Demonstrator project definition and system design studies

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.

Co-funded by
the European Union

DISCLAIMER:

PROJECT DETAILS:

Duration: 1 January 2023 – 30 April 2027
Grant agreement: 101095874

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DELIVERABLE 3.1

JANUARY 2024

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Executive summary

The aim of this task is to define the demonstrator topology of the InterOPERA project while at the same time providing an overall understanding of the foreseen and future planned HVDC systems. The InterOPERA demonstrator topology shall demonstrate that multi-vendor HVDC system control and protection functions can reach the desired technology readiness level (TRL) of value 6-7, as stated in the InterOPERA project grand agreement. That is considered the last step before the full-scale industrial implementation.

The report is organized as follows. In the first part, the demonstrator topology is exhausted. Advocating on the topology selection, insights on multi-terminal multi-vendor HVDC systems in Europe are provided based on TSO experience. This variety of different multi-terminal HVDC system use cases has been collated in a long list of projects and disseminated in this report as a basis for initial discussion. Based on the InterOPERA stakeholder perspectives, results and lessons-learned from past and current full-scale projects are detailed in a short list of projects which establishes key common characteristics of multi-terminal HVDC systems. The entries of the short list are evaluated based on high-priority interoperability functions identified in InterOPERA. In the second phase of Task 3.1 "Offshore HVDC grid system design" (T3.1) preliminary conceptual system design studies are conducted. The studies consist of stationary, quasi-stationary and transient analysis and contribute to the selection of the preliminary main circuit parameters of the InterOPERA demonstrator.

The InterOPERA demonstrator – Enabling meshed DC grids

The InterOPERA demonstrator enables the testing of key functionalities of multi-vendor HVDC systems. The full extent of the topology consists of five converter stations and five DC switching stations which ensures step-by-step verification process development of control and protection functions. Moreover, it enables extended testing procedures for advanced grid forming capabilities, a key outcome of the project. Via this topology, partial and full selective fault clearing strategies including DC-Fault Separation Devices (DC-FSD) in longitudinal couplings and on both DC line ends are covered. The AC connection of offshore converter stations connecting offshore wind farms using wind turbines from different Original Equipment Manufacturers (OEM) and onshore converter stations of different HVDC vendors in different synchronous areas enables the testing of interoperability of windfarms with HVDC converter stations and the testing of advanced grid forming capabilities. To increase flexibility for offline and online testing purposes, the allocation of offshore and onshore converter stations can be adjusted accordingly leading to two variants of the InterOPERA demonstrator topology. The first variant represents a meshed offshore grid for wind export and consists of three offshore converter stations, two onshore converter stations and five DC switching stations (DCSS) which enables testing scenarios for two offshore converter stations in close electrical vicinity. The second variant represents a meshed multi-purpose hybrid interconnector and consists of two offshore converter stations, three onshore converter stations and five DC switching stations which enables e.g. the analysis of AC-side interactions between two onshore stations in close electrical vicinity.

Preliminary conceptual system design studies

In the second phase of T3.1, preliminary conceptual system design studies are conducted, namely stationary, quasi-stationary, and transient analysis. These studies outline the approach that results in the definition of a stationary, temporary, and transient DC voltage and DC current for the offshore and onshore converter stations. The results contribute to selection of the preliminary main circuit parameters. Besides that, general AC- and DC-system data as well as system- level concepts (e.g. protection design concepts, system states, and modes of operation) are defined to characterize the demonstrator grid design quantitatively. Moreover, the results of this task shall be considered in future activities and detailed specifications of WP3.

1. Introduction

The goal of Task 3.1 and the deliverable D3.1 is to define the demonstrator for the InterOPERA project, to provide transparency, mutual understanding, and consensus of the foreseen and planned multi-terminal multi-vendor (MT-MV) High Voltage Direct Current (HVDC) systems and to provide guidance from the asset owner / Transmission System Operator (TSO) perspective.

Initially, a general assessment of planned multi-terminal and potential multi-vendor HVDC projects is carried out and a long list of multi-terminals HVDC use cases is established. Moreover, internal but also external stakeholders are consulted, and an overview of the stakeholder perspectives is given.

Third, high-level selection criteria are used to establish a condensed short list of use cases. These criteria consider the results of further past and current research projects. e.g., PROMOTioN [1], READY4DC [2], NSWPH [3]. The results and most importantly the lessons learned from these research projects and initiatives are also considered. Next, an overview of the short-list of multi-terminal HVDC use cases is established and further insights to the specifics of the individual use cases are provided.

Finally, the entries to the short list are evaluated based on high-priority interoperability functions identified in InterOPERA. The topology and specifics of the InterOPERA demonstrator is proposed, also taking the recommendations from InterOPERA work package 2 (WP2) and general boundary conditions of the InterOPERA (e.g., in-scope/out-of-scope) into account.

After proposing and aligning the topology of the InterOPERA demonstrator, the further activities in Task 3.1 will be focused on preliminary conceptual system design studies in order to further detail the main characteristics of the InterOPERA demonstrator.

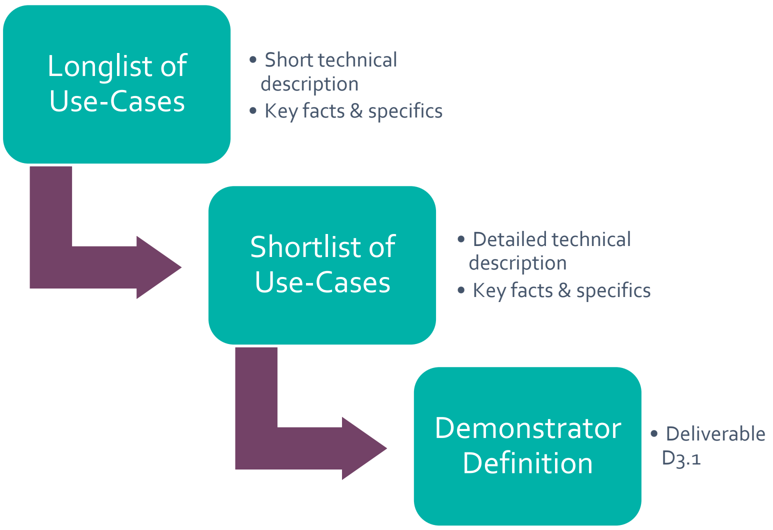


FIGURE 1-1:

Task 3.1 process description of the demonstrator definition.

2. Longlist of HVDC use cases

A general assessment and review is carried out to establish an overview of the relevant MT-HVDC use cases provided by the European TSO's involved in the InterOPERA project. Currently planned national initiatives, the ENTSO-E's Ten-Year Network Development Plan (TYNDP) [4] and Projects of Common Interest (PCIs) [5] are screened and considered as well.

For each MT-HVDC use case a short project description, illustrative figures and a short tabular overview is given. The main items, further background information and technical data are provided by the individual promoters to further detail the MT-HVDC use cases. Below is a brief explanation of the queried characteristics:

GENERAL PROJECT CHARACTERISTIC:

- Category – *HVDC system type point-to-point (P2P) or MT*
- Involved countries – *Countries with converter or switching stations*
- Promoters – *Consortium partners that introduced the project*
- Location – *Geographic location of the project/grid connection systems (GCS)*
- Planned ISD – *Planned in-service date*

HVDC PROJECT CHARACTERISTICS

- Number of offshore converter stations
- Number of onshore converter stations
- Stand-alone DC switching stations – *DC switching station without a related converter station in close vicinity*
- DC-Grid topology – *P2P / MT / MT meshed*
- "Alternating Current" (AC) embedment – *Type of embedment into the (onshore) AC grid / synchronous areas*
- HVDC configuration – *Bipole / Bipole with dedicated metallic return (DMR) / symmetrical monopole*
- Nominal power per converter station – *rating in /GW*
- Nominal DC voltage – *system voltage in kV*

PROTECTION DESIGN CHARACTERISTICS

- DC fault clearing strategy – *Non-selective / partially-selective / fully-selective*
- Planning criteria / Loss of infeed / Loss of transmission capacity

OFFSHORE AC CHARACTERISTICS

- AC offshore connection concept – *Direct connection 66 kV or 132 kV* / Additional HV AC collector bus 400 kV, 220 kV or 155 kV
- AC offshore loads – *planned AC offshore loads, e.g. offshore electrolysis platforms*

2.1. Use case #1: Centre Manche

Centre Manche 1 and Centre Manche 2 will consist of two symmetrical monopoles with a rated power of 1250 MW and a rated DC voltage of ±320 kV using Voltage Sourced Converter technology for each link. Centre Manche 1 will connect the offshore wind farms of AO4 (1050 MW) and part of AO8 (200 MW) to the French 400 kV substation at Menuel through an approximately 100 km DC cable. Centre Manche 2 will connect the offshore wind farms of AO8 to the French 400 kV substation at Tourbe through an approximately 120 km DC cable. The offshore substations will be connected by an Inter Station Link, made up of 3 AC 3-phase cables with either 66 kV or 132 kV.

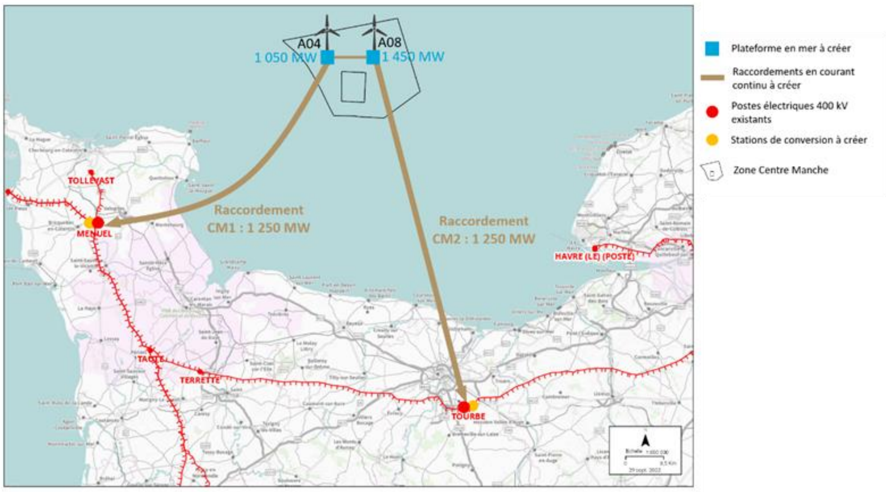


FIGURE 2-1

Overview Use case Centre Manche 1 (FR).

TABLE 2-1

Key facts and specifics of use case / Centre Manche (FR).

	Description
Category	Point-to-Point (P2P) HVDC system
Involved countries	France
Promoters	RTE
Location	2x Grid Connection Systems (GCS) to FR onshore grid
Planned ISD	-
Number of offshore converter stations	2
Number of onshore converter stations	2
DC switching station	No DC Switching Stations (DCSS, AC offshore interstation link)
DC grid topology	2x P2P (AC offshore coupled)
AC embedment	Partially AC embedded 2x AC embedded + 3x OWP AC interconnected Offshore: islanded network / AC interconnected Offshore PPMs 1x 1250 MW PPM 1x 1050 MW PPM 1x 200 MW PPM Onshore: Fully AC embedded
HVDC configuration	Symmetrical monopole
Nominal power per converter station	2x 1250 MW
Nominal DC voltage	±320 kV
DC fault clearing strategy	Non-selective
Planning criteria / loss of infeed / loss of transmission capacity	-
AC offshore connection concept	Direct connection 66 kV or 132 kV
AC offshore loads	No

2.2. Use case #2: Atlantic Shore

The Atlantic Shore project connects in DC the region of Nantes and the region of Bordeaux with two DC submarine links, each of them being connected to an offshore wind park of 1200 MW. The submarine length is 230 km, and the underground length is 130 km. On its southern end, one link will likely be connected to the 400 kV substation on Cubnezais and the other one to the 400 kV substation of Braud. Roughly midway on its route, the link runs by the wind turbines park called AO7 off the coast of La Rochelle. There is no connection with it. It is also foreseen that the two links will be used to evacuate the electric power of another wind turbine park, on its northern side, around 2035; this will lead to the construction of offshore converter stations.

FIGURE 2-2

Overview Use case #2 Atlantic Shore (FR).

TABLE 2-2

Key facts and specifics of use case / Atlantic Shore (FR)

	Description
Category	Multiterminal HVDC system
Involved countries	France
Promoters	RTE
Location	North Atlantic shore between Bordeaux and Nantes
Planned ISD	2032 and 2035
Number of offshore converter stations	2 (1 per link) not before 2035
Number of onshore converter stations	4 (2 per link)
DC switching station	TBD
DC grid topology	-
AC embedment	Onshore: fully AC embedded
HVDC configuration	Symmetric monopole
Nominal power per converter station	1200 MW
Nominal DC voltage	±320 kV
DC fault clearing strategy	Non-selective (TBD)
Planning criteria / loss of infeed / loss of transmission capacity	-
AC offshore connection concept	TBD
AC offshore loads	No

2.3. Use case #3: Lion Link

The Lion Link is a MT-HVDC system with a total wind capacity of 1x 2 GW. One GCS is connected to the onshore grid of the Netherlands with a submarine cable of approximately 150-200 km length. The system further includes an interconnection from the offshore converter platform to the UK (approx. 150-200 km) to enable usage of the existing GCS for energy trading purposes (Multi-Purpose Interconnector). Due to the offshore MT extension, the DC submarine cables can be used more efficiently during low-wind conditions, to optimize and increase the utilization of the offshore assets and provide additional capacity for energy trading.

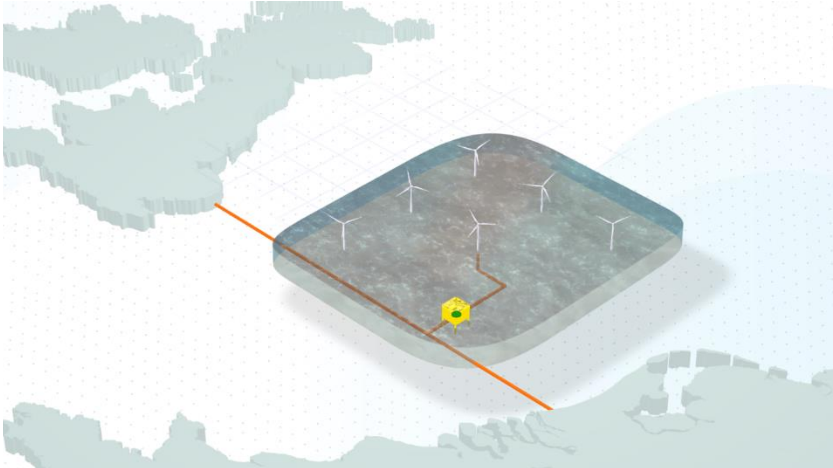


FIGURE 2-3

Overview use case #3: Lion Link 1 (NL-UK)

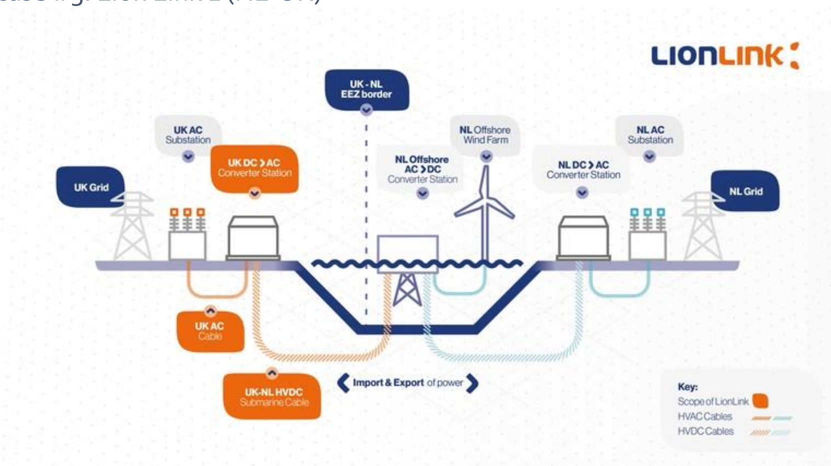


FIGURE 2-4

Overview use case #3: Lion Link 2 (NL-UK)

TABLE 2-3

Key facts and specifics of use case / Lion Link (NL-UK)

	Description
Category	MT HVDC system
Involved countries	Netherlands and UK
Promoters	TenneT Holding B.V National Grid Ventures
Location	1x GCS to NL onshore & interconnection to UK
Planned ISD	2030
Number of offshore converter stations	1
Number of onshore converter stations	2
DC switching station	1 (Offshore)
DC grid topology	Linear MT
AC embedment	All separated 2x AC separated + 1xOWP Offshore: islanded network 2x (4x 500 MW PPM) Onshore: AC separated
HVDC configuration	Bipole with DMR
Nominal power per converter station	2000 MW (2x 1000 MW)
Nominal DC voltage	±525 kV
DC fault clearing strategy	Non-selective
Planning criteria / max. loss of infeed / max. loss of transmission capacity	UK max. loss of infeed 1800 MW
AC offshore connection concept	Direct connection 66 kV
AC offshore loads	No

2.4. Use case #4: Hub2Hub interconnection

The Hub2Hub Interconnection is a planned MT-HVDC system with a total capacity of (min.) 1 x 2 GW, via one interconnector between the NL Hub and the Danish North Sea Energy Island, by a submarine cable of about 200 km in length. This is for the exchange of RES (offshore wind generation) for consumption and/or storage / sector-coupling (e.g. P2X) and enforcing the security of supply. Further, the hubs will have one or more connections to the Netherlands and Denmark, other neighboring countries, and/or sector coupling. Due to the offshore interconnector, the DC submarine cables can be used more efficiently during low-wind conditions, to optimize and increase the utilization of the offshore assets and provide additional capacity for energy trading.

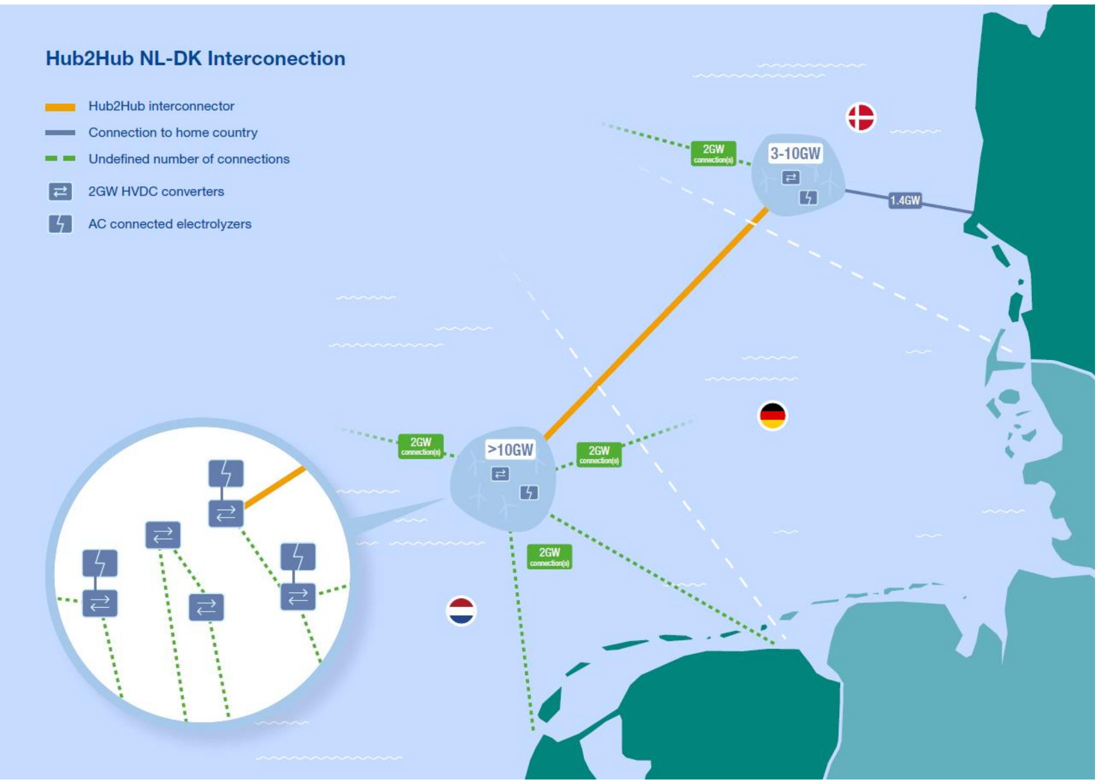


FIGURE 2-5

Overview use case #4 Hub2Hub Interconnection (NL-DK)

TABLE 2-4

Key facts and specifics of use case / Hub2Hub Interconnection (NL-DK)

	Description
Category	MT HVDC system
Involved countries	Netherlands and Denmark
Promoters	TenneT Holding B.V Energinet
Location	1x interconnector from NL Hub to DK North Sea Energy Island Hub
Planned ISD	TBD
Number of offshore converter stations	2 (half bridge)
Number of onshore converter stations	2 (half bridge)
DC switching station	2 (offshore)
DC grid topology	Linear MT / meshed MT (TBD)
AC embedment	Offshore: islanded network 2x (4x 500 MW PPM) Onshore: partially AC separated
HVDC configuration	Bipole with DMR
Nominal power per converter station	(min.) 2000 MW (2x 1000 MW)
Nominal DC voltage	±525 kV
DC fault clearing strategy	Partially-selective / fully-selective
Planning criteria / loss of infeed / loss of transmission capacity	-
AC offshore connection concept	Direct connection 66 kV or 132 kV (TBD)
AC offshore loads	Electrolyzes or other loads

2.5. Use case #5: HeideHub

The HeideHub is a planned MT-HVDC system with a total capacity of 2x 2 GW. Two GCS are connected to the DC substation in Heide by two submarine cable routes of about 250-300 km in length to feed 1x 2 GW of RES (offshore wind generation) to a converter located in the Heide substation. Besides feeding the energy to the AC network in the coastal region, storage / sector-coupling (e.g. P2X) are additional use cases. Further interconnection between the Heide DC-substation to Klein-Rogahn (approx. 250 km) to directly transmit 1x 2 GW from DC-substation Heide to load centers in north-eastern / southern parts of Germany. Due to the DC-Hub configuration, the DC onshore cable corridor can be used more efficiently during low-wind conditions, to optimize and increase the utilization of the onshore assets and alleviate grid constraints between the onshore grid connection points. Thus, the converter stations can be also used to further stabilize and support the onshore AC grid.

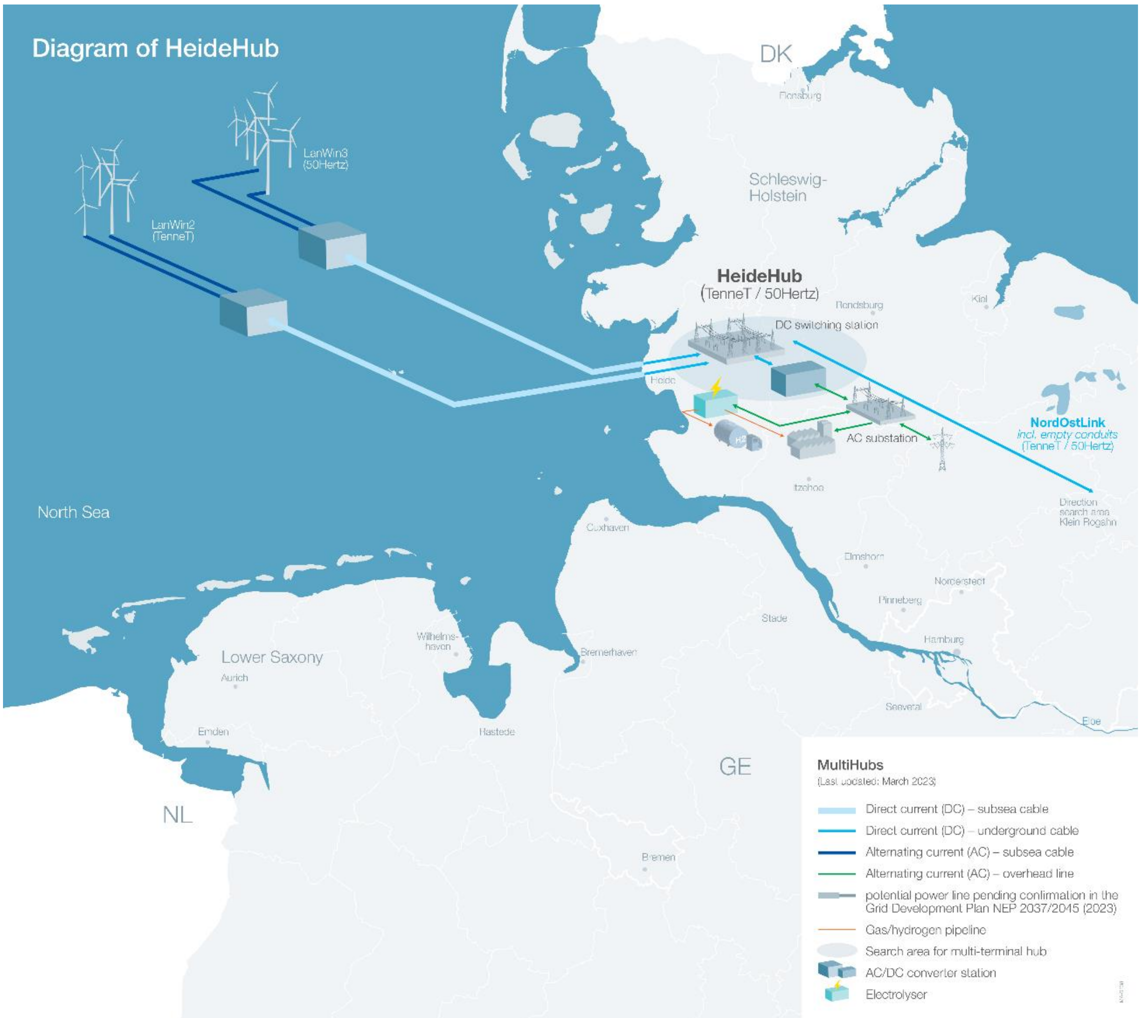


FIGURE 2-6

Overview use case #5 HeideHub (DE)

TABLE 2-5

Key facts and specifics of use case / HeideHub (DE)

	Description
Category	MT HVDC System
Involved countries	Germany
Promoters	TenneT TSO GmbH 50Hertz Transmission GmbH
Location	2x GCS to Heide DC substation (DE) & interconnection to Klein Rogahn (DE)
Planned ISD	2030/2032
Number of offshore converter stations	2 (half bridge)
Number of onshore converter stations	2 (half bridge)
DC switching station	1 (onshore)
DC grid topology	Linear MT
AC embedment	Partially AC embedded 2x AC embedded + 2x OWP Offshore: islanded network 2x (4x 500 MW PPM) Onshore: Fully AC embedded
HVDC configuration	Bipole with DMR
Nominal power per converter station	2000 MW (2x 1000 MW)
Nominal DC voltage	±525 kV
DC fault clearing strategy	Partially-selective
Planning criteria / loss of infeed / loss of transmission capacity	-
AC offshore connection concept	Direct connection 66 kV (t< 2032) Direct connection 132 kV (t> 2032)
AC offshore loads	No

2.6. Use case #6: NordWestHub

The NordWestHub is a planned MT-HVDC system with a total capacity of 2x 2 GW. Two GCS are connected to the DC substation around Rastede with two submarine cables of about 350 km length to feed 1x 2 GW of RES (offshore wind generation) to the coastal region for storage / sector-coupling (e.g. P2X). Further interconnections from DC-substation Rastede to Bürstadt and Marxheim (approx. 550 km) to directly transmit 2x 2 GW from DC-substation Rastede to load centers in western / southern parts of Germany. Due to the DC-Hub configuration, the DC land cable corridors can be used more efficiently during low-wind conditions, to optimize and increase the utilization of the onshore assets and alleviate grid constraints between the onshore grid connection points. Thus, the converter stations can be also used to further stabilize and support the AC onshore grid.

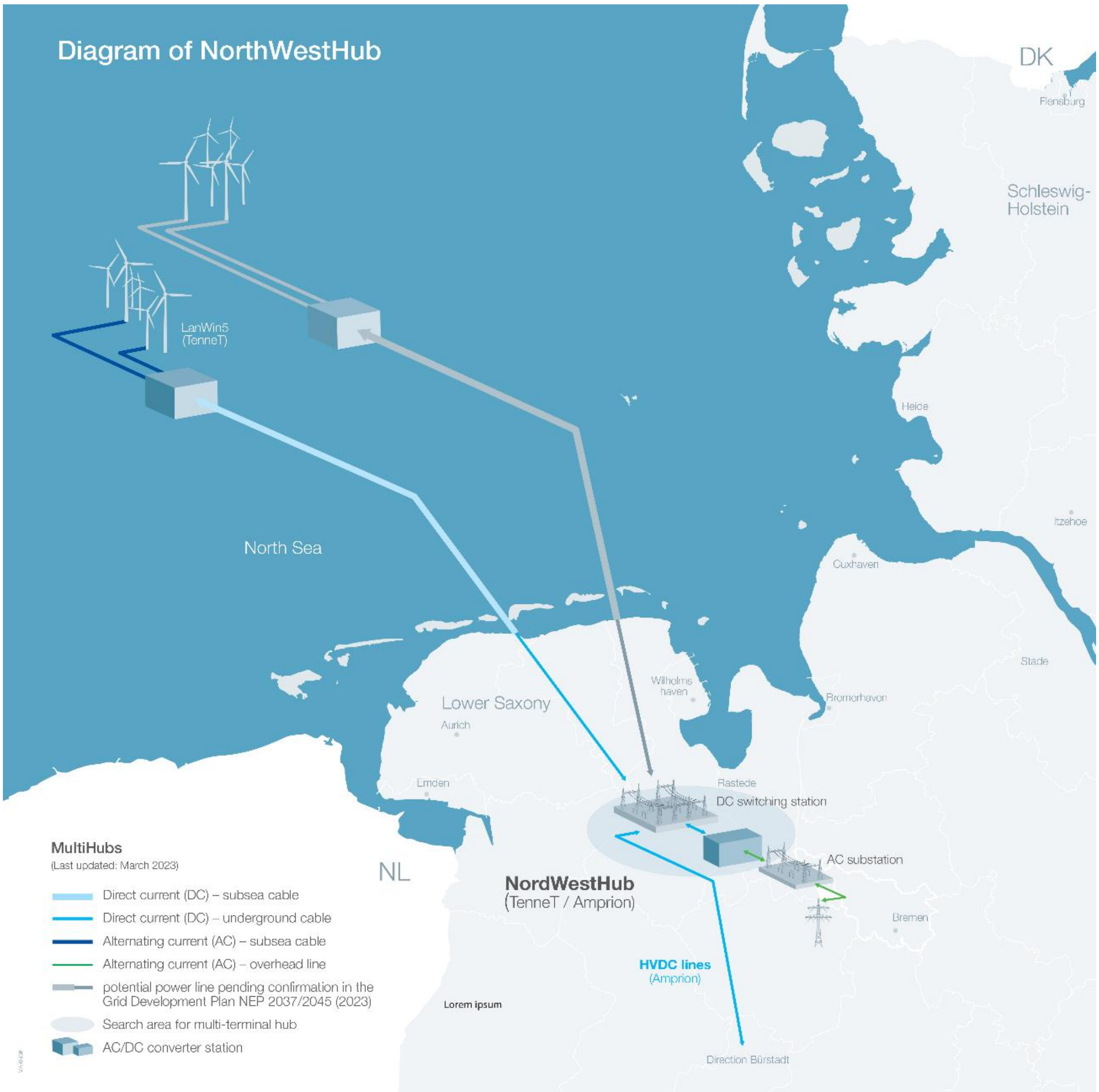


FIGURE 2-7

Overview use case #6: NordWestHub (DE)

TABLE 2-6

Key facts and specifics of use case / NordWestHub (DE)

	Description
Category	MT HVDC system
Involved countries	Germany
Promoters	TenneT TSO GmbH Amprion GmbH
Location	2x GCS to Heide DC substation (DE) & interconnection to Bürstadt & Marxheim (DE)
Planned ISD	2031/2033/2037/2039
Number of offshore converter stations	2
Number of onshore converter stations	3
DC switching station	1 (onshore)
DC grid topology	MT
AC embedment	Partially AC embedded 3x AC embedded + 2xOWP Offshore: Islanded Network 2x (4x 500 MW PPM) Onshore: fully AC embedded
HVDC configuration	Bipole with DMR
Nominal power per converter station	2000 MW (2x 1000 MW)
Nominal DC voltage	±525kV
DC fault clearing strategy	Partially-selective
Planning criteria / loss of infeed / loss of transmission capacity	-
AC offshore connection concept	Direct connection 66 kV (t< 2032) Direct connection 132 kV (t> 2032)
AC offshore loads	No

2.7. Use case #7: Offshore grid connections in the German EEZ

The German TSOs 50Hertz, Amprion, and TenneT, have presented together with Germany's Federal Ministry for Economic Affairs and Climate Protection (BMWK), the initial plans for interconnecting offshore wind farms of 10 GW in total in the North Sea. In addition to connecting the wind farms to the German power grid, the interconnectors shall also enable the exchange of electricity with Germany's neighboring countries like Denmark and the Netherlands. In parallel with the planning, the BMWK has commissioned a study to investigate the overall benefits of such an international power grid in the North Sea. The results show that interconnection reduces greenhouse gas emissions, increases supply security, makes more efficient use of the available space, and saves considerable costs.

The TSOs' plans for interconnecting offshore wind farms will be introduced into official German (Grid Development Plan 2037/2045 (2023)) and European planning processes in the next step. Together with the TSOs of neighboring countries, this will lay the foundation for an international offshore grid in the North Sea. The national offshore grid connection systems (GCS) will be realized as 2 GW / ± 525 kV HVDC systems. In the first step, two times two GCSs will be connected offshore on the DC side resulting in two four-terminal HVDC systems. The commission of the DC-side connection is envisioned for the mid-2030s. Moreover, the plan considers the international offshore connection to Denmark, and the Netherlands as well as the extension of the initial MTDC system as shown in Figure 2-8.

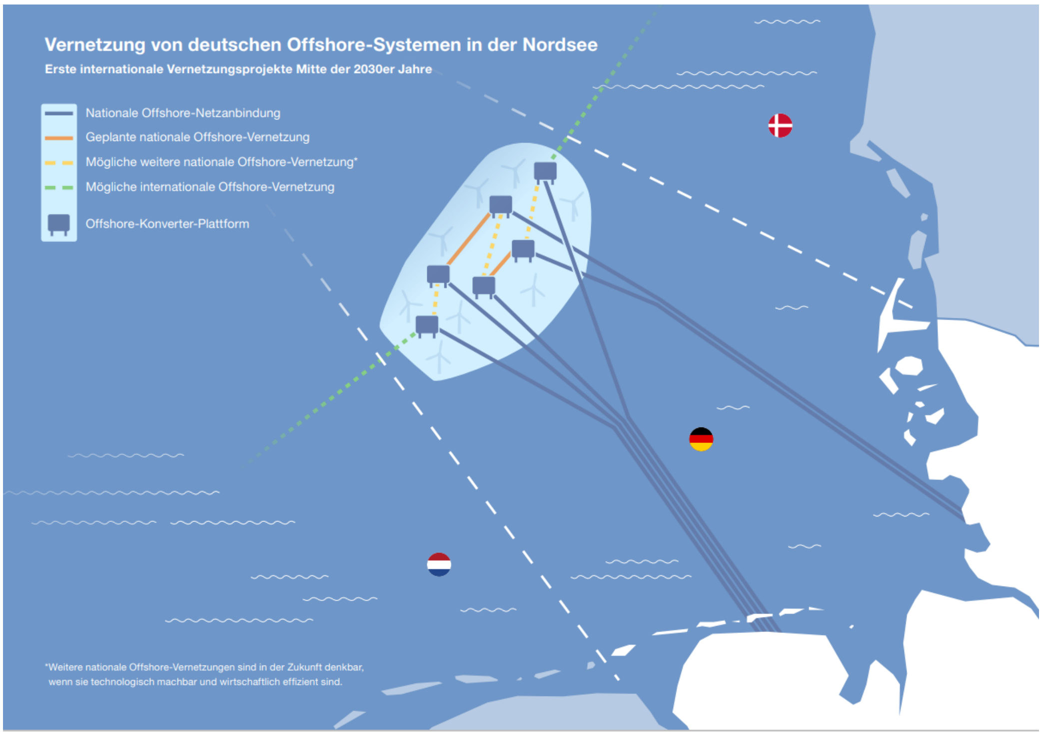


FIGURE 2-8

Offshore grid connections in the German EEZ (DE)

TABLE 2-7

Key facts and specifics of use case / Offshore grid connections in the German EEZ (DE)

	Description
Category	MT HVDC system
Involved countries	Phase 1: DE Phase 2: NL, DK
Promoters	50Hertz Transmission GmbH Amprion GmbH TenneT TSO GmbH
Location	Germany
Planned ISD	National interconnections: 2033-2038 International interconnections: not scheduled until now
Number of offshore converter stations	4 (half bridge)
Number of onshore converter stations	4 (half bridge)
DC switching station	TBD
DC grid topology	Linear MT
AC embedment	2x AC embedded + 2x OWP 2x AC embedded + 2x OWP
HVDC configuration	Bipole with DMR
Nominal power per converter station	2000 MW
Nominal DC voltage	±525 kV
DC fault clearing strategy	TBD
Planning criteria / loss of infeed / loss of transmission capacity	4 terminals with preventive separation of the systems in case of infeed > 3 GW (fallback to P2P)
AC offshore connection concept	Direct connection 132 kV
AC offshore loads	No

2.8. Use case #8: Bornholm Energy Island

The four terminal HVDC system will connect the island of Bornholm to Denmark and Germany via submarine cables with two converter stations on Bornholm, and one in Denmark and Germany each. Besides, integrating 2 GW of offshore wind to Denmark and Germany, it will act as an interconnector between Denmark, Germany, and Bornholm. It will also serve the local AC grid on Bornholm and connect possible P2X-facilities built there.

The MTDC system is planned with a capacity of 1,2 GW to Denmark and 2 GW to Germany. A DC switching station will be located on Bornholm and likely contain fault separation devices (FSD). Future extensions of the MTDC system with additional interconnectors from Bornholm to other Baltic states (e.g., Poland and Sweden) are possible.

FIGURE 2-9

Geographical overview use case #8: Bornholm Energy Island (DK/DE)

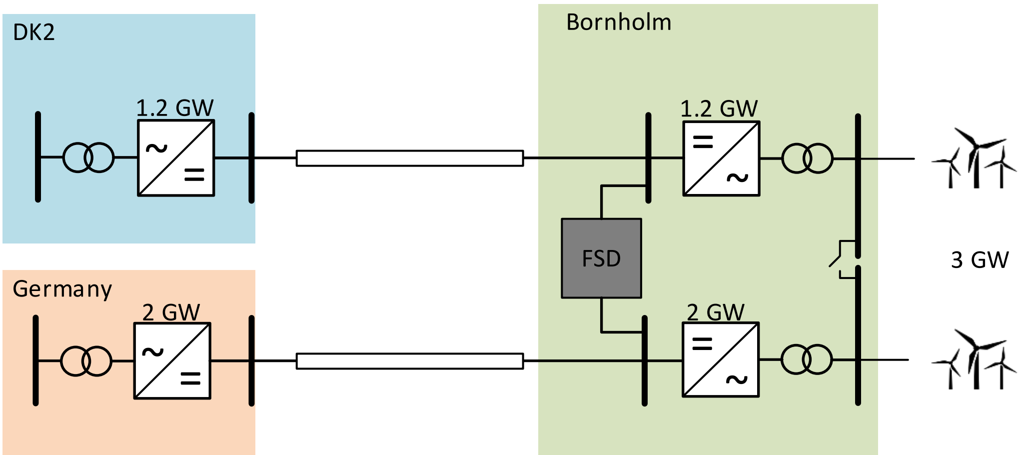


FIGURE 2-10

Electrical overview of the use case #8: Bornholm Energy Island (DK/DE)

TABLE 2-8

Key facts and specifics of use case / Bornholm Energy Island (DK-DE)

	Description
Category	MT HVDC system
Involved countries	Denmark Germany
Promoters	Energinet 50Hertz Transmission GmbH
Location	2x Converter stations on Bornholm and 1x converter station in Denmark and Germany each
Planned ISD	2030
Number of offshore converter stations	2 (on Bornholm, half bridge)
Number of onshore converter stations	2 (Half bridge)
DC switching station	1 (on Bornholm)
DC grid topology	MT
AC embedment	AC all separated 2x AC separated, 2x islanded network Offshore: islanded network (poles of the bipole system can be coupled) Onshore: AC separated
HVDC configuration	Bipole + Dedicated Metallic Return (DMR)
Nominal power per converter station	2000 MW (2x 1000 MW) Germany 1200 MW (2x 600 MW) Denmark
Nominal DC voltage	±525 kV
DC fault clearing strategy	Partially-selective
Planning criteria / loss of infeed / loss of transmission capacity	-
AC offshore connection concept	-
AC offshore loads	On Bornholm

2.9. Use case #9: Danish energy island in the North Sea

In the North Sea, Denmark is planning to install an artificial island where offshore wind farms are connected to HVDC equipment for connections to shore in different countries. In the first phase, it is planned to have up to 4 GW wind power connected to the energy island with 66 kV array cables and a MTDC with four terminals with one terminal located in Denmark and one in Belgium (Triton link, see description in section 4.12). It must be possible to expand the MTDC by connections of up to three 2 GW HVDC platforms in the Danish part of the North Sea. Each platform will have one connection to the shore and one or two connections to the artificial island or other platforms.

On the island, there will also be a 400 kV switchyard between the offshore wind farms and the two terminals, to make it possible to connect offshore P2X facilities in the future. It must be possible to operate the two bipole converters on the energy island with a connection on the AC or the DC side. All future terminals will only be connected on the DC side. It is planned to use a partial-selective fault-clearing strategy with most of the fault separation devices (DC-FSDs) installed on the artificial island.

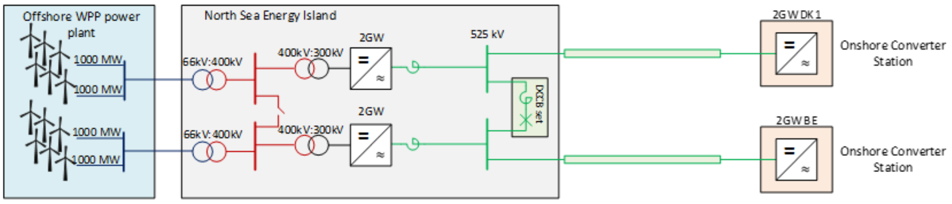


FIGURE 2-11

Overview use case #9: DK energy island in the North Sea (first phase)

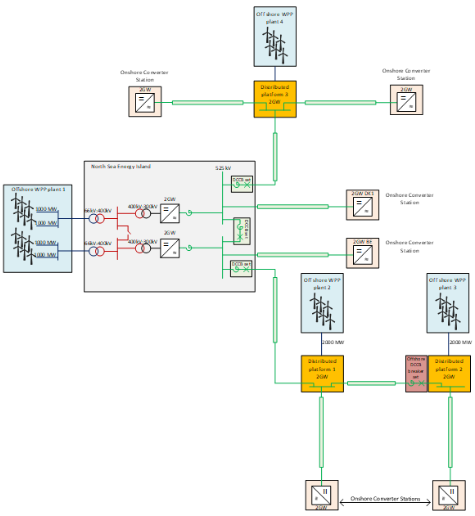


FIGURE 2-12

Overview use case #9: DK energy island in the North Sea (expanded to 10 GW)

TABLE 2-9

Key facts and specifics of use case / DK energy island in the North Sea

	Description
Category	MT HVDC system
Involved countries	Denmark Belgium
Promoters	Energinet
Location	2x Converter stations on an artificial island and 1 converter station in Denmark and 1 in Belgium (first phase)
Planned ISD	2033 (first phase)
Number of offshore converter stations	2 (first phase) 5 (expanded)
Number of onshore converter stations	2 (first phase) 5 (expanded)
DC switching station	1 (offshore)
DC grid topology	Linear MT
AC embedment	Offshore: separate AC grids (Exception: In the first phase it will be possible to connect the two first HVDC links on the AC side (400 kV) in addition to the multiterminal HVDC) Onshore: AC embedded (first phase) Connection to more than one sync. area (expanded)
HVDC configuration	Bipole with DMR
Nominal power per converter station	2000 MW (2x 1000 MW)
Nominal DC voltage	±525 kV
DC fault clearing strategy	Partially-selective
Planning criteria / loss of infeed / loss of transmission capacity	-
AC offshore connection concept	66 kV array cables, 66/400 kV transformers, 400 kV busbar, converter transformers
AC offshore loads	Prepared for loads

2.10. Use case #10: Generic MT offshore wind

There are two HVDC systems connecting offshore wind farms to the existing synchronous AC grid. HVDC systems are ±525 kV HVDC bipole with DMR. Onshore converters are placed in a synchronous grid and their geographical distance is approx. 100 km. The distance between two offshore converters is approx. 20 km. Offshore converters will be meshed with 525 kV cable system. A non-selective protection concept is planned, i.e., only intrinsic capabilities of bipole scheme with DMR will be used (e.g. in case of pole outage one pole will still be in operation).

DC-FSDs were not considered due to the following reasons:

- Technology readiness of DC-FSDs – which could cause time delay in project
- No clear design (different manufacturers with different approaches)
- Limited place offshore (DC-FSDs will significantly increase size, weight, and costs of the offshore platform)
- Planning resources for new equipment (HVDC vendors right now very busy)
- Deregulated US market – low investment security

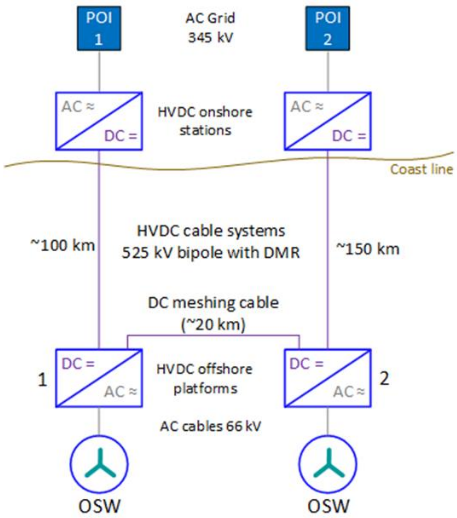


FIGURE 2-13

Overview use case #10: generic MT offshore wind (US)

TABLE 2-10

Key facts and specifics of use case / generic MT offshore wind (US)

	Description
Category	MT HVDC system
Involved countries	US
Promoters	WindGrid, Elia Group
Location	US
Planned ISD	2032
Number of offshore converter stations	2 (half bridge)
Number of onshore converter stations	2 (half bridge)
DC switching station	1 (offshore)
DC grid topology	Linear MT
AC embedment	Partially AC embedded 2x AC embedded + 2x OWP
HVDC configuration	Bipole with DMR
Nominal power per converter station	2000 MW
Nominal DC voltage	±525 kV
DC fault clearing strategy	Non-selective / partially-selective (TBD)
Planning criteria / loss of infeed / loss of transmission capacity	-
AC offshore connection concept	Direct connection 66 kV (in the future 132 kV)
AC offshore loads	No

2.11. Use case #11: Generic MT HVDC system

The proposed generic system includes a four-terminal HVDC system with the infeed of two wind parks and onshore connections to two asynchronous AC grids. The variation emphasizes the mixing of converter configurations between rigid bipole and bipole with DMR, symmetrical monopole, and asymmetrical monopole. The voltage level can be between 320 kV and 525 kV and is up for discussion. The position of DC-FSD's (red squares) is based on Inter-OPERA's suggested demonstrator use case and is also up for discussion.

Figure 2-14 shows a proposal with three bipole configurations with DMR and one symmetrical monopole configuration. If feasible within the scope of this project, the following modifications should be considered:

- Changing one onshore bipole converter with DMR to rigid bipole (this option is indicated by use of the grey line for the DMR to the upper right onshore converter),
  or
- changing the offshore bipole converter with DMR to an asymmetrical monopole

The latter is to be able to study a system with neutral current flow which will happen in normal operation in a system with an asymmetrical monopole connected, or in a contingency situation where a bipole with DMR is in monopole operation.

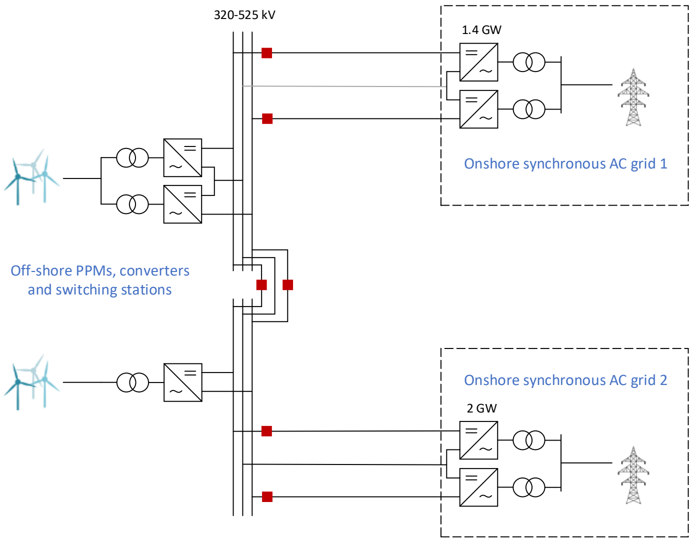


FIGURE 2-14

Overview use case #11: Generic MT HVDC system (NOR)

TABLE 2-11

Key facts and specifics of use case / generic MT HVDC system (NOR)

	Description
Category	MT HVDC system
Involved countries	Generic
Promoters	Statnett
Location	Generic
Planned ISD	N/A
Number of offshore converter stations	2
Number of onshore converter stations	2
DC switching station	1 or 2 (offshore)
DC grid topology	MT
AC embedment	2x AC embedded + 2x OWP Offshore: Islanded or AC interconnected Offshore network Onshore: AC embedded, separate synchronous areas
HVDC configuration	Bipole with DMR Symmetrical monopole (Rigid bipole or asymmetrical monopole if feasible in project scope)
Nominal power per converter station	2000 MW and 1400 MW (Emphasis on having two different ratings for onshore converters)
Nominal DC voltage	±320 kV / ±525 kV
DC fault clearing strategy	Partially-selective / fully-selectivity
Planning criteria / loss of infeed / loss of transmission capacity	-
AC offshore connection concept	Optional
AC offshore loads	Optional

2.12. Use case #12: Princess Elisabeth-Nautilus-Triton

Three combined projects will lead to a multi-terminal multi-vendor HVDC system in the North Sea.

Princess Elisabeth (phase 1)
The development of the Modular Offshore Grid 2 project is ongoing. The key to this project is the construction of the 'Princess Elisabeth Energy Island' which has recently been awarded. The island will be ready for outfitting by the end of 2026.

On this island, 3.5 GW of offshore wind will be connected (66 kV). 2.1 GW will be brought onshore through six 220 kV offshore cable connections whereas 1.4 GW will go through a 2 GW 525 kV bipole system. On the island itself, the 66 kV wind power will be converted to 220 kV which should lead to a seamless exchange of power between the AC & DC part of the connections. A DC yard will allow for the further expansion of the DC network on the island.

FIGURE 2-15

Overview use case #12: Princess Elisabeth-Nautilus-Triton 1 (BE)

Nautilus (future 1)
The Nautilus project will expand the Princess Elisabeth HVDC project to a multiterminal set-up with four converter stations. An HVDC connection from the Belgian Energy Island towards the UK mainland with an extra converter to accommodate UK offshore wind will be added to the existing Princess Elisabeth Island configuration.

Triton (future 2)
The Triton project is the third step in the ambitious HVDC project. It will consist of a new P2P connection between Belgium & Denmark; however, it will be connected on Princess Elisabeth Energy Island using a DC-FSD. The connection on the Danish energy island is still under development, one of the possible layouts has been drawn below (reference is made to the Danish Energy Island).

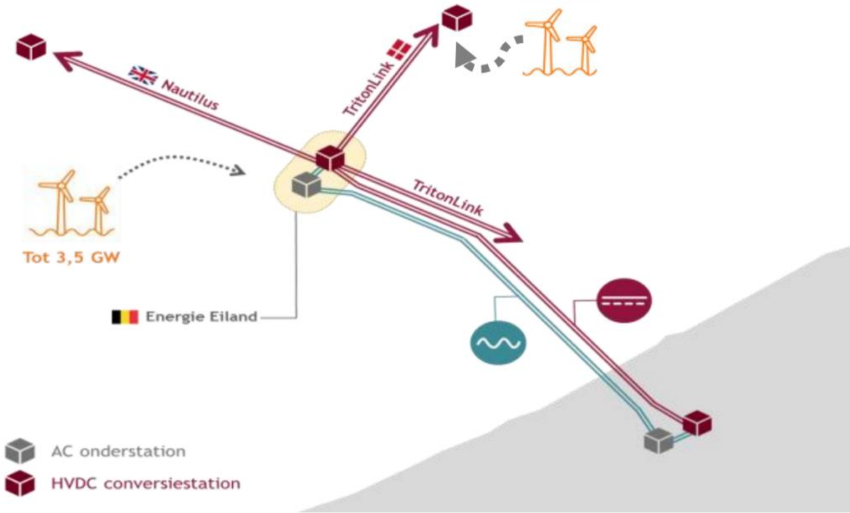


FIGURE 2-16

Overview use case #12: Princess Elisabeth-Nautilus-Triton 2 (BE)

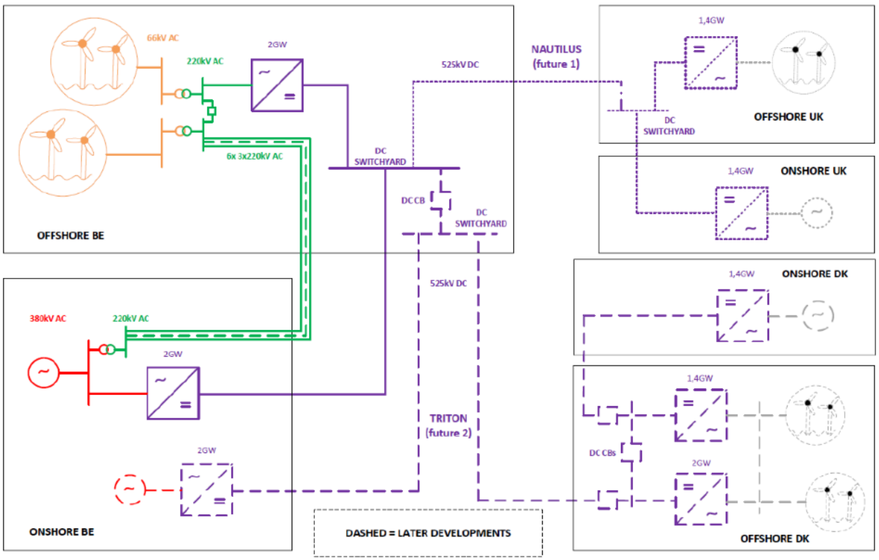


FIGURE 2-17

Overview use case #12: Princess Elisabeth-Nautilus-Triton (BE)

TABLE 2-12

Key facts and specifics of use case / Princess Elisabeth-Nautilus-Triton (BE)

	Description
Category	MT HVDC system
Involved countries	Belgium UK Denmark
Promoters	Elia National Grid Ventures Energinet
Location	North Sea (BE, UK, DK) Princes Elisabeth Island (BE) Danish Energy Island (DK)
Planned ISD	N/A
Number of offshore converter stations	3
Number of onshore converter stations	4
DC switching station	3 + (1)
DC grid topology	Meshed MT
AC embedment	Partially AC embedded 3 x AC embedded (onshore) + 3 x OWP AC (inter)connected
HVDC configuration	Bipole (with DMR)
Nominal power per converter station	2000 MW
Nominal DC voltage	±525 kV
DC fault clearing strategy	Partially-selective (project phase dependent)
Planning criteria / loss of infeed / loss of transmission capacity	-
AC offshore connection concept	220 kV busbar collector with AC interconnection to mainland
AC offshore loads	No

2.13. Use case #13: Holistic Network Design / Peterhead Hub – Project Aquila

Short Technical Description:

The Peterhead Hub is a future and stepwise planned MT-HVDC system with a total prospective capacity of up to 8x 2 GW which is connected to a central DC switching station (DCSS) in Peterhead. The DCSS is planned to be developed in stages to avoid compounding technology risks and to facilitate real-world demonstration of P2P MV as well as MT MV capabilities. In addition, the Aquila Interoperability Package (AIP) seeks to develop and establish an aligned control & protection strategy, modelling, and control systems framework in a coordinated activity between the UK stakeholders and the HVDC vendors. The envisioned development phases of the Peterhead Hub are outlined as follows:

Phase 1 – Target 2030 delivery:

- Mixture of rigid & non-rigid / bipole with DMR P2P HVDC systems
- DCSS designed as a double busbar system with 4 bays, busbar coupler normally-open
- DCSS designed with expansion capability to integrate up to 8 bays
- DCSS equipment delivered and installed during execution works for P2P HVDC systems
- Software structured and functionally capable to deliver MT MV functionalities
- No requirement to enable MT MV functionalities, no requirement to integrate DC-FSDs

Phase 2 – Demonstrate MV P2P and MT MV Interoperability (2031+):

- Following successful work in the Aquila Interoperability Package (AIP)
- Enable and parameterize MT MV functionalities
- Demonstrate P2P / 2-terminal MV interoperability
- Demonstrate MT MV interoperability

Phase 3 – Further Expansion (2035+):

- Following further successful work in AIP
- Integration of additional terminals and Offshore Wind Generation
- Potential integration of DC-FSDs to further enable offshore connections (mid 2030s)
- Meshed HVDC grid development

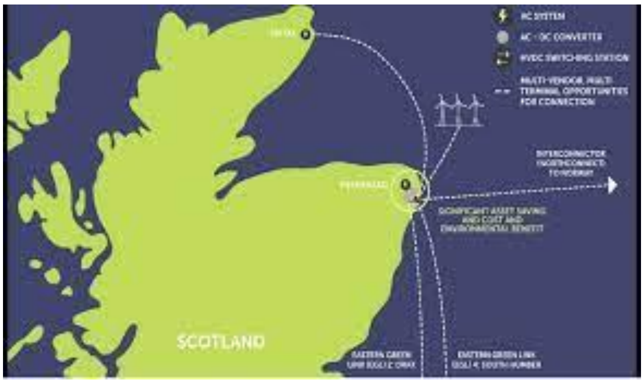


FIGURE 2-18

Overview Use case #18: HND/ Peterhead Hub - Project Aquila (UK)

TABLE 2-13

Key Facts and Specifics of Use Case #13: HND/ Peterhead Hub - Project Aquila (UK)

	Description
Category	Phase 1: P2P Phase 2 & 3: MT HVDC system
Involved countries	UK
Promoters	UK stakeholders
Location	Peterhead
Planned ISD	Phase 1: 2030 Phase 2: 2031+ / Phase 3:2035+
Number of offshore converter stations	Phase 1:0 / Phase 2 & 3: 2-3
Number of onshore converter stations	Phase 1:4 / Phase 2 & 3:6-5
DC switching station	1x Onshore DCSS Phase 1 without DC-FSDs Phase 2 & Phase 3 including DCSS extension with DC-FSDs
DC grid topology	MT
AC embedment	Onshore: Fully AC embedded Offshore: Islanded network / OWP
HVDC configuration	Bipole with DMR Rigid bipole
Nominal power per converter station	2000 MW
Nominal DC voltage	±525 kV
DC fault clearing strategy	Non-selective Partially-selective
Planning criteria / loss of infeed / loss of transmission capacity	1800 MW max. loss of infeed
AC offshore connection concept	Direct connection 66 kV / 132 kV
AC offshore loads	NA

2.14. Summary of MT-HVDC use cases

This section provides an overview of the technical characteristics of the use cases introduced in this chapter. The characteristics are listed in Table 2-14 and Table 2-15. The focus lies on MT-HVDC systems. Point-to-point HVDC connections are not included.

TABLE 2-14

Overview of planned MT-HVDC use cases - part 1

Name of HVDC project	*DC voltage converter rating*	*CNV type*	*# of converter stations* *# of DC switching stations* *grid architecture* *HVDC configuration*	*DC protection strategy*	*AC offshore connection concept*
Use case #2 Atlantic Shore (FR)	±320 kV 1200 MW	Voltage Source Converter (VSC)	4 onshore / 2 offshore Not applicable MT HVDC system Symmetric monopole	Preliminary: Non-selective	Under review
Use case #3 Lion Link (NL-UK)	±525 kV 2000 MW	VSC	2 onshore / 1 offshore 1 offshore DCSS MT HVDC system Bipole with DMR	Non-selective	Direct connection 66 kV
Use case #4 Hub2Hub (NL-DK)	±525 kV 2000 MW	VSC	2 onshore / 2 offshore 2 offshore DCSS MT HVDC system Bipole with DMR	Partially-selective Fully-selective	Direct connection 66 kV or 132 kV (TBD)
Use case #5 HeideHub (DE)	±525 kV 2000 MW	VSC	2 onshore / 2 offshore 1 Onshore DCSS MT HVDC system Bipole with DMR	Partially-selective	Direct connection 66 kV (t< 2032) Direct connection 132 kV (t> 2032)
Use case #6 NordWest-Hub (DE)	±525 kV 2x 2000 MW	VSC	3 onshore / 2 offshore 1 onshore DCSS MT HVDC system Bipole with DMR	Partially-selective	Direct connection 66 kV (t< 2032) Direct connection 132 kV (t> 2032)
Use case #7 Offshore GCS in EEZ	±525 kV 2000 MW	VSC	2x (2 onshore / 2 offshore) 4 offshore DCSS MT HVDC system Bipole with DMR	Preliminary: Non-selective Partially-selective	Direct connection 132 kV

TABLE 2-15

Overview of planned MT-HVDC use cases - part 2

Name of HVDC project	*DC voltage converter rating*	*CNV type*	*# of converter stations* *# of DC switching stations* *grid architecture* *HVDC configuration*	*DC protection strategy*	*AC offshore connection concept*
Use case #8 Bornholm Energy Island	±525 kV 2000 MW & 1200 MW	VSC	2 onshore / 2 offshore 1 offshore DCSS (Bornholm) MT HVDC system Bipole with DMR	Partially-selective	400 kV busbar collector, connecting the local Bornholm 66 kV network and WTGs
Use case #9 Danish Energy Island	±525 kV 2000 MW	VSC	2 onshore / 2 offshore 1 offshore DCSS (artificial island) MT HVDC system Bipole with DMR	Partially-selective	400 kV busbar collector on the artificial island
Use case #10 Generic MT US	±525 kV 2000 MW	VSC	2 onshore / 2 offshore 1 offshore DCSS MT HVDC system Bipole with DMR	Non-selective	Direct connection 66 kV (in future 132 kV)
Use case #11 Generic MT HVDC NOR	±525 kV/ ±320 kV 2000 MW /1400 MW	VSC	2 onshore / 2 offshore 2 offshore DCSS MT HVDC System Bipole with DMR, rigid bipole, asymmetrical &, Symmetrical monopole	Partially-selective Fully-selective	Under review
Use case #12 Princess Elisabeth-Nautilus-Triton	±525 kV 2000 MW	VSC	4 onshore / 3 offshore 1 offshore DCSS (Artificial Island) MT HVDC system Bipole with DMR	Partially-selective	220 kV busbar collector with AC interconnection to mainland
Use case #13 Peterhead Hub (UK)	±525 kV 2000 MW	VSC	4 onshore 1 onshore DCSS (Peterhead) MT HVDC system Bipole with DMR	Non-selective Partially-selective	Not applicable

3. Summary of stakeholder perspectives

This section provides a short summary of stakeholder interviews conducted during the demonstrator definition of WP3. The stakeholder groups represented in the consortium, namely TSOs, HVDC vendors, offshore wind park developers/wind turbine manufacturers as well as external stakeholders, have been interviewed separately. The interviews aimed to reflect on planned MT-HVDC use. Selection and decision criteria were discussed and evaluated.

3.1. Wind farm developers and wind turbine vendors

From a WTG vendor / OWP developer perspective the InterOPERA demonstrator should fulfil the defined in-service dates and should be in the North Sea. Furthermore, an AC offshore connection concept including AC offshore connecters should be part of the demonstrator. This is useful to assess the AC offshore interaction between different wind farms and to prove that interoperability can be achieved between wind farms from different WTG vendors. In addition, redundancy in case of a converter failure is possible with an AC offshore interconnection. The HVDC configuration and the maturity of key equipment are also crucial items that should be considered for the demonstrator.

Regarding possible selection criteria, the proposed demonstrator should reflect the aspects of AC interactions, robustness, and redundancy. In addition, the demonstrator should be flexible. AC offshore interconnection, which is understood as an offshore interconnection between two separate offshore converter stations, is desirable under the assumption that the interconnections increase the availability of offshore wind parks. Additionally, the coordination between offshore HVDC converter stations and wind turbines under defined contingency cases can be investigated. Scenarios that keep the wind park operational during temporary blocking and deblocking of offshore converter stations shall be investigated. Coordination between HVDC converter stations and wind farms to provide synthetic inertia to AC onshore grids from wind parks.

Regarding possible decision criteria the proposed demonstrator should be aligned with the InterOPERA key objectives and cover the aspects of expandability, scalability, reliability and generation availability. A common goal should be to find a solution that integrates as much wind power as possible into the European electricity grid. As of now, wind farms are primarily operated to maximize energy production. Using wind farms as reserves / ancillary services is not widely pursued by wind farm developers in the upcoming years.

Wind farm developers focus on minimizing platform size to optimize CAPEX and OPEX for the offshore systems. However, due to individual regional constraints (e.g. issues with deep waters) in European countries this process leads to different optimization results and HVDC configurations. Therefore, it is recommended that converter stations with various HVDC configurations (symmetrical monopoles, rigid bipole, bipole + DMR) and ratings are considered for the final demonstrator topology. Only with the flexibility to choose multiple HVDC configurations and ratings can the offshore system be optimized.

3.2. TSOs

From a TSOs perspective the InterOPERA demonstrator should represent a cross TSO project and focus on the developments in the North Sea. The number of converter stations, the type of AC embedment, the DC-grid topology and the HVDC configuration are identified as important items. Furthermore, the demonstrator definition should include future proof concepts, respect the allowed loss of infeed, and consider expandability aspects. Finally, it is important to de-risk the first MT-MV projects around the North Sea. Therefore, possible fallback options are required. In general, the demonstrator should cover a large variety of technical solutions and its complexity should be sufficient for demonstrating interoperability. With that being said, it is also possible to consider technologies that are not established in the European market yet (e.g. DC-FSD).

Regarding possible selection criteria the proposed demonstrator should consist of at least four HVDC converter stations and include the possibility of connecting to at least two different synchronous AC grids. This is important for the demonstration of grid forming from DC connected PPMs and the parallel operation of PPMs.

Regarding possible decision criteria, the proposed demonstrator will be aligned with the InterOPERA key objectives. In addition, expandability and scalability aspects will be covered in the demonstrator.

3.3. HVDC vendors

Based on the ranking questions the InterOPERA demonstrator should be part of a cross TSO project and consider in-service dates of planned projects. The number of converter and DC switching stations as well as the HVDC configuration and the DC-grid topology are important items for the demonstrator from a HVDC vendor perspective. Additionally, the demonstrator should be aligned with the InterOPERA key objectives.

The demonstrator should serve as a generic test network for concept validation. It should reflect a large variety of technical solutions but also focus on the reusability of the results. The demonstrator considers requirements from the use cases to achieve empirical results (e. g. ratings and parameters from real use cases on both AC and DC side are utilized for the simulations). In general, the complexity of the demonstrator should be such that manageable results can still be achieved.

Offline simulations are deemed better suited for complex simulation tasks. Therefore, it is expected that offline simulations are better suited to study control interactions and protection phenomena in a multi-terminal HVDC system. In contrast, online or real-time simulations (mostly in a hardware-in-the-loop (HIL) setup) are best suited for validation / benchmarking purposes and for operational aspects (e.g. sequences). Since three HVDC converter station vendors are involved in InterOPERA, the demonstrator should consist of three converter stations in the real-time setup. This limits the number of possible topologies for the demonstrator. However, adding more stations should be considered as an option for offline simulations.

As of now, software-in-the-loop (SIL) is regarded as not mature enough for use in real-time simulation setups and should therefore not be considered for the demonstrator.

3.4. External stakeholders

External stakeholders from the UK were interviewed to also gather their perspectives on future MT-MV projects in UK and Europe. During the interview session it was stated that a mixture of different HVDC configurations (e. g. bipole with DMR and rigid bipole systems) is envisioned to be connected to a central DC switching station – see use case #13. Regarding the development roadmap of such DC switching stations for MT-MV HVDC systems, the UK stakeholders heavily focus on the technology readiness of the required key components and the maturity of the required control & protection systems to be capable of MT MV functionalities.

Therefore, a step-by-step development roadmap is foreseen. First, P2P HVDC systems are integrated to a DC switching station. Second, MV interoperability is demonstrated for P2P HVDC systems. Third, MV interoperability is demonstrated for MT HVDC systems. Thus, DC-FSDs are only considered relevant in future development phases and further expansion scenarios.

DC switching stations are said to be planned and designed with an adequate and sufficient expansion capability to enable future developments and transition towards a meshed HVDC grid. This includes DCSS extensions and the potential integration of DC-FSDs in further development stages.

The key interoperability considerations from the UK stakeholders are:

- Real world and practical application demonstration of outcomes
- Minimum industry disruption
- Protection of vendors' IP
- Safe to fail
- HVDC Vendors' buy-in

3.5. Evaluation of priorities

The results of the ranking questions are depicted in Figure 3-1 Figure 3-1 to Figure 3-4 Figure 3-4. Each stakeholder group was asked to provide their perspective regarding characteristic and desires as well as priorities for the demonstrator. Characteristics are ranked from most to least relevant. For each ranking item, possible questions related to that item are listed and used for descriptive purposes.

General overarching characteristics

The first ranking question covers general, overarching characteristics such as:

- **Cross border project**: Will the terminals of the demonstrator be in different countries?
- **Cross TSO project / cooperation effort:** Are multiple TSOs involved in the development?
- **Location / North Sea needs:** Does the demonstrator fulfil North Sea needs or is in the North Sea?
- **Number of promoters / alignment effort:** How many promoters will be involved?
- **In Service date / urgency:** Should In-Service dates be considered for the demonstrator?

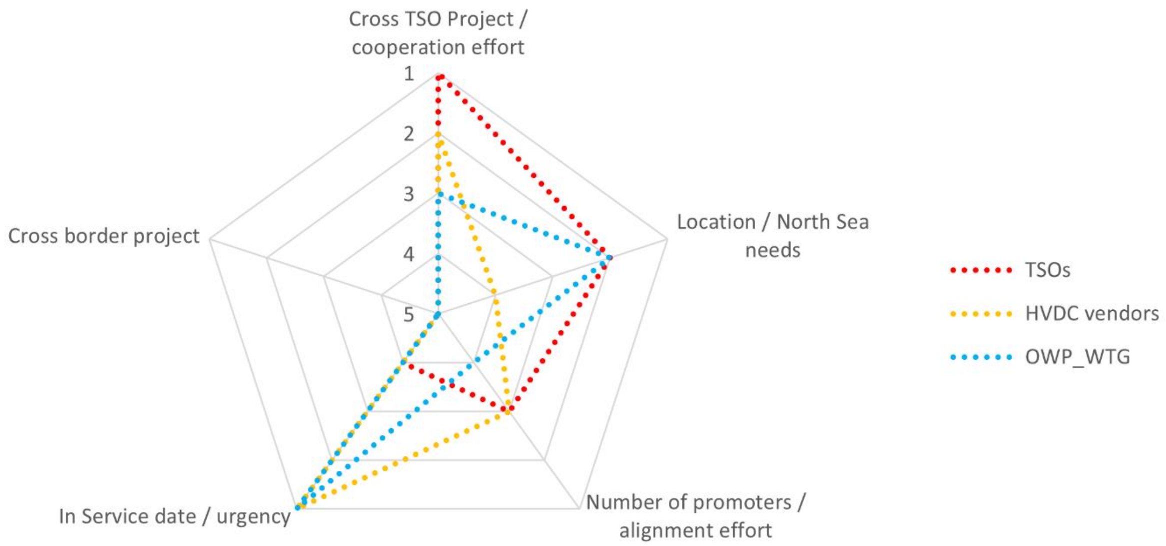


FIGURE 3-1

Ranking of general, overarching characteristics

Overarching project characteristics

The second ranking question covers overarching project characteristics such as:

- **AC offshore connection concept:** What type of connection concept is used for the AC-offshore side?
- **Number of converter stations:** How many converter stations are considered?
- **Type of AC embedment / synchronous areas:** Should different synchronous AC grids be considered for the demonstrator?
- **Number of DC switching stations:** How many DC switching stations are considered?
- **AC offshore connecters:** Are AC offshore connectors included?

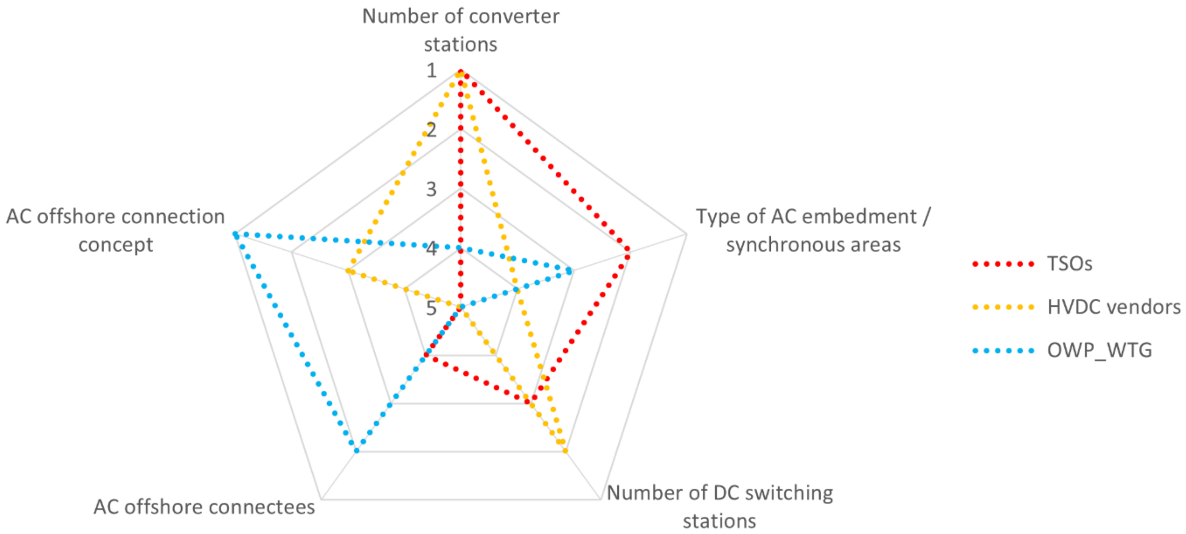


FIGURE 3-2

Ranking of overarching project characteristics

DC grid characteristics

The third ranking covers characteristics of the DC grid such as:

- **DC voltage level / converter rating:** What is the voltage level at the DC side? What is the rating of the converters? Should the demonstrator be flexible to connect different converter ratings?
- **DC grid topology / nodes & lines:** What DC grid topology will be used for the demonstrator (linear, MT, etc.)?
- **HVDC configuration / feasibility:** What type of HVDC configuration should be considered for the demonstrator?
- **DC fault propagation / selectivity:** What selectivity concept (non-selective, partially-selective, fully-selective) will be used for the demonstrator?
- **TRL & maturity of key equipment / feasibility:** Is the equipment utilized for the demonstrator technology ready?

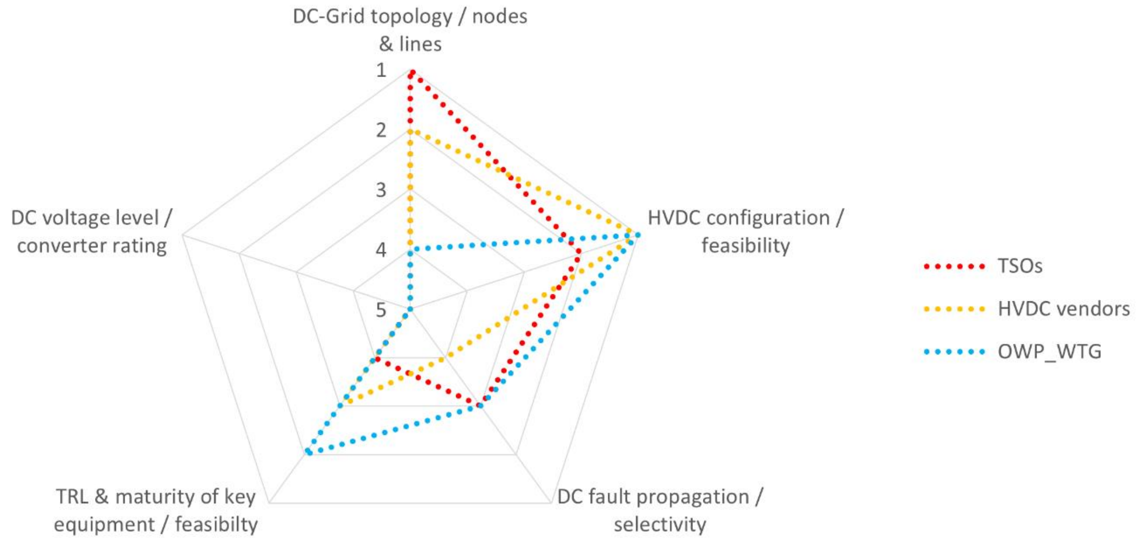


FIGURE 3-3

Ranking of DC grid characteristics

Project & InterOPERA target characteristics

The fourth ranking question covers project & InterOPERA target characteristics such as:

- **Urgency / In-Service date & timeline:** Should a timeline and In-Service dates be considered for the demonstrator?
- **Alignment to InterOPERA key objectives:** Is the demonstrator aligned with the objectives listed in the InterOPERA demonstrator?
- **Expandability & scalability:** Is expandability foreseen by the demonstrator?
- **Variety of technical solutions / complexity / practicality:** Does the demonstrator show a variety of technical solutions?
- **Innovations / stretch-goal indicator:** Is the demonstrator innovative?

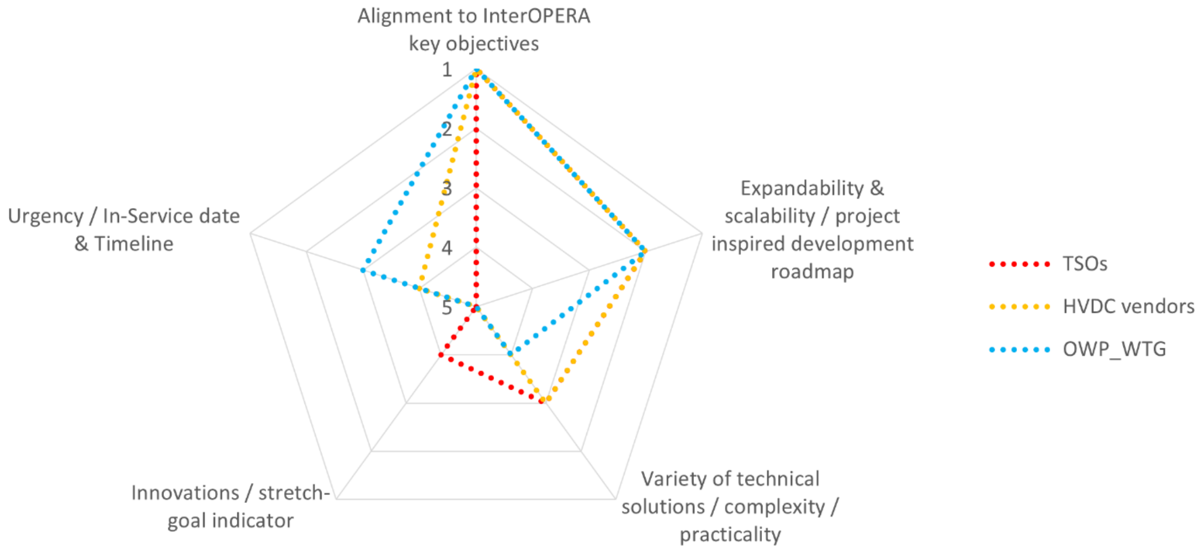


FIGURE 3-4

Ranking of project & InterOPERA target characteristics

4. Selection criteria

The subsequent matrix is used for clustering the proposed use cases of the long list and to narrow them down to a short list of generic project descriptions of the InterOPERA demonstrator (see section 5). The criteria are based on the conducted stakeholders' interviews and, to a certain extent, on the results of the Horizon Europe project READY4DC [2].

COMPLIANCE TO SYSTEM OPERATIONS GUIDELINES (SOGL)

The discussion built around the introduction of MT MV HVDC systems is based on the system needs of existing AC grids. This includes among other needs how much generation capacity is allowed to be lost and for how long, also often referred to as maximum loss of infeed. A non-exhaustive set of relevant grid code compliance criteria based on the grid codes used in different countries and the ENTSO-E system operations guideline can be found in research projects such as READY4DC [2] or PROMOTioN [1].

MULTI-TERMINAL

A multi-terminal system is understood in the first stage to consist of three or more terminals connected at the DC side. It may be expanded in future stages. Uncertainties with regards to realizing widespread DC grids are highly related to the concept of having multiple HVDC terminals.

EXPANDABILITY

In the future, it is expected that HVDC systems will be built by multiple vendors, in multiple stages as described for example in READY4DC [2]. Therefore, expandability is a key characteristic of future Multi-Terminal HVDC systems. From a system design and protection concept perspective, the demonstrator should at least be compatible to the first development stages towards a European meshed DC grid.

PLANNED ISD

A global objective of InterOPERA is to de-risk the multi-vendor multi-terminal HVDC technology and 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. Therefore, special consideration should be given to specifics and characteristics of HVDC use cases with a near-term planned "In-service date" (ISD).

TABLE 4-1

Overview of the selection criteria matrix

Name of HVDC Project	*Compliance to SOGL*	*Multi Terminal*	*Expandability*	*Planned ISD*
Use case #1 *Centre Marche (FR)*	✓	✗	✗	NA
Use case #2 *Atlantic Shore (FR)*	✓	✓	✗	2032/2035
Use case #3 *Lion Link (NL-UK)*	✓	✓	✗	2030
Use case #4 *Hub2Hub (NL-DK)*	✓	✓	✓	NA
Use case #5 *HeideHub (DE)*	✓	✓	✓	2030/2032
Use case #6 *NordWestHub (DE)*	✓	✓	✓	2031/2033/ 2037/2039
Use case #7 *Offshore GCS (DE-DK / DE-NL)*	✓	✓	✗	2035
Use case #8 *Bornholm Island (DK-DE)*	✓	✓	✓	2030
Use case #9 *NSEI (DK-BE-DE-NL)*	✓	✓	✓	2033 (first phase)
Use case #10 *Generic MT Offshore Wind (US)*	✓	✓	✗	Generic Use case
Use case #11 *Generic MT HVDC (NOR-X)*	✓	✓	✓	Generic Use case
Use case #12 *Princess Elisabeth-Nautilus-Triton (BE)*	✓	✓	✓	NA
Use case #13 *Peterhead Hub (UK)*	✓	✓	✓	2030/2031 2035+

5. Shortlist of MT-HVDC use cases

The shortlist of use caseTable 5-1 results out of the application of the selection criteria to the long list of HVDC use cases in chapter 4. The shortlist entries are created on a generic basis and represent a summarization of key characteristics reflected in each longlist entry. Only entries which fulfill the selection criteria are considered leading to eight shortlist entries which are described in the following.

In addition, the HVDC vendors involved in the InterOPERA project HVDC vendors shared their proposal of a topology used for basic studies and verification purposes. The proposal is described in short list entry #9.

Enlarged representations of the short list entries can be found in the appendix 1.

TABLE 5-1

Shortlist of MT HVDC use cases

Short list #	*Name of HVDC project*	*DC protection strategy*	*AC offshore connection concept*	*# of converter stations # of DC switching stations Grid architecture HVDC configuration*
#1	Use case #4 Hub2Hub (NL-DK)	Partially-selective Fully-selective	Direct connection 66 kV or 132 kV	2 onshore / 2 Offshore 2 Offshore DCSS MT HVDC system Bipole with DMR
#2	Use case #5 HeideHub (DE)	Partially-selective	Direct connection 66 kV (t< 2032) Direct connection 132 kV (t> 2032)	2 onshore / 2 offshore 1 onshore DCSS MT HVDC system Bipole with DMR
#3	Use case #6 NordWestHub (DE)	Partially-selective	Direct connection 66 kV (t< 2032) Direct connection 132 kV (t> 2032)	3 onshore / 2 offshore 1 Onshore DCSS MT HVDC system Bipole with DMR
#4	Use case #8 Bornholm Energy Island (DK-DE)	Partially-selective	400 kV busbar collector, connecting the local Bornholm 66 kV network and WTGs	2 onshore / 2 offshore 1 offshore DCSS (Bornholm) MT HVDC system Bipole with DMR
#5	Use case #9 Danish Energy Island (Phase 1: DK-BE) (Phase 2: +DK-DE/ + DK-NL)	Partially-selective	400 kV busbar collector on the artificial island	2 onshore / 2 offshore 1 offshore DCSS (Artificial Island) MT HVDC system Bipole with DMR

Short list #	*Name of HVDC project*	*DC protection strategy*	*AC offshore connection concept*	*# of converter stations # of DC switching stations Grid architecture HVDC configuration*
#6	Use case #12 Princess Elisabeth-Nautilus-Triton (BE)	Partially-selective	220 kV busbar collector with AC interconnection to mainland	4 onshore / 3 offshore 1 offshore DCSS (artificial island) MT HVDC system Bipole with DMR
#7	Use case #11 Generic MT HVDC (NOR-X)	Partially-selective Fully-selective	Under review	2 onshore / 2 offshore 2 offshore DCSS MT HVDC system Bipole with DMR, rigid bipole, asymmetrical Monopole; Symmetrical monopole
#8	Use case #13 Peterhead Hub (UK)	Non-selective Partially-selective	Not applicable	4 onshore 1 onshore DCSS (Peterhead) MT HVDC system Bipole with DMR
#9	Vendor's proposed topology	Non-selective Partially-selective	NA	5 converter stations 4 DCSS MT HVDC system (including a meshed DC grid section/ ring topology) Bipole with DMR

Please note: The following figures are indicative and based on the information available and as presented in the longlist of HVDC use cases.

5.1. Shortlist entry #1

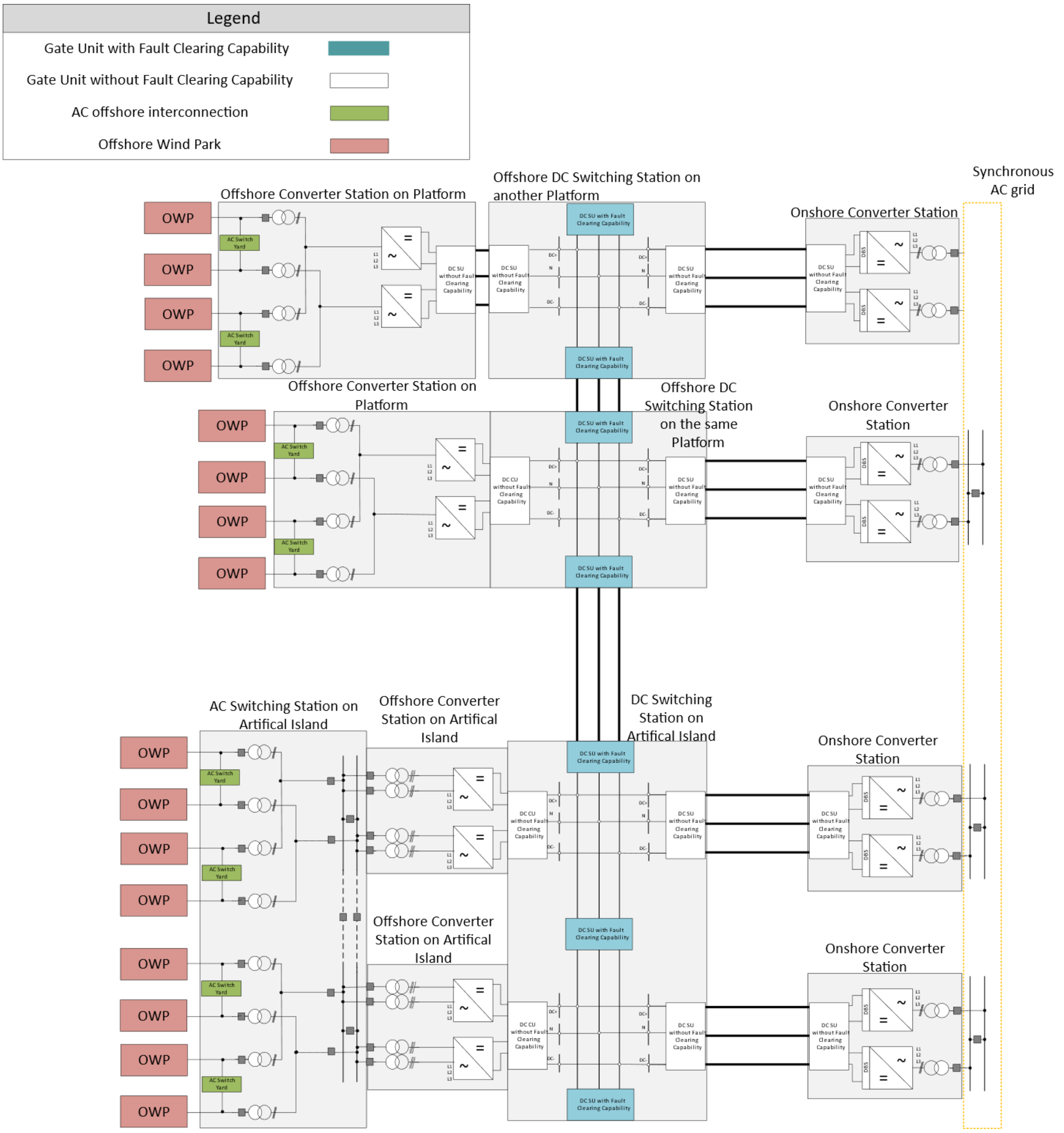


FIGURE 5-1

Simplified overview – Shortlist entry #1. Synchronous areas at the onshore side are indicated with yellow dotted boxes.

Shortlist entry #1 represents a generic Hub to Hub connection with the following topological key characteristics:

CHARACTERISTICS OF THE DC SWITCHING STATION TYPE 1 / STAND-ALONE PLATFORM:

- 1x DC busbar section
- 2x DC Switching Unit (DC SU)s for DC cable connections with DC-FSDs
- 1x DC SU for DC cable connections without DC-FSDs
- 1x DC SU for converter connection without DC-FSDs

CHARACTERISTICS OF THE DC SWITCHING STATION TYPE 2 / SAME PLATFORM:

- 1x DC busbar section
- 2x DC-SUs for DC cable connections with DC-FSDs
- 1x DC-SUs for DC cable connections without DC-FSDs
- 1x DC-SUs for converter connection without DC-FSDs

CHARACTERISTICS OF THE ONSHORE CONVERTER STATIONS:

- 1x DC SU to connect converter station to DC cable system
- Half bridge converters
- Integrated "Dynamic Breaking System" (DBS, if required)

CHARACTERISTICS OF THE OFFSHORE CONVERTER STATIONS:

- 1x DC SU to connect converter station to DC cable system or integrated DCSS Type 2 functionalities
- Half bridge converters
- Direct connection

5.2. Shortlist entry #2

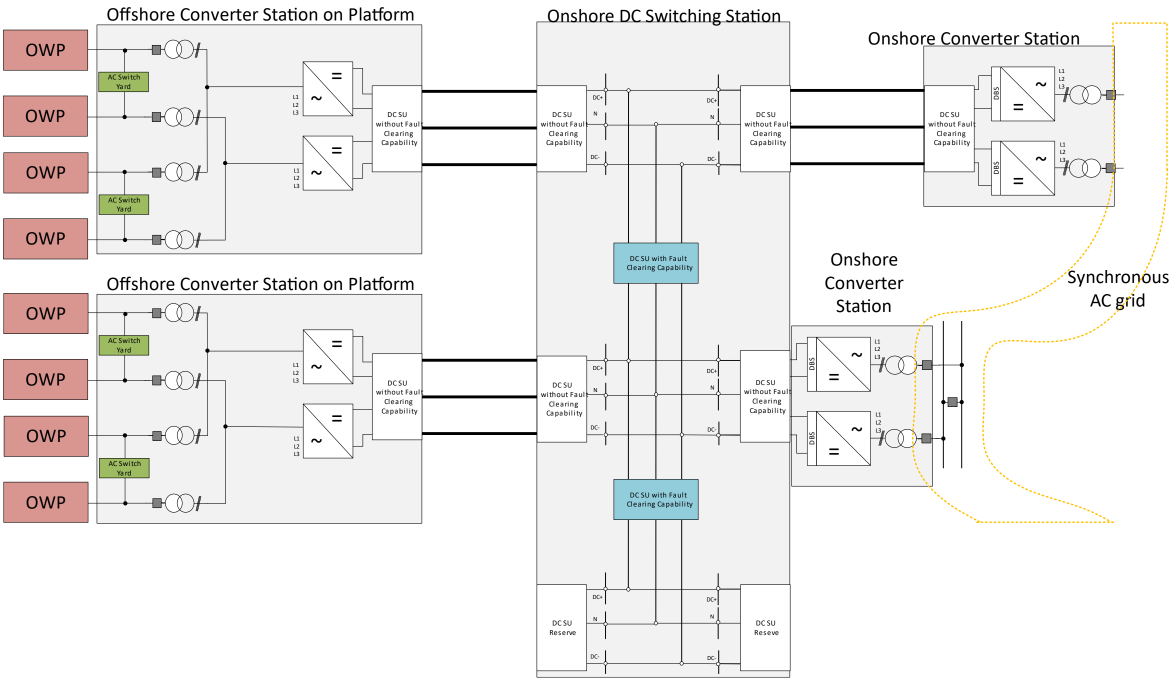


FIGURE 5-2

Simplified overview – shortlist entry #2. Synchronous areas at the onshore side are indicated with yellow dotted boxes.

Shortlist entry #2 represents a generic four terminal HVDC system connected to a single synchronous area (onshore). The following topological key characteristics are identified:

CHARACTERISTICS OF THE DC SWITCHING STATION:

- 3x DC busbar sections
- 2x DC SU with longitudinal coupling with DC-FSDs
- DC-SUs for DC cable connections without DC-FSDs
- DC-SUs for converter connection without DC-FSDs
- Space provisions for future integration of DC-FSDs
- 2x DC SUs for future expansion stages

CHARACTERISTICS OF THE ONSHORE CONVERTER STATIONS:

- 1x DC SU to connect Converter Station to DC cable system
- Half bridge converters
- Integrated DBS (if required)

CHARACTERISTICS OF THE OFFSHORE CONVERTER STATIONS:

- 1x DC SU to connect converter station to DC cable system
- (As an option: provision of 1x additional DC SU to connect additional DC cable system)
- Half bridge converters
- Direct connection

5.3. Shortlist entry #3

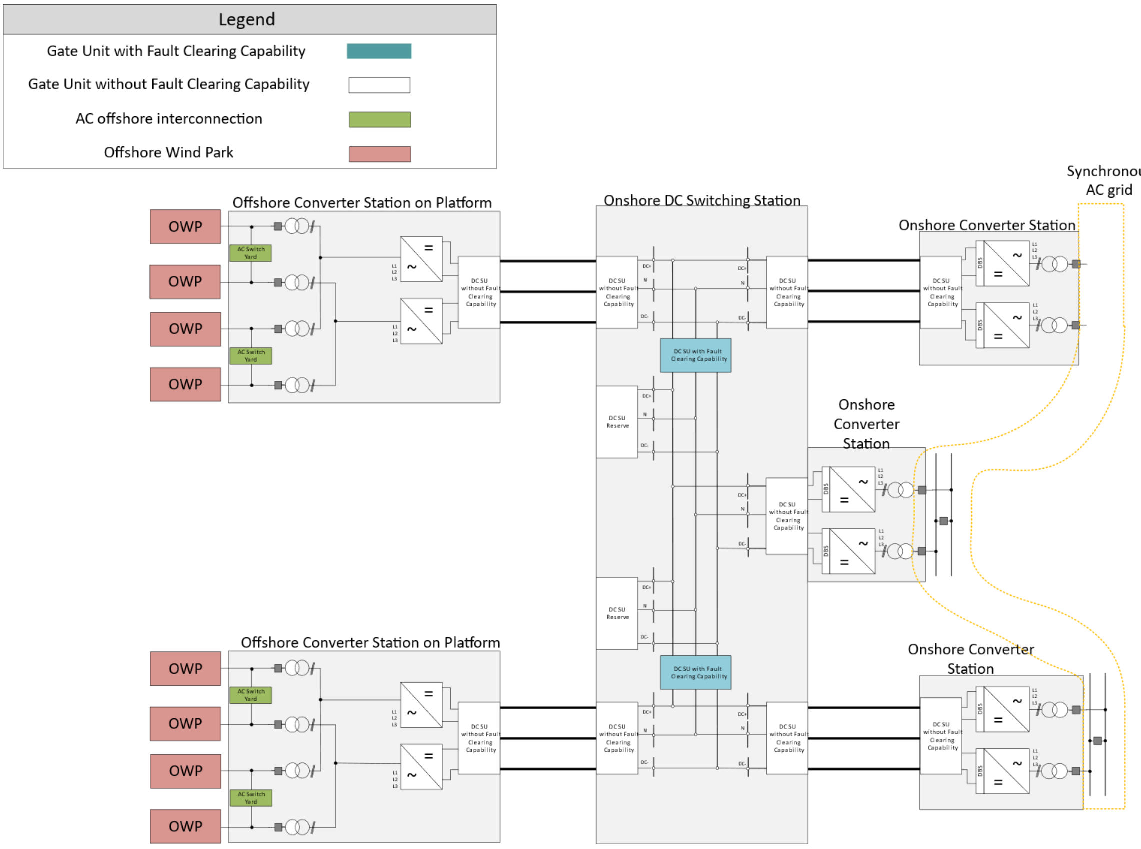


FIGURE 5-3

Simplified overview – shortlist entry #3. Synchronous areas at the onshore side are indicated with yellow dotted boxes.

Shortlist entry #3 represents a generic five terminal HVDC system connected to a single synchronous area (onshore). The following topological key characteristics are identified:

CHARACTERISTICS OF THE DC SWITCHING STATION:

- 3x DC busbar sections
- 2x DC SUs with longitudinal coupling with DC-FSDs
- DC SUs for DC cable connections without DC-FSDs
- DC SUs for converter connection without DC-FSDs
- Space provisions for future integration of DC-FSDs
- 2x DC SUs for future expansion stages

CHARACTERISTICS OF THE ONSHORE CONVERTER STATIONS:

- 1x DC SUs to connect converter station to DC cable system
- Half bridge converters
- Integrated DBS (if required)

CHARACTERISTICS OF THE OFFSHORE CONVERTER STATIONS:

- 1x DC SU to connect converter station to DC cable system
- (As an option: Provision of 1x additional DC SU to connect additional DC cable system)
- Half bridge converters

5.4. Shortlist entry #4

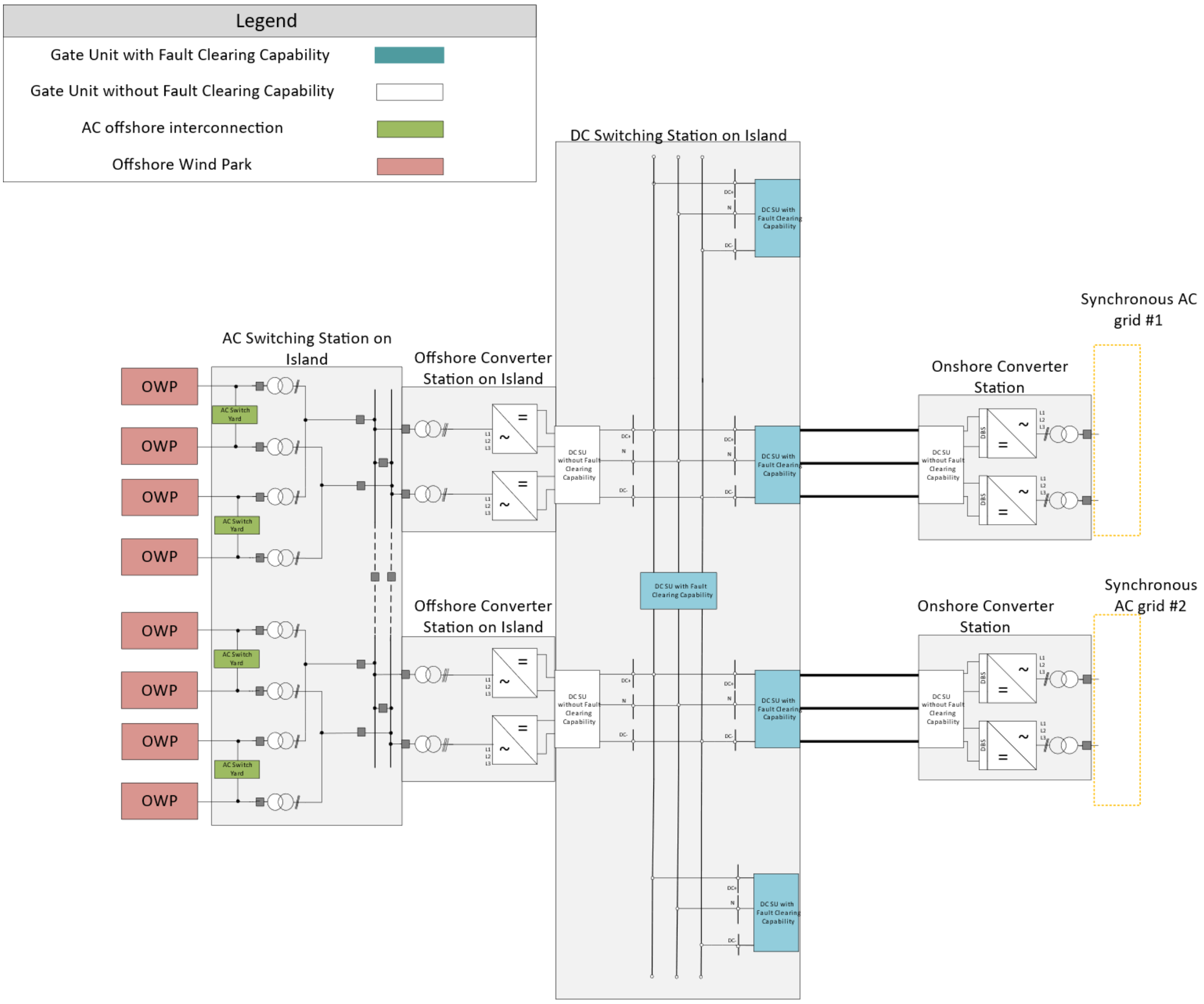


FIGURE 5-4

Simplified overview – Shortlist entry #4. Synchronous areas at the onshore side are indicated with yellow dotted boxes.

Shortlist entry #4 represents a generic four terminal HVDC system connected to a two synchronous areas (onshore) and including an additional AC offshore collector busbar. The following topological key characteristics are identified:

CHARACTERISTICS OF THE DC SWITCHING STATION:

- 2x DC busbar sections
- 1x DC SU with longitudinal coupling with DC-FSDs
- DC SUs for DC cable connections without DC-FSDs in first development stage
- DC SUs for converter connection without DC-FSDs
- Space provisions for future integration of DC-FSDs
- 2x DC SUs for future expansion stages

CHARACTERISTICS OF THE ONSHORE CONVERTER STATIONS:

- 1x DC SU to connect converter station to DC cable system
- Half bridge converters

- Integrated DBS (if required)

CHARACTERISTICS OF THE OFFSHORE CONVERTER STATIONS:

- 1x DC SU to connect converter station to DC busbar system
- Half bridge converters
- 400 kV AC offshore collector busbar

5.5. Shortlist entry #5

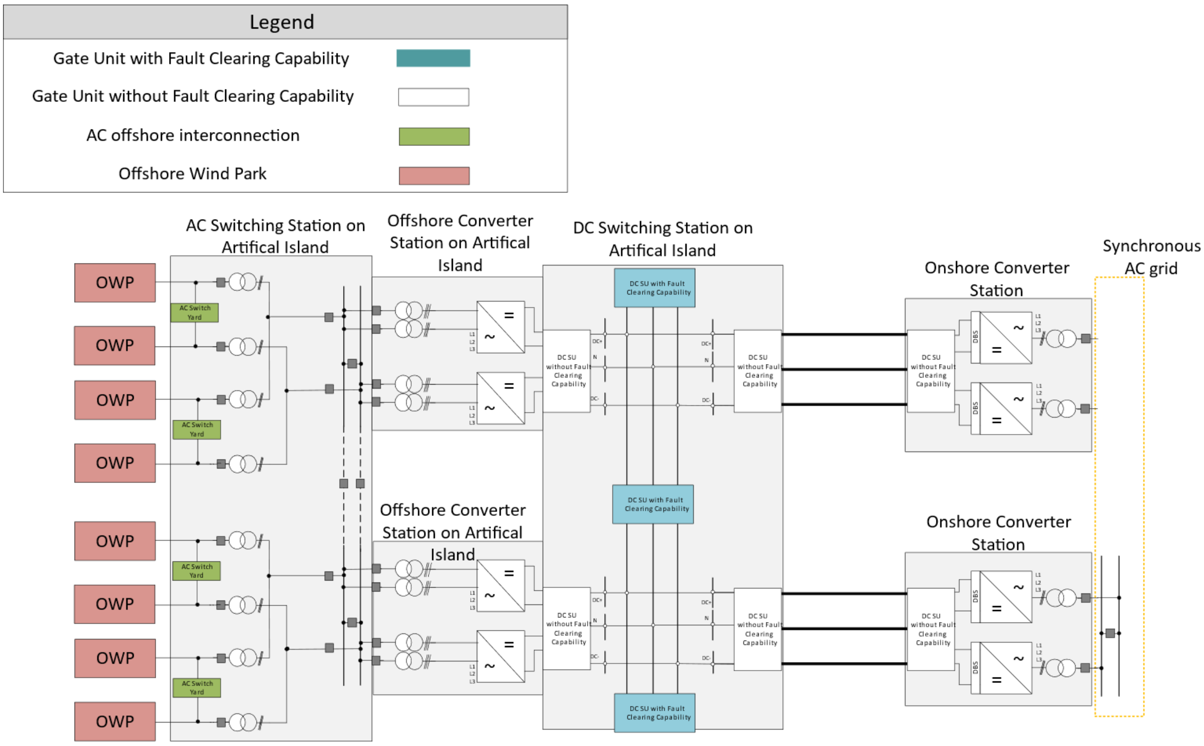


FIGURE 5-5

Simplified overview – Shortlist entry #5. Synchronous areas at the onshore side are indicated with yellow dotted boxes.

Shortlist entry #5 represents a generic five terminal HVDC system connected to a single synchronous area (onshore) and including an additional AC offshore collector busbar. The following topological key characteristics are identified:

CHARACTERISTICS OF THE DC SWITCHING STATION:

- 2x DC busbar sections
- 1x DC SU with longitudinal coupling with DC-FSDs
- DC SUs for DC cable connections without DC-FSDs in first development stage
- DC SUs for converter connection without DC-FSDs
- Space provisions for future integration of DC-FSDs
- 2x DC SU for future expansion stages

CHARACTERISTICS OF THE ONSHORE CONVERTER STATIONS:

- 1x DC SU to connect converter station to DC cable system
- Half bridge converters
- Integrated DBS (if required)

CHARACTERISTICS OF THE OFFSHORE CONVERTER STATIONS:

- 1x DC SU to connect converter station to DC busbar system
- Half bridge converters
- 400 kV AC offshore collector busbar

5.6. Shortlist entry #6

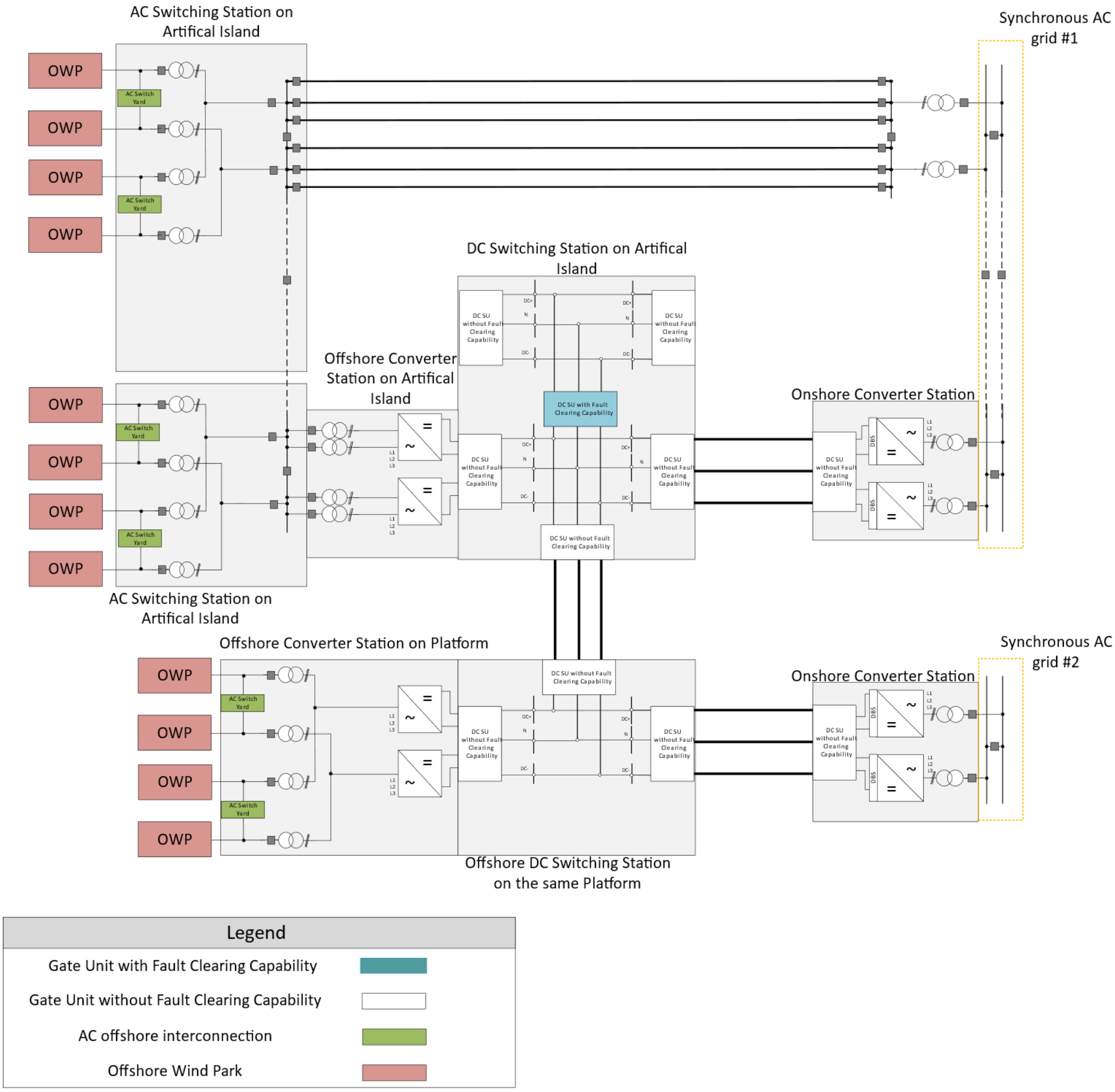


FIGURE 5-6

Simplified overview – Shortlist entry #6. Synchronous areas at the onshore side are indicated with yellow dotted boxes.

Shortlist entry #6 represents a generic HVDC system connected to a two synchronous areas (onshore). Apart from HVDC transmission, parallel HVAC transmission is considered in this entry. The following topological key characteristics are identified:

CHARACTERISTICS OF THE DC SWITCHING STATION:

- 2x DC busbar sections
- 1x DC SU with longitudinal coupling with DC-FSDs
- DC SUs for DC cable connections without DC-FSDs
- DC SUs for converter connection without DC-FSDs
- 1x DC SU with longitudinal coupling with DC-FSDs for future expansion stages

- 2x DC SU for future expansion stages

CHARACTERISTICS OF THE ONSHORE CONVERTER STATIONS:

- 1x DC SU to connect converter station to DC cable system
- Half bridge converters
- Integrated DBS (if required)

CHARACTERISTICS OF THE OFFSHORE CONVERTER STATIONS:

- 1x DC SU to connect converter station to DC cable system
- Half bridge converters
- 220 kV AC offshore collector busbar

5.7. Shortlist entry #7

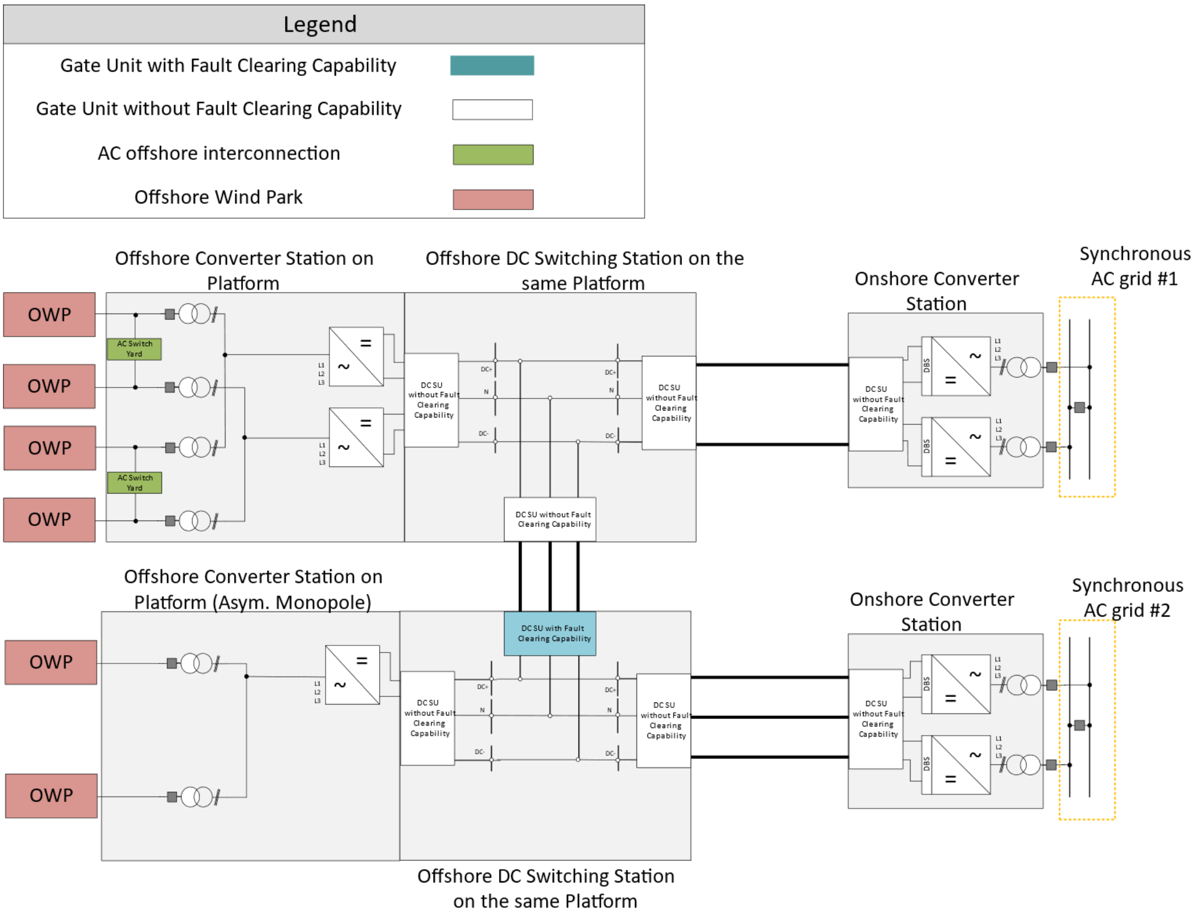


FIGURE 5-7

Simplified overview – Shortlist entry #7. Synchronous areas at the onshore side are indicated with yellow dotted boxes.

Shortlist entry #7 represents a generic HVDC system connected to a two synchronous areas (onshore). Different HVDC configurations such as bipole with DMR, rigid bipole and symmetrical monopole are considered. The following topological key characteristics are identified:

CHARACTERISTICS OF THE DCSS (BIPOLE / RIGID BIPOLE) - SAME PLATFORM:

- 1x DC busbar section
- 1x DC SUs for DC cable connections without DC-FSDs (RBP)
- 1x DC SUs for DC cable connections without DC-FSDs (BP)
- 1x DC SUs for converter connection without DC-FSDs (BP)

CHARACTERISTICS OF THE DCSS (BIPOLE - SYMMETRICAL MONOPOLE) - SAME PLATFORM:

- 1x DC busbar section
- 1x DC SUs for DC cable connections without DC-FSDs (BP)
- 1x DC SUs for DC cable connections with DC-FSDs (BP)
- 1x DC SUs for converter connection without DC-FSDs (SMP)

CHARACTERISTICS OF THE ONSHORE CONVERTER STATIONS:

- 1x DC SU to connect converter station to DC cable system
- Half bridge converters
- Integrated DBS (if required)

CHARACTERISTICS OF THE OFFSHORE CONVERTER STATIONS:

- 1x DC SU to connect converter station to DC cable system
- (As an option: provision of 1x additional DC-SU to connect additional DC cable system)
- Half bridge converters
- Direct connection

5.8. Shortlist entry #8

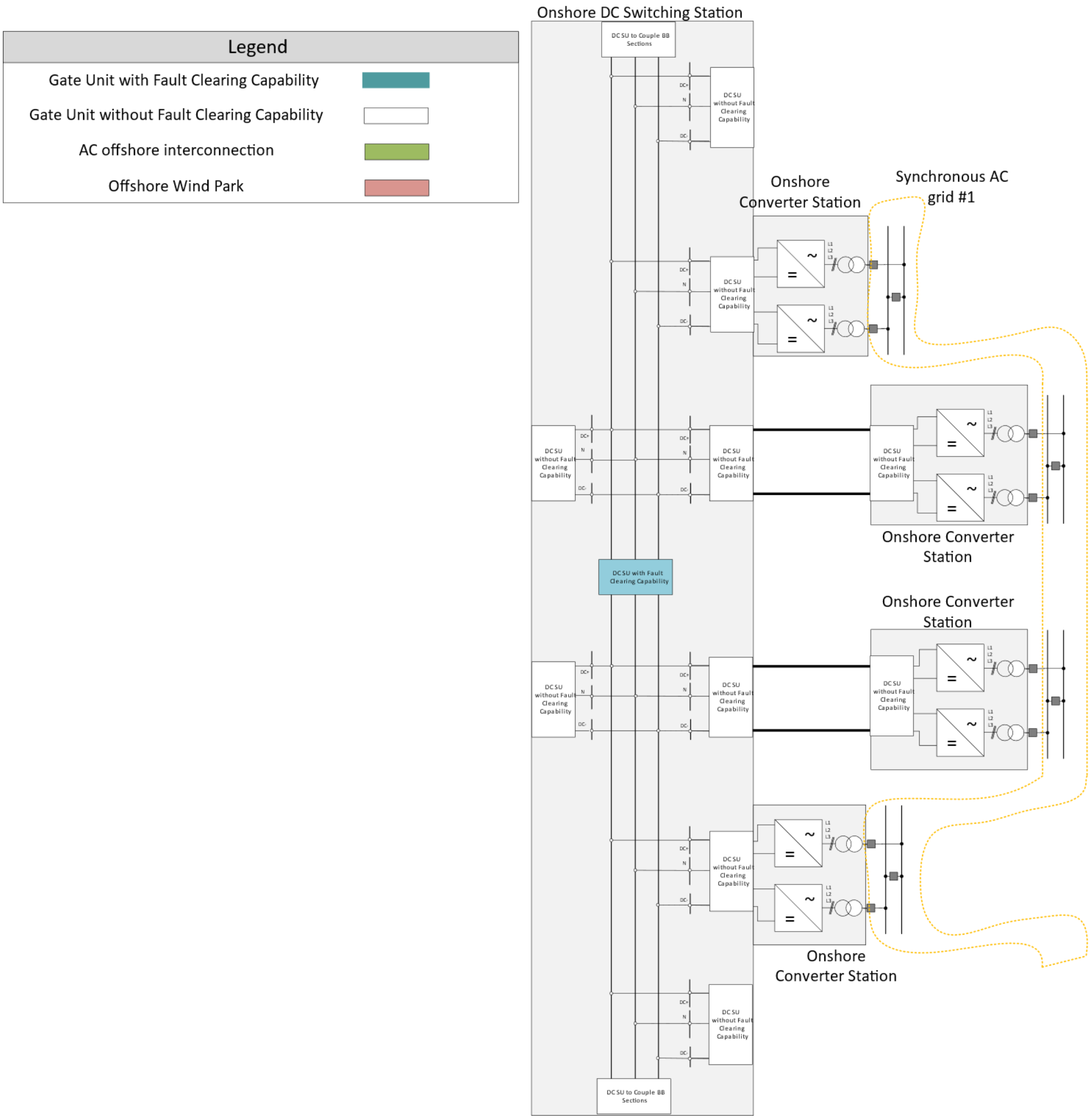


FIGURE 5-8

Simplified overview – Shortlist entry #8. Synchronous areas at the onshore side are indicated with yellow dotted boxes.

The following topological key characteristics are identified for shortlist entry #8:

CHARACTERISTICS OF THE DC SWITCHING STATION (PHASE 1)

- 2x DC busbar sections, double busbar system,
- 1x DC SU including DC bus couplers; Bus couplers normally-open
- DC-SUs for DC-Cable connections without DC-FSDs
- DC-SUs for converter connection without DC-FSDs

CHARACTERISTICS OF THE DC SWITCHING STATION (PHASE 2)

- 2x DC SU for future expansion stages to integrate offshore wind power plants (BP+DMR)

- 2x DC SU for future expansion stages to integrate an additional interconnector respective an additional grid enforcement (RBP or DP+DMR)

CHARACTERISTICS OF THE DC SWITCHING STATION (PHASE 3)

- Space provisions for future extension of the DCSS to enable "open ring DC bus arrangement"
- 1x DC-SU for longitudinal coupling including DC-FSDs

CHARACTERISTICS OF THE ONSHORE CONVERTER STATIONS:

- 1x DC SU to connect Converter Station to DC cable system or DC busbar system
- Half bridge Converters
- Integrated DBS (if required)

CHARACTERISTICS OF THE OFFSHORE CONVERTER STATIONS:

- No information available

FURTHER REMARKS:

- Open ring DC bus arrangement
- Double busbar

5.9. Shortlist entry #9

Shortlist entry #9 includes proposed topologies provided by the HVDC vendors involved in the InterOPERA project. Figure 5-9 shows a three terminal HVDC system which represents the proposed topology for basic studies and verification purposes. In addition, Figure 5-10 shows a five terminal HVDC system which could be beneficial for expanded DC grid testing scenarios.

The following topological key characteristics are identified for shortlist entry #9:

TWO TYPES OF DC SWITCHING STATIONS:

- DCCS type 1: DCSS to connect converter stations to DC-busbar system as well as DC lines
- DCCS type 2: Standalone DCSS with various DC-SUs to connect DC lines and a DBS connected to it
- Non-selective, partial-selective as well as fully-selective sections of the DC grid

CHARACTERISTICS OF THE ONSHORE AND OFFSHORE CONVERTER STATIONS:

- 1x DC SU to connect converter station to DC busbar systems
- Half bridge converters
- No integrated DBS

FURTHER REMARKS:

- Unspecific to onshore & offshore stations characteristics
- Meshed DC grid section / ring topology
- Standalone DBS
- Step-by-step workflow recommended

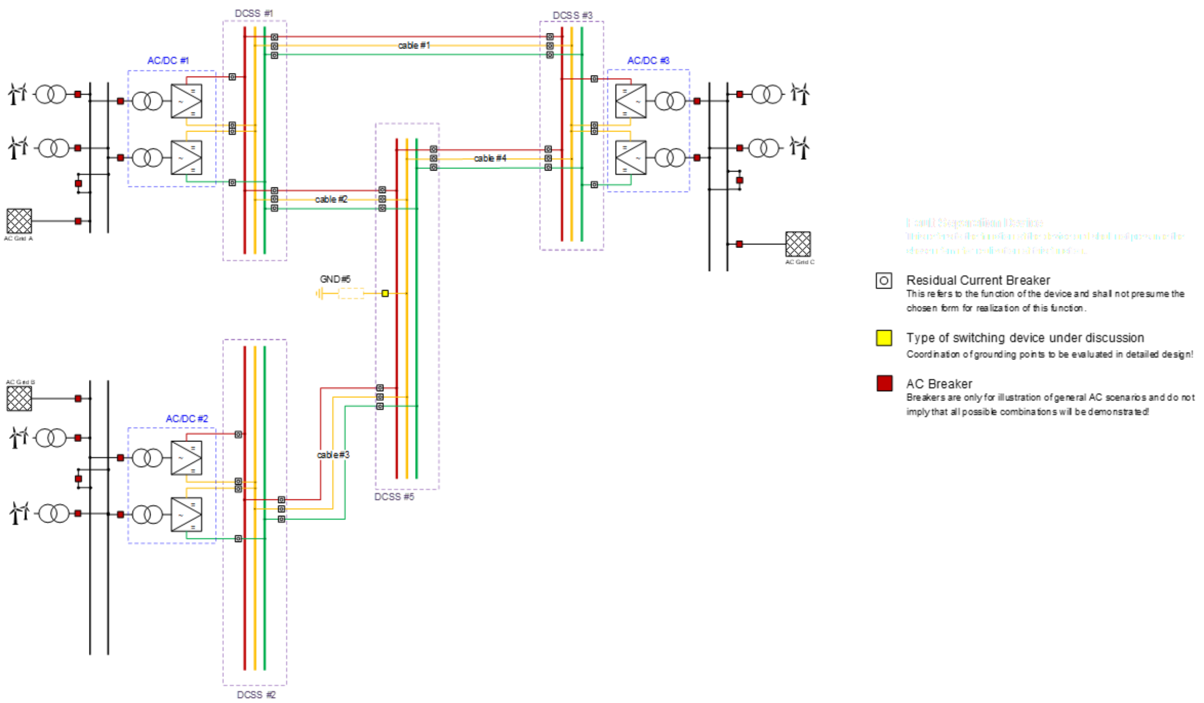


FIGURE 5-9

HVDC vendors – proposed topology for basic studies and verification purposes

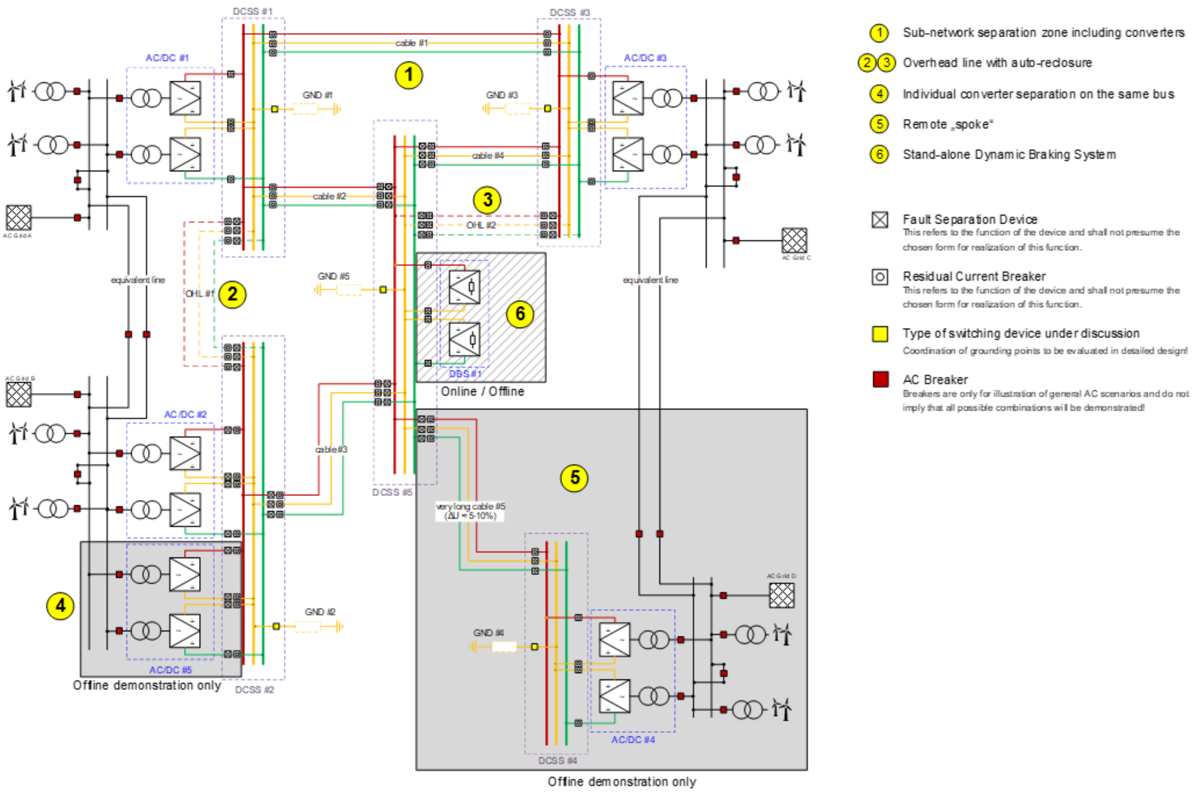


FIGURE 5-10

HVDC vendors – proposed topology for expanded DC grid scenario

6. Recommendations of InterOPERA work packages and tasks

This chapter covers recommendations from other work packages with regard to the definition of the InterOPERA demonstrator. Recommendations from T2.1, T2.4 and the HVDC vendors are described in the subsequent sections.

In addition, to get from the shortlist entries to the final demonstrator topology, a set of DC grid characteristics which are clustered in three main categories (General topology, DC grid protection, Grid forming functionalities) relevant for interoperability functions is identified based on the recommendations from other work packages. Each shortlist entry is evaluated in terms of these grid characteristics to identify similarities and differences. The results are used to define the final demonstrator topology in chapter 7.

6.1. WP2 / T2.1: DC grid protection and DC fault clearing strategy

The following items express recommendations for the InterOPERA demonstrator from T2.1 of WP2. The items are listed in prioritized order with respect to the ability to demonstrate DC grid protection and DC fault clearing strategies:

1. The demonstrator should perform primary and backup protection sequences. Primary protection in a radial three terminal DC grid always leads to a point-to-point configuration. Back-up protection in a radial three terminal DC grid leads to a shut-down of active power in the faulty pole of the DC grid. Therefore, from a DC grid protection perspective a 4-terminal topology is recommended. If this is not possible, the three terminal grid should be of meshed configuration.
2. A three terminal DC grid would reduce the choice of fault clearing strategies significantly.
3. The demonstrator should involve at least two DC switching stations from different vendors to prove DC grid protection interoperability. The demonstrator should integrate at least two different DC-FSDs to prove interoperability in the fault handling process.
4. Faults detection and discrimination should be implemented to show closed-loop protection operation.
5. The demonstrator should perform post fault voltage and active power recovery. In this context energy dissipation devices should be foreseen in the demonstrator.
6. Auto-reclosing functionality could be demonstrated (i.e., by considering a hybrid line with one cable section to shore and one OHL section to converter).

LIST OF PROTECTION FUNCTIONS TO BE CONSIDERED:

Fault types	Fault handling sequence	Post-fault recovery
• Pole-to-ground faults • Busbar faults • Converter faults • Pole-to-pole faults • DMR faults	• Fault detection & discrimination • Fault separation • Primary protection • Backup protection (i.e., due to DC-FSD failure) • Fault clearing • Optional: Auto-reclosing (i.e., in case of OHL), energy dissipation device	• Energy dissipation device operation • Voltage & active power restoration

6.2. WP2 / T2.4: Grid forming functionalities

The following items express recommendations for the InterOPERA demonstrator from T2.4 of WP2. The items are listed in prioritized order with respect to the ability to demonstrate grid-forming capabilities of PE devices, e.g., HVDC converters and DC-connected PPMs:

1. The demonstrator should connect two different synchronous areas through the MT HVDC grid
2. The demonstrator should involve at least two different HVDC vendors at the offshore converter stations
3. The demonstrator should involve at least two different wind power OEMs (original equipment manufacturer) at the offshore converter stations as DC connected PPMs.
4. If the demonstrator cannot have both two wind power plants and two synchronous areas, having two synchronous areas is preferred.
5. The above items imply at least four converter stations shall be included. If this is not possible and only 3 converters are available for the demonstrator, it should be possible to operate them in different variants, i.e., either representing an offshore connection, and connection to the main grid. Having two offshore stations and one onshore as well as having one offshore and two on-shore stations should be easily configurable.
6. The demonstrator should allow the possibility to connect the offshore converters (HVDC and PPMs) on the AC side.

6.3. WP3 / HVDC vendors

The following section states the consolidated view and recommendations for the demonstrator from the HVDC vendors involved in WP3.

HVDC BUILDING BLOCKS

Table 6-1 lists all the building blocks considered by each HVDC vendor as in scope for InterOPERA. This mainly includes designs and models for the offshore and onshore AC/DC converter as well as a stand-alone DC switching station. The deliverable of the design and models of the DC-FSD for a cable configuration is marked as optional by some vendors. In addition, the building blocks for the dynamic braking system (stand-alone) and the DC-FSD (OHL) could be delivered by some vendors if a scope extension is foreseen (see Table 6-2).

TABLE-6-1

HVDC vendors – the main building blocks for the InterOPERA demonstrator

✓: Deliverable planned X: Deliverable not planned (X): Deliverable optional		AC/DC converter station (onshore) Design + model	AC/DC converter station (offshore) Design + model	DC switching station (stand-alone) Design + model	DC circuit breakers (cable) Design + model
GE Vernova	Online (HIL)	✓	✓	✓	X
	Offline (EMT)	✓	✓	✓	(X)
Siemens Energy	Online (HIL)	✓	✓	✓	X
	Offline (EMT)	✓	✓	✓	(X)
Hitachi Energy	Online (HIL)	✓	✓	✓	✓
	Offline (EMT)	✓	✓	✓	✓
SciBreak	Online (HIL)	X	X	✓	✓
	Offline (EMT)	X	X	✓	✓

TABLE 6-2

HVDC vendors – Additional building blocks for a potential scope extension

✓: *Deliverable planned* X: *Deliverable not planned* (X): *Deliverable optional*		*Dynamic braking system (stand-alone)* *Design + model*	*DC circuit breakers (OHL)* *Design + model*
GE Vernova	*Online (HIL)*	X	X
	Offline (EMT)	✓	(X)
Siemens Energy	*Online (HIL)*	X	X
	Offline (EMT)	✓	(X)
Hitachi Energy	*Online (HIL)*	✓	✓
	Offline (EMT)	✓	✓
SciBreak	*Online (HIL)*	X	✓
	Offline (EMT)	X	✓

RECOMMENDED WORKFLOW AND STEP BY STEP PROCESS[1]

From a HVDC vendors' perspective it is recommended following a step-by-step development process which is depicted in Figure 6-1. At first, the design phase (grid planning) should be performed with a full extent topology which already covers the topology of the upcoming two phases described below.

After that, the basic studies and tests are executed using a topology with a reduced number of terminals. The proposed topology consists of three terminals and one stand-alone DC switching station. Both offline and online simulations are performed with this topology. It is important to have the same online setup in both labs to verify and validate the results.

Finally expanded studies (e.g., stability studies, grid forming, DC protection) could be carried out using the full extent topology from the design phase. Different studies can be performed in the offline and online setup as well as in the two labs.

[1] This chapter gives and outlook and recommendations. Test procedures and functionalities to be tested are not finally defined in T3.1.

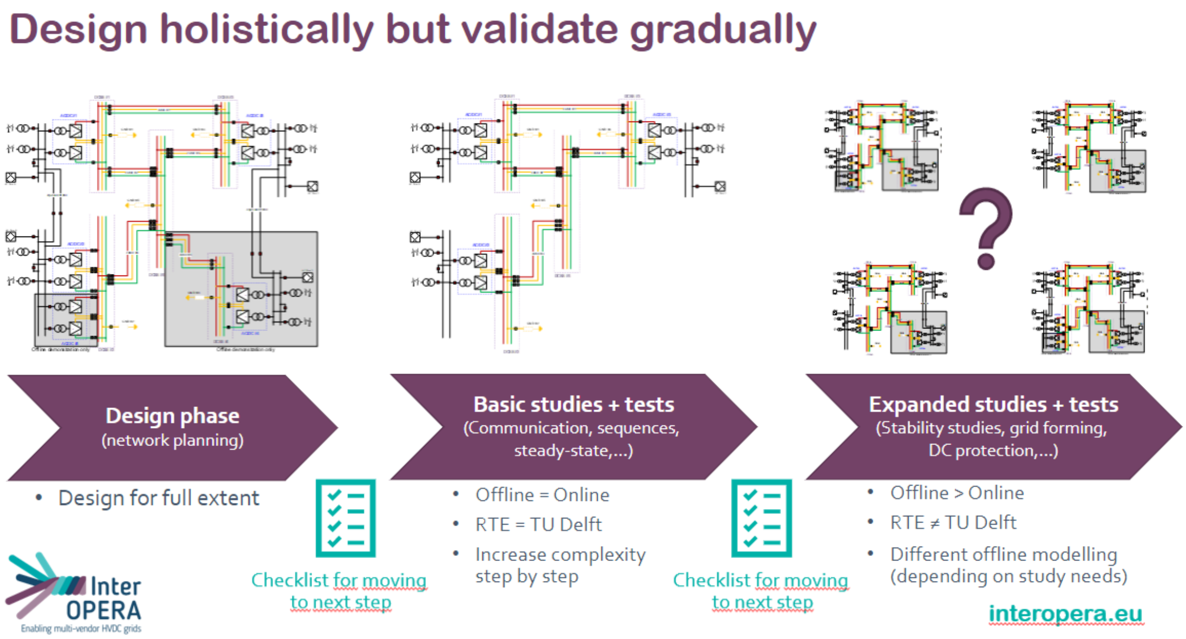


FIGURE 6-1

HVDC vendors – Proposed workflow and step-by-step process for the design phase, basic studies and expanded studies

RECOMMENDATIONS REGARDING THE DC GRID PROTECTION

Regarding DC grid protection the following approach is outlined and advised:

- Consider requirements from DC grid protection in the demonstrator design phase (fault handling, protection zones, etc. ...)
- Deliver equipment and functions in both online and offline demonstrator (equipment simulation model + controls, supporting functions, algorithms, etc. ...)
- Gradually introduce DC grid protection to the demonstrator test scenarios

6.4. HVDC technology alignment

To enable multi-vendor HVDC grids, system compatibility is needed as basis for interoperability. To be interoperable, the HVDC systems must be compatible in the first place. Today, heterogenous HVDC systems, that for example do not have the same voltage level (320 kV, 525 kV) or do not share similar topologies (bipole configurations vs symmetrical monopoles), are incompatible.

To satisfy this need for compatibility, the HVDC system planning must be coordinated where potential interconnection is envisaged now or in the future at a regional level (I.e.: around the North Sea). Otherwise, the different HVDC systems may be unable to connect to the same HVDC grid. Today, such coordination of system planning to ensure compatibility at regional level exists to some extent but is not complete. A major issue is that the techno-economic optimum regarding HVDC system characteristics and topologies may differ for different geophysical locations or applications (e.g.: symmetrical monopoles may be preferred for longer distances and in deeper waters, whereas bipoles with metallic return may be preferred in other situations) and lead to the construction of incompatible HVDC systems at the regional level. InterOPERA is not about defining the future planning standards, and this issue of coordination and convergence should be addressed by the stakeholder community outside the project.

As much as possible, the functional framework for interoperability that is to be developed within InterOPERA will include and address the diversity of HVDC systems characteristics. But due to the constraints of the project, InterOPERA is unable to explore and test all the potential topologies: for the Demonstrator, choices must be made. As a compromise, the collectively selected configuration is a 525 kV bipolar configuration with metallic return. This was seen as a good test bed to increase TRL of HVDC interoperability and to prepare for future HVDC systems that can be assembled with different building blocks supplied by different vendors. Furthermore, most of the future projects in short and long list are planning the implementation of 525 kV bipole with DMR. Another important reason for this selected configuration, is to allow the integration and the demonstration of rigid bipole's and asymmetrical monopoles. The demonstrator shall therefore include rigid bipole's and asymmetrical monopoles as operational modes of the bipolar system with metallic return. Any issues or obstacles related to the integration of symmetrical monopoles shall be addressed in InterOPERA reports related to interoperability issues even if they are not tested in the demonstrator.

In the future, innovative solutions may allow us to interface and/or make heterogeneous HVDC systems mutually compatible (e.g.: use of DC/DC converters), but InterOPERA is building on the current state of the art for HVDC technology. InterOPERA recommends that further studies or projects should be programmed in the future to integrate other solutions, topologies, technologies, and operating conditions facilitating fully integrated HVDC grids.

6.5. Interoperability functions and stakeholder recommendations for the demonstrator topology

This section provides a basis for decision making on the InterOPERA demonstrator. Based on key characteristics and properties of the short list entries (see chapter 5) and recommendations from other InterOPERA work packages (see chapter 6) a set of DC grid characteristics relevant for interoperability functions is identified. The system functionalities are clustered in three main categories and are summarized in tabular form:

- General topology (Table 6-3)
- DC grid protection (Table 6-4)
- GFM functionality (Table 6-5)

The tabular overviews identify the similarities and differences between the short-list entries. A „black-and-white" checking-procedure is applied to provide a clear overview which key characteristics and functionalities are included or excluded in each short list entries. If required, footnotes are added to clarify line items for individual short list entries. Column "D" (demonstrator column) in Table 6-3, Table 6-4 and Table 6-5 provides an overview of which interoperability functions are included or excluded in the demonstrator definition. Reasoning for the table entries is given below.

The guiding principles for the InterOPERA demonstrator definition are as follows:

- Cover project-inspired key characteristics and functionalities
- Cover functionalities with high relevance for enabling meshed offshore DC grids
- Design the demonstrator holistically

To keep it manageable, the following items are excluded due to minor relevance for meshed offshore DC grids, or due to explicit advice from the HVDC vendors or other consortium partners:

- Mixed topologies including sym. monopoles
- Parallel AC offshore cable connections from shore
- Overhead lines (OHL) & auto-reclosing functionalities
- Stand-alone Dynamic Braking Systems[2]
- AC Offshore Connection with additional HV AC collector bus

In contrast, the following items are included even though the shortlist entries indicate a minor relevance for planned projects. They are included either due to a high relevance for meshed offshore DC grids or due to explicit advice from the HVDC vendors or other consortium partners:

- Meshed DC grid topology, e.g. parallel DC lines
- Double-ended DC grid protection schemes, e.g. DC-FSDs at both DC line ends
- Different types of DC switching stations (DCSS), e.g. including different types of DC-FSDs.

Based on column "D" the InterOPERA demonstrator will be outlined in chapter 7 considering the InterOPERA boundary conditions and the in-scope defined hardware & engineering services.

[2] The DBS is functionally described as an independent subsystem. Dependent on the progress of the InterOPERA project the function of energy dissipation devices might also be realized as a standalone device at the onshore converter station.

TABLE 6-3

Interoperability functionalities and characteristics - general topology

Short List Entry	*#1*	*#2 #3*	*#4 #5*	*#6*	*#7*	*#8*	*#9*	*D*
Promoter	*Asset Owner / TSOs*						*Vendors*	*InterOPERA*
General Topology								
2 Converters at the same DC busbar in close electrical vicinity	✗	✗	✓	✗	✗	✗	✓	✓
DCSS with >1 DC-busbar sections including DC-FSD as bus coupler	✗	✓	✓	✓	✗	✓	✗	✓
DCSS including multiple options to coordinate system grounding	✗	✓	✓	✓	✗	✓	✗	✓
Stand-alone DCSS	✗	✗	✗	✗	✗	✗	✓	✓
Long-distance "spokes" / "taps"	✓	✓	✓	✓	✓	✓	✓	✓
Integrated DBS at the Onshore converter station[3]	✓	✓	✓	✓	✗	✓	✗	✓
Stand-alone DBS (e.g. at DCSS)[4]	✗	✗	✗	✗	✗	✗	✓	✗
Parallel AC Cable Interconnection from onshore	✗	✗	✗	✓	✗	✗	✗	✗
Including a meshed section or ring in the DC grid topologies	✗	✗	✗	✗	✗	✗	✓	✓
Including DC-OHLs	✗	✗	✗	✗	✗	✗	✓	✗
Mixed topology – Type 1 Bipole with DMR & Rigid Bipole & Asym. Monopole[5]	✓	✓	✓	✓	✓	✓	✓	✓
Mixed topology – Type 2 Bipole with DMR & Rigid Bipole & Asym. Monopole & Sym. Monopole	✗	✗	✗	✗	✓	✗	✗	✗

[3] Dependent on the progress of the InterOPERA project the function of energy dissipation devices might also be realized as a standalone device at the onshore converter station.

[4] Dependent on the progress of the InterOPERA project the function of energy dissipation devices might also be realized as a standalone device at the DC switching station.

[5] Mixed topologies refer to the possibility to operate the system in different configurations but not is not indicating default modes of operation.

TABLE 6-4

Interoperability functionalities and characteristics – DC grid protection

Short List Entry	***#1***	***#2 #3***	***#4 #5***	***#6***	***#7***	***#8***	***#9***	***D***
Promoter	***Asset Owner / TSOs***						***HVDC Vendors***	***InterOPERA***
DC Grid Protection								
Primary & back-up protection sequences using DC-FSDs	✓	✗	✓	✗	✗	✗	✓	✓
Double-ended protection sequences using DC-FSDs[6]	✗	✗	✗	✗	✗	✗	✓	✓
Primary & back-up protection using DC-FSDs in meshed DC grid configurations[7]	✗	✗	✗	✗	✗	✗	✓	✓
More than 2 DCSS	✓	✗	✗	✗	✓	✗	✓	✓
Different types of DCSS, e.g. Offshore & Onshore DCSSs[8]	✗	✗	✗	✗	✗	✗	✓	✓
Different types of DC-FSDs, e.g. MV for DC-FSDs in the same DCSS	✗	✗	✗	✗	✗	✗	✓	✓
Auto-reclosing functionality	✗	✗	✗	✗	✗	✗	✓	✗

[6] Double-ended: Both ends of a DC-line protected with DC-FSDs.

[7] Meshed configuration: DC grid topology considering, e.g., ring structures or parallel DC-lines.

[8] The topology of short list entry #9 provides the capability to test different types of DCSS.

TABLE 6-5

Interoperability functionalities and characteristics – GFM

Short List Entry	***#1***	***#2 #3***	***#4 #5***	***#6***	***#7***	***#8***	***#9***	***D***
Promoter	***Asset Owner / TSOs***						***HVDC Vendors***	***InterOPERA***
GFM Functionality								
Two different synchronous areas	✗	✗ ✗	✓ ✗ [9]	✓	✓	✗	✓	✓
HVDC MV at Offshore converter stations[10]	✗	✗	✓	✗	✗	✗	✓	✓
WTG/PPM MV at Offshore converter station	✓	✓	✓	✓	✓	✗	✓	✓
AC Offshore Connection with additional HV AC collector bus	✗	✗	✓	✓	✗	✗	NA	✗
AC Onshore split busbar requirements[11]	NA	NA	NA	NA	NA	NA	NA	✓

[9] Future expansion stages might include a connection between two different synchronous areas.

[10] Refers to AC side interoperability of two offshore converters in GFM mode in close electrical vicinity.

[11] Dependent on the progress of the InterOPERA project AC onshore split bus bar requirements should be also investigated due to its relevance to HVDC projects. To which extent AC onshore split busbar requirements could be assessed is subject to further alignment among the consortium partners.

7. Demonstrator definition

The definition of the demonstrator was carried out utilizing the process outlined in Figure 1-1. Based on characteristics and specifics of real-world projects provided by the asset owners and recommendations by InterOPERA work packages, key functionalities were identified that enable offshore meshed DC grids. Additionally, the distinct boundary conditions and general in-scope constraints of the InterOPERA project (e.g., hardware for real-time simulations summarized Table-6-1 and Table 6-2) are considered. Table 6-3, Table 6-4 and Table 6-5 provide an overview of key characteristics and functionalities that are either included or excluded in the demonstrator definition.

Section 6 defines the full extent of the InterOPERA demonstrator. Full extent shall be understood as the maximum size and maximum number of converter stations towards the presented DC grid is designed. Two variants for the full extent of the demonstrator are defined which are shown in Figure 7-1 and Figure 7-2**Error! Reference source not found.**. Within the project specific boundary conditions described in chapter 6, the DC grid design maintains flexibility for testing purposes for online simulations (HIL) and provides extended testing capabilities for DC grid control, protection and grid forming functionalities. That especially includes the possibility to vary the placement of HVDC building blocks based on design studies or testing requirements in the InterOPERA demonstrator, leading to the two variants of the demonstrator topology. Detailed information regarding testing procedures and interaction study processes are given in the deliverables of InterOPERA WP1, WP2 and WP3 / T3.3.

Section 7.2 provides an overview of subsets of the first variant of the InterOPERA demonstrator that gradually add DC grid functionalities and AC functionalities to be tested. The number of terminals is increased starting with a subset of a P2P HVDC grid connection system and gradually developing the topology of the demonstrator up to five converter stations.

It should be noted that, for the demonstrator topologies and its subsets, when it concerns AC side functional requirements we consider that those and their relevant parameters are given in NC HVDC and its national implementations. In addition, the D2.2 gives recommendations which grid forming functionalities to demonstrate. Concerning the testing of those AC side functionalities, they should be discussed in both Task 3.3-3.4 of WP3 as well as in WP1 and WP2 relevant tasks. Full-size figures of the demonstrator variants (& subsets) are included in the appendix.

7.1. Demonstrator – full extent

The first variant of the demonstrator topology considered in this project is depicted in Figure 7-1. This first variant represents a **meshed offshore grid for wind power export** including three offshore and two onshore converter stations. Converter station #1, #3 and #5 connect an offshore wind park via a direct connection with 132 kV AC offshore cables. Converter station #1 and #5 are in close electrical vicinity and the two stations can be coupled via the offshore AC switchyard and/or via the DC busbar system in the DCSS. Converter station #4 is connected to the stand-alone DCSS #5 via a relatively long DC transmission line. Dynamic braking systems (DBS) are considered at the onshore converter stations. Converter station #1, #2, #5 are operated as an AC offshore islanded network by default as well. By default, converter station #2 and converter station #4 are not in synchronous AC systems as the MT HVDC system connects two different synchronous areas.

The stand-alone DCSS in the middle includes five DC switching units with fault clearing capability, including one DC switching unit with fault clearing capability as a longitudinal coupling. Additionally, four DC switching units with fault clearing capability are included in the DCSS of converter station #1 & #5.

The first variant makes it possible to investigate interoperability issues between two offshore converter stations (#1 and #5) in grid forming control mode connected in close electrical vicinity to offshore DCSS #1.

Variant 1 of the InterOPERA demonstrator will be used for the preliminary conceptual system design studies performed in chapter 8.

Please note: For more information on testing procedures or interaction study processes, please refer to WP1, WP2 and WP3 / T3.3.

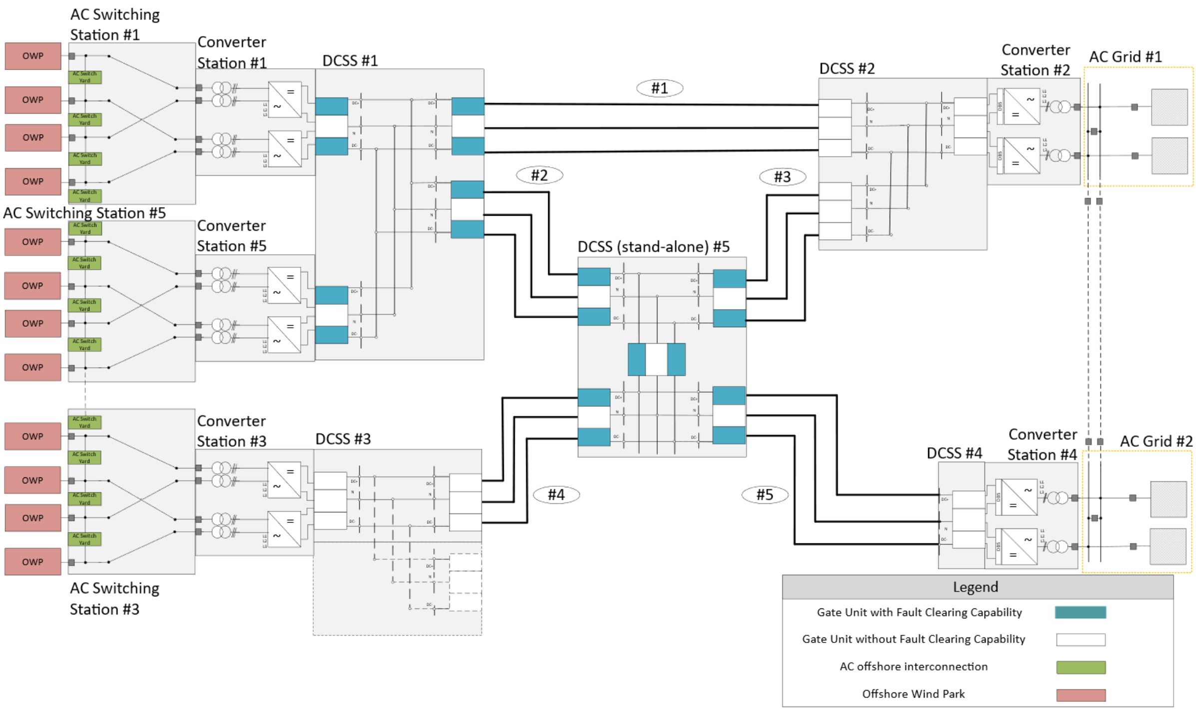


FIGURE 7-1

5MT – Full extent variant 1: Meshed offshore grid for wind export

Variant 2 of the InterOPERA demonstrator is depicted in Figure 7-2 and represents a **multi-purpose hybrid interconnector**. It describes a MT-HVDC system consisting of a stand-alone DCSS, two offshore (#1, #3) and three onshore converter stations (#2, #4, #5) with DCSS connected to two synchronous areas. Dynamic braking systems (DBS) are considered at the onshore converter stations. With regards to grid forming capability and its implementation in variant 2, the recommendations of the D2.2. shall apply.

The offshore converter stations are connected to an offshore wind park via a direct connection with 132 kV. The two onshore converter stations that are connected to DCSS#1 are in close electrical vicinity and the two stations can be coupled. The converter station connected to DCSS#3 is connected to the stand-alone DCSS via a comparatively long DC line. With the second variant of the demonstrator topology, AC-side interaction between two onshore converter stations in close electrical vicinity and in the same synchronous area shall be tested. In that case, an electrical AC equivalent impedance shall be defined between the two of the three onshore stations.

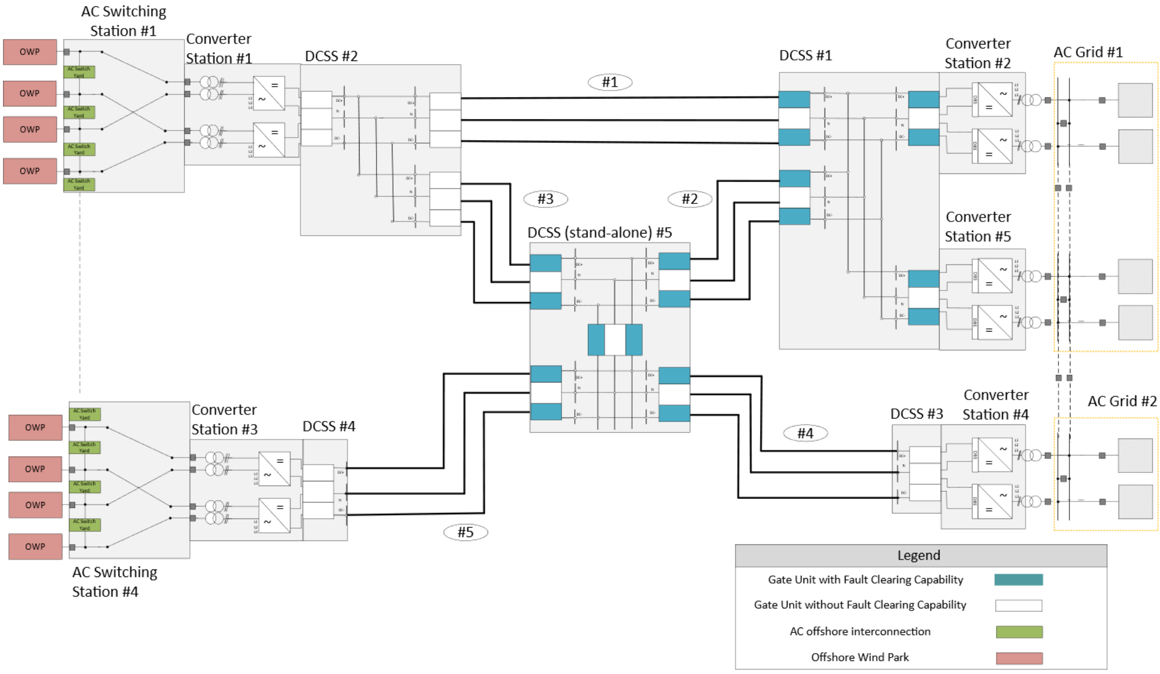


FIGURE 7-2

5MT – Full extent variant 2: Meshed multi-purpose hybrid interconnector

7.2. Demonstrator – subsets

Section 7.2 describes subsets of the first variant of demonstrator topology shown in section 7.1. The subsets show a step-by-step development in DC and AC grid functionalities. According to section 6.3, three converter stations are available for online (HIL) simulations indicated in subset 2. Subsets 3, 4 and 5 include more than three converter stations.

SUBSET 0: P2P HVDC & GRID CONNECTION SYSTEMS

Subset 0 describes a P2P HVDC GCS consisting of one offshore converter station with DCSS and an onshore converter station with a DCSS. An integrated DBS is located at the onshore converter station. The offshore wind park is connected utilizing a direct connection with 132 kV. A fault clearing concept is realized with the AC circuit breakers. For subset 0 there is no fault clearing capability on the DC side.

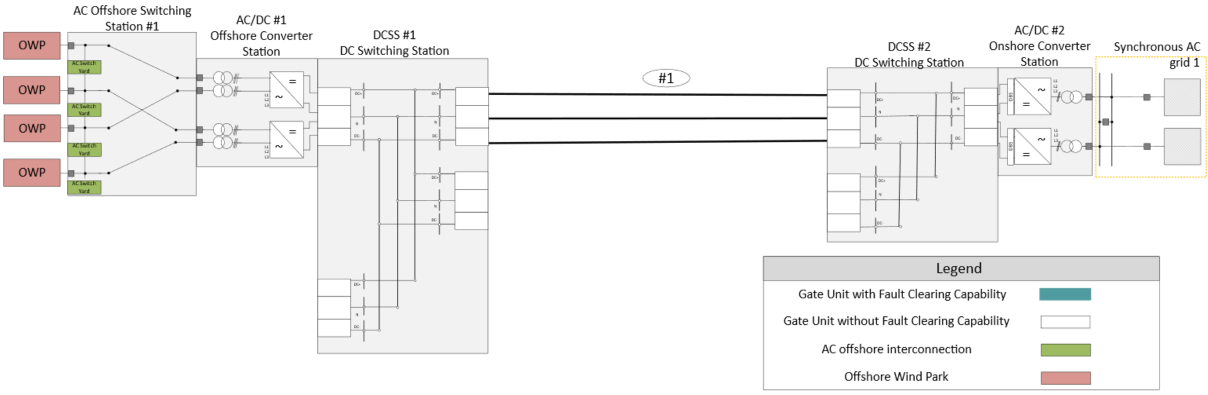


FIGURE 7-3

P2P HVDC & grid connection systems

SUBSET 1: P2P – INTEGRATION OF STAND-ALONE DCSS

Subset 1 describes a P2P HVDC system consisting of one offshore converter station with a DCSS and an onshore converter station with a DCSS. An integrated DBS are located at the onshore converter station. The offshore wind park is connected utilizing a direct connection with 132 kV. A fault clearing concept is realized with the AC circuit breakers. For subset 1 there is no fault clearing capability on the DC side.

Subset 1 allows to assess the function of a stand-alone DCSS using parallel DC-lines.

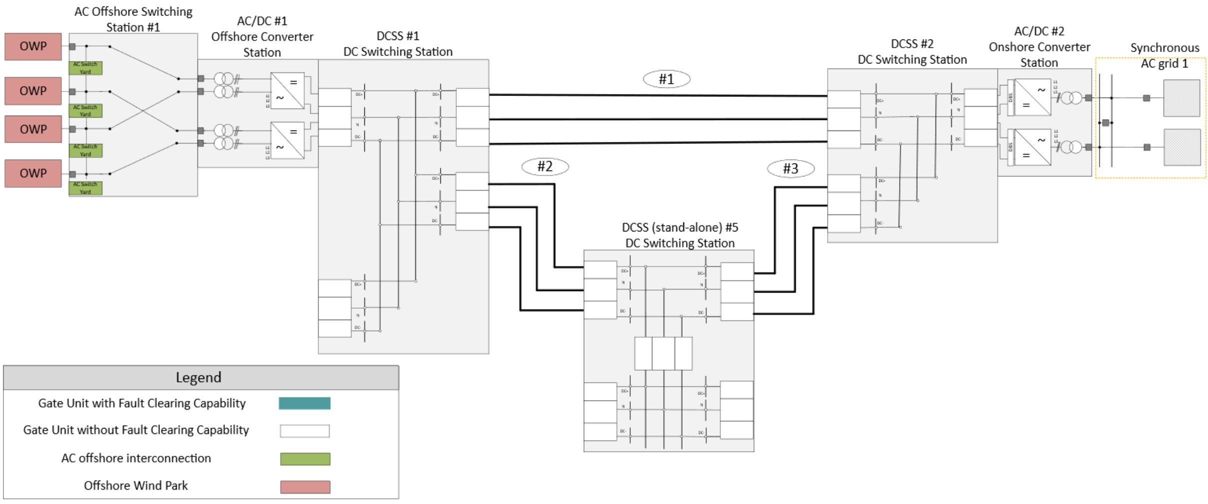


FIGURE 7-4

P2P - Integration of stand-alone DCSS

SUBSET 2: 3 MT - BASE TOPOLOGY

Subset 2 consists of two variants. Variant 1 (Figure 7-5) describes a MT HVDC system consisting of two offshore converter stations with DCSS and one onshore converter station with a DCSS. Variant 2 (Figure 7-6) describes a MT HVDC system consisting of one offshore converter station with DCSS and two onshore converter stations with a DCSS. An integrated DBS is located at each onshore converter station. The offshore converter stations connect the wind park via a direct connection with 132 kV. A fault clearing concept is realized with AC circuit breakers. For subset 2 there is no fault clearing capability on the DC side.

Subset 2 allows to assess the basic functions of a MT HVDC system as three converter stations are integrated while maintaining flexibility of the online (HIL) setup for testing purposes.

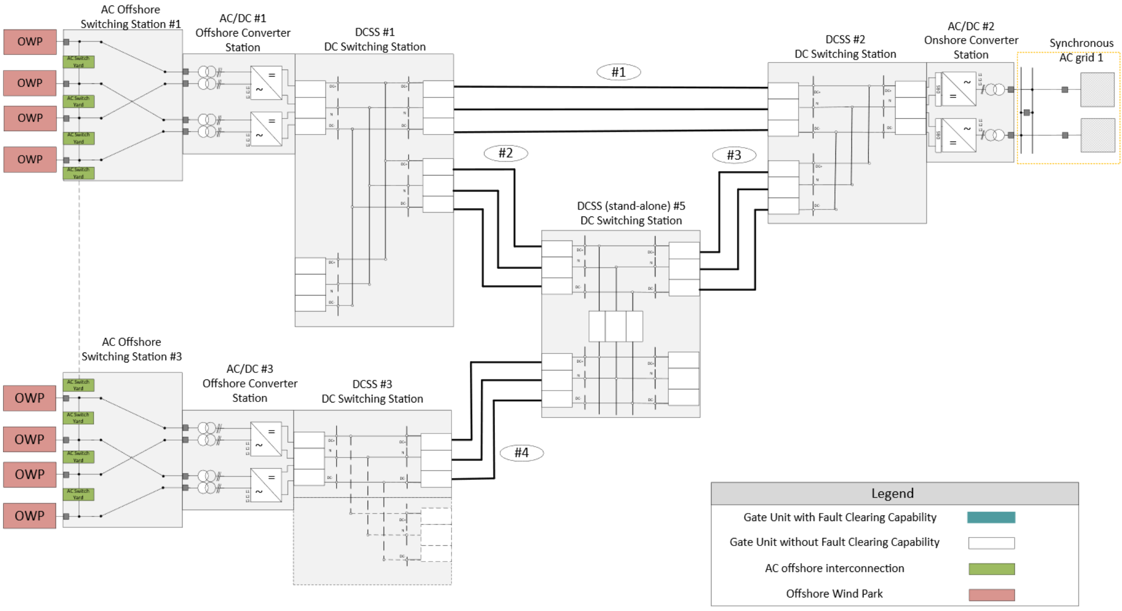


FIGURE 7-5

3MT - Base topology (variant 1)

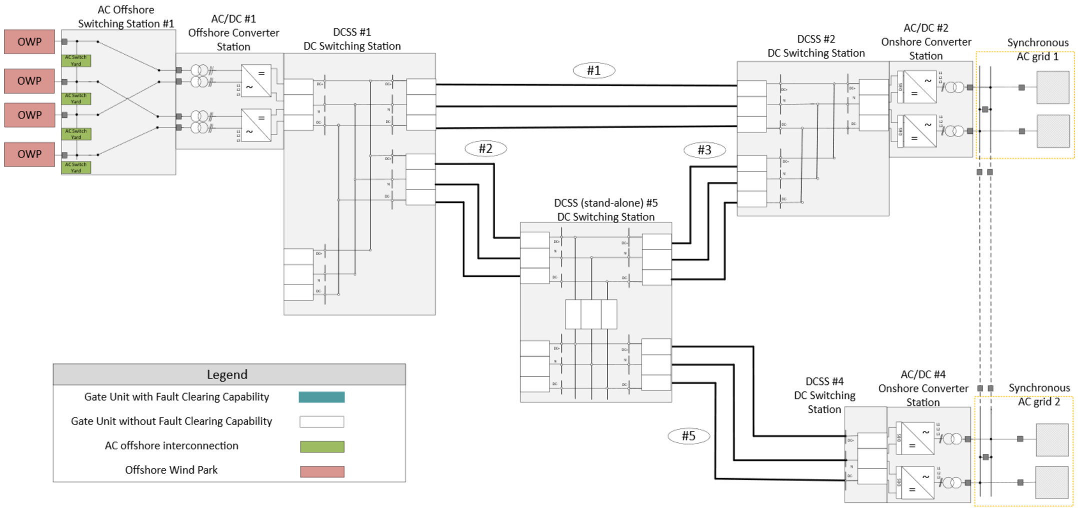


FIGURE 7-6

3MT - Base topology (variant 2)

The figures illustrate how flexibility of the InterOPERA demonstrator could be achieved. As an example, Variant 2 is motivated to cover specific onshore GFM requirements, e.g. to considering two different synchronous areas. With regards to the grid forming functionality the recommendations of the D2.2. shall be followed.

SUBSET 3: 4 MT – LONG DC TAP

Subset 3 describes an MT HVDC system consisting of two offshore converter stations with DCSS and two onshore converter stations with a DCSS and an integrated DBS. Converter station #1 and #3 connects the offshore wind park via a direct connection with 132 kV. Converter Station #4 is connected to the stand-alone DCSS via a relatively long DC line. A fault clearing concept is realized with AC circuit breakers. For subset 3 there is no fault clearing capability on the DC side.

Subset 3 allows to assess further functions of a MT-MV HVDC system as a fourth terminal is added using a considerable long DC cable to integrate an additional onshore converter station. Converter station #2 and converter station #4 can either be in two different synchronous AC grids or in the same synchronous AC grid.

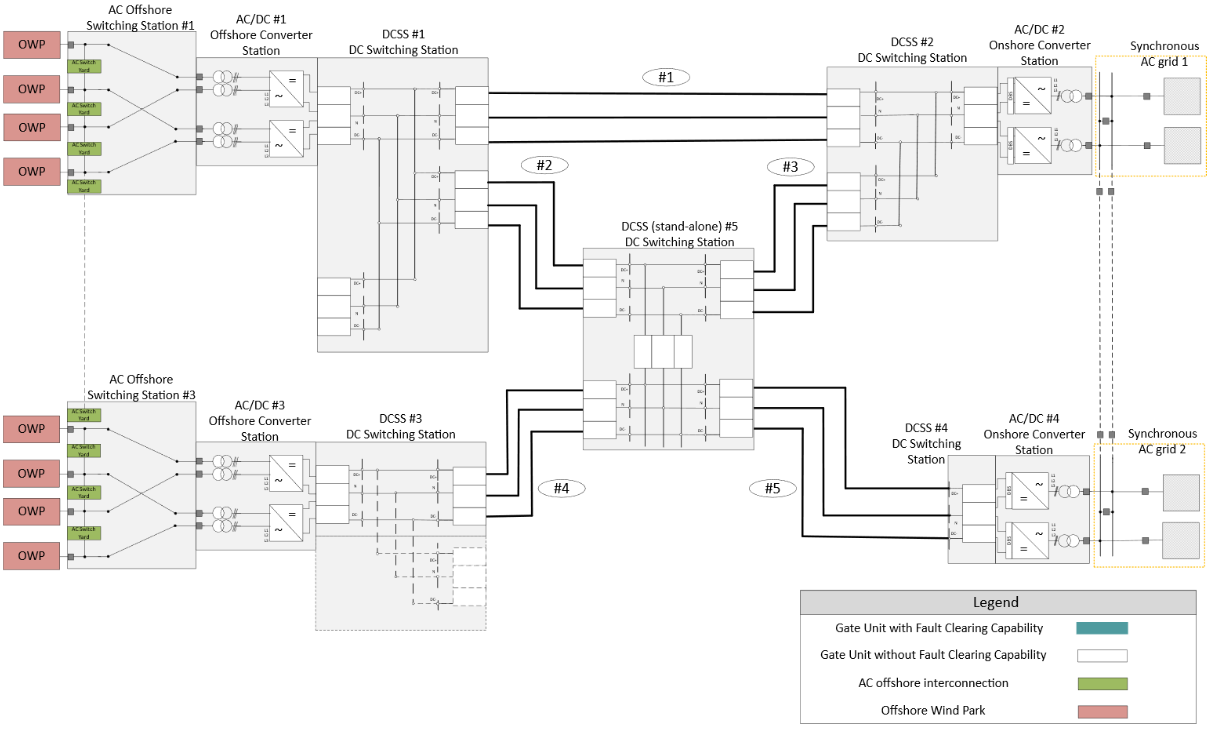


FIGURE 7-7

4MT – Long DC tap

SUBSET 4: 4 MT – DC-FSD INTEGRATION

Subset 4 describes a MT HVDC system consisting of two offshore converter stations with DCSS and two onshore converter stations with a DCSS and an integrated DBS. Converter station #1 and #3 connects the offshore wind park via a direct connection with 132 kV. Converter Station #4 is connected to the stand-alone DCSS via a relatively long DC line. In subset 4, DC-FSDs are introduced to the MT HVDC system. The stand-alone DCSS #5 includes five DC switching units including DC-FSDs, four DC switching units to connect DC-lines and one DC switching unit as a longitudinal coupling. Additionally, DCSS #1 includes one DC switching unit including DC-FSDs to connect the DC line towards the stand-alone DCSS.

Subset 4 allows to assess the integration of DC-FSDs to a MT HVDC system. DC-FSDs are integrated to the stand-alone DCSS #5, as well as to the DCSS #1.

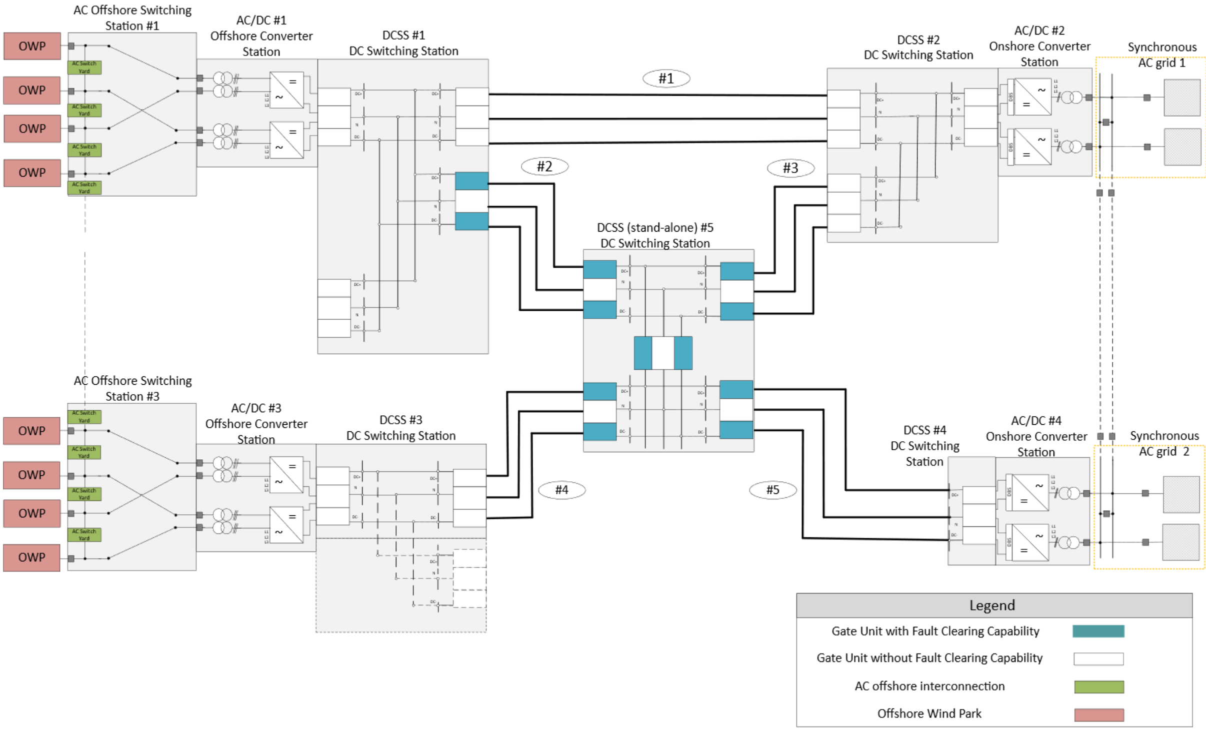


FIGURE 7-8

4MT- DC-FSD integration

8. Preliminary main circuit parameters & system design studies

Chapter 8 elaborates on the main characteristics and system level concepts of the InterOPERA demonstrator based on preliminary main circuit parameters. Section 7 provides general grid system data of the demonstrator to characterize the demonstrator grid design quantitatively and provide a basis for the HVDC grid subsystem pre-design and detailed functional specifications. The characteristics and parameters presented in section 7 are used as input for the subsequent study packages described in section 8.2 to **Error! Reference source not found.**

The preliminary system design studies performed in T3.1 consist of three study packages - a stationary analysis (section 8.2), a quasi-stationary analysis (section 8.3) and a transient analysis (section **Error! Reference source not found.**). The study results lead to basic requirements for the demonstrator, which are – besides additional parameters – summarized in preliminary main circuit parameters for the onshore / offshore converter station and the DC switching station.

8.1. Preliminary main circuit parameters and system design concepts

HVDC system data is defined to characterize the demonstrator topology (depicted in Figure 8-1) quantitively. For each grid system (DC grid system, offshore AC grid system, onshore AC grid system) topology, transmission line data, voltage ranges and frequency ranges are listed separately.

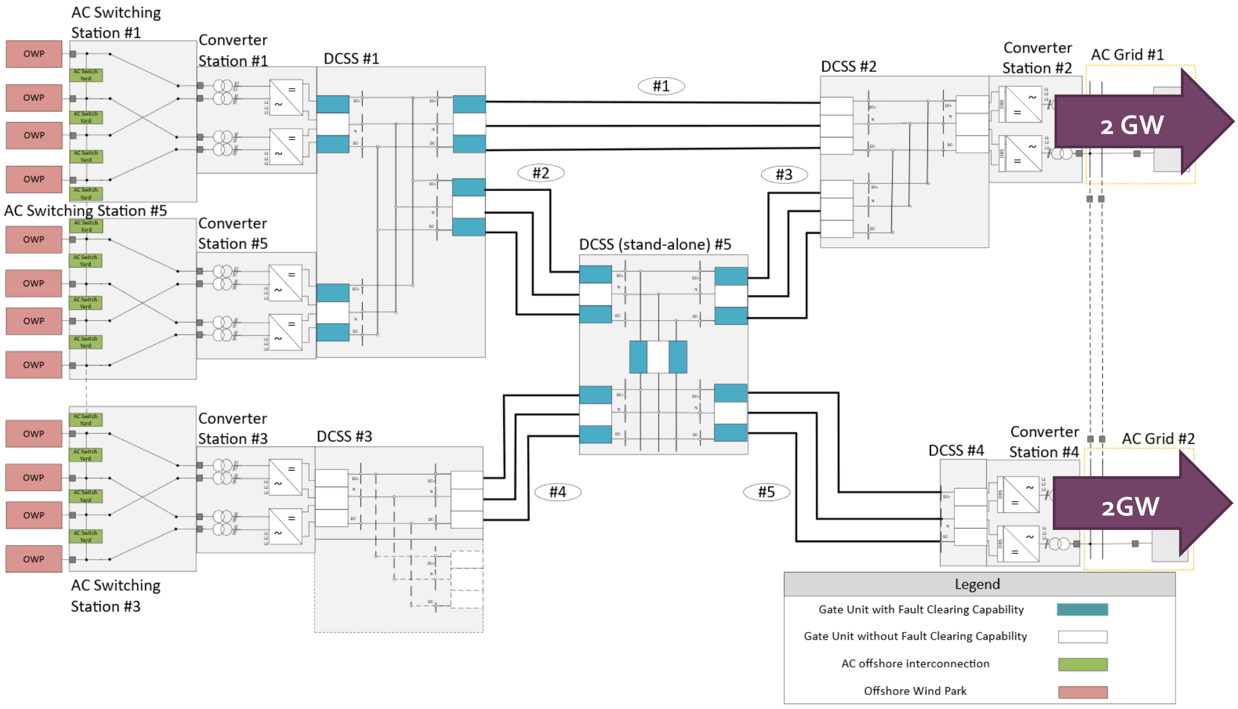


FIGURE 8-1

5MT – Full extent (variant 1)

TABLE 8-1

Basic system requirements of the InterOPERA demonstrator for (variant 1)

	Unit	Value	Comment
Integration of Offshore Wind	GW	≤ 4	-
Power transmission between Onshore AC Terminals	GW	≤ 2	-

The main power flow is between the offshore stations and the onshore stations as well as between the two onshore stations in variant 1 or three onshore stations in variant 2.

8.1.1. HVDC system - system level design

The following grid system design concepts provide a level of detail that is required for preliminary conceptual system studies and therefore the drafting preliminary main circuit parameters for the demonstrator. The concepts and strategies presented are further detailed during the grid subsystem pre-design and the drafting of the detailed function specifications.

Modes of operation - system level and system splits

This section describes modes of operation and system splits on a system level. A description of modes of operation and reconfiguration sequences is given in section 8.1.6 and section 8.1.7.

The InterOPERA demonstrator system is a multi-vendor multi-terminal system designed as a bipole with dedicated metallic return cable. Each monopole can be operated separately with a return path via the dedicated metallic return cable (asymmetrical monopole operation) with half of the bipole active power transmission capability. The default operational mode is bipole with metallic return for the entire system including all subsystems. Each converter station can operate independently from the system in the operational modes described for offshore and onshore converter stations in section 8.1.6 and section 8.1.7. In case of a system split (e.g. split in the standalone DCSS#5) or partial operation of the system full operational flexibility is maintained. Each possible point-to-point operation between offshore and onshore converter stations can operate in the modes of operation described in section 8.1.6 and section 8.1.7. The HVDC system can be operated in any P2P configuration and multi-terminal configuration including three, four or five converter stations in the modes of operation described section 8.1.6 and section 8.1.7.

Grid control – basic control modes & conceptual functions

With the goal to derive preliminary main circuit parameters, the AC control modes and conceptual DC Grid control functions in subsections 8.1.6 and 8.1.7 are assumed. Further definitions regarding functionalities and test scenarios especially on station-level and unit-level control are made in T2.1 WS Continuous Control and during the sub-system design of T3.2. Specific functional requirements regarding grid forming control are given by T2.4.

All onshore and offshore HVDC converter stations shall be equipped with appropriate converter energy controls to ensure power balance between the AC and the DC side of each HVDC converter station, as well as balancing of the series connected submodules.

Testing scenarios and procedures are not finally defined in T3.1 but shall be detailed in WP2 and task 2.2. Tested functionalities shall be compliant to relevant control modes and immunity requirements as they appear in the NC HVDC [6]. The VDE-AR-N 4131:2019-03 national implementation [7] shall apply in the case that exhaustive parameters are needed (for example grid forming) and not given detail in the NC HVDC.

The AC control modes assumed for the offshore and onshore converter stations are described in section 8.1.6 and section 8.1.7 respectively. In the sections below, basic concepts and functional requirements regarding DC system control are described.

Primary DC voltage control

The primary DC voltage control is achieved by a DC voltage droop control. According to [8] the droop is defined as the change of active power in response to a deviation of the DC voltage reference value. In the first step, a droop parameter at a system level is defined considering the maximum post-contingency steady-state DC voltage deviation and the maximum power disturbance in the system. The system level droop represents an aggregated droop parameter of all converter stations being in droop control mode. It is considered as a measure for the required system reserve. Please note that the system level droop does not equal to the station level droop factors used for the converter stations in the quasi-stationary analysis.

ΔV_{DC} is the maximum post-contingency steady-state DC voltage deviation, which is assumed to 10% for the conceptual studies of this task (referring to 525 kV). According to the investigated contingencies in section 8.3, $\Delta P = \pm 2\,GW$ is the maximum power disturbance which is relevant for the primary DC voltage control. Based on these two values, the corresponding system level droop parameter is obtained and listed in Table 8-2.

$$s_{P-U_{DC}} = \frac{\Delta V_{DC}}{\Delta P} = \frac{10\% \cdot 525kV}{2000\,MW} \approx 0.026\frac{kV}{MW}$$

TABLE 8-2

Primary voltage control parameters

	Unit	Value	Comment
Max. Disturbance	MW	2000	Based on section 8.3
System Level Droop Characteristic	kV/MW	0.026	-

Secondary DC voltage control

The secondary DC voltage control returns local voltages to their setpoint values defined through the optimal power flow algorithm of the HVDC grid controller. Additionally, it restores the security margin of the DC voltage after a contingency to restore controllability headroom of the converter station.

TABLE 8-3

Secondary voltage control parameters

	Unit	Value	Comment
Secondary V_{DC} time	s	30	-

DC grid protection design concept

Figure 8-2 shows fault separation zones (FSZ) and fault clearing zones (FCZ). Each zone is additionally divided between the high voltage poles and the DMR. A fault separation zone is a zone in the grid which is separated from the surrounding grid in case of a fault. The boundaries are defined by the availability of fault separation functionalities. A fault clearing zone is a zone in the grid in which a residual current will be interrupted after a fault and subsequent fault current suppression. The boundaries are defined by the availability residual current breaking functionality. Selective FSZs are indicated in blue. Partially-selective FSZs are indicated in purple.

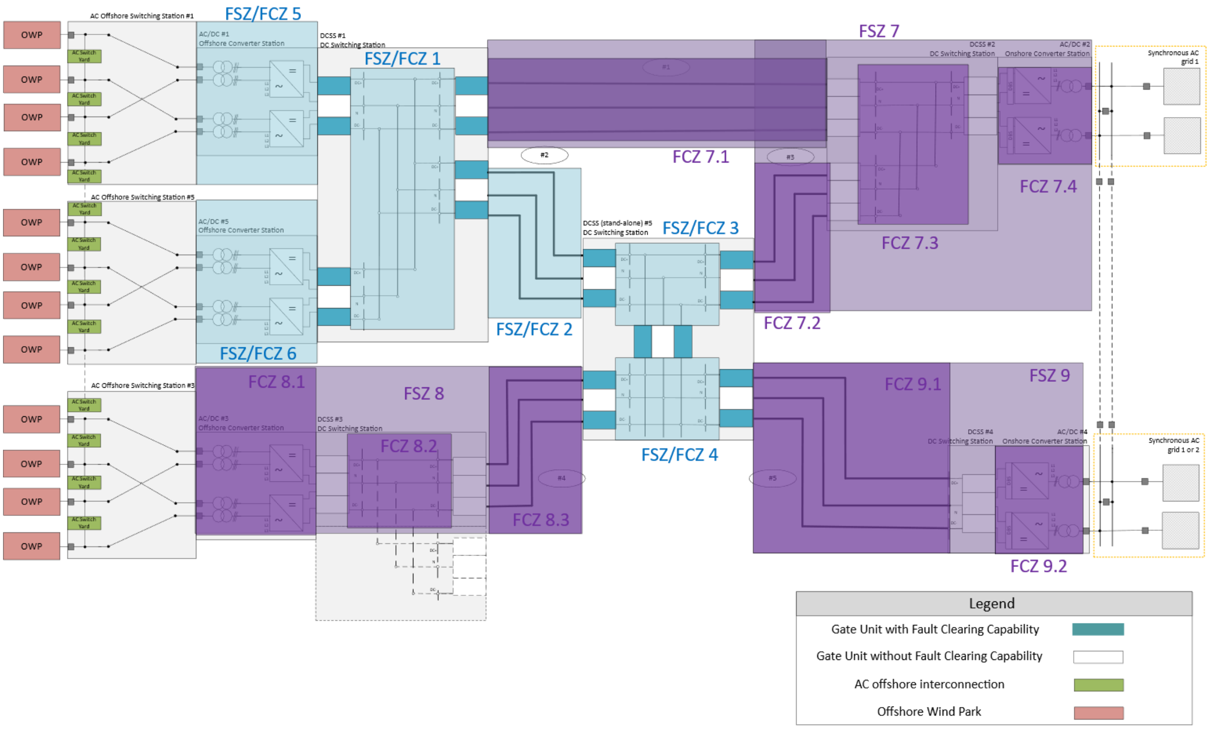


FIGURE 8-2

Initial zones for primary protection

In Table 8-4 a base system protection matrix is described including the states continued operation (CO) and permanent stop (PS). In Table 8-5 an optional system protection matrix is shown that allows the option of converter stations to perform a temporary stop (TS). Continued operation of a converter station includes the requirement of full controllability of the converter station after any contingency or fault. During a temporary stop, a complete stop of active and reactive power after a DC contingency during a short duration (< 10 ms) occurs. The allowed duration depends on AC grid stability – especially frequency and voltage stability.

TABLE 8-4

System protection matrix – base variant

FSZ	CNVS #1	CNVS #2	CNVS #3	CNVS #4	CNVS #5
1	PS	CO	CO	CO	PS
2	CO	CO	CO	CO	CO
3	CO	CO	CO	CO	CO
4	CO	CO	PS	PS	CO
5	PS	CO	CO	CO	CO
6	CO	CO	CO	CO	PS
7	CO	PS	CO	CO	CO
8	CO	CO	PS	CO	CO
9	CO	CO	CO	PS	CO

TABLE 8-5

Protection matrix – optional including temporary stops

FSZ	CNVS #1	CNVS #2	CNVS #3	CNVS #4	CNVS #5
1	**TS**	CO	CO	CO	**TS**
2	**TS**	CO	CO	CO	**TS**
3	CO	CO	CO	CO	CO
4	CO	CO	**TS**	PS	CO
5	PS	CO	CO	CO	CO
6	CO	CO	CO	CO	PS
7	TS	PS	CO	CO	**TS**
8	CO	CO	PS	CO	CO
9	CO	CO	**TS**	PS	CO

Fault events lead to a separation of the system into subsystems according to the fault separation zones shown in Figure 8-2. Sub-systems outside of the affected fault separation zone shall remain in operation. After fault clearing, the affected fault clearing zone remains disconnected. If unaffected fault clearing zones were disconnected during fault neutralisation, they are reconnected after fault clearing.

Contingencies and response

Table 8-6 shows the DC contingency list for the InterOPERA demonstrator. The combination of fault types and fault locations are categorized into ordinary contingencies (A), which are considered for the preliminary conceptual system design studies performed in T3.1, and exceptional contingencies (B), which are excluded.

All pole-to-ground faults (DC-, DC+) are considered as ordinary contingencies. In general, pole-to-pole faults are considered exceptional contingencies, mainly due to their low likelihood of occurrence or their low severity. An exception is offshore transmission lines since offshore cables are assumed to be bundled. Pole-to-pole or pole-to-DMR faults are assumed to be excluded through structural measures.

It shall be noticed that according to the CIGRE TB 815 "Update of service experience of HV underground and submarine cable systems" [9] the DC XLPE submarine cables at voltages higher than 110 kV there were no failures recorded. This is a survey for the cables installed from 2006-2015 – total of 763 km.

TABLE 8-6

Fault types (rows) and fault location (columns)

	Converter (DC-side)	DC-SU Converter	DC transmission line (onshore, unbundled)	DC transmission line (offshore, bundled)	DCSS / DC busbar
Pole (DC+) to ground fault	A	A	A	A	A
Pole (DC-) to ground fault	A	A	A	A	A
DMR to ground fault	B	A	A	A	A
Pole (DC+) to DMR fault	B	B	B	A	B
Pole (DC-) to DMR fault	B	B	B	A	B
Pole (DC+) to Pole (DC-) fault	B	B	B	A	B
Pole (DC+) to Pole (DC-) to ground fault	B	B	B	A	B

System states

The following system states of the demonstrator topology are described.

Normal operation: In normal operation (normal state) the system is within operational security limits and no transmission system element is unavailable due to the occurrence of an unplanned event.

Alert operation: In alert state the system operates within operational security limits, but a contingency has been detected. Under this contingency, counter measures are foreseen to bring the system back to normal operation in order to avoid entering an emergency state.

Emergency Operation: Emergency state describes a state in which one or more operational security limits are violated.

Energisation

Energisation of the multi-terminal system is performed sequentially. To simplify the design of the pre-insertion resistors only one part of the multi-terminal system is energized at a time. The onshore converter stations, energy dissipation devices and connected cables are energized via the AC pre-insertion resistor. If possible, the central DC switching station #5 is energized after the energisation of one onshore converter station. Subsequent cables and connected converter stations are energized from the DC switching station #5. The offshore converter stations are energized together with the offshore cables via the DC pre-insertion resistors in the DC switching station. Additionally, it is possible to synchronize and connect already energized converter stations to an energized DC cable. Offshore black-start scenarios and capabilities as a restoration strategy are not foreseen in the conceptual system studies of T3.1.

Wind farm curtailment

After a contingency event the curtailment of wind farms might be necessary to restore energy equilibrium after the event. In principle, three technically feasible options for the curtailment of windfarms in multi-terminal grids were identified – coordinated curtailment by the DC grid controller, coordinated curtailment at an operating zone level and uncoordinated curtailment. In Figure 8-3Figure 5-3 the steps of the three options are shown.

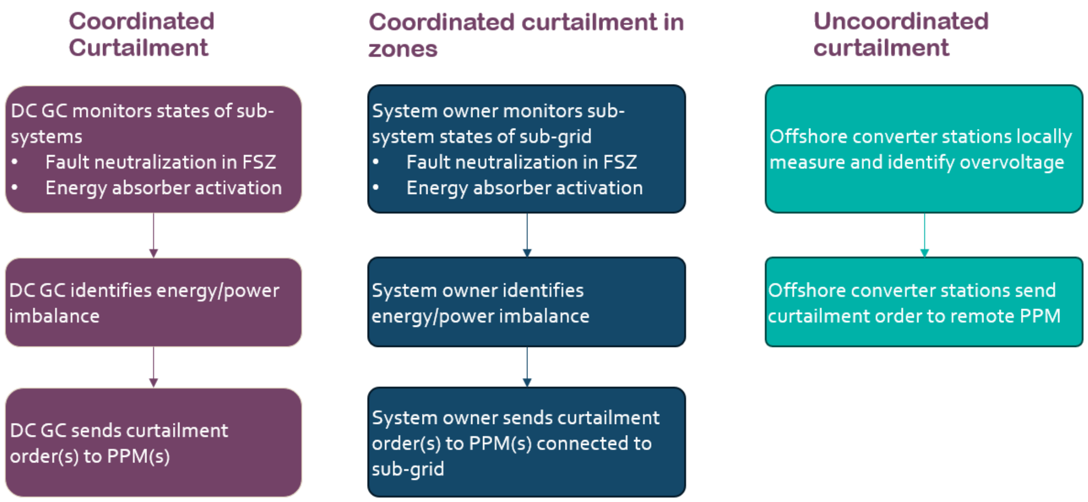


FIGURE 8-3

Options for wind farm curtailment

Since local voltage measurements do not ensure wind power curtailment in every possible situation (for example if DBSs are active, diverting the excessive wind energy and, thus, limiting overvoltage across the HVDC grid), then coordinated curtailment measures by the HVDC grid controller shall be implemented, based on communication signals sent to the offshore converter stations. A curtailment matrix based on a set of curtailment rules enables an optimized curtailment of energy. Such a matrix shall then consider curtailment at an operating zone level (coordinated curtailment in zones). Additionally, as a fallback option, uncoordinated curtailment of PPM(s) based on local voltage measurements shall be ensured, which should be part of the Autonomous Adaptation Control layer applied to the offshore converter stations. The uncoordinated curtailment would act, after sensing local overvoltage, in case the coordinated actions would fail and the DBSs energy limits would be exceeded, and these devices would no longer be limiting overvoltage across the DC grid.

DC system grounding

A harmonized grounding concept on a system level is necessary in a multi-terminal multi-vendor context. The detailed design of the grounding resistor must be a trade-off between the required damping of phase-to-ground faults located between the converter and the transformer, and the stress in the DC system after pole-to-ground faults. Solid or low-impedance system grounding show advantages regarding voltage stress on the DMR and HV pole after pole-to-ground faults. For the preliminary conceptual system design studies in sections 8.2, 8.3 and 8.4 a solid system grounding is applied[12].

The DC system is grounded at only one DC switching station at a time in order to prevent earth currents between grounding locations (except during system reconfiguration sequences). In normal operation, DC grounding is exclusively foreseen in the (standalone) DCSS #5. Each subsection of the busbar in the standalone DCSS has a separate grounding point. During normal operation of the complete DC system, only one busbar section in DCSS#5 is grounded (see Figure 8-4). In case of a system split, both busbar sections of the (standalone) DCSS#5 is grounded (see Figure 8-5). In case of point-to-point operation between DCSS #3 and DCSS #4, the onshore DCSS#4 is grounded (see Figure 8-6). If one or multiple converter stations are in Mode 5 (STATCOM operation), the respective converter station grounding is used. The figures below illustrate the described scenarios.

According to the energisation sequence described in this chapter the (standalone) DCCS #5 is energized as early in the sequence as possible. If the (standalone) DCSS #5 is not yet energized DC grounding is provided by onshore DCSS #2 or DCSS 4# (see Figure 8-6) during the according energisation sequence.

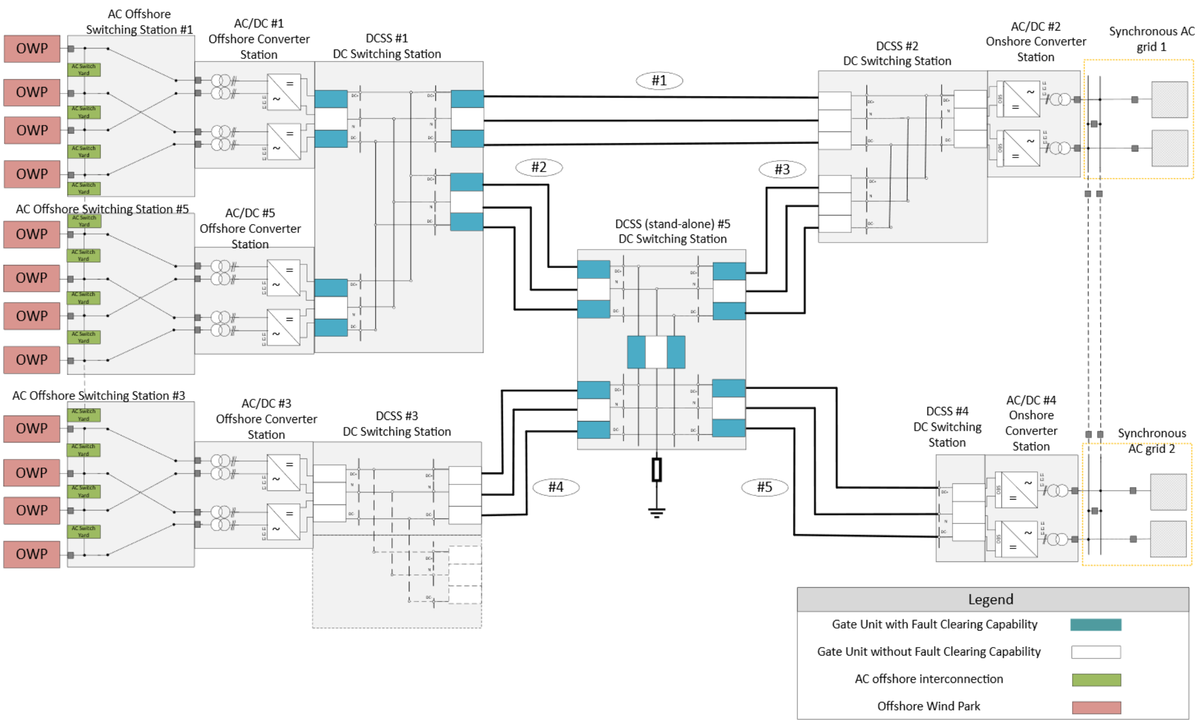


FIGURE 8-4

Grounding location - full extent (variant 1)

[12] Solid system grounding is assumed as a starting point for preliminary system studies and design. Due to further system design considerations the grounding impedance can deviate from this in upcoming system design iterations.

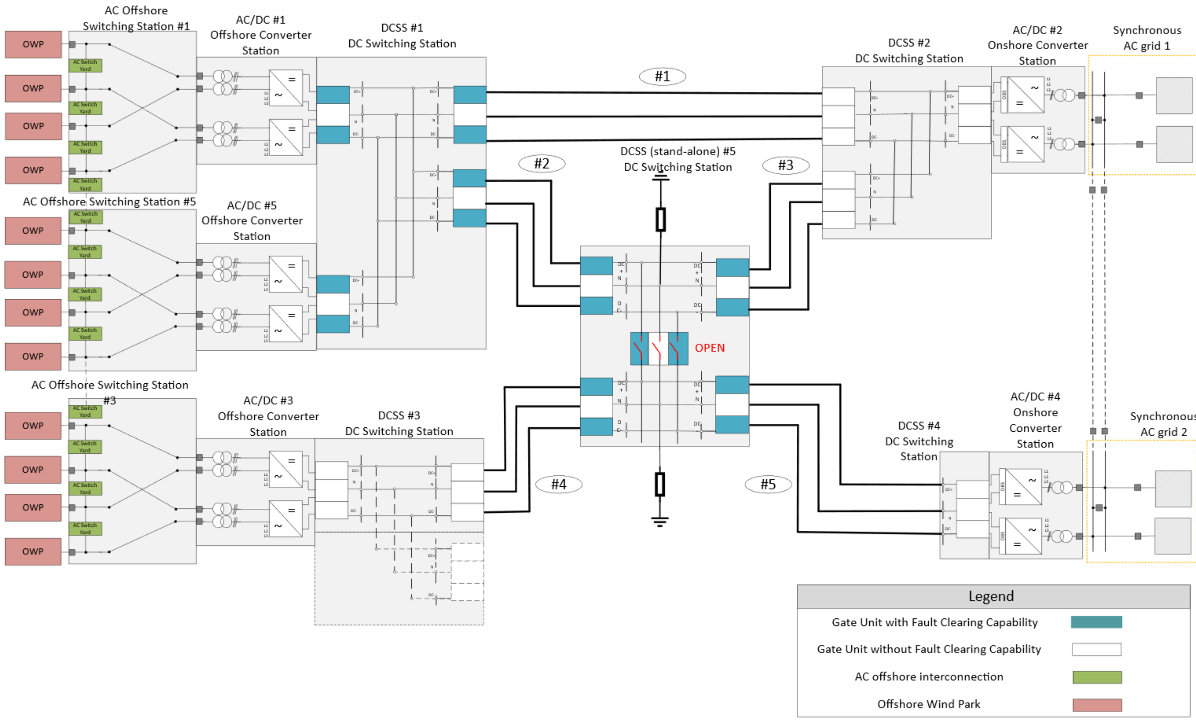


FIGURE 8-5

Grounding location - system split at DCSS#5

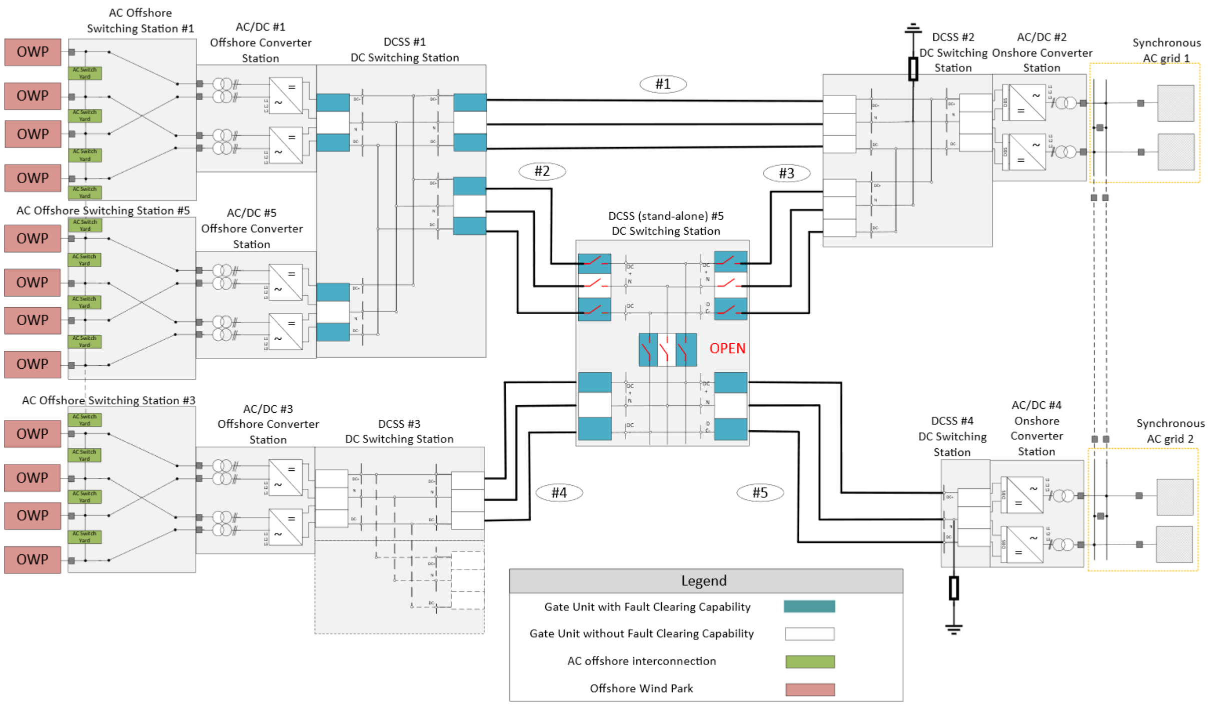


FIGURE 8-6

Grounding location - P2P configuration

8.1.2. DC system data

The tables in this section 8.1.2 describe the DC grid topology as well as cable length and DC cable data. Line lengths are based on typical values out of the use cases listed in chapter 2. Cable data is based on asset owner experience for 525 kV P2P HVDC systems.

TABLE 8-7

DC grid topology

	Unit	Value	Comment
Type of DC grid topology	-	5MT / DC-Grid	
Number of offshore converter stations	-	2/3	*)
Number of onshore converter stations	-	2/3	*)
Number of DC switching stations	-	5	

*) *Number of offshore and onshore converter stations is configurable based on the variant (see chapter 7)*

TABLE 8-8

DC line topology main data

	Unit	Value	Comment
Length of DC line #1	km	400	Max distance Offshore-Onshore
Length of DC line #2	km	350	∑ 400 km 1:1 current sharing of parallel cable sections
Length of DC line #3	km	50	
Length of DC line #4	km	350	Offshore connection to standalone DCSS
Length of DC line #5	km	800	Onshore connection to standalone DCSS "long spoke"

TABLE 8-9

DC pole voltage data

	Unit	Value	Comment
Nominal operating DC voltage	kV_{DC}	±525	
Maximum continuous DC voltage	kV_{DC}	±550	DC cable rating

TABLE 8-10

DC lines main data 2 GW (offshore)

	Unit	Value	Comment
Line Types	-	Cable	
Insulation Types	-	XLPE	Working assumption
Conductor Types	-	Cu	Base case
Specific resistance (at 20°C)	mΩ/km	7.2	approx.2500mm^2
Specific resistance (at 70°C)	mΩ/km	8.56	
Specific capacitance	µF/km	0.25	
Specific inductance	mH/km	0.14	

TABLE 8-11

DC lines main data 2 GW (onshore)

	Unit	Value	Comment
Line Types	-	Cable	
Insulation Types	-	XLPE	Working assumption
Conductor Types	-	Cu	Base case
Specific resistance (at 20°C)	mΩ/km	6.7	approx. 3000mm²
Specific resistance (at 70°C)	mΩ/km	7.9	
Specific capacitance	µF/km	0.23	
Specific inductance	mH/km	0.135	

TABLE 8-12

DC current max. data (2 GW)

	Unit	Value	Comment
Nom. operating DC current	A	1905	1000 MW / 525 kV
Max. continuous rating DC current	A	2100	1000 MW / 480 kV

TABLE 8-13

Transient overvoltage profile cables

	Unit	Value	Comment
U_0	kV	525	
U_1	kV	893	$1.7 * U_0$
t_1	ms	4-10	7±3
U_2	kV	856	U_{90}
t_2-t_1	ms	20-60	
U_3	kV	709	U_{50}
t_3-t_1	ms	100-200	

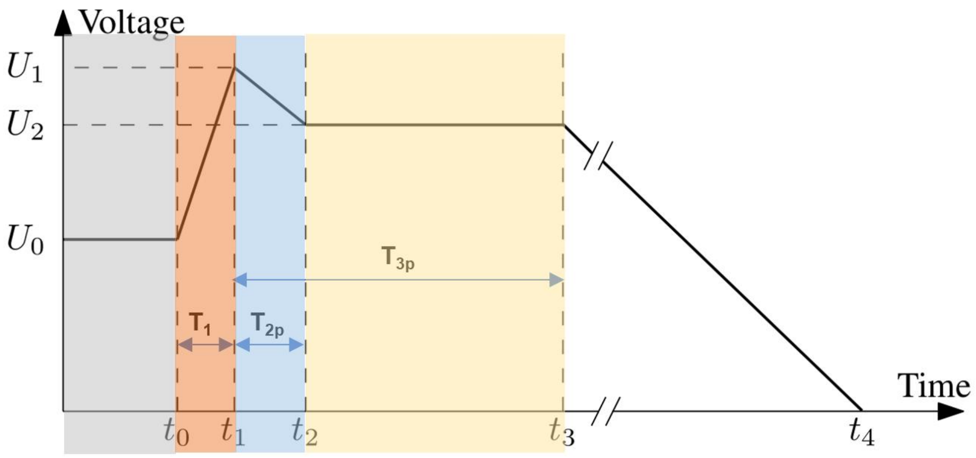


FIGURE 8-7

Transient overvoltage cable profile

TABLE 8-14

Overcurrent profile cables

	Unit	Conductor	Metallic Sheath
Max. accepted short circuit current I_k on cable pre-loaded with I_{max} for duration up to 0.2 s	kA	1000	130
Max. accepted short circuit current I_k on cable pre-loaded with I_{max} for duration up to 1.0 s	kA	460	60
Max. accepted short circuit current I_k on cable pre-loaded with I_{max} for duration up to 5.0 s	kA	200	30

8.1.3. AC system data onshore

The AC system data listed in this section is based on typical values for AC grids around the North Sea. Short circuit levels are shown for both a weak and a strong grid.

TABLE 8-15

AC voltage ranges onshore (grid 1)

	Unit	Value	Comment
Nom. voltage	kV_{RMS}	400	Nom.
Max. continuous voltage	kV_{RMS}	420	
Min continuous voltage	kV_{RMS}	360	
Max. temporary voltage	kV_{RMS}	440	60 min
Min temporary voltage	kV_{RMS}	340	

TABLE 8-16

AC SC levels onshore (grid 1)

	Unit	Value	Comment
Max. SCL	MVA	55426	
SCC	kA	80	For rating
X/R	-	20	Assumed
Min. SCL	MVA	4000	SCR ca. 2 for 2 GW
SCC	kA	5.77	
X/R	-	10	Assumed
Z_0/Z_1	-	TBD	Assumed

TABLE 8-17

AC voltage ranges onshore (grid 2)

	Unit	Value	Comment
Nom. voltage	kV_{RMS}	400	Nom.
Max. continuous voltage	kV_{RMS}	420	
Min continuous voltage	kV_{RMS}	360	
Max. temporary voltage	kV_{RMS}	440	60 min
Min temporary voltage	kV_{RMS}	340	

TABLE 8-18

AC SC levels onshore (grid 2)

	Unit	Value	Comment
Max. SCL	MVA	29099	
SCC	kA	40	For rating
X/R	-	20	Assumed
Min. SCL	MVA	10185	SCR ca. 5 for 2 GW
SCC	kA	14	
X/R	-	10	Assumed
Z_0/Z_1	-	TBD	

8.1.4. AC system data offshore

This section describes the AC system offshore topology including a 132 kV wind park. Figure 8-8 shows the AC offshore topology. The AC cable data are shown for typical cables with the cross sections of 630 mm² and 400 mm².

TABLE 8-19

AC offshore grid topology

	Unit	Value	Comment
Number of strings per pole	-	8	
Number of WT per string	-	8/9	6x 8WT + 2x 9WT
Cable length (distance between WT)	km	6/3	
Cable cross sections	mm²	630/400	
Nominal power per WT	MW	15	

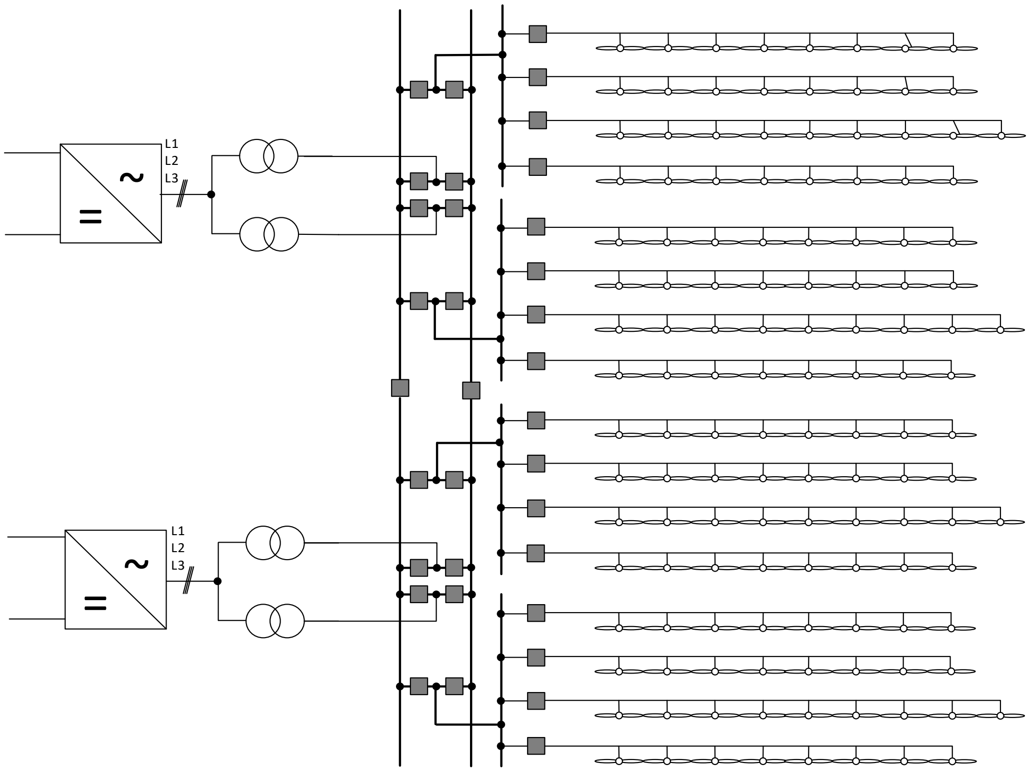


FIGURE 8-8

AC offshore grid topology - 132 kV windfarm

TABLE 8-20

AC voltage ranges offshore

	Unit	Value	Comment
Nom. voltage	kV_{RMS}	132 kV	
Max. continuous voltage	kV_{RMS}	145 kV	
Min continuous voltage	kV_{RMS}	119 kV	
Max. temporary voltage	kV_{RMS}	152 kV	30 min
Min temporary voltage	kV_{RMS}	112 kV	60 min

TABLE 8-21

AC SC levels offshore

	Unit	Value	Comment
Max. SCL	MVA	7316	
SCC	kA	32	For rating
X/R	-	10	Assumed
Min. SCL	MVA	0 – 2200	+10% for SCL TBD - consider overplanting and OWP specifics
SCC	kA	9.7	
X/R	-	10	Assumed

TABLE 8-22

AC offshore / generator block data & rated power generation capacity

	Unit	Value	Comment
Number of generator blocks (per Offshore Converter Station)	-	4	2 GW -> 4x 500 MW

TABLE 8-23

AC offshore cable data (630 mm² / 400 mm²)

	Unit	Value	Comment
Line Types	-	AC cable	
Insulation Types	-	XLPE	
Conductor Types	-	Copper	
Length of AC Cables	km	6/3	
Nominal Voltage U_o	kV	132	
Rated voltage U_m	kV	145	
Cross section	mm²	640/400	
Rated thermal short circuit current	A	825/590	
Max. conductor temperature	°C	90	
Specific resistance (at 20°C)	mΩ/km	41/56	
Specific capacitance	µF/km	0.196/0.165	
Specific inductance	mH/km	0.334/0.369	

8.1.5. DC switching stations (#1, #2, #3, #4 and #5)

The DC switching stations can be classified into two types - standalone DC switching stations and converter DC switching stations. DC switching stations #1, #2, #3, and #4 are converter DC switching stations. DC switching station #5 is a standalone DC switching station.

The main functionalities of DC switching stations are listed below:

- Connect the DC transmission elements / DC lines to the DC switching Units (DC-SU) of the individual DC switching stations
- Enable all DC grid configurations considering all the individual DC switching stations and the required grid connection modes
- Provide a reference to ground according to the grounding strategy (e.g. DCSS #5)
- Provide pre-insertion resistance according to the energisation strategy
- Provide switching functionality of residual, load and fault currents with the respective switching devices

Schematic overview of a converter DC switching station

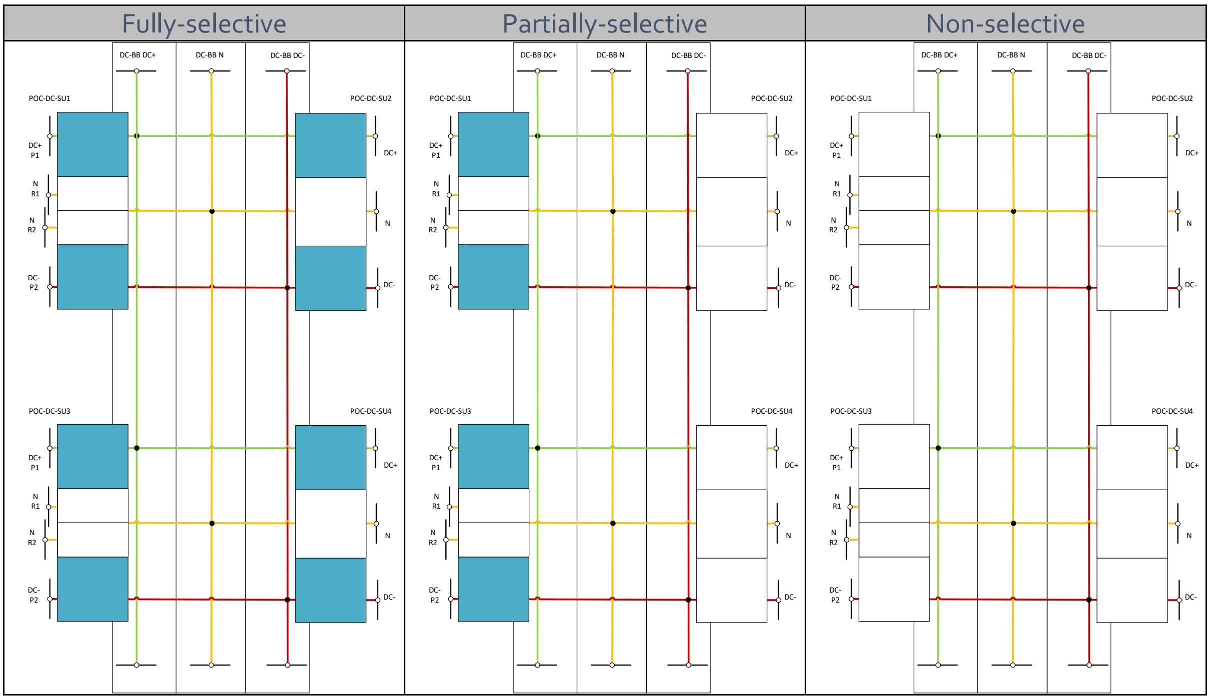


FIGURE 8-9

Schematic overview of DCSS #1,2,3,4 (fully-selective / partially-selective / non-selective)

In the following the main elements of the DC switching station are stated and the different DC switching units are introduced:

- DC busbar sections (DC-BB) 3x
- DC-SU offshore/onshore cable (DC-SU-OFFSH) 2x
- DC-SU converter units (DC-SU-CNV) 2x

Schematic overview of DC switching station (standalone)

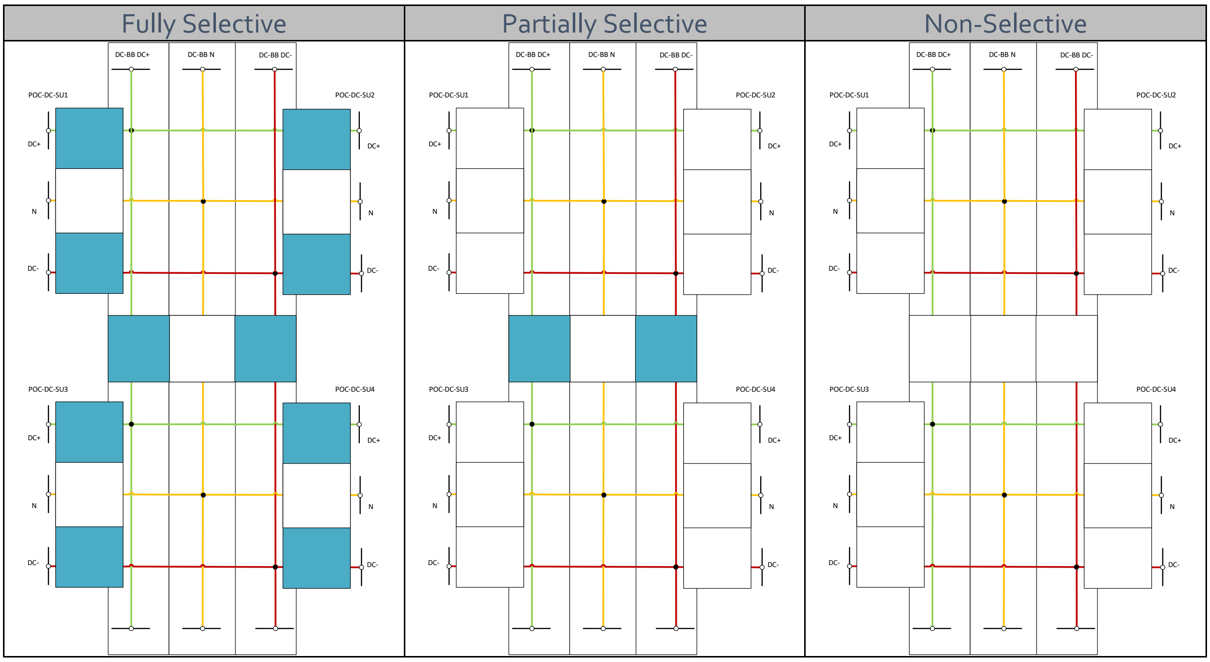


FIGURE 8-10

Schematic overview of DC switching station #5 (standalone; fully-selective / partially-selective / non-selective)

In the following, the main elements of the standalone DC switching station are stated and the different DC switching units are introduced:

- DC busbar sections (DC-BB) 6x
- DC SU bus coupler (DC-SU-BC) 1x
- DC-SU offshore cable (DC-SU-OFFSH) 2x
- DC-SU onshore cable (DC-SU-ONSH) 2x

DC busbar systems and DC busbar sections

A DC-busbar system for a DC grid in bipole configuration comprises at least three individual DC busbar sections. Two HV-side/pole DC busbar sections and one neutral DC busbar section.

- HV-side/pole
    - DC+ busbar section
    - DC- busbar section
- Neutral busbar section

HV-side/ pole DC busbar sections and busbar redundancy

- As a base case, the functional HV-side/pole DC busbar arrangement is considered a single DC busbar section.
- Fault events and contingencies in the HV-side/pole area of the transmission units, the DC switching stations, or the converter units cause significant DC fault currents. Typically, an immediate DC fault clearance sequence is initiated to mitigate any damages to the converter units or other equipment of the MT HVDC system.

DC busbar redundancy for interoperability testing scenarios or operational needs may be considered and is required to be evaluated on a case-by-case basis. Operational and maintenance related performance characteristics may be affected. In general, functional redundancy for HV side DC busbar sections are not state-of-the-art and requires a case-by-case evaluation.

Neutral DC busbar sections and busbar redundancy

As a base case, the functional neutral DC busbar arrangement is considered a single DC busbar section. If an operational mode with parallel return or HV return is considered a double busbar arrangement in the neutral DC busbar can be considered. For the preliminary main circuit parameters parallel return and HV return are not considered.

DC Switching units

The DC switching stations include switching devices based on the respective system level requirements. Switching units that are marked blue provide fault current neutralization and suppression capabilities. Other switching equipment is foreseen based on connection modes and reconfiguration sequences. The capabilities and amount of switchgear in a switching unit varies and depends on the required system level functionality. In Figure 8-2 fault separation zones and fault clearing zones are distinguished. Switching units at the border of fault separation zones require fault separation functionality. Switching units with fault separation capability are shown in blue. Switching units at the borders of fault clearing zones provide fault clearing capability. The choice of devices and technology is left open to the DC switching station supplier.

8.1.6. Onshore converter stations

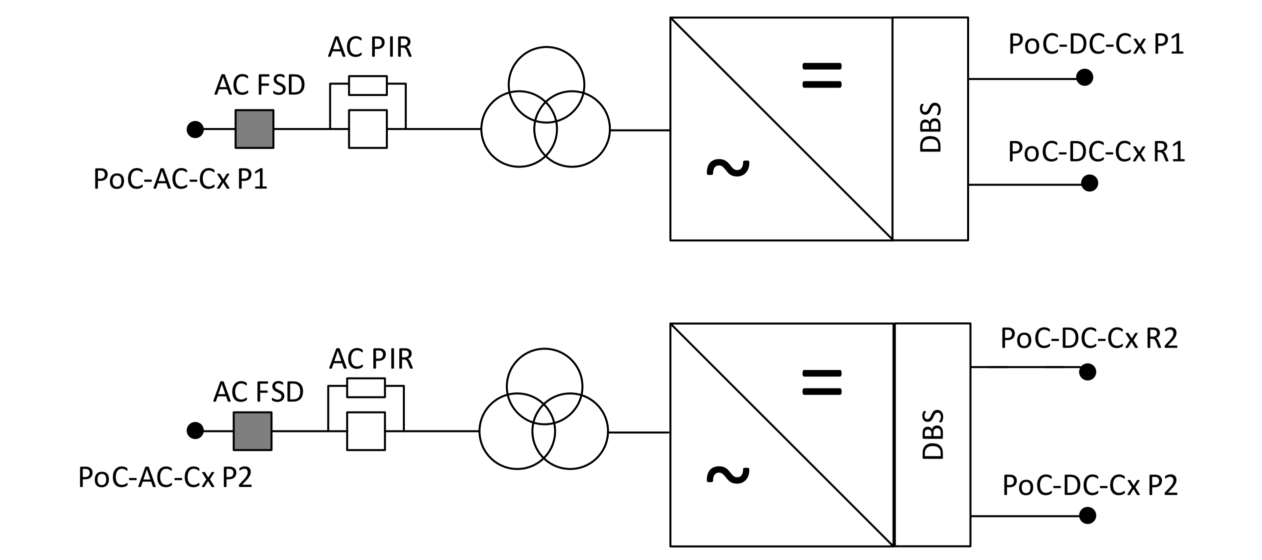
Schematic overview / functional Singe Line Diagram

According to the results of Task 2.1, a functional scope split into functional levels of a DC grid (converter units, transmission units, DC switching units) is considered. AC-FSDs and AC-PIRs are considered in the functional overview of the onshore converter station.

TABLE 8-24

Onshore converter station – functional overview

Onshore Converter Station Functional Overview	



AC-FSD	Yes
AC-PIR	Yes

Modes of operation - onshore station

Each individual converter station (independent from other converter stations) can operate in the following operation modes

- Mode 1: Bipole (BP) operation with DMR
- Mode 2: Bipole operation without DMR (Rigid Bipole)
- Mode 3 & 4: Asymmetrical Monopole (MP) operation with DMR
    - Initially a HV return or parallel return mode is not foreseen
- Mode 5: STATCOM Decoupled (with 1 or with 2 converter poles)

Note: The modes of operation are defined at a converter station level taking the topology of the converter station into account and the configuration of DC transmission lines.

Reconfiguration sequences between modes of operation - onshore converter station

In the following section, the possible online reconfiguration sequences are described. Further possible offline reconfiguration sequences are not further described here.

- Mode 1 -> Mode 2 (Bipole operation with DMR to Rigid bipole operation)
- Mode 2 -> Mode 1 (Rigid bipole operation to Bipole operation with DMR)

- Mode 1 -> Mode 3&4 (Bipole operation with DMR to Asymmetrical Monopole (MP) operation with DMR)
- Mode 3&4 -> Mode 1 (Asymmetrical Monopole with DMR to Bipole Operation with DMR)
- Mode 2 -> Mode 5 (Rigid Bipole to STATCOM Decoupled)
- Mode 3&4 -> Mode 5 (Asymmetrical Monopole with DMR to monopole STATCOM Decoupled)

Switching sequences – onshore converter station

Based on the system level behavior defined in section 8.1.1 the onshore converter station contains equipment for the following AC switching sequences:

- Fault clearing on the AC side of the converter utilizing AC-FSDs
- Energization of the onshore converter stations (and, if applicable, adjacent cable sections) utilizing the AC-PIRs

AC control modes – onshore converter station

The onshore converter stations are capable of applying grid forming control. A detailed description of concepts and parameters of grid forming control is based on the input provided by Task 2.4 including a given range of performance parameters.

Testing scenarios and procedures are not finally defined in T3.1. Tested functionalities shall be compliant to relevant control modes and immunity requirements as they appear in the NC HVDC. With regards to the grid forming functionality and how they shall be implemented the demonstrator, the recommendations of the D2.2. shall be followed. More specifically, the recommendation made in chapter 7 of the D2.2. The VDE-AR-N 4131:2019-03 as a national implementation of NC HVDC shall apply in the case that exhaustive parameters are needed.

Active power exchange requirements

The onshore HVDC converters are considered to be optimized for operation of the demonstrator and a modular approach is chosen in comparison to a fully integrated system approach. The active power transmission capability of the onshore HVDC converter is defined at the AC-PoC.

The required active power transmission capability of the onshore converter stations is stated in the following:

- 2000 MW power, measured as the sum of all active powers at the AC-PoC, when the onshore converter station is operated in bipole mode as rectifier, during multi-terminal operation within the continuous operating conditions.
- 1000 MW power, measured as the sum of all active powers at the AC-PoC, when the onshore converter station is operated in asymmetrical monopole mode as rectifier, during multi-terminal operation within the continuous operating conditions.
- Besides the power transmission requirement from offshore to onshore, the HVDC system shall enable full bi-directional power transmission up-to its rated transmission power capabilities, measured at PCC (AC-PoC), when its onshore HVDC converter(s) are operated as rectifier during the multi-terminal operation, within the continuous operating conditions.

Table 8-25 describes the active power rating requirements for the onshore converter stations.

TABLE 8-25

Onshore converter station / minimum rating requirement & rating headroom

	Unit	Value	Comment
Min. Power Transmission Requirement	GW	2.0	2 GW -> 2x 1.0 GW per Pole
Rating Requirement	GW	2.0	2 GW -> 2x 1.0 GW per Pole
Rating Headroom Rating Utilization Factor	-	0% 100%	(Rating – Min) / Rating Min / Rating

Reactive power exchange requirements

The required reactive power requirements at the AC-PoC are stated in Table 8-26 and are based on the AC voltage ranges defined in section 8.1.3. For the continuous AC voltage band (360 kV – 420 kV) a constant inductive and capacitive reactive power provision is assumed for the onshore converter stations.

TABLE 8-26

Reactive power requirements onshore

Mode of operation ↓	AC system voltage at PCC	Undervoltage conditions		Normal conditions	Overvoltage conditions	
	U_{PCC} (pu)	0.85	0.9	1	1.05	1.1
	U_{PCC} (kV)	340	360	400	420	440
Bipole	Q_{min} (MVAr)	-200	-800	-800	-800	-800
	Q_{max} (MVAr)	+700	700	+700	+700	+200
Rigid Bipole	Q_{min} (MVAr)	-200	-800	-800	-800	-800
	Q_{max} (MVAr)	+700	+700	+700	+700	+200
Asym. Monopole	Q_{min} (MVAr)	-100	-400	-400	-400	-400
	Q_{max} (MVAr)	+350	+350	+350	+350	+100

'+' (capacitive) indicates generation of reactive power. This is referred to as Q_{max}

'- '(inductive) indicates consumption of reactive power. This is referred to as Q_{min}.

Based on Table 8-26 the following QU characteristic for the onshore converters operated at rated active power (1 GW) is considered.

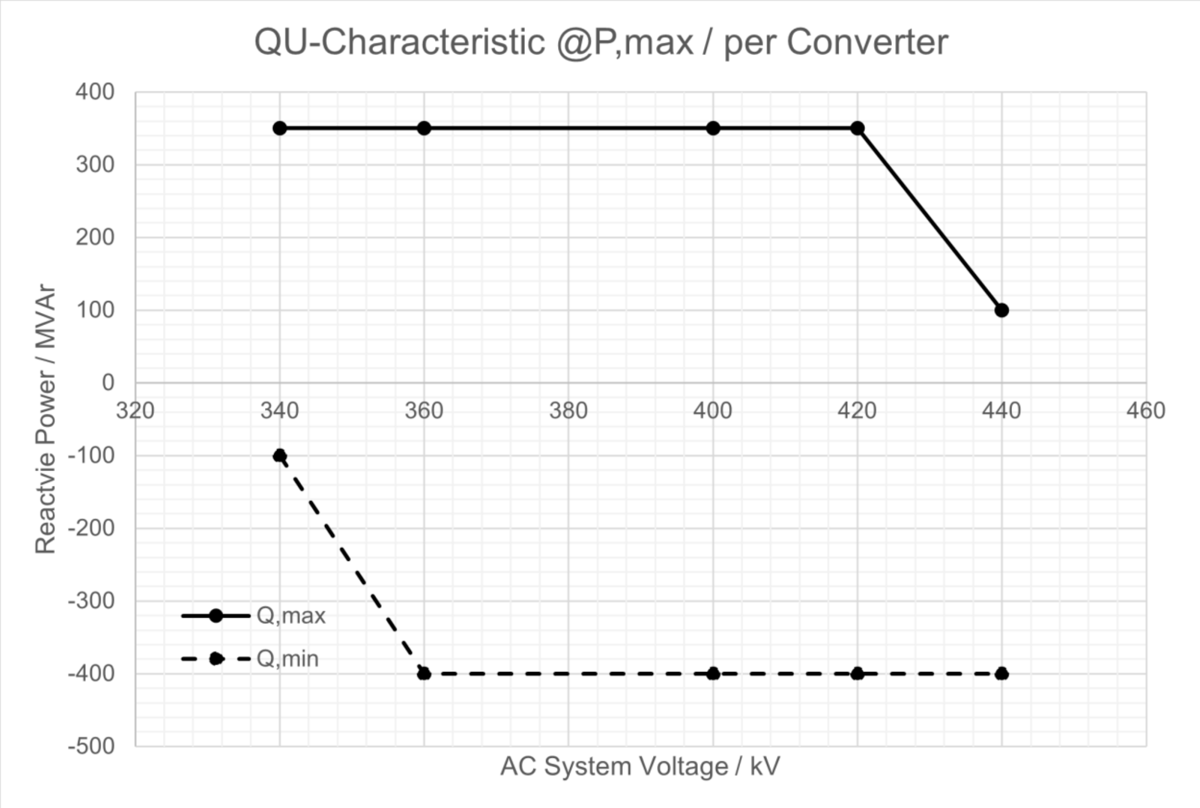


FIGURE 8-11

Onshore converter station – QU-characteristic at rated active power

PQ characteristics at AC-PoC

Based on the assumed active and reactive power requirements the following PQ Characteristic at the AC-PoC is considered for the onshore converters.

Figure 8-12 shows the PQ characteristic for the continuous steady state AC system voltage range 360 kV to 420 kV. In this voltage range the PQ characteristic is not restricted and the converter design shall consider full capacitive as well as full inductive reactive power while maintaining the required active power.

Figure 8-13 shows the PQ characteristic during AC system undervoltage condition of 340 kV (15% undervoltage). During this AC system voltage condition the converter design shall consider full capacitive reactive power while maintaining the required active power. The inductive reactive power output is not required fully during such grid conditions and is considered with reduced values accordingly.

Figure 8-14 shows the PQ characteristic during an AC system overvoltage condition of 72.6 kV (10% overvoltage). During this AC system voltage condition the converter design shall consider full inductive reactive power. The capacitive reactive power output is not required fully during such grid conditions and is considered with reduced values accordingly.

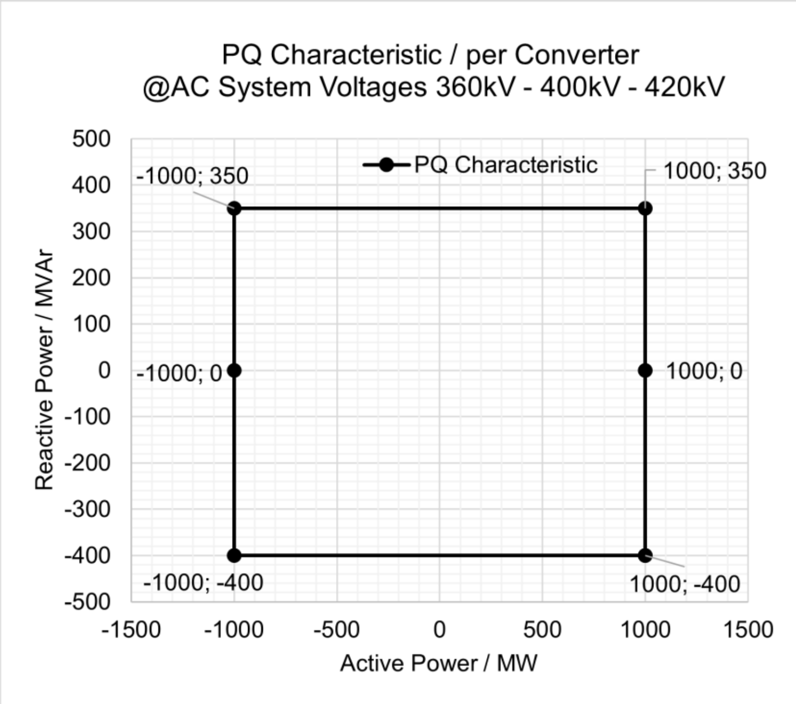


FIGURE 8-12

Operating data – PQ characteristic / per converter (onshore)

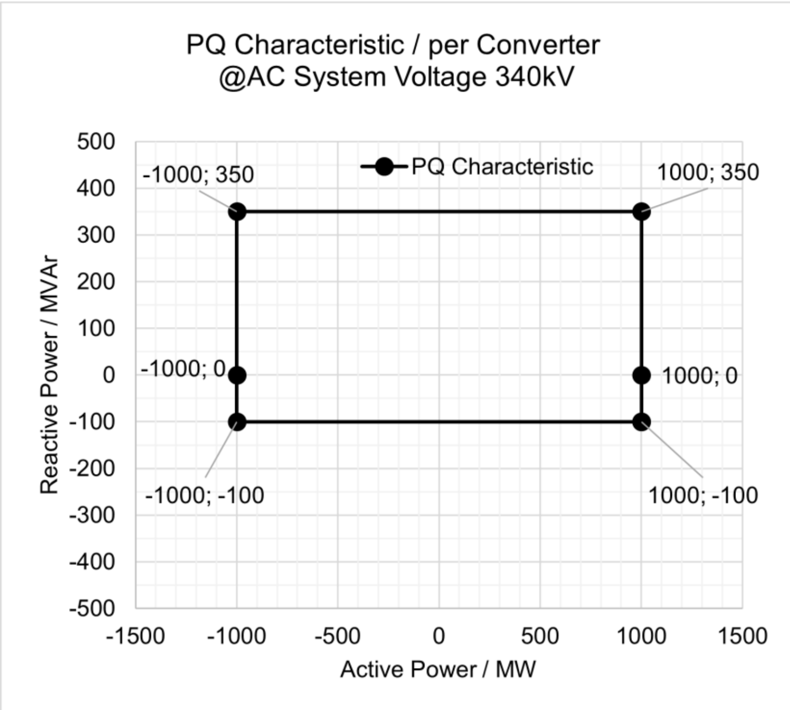


FIGURE 8-13

Operating data – PQ characteristic / per converter (onshore) for undervoltage conditions

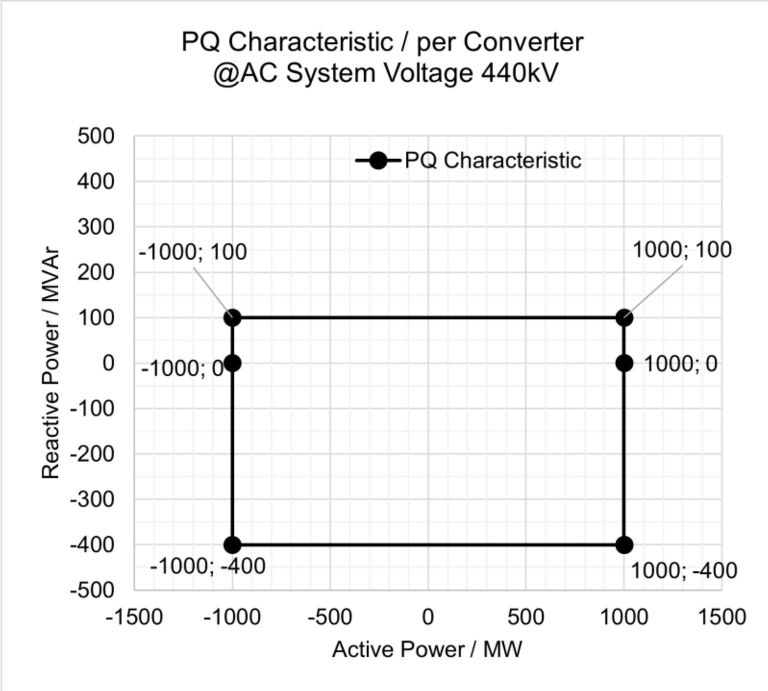


FIGURE 8-14

Operating data – PQ characteristic / per converter (onshore) for overvoltage conditions

Power exchange requirements at DC-PoC

Figure 8-15 shows the P-U_{DC} characteristic at the DC-PoC of an onshore converter unit. Within the defined stationary DC voltage conditions (based on the stationary analysis in section 8.2) the converter unit shall provide the required active power.

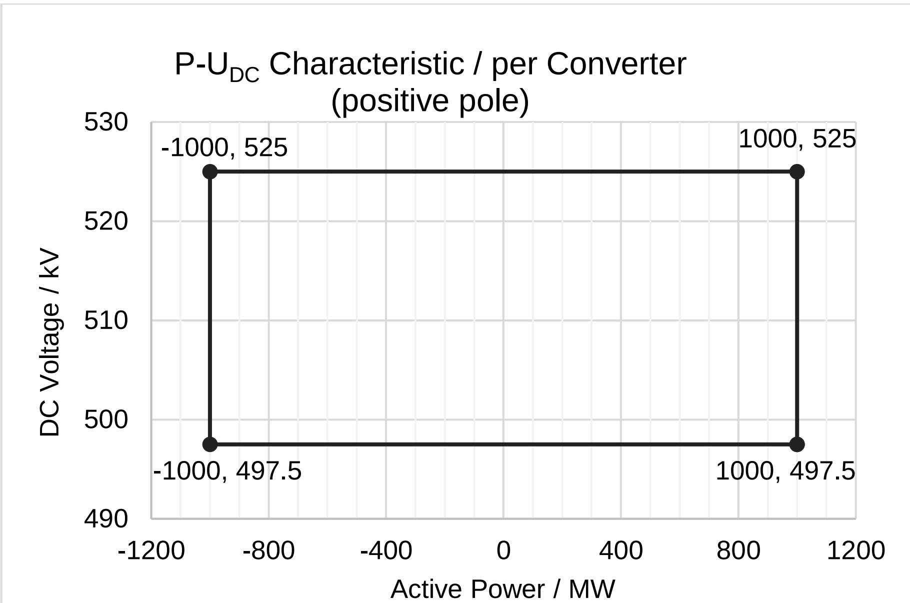


FIGURE 8-15

Operating data – P-U_{DC} characteristic / per converter (onshore) for the positive pole

Tap changer requirements

All onshore converter transformers are equipped with tap changers and the capabilities of the onshore converter are assumed to be designed accordingly. The converter side no-load voltage shall be designed accordingly to achieve the specified operating points with a robust modulation index to ensure dynamic performance criteria can be met reliably.

Preliminary DC voltage & current ranges

The following DC voltage and DC current ranges are preliminary values for the DC-PoC of the onshore converter stations. The bands are based on the results of the stationary, quasi-stationary and transient study package which provide a reasoning for the given values.

TABLE 8-27

DC voltage data (DC+, DC-) at the DC-PoC

	Unit	Value	Comment
Nominal operating DC voltage	kV_{DC}	±525	
Max. continuous stationary DC voltage	kV_{DC}	±525	Result of 8.2
Min. continuous stationary DC voltage	kV_{DC}	±497.5	Result of 8.2
Max. temporary voltage	kV_{DC}	±550	Result of 8.3
Min temporary voltage	kV_{DC}	±467	Result of 8.3
Max. transient voltage	kV_{DC}	±568	Result of 8.4

TABLE 8-28

DC current data (DC+, DC-) at the DC-PoC

	Unit	Value	Comment
Nominal operating DC current	kA_{DC}	±1.905	
Max. continuous stationary DC current	kA_{DC}	±2.0	Result of 8.2
Min continuous current	kA_{DC}	0.0	No load condition
Max. temporary DC current (peak)	kA_{DC}	±2.07	Result of 8.3
Min. temporary DC current (peak)	kA_{DC}	0.0	No load condition
Max. transient DC current (peak)	kA_{DC}	±19.05	Result of 8.4 DCSS#1, I_{OCC} = 7 kA
Min. transient DC current (peak)	kA_{DC}	0.0	No load condition

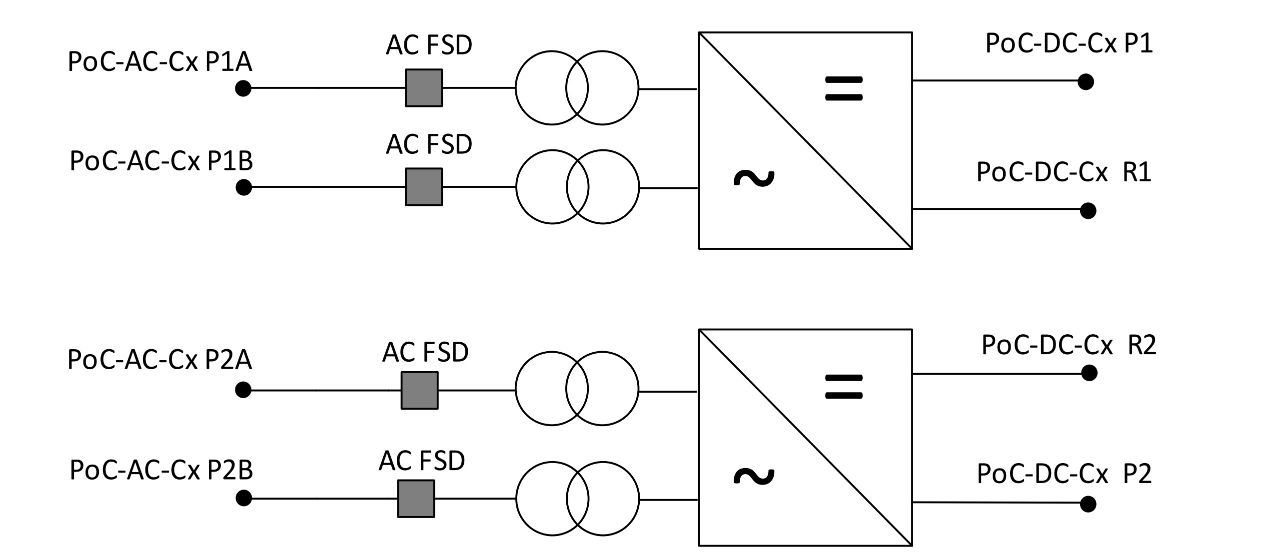
8.1.7. Offshore converter stations

Schematic overview / functional Single Line Diagram

According to the results of Task 2.1, a functional scope split into functional levels of a DC grid (converter units, transmission units, DC switching units). Based on this, Table 8-29 gives a functional overview of the offshore converter stations with the respective point of connections on the DC side. Only AC-fault separation devices are considered in the functional overview.

TABLE 8-29

Offshore converter station – functional overview

<table>
<tr><th colspan="2">Offshore Converter Station
Functional Overview</th></tr>
<tr><td colspan="2">


</td></tr>
<tr><td>AC-FSD</td><td>Yes</td></tr>
</table>

Modes of operation – offshore station

Each individual offshore converter station can operate in the following operation modes

- Mode 1: Bipole (BP) operation with DMR
- Mode 2: Bipole operation without DMR (Rigid Bipole)
- Mode 3 & 4: Asymmetrical Monopole (MP) operation with DMR
    - Initially a HV return or parallel return mode is not foreseen

Note: The modes of operation are defined at a converter station level considering the topology of the converter station and the configuration of the DC lines.

Reconfiguration sequences between modes of operation - offshore station

In the following section, the possible online reconfiguration sequences are described. Further possible offline reconfiguration sequences are not further described here.

- Mode 1 -> Mode 2 (Bipole operation with DMR to Rigid bipole operation)
- Mode 2 -> Mode 1 (Rigid bipole operation to Bipole operation with DMR)
- Mode 1 -> Mode 3&4 (Bipole operation with DMR to Asymmetrical Monopole (MP) operation with DMR)
- Mode 3&4 -> Mode 1 (Asymmetrical Monopole with DMR to Bipole Operation with DMR)

Switching sequences – offshore converter station

Based on the functional overview depicted in Table 8-29 the following functionalities on AC switching sequences are enabled:

- Fault clearing on the AC-side using AC-FSDs

AC control modes of the offshore converter station

Testing scenarios and procedures are not finally defined in T3.1. Tested functionalities shall be compliant to relevant control modes and immunity requirements as they appear in the NC HVDC. With regards to the grid forming functionality and how they shall be implemented in the demonstrator, the recommendations of the D2.2. could be followed. More specifically, the recommendation made in chapter 7 of the D2.2. In the preliminary studies in this document the offshore converter stations are operated in a constant active power mode since grid forming PPMs were not considered.

Active power exchange requirements

The offshore HVDC converters are considered to be optimized for the desired offshore wind power generation capacity. That's why the active power transmission capability of the offshore HVDC converter is defined at the AC-PoC during rectifier operation.

The required active power transmission capability of the offshore converter station is stated in the following:

- 2000 MW power, measured as the sum of all active powers at the AC-PoC, when the offshore converter station is operated in bipole mode as rectifier, during the multi-terminal operation within the continuous operating conditions.
- 1000 MW power measured as the sum of all active powers at the AC-PoC, when the offshore converter station is operated in asymmetrical monopole mode as rectifier, during the DC-Hub/ multi-terminal operation within the continuous operating conditions.

Table 8-30 depicts the active power rating requirements for the offshore converter stations.

TABLE 8-30

Offshore converter station / min rating requirement & rating headroom

	Unit	Value	Comment
Min. Power Transmission Requirement	GW	2.0	2 GW -> 2x 1.0 GW per Pole
Rating Requirement	GW	2.0	2 GW -> 2x 1.0 GW per Pole
Rating Headroom Rating Utilization Factor	-	0% 100%	(Rating – Min) / Rating Min / Rating

Reactive power exchange requirements

The required reactive power requirements at the AC-PoC are stated Table 8-31 and is based on the AC voltage ranges defined in section 7. For the continuous AC voltage band (119 kV – 145 kV) a constant inductive and capacitive reactive power provision is assumed for the offshore converter stations.

TABLE 8-31

Reactive power requirements offshore

Mode of Operation ↓	AC System Voltage at PCC	Undervoltage Conditions		Nominal Condition	Overvoltage Conditions	
	U_{PCC} (pu)	0.85	0.90	1.00	1.10	1.15
	U_{PCC} (kV)	112	119	132	145	152
Bipole	Q_{min} (MVAr)	0	-280	-280	-280	-280
	Q_{max} (MVAr)	+280	+280	+280	+280	0
Rigid Bipole	Q_{min} (MVAr)	0	-280	-280	-280	-280
	Q_{max} (MVAr)	+280	+280	+280	+280	0
Asym. Monopole	Q_{min} (MVAr)	0	-140	-140	-140	-140
	Q_{max} (MVAr)	+140	+140	+140	+140	0

'+' (capacitive) indicates generation of reactive power. This is referred to as Q_{max}

'-' (inductive) indicates consumption of reactive power. This is referred to as Q_{min}.

Based on Table 8-31, the following QU characteristic for the offshore converters operated at rated active power (1 GW) is considered.

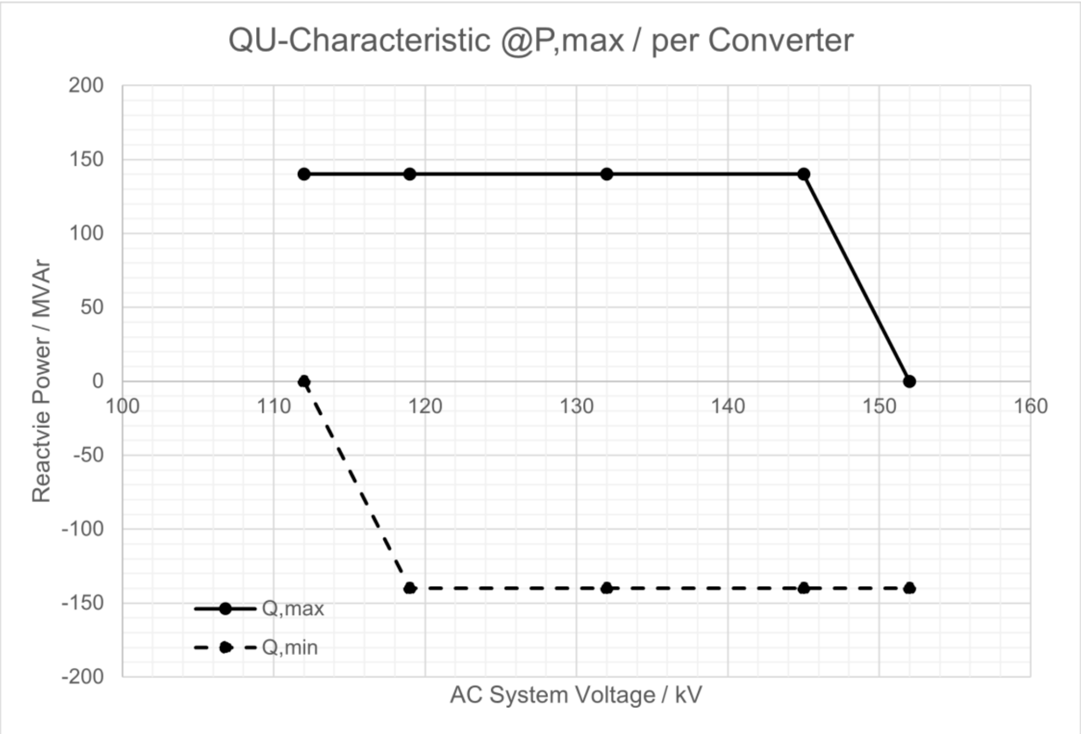


FIGURE 8-16

Offshore converter station – QU-characteristic at rated active power

PQ characteristics at AC-PoC

Based on the assumed active and reactive power requirements the following PQ Characteristic at the AC-PoC is considered for the offshore converters.

Figure 8-17 shows the PQ characteristic for the normal steady state AC system voltage range 119 kV – 145 kV. In this voltage range the PQ characteristic is not restricted and the converter design shall consider full capacitive as well as full inductive reactive power while maintaining the required active power.

Figure 8-18 shows the PQ characteristic during an AC system undervoltage condition of 112 kV (15% undervoltage). During this AC system voltage condition, the converter design shall consider full capacitive reactive power. The inductive reactive power output is not required during such grid conditions and is reduced to 0 MVAr.

Figure 8-19 shows the PQ characteristic during an AC system overvoltage condition of 152 kV (15% overvoltage). During this AC system voltage condition the converter design shall consider full inductive reactive power. The capacitive reactive power output is not required during such grid conditions and is reduced to 0 MVAr.

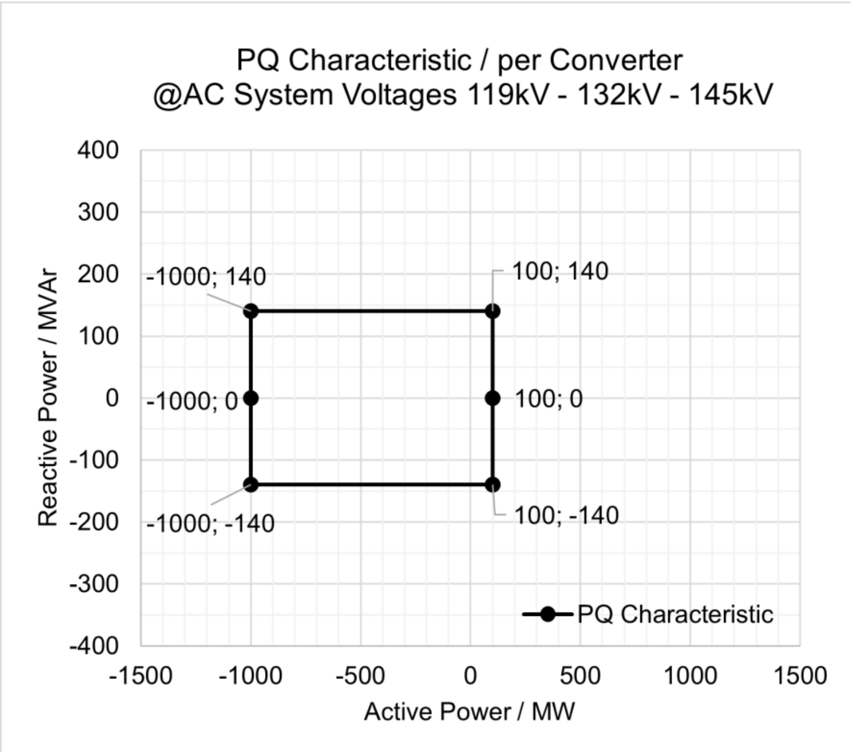


FIGURE 8-17

Operating data – PQ characteristic / per converter (offshore)

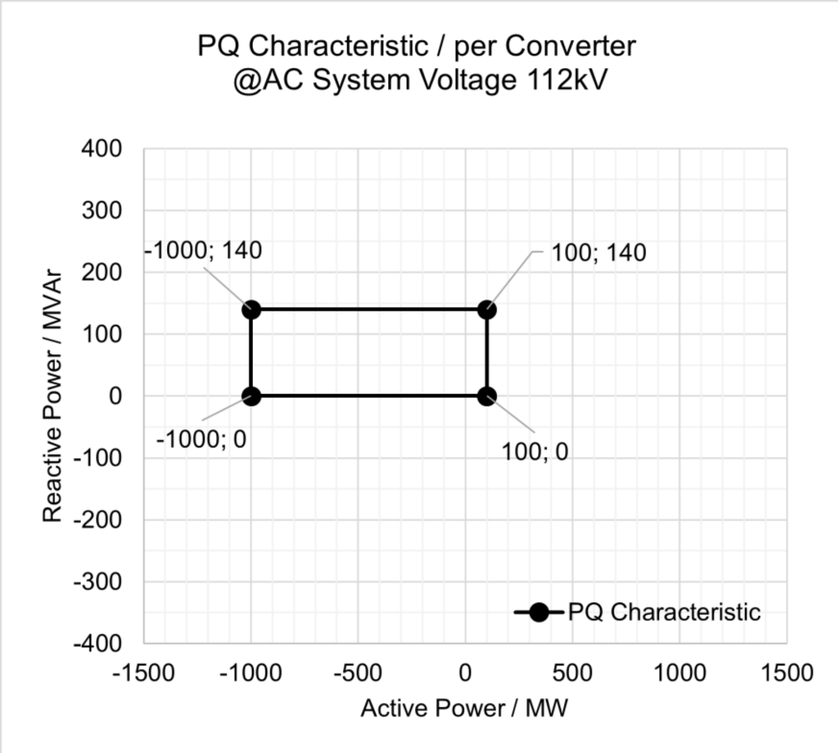


FIGURE 8-18

Operating data – PQ characteristic / per converter (offshore) for undervoltage conditions

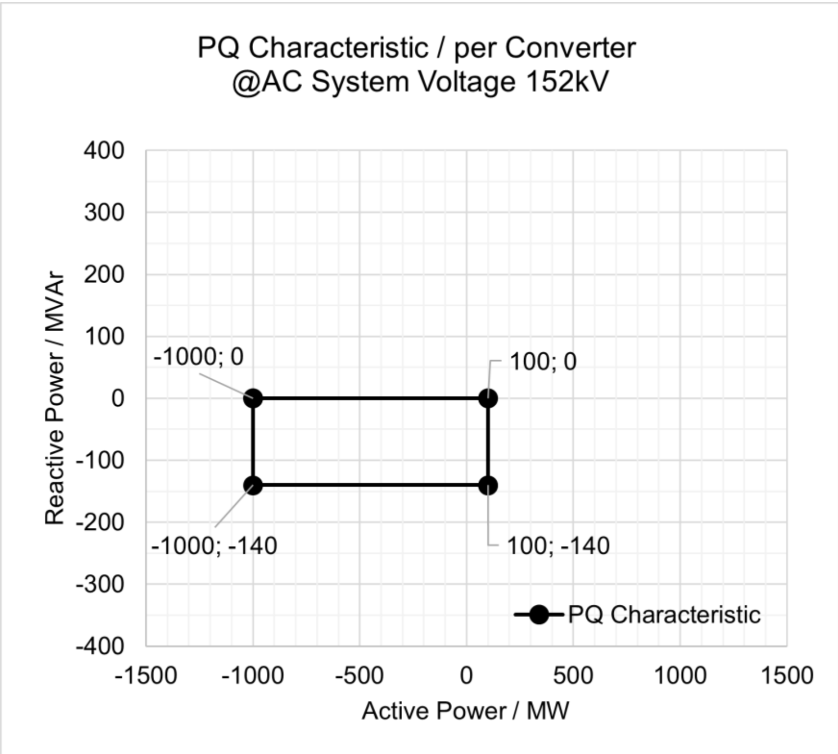


FIGURE 8-19

Operating data – PQ characteristic / per converter (offshore) for overvoltage conditions

Power exchange requirements at DC-PoC

Figure 8-20Figure 8-15 shows the P-U_{DC} characteristic at the DC-PoC of an offshore converter unit. Within the defined stationary DC voltage conditions (based on the stationary analysis in section 8.2) the converter unit shall provide the required active power.

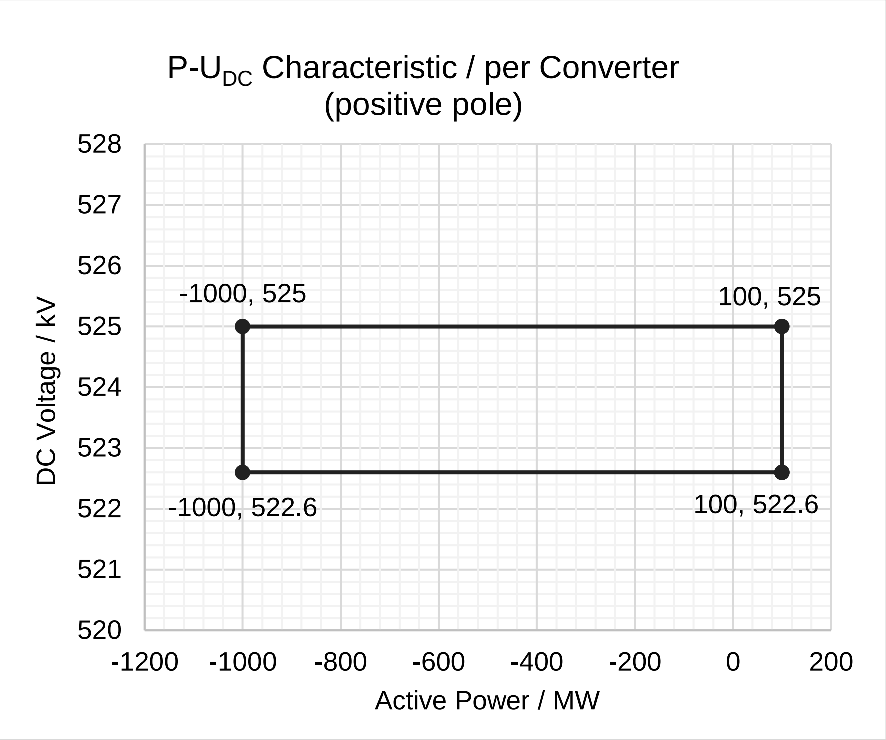


FIGURE 8-20

Operating data – P-U_{DC} characteristic / per converter (offshore) for the positive pole

Tap changer requirements

All offshore converter transformers and the capabilities of the offshore converters shall preferably be designed without tap changers. The converter side no-load voltage shall be designed accordingly to achieve the specified operating points with a robust modulation index.

Preliminary DC Voltage & Current Ranges

The following DC voltage and DC current ranges are preliminary values for the DC-PoC of the offshore converter stations. The bands are based on the results of the stationary, quasi-stationary and transient study package which provide a reasoning for the given values.

TABLE 8-32

DC voltage data (DC+, DC-) at the DC-PoC

	Unit	Value	Comment
Nominal operating DC voltage	kV_{DC}	±525	
Max. continuous stationary DC voltage	kV_{DC}	±525	Result of 8.2
Min. continuous stationary DC voltage	kV_{DC}	±522.6	Result of 8.2
Max. temporary voltage	kV_{DC}	±557	Result of 8.3
Min temporary voltage	kV_{DC}	±470	Result of 8.3
Max. transient voltage	kV_{DC}	±777	Result of 8.4

TABLE 8-33

DC current data (DC+, DC-) at the DC-PoC

	Unit	Value	Comment
Nominal operating DC current	kA_{DC}	±1.905	
Max. continuous stationary DC current	kA_{DC}	±2.0	Result of 8.2
Min continuous current	kA_{DC}	0.0	No load condition
Max. temporary DC current (peak)	kA_{DC}	±1.91	Result of 8.3
Min. temporary DC current (peak)	kA_{DC}	0.0	No load condition
Max. transient DC current (peak)	kA_{DC}	±18.22	Result of 8.4 DCSS#1, I_{OCC} = 7 kA
Min. transient DC current (peak)	kA_{DC}	0.0	No load condition

8.2. Stationary analysis

Chapter 8.2 describes the stationary analysis that is used to determine the steady-state (= stationary) DC voltage and DC current bands for the offshore and onshore converter stations of the InterOPERA demonstrator. Modelling assumptions for the HVDC grid and study scenarios are discussed in section 8.2.1. In section 8.2.2 and 8.2.3 the main results and conclusions of the study package are summarized respectively.

8.2.1. Methodical approach

To perform the stationary analysis, a simulation model in DIgSILENT PowerFactory 2022 [10] is used. The following chapter describes the assumptions made and the investigated study scenarios.

Simulation model description

Figure 8-21 shows the structure of the developed grid model. The figure includes information on the grid topology, which consists of offshore converter stations, onshore converter stations and (standalone) DC switching stations, as well as adjacent AC grids. The purpose of this study package is to determine the design relevant rated values of DC voltages and DC currents for assuming the maximum active power injection at the offshore converter stations leading to the highest voltage drops. Two topological distinctions are made to determine the design relevant rated values in the event of a system split due to a contingency:

- **V-FT:** Full network topology with maximum active power injection
- **V-P2P:** Point-to-point (P2P) link with maximum voltage drop (onshore / offshore)

These topologies allow the worst-case load flow situation to be identified for the full topology in normal operation, as well as the study of the worst possible point-to-point link after a system split at DCSS#5.

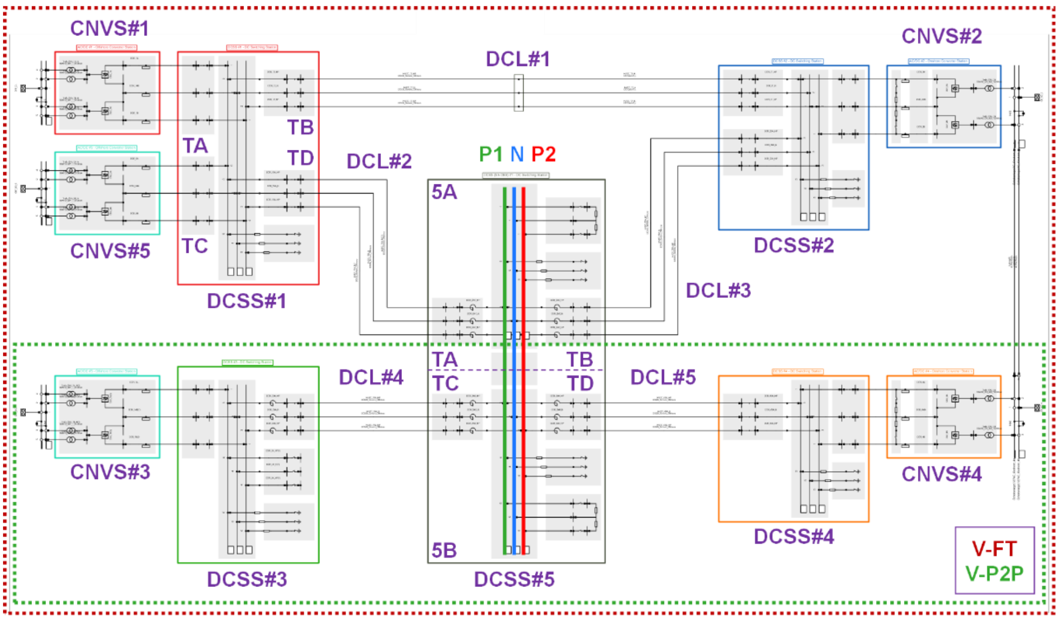


FIGURE 8-21

Network topology considering DC transmission lines (DCL), DC switching stations (DCSS) onshore and offshore converter stations (CNVS) and the two study cases (V-FT, V-P2P)

An enlarged version of Figure 8-21 can be found in the appendix.

Input parameters

Typical assumptions are made for the modelling of the DC transmission lines. The lengths of the corresponding onshore and offshore sections from Table 8-8 are multiplied with the assumptions on the resistance per unit length of onshore transmission lines (see Table 8-10) and offshore transmission lines (see Table 8-11). The resulting resistances are shown in Table 8-34 and used to derive the admittance matrix of the grid topology. Based on this and the assumptions on the active power injection at the offshore switching stations, the distribution of DC currents in the network and DC voltages at the DC switching stations can be calculated. In addition, the losses of the converter stations and the losses of the DC fault separation devices are integrated in the admittance matrix Table 8-34.

TABLE 8-34

Input parameters – DC line resistances

	Unit	Value	Comment
Resistance of DC Line #1	Ω	2.86	Offshore and onshore section
Resistance of DC Line #2	Ω	2.5	Offshore DC line #2 and onshore DC line #3 1:1 current sharing with DC line #1 (R_{Σ} = 2.86)
Resistance of DC Line #3	Ω	0.36	
Resistance of DC Line #4	Ω	2.5	Offshore connection to standalone DCSS
Resistance of DC Line #5	Ω	5.36	Onshore connection to standalone DCSS (long spoke)

The converter station losses are defined in the simulation model as a constant loss of 1% referred to the nominal active power. This assumption is independent of the injected active power, which represents the worst-case conditions.

The DC fault separation device (DC-FSD) losses are conservatively assumed to be 0.667% of the nominal active power. This is used to calculate the equivalent resistance according to Table 8-34. The resulting resistances are integrated into the admittance matrix according to the positions shown in Figure 8-21. It should be noted that the DC-FSD losses considered are chosen to provide sufficient headroom for the definition of the minimum stationary DC voltage. The assumption also accounts for the losses of other components, such as the reactor resistance of the DC-FSD and the switchgear. Current DC-FSD technologies are expected to have much lower losses, as discussed below:

- **For hybrid FSDs with power electronics** in the main branch, the IGBTs dissipate approximately 4.5 V at a rated current of 2 kA. This gives 4.5 V x 2000 A = 9 kW for a stack of IGBTs. Assuming up to 3 stacks in series, the total loss would be approximately 30 kW.
- **For DC-FSDs without power electronics** in the main branch and assuming 'natural air' cooling, the losses must be less than 200 W per vacuum interrupter (50 µOhm x 2000 A²). Scaling this up to a nominal voltage of 525 kV would result in approximately 20 modules in series, giving a total loss of 4 kW per DC-FSD.

TABLE 8-35

Input parameter – Full-load losses of grid objects 2 GW

	Unit	Value	Comment
Converter station	%	1	$P_{Loss,CNV}$ = 1.0 GW x 1 % → 10 MW per pole.
DC-FSD	%	0.667	$P_{Loss,DCCB}$ = 1.0 GW x 0.667 % → 6.67 MW per pole. Active power losses related to a rated current of 1.905 kA result in a resistance with a value of 1.837 Ω per pole.

Study case description

The assumptions regarding the load flow situations (LFS) of the study cases can be found in Table 8-36. For the full topology (V-FT), the active power injection at the offshore converter stations varies according to four different load flow situations (LFS1-4). These load flow situations represent the limits at which the maximum active power transfer through the DC network is reached. To avoid exceeding the permissible ratings for the onshore converter stations (CNVS#2, CNVS#4), voltage set points are identified to achieve an even distribution of the active power injection of 2 GW per converter station. In addition, the maximum continuous DC voltage at the DC switching stations is set at 525 kV, which represents the nominal DC voltage. Given this limit, the minimum voltage band in the network can be defined based on the load flow results. Regarding the upper voltage band, we do not operate the system above the nominal conditions. For higher voltages, the relevant cable ratings must be considered (see Table 8-9). The load flow situations represent a step change in active power injection from 4 GW down to 2 GW at DCSS#1. The active power injection at DCSS#3 follows inversely from 0 GW to 2 GW. In addition to this, an even distribution of the injected active power of 1.33 GW between the offshore converter stations is investigated.

For the point-to-point link (V-P2P), the maximum active power transfer of 2 GW is assumed. This corresponds to the permissible ratings of the converter stations and leads to the maximum expected current through the HVDC link. Due to the long distance and the high resistance of the transmission line, the maximum voltage drop can be expected. The voltage setpoint at the onshore converter station CNVS#4 is defined to operate the offshore DC switching station DCSS#3 at nominal voltage.

For both study cases, different influencing factors are considered. On the one hand, the operating modes of the converter stations, as discussed in section 8.1, make it possible to assess symmetrical and asymmetrical operating conditions. A distinction is made between

- BP – Bipole with DMR
- MP – Asymmetrical monopole

It also discusses the choice of grounding location as defined in the paragraph DC **system** section 7. This allows the neutral voltage band to be assessed. A distinction is made between:

- CE – Earthing at central switching station DCSS#5
- OE – Earthing at long spoke onshore switching station DCSS#4

TABLE 8-36

Description of the load flow situations (LFS) defining the active power injection at the offshore converter stations to assess the full topology (V-FT) and the point-to-point link (V-P2P)

	Description	Operating conditions
V-FT	Determine the design ratings for the full topology.	Active power injection at the offshore converter stations to represent different load flow situations (LFS): PCNVS#1/5 PCNVS#3 LFS1: 4 GW 0 GW LFS2: 3 GW 1 GW LFS3: 2.66 GW 1.33 GW LFS4: 2 GW 2 GW Onshore converter station voltage setpoints for 2 GW injection for each AC connection point ($P_{CNVS\#2/4}$).
V-P2P	Determine the P2P link design ratings will result in the maximum voltage drop.	Active power injection at the offshore converter station of 2 GW ($P_{CNVS\#3}$ = 2 GW). Onshore converter station voltage setpoints for rated voltage at offshore converter station ($V_{DCSS\#3}$ = 1 pu).

8.2.2. Steady state voltage and current bands

The results of the load flow calculations for the previous defined study cases are discussed below. The discussion serves as a basis to better understand the system behavior and to derive the preliminary main circuit parameters, which are presented in chapter 8.

V-FT: Full Demonstrator Topology

First, load flow calculations are carried out for the load flow situations (LFS) listed in Table 8-36. Figure 8-22 shows the resulting voltage distribution at the DC switching stations (DCSS), as well as the distribution of currents through the DC transmission lines (DCL). For each load flow situation, the corresponding voltage set points of the onshore converter stations (VSP) are also given. These result in an even distribution of the active power injection at the AC coupling points and prevent the offshore converter stations from operating above the nominal voltage of 525 kV.

The results show that for all load flow situations, the lowest voltage occurs at DCSS#4 due to the voltage drop along the long-distance DC transmission line. In general, a higher active power injection at DCSS#1 up to 4GW lowers the overall voltage level in the system. This is due to the increased utilization of the transmission lines and the fault separation devices, resulting in increased losses and a higher voltage drop. Since the active power injection at DCSS#3 cannot increase above 2 GW, there is less of an impact. When the injected active power at DCSS#1 and DCSS#3 is 2 GW each, there is no active power exchange through DCSS#5. LFS1 results in a minimum voltage of 497.5 kV at DCSS#4 with an active power injection of 4 GW at the offshore converter stations CNVS#1 and CNVS#5.

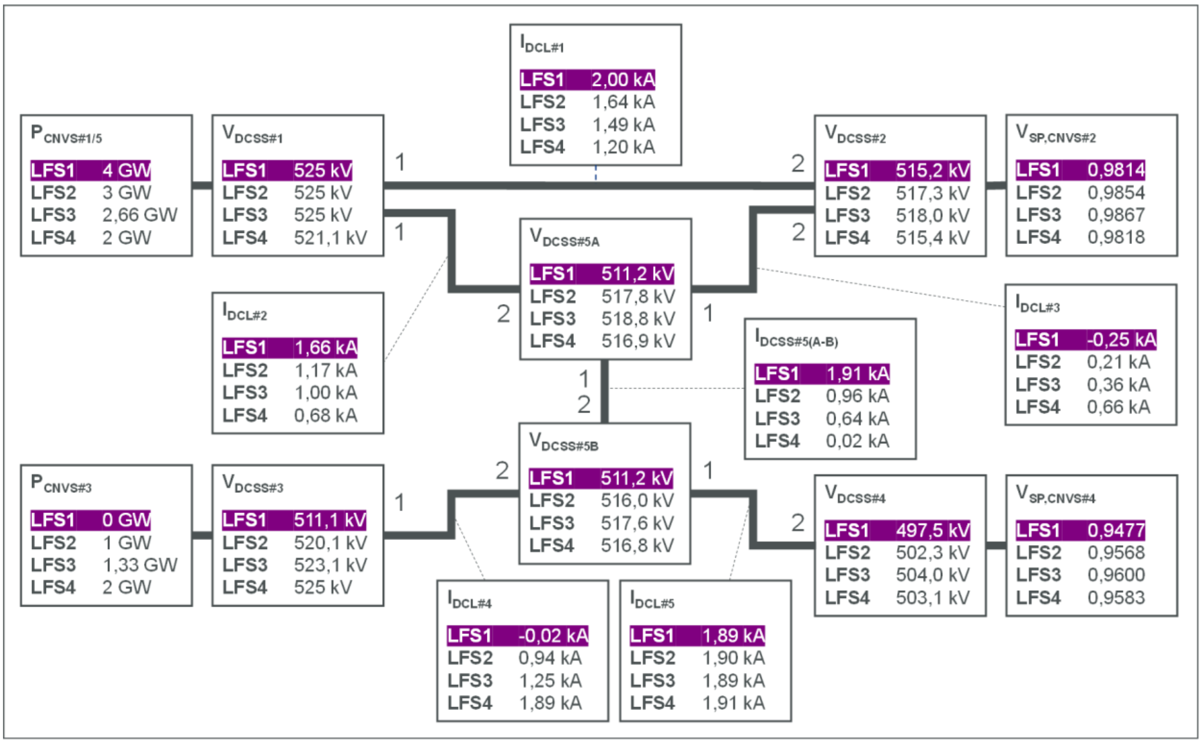


FIGURE 8-22

Load flow results ($V_{DCSS\#1/2/3/4/5}$, $I_{DCL\#1/2/3/4/5}$, $V_{SP,CNVS\#2/4}$) of different load flow situations (LFS1-4) according to Table 8-21 to identify the stationary voltage and current bands

LFS1 is used for the stationary analysis. The following tables show the voltage set points of the onshore converter stations (CNVS#2, CNVS#4) and the resulting voltages at the offshore converter stations (CNVS#1, CNVS#3, CNVS#5). Table 8-37 shows the results for the assumption of a central earthing (CE) at DCSS#5 and Table 8-38 for the assumption of an onshore earthing (OE) at DCSS#4. Also included are the set points for the injected active power at the offshore converter stations ($P_{SP,CNVS\#1/3/5}$). The active power injected into the AC system at the receiving ends of the onshore converter stations ($P_{SP,CNVS\#2/4}$) is also shown, which becomes reduced by the transmission line and FSD losses. All results are given for both operating modes of converters. The symmetrical pole values are shown for bipolar operation and the pole and DMR values are shown for monopolar operation.

As the considered load flow situation assumes that only DCSS#1 is in-service, the corresponding terminal voltage is used for the voltage control. With the constraint of an even distribution of the active power injection at the AC connection points, it is not possible to maintain a voltage of 525 kV at DCSS#3, which operates at a lower value. Due to the long distance of DCL#5, a lower voltage setpoint is required at CNVS#4 to transfer active power from DCSS#5 to DCSS#4. As the distance of DCL#3 is much shorter, the influence of CNVS#2 on the overall voltage level in the DC system is much higher.

Table 8-39 shows the resulting voltage bands at the DC switching stations (DCSS) for central earthing (CE) at DCSS#5. From this, the lowest DC voltage of 497.5 kV can be found at DCSS#4 for asymmetric monopole (MP) operation. The maximum voltage drop between DCSS#1 and DCSS#4 is 27.5 kV (5.2 %). This value refers to the design rating that is taken for the preliminary main circuit parameters (see Table 8-27). Table 8-39 shows the voltage bands in the case of onshore earthing (OE) at DCSS#4, which leads to the same minimum value of the DC voltage. Regarding the asymmetric monopole operation, the neutral voltages are higher in the case of onshore earthing (OE) up to 26.3 kV, compared with a value of 13.5 kV in the case of central earthing (CE).

TABLE 8-37

Converter station voltage setpoints (V_{SP}) in per unit and active power injection (P_{SP}) in GW. Considering bipole (BP) and monopole (MP) operation and central earthing (CE) at DCSS#5 for LFS1

		V_{SP}		P_{SP}	
Operating mode		BP (± Pole)	MP (Pole / DMR)	BP (± Pole)	MP (Pole / DMR)
Offshore	CNVS#1	1.007	1.006 / -0.03	2.00	1.00 / 0.00
	CNVS#3	0.974	0.974 / 0.00	0.00	0.00 / 0.00
	CNVS#5	1.007	1.006 / -0.03	2.00	1.00 / 0.00
Onshore	CNVS#2	0.9814	0.9896 / -0.01	1.87	0.90 / -0.007
	CNVS#4	0.9477	0.9233 / 0.03	1.87	0.92 / 0.002

TABLE 8-38

Converter station voltage setpoints (V_{SP}) per unit and active power injection (P_{SP}) in GW. Considering bipole (BP) and monopole (MP) operation and onshore earthing (OE) at DCSS#4 for LFS1

		V_{SP}		P_{SP}	
Operating mode		BP (± Pole)	MP (Pole / DMR)	BP (± Pole)	MP (Pole / DMR)
Offshore	CNVS#1	1.007	1.006 / -0.06	2.00	1.00 / 0.00
	CNVS#3	0.974	0.975 / -0.06	0.00	0.00 / 0.00
	CNVS#5	1.007	1.006 / -0.02	2.00	1.00 / 0.00
Onshore	CNVS#2	0.9814	1.015 / -0.03	1.87	0.88 / -0.003
	CNVS#4	0.9477	0.950 / 0.00	1.87	0.91 / 0.00

TABLE 8-39

DC voltages in kV_{DC} for bipole operation with DMR (BP) and asymmetric monopole operation (MP) for central earthing (CE) at DCSS#5 and onshore earthing (OE) at DCSS#4. Voltages referred to pole voltage and DMR voltage ($V_{DCSS,\ BP}$) and asymmetric monopole operation ($V_{DCSS,\ MP}$)

	DCSS#1		DCSS#2		DCSS#3		DCSS#4		DCSS#5	
	± Pole	DMR	± Pole	DMR	± Pole	DMR	± Pole	DMR	± Pole A ± Pole B	DMR
$V_{BP,CE}$	525	0	515.2	0	511.1	0	497.5	0	514.7 511.2	0 0
$V_{MP,CE}$	525	-13.5	515.5	-4.0	511.4	0.1	498.1	13.4	515.0 511.5	-0.01 0
$V_{BP,OE}$	525	0	515.2	0	511.1	0	497.5	0	514.7 511.2	0 0
$V_{MP,OE}$	525	-26.3	515.8	-17.1	511.8	-13.0	498.7	0.00	515.2 511.9	-16.5 -13.1

Table 8-40 shows the resulting currents through the DC lines (DCL) for the assumption of a central earthing location (CE) and Table 8-41 for an onshore earthing location (OE). All results are given for both operating modes of the converter stations, defined as bipole with DMR (BP) and asymmetric monopole (MP). The lowest DC current of 0.02 kA can be found for DCL#4 because the offshore converter station CNVS#3 does not show any injection of active power for the considered load flow situation (LFS1). The considered value for the preliminary main circuit parameters is assumed to be zero (see Table 8-28 and Table 8-33). The second lowest value can be found for DCL#3 with a value of 0.25 kA. The maximum value of the DC current is 2.00 kA through DCL#1, which is according to the cable rating and considered to define the current band of the preliminary main circuit parameters. The distribution of currents through the remaining DC lines depends on the admittance matrix and leads to around 1.90 kA of current injection to the onshore converter stations CNVS#2 and CNVS#4.

TABLE 8-40

DC currents in kA considering bipole operation (BP) and monopole operation (MP), as well as central earthing (CE) at DCSS#5 and onshore earthing (OE) at DCSS#4 for LFS1

	DCL#1		DCL#2		DCL#3		DCL#4		DCL#5	
	± Pole	DMR	± Pole	DMR	± Pole	DMR	± Pole	DMR	± Pole	DMR
$I_{BP,CE}$	2.00	0	1.66	0	-0.25	0	-0.02	0	1.90	0
$I_{MP,CE}$	2.00	-2.00	1.62	-1.62	-0.26	+0.26	-0.02	0.02	1.86	-1.86
$I_{BP,OE}$	2.00	0	1.66	0	-0.25	0	0.02	0	1.90	0
$I_{MP,OE}$	1.96	-1.96	1.58	-1.58	-0.26	0.26	-0.02	0.02	1.82	-1.82

Table 8-41 shows the losses of the DC transmission lines (DCL) and

Table 8-42 shows the losses of the converter stations (CNVS). In Table 8-43 the corresponding results for the DC fault separation devices (DC-FSD) at the DC switching stations (DCSS) are given. A distinction is made between the four terminals (TA, TB, TC, TD), according to the locations as indicated in Figure 8-21. Regarding the DC lines, the losses become higher with a longer distance and a higher utilization. However, the long distance of DCL#5 leads to the maximum loss of 19.35 MW in the case of bipolar operation and central earthing (CE), even though the current is a little lower than for DCL#1 with a loss of 11.44 MW. The converter losses depend on the active power injection with a maximum value of 10 MW in the case of the rated active power of 1 GW per pole, which is half of the maximum loss through the DC transmission lines. About FSD the losses are between the transmission lines and converters with a maximum value of 7.35 MW at DCSS#1 for terminal A, which connects DCL#2.

TABLE 8-41

DC transmission line (DCL) losses in MW considering bipole operation (BP) and monopole operation (MP), as well as central earthing (CE) at DCSS#5 and onshore earthing (OE) at DCSS#4 for LFS1

	DCL#1		DCL#2		DCL#3		DCL#4		DCL#5	
	± Pole	DMR	± Pole	DMR	± Pole	DMR	± Pole	DMR	± Pole	DMR
$P_{L,BP,CE}$	11.44	0	6.89	0	0.02	0	0	0	19.35	0
$P_{L,MP,CE}$	11.44	11.44	6.56	-6.56	0.02	-0.02	0	0	18.54	-18.54
$P_{L,BP,OE}$	11.44	0	6.89	0	0.02	0	0	0	19.35	0
$P_{L,MP,OE}$	10.99	-10.99	6.24	-6.24	0.02	-0.02	0	0	17.75	-17.75

TABLE 8-42

Converter station (CNVS) losses in MW considering bipole operation (BP) and monopole operation (MP), as well as central earthing (CE) at DCSS#5 and onshore earthing (OE) at DCSS#4 for LFS1

	CNVS#1	CNVS#2	CNVS#3	CNVS#4	CNVS#5
	± Pole	± Pole	± Pole	± Pole	± Pole
$P_{L,BP,CE}$	10	9.35	10	9.35	9.35
$P_{L,MP,CE}$	5	4.5	5	4.5	4.6
$P_{L,BP,OE}$	10	9.35	10	9.35	9.35
$P_{L,MP,OE}$	5	4.4	5	4.4	4.55

TABLE 8-43

DC fault separation devices (DC-FSD) losses in MW for central earthing (CE) and for onshore earthing (OE) for LFS1

		Terminal A	Terminal B	Terminal C	Terminal D
		± Pole	± Pole	± Pole	± Pole
DCSS#1	$P_{L,BP,CE}$	7.35	7.35	5.06	5.06
	$P_{L,MP,CE}$	7.35	7.35	4.82	4.82
	$P_{L,BP,OE}$	7.35	7.35	5.06	5.06
	$P_{L,MP,OE}$	7.06	7.06	4.59	4.59
DCSS#5	$P_{L,BP,CE}$	5.06	0.11	1.90	6.63
	$P_{L,MP,CE}$	4.82	0.12	1.86	6.36
	$P_{L,BP,OE}$	5.06	0.11	1.90	6.63
	$P_{L,MP,OE}$	4.59	0.12	1.82	6.36

V-P2P: Point to point with maximum voltage drop onshore

Table 8-44 shows the voltage set points of the onshore converter station (CNVS#4) and the resulting voltages at the offshore converter station (CNVS#3) for a central earthing (CE) at DCSS#5. Also included is the injected active power for the offshore converter stations and the injected active power into the AC connection points at the receiving ends reduced by the DC transmission losses. Table 8-45 provides those results for onshore earthing (OE). Table 8-46 shows the voltage bands at the DC switching stations (DCSS). Table 8-47 shows the resulting currents of the DC lines (DCL).

Table 8-48 shows the losses of the DC lines (DCL) and the losses of the DC fault separation devices (DC-FSD). All results are given for both modes of converter operation (BP: Bipole, MP: Monopole).

The minimum voltage is 503.3 kV at DCSS#4. The maximum current through the transmission lines is 1.885 kA. For this topology, a maximum DC neutral voltage is found with a value of -20.9 kV. The losses of the DC transmission lines are up to 8.93 MW for the short distance and 19.05 MW for the long distance. The DC-FSD losses are up to 6.36 MW per pole. The converter losses are up to 10 MW.

TABLE 8-44

Converter station (CNVS) voltage setpoints (V_{SP}) in per unit and active power injection (P_{SP}) in GW. Considering central earthing (CE) at DCSS#5

	V_{SP}	P_{SP}

Operating Mode	BP	MP	BP	MP
CNVS#3	1.0	1.0	2	1
CNVS#4	0.9586	0.9338	-1.878	-0.901

TABLE 8-45

Converter station (CNVS) voltage setpoints (V_{SP}) in per unit and active power injection (P_{SP}) in GW. Considering onshore earthing (OE) at DCSS#4

	V_{SP}		P_{SP}	
Operating Mode	BP	MP	BP	MP
CNVS#3	1.0000	1.0000	2.00	1.00
CNVS#4	0.9586	0.9602	-1.878	-0.903

TABLE 8-46

DC voltages in kV_{DC} for bipole operation with DMR ($V_{DCSS,BP}$) and asymmetric monopole operation ($V_{DCSS,MP}$). Voltages referred to pole voltage and DMR voltage

	DCSS#3		DCSS#5		DCSS#4	
	± Pole	DMR	± Pole	DMR	± Pole	DMR
$V_{BP,CE}$	525	0	516.8	0	503.3	0
$V_{MP,CE}$	525	-8.1	517.0	0	503.6	+ 13.4
$V_{BP,OE}$	525	0	516.8	0	503.3	0
$V_{MP,OE}$	525	-20.9	517.1	-13.0	504.1	0

TABLE 8-47

DC line (DCL) currents in kA for monopole operation (MP) and bipole operation (BP), as well as for central earthing (CE) at DCSS#5 and onshore earthing (OE) at DCSS#4

	DCL#4		DCL#5	
	± Pole	DMR	± Pole	DMR
$I_{BP,CE}$	1.885	0	1.885	0
$I_{MP,CE}$	1.856	- 1.856	1.856	- 1.856
$I_{BP,OE}$	1.885	0	1.885	0
$I_{MP,OE}$	1.811	- 1.811	1.811	- 1.811

TABLE 8-48

DC line (DCL) losses in MW and DC fault separations devices (DC-FSD) losses in MW for monopole operation (MP) and bipole operation (BP), as well as for central earthing (CE) at DCSS#5 and onshore earthing (OE) at DCSS#4

	DCL#4		DC-FSD#4	DC-FSD#5	DCL#5	
	± Pole	DMR	± Pole	± Pole	± Pole	DMR
$P_{Loss,BP,CE}$	8.93	0	6.56	6.56	19.05	0
$P_{Loss,MP,CE}$	8.65	8.65	6.36	6.36	18.46	18.46
$P_{Loss,BP,OE}$	8.93	0	6.56	6.56	19.05	0
$P_{Loss,MP,OE}$	8.19	8.19	6.02	6.02	17.58	17.58

TABLE 8-49

Converter station (CNVS) losses in MW considering bipole operation (BP) and monopole operation (MP), as well as central earthing (CE) at DCSS#5 and onshore earthing (OE) at DCSS#4

	CNVS#3	CNVS#2
	± Pole	± Pole
$P_{L,BP,CE}$	10	9.32
$P_{L,MP,CE}$	5	4.5
$P_{L,BP,OE}$	10	9.32
$P_{L,MP,OE}$	5	4.5

Point to point with maximum voltage drop offshore

Table 8-50 shows the voltage set points of the onshore converter station (CNVS#4) and the resulting voltages at the offshore converter station (CNVS#3) for a central earthing (CE) at DCSS#5. Table 8-51 shows the voltage bands at the DCSS. Table 8-52 shows the resulting currents of the DC lines (DCL).

TABLE 8-50

Converter station (CNVS) voltage setpoints (V_{SP}) in per unit and active power injection (P_{SP}) in GW. Considering central earthing (CE) at DCSS#5

	V_{SP}		P_{SP}	
Operating Mode	BP	MP	BP	MP
CNVS#3	0.995	0.992	0.1099	0.1101
CNVS#4	1.0	1.0028	0.1104	0.1106

TABLE 8-51

DC voltages in kV_{DC} for bipole operation with DMR ($V_{DCSS,BP}$) and asymmetric monopole operation ($V_{DCSS,MP}$). Voltages referred to pole voltage and DMR voltage

	DCSS#3		DCSS#5		DCSS#4	
	± Pole	DMR	± Pole	DMR	± Pole	DMR
$V_{BP,CE}$	522.6	0	523.5	0	525	0
$V_{MP,CE}$	522.5	0.9	523.4	0	525	-1.5
$V_{BP,OE}$	522.6	0	523.5	0	525	0
$V_{MP,OE}$	522.6	2.4	523.5	1.5	525	0

TABLE 8-52

DC line (DCL) currents in kA for monopole operation (MP) and bipole operation (BP), as well as for central earthing (CE) at DCSS#5 and onshore earthing (OE) at DCSS#4

	DCL#4		DCL#5	
	± Pole	DMR	± Pole	DMR
$I_{BP,CE}$	0.21	0	0.21	0
$I_{MP,CE}$	0.21	0.21	0.21	0.21
$I_{BP,OE}$	0.21	0	0.21	0
$I_{MP,OE}$	0.21	0.21	0.21	0.21

8.2.3. Conclusions

The following tables summarize the design relevant rated values obtained with the stationary analysis. These values are based on the results of the stationary analysis and the current requirements for the operating ranges and load capacity of the transmission lines.

Regarding the upper voltage band, we do not operate the system above the nominal conditions. In the case of higher voltages, the relevant cable ratings need to be considered (see Table 8-53). For the minimum value of the voltage, the point at which the maximum voltage drop occurs is selected from all the calculated cases. In terms of current, the maximum limit is defined by the rated value of the HVDC cable. The stationary analysis shows that for nominal operating conditions, the cables are being operated at this value.

Table 8-53 defines the DC pole voltage bands. Table 8-54 defines the DC pole current bands. Table 8-55 defines the DC neutral voltage bands. The results contribute to the preliminary main circuit parameters presented in section 8.17.

TABLE 8-53

DC pole voltage band (DC+ / DC-)

	Unit	Value	Comment
Max. continuous DC voltage	kV_{DC}	± 525	According to nominal voltage
Nominal operating DC voltage	kV_{DC}	± 525	Nominal operating conditions
Min. continuous DC voltage onshore	kV_{DC}	± 497.5	Result of stationary analysis
Min. continuous DC voltage offshore	kV_{DC}	± 522.6	Result of stationary analysis

TABLE 8-54

DC pole current band (DC+ / DC-)

	Unit	Value	Comment
Max. continuous rating DC current	kA_{DC}	± 2.0	Maximum cable rating
Max. continuous DC current	kA_{DC}	± 2.0	Result of stationary analysis
Nominal operating DC current	kA_{DC}	± 2.0	Nominal operating conditions
Min. continuous DC current	kA_{DC}	~0	No load condition

TABLE 8-55

DC neutral voltage band (N / sym. voltage band)

	Unit	Value	Comment
Max. continuous rating DC voltage	kV_{DC}	±27.6	Additional headroom of ± 5%
Max. continuous voltage	kV_{DC}	± 26.3	Result of stationary analysis
Min continuous voltage	kV_{DC}	~0	Symmetrical operation

8.3. Quasi-stationary analysis

Section 8.3 describes the methodical approach, the simulation model, input parameters and results of the quasi-stationary analysis. The quasi-stationary study package analyzes the behavior of the demonstrator in case of a contingency in the DC grid. From a quasi-stationary perspective, a contingency occurring in the DC system (e.g. after a DC fault) leads to an energy imbalance between energy feed in and feed out of the DC system. This causes either a voltage drop or voltage rise at the respective converter stations which results in a primary DC voltage control action. However, a post-contingency steady-state deviation of the DC voltage remains, and a secondary DC voltage control is required to reach the pre-contingency DC voltage set points.

In this regard, the main goal of this analysis is to assess the DC voltage withstand capability of the demonstrator by defining a preliminary temporary DC voltage and DC current band at the DC-PoC of the offshore and onshore converter stations. The bands are defined as the minimum and maximum permissible converter voltages and currents during DC primary control response but before the DC secondary control response. Together with a set of model assumptions, the obtained bands are verified by simulation. The results are incorporated into the preliminary main circuit parameters in section 7. The dynamic behavior of the DC voltage at a given DC-PoC is highly influenced by the chosen control scheme and control parameters. Conservative assumptions are made in this study package to force comparably large DC voltage drops in case of a contingency. The defined temporary DC voltage and current bands serve as worst-case estimation and shall be basis for the subsystem design of the InterOPERA demonstrator.

The quasi-stationary analysis is structured as follows. A short description of the simulation model used for the analysis is given in section 8.3.1 including an overview of the assumed parameters and the investigated contingencies. Section 8.3.2 discusses the calculations and results leading to the main findings of this study package and requirements for T3.2 summarized in section 8.3.3. Section 8.3.4 provides an outlook and recommendation to further design studies.

8.3.1. Methodical approach

Simulation model description

To perform the quasi-stationary analysis a PSCAD V4.6.3 [11] model is used based on the demonstrator topology described in section 7.1. The DC-system is grounded at the central DCSS#5 (solid grounding assumption) as described in section 8.1.1. The main building blocks of the model are described in the following paragraphs.

The AC side is modelled by a Thevenin equivalent voltage source. The DC transmission lines are modelled as pi-sections. DC-switching stations are represented by ideal busbars. The resistances and inductances of DC-FSDs are considered in the DC switching stations. All representations are depicted in Figure 8-23.

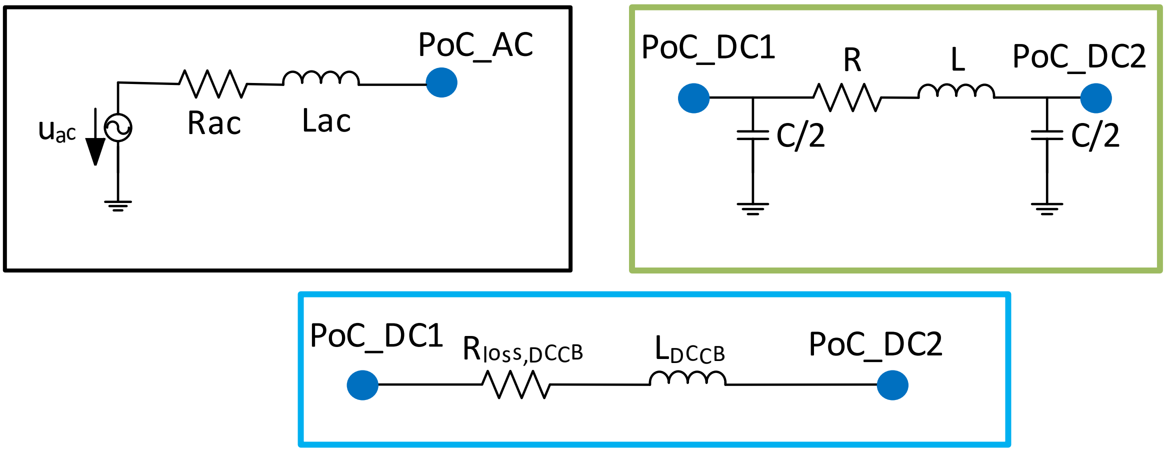


FIGURE 8-23

Representation of the AC-system (left) and DC-transmission lines (right) and DC-FSDs (bottom)

An "Average Value Model (AVM)" is used for the modelling of converter stations. An AVM has the benefit that comparably few parameters are required for the converter model. An exemplary representation of the AVM is depicted in Figure 8-24. One of the main characteristics of an AVM is the fact that the AC- and DC-side of the converter are modelled separately. For the AC-side, the behavior of the converter is represented by three controlled voltage sources which follow the AC voltage set-points generated by the converter's control. The DC side is represented by a controlled current source connected in parallel with an capacitor. The DC current is derived based on the ideal power conversion principle. The losses inside the converter, which are assumed to 1% in this analysis, are represented by the resistance on the AC- and DC- side (the values are set accordingly). The capacitor reflects an aggregation of all submodule capacitors. [7]

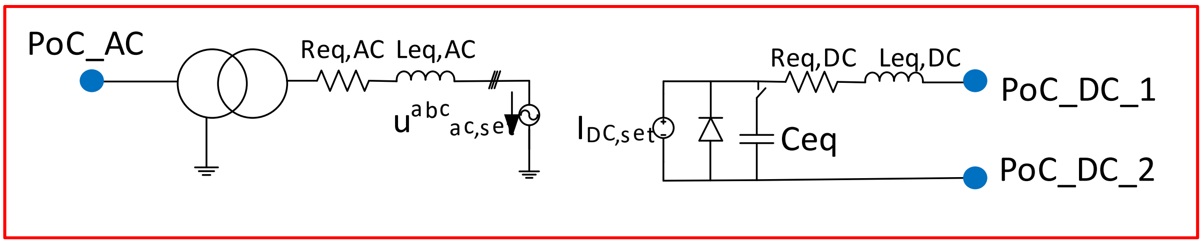


FIGURE 8-24

Schematic illustration of an "Averaged Value Model" used in the quasi-stationary study based on [7]

The dynamic behaviour of the DC voltage at a given DC-PoC is highly influenced by the chosen control scheme and control parameters. Regarding the converter control a simplified algorithm is chosen comprising of an outer and inner control loop in dq-coordinates. A short illustration of the control is depicted in Figure 8-25. Two control modes are used within the outer control loop (fixed active power control (AC-side) and DC voltage droop control). It is assumed that all offshore converter stations are operated in fixed active power control mode. V/f control mode is not considered within this study. PI controller, which are tuned with the respective proportional and integral gain (marked in green), are used for the regulation of the active power or DC voltage respectively. The control parameters assumed in this study are listed in Table 8-62. Outcome of the outer control are current set-points in dq-coordinates which will be used in the inner control loop to calculate the desired voltages for the AC-side of the AVM. The implemented control scheme does not include any balancing controls. This topic will be investigated in WP2.

In MT-HVDC systems the primary DC voltage control is typically implemented by a DC voltage droop control. Therefore, it is assumed the onshore converter stations are operated in DC voltage droop control mode. Several implementation schemes for the droop control exists in the literature. All of them have a different impact on the dynamic behavior of the converter stations operated in droop control mode. Within this study and according to [12], the droop parameter "K_{droop}" is defined as the change of DC current in response to a deviation of the DC voltage from its reference value. In this regard, the following DC voltage droop control is implemented (marked in red).[13]

A secondary voltage control is not included in the model used for the study, as the control generally is much slower compared to the primary control and thus the reaction is not of significant importance.

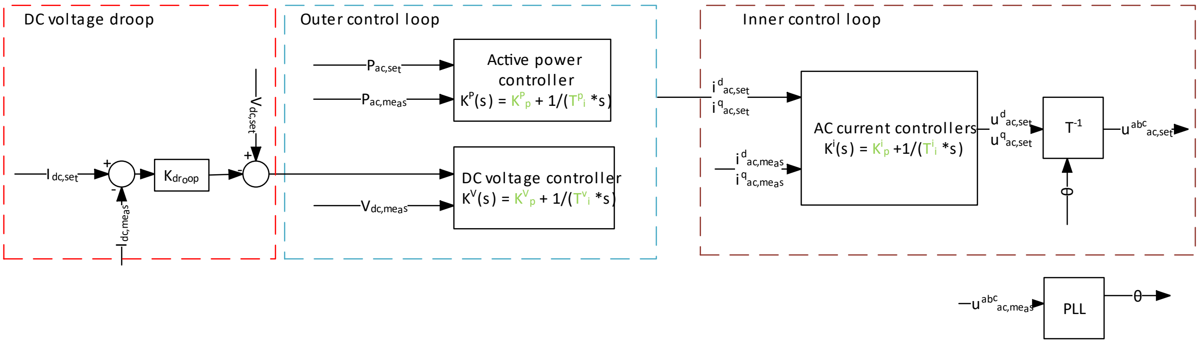


FIGURE 8-25

Control scheme used in the quasi-stationary analysis with the respective transfer function of the PI controllers

Please note:

The activation of energy dissipation devices (if necessary) and a power derating of wind farms are actions, which are not considered in the model used in the quasi-stationary analysis.

Used parameters

The following parameters are assumed for the quasi-stationary analysis. The equivalent values for the AVM are based on the assumed converter parameters of the transient analysis. Resistances $R_{eq,AC}$ and $R_{eq,DC}$ are defined to match with the 1% total converter losses assumption at maximum power conversion.

TABLE 8-56

Basic DC system data used for the quasi-stationary analysis. Values are based on the specific parameters listed in Table 8-11 (onshore cables) and Table 8-10 (offshore cables) and the cable lengths listed in Table 8-8. The reference frequency for the resistance is 0 Hz. The reference frequency for the inductance is 10 kHz.

	Unit	Value	Comment
Resistance of DC Line #1	Ω	2.86	Offshore and onshore section
Resistance of DC Line #2	Ω	2.5	Offshore DC line #2 and onshore DC line #3 1:1 current sharing with DC line #1 (R_{Σ} = 2.86)
Resistance of DC Line #3	Ω	0.36	

[13] This assumption is only used for the studies performed in T3.1. T3.1 does not impose the HVDC vendors or other stakeholders to use the same droop implementation for the upcoming tasks in InterOPERA.

Resistance of DC Line #4	Ω	2.5	Offshore connection to standalone DCSS
Resistance of DC Line #5	Ω	5.36	Onshore connection to standalone DCSS (long spoke)
Capacity of DC Line #1	mF	0.100	
Capacity of DC Line #2	mF	0.088	
Capacity of DC Line #3	mF	0.012	
Capacity of DC Line #4	mF	0.088	
Capacity of DC Line #5	mF	0.184	
Inductance of DC Line #1	H	0.056	
Inductance of DC Line #2	H	0.049	
Inductance of DC Line #3	H	0.007	
Inductance of DC Line #4	H	0.049	
Inductance of DC Line #5	H	0.108	

TABLE 8-57

Basic AC system data used for AC-system #1, #3 and #5

	Unit	Value	Comment
Nominal AC voltage (LL, rms)	kV	132	See Table 8-20
Short Circuit Level	MVA	7316	See Table 8-21
X to R Ratio	-	10	See Table 8-21

TABLE 8-58

Basic AC system data used for AC-system #2

	Unit	Value	Comment
Nominal AC voltage (LL, rms)	kV	400	See Table 8-15
Short Circuit Level	MVA	55426	See Table 8-16
X to R Ratio	-	20	See Table 8-16

TABLE 8-59

Basic AC system data used for AC-system #4

	Unit	Value	Comment
Nominal AC voltage (LL, rms)	kV	400	See Table 8-17
Short Circuit Level	MVA	29099	See Table 8-18
X to R Ratio	-	20	See Table 8-18

TABLE 8-60

Data used for the onshore converter stations

	Unit	Value	Comment
Transformer primary voltage (LL, rms)	kV	400	

Transformer secondary voltage (peak, LE)	kV	233.5	Maximum AC voltage at the secondary side of the transformer to prevent overmodulation of the converters.
Equivalent Capacity Ceq	mF	0.24	
Equivalent inductance $L_{eq,AC}$ (AC-side)	mH	22	
Equivalent resistance $R_{eq,AC}$ (AC-side)	Ω	0.5	
Equivalent inductance $L_{eq,DC}$ (DC-side)	mH	29	
Equivalent resistance $Req_{,DC}$ (DC-side)	Ω	0.5	

TABLE 8-61

Data used for the offshore converter stations

	Unit	Value	Comment
Transformer primary voltage (LL, rms)	kV	132	
Transformer secondary voltage (peak, LE)	kV	233.5	Maximum AC voltage at the secondary side of the transformer to prevent overmodulation of the converters.
Equivalent Capacity C_{eq}	mF	0.24	
Equivalent inductance $L_{eq,AC}$ (AC-side)	mH	22	
Equivalent resistance $R_{eq,AC}$ (AC-side)	Ω	0.5	
Equivalent inductance $L_{eq,DC}$ (DC-side)	mH	29	
Equivalent resistance $R_{eq,DC}$ (DC-side)	Ω	0.5	

TABLE 8-62

Control parameters used in this study package

	Unit	Value	Comment
Proportional gain K^V_p	-	15	DC voltage control (outer loop)
Integral gain T^V_i	ms	1	DC voltage control (outer loop)
Proportional gain K^P_p	-	2	Active power control (outer loop)
Integral gain T^P_i	ms	3	Active power control (outer loop)
Proportional gain K^i_p	-	1	Current control (inner loop)
Integral gain T^i_i	ms	0.1	Current control (inner loop)

TABLE 8-63

Data DC switching stations

	Unit	Value	Comment
Resistance DC-FSD (R_{loss})[14][15]	Ω	1.837	6.67 MW of total steady state losses per pole (worst case assumption, see section 8.2)
Inductance DC-FSD (L_{DCCB})	mH	200	In accordance with the transient analysis.

Investigated contingencies

Table 8-6 shows a list of ordinary contingencies which are considered for the preliminary conceptual system design studies performed in T3.1. Similar to the stationary analysis, the focus on the quasi-stationary study is on design-relevant worst-case scenarios. In this context, two scenarios have been identified as the dimensioning incidents regarding an upper and a lower DC voltage limit (maximum loss of power infeed and maximum loss of load respectively).

Considering the demonstrator topology and the location of DC-FSDs, the maximum loss of active power infeed caused by an ordinary contingency is identified as a loss of one converter unit of converter station #1 and #5. From a quasi-stationary perspective, this results in a maximum loss of 2 GW power infeed for one pole (asymmetrical outage). This event is caused e. g. by a pole-to-ground fault at the positive busbar in DCSS#1 which leads to a trip of the two converter units in the DCSS. The loss of power infeed leads to a DC voltage drop and a rise in the DC current. For this reason, scenario 1 is used to estimate the lower limit of the temporary DC voltage band.

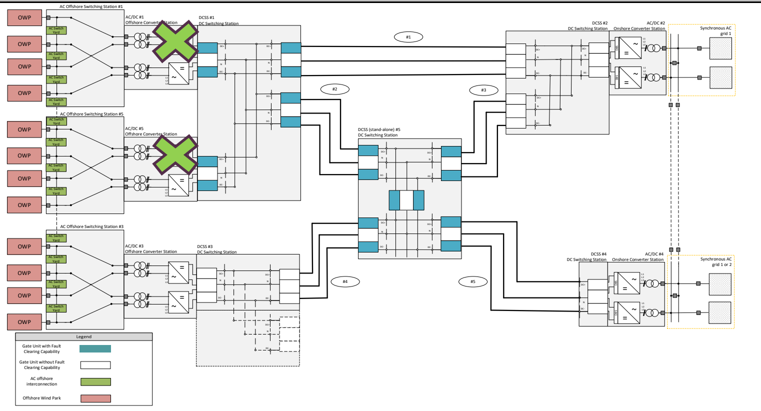
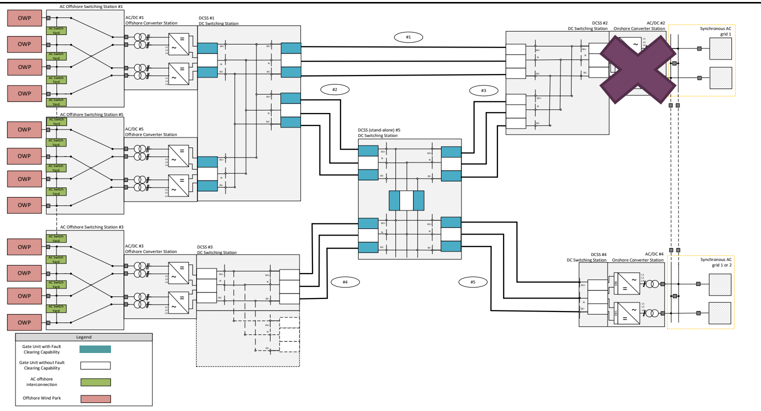
The second scenario identified is a trip of onshore converter station #2 resulting in a loss of load. The demonstrator topology variant 1 consists of two onshore converter stations, which means that if station #2 was to fail, only one onshore station, namely #4, would still be in operation. To comply with the power ratings of the converter units and due to the limitations of the model used in the quasi-stationary analysis (no implementation of a wind farm ramp down sequence, no implementation of an energy dissipation device activation), a scenario with half maximum power infeed is calculated. Thus, in scenario 2 of the quasi-stationary analysis, a loss of 1GW load is investigated. However, it should be noted that the maximum loss of load is very likely to be at a higher power of 2GW.

[14] The loss assumption for the DC-FSDs is based on the stationary analysis to achieve an identical pre contingency load flow for the quasi-stationary analysis. A reasoning can be found in section 8.2. In reality, it is expected that the losses of the DC-FSD are much lower.

[15] The loss assumption represents the worst case for the stationary analysis. However, for the quasi-stationary analysis the lower limit of DC-FSD resistances most likely represents the worst case due to the lower damping which leads to higher dynamics.

TABLE 8-64

List of investigated worst-case scenarios

	Description	Contingency Event	Illustration
Scenario #1	Maximum loss of active power injection	Trip of two converter units of different stations connected to DCSS#1 (loss of 2 GW active power injection for one pole)	
Scenario #2	Loss of load	Trip of onshore converter station #2 (loss of 1GW load in total)	

8.3.2. Temporary DC voltage and current bands

This section summarizes the simulation results including DC voltage and DC current profiles for the investigated scenarios of Table 8-64.

Maximum loss of active power infeed

For the first investigation, a maximum loss of active power infeed is investigated leading to the trip of the upper converter unit of station #1 and #5. This results in a maximum loss of 2 GW for one pole.

The initial operating set-points of each converter station are listed in Table 8-65. To determine the minimum permissible temporary DC voltage, the set-points are based on the worst-case load flow of the stationary analysis (LFS1) where station #1 and #5 each feed 2 GW into the grid. This load flow results in the lowest stationary DC-voltage at the onshore stations identified in section 8.2 which will reduced even further due to the contingency and the loss of active power injection.

In the scenario described, it is assumed that the post-contingency steady-state DC voltage deviation at the onshore stations does not fall below a value of 10% (referring to 525 kV). Since each onshore station has a different pre-contingency steady-state DC voltage due to the given load flow, this results in different droop factors for converter station #2 and #4. Station #2 has a steeper droop characteristic than station #4.

TABLE 8-65

Operating set-points for each converter station before the disturbance for the analysis of the maximum loss of active power injection. The tripped converter units are highlighted in purple.

	Control mode	Active power set point (AC-side)[1]	DC voltage set point	Droop gain
Upper converter unit of CNVS#1	Constant P_{AC} control	1000 MW	N/A	N/A
Lower Converter unit of CNVS#1	Constant P_{AC} control	1000 MW	N/A	N/A
Upper converter unit of CNVS #2	DC voltage droop control	-930 MW	515.2 kV	20.8 kV/kA
Lower converter unit of CNVS #2	DC voltage droop control	-930 MW	515.2 kV	20.8 kV/kA
Upper converter unit of CNVS #3	Constant P_{AC} control	0 MW	N/A	N/A
Lower converter unit of CNVS #3	Constant P_{AC} control	0 MW	N/A	N/A
Upper converter unit of CNVS #4	DC voltage droop control	-947 MW	497.5 kV	13.7 kV/kA
Lower converter unit of CNVS #4	DC voltage droop control	-947 MW	497.5 kV	13.7 kV/kA
Upper converter unit of CNVS #5	Constant P_{AC} control	1000 MW	N/A	N/A
Lower converter unit of CNVS #5	Constant P_{AC} control	1000 MW	N/A	N/A

1) Positive value means power injection into the DC grid.

The obtained DC-voltage and DC-current profiles are depicted in Figure 8-27 (DC+), Figure 8-26 (DMR) and Figure 8-28 (DC-). In pre-contingency state, the system is equally balanced with the current flowing through the DC+ and DC- part of the system. The DMR is not loaded. At approximately t=1s, the loss of power injection at the positive pole provokes, and energy imbalance resulting in a temporary voltage drop at the DC+ PoC of all converter stations (up to 467 kV). Due to the primary DC voltage control this drop is contained and the system undergoes a transition to the post-contingency steady state. Since only the positive polarity of the system is directly affected by the contingency, the current commutates from the DC+ to the DMR as depicted in Figure 8-26. Together with the resistance of the DMR, this leads to a voltage drop across the DMR. Due to the connection of the positive and negative polarity of the system via the DMR, the negative polarity is also slightly affected by the contingency. Both onshore converter units change their voltage set-point to a minor extent according to their droop characteristic.

The temporary voltage drop does also affect the power distribution in the DC grid which is depicted in the current profiles. Since there is no power injection in the positive part of the MT system after the contingency, all DC+ currents converge to zero and this part of the system is no longer in use. To be able to set the DC voltage at the onshore converter units according to their droop characteristic, the units temporarily draw power from the connected AC onshore grid.

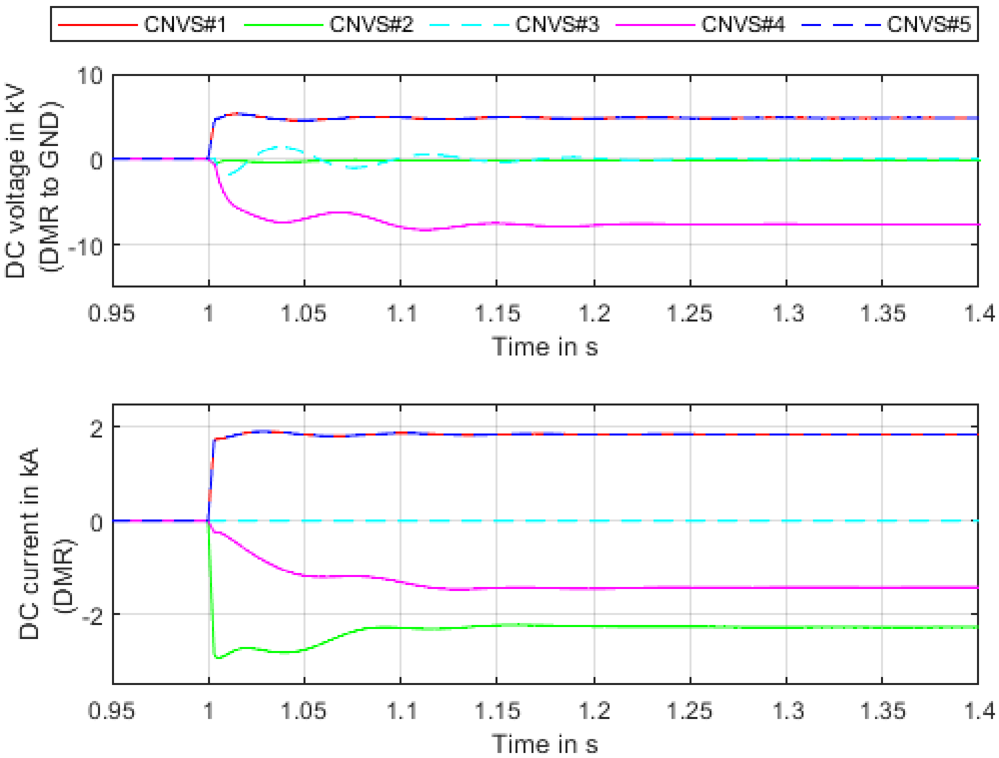


FIGURE 8-26

DC voltages (DMR to ground) and DC currents (DMR) at the five converter stations

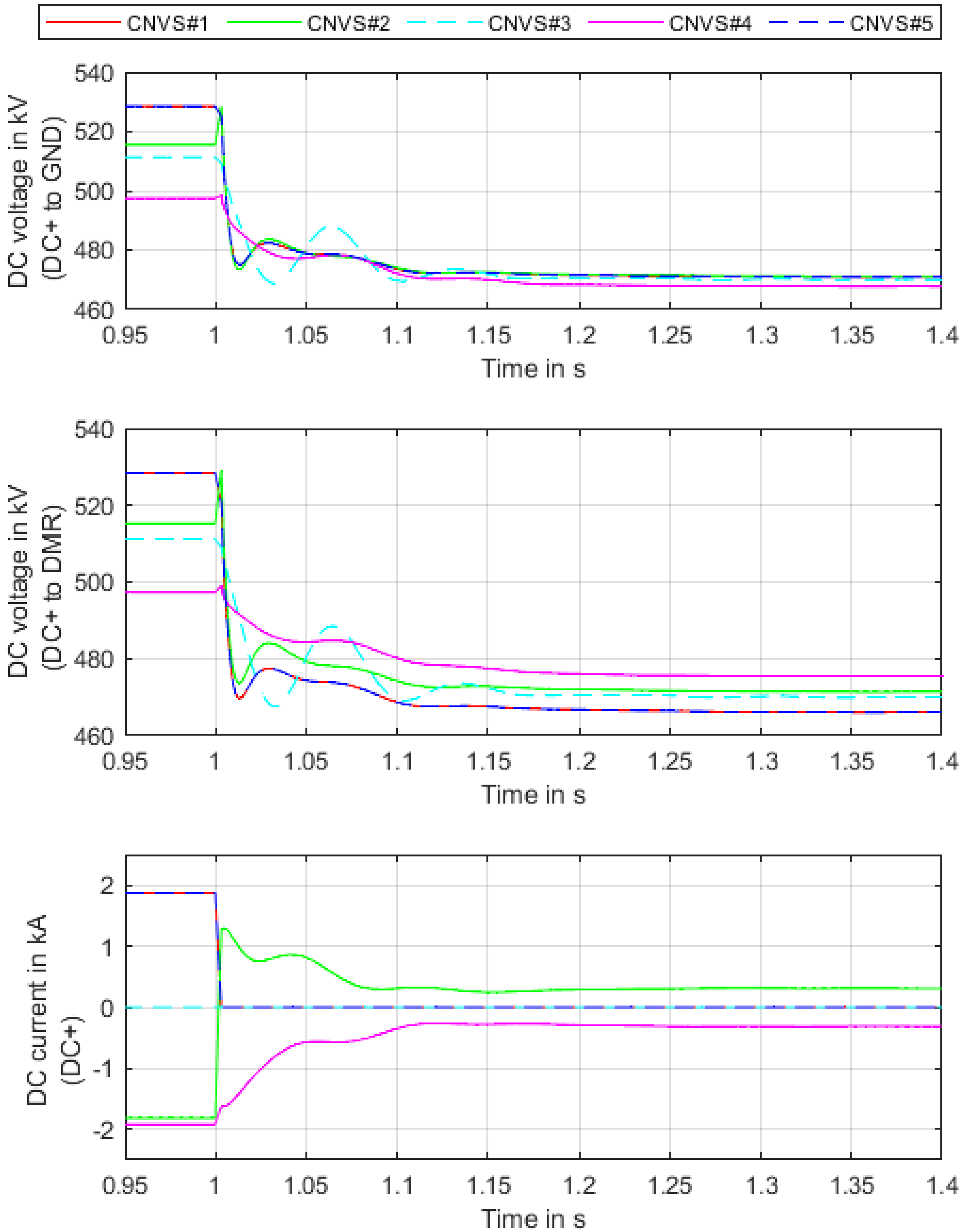


FIGURE 8-27

DC voltages (DC+ to GND and DC+ to DMR) and DC currents (DC+) at the five converter stations

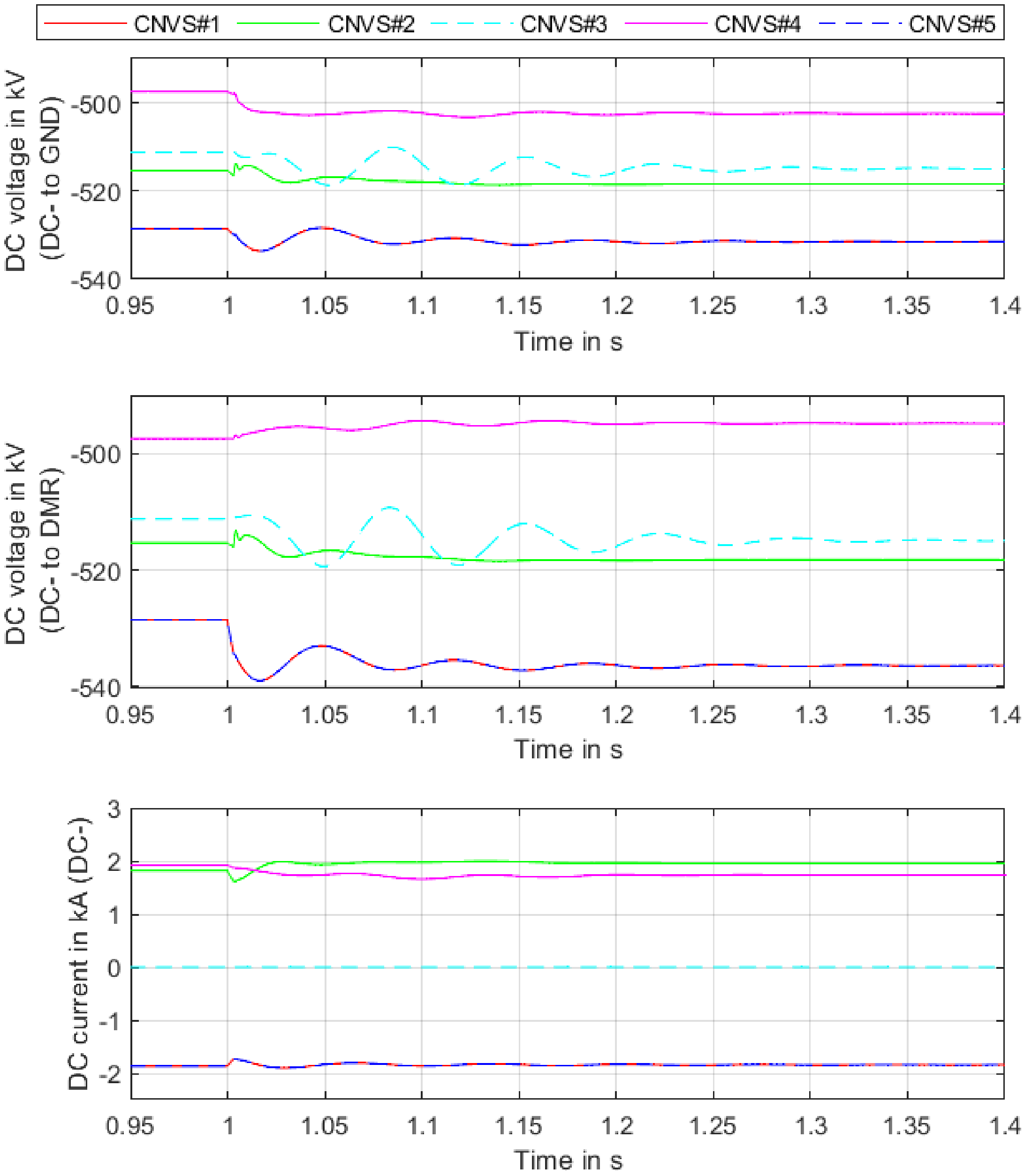


FIGURE 8-28

DC voltages (DC- to GND and DC- to DMR) and DC currents (DC-) at the five converter stations

Within this investigation, the largest temporary voltage drop and maximum current rise are of significant interest. Therefore, the minimum temporary DC voltage for the positive and negative polarity during primary DC voltage response is shown in Table 8-66 (onshore station) and Table 8-67 (offshore station).

The maximum temporary voltages and currents in the neutral part of the system are also listed (see Table 8-68 and Table 8-69).

TABLE 8-66

Minimum temporary DC voltage and maximum current for the onshore converter stations (DC+, DC-) considering only scenario #1

	Unit	Value	Comment
Min. temporary voltage (pole to ground)	kV_{DC}	467	0.89 p.u.
Max. temporary current	kA_{DC}	2.00	Absolute value

TABLE 8-67

Minimum temporary DC voltage and maximum current for the offshore converter stations (DC+, DC-) considering only scenario #1

	Unit	Value	Comment
Min. temporary voltage (pole to ground)	kV_{DC}	470	0.90 p.u.
Max. temporary current	kA_{DC}	1.91	Absolute value

TABLE 8-68

Maximum temporary DC voltage and maximum current for the onshore converter stations (DMR) considering only scenario #1

	Unit	Value	Comment
Max. temporary voltage (pole to ground)	kV_{DC}	8.3	Absolute value
Max. temporary current	kA_{DC}	2.92	Absolute value

TABLE 8-69

Maximum temporary DC voltage and maximum current for the offshore converter stations (DMR) considering only scenario #1

	Unit	Value	Comment
Max. temporary voltage (pole to ground)	kV_{DC}	5.3	Absolute value
Max. temporary current	kA_{DC}	1.91	Absolute value

Loss of load

The second investigation focuses on a loss of load. Here, the trip of onshore converter station #2 resulting in a loss of 1 GW load is considered to determine the upper limit of the temporary DC voltage band.

The initial operating set-points of each converter station are listed in Table 8-70. According to the stationary analysis, load flow situation #3 leads to the highest steady-state DC voltages at the onshore converter stations considering a total active power injection of 4GW into the DC grid. For this analysis, a similar load flow, but with only half the power infeed of the offshore stations, is considered. The DC are even further increased during the DC primary control response. The same droop gains for the onshore converter stations as in the first investigation are assumed.

TABLE 8-70

Operating set-points for each converter station before the disturbance for the analysis of the loss of active power injection. The tripped converter units are highlighted in purple.

	Control mode	Active power set point (AC-side)[1]	DC voltage set point	Droop gain
Upper converter unit of CNVS#1	Constant Pac control	332.5MW	N/A	N/A
Lower Converter unit of CNVS#1	Constant Pac control	332.5MW	N/A	N/A
Upper converter unit of CNVS #2	DC voltage droop control	-510 MW	519 kV	20.8 kV/kA
Lower converter unit of CNVS #2	DC voltage droop control	-510 MW	519 kV	20.8 kV/kA
Upper converter unit of CNVS #3	Constant Pac control	332.5MW	N/A	N/A
Lower converter unit of CNVS #2	Constant Pac control	332.5 MW	N/A	N/A
Upper converter unit of CNVS #4	DC voltage droop control	-465 MW	513 kV	13.7 kV/kA
Lower converter unit of CNVS #4	DC voltage droop control	-465 MW	513 kV	13.7 kV/kA
Upper converter unit of CNVS #5	Constant Pac control	332.5 MW	N/A	N/A
Lower converter unit of CNVS #5	Constant Pac control	332.5 MW	N/A	N/A

1) A positive value indicates a power injection into the DC grid.

The obtained DC voltage and DC current profiles are depicted in Figure 8-29. At t=1 s, the upper and lower converter of onshore converter station #2 trip and the energy imbalance between generated and consumed energy provokes a temporary voltage rise at the DC-PoC of all converters. Due to the primary DC voltage control this rise is contained and the system undergoes a transition to the post-contingency steady state. Since a symmetrical outage (trip of the complete onshore station #2 and a loss of 1 GW load) is considered, the voltage and current profiles of the positive and negative pole are symmetrical. The DMR is not loaded and therefore the profiles of the DMR and the negative polarity are not shown.

The temporary voltage rise does also affect the power distribution in the DC grid which is depicted in the current profiles of Figure 8-29. The sudden trip of onshore converter station #2 at t=1 s is visible in the current profile of CNVS#2 leading to an overcurrent at onshore converter station #4 which remains in operation. The maximum temporary currents are shown in Table 8-71 (onshore station) and Table 8-72 (offshore station). Since CNVS#4 is the only onshore station which remains in operation after the trip of CNVS#2, the steady-state DC current of CNVS#4 increases from about 1 kA before the incident to 2 kA after the incident.

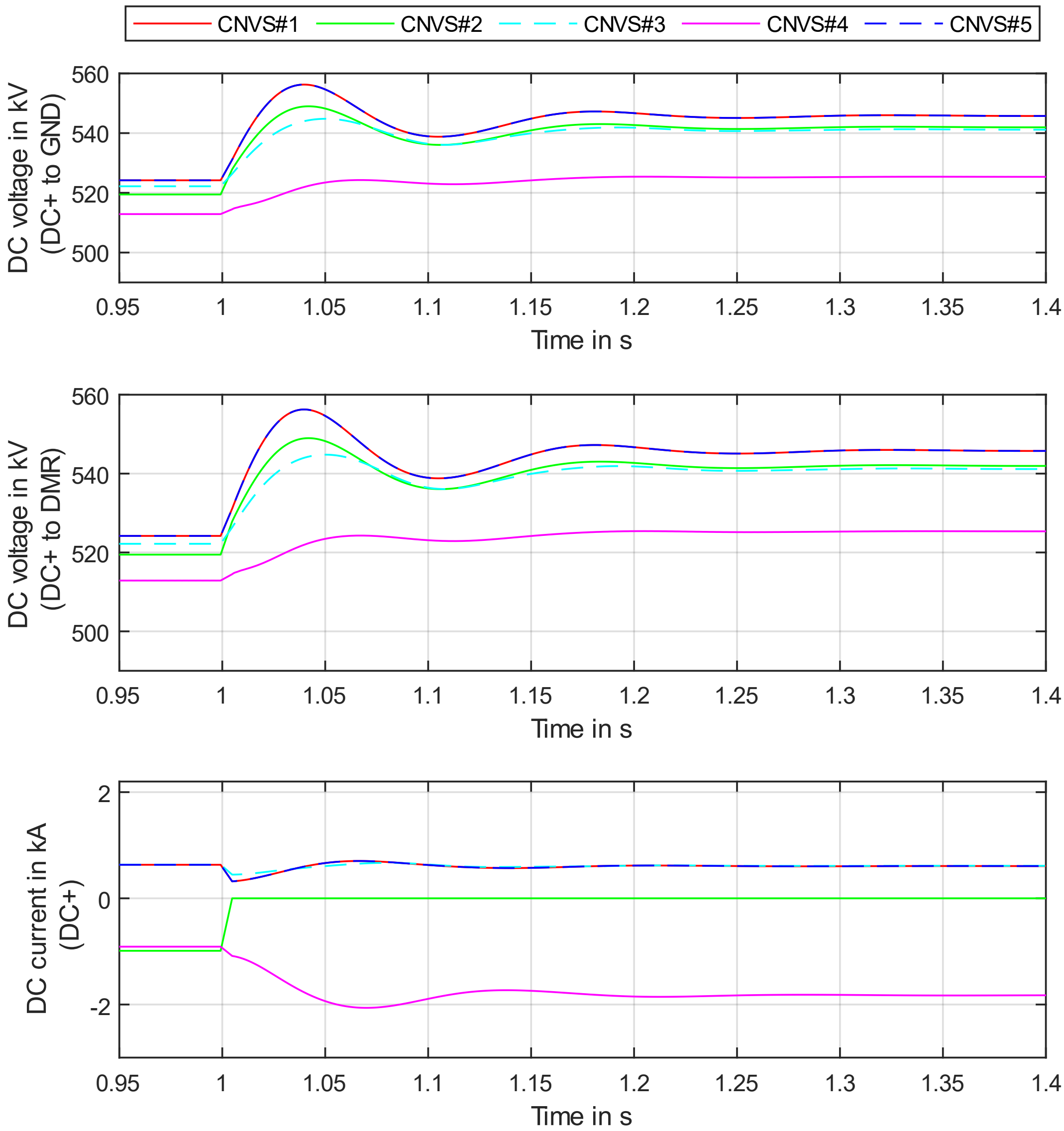


FIGURE 8-29

DC voltages and DC currents (DC+) at the five converter stations. Trip of converter station #2 at t=1 s

Within this investigation, the largest rise of the temporary voltage is of significant interest. Therefore, the maximum temporary DC voltage for the positive and negative polarity of the MT-system during and after primary DC voltage control but before secondary voltage control response is shown in Table 8-71 (onshore station) and Table 8-72 (offshore station). No assessment of the DMR behavior is made in this scenario.

TABLE 8-71

Maximum temporary DC voltage and current for the onshore converter stations (DC+, DC-) considering only the loss of load

	Unit	Value	Comment
Max. temporary voltage (pole to ground)	kV_{DC}	±550	1.05 p.u.
Max. temporary current	kA_{DC}	2.07	Absolute value

TABLE 8-72

Maximum DC voltage and current for the offshore converter stations (DC+, DC-) considering only the loss of load

	Unit	Value	Comment
Max. temporary voltage (pole to ground)	kV_{DC}	±557	1.06 p.u.
Max. temporary current	kA_{DC}	0.71	Absolute value

8.3.3. Conclusions

Based on the results of the quasi-stationary analysis and all investigated scenarios, the following preliminary temporary DC voltage and DC current bands for the onshore (see Table 8-73 and Table 8-74) and offshore converter station (see Table 8-75 and Table 8-76) are determined. These values define the minimum and maximum temporary DC voltage during and after primary DC voltage control but before secondary voltage control response and contribute to the preliminary main circuit parameters of the onshore and offshore converter stations listed in section 8.1.6 and 8.1.7.

TABLE 8-73

Preliminary temporary DC voltage and current bands for the onshore converter stations (DC+, DC-)

	Unit	Value	Comment
Max. temporary voltage (pole to ground)	kV_{DC}	±550	1.05 p.u.
Min temporary voltage (pole to ground)	kV_{DC}	±467	0.89 p.u.
Max. temporary current	kA_{DC}	±2.07	-
Min. temporary current	kA_{DC}	±0	No load condition

TABLE 8-74

Preliminary temporary DC voltage and current bands for the onshore converter stations (DMR)

	Unit	Value	Comment
Max. temporary voltage (pole to ground)	kV_{DC}	±8.3	-
Min temporary voltage (pole to ground)	kV_{DC}	±0	-
Max. temporary current	kA_{DC}	±2.92	-
Min. temporary current	kA_{DC}	±0	No load condition

TABLE 8-75

Preliminary temporary DC voltage and current bands for the offshore converter stations (DC+, DC-)

	Unit	Value	Comment
Max. temporary voltage (pole to ground)	kV_{DC}	±557	1.06 p.u.
Min temporary voltage (pole to ground)	kV_{DC}	±470	0.90 p.u.
Max. temporary current	kA_{DC}	±1.91	-
Min. temporary current	kA_{DC}	±0	No load condition

TABLE 8-76

Preliminary temporary DC voltage and current bands for the offshore converter stations (DMR)

	Unit	Value	Comment
Max. temporary voltage (pole to ground)	kV_{DC}	±5.3	-
Min temporary voltage (pole to ground)	kV_{DC}	±0	-
Max. temporary current	kA_{DC}	±1.91	-
Min. temporary current	kA_{DC}	±0	No load condition

8.3.4. Recommendations

The conceptual system design studies conducted in Task 3.1 are considered as preliminary and based on a given set of assumptions. The quasi-stationary study package provides a first insight into the derivation of temporary DC voltages and DC currents, taking into account the generic input data and other initial assumptions. However, due to available time, it was not possible to implement and consider all the feedback which was received during the study discussions with the consortium partners in T3.1.

The following recommendations were identified within Task 3.1 in the context of the quasi-stationary analysis:

- The model used for a future quasi-stationary analysis should include energy dissipation devices. In addition, a power derating functionality for offshore wind farms and offshore converter units should be considered. Both items are of great importance for a loss of load analysis and were not implemented in the model used for the study performed in Task 3.1.
- Control algorithms of the HVDC converter units should include current limiting functions.
- The quasi-stationary analysis was performed for variant 1 of the demonstrator topology (three offshore and two onshore converter stations). It is recommended to also perform the study for variant 2 of the demonstrator topology which includes three onshore converter stations.

It should be noted that the preliminary studies conducted in Task 3.1 are the first iteration, on which basis further detailed system studies will be performed. The identified recommendations could contribute to those studies.

8.4. Transient analysis

The transient analysis aims to investigate the transient behavior of the demonstrator during the event of a DC fault in the system. The focus of the transient study package is on ordinary fault events according to the contingency list in section 8.1.1. DC-FSDs are utilized to separate fault separation zones in the DC system. DC fault currents can have higher magnitudes and transients compared to faults occurring in typical AC networks. Furthermore, the prospective transient current is limited by the impedance of the DC transmission line which is lower compared to AC transmission lines of the same voltage level. This provokes higher fault current magnitudes and transients. [13]

In this regard, the main goal of the analysis is to assess the transient stress of the InterOPERA demonstrator by defining a prospective transient DC voltage and DC current band at the DC-PoC for the offshore, onshore converter stations and DC-switching station. The bands are defined as the minimum and maximum permissible DC voltages and DC currents during the fault separation time of given DC fault scenarios. Together with a set of model assumptions, the obtained bands are verified by simulation. In addition, an assessment of the dissipated energy for certain subsystems is given. The results are incorporated into the preliminary main circuit parameters in section 8. The defined prospective transient DC voltage and current bands serve as worst-case estimation. The use of DBS was not considered on the analyses.

The transient analysis is structured as follows. Section 8.4.1 provides an overview of the methodical approach including a simulation model description, assumed parameters and the investigated faults. Section 8.4.2 discusses the main findings of the transient analysis. The main outcomes and requirements for T3.2 are summarized in section 8.4.3.

8.4.1. Methodical approach

To perform the transient analysis, a simulation model in PSCAD 5.0.0 [10] is used. The following chapter describes the assumptions made and the investigated study cases.

Simulation model description

In the following, brief insights are given to the PSCAD model which is used for the transient analysis. An illustration of the overall topology is depicted in Figure 8-30. The model is based on generic assumptions and no proprietary or vendor specific modulation techniques or control strategies are applied.

The main building blocks of the model are described in the following sections.

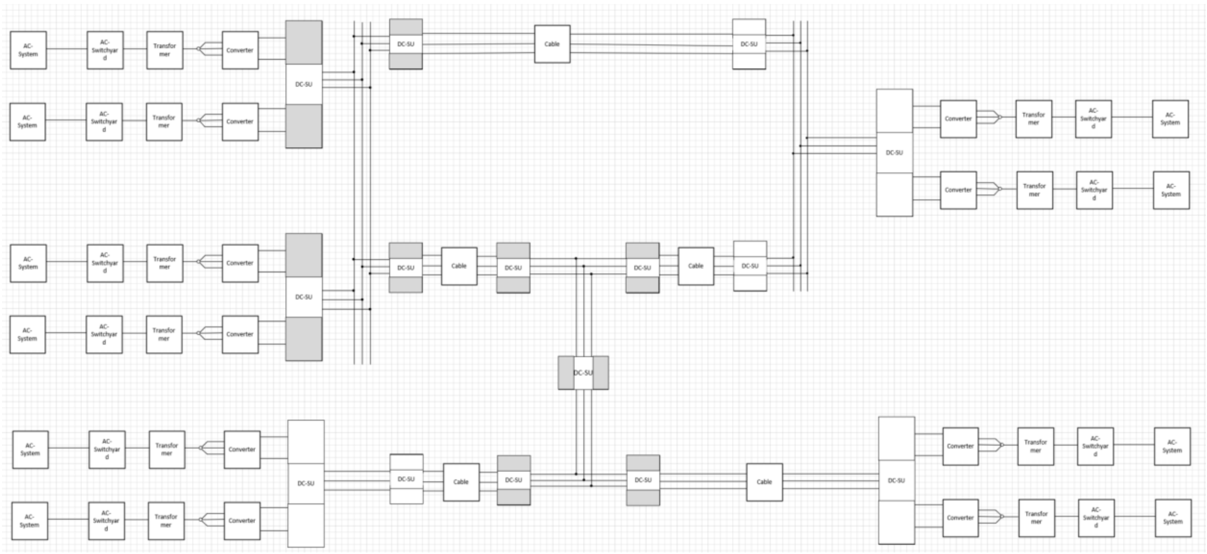


FIGURE 8-30

Overview the PSCAD model used in the transient analysis – the topology is based on variant 1 of the demonstrator as described in section 7.1

AC-System

Similar to the quasi-stationary analysis, the AC-system of the offshore and onshore grid is represented by an equivalent Thevenin voltage source as depicted in Figure 8-31. The grounding impedance as well as the equivalent grid impedance (resistance and reactance) are based on the assumed short circuit level, X to R ratio and Z_0/Z_1 ratio (ratio between the zero and positive sequence impedance) listed in Table 8-77 to Table 8-79. A distinction between the offshore AC grid and the two onshore AC grids is made.

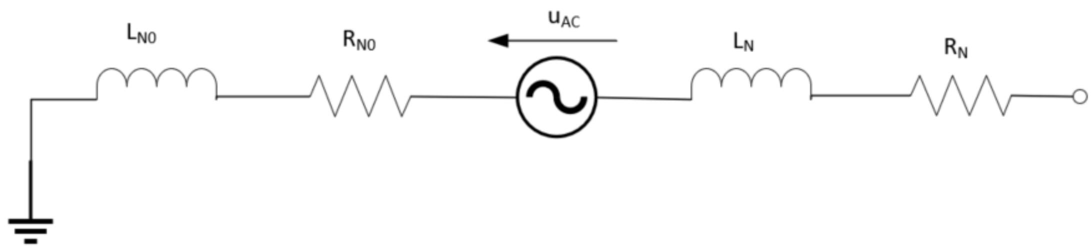


FIGURE 8-31

Overview of the AC-system representation used in the transient model

AC-Switchyard

The AC switchyard consists of an AC circuit breaker which is represented by an ideal switch without an arc characteristic. AC circuit breakers are considered to achieve a fault-clearing sequence of the converters in the affected fault separation zone. In case of a fault, at the first the submodule IGBTs of the converter are blocked. Afterward, with a conservative time delay of 100 ms, the AC circuit breaker are opened at the zero current crossing. The 100 ms time includes both the signal propagation time and the opening time of the AC circuit breaker.

Transformer

A standard PSCAD transformer is used in the model. Saturation of the transformer is considered. The parameters assumed for the transformer are listed in Table 8-80 (onshore) and Table 8-81 (offshore).

AC/DC converter

A B6 source converter model representing a Modular Multilevel Converter (MMC) with half bridge submodules is used for the transient analysis. This simplified average arm model (type 5/6 according to CIGRE classification) is depicted in Figure 8-32.

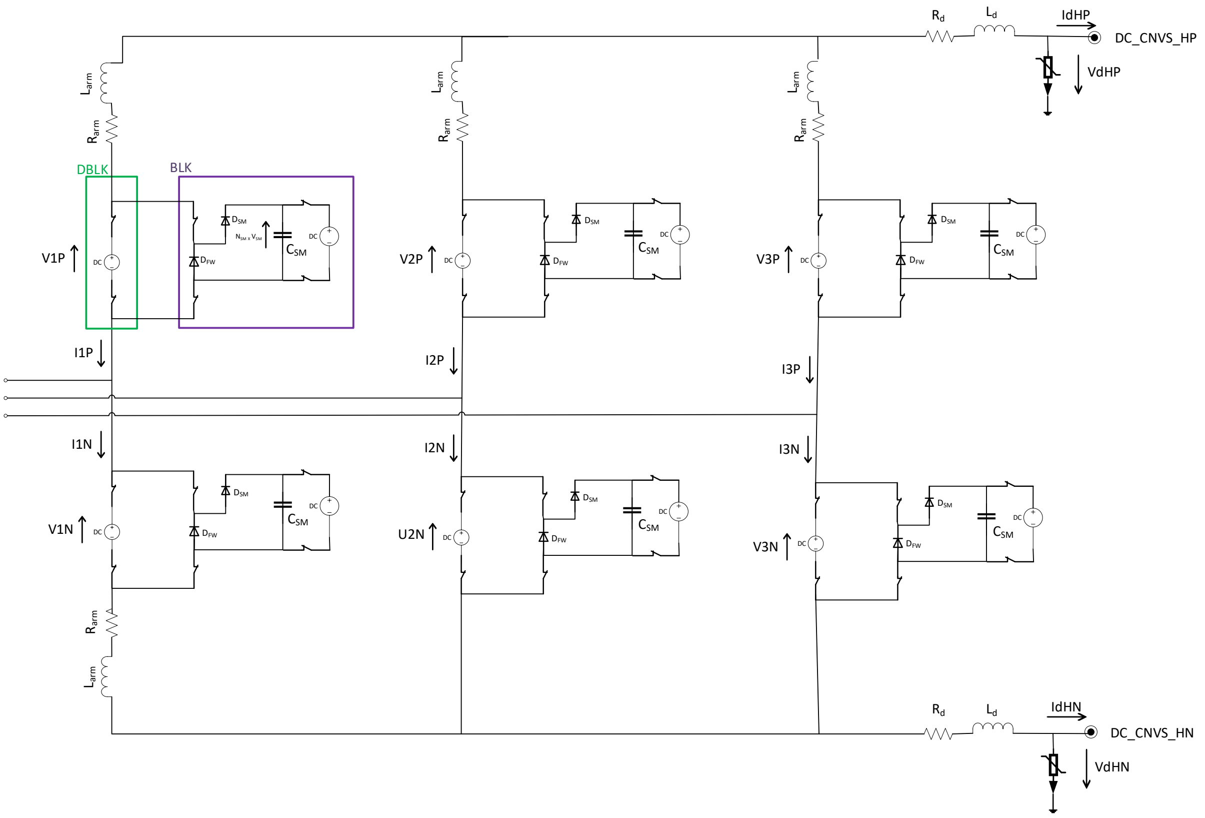


FIGURE 8-32

Overview of the average arm converter model including the parts which are active during deblocked (DBLK) and blocked (BLK) mode

In deblocked mode (DBLK), each converter arm is represented by a controlled voltage source behind an impedance. A simplified control system for the voltage source is used to start up the system and achieve the defined operating conditions. The control output is then frozen so that the voltage source has a constant operating state that does not change during an EMT simulation. Starting from the initial operating state, fault locations can be defined in order to investigate the transient stresses under consideration of different system constraints. In the event of a short circuit in the HVDC grid, the electrical properties of the modelled grid elements (e.g. converters, cables, protection devices) take effect. This simplification is permissible as the focus of the transient analysis is on the time range of the primary protection in order to determine the transient maximum values of the voltages and currents. In this time range, it can be assumed that the converter control has no major influence on the transient dynamics of the HVDC system.

If the DC current or the DC voltage at the converter terminals exceeds a previously defined threshold due to a short-circuit, the converter model switches to blocking mode with a time delay (see Table Table 8-82). For this, the arm current is commutated by ideal switches from the circuit with the fixed voltage source (DBLK) to a simplified circuit of the blocked converter (BLK). In this case, each converter arm is represented by a freewheeling diode and the aggregated values of the submodule capacitance. In the initial operating state, the voltage at the submodule capacitance corresponds to the value of the controlled voltage source in non-blocked mode (DBLK). In the event of a fault, charging and discharging processes may occur if the blocking voltage at the diode of the submodule capacitance is exceeded. This display variant corresponds to a type 5/6 model. There is no detailed modelling of the blocking behavior, as the transient stresses of the currents and voltages are to be determined for the case of non-blocked converters. For this reason, a distinction is made in section 8.4.2 between the results for the case in which a converter remains in operation (CO) and for the case in which a converter is blocked (BLK).

The following protections functions for entering the blocking mode are considered for the converters:

- Converter arm overcurrent threshold: Self-protection of the converter if the arm current exceeds a given threshold.
- DC overvoltage threshold: Self-protection of the converter if the DC voltage exceeds a given threshold.

The assumed converter parameters are listed in Table 8-82.

DC-Switching stations

The DCSS are represented by ideal busbars and three types of DC-Switching Units:

- DC-SU connected to two converters and a transmission line. An illustration is depicted in Figure 8-33.
- DC-SU connected to a DC busbar and a transmission line. An illustration is depicted in Figure 8-34.
- DC-SU connected to two DC busbars (longitudinal coupling). An illustration is depicted in Figure 8-35. The central DC system grounding is allocated to this DC-SU. A solid grounding is assumed.

All switching units consist of reactors, arresters and DC-FSDs (if foreseen in the respective unit). The FSDs are represented by an ideal PSCAD switch including a parallel arrester. The assumed parameters are listed in Table 8-83.

The following protection function is considered for the DC-FSDs:

- DC-FSD: Identification of the travelling wave by voltage gradient measurement (dv/dt) at the DC-FSD location. Current suppression starts after the voltage wave was detected at the DC-FSD location after 1 ms, 2 ms and 5 ms. More detailed information can be found in the study case description.

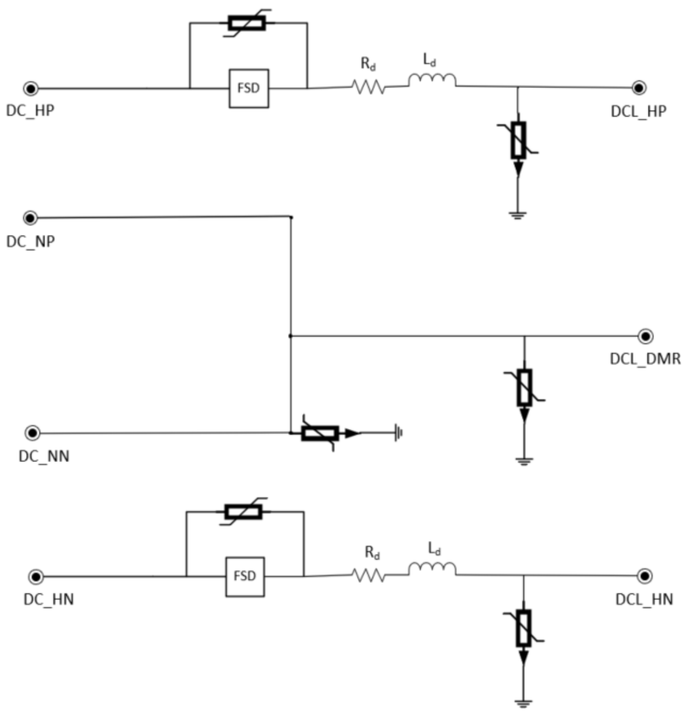


FIGURE 8-33

Electrical circuit of the DC-SU connecting two converters and a DC transmission line

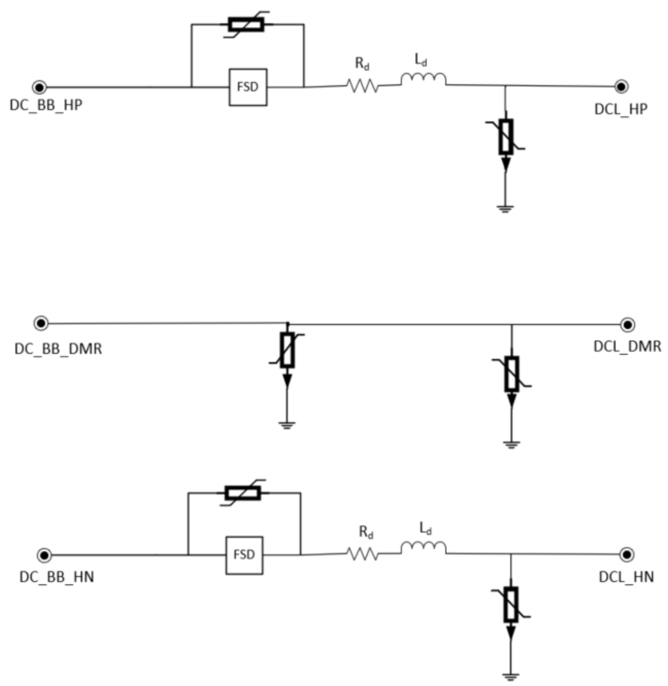


FIGURE 8-34

Electrical circuit of the DC-SU connected to DC busbars and a transmission line

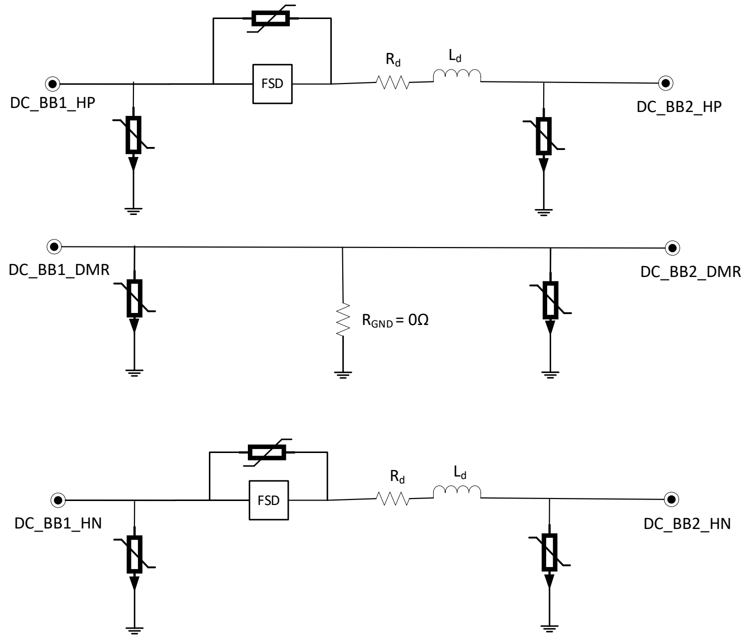


FIGURE 8-35

Electrical circuit of the bus coupler in DCSS#5 connecting two DC busbar sections (longitudinal coupling) with solid grounding

DC Transmission lines

DC transmission lines are modeled with a frequency dependent (phase) model in PSCAD. This model is a distributed RLC traveling wave model, which incorporates the frequency dependence of the line parameters solved at many frequency points. Only underground cables are considered for the transient analysis. A distinction is made between offshore and onshore cable segments. The cable parameters are based on the DC-system data listed in section 8.1.2 in combination with common cross-sectional data for 2 GW cables.

Input parameters

The following parameters are assumed for the transient analysis. The values partly are based on AC- and DC-system data listed in section 8.

TABLE 8-77

Basic AC system data used for AC-system #1, #3 and #5

	Unit	Value	Comment
Nominal AC voltage (LL, rms)	kV	132	See Table 8-20
Short Circuit Level	MVAr	7316	See Table 8-21
X to R Ratio	-	10	See Table 8-21
Z_0 to Z_1 ratio	-	1.35	

TABLE 8-78

Basic AC system data used for AC-system #2

	Unit	Value	Comment
Nominal AC voltage (LL, RMS)	kV	400	See Table 8-15
Short Circuit Level	MVA	55426	See Table 8-16
X to R ratio	-	20	See Table 8-16Table 8-16
Z_0 to Z_1 ratio	-	1.35	

TABLE 8-79

Basic AC system data used for AC-system #4

	Unit	Value	Comment
Nominal AC voltage (LL, RMS)	kV	400	See Table 8-17
Short Circuit Level	MVA	29099	See Table 8-18
X to R ratio	-	20	See Table 8-18Table 8-18
Z_0 to Z_1 ratio	-	1.35	

TABLE 8-80

Transformer data (onshore)

	Unit	Value	Comment
Nominal apparent power	MVA	1179	
Winding #1 Type	-	Y	
Winding #2 Type	-	D	
Positive Sequence Leakage Reactance	p.u.	0.125	
Eddy current loss	p.u.	0.00225	
Copper Losses	p.u.	0.00225	
Primary voltage (RMS, LL)	kV	400	
Transformer secondary voltage (peak, LE)	kV	233.5	
Transformer secondary voltage (peak, LE)	kV	233.5	
Magnetizing current	%	2	
Knee voltage	p.u.	1.2	
Air core reactance	p.u.	0.4	

TABLE 8-81

Transformer data (offshore)

	Unit	Value	Comment
Nominal apparent power	MVA	510	Two parallel transformers are considered.
Winding #1 Type	-	Y	
Winding #2 Type	-	D	
Positive Sequence Leakage Reactance	p.u.	0.125	
Eddy current loss	p.u.	0.00225	
Copper Losses	p.u.	0.00225	
Primary voltage (RMS, LL)	kV	132	
Transformer secondary voltage (peak, LE)	kV	233.5	Converter side
Magnetizing current	%	2	
Knee voltage	p.u.	1.2	
Air core reactance	p.u.	0.4	

TABLE 8-82

Converter parameters (set 1)

	Unit	Value	Comment
Average submodule capacitance (C_{SM})	mF	8	
Number of submodules per arm (N_{SM})	1	220	
Average submodule capacitor voltage (V_{SM})	kV	4	
Arm inductance L_{arm}	mH	43	
DC reactor L_d	mH	10	
Arrester voltage ratings	kV	A: 525 B: 100	A: DC+/DC- B: Neutral bus Default characteristics of a metal oxide surge arrester (ASEA XAP-A, PSCAD 5.0) referred to the arrester voltage rating.
Arm overcurrent threshold	kA	3.5 5 7	More information can be taken from the description of the study cases. If the overcurrent threshold is exceeded, the relay trips after two sampling steps (40µs). The peak values of the DC current are therefore above the overcurrent threshold.
Arm overvoltage protection	kV	787.5	1.5 pu (10ms delay)

TABLE 8-83

Parameters for the DC-switching units

	Unit	Value	Comment
Series reactor L_d	mH	50 200 400	More information can be taken from the description of the study cases.
Series resistance R_d	Ω	0	
Arrester voltage ratings	kV	A: 525 B: 100 C: 400	A: DC+/DC- B: Neutral bus (parallel Arrester) C: FSD varistor/arrester Default characteristics of a metal oxide surge arrester (ASEA XAP-A, PSCAD 5.0) referred to the arrester voltage rating.
Grounding resistance R_{GND}	Ω	0.0	Solid grounding

Study case description

For the transient analysis, a maximum active power transfer of approximately 4 GW is considered. It is assumed that the active power injection is evenly distributed across the offshore converter stations. For this load flow situation, voltage set points are considered according to the stationary analysis in chapter 8.2. Table 8-84 gives an overview of the specific values.

TABLE 8-84

Active power injection at the converter stations

	Unit	CNVS#1	CNVS#2	CNVS#3	CNVS#4	CNVS#5
Active power injection	GW	1.33	-2.00	1.33	-2.00	1.33
Voltage setpoint	kV	525.00	521.48	524.79	511.35	525.00

The transient analysis focuses on the full extent demonstrator topology. Figure 8-36 shows the fault locations considered within this study. A distinction is made between ordinary faults within the fault separation zones (see section 8.1.1) and faults with a greater electrical distance to these zones. Ordinary faults are considered for the investigation as defined in section 8.1.1. For converter stations and DC switching stations, pole-to-ground faults are assumed to be ordinary faults. For DC lines, pole-to-ground and pole-to-pole faults are considered.

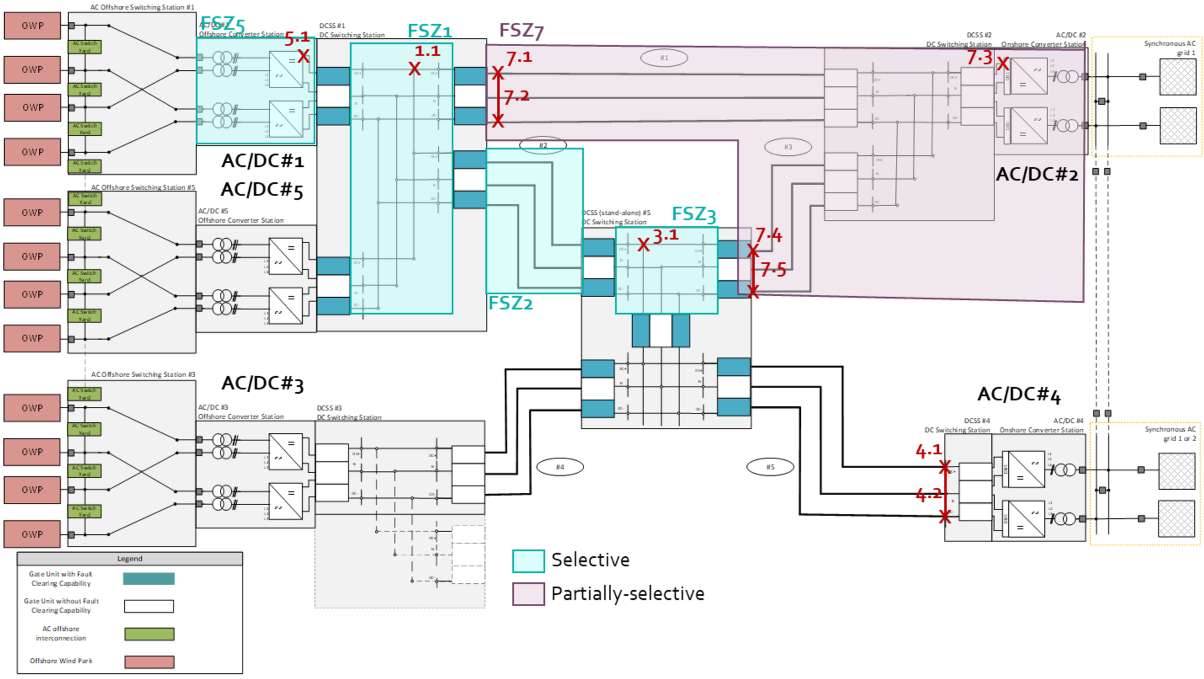


FIGURE 8-36

Illustration of the investigation fault locations in the system

To assess the transient stresses, potential system constraints are considered, such as different converter overcurrent capabilities, sizing of DC reactors for the locations of fault separation devices and the fault neutralization time. The fault neutralization time defines the time between the detection of a traveling wave at a specific FSD location and the start of the current suppression. It is illustrated as $t_{1ms/2ms/5ms}$ in Figure 8-37. The detection of the traveling wave is based on a simplified measurement of the voltage gradient at the FSD location.

The following list gives an overview of the considered system constraints:

- Converter overcurrent capability (I_{OCC}): 3.5 kA, 5 kA, 7 kA
- DC inductance at FSD locations (L_{DC}): 50 mH, 200 mH, 400 mH
- Fault neutralization time (T_N): 1 ms, 2 ms, 5 ms

Simulations are run for the above faults and the various assumptions. Based on this, the worst-case fault locations are identified for the given set of simulations. For these cases, the transient stresses in terms of DC voltage and current bands, as well as the arm voltages and currents and the dissipated energies in the converter stations and DCSS#1 and DCSS#5 are observed.

The objective is to provide an assessment of the transient stresses expected for a combination of constraints. Due to the large number of results, the following analysis focuses on the 3.5 kA and 7 kA converter overcurrent capability and the limits of the given assumptions for DC inductances (50 mH, 400 mH) and fault neutralization time (1 ms, 5 ms). The results for all other combinations fall between these parameter ranges.

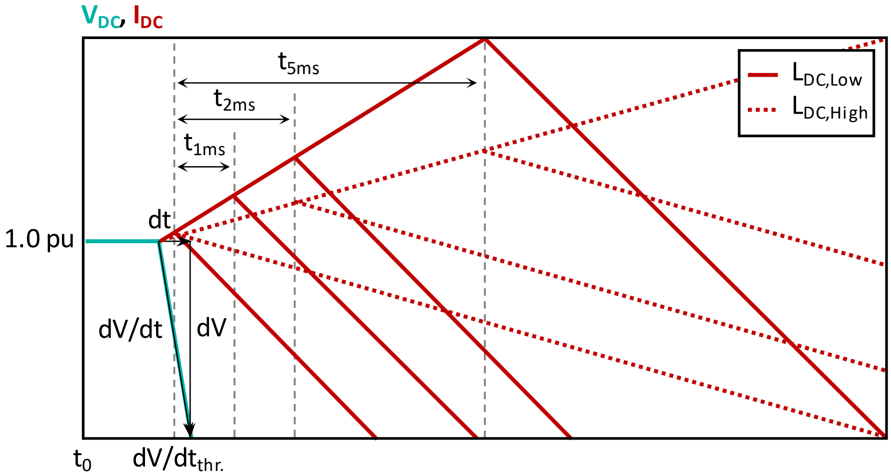


FIGURE 8-37

Illustration of the simplified fault detection at the FSD location based on the voltage gradient (dV/dt) of the travelling wave and different breaker operating times ($t_{1\,ms}$, $t_{2\,ms}$, $t_{5\,ms}$)

8.4.2. Transient DC voltage and current bands

This section leads through the study to derive transient DC voltage and current bands. The focus of this analysis is on the fault neutralization time.

Identification of critical fault locations

Below, information on the system performance for different constraints is provided by the identification of critical fault locations. This can be seen as an indication of the influence of different constraints on the performance of the system. First, an overview of all simulation results is given for the entire simulation time range. This is followed by a more detailed assessment of the fault locations that lead to the maximum transient stresses in the fault neutralization time range. Table 8-85 summarizes the results in terms of transient DC voltages and current bands, including information on the corresponding fault location and system constraints. Based on the maximum transient DC voltages and currents, the resulting values assuming a higher overcurrent capability of 7 kA are also shown.

There are different peak values depending on whether a converter blocks or remains in continuous operation. In the case of voltage, the maximum values occur at the time after CNVS#1/5 block. This is due to the fact that this is a simplified type 5/6 model, which does not reflect the blocking dynamics of the converters. The maximum voltage value of 997.55 kV occurs due to an exceedance of the reverse voltage of the diode at the point of connection of the submodule capacitance. As a result, the aggregated submodule voltage, which is made up of the number of submodules and the submodule voltage, is present at the converter arm in the simulation. It should be noted that this is not the actual expected behavior of a blocking converter. Nevertheless, these values are given for the sake of completeness. The relevant focus for the study package is the time range of primary protection for converters in continuous operation (CO). This leads to a high voltage peak, which is then limited by the pole arresters. Further information on the location of the diode at the submodule capacitance and the characteristics of the arresters can be found in the description of the modelling approach referred to Figure 8-32.

TABLE 8-85

Peak values of DC voltages and DC currents at the converter terminals (DC_CNVS_HP/HN) and the DC switching stations (DC_HP/HN, DC_BB_HP/HN, DC_DCL_HP/HN) for different fault locations and description of system constraints (I_{OCC} = 3.5 kA)

		Unit	Value	Time [s]	Object	Fault	Info
CNVS Offshore	Max. Interruption Current (DC+/DC-)	kA	5.01 9.5 10.22 19.05	1.0514 1.0508 1.0554 1.0508	CNVS#1	5.1	CO (3.5 kA) PS (3.5 kA) CO (7 kA) PS (7 kA)
	Max. Voltage (DC+/DC-)	kV	776.53 997.55	1.0568 1.0566	CNVS#1/5	5.1	CO (3.5 kA) PS (3.5 kA)
CNVS Onshore	Max. Interruption Current (DC+/DC-)	kA	3.65 8.60 14.74 19.01	1.0512 1.0528 1.0526 1.056	CNVS#2	7.3	CO (3.5 kA) PS (3.5 kA) CO (7 kA) PS (7 kA)
	Max. Voltage (DC+/DC-)	kV	567.74 600.36	1.0531 1.1420	CNVS#2	5.1	CO (3.5 kA) PS (3.5 kA)
DCSS#1	Max. Interruption Current (DC+/DC-) Peak values for: • L_{DC} = 50 mH • T_O = 5 ms	kA	20.78 29.43	1.0543 1.0554	DCSU#11	7.2	3.5 kA 7 kA
	Max. Voltage (DC+/DC-)	kV	721.67	1.0596	DCSU#C1/C5	7.5	50 mH, 5 ms
DCSS#5	Max. Current (DC+/DC-) Peak values for: • L_{DC} = 50 mH • T_O = 5 ms	kA	22.75 22.75	1.0554 1.0549	DCSU#52	7.5	3.5 kA 7 kA
	Max. Voltage (DC+/DC-)	kV	721.67	1.0596	DCSU#52	7.5	50 mH, 5 ms

Pole-to-ground faults

Figure 8-38 and Figure 8-39 provide an overview of the simulation results for the pole-to-ground faults within FSZ1, FSZ3 and FSZ5 (FCZ 1.1, 3.1, 5.1), as well as in FSZ7 (FCZ 7.1, 7.5) and at the end of the long-distance DC transmission line at converter station CNVS#4 (FCZ 4.1). The figures show transient profiles of the DC voltages and currents at the offshore and onshore converter station terminals (DC+/DC-). These figures are only intended to give an overview of the extracted results. The transient DC voltage and current bands are extracted by a more detailed analysis of each set of simulation results, which is described in the next section. However, the maximum values of the transient DC voltage occur for the set of simulations with an overcurrent capability of 3.5 kA. Therefore, the extraction of the peak values is focused on this parameter set. For the transient DC currents, a comparison of the maximum currents is provided for the fault neutralization time, as indicated in section 8.4.1.

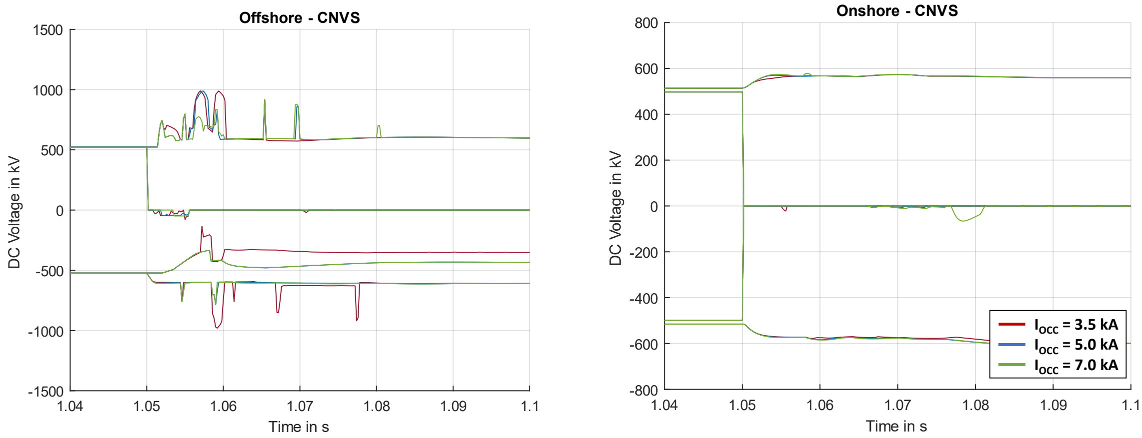


FIGURE 8-38

Envelopes of the transient DC voltages at offshore (CNVS#1/5/3) and onshore (CNVS#2/4) converter stations for all pole-to-ground faults for all simulations with variation of T_N and L_{DC} and different converter overcurrent capabilities (I_{OCC})

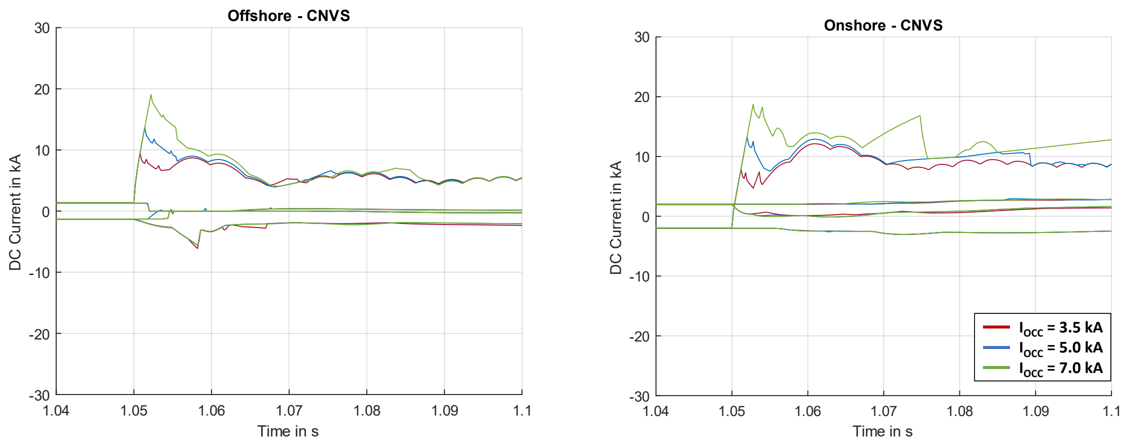


FIGURE 8-39

Envelopes of the transient DC currents at offshore (CNVS#1/5/3) and onshore (CNVS#2/4) converter stations for all pole-to-ground faults for all simulations with variation of T_N and L_{DC} and different converter overcurrent capabilities (I_{OCC})

Figure 8-40 and Figure 8-41 give an overview of the transient DC voltages and currents for the pole-to-ground faults. This refers to the faults within FSZ1, FSZ3 and FSZ5 (FCZ 1.1, 3.1, 5.1), as well as in FSZ7 (FCZ 7.1, 7.5) and at the end of the long-distance DC transmission line at converter station CNVS#4 (4.1). A detailed assessment for specific cases leading to the maximum DC voltages and currents follows in the next section. The figures show the DC voltages and currents at DCSS#1 and DCSS#5 (DC+/DC-).

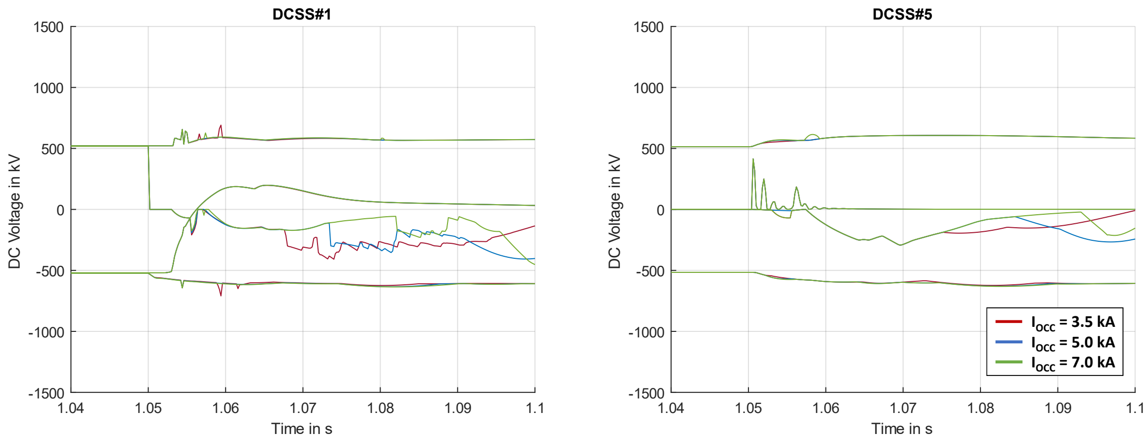


FIGURE 8-40

Envelopes of the transient DC voltages at DCSS#1 and DCSS#5 for all pole-to-ground faults for all simulations with variation of T_N and L_{DC} and different converter overcurrent capabilities (I_{OCC})

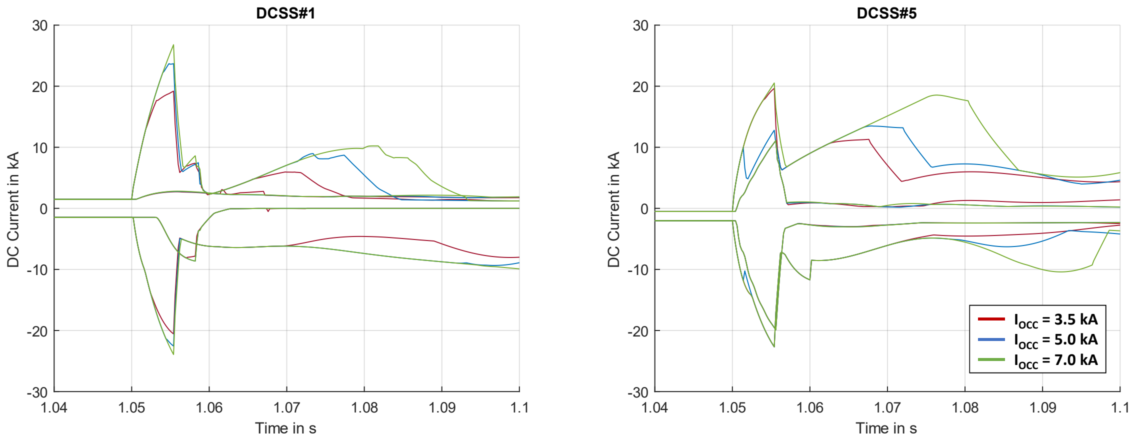


FIGURE 8-41

Envelopes of the transient DC currents at DCSS#1 and DCSS#5 for all pole-to-ground faults for all simulations with variation of T_N and L_{DC} and different converter overcurrent capabilities (I_{OCC})

Pole-to-pole faults

Figure 8-42 and Figure 8-43 give an overview of all simulation results for the pole-to-pole faults (FCZ 7.2, 7.5), which are located within FSZ7 and at the end of the long-distance DC transmission line at converter station CNVS#4 (FCZ 4.2). The figures show the DC voltages and currents at the offshore and onshore converter station terminals (DC+/DC-). The contribution to the fault current from the offshore stations is smaller because they are protected by DC-FSDs. This will be discussed in more detail in the next section. As in the case of the pole-to-ground faults, the maximum DC voltages occur for the 3.5 kA converter overcurrent capability in the simulation sets. This is considered in the description of peak values for transient DC voltages and currents.

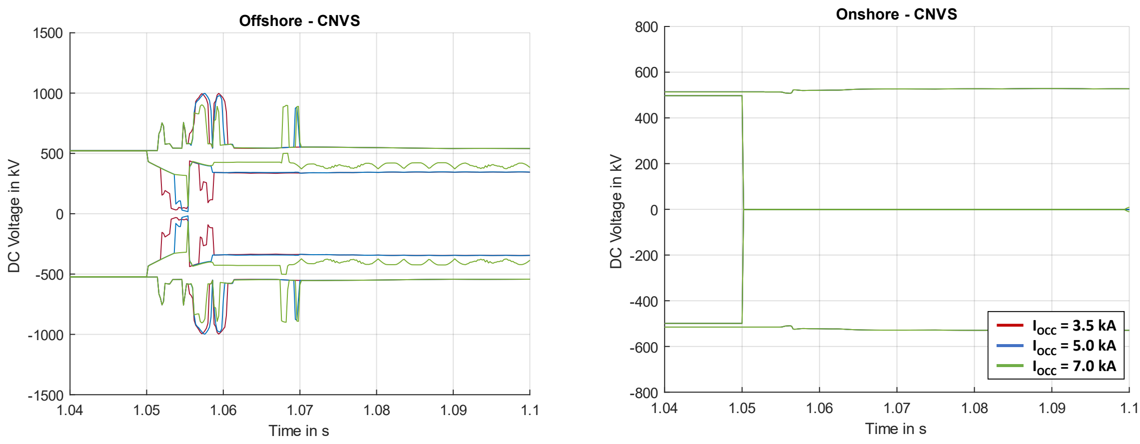


FIGURE 8-42

Envelopes of the transient DC voltages at offshore (CNVS#1/5/3) and onshore (CNVS#2/4) converter stations for all pole-to-pole faults for all simulations with variation of T_N and L_{DC} and different converter overcurrent capabilities (I_{OCC})

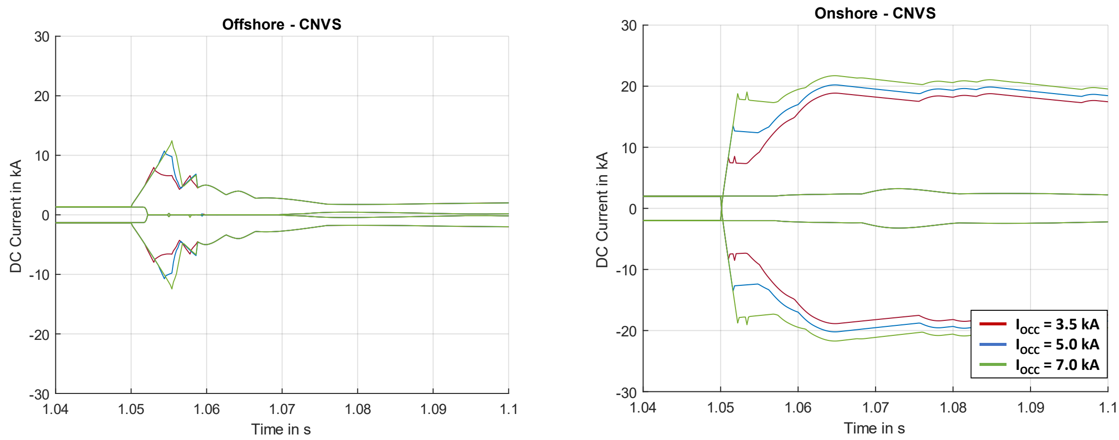


FIGURE 8-43

Envelopes of the transient DC currents at offshore (CNVS#1/5/3) and onshore (CNVS#2/4) converter stations for all pole-to-pole faults for all simulations with variation of T_N and L_{DC} and different converter overcurrent capabilities (I_{OCC})

Figure 8-44 gives an overview of the transient DC voltages and currents for the pole-to-pole faults. This refers to the faults within FSZ7 (FCZ 7.2, 7.5) and at the end of the long-distance DC transmission line at converter station CNVS#4 (FCZ 4.2). A detailed assessment for specific cases leading to the maximum DC voltages and currents follows the next section. The figures show the DC voltages and currents at DCSS#1 and DCSS#5 (DC+/DC-).

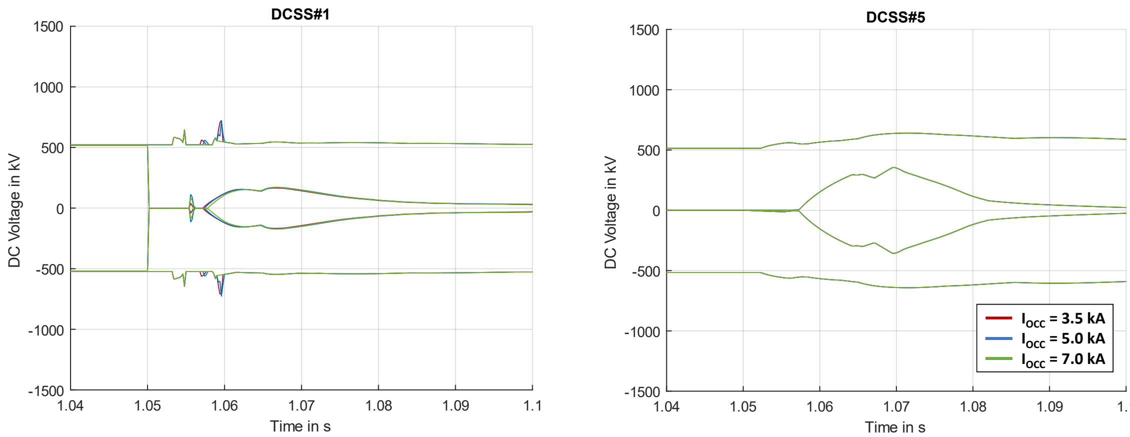


FIGURE 8-44

Envelopes of the transient DC currents at DCSS #1 and DCSS #5 for all pole-to-pole faults for all simulations with variation of T_N and L_{DC} and different converter overcurrent capabilities (I_{OCC})

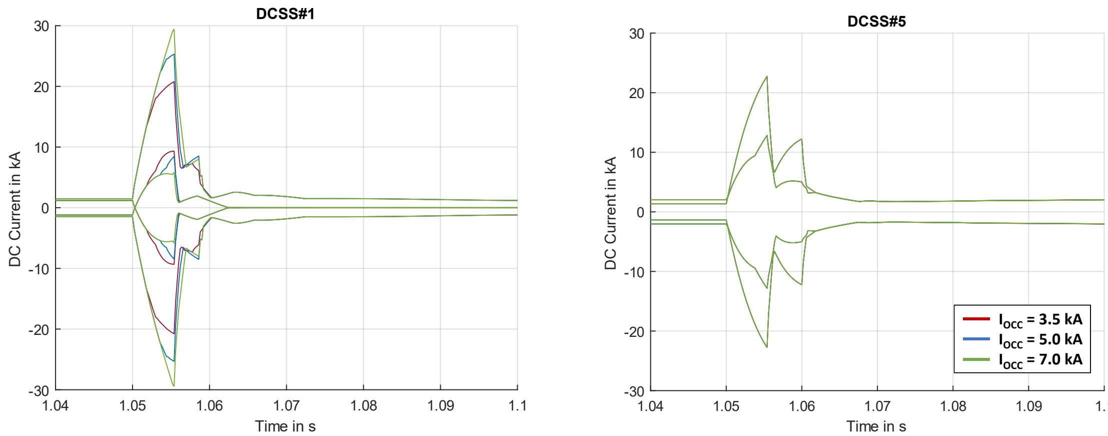


FIGURE 8-45

Envelopes of the transient DC voltages at DCSS #1 and DCSS #5 for all pole-to-pole faults for all simulations with variation of T_N and L_{DC} and different converter overcurrent capabilities (I_{OCC})

Protection matrix

Table 8-86 gives an overview of the blocking behavior of the converter stations for the different faults, considering the system constraints discussed (i.e. DC inductance, fault neutralization time). A comparison is made according to the System Protection Matrix (SPM) in section 8.1.1. For a given DC fault in a certain fault separation zone, the SPM indicates which converter stations should remain in continuous operation (CO) or are allowed to show a permanent stop (PS). If the converter station behavior according to the SPM is not achieved (√) for a given case, Table 8-86 indicates whether a converter station blocks for a single pole (SP#X) or both poles (DP#X). In some cases, a temporary stop (TS) could also be considered for certain converter stations (see section 8.1.1). Additional tables showing the results for higher converter overcurrent capabilities of 5 kA and 7 kA can be found in Annex 4: SPM conformity check.

TABLE 8-86

SPM check for the considered cases and converter overcurrent capability of 3.5 kA (√: SPM conform, SP: Single pole blocks, DP: Double pole blocks)

SPM conformity check					
Fault location	SPM	3.5 kA			
		50 mH 1 ms	50 mH 5 ms	400 mH 1 ms	400 mH 5 ms
1.1 (P2G) BB_HP_1	PS(TS) DP#1/5	√	SP#2	SP#2	SP#1/5
3.1 (P2G) BB_HP_5A	CO	SP#1	SP#1/5/2/3	SP#5/2	SP#1/5/2
5.1 (P2G) HP_1	PS DP#1	√	DP#5	√	√
7.1 (P2G) DCL_HP_12	PS DP#2 (TS DP#1/5)	√	SP#1/5	√	√
7.2 (P2P) DCL_HP_HN_12	PS DP#2 (TS DP#1/5)	√	DP#1/5	√	√
7.3 (P2G) DCL_HP_52	PS DP#2 (TS DP#1/5)	√	SP#1/5	√	√
7.4 (P2G) DCL_HP_HN_52	PS DP#2 (TS CNVS1/5)	√	DP#1/5	√	√
7.5 (P2G) HP_2	PS CNVS2 (TS CNVS1/5)	√	SP#1/5	√	√
4.1 (P2G) BB_HP_4	N/A	SP#4	SP#4	SP#4	SP#4
4.2 (P2P) BB_HP_HN_4	N/A	DP#4	DP#4	DP#4	DP#4

Derivation of the transient DC voltage and current bands

From all the simulation sets, the fault locations that result in the maximum transient stresses are identified. These cases are used to define the transient DC voltage and current bands. The dissipated energies are also determined for the same scenario. All results are shown for converter stations and DC switching stations. For the converter stations, a separation between offshore (CNVS#1/3/5) and onshore converter stations (CNVS#2/4) is considered. Therefore, the initial current is 1.33 kA for each offshore converter station and 2 kA for each onshore converter station. The figures show the DC voltages and currents for all converter stations and poles in a single plot (DC+/DC-). For the DC Switching Stations (DCSS), a separation between DCSS#1 and DCSS#5 (stand-alone) is considered. The figures show the DC voltages and currents (DC+/DC-) for all DC Switching Units (DCSU) at the DCSS.

Transient DC voltage bands

The transient DC voltage bands are derived below. The results are separated between the values at the converter station terminals and the DC Switching Stations.

Converter stations

The maximum and minimum DC voltages for the pole to ground faults occur at the offshore converter stations. Figure 8-46 shows the corresponding values for the fault locations 5.1 (HP_1) for the maximum

DC voltages and 3.1 (BB_HP_5A) for the minimum DC voltages. In addition, the corresponding DC voltages are shown for the other converter stations.

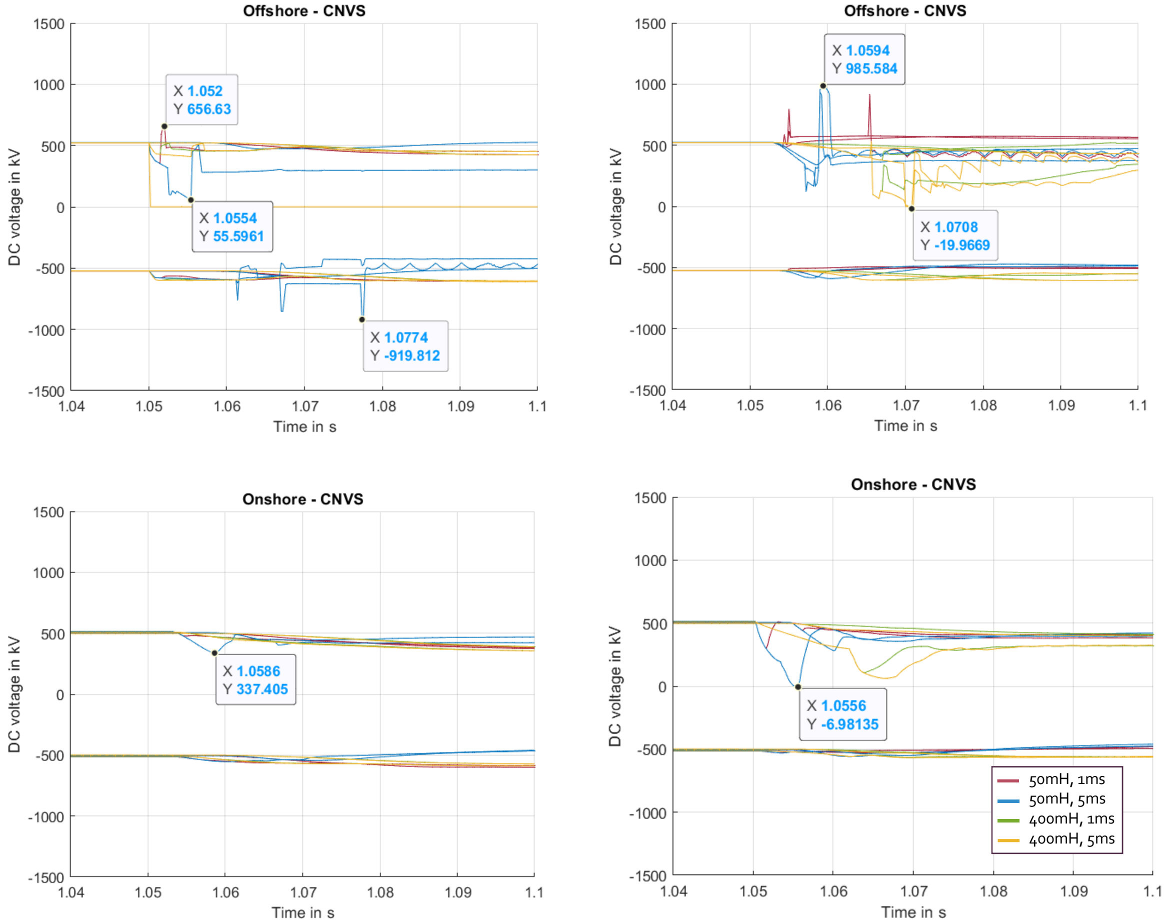


FIGURE 8-46

Maximum DC voltages at offshore converter stations for fault location 5.1 (HP_1) and minimum DC voltages (voltage reversal) at onshore converter stations for fault location 3.1 (BB_HP_5A) for pole to ground faults and corresponding DC voltages at onshore converter stations.

The maximum and minimum DC voltages for the pole-to-pole faults occur at the offshore converter stations. Figure 8-47 shows the corresponding values for the fault locations 7.5 (DCL_HP_HN_52) for the maximum DC voltages and 7.2 (DCL_HP_HN_12) for the minimum DC voltages. In addition, the corresponding DC voltages are shown for the onshore converter stations. It becomes clear that those do not show an increase in DC voltages.

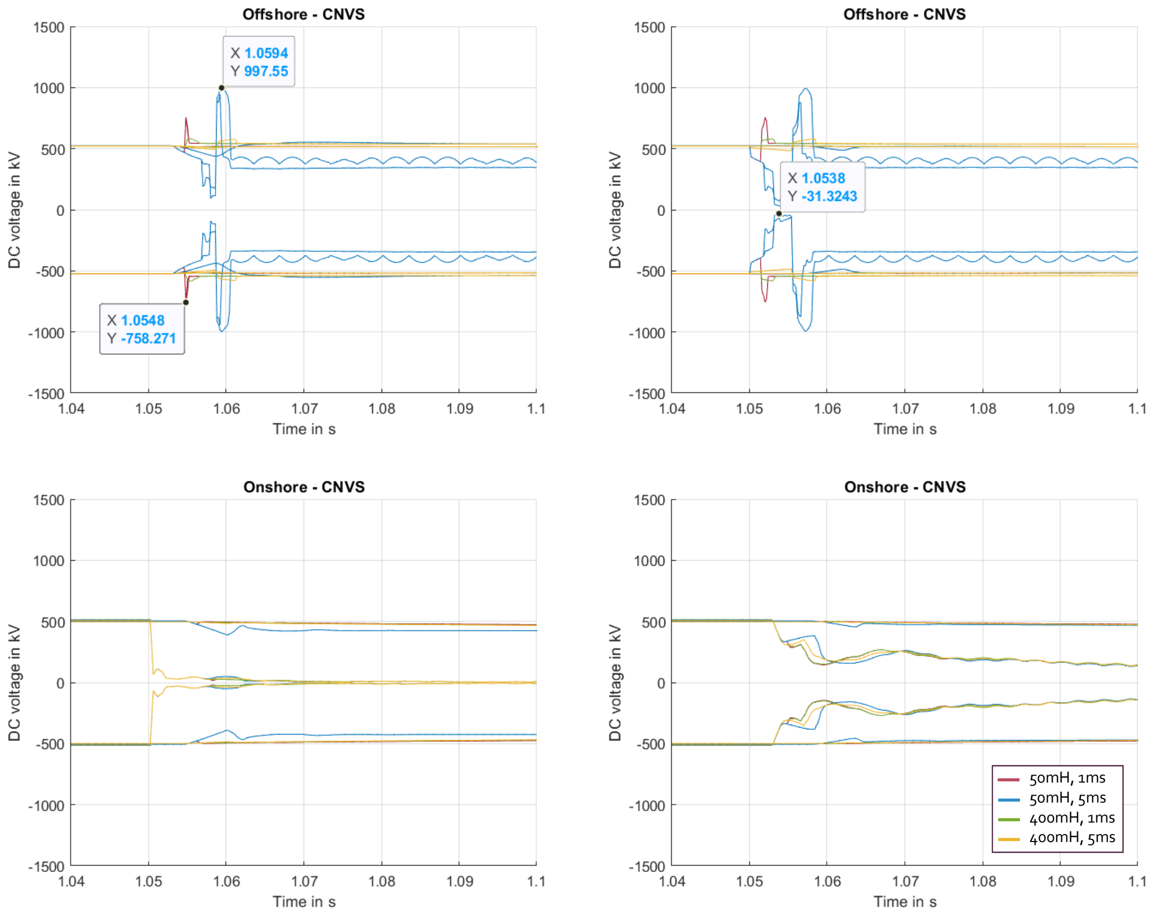


FIGURE 8-47

Maximum DC voltages at offshore converter stations for fault location 7.5 (DCL_HP_HN_52) and minimum DC voltages at offshore converter stations for fault location 7.2 (DCL_HP_HN_12) for pole-to-pole faults and corresponding DC voltages at onshore converter stations.

<u>DC Switching Stations</u>

The maximum DC voltages at DC switching station #1 for the pole-to-ground faults occur for fault location 7.3 (HP_2). The maximum DC voltages at DC witching station #5 for the pole-to ground faults occurs at DCSU#51 for fault location 3.1 (BB_HP_5A).

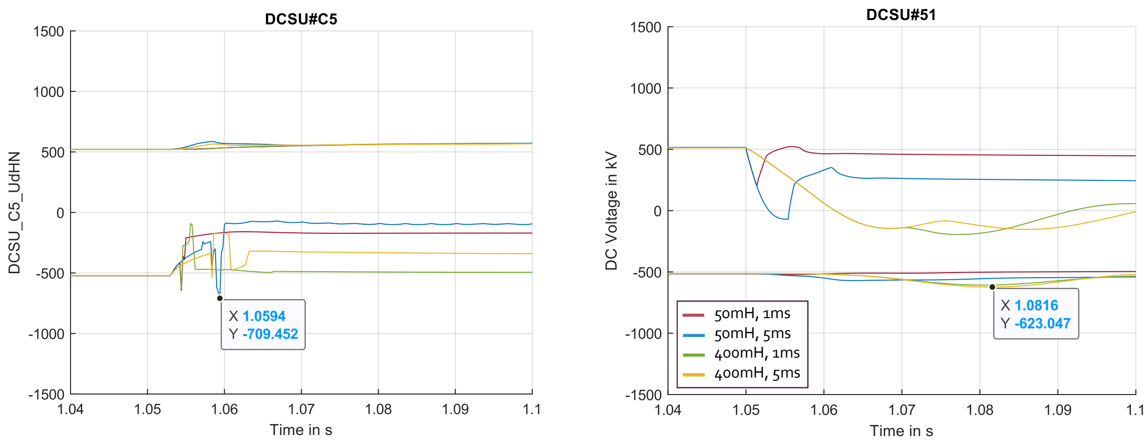


FIGURE 8-48

Transient DC voltages for fault locations 7.3 (HP_2, DCSU#C1/C5) and 3.1 (BB_HP_5A, DCSU#51) that lead to the maximum values for the pole-to-ground faults

The minimum DC voltage (voltage reversal) at DC switching station #1 for the pole to ground faults occur for fault location 3.1 (BB_HP_5A). The minimum DC voltages at DC switching station #5 for the pole-to-ground faults occurs at DCSU#52 for fault location 7.3 (HP_2).

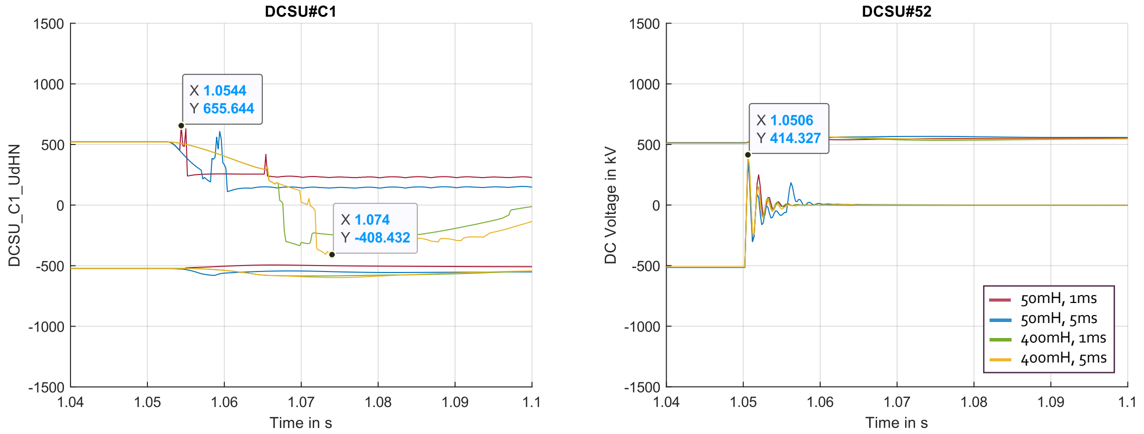


FIGURE 8-49

Transient DC voltages for fault locations 3.1 (BB_HP_5A, DCSU#C1/C5) and 7.3 (HP_2, DCSU#52) that lead to the minimum values for the pole-to-ground faults

The maximum DC voltages at DC switching station #1 for the pole-to-pole faults occurs at DCSU#C1 for fault location 7.5 (DCL_HP_HN_52). The maximum DC voltages at DC switching station #5 for the pole-to pole-faults occur at DCSU#53 for fault location 7.5 (DCL_HP_HN_52).

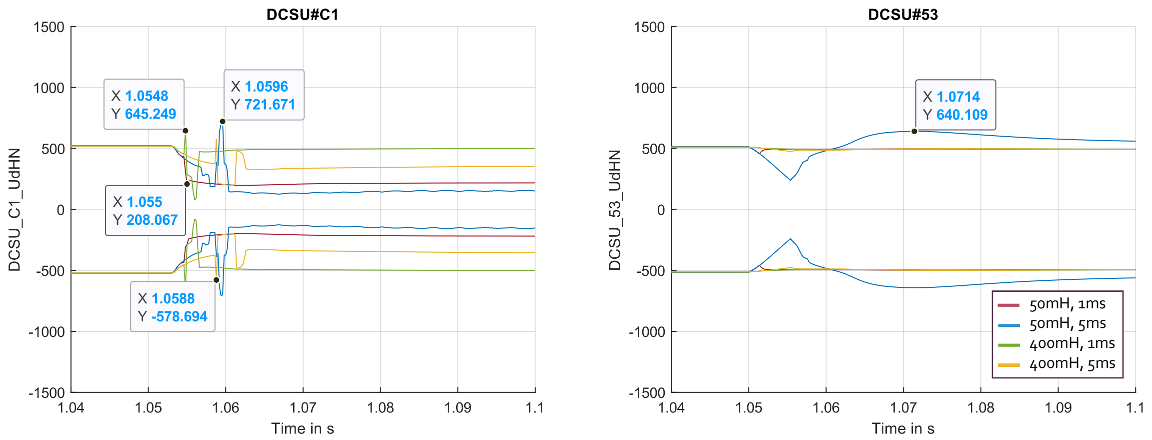


FIGURE 8-50

Transient DC voltages for fault locations 7.5 (DCL_HP_HN_52, DCSU#C1) and 7.5 (DCL_HP_HN_52, DCSS#5) that lead to the maximum values for the pole-to-pole faults

The minimum DC voltages (voltage reversal) at DC switching station #1 for the pole-to-pole faults occur for fault location 7.5 (DCL_HP_HN_52). The minimum DC voltages (voltage reversal) at DCSS#5 for the pole-to-pole faults occur at DCSU#5 for fault location 4.2 (BB_HP_HN_4).

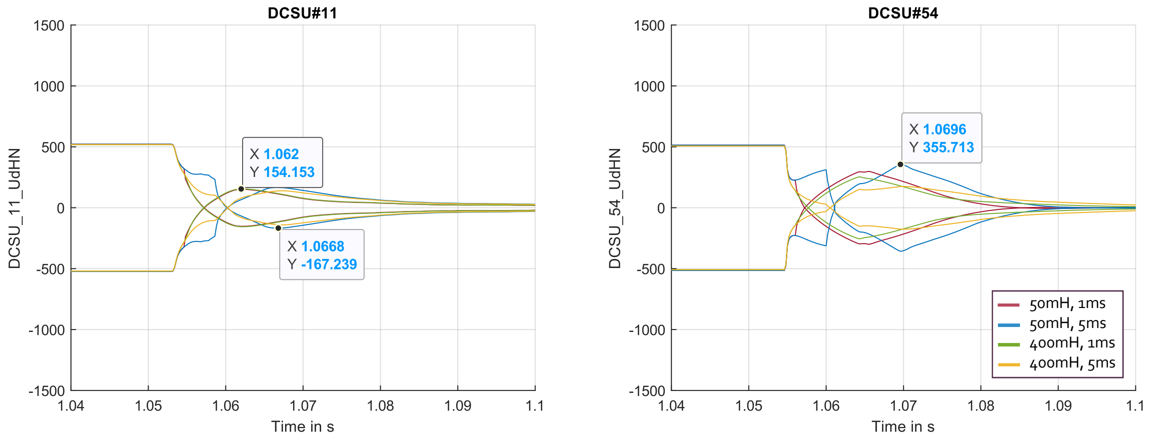


FIGURE 8-51

Transient DC voltages for fault locations 7.5 (DCL_HP_HN_52, DCSU#11) and 4.2 (BB_HP_HN_4, DCSS#5) that lead to the minimum values (voltage reversal) for the pole-to-pole faults

Transient DC current bands

In the following the transient DC current bands are derived. The results are separated between values at the converter station terminals and the DC switching stations.

<u>Converter stations</u>

The maximum DC currents at the offshore converter stations for the pole-to-ground faults occur for fault location 5.1 (HP_1). The maximum DC currents at the onshore converter stations occur for the pole-to-ground faults for fault location 7.3 (HP_2). In both cases, obviously the pole-to-ground fault at one of the terminals at the converter stations leads to the maximum transient stresses within the fault neutralization time range. The pole of the converter station is affected by the fault blocks. A higher overcurrent capability of the converter would lead to a later blocking, and thus to a higher DC current, as shown in Figure 8-52. Due to the load flow situation in all cases the onshore converter stations show a reversal in the DC currents, while offshore converters increase the injected DC currents at their terminals.

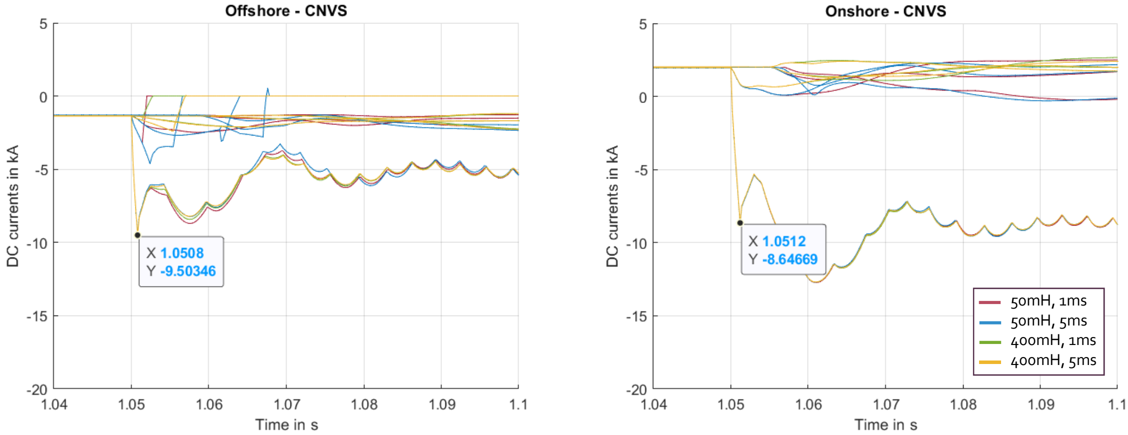


FIGURE 8-52

Transient DC current for fault locations 5.1 (HP_1, offshore) and 7.3 (HP_2, onshore) that lead to the maximum values for the pole to ground faults (overcurrent capability of 3.5 kA)

A higher overcurrent capability of the converter would lead to a later blocking, and thus to a higher DC current, as shown in Figure 8-53.

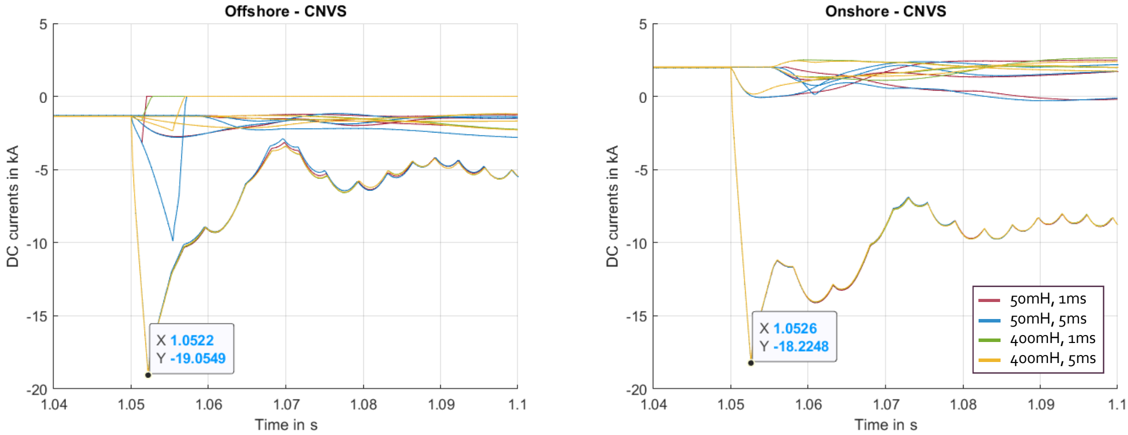


FIGURE 8-53

Transient DC current for fault locations 5.1 (HP_1, offshore) and 7.3 (HP_2, onshore) that lead to the maximum values for the pole to ground faults (overcurrent capability of 7 kA)

The maximum DC currents at the offshore converter stations for the pole-to-pole faults occur for fault location 7.2 (DCL_HP_HN_12). The maximum DC currents at the onshore converter stations occur for the pole-to-pole faults for fault location 4.2 (BB_HP_HN_4).

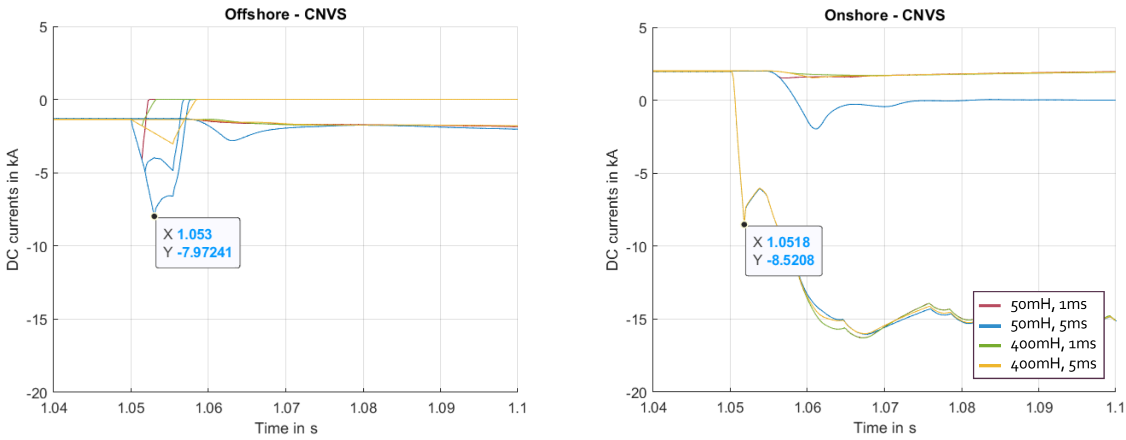


FIGURE 8-54

Transient DC current for fault locations 7.2 (DCL_HP_HN_12, offshore) and 7.5 (DCL_HP_HN_52, onshore) that lead to the maximum values for the pole-to-pole faults (overcurrent capability of 3.5 kA)

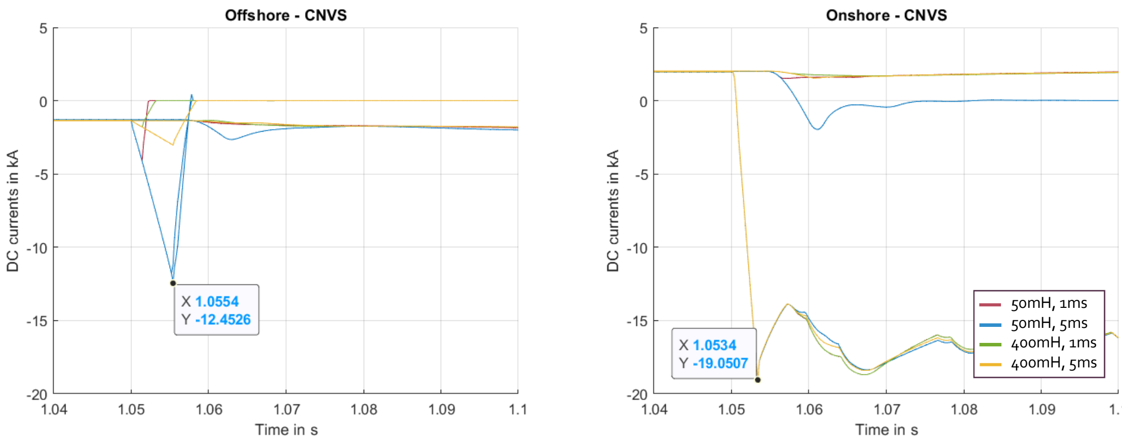


FIGURE 8-55

Transient DC current for fault locations 7.2 (DCL_HP_HN_12, offshore) and 7.5 (DCL_HP_HN_52, onshore) that lead to the maximum values for the pole-to-pole faults (overcurrent capability of 7 kA)

<u>DC switching stations</u>

The maximum DC currents at DC switching station #1 for the pole to ground faults occur for fault location 5.1 (DC_HP_1). The terminal is related to the connection point of the converter station CNVS#1. A pole-to-ground fault at the terminal leads to the highest DC current in DCSS#1. The maximum DC currents at DC switching station #5 for the pole-to-ground faults occurs at DCSU#52 for fault location 7.4 (DCL_HP_52).

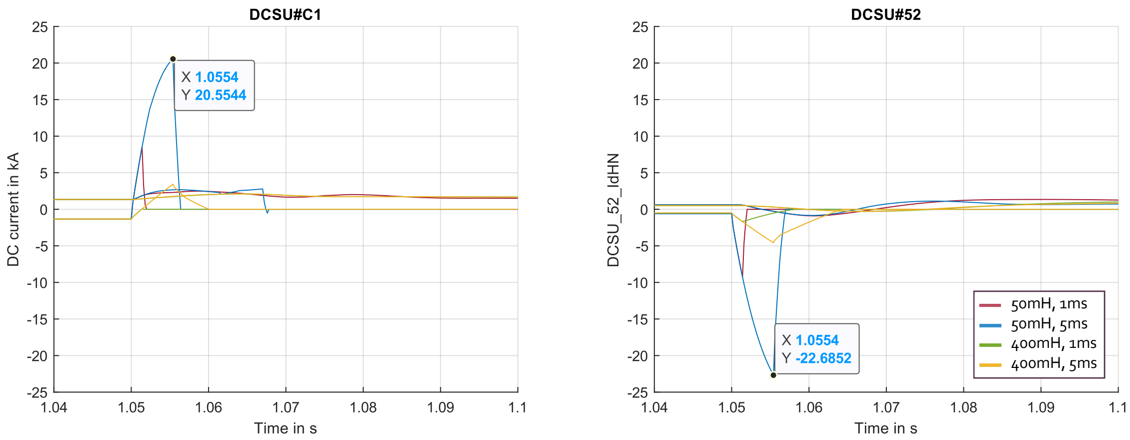


FIGURE 8-56

Transient DC current for fault locations 5.1 (HP_1, DCSS#1) and 7.4(DCL_HP_52, DCSS#5) that lead to the maximum values for the pole-to-ground faults (overcurrent capability 3.5 kA)

A higher overcurrent capability increases the current at DCSU#C1, which is connected to converter station #1. In the case of DCSU#52, the change in overcurrent capability does not affect the maximum value of the transient DC current too much. The difference is lower with a shorter fault neutralization time.

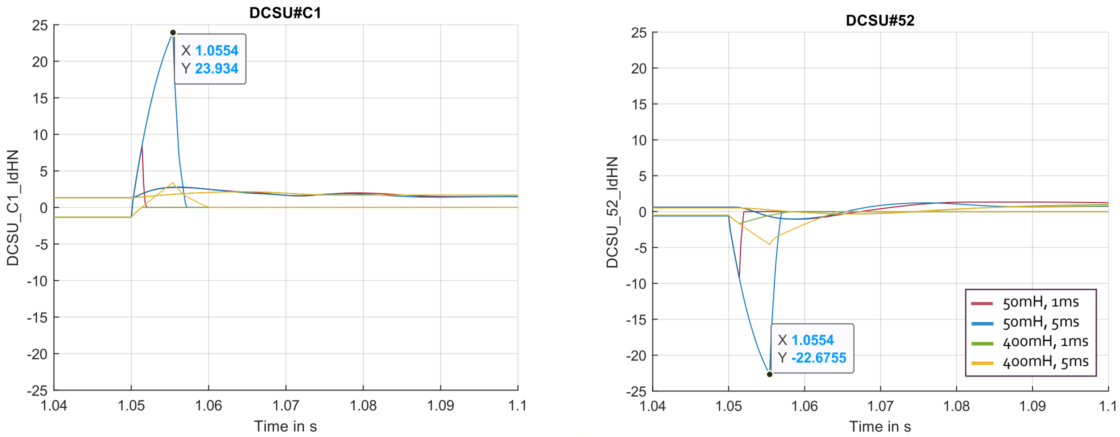


FIGURE 8-57

Transient DC current for fault locations 5.1 (HP_1, DCSS#1) and 7.4 (DCL_HP_52, DCSS#5) that lead to the maximum values for the pole to ground faults (overcurrent capability 7 kA)

The maximum DC currents at DC switching station #1 for the pole-to-pole faults occur at DCSU#11 for fault location 7.2 (DCL_HP_HN_12). The maximum DC currents at DCs witching station #5 for the pole-to-pole faults occurs at DCSU#52 for fault location 7.5 (DCL_HP_HN_52).

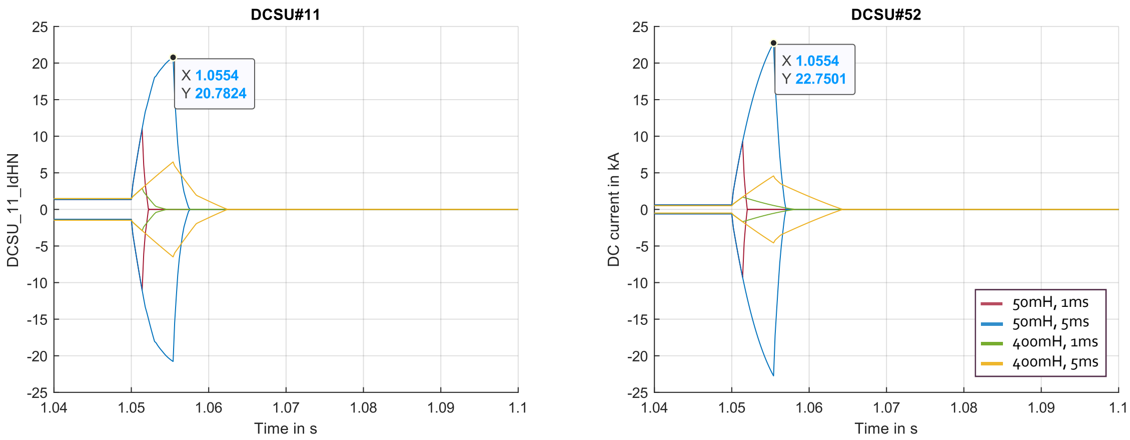


FIGURE 8-58

Transient DC current for fault locations 7.2 (DCL_HP_HN_12, DCSS#1) and 7.5 (DCL_HP_HN_52, DCSS#5) that lead to the maximum values for the pole-to-pole faults (overcurrent capability 3.5 kA)

A higher overcurrent capability increases the current at DCSU#11, which is connected to converter station #1. In the case of DCSU#52, the change in overcurrent capability does not affect the maximum value of the transient DC current. Again, the difference at the converter station terminals is only relevant for a long fault neutralization time.

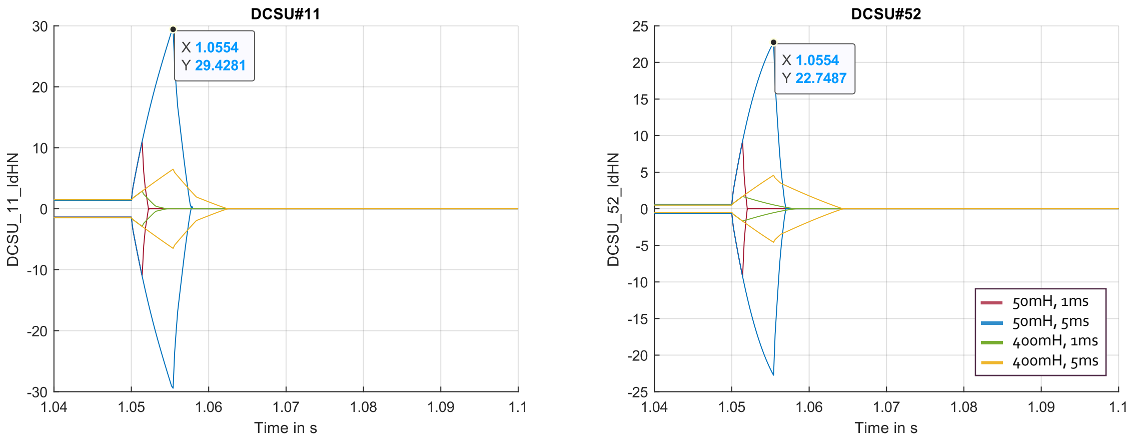


FIGURE 8-59

Transient DC current for fault locations 7.2 (DCL_HP_HN_12, DCSS#1) and 7.5 (DCL_HP_HN_52, DCSS#5) that lead to the maximum values for the pole-to-pole faults (overcurrent capability 7 kA)

Transient arm voltages and currents

In the following the transient arm voltages and currents are shown for the fault locations that lead to maximum values. The results are separated between values at the converter station terminals and the DC switching stations.

Arm voltages

Figure 8-60 shows the transient arm voltages for the fault location 7.5 (DCL_HP_HN_52, pole-to-pole), which leads to the highest peak value at the offshore converter stations. In addition, the arm voltages of the onshore converter stations are shown for the same fault location. This example represents the case of the maximum transient voltage in the case a converter blocks. The arm voltage is limited by the pole arresters, which are part of the vendor specific sub-system design and need to be further specified in the detailed study packages of T3.6.

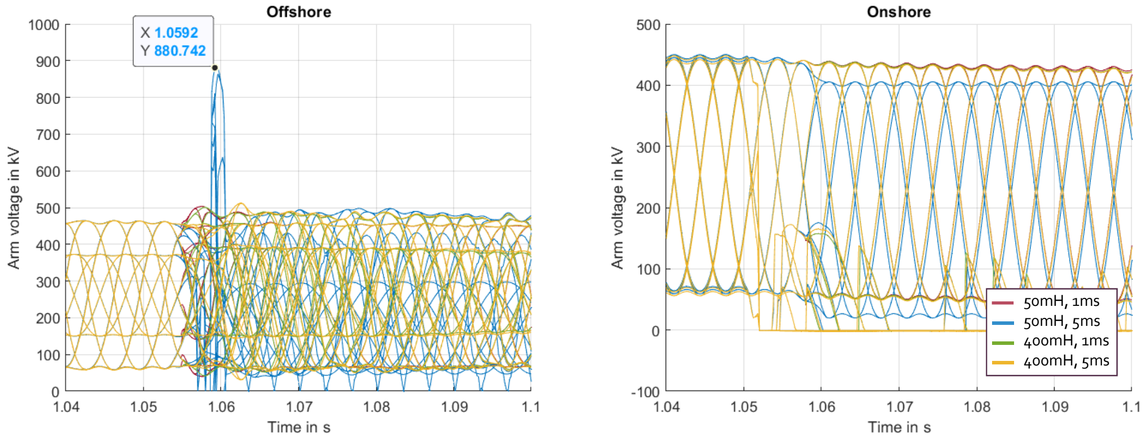


FIGURE 8-60

Transient arm voltages at the offshore and onshore converter stations for fault location 7.5 (DCL_HP_HN_52)

Figure 8-61 shows the transient arm voltages for the offshore and onshore converter stations for the pole to ground fault location 1.1 (BB_HP_1). In this case, there is no limitation due to the pole arrester, as the arm voltages do not rise as high as in the previous case.

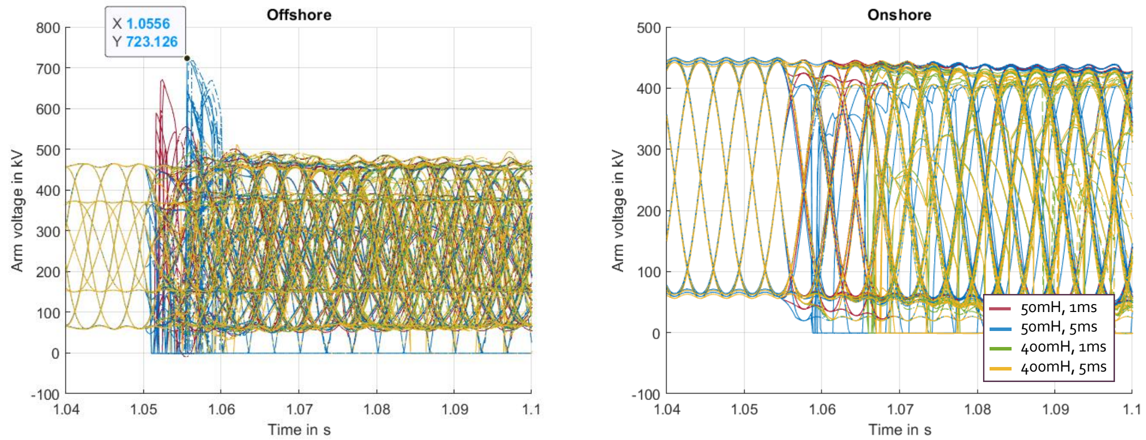


FIGURE 8-61

Transient arm voltages at the offshore and onshore converter stations for fault location 1.1 (BB_HP_1)

Arm currents

Figure 8-62 shows the transient arm currents for the offshore and onshore converter stations for the pole to ground faults. The maximum arm currents occur at the offshore converter stations for fault location DC_BB_HP_1 and at the onshore converter stations for fault location DC_HP_2. The analysis is focused on the fault neutralization time range.

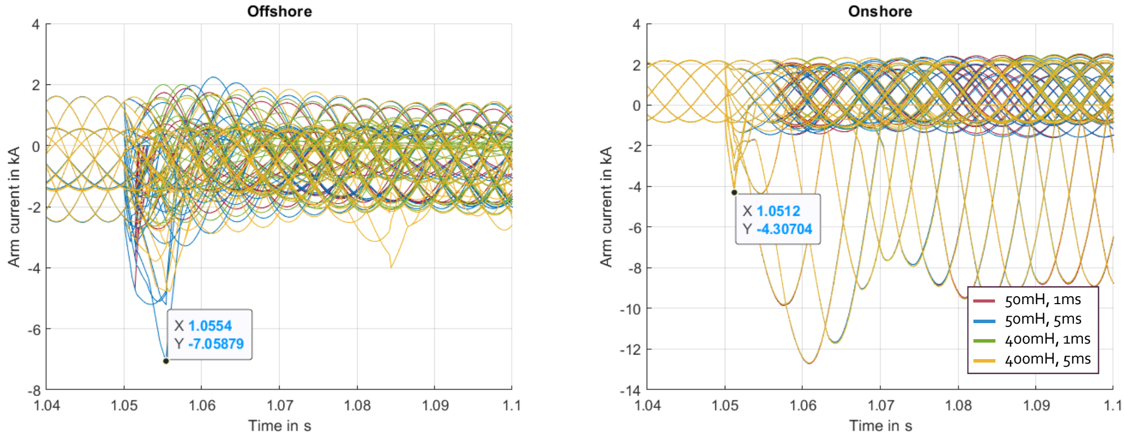


FIGURE 8-62

Transient arm currents at the offshore converter stations for fault location 5.1 (BB_HP_1) and at the onshore converter stations for fault location 7.3 (HP_2) for the pole-to-ground faults

Figure 8-63 shows the transient arm currents for the offshore and onshore converter stations for the pole-to pole-faults. The maximum arm currents occur at the offshore converter stations for fault location 7.2 (DCL_HP_HN_12) and at the onshore converter stations for fault location 7.5 (DCL_HP_HN_52). The analysis is focused on the fault neutralization time range.

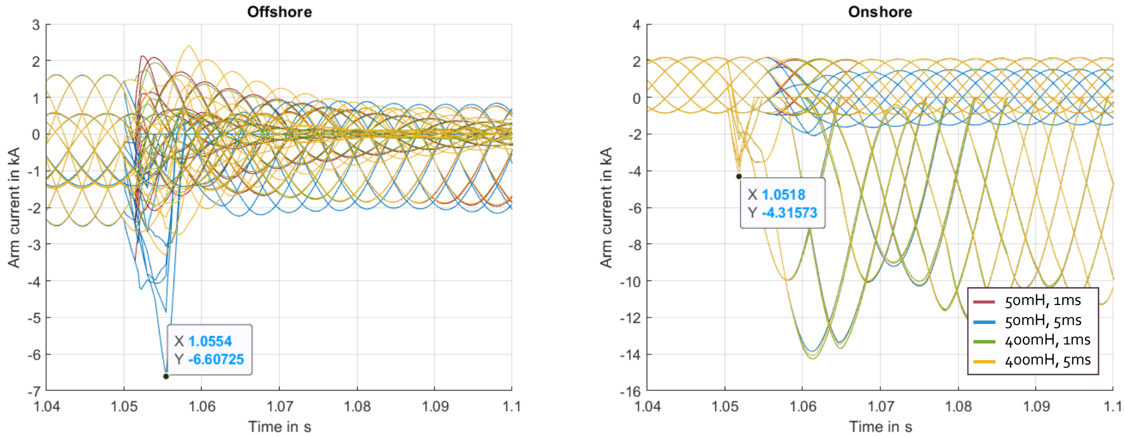


FIGURE 8-63

Transient arm currents at the offshore converter stations for fault location 7.2 (DCL_HP_HN_12) and at the onshore converter stations for fault location 7.5 (DCL_HP_HN_52) for the pole-to-pole faults.

Assessment of dissipated energy

In the following section the dissipated energies at the DC switching stations (DCSS) are assessed. For this, the largest energies dissipated by an individual FSD per DCSS are identified. This is done for each set of simulations considering different fault neutralization times (T_N) and DC inductances (L_{DC}). The shown values represent the cumulated dissipated energies for the individual DC-FSD with maximum value for DCSS#1 and DCSS#5. Figure 8-64 gives an example on the determination of the dissipated energies for the FSDs in DCSS#1 for fault location 3.1 (BB_HP_5A) and DCSS#5 for fault location 1.1 (BB_HP_1).

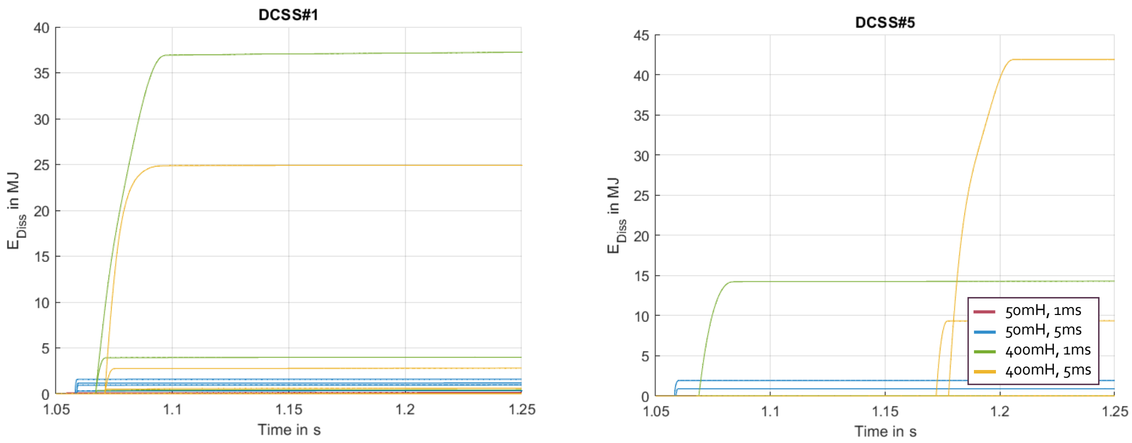


FIGURE 8-64

Maximum dissipated energies for fault location 3.1 (BB_HP_5A) at DCSS#1 and at DCSS#5 for 1.1 (BB_HP_1).

Table 8-87 and Table 8-88 give an overview of the energy dissipated at DCSS#1 and DCSS#5 for different fault locations considering different fault neutralization times (T_N) and DC inductances (L_{DC}). The maximum value of 37.72 MJ is obtained for fault location 3.1 (BB_HP_5A) at DCSS#1 with a T_N of 1 ms and a L_{DC} of 400 mH. For DCSS#5, the maximum value of 41.88 MJ is obtained for fault location 1.1 (BB_HP_1) with a T_N of 5 ms and a L_{DC} of 400 mH.

TABLE 8-87

Maximum values of dissipated energies for an individual DC-FSD at DCSS#1 considering different fault locations, fault neutralization times and DC inductances.

Dissipated energies in kJ (DCSS#1)				
Fault location	3.5 kA			
	50 mH 1 ms	50 mH 5 ms	400 mH 1 ms	400 mH 5 ms
1.1 (P2G) BB_HP_1	4,483.67	8,576.23	6,073.26	12,823.50
3.1 (P2G) BB_HP_5A	203.19	1,590.26	**37,716.90**	24,930.80
5.1 (P2G) HP_1	1,106.65	7,140.48	752.99	4,908.77
7.1 (P2G) DCL_HP_12	2,322.23	8,401.58	2,480.48	12,262.90
7.2 (P2P) DCL_HP_HN_12	2,570.38	11,149.30	2,510.48	12,863.30
7.3 (P2G) DCL_HP_52	231.04	1,531.08	1,401.02	4,529.34
7.4 (P2G) DCL_HP_HN_52	237.13	1,701.15	1,399.13	4,855.63
7.5 (P2G) HP_2	372.16	1,558.32	1,538.10	5,535.54
4.1 (P2G) BB_HP_4	209.32	435.17	1,749.21	2,326.21
4.2 (P2P) BB_HP_HN_4	67.19	66.50	66.90	66.31

TABLE 8-88

Maximum values of dissipated energies for an individual DC-FSD at DCSS#5 considering different fault locations, fault neutralization times and DC inductances.

Fault location	Dissipated energies in kJ (DCSS#5)			
	3.5 kA			
	50 mH 1 ms	50 mH 5 ms	400 mH 1 ms	400 mH 5 ms
1.1 (P2G) BB_HP_1	7.55	1,915.29	14,398.10	**41,883.30**
3.1 (P2G) BB_HP_5A	4,613.85	8,165.31	30,883.80	32,734.00
5.1 (P2G) HP_1	0.00	317.04	0.00	0.00
7.1 (P2G) DCL_HP_12	134.28	1,567.81	635.33	1,331.95
7.2 (P2P) DCL_HP_HN_12	143.66	1325.75	432.77	1,662.64
7.3 (P2G) DCL_HP_52	1,596.14	11,733.80	4,443.01	13,367.50
7.4 (P2G) DCL_HP_HN_52	1,622.77	11,830.90	4,500.47	13,544.90
7.5 (P2G) HP_2	1,954.29	9,945.47	4,352.77	12,896.80
4.1 (P2G) BB_HP_4	1,334.87	4,573.90	1,2464.8	22,481.40
4.2 (P2P) BB_HP_HN_4	1,401.92	4,858.51	16,363.00	30,162.70

8.4.3. Conclusions

The following tables summarize the preliminary transient voltage and current bands. They contribute to the preliminary main circuit parameters of the onshore and offshore converter stations listed in section 8.1.6 and 8.1.7.

TABLE 8-89

DC pole transient voltages at converter stations (DC+ / DC-)

	Unit	Value	Comment
Max. transient DC voltage (DC+/DC-)	kV	776.53	Offshore
Max. transient DC voltage (DC+/DC-)	kV	567.74	Onshore

TABLE 8-90

DC pole transient current at offshore converter stations (DC+ / DC-) for different converter overcurrent capabilities

	Unit	Value	Comment
Max. transient DC current (DC+/DC-)	kA	9.5 (19.05)	3.5 kA (7 kA) Offshore
Max. transient DC current (DC+/DC-)	kA	8.6 (18.22)	3.5 kA (7 kA) Onshore

TABLE 8-91

Max. dissipated energies at DC switching stations (DCSS)

	Unit	Value	Fault location
DCSS#1	MJ	37.72	3.1 (BB_HP_5A)
DCSS#5	MJ	41.88	1.1 (BB_HP_1)

8.4.4. Recommendations

Despite the limited time frame for Task 3.1, a comprehensive initial assessment of the demonstrator topology was carried out. The transient study package provides a first insight into the transient DC voltages and currents, taking into account the input data agreed with the manufacturers. It should be noted that this is the first iteration, on which basis further detailed system studies will be possible in Task 3.6.

For this purpose, adjustments to both the simulation model and the assumptions made are recommended. The transient study package focused on the primary protection, with generic assumptions agreed and compared with the vendors. The simulations show that a simplified Type 5/6 model has limitations in representing the blocking behavior of the converters. As this has a significant impact on system and protection design, a type 4 simulation model should be developed to enable a more detailed investigation. For reasons of transparency, detailed documentation of the modelling should be provided.

In addition, the assumptions regarding the converter and switchgear capacities have a significant influence on the transient peak values and the resulting energies. It became clear that the manufacturer-specific designs can differ considerably from each other, so that further iterations are necessary to harmonize the detailed assumptions for the simulations and to adapt them to the practical solutions for the first demonstrator.

Abbreviations and acronyms

	Description
AC	Alternating Current
AVM	Average Value Model
CENELEC	European Committee for Electrotechnical Standardization
DBS	Dynamic Braking System (Energy Dissipation System)
DC	Direct Current
DC GC	DC Grid Controller
DCSS	DC Switching Station
DC SU	DC Switching Unit
DC-FSD	DC Fault Separation Device
DMR	Dedicated Metallic Return
GCS	Grid Connection System
HIL	Hardware in the loop
HVDC	High Voltage Direct Current
ISD	In-service date
MT	Multi-Terminal
MV	Multi-Vendor
LCC	Line Commuted Converter
OEM	Original Equipment Manufacturer
P2P	Point-to-Point HVDC
PoC	Point of Connection
SIL	Software in the loop
SPM	System protection matrix
TSO	Transmission System Operator
VSC	Voltage Source Converter

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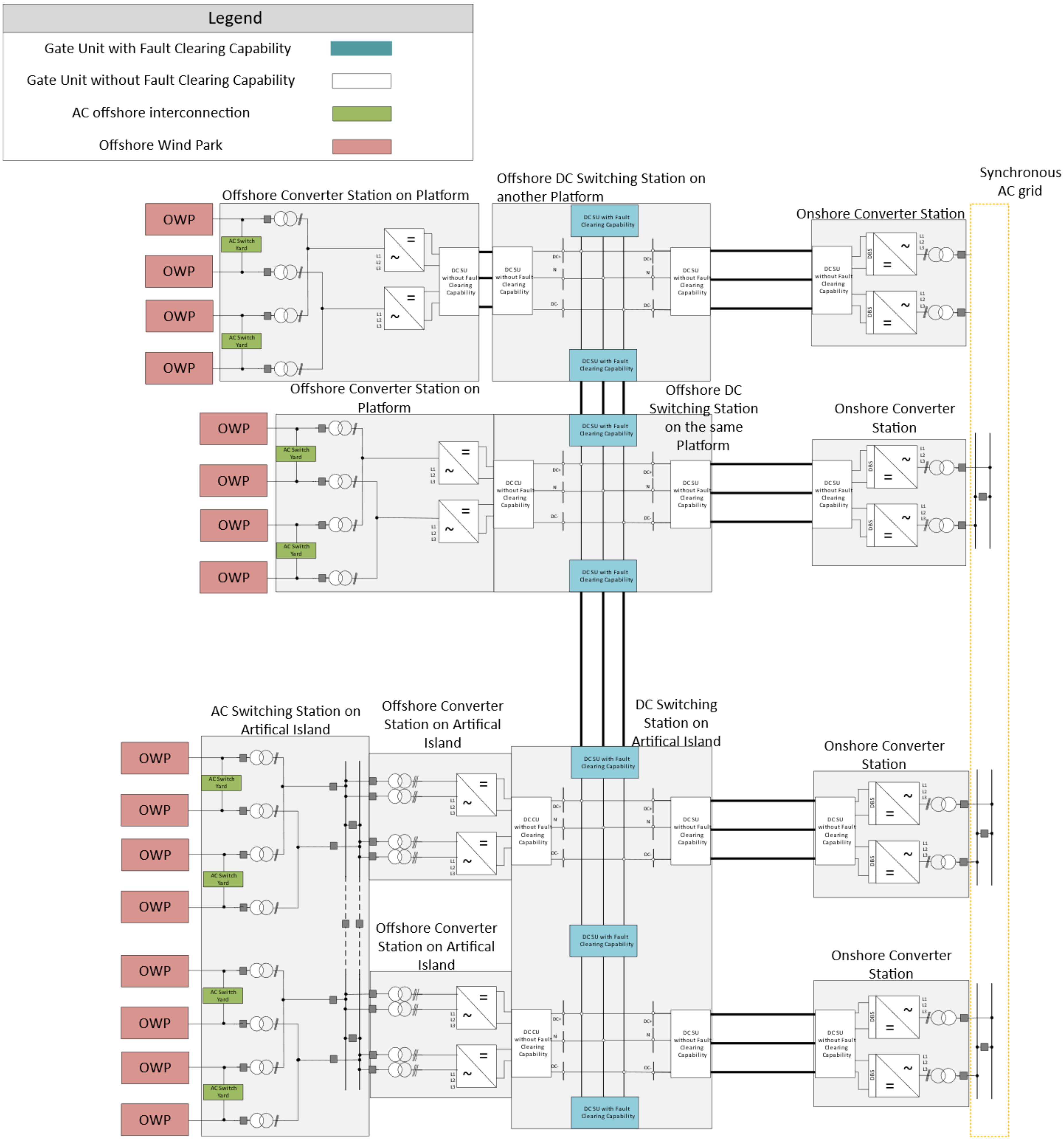
Annex 1: Shortlist entries

SHORTLIST ENTRY #1:



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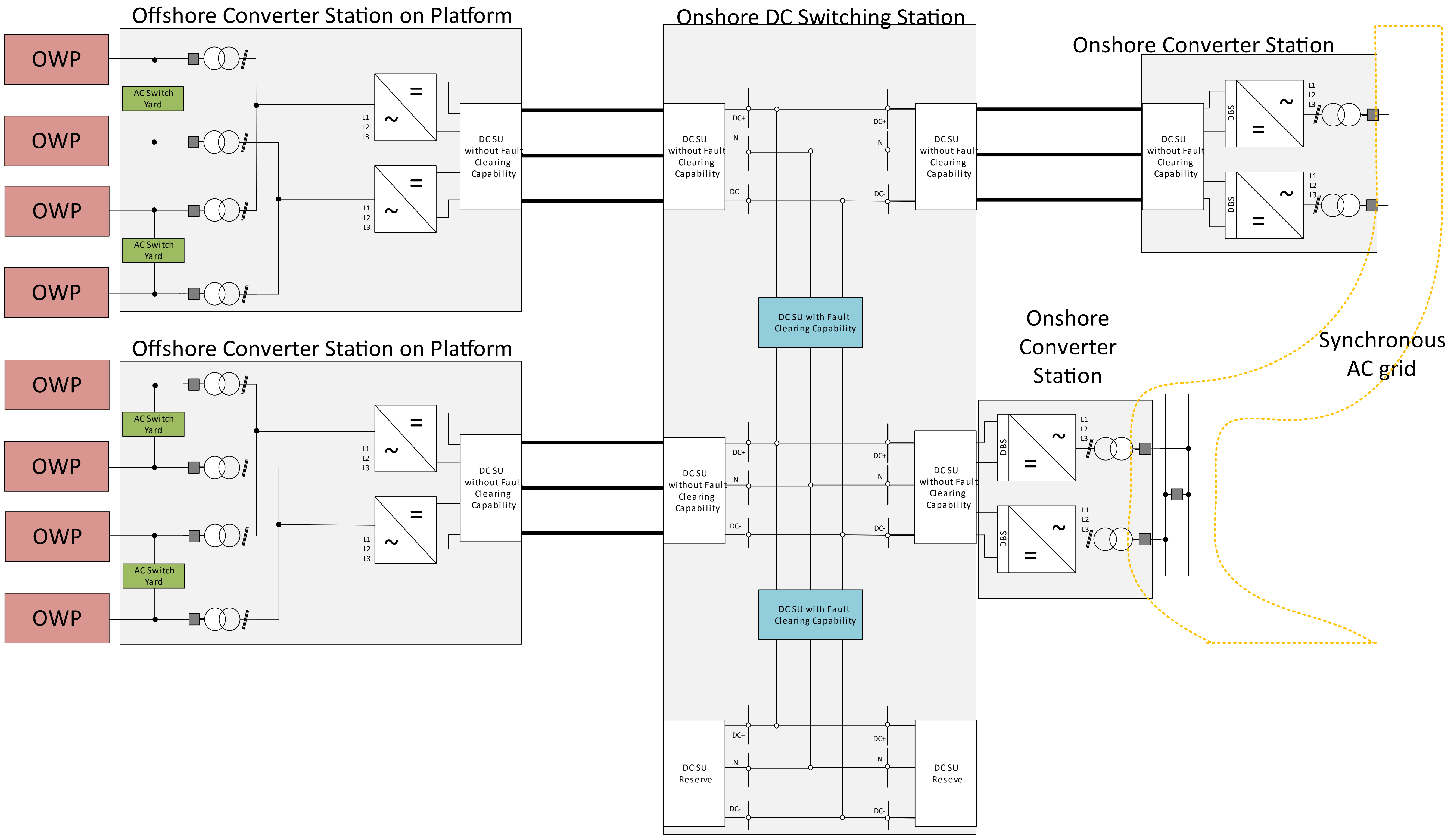

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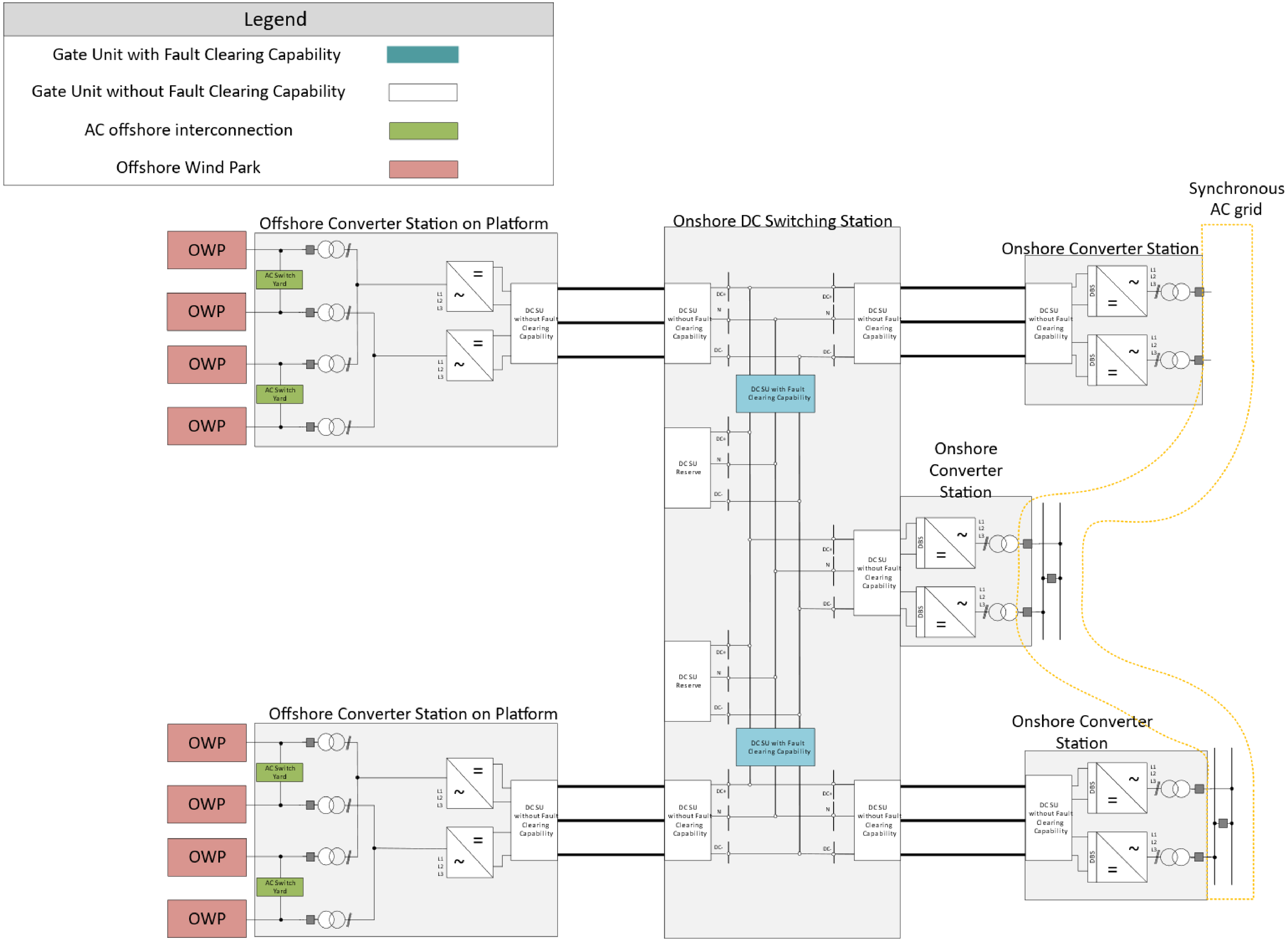

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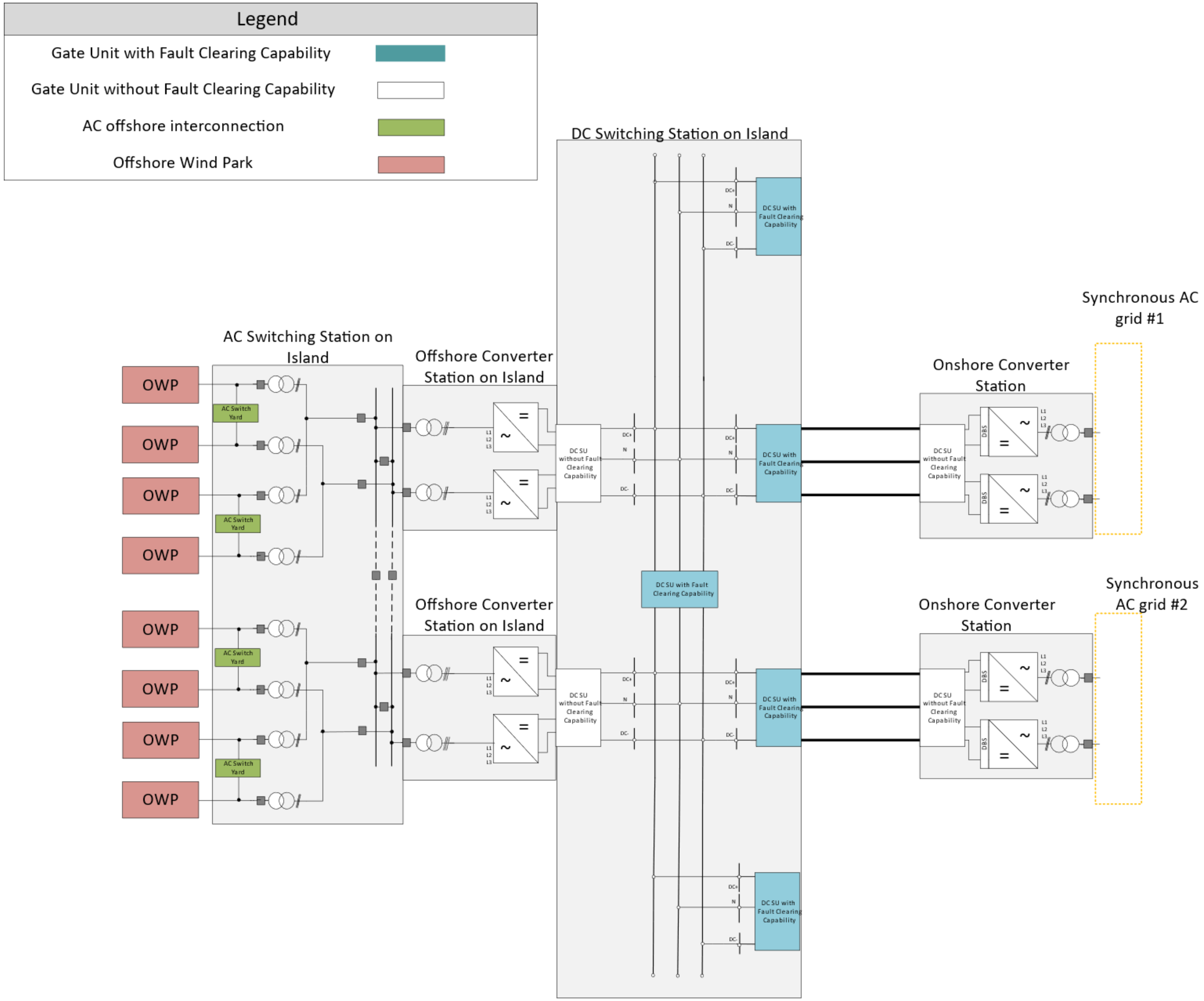

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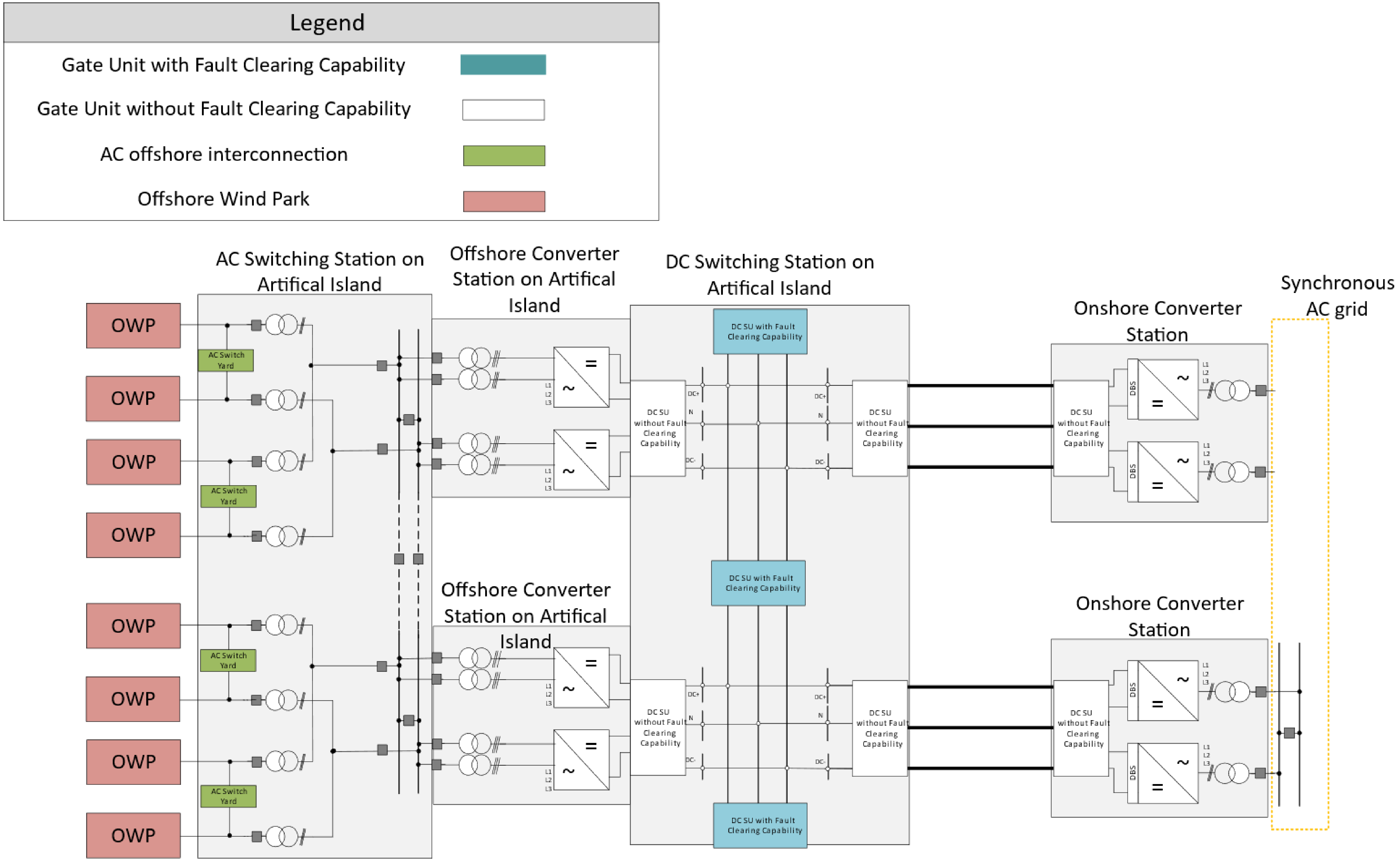

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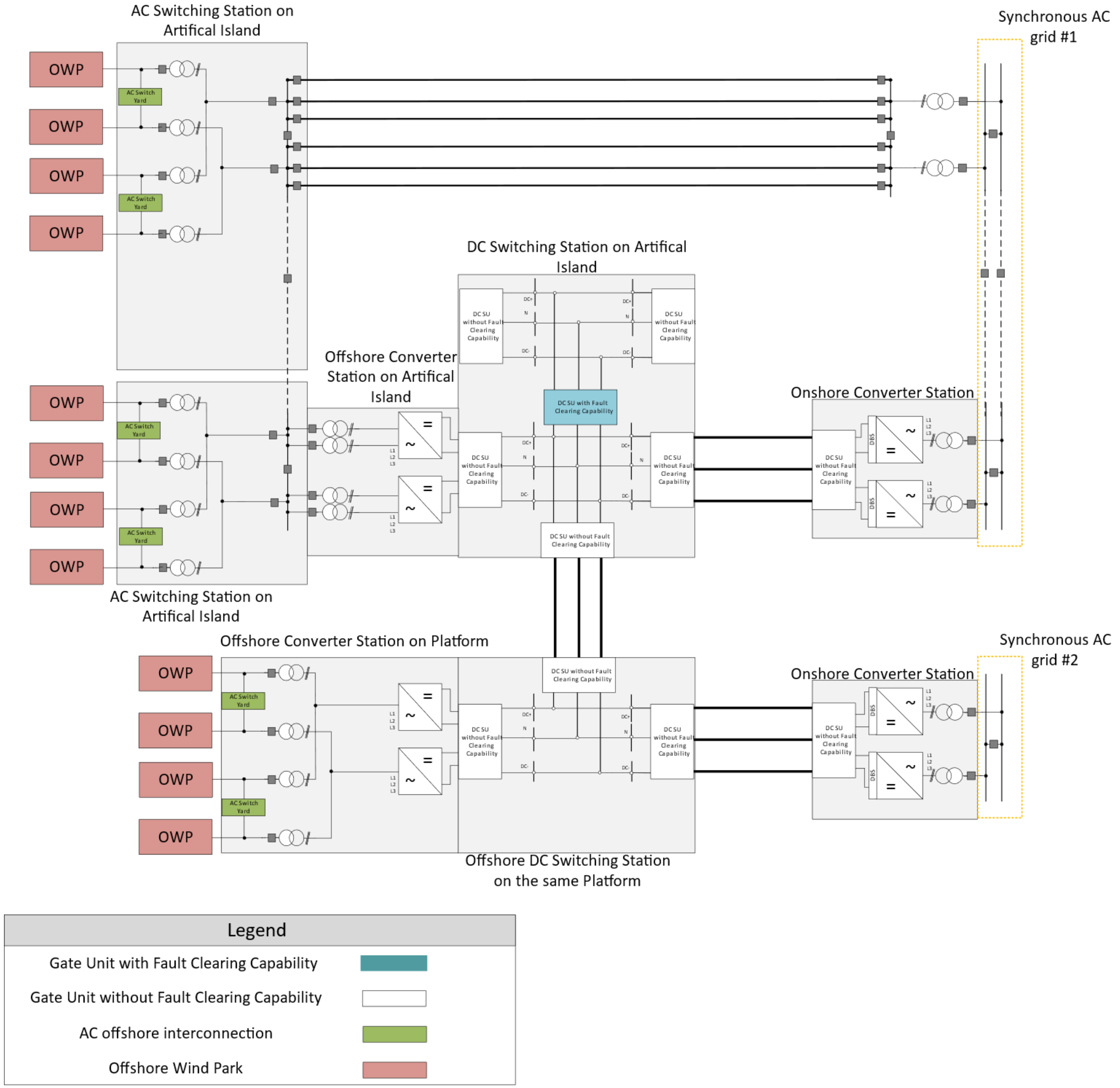

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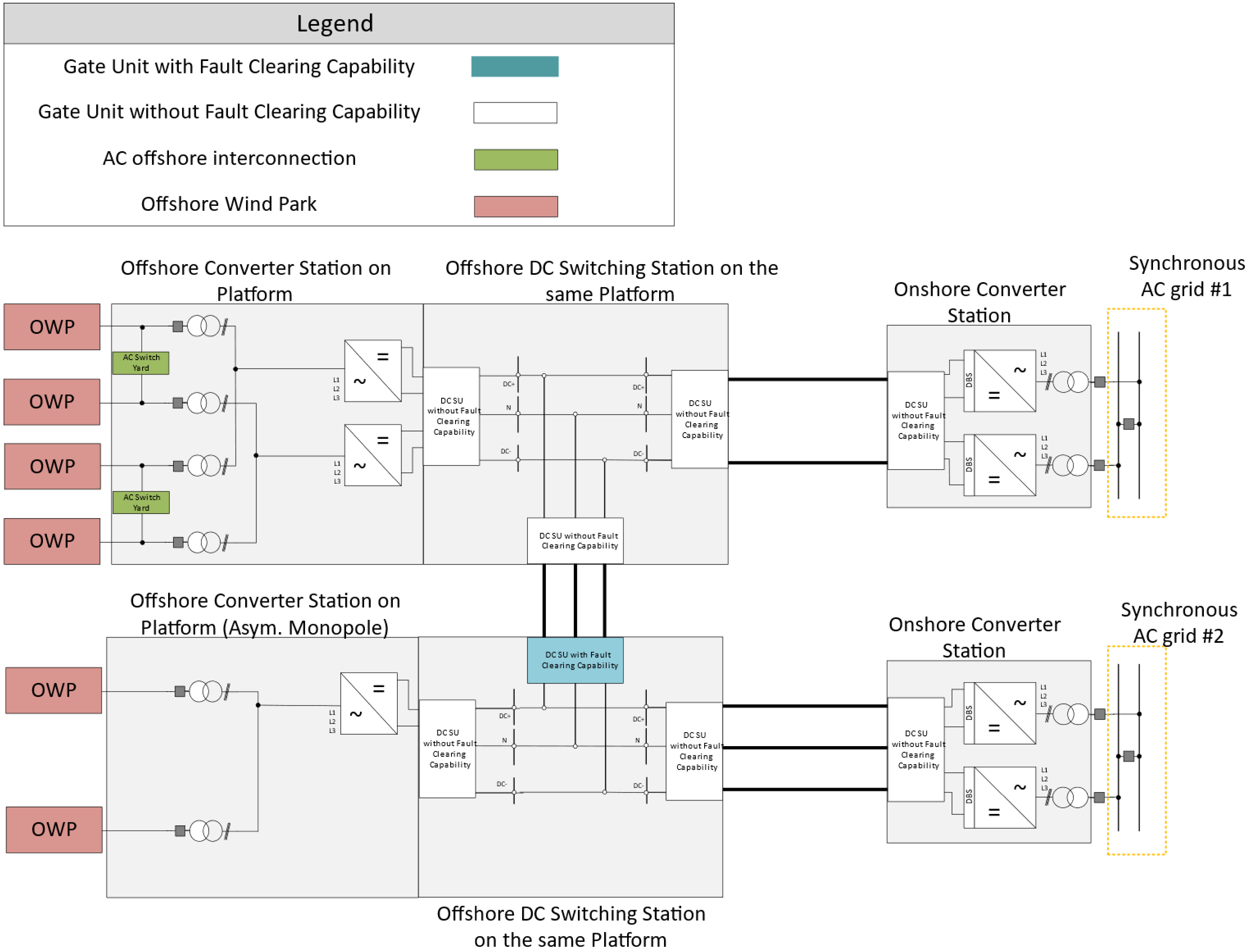
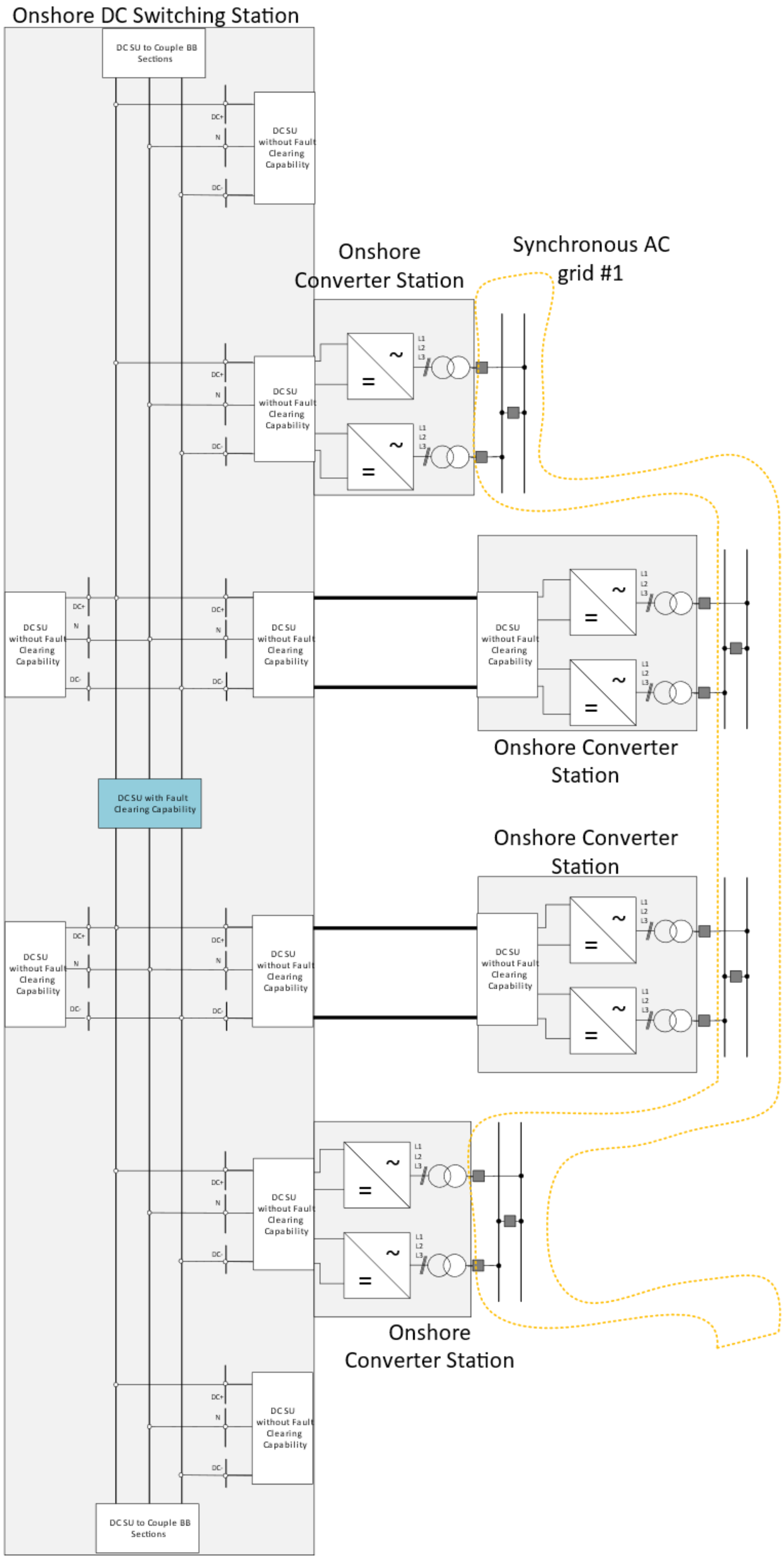


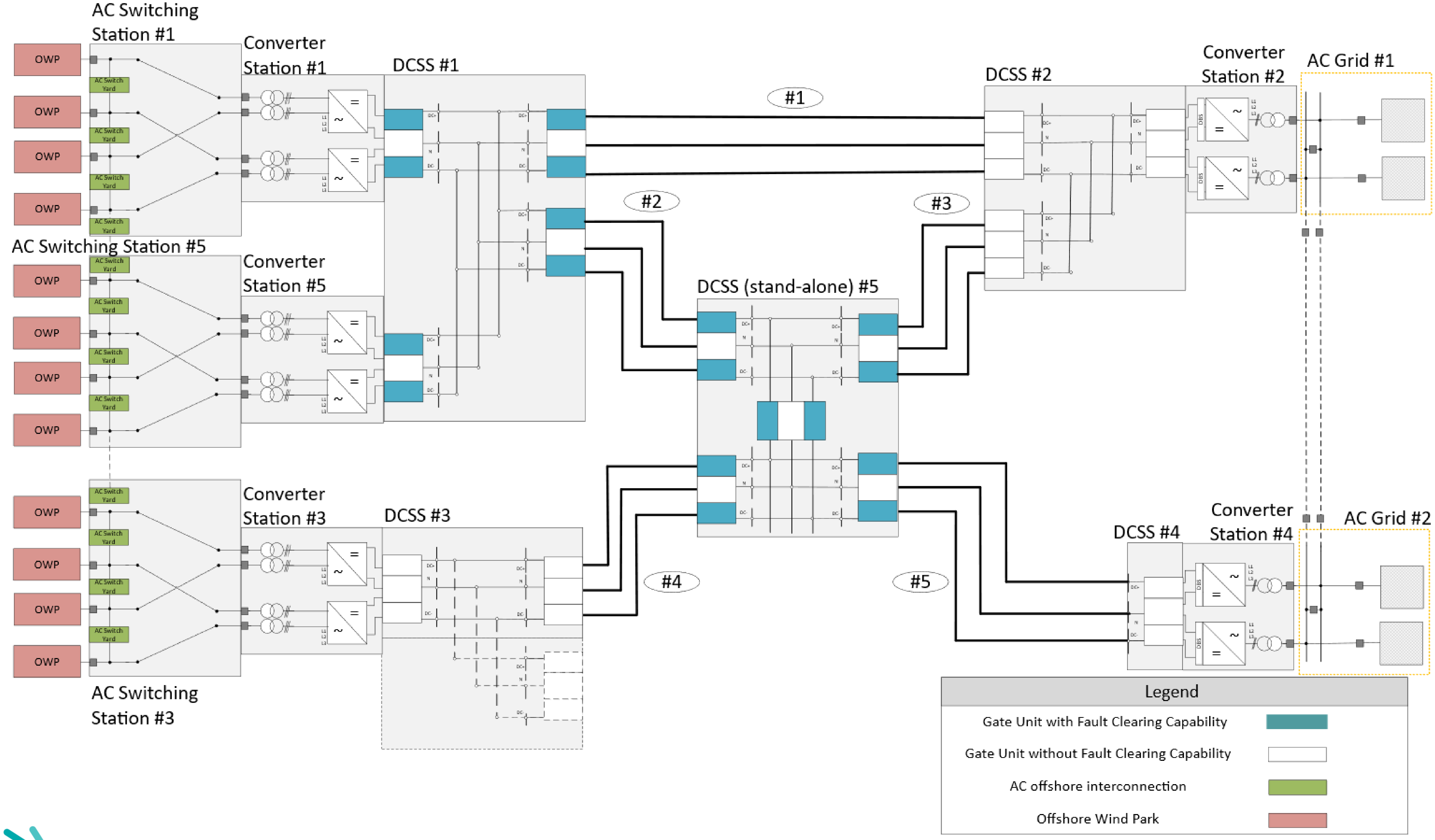
SHORTLIST ENTRY #8:

Legend	
Gate Unit with Fault Clearing Capability	
Gate Unit without Fault Clearing Capability	
AC offshore interconnection	
Offshore Wind Park	

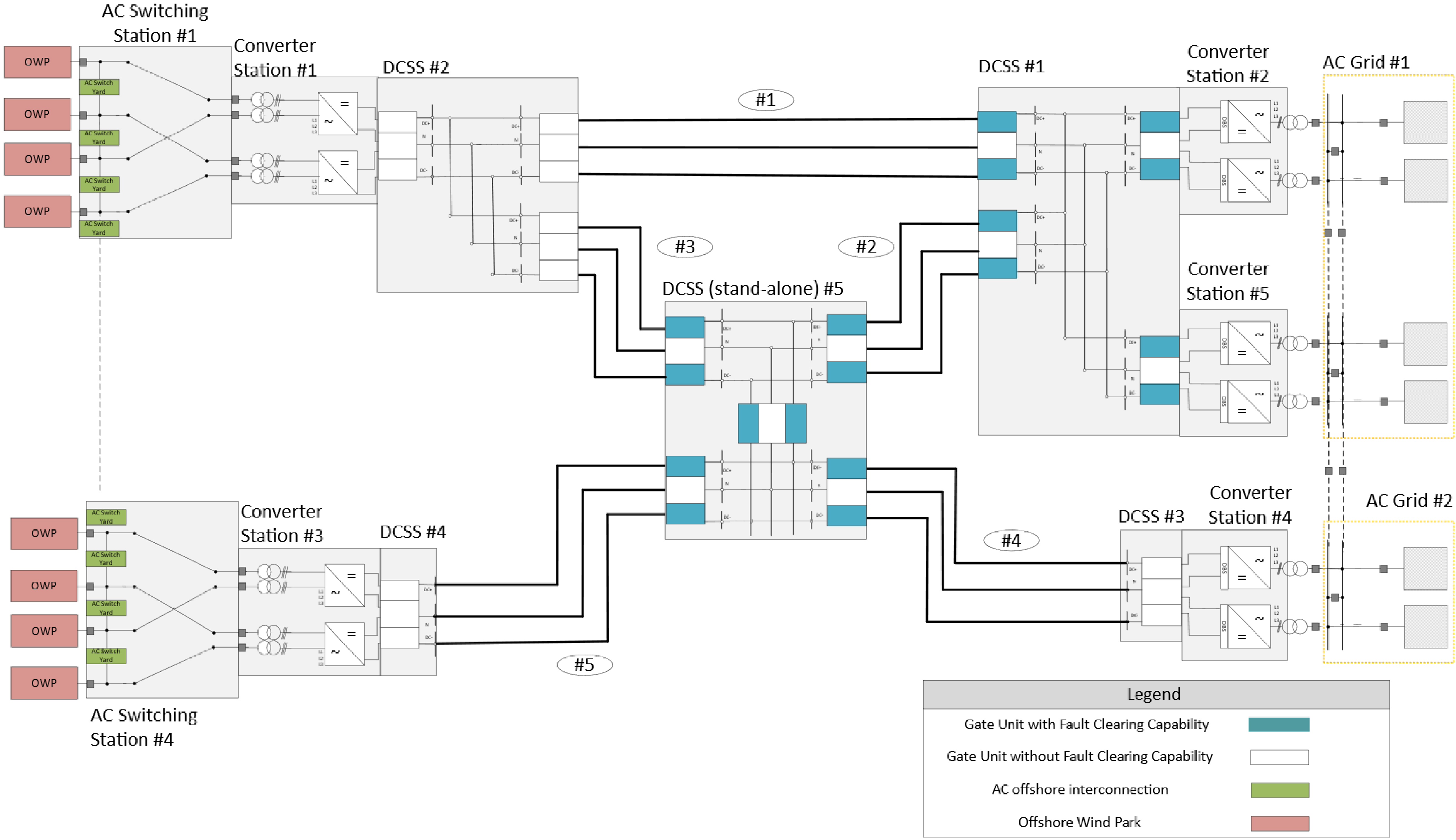


Annex 2: Demonstrator – full extent and subsets

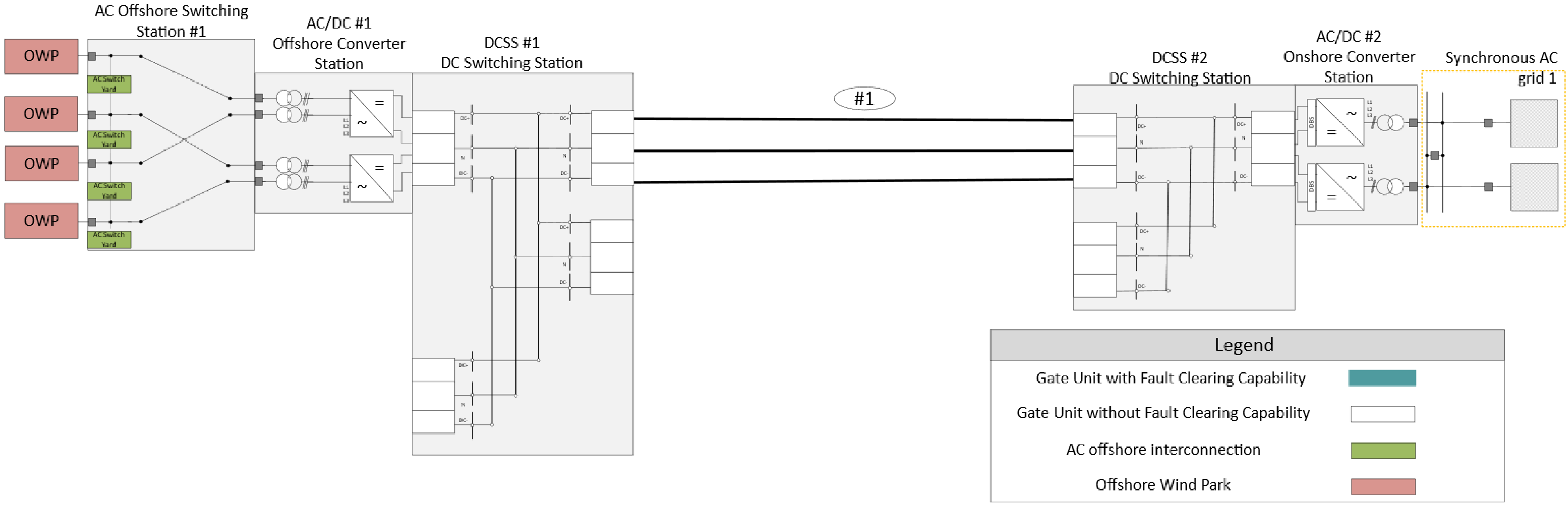
DEMONSTRATOR – FULL EXTENT (VARIANT 1)



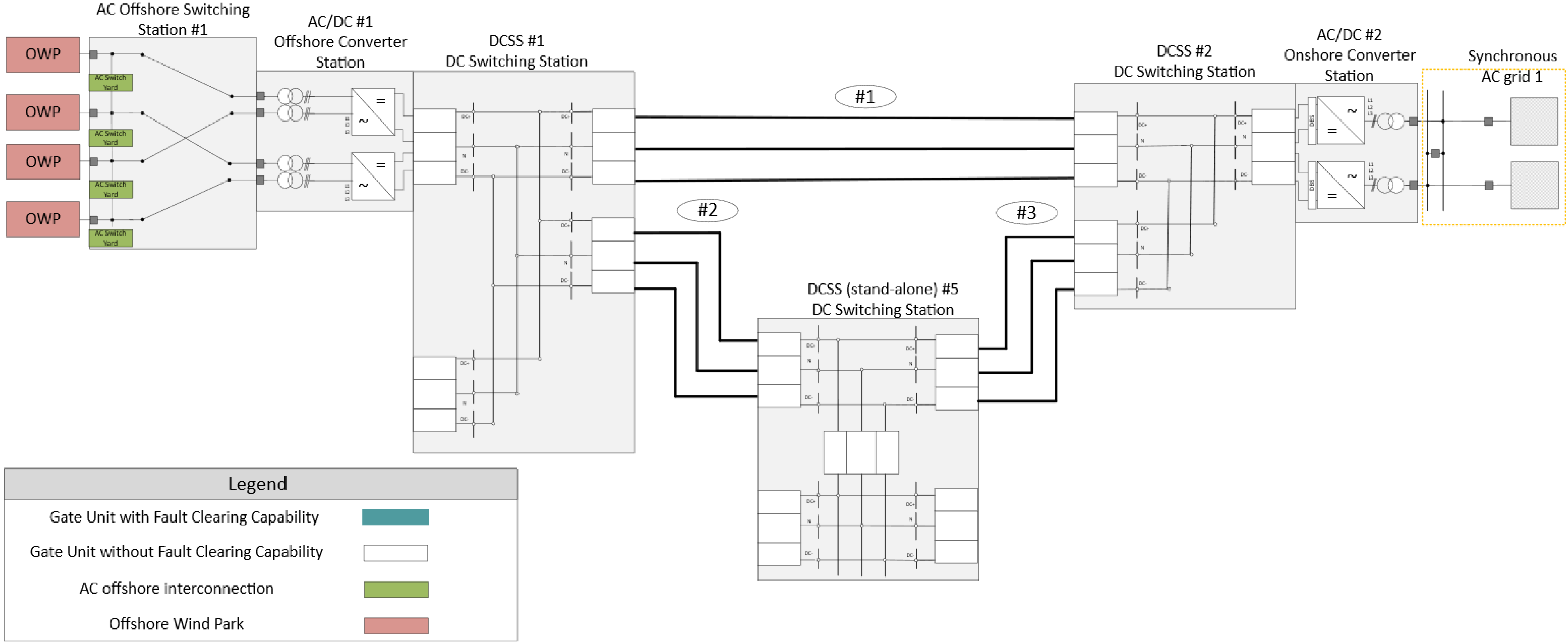
DEMONSTRATOR – FULL EXTENT (VARIANT 2)



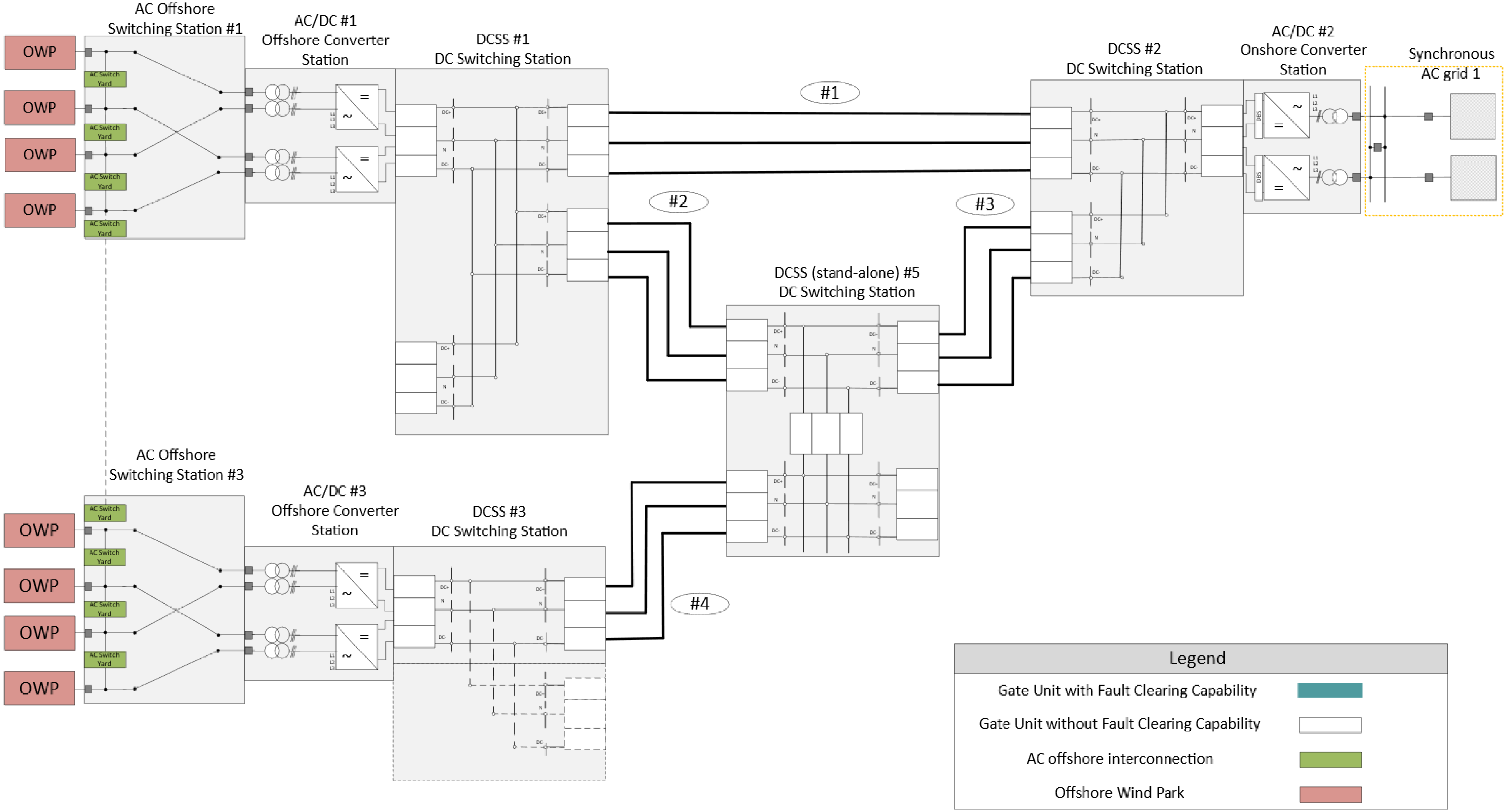
SUBSET 0: P2P HVDC & GRID CONNECTION SYSTEMS



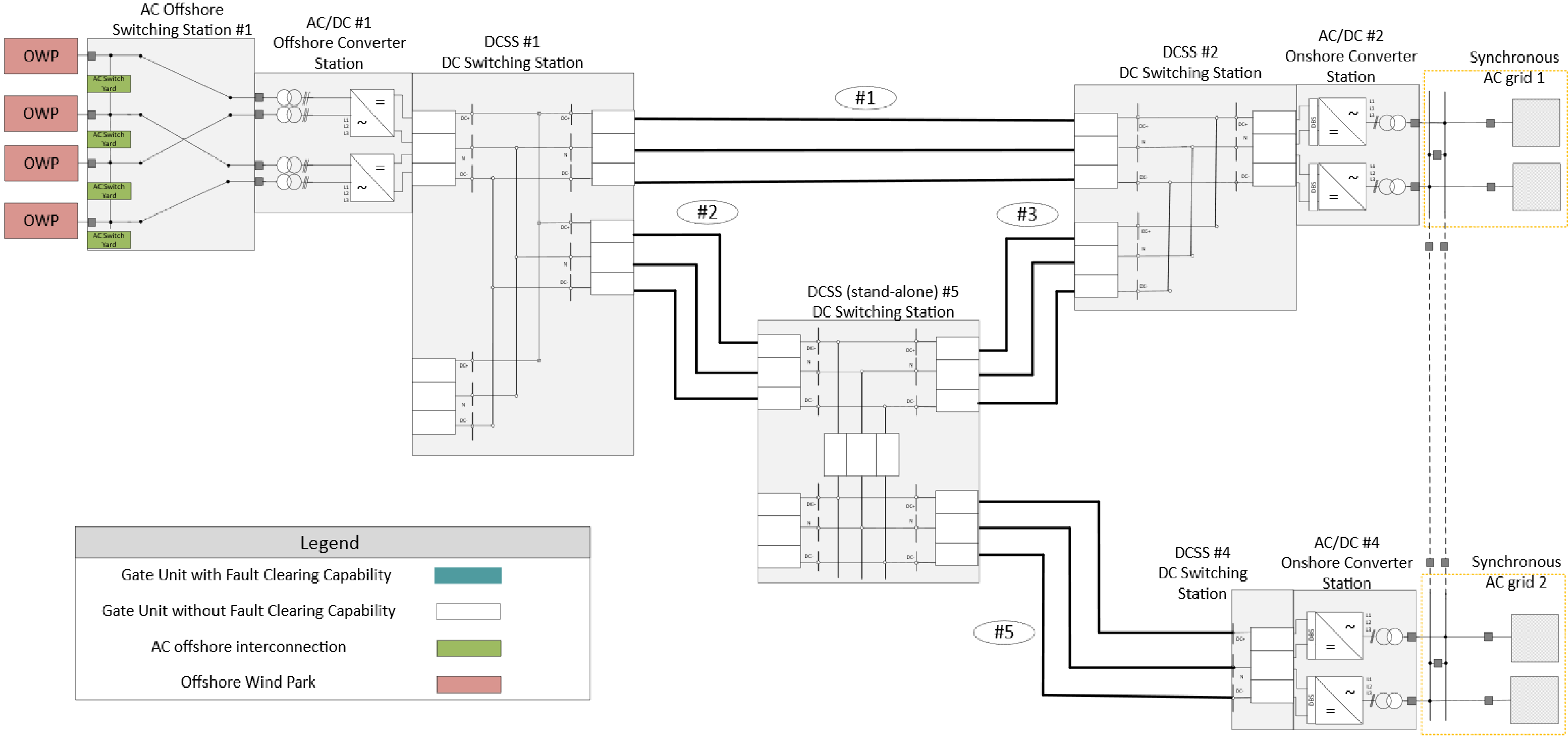
SUBSET 1: P2P – INTEGRATION OF STAND-ALONE DCSS



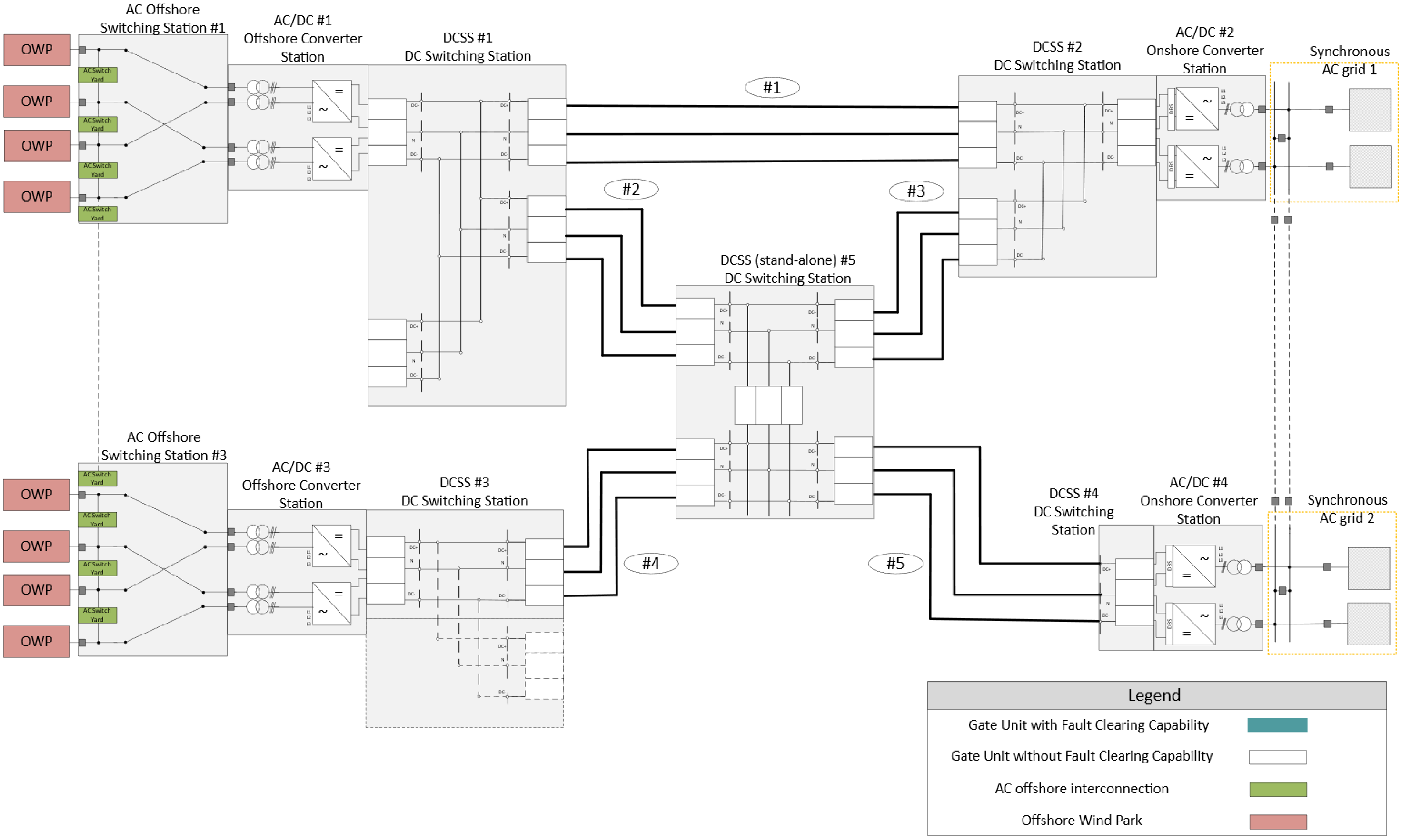
SUBSET 2: 3 MT - BASE TOPOLOGY (VARIANT 1)



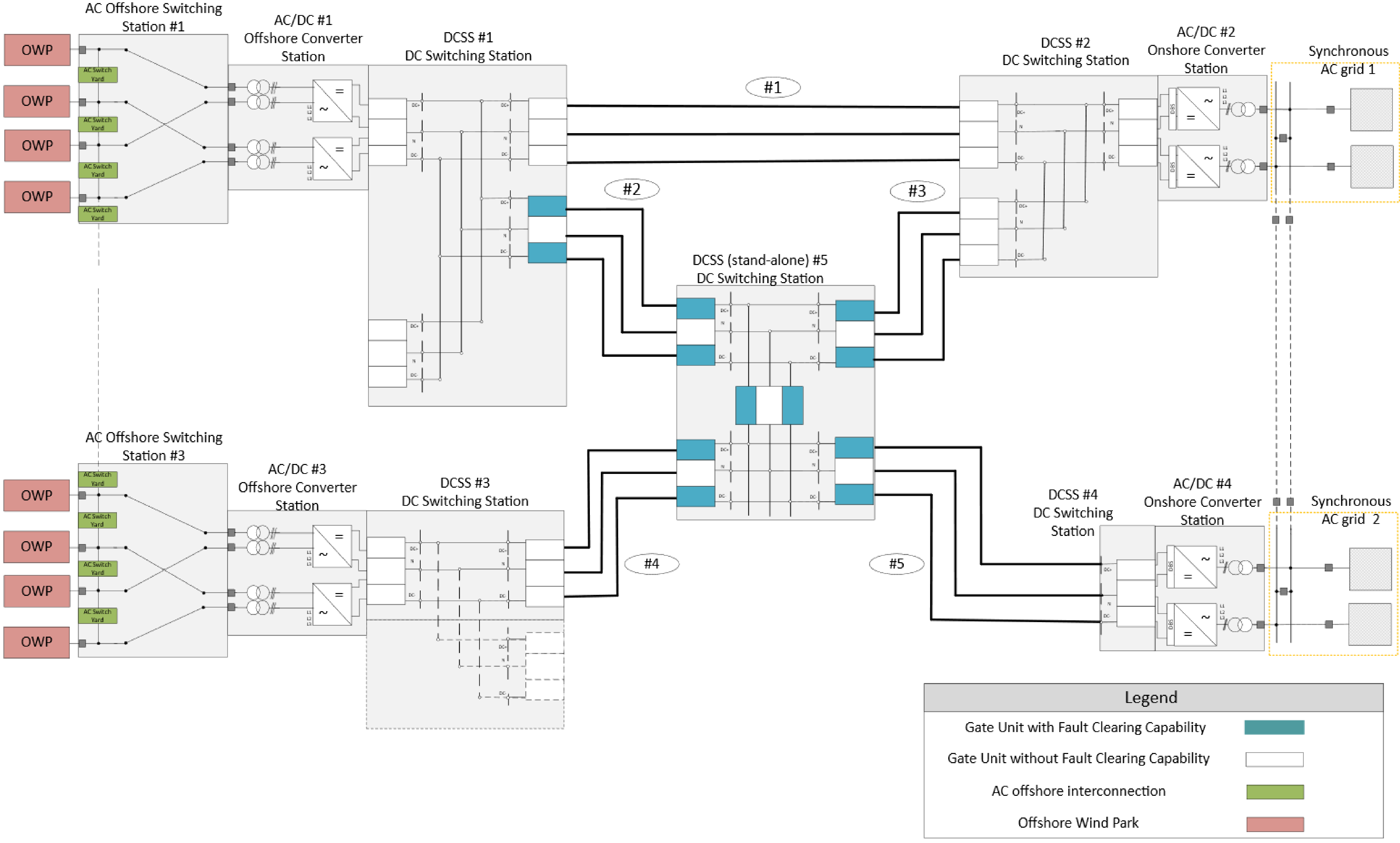
SUBSET 2: 3 MT - BASE TOPOLOGY (VARIANT 2)



SUBSET 3: 4 MT – LONG DC TAP

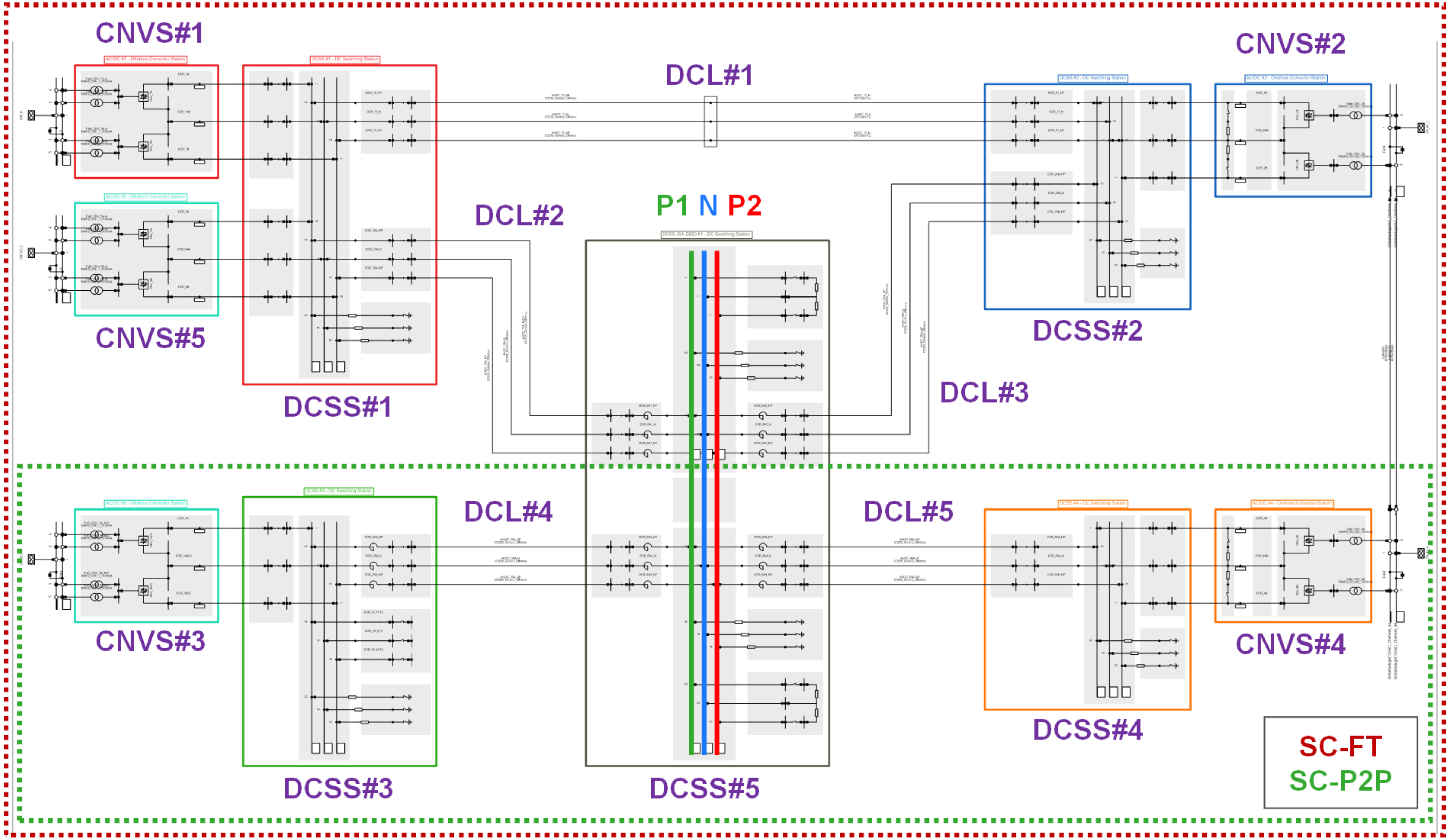


SUBSET 4: 4 MT – DC-FSD INTEGRATION



Annex 3: Graphical representation study models

GRAPHICAL MODEL REPRESENTATION: STEADY-STATE STUDY



Annex 4: SPM conformity check

TABLE A4-1

SPM check for the considered cases and converter overcurrent capability of 5kA kA (√: SPM conform, SP: Single pole blocks, DP: Double pole blocks)

SPM conformity check					
Fault location	SPM	5 kA			
		50mH 1ms	50mH 5 ms	400mH 1ms	400mH 5ms
1 (P2G) BB_HP_1	PS(TS) DP#1/5	√	√	DP#2	SP#2
3 (P2G) BB_HP_5A	CO	SP#1	SP#1/5	DP#2	DP#2
5 (P2G) HP_1	PS DP#1	√	SP#5	DP#2	DP#2
7.1 (P2G) DCL_HP_12	PS DP#2 (TS DP#1/5)	√	SP#1/5	√	√
7.2 (P2P) DCL_HP_HN_12	PS DP#2 (TS DP#1/5)	√	DP#1/5	√	√
7.3 (P2G) DCL_HP_52	PS DP#2 (TS DP#1/5)	√	SP#1/5	√	√
7.4 (P2G) DCL_HP_HN_52	PS DP#2 (TS CNVS1/5)	√	DP#1/5	√	√
7.5 (P2G) HP_2	PS CNVS2 (TS CNVS1/5)	√	SP#2	√	√
4.1 (P2G) BB_HP_4	N/A	SP#4	SP#4	SP#4	SP#4
4.2 (P2P) BB_HP_HN_4	N/A	DP#4	DP#4	DP#4	DP#4

TABLE A4-2

SPM check for the considered cases and converter overcurrent capability of 7kA kA (√: SPM conform, SP: Single pole blocks, DP: Double pole blocks)

SPM conformity check					
Fault location	SPM	7 kA			
		50mH 1ms	50mH 5 ms	400mH 1ms	400mH 5ms
1 (P2G) BB_HP_1	PS(TS) DP#1/5	√	√	√	√
3 (P2G) BB_HP_5A	CO	SP#1	SP#1/5	SP#5/2	SP#5/2
5 (P2G) HP_1	PS DP#1	√	√	√	√
7.1 (P2G) DCL_HP_12	PS DP#2 (TS DP#1/5)	√	√	√	√
7.2 (P2P) DCL_HP_HN_12	PS DP#2 (TS DP#1/5)	√	DP#1/5	√	√
7.3 (P2G) DCL_HP_52	PS DP#2 (TS DP#1/5)	√	SP#1/5	√	√
7.4 (P2G) DCL_HP_HN_52	PS DP#2 (TS CNVS1/5)	√	DP#1/5	√	√
7.5 (P2G) HP_2	PS CNVS2 (TS CNVS1/5)	√	√	√	√
4.1 (P2G) BB_HP_4	N/A	SP#4	SP#4	SP#4	SP#4
4.2 (P2P) BB_HP_HN_4	N/A	DP#4	DP#4	DP#4	DP#4