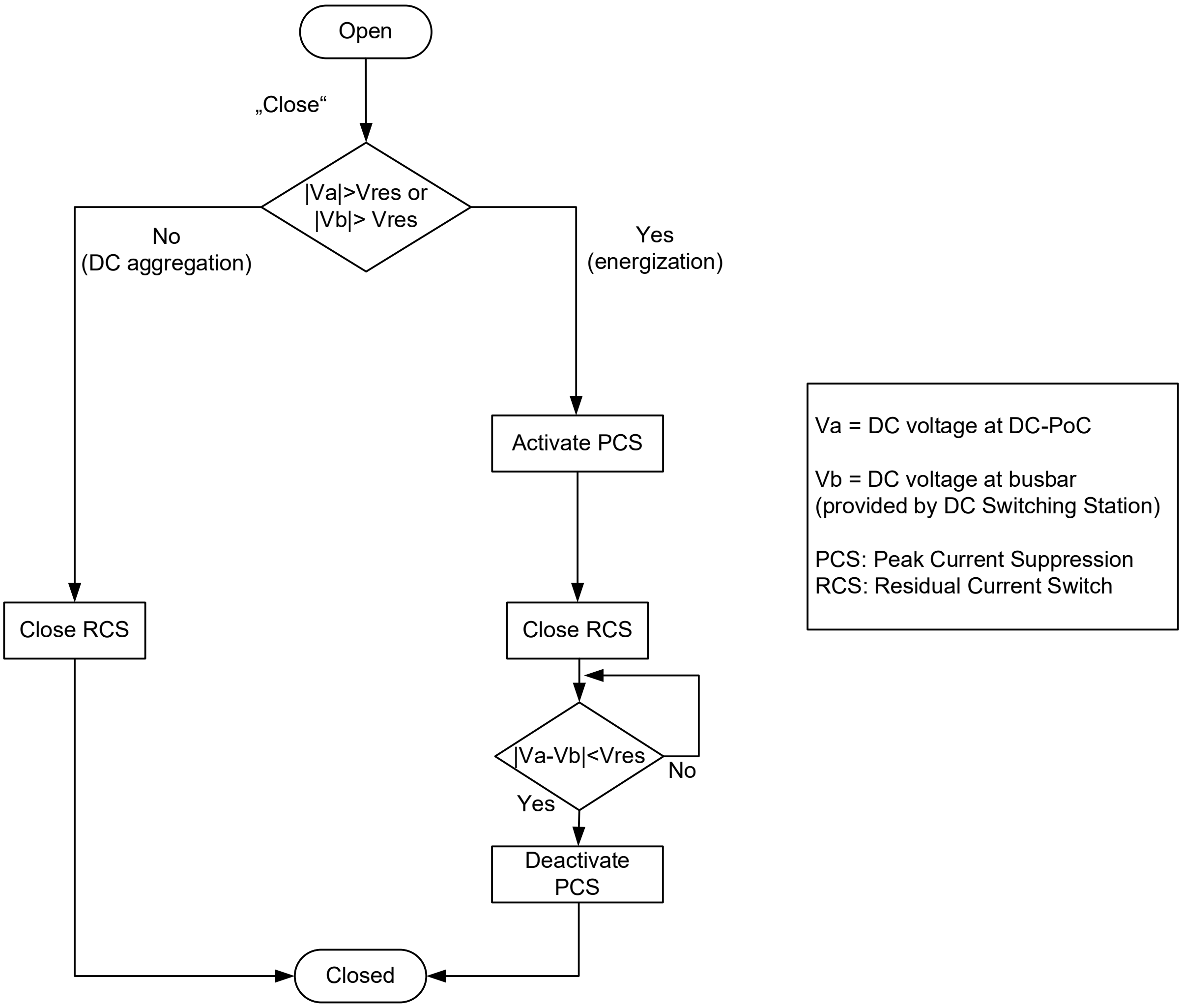


Figure 4-8: Transition sequence of a switching unit for the close command (adapted from [01])

Opening sequence

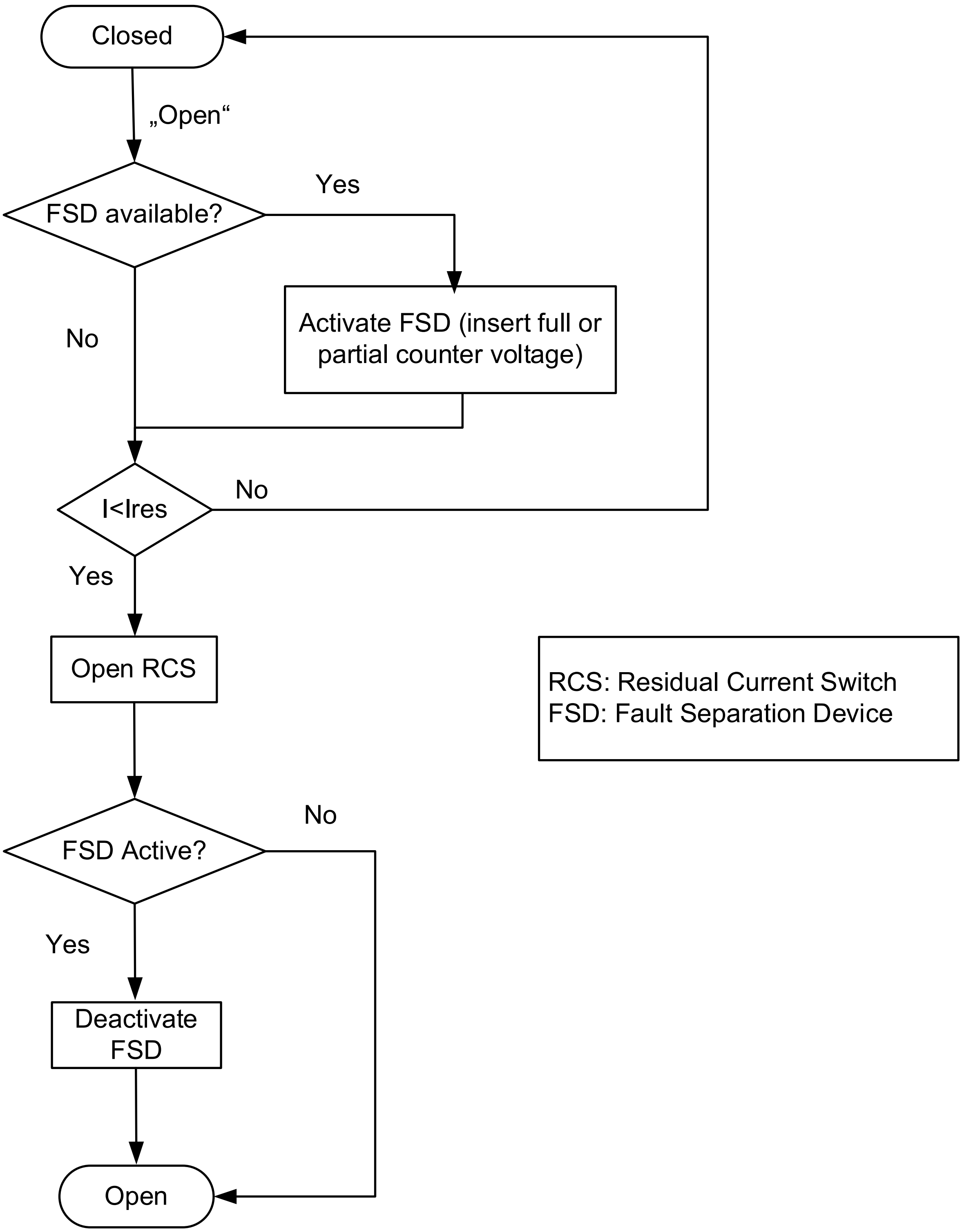


Figure 4-9: Transition sequence of a switching unit for the open command (adapted from [01])

4.2.3. Primary design requirements

For the insulation coordination towards the DC grid, i.e. at PoC-DC, the following levels shall be used. In addition to the standard impulse levels, specific requirements (e.g. DC cable TOV limits from the Overall Demonstrator definition) shall also be considered.

Table 4-4: Parameters for DC grid insulation coordination

Parameter	High-voltage DC system (P1 / P2)	Neutral DC system (R)
SIWL	1050 kV	
Safety factor	1.15	
LIWL	1050 kV	250 kV
Safety factor	1.20	1.20

As the implementation of the surge arrester batteries is vendor specific, the LIPL level is not used for dimensioning the energy handling capabilities of a single arrester. Therefore, the LIPL can assume the same value as the SIPL in this case, as lightning strokes are not likely to directly hit the subsystems of the demonstrator.

4.3. DC Grounding Unit

The grounding units of the central switching station are functionally identical to the grounding units of other switching stations. The difference may lie in the size of the resistor connected in series with the switch, but this does not alter the unit's function. The function description is repeated here for the sake of consistent report structure.

The DC Grounding Unit is a special variant of a DC switching unit establishing a local reference to ground with a defined resistance for the whole DC part of the demonstrator grid. The grounding resistance used is a compromise that should take into consideration possible overvoltages appearing on healthy poles in case of fault scenarios in the DC grid (when using large grounding resistance) and lacking current zero-crossings on the AC side of converters in case of fault scenarios (when using small grounding resistance).

Figure 4-10 is showing a functional single line diagram. This shall serve as reference for, and simplify the understanding of, functional descriptions in this section. Please note that the diagram depicts only one possible way of implementing a DC grounding unit. It shall not prescribe any specific implementation and or any specific arrangement of equipment within a DC grounding unit. The implementation of requested functionality shall remain vendor specific.

However, due to its relevance for the whole HVDC system, the DC grounding resistance is explicitly specified following the Overall Demonstrator Definition and shall be 10 Ohm.

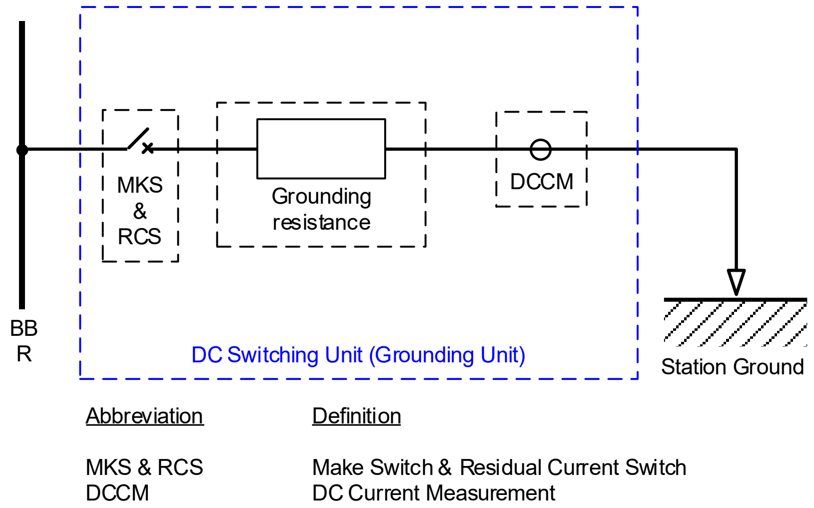


Figure 4-10: DC grounding unit functional topology

4.3.1. Sequential controls

In general, a DC grounding unit shall follow the same unit states and sequential controls as a regular DC switching unit described in section 4.2.2. Due to its much simpler structure, consisting of only one active switching device, the corresponding states must be aggregated as depicted in **Table 4-5**. Accordingly, sequential control commands "Open" and "Close" do not initiate sequences but simply operate the single switching device in the DC grounding unit.

Table 4-5: DC Grounding Unit state definition

DC Grounding Unit	MKS & RCS
Maintenance earthed	Open and not available
Ready to connect = Open	Open and available
Closed	Closed

5. Interface to DC Grid Controller

The DC switching station controller shall forward the commands received from DC Grid Controller (DCGC) to the relevant DCSUs. It shall also send back the requested information such as the state of a certain DCSU and measured data to the DCGC in accordance with the rules of the chosen communication method.

Interfacing the DCGC, the DCSS controller shall

- Forward commands to switching units (open, close, go to maintenance, prepare to connect, open/close earthing switch of external transmission unit)
- Forward status signals of all switching units (open, close, maintenance, transmission unit earthed) and grounding units (maintenance, open, close)
- Forward measured electrical quantities at switching units (voltage on the transmission unit side of the switching unit, current through the switching unit) and at the busbar poles (voltage in each section)
- Implement interlocking (e.g., commands from the DGCG to a switching unit that would result in potential fault scenarios shall not be forwarded by the DCSS controller; in case of earthing the adjacent transmission unit, the DCSS controller does not have the data necessary to determine if interlocking shall be executed or not and the implementation of the interlocking shall remain at the DCGC)

The update frequency of data passed from DCSS controller to DCGC shall be compliant with the rules of the chosen communication method. In particular, if the IEC 61850 MMS protocol is used for data exchange, some data may only be updated once they exceed a predefined dead band around a predefined dead band reference value. In other words, a set frequency of data being exchanged (similarly to the case of a communication protocol using polling) might not be defined.

Interfacing the DCSUs, the DCSS controller shall

- Forward commands from the DCGC (open, close, go to maintenance, prepare to connect, open/close earthing switch of external transmission unit)
- Forward measured electrical quantities (voltages on the transmission unit side of the switching units, current through switching units and grounding units, busbar pole voltages) to the DCGC

The function of forwarding status signals of the DCSUs is explicitly not required. As there will be no switching unit failures simulated in InterOPERA, the DCSS controller can determine the status of the DCSUs that belong to the DCSS in question based on the commands coming from the DCGC. Moreover, when an FSD of a DCSU is activated (either by an external trip signal or by an implemented protection relay function), the DCGC does not need the information about an FSD activation; the controller would determine what had happened in the grid by aggregating information from other DCSUs.

For the set of signals that the DCSS controller shall interface the DCGC with, please refer to [04]

References

Ref. No.	Title
01	InterOPERA D2.1 (PUBLIC) "Functional requirements for HVDC grid systems and subsystems"
02	InterOPERA D3.1 (PUBLIC) "Demonstrator project definition and system design studies"
03	InterOPERA D3.2 (SENSITIVE) "Subsystems pre-design phase process and outcomes"
04	InterOPERA D3.3(b) Annex 3.3.2 (RESTRICTED) "DC Grid Controller & Comm"

Annex 3.3.5: AC Onshore Testbench

WP3

Multi-vendor / Multi-terminal demonstrator project

Deliverable 3.3(b)

Detailed Functional Specifications

Subtask 3.3.5

Onshore AC testbench for the demonstrator
(Final)

Detailed Functional Specifications

Onshore AC testbench for the demonstrator

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VERSION CONTROL

Version number	V1
Created by	Laurids Dall
Date created	3/9/2025
Status	Prepared for Stage 2

Table of contents

1. Introduction and specification summary

This document provides a specification of the onshore AC testbench for the demonstrator. It is structured into several chapters, each detailing a specific aspect of the onshore test bench. The specification is closely related to and aligned with the onshore AC test cases for the demonstrator as described in [9].

Chapter 1, **Introduction and specification summary,** describes the relationship between the demonstrator use cases and the onshore AC specification within this document. Section 1.2 include a summary of the specification without background information and shall be used as reference for the implementation the specification.

Chapter 2, **Electrical topology of the onshore connection point**, describes the electrical topology representing the AC substation and background AC network at the connection point of the HVDC converter stations of the demonstrator. It explores different configurations, including single and double AC source grid-equivalents, and their implications for the project.

Chapter 3, **Grid equivalents**, presents the grid equivalent model for the Continental Europe system connection point and the Nordic system connection point. It includes Thevenin equivalent data, such as rated AC voltage, fundamental frequency, short circuit power, short circuit current, and X/R ratio. The chapter also introduces a frequency dynamic model that considers the inertia of the AC grid, which means the grid's frequency is affected by power flows within the grid. The model is designed to be simple yet effective for studying the frequency dynamics without unnecessary complications. The chapter provides detailed parameters and assumptions for tuning the model based on real incident data or generic estimations.

Chapter 4, **General HVDC converter station requirements,** specifying that the applicable grid-code in InterOPERA is the VDE-AR-N 4131 and TenneTs associated NAR annexes [5]. The chapter describes the link between the grid-code requirements and the use cases.

Chapter 5, **Dynamic performance requirements and test of GFM control**, specifies a modified set of dynamic performance criteria based on the VDE FNN and TenneT NAR B.409 reference curves and test of phase jump active power, inertial active power and inherent reactive power capabilities as qualitatively described in InterOPERA D2.2.

1.1 Overview of onshore AC use cases

The onshore AC test bench specification, including onshore grid parameters, test cases and dynamic performance criteria need to be well aligned with the InterOPERA demonstrator use cases specified in [9]. This section provides an overview of the link between the demonstrator onshore AC use cases and the specifications provided within this document (Task 3.3.5).

For reference purpose Figure 1 shows the demonstrator 3 terminal topology with 2 onshore HVDC converter stations connected to two different AC grids. The onshore POC topologies and equivalent interconnection line is shown[1].

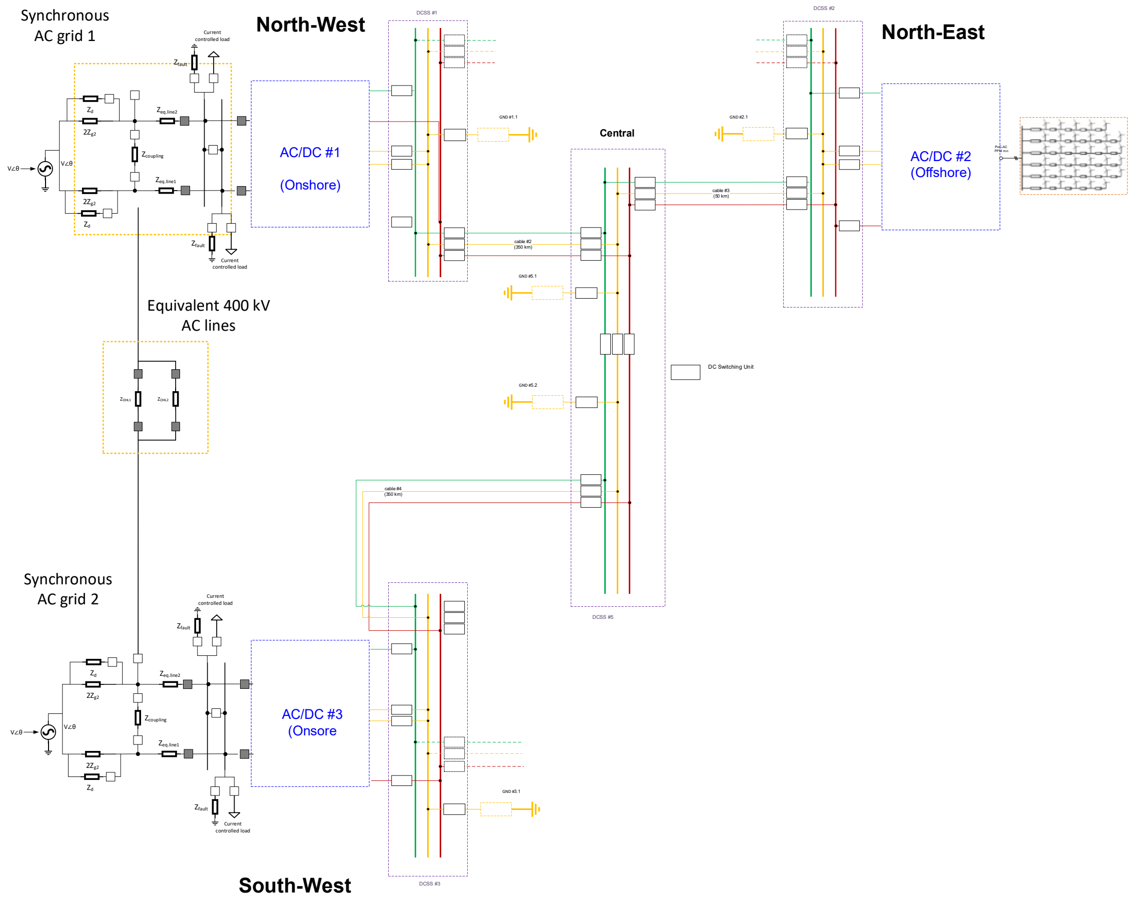


Figure 1. Demonstrator 3 terminal variant 2 (2 onshore AC stations and 1 remote-end isolated AC grid station with PPMs)

The following use cases from the InterOPERA demonstrator use case document [9] are relevant for the onshore AC testbench specification. It is important to distinguish the use cases which involves grid-following control of the onshore HVDC converters, and which use cases involve grid-forming control as they will have different requirements both regarding which electrical equivalent representation and parametrization of the onshore AC grid to be used and which dynamic performance requirements applies. The demonstration, and thereby also the specification is to be done in two stages, where it is

[1] The purpose of the equivalent AC line is to accommodate UC05-12, where the small-signal stability and interoperability of creating a coupling between two different onshore AC/DC converter stations is explored. The purpose of the equivalent line is not to test the transient response of synchronizing two asynchronous AC grids.

decided that Stage 1 focuses on GFL control mode of the onshore HVDC converter stations, while Stage 2 focuses on GFM control mode of the onshore HVDC converter stations[2].

Stage 1 – Preliminary specification focused on GFL mode

Table 1. Onshore AC use cases relevant for Stage 1 focused on GFL control of the onshore HVDC converter stations.

Use case ID	Use case name
UC05-01	Onshore AC fault ride through capability and post fault active power recovery

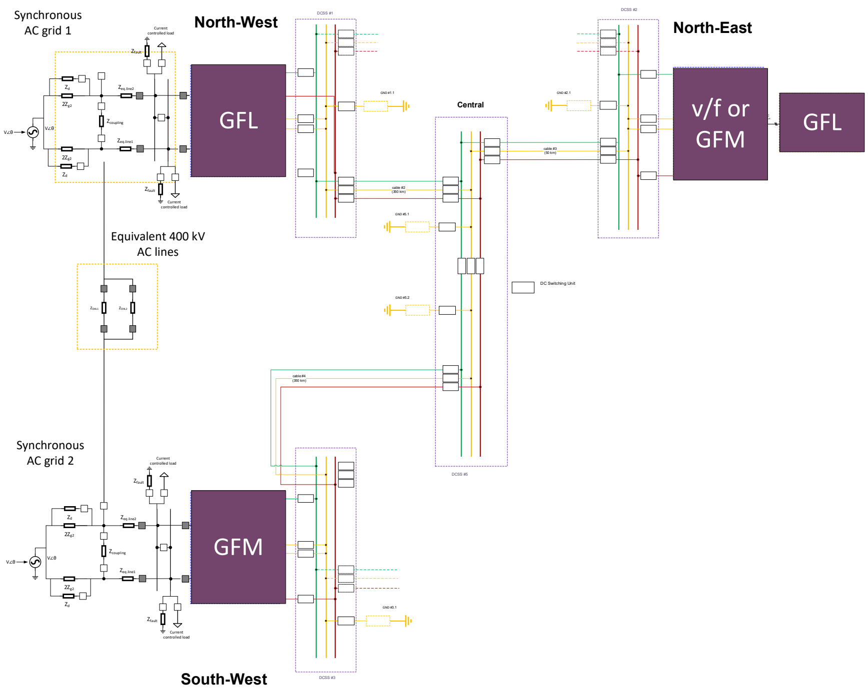


Figure 2. Demonstrator Phase 1, 3-terminal configuration of control modes

Stage 2 – Final specification focused on GFM mode

Table 2. Onshore AC use cases relevant for Stage 2 focused on GFM control of the onshore HVDC converter stations.

Use case ID	Use case name
UC05-01 (iteration #2)	Onshore AC fault ride through capability and post fault active power recovery (second iteration for verification of interoperability when the disturbed HVDC converter station is in GFM control mode)
UC05-02	Reactive power support under extreme grid conditions
UC05-03	Grid forming active power support to the onshore AC grid[3]
UC05-12	Exploration of HVDC system stability and interoperability with interconnected AC areas

[2] The decision regarding the demonstrator's configuration between GFL or GFM in Stage 1 and Stage 2 is dictated by the HVDC vendors expected delivery schedule of control solutions to the laboratories as documented on T3.3 steering level.

[3] As a fall-back solution this use-case can also be performed on the control configuration for Stage 1 as shown in Figure 2, where one onshore HVDC converter station is in GFM-APC control mode, and another onshore HVDC converter station is in GFL-Vdc fixed control mode.

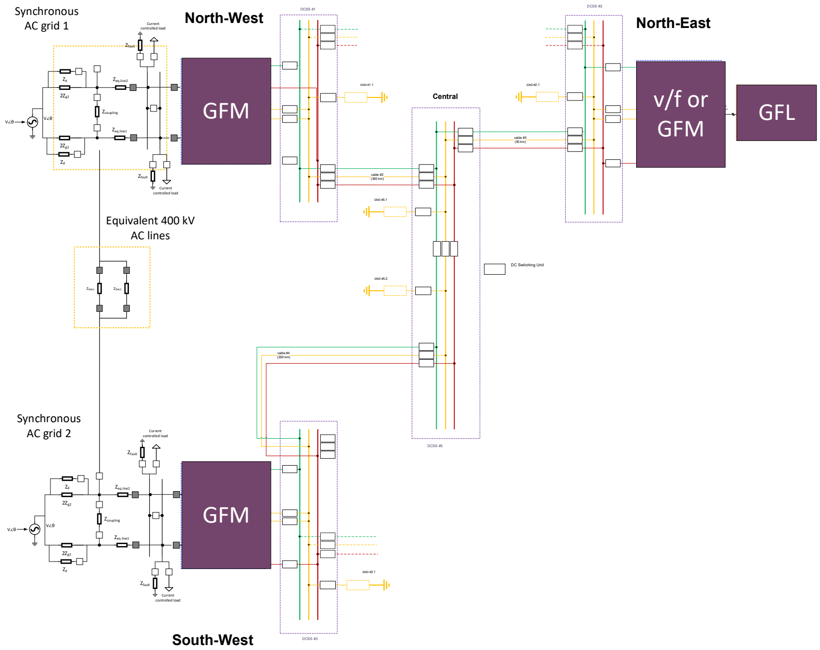


Figure 3. Demonstrator Phase 2, 3-terminal configuration of control modes

Stage X – Optional offline EMT demonstration of GFM

Table 3. Optional onshore AC use case for demonstrating GFM with support from offshore WTGs.

Use case ID	Use case name
UC05-04	Grid forming active power support to the onshore AC grid including support from offshore WTGs

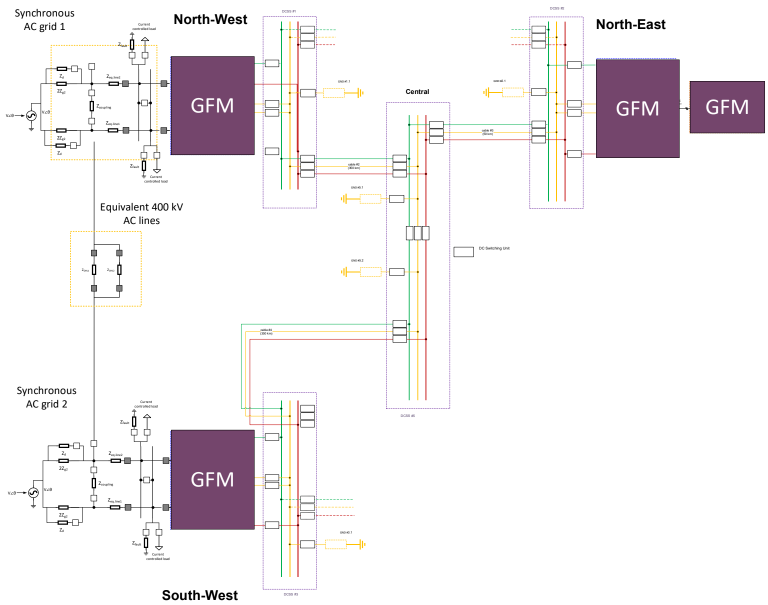


Figure 4 Demonstrator Stage X, 3-terminal configuration of control modes (expected to be offline EMT only)

1.2 Specification

Table 4 provides an overview of the specification of the onshore AC grid which impacts the onshore HVDC converter station specification and the overall HVDC system of the demonstrator project.

Table 4. High level summary of requirements specified for the onshore HVDC converter stations in Task 3.3.5

	General requirements	
	Preliminary specification (Stage 1)	**Final specification (Stage 2)**
Onshore AC grid topology	Option 3 and its associated electrical parameters as described in Subsection 2.3 shall be applied for representation of the onshore AC connection points in the demonstrator	Same as Stage 1
Thevenin equivalent parameters	AC grids shall use the Thevenin equivalent parameters presented in Section 3.1 Table 8 to represent a Continental Europe synchronous area connection point[4]. The minimum short-circuit level for GFL can be used as design basis in Stage 1.	Same as Stage 1, but using the specified minimum level for GFM converter stations.
Equivalent AC line between onshore grid areas	Not required	The equivalent AC line parameters specified in Section 2.5 shall be used for UC05-12 as per [9].
Frequency dependent grid representation	Not required	The Nordic frequency dependent grid model and parameters presented in Section 3.4 shall be used as design basis as it represents the lowest inertia level. Note that as part of the GFM use cases (UC05-01, UC05-02, UC05-03, UC05-04 and UC05-12), the Continental Europe frequency dependent model is to be tested which represents a higher inertia level.
General grid code compliance	The onshore HVDC converter stations shall be compliant to the German implementation of the NC HVDC, referenced as VDE-4131, with further detailing as specified under TenneT NAR Annex B.300.	Same as Stage 1

[4] To avoid that the AC/DC converters have to be designed for more than one AC connection point it is decided to use the Continental Europe Thevenin equivalent parameters for design basis. This is also decided to enable rotation of the different AC/DC converter OEMs for interoperability testing in the demonstrator.

Withstand requirements for GFM control	Not required	The GFM HVDC converter stations shall be capable of withstanding the conditions and test cases described in Section 5.9
Dynamic performance requirements for GFM control	Not required	The dynamic performance criteria and test cases specified in Chapter 5 shall be followed in the GFM use cases as specified.
	Use case specific requirements	
UC05-01: FRT and PFAPR	Required (See details in Section 4.4)	Required. Same requirements Stage 1
UC05-02: Inherent reactive power capability and voltage control	Not required	Required (See Section 4.4 and Chapter 5)
UC05-03: Phase jump active power and inertial active power	Not required	Required (See Section 4.4 and Chapter 5)
UC05-04: Phase jump active power and inertial active power with support from remote-end WTGs	Not required	Optional (See Section 4.4 and Chapter 5 for onshore HVDC converter station requirements).
UC05-12: Parallel operation of GFM converters	Not required	Required, but no performance requirements.

1.3 Implementation of grid models and measurement methods in the demonstrator

The laboratories will be responsible for implementing the onshore AC network representation for the demonstrator in offline and real-time environments according to the specification in Chapter 2 and Chapter 3 with the calculation methods for measurements as specified in Section 5.2.

2. Electrical topology of the onshore connection point

This section describes the electrical topology representing the AC substation and background AC network in the connection point of the HVDC converter stations of the demonstrator.

In some bi-pole HVDC VSC projects the two converter units encompassing 2 GW bi-pole converter station are directly coupled in the same AC substation, and has equivalent connection to AC transmission lines going in and out of the substation. In other bi-pole HVDC VSC projects the two converter are electrically separated in the AC substation and connects to different AC transmission lines going out of the AC substation and connects to separate areas of the AC network. In this latter case the two converter units are considered weakly coupled through a longer electrical distance.

The following Section 2.1 and Section 2.2 describes these two options considered for the InterOPERA demonstrator.

2.1 Option 1: Single AC source grid-equivalent with AC coupled bi-pole converter units

Note that the following grid representation (Option 1) is NOT the required for the InterOPERA demonstration. It is included here for documentation purposes to reflect the decision process. In Section 1.2 it is stated that Option 3 is the required grid representation.

Figure 5 show the considered Option 1 for representation of the onshore grid in the POC of the converter station.

In Option 1 there is one Thevenin equivalent AC source to represent the AC network. The two converter units of the converter station is in *split bus configuration* in normal operation, as indicated by the open switching units (empty boxes). The equivalent line parameters $Z_{eq.line1}$ and $Z_{eq.line2}$ can be either equal or or different in magnitude. The purpose of making them different would be to represent a situation where the two converter units are connected to the background AC network via different AC transmission lines, resulting in a different short-circuit level at each converter unit.

The impedances can be set to zero to represent a case where the two converter units of the converter station are directly coupled, as it the case in some bi-pole HVDC projects.

$Z_{eq.line3}$ is normally disconnected but can be utilized to simulate a phase jump or SCL disturbance at the converter unit level.

The single Thevenin source representation simplifies the implementation of the more advanced electromechanical grid-equivalent.

An advantage of this option is the simplicity of representation of the impedances linking each converter pole to the network represented by an equivalent impedance. Hence, the number of parameters to represent the AC system is minimal. However, there is less flexibility in this topology, as a split-bus operational scenario of the two converter poles cannot be approximated without significantly increasing the value of $Z_{eq.line1}$ or $Z_{eq.line2}$, which will enforce extreme weak grid operation of at least one converter pole.

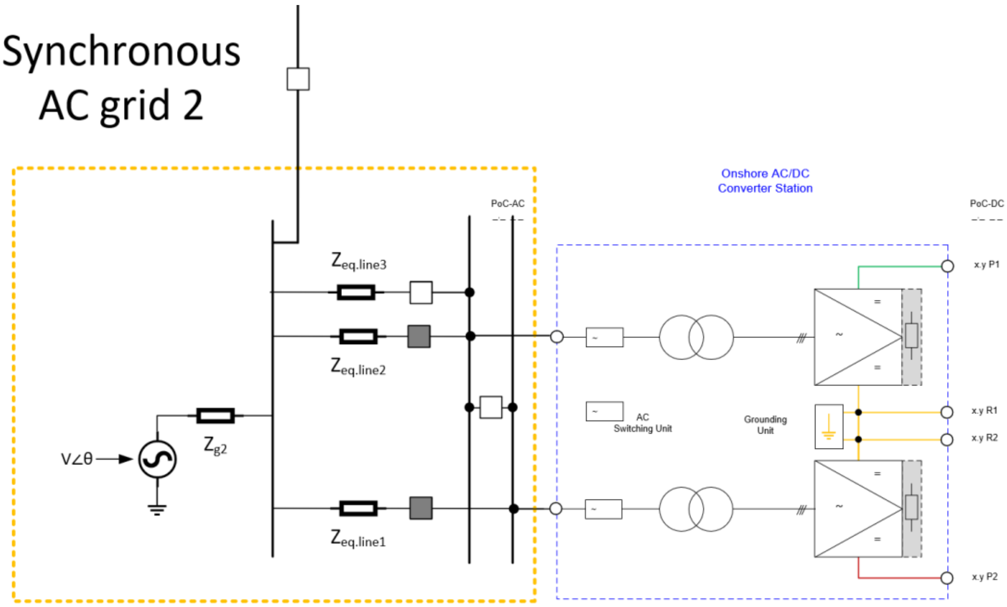


Figure 5. Electrical topology Option 1 of the synchronous AC grid

2.2 Option 2: Double AC source grid-equivalent with normally decoupled bi-pole converter units

Note that the following grid representation (Option 2) is NOT the required for the InterOPERA demonstration. It is included here for documentation purposes to reflect the decision process. In Section 1.2 it is stated that Option 3 is the required grid representation.

Figure 6 show the considered Option 2 for representation of the onshore grid in the POC of the converter station.

In Option 2 there are two Thevenin equivalent AC sources to represent the background network.

Similar to Option 1 the two converter units of the converter station is in *split bus configuration* in normal operation, as indicated by the open switching units (empty boxes). The equivalent line parameters $Z_{eq.line1}$ and $Z_{eq.line2}$ can be either equal or or different in magnitude.

The main difference to Option 1 is that the background AC network is represented by two equivalent Thevenin sources – one connected two each converter unit.

There is no electrical coupling between the two converter units, unless the impedance denoted $Z_{coupling}$ is connected. $Z_{coupling}$ can either be small or large in magnitude, to either represent a strong electrical coupling or a weak electrical coupling respectively. An advantage of this option is the completeness and high flexibility, leading to more phenomena that can be studied. For example, in addition to local coupling emulation through $Z_{coupling}$, this coupling impedance can also be used to emulate interactive behaviours between the converter poles dictated by how far apart they can be seen from the system. However, this option depending on the study case requires a skilled engineer to be aware. For example, if line 1 is disconnected, then, $Z_{coupling}$ should be set to a very large value (effectively decoupling both converter poles) or removed completely. Furthermore, this option being a more complex representation requires more parameters and an implicit fine-tuning process to find the most representative parameters, which may take time.

In a situation where the equivalent line is connected to represent an interconnection between the two onshore HVDC converter stations, the AC switching unit between the two converter units (bus coupler) is to be closed such that both converter units are electrically connected to the other onshore converter station.

Due to the double Thevenin equivalent representation it is more complex to integrate the electromechanical addon model due to the risk of oscillations between the two sources.

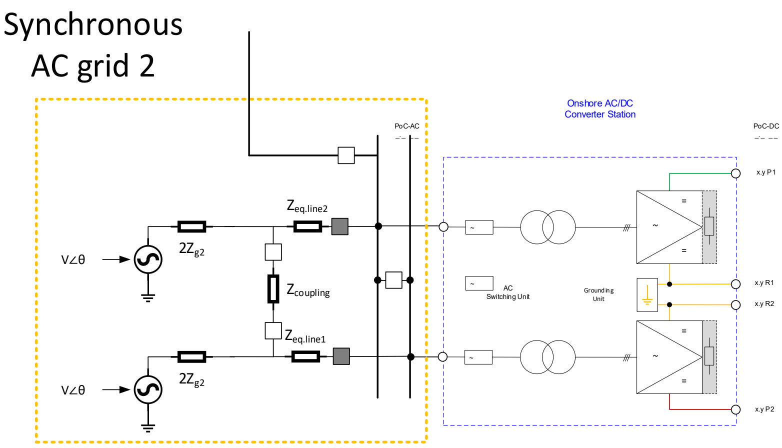


Figure 6. Electrical topology Option 2 of the synchronous AC grid

2.3 Option 3: Single AC source grid-equivalent with normally weak coupling between bi-pole converter units

As stated in Section 1.2 the following grid representation is the required for the InterOPERA demonstration.

Figure 7 show the proposed Option 3 topology of the onshore AC grid equivalent. Option 3 is a compromise between Option 1 and Option 2.

Option 3 contains a single AC source representation for simplicity regarding adding electromechanical dynamics. In the normal operation the HVDC converter station is connected in a split-bus configuration with different impedances $Z_{eq.line1}$ and $Z_{eq.line2}$. The source impedance Z_g is divided into two parallel connected impedances, such that in normal operation the HVDC converter units are electrically coupled through these impedances.

The effective short circuit level (SCL) at the terminals of each HVDC converter units will be lower than the specified value of the Thevenin source due to the impedances $Z_{eq.line1}$ and $Z_{eq.line2}$ respectively.

There is an optional parallel connecting impedance, $Z_{coupling}$, to enable a closer electrical coupling between the two converter units.

This coupling impedance, $Z_{coupling}$, should also be connected in the event where the connection to the other AC area is tested.

Z_d is used for making step changes in the short circuit power in the connection point.

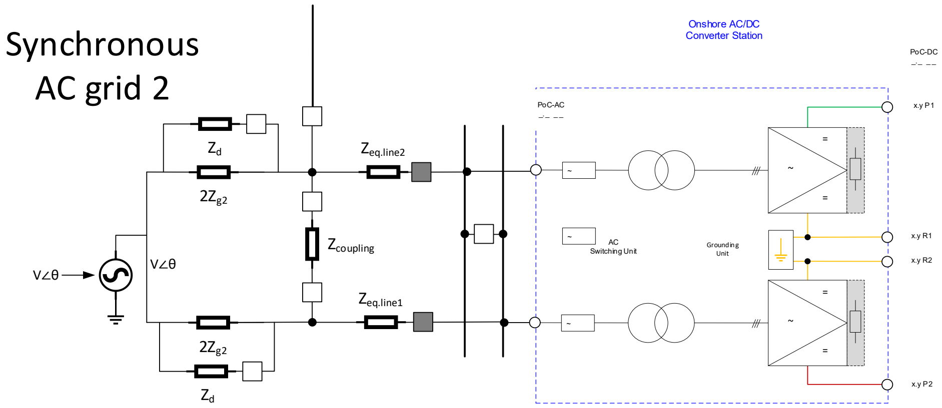


Figure 7. Electrical topology Option 3 of the synchronous AC grid

2.4 Interconnection and AC coupling between onshore converter stations

The base case for the demonstrator is that the two onshore AC systems are electrically decoupled and can be considered as two different synchronous areas.

However, in order to investigate the interaction issues that may arise, it is decided to implement an optional interconnection between two different onshore AC systems. Figure 8 show the proposed topology for the electrical interconnection between the two areas. It is proposed to base the impedances on equivalent 400 kV overhead lines, with the possibility to have two different kinds of electrical coupling between AC grid 1 and AC grid 2 by changing between Z_{OHL1} and Z_{OHL2}.

It is proposed that Z_{OHL1} represents a relatively long equivalent electrical distance of 250 km as the base case, while Z_{OHL2} represents a short electrical distance of just 50 km equivalent electrical distance.

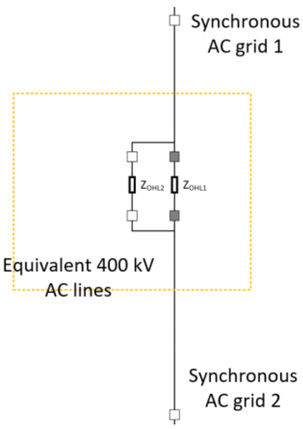


Figure 8. Optional interconnection between synchronous AC grid 1 and synchronous AC grid 2

To determine the maximum length of the equivalent 400 kV line between AC grid 1 and AC grid 2 a power flow calculation is done. The objective of the power flow calculation is to approximate the maximum possible electrical distance without violating the steady state stability limit of 90° power angle difference between AC grid 1 and AC grid 2. Two sets of calculation is done, one with a power flow of 1000 MW and another with a power flows of 2000 MW between AC grid 1 and AC grid 2. These values are selected as they would represent the unbalance created between AC grid 1 and AC grid 2 in case of either an HVDC converter unit trip (1000 MW) or a full HVDC converter station trip (2000 MW). The results of the power flow calculation are shown in Figure 9. The results show that in order to ensure a proper margin to the 90° steady state stability limit the electrical distance between AC grid 1 and AC grid 2 should not exceed approximately 250 km of equivalent 400 kV overhead line in order to handle a power flow of 2000 MW between the two areas.

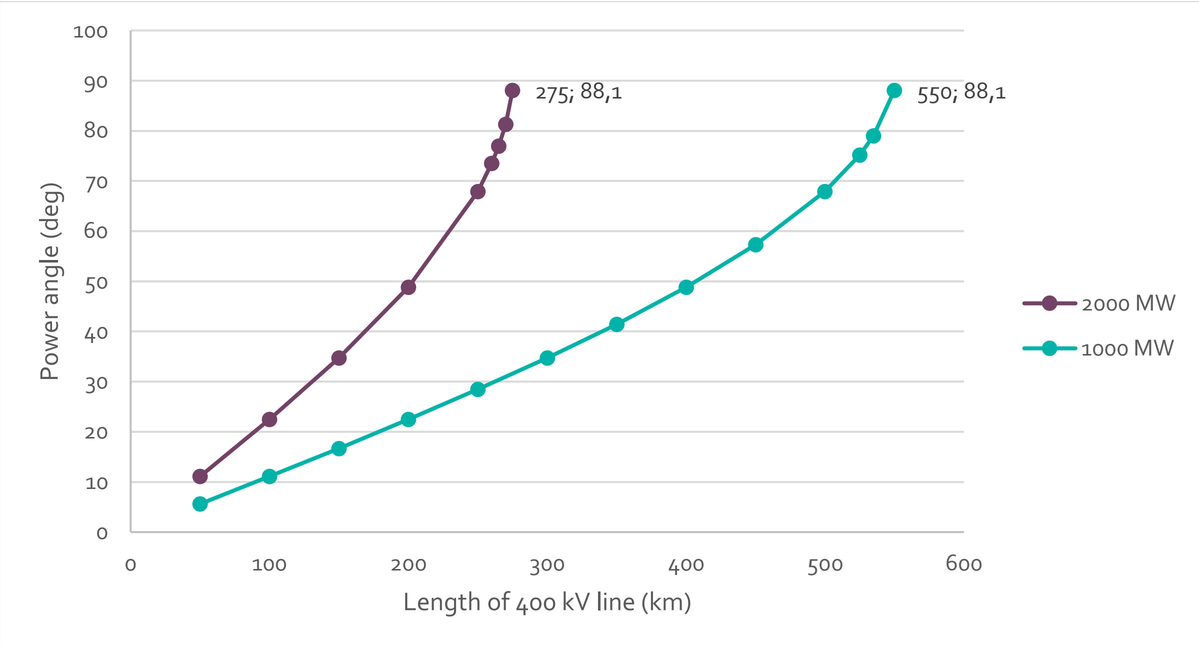


Figure 9. Relationship between the length of the equivalent 400 kV line and the power angle between Area 1 and Area 2 at 1000 MW and 2000 MW power flows.

2.5 Equivalent line parameters

Table 5 show the resistance, reactance and capacitance values per km at 50 Hz nominal frequency for a typical 400 kV overhead line. These data are selected as assumptions for line impedances to be used in onshore AC grid topology.

Table 5. 400 kV overhead line parameters assumed for equivalent line modelling.

Parameter	Value per km	Unit
R	0.022	Ohm/km
X	0.31	Ohm/km
C	0.012	µF/km

Table 6 show the total resistance, reactance and capacitance values at the chosen equivalent line lengths of 10 km and 100 km for $Z_{eq.line1}$ and $Z_{eq.line2}$ respectively. The electrical distance of the coupling impedance, $Z_{coupling}$, can be varied. However, as a base case a close electrical coupling with an impedance equivalent to 1 km of 400 kV overhead line is proposed.

Table 6. Option 3 Total resistance, reactance and capacitance values for equivalent lines.

Parameter	Label	Length (km)	R_{total} (Ohm)	X_{total} (Ohm)	C_{total} (µF)
Equivalent Line 1	$Z_{eq.line1}$	10	0.22	3.1	0.12
Equivalent Line 2	$Z_{eq.line2}$	100	2.2	31	1.2
Unit coupling*	$Z_{coupling}$	1	0.022	0.31	0.012

Table 7 show the total resistance, reactance and capacitance values for the equivalent lines connecting AC area 1 and AC area 2 in case of the optional interconnection between the areas.

Table 7. Line parameters of lines connecting AC grid 1 and AC grid 2

	Label	Length (km)	R_{total} (Ohm)	X_{total} (Ohm)	C_{total} (µF)
AC grid1-2 line 1	Z_{OHL1}	250	5.5	77.5	3
AC grid1-2 line 2	Z_{OHL2}	50	1.1	15.5	0.6

3. Grid equivalents

3.1 Thevenin equivalent data

The Thevenin equivalent data is presented in Table 8 and Table 9.

Note that for Stage 1 the minimum short circuit power is 8000 MVA for both the Nordic and Continental Europe grid equivalents. With an SCL of 8000 MVA at the terminals of the Thevenin equivalent, the effective SCL at the converter terminals using the AC grid topology Option 3 will be approximately 3 GVA (SCR = 3) for the HVDC converter unit connected to the 100 km line, and approximately 7 GVA (SCR = 7) for the HVDC converter unit connected to the 10 km line.

For Stage 2 the minimum short circuit power is 3500 MVA for both grids. With an SCL of 3500 MVA at the terminals of the Thevenin equivalent, the effective SCL at the converter terminals using the AC grid topology Option 3 will be approximately 2.1 GVA (SCR ≈ 2) for the HVDC converter unit connected to the 100 km line, and approximately 3.2 GVA (SCR ≈ 3) for the HVDC converter unit connected to the 10 km line.

Continental Europe grid Thevenin equivalent data

Table 8. Continental Europe synchronous area inspired grid-equivalent

Rated AC voltage	400 kV			
Fundamental frequency	50 Hz			
		Maximum	Minimum for GFM converter stations (Stage 2)	Minimum for GFL converter stations (Stage 1)
Short circuit power, S_{kss} (MVA)		55000	3500	8000
Short circuit current, I_{kss} (kA)		80	-	-
X/R ratio		20	10	10

Nordic grid Thevenin equivalent data

Table 9. Nordic synchronous area inspired grid-equivalent

Rated AC voltage	400 kV			
Fundamental frequency	50 Hz			
		Maximum	Minimum for GFM converter stations (Stage 2)	Minimum for GFL converter stations (Stage 1)
Short circuit power, S_{kss} (MVA)		45000	3500	8000
Short circuit current, I_{kss} (kA)		65	-	-
X/R ratio		20	10	10

3.2 Frequency dynamic model for the Nordic power system

Following the guidelines proposed in InterOPERA D3.2 [10] this section describes a structure and possible parametrization of model that can represent aggregate inertia and frequency dynamics of the Nordic synchronous area.

The starting point is to try and parameterize a frequency response model with a similar structure to what is proposed earlier, for example as shown in Figure 10.

By using measurements recorded from previous disturbances in the Nordic synchronous area, the approach is:

- First, to verify if the model structure is suitable for representing the dynamic characteristics of interest, and
- secondly to identify model parameters that represent a future - yet realistic - low inertia operating situation.

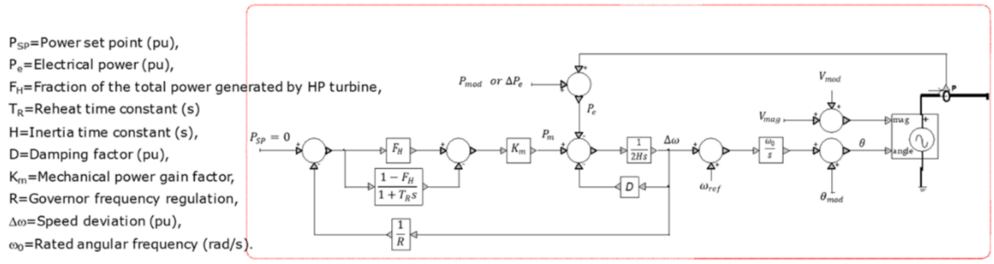


Figure 10. Initially proposed model structure

Large disturbances in the Nordic synchronous area

There are several recorded disturbances that can be used to validate a simulation model. These are typically cases where there is a sudden outage of a large generator or loss of import on HVDC links from a neighbouring synchronous area.

We have chosen one example that clearly show the frequency dynamics. This is a case where the sudden disconnection of a large power plant resulted in a loss of approximately 1200 MW. See Figure 11 and Figure 12.

Figure 11 shows frequency and two power flow measurements over a 3-minute period. By inspecting the frequency drop after the first main swing due to activation of Frequency containment reserves (FCR), it is possible to estimate the frequency bias, which can be used as an initial value for the system frequency droop.

Figure 12 zooms in on the frequency and power flow measurements. From this we can make a rough estimate the total inertia of the Nordic system.

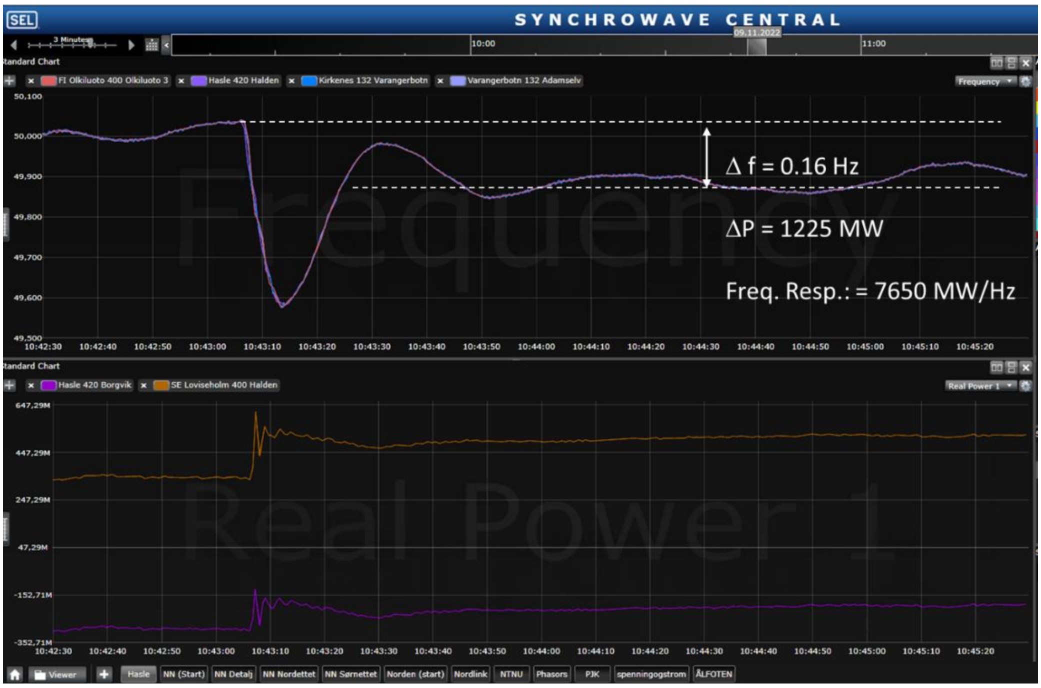


Figure 11. Four frequency and two power flow measurements over a 3-minute period.

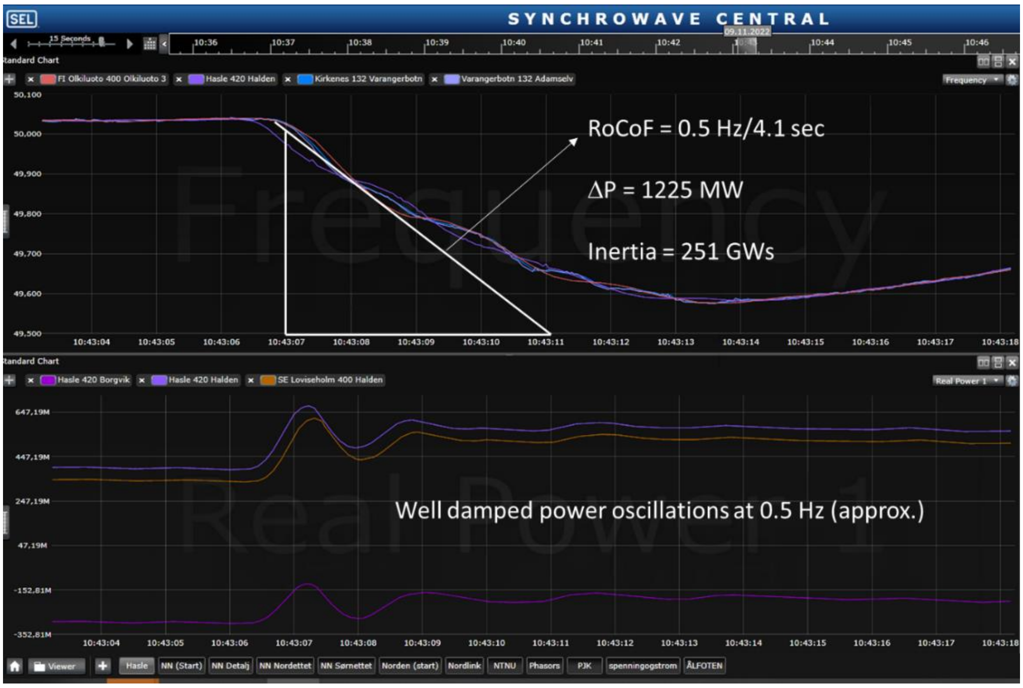


Figure 12. Zoom in on the frequency and power flow measurements.

Modelling and simulations for parameterization

The modelling and simulations presented here aim at illustrating the following:

- What characterizes the Nordic power system now?
- What are the relevant dynamic phenomena that might be possible to represent by a simplified model equivalent?
- What can we expect in the future with lower inertia and much more Inverter Based Resources?
- Which parameters need to be tuned - and how - to obtain a desired response?

By inspection of the high resolution synchrophasor measurement shown above, we start with the two important parameters that can be used directly to initiate tuning of the simplified frequency response model, i.e. the inertia constant and the governor droop. Thereafter, we tune the remaining set of parameters in the proposed model shown in Figure 13. Satisfactory performance of the tuned model was achieved with the set of parameters listed in Table 10 below. For comparison, both measured (red curve) and simulated (blue curve) responses of the present system are shown to the left in Figure 14.

Finally, we propose a set of parameters for the final model that can be used in the further simulation studies in InterOPERA.

The model structure shown in Figure 13 was implemented in MATLAB for this purpose. Since most of the frequency containment reserves in the Nordic system are provided by Hydro power plants, we propose to use a frequency control model that resembles the hydro turbine governing system as a PID-controller with droop feedback.

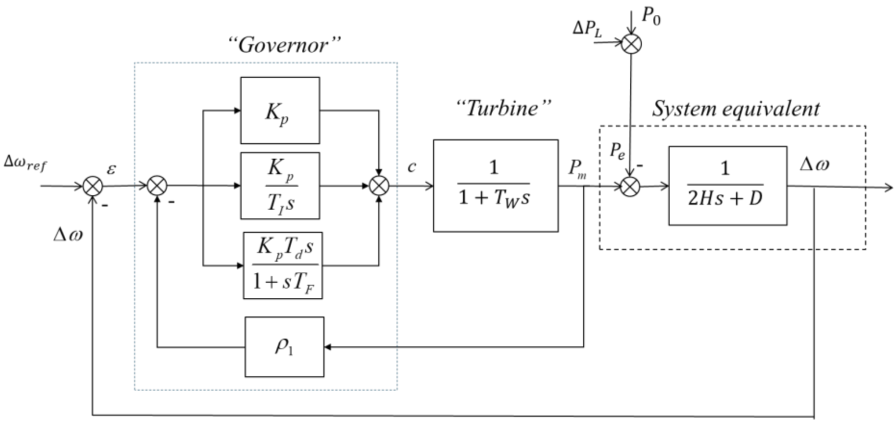


Figure 13. Proposed model structure for parameter identification.

Simulations are performed by applying a step response in net load, ΔP_L (equal to the assumed 1225 MW loss of generation) and then comparing the simulated and measure response in frequency, $\Delta\omega$.

The initial value on frequency droop, ρ_1, is set to give a frequency bias of 7650 MW/Hz. Using base values of power, S_N = 2000MW and frequency, f_N = 50 Hz, this gives:

$$\rho_1 = \frac{\Delta f}{\Delta P} \cdot \frac{S_N}{f_n} = \frac{2000}{7650 \cdot 50} = 0.0052\ p.u$$

Initial value on inertia is set to 250 GWs. Using the same base values on power, S_N = 2000MW, the inertia constant to be used is:

$$H = \frac{250\ GWs}{S_N} = \frac{250\ GWs}{2\ GW} = 125\ s$$

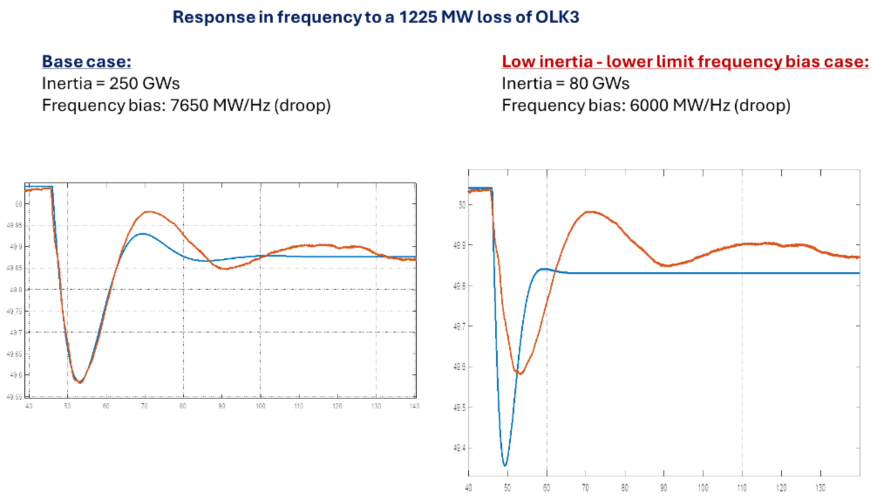


Figure 14. Left: Measured (red curve) and simulated (blue curve) responses of the present system with the parameters listed below. Right: The blue curve show simulated response of a system with less inertia and less frequency containment reserves (higher droop).

Table 10. Suggested parameters for representation of the present Nordic power system and a future low inertia operating state.

Parameter	Base case – present system	Low inertia - lower limit frequency bias case:	Comments
Inertia constant	$H = 125$ s	$H = 40$ s	40 s → 80 GWs
Damping factor	$D = 0$	$D = 0$	
Permanent droop	$\rho_I = 0.00523\ p.u$	$\rho_I = 0.0067\ p.u$	6000 MW/Hz
Governor gain	$K_p = 50\ p.u.$	$K_p = 50\ p.u.$	
Integral time	$T_I = 4.0$ sec.	$T_I = 4.0$ sec.	
Derivative time	$T_d = 0$	$T_d = 0$	
Turbine-governor time lag	$T_W = 1.0$ sec.	$T_W = 1.0$ sec.	
Per unit base: S_N = 2000 MVA, f_N = 50 Hz, ω_0 =2p 50 radians/s			

Response in frequency to a 1200 MW loss of import

For further verification the model was tuned and compared with another recorded case - measured response to sudden loss of import to Norway on one of the HVDC links.

Base case:

Similarly as in the first case above, the total inertia was estimated to 200 GWs, and the frequency bias to 8000 MW/Hz. The measured (red curve) and simulated (blue curve) responses to the given disturbance are shown to the left in

Figure 15.

Low inertia - lower limit frequency bias case:

The lower inertia case, shown in the right figure, was simulated with Inertia = 80 GWs, and frequency bias = 6000 MW/Hz (droop)

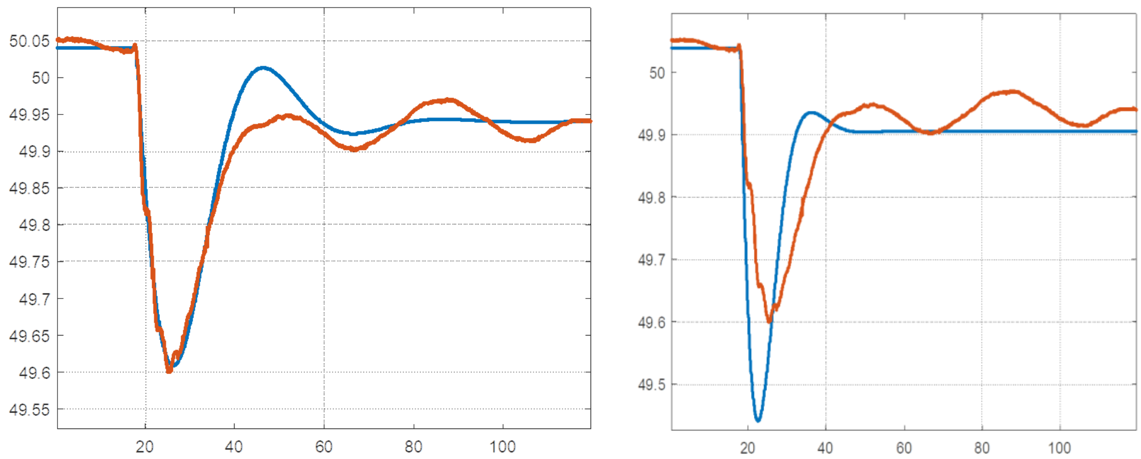


Figure 15. Left: Measured (red curve) and simulated (blue curve) responses of the present system. Right: The blue curve show simulated response of a system with less inertia and less frequency containment reserves (higher droop).

Discussion

The choice of model structure and model order depend on which dynamic phenomena to include. Power system dynamics of interest may range from electromagnetic transients, inertia, electro-mechanical modes, down to the response of primary frequency control (FCR) and slower variations.

With the presented one-mass model it is clearly possible to represent the total inertia within the synchronous area and the aggregated response of primary frequency control.

The model cannot adequately represent electro-mechanical modes and power swings that have an impact on transient frequency behaviour. To include that it would be necessary to use a multi-mass model, however, that would also make the model more difficult to tune.

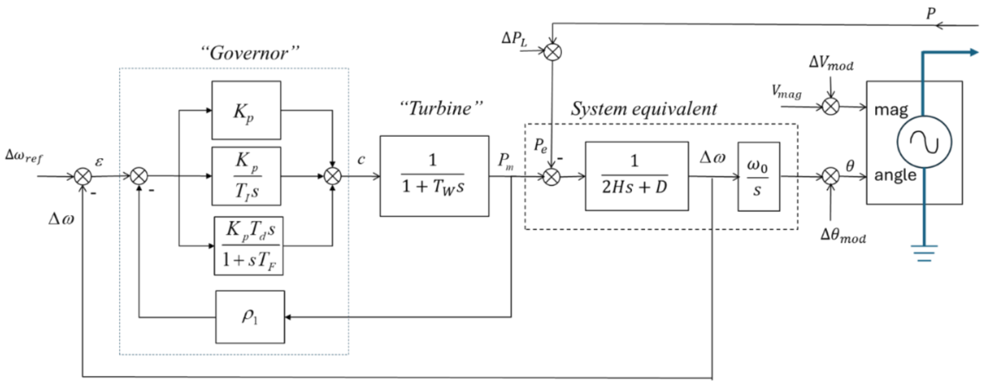


Figure 16. The complete proposed model to represent both voltage amplitude and angle at point of connection to the HVDC converter. Change of power from the DC grid is added to the total load in the AC grid.

Comments

- The complete model structure as shown in Figure 16 is proposed to represent the frequency dynamics in the Nordic grid. It seems possible to tune the proposed model to represent the "primary" frequency dynamics very well.
- To represent a future scenario, one can reduce frequency bias (low operating limit in the Nordics is 6000 MW/Hz) and Inertia to less than 100 GWs
- Damping, D, can be set to near zero as we don't really know the frequency dependence of the load.
- In this example, it was not necessary to use the derivative part of the PID controller to obtain satisfactory performance.
- Note: If one chooses to change the system base, it is necessary also to adjust the governor gain – inverse proportional to system base
- To include low frequency electro-mechanical modes, we need several of these models, but we can come back to that if it becomes relevant.
- Note: RoCoF can locally be larger due to angle swings

3.3 Frequency dynamic model for the Continental European power system

This section describes a structure and parametrization of the model that can represent aggregate inertia and frequency dynamics of the Continental European synchronous area.

Large disturbance in the Continental European grid

PMU measurements were used to estimate the parameters of the frequency dynamic model for the CE power system. ARMAX estimation method [Ref-2][5] was used to identify the total system inertia. The identification method requires active power deviation (ΔP) and frequency measurements. Figure 17 displays the frequency measured by PMU on the French grid following a ElecLink trip (ΔP approximately 1130 MW). Before applying the identification technique, the frequency signal needs to be in per-unit (50 Hz base frequency) and a post-disturbance data window length should be selected (see Figure 17). A second-order model was applied, and the inertia constant was extracted from the identified transfer function Δf/ΔP. The estimated inertia constant is 607 s (base power 2000 MW). Similarly to the Nordic power system case, the frequency droop (R) was estimated by inspecting the frequency bias:

$$R = \frac{\Delta f}{\Delta P} \cdot \frac{S_N}{f_n} = \frac{0.035 \cdot 2000}{1130 \cdot 50} = 0.0012\, p.u$$

The reduced order model shown in Figure 19 was implemented considering the parameters given in table below. The model response to a load step of 0.565 pu (2000 MW base power) is shown in Figure 18. It can be noted with this simplified model is possible to represent the system inertia and the equivalent frequency droop gain (R).

Table 11. Parameters for the reduced order model. The inertia constant and p.u. values are calculated on a 2000 MVA power base.

	Parameter value
H	607 s
F_H	0.3
D	0
K_m	1
R	0.0012 pu
T_R	8 s

[5] [Ref-2]: B. Pinheiro, L. Lugnani and D. Dotta, "A Procedure for the Estimation of Frequency Response using a Data-Driven Method," 2021 IEEE Power & Energy Society General Meeting (PESGM), Washington, DC, USA, 2021, pp. 01-05, doi: 10.1109/PESGM46819.2021.9637946.

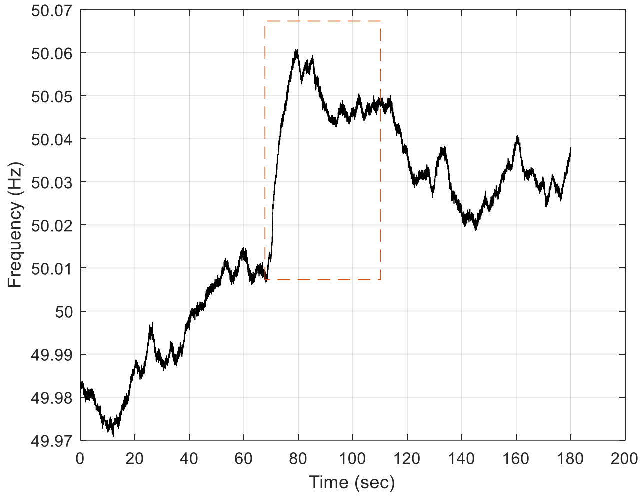


Figure 17 Eleclink trip: PMU measured frequency on the French grid

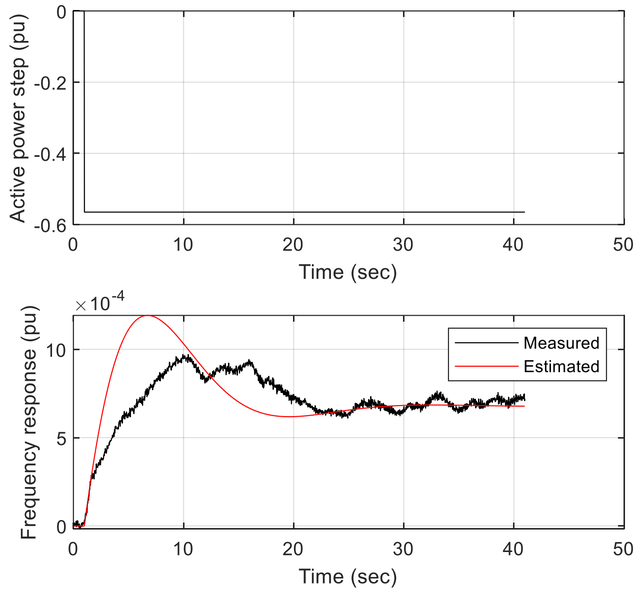


Figure 18 Simulated frequency response of the low order model following a active power step of 0.565 (1130 MW/2000 MW)

Modelling and simulations for parameterization

This section presents the grid equivalent model consisting of the frequency dynamics. Such a model considers the inertia of the AC grid which means the frequency of the grid is affected by the power flows of the same grid. For this study, a model with low-order system frequency shown in Figure 19 is sufficient [Ref-1][6]. To prevent unnecessary complications, the system defense plan (SPD) related functionalities are not included.

[6] [Ref-1]: Anderson, P.M. and Mirheydar, M., 1990. A low-order system frequency response model. IEEE transactions on power systems, 5(3), pp.720-729.

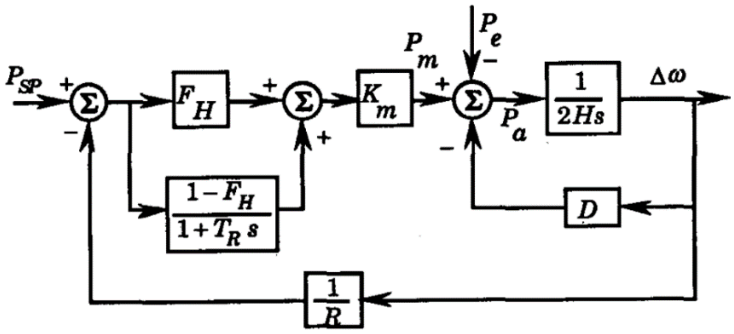


Figure 19. The reduced order system frequency response[7]

where,

P_{SP} = Incremental power set point, per unit
P_m = Turbine mechanical power, per unit
P_e = Generator electrical load power, per unit
$P_a = P_m - P_e$ = Accelerating power, per unit
$\Delta\omega$ = Incremental speed, per unit
F_H = Fraction of total power generated by the HP turbine
T_R = Reheat time constant, seconds
H = Inertia constant, seconds
D = Damping Factor
K_m = Mechanical Power Gain Factor

Modeling parameters

The inertia constant (H) of the reduced order system is obtained by dividing the total kinetic energy over the total rated power of the system. Based on the defined scenarios in the ENTSO-E report for underfrequency support settings of new flexibilities [Ref-2][8], the total kinetic energy for the CE is assumed to be in the range of 480 GWs to 1280 GWs. Table 12 shows the summary of the related variables form [Ref-2].

Table 12. Overview of scenarios and parameters used in the simulation model [Ref-2]

	Unit	Scenario A: "High Load"	Scenario B: "Low Load"	Scenario C: "Peak RES"
TYNDP Target Year	(yr)	2030	2030	2030
…	…	…	…	…
Load	(GW)	520	260	400
inertia constant H calculated for the system	(s)	2.46	3.38	1.2

The assumed range of kinetic energy is aligned with the data reported in [Ref-3][9] as shown in Figure 20.

[7] Note the sign convention with +/+ summation which is the correct implementation of this block diagram.
[8] [Ref-2]: ENTSO-E, "Investigation on Default Underfrequency Support Settings of New Flexibilities in Continental Europe", Version 3.1, SG SPD-TF Inertia, 18 April 2024
[9] [Ref-3]: ENTSO-E, "Inertia and Rate of Change of Frequency (RoCoF)", Version 17, SPD-Inertia TF, 16. Dec. 2020

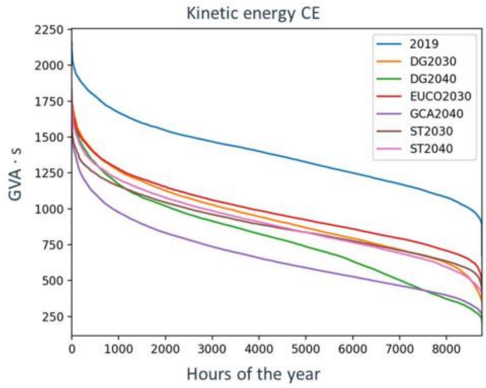


Figure 20. Duration curves of the estimated total kinetic energy in Continental Europe [Ref-3]

Using the base power of 2000 MVA, the inertia constant (H) can be assumed to be in the range of:

- H_{low}=240 s and H_{high}=640 s

As an assumption, for the listed parameters below, generic values are assigned as:

- F_H=0.3
- D=0
- K_m=1

Next, for tuning of R and T_R, an EMT benchmark model is created in PSCAD environment with the frequency dynamic model of Figure 19.

Figure 21 and Figure 22 respectively show the benchmark grid, and the frequency calculation diagrams.

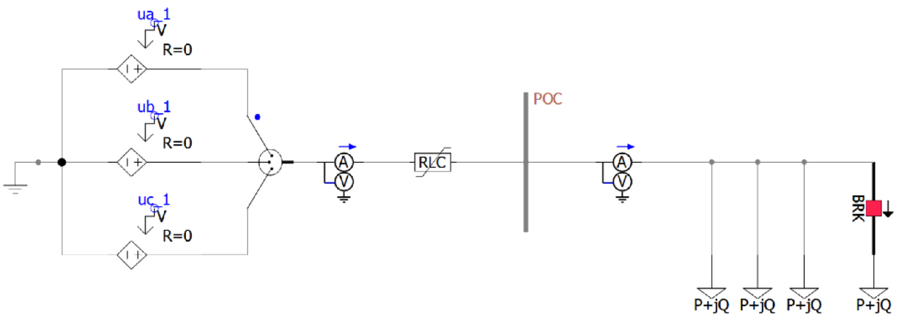


Figure 21. The benchmark grid of frequency dynamic model in PSCAD

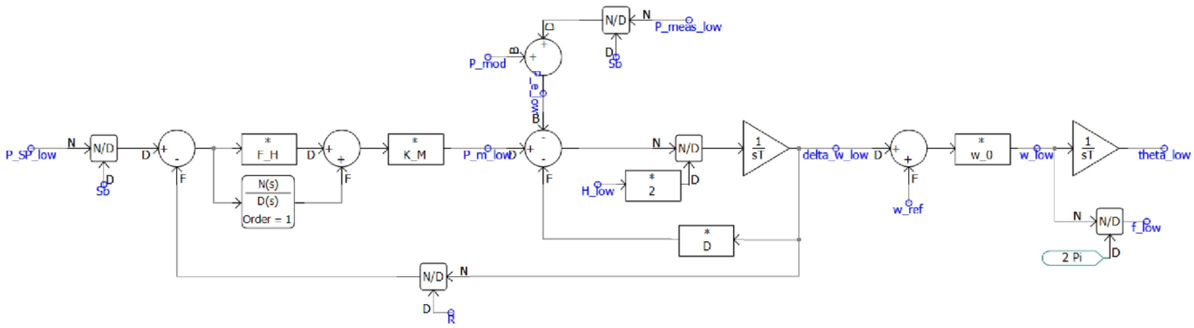


Figure 22. The frequency calculation diagram in PSCAD

The reference case of ENTSO-E study in [Ref-2] is selected as basis to tune the parameters. For this test case, the frequency is plotted vs time for disturbance that led to RoCof=1 Hz/s. The imbalanced power that leads to RoCof = 1 Hz/s is chosen based on Figure 23 (see [Ref-4][10]) to be equal to 24GW for "Peak RES", which corresponds to H_{low}.

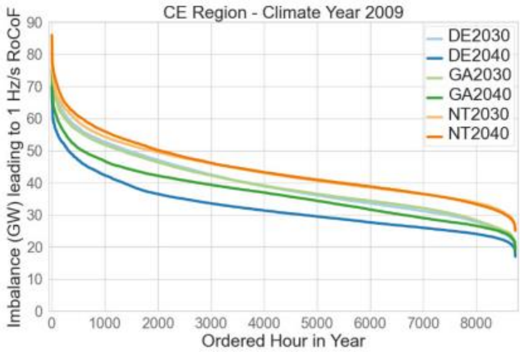


Figure 23. Imbalance leading to 1 Hz/s RoCoF [Ref-4]

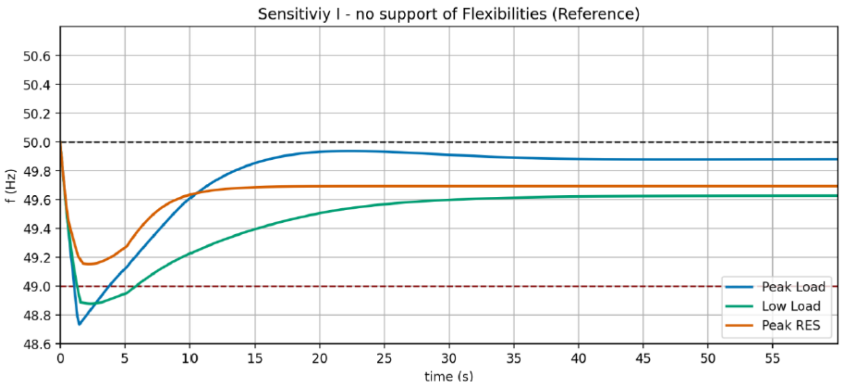


Figure 24. Frequency measurement of reference case for three scenarios [Ref-2]

In the developed PSCAD model (with removed grid impedance), the steady-state value of the frequency is used to tune R. Next, the RoCof and frequency nadir are used to tune T_R by test & trial. Figure 25 shows the frequency response in the test benchmark with the following values of R and T_R:

- R = 5.3e-4 pu
- T_R=12 s

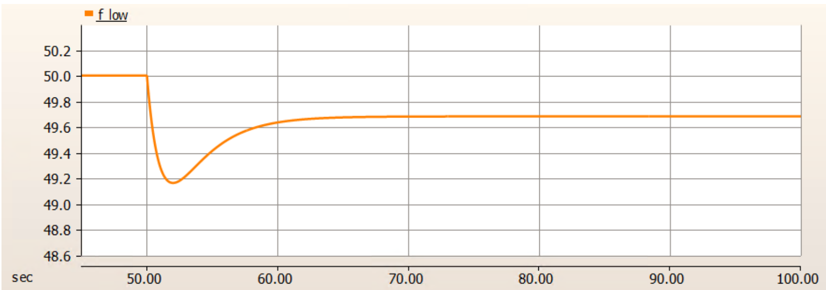


Figure 25. Frequency measurement of tuned case for low-inertia or "Peak RES".

[10] [Ref-4]: ENTSO-E, "TYNDP 2022 - System Needs Study," 05 2023. [Online]. Available: https://eepublicdownloads.blob.core.windows.net/public-cdn-container/tyndp-documents/TYNDP2022/public/syst-dynamic-operational-challenges.pdf. [Accessed 17 12 2023].

3.4 Final frequency dependent model for the InterOPERA demonstrator

Nordic synchronous area representation

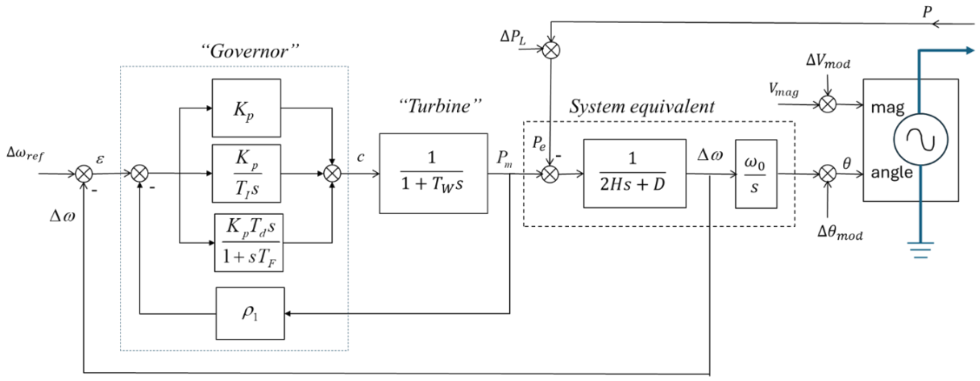


Figure 26. Nordic area frequency dependent model for the InterOPERA demo project.

Table 13. Parameters for the Nordic frequency dependent model. The inertia constant and p.u. values are calculated on a 2000 MVA power base.

Variable P: Represents electrical power measured at the source terminal, and positive direction is into the HVDC converter AC terminals.

	Parameter value
H	40 s
D	0
T_w	1
K_p	50
T_d	0
T_i	4
T_F	Derivative part excluded[11]
ρ_i	0.0067

[11] T_F: This is meant to represent a low pass filter for the derivative part of the controller. In practice this is necessary to avoid amplification of high(er) frequency dynamics and noise. It is not so relevant for InterOPERA, but if one would use the derivative part, T_F could be set to be some 5-20% of T_d

Continental Europe synchronous area representation

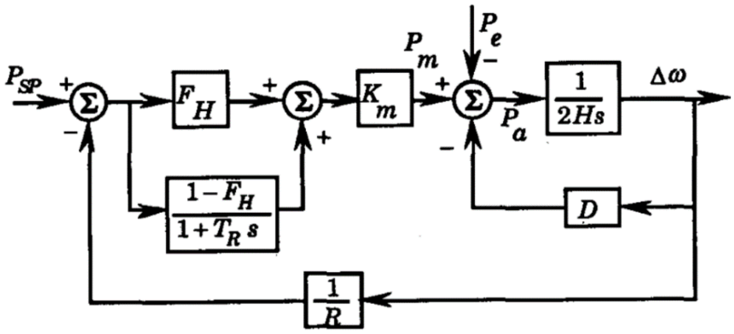


Figure 27. Continental Europe area frequency dependent model for the InterOPERA demo project.

Variable P_e: Represents electrical power measured at the source terminal, and positive direction is into the HVDC converter AC terminals.

Table 14. Parameters for the Continental Europe frequency dependent model. The inertia constant and p.u. values are calculated on a 2000 MVA power base.

	Parameter value
H	240 s
F_H	0.3
D	0
K_m	1
R	5.3e-4 pu
T_R	12 s

4. General HVDC converter station requirements

Regarding the technical requirements to the HVDC converter stations of the HVDC system in the AC connection points the InterOPERA demonstrator HVDC system shall be compliant with the European network code for HVDC systems, Commission Regulation (EU) 2016/144, also referred to as NC HVDC [1]. However, several paragraphs of the NC HVDC are so called non-exhaustive, meaning that the detailed specification of the requirement is open to each member state of European Commission. Thus, in order to achieve a NC HVDC compliant InterOPERA demonstrator the details of the technical requirements must be exhausted.

As the primary purpose of InterOPERA is to develop multi-terminal multi-vendor capabilities of HVDC systems the main technical focus is on the requirements in the DC connection points of the system, and not to revise the typical functionalities towards the AC connection points. Thus, it is proposed to adopt the exhaustive requirements to be stipulated under the NC HVDC from existing approved requirements from one of the member states.

Due to maturity, detail level and public available it is decided to propose TenneT TSO GmbH Netzanschlussregeln Hoch- und Höchstspannung (NAR) [2], which is a detailed specification under the VDE-AR-N 4131 [3], which is the German national implementation of the NC HVDC.

The relationship and hierarchy between the requirements under the NC HVDC is shown Figure 28.

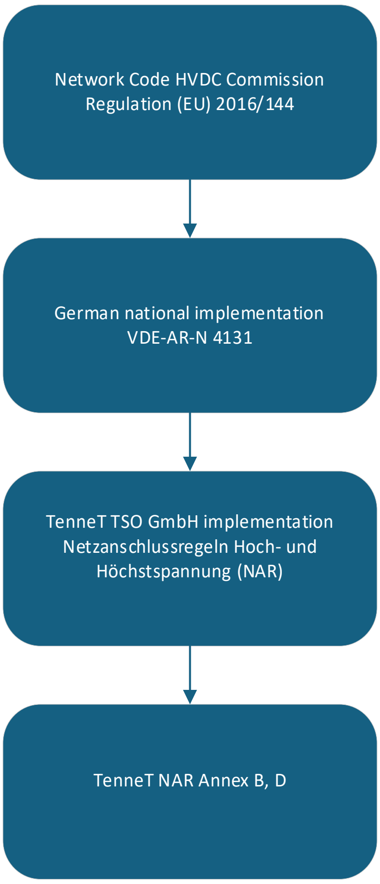


Figure 28. Applicable grid-code hierachy for InterOPERA demonstrator HVDC system

4.1 AC frequency range

The AC voltage range is specified in VDE-AR-N 4131 [3] and is shown in Table 15.

Table 15. AC frequency range as per VDE-AR-N 4131

Frequency range	Minimum time periods for operation
47.0 Hz to 47.5 Hz	> 60 s
47.5 Hz to 49.0 Hz	> 90 min
49.0 Hz to 51.0 Hz	Unlimited
51.0 Hz to 51.5 Hz	> 90 min
51.5 Hz to 52.0 Hz	> 15 min

4.2 AC voltage range

The AC voltage range is specified in VDE-AR-N 4131 [3] and is shown in Table 16.

Table 16. AC voltage range as per VDE-AR-N 4131

Nominal network voltage (kV)	Voltage range (kV)	Minimum time period for operation
380	340 to 420	Unlimited
380	420 to 440	60 min

4.3 Reactive power capability

The reactive power capabilities are specified in TenneT NAR Annex B.403, as shown in Figure 29, which corresponds to Variant 2 in VDE-AR-N 4131.

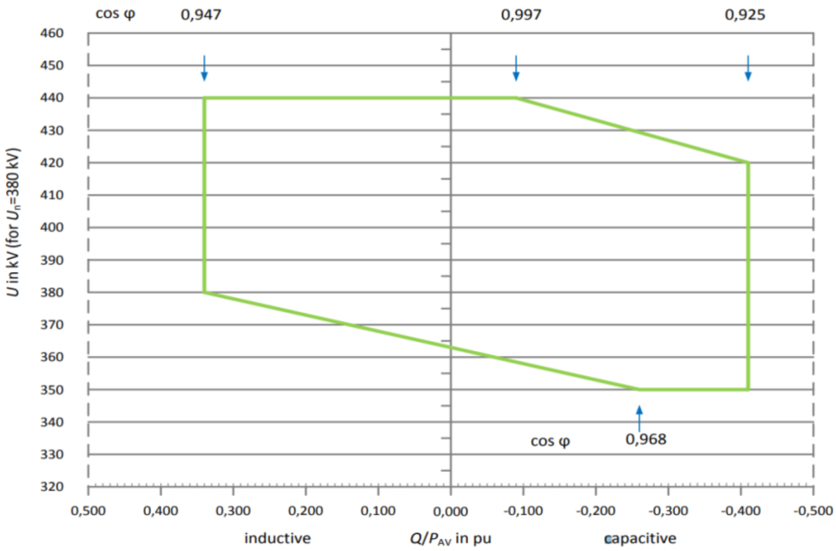


Figure 29. Reactive power capability as required in TenneT NAR Annex B.403 corresponding to Variant 2 in VDE-AR-N 4131.

4.4 Application of requirements in relevant use-cases

UC05-01 Onshore AC fault ride through capability and post fault active power recovery

FRT requirements as specified in:

- VDE-AR-N 4131 Section 10.1.15

Current response during faults:

- For GFL converter stations: Dynamic voltage control with reactive current specification as specified in VDE-AR-N 4131 Section 10.1.9.3
- For GFM converter stations: The inherent reactive power capability of GFM control as specified in [6] replaces the specified "dynamic voltage control with reactive current specification".

Post fault active power recovery requirements as specified in:

- VDE-AR-N 4131 Section 10.1.16, and
- TTG NAR B.300 Section 6.9
- For Requirement 6.9.1 of NAR B.300 the HVDC converter vendor proposes a ramp rate

Test cases:

- Fault cases as per Section 5.10

UC05-02 Reactive power support under extreme grid conditions

Inherent reactive power capability required for HVDC converter stations with GFM control:

- Functionality required as specified in InterOPERA D2.2
- Dynamic performance criteria as per Section 5.7 (this document) based on TTG NAR B.409

Voltage control mode with reactive power droop required for all onshore HVDC converter stations as specified in:

- TTG NAR B.300 Section 6.3
- The inherent reactive power capability of GFM control replaces the specified "dynamic voltage control".
- For requirement 6.3.1.14 the HVDC converter vendor proposes a rise time and settling time within the limits set out in the NC HVDC.
- The HVDC converter station shall be able to fulfill the U-Q/Pmax profile specified in TTG VAR Annex B.403 and as show in Figure 29.

Test cases:

- Voltage step tests as per Section 5.10
- Step changes in short circuit power as per Section 5.9

UC05-03 Grid forming active power support to the onshore AC grid

Phase jump active power capability

- Functionality as specified in InterOPERA D2.2
- Dynamic performance criteria as per Section 5.5 (this document) based on TTG NAR B.409

Inertial active power capability

- Functionality as specified in InterOPERA D2.2
- Dynamic performance criteria as per Section 5.6 (this document) based on TTG NAR B.409

Test cases:

- Phase jump tests as per Section 5.5
- Frequency ramp test (RoCoF) as per Section 5.6

UC05-04 Grid forming active power support to the onshore AC grid including support from offshore WTGs (OPTIONAL)

Phase jump active power capability

- Functionality as specified in InterOPERA D2.2
- Dynamic performance criteria as per Section 5.5 (this document) based on TTG NAR B.409

Inertial active power capability

- Functionality as specified in InterOPERA D2.2
- Dynamic performance criteria as per Section 5.6 (this document) based on TTG NAR B.409

UC05-12 Exploration of HVDC system stability and interoperability with interconnected AC areas

No performance requirements enforced.

Test cases:

Steady-state analysis:

1. Initialization of steady-state conditions
2. Change power flow from Area 1 to Area 2
3. Detection of any oscillations in active power and/or voltage in the combined (interconnected) onshore AC system
4. If oscillations identified: Apply small-signal analysis

Large-signal stability analysis:

(pre-condition: The system is steady-state stable in pre-fault and post-fault conditions (see small-signal stability analysis step)).

1. Three phase to ground fault at the connection point of the HVDC converter station: Fault duration: 150 ms, residual voltage: 0.1 p.u.
2. Spontaneous (no fault) trip of
    a. Singe HVDC converter unit (1 pole)
    b. Full HVDC converter station (both poles)

5. Dynamic performance requirements and test of GFM control

InterOPERA Deliverable D2.2 [6] formulated functional requirements for grid forming control for HVDC converter stations and DC connected PPM. Here, the 5 core mandatory functions shown in Table 17 of GFM converters where specified.

However, as also stated and discussed in [6] one of the remaining gaps is to specify detailed dynamic performance criteria associated with the core grid forming functionalities.

The challenge highlighted is the high dependency between grid-forming dynamic performance and the grid-characteristics in the specific connection point of the grid-forming converter. Grid strength and associated characteristics highly influence the behaviour of the grid forming converter. Thus, it is difficult to harmonize towards a set of quantified set of dynamic performance requirements which suits a wide range of grid conditions.

Chapter 5 of InterOPERA D2.2 provides preliminary suggestions for dynamic performance criteria and evaluation methods to be considered for the InterOPERA demonstration. However, there is a need for further detailing.

Table 17. Grid-forming functionalities specified in InterOPERA D2.2 [6].

	MANDATORY FUNCTIONS	OPTIONAL* FUNCTIONS	WITHSTAND CAPABILITIES
1	Self-synchronization	Black start	Maximum step change of SCR at POC
2	Phase jump active power	Sink for voltage unbalances	Maximum phase jump
3	Inertial active power	Sink for harmonics	Maximum RoCoF
4	Inherent reactive power		Temporary islanding of PPMs
5	Positive damping power		

For the purpose of providing dynamic performance requirements for the core grid-forming functionalities specified in [6] for the InterOPERA demonstration of grid-forming capabilities it is suggested to take the basis of the VDE FNN guideline: Grid forming behaviour of HVDC systems and DC-connected PPMs [4] and the TenneT NAR Annex B4.09 Grid forming control study [5].

The input process of formulating detailed specifications for dynamic performance criteria for the grid-forming control demonstration in InterOPERA is shown in Figure 30.

The main framework is the consolidated functionalities defined in D2.2, whereas the evaluation criteria are inspired by the VDE FNN guideline and TenneT NAR Annex B.409.

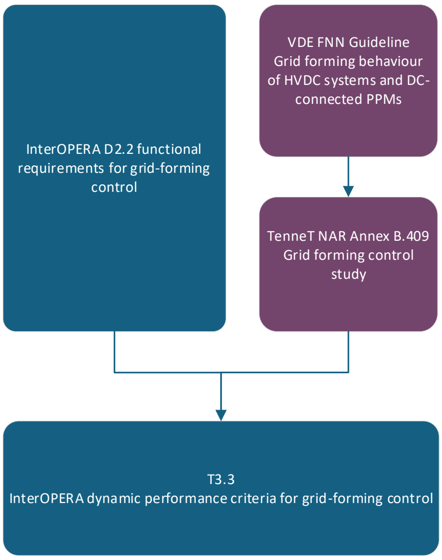


Figure 30. Process of formulating detailed specifications for dynamic performance criteria for grid-forming control in InterOPERA

5.1 Test system

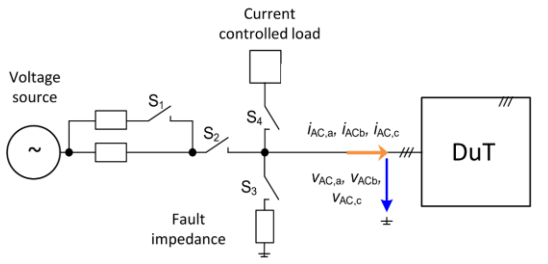
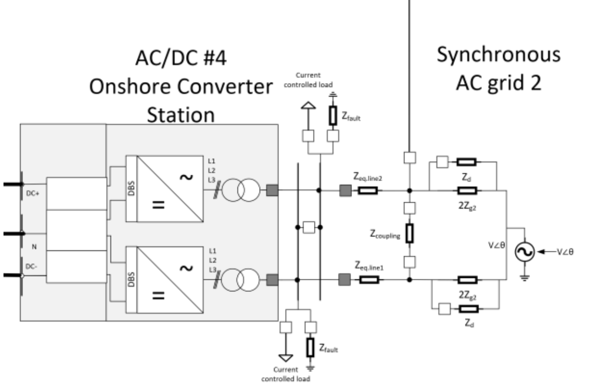
The test system shall use the electrical topology Option 3 as specified in Chapter 2 with the grid equivalent data specified in Chapter 3 for representation of the Continental Europe and Nordic grid systems respectively.

Regarding representation of the DC side the test system shall include either

1. A full representation of the DC grid and all DC sources in the grid, or
2. A validated DC grid equivalent

As specified in Section 7.3 of TenneT NAR B.409 [5], the test setup must have a fault impedance which can be switched in for testing purposes.

Table 18. Test setup integration into InterOPERA onshore AC grid topology.

TenneT NAR B.409	InterOPERA grid equivalent
	

5.2 Calculation method for evaluation

For the verification procedure, the connectee shall use the following calculation method for evaluating the electrical quantities at the connection point.

Informative: The method described below is used exclusively for ensuring the comparability of post-processed signal in conformity verification. It does not specify how PLL and signal evaluation in the converter controls shall be implemented.

Based on the instantaneous values of the phase voltages (vAC,a, vAC,b, vAC,c) and currents (iAC,a, iAC,b, iAC,c) the calculation method defined in [7] shall be used for getting the positive and negative sequence quantities.

Active and reactive power (for positive and negative sequence), active and reactive current (for positive and negative sequence) and rms values of the phase-to-phase voltage (for positive and negative sequence of the fundamental wave) shall be calculated based on this method.

For the calculation of the Fourier coefficients in line with [7], a nominal window width of 20 ms and a sufficiently accurate nominal sampling time shall be assumed.

To be able to use the method according to [7] also for scenarios with time-variable grid frequency, a combination of a Digital Fourier Transformation (DFT) and a Phase Locked Loop (PLL) shall be used (see [8])[12].

Informative: The combination of DFT and PLL ensures that the sampling time of the evaluation algorithm is adjusted as a function of the network frequency. This is illustrated in Figure 31.

The PLL shall be designed such, that the combination of DFT and PLL has a time constant of 200 ms for a frequency step (time until output signal reaches 63.2 % of the final value).

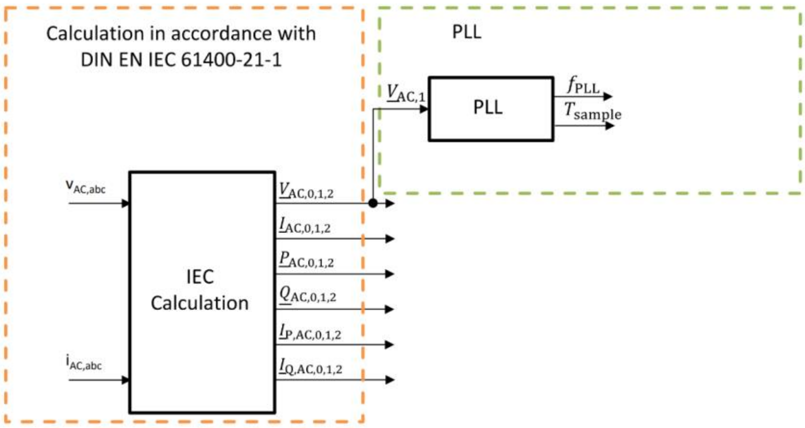


Figure 31. Principle of signal post processing in accordance with IEC

[12] The InterOPERA laboratories shall implement the measurement component for both online and offline simulations with proper functionalities (e.g. allow to start from a snapshot in PSCAD).

5.3 Preconditions and limitations

DC voltage control and energy availability

The pre-condition for following tests and associated dynamic performance criteria is that the HVDC converter station is connected to a HVDC system where the necessary energy for the grid-forming action is available in the HVDC system. Although the GFM HVDC converter station is required to have simultaneous DC voltage droop and GFM capability as described in InterOPERA D2.2 [6] this typically implies that other HVDC converter stations in the HVDC system sufficiently contributes to DC voltage control by transferring energy in and out of the DC grid to and from its AC connection points or interfaces.

For the InterOPERA demonstration of grid forming capabilities the NAR B.409 test cases labeled “without additional energy storage” is selected due GFM dynamic performance ranking lower than DC voltage control stability. As discussed in InterOPERA D2.2 [6] high inertia design of grid-forming control of HVDC converter stations connected to a multi-terminal HVDC system may compromise the overall control and stability of the DC grid.

Guiding not binding reference curves

By agreement between the TSOs and HVDC OEMs of InterOPERA the time-domain reference curves provided in Section 5.5, 5.6 and 5.7 respectively are to be considered non-binding and for guiding purposes mainly. Any violations of the curves are accepted as long as well justified by the HVDC OEM. The reference curves originating from NAR B.409 are the so-called *preliminary* reference curves, whereas legally binding and final reference curves are developed through iterations in a commercial project. It is acknowledged that strictly enforcing the preliminary reference curves may lead to sub-optimal converter design and degrade the overall converter performance in various aspects. Thus, within InterOPERA and for the purpose of the InterOPERA grid-forming demonstration the reference curves shall be applied for evaluation purposes, but deviations are accepted and expected.

5.4 Evaluation of self-synchronization capability

Evaluation of self-synchronization capability has been considered unnecessary for the demonstration of grid-forming in InterOPERA, and is therefore excluded. For reference purpose the capability can be demonstrated with TenneT NAR B.409 test from Section 8.7: Islanding with DuT and active load.

5.5 Evaluation of phase jump active power capability

Modification of TenneT NAR B.409 test from Section 8.5: Step in voltage angle at the connection point.

Test conditions

Table 19. Operating point before the event

Signal	Value
Active power	0.5 p.u.
Reactive power	0.0 p.u.
Reactive power control mode	Voltage control mode (Q-v droop)
Inertia / Equivalent mechanical starting time	TA1 ≥ 0.5 s (TA=2H)
Short circuit ratio SCR=Sk	SCRmin (as specified in Chapter 3 and 4)
Short circuit impedance ratio	X/R at SCR min (as specified in Chapter 3 and 4)
frequency sensitive mode (FSM) / limited frequency sensitive mode (LFSM)	Not active

Table 20. Characteristic of the event

Event	Characteristics
Step in voltage angle at the connection point	The disturbance occurs at the time of the maximum voltage vAC,a in phase a at t =0.1 s at the connection point. Change in the voltage angle of the positive sequence: $\Delta\phi1 = -10°$

Acceptance criteria

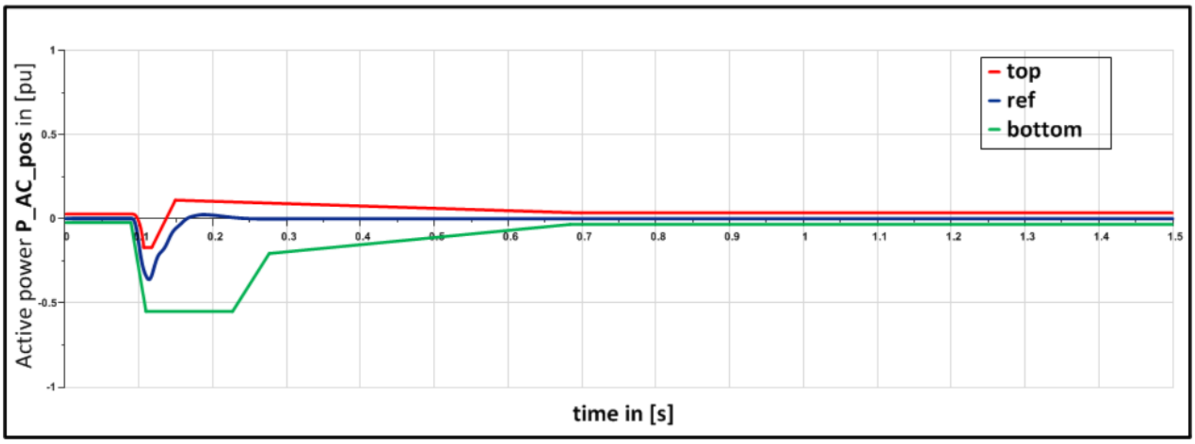


Figure 32. Active power reference curve for phase jump active power (NAR B.409 Figure 7 – step in voltage angle for a DuT without additional energy storage).

1. Immediately after the change in the voltage there shall be an inherent and undelayed current reaction.
2. The system behaviour of the DuT shall not exceed the envelope curves for PAC,pos,act (P_AC_pos)*.

3. The upper envelope of P_AC_pos in Figure 32 shall not be violated in any case until the active power minimum is reached.*
4. The maximum active power and current contribution shall be reached within the time given by the envelopes (i.e. at approx. 20 ms).
5. Afterwards active power and current are reduced to the value prior to the event after 1 s.
6. A slower return of active power and current to the pre-fault value may be allowed and is considered in the wider envelopes.
7. Any oscillatory behaviour shall be well damped, as given in the reference curves.
8. The DC component in the instantaneous values of the currents at the evaluation point (iAC,a, iAC,b, iAC,c) shall be suppressed.
9. The reaction in the reactive power shall be as small as possible.
10. The reactive power shall return to the pre-fault value as fast as possible**.
    - **Informative:** A reaction in the reactive power cannot be suppressed completely, not even for pure inductive networks (DC component in the currents, signal post processing, etc.).

*(InterOPERA demo implementation: By agreement with the HVDC OEMs the curves may be violated as long as well justified by the HVDC OEM).

** The original requirement from TenneT NAR B.409 stipulates that the reactive power shall return to the pre-fault value latest 100 ms after the event. However, this requirement is removed for the InterOPERA demonstrator in order to avoid any adverse restrictions on the inherent reactive power capability. This will be subject to evaluation based on the demonstrator results.

5.6 Evaluation of Inertial active power capability

Modification from TenneT NAR B.409 test from Section 8.8: Linear change of frequency.

Test conditions

Table 21. Operating point before the event

Signal	Value
Active power	0.5 p.u.
Reactive power	0 p.u.
Reactive power control mode	Voltage control mode (Q-v droop)
Inertia / Equivalent mechanical starting time	TA1 ≥ 0.5 s (TA=2H)
Short circuit ratio SCR=Sk	SCRmin (as specified in Chapter 3 and 4)
Short circuit impedance ratio	X/R at SCR min (as specified in Chapter 3 and 4)
frequency sensitive mode (FSM) / limited frequency sensitive mode (LFSM)	Not active

Table 22. Characteristic of the event

Event	Characteristics
Linear frequency change – High RoCoF	he disturbance occurs at the time of the maximum voltage vAC,a in phase a at t =0.1 s at the GAP. Rate of Change of Frequency (RoCoF): -2 Hz/s from 50 Hz to 47,5 Hz.
Linear frequency change – Low RoCoF (used for inertia constant approximation)	Rate of Change of Frequency (RoCoF): -0.3 Hz/s from 50 Hz to 47,5 Hz.

Acceptance criteria

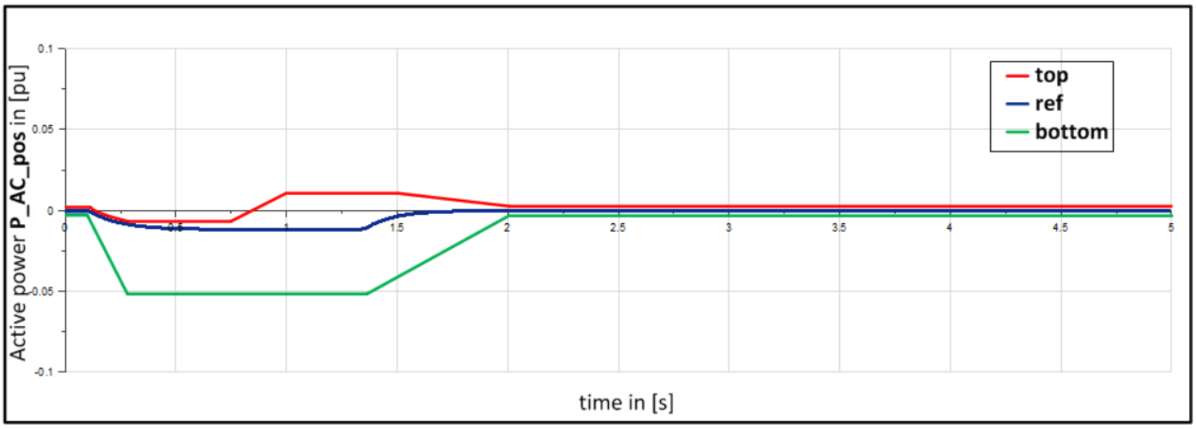


Figure 33. Active power reference curve for inertial active power capability (NAR B.409 Figure 14 – linear change of frequency for a DuT without additional energy storage).

1. The system behaviour of the DuT shall not exceed the envelope curves for PAC,pos,act (P_AC_pos)*.
1. Immediately after the frequency starts to decline, there shall be an inherent and undelayed current change in the active component.
2. The upper envelope of the active power P_AC_pos shall not be violated before the minimum active power in any case*.
3. The DC component in the instantaneous values of the currents at the evaluation point (iAC,a, iAC,b, iAC,c) shall be suppressed.
    a. **Informative:** The reference behaviour indicates the minimum active power response resulting from the inherent grid forming behaviour and the energy taken from the DuT to support the network frequency.
4. No oscillations with a non-negligible amplitude (larger than 10 % of the nominal values) in system or network quantities shall occur.

*(InterOPERA demo implementation: By agreement with the HVDC OEMs the curves may be violated as long as well justified by the HVDC OEM).

5.7 Evaluation of inherent reactive power capability

Modified from TenneT NAR B.409 test from Section 8.4: Step in voltage magnitude at the connection point.

Test conditions

Table 23. Operating point before the event

Signal	Value
Active power	0.5 p.u.
Reactive power	0 p.u.
Reactive power control mode[13]	Voltage control mode deactivated to see pure inherent reactive power response. Reactive power control mode with Q_{ref} = 0 may be active.
Inertia / Equivalent mechanical starting time	TA1 ≥ 0.5 s (TA=2H)
Short circuit ratio SCR=Sk	SCR_{min} (as specified in Chapter 3 and 4)
Short circuit impedance ratio	X/R at SCR min (as specified in Chapter 3 and 4)

Table 24. Characteristic of the event

Event	Characteristics
3 phase step in voltage magnitude at the GAP	The disturbance occurs at the time of the maximum voltage $V_{AC,a}$ in phase a at the GAP at t = 0.1 s. Residual voltage 0.9 p.u. at the voltage source System returns to initial state after 150 ms p.u. Voltage magnitude prior and after event: 1 p.u.

Acceptance criteria

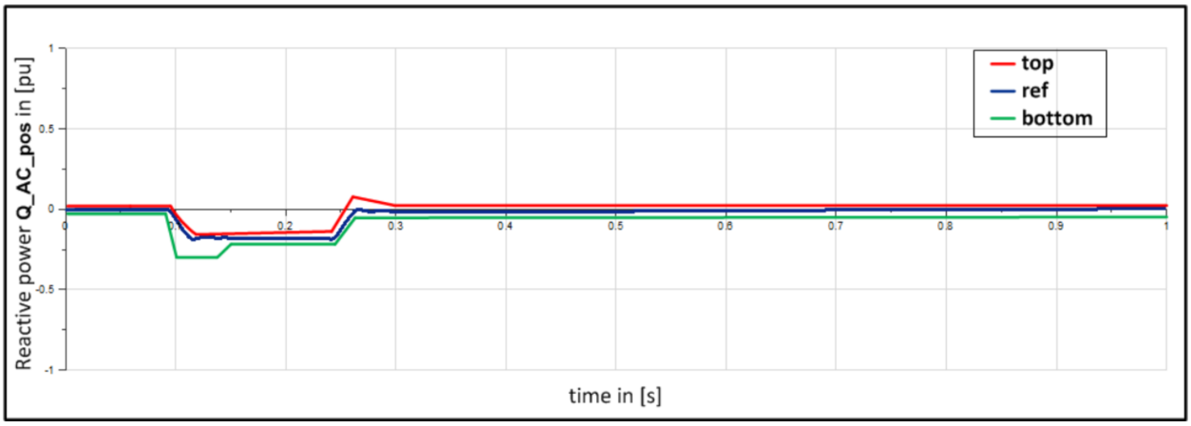


Figure 34. Envelope curve for inherent reactive power capability evaluation.

[13] Reactive power control modes as per definitions in Article 22 of the NC HVDC, where reactive power control modes is the umbrella definition of voltage control mode, reactive power control mode and power factor control mode

- The system behaviour of the DuT shall not exceed the envelope curves for QAC,pos,act(Q_AC_pos)*.
- Immediately after the voltage change to 0.9 p.u there is an inherent and underlayed current reaction
- The upper envelope of Q_AC_pos should not be exceeded*.
- The rise time as defined in [8] for the reactive current and reactive power shall not be larger than 20 ms.
- The steady-state reactive current (tolerance band ±5 %) shall be reached latest 50 ms after the event. Oscillations within the envelope curves are not permitted.
- Before the steady-state value is reached, an increased reactive current contribution will be accepted.
- Immediately after the voltage returns to 1.0 p.u., there is an inherent and undelayed return of the current to the initial value. During this return, the lower envelope of Q_AC_pos shall not be violated in any case*.
- The steady-state final value of the reactive current (here: 0 p.u., set point +-1 %) is reestablished at the latest 50 ms after the voltage returns to 1.0 pu.
- Since the inertia of the DuT does not play a significant role for this scenario, the reference behaviour shown and explained above applies both to converters without and with additional energy storage.

*(InterOPERA demo implementation: By agreement with the HVDC OEMs the curves may be violated as long as well justified by the HVDC OEM).

5.8 Evaluation of positive damping power

Not evaluated in InterOPERA as per agreement from Task 2.4.

5.9 GFM HVDC converter station withstand capabilities

The GFM HVDC converter station shall be able to remain connected when subject to the following disturbances which defines the minimum withstand capabilities of the HVDC converter station.

As discussed in InterOPERA D2.2 [6] withstand capabilities are specified generally for grid following and grid forming HVDC converter stations under the NC HVDC [1], but certain withstand capabilities such as maximum phase jump, frequency change (RoCoF) and change in short-circuit power in the connection point is of special concern for grid-forming converters as they are generally expected to have enhanced withstand capability towards such events compared to grid following converters.

For this reason the following withstand tests are required as part of the InterOPERA grid-forming demonstration. However, note that there are no envelope curves specified for withstand tests.

Phase jump of AC system voltage in the connection point

1. Phase angle jump of positive sequence voltage: $\Delta\phi 1$=-10°, voltage before disturbance:
   a. 1 p.u., AC system frequency before disturbance: 50 Hz,
2. Phase angle jump of positive sequence voltage: $\Delta\phi 1$=-30°, voltage before disturbance:
   a. 1 p.u., AC system frequency before disturbance: 50 Hz
3. Phase angle jump of positive sequence voltage: $\Delta\phi 1$=+10°, voltage before disturbance:

   a. 1 p.u., AC system frequency before disturbance: 50 Hz
4. Phase angle jump of positive sequence voltage: $\Delta\phi 1=+30°$, voltage before disturbance:
   a. 1 p.u., AC system frequency before disturbance: 50 Hz

Step change in short-circuit power in the connection point

The grid forming HVDC converter station shall be robust to step changes in the short-circuit power in the connection point, while being able to operate in the full range from SCLmin to SCLmax as specified in Chapter 3 and Chapter 4 respectively.

However, consistency between the phase jump withstand requirements and the SCL jump withstand shall be secured. A step change in SCL shall not lead to a step in voltage phase angle larger than the maximum required withstand angle (e.g. 30 degree for InterOPERA according to NAR Annex B.300 [5]. The following relationships shall be considered when designing the test:

At SCRmin, $\delta max = \arcsin(Pcon/Skmin)$

At SCRmax, $\delta min = \arcsin(Pcon/Skmax)$

$\Delta\delta = \delta max - \delta min$

The following step tests shall be carried out:

Low SCL operation:

1. Step reduction in short-circuit power:
   a. Operation at SCL= 6 GVA[14] and reduction to SCLmin as specified in Chapter 3 and Chapter 4 for CE and Nordic grid areas respectively.
2. Step increase in short-circuit power:
   a. Operation at SCLmin and increase to SCL = 6 GVA

High SCL operation

1. Step increase in short-circuit power
   b. Operation at SCL = 10 GVA and increase to SCLmax as specified in Chapter 3 and Chapter 4 for CE and Nordic grid areas respectively.

Maxium RoCoF withstand test

Updated over- and under frequency curves as proposed under the revised version of the NC HVDC.

The HVDC converter station must stay connected when exposed to the frequency variations shown in Figure 35 and Figure 36, with the general RoCoF properties[15]:

± 5 Hz/s over a period of 0.25 s

± 2.5 Hz/s over a period of 0.5 s

± 1.25 Hz/s over a period of 2 s

[14] Measured at Thevenin source.
[15] Demonstration at +/- 5 Hz/s can be considered sufficient for compliance verification.

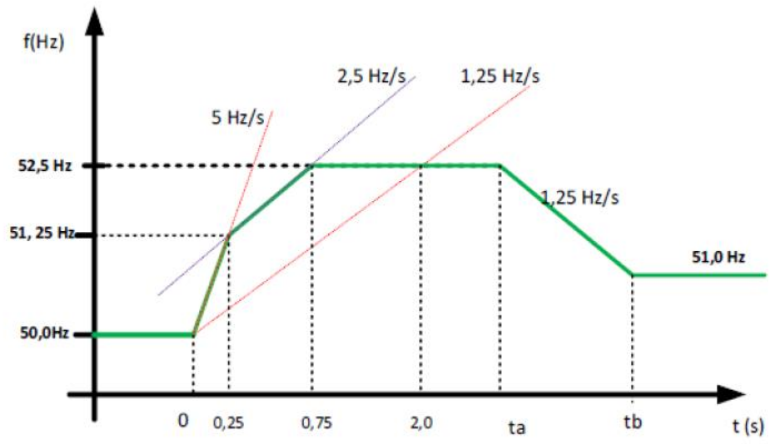


Figure 35. Time-varying over-frequency withstand curve

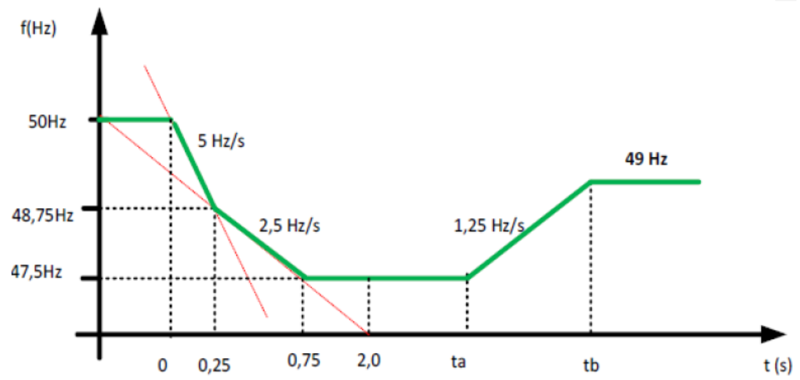


Figure 36. Time-varying under frequency withstand curve

5.10 Additional test cases for the design of HVDC converter stations with GFM control

In addition to the GFM dynamic performance test cases listed in Chapter 5, the following test cases from TenneT NAR Annex B.409 Chapter 5 "Test scenarios" considered in the GFM HVDC converter station design [5].

Fault scenarios

The following fault scenarios are to be used for UC05-01 Onshore AC fault ride through capability and post fault active power recovery.

1. Single phase to ground fault at the connection point
   a. Fault duration: 150 ms, residual voltage: 0.1 p.u.
2. Two phase fault at the connection point
   a. Fault duration: 150 ms, residual voltage: 0.1 p.u
3. Two phase to ground fault at the connection point
   a. Fault duration: 150 ms, residual voltage: 0.1 p.u
4. Three phase to ground fault at GAP
   a. Fault duration: 150 ms, residual voltage: 0.1 p.u.

Voltage step of AC system voltage magnitude

The following voltage step changes are to be used for UC05-02 reactive power support under extreme grid conditions

1. Voltage step of phase to phase positive sequence voltage magnitude from 1 p.u. to 0.95 p.u., AC system frequency before disturbance: 50 Hz
2. Voltage step of phase to phase positive sequence voltage magnitude from 1 p.u. to 0.85 p.u., AC system frequency before disturbance: 50 Hz
3. Voltage step of phase to phase positive sequence voltage magnitude from 1 p.u. to 1.05 p.u., AC system frequency before disturbance: 50 Hz
4. Voltage step of phase to phase positive sequence voltage magnitude from 1 p.u. to 1.10 p.u., AC system frequency before disturbance: 50 Hz

6. References

[1] NC HVDC: https://www.entsoe.eu/network_codes/hvdc/

[2] https://www.tennet.eu/de/strommarkt/kunden-deutschland/netzkunden/netzanschlussregeln

[3] https://www.vde-verlag.de/standards/0100511/vde-ar-n-4131-anwendungsregel-2019-03.html

[4] https://www.vde-verlag.de/books/636341/grid-forming-behaviour-of-hvdc-systems-and-dc-connected-ppms.html

[5] Download link for NAR Anhang-B: https://tennet-drupal.s3.eu-central-1.amazonaws.com/default/2023-07/Annexes-B.zip

[6] https://interopera.eu/wp-content/uploads/files/deliverables/InterOPERA-D2.2-GFM-functional-requirements-202401.pdf

[7] DIN EN IEC 61400-21-1: Measurement and assessment of electrical characteristics – Windturbines, Annex C: Measurement of active power, reactive power and voltage

[8] FNN Guideline: Grid forming behaviour of HVDC systems and DC-connected PPMs, June 2020

[9] Demonstrator's use cases and features.docx

[10] InterOPERA D3.2: D3.2 Version to resolve comments_GE-SGD-LAP-234.pdf

Annex 3.3.6: PPM and AC Offshore Testbench

WP3

Multi-vendor / Multi-terminal demonstrator project

Deliverable 3.3(b)

Detailed Functional Specifications

Subtask 3.3.6

PPM + AC Offshore Testbench Subsystems

Inter OPERA

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.

Co-funded by
the European Union

DISCLAIMER:

PROJECT DETAILS:

Duration: 1 January 2023 – 30 April 2027
Grant agreement: 101095874 — InterOPERA — HORIZON-CL5-2022-D3-01

Detailed Functional Specifications

PPM + AC OFFSHORE TESTBENCH SUBSYSTEMS

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Table of Contents

VERSION CONTROL

Version	Date	Created/modified by	Comments
1.0	18.12.2024	G. Figueiredo Gontijo (Ørsted A/S)	First issue for review
1.1	31.01.2025	R. Longo (WindEurope)	Rev1.1 after internal review
1.2	18.03.2025	R. Longo (WindEurope)	Second issue (clean) for consensus review
1.3	27.06.2025	R. Longo (WindEurope)	Rev1.2 after internal review

1. Introduction

The objective of this subtask is to develop PPMs and offshore AC Grid subsystem specifications, including defining numerical values and parameters that will be provided to the vendors and the laboratories. These specifications will encompass essential details required for designing the PPMs and offshore AC grid subsystems from a topology perspective (such as array system arrangement, cable lengths, ampacity, cross sections, etc.) but also from a functional requirement perspective in coordination with the Use Case List of the InterOPERA demonstrator. Since the operation of the Offshore AC Grid subsystem depends on the control of the offshore AC/DC Converter Station, some specifications are also defined for this subsystem of the demonstrator. The specifications developed in this subtask should not deviate significantly from existing and standard HVDC system designs, implying that existing TSO grid codes (from TenneT and Energinet) are used as supporting documents to define functional specifications.

This subtask utilizes preliminary data and layouts from Deliverable 3.1, including cable lengths/parameters and turbine numbers, as a starting point for further definitions.

2. Base Topology and Parameters

The base topology of the Offshore AC Grid and PPM for the InterOPERA demonstrator is the one shown in **Figure 1** below and their main parameters are described in **Table 1**. This is a 2-GW bipole HVDC system (1 GW per pole) connected to an Offshore AC grid (AC switching station) capable of interconnecting the different poles as well as interconnecting the different PPM busbars. Depending on the Use Case, these switches might operate normally open or normally closed. As agreed in the consortium, the Offshore AC Grid is a 66-kV system with four different PPMs connected to it - two PPMs from each WTG vendor involved in InterOPERA-. Points of connection (POCs) for PPMs and offshore AC/DC Converter Stations are represented by red and green dots, respectively, at the 66-kV busbar. To represent standard products/platforms from the two WTG vendors, two different power ratings were defined for the WTGs, i.e., 15 MW and 14 MW. Different designs were considered for the four PPMs: Layout 1, 2, 3 and 4 - see **Table 2**, **Table 3**, **Table 4**, and **Table 5**. This choice was performed to maximize the possibility of interactions to be investigated in the demonstrator due to different electrical distances between converters. The different layouts are defined based on the array-system cable lengths. The number of WTGs per string were defined based on the power ratings of the WTGs and based on the maximum cable ampacity considered, which is related to a 1000-mm², 66-kV cable. According to this, the number of WTGs per string can be equal to either five or six. To reach a realistic design with a power rating value of approximately 500 MW for each PPM, a value of six strings per PPM was considered. This way, for the different PPMs, a total number of WTGs of either thirty-four or thirty-six was defined, i.e., for the WTG Vendor 1 (adopting 15-MW WTGs) a total number of WTGs of thirty-four was considered, resulting in a total PPM power of 510 MW; For the WTG Vendor 2 (adopting 14-MW WTGs) a total number of WTGs of thirty-six was considered, resulting in a total PPM power of 504 MW. A total power of 2.028 GW per bipole is obtained, which is acceptable considering losses in the array system, small overcurrent capabilities in HVDC converters, plus the fact that the four PPMs would unlikely produce together 1 pu of power. Lengths of cables between WTGs were set between 2 and 3 km. The length of the cables connecting the strings to the 66-kV busbars were set between 4 and 6 km. Four different cable cross sections were considered, i.e., 150 mm², 300 mm², 800 mm², and 1000 mm². The cable parameters - **Table 6**, **Table 7**, **Table 8**, and **Table 9** - were obtained from [1] and through inputs from InterOPERA partners based on engineering experience.

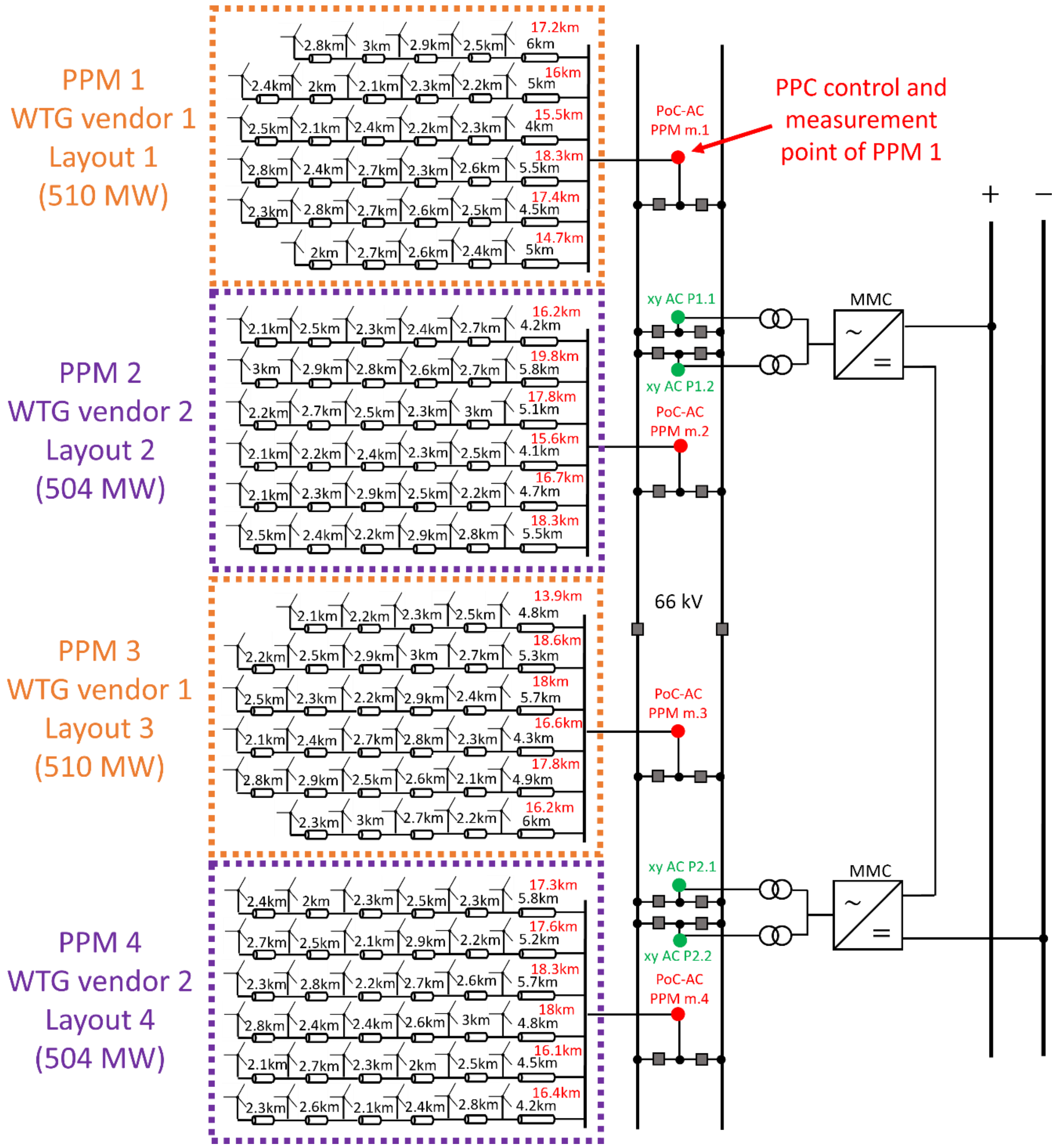

Figure 1: Base Topology and indicative parameters employed. As a basic setup, the 66kV busbars would be run as four separate busbars, with one PPM connected to each HVDC transformer and bus couplers open.

Table 1: Offshore AC System Parameters

System Parameters	Unit	Value	Comment
Array system voltage level	kV	66	Agreed in consortium as realistic value in terms of model maturity of WTG vendors.
Nominal WTG power (WTG vendor 1)	MW	15	State-of-the-art product/platform of WTG vendor as agreed in InterOPERA.
Nominal WTG power (WTG vendor 2)	MW	14	State-of-the-art product/platform of WTG vendor as agreed in InterOPERA.
Number of strings per PPM (WTG vendor 1)	-	6	To be able to come up with a realistic design considering string power, cable cross sections and ampacity.
Number of strings per PPM (WTG vendor 2)	-	6	To be able to come up with a realistic design considering string power, cable cross sections and ampacity.
Number of WTGs per string (WTG vendor 1)	-	5 or 6	4 strings with 6 WTGs each and 2 strings with 5 WTGs each
Number of WTGs per string (WTG vendor 2)	-	6	6 strings with 6 WTGs each
Number of WTGs per PPM (WTG vendor 1)	-	34	4 x 6 WTGs + 2 x 5 WTGs
Number of WTGs per PPM (WTG vendor 2)	-	36	6 x 6 WTGs
Total PPM power (WTG vendor 1)	MW	510	34 WTGs x 15 MW
Total PPM power (WTG vendor 2)	MW	504	36 WTGs x 14 MW
Cable length (distance between WTGs)	km	2 - 3	
66-kV busbar cable length (longest)	km	4 - 6	

Table 2: PPM Layout 1 (WTG Vendor 1)		String 1 (uppermost one)	String 2	String 3	String 4	String 5	String 6 (lowermost one)
Cable section 1 (closest to 66kV busbar)	Length	6.0 km	5.0 km	4.0 km	5.5 km	4.5 km	5.0 km
	Cross section	1000 mm²	1000 mm²	1000 mm²	1000 mm²	1000 mm²	1000 mm²
Cable section 2	Length	2.5 km	2.2 km	2.3 km	2.6 km	2.5 km	2.4 km
	Cross section	300 mm²	1000 mm²	1000 mm²	1000 mm²	1000 mm²	300 mm²
Cable section 3	Length	2.9 km	2.3 km	2.2 km	2.3 km	2.6 km	2.6 km
	Cross section	300 mm²	300 mm²	300 mm²	300 mm²	300 mm²	300 mm²
Cable section 4	Length	3.0 km	2.1 km	2.4 km	2.7 km	2.7 km	2.7 km
	Cross section	150 mm²	300 mm²	300 mm²	300 mm²	300 mm²	150 mm²
Cable section 5	Length	2.8 km	2.0 km	2.1 km	2.4 km	2.8 km	2.0 km
	Cross section	150 mm²	150 mm²	150 mm²	150 mm²	150 mm²	150 mm²
Cable section 6 (farthest from 66kV busbar)	Length		2.4 km	2.5 km	2.8 km	2.3 km	
	Cross section		150 mm²	150 mm²	150 mm²	150 mm²	
Total length		17.2 km	16 km	15.5 km	18.3 km	17.4 km	14.7 km

Table 3: PPM Layout 2 (WTG Vendor 2)		String 1 (uppermost one)	String 2	String 3	String 4	String 5	String 6 (lowermost one)
Cable section 1 (closest to 66kV busbar)	Length	4.2 km	5.8 km	5.1 km	4.1 km	4.7 km	5.5 km
	Cross section	800 mm²	800 mm²	800 mm²	800 mm²	800 mm²	800 mm²
Cable section 2	Length	2.7 km	2.7 km	3.0 km	2.5 km	2.2 km	2.8 km
	Cross section	800 mm²	800 mm²	800 mm²	800 mm²	800 mm²	800 mm²
Cable section 3	Length	2.4 km	2.6 km	2.3 km	2.3 km	2.5 km	2.9 km
	Cross section	300 mm²	300 mm²	300 mm²	300 mm²	300 mm²	300 mm²
Cable section 4	Length	2.3 km	2.8 km	2.5 km	2.4 km	2.9 km	2.2 km
	Cross section	150 mm²	150 mm²	150 mm²	150 mm²	150 mm²	150 mm²
Cable section 5	Length	2.5 km	2.9 km	2.7 km	2.2 km	2.3 km	2.4 km
	Cross section	150 mm²	150 mm²	150 mm²	150 mm²	150 mm²	150 mm²
Cable section 6 (farthest from 66kV busbar)	Length	2.1 km	3.0 km	2.2 km	2.1 km	2.1 km	2.5 km
	Cross section	150 mm²	150 mm²	150 mm²	150 mm²	150 mm²	150 mm²
Total length		16.2 km	19.8 km	17.8 km	15.6 km	16.7 km	18.3 km

Table 4: PPM Layout 3 (WTG Vendor 1)		String 1 (uppermost one)	String 2	String 3	String 4	String 5	String 6 (lowermost one)
Cable section 1 (closest to 66kV busbar)	Length	4.8 km	5.3 km	5.7 km	4.3 km	4.9 km	6.0 km
	Cross section	1000 mm²	1000 mm²	1000 mm²	1000 mm²	1000 mm²	1000 mm²
Cable section 2	Length	2.5 km	2.7 km	2.4 km	2.3 km	2.1 km	2.2 km
	Cross section	300 mm²	1000 mm²	1000 mm²	1000 mm²	1000 mm²	300 mm²
Cable section 3	Length	2.3 km	3.0 km	2.9 km	2.8 km	2.6 km	2.7 km
	Cross section	300 mm²	300 mm²	300 mm²	300 mm²	300 mm²	300 mm²
Cable section 4	Length	2.2 km	2.9 km	2.2 km	2.7 km	2.5 km	3.0 km
	Cross section	150 mm²	300 mm²	300 mm²	300 mm²	300 mm²	150 mm²
Cable section 5	Length	2.1 km	2.5 km	2.3 km	2.4 km	2.9 km	2.3 km
	Cross section	150 mm²	150 mm²	150 mm²	150 mm²	150 mm²	150 mm²
Cable section 6 (farthest from 66kV busbar)	Length		2.2 km	2.5 km	2.1 km	2.8 km	
	Cross section		150 mm²	150 mm²	150 mm²	150 mm²	
Total length		13.9 km	18.6 km	18.0 km	16.6 km	17.8 km	16.2 km

Table 5: PPM Layout 4 (WTG Vendor 2)

		String 1 (uppermost one)	String 2	String 3	String 4	String 5	String 6 (lowermost one)
Cable section 1 (closest to 66kV busbar)	Length	5.8 km	5.2 km	5.7 km	4.8 km	4.5 km	4.2 km
	Cross section	800 mm²	800 mm²	800 mm²	800 mm²	800 mm²	800 mm²
Cable section 2	Length	2.3 km	2.2 km	2.6 km	3.0 km	2.5 km	2.8 km
	Cross section	800 mm²	800 mm²	800 mm²	800 mm²	800 mm²	800 mm²
Cable section 3	Length	2.5 km	2.9 km	2.7 km	2.6 km	2.0 km	2.4 km
	Cross section	300 mm²	300 mm²	300 mm²	300 mm²	300 mm²	300 mm²
Cable section 4	Length	2.3 km	2.1 km	2.2 km	2.4 km	2.3 km	2.1 km
	Cross section	150 mm²	150 mm²	150 mm²	150 mm²	150 mm²	150 mm²
Cable section 5	Length	2.0 km	2.5 km	2.8 km	2.4 km	2.7 km	2.6 km
	Cross section	150 mm²	150 mm²	150 mm²	150 mm²	150 mm²	150 mm²
Cable section 6 (farthest from 66kV busbar)	Length	2.4 km	2.7 km	2.3 km	2.8 km	2.1 km	2.3 km
	Cross section	150 mm²	150 mm²	150 mm²	150 mm²	150 mm²	150 mm²
Total length		17.3 km	17.6 km	18.3 km	18.0 km	16.1 km	16.4 km

Table 6: AC Cable Data - 1000 mm²

	Unit	Value
Line Types	-	AC cable
Insulation Types	-	XLPE
Conductor Types	-	Copper
Nominal Voltage Uo	kV	66
Rated voltage Um	kV	72.5
Cross section	mm²	1000
Maximum continuous current	A	825
Specific resistance	mΩ/km	18.00
Specific capacitance	µF/km	0.426
Specific inductance	mH/km	0.337

Table 7: AC Cable Data - 800 mm²

	Unit	Value
Line Types	-	AC cable
Insulation Types	-	XLPE
Conductor Types	-	Copper
Nominal Voltage Uo	kV	66
Rated voltage Um	kV	72.5
Cross section	mm²	800
Maximum continuous current	A	775
Specific resistance	mΩ/km	22.00
Specific capacitance	µF/km	0.381
Specific inductance	mH/km	0.348

Table 8: AC Cable Data - 300 mm²

	Unit	Value
Line Types	-	AC cable
Insulation Types	-	XLPE
Conductor Types	-	Copper
Nominal Voltage Uo	kV	66
Rated voltage Um	kV	72.5
Cross section	mm²	300
Maximum continuous current	A	530
Specific resistance	mΩ/km	60.00
Specific capacitance	µF/km	0.381
Specific inductance	mH/km	0.396

Table 9: AC Cable Data - 150 mm²

	Unit	Value
Line Types	-	AC cable
Insulation Types	-	XLPE
Conductor Types	-	Copper
Nominal Voltage Uo	kV	66
Rated voltage Um	kV	72.5
Cross section	mm²	150
Maximum continuous current	A	375
Specific resistance	mΩ/km	105.60
Specific capacitance	µF/km	0.181
Specific inductance	mH/km	0.434

Values given here are derived from data provided by manufacturers to Vattenfall. All resistances are given as DC resistance at 20°C.

3. Use Cases

All the UCs that involve the Offshore AC Grid and PPM subsystems are listed below, disregarding only UCs labelled as "Optional" or "Excluded". Most of these UCs require definitions of functional specifications for the PPM and Offshore AC Grid subsystems.

3.1. Basic Use Cases

Table 10: *List and description of the basic use cases.*

UC04-01	Offshore grid energization from 1 offshore HVDC station ("soft start")
UC04-02	PPMs from two different vendors directly connected to the same busbar (steady-state small-signal operation validation)
UC04-03	Re-energization of tripped PPM after HVDC transformer fault by closing busbar coupler ("hard start")
UC04-051	Ride through offshore HVDC converter temporary blocking with WTGs in GFL control mode
UC04-07	DC-side contingency leading, after energy absorber activation, to a coordinated emergency offshore wind ramp-down or curtailment
UC04-081	Offshore AC fault ride through capability with GFL WTGs - Post fault active power recovery
UC04-111	HVDC converter permanent blocking with WTGs in GFL control mode

Some specifications can be obtained through existing TSO documents with functional requirements for HVDC-connected PPMs. Both TenneT and Energinet have public documents [2], [3], [4], [5] that can be used to obtain functional specifications. It is important to emphasize that, at this stage, the Energinet document is still a draft that is under development, which means that updates might still take place before reaching a final public version.

Some specifications are new to InterOPERA and not covered in existing TSO documents. These values will have to be obtained through technical discussions and simulation studies carried out in InterOPERA. Below, an overview is presented regarding the functional specifications to be defined for the UCs of the InterOPERA demonstrator related to the PPM and Offshore AC Grid subsystems.

3.2. Use-Case Functional Specification Requirements

This section describes only the UCs that require the definition of functional specifications. If a UC is deemed unnecessary for defining functional specifications for the PPM, Offshore AC Grid, and Offshore AC/DC Converter Station subsystems, it is not included in the list below.

UC04-02 PPMs from two different vendors directly connected to the same busbar (steady-state small-signal operation validation)

This UC requires the pre-definition of control modes - voltage, reactive power, power factor - and setpoints for the PPM's PPC so that they can operate harmonically. Since the different PPCs will be measuring and controlling quantities at the same electrical point, it is recommended not to adopt direct voltage control to avoid control hunting. Reactive power mode for PPMs is recommended, and its range should be defined through existing TSO documents. TenneT and Energinet documents were used as references. Operational voltage specifications should also be defined based on the TSO documents. In T.3.3.6, specifications for reactive power and voltage ranges are defined, but control mode and setpoint definitions should be decided in T3.5. Since the offshore AC/DC Converter Station is the one forming the Offshore AC Grid, then specifications for voltage, reactive power and frequency should also be defined for this subsystem.

UC04-03 Re-energization of tripped PPM after HVDC transformer fault by closing busbar coupler ("hard start")

TenneT's existing document [3] covers energization and synchronization functional requirements that can be used for this UC. It is also needed to specify the requirements for reconfiguration of the Offshore AC Grid - AC switching station - due to HVDC system outages.

UC04-051 Ride through offshore HVDC converter temporary blocking with WTGs in GFL controls

This UC requires the pre-definition of functional specifications for the PPMs based on GFL WTGs to be capable of riding through the temporary blocking of the HVDC converter. According to studies carried out in WP2 DC Protection workstream and T3.3.6, it is recommended to assess whether and how PPMs can be capable of limiting the frequency excursion and the overvoltages that could lead to their tripping according to protective measures. It is also important to identify possible ways to detect and/or communicate the islanding condition for the control actions. Finally, synchronization methods must be considered to avoid critical transients after the deblocking of the HVDC converter. The synchronization method is a specification imposed to the offshore AC/DC Converter Station.

While voltage and frequency ranges and maximum expected time for temporary blocking are not quantitatively defined in this document, the demonstrator tests for this use case should be used to investigate the overall feasibility of blocking ride-through and to more firmly define such parameters.

UC04-07 DC-side contingency leading, after energy absorber activation, to a coordinated emergency offshore wind ramp-down or curtailment

This UC requires definition of Emergency Power Control and Special Protection Scheme requirements for the PPMs considering, among others, communication delay and ramp-down speed. TenneT and Energinet documents are adopted as references. The functional specifications regarding communication between the PPCs and the DCGC must also be defined considering a signal list.

UC04-081 Offshore AC fault ride through capability with GFL WTGs – Post fault active power recovery

This UC requires definition of FRT curves, fault-current contribution requirements as well as post fault active power recovery requirements. All these specifications can be obtained through existing TSO documents. Offshore AC faults also impose ride through specifications to the offshore AC/DC Converter Stations.

UC04-111 HVDC converter permanent blocking with WTGs in GFL control mode

This UC requires the pre-definition of functional specifications for the PPMs based on GFL WTGs to be capable of handling the permanent blocking of the HVDC converter without damaging equipment. Typically, the PPMs would have to be capable to identify the islanding situation and to trip while keeping voltages within limits. TenneT's existing document covers this requirement. It is important to highlight that this must be achieved at a PPM level by eventually relying on devices like energy dissipation devices and not necessarily relying only on the wind-turbine converter control.

4. Functional Specifications for PPMs and Offshore AC/DC Converter Stations

A significant amount of information covered in existing TSO documents [2], [3], [4], [5] can be linked to functional specifications for the PPMs and offshore AC/DC Converter Stations potentially needed in the context of the InterOPERA demonstrator. However, only the narrowed-down key elements essential for the implementation of the demonstrator UCs are presented in this section.

4.1. Specifications for PPMs

4.1.1. From TSO Grid Codes

Voltage Specifications

Applied to UC04-02 (PPMs from two different vendors directly connected to the same busbar (steady-state small-signal operation validation)). Both Energinet's [2] and TenneT's [4], [3] documents provide voltage specifications but, due to higher maturity, the TenneT ones were selected for InterOPERA as summarized below.

Static voltage stability - TenneT

For a nominal voltage of 66 kV, the specifications of **Table 11** apply as requirements [4].

Table 11: nominal voltage, voltage range and minimum time for operation for a nominal voltage of 66 kV.

Nominal voltage U_n in kV	Voltage range in kV	Minimum time period for operation
66	56,1 to 59,4	60 min
	59,4 to 72,5	Unlimited
	72,5 to 75,9	30 min

Dynamic grid stabilisation – Overvoltages (TenneT)

The standardised insulation levels as per DIN EN 60071-1 (VDE 0111-1) [4] , displayed in **Table 12**, are to be used.

Table 12: standardized insulation levels as per DIN EN 60071-1 (VDE 0111-1).

Highest voltage for equipment, U_m kV (RMS value)	Standard rated short-duration power-frequency withstand voltage kV (RMS value)	Standard rated lightning impulse withstand voltage kV (peak value)
72,5	140	325

Reactive Power Capabilities

Applied to UC04-02 (PPMs from two different vendors directly connected to the same busbar (steady-state small-signal operation validation)). Both Energinet's [2] and TenneT's [4], [3] documents provide reactive power capabilities but, due to higher maturity, the TenneT ones were selected for InterOPERA as summarized below.

Reactive power exchange with active power feed-in into the network (TenneT)

PPMs shall meet the requirements regarding the reactive power exchange specified for voltage variations by the relevant system operator in agreement with the relevant transmission system operator. Based on a cost-benefit analysis, the relevant system operator shall specify a U-Q/PAV profile within the outer envelope defined in **Figure 2** in which the PPM shall be capable of reactive power supply throughout the range between its technical minimum active power and its agreed active connection power [3]. In the InterOPERA case, the PPM POC is at 66 kV and the voltage values in **Figure 2** are in per unit based on this voltage level. It is recommended to use the basic requirement values for design of converters if stability can be ensured in the demonstrator.

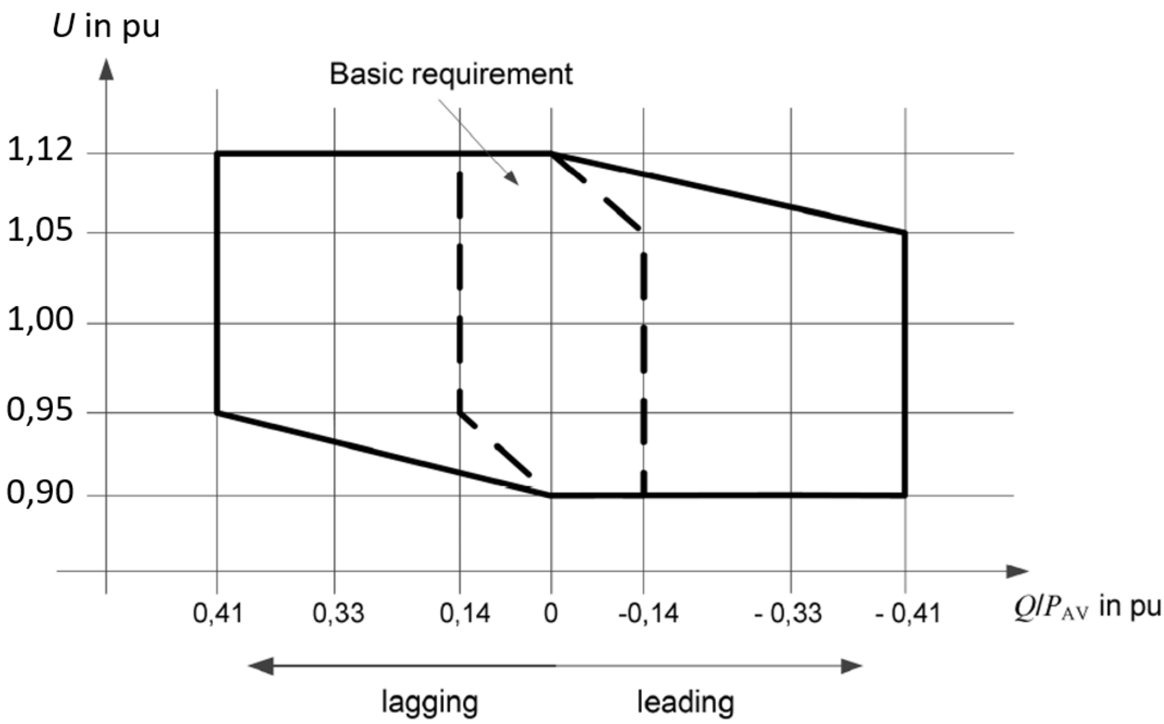

Figure 2: TenneT's reactive power capabilities imposed to HVDC-connected PPMs.

Active Power Management – Setpoints, Recovery

Applied to UC04-091 (Offshore AC fault ride through capability with GFL WTGs - Post fault active power recovery). Both Energinet's [2] and TenneT's [3] documents provide specifications for active power management and recovery but, due to higher maturity, the TenneT ones were selected for InterOPERA, as summarized below.

Post-fault active power recovery (TenneT)

For all power generating plants remaining connected to the network during a fault, the active power output shall be increased to the initial value with a gradient of at least 10 % per second but not more than 20 % per second of the PPM's nominal power [3].

FRT Requirements

Applied to UC04-091 (Offshore AC fault ride through capability with GFL WTGs - Post fault active power recovery). Both Energinet's [2] and TenneT's [3] documents provide FRT requirements but, due to higher maturity, the TenneT ones were selected for InterOPERA as summarized below.

The PPM shall be capable of maintaining both the connection to the network and stable operation as long as the three line-to-line voltages at the connection point remain within the voltage/time characteristic curve shown in **Figure 3** during a symmetrical fault.

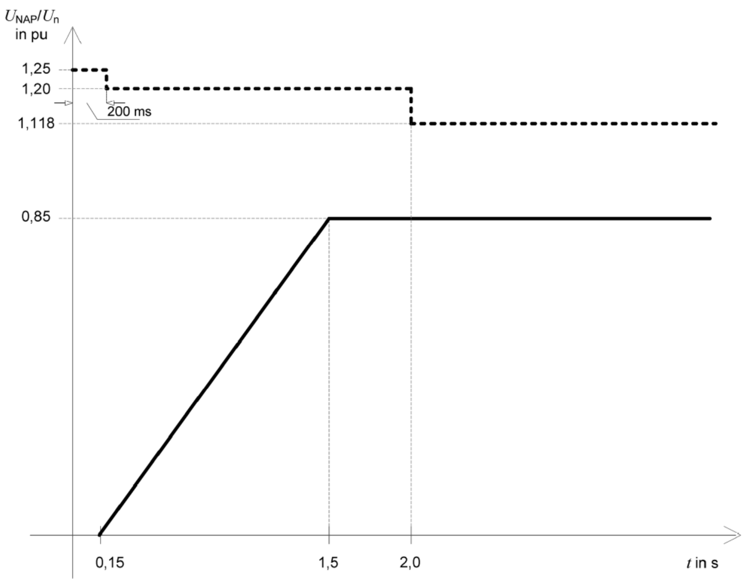

Figure 3: FRT requirements according to TenneT.

HVDC Converter Permanent Blocking and Islanding Requirements

Applied to UC04-111 (HVDC converter permanent blocking with WTGs in GFL control mode). The HVDC converter permanent blocking and islanding specifications are obtained through TenneT's document [3].

Behaviour in island operation (TenneT)

The PPM shall ensure through suitable measures that a possible island operation of the system is reliably detected and ended within no more than 3 s by disconnection of the PPM from the grid. If the PPM independently ensures the island operability, shutting down in the event of island operation is not required.

Behaviour upon blocking of the HVDC converter (TenneT)

The PPM shall ensure in accordance with the requirements for dynamic voltage control that, in the event of blocking of the HVDC converter, the fundamental-frequency overvoltage does not lead to a violation of the upper limit of the voltage band or the FRT profile (see **Figure 3**).

Power Curtailment to Support HVDC Grid Stability

Applied to UC04-08 (DC-side contingency leading, after energy absorber activation, to a coordinated emergency offshore wind ramp-down or curtailment).

Due to the presence of DBS in the HVDC grid, which is responsible for diverting surplus PPM power during abnormal events, the consortium has agreed to adopt the EPC requirements proposed by TenneT as a preliminary specification. These requirements are not extremely fast and state that the PPM should be capable of curtailing power at a rate of 25% per second of the cumulative nominal active power of the operational generating units at the time of receiving the EPC signal.

This is a base value that will serve as input to simulation investigations for the design of the HVDC grid and DBS specifications. The result of these studies could eventually indicate the need for a faster reaction from the PPMs. Additionally, a faster PPM curtailment reaction may be required for the implementation of other UCs. This must be further investigated through simulations, which will define the final specifications.

Frequency Ranges

Applied to UC04-051 (Ride through offshore HVDC converter temporary blocking with WTGs in GFL control mode). The specifications regarding frequency range of operation for PPMs are obtained through TenneT's document [3].

Frequency ranges (TenneT)

PPMs shall be capable of remaining connected to the network of the Offshore AC/DC Converter Station and operating within the frequency ranges and time periods given in **Table 13** for the 50 Hz nominal network frequency.

Table 13: frequency range and corresponding minimum time periods for operation.

Frequency range	Minimum time periods for operation
47,0 Hz to 47,5 Hz	20 s
47,5 Hz to 49,0 Hz	90 min
49,0 Hz to 51,0 Hz	Unlimited
51,0 Hz to 51,5 Hz	90 min
51,5 Hz to 52,0 Hz	15 min

Rate-of-change-of-frequency withstand capability (TenneT)

PPMs shall be capable of maintaining operation if, at a nominal network frequency of 50 Hz, the frequency at the POC of the PPM changes at a rate of up to ±2 Hz/s for the duration of 1 s. This rate is measured at any point in time as the average rate of change of frequency over the previous second.

Energization and Synchronization

Applied to UC04-03 (Re-energization of tripped PPM after HVDC transformer fault by closing busbar coupler ("hard start")). The specifications regarding energisation are obtained via TenneT's document [3].

Energisation and synchronisation -Temporary power-frequency voltage changes (TenneT)

The connection owner shall ensure that neither the energization, synchronization, nor planned disconnection of a PPM causes temporary power-frequency variations exceeding a voltage limit of 10% at any connection point. Within 3 s, the transient gradings shall have subsided such that the steady-state limit values are met.

4.1.2. New and Specific to InterOPERA Demonstrator

Communication Requirements Between PPC and DCGC

Applied to UC04-08 (DC-side contingency leading, after energy absorber activation, to a coordinated emergency offshore wind ramp-down or curtailment).

To support the controllability and stability of an HVDC grid, the PPMs should be capable of curtailing power with the speed defined in the Section "Power Curtailment to Support the HVDC Grid Stability", but it must also be capable of receiving the following two command signals from the DCGC and of promptly reacting to them (based on T.3.3.1 and T.3.3.2 definitions):

- Signal 1 – New power setpoint.
- Signal 2 – Speed/ramp of response for power curtailment (PPMs must be capable of complying with the 25 % per second requirement, but they might also be requested to have a slower action to achieve a coordinated curtailment response from all the PPMs to support the controllability and stability of the HVDC grid).

HVDC Converter Temporary Blocking Requirements

Applied to UC04-051 (Ride through offshore HVDC converter temporary blocking with WTGs in GFL control mode) and UC04-111 (HVDC converter permanent blocking with WTGs in GFL mode). These specifications were drafted in InterOPERA, by SuperGrid Institute, as part of the DC Protection workstream and T.3.3.6 work.

During the temporary block of the offshore AC/DC Converter, the islanded Offshore AC Grid experiences overvoltages and frequency deviations, which can lead to the undesired tripping of the connected PPMs. The deviations are typically caused by a combination of several factors including PPM infrastructure (e.g. undersea cables, transformers) and the conventional GFL control which is not designed to operate under an islanded condition. For this reason, control modifications are necessary to prevent the tripping of the PPMs during the temporary blocking of the offshore AC/DC Converter.

In general terms, the HVDC converter temporary blocking specifications can be defined considering the following: in case of an HVDC converter blocking event - loss of frequency reference and power export capability, overvoltage - the PPMs shall be capable of detecting the event, automatically changing to a safe operation mode - islanding mode with grid connection maintained - limiting AC voltage amplitude and frequency deviation. The offshore AC/DC Converter Station shall be capable to smoothly resynchronize to the Offshore AC Grid and the PPMs to resume normal operation and restore the power flow, after the deblocking event.

From a functional requirement, AC temporary blocking time requirement shall align with the DC-FRT time frame and requirements as specified in the Overall Demonstrator Definition, in Annex 03, as well as in section 9.9.4 of the deliverable D.2.1.

Activation of islanded mode

The PPMs must be capable to detect an abnormal situation at the Offshore AC Grid and trigger the islanding mode. The operation of GFL PPMs without voltage reference leads to an increase in voltage magnitude and frequency. This increase in magnitude is used to trigger the islanded mode of the PPMs (See **Figure 4** below). To prevent the overvoltage FRT (OVFRT) protection from triggering (see **Figure 3**), the threshold for activation of the islanded mode (U_{IM}) is set to a value considerably below the maximum of U_{OV1}, to avoid tripping due to delay of measurement and detection that might cause the value to increase a little bit over the threshold value even after activation of the islanded mode (increase a little bit over U_{IM}).

Voltage limitation requirement

Once activated, the voltage magnitude must be limited to prevent triggering the OVRT protection (U_{OV1}) illustrated in **Figure 4**.

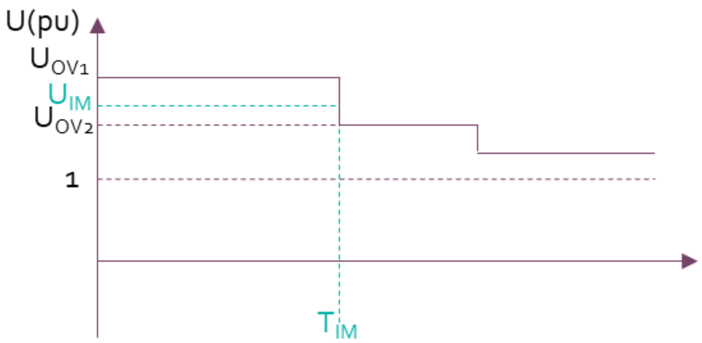

Figure 4: Voltage requirement during islanded mode.

The system must limit the voltage to a level U_{IM} between U_{OV1} and U_{OV2}. With this voltage limitation, the PPMs shall:

- Prevent the transfer of active power to the HVDC grid through the blocked MMC since the pulsating power injection, caused by the non-linear rectifying behaviour, could act destabilizing the HVDC grid. The rectification only happens if the AC voltage is high enough. Therefore, the closer the value of U_{IM} is to U_{OV2} the better.

- Maintain a stable voltage profile at a value different from 1 pu to allow detection of the MMC deblocking.

- Be able to "detect" permanent blocking (UC04-111). With this voltage limit, the system will trip due to OVRT protection for $t > T_{IM}$ which doesn't conflict with temporary blocking as DC protection time frame is considerably shorter, and the deblocking would happen a dozen of ms after the fault at most. In other words, the full cycle of temporary blocking and deblocking would never last for T_{IM}, which means that the temporary blocking and permanent blocking events can be clearly distinguished.

Frequency limitation requirement

Once in islanded mode, the system shall prevent frequency excursions that would cause the PPMs to trip. As referred in **Table 13**, PPMs are not obliged to remain connected if the frequency exceeds 52 Hz. Therefore, while in islanded mode, limiting the frequency obtained from the phase-locked loops (PLLs) becomes critical to maintaining stability and preventing tripping. In other words, the PPMs' PLL frequency, responsible for the frequency increase at the Offshore AC Grid during the offshore AC/DC Converter Station blocking, needs to be limited between 48 and 52 Hz to prevent tripping of the PPM.

4.2. Specifications for Offshore AC/DC Converter Stations

By default, Offshore AC/DC Converter Stations operate in V/f mode, shaping the voltage and frequency profile of the Offshore AC Grid. However, voltage, reactive power, and frequency ranges must be specified to facilitate the design of the HVDC converters.

4.2.1. From TSO Grid Codes

Voltage Specifications

Static voltage stability (TenneT)

For a nominal voltage of 66 kV, the specifications of **Table 14** apply as requirements [4].

Table 14: nominal voltage, voltage range and minimum time for operation for a nominal voltage of 66 kV.

Nominal Network Voltage	Voltage Range (pu)	Minimum Period of Operation
66 kV	0,85 - 0,90	60 mins
	0,90 - 1,10	Unlimited
	1,10 - 1,15	30 mins

Reactive Power Capabilities

Reactive power exchange with active power feed-in into the network (TenneT)

Offshore AC/DC Converter Stations shall meet the requirements regarding the reactive power exchange specified for voltage variations by the relevant system operator in agreement with the relevant transmission system operator. Based on a cost-benefit analysis, the relevant system operator shall specify a U-Q/PAV profile within the outer envelope defined in **Figure 5** in which the offshore AC/DC Converter Station shall be capable of reactive power supply throughout the range between its technical minimum active power and its agreed active connection power [3]. In the InterOPERA case, the offshore AC/DC Converter Station POC is at 66 kV and the voltage values in **Figure 5** are in per unit based on this voltage level. It is recommended to use the basic requirement values for design of converters if stability can be ensured in the demonstrator.

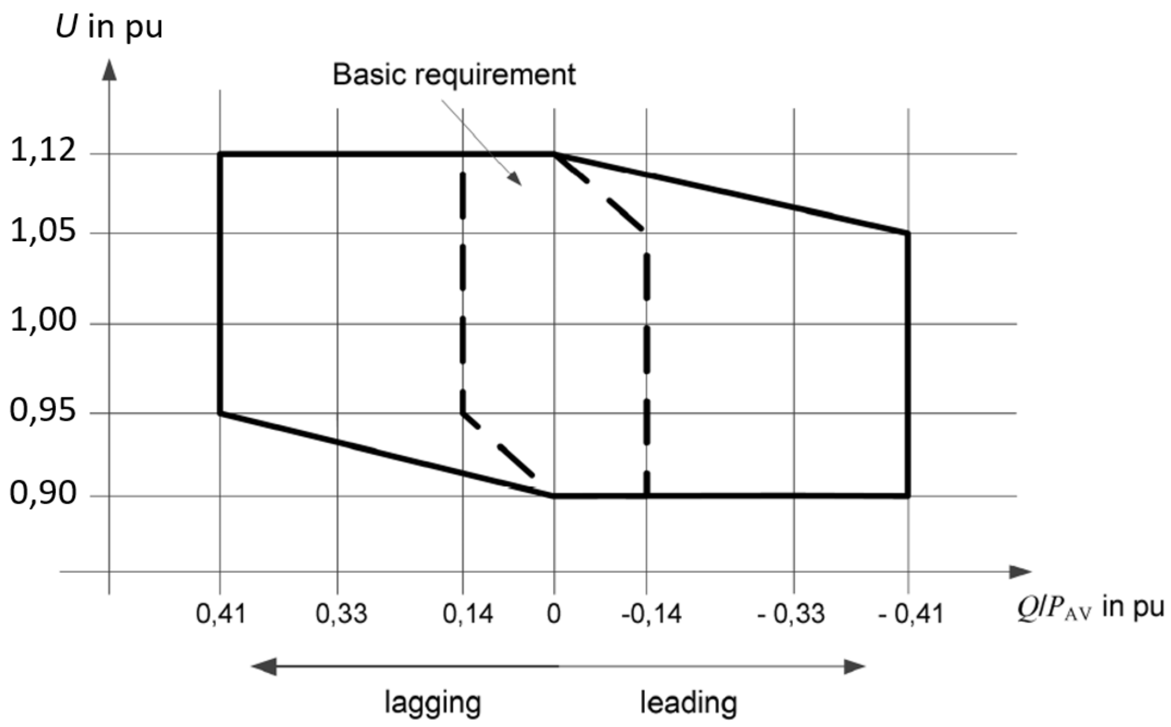

Figure 5: TenneT's reactive power capabilities imposed to offshore AC/DC Converter Stations.

Frequency Ranges

Frequency ranges (TenneT)

Offshore AC/DC Converter Stations shall be capable of remaining connected to the network and maintaining operation within the frequency ranges and time periods given in **Table 15**.

Table 15: frequency range and corresponding minimum time periods for operation.

Frequency range	Minimum time periods for operation
47,0 Hz to 47,5 Hz	longer than 60 s
47,5 Hz to 49,0 Hz	longer than 90 min
49,0 Hz to 51,0 Hz	unlimited
51,0 Hz to 51,5 Hz	longer than 90 min
51,5 Hz to 52,0 Hz	longer than 15 min

4.2.2. Impact of resynchronization process under different initial voltage angles

The offshore AC/DC Converter Station shall be capable to smoothly resynchronize to the Offshore AC Grid and the PPMs to resume normal operation and restore the power flow, after the deblocking event.

A potential solution is to have the offshore AC/DC Converter Station to track the angle of the Offshore AC Grid even during the converter blocking. Then, the measured angle can then be used to initialize the V/f control during the deblocking (**Figure 6**). This is only one illustrative example and not intended as a required or preferred solution. Vendors are free to propose and justify their own approaches to achieving smooth resynchronization.

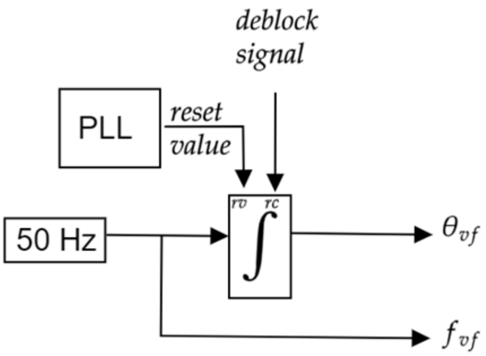

Figure 6: A suggestion of resynchronization solution for the offshore converter.

The voltage magnitude and frequency deviation shall not exceed the OVRT protection limits previously applied for frequency and voltage magnitude (**Table 15** for frequency, **Figure 3** for voltage magnitude). The voltage magnitude and frequency shall be resumed within 100 ms from the deblocking of the offshore AC/DC Converter Station.

Once resynchronized, the offshore AC/DC Converter Station is expected to resume normal control and restore nominal voltage magnitude and frequency. After resynchronization of the offshore AC/DC Converter Station, the PPMs shall return from islanded mode operation to the normal pre-blocking GFL control mode. This change of control mode shall be triggered by the measurement of a voltage close to the nominal value (V<1.05 pu). The step response of active power shall be compliant with post-fault active power recovery requirements defined in D.2.1.

5. Abbreviations

	Description
AC	Alternating Current
DC	Direct Current
DCGC	Direct Current Grid Controller
EPC	Emergency Power Control
FRT	Fault Ride-Through
GFL	Grid-Following
GFM	Grid-Forming
HVDC	High Voltage Direct Current
OVFRT	Overvoltage Fault Ride-Through
PLL	Phase-locked loop
PPC	Power Plant Controller
UC	Use Case
XLPE	Cross-Linked Polyethylene
POC	Point of Connection

6. References

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[3] TenneT, "TenneT - VDE-AR-N_4131_2019-03 - EN," in *SharePoint - WP3/T.3/02_WorkingLevel/06_PPM_ACOffshoreTestBench_WindEurope/References for Specifications*.

[4] TenneT, "TenneT - Grid Connection Requirements TenneT Germany," in *SharePoint - WP3/T.3/02_WorkingLevel/06_PPM_ACOffshoreTestBench_WindEurope/References for Specifications*.

[5] TenneT, "TenneT - Annex C.2.350," in *SharePoint - WP3/T.3/02_WorkingLevel/06_PPM_ACOffshoreTestBench_WindEurope/References for Specifications*.

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[9] B. Hartmann Vilmann, "Stability analysis of parallel MMC-HVDC connections operating in grid-forming mode in offshore energy hubs," in *Technical University of Denmark*, Copenhagen, 2024.

[10] ENTSO-E, "Expert Group on Connection Requirements for Offshore Systems - Phase II (Proposal for the NC HVDC Amendment)," 2023.