Hybrid Provision of Energy based on Reliability and Resiliency by Integration of Dc Equipment

Work Package WP3

Hybrid grid enabling solutions

Deliverable D3.1

Requirements on MV DC circuit breakers

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Table of Contents

List of Figures

List of Tables

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List of Abbreviations

AC	Alternating Current
AFE	Active Front End
DAB	Dual Active Bridge
DC	Direct Current
DCCB	Direct Current Circuit Breaker
EMT	Electromagnetic Transients
EV	Electric vehicle
HVDC	High-voltage Direct Current
IEC	International Electric Commission
IED	Intelligent Electronic Device
IGBT	Insulated Gate Bipolar Transistor
IGCT	Integrated Gate-Commutated Thyristor
MMC	Modular Multilevel Converter
MOV	Metal-Oxide Varistor
MVDC	Medium-Voltage Direct Current
NPC	Neutral Point Clamped
RES	Renewable Energy Sources
TIV	Transient Interruption Voltage
VARC	VSC-Assisted Resonant Current
VI	Vacuum Interrupter
VSC	Voltage Source Converter
WP	Work Package

Executive Summary

Direct Current (DC) power transmission offers many benefits over Alternating Current (AC) and it is therefore making fast inroads in electrical energy systems all over the world. High voltage direct current transmission High-voltage Direct Current (HVDC) offers efficient transmission over long distances particularly when cables must be used, for instance for subsea links. DC is also used at low voltage, for instance for grids supplying the many servers in data centres. Also at medium voltage (>1500 V – 50 000 V) DC potentially offers significant advantages in many applications. The power conversion chain can be simplified and power flow can be more accurately controlled.

The HYPERRIDE project (HYbrid Provision of Energy based on Reliabilty and Resiliency via Integration of Dc Equipment) contributes to the field implementation of DC and hybrid AC/DC grids. Starting with the definition of most relevant fields of application for DC grids (local microgrids, grid enforcement to overcome congestions, coupling of AC grid sections, etc.), the enabling technologies shall be specified in detail on different levels. One such enabling technology is Direct Current Circuit Breakers (DCCBs) for Medium-Voltage Direct Current (MVDC) grids. Even though MVDC DCCBs are available for DC railway systems e.g., MVDC distribution grid applications have different requirements, mainly with respect to the speed of operation. In recent years different DCCB prototypes for grid applications for MV have been developed using state-of-the-art (mechanical) techniques but also novel solutions, such as the VSC-assisted resonant current (VARC) concept from the project partner SCiBreak AB.

In this report, the most important grid parameters (e.g. grid configuration, converter topology, DC reactor size) impacting the requirements for DC circuit breakers are analysed by means of simplified circuit models. The results of grid simulation studies concerning the consequences of short circuit scenarios for DCCBs in real a MVDC demonstrator grid as well as in a fictional 14 kV grid are also presented.

A list of requirements for MVDC circuit breakers is put together in the report. Moreover, a review of HVDC standards and standards concerning DC railway applications that may be relevant for establishing MVDC standards in the future is given, with the indication of relevant technical brochures and normative documents that are likely to be published in the upcoming years.

1 Introduction

1.1 Purpose and Scope of the Document

Earlier in the project in Deliverable D2.3 (*Enabling technologies requirements and specification report*, 2021) general requirements and specifications for enabling technologies for the concerned novel power grids were defined. In this report, ways of specifying the requirements for DCCBs for MVDC grids are described in more detail. To enhance the value of the work to engineers and researchers also outside the project the focus is put on how to define the requirements for a DCCB for any given use case. At the end of the report, the methodology is then put to use in defining the requirements for two specific cases of particular importance to HYPERRIDE.

The protection of, DC grids and MVDC grids in particular, differs from AC grids. In a DC grid the fault current is not limited by any short-circuit impedance, other than the very low resistance in cables or overhead lines. This means that the fault current must be limited long before it can reach its prospective value. This puts high requirements on the speed of the circuit breaker. Furthermore, the current interruption process is different, since there are by nature no zero-crossings in the current in a DC application. For that reason a DCCB has to force the current to zero overcoming any inductance in the grid and absorbing the corresponding magnetic energy.

The peculiarities of DC grid protection means that methodology used to derive the requirements for AC switchgear is not useful. Generally, Electromagnetic Transients (EMT) simulation programs such as Simulink®, PLECS® or PSCAD® have to be used to obtain the waveforms of the fault current and other relevant variables. The simulation models have to represent the grid accurately including converters, cables, grounding, and any switchgear. Section 2 of the report provides an overview of MVDC grids and their protection with the aim to better understand how to define DCCB requirements.

To define requirements for DCCBs it is also necessary to understand the state of the art in the field of DCCB technology and its capabilities. There are several different concepts available. In the past, mostly mechanical breakers using arc chutes were used and they are still widely used in railway applications. However, this technology is not useful beyond a few kilovolts and also results in slow current interruption performance. Different concepts combining mechanical breaking elements and power semiconductors are currently being developed and can offer both faster operation and higher operating voltages. It is also possible to use pure steady-state breakers that use power semiconductors for both conducting and interrupting currents. This offers very fast switching but today it is also costly and lossy. In section 3 a review of DC switchgear is made explaining the differences in performance and features between the different technologies.

Since MVDC power distribution currently is a rather immature technology there are few standards and other normative documents regulating it. However, in the design of MVDC grids, including their switchgear, it is still useful to study existing standards for adjacent fields, such as HVDC power transmission. Standardisation work for DC power distribution systems, and in particular MVDC, is currently ongoing, and several new standards and other normative documents will be issued in the coming years. Section 5 gives an overview of the most relevant normative documents while also mentioning draft MVDC-related standards.

One of the main objectives of HYPERRIDE is to provide demonstrator grids where different enabling technologies can be evaluated in practice to collect important operational experience as input for preparing new standards. One of these is located at the premises of the project partner RWTH University in Aachen, Germany, and is referred to as the German pilot in this report. It is partly a DC microgrid operating at 5 kV, interconnecting buildings at the university campus. Several different DC/DC and DC/AC converters are available for interfacing the grid both to the AC grid and to an LVDC grid also present at RWTH University. Within HYPERRIDE suitable fast DCCBs for the protection of this 5 kV grid will be provided, which will be done by the project partner SCiBreak AB. The reasoning and the methodology in this report is used to define the requirements for the 5 kV DCCBs. The derivation of the the requirements and the resulting list of requirements can be found in section 6.

Within the project the partner Eaton have defined a use case for an MVDC distribution system where a business potential has been defined. It relates to Electric vehicle (EV) charging in large cities, where MVDC can bring significant benefits. The definition of the use case and the derivation of the requirements for suitable DCCBs is provided in section 7.

1.2 Structure of the Document

This document is organised as follows: Section 2 gives a general overview of protection and short-circuit fault handling issues in MVDC grids as a background for understanding the need for DCCBs and what requirements need to defined. Thereafter, Section 3 deals with the needed technology, starting by explaining the function of different types of DCCBs. Section 4 details prospective MV DCCB requirements from a general perspective. In Section 5 a review of various standards and other normative documents relevant to DC switchgear is given, with special emphasis on those relevant to MVDC applications. The derivation of the requirements for circuit breakers to be used in the RWTH University microgrid can be found in Section 6. In Section 7 the requirements for a DCCB rated at 14 kV nominal voltage suited to a use case defined by the project partner Eaton is elaborated. The report is concluded in Section 8 and recommendations for upcoming work are provided. Finally, in the Appendix a table of all the various standards and other normative documents pertaining to DCCBs that were found during the work is provided.

2 MVDC Grid Fault Handling

Any electric power grid needs protection in case of faults. Excessive over- and short-circuit currents must be avoided to prevent damage to equipment, avoid fire hazards, and other types of destruction of assets. In addition, selective protection is needed to ensure that only the faulty parts are disconnected from the grid, while the rest still remains operational. This section should give an introduction to DC grids with particular focus on the condition in an MVDC grid.

2.1 DC Grid Configurations

A DC grid or DC point-to-point connection can be configured in a couple of different ways with regard to grounding. This has a major impact on the transient voltages and currents during a short-circuit fault, and needs to be taken into account when designing the protection system, including the DC circuit breakers. It is currently not clear which grounding configuration will mostly be used for MVDC grids. Therefore, the most common existing possibilities will briefly be reviewed and discussed below. See also Figure 1.

2.1.1 Asymmetrical Monopole

The *asymmetrical monopole* consists of a single voltage with one pole grounded. This configuration is inefficient with respect to the power that can be transferred for a given dielectric rating (pole-to-ground), compared to the symmetrical monopole and the bipole, see below. Therefore, these configurations are mostly preferred in case a DC link is first built as a monopole for later expansion into a bipole. A pole-to-ground fault will naturally result in a large fault current.

2.1.2 Symmetrical Monopole

In a *symmetric monopole* there is only a single DC voltage $2U_d$ in the system, as in the case of the asymmetric monopole. However, none of the poles is solidly grounded. Instead, the aim is to keep the poles at approximately $+U_d$ and $-U_d$, respectively. It may be necessary to use a weak (high-impedance) grounding to achieve this. Since there is no connection to ground,

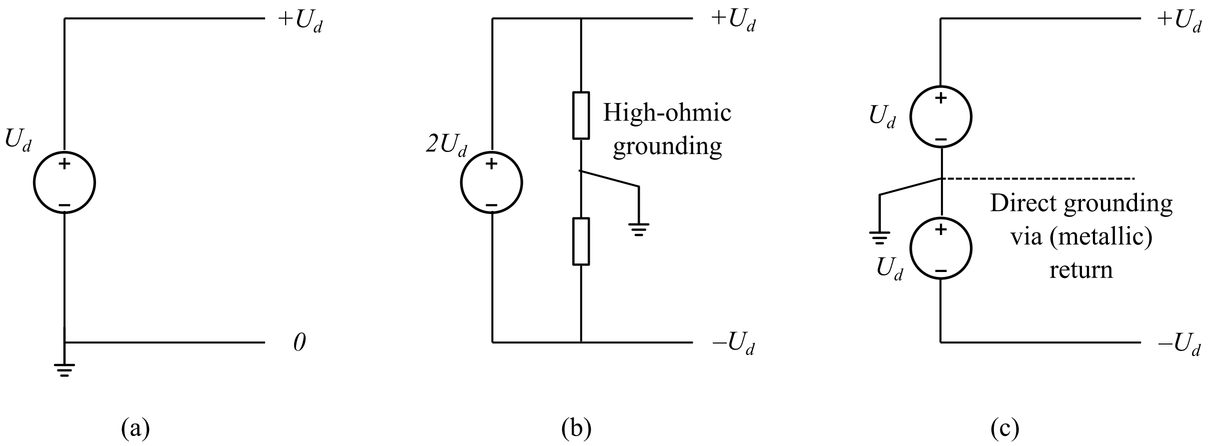

Figure 1: Basic DC grid configurations: (a) Asymmetric monopole, (b) Symmetric monopole, (c) Bipole.

a pole-to-ground fault will in most cases not result in a high fault current. The currents flowing during a fault will mostly result from discharging of line capacitances. These are particularly prominent in cable-based systems. On the other hand, the lack of grounding means that the healthy pole will appear at the potential $2U_d$ (i.e. the full pole-to-pole voltage) in case of a fault. If this is not feasible from a dielectric point of view surge arresters to ground can be used. This is always the case in HVDC symmetric monopole systems since the DC cable insulation is not made to withstand the full pole-to-pole DC voltage. The arresters will then contribute to the currents flowing in case of a fault. A pole-to-pole short-circuit fault will, however, obviously cause high fault currents. Such faults are rare in cable systems but more frequent in DC overhead line systems, where a ground fault caused by lightning, for instance, will often develop into a pole-to-pole fault.

2.1.3 Bipole

In the case of a DC *bipole*, two series-connected independent DC voltages with the midpoint solidly grounded is used, See Figure 1(c). With this configuration, any short-circuit fault (pole-ground, pole-pole) will generally result in a significant and fast-rising short-circuit current. A benefit over the symmetrical monopole is, however, that in case of a pole-to-ground fault, the voltage of the healthy pole will not change, thus reducing the requirements on the overvoltage arresters. The required insulation withstand levels against earth of all other components are reduced as well. This configuration is generally more costly to implement than the monopole configurations discussed in the previous two subsections since two separate voltage sources (in practice converters) are needed wherever the grid should interface to other grids, loads, or sources. On the other hand, a great advantage is that in case of a ground fault on one of the poles, the other pole can be kept in operation. Thus, even with a fault on one of the poles, half of the power transfer capability is still available. This obviously requires that there is a metallic return path for the neutral current, indicated by a dashed line in Figure 1(c).

2.2 Short-circuit Currents in MVDC Circuits

An MVDC grid is generally connected to the AC grid or another DC grid through power electronic converters. From a protection point of view, it is of interest to understand the behavior of such converters in case of a short-circuit fault in the MVDC grid.

2.2.1 Diode Rectifier

In case of a DC-side short circuit fault of an uncontrolled diode rectifier it will mostly behave as a short circuit also as seen from the AC side. The DC-side currents will rise rapidly, initially in a fashion similar to the shorting of a DC voltage source through an impedance. Eventually, if not interrupted or otherwise limited the currents will be limited by the AC-side reactances. In (Pozzobon, 1998) analytical expressions are derived for the DC-side fault currents of diode rectifiers, both transient and stationary.

2.2.2 Thyristor Rectifiers

Without the use of special control algorithms to handle DC grid fault scenarios, a converter using thyristors as power switches behaves very much like a diode bridge rectifier when subjected to a DC-side short-circuit.

Results of research have been published that describe methods using the control of thyristor switches to quench DC-side fault currents in marine DC applications (Dong, Pan, Lai, Wu, & Weeber, 2017). However, these rely on the reactance of on-board generators that considerably decreases the rate of change of fault currents and they are relatively slow (in the range of tens of milliseconds). It is estimated that the speed of such thyristor-based protection methods is too low for successfully protecting a VSC-based MVDC grid. Therefore, they are not considered further in this report.

2.2.3 Voltage Source Converter

A two-level Voltage Source Converter (VSC) resembles a diode rectifier in terms of circuit topology, but the diodes are replaced by valves consisting of switches with turn-off capability and antiparallel diodes. In case of a DC-side fault, where the DC voltage collapses, the converter loses the capability to control the currents on both the DC and AC sides. Due to the free wheeling diodes of the converter, the VSC will start behaving like a diode rectifier shorted on the DC side, see previous section, and Figure 2. The DC-side currents will keep rising until they are limited by reactances on the AC side, or breakers open on either side. The DC-side capacitor of a VSC may also contribute significantly to the DC side short-circuit current. Notably, the capacitor will act as a voltage source in the short time frame, and the corresponding short circuit current will only be limited by any inductance present on the DC-side. Assuming that the path to the fault is purely inductive (inductance L), the peak fault current emanating from the DC capacitor can be computed from:

$$\hat{I} = U_d\sqrt{\frac{C}{L}}. \tag{1}$$

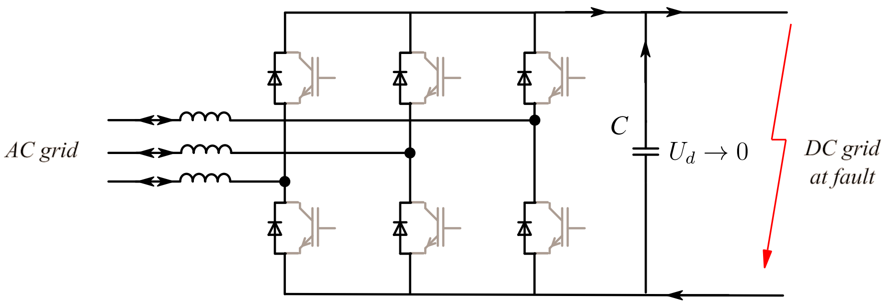

Figure 2: Schematic diagram of a two-level Voltage Source Converter (VSC) under a DC-side short-circuit fault. The semiconductor switches are greyed out as they are blocked during the fault.

For medium voltage applications the three-level Neutral Point Clamped (NPC) converter, first presented in (Nabae, Takahashi, & Akagi, 1981) is an option, see Figure 3. It allows for doubling the DC and AC voltages using power semiconductors with a certain voltage rating without direct series connection of the semiconductors. As the name suggests, it has three levels in the AC-side phase voltages allowing for better harmonic performance. However, in terms of its DC-side short-circuit behavior it is similar to the two-level VSC. In addition, the DC capacitor in an NPC converter may be larger than in a two-level VSC, thus exacerbating the short-circuit currents emanating from the DC capacitor.

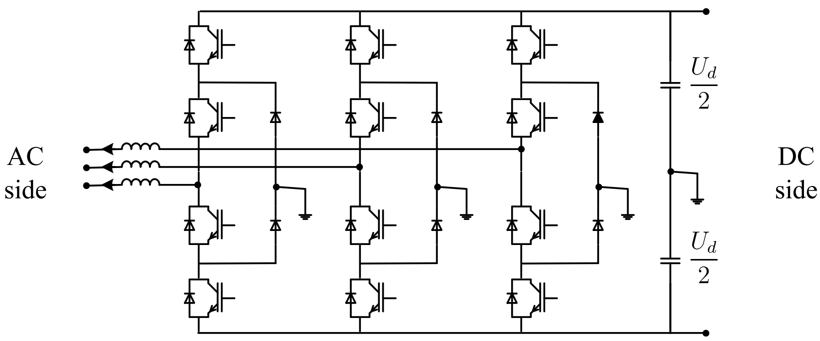

Figure 3: Schematic diagram of a three-level Neutral Point Clamped (NPC) converter.

2.2.4 Conventional Modular Multilevel Converter with Half-bridge Cells

The basic Modular Multilevel Converter (MMC) can be seen in Figure 4(a). Its topology resembles that of the ordinary two-level converter, but the semiconductor valves are replaced by strings of converter cells which act as controllable voltage sources. These voltage sources are controlled to provide unipolar voltages each having a DC as well as an AC component. The DC components are common to both phase arms in a phase leg whereas the AC components have opposite signs.

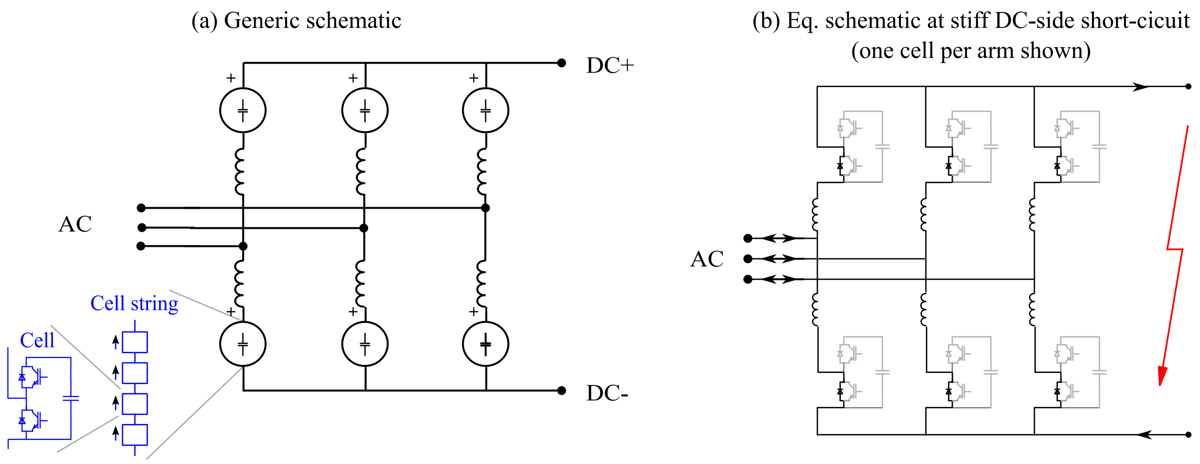

Figure 4: (a) Schematic diagram of a generic modular multilevel converter (MMC). (b) Equivalent circuit diagram in the case of a stiff DC-side short-circuit. Only one cell per arm shown, for clarity.

A great benefit of the MMC is that there is no capacitance needed across the DC poles like in a two-level converter. This means that there is no immediate discharge of a capacitor in case of a DC side short circuit. However, just like the conventional two-level converter it will lose control of all currents in case of a DC-side short-circuit. This can be understood by observing Figure 4(b) which shows an equivalent schematic of an MMC with the DC-side shorted. Notably, the unipolar voltages that can be provided by the cell strings would only add to the DC-side short-circuit currents and the cells thus have to be blocked or bypassed. As a result the converter will also behave as as a rectifier of the AC side short-circuit currents, which will only be limited by the impedances on the AC-side and the arm inductors. In practice this means that a DC-side short-circuit causes a need to block the power semiconductor switches in the cells a short while, in case the DC-side fault current cannot be interrupted. This means that the converter will cease to operate normally and cannot even provide reactive power on the AC-side.

2.2.5 MMC with Full-bridges

The shortcomings in terms of fault current limitation of the ordinary MMC with half-bridges can be overcome by replacing the half-bridges with full-bridges, see Figure 5(b). The bipolar voltage that can be provided by full-bridge strings ($\pm U_{cap}$) means that the converter will be able to control both DC and AC currents even in the case of a stiff DC-side short circuit. This can be understood by considering Figure 4(b) and replacing the half-bridge strings by full-bridge strings. Thereby, the converter will be able to support the connected AC grid with reactive power even during a DC-side fault. However, the semiconductor expenditure of the full-bridge MMC will in the first approximation be doubled since the same number of cells is required, given a certain DC voltage, but each cell has two phase legs. Still, in the normal operation, when the arms are providing a unipolar voltage, the switching frequency of each valve can in theory be halved, maintaining the same output voltage and cell-capacitor voltage-ripple. Hence the overall semiconductor losses will not double compared to the half-bridge case.

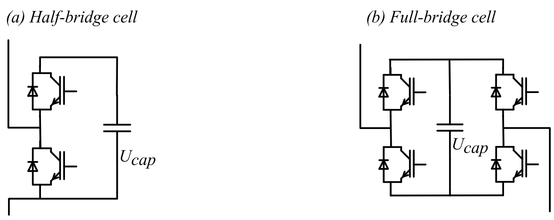

Figure 5: Different cell types for modular multilevel converters.

2.2.6 Transmission Lines and Cables

Any transmission line, such as a cable or an overhead line exhibits distributed impedance parameters, most important of which are the line inductance l (H/km) the line resistance r (ohms/km) and the shunt capacitance c (F/km). In high voltage (hundreds of kV) systems with long cables (hundreds of km) the transmission line properties of the cables can be very significant and need to be taken into account. Notably, a transmission line with the characteristic impedance $Z_0 = \sqrt{l/c}$ charged to the DC voltage U_d will initially, in the first approximation, produce a short-circuit current of U_d/Z_0. It will be sustained until the electromagnetic wave has travelled back and forth in the cable once, which can be in the order of milliseconds. A typical value of Z_0 for a cable is in the order of 30 ohms regardless of whether the cable is intended for high- or medium voltage. In an HVDC application this cable discharge current can be very significant, particularly as it appears with very short rise-time. For instance in a ± 320 kV HVDC system the cable discharge current will be in excess of 10 kA. However, in a MVDC application the discharge current will be much lower, and will have less impact on the protection.

2.3 Strategies for Fault Handling in MVDC Grids

A DC grid differs from an AC grid in that there is no limit to the fault current set by the grid impedance, other than the very low resistance. This means that the fault current will attain a very large steady-state value if it is not interrupted. Furthermore, an MVDC grid will always be fed by converters, either AC/DC converters interfacing to AC grids, or DC/DC converters connecting to other DC grids. Depending on topology, some converters can limit the DC-side current at a fault (see Section 2.2.5), whereas others will lose control of the currents in case the DC voltage collapses. These circumstances have resulted in a couple of strategies for handling faults, which are reviewed below.

1. *AC-side protection*

   In a DC grid interfacing AC grids using converters without DC-side control or blocking capability (e.g. two-level VSCs or MMCs with half-bridge cells), and where no fast DC breakers are installed, the only option in case of a DC fault is to block the converters and open the AC-side breakers. There is thus only one protection zone in the system and the grid discharges via the fault. This method is commonly used for point-to-point HVDC links, where selective fault detection is not meaningful. However, for a DC grid with several nodes this method will not be acceptable since vast transmission assets could be put out of operation due to a single fault.

2. *DC circuit breaker selective protection*

   In case fast DCCBs are installed in all DC lines it can be possible to selectively isolate a fault on a line before the converters need to be blocked. This strategy resembles AC grid protection systems and can prevent significant disturbances on the healthy lines. An important difference is, however, that the entire process of detecting, locating, and isolating the fault has to be completed in much shorter time, typically a few milliseconds or less. This time is determined by several factors. First, the fault current cannot increase to excessive levels as otherwise a converter or any other equipment may be damaged. Second, it is desirable that no converter needs to block since this implies an interruption of both the active power flow as well as the capability of the converters to support a connected AC-grid by reactive power. This requirement generally puts a more severe limitation on the neutralization speed since the converter semiconductor switches tend to be the most sensitive part of the system. Reference (Jahn, Johannesson, & Norrga, 2017) reviews various methods for fault detection to achieve fast selective protection in DC grids. Although the targeted application in this paper was HVDC, the methods are applicable to MVDC as well.

3. *Open-grid protection*

   Another way of protecting DC grids is the so called *open grid* protection concept (Barker & Whitehouse, 2012). It aims to address the problem that it may take to long to locate the fault, during which time the fault current will keep rising. Therefore, it stipulates that all DC breakers in the system are opened as soon as a fault is detected. Subsequently, the faulty line is identified and the breakers connecting to the other lines in the system are closed again, and power flow on these is restored. One of the main benefits of the open grid protection strategy is the distribution of the breaker energy absorption requirements over different breakers. This way the MOVs of each circuit breaker may be rated for less energy than would be required with the fully selective protection. The obvious drawback, on the other hand, is that any fault will interrupt the power flow in the entire DC grid.

4. *Protection using current-limiting converters and fast DC switches*

   A further fault-handling method relies on using converters capable of rapidly blocking or limiting the DC-side current (Ruffing, Brantl, Petino, & Schnettler, 2018). Notably, some converter topologies that may be used as interfaces to MVDC grids have the ability to rapidly limit or even control fault current (within microseconds). This applies to, for instance, the full-bridge MMC and the Dual Active Bridge (DAB) DC/DC converter. It makes it possible to rapidly reduce the DC currents fed into the grid from the converters in case of a fault. Thereby, the fault can be isolated by fast DC switches rather than DC circuit breakers. This method has the drawback that, for AC/DC conversion, considerably more costly converters need to be used. In the case of modular multilevel converters the DC current-limiting variety, with full-bridge cells, suffers from much higher semiconductor cost than the conventional MMC with half-bridges. Also the power losses are higher, since the current has to pass through two power semiconductors in each cell. Furthermore, since all converters need to reduce their DC-side current to zero the power flow in the entire grid will cease until the fault has been cleared. A benefit of the method is that DC circuit breakers are not needed, only fast DC switches, which are less expensive to implement.

Differing from the HVDC transmission grids, the MVDC system contains a large number of distributed energy sources and directly supplies users. When a fault occurs, the tripping of the entire network without selectivity will impact the system adversely. Hence, the use of DCCBs is desirable in MVDC networks. In addition, even though the MVDC grid usually benefits from the converters with fault blocking capability, such a choice of converters more or less challenges the speed and the sensitivity of DC protection. Therefore, the possible conflict between the fault blocking converters and the DCCB based protection scheme needs to be further studied.

2.4 Notes on Protection Algorithms for MVDC Grids

Many fault detection algorithms have been proposed for MVDC distribution systems (Babaei, Shi, & Abdelwahed, 2018). Notably, many of these fault detection algorithms correspond to those suggested for HVDC systems (Jahn et al., 2017). The choice of a specific fault detection algorithm depends on the MVDC grid topology and —- to some degree — the chosen protection strategy. Compared to AC systems, the fault detection algorithms in MVDC systems have to consider the active behaviour of sources and loads, the DC nature of the system to be protected, and in particular high speed requirements to avoid large fault currents.

2.5 Analysis of Fault Clearing Transients

For the rating and parameter selection of the components of the protection system there is a need to determine the time evolution of voltages and currents during a fault transient, including its clearing by the protection system. A DC system differs from an AC system in this regard. In an AC system the short-circuit currents can be calculated by steady state methods, correcting for the voltage point of wave of the fault inception to find the peak instantaneous current. In a DC system however, the prospective fault current cannot be allowed to be reached since it is usually only limited by the resistance in the system. The fault current magnitude would risk causing disruption to operation the entire grid as well as the destruction of components such as converters and DC circuit breakers. As the fault currents need to be limited while they are rising, the transient evolution of the currents and voltages needs to be studied. This is best done by circuit simulators such as Simulink, PLECS or PSCAD. From a detailed circuit simulation a number of key results must be derived. Some examples are the following:

1. The peak current through the circuit breaker at the time of commutation of the fault current to the Metal-Oxide Varistor (MOV).
2. The rate of rise of the fault current.
3. The voltage and current stress on different components of the grid during the fault clearing transient.
4. The dissipated energy in the MOV of the circuit breaker.
5. Whether the circumstances make it necessary to block one or several converters, and for how long the blocking has to be maintained.
6. What protection algorithms are useful and will detect faults with sufficient reliability and selectivity. A useful approach is generally to apply the simulated current and voltage waveforms to different protection algorithms to evaluate their performance in the relevant case.

As will be noted in Section 3.3 there are different possibilities for choosing the parameters of the DCCB and the current-limiting reactor. Parameters such as the inductor size, the breaker speed, and the MOV protection voltage and its energy dissipation capability are strongly interrelated and have to be optimized simultaneously. Repetitive simulations with systematic parameter variations could also allow for proper adaptation of the parameters both of the protection algorithms and the system parameters. It has also been reported how time-domain simulations can be used as part of an optimization algorithm (see reference (Jahn, Chaffey, Svensson, & Norrga, 2021)).

The simulations need to fulfil a number of requirements to be useful in designing the protection system and defining the component requirements. The following items indicate what must be considered when setting up simulation models.

1. The protection *Intelligent Electronic Device (IED)* (known as a protection relay in AC grids) needs to be properly represented in the model. Not just the protection algorithms, but also their implementation, including the sampling frequency and bandwidth of the signal acquisition used in the IED.
2. Any DC cables if needed modelled as transmission lines with distributed parameters. (overhead lines).
3. Converter models need to take the converter control and protection system behavior properly into account. Particularly the response of converters in case of DC-side faults must be replicated accurately. The level of overcurrent and the overcurrent duration necessitating blocking of the converter switching has to be considered by the model. The modelling of other aspects of the converter behavior can often be relaxed.
4. The DC circuit breakers need to be modelled at sufficient detail. For circuit simulations, simplified models mainly taking the external behavior into account are sufficient in most cases, see reference (Augustin, Norrga, & Nee, 2017).
5. Overvoltage protection equipment such as MOVs (in addition to the MOVs in the DCCBs) need to be accurately modelled since these are frequently activated during fault transients, possibly taking into account uneven current sharing among parallel-connected devices (Liu, Popov, Belda, Smeets, & Liu, 2021).

3 DC Circuit Breaker Technology

3.1 Different Types of DC Switchgear

There are several kinds of DC switchgear with different functionality. This report is focusing on defining requirements for MVDC Circuit Breakers, since DC fault current interruption is challenging, and requires the most research and development effort. Still, for completeness, a brief introduction to some different kinds of DC switchgears that may be used in MVDC grids is given in the sections below, see also ref (*CIGRE Technical Brochure 683: Technical Requirements and Specifications of State-of-the-Art HVDC Switching Equipment*, 2017).

3.1.1 Disconnectors

A *disconnector* (also known as *isolator switch*) lacks any significant current interruption capability, but needs to withstand the full system voltage and, depending on the application, it may also have making capability, i.e. that it can turn on current, potentially with a latent short-circuit fault present. It is used for isolation and safety purposes, to ensure that a circuit is galvanically separated from a source. DC circuit breakers usually rely on having a MOV arrestor connected in parallel, to absorb magnetic energy during interruption, see Section 3.2. Thus, there will not be a complete galvanic separation after opening the breaker and a small current will flow though the MOV (less than one per cent of the nominal current) even after the breaker has opened. Therefore, there will generally be a disconnector connected in series, which will need a very limited interruption capability (few amperes).

3.1.2 Earthing Switches and Transfer Switches

In HVDC applications there is also a number of specialized switchgear types used. These may possibly be used also for MVDC, at least at the higher end of the MVDC range. First, *earthing switches* are used for earthing and short-circuiting a de-energized converter or part of a line during maintenance and during testing. They need to be able to carry current for a limited time, but not continuously. In some cases they need to have making capability. Another category is the *transfer switches*. Their role is to transfer load current from one circuit to another. In bipolar HVDC systems they are typically used to transfer the load current to and from the metallic return branch, to allow for seamless transfer between bipolar and monopolar operation. Possibly this application will also be relevant and beneficial for MVDC systems. A transfer switch generally needs making (turn-on) capability and interruption capability, up to the load current in both cases.

3.1.3 DC Circuit Breakers

The task of a *Direct Current Circuit Breaker (DCCB)* is generally to interrupt DC current. Since no current zero-crossings occur in DC circuits this means that a breaker should be able to provide a counter-voltage of sufficient magnitude to force the current down to zero. The next section will discuss in more detail how this is commonly achieved.

A basic DCCB will not achieve galvanic separation after interruption. An MOV, and in some cases other circuitry, will remain connected, permitting a leakage current to flow. A DCCB is therefore in many cases combined with a series-connected disconnector able to interrupt the leakage current and achieve galvanic isolation. The disconnector may be considered as part of the delivery scope of the DCCB or be provided as a separate part. With no further qualifications, a DCCB is assumed to be able to interrupt a fault current. However, there are also *load current breakers* where the interruption capability is limited to the normal operating current.

In general, a DCCB will also need *making* capability, i.e., the ability to turn on in a situation where a current will immediately start to flow. Often it is even required that it should be possible to turn on with a short-circuit fault applied, meaning that a fault current surge will occur instantly. The breaker will then obviously also need to immediately interrupt the current. A common cause of such faults is that a short-circuiting rod has been left in place by mistake after a maintenance event.

3.2 Generic Configuration of a DC Circuit Breaker

The interruption of direct current in case of a grid fault differs fundamentally from AC current interruption. Since there are no current zero crossings it is necessary to actively force the fault current down to zero, overcoming the magnetic energy of the grid section between power feed-in and the fault location. In Figure 6(a) an idealized generic arrangement to accomplish this is displayed. It consists of an ideal switch, that can open even if a current flows though it, with an MOV connected in parallel. The MOV is assumed to also have ideal properties, meaning that it conducts no current at all below a certain level, labeled the *protection level*, and easily conducts current beyond it, thus limiting the voltage at the protection level. In practice, an actual MOV shows a non-ideal characteristic, but for the initial understanding of the DCCB operation this assumption is acceptable. Figure 6(b) shows the principal waveforms of the current and voltage during a fault current interruption procedure using this arrangement. Initially, the load current is carried by the switch, which provides the normal current path. At the fault inception the current starts rising, and after a short while, the relay time, the IED has detected the fault and the DCCB will be commanded to open. The opening of the ideal switch is then commenced and after the *internal current commutation time* has passed the commutation to the MOV happens. The sum of the relay time and the internal current commutation time is labelled the *neutralization time*, t_n. As the current is forced to flow through the MOV the protection level voltage will appear across it. Provided that this voltage exceeds the grid voltage the line current will be forced down to zero.

All modern implementations of fast DCCBs follow this basic paradigm. They differ mostly in terms of the way that the current is transferred from the normally conducting branch to the MOV branch, i.e., the way that the ideal switch is implemented. In section 3.4, a few different types of DCCBs are described, that implement this function in different ways.

3.3 Relationships Between Grid and Breaker Parameter During Fault Transients

The key design parameters of a DC grid protection system (the breaker speed, the current-limiting inductance, and the MOV protection level) are interdependent, and there is generally not an obvious choice of optimal parameters. Some simplified derivations can be made to clarify how the parameters are linked and shed some light on the considerations that need to be made. To this end a simple fault case is defined, see Figure 6. An ideal DC source U_d feeds a DC grid, protected by a DC circuit breaker. The breaker is defined by its design parameters U_{mov}, the MOV protection level and t_n, the neutralization time, i.e., the time from the fault

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inception until the current suppression sets in. There is also an inductance in the system, L, which will limit the rate of rise of the fault current. This inductance may in a real system be composed of the inductances inherent to a converter feeding the system, and possibly a reactor installed to limit the current increase. A short circuit fault can occur just outside this inductance. This represents the worst fault case in most grid topologies provided that the parameters are adjusted accordingly. The different phases of the current interruption process will now be described. First, the parameter k_{mov} is defined as the amount by which the MOV protection level exceeds the DC voltage, normalised by the DC voltage.

$$k_{mov} = \frac{U_{mov} - U_d}{U_d} \Rightarrow U_{mov} = U_d\,(1 + k_{mov}) \tag{2}$$

A typical value is $k_{mov} = 0.5$, meaning that the MOV voltage is 50% higher than the grid nominal voltage. The different stages of a grid fault and its subsequent clearing will now be described in detail.

1. Normal operating conditions

   This is the situation before the fault. The current stays within the normal operating range.

2. Fault current increase phase

   This is the phase from the fault inception until the breaker starts forcing the current down. It consists of the breaker neutralization time t_n, i.e., the time required for the breaker to be ready to commutate the current into the MOV. The breaker has no impact on the circuit and the current rises linearly from the pre-fault value I_0 according to

$$I_1 = I_0 + (t_n)\,\frac{U_d}{L}. \tag{3}$$

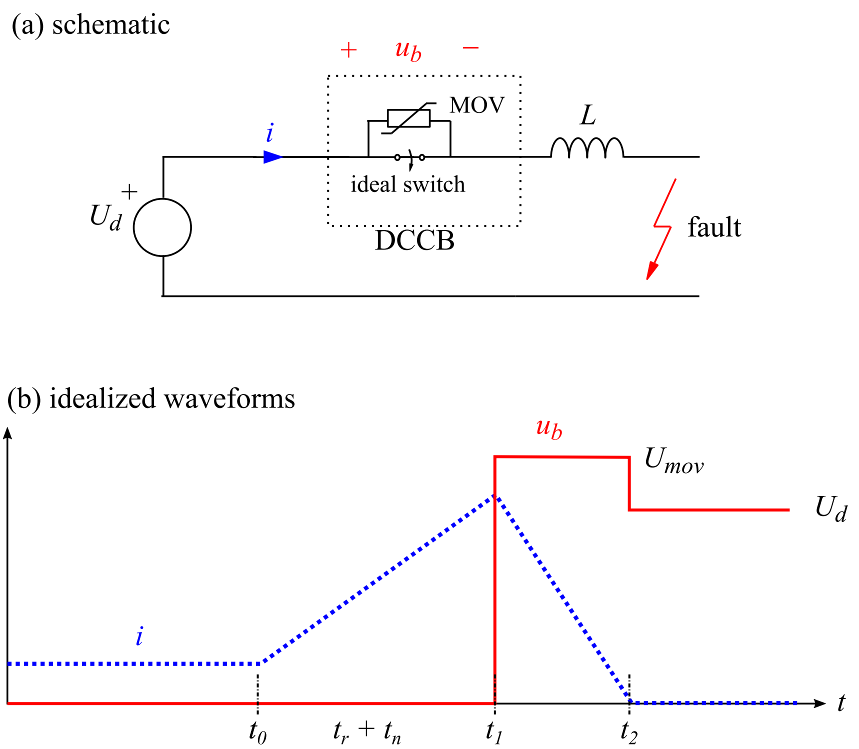

Figure 6: Generic DC circuit breaker configuration: (a) schematic, (b) simplified voltage and current waveforms during interruption.

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The stored magnetic energy at t_1 corresponds to $LI_1^2/2$.

3. Current suppression phase

   The current ramps down linearly from I_1 to zero. The voltage across the inductance is $-(U_{mov} - U_d)$. The duration t_s of this phase is

$$t_s = \frac{LI_1}{U_{mov} - U_d}. \tag{4}$$

4. Breaker open state

   The line current has been forced down to zero. The voltage across the breaker falls back from the MOV protection level to the DC voltage provided by the system (U_d). This phase is usually initially characterised by a certain oscillation in the current caused by parasitic elements in the grid and the DCCB. As there will be a small leakage current flowing through the MOV, it is generally preferred to open the series disconnector at this stage. This will eliminate the leakage current and avoid unwanted heating of the MOV.

The energy dissipated in the MOV during the turn-off process can be approximated by

$$E_{mov} = \frac{t_s U_{mov} I_1}{2} = \left(1 + \frac{1}{k_{mov}}\right) \frac{LI_1^2}{2}. \tag{5}$$

Notably, it exceeds the stored magnetic energy at t_1, $(LI_1^2/2)$, because the voltage source U_d will keep feeding power into the MOV during the ramp-down period. In the interest of simplifying the calculation, we assume that the pre-fault current is negligible, whereby Equation 5 can be written

$$E_{mov} \approx \left(1 + \frac{1}{k_{mov}}\right) {t_n}^2 \frac{U_d^2}{2L}. \tag{6}$$

By observation of this expression, a few important conclusions become clear. To minimize the required MOV energy dissipation capability it is vital to reduce the total time to current suppression t_n as much as possible, as it enters the expression squared. Furthermore, the MOV energy can also be reduced by increasing the inductance L or by increasing k_{mov}, i.e., increasing the MOV protection level. Neither of these two measures are desired, however, and an optimisation needs to take place. Increasing the inductance may cause added power losses (in the inductors during normal operation) and added equipment cost, if additional devices are needed. Increasing the MOV voltage may also have drawbacks in that respect that the transient overvoltage stress on the system becomes higher. Assuming that the neutralisation time and the maximum turn-off current are fixed quantities defined by the capability of the circuit breaker or other concerns, the minimum required series inductance will be

$$L = t_n \frac{U_d}{I_1 - I_0}, \tag{7}$$

Specifying a certain required neutralisation speed or a certain current limiting inductor would likely be counterproductive, and limit further benefits to be gained from the use of MVDC systems. Instead, a holistic cost optimisation should be undertaken.

3.4 Types of DC Circuit Breakers

3.4.1 Semiconductor-based DC Circuit Breaker

A straight-forward method to implement a DCCB is to connect a power semiconductor switch with turn-off capability (e.g. an Insulated Gate Bipolar Transistor (IGBT), an Integrated Gate-Commutated Thyristor (IGCT) or a power MOSFET) in parallel with an MOV, keeping it in its on-state in normal operation and blocking it when breaking is required. The switch must be designed to withstand the maximum MOV protection voltage, which is typically in the range 1.3–1.6 times the nominal dc voltage for a symmetric monopole. Normally a bidirectional switch will be required, which means that two IGBT valves connected in anti-series must be used. Such a switch would therefore need at least as many semiconductor devices as in one phase leg in the connected converters. The corresponding power loss can be estimated at 0.15 % - 0.3 % of the maximum transferred power. Such high losses impose a severe penalty on the described DC breaker approach. The power losses can also cause a thermal problem for the design of a semiconductor-based breaker. The cooling of the semiconductors need attention and in the worst case active cooling relying on fans and/or pumps is needed, which generally will reduce the overall system reliability. A further drawback of this approach is that the overcurrent capability will be very limited compared to a breaker that carries the current through a mechanical contact in normal operation. This is a problem with regard to the temporary overcurrent withstand capability, which is needed for fault cases where the breaker fails to open and needs to stay connected until the backup protection is activated. The benefit of semiconductor switching is the speed at which it can be carried out. A power semiconductor device can be switched off in less than a microsecond, which should be compared to the operating speed of a mechanical contact which generally takes a millisecond or more.

3.4.2 Hybrid DC Circuit Breaker

Hybrid DC circuit breakers come in several types with different methods for current commutation. According to this solution (Cwikowski, Barnes, Shuttleworth, & Chang, 2015), during normal operation the current is conducted through a mechanical switch (in this context referred to an *ultrafast disconnector (UFD)*), in series with a power electronic switch with limited voltage handling capability, labelled *transfer switch*. The power electronic switch typically consists of only one or a few power semiconductor elements in series. Therefore its voltage drop is fairly small and accordingly the power losses in normal operating conditions are negligible. When a fault occurs, the line current is forced to commutate into a parallel branch with low voltage drop. This eliminates the current through the mechanical switch, which then can open. At zero-current conditions the mechanical switch can open very fast and provide full voltage withstand capability in a few milliseconds. Once the mechanical switch has established sufficient voltage withstand capability, the current will be forced to commutate again, this time into a further parallel branch containing an MOV. The latter inserts the high counter-voltage that brings the current down to zero. Figure 7 illustrates the hybrid HVDC breaker. Prior to the fault the line current passes through the fast disconnector and the auxiliary dc breaker causing only small losses. The breaking operation will be executed in a two-stage process: 1. At a breaking command the electronic main switch is gated on and the transfer switch is blocked, which causes the line current to commutate into the electronic main switch. 2. The fast disconnector can then be opened, and when it after a few milliseconds has gained its full voltage withstand capability, the electronic main switch can be blocked forcing the line current to flow through the MOV. It is clear that the first step in this process may be executed already when the line current starts to increase, so that breaking can be executed without any delay once the current reaches the trip level. If it turns out that the trip level is never reached, the normal conduction path may be reestablished. The major drawback of hybrid circuit breakers is the opening time of the mechanical conduction path in comparison to the current rise during near faults. While an uncontrolled current flow might reach the maximum breaking current of the hybrid circuit breaker after several tens of microseconds, the opening time is in a range of milliseconds. This leads to a need for devices which can limit the current rise to a safe value. The most prominent solution for this would be the application of a current limiting inductor placed in series with the circuit breaker, but due to the size needed this can lead to problems with fitting the circuit breaker into smaller enclosures and prohibit retrofitting of older AC equipment rooms with new DC technology.

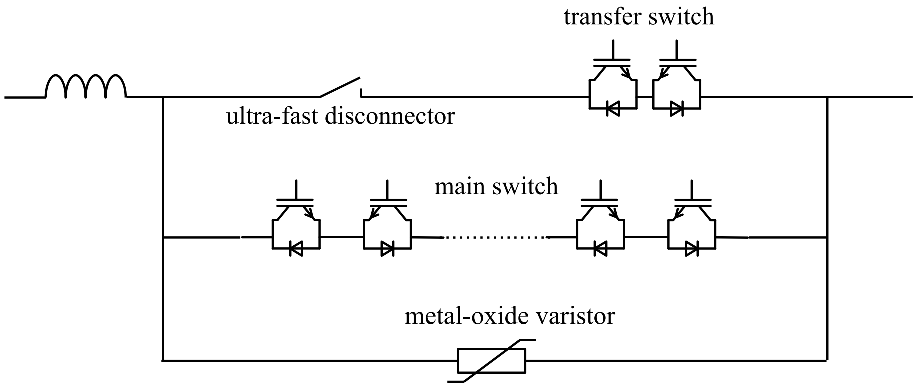

Figure 7: Simplified schematic diagram of a hybrid DC circuit breaker.

3.4.3 Active Resonant DC Circuit Breaker

Another physical mechanism to insert the MOV in series with the line makes use of an auxiliary circuit to force the current through a vacuum interrupter, normally conducting the line current, to cross zero while its contacts are separating. Figure 8 illustrates this principle. The line current normally flows in the vacuum interrupter (VI) through low-loss mechanical contacts. At a breaking operation the mechanical breaker is commanded to open and a fast-acting actuator starts to separate the mechanical contacts. An arc with quite moderate voltage drop continues to carry the line current between the contacts. While the arcing between the contacts is ongoing some arrangement in an auxiliary circuit is commanded to create a circulating current which opposes the current in the arc, forcing it to zero. The figure illustrates an example which uses a branch containing a closing switch in series with an LC resonant circuit with an initially charged capacitor connected in parallel with the mechanical interrupter. The current pulse is initiated by closing this switch and the arc current approaches zero if the pulse amplitude exceeds the line current. The mechanical breaker then extinguishes the arc current if the distance between the separating contacts is sufficient to provide the required voltage withstand capability. If so, the line current is transferred into the resonant circuit, charging the capacitor. When the voltage reaches the MOV protective voltage level the current commutates into the MOV branch. As this circuit breaker also uses a mechanical conduction part, it suffers from the same drawback, especially the need for current limiting device, as the previously mentioned normal hybrid circuit breaker.

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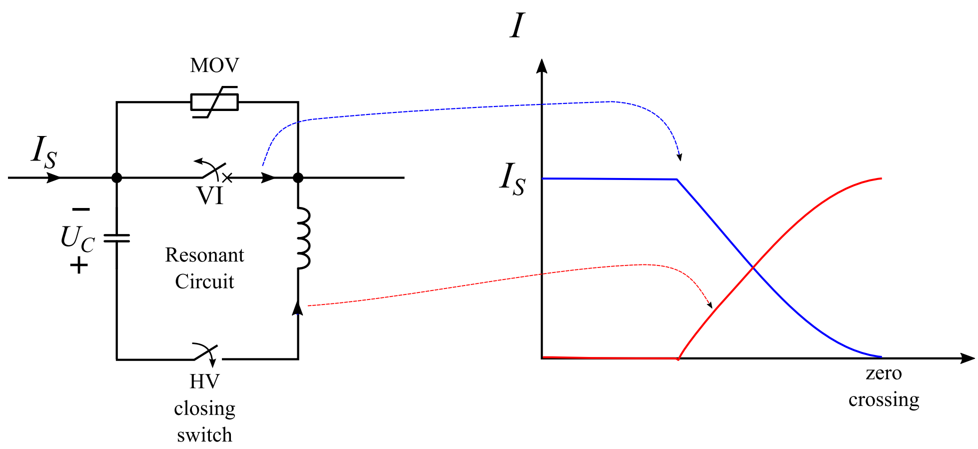

Figure 8: Active resonant DC circuit breaker. Circuit schematic (left), simplified current waveforms (right).

3.4.4 VARC DC Circuit Breaker

The main circuit of a VSC-Assisted Resonant Current (VARC) circuit breaker, and the principal voltage and current waveforms during a current interruption, are shown in Figure 9. The line current is conducted by metallic contacts in a vacuum interrupter (VI) during normal, closed conditions. Thereby, the losses are kept low, and cooling systems are not needed. Furthermore, a Vacuum Interrupter (VI) also has good current interruption capability at current zero-crossings and can withstand both high voltage and high voltage-derivative following current extinction. However, an artificial current zero cross-over in the VI current is required for current extinction. To provide it, in this case a current injection branch, consisting of a capacitor C, an inductor L and a small VSC, is connected in parallel with the main VI. During an interruption, a VI contact opening by an ultrafast actuator is first initiated. When the contact separation is sufficient, the VSC is controlled to produce a high-frequency square-wave voltage, U_{VSC}, which results in an oscillating current with increasing magnitude I_{RES} in the injection branch. This current soon approaches the line current I_S in magnitude. Since the resonant circuit also comprises the VI, this implies a zero crossing in the current through the VI, upon which it interrupts. The line current is forced into the resonant circuit whereby the capacitor is charged. When the capacitor voltage reaches the MOV protection voltage the current transfers to the MOV branch and the current interruption can be completed. As this type of hybrid circuit breaker also uses a mechanical conduction path, it also suffers from the same drawback as described for a normal hybrid circuit breaker, namely the rate of rise of fault current may need to be limited by the use of an inductor installed in series with the breaker.

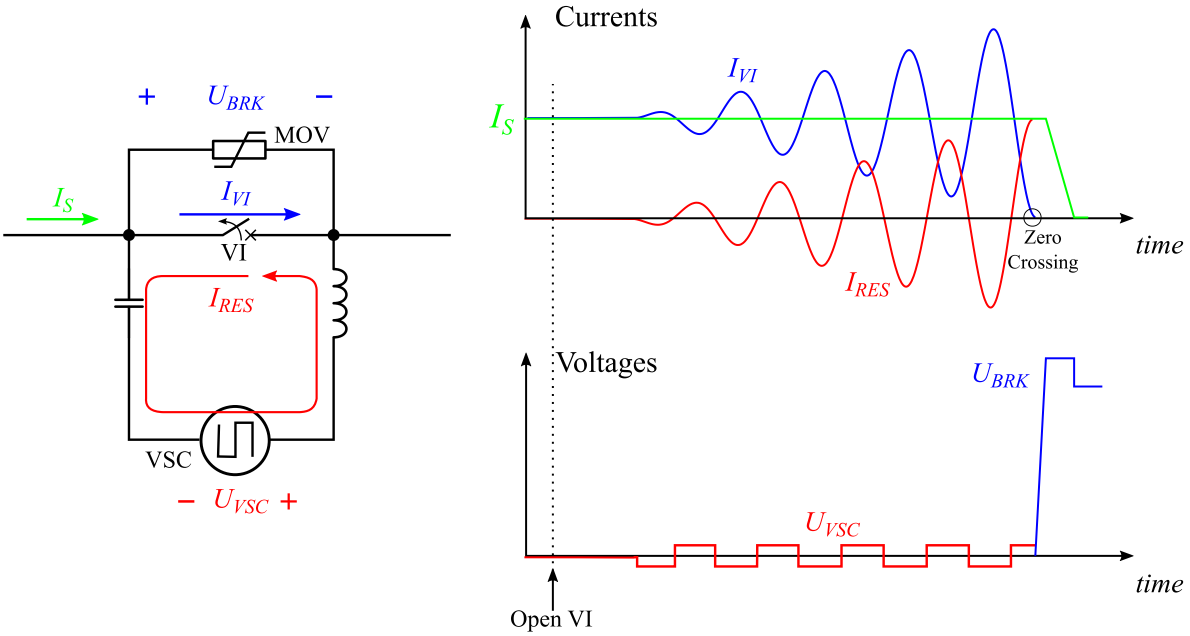

Figure 9: Voltage source converter assisted resonant current (VARC) DC circuit breaker.

4 Requirements for MVDC Circuit Breakers

Based on the description of the function of DC circuit breakers and their applications in the previous chapters as well as discussions held among the partners of the HYPERRIDE project a number of generic requirements for MVDC circuit breakers have been identified. The purpose has not been to specify exact requirements but to define what parameters, ratings and features that need to be specified in order to procure a DCCB for an actual MVDC application.

4.1 General

Certain general characteristics of a DCCB, and the grid it will be installed in, need to be specified firstly. These also influence the various ratings which are discussed in the coming sections.

Grid configuration As mentioned in section 2 there are different ways of arranging the grounding of a DC grid. Is the DCCB intended for use in a symmetric monopole, an asymmetric monopole or a bipole grid?

Current directionality Certain types of DCCBs can only carry and interrupt currrent in one direction, while offering benefits such as lower cost. Therefore it should be specified whether the DCCB should be bidirectional or a unidirectional apparatus is sufficient.

4.2 Voltage Ratings

A number of requirements generally need to be specified for the voltage handling capability of a DC circuit breaker. These are listed and described below.

Nominal Voltage The nominal voltage of the installation the breaker is connected to. Typical standardised voltages in MVDC grid are mentioned in reference (CIGRE WG C6.31, 2020).

Rated voltage The maximum voltage the circuit breaker can withstand for a long period of time. It is generally between 5 % and 10 % higher than the nominal voltage

Short-term withstand voltage A breaker may need to withstand a higher voltage for a short time period, whose length should be specified. Such a temporary overvoltage may arise during a fault if the primary protection fails, while waiting for the backup protection of trip.

Transient overvoltages Like any other power apparatus, a DC breaker may be subjected to transient overvoltages, and its capability to withstand them needs to be defined. Generally a distinction is made between *switching* and *lightning* overvoltages and separate values may be defined. Standardised test procedures exist defining the rise and fall times for both of these overvoltage transients (IEC 60060). Also, a distinction is generally made between transient overvoltages across the breaker, on the one hand, and between the breaker terminals and ground, on the other.

Transient Interruption Voltage (TIV) This is not really a rating but rather a design parameter. The TIV is the voltage that appears across the breaker during interruption during the time when the fault current is forced down to zero. It is defined by the Metal-Oxide Varistor (MOV) used as part of the breaker to absorb energy, and to some extent by the instantaneous value of the current, as the characteristics of the MOV cannot be expected to be ideal.

4.3 Current Ratings and Energy Absorption Capability

Depending on the application a number of current-related ratings need to be defined for a DCCB.

Rated continuous current This rating defines the value of the current the switchgear and control gear can carry continuously for its service conditions. From a rating perspective, it is mostly limited by thermal concerns.

Rated short term operational current Short term operational current that the DCCB should withstand.

Rated short-time withstand current This is the overcurrent level that the DCCB should be able to withstand for a short time, typically in the range of one second. It is generally defined by a fault case leading to an overcurrent where the DCCB is not opening (for instance because the primary protection IED is not tripping). Under such circumstances the breaker needs to carry the fault current until the backup protection is activated. Therefore, usually also a *Rated duration of the short-circuit* is defined that specifies for how long time the short-time withstand current can be tolerated.

Rated turn-off current The maximum instantaneous current that the breaker can turn off. It is generally determined by the capability of the DCCB to commutate the current to the MOV. As discussed in section 3.3 in this report, the current level depends heavily on the neutralization time, i.e., the time interval from the fault inception until the fault current is commutated into the MOV.

Energy absorption capability The amount of energy the DCCB can absorb during one or several subsequent interruption operations needs to be defined. In case rapid Open-Close-Open sequences are enabled by the DCCB the overall energy absorption capability during such a sequence should be specified. The specifications should also cover the recovery time, i.e., the time required for the DCCB to be prepared to operate again after the MOV has absorbed the energy associated with a single or double operation.

4.4 Operation of the DCCB – The Switching Process

The differences in operation compared to an AC circuit breaker make it necessary to specify certain aspects of the operation in detail.

Startup time The time required from the connection of auxiliary power until the DCCB is ready to operate.

Neutralization time The time from the interrupt order until the fault current is forced into the MOV and starts to decrease.

Timing during a switching sequence In case the breaker should be capable of executing a rapid Open-Close-Open sequence, the timings during such a sequence should be defined.

4.5 Auxiliary and Control Equipment and Circuits, and Their Interfaces

The control and communication and other external interfaces apart from the power circuit need to be specified.

Auxiliary power voltage Rated supply voltage range of auxiliary and control circuits, and its frequency in case AC auxiliary supply is used.

Auxiliary power consumption Continuous auxiliary power required, and peak requirement during switching sequences.

Protection functions Are fault detection functions internal to the breaker or external?

Diagnostics, self-testing Does the DCCB have diagnostic functions implemented in the control system to, for instance, determine the remaining useful life based on measured parameters? Are self-testing procedures of some kind implemented?

4.6 Other Features and Properties

In addition to the above mentioned specifications there are other features and properties that may need to be defined.

Maintenance requirements Planned maintenance interval (time, number of operations). Also, are additional maintenance events required in case of extreme duty?

Mechanical Lifetime In case the DCCB incorporates a mechanical breaking element, the estimated no of operations (without current) is stated.

Number of operations at normal operating current The estimated DCCB lifetime, in terms of the number of operations at the normal operation current.

Number of operations at the maximum turn-off current The estimated DCCB lifetime, in terms of the number of operations at the maximum turn-off current.

Retrofit possibilities Is it possible to retrofit the DCCB by replacing aged or worn parts to extend the lifetime? When is this needed? What are the conditions?

Physical dimensions The exact physical dimensions as well as the clearances required with respect to dielectric and magnetic considerations. Can the DCCB fit into some kind of standardized switchgear cabinet?

Operating environment Any requirements on environmental factors such as EMI immunity, ambient temperature, humidity, air pressure, altitude above sea level, and air contamination should be specified.

Presence of hazardous substances In case the breaker contains regulated and/or hazardous gases or fluids, such as SF6, this should be specified and the requirements on handling of these substances be described.

5 Review of Standards for DC Circuit Breakers

Standards can be imposed where there are established and reasonably mature technical solutions. Issuing a standard in an application field where there is still not a consensus about what fundamental technical solutions should be used can be counterproductive and hamper development. Furthermore, the drafting and approval of new standards is a lengthy process. Medium voltage DC technologies have not been extensively used so far, with the exception of certain railway and shipboard applications. Therefore, there are few standards in force that regulate the technology for MVDC systems. This section presents a review of various normative publications that apply to MVDC breaker technology, as well as some adjacent fields. In addition, normative documents that are currently being drafted are mentioned.

5.1 CIGRE Publications

CIGRE (International Council on Large Electric Systems) is an international organization focused on high-voltage electricity. In later years, the area of interest has been widened to also cover aspects of electric power distribution, and notably MVDC. CIGRE issues *Technical Brochures (TB)*, which are the result of the work of dedicated work groups that work 3-4 years on a specific topic. These are often to some extent normative. Some of the TBs that have an impact on MVDC circuit breakers, directly or indirectly, are described below.

CIGRE TB 683 – Technical requirements and specifications of HVDC switching equipment. This brochure (*CIGRE Technical Brochure 683: Technical Requirements and Specifications of State-of-the-Art HVDC Switching Equipment*, 2017) was issued in 2017. It covers all aspects of HVDC switching equipment, including modern fast DC circuit breakers with millisecond neutralization capability. Although the brochure focuses on the HVDC field, it is still of interest in MVDC applications since it gives a very elaborate and detailed description of DC protection using fast circuit breakers, i.e. the kind expected to be used in MVDC systems.

CIGRE TB 793 – Medium voltage direct current (MVDC) grid feasibility study. This brochure looks into the state of the art in MVDC grid technology and identifies the gaps in terms of research and development for further deployment. It is to date the only normative publication available that specifically treats MVDC grids. MVDC distribution systems and applications with a voltage range between 1.5 kV (±750 V) and 100 kV (±50 kV). Of particular interest is a discussion of possible and recommended voltage levels for MVDC systems.

In addition to the above mentioned CIGRE Technical Brochures, there are also a few CIGRE working groups currently active on topics relevant to MVDC switchgear. They will eventually also produce technical brochures.

WG A3.40 – Technical requirements and field experiences with MV DC switching equipment. This work group started in 2018 and is expected to deliver its technical brochure in 2022. It will review the state of the art in MVDC switching equipment and collect experiences from existing MVDC installations and their operation. The output will be a summary of technical requirements on MVDC switchgear as compared to AC and MVDC applications. In addition, recommendations for testing requirements will be given.

JWG C6/B4.37 – Medium Voltage DC distribution systems. This WG started in 2018 and should deliver its TB in 2022. It focuses on various aspects of MVDC networks and their applications, including their protection.

JWG B4/A3.80 – HVDC Circuit Breakers – Technical Requirements, Stresses and Testing Methods to investigate the interaction with the system. This joint work group builds onto the work reported in TB 683 to provide a guide to define the technical requirements for circuit breakers in HVDC applications. A report on the design, test and application of HVDC circuit breakers is planned for delivery in 2022. It will present HVDC grid fault management strategies with DCCB functional requirements and technology alternatives. Also included is and overview of operational experiences of existing DCCB installations, type test requirements and alternative test circuits.

5.2 IEC Publications

The *International Electric Commission (IEC)* prepares and publishes international standards for all electrical, electronic and related technologies. The issued publications fall into a few different categories:

International standards(IS) - The definition given in all IEC standards reads: "A normative document, developed according to consensus procedures, which has been approved by the IEC National Committee members of the responsible committee in accordance with Part 1 of the ISO/IEC Directives."

Technical specification (TS) - A technical specification approaches an international standard in terms of detail and completeness but has not yet passed through all approval stages, either because consensus has not been reached or because standardization is seen to be premature.

5.2.1 IEC Railway Related Normative Publications

Since DC distribution has traditionally mostly been used in railway power supply networks IEC standards that may have an impact on DC circuit breakers are mostly related to railway applications.

IEC 61992 - RAILWAY APPLICATIONS – FIXED INSTALLATIONS – DC SWITCHGEAR The IEC 61992 series specifies requirements for DC switchgear and controlgear and is intended to be used in fixed electrical installations with nominal voltage not exceeding 3 000 V d.c., which supply electrical power to vehicles for public guided transport, i.e. railway vehicles, tramway vehicles, underground vehicles and trolley-buses. It consists of a number of parts, where those most relevant to the specification of MVDC circuit breakers are listed below. In terms of circuit breakers, generally the focus is on mechanical breakers with arc chutes, since these are the most commonly used in DC railway applications.

Part 1. 6 (IEC 61992-1) General This is an introductory part containing definitions and terminology, focusing on the types of DC switchgear currently in use in railway applications.

Table 1: Pending additions to the IEC series 62271 (High-voltage switchgear and controlgear) related to DC switchgear.

Number	Title
IEC TS 62271-5	Common specifications for direct current switchgear
IEC TS 62271-313	Direct current circuit-breakers
IEC TS 62271-314	Direct current disconnectors and earthing switches
IEC TS 62271-315	Direct current (DC) transfer switches
IEC TS 62271-316	Direct current by-pass switches and paralleling switches

Part 2: (IEC 61992-2) DC circuit-breakers This part of IEC 61992 specifies requirements for DC circuit-breakers for use in fixed installations of traction systems. Switchgear assemblies, electromagnetic compatibility (EMC) and dependability are not covered in this standard, but by other parts of this standard or by other standards, as indicated in IEC 61992-1.

Part 6 (IEC 61992-6) DC switchgear assemblies This part of IEC 61992 covers DC metal-enclosed and non-metallic enclosed switchgear assemblies used in indoor stationary installations of traction systems, with nominal voltage not exceeding 3 000 V. It is intended that individual items of equipment, for example circuit breakers, housed in the assembly are designed, manufactured and individually tested (simulating the enclosure when necessary) in accordance with their respective parts of IEC 61992 or, when appropriate, with another applicable standard.

IEC 60077-3 Railway applications - Electric equipment for rolling stock - Part 3: Electrotechnical components - Rules for DC circuit-breakers This international standard is part of a series regulating the electric equipment of rolling stock (i.e., electric railway vehicles). It concerns DC circuit breakers for the auxiliary and drive circuits for such vehicles. The maximum rated voltage is 3 000 V as in the case of fixed installations for railway power supply.

5.2.2 Other IEC Publications

IEC 61936-2 Power installations exceeding 1 kV a.c. and 1,5 kV d.c. - Part 2: d.c. This technical specification relates mostly to HVDC installations, although the scope covers voltages down to 1.5 kV DC. Among other things, it specifies rules for the design of converter stations including the clearances with regard to avoiding flashovers in case of lightning and switching transients.

5.2.3 Pending IEC Publications

There are a number of normative documents, to be issued by the IEC, targeting DC switchgear, that are currently in preparation, see Table 1. They are part of the IEC 62271 series of documents (*High-voltage switchgear and controlgear*), i.e., the main IEC series of normative documents relating to switchgear. These are not public yet, even in draft form, but are likely to be influential when they are finally issued. They will all be issued as technical specifications, i.e. the classification below a standard, reflecting the rapid development in the field on DC switchgear.

5.3 IEEE Standards

The *Institute of Electrical and Electronic Engineers (IEEE)* is an international organization whose mission is to “promote the development of electro-technology and allied sciences, the application of those technologies for the benefit of humanity, the advancement of the profession, and the well-being of its Members”. The IEEE also issues standards. These are mostly observed in North and South America, but in many cases are also influential in other parts of the world. There is generally a desire to homogenize the IEC and IEEE standards. The IEEE standards with most relevance to MVDC circuit breakers are listed below.

IEEE Std 1709-2018 The IEEE Std 1709-2018 (IEEE Recommended Practice for 1 kV to 35 kV Medium-Voltage DC Power Systems on Ships) This publication provides analytical methods, preferred interconnection interfaces, performance characteristics and testing for applying 1 kV to 35 kV MVDC power distribution and dc power-delivery systems on ships. It is interesting in that it relates to MVDC. However, it focuses on MVDC systems protected without DCCBs i.e. it foresees the use of converters with current-limiting capability paired with fast switches without interruption capability.

6 Requirements for 5 kV DC Circuit Breakers for the HYPERRIDE German Demonstrator

6.1 Introduction

The requirements on the circuit breaker performance depend on among others the configuration of the protected grid, the type of the protected converter and the presence of a current limiting reactor. Moreover, in case of a DCCB, the insulation coordination of the grid and the length of the conductors also impact the design of the energy absorbing branch of the circuit breaker (see Section 2). In the following list, the contribution of these factors to the circuit breaker requirements are detailed.

1. Grid configuration

   The configuration of the grid (see Section 2) plays a role in whether pole-to-ground faults result in large fault currents or not. In case the pole-to-ground faults do not cause quickly rising fault currents, a single circuit breaker capable of clearing pole-to-pole faults may be sufficient to protect the transmission line. If a pole-to-ground fault results in large fault currents, then both poles of the transmission line should be protected by a dedicated circuit breaker.

2. Converter type

   The converter type plays a role in how large the initial fault current amplitudes can be in case of a short circuit occurring electrically close to the converter. More energy stored in the converter DC side capacitor results in larger initial fault current surge peaks and rise times. The MMC converters are more advantageous in this respect as they have their DC side capacitance distributed along the submodules of their converter arms, see section 2.2.4 and reference (Sharifabadi, Harnefors, Nee, Norrga, & Teodorescu, 2016).

3. Current limiting reactor

   Depending on the type of circuit breaker used, a current limiting DC reactor needs to be designed into a grid so that it reduces the rate of rise of all types of fault currents in that grid. The reduction of the rate of rise of current should be sufficient so that the circuit breaker is enabled to break before the fault current exceeds its maximum breaking current. The reactor design should also take into account many other technical requirements (e.g. nominal current, available space for the reactor, basic insulation level, losses, electromagnetic interference with other components etc.).

4. Insulation coordination

   The insulation coordination of a grid influences how large the clamping voltage of the DCCB energy absorbing branch can be. This in turn impacts how fast a fault current suppression can be and therefore how much energy the branch should absorb during a single breaking operation (see Subsection 3.3). As there are no established standards regarding the insulation coordination in MVDC grids as of the writing of this report (early 2022), setting the nominal system voltage does not automatically determine the clamping voltage of the circuit breaker; it rather yields a range of feasible clamping voltages.

5. Conductor length

   During a breaking operation the magnetic energy stored in the grid conductors has to be dissipated in the energy absorbing branch of the DCCB. This magnetic energy depends

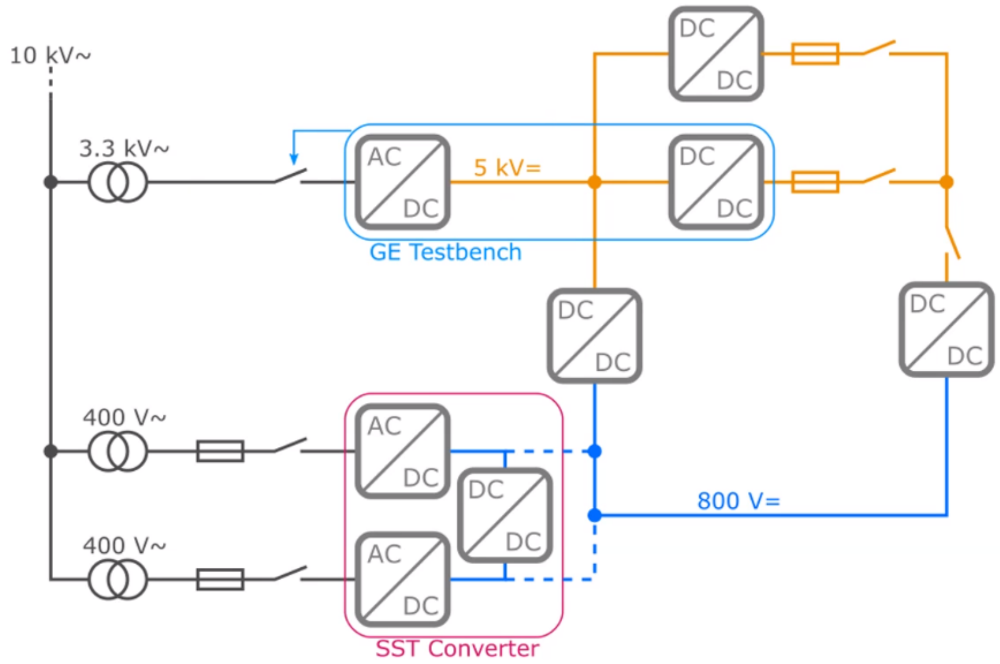

Figure 10: Circuit schematic of the FEN MVDC Research grid.

on the peak fault current amplitude at the beginning of the fault current suppression phase and on the inductance of the protected lines. The latter is proportional to the length of the conductors.

6.2 The German Pilot

A short description of the relevant part of the FEN MVDC Research grid is given here to provide the context. This research grid (located in Aachen) has not been completed as of the writing of this report (early 2022), so the circuit breaker to be developed in this Work Package (WP) needs to be designed according to the already existing parts of the grid.

This German pilot grid is aimed to become a multiterminal MVDC grid. There are scientific papers published on how the grid topology is planned, e.g. (Stieneker, Butz, Rabiee, Stagge, & Doncker, 2015).

At the time of the writing of this report, the electrical circuit schematic of the network looks like the one in Figure 10.

The DCCB is going to be installed on the $5\,\mathrm{kV}$ side of the grid. This grid is arranged in a $\pm 2.5\,\mathrm{kV}$ symmetric monopolar configuration with the midpoint of the converters grounded via high impedance. Later on, after the expansion of the grid, the already existing mid-point conductor might be connected to enable bipole operation. But in the symmetric monopolar configuration, as a pole-to-ground fault does not result in quickly rising fault currents, a single circuit breaker capable of clearing pole-to-pole fault currents is sufficient to protect the grid.

Cables of the FEN MVDC Research grid are protected by surge arresters connected between poles and ground that have a rated voltage of $4.8\,\mathrm{kV}$. This means that the clamping voltage of these surge arresters are around 9.8 kV if the current flowing through them is 250 A. The implication is that a VARC circuit breaker with a TIV of less than 9 kV at the designed resonant current can be used to protect the grid without jeopardizing the already installed surge arresters.

6.3 The GE Test Bench

Currently, the 5 kV part of the FEN MVDC Research grid consists of power converters, fuses, disconnectors and cables that will interconnect the converters with other grid terminals that will be built later. The GE test bench of this German pilot grid is of particular interest from the circuit breaker design point of view as the circuit breaker will be installed here. The already installed converters are part of this test bench, see Figure 10. They are designed for a rated power of 5 MW, that yields 1 kA as the rated converter DC current at the nominal voltage of the grid. In (Stieneker et al., 2015) it is detailed that the converter connecting the AC grid to the DC network is an Active Front End (AFE) while the test bench is connected to the research grid by a DAB converter. While the transformer of the DAB and the converter control system are tailored to the planned application, other parts such as the power electronic switches and the DC link capacitors belong to the original converter design. Both the AFE and the DAB are off-the-shelf converters manufactured by General Electric and they belong to the MV7000 drive family.

6.4 Impact of the Converter DC Capacitor Size

Based on the MV7000 brochures (GE Power Conversion, 2020a) and (GE Power Conversion, 2020b), the switching frequency of the converter power switches is considerably lower than that of their planned operation as part of the research DC grid. This implies that the DC-side capacitor bank of the AFE and the DC capacitors of the DAB are oversized for the planned operation. According to (van Hertem, Gomis-Bellmunt, & Liang, 2016), for VSC-HVDC applications it is usual to choose the converter DC capacitor size so that the ratio of the energy stored in the capacitor at nominal voltage and the nominal power of the converter becomes $2-5$ J/kW. This ensures that the converter DC capacitor bank can be charged from zero to nominal voltage with nominal converter power in a few milliseconds while the voltage ripple of the DC side is acceptable. Since fast control of the converter DC capacitor voltage and low DC voltage ripple are desirable in MVDC grids as well, the same capacitor sizing method can be applied in the case of the German pilot. The aforementioned ratio for both the AFE and the DAB primary side (i.e., the side directly connected to the AFE DC side) is 11.25 J/kW and for the DAB secondary side it is approximately 14 J/kW.

The capacitors on the DC side of the AFE and on the primary side of the DAB are connected together and they are installed in the same cabinet, as shown in Figure 11. This means that the circuit breaker cannot be installed in a way that it would provide the option of separating the capacitor banks of the two converters from one another. This has implications on the magnitude of fault currents in worst-case short circuit scenarios.

As will be shown in Subsection 6.7, a sudden discharge of the fully charged capacitors through a low impedance path (e.g. a pole-to-pole short circuit occurring electrically close to the converters) would result in unacceptably large short circuit currents. Since the fault current would rise very steeply, the DCCB should stay closed as an interruption of this fast-rising current would not be feasible. That means that almost all of the energy stored in the capacitor banks

Figure 11: Capacitor banks of the converters of the FEN MVDC Research grid.

would be released into the ambience in the form of a powerful electric arc, posing threat to the safety of both personnel and equipment.

6.5 Fault Detection

Depending on the size of the grid, there are several ways in which faults can be detected. Many protection strategies involve relays that measure the impedance of the conductors between the substation and a fault that occurred, check instantaneous currents through them against preset levels or compare current derivatives to preset values.

The information about the fault that is yielded by the protection relays can be used to determine which circuit breakers should operate and the central control system can issue the trip commands to the circuit breakers. It, however, may take several milliseconds from fault inception till the breaker neutralizes the fault. In case of DC grids, it is anticipated that there is no such long time available for the circuit breaker to break the fault current (refer to Section 2.3).

Therefore, it is necessary to design the circuit breaker so that it can autonomously decide whether to interrupt the current through its VI. If the current is evolving in a way that it would reach the maximum breaking current of the circuit breaker before a higher-level or central control system could detect a fault, relay the trip command and the breaking operation could be executed, then the circuit breaker should be able to protect itself.

This self-protection can be implemented by measuring the current through the VI for a short time and extrapolating it. Since the maximum breaking current of the circuit breaker and the breaker operation time are known, a control algorithm can decide if tripping the circuit breaker in the given moment is necessary.

In case of the VARC circuit breaker, the fault detection takes approximately $200\,\mu s$ and the breaker operation time is approximately $1\,ms$. Therefore, a fault neutralization time of $1.2\,ms$ is expected.

6.6 Additional Circuit Breaker Requirements

6.6.1 Galvanic Isolation

Because the VARC circuit breaker consists of a surge arrester connected in parallel with the normal path of the operational current through the breaker, after a breaking operation the circuit breaker cannot guarantee a galvanic isolation between its terminals by itself. If galvanic isolation is required, an additional circuit breaker (or disconnector) capable of providing galvanic isolation should be installed in series with the main circuit breaker.

In case of the German pilot, there are disconnectors installed already.

6.6.2 Start-up Time

The circuit breaker prototypes that SCiBreak have built contain multiple capacitor banks for storing energy. These banks have to be charged before the circuit breaker can become ready to operate. Currently, the charging times of the capacitor banks are in the range of several tens of seconds, but it can be shortened by enhancing the auxiliary power supply.

6.6.3 Sequencing

Owing to the actuator used in the VARC circuit breaker, it is possible to perform an O - t - CO sequence of breaker operations. During the discussions with the developers of the German research grid, it was not explicitly stated that performing such a sequence is necessary. However, if it was necessary, a sequence with a very small t would be possible. The time between the first 'open' and the 'close' operations is practically the settling time of the mechanism moving the contact of the VI after a breaking operation.

After the second 'open' operation, in order for the circuit breaker to become operational again, it needs tens of seconds to recharge its capacitor banks.

6.6.4 Mechanical Life of the Breaker

For this application, where a low number of short circuits are expected, a duty M1 according to Section 6.101.2.1 of Edition 2.1 of the IEC 62271-100 standard will be sufficient. This corresponds to a rated number of 2000 mechanical operation cycles between check-ups on the circuit breaker.

6.6.5 Interfacing with the Circuit Breaker

The family of standards regarding a possible protocol that would manage the communication between the converter control system and the circuit breaker was identified to be IEC 61850.

In other circuit breaker prototypes of SCiBreak, a dedicated interface board manages the communication between the control system of the circuit breaker and the substation where the breaker is installed. The channels of communications are implemented by the use of relays, optical transceivers and Ethernet connectors.

The communication issues with be further investigated in Task 3.5 of the HYPERRIDE project.

6.6.6 Enclosure

The exact enclosure in which the VARC circuit breaker must fit has not been determined as of the writing of this report (early 2022). It will be determined as part of Task 3.9 of WP 3 of the HYPERRIDE project.

6.7 Grid Simulations

The aim of the simulations is to investigate how the fault current would develop without a circuit breaker to interrupt it. From the results it is possible to determine how fast the breaking operation of the DCCB should be for given converter capacitor and line reactor sizes. Conversely, it is also possible to compute how large the line reactor needs to be for a given converter capacitor size, circuit breaker operation time and maximum breaking current, see section 3.3.

The Simulink model of the FEN MVDC Research grid contains the components relevant for determining the pole-to-pole fault current waveform. The AC side of the AFE has been substituted for an equivalent source model so that the converters could be represented by an AC

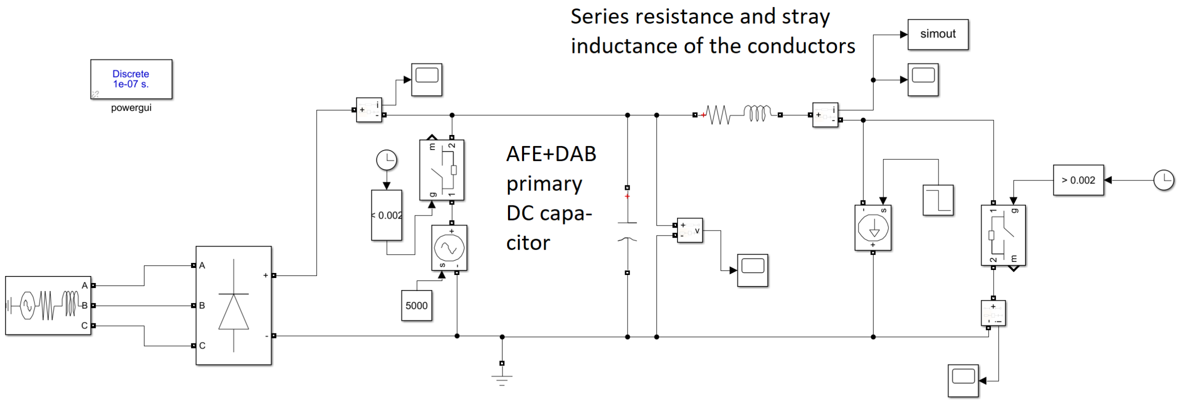

Figure 12: FEN MVDC Research grid model, without long cables connecting the power source to the fault location.

source and a diode bridge rectifier. The source model has the proper voltage level, transformer reactance and switching frequency.

There are two artificial sources in the model. A voltage source is connected in parallel with the DC capacitor in order to prevent capacitor discharge before the fault is simulated. A current source is connected in parallel with the fault model in order to set the pre-fault load current through the conductors and the line reactor.

The Simulink grid model including the cable models also has a high-value, artificial resistance connected in parallel with the fault model in order to eliminate computational artefacts. Without this resistance, large-amplitude, high-frequency oscillations could be observed in the line reactor current due to resonance of the cable model capacitance and the inductance of the grid elements.

The impedance of the current commutation path within the converter has been neglected as the initial current pulse in case of a fault is caused by the capacitor discharge. The converter starts to feed power into the fault once the capacitor voltage dropped to zero.

The pre-fault current has been assumed to be the nominal converter current, $1\,\mathrm{kA}$.

In the next part of the subsection several variants of a fault occurring in the FEN MVDC Research grid model are presented.

1. Short circuit occurring electrically close to the converter without a line reactor

   The grid model is shown in Figure 12.

   The series resistance is $10\,\mathrm{m}\Omega$ and the stray inductance is $10\,\mu\mathrm{H}$. This represent a few meters of conductors from the converters to the fault location.

   The simulated discharge current is shown in Figure 13. It can be observed that the current rises very fast. It grows from zero till its maximum of almost $120\,\mathrm{kA}$ in less than half a millisecond. This high rate of rise of current exceeds the capabilities of most DCCB types. Therefore, an additional inductance in form of a line reactor has to be added if the circuit breaker is to successfully break the current.

   While the simulated current peak is almost $120\,\mathrm{kA}$, in a real short circuit case the current amplitude would probably not reach such a high value. As the cables are rated for a few kA only, increasing the short circuit current this much would mean that the resistive

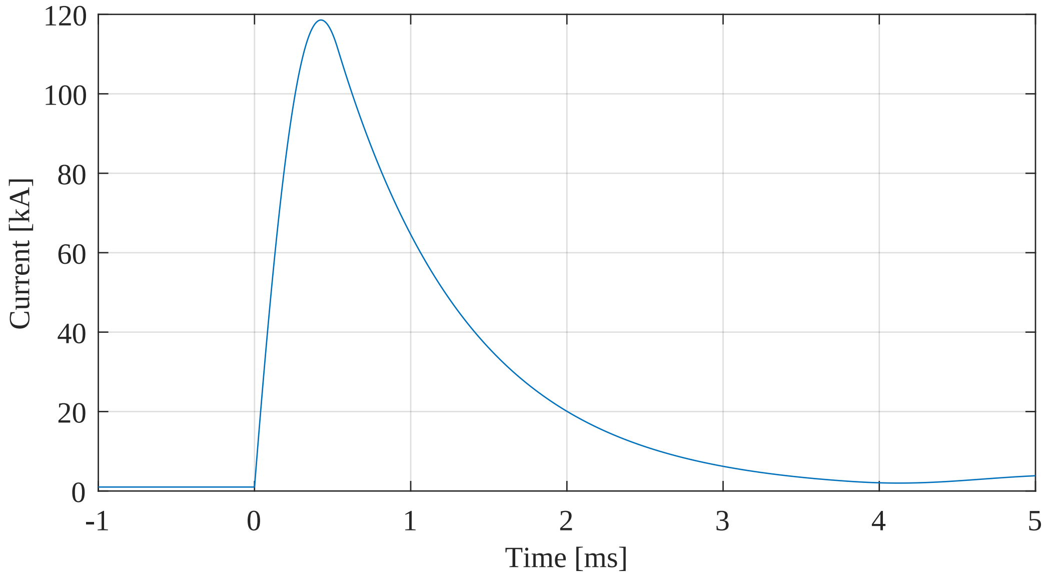

Figure 13: Short circuit current if there is no line reactor installed; the fault current is 8.0 kA *at* 14 µs *and* 120 kA *at* 423 µs *after fault inception, respectively.*

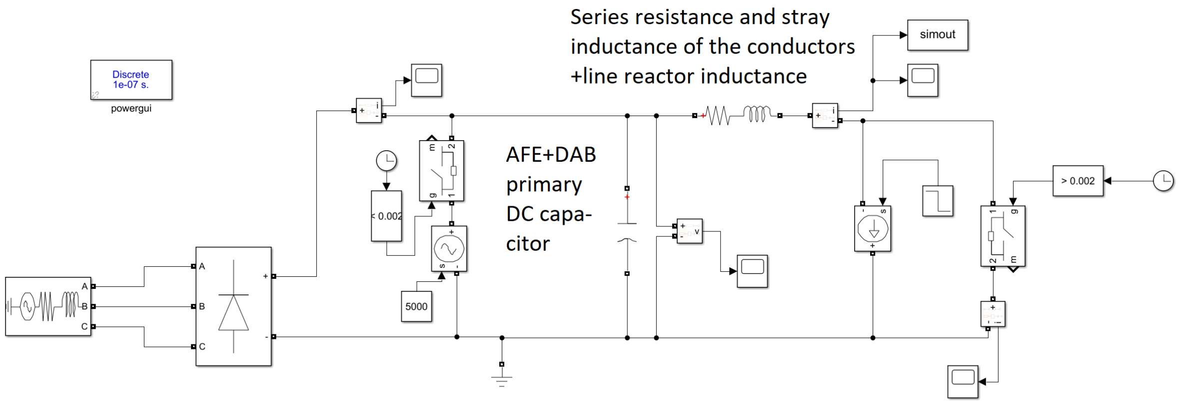

Figure 14: FEN MVDC Research grid model, without long cables connecting the power source to the fault location.

voltage drop of the cables becomes higher. Practically, the current peak could be reduced by a few tens of kA in case of a real fault, but it would still be very large; it is unreasonable to expect that the cable impedance eliminates the need for a line reactor.

2. Short circuit occurring electrically close to the converter with a line reactor

   The grid model is shown in Figure 14.

   As outlined in Subsection 3.3, based on the circuit breaker parameters (operation speed, maximum breaking current) and the current through the circuit breaker before the fault, it is possible to compute the size of the line reactor. Inserting 8 kA of maximum breaking current, 1 kA pre-fault current, 5 kV system voltage and 1.2 ms of circuit breaker operation time into Equation 7 of Section 3 yields 857 µH. As the voltage source is considered stiff in the formula, this is a worst-case when it comes to rate of rise of fault current. As the simulation shows, in case of a DC capacitor bank, the line reactor can have a slightly

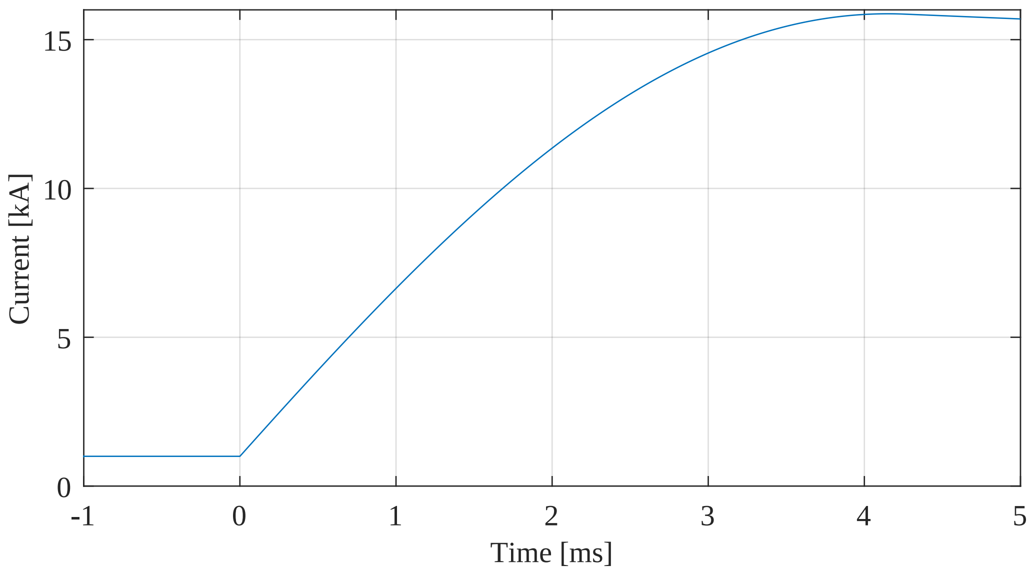

Figure 15: Short circuit current if there is a line reactor installed; the fault current is 7.7 kA at 1.2 ms after fault inception.

lower inductance.

The series resistance is 10 mΩ while the inductance of the line reactor is 850 µH. This represents a few meters of conductors and the line reactor connecting the converters to the fault location.

The simulated discharge current is shown in Figure 15. It can be observed that the line reactor makes a huge difference when it comes to slowing down the DC capacitor discharge. It takes the short circuit current about 1.3 ms to reach 8 kA. Therefore, a circuit breaker with 8 kA of maximum breaking current and with a breaker operation time in the 1 ms – 1.2 ms range can be used to protect the grid if a line reactor of 850 µH is installed.

3. Short circuit occurring electrically far from the converter with a line reactor

   The grid model is shown in Figure 16.

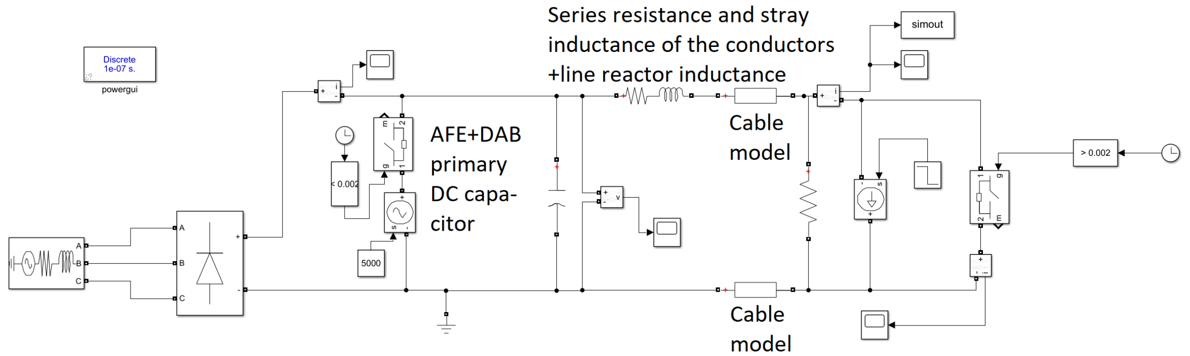

Figure 16: FEN MVDC Research grid model, with long cables connecting the power source to the fault location.

The inductance of the line reactor is taken as 850 µH. The cables are 1 km long and they are represented by their resistance per unit length (52.6 mΩ/km), external inductance per

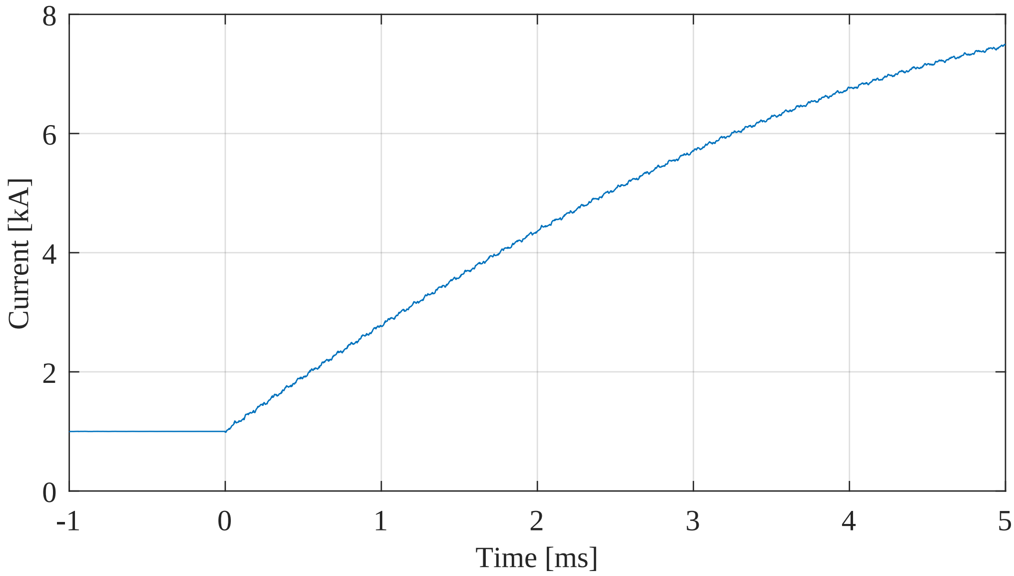

Figure 17: Short circuit current if there are cables and a line reactor between power source and fault; the fault current is 3.1 kA *at* 1.2 ms *after fault inception.*

unit length (896 µH/km) and internal capacitance per unit length (254 nF/km). A fault can occur along the cables anywhere, but one extreme (i.e., no cables between power source and fault) has been described in item 2 above. Therefore, the other extreme (i.e., the whole length of the cables are in between the power source and the fault) is discussed here; a real fault at an arbitrary location along the cables would result in a short current waveform in between those of the extreme scenarios.

The simulated discharge current is shown in Figure 17. It can be observed that the cable inductance contribute to slowing the DC capacitor discharge in addition to the line reactor. Therefore, a DCCB with the ratings of 8 kA of maximum breaking current and 1.2 ms of breaker operation can be used to protect the grid from pole-to-pole faults regardless of the fault location.

4. Short circuit occurring electrically close to the converter with a smaller DC side capacitance and without a line reactor

   The grid model is shown again in Figure 12.

   The purpose of this simulation is to show whether a converter with a DC capacitor properly designed for the application still necessitates the use of a line reactor to slow the rise of the capacitor discharge current down. As mentioned in Subsection 6.4, the capacitor banks of the AFE and the DAB are oversized for their planned operation in the FEN MVDC Research grid. Following the calculations outlined in (van Hertem et al., 2016), a capacitor size is deemed to be more adequate for the specific application if the ratio of the energy stored within the capacitor charged to nominal voltage and the nominal power of the converter is 2-3 J/kW. A pole-to-pole capacitor size of 1 mF for both the AFE and the DAB is predicted to be sufficient (considering 1 kHz of converter switch operating frequency and $\pm$ 1 % ripple of the nominal 5 kV DC voltage).

   The simulated discharge current is shown in Figure 18. It can be observed that the current peak is roughly half of the peak current that would occur if the capacitor banks were the

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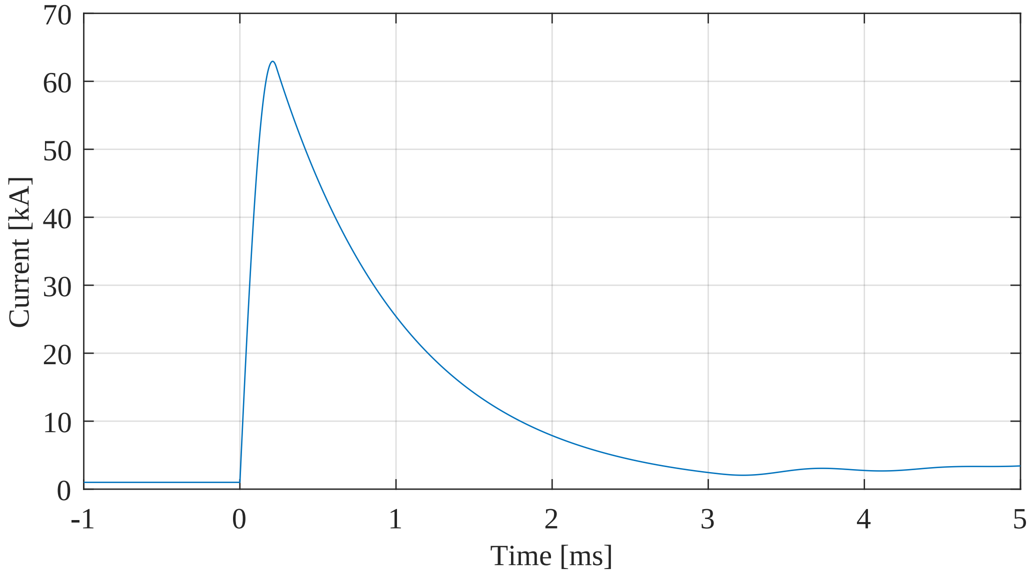

Figure 18: Short circuit current of a capacitor with reduced size, without a line reactor; the fault current is 8.0 kA *at* 14 µs *and* 63 kA *at* 209 µs *after fault inception, respectively.*

original size (i.e., 9 mF in total). This is expected as the total capacitor size has been decreased by a factor of 4.5. Since the current peak can be estimated as the nominal capacitor voltage over the characteristic impedance of the grid, if the capacitor size is decreased by a factor of n, the current amplitude decreases by a factor of $\sqrt{n}$. In this case, $\sqrt{4.5}$ equals approximately to 2.12.

The capacitor discharge current is rising still too fast and reaches a value too high to be interrupted by the DCCB. Therefore, a line reactor is needed to slow the rate of rise of the current down.

5. Short circuit occurring electrically close to the converter with a smaller DC side capacitance and with a line reactor

   The relevant grid model is again found in Figure 14.

   The equation to calculate the minimum inductance of the line reactor (see Subsection 3.3) is based on the assumption that the DC source is considered stiff. With a smaller converter capacitor the source can be treated as a 'less stiff' source in the fault simulation.

   The purpose of this simulation is to show whether a line reactor smaller than assumed in the previous simulations is sufficient to slow the rise of the capacitor discharge current down. And if yes, how much smaller the line reactor can be.

   The simulated discharge currents in case of a line reactor with an inductance of 700 µH and 650 µH are shown in Figure 19 and Figure 20, respectively. It can be observed that taking the same DCCB as discussed previously and the same normal operational current of 1 kA through the circuit breaker, the size of the line reactor can be decreased from 850 µH to 700 µH and the breaker can still be expected to successfully break the current in case of a short circuit. Further reduction of the line reactor inductance, however, cannot be recommended.

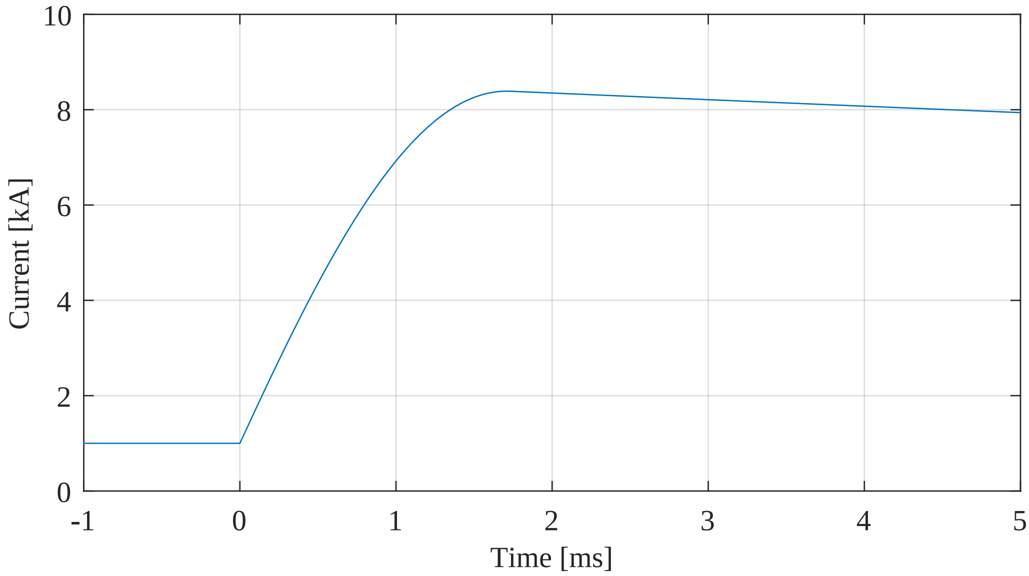

Figure 19: Short circuit current of a capacitor with reduced size and with a line reactor of 700 µH*; the fault current is* 7.6 kA *at* 1.2 ms *after fault inception.*

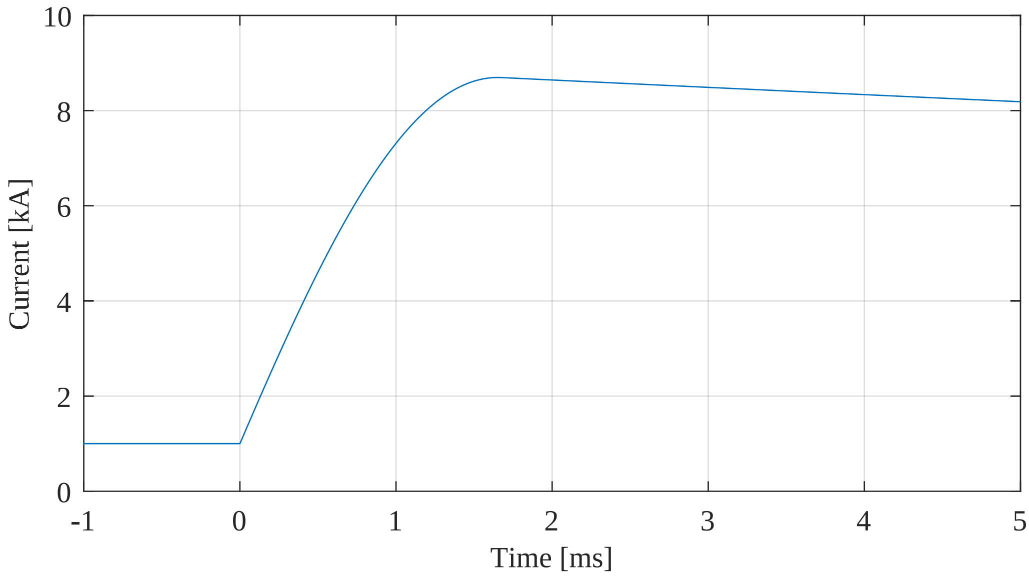

Figure 20: Short circuit current of a capacitor with reduced size and with a line reactor of 650 µH*; the fault current is slightly above* 8 kA *at* 1.2 ms *after fault inception.*

6.8 Summary of the Circuit Breaker Requirements

The aspects described in this Section result in numerous requirements when an MVDC circuit breaker is designed. These requirements are summarized in Table 2.

Table 2: 5 kV circuit breaker design requirements.

Parameter	Value
Rated voltage (U_r)	5 kV
Maximum breaker surge arrester voltage	9 kV
Pole-to-ground discharge voltage of system surge arresters	9.8 kV
Rated continuous current (I_r)	1000 A
Maximum breaking current (I_{max})	8000 A
Fault detection time (t_r)	200 µs
Breaker operation time (t_n)	1 ms
Minimum size of a series connected line reactor	850 µH
Operating sequence	O – t – CO
Number of mechanical operations	2000

7 Requirements for 14 kV MVDC Circuit Breakers

7.1 Use Case Definition

Considering the forecast massive penetration of the electric vehicles in the cities, there is an obvious need for mass deployment of charging outlets. Most of the current parking places, especially the ones on the street, do not offer charging capability. Furthermore, if the number of electric vehicles would increase significantly, the current power distribution infrastructure cannot address even the need for EV charging in garage places. The main challenges are:

1. Limited capacity of the existing power distribution grid.
2. The high cost of upgrading the infrastructure to allow the spikes in power consumption (which also implies higher costs of the electrical bill).

   This challenge is usually addressed by implementing a smart charging procedure, using power flow control and scheduling (longer charging at moderate power, when the electricity price is lower).
3. Environmental impact.

   The environmental benefit of the EV adoption is significantly reduced if the electric power used to recharge the batteries does not come from Renewable Energy Sources (RES). Dedicated agreements should be created with the distribution company, to increase the percentage of green energy provided to the MVDC grid. The green energy of large, local plants of RES could be connected with direct power lines and consumed by the cars without the need of additional buffer stages of considerable size.

The diagram of the use case is presented in Figure 21.

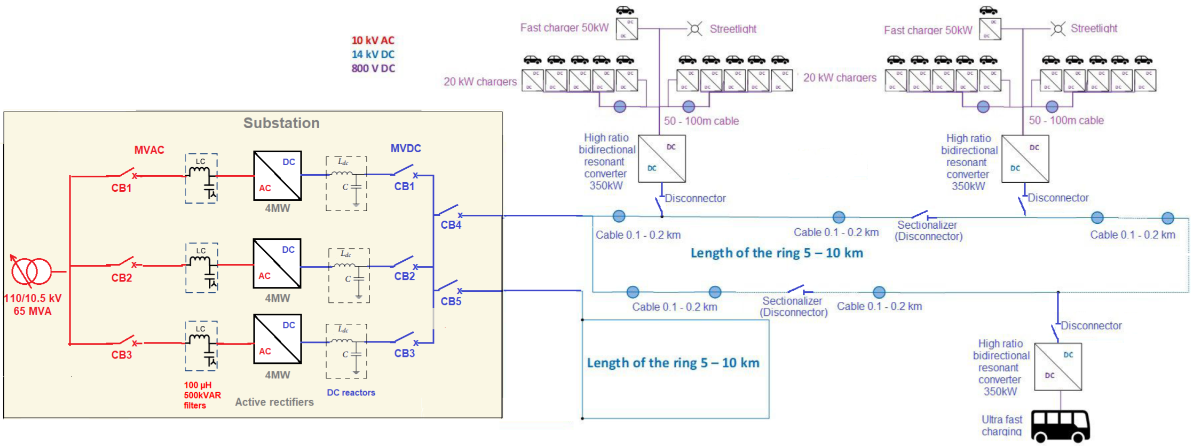

Figure 21: EV Charging Infrastructure (EVCI) Power Distribution Use Case.

The proposed implementation of the DC power distribution uses a ring topology over several kilometers, connecting multiple EV charging points, including DC-DC converters. The connection cable is split into sections, separated by sectionalizers. These devices are used to disconnect the section, in case the circuit breaker trips due to a fault and cannot reconnect on the load. Both ends of the cable are connected to a single MVDC circuit breaker. The cable is rated for maximum 500 A. The total nominal current through an MVDC circuit breaker is maximum 2x500 A = 1000 A.

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The DC-DC converters are high voltage ratio, bidirectional converters providing power to 800 V DC micro-grids (purple section in Figure 21) that serve several DC car chargers. These chargers will be located directly on the street and most of them will provide power up to 20 kW for slow charging (during the night). One charging spot, the closest to the DC-DC converter connected to the MVDC line, will be the charger for fast charging – 50 kW. For this configuration it is assumed that not all the chargers connected to a single MVDC converter will be used simultaneously, but smart charging algorithms will be employed, so that the total power will not exceed 350 kW. This enables:

- Charging one car fast (50 kW). This parking spot can be occupied only temporarily (for 1 hour max).
- Charging several cars semi-fast (20 kW). Full power is enabled only for a dedicated amount of time (typically one hour).
- Charging all cars slowly (<20 kW) or even provide power from EV to other EVs, which requires a connection by bidirectional converters. In this case it is expected that a car will be staying on a charging spot for several hours (whole night or even week). However, after a time interval of predetermined length, the car will be charged and will be ready to leave with full battery.

An example of such grid is shown in Figure 22.

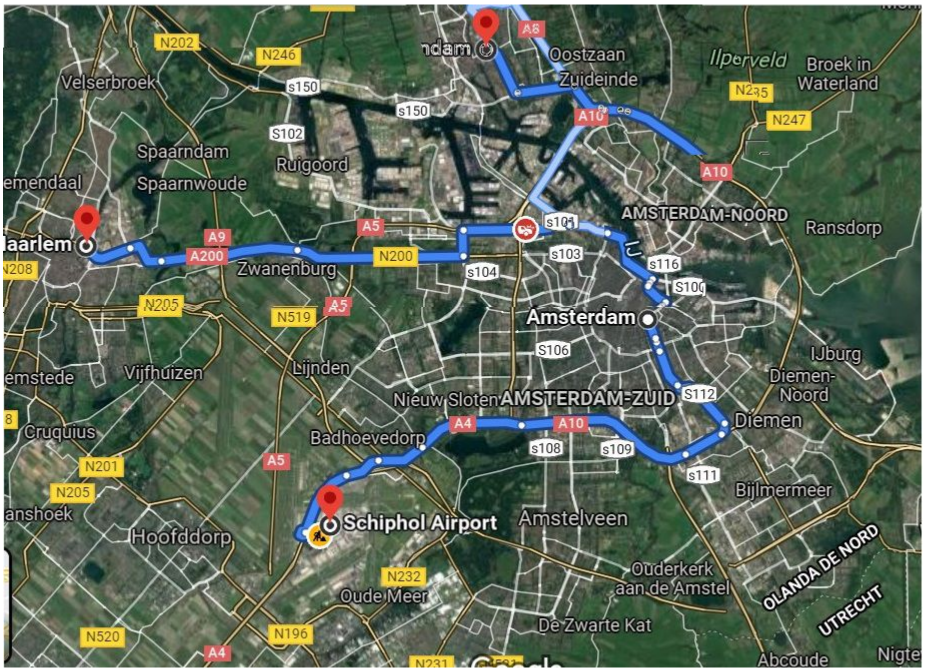

Figure 22: Example of an MVDC micro-grid for EV charging.

7.2 Why is DC Better Than AC in This Use Case?

There are several reasons, for which DC power is recommended in this use case:

1. The ampacity of long DC cables is higher than that of AC cables – there is no reactive power, therefore the losses are lower.

2. In DC microgrids the power flow could be controlled by the “voltage droop control” method. The power flow to the loads can be controlled by measuring only the voltage. This enables distribution companies to continuously control the power consumption and allows for a better integration of uncontrollable sources like wind and solar power plants into MVDC grids.
3. The skin effect does not play a role in DC power distribution. It enables the use of higher diameter cables that would not be suitable for AC due to skin effect.
4. The converters and therefore the microgrid can be made small (when using high switching frequency) and modular which brings two benefits:
    a Scalability – if more power is required, several smaller converters connected in parallel could be utilized. For AC there is no advantage, since the size of the transformer would be similar for 100 kW as for 500 kW.
    b Reliability – if one converter fails, the other parallel converters continue operating. The maintenance happens only on the failed converter. There will be no outage, only a decrease in capacity. In case the power flow is lower, some converters can be switched off and their lifetime can be preserved.

7.3 Power Flow Control

The power flow control is implemented by voltage droop control. If the distribution company wants to decrease the load, it can request this by decreasing the DC voltage. There are generally two ways to do it:

1. Decrease the voltage on the 10 kV AC side by using a tap changer. In this case it is possible to use a passive AC-DC rectifier.
2. Use an active AC-DC rectifier.

Option 1: Transformer with tap changers and passive rectifier

Advantages:

- Cheaper solution,
- No large filters are required on the AC side,
- The DC side does not require filtering capacitors – no inrush currents or high peak short circuit currents.

Disadvantages:

- Unidirectional operation,
- Limited number of steps in the tap changers – the voltage variation is not continuous,
- Reliability of the tap changer,
- Higher harmonic distortion.

Option 2: Active AC-DC Rectifier

Advantages:

- Bidirectional operation is possible,

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- Continuous power flow control (continuous voltage control),
- Transformer without tap changer,
- Less harmonic distortion in case of filter usage.

Disadvantages:

- More expensive solution,
- AC filters are mandatory,
- DC link capacitor is mandatory – higher inrush currents, high peak short circuit currents.

7.4 Protection Principles

An MV DCCB is used for disconnecting the faults happening on the DC side. As the short circuit current in the DC grid has a fast increase, an efficient detection should measure the slope of the current (di/dt), so it can send the tripping signal as fast as possible. In this way, the current will not reach destructive values during the operation time of the circuit breaker. We propose two possible operating sequences (for the configuration in Figure 21), based on the location of the fault:

1. **In the rectifier**:
   a The MV DCCB detects high current into the rectifier (the DC grid side) and disconnects.

   For the use case in Figure 21, a coordination protocol can be implemented such that the circuit breaker that is closest to the affected rectifier is tripped first, and the rest of the circuit breakers are tripped only if the current continues to increase.

   b The corresponding CB on the AC side detects high current and disconnects.

   c All the other breakers continue their operation.

2. **In the cable or loads connected to the cable:**
   a The MV DCCB connected to the affected branch (as CB1 - CB4 in Figure 21) detects high current increase and disconnects. The coordination protocol would delay the tripping of the other breakers, so as to avoid disconnection in case the current increase is stopped after the operation of the first breaker.

   b The location of the fault is detected, and isolated by the disconnectors/sectionalizers.

   c The MV DCCB reconnects and restores power to the grid.

7.5 Modeling

The model consists of:

1. A 110 kV transmission grid connection with 22 kA short circuit current.
2. A 110 kV / 10 kV transformer of 63 MVA rated power with a high leakage inductance of 30 % for the 6-pulse passive rectifier case and a 110 kV / 10 kV / 10 kV transformer of 20 MVA rated power with a leakage inductance of 8 % for the active rectifier case.

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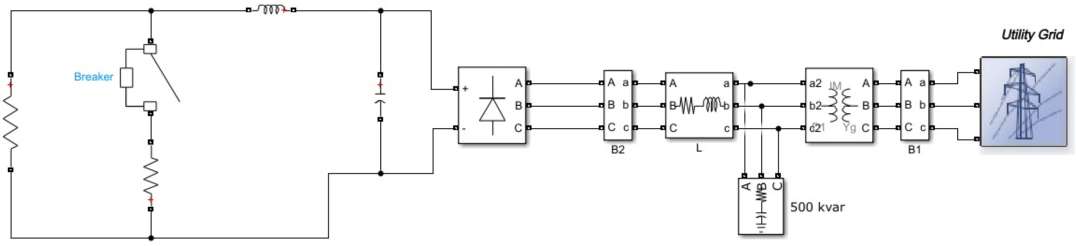

Figure 23: Passive rectifier short circuit scenario.

3. A filter AC inductor of 100 µH for the 6-pulse passive rectifier and the active rectifier cases.
4. A filtering AC capacitor of 500 kVAr for the 6-pulse passive rectifier and the active rectifier cases.
5. A filtering DC inductor of 1 mH for the 12-pulse passive rectifier case, 2 mH for the 6-pulse passive rectifier case and 3 mH for the active rectifier case.
6. A filtering DC capacitor of 500 µF for 6-pulse passive rectifier case and active rectifier case.

The tested scenario was a short circuit just after the DC inductor, since this is considered the worst-case scenario (highest di/dt).

In this scenario, the parallel configuration of several rectifiers was substituted by a single rectifier. The design of the filtering DC reactor has to consider two conflicting effects. For minimising the losses, the series resistance of the reactor should be kept as low as possible. However, in Figures 24, 26 and 28 it can be seen that the duration of the decay of the LR circuit discharge current, after a fault event, is more that 500 ms for reactor resistance below 1 mΩ. The design should optimise this resistance for acceptable decay time and losses (which at 1 kA nominal current will increase by 1 kW when the resistance increases by 1 mΩ).

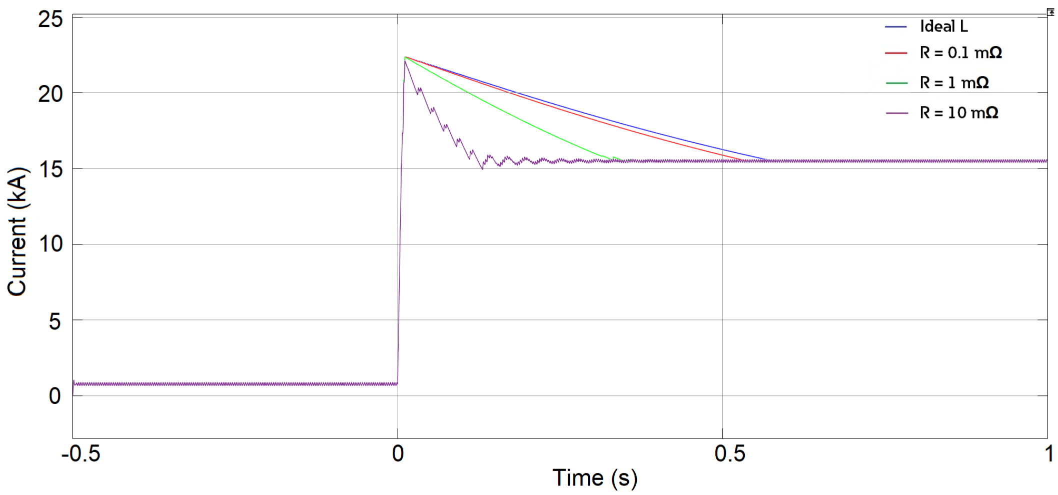

Figure 24: Passive rectifier 6-pulse short circuit current.

If more rectifiers are used in parallel, it is necessary to decrease the individual DC link capacitor size by a factor $n = r^2$ (where r is the number of rectifiers in parallel), to be able to keep a

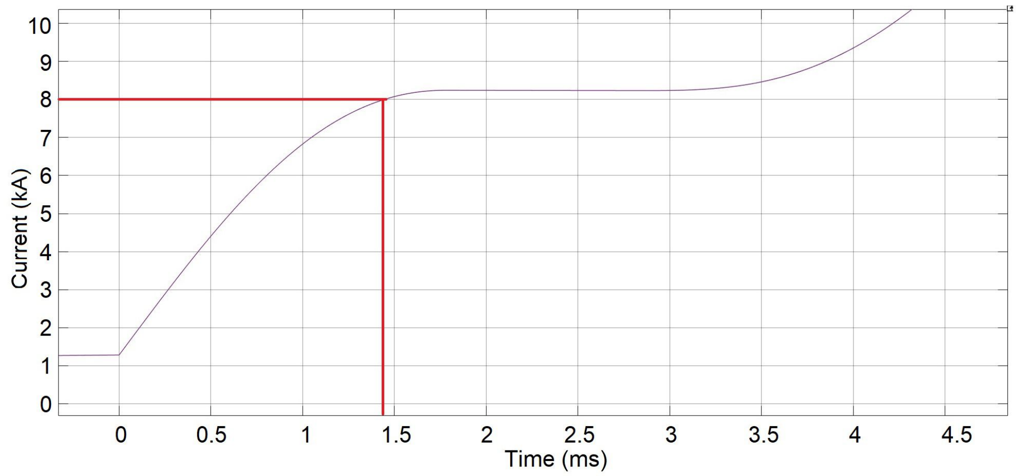

Figure 25: Passive rectifier 6-pulse short circuit current detail.

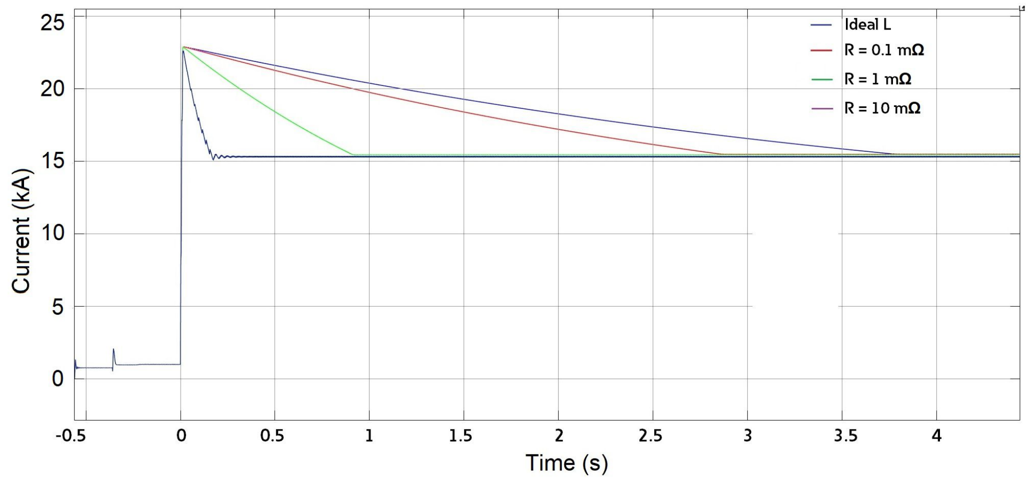

Figure 26: Active rectifier short circuit current.

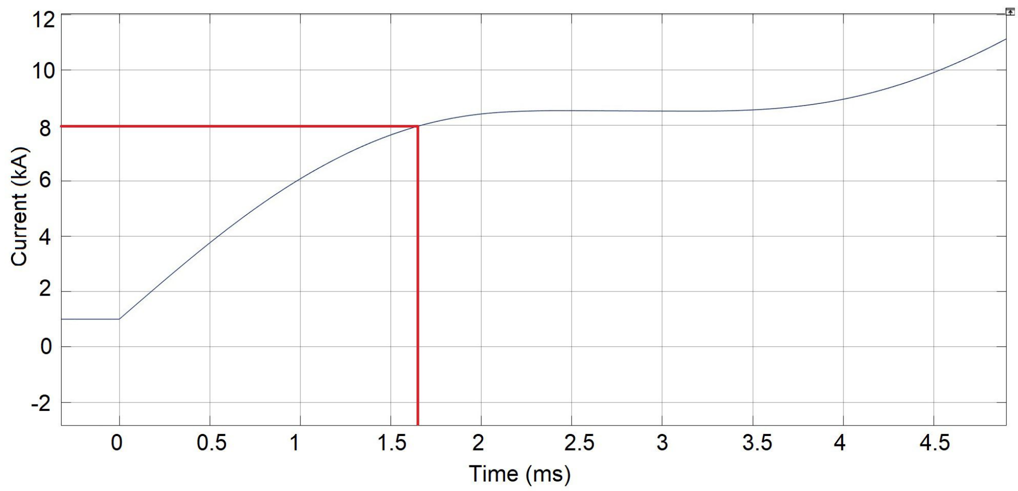

Figure 27: Active rectifier short circuit current detail.

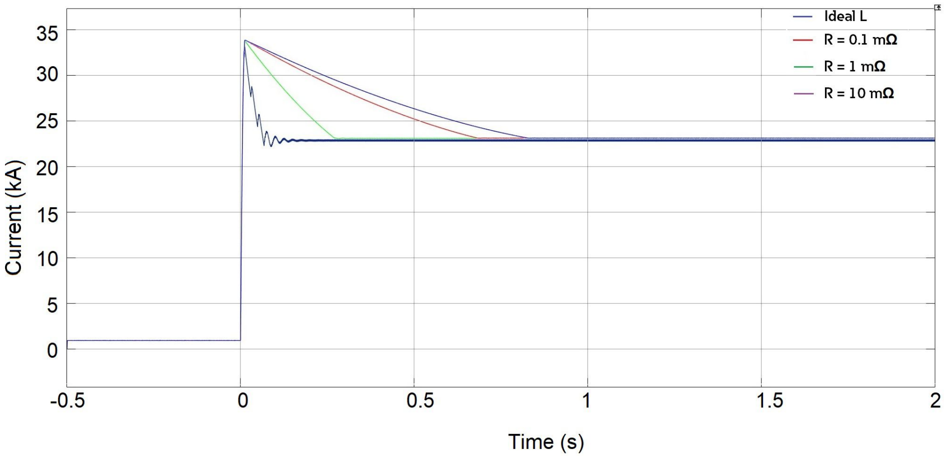

Figure 28: Passive rectifier 12-pulse short circuit current.

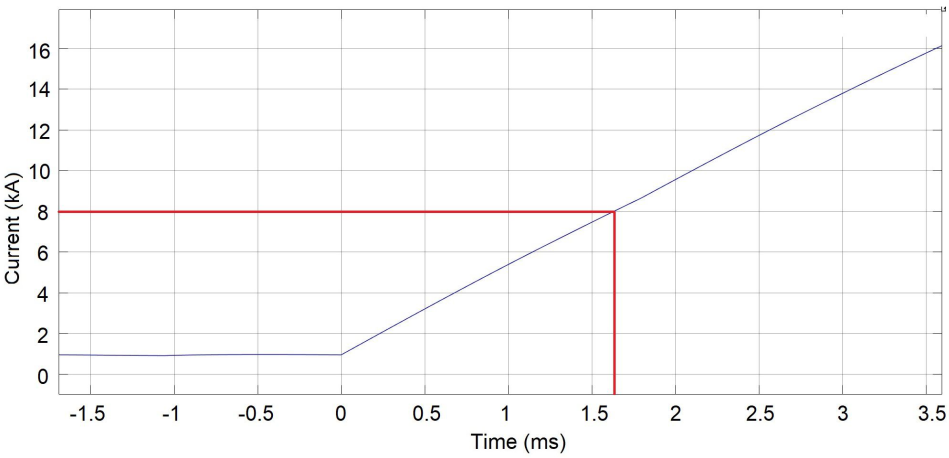

Figure 29: Passive rectifier 12-pulse short circuit detail.

similar short circuit current profile for the first $2{-}3\,\mathrm{ms}$. Therefore, it is recommended to use a low number of parallel rectifiers (up to three), in order to ensure reliability, while keeping a high DC link capacitance.

For lower ripple of the voltage and current, it is recommended to use a phase shift between the parallel converters or an AC transformer with higher number of windings and a phase shift between windings.

7.6 MVDC CB Specification

When designing an MVDC circuit breaker, the following general design requirements are considered:

1. **Main Required Features**

   A. Safety emergency state.

   A normal operation of the protection system implies the use of an auxiliary power line for operating the control systems of the circuit breaker. In case of auxiliary power interruption, the system should transition to a safe state. The protection coordination procedure may specify a staged tripping of a system of circuit breakers. In this case, the circuit breakers may use a small storage unit (milliseconds), to maintain operation, under the protection control algorithm, while a back-up circuit breaker is tripped. However, if the protection system is simpler, and the coordination procedure is not staged, every circuit breaker could interrupt the distribution at its level if the circuit breaker loses the contact with the control system.

B. DC bidirectional operation. This way, the circuit breaker can protect from various fault scenarios.

C. Fast short circuit detection and short-circuit mitigation/disconnection.

D. Intelligent short-circuit detection. The control circuitry should recognize nuisance tripping and avoid disconnection.

E. Full galvanic separation (optional).

F. Auto re-closing operation. The feature is required in case the circuit breaker is promoted for both AC and DC operation. For aerial AC systems, this procedure allows a fast recovery in case of temporary fault conditions (lightning, tree branch...). The control circuitry will re-close the circuit breaker after a defined time (1-2 sec) and disconnect again if the fault is still present.

Originally, the design should have followed the requirements stated in IEC TS 62271-313. Since the definition of high voltage according to IEC TS 62271-5 has been changed from 1500 V to 100 kV, IEC TS 62271-313 is only covering DCCB requirements above 100 kV. Therefore, a proportional down-scaling of the voltage levels stated in IEC TS 62271-313 may be a possible way to determine the relevant MVDC circuit breaker requirements.

2. Parameters - circuit breaker design requirements

Relevant design parameters and their values are listed in Table 3.

Table 3: Circuit breaker design requirements.

Parameter	Value
Rated voltage (U_r)	17 kV
Rated TIV	26 kV
Rated Insulation Level (U_d/U_p) (IEC 60071-5)	33.3/53 kVDC comm.
	38.9/60 kVDC isol. dist.
Rated Continuous Current (I_r)	1000 A
Interrupting time (t_k)	0.002 s
Clearing time (t_c)	0.007 s
Rated Supply Voltage For Aux.(U_a)	48 VDC or 230 VAC1PH
Rated Frequency For Aux. Circuits	50 Hz
Rated pressure or gas or hydraulics	not applicable
Rated Operating Sequence	O – t – CO
Rated SC Breaking Current	8000 A
Rated Class Of Mechanical Operation	M1 (2000 operations)
Rated Dissipated Energy During Breaking	0.6 MJ

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The rated voltage of the DCCB (U_r) should be chosen so as to be at least equal to the highest voltage of the system at the point where the circuit-breaker is to be installed. In case the $10\,\mathrm{kV}$ AC voltage is rectified by a 6-pulse bridge rectifier, the average DC voltage becomes $10 \times \sqrt{2} \times 0.96 = 13.6\,\mathrm{kV}$. This is termed the nominal DC voltage of the system. According to the EN50160 standard for medium voltage grids, the system voltage should be within a tolerance band of $\pm\ 10\,\%$ around the nominal DC voltage for 95 percent of the week. Therefore, the rated voltage of the DCCB should be at least $10\,\%$ higher than the nominal DC voltage. In this case, U_r is at least $= 1.1\times\ 13.6\,\mathrm{kV} = 14.9\,\mathrm{kV}$.

The Rated Insulation Level in Table 3 is valid in case of the following ambient parameters: the considered altitude is less than $1000\,\mathrm{m}$ above sea level, the temperature is $20\,^{\circ}\mathrm{C}$, the pressure is $101.3\,\mathrm{kPa}$ and the humidity is $11\,\mathrm{g/m^3}$.

7.7 Architecture and Power Supply

Power Circuit Topology

The basic power circuit topology is shown in Figure 30. The circuit breaker concept, proposed in (Angquist, Norrga, & Modeer, 2016) (Angquist, Baudoin, Modeer, Nee, & Norrga, 2018) (Angquist et al., 2019), uses a known principle (VSC Assisted Resonant Current - VARC) with the following characteristics:

1. a mechanical vacuum interrupter (Q1) is used to conduct the load current in normal closed conditions, with negligible losses.
2. an auxiliary circuit (comprising of a VSC, built with T_1 - T_4 , and the passive elements C_0, L_0 and MOV) creates a resonant current pulse through the arc in the switch, which is added to the current through the switch, creating zero crossings of this current.
3. the mechanical interrupter Q1 is actuated to create the interruption when the current through it approaches zero.

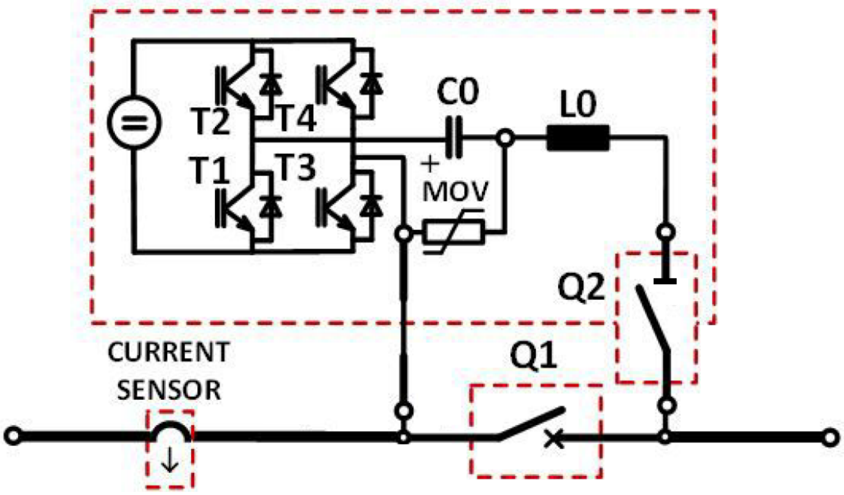

Figure 30: Power Circuit Topology.

Control Architecture

The interface between SCiBreak units and Eaton units is indicated in Figure 31.

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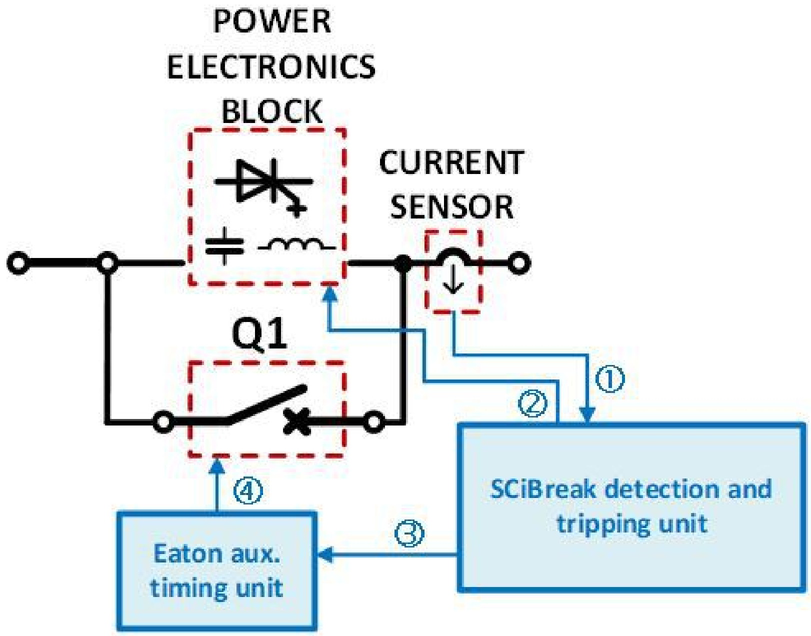

Figure 31: Block Diagram of Control Architecture.

The short-circuit detection and the associated commands will be addressed in the SCiBreak unit. The Eaton unit will drive the actuator in a proper way in order to move the VI contact very fast.

When a short-circuit is detected (from current sensor by signal (1)), the SCiBreak unit sends the tripping signal to the resonant block (2) and the VI Eaton auxiliary timing unit(3). The Eaton timing unit, by using two coils, will ensure a fast movement of the VI contact, with appropriate contact breaking (4).

A more detailed overview is shown in Figure 32.

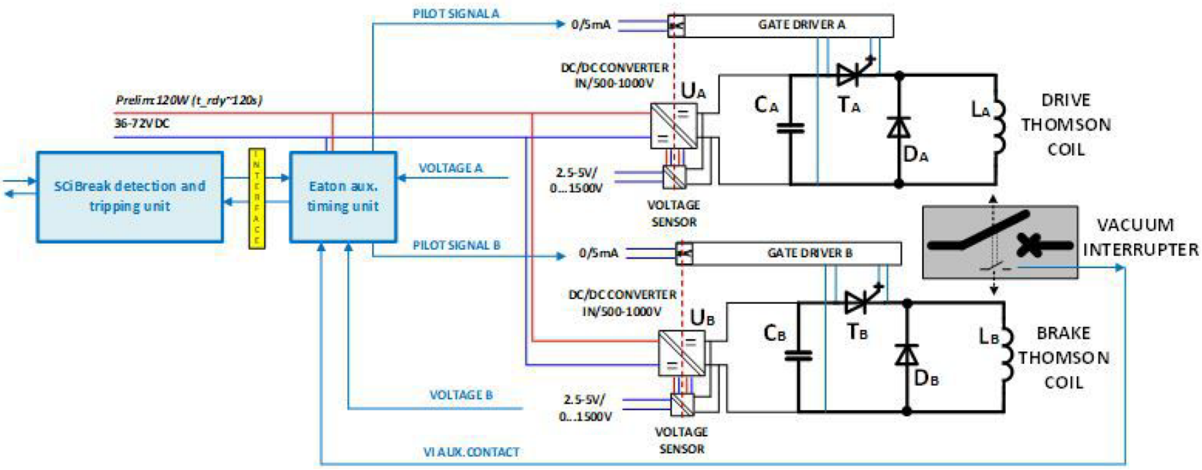

Figure 32: Eaton Aux. Timing Unit with Related Circuits.

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8 Conclusions

In this report, several aspects of a prospective MVDC grid design have been analysed. These aspects are playing a key role when determining requirements for the DCCB that is to protect the grid.

Section 2 presents the different grid topologies and fault handling strategies that an MVDC grid is likely to use in the future. Section 3 various DC circuit breaker types which may be used in MVDC networks. Section 4 presents a set of generic circuit breaker ratings and parameters that should be taken into consideration during the design phase of a DCCB. Section 5 reviews the state-of-the-art of relevant standards and technical papers.

Sections 6 and 7 detail the requirements for DCCBs imposed by the already built and commissioned part of the FEN Research Grid in Aachen and by a conceptual, 14 kV MVDC system, respectively.

Future work, including refinement of the circuit breaker requirements, is expected to be done once DCCBs have been installed in the FEN Research Grid as part of the HYPERRIDE project and they start to provide operational experience. Moreover, the publication of additional technical brochures and papers listed in Section 5 can help identifying new directions where research activity may be necessary.

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Appendix: Normative DC Switchgear Documents

In the following pages of this appendix a list of standards and other normative documents for DC switchgear is given, with focus on MVDC applications. Notably, many new normative documents pertaining to DC switchgear and MVDC in particular are currently being drafted and will be issued in coming years. See also Table 1 in Section 5 for a list of coming additions to the already published documents.

Table 4: Table of normative documents for DC switchgear.

Org.	Type	Main Doc.	Part	Com-mittee	Number	Title	Year
Chinese Ind Std.	Standard	42107			NB/T 42107	High-voltage direct current circuit-breaker	2017
CIGRE	TB	683		A3/B4.34	TB 683	Technical requirements and specifications of HVDC switching equipment	2017
CIGRE	TB	793		C6.31	TB 793	Medium voltage direct current (MVDC) grid feasibility study	2020
IEC		60850		9	60850	Railway applications – Supply voltages of traction systems	2014
IEC	IS	60898	3	23	60898-3	Electrical accessories - Circuit-breakers for overcurrent protection for household and similar installations - Part 3: Circuit-breakers for DC operation	2019
IEC	IS	62128	1		62128-1	Railway applications - Fixed installations - Electrical safety, earthing and the return circuit - Part 1: Protective provisions against electric shock	2013
IEC	IS	62128	2		62128-2	Railway applications - Fixed installations - Electrical safety, earthing and the return circuit - Part 2: Provisions against the effects of stray currents caused by d.c. traction systems	2013
IEC		62497			62497-1	Railway applications – Insulation coordination – Part 1: Basic requirements – Clearances and creepage distances for all electric and electronic equipment	2010
IEC	TS				61936-2	Power installations exceeding 1 kV a.c. and 1,5 kV d.c. - Part 2: d.c.	2015
IEC		60947	10	23	60947-10	Low-voltage switchgear and controlgear – Part 10: Semiconductor circuit-breakers	
IEC	IS	61992	1	9	61992-1	Railway applications - Fixed installations - DC switchgear - Part 1:General	2006
IEC	IS	61992	2	9	61992-2	Railway applications - Fixed installations - DC switchgear - Part 2: DC circuit-breakers	2006

Org.	Type	Main Doc.	Part	Com-mittee	Number	Title	Year
IEC	IS	61992	3	9	61992-3	Amendment 1 - Railway applications - Fixed installations - DC switchgear - Part 3: Indoor d.c. disconnectors, switch-disconnectors and earthing switches	2006
IEC	IS	61992	6	9	61992-6	Amendment 1 - Railway applications - Fixed installations - DC switchgear - Part 6: DC switchgear assemblies	2006
IEC	IS	61992	7-1	9	61992-7-1	Railway applications – Fixed installations; D.C. switchgear – Part 7 1:Measurement, control and protection devices for specific use in d.c. tractions systems; Applications guide	2006
IEC	IS	61992	7-2	9	61992-7-2	Railway applications - Fixed installations - DC switchgear - Part 7-2: Measurement, control and protection devices for specific use in d.c. traction systems - Isolating current transducers and other current measuring devices	2006
IEC	IS	61992	7-3	9	61992-7-3	Railway applications - Fixed installations - DC switchgear - Part 7-3: Indoor d.c. disconnectors, switch-disconnectors and earthing switches	2006
IEC	IS	62271	1	17	62271-1	High-voltage switchgear and controlgear - Part 1: Common specifications for alternating current switchgear and controlgear	2017
IEC		62271	5	17	62271-5	High-voltage switchgear and controlgear - Part 5: Common specifications for direct current switchgear	PI 2022
IEC	TS	62271	313	17A	62271-313	High-voltage switchgear and controlgear - Part 313: Direct current circuit-breakers	PI 2022
IEC	TS	62271	314	17A	62271-314	High-voltage switchgear and controlgear - Part 314: Direct current disconnectors and earthing switches	PI 2022
IEC	TS	62271	315	17A	62271-315	High-voltage switchgear and controlgear - Part 315: Direct current (DC) transfer switches	PI 2023
IEC	TS	62271	316	17A	62271-316	High-voltage switchgear and controlgear - Part 316: Direct current by-pass switches and paralleling switches	PI 2022

Org.	Type	Main Doc.	Part	Com-mittee	Number	Title	Year
IEC	TS	63014	1		63014-1	High voltage direct current (HVDC) power transmission - System requirements for DC-side equipment - Part 1: Using line-commutated converters	2018
IEEE	Std	1709			1709-2018	IEEE Recommended Practice for 1 kV to 35 kV Medium-Voltage DC Power Systems on Ships	2018
IEEE	Std	C37	14	Switchgear	C37.14	IEEE Standard for DC (3200 V and below) Power Circuit Breakers Used in Enclosures	2015

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