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Technical Guidelines for Radial HVDC Networks

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National foreword

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Technical Guidelines for Radial HVDC Networks

Directives techniques pour les réseaux HVDC radiaux

Technischer Leitfaden für radiale HGÜ-Netze

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CENELEC

European Committee for Electrotechnical Standardization
Comité Européen de Normalisation Electrotechnique
Europäisches Komitee für Elektrotechnische Normung

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Contents

Page

Foreword

This document (CLC/TR 50609:2014) has been prepared by CLC/TC 8X “System aspects of electrical energy supply”.

Attention is drawn to the possibility that some of the elements of this document may be the subject of patent rights. CENELEC [and/or CEN] shall not be held responsible for identifying any or all such patent rights.

This document has been prepared under a mandate given to CENELEC by the European Commission and the European Free Trade Association.

This document was already sent out within CLC/TC 8X for comments and the comments received were discussed within CLC/TC 8X/WG 06 and were incorporated in the current document as far as appropriate.

0 Introduction

0.1 The European HVDC Grid Study Group

Existing power systems in Europe have been developing for more than 100 years to transmit the power, generated mainly by fossil and nuclear power plants to the loads. Climate change, limited fossil resources and concerns over the security of nuclear power are drivers for an increased utilization of renewable sources, such as wind and solar, to realize a sustainable energy supply. According to the geological conditions, the location of large scale renewable energy sources is different to the location of existing conventional power plants and imposes new challenges for the electric power transmission networks, such as extended transmission capacity requirements over long distances, load flow control and system stability. The excellent bulk power long distance transmission capabilities, low transmission losses and precise power flow control make High Voltage Direct Current (HVDC) the key transmission technology for mastering these challenges, in particular for connection of offshore wind power plants to the onshore transmission systems.

While the power system reinforcement is already underway by a number of new point-to-point HVDC interconnections, the advantages offered by multiterminal HVDC systems and HVDC grids become more and more attractive. Examples are grid access projects connecting various wind power plants or combining wind plants with point-to-point transmission, e.g. in the North and Baltic Seas. Multiterminal projects are already in execution and there is planning for pan-European HVDC grids. In this document, multiterminal HVDC systems and HVDC grids are referred to as HVDC Grid Systems.

To become reality, HVDC Grid Systems need, in addition to the necessary political framework for cross country system design, construction and operation, competitive supply chains of equipment capable of operating together as an integrated system. This marks a significant change in the HVDC technology market. While today - with very few exceptions – a HVDC transmission system has been provided by a single manufacturer, future HVDC Grid Systems will be built step by step composed of converters and HVDC substations supplied by different manufacturers. Interoperability will thus become a fundamental requirement for future HVDC technology.

Common understanding of basic operating and design principles of HVDC Grid Systems is seen as a first step towards multi vendor systems, as it will help the development for the next round of European multiterminal projects. Furthermore, it will prepare the ground for more detailed standardization work.

Based on an initiative by the DKE German Commission for Electrical, Electronic and Information Technologies, the European HVDC Grid Study Group has been founded in September 2010 to develop “Technical Guidelines for first HVDC Grids”. The Study Group has the following objectives:

- to describe basic principles of HVDC grids with the focus on near term applications;
- to develop functional specifications of the main equipment and HVDC grid controllers;
- to develop “New Work Item Proposals” to be offered to CENELEC for starting standardization work.

CIGRÉ SC B4, CENELEC TC8x and ENTSO-E and “Friends of the Supergrid” are involved at an informative level with the results of the work.

Members affiliated with the following companies and organizations have been actively contributing to the results of the Study Group achieved so far: 50 Hz Transmission, ABB, ALSTOM, Amprion, DKE, TransnetBW, Energinet.dk, ETH Zurich, National Grid, Nexans, Prysmian, SEK, Siemens, TenneT and TU Darmstadt.

As a starting point the Study Group has been investigating typical applications and performance requirements of HVDC Grid Systems. This information helps elaborating the basic principles of HVDC networks, which are described in the following clauses:

- Clause 3, Typical Applications of HVDC Grids;
- Clause 4, Principles of DC Load Flow;
- Clause 5, Short-Circuit Currents and Earthing;
- Clause 6, Principles of HVDC Grid Protection.

From the technical principles described, functional specifications for the main equipment of HVDC networks are derived and summarized in Clause 7.

0.2 Technology

0.2.1 Converters

HVDC transmission started more than 60 years ago. Today, the installed HVDC transmission capacity exceeds 200 GW worldwide. The vast majority of the existing HVDC links are based on so-called Line-Commutated-Converters (LCC). LCC today are built from Thyristors. The power exchange of such converters is determined by controlling the point–on-wave of valve turn-on, while the turn-off occurs due to the natural zero crossing of valve current forced by the AC network voltage. That is why LCC rely on relatively strong AC systems to provide conversion from AC to DC and vice versa.

With so-called Voltage Sourced Converters (VSC), a different type of converters has been introduced to HVDC transmission slightly more than a decade ago. VSCs today utilize Insulated Gate Bipolar Transistors (IGBT) as the main switching elements. IGBTs have controlled turn-on as well as turn-off capability making the VSCs capable of operating under weak AC system conditions or supplying power systems where there is no other voltage source, also referred to as passive networks.

The evolution of VSC transmission was started with so-called Two-Level converters at the end of the 1990s and has commenced to Three Level Converters and further to Modular Multilevel Converters (MMC) which have made their break-through in the mid to late 2000s. All MMC type converters apply the same principle of connecting a number of identical converter building blocks in series. However, at the present time there are basically two types of such building blocks: referred to as Half-Bridge (HB) and Full-Bridge (FB) modules.

Other converter equipment which have been proposed for HVDC Grid applications, such as DC/DC converters, load flow controllers, etc. are not discussed in this document.

0.2.2 DC Circuit

Similar to AC networks, HVDC transmission systems can be distinguished by their network topologies as radial and/or meshed networks and with respect to earthing in effectively grounded and isolated systems. Both aspects influence the design criteria and the behaviour of the HVDC system.

– Radial and Meshed Topologies:

In radial systems, there is not more than one connection between two arbitrary nodes of the network. The DC voltages of the converter stations connected to each end of a line solely determine the power flow through that line, for example in Figure 1-1, station C is radially connected with station D.

In meshed systems, at least two converter stations have more than one connecting path. Without any additional measures the current through a line will then be determined by the DC voltages of the converter stations as well as the resistances of the parallel connections. In Figure 1-1, the DC circuit connecting stations A, B and C forms a meshed system while C and D is a radial connection. A HVDC Grid System having a meshed topology can be operated as a radial system if parallel connections are opened by disconnectors or breakers.

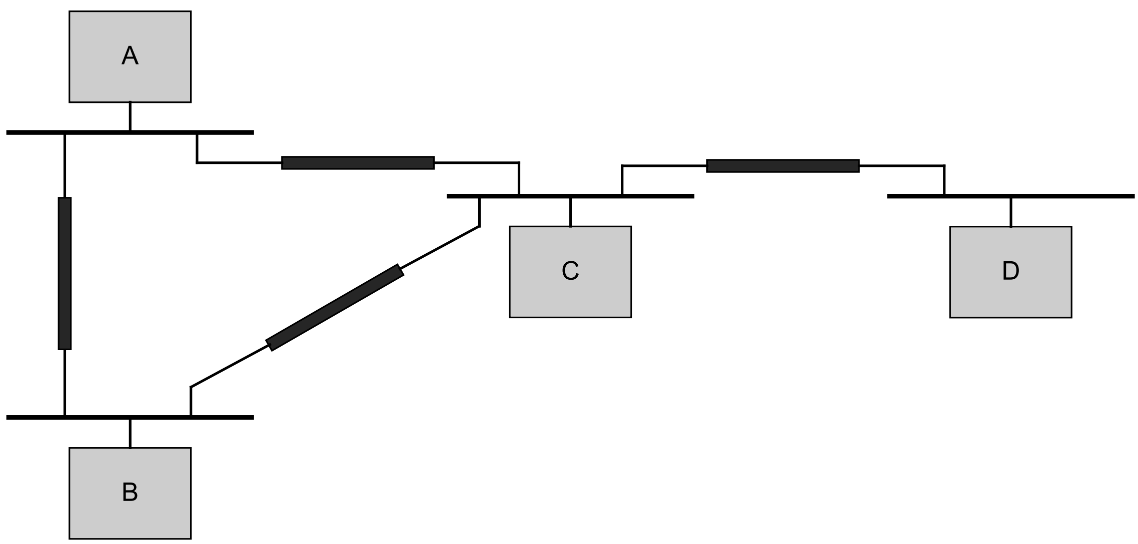


Figure 1-1 — Example of an HVDC Grid System having a meshed and radial structure

– Earthing:

DC circuits can be effectively grounded if one DC pole is connected to earth through a low ohmic branch. Such systems are also referred to as asymmetrical Monopoles or just “Monopoles”. Two Monopoles of opposite DC voltage polarity are often combined into so-called bipolar systems or just “Bipoles”.

Isolated DC circuits do not have a low ohmic connection to ground on the DC side. These configurations are also referred to as “Symmetrical Monopoles”.

0.2.3 Technological Focus of the European HVDC Grid Study Group

Various technologies are available for building HVDC Grid Systems. Some of them have already been used in commercial projects; others are in the demonstration phase or are in an early stage of discussion. This applies to the converter technology as well as the topologies of connecting them into a HVDC Grid System.

Serving the near term applications, the Study Group decided to focus its scope of work on radial HVDC network structures as well as pure VSC based solutions. Both grounded and ungrounded DC circuits are considered.

The integration of HVDC Grid Systems is seen as an important part of developing future electric power systems. The Study Group bases its work on typical requirements applied to state of the art HVDC converter stations today and investigates aspects that are specifically related to the design and operation of converter stations and DC circuits. The requirements from the AC systems as known today are included. Secondary effects associated with changing the AC systems, e.g. the replacement of rotating machines by power electronic devices, are not within the scope of the Study Group.

The Study Group report summarizes the selected results of work and gives recommendations for the next steps towards preparing the ground for standardization of HVDC multiterminal systems and HVDC Grid Systems.

The interface requirements and functional specifications given in this document are intended to support the specification and purchase of multi vendor multiterminal HVDC Grid Systems.

1 Scope

This Technical Report applies to HVDC Systems having more than two converter stations connected to a common DC network, also referred to as HVDC Grid Systems. Serving the near term applications, this report describes radial HVDC network structures as well as pure VSC based solutions. Both grounded and ungrounded DC circuits are considered.

Based on typical requirements applied to state of the art HVDC converter stations today this report addresses aspects that are specifically related to the design and operation of converter stations and DC circuits in HVDC Grid Systems. The requirements from the AC systems as known today are included. Secondary effects associated with changing the AC systems, e.g. the replacement of rotating machines by power electronic devices, are not within the scope of the present report.

The report summarizes applications and concepts of HVDC Grid Systems with the purpose of preparing the ground for standardization of such systems.

The interface requirements and functional specifications given in this document are intended to support the specification and purchase of multi-vendor multiterminal HVDC Grid Systems.

2 Terminology and abbreviations

2.1 General

In the work undertaken here it has been identified that a common list of terminology and abbreviations used specifically to describe HVDC Grids should be established.

The International Electrotechnical Commission (IEC) standard EN 60633 [1] describes General Terminology for HVDC Transmission and is the reference for common terms and abbreviations. Furthermore EN 62501 [2] describes electrical testing of VSC. A new proposed work item in IEC is to develop terminology for VSC HVDC systems. In addition CIGRÉ has published a brochure 269 on basic operational principles of VSC-HVDC [3]. Specific terms required for components and methods for multiterminal HVDC Transmission, e.g. HVDC breakers and control modes, are described here.

The Study Group has established information exchange established with the ongoing CIGRÉ B4.52 feasibility study on DC Grids. Also in the CIGRÉ work, new terms used to describe phenomena and components in DC grids are used. The terminology used in this report corresponds to the terminology used in the CIGRÉ working group.

2.2 Terminology and abbreviations for HVDC Grid Systems used in this report

AC	Alternating Current
DC	Direct Current
ENTSO-E	European Network of Transmission System Operators for Electricity
FB	Full Bridge
GW	Giga Watts

HB	Half Bridge
HSS	High Speed Switch
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
IGBT	Insulated Gate Bipolar Transistor
LCC	Line Commutated Converter
MMC	Modular Multilevel Converter
OHL	Overhead transmission line
PCC AC	Point of common coupling (ac side)
PCC DC	Point of common coupling (dc side)
TRV	Transient Recovery Voltage
TSO	Transmission System Operator
VCD•	Voltage-current droop
VPD•	Voltage-power droop
VPDDB•	Voltage-power droop together with dead band
VSC	Voltage Sourced Converter

2.3 Proposed Terminology by the Study Group

– Converter Station Controller: A controller determining the voltages and currents at DC and AC terminals of its converter station.

  4.2.2, Converter Station Controller

– Dynamic Braking Device: A controllable branch absorbing energy from the DC circuit.

  7.2.2.2, Energy absorption capability (Dynamic Braking Device)

– HVDC Grid Controller: A high level controller linked to each individual Converter Station Controller

  4.2.3, HVDC Grid Controller

3 Typical Applications of HVDC Grids

3.1 The Development of HVDC Grid Systems

Today power transmission systems are largely based on AC. AC is beneficial in most applications for a number of reasons:

- easy to generate from mechanical energy in rotating machines or to convert back;
- easy to transform to higher voltage levels reducing power transmission losses;
- current zero crossings allow simple principles for load current switching and fault clearing.

However, there are applications where AC cannot be used or where DC technology is more economical than AC. Examples are:

- connecting asynchronous AC systems;
- long distance Overhead Line (OHL) or cable transmission;
- power flow control in large integrated AC systems (improving system stability).

Since its introduction in the middle of the 20th century, High Voltage Direct Current (HVDC) transmission has become a fundamental part of many electric power transmission systems worldwide. With a few exceptions, HVDC transmission systems are built so far as point-to-point links.

The requirements for point-to-point links have been specified by the Transmission System Operators (TSOs) involved according to the functionality needed as well as the respective AC network operating conditions. When HVDC technology is considered for multi-terminal systems or HVDC grids, more TSOs are involved with system planning and operation. At the same time the functional requirements and variety of AC system conditions to be covered increases. This requires establishing efficient coordination of design, operation, control and regulation between the connected AC and DC systems. Agreement contracts on physical and regulatory boundaries, responsibilities and utilization of the AC/DC converter stations as well as harmonization of technical regulations for the AC and DC systems are necessary pre-requisites for the cooperation between the involved operators.

Multi-terminal Systems and HVDC Grids will further on be referred to in this report as “HVDC Grid Systems”.

Similar to the evolution of AC transmission systems, HVDC Grid Systems should have the ability to grow according to demand. It should be possible to interconnect several smaller HVDC systems into larger integrated systems.

Some of the future HVDC Grid Systems may be financed and operated by independent HVDC Grid System companies. To ensure the required level of interoperability, the system design and operation requirements for the individual HVDC systems need to be harmonized in corresponding Grid Codes.

The development of HVDC Grid Systems is likely to start in small scale radial configurations, like with DC connections between existing AC systems. The Kriegers Flak Combined Grid Solution (CGS) project in the Baltic Sea may be amongst the first pilot projects of such future HVDC Grid Systems. If commissioned as the CGS, the offshore based HVDC Grid System will connect the expected 600 MW wind power at the Danish area of Kriegers Flak and approx. 400 MW at the Baltic 1 and Baltic 2 German wind power plants to the onshore AC transmission systems of Denmark and Germany and provide a connection between the AC systems of these two countries. The commissioning period of the HVDC-based CGS is expected between 2018 and 2020. The Kriegers Flak CGS shall be specified, commissioned and operated by the Danish TSO Energinet.dk and the German TSO 50 Hz Transmission GmbH. The Kriegers Flak CGS project has been granted European Union funding from the European Energy Programme for Recovery (EEPR).

The present clause describes important system operation and design criteria for HVDC Grid Systems that are intended to become integral part of the European electric power transmission systems. This work gives guidance to the elaboration of the functional requirements for HVDC grid components and systems within the European HVDC Grid Study Group. It intends also provide a contribution to the development of a common Grid Code for European HVDC Grid Systems.

3.2 Planning Criteria for Topologies

3.2.1 General

The starting point and a governing factor when evaluating and deciding on the system topology is the geography with the primary consumers, producers, and load flow exporters and importers. The first choice for this system topology will be the most obvious, easiest and immediately the cheapest way to connect the consumers and producers with each other.

The normal operational flow direction is defined from production to consumption centres. For example, in the case of a wind power plant, bi-directional power flow may be required: In normal operation the wind turbines produce energy that is transferred from the offshore platform to the onshore substation. Occasionally it will also be necessary to transfer energy from the onshore substation to the offshore platform converter when there is no wind, when the electrical equipment on the platform has to be maintained or the wind turbines are starting up, e.g. energizing the offshore platform converter and the offshore medium voltage (MV) and HV networks.

When choosing the system topology, the AC grid connection-point candidates are evaluated. The evaluation comprises, but is not limited to, benchmarking of the connection-point candidates from technical, environmental, cost-benefit and socioeconomic criteria. The benchmarking process shall also consider if the topology and connection-point candidates are dependent on each other; e. g. alternative topologies evolve from alternative connection-points and vice versa.

The needs and ability for the topology to expand in the future is difficult to predict. Therefore there is a risk of “built-in” overcapacity within the selected topology to cover possible, but not necessarily provable, future expansion. At present, the national AC grid operators apply similar, but area- and country-specific, procedures including technical, cost-benefit and socioeconomic evaluation criteria for future grid capacity and topology. The differences between such area- and country-specific procedures are due to different grid design and operation practice, regulations and definition of security of supply. The common goal should be that the AC and, in future, DC grid operators establish standard, European-level procedures. The standard procedures should be established for decisions on the overcapacity financing model including technical, regulatory, cost-benefit and socioeconomic evaluations of risks, benefits and disadvantages of the topology from present and future perspectives. The future perspective should be evaluated for mid term, i.e. for between 5 and 10 years perspective, and long term, i.e. over 10 years perspective, from the commissioning date.

Depending on the specific topologies, there can be various constraints for system operation, as there are:

- operation conditions (grid revision plans);
- disturbances (faults and outages);
- controllability restrictions;
- limitation of maximum short circuit currents;
- load flows congestions.

Operational constraints can be present both in the DC and AC transmission systems due to limitations of the system components. By careful selection of the system topology, adequate system capacity and sufficient controllability and redundancy the consequences of system constraints can be minimized.

For relatively short distances and small energy flows, AC cable transmission systems are economically competitive and advantageous to DC transmission systems. The competitive elements of DC transmission may include the cost-benefit evaluations of the AC versus DC system components, technical and commissioning aspects, arrangements for required ancillary services, maintenance, reliability, losses minimization, commercial availability and experience from earlier projects etc. The evaluation shall be performed for the (expected) lifetime period of the system. The advantages gained with a DC system should outweigh the cost.

3.2.2 Power Transfer Requirements

The main purpose of an electrical transmission system is the exchange of energy between its sub-stations representing energy consumption or energy production.

AC transmission systems are built for operation at high voltage levels, e.g. above 110 kV AC, whereas distribution systems belong to medium-voltage (MV) and low-voltage (LV) levels. At present, AC dominates the transmission systems whereas DC technology is present as part of the AC systems, for instance, in point-to-point connectors between two AC systems. AC is also the standard for distribution level systems.

Both HVAC and HVDC systems are utilized to transport significant amounts of power and energy over great geographical distances. HVDC transmission has advantages if costs associated with the distances and amounts of the power to be transmitted are lower than the costs for an appropriate HVAC transmission. Typical break-even distances of HVAC versus HVDC transmission utilizations are in the range of 50-110 km for cable connections, and in the range of 500-600 km for connections via overhead transmission lines. The ranges are dependent on several technical factors such as the nominal voltage, nominal power, losses, but also non-technical factors like rights of way. When two asynchronous HVAC areas are interconnected, HVDC is chosen for technical reasons.

HVDC transmission is also used in parallel, with HVAC connections; this is referred to as “embedded HVDC” systems. In addition to its main function of power transport, embedded HVDC systems are used for stabilization and power flow control of the corresponding HVAC connections. For example, HVDC systems in parallel with HVAC lines may be used for damping of inter area oscillations. [4], [5], [6] Furthermore, within their design capabilities, HVDC converter stations can support the HVAC transmission systems by providing reactive-power, AC voltage and frequency control.

Until today, the main focus of HVDC transmission has been mainly on design, operation and reliability of the AC system. The AC/DC converter stations have been interpreted as generator-like units and assigned to the grid code requirements of the AC system operators [7]. When the HVDC Grid System expands in terms of system dimensions and power capacity, the HVDC Grid System is expected to require ancillary services from the adjacent AC systems. This may lead to the DC system design, operation and reliability being based on similar procedures and criteria as applied to AC systems today. For example, similar to the concept of HVDC Grid Systems complementing AC systems, an islanded AC system can also be used to interconnect various HVDC links. At the same time the islanded AC system can provide connection for local generation (or load) such as offshore wind power plants (or oil and gas platforms) [8].

3.2.3 Reliability

The reliability requirements of the HVDC grid will impact upon the redundancy and maintainability of the individual components. Hence the reliability and security-of-supply aspects will have great influence on the final system topology. While reliability is a well-known criterion for AC system planning, its application to HVDC Grid Systems still needs to be defined.

a) AC System Reliability:

The expansion of an AC grid is always targeted to the agreed or predicted power and energy transmission needs. An AC grid is developed so that safe and reliable operational management with a sufficiently high security of supply is achieved. The security of supply has two major terms: the system adequacy and the system security. For further use in this document, those terms are explained below.

The system adequacy is based on probabilistic analysis combining availability of transmission lines and components, energy production and capacity as well as energy demand. The system adequacy is measured in terms of not-delivered energy by amount and time. Periods of not-delivered energy are defined as the time, when some consumption centres do not get all the required energy due to system constraints, lack of energy production or lack of energy capacity. The system adequacy is evaluated for a system in normal operation and in contingencies. The system adequacy is indexed from 0 (the lowest grade) to 100 (the highest grade). When the system is able to deliver all the required energy to all consumption centres at any time, with no constraints or interruptions, then the system adequacy is 100. Here not-delivered energy over a year is zero. When the system is not able to deliver energy to the consumption centres at all, the system adequacy is 0.

The system security is defined as the ability to maintain normal operation in case of forced events such as failures and outages of components or production units. The system security is analysed for rare, but severe and often the most critical, situations determined from practical experience and expert evaluations. However, not all critical situations are possible to predict and analyse. While some unreasonable and unrealistic situations are excluded from such analysis, other plausible severe situations might be overlooked. This means that short-term interruptions of energy delivery to consumption centres may occur and are deemed acceptable in extremely severe and unpredicted operational conditions. The system security can be measured as percentage of energy supply without interruptions, in amount and duration, over a year. Each country and each grid operator have defined targets for what to consider as a sufficiently high system security.

Investments increasing the AC system security of supply should be justified from technical, cost-benefit and socioeconomic evaluations including cooperation with neighbouring system operators. Such cooperation often relies on common rules and grid codes, which the participating members shall comply with. Today, the compliance of each member contributes to efficient operation and security of supply of the entire interconnected system. However, each grid operator remains responsible for the security of supply within his own system.

With increasing European interconnections and the utilization of HVDC Grid Systems in particular, bodies coordinating the individual TSOs on an European level become more and more important

As the first step to a possible grid expansion, the dimensioning of the grid resources is evaluated with respect to the system adequacy. The common rule for the system adequacy evaluation is n-1 criteria [9], but it can be extended to comply with specific needs of individual grids [10].

The n-1 criterion is fulfilled, if after an outage of a component of the transmission system (overhead line, cable, interconnector, transformer, compensation devices or production units) the following effects are excluded [11], [12]:

1) permanent off-limit conditions of nominal operating data and conditions that lead to a significant hazard to reliable operational management or to the damage of electrical equipment;

2) interruption of supply despite all available redundancies;

3) cascade tripping of protection devices of not direct influenced electrical equipment;

4) loss of stability (static and dynamic).

When evaluating the impact of an individual HVDC link on the AC system security, both the function of active power transmission and the ancillary services like reactive power and voltage control should be considered. With respect to active power, individual HVDC links can be divided into the following groups:

5) systems connecting wind parks or interconnectors to a different TSO; HVDC systems belonging to this group are considered like controllable generators. Generators are normally built n-0 secure as long as their ratings do not exceed the tolerance imposed by the primary reserve.

6) HVDC systems that are embedded into an AC system; HVDC systems belonging to this group are considered like a transmission line. The whole system including the HVDC normally has to fulfil the n-1 criterion. The HVDC system itself is often considered for 100 % operating utilization.

b) <u>HVDC Grid System Reliability:</u>

The HVDC Grid System needs to be considered together with the HVAC grid system as part of the same transmission grid. The rules to be applied should be analogue to the reliability and security-of-supply aspects of existing HVAC transmission systems: The security of supply of the entire system can be divided into the system adequacy and the system security.

Similar to the practice for AC systems, system adequacy evaluation can be based on the n-1 criterion taking into account technical and socioeconomic factors, cost benefits as well as practical experience and regulations. The transmission system operator(s) can define and approve a required (guaranteed) level of the HVDC Grid System performance.

The selected criterion would have to be fulfilled for the combined HVDC/HVAC systems in a similar way as the system adequacy is applied for dimensioning the AC system resources and securing the desired (guaranteed) level of the system adequacy. This means that redundancy, normal-operation and possible overload conditions of the DC-connections would have to be already addressed and considered in the design stage of the HVDC Grid System. This could require:

1) Dimensioning the HVDC Grid System resources so that, in a case of an outage of any single component (e.g. a HVDC line or a HVDC converter station), the scheduled or predicted energy transport requirements can be fulfilled within the required level of the system adequacy. This may require some HVDC converter stations or HVDC lines to be designed to include extra margin (temporary or permanent) for utilization resulting in a capacity margin to handle extra energy transport due to redistribution of power flows within the HVDC Grid System.

2) Fast system reconfiguration providing alternative connections to transmit power.

When defining the system topology, the system operators decide how to achieve the required security of supply considering:

3) HVDC circuit topology (monopole or bipole connection);

4) protection concept;

5) topology of protection zones;

6) definition of the maximum fault clearing time (establish the new load balance after a predetermined time period);

7) relevant faults and outages on the AC system as well on the HVDC grid system;

8) static and dynamic stability of the HVDC Grid System and AC systems;

9) possibility of energization and de-energization of the HVDC Grid System and AC systems.

3.2.4 Losses

Power transmission is associated with power losses. Within certain limits, the power losses can be influenced by the design of the network components, e. g. cables, converter station or transformers. Typically, the losses at a component behave in an inverse proportion to the investment cost, i.e. a requirement for lower losses results in higher equipment cost. Important reasons for this behaviour are that an increased amount of material may be needed to enlarge conductor cross sections, more expensive materials required or more advanced and precise monitoring and control equipment to be implemented and maintained. An overall economic solution can be achieved based on a realistic assessment of the value of power losses versus equipment cost.

One of the important benefits of HVDC power transmission is its efficiency in terms of losses over long distance transmission in comparison to HVAC power transmission. However it is also important to consider the losses for the total combined AC and DC system as a HVDC transmission link in parallel to an AC transmission system may reduce the losses in the AC transmission system. The no load losses of both HVAC and HVDC power transmissions should also be considered.

One advantage of a multi-terminal scheme instead of separated HVDC links is that a multi-terminal scheme reduces the number of power conversion from AC to DC and vice versa. Each additional conversion will give both greater losses and higher investment cost.

Operating losses are largely influenced by the selection of the nominal DC transmission voltage for the HVDC overhead lines or HVDC cables. An increase of the nominal transmission voltage will reduce the transmission losses due to the lower current, but at the same time likely increases the size and weight of the AC/DC converter stations and its platforms to meet insulation requirements. The cost of equipment would be increased accordingly as are the cost of the transmission lines. Optimization between operation costs and investment costs, taking into account possible future expansion is therefore recommended.

Both in point-to-point HVDC connections and in HVDC Grid System, typical operational power profiles could be used in the loss evaluation. No-load losses in HVDC Grid Systems can be treated by the same evaluation procedure as in point-to-point HVDC connections.

IEC has published standard procedures to calculate the losses in the main components in AC grids. Corresponding loss calculation standards are recommended for all components in a HVDC Grid System. Some of the standards exist and others are under development.

The value of the losses can be calculated with a typical socioeconomic value of e.g. 6 Eurocent/kWh; however the typical support regime value is higher in the North Sea area (the Netherlands, Germany, UK, and Denmark).

At present, the value of losses is often linked to the market value for electricity, disregarding that the factual cost of producing and transporting electricity offshore is higher than onshore. The calculation procedure for present and future (accumulated) value of losses is recommended to be harmonized. The harmonization process should take place within an IEC/CENELEC framework with participation of technical experts from research institutions, industry and grid operators. The harmonized procedure should account for the socioeconomic discounting percent rate and the economic interest rate of the company, e.g. owning and operating the grid. The harmonized procedure should also account for variations of the economic interest rate in time and limits of the support regime, for example a warranty limit of 15 years.

Typically the value of losses is expressed by a loss evaluation formula. The following equation is just one example. It may differ according to the specific conditions of an application.

$$K_P = K_0 * P_0 + \sum_n K_n * P_n \tag{3-1}$$

where

K_P is the total cost of losses;

K_0 is the cost of no-load losses;

K_n is the cost of load losses at a defined operating point or average value of load losses for a defined operating range;

P_0 is the no-load losses (not depending on the operating point);

P_n is the load losses at a defined operating point or for a defined operating range.

Such formula allows the manufacturer to design his equipment to an optimum of investment cost and cost of power losses during operation.

3.2.5 Future Expansions

Whilst consideration of the benefits of possible future expansion is recommended, this should be balanced with the early investment in additional equipment

Future system expansions should be considered in an early stage of system planning as such aspects are likely to influence both the electrical design and the interfaces at the DC side of the AC/DC converter stations with respect to selection of the nominal DC voltage and DC current as well as the control functions.

In radial network topologies, the coordinated control of AC/DC converter stations can determine the power flow through their adjacent cable or overhead line, respectively. In case of meshed multi-terminal topologies, load flow distribution between parallel paths is determined by equivalent path resistances and power flow control of the converter stations. In principle, small series DC voltage injections could be used to control the power flow, but this would require the provision of the corresponding type of equipment, power flow monitoring systems and an advanced control coordination.

From a system planning perspective, it is possible to extend the system transmission capacity at a later stage by adding parallel HVDC connections.

In addition to the design considerations for future grid expansion, an open market for equipment based on the same regulatory rules is an important prerequisite for reliable system planning. Systems that may be built in its initial phase by a single manufacturer should be expandable later using systems from other manufacturers, i.e. multi-vendor systems. Standardization of the principles of equipment function, system operation, control and communication (protocols) will make expansion easier.

At present, the market for AC transmission equipment and systems can be considered a role model for future DC transmission. In modern AC systems standardization gives detailed rules for specifying equipment dedicated to specific tasks. This applies to single components like switchgear or transformers as well as to complex systems like power plants or Static VAR Compensators (SVC). The equipment specified and manufactured according to standardized rules can be selected from different manufacturers and once it is added to the AC system, it becomes an integral part of it.

The development of multi-terminal, multi-vendor HVDC systems and HVDC grids will be simplified by standardized interface requirements of HVDC terminals. Moreover, other types of equipment should be considered, for example HVDC breakers.

3.3 Technical Requirements

3.3.1 General

Functional requirements for a HVDC Grid System can be described by a number of criteria, such as rated power, rated voltage, frequency, losses, reliability, availability and maintenance as well as the weight and dimensions. In addition the technical regulations (grid code) of the system operators need consideration.

The following section introduces important aspects which are relevant for reliable and stable operation of the AC and DC transmission systems.

3.3.2 Converter Functionality

The main functional requirements for the converters connected to a HVDC Grid System are:

- the power reversal of a single station shall not lead to DC transmission system voltage instabilities.
- disturbance in the AC system in one converter should not result in collapse of the DC grid voltage.

Two fundamentally different HVDC technologies are commercially available and, with some restrictions, are potential candidates for the DC transmission systems. The technologies are: the Line Commutated Converter (LCC) technology and the Voltage Sourced Converter (VSC) technology. The LCC technology is a tried-and-proven technology used in numerous point-to-point connection projects worldwide.

a) Power reversal:

The LCC technology utilizes thyristor based converter stations and as the thyristors can carry current in one direction only, the DC current direction is fixed. To change the power direction, the DC voltage polarity has to be changed.

VSC technology utilizes IGBT devices with bi-directional conduction and allows changing the DC current direction, so that the DC voltage polarity can be fixed. This concept is applied to VSCs based on so-called Half-Bridge (HB) building blocks (Half Bridge type Modular Multilevel Converters - MMC HB). VSCs based on so-called Full Bridge (FB) building blocks feature both changing the DC current direction as well as changing the DC voltage polarity (Full Bridge type Modular Multilevel Converter - MMC FB). Both types of converters are referred to in more detail in 5.3.4, Contribution of Converter Stations, and [17].

b) Disturbance:

The use of thyristor based converter stations requires access to relatively strong AC systems at all stations. That is, the AC systems have to have sufficient levels of short-circuit capacities at the point of interconnection. The system strength is often described by the Short-Circuit Ratio (SCR) as defined by Formula (3-2):

$$SCR = \frac{S_{SC}}{P_{dn}} \tag{3-2}$$

where

S_{sc} is the actual short circuit power level of the AC system;

P_{dn} is the nominal DC power of the converter station.

Subtracting total reactive power of filters and capacitor banks from actual short circuit power level in Formula (3-2) yields the Effective Short Circuit Ratio (ESCR). Based on ESCR’s value, AC system strength is classified by Cigré as follows, considering a reactive power compensation of 50 % of the nominal DC power [13] [14]:

- strong ac system (high levels): SCR ≥ 3, i.e. ESCR ≥ 2,5

- weak ac system (low levels): 3 > SCR ≥ 2, i.e. 2,5 > ESCR ≥ 1,5
- very weak ac system (very low levels): SCR < 2, i.e. ESCR < 1,5

Furthermore, pre-established AC voltages within defined operating ranges are amongst the prerequisites for a LCC converter station to start operation. Thyristors can be turned on but cannot turn off and therefore rely on the ac system voltage to commutate the current from one device to another. Consequently AC system disturbances may cause LCC to have commutation failures leading to large DC voltage disturbances.

The VSC technology is based on semiconductor devices with controlled turn off capability such as the IGBT. The use of VSC based converter stations allows independent control of the active and reactive current within the power rating of the station and does not require established ac voltages for turn off and do not experience commutation failures, hence, the short-circuit ratio of the AC system can be low. The VSC converter stations can also control and black-start islanded AC systems.

At present, VSC offer many advantages for HVDC Grid Systems. There is one project (Skagerrak 4) combining LCC and VSC technology in a bipolar arrangement with the purpose of expanding the existing LCC capacity.

In this document, the terms referring to AC/DC converter stations and HVDC Grid Systems imply pure VSC transmission, i.e. VSC HVDC converter stations and transmission systems.

3.3.3 Start/stop Behaviour of Individual Converter Stations

The converter station may stop for the following reasons:

- as part of normal operation;
- due to scheduled maintenance periods;
- in situations where protective action is needed.

When the HVDC Grid System shall go back to normal operation conditions the AC/DC converter station shall energize and re-start.

The time for a start/stop sequences depends on the specific operating requirements of the AC/DC converter station and the HVDC Grid System.

In case of a DC fault, the start/stop sequence of the AC/DC converter system(s) and the faulted part of the DC system should be fast. Typical timings are:

- stop and clear the DC fault within a few cycles of the fundamental AC system frequency;
- reconfigure, energize and re-start the affected converter station(s) as needed within some tens of milliseconds to a few seconds.

In case of a scheduled revision, there is no need for fast start/stop sequences. The time specification of the start/stop sequence should follow the common safety rules of the AC and DC transmission system operator(s) owning / operating the AC/DC converter station(s) and relevant part of the HVDC Grid System.

The term Black Start is used in conjunction with the start-up of a power system, i.e. going from a de-energized condition to an operation condition, and starting power delivery. Black Start includes start-up of house-load and islanded operation capabilities for the respective AC system and HVDC Grid System. The house-load, islanded-operation and black-start capabilities of the AC/DC converter stations should be specified by the respective system operators.

The following sequence can be applied for the Black-Start of a power system:

1) An AC source is needed to energize the DC Grid System through one HVDC converter.

2) Thereafter, other HVDC converters can be energized from their DC side or AC side (if energized). This will require the HVDC converter station to be designed for start-up from the relevant source (for example by charging resistors).

3) Energizing an islanded AC system via an HVDC converter. The converter should control the voltage and frequency in the islanded AC network.

3.3.4 Network Behaviour during Faults

Short-circuit faults can be distinguished in faults in the AC network, inside a converter station and on the DC network. Faults inside a converter station can be further differentiated in to faults on the converter AC side and faults on the converter DC side.

The fault behaviour of AC systems is well defined by existing AC Grid Codes [7]. Recommended requirements for the other types of faults are described in the following paragraphs.

– <u>AC Side Converter Station Faults:</u>

Faults that are on the network side of the station transformer require the station transformer to stay operational as per the requirement in ENTSO-E, ref [9].

Faults of the converter station transformer or inside the converter station are allowed to lead to an emergency disconnection sequence of the respective converter station. The system has to be designed in a way that the emergency switch off does not result in unacceptable conditions for other equipment in the AC or DC networks.

– <u>DC Side Converter Station Faults:</u>

Faults that are inside the converter station can lead to an emergency disconnection sequence of that respective converter station. Disconnection on the DC side may involve a temporary shutdown of the DC circuit, reconfiguration, and restart of the remaining DC network without the faulty station. The system has to be designed in a way that the emergency switch off does not result in unacceptable conditions for other equipment in the AC or DC networks.

– <u>DC Network Faults:</u>

Ground faults within a HVDC Grid System have a different behaviour to that from the condition known from AC networks. Without any countermeasures, the lack of significant short circuit impedance inside the DC circuit will cause the rapid collapse of the DC voltage throughout the DC network. Consequently, any ground fault inside the DC network will affect all interconnected AC/DC converter stations and influence the adjacent AC systems accordingly. From the perspective of the adjacent AC systems, a DC network short circuit fault will be seen as a temporary three-phase voltage drop at different locations simultaneously.

The DC fault behaviour can be described as follows:

- As soon as a fault on the DC feeder occurs, the energy that is stored in the capacitance of the DC system (cables, overhead lines and DC-side capacitors of the converter stations if any) is discharged into the fault. This produces an over-current with similar shape as a classical RC-discharge.

- The fault behaviour of the converter station depends on the type of converter, i.e. whether or not the converter has a fault current control capability. The converters with fault current control capability can interrupt fault current with appropriate control of converter valves (additional fault isolation reconfiguration is needed). The converters without fault current control capability need AC or DC circuit breakers to interrupt the fault current. HVDC breakers are under development and may become standardized in the future.

Depending on possible interruption methods of a DC fault current, two different reactions are to be distinguished:

- <u>Fast clearing, without temporary stop</u> will have minimum impact on operation and stability of the DC and adjacent AC systems and would be required in a system where the n-1 requirement applies also for the DC system. This would only allow stopping the affected part of the DC system. A fast fault recovery for the healthy part of the system is required where the power loss due to the DC system shutdown is not acceptable for security of supply. The tolerable interruption time of power flow through the DC circuit should be studied considering the adequacy requirements of both the AC and DC power systems.

- <u>Fast clearing with temporary stop</u> of the affected DC system will allow more time for system reconfiguration and restart. A typical example of this is fault clearing by the AC side converter station circuit breaker, where the corresponding DC circuit is temporarily discharged, reconfigured if necessary, re-energized and transmission re-started.

In either case, fast fault detection and localization will be required as a pre-requisite for appropriate system reconfiguration.

The difference in the allowed actions regarding the DC fault clearing also influences the requirements for the AC/DC converter stations as well as delivery of ancillary services to the AC systems.

Fast clearing and isolation is a likely requirement when overhead lines are part of the HVDC Grid System as they are prone to suffer faults due to their exposure to environment phenomena such as thunderstorms.

3.3.5 DC-AC Interface Requirements

AC/DC converter stations have to comply with a set of requirements formulated by the AC system operators. For example ref. [7] provides common technical regulations for all generator types connected to the ENTSO-E HVAC system.

From the AC system operation and stability perspective, common requirements may comprise, but are not necessarily limited to, the following categories:

- definition of interfaces between DC and AC;
- operation ranges and ancillary services in normal operation of the AC system;
- operation ranges and ancillary services at over- / under- frequency and voltage in the AC system;
- low-voltage fault-ride-through and support to the grid in AC short-circuit faults;
- high-voltage fault-ride-through as consequence of grid disturbances (separation from the main AC grid);
- power Quality, e.g. allowed harmonic emission ranges;
- tests and documentation requirements;
- model delivery and validation.

It is recommended that similar categories are defined for the DC side.

3.3.6 The Role of Communication

The HVDC Grid System should be designed to operate without interruption and in a safe way even in the event of loss of communication. The converter station protection should be operating locally and not rely on communication.

Nevertheless, communication will play an important role for HVDC Grid Systems in order to simplify and optimize coordination of DC grid operation modes, such as:

- power control;
- power flow control;
- mode control of individual converter station, e.g. start/stop sequences, emergency power control, DC voltage control, Frequency control, etc.
- reactive power control.

The HVDC Grid System operation will be governed by a HVDC Grid Controller which is linked to each individual converter station controller via the communication system. Communication between the HVDC Grid Controller and a Converter Station Controller should allow:

- coordinating the operation modes of the converter stations, i.e. assigning power or DC-voltage control mode and reference values;
- optimizing the power flow in the HVDC Grid System, e.g. assigning the DC voltage references and specific control parameters, such as droops, selecting operation regimes minimizing power losses etc.; specific description to this control coordination part is given in Clause 3;

- status information and switching orders to and from each HVDC station.

Communication with the TSO’s operation control centres informs the system operators of the status, capacity and power flow of a converter station, and enable them to operate the HVDC Grid system efficiently. In general, communication functions that are essential for operating the HVDC Grid system should be implemented as redundant systems.

3.4 Typical Applications – Relevant Topologies

3.4.1 General

This section makes a connection between theoretical, feasible requirements which a HVDC Grid System should comply with, and practical realistic application cases for the near future. In general, the HVDC Grid system topologies distinguish in:

- radial applications;
- meshed applications.

The HVDC Grid System topologies can also be combined with the AC system islands and AC lines.

3.4.2 Radial Topology

In radial topologies, each of the converter stations is connected by a single line at any time. Typical radial topologies radial topologies are illustrated in Figure 3-1.

The case present in Figure 3-1 a) shows AC/DC converter stations that are connected via the DC line/cable.

In the case present in Figure 3-1 b), the two converter stations are connected to the DC line/cable at a common DC bus bar.

As an example in offshore HVDC Grid Systems, the AC/DC converter stations utilizing the radial topology may be:

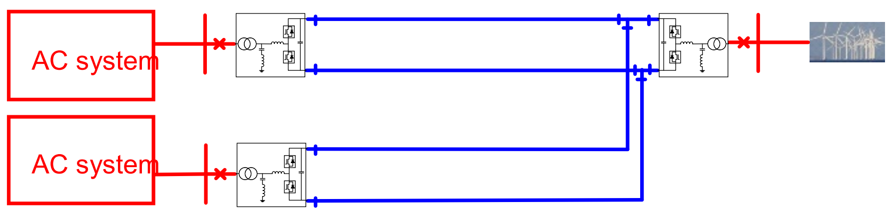
- wind power plants, when considering generation units;
- large oil platforms, when considering consumption units.

In Figure 3-1 a), the two AC/DC converter stations feeding into the AC systems can represent the DC connection between two separate and asynchronous AC systems which could be many, possibly hundreds of kilometres, apart. Offshore, there could be two (or more) wind power plants that are connected into the main DC line.

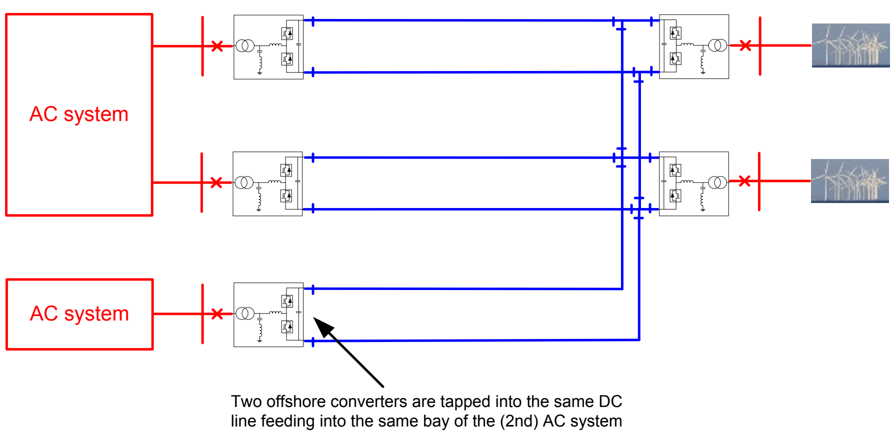
An example of the topology shown in Figure 3-1 a) is the HVDC VSC part of the Kriegers Flak Combined Grid Solution, which is presented in 3.1. The Development of HVDC Grid Systems. The topology of Figure 3-1 b) illustrates the Kriegers Flak CGS expansion to Sweden, and additional offshore wind power plant are connected to the main DC line.

Figure 3-1 c) illustrates a parallel system where there are two AC terminals offshore and one AC terminal onshore. The shown DC system has a crossover DC line between the two parallel DC lines. By disconnecting and crossing the respective DC lines, one AC/DC converter station can use the other AC/DC converter station's parallel DC line for the power transport. Such power transport rearrangement is useful if one of the DC lines is out of service.

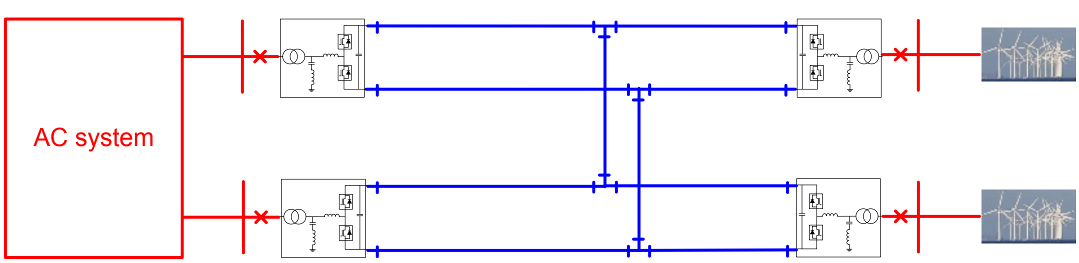
In HVDC Grid Systems having a radial topology the current through each DC line is controllable through the AC/DC converter stations coordinated by the HVDC Grid Controller.



a) One offshore wind power plant with connection to two (non-synchronized) AC systems



b) Two offshore wind power plants with connections to two AC systems



c) Two offshore wind power plants with cross connected parallel DC sea cables connected to one AC systems

Figure 3-1 — Radial HVDC VSC system topologies illustrating possible configurations of the Kriegers Flak Combined Grid Solution

3.4.3 Meshed Topology

In case of meshed topologies, at least two converter stations are connected by more than one transmission line forming parallel paths for the power flow. This will allow some redundancy of power transmission capability, within the limits of power and current ratings of the DC lines and AC/DC converter stations respectively. The value of the redundancy for the overall system should be justified by cost-benefit analysis. That is, the additional cost of redundancy is justified in comparison to the benefits of continuing power transport and retaining the agreed level of security of supply. Figure 3-2 illustrates the use of a meshed HVDC Grid System with redundancy by means of two DC connectors. The DC system shown can be operated in two ways: with or without connections between the DC lines during normal operation.

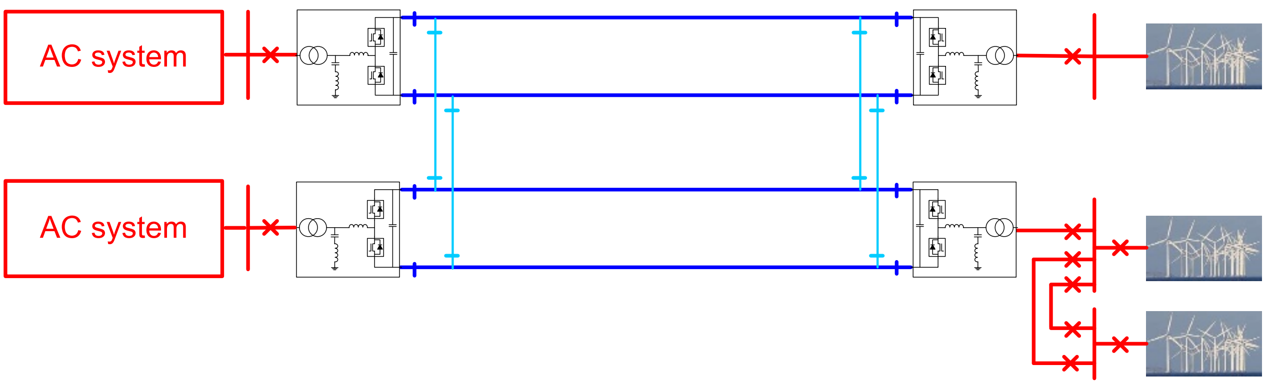


Figure 3-2 — Meshed HVDC Grid System topology with redundancy by means of DC connectors

Operating the system without connection between the DC lines, results in two independent DC circuits. If an outage of one of the DC lines occurs, both AC/DC converter stations could be connected to the remaining healthy DC line. This will require appropriate switching equipment on the DC side of the AC/DC converter stations. System reconfiguration may require the temporary interruption of transmission on the healthy system. The required switching equipment can include HVDC breakers, HVDC disconnectors or manual connectors. The type of switchgear should be selected according to the speed of system reconfiguration needed. In this configuration the DC switching equipment is not required to break fault currents. However, when specifying the switchgear the charging current for the DC lines as well as the remote converter stations should be considered.

It may be necessary to take both main DC lines out of operation when changing the configuration on the DC side.

Operating the system with connection between the DC lines may be advantageous if fast fault clearing and isolation technologies are used. The technology of fast fault clearing and isolation should be carefully analysed and selected to minimize the possibility of outage of both DC lines due to DC faults which will affect all of the dc converters simultaneously.

3.4.4 HVDC Grid Systems Connecting Offshore Wind Power Plants

An important application of HVDC Grid Systems will be the connection of large offshore wind power plants to the adjacent, onshore AC transmission systems. Referring to 3.1, The Development of HVDC Grid

Systems, the Kriegers Flak CGS is one example for the establishment of such offshore HVDC Grid Systems, shown as a draft in Figure 3-3.

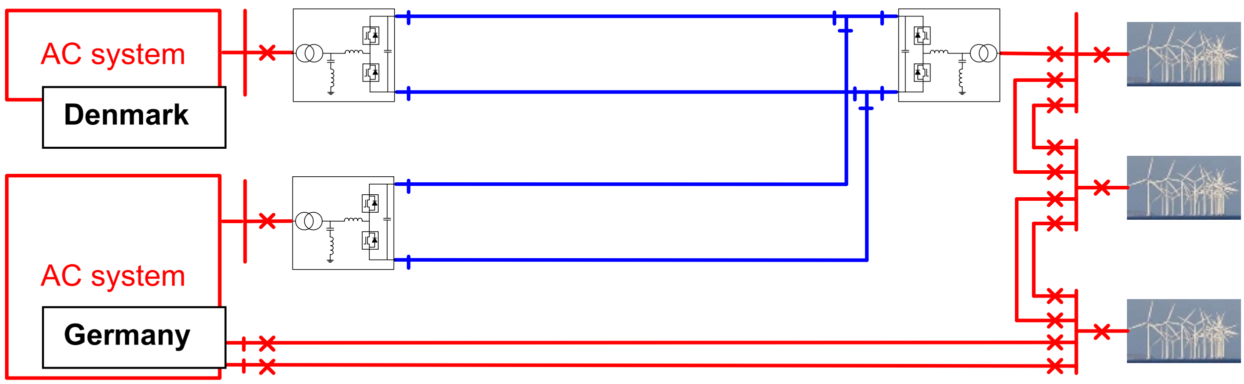


Figure 3-3 — Possible grid-connection topology of approximately 1 000 MW offshore wind power at Kriegers Flak to two onshore not-synchronized AC systems of Denmark-East and Germany

At present, the DC part does not require fast fault clearing and isolation technologies as in the event of a DC system outage, some power from the offshore wind power plants can still be transported through the AC lines. In case of an outage of the AC lines, the wind power is collected at the offshore AC/DC converter station and transported through the HVDC system to the onshore AC systems. Hence, the connection between the wind power plants provides a redundant path for power transmission. The value of this redundancy is to be justified by cost-benefit analysis.

3.4.5 Connection of a wind power plant to an existing HVDC VSC link

Figure 3-4 illustrates the case, where a new offshore wind power plant is connected to an existing HVDC Grid System (e.g. between two AC systems).

The existing DC cables are extended to reach the offshore platform. It would be possible to remove a faulty section of the DC cable and keep the rest of the DC system in operation. Appropriate DC switchgear would be an advantage in order to achieve a rapid system reconfiguration and thus minimize the outage period for the remaining healthy parts of the dc system.

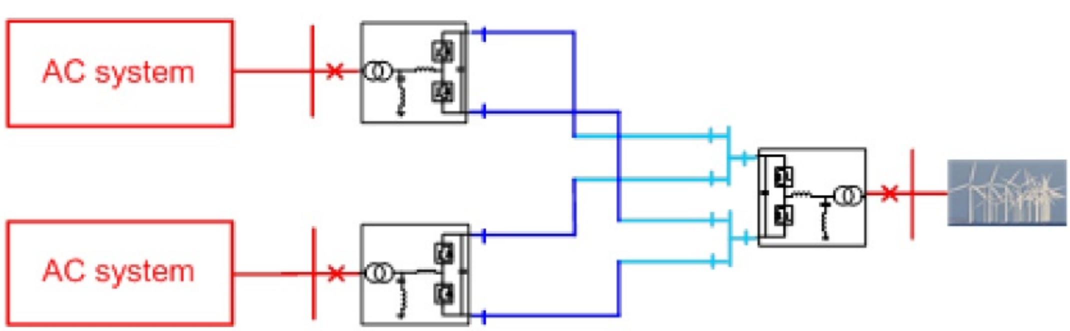


Figure 3-4 — Connection arrangements of a new offshore wind power plant to an existing HVDC Grid System

4 Principles of DC Load Flow

4.1 General

This clause discusses the principles of steady-state and dynamic load flow control for a HVDC Grid System. The primary objective of the control system is to achieve reliable and stable power flow over all operating conditions including unplanned or unscheduled power flows caused by outages and fault conditions.

4.2 Structure of Load Flow Controls

4.2.1 General

The primary objective of an HVDC Grid System is to transmit power between its converter stations. Depending on the transmission task, some converter stations import power into the DC circuit, others export power. Power import tends to increase the DC voltage level of the network; power export tends to decrease the DC voltage. Transmitting power requires the DC voltage to be maintained within certain limits.

Maintaining the DC voltage within acceptable limits means that any power surplus either needs to be stored in appropriate energy storage devices or dissipated as heat using dedicated discharging devices, usually referred to as Dynamic Braking Devices. Energy storage will also have to compensate any power deficit to keep the DC voltage reasonably constant. If a DC network does not contain energy storages or Dynamic Braking Devices, power export and import have to be balanced at all times by the proper control of the converter stations.

The control functions of a DC Grid can be differentiated, with respect to their dynamics, into Converter Station Controls and HVDC Grid Controls.

4.2.2 Converter Station Controller

The Converter Station Controller determines the operating point of its converter. It controls the voltages and currents at the converter DC and AC terminals with response times typically in the range of a few milliseconds. Control objectives may be:

- active power flow through the converter;
- AC system frequency;
- DC voltage;
- reactive power exchange with the AC network;
- AC voltage.

In general the Converter Station Controller obtains measuring signals from its own converter station or receives status signals from external controllers that may influence the control strategy. The Converter Station Controller does not rely on external communication. Coordination with the DC and AC networks is achieved by pre-determined characteristics, such as fix reference values or droop characteristics.

The dynamic operation of the control system has a direct influence on the rating of the internal DC capacitors of the converter. This in turn has a significant impact of the cost and space requirements of the converter.

The Converter Station Controller sends local status and measured signals to the HVDC Grid Controller.

4.2.3 HVDC Grid Controller

4.2.3.1 General

The HVDC Grid Controller provides the individual Converter Station Controllers with their control characteristics and reference values. It uses the status and measured signals to optimize the power flow within the network according to pre-defined rules. It provides the interface to the system operators. The HVDC Grid Controller relies on communication.

If the telecommunication between the HVDC Grid Controller and any station is out of service, the loading of this station has to be an estimate based on information from other stations or manually entered by the operator.

When an HVDC Grid System is separated into two parts, e.g. following a permanent fault on a transmission line, each part requires an HVDC Grid Controller to continue operation.

To ensure control of the HVDC Grid System in event of major losses of equipment, there should be a “back-up” HVDC Grid Controller. The back-up HVDC Grid Controller should be located at a different location.

4.2.3.2 Steady State Load Flow Control

HVDC Grid Controller aims to compensate mismatches in the grid dispatched power by increasing or decreasing the overall voltage level. This can be used to handle small power variations as they occur for example at wind farms. However, such variations have to allow sufficient margin in the permitted voltage bands. Under steady-state conditions the utilized voltage bands shall be smaller than the maximum allowable value. To achieve this, the HVDC Grid Controller pre-calculates the load flow in the DC circuit to determine the reference values for all individual Converter Station Controllers. Therefore information on the DC Network Topology and network components is require, for example:

a) Switchgear (Disconnectors and Circuit Breakers (if any)):

   1) present status (open, closed);

b) Load Flow:

   1) dispatch patterns;

   2) contingency conditions and strategies;

   3) loading of all converters;

   4) loading of all DC power lines;

5) DC voltages in all stations;

c) Converter Station:

1) present status (blocked, de-blocked);

2) maximum and minimum voltages;

3) maximum currents;

4) control mode (Udc or active power);

d) Lines and Cables:

1) resistances;

2) maximum temporary and steady-state current ratings;

e) Energy Storages and Dynamic Braking Devices (if any):

1) present status;

2) maximum and minimum voltages;

3) maximum currents;

4) energy absorption/supply capability.

Once all information has been factored into a load flow model, the study procedure will be similar to that of a conventional AC network steady-state load flow study. For any combination of dispatch patterns and contingency conditions the load flow will be solved and shown that the given voltage bands will not be violated and the given current ratings (converters and lines/cables) will not be exceeded. In case of an initial network planning stage, necessary voltage and current ratings can be determined.

4.2.3.3 Dynamic Load Flow Control

For major disturbances of the load flow, such as load rejections of complete converter stations or tripping of lines, the resulting voltage variations will be large. Therefore converter stations injecting active power into the DC grid should limit overvoltages by reducing power import. On the other hand any station exporting power should limit undervoltages by reducing power export.

A dynamic model of the DC system has to include, in addition to that required for the steady-state load flow study, data on network reactance and dynamic limitation functions. A time-domain based calculation will provide the dynamic over-voltages and currents to be expected as well as show the dynamic system stability.

Appropriate strategies have to ensure, that the capabilities of the AC systems connected to the individual converter stations are taken into account. This may require high level coordination between the AC and DC network operations.

4.3 Converter Station Control Functions

4.3.1 General

Traditionally the operational status of a converter station is distinguished into “rectifier” and “inverter” operation depending on the direction of active power flow. Especially with the respect to multiterminal HVDC systems, another way to categorize the behaviour of an individual converter station has become more important. Regardless of the actual direction of active power flow (from AC to DC or vice versa), a converter station can be operated in “DC voltage control mode” or as an “active power station”. In the special case, where an active power station is controlled by an AC system frequency controller, the active power station is operated in “frequency control mode”. In either case the converter stations have to stay within their voltage and current operating limits. As a consequence the power rating of these stations has to be coordinated with the worst case scenario to be considered for loss of load or generation in the DC system.

The following sections describe these options and give indications on the constraints for the connected AC networks.

4.3.2 DC Voltage (U_{DC}) Stations

A converter station operating in DC voltage control mode adjusts its active power exchange to meet the DC voltage reference value. As a consequence, the active power of this particular station is determined to balance power in the DC circuit.

In principle the voltage reference value can be kept constant within certain power limits or it can follow a droop characteristic, meaning that a given DC voltage results in a defined power exchange. With respect to DC system stability, controlling the DC voltage requires the AC system connected to a DC voltage controlling station to accommodate the active power export or import determined by the HVDC Grid System. It is recommended that dynamic network simulations are undertaken to assess the stability of combined AC and DC systems to identify the limitations to operation.

4.3.3 Active Power (P_{DC}) and Frequency (f) Controlling Stations

A converter station operating in active power mode adjusts its DC voltage to meet the active power reference value.

This control mode can be used to balance active power in the adjacent AC network. In that case, the power reference value could be provided by a secondary control loop controlling the frequency in the AC system, making the station a Frequency Controlling Station. Frequency control will be required for isolated AC grids, like offshore wind parks or oil and gas platforms.

In principle the active power reference value can be kept constant within certain DC voltage limits or it can follow a given droop characteristic, meaning that the given active power results in a defined DC voltage.

With respect to DC system stability, controlling the active power or frequency control requires the DC system to accommodate the active power export or import determined by the connected AC grid. This has to be achieved maintaining voltage and current limits of all converter stations in the network. Temporary overvoltages in the DC system may have to be limited, e.g. by appropriate power run-back functions or Dynamic Braking Devices. Similarly, temporary undervoltages may have to be limited by appropriate power run-up functions. Dynamic network simulations taking into account the actual capabilities of the DC system are recommended investigating the system stability of the DC network together with its AC system environment as well as identifying proper measures.

Active power or frequency control is recommended for weak AC grids. In case of strong AC systems, the station can be used for constant DC power operation.

4.4 Paralleling Transmission Systems

4.4.1 General

Special considerations have to be made in case that two (or more) converters are connected in parallel at one sub-station. The paralleling may take place on their AC sides or on their DC terminals (or both).

4.4.2 Paralleling on AC and DC side

Converters that are connected commonly to the same nodes on the AC and DC side appear like one converter in the system. A typical situation is shown in Figure 4-1 at Sub-Station A, when the dashed connection on the DC side is in place. Applications include extending existing stations or converter stations having power ratings exceeding the capabilities of a single converter.

When converters are connected in parallel each converter control system has to ensure that its converter contributes a predetermined fraction of the active and reactive power of the overall converter station at all times. In particular, situations where one station increasingly feeds power while another one counteracts are to be avoided. Such situations are also referred to as “hunting” and result in uncontrolled loop-flows and unstable operation. Hunting may be avoided by implementing a station master controller that provides each converter control with exact reference values. Alternatively, applying droop characteristics to the appropriate control modes, e.g. DC voltage, active power, AC voltage, Reactive power. Droop characteristics require the dynamic behaviour of the individual converters to be studied in order to avoid hunting.

4.4.3 Paralleling on the AC side

Figure 4-1 shows and example at Sub-Station A with two converters connected in parallel on the AC side assuming the dashed connection on the DC side does not exist. One example for such a configuration can be islanded AC networks connecting wind parks with different HVDC stations. The HVDC converters may via DC networks be connected to:

1) different AC systems if the AC connections between Sub-Stations A, B and C do not exist, or

2) the same AC system but at different nodes (at least partly) if the connection between Sub-Stations B and C or A and C exist.

In case 1), the active power requirements as well as the active power capabilities of the DC systems DC_1 and DC_2 will often be different. The DC systems may even require different control modes, such as U_{DC} control for VSC_1 and P_{DC} control for VSC_2. These conditions will result in different reference values for P_1 and P_2. The Sum of P_1 and P_2 has to be provided or absorbed by the system AC_3.

In case VSC_1 and VSC_2 share frequency control in the system AC_3, the capabilities of the systems DC_1 and DC_2 can be taken into account when defining the power-frequency droop characteristics applied to VSC_1 and VSC_2.

In Case 2) the same conditions can apply as described in Case 1. However, the additional connection between the systems DC_1 and DC_2 opens up the possibility of power loop flows between VSC_1 and VSC_2 via the AC systems AC_1 and AC_2. Such power loop flows are further described in 4.4.4, Steady-State Loadflow in Hybrid AC/DC Networks. Load flow studies investigating all relevant operating conditions are required to identify appropriate strategies for the AC and DC system dispatch controls (see 4.5, Load Flow Control for more details).

The AC connection between systems AC_3 and AC_2 allows power loop flow and this situation applies to all HVDC links embedded into integrated AC systems. The possibility of power loop flow occurring should be considered when determining the P_1 and P_2 reference values.

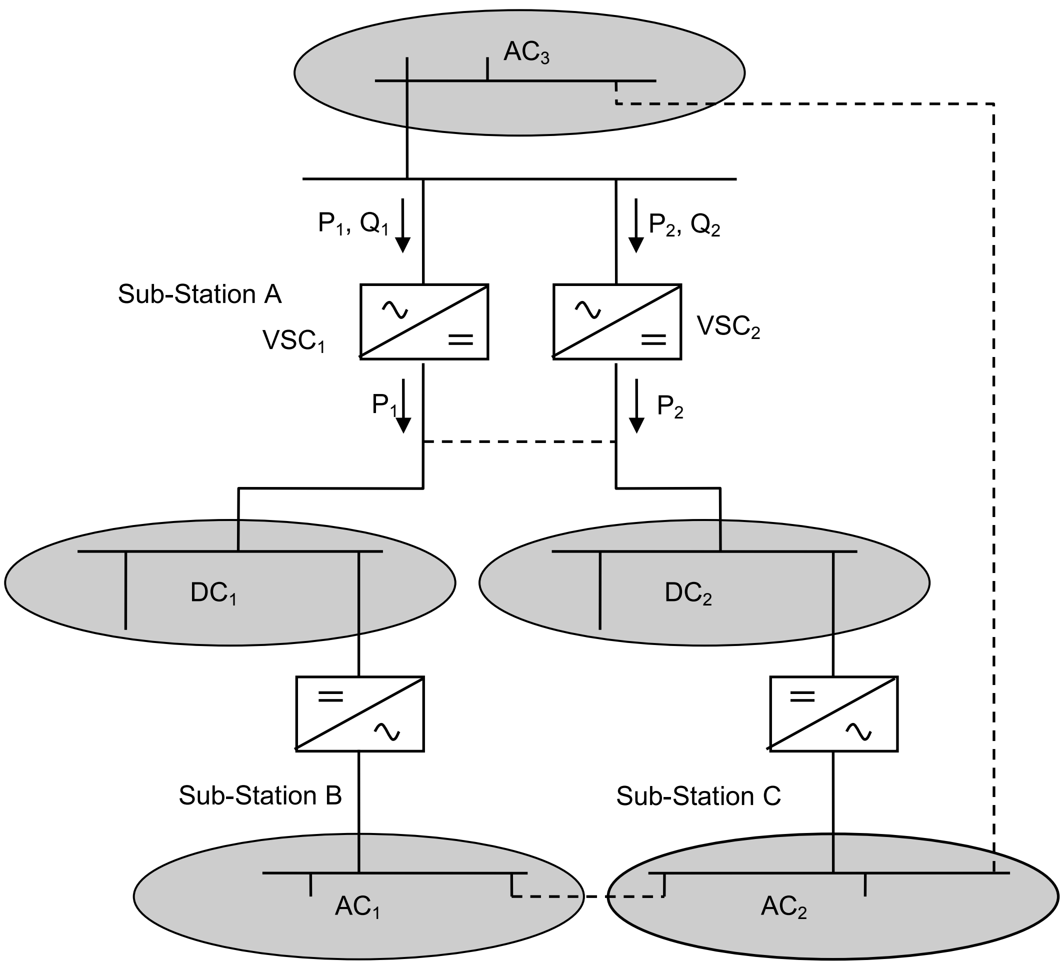


Figure 4-1 — Network showing parallel operation of converters in various configurations (example)

4.4.4 Steady-State Loadflow in Hybrid AC/DC Networks

Figure 4-2 shows the simplified DC and AC connection between two nodes of a large DC grid and the associated AC system. The DC grid superimposed on an AC grid can provide an alternative path to transfer bulk power across a large geographical area, potentially providing lower transmission loss and avoiding congestion in the AC grid. Such power flow control will be achieved through both AC and DC dispatch control.

Inefficiencies in the transmission system may arise as a result of poor power flow dispatch. Figure 4-3 indicates a simplified case where the dispatch has been defined as indicated in Figure 4-2, but the “load” is no longer present. Consequently, the active power from the converter will flow into the AC system and could, via the AC system, return to the DC grid through another converter node. This circulation of active power through the DC grid and then through the AC grid without supplying an active load is known as “wheeling” active power. The “wheeling” of power gives additional and unnecessary transmission losses.

In order to avoid wheeling of active power the load flow studies performed by the system operators shall consider both the AC and the overlaid DC grid. Where some degree of active power wheeling cannot be avoided because of the system topology there may be some advantage in islanding parts of the AC grid in order to ‘break’ the AC conduction path. This ‘islanding’ of the AC system may also offer some benefit in terms of reducing the risk of AC system cascade failure under fault conditions.

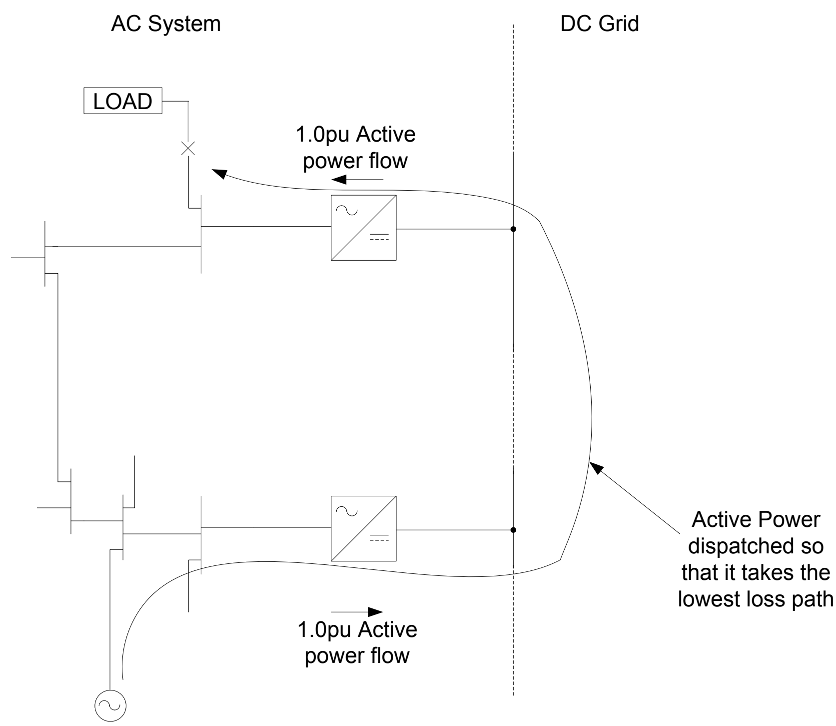


Figure 4-2 — Active power flow through a DC Grid

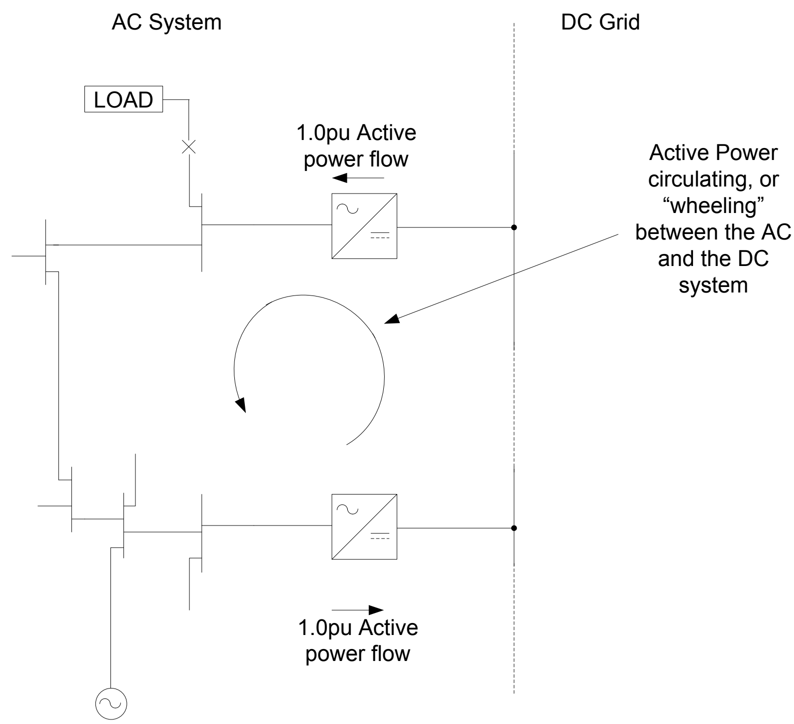


Figure 4-3 — Wheeling active power between the AC and DC grids

4.5 Load Flow Control

4.5.1 DC Voltage Operating Range

For steady-state load flow considerations any given DC grid can be modelled as a purely resistive network. Under no-load conditions the DC voltage at all network nodes equals the no-load voltage. To establish an envisaged load flow the individual node voltages have to be increased (to inject active power into the DC grid) or reduced (to consume active power from the DC grid).

Using the concept of Active Power (P_{DC}), Frequency (f) and DC Voltage (U_{DC}) converter stations as described in 4.3, Converter Station Control Functions, results in a load flow with increased DC voltages at rectifiers and reduced voltages at inverters.

The voltage operating range at a converter DC terminal is an important design parameter for HVDC Grid Systems. It depends on the length of the transmission lines, their resistances and the current flowing. Higher grid voltage levels allow transmitting the required power at less current and thus reduce the voltage drop along the transmission lines. Consequently, longer transmission distances and higher power require higher transmission voltage levels.

In the planning phase of an HVDC Grid System, steady-state load flow calculations considering all requirements as far as available should be carried out to define the appropriate transmission voltage level as well as the DC voltage operating range throughout the grid. Load flow calculations can also provide the required static control settings of the individual converters such as voltage reference values, dead bands or droop characteristics respectively.

In addition to the steady-state voltage conditions, dynamic and transient conditions need to be considered. The dynamic operating voltage range is determined by the speed of response to varying power orders or abrupt load changes.

Changing the power flow requires changing the DC current. The DC current response in turn is determined by the inductance of the DC circuit and the driving dynamic voltage difference between converters. The inductance of the DC circuit is formed by the inductance of the transmission line and extra reactors, which might be used to limit the di/dt in case of faults causing DC short circuits. Dynamic simulations should be carried out to derive the required dynamic DC operating voltage range at a converter station.

The transient DC voltage operating range is not directly related to the load flow control. Transient over- and undervoltages can occur for example in response to switching of transmission lines or lightning strikes in overhead transmission. Transient system studies should be carried out in order to determine the transient DC voltage operating range.

4.5.2 Static and Dynamic System Stability

Network simulations covering the HVDC Grid System together with its surrounding AC networks are required to investigate the static and dynamic system stability.

The entire transmission system (AC and DC) is statically stable, if changing load flow conditions or a system reconfiguration lead to a new status of equilibrium with all voltages and currents being constant. The new operating point needs to be within the capabilities of all equipment, such as converters or transmission lines as well as the AC systems. Load flow simulations including a detailed replica of the HVDC Grid System and the associated AC systems can be used to investigate the static stability of the system. Models of the converter stations should include voltage/current operating characteristics with their respective limitations.

The entire transmission system (AC and DC) is dynamically stable, if any changes and disturbances in the system lead, after some oscillations, to a new status of equilibrium. The oscillations shall be short in time and well damped. Investigating the dynamic stability requires simulations using a detailed replica of the network including the dynamic behaviour of converters and machines in the AC system. The system behaviour should be investigated for critical modes of oscillation. Appropriate countermeasures may include dedicated damping control algorithms applied to the converter controls.

The HVDC Grid System can provide damping to power oscillations in the AC system. This requires careful coordination of the control actions of the individual converter stations to achieve the required power flow through the DC grid.

4.5.3 Step response

A typical dynamic system response is shown in Figure 4-4. The individual parameters can be defined as follows:

- **Response time:** The change of stepped value should reach Δv_1 % of the total change within t_1 ms of the initiating control signal of voltage reference.
- **Maximum Overshoot:** The maximum overshoot should not exceed Δv_2 % of the ordered change.

- **Settling time:** The settling time should not exceed t_2 ms, after which the stepped value should be within Δv_3 % of the ordered change (ΔC).

Similar dynamic response parameters can be defined for change of power direction (Power Reversal) or recovery from DC side faults

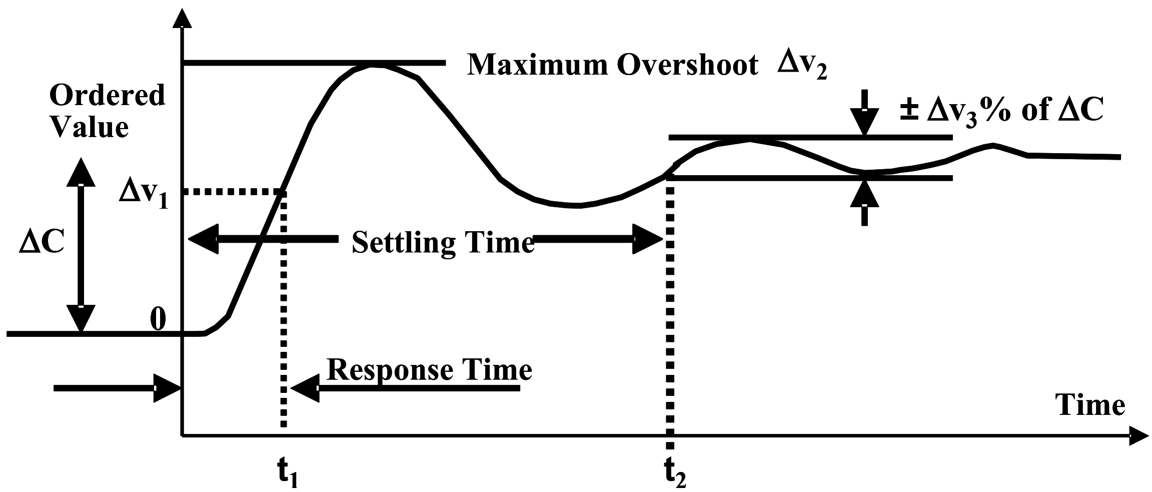


Figure 4-4 — Dynamic Response Parameters

4.6 HVDC Grid Control Concepts

4.6.1 General

There are different concepts for the HVDC Grid Controller and the Converter Station Controller to achieve the desired load flow:

- voltage-power droop together with dead band (VPDDB);
- voltage-current droop (VCD);
- voltage-power droop (VPD).

The control concepts are summarized in Table 4-1 and described in the following paragraphs.

Table 4-1 — Requirement for HVDC Grid Controls

The table shows a typical separation of the functionalities between Converter Station Controller and DC Grid Controller.

Requirement	**Converter Station Controller**	**HVDC Grid Controller**	**Voltage-power droop together with dead band**	**Voltage-current droop**	**Voltage-power droop**
Main operation principle			DC dead band together with voltage droop control (voltage-power droop); only one station in Udc control mode [b]	DC voltage droop control (voltage-current droop)	DC voltage droop control (voltage-power droop)
fulfill P or Udc reference points	x		exactly fulfilled within the P or Udc dead bands respectively; Offset by droop outside the dead bands.	offset by droop	offset by droop
calculate well defined operating points in terms of P and Udc taking into account known system restriction		x	yes	yes	yes
continue operation at a stable operating point after a large disturbance, e.g.: - after loosing a converter or the connection to the AC system - after loosing a DC line - after loosing load or generation (trip of wind farm)	x		yes	yes	yes
schedule optimal power flow (keep DC voltage at the rectifier as close as possible to its maximum value)		x	yes (send individual power orders and DC-References to each station)	yes (send individual power orders and a common DC-reference)	yes (send individual power orders and DC-reference)

Requirement	**Converter Station Controller**	**HVDC Grid Controller**	**Voltage-power droop together with dead band**	**Voltage-current droop**	**Voltage-power droop**
handle fluctuating loads and generation	x		yes (staying within the dead-bands of all stations, no change in the power controlling stations necessary)	yes (fluctuations of power shared between all stations, except those that are in power or frequency control mode)	yes (fluctuations of power shared between all stations, except those that are in power or frequency control mode)
be flexible with respect to combinations of Uac/f, P/Q and Udc control	x		yes	yes	yes
handle restrictions and limitations in the DC and AC networks - islanded AC networks - fast acting run-back/run-up strategies	x		yes (dead bands can be increased temporarily to fulfill the run-back order)	yes (small deviation from power order due to droop)	yes (deviation from power order according to droop)
- thermal and stability limitations in AC system components - run-back/run-up strategies - power oscillation damping		x	yes	yes	yes
Prevention of overload of any DC grid component (cables, overhead lines, etc.)		x	yes	yes	yes
the primary controller shall keep the DC voltage within acceptable limits	x		yes	yes	yes
provide autonomous control during temporary loss of communication [c]	x		yes	yes	yes
be robust against non-ideal conditions (e.g. tolerances of measuring and power equipment)	x		yes (staying within the dead-bands of all stations, no change in the power controlling stations)	yes (small deviation from power order due to droop)	yes (small deviation from power order due to droop)
Interoperability			yes	yes	yes
Signals for load flow control from the HVDC Grid Controller to the Converter Station Controller			- requested operating mode	- requested operating mode	- requested operating mode

Requirement	**Converter Station Controller**	**HVDC Grid Controller**	**Voltage-power droop together with dead band**	**Voltage-current droop**	**Voltage-power droop**
			(power, voltage or frequency) - power order - local DC voltage reference - voltage droop constants - power droop for DC voltage controlling converter station - dead bands for DC voltage - dead bands for power - end value and time of change value for power - end value and time of change value for DC voltage - stop commands	(power, voltage droop or frequency) - power order - load reference set point - voltage droop constants - end value and time of change value for power - end value and time of change value for DC voltage - stop commands	(power, voltage droop or frequency) - power order - load reference set point - voltage droop constants - end value and time of change value for power - end value and time of change value for DC voltage - stop commands
Signals for load flow control from the Converter Station Controller to the HVDC Grid Controller			- present status of operation - measured power - measured DC voltage - converter power export limitations [a] - converter power import limitations	- present status of operation - measured power - measured DC voltage - converter power export limitations [a] - converter power import limitations	- present status of operation - measured power - measured DC voltage - converter power export limitations [a] - converter power

Requirement	**Converter Station Controller**	**HVDC Grid Controller**	**Voltage-power droop together with dead band**	**Voltage-current droop**	**Voltage-power droop**
			[a] - "Ready for Ramp" signal - Start-up and Shut-down sequences	[a] - "Ready for Ramp" signal - Start-up and Shut-down sequences	import limitations [a] - "Ready for Ramp" signal - Start-up and Shut-down sequences

[a] Export and import as seen from the DC Grid.
[b] Disabling the power and voltage dead bands results in a behaviour similar to the voltage-power droop method.
[c] Autonomous control requires the over- und undervoltage limits vs. time to be kept. This can be achieved by implementing voltage vs. time characteristics into each Converter Station Controller.

4.6.2 Voltage-Power Droop Together with Dead Band

4.6.2.1 General

For coordination of power orders and DC voltage references to all stations in the DC grid there shall be a HVDC Grid Controller. The functions are described in 4.2.3, HVDC Grid Controller.

The steady-state and dynamic Control of DC Grid DC Voltage are described in the following paragraphs.

4.6.2.2 Steady State DC Voltage Control

Short-term and Long Term DC Voltage Control are defined as follows:

a) Short-term DC Voltage Control:

To ensure transient and dynamic stability and for minimizing the risks for interaction between power controls of different stations, the DC voltage profile of the system shall be fixed in a short-term. Otherwise, power changes in any station will result in voltage variation in all other stations, which will be counteracted by the power control in those stations. This is done through a dead-band in DC voltage and power for each converter, see Figure 4-5. See section "Converter Dynamic Characteristics" below.

The set-point for the DC voltage reference for each converter is defined by the HVDC Grid Controller considering the DC voltage profile of the complete DC grid.

For minimizing the transmission losses it is foreseen that the converter station with the highest DC voltage will operate close to maximum continuous DC voltage.

b) Long Term DC Voltage Control:

The power dispatch varies with time and so does the DC voltage profile. In order to optimize the network for the varied power dispatch the HVDC Grid Controller adjusts the DC voltage references. This is a long term process, and there shall be allowance for tap changers to adjust for the modified voltage levels. Consequently, the rate of change shall be in order of 1-5 % of rated DC voltage per minute.

4.6.2.3 Dynamic DC Voltage Control

The balanced operation of the DC grid will be disturbed by faults and trip events. The main reasons for the disturbed operation are:

- Trip of a converter;
- Trip of a DC power line;
- AC faults.

In all cases it is important that the DC voltage all the time is kept within the acceptable range, which is an inherent functionality in the Converter Station Controller.

a) Converter Dynamic Characteristics:

A fast DC voltage control, in each converter control system, ensures that no converter is operating outside the DC voltage limits of the converters, i.e. the horizontal lines at +10 kV in the example given in Figure 4-5.

Transiently and dynamically, the station selected for DC voltage control mode, controls its DC voltage to the short-term fixed reference within the defined power dead-band for normal operation.

The converters selected for active power control mode will control their AC side power to the ordered value as long as the DC voltage is within the defined dc voltage dead-band for normal operation.

Outside the defined voltage/power dead-bands for normal steady-state operation the converter has a voltage/power droop characteristic as shown in Figure 4-5. A voltage/power droop characteristic allows all converters to assist stabilizing the DC grid during a major disturbance, e.g. at protective shutdown of a converter. Full details of the electrical system are described in CIGRE Technical Brochure No 533 [25].

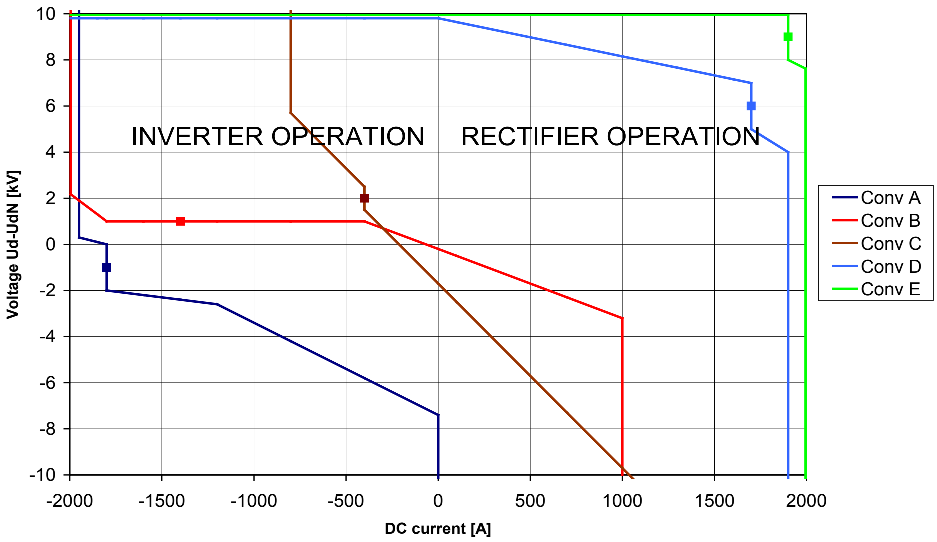


Figure 4-5 — Example of characteristics for five converters connected to a DC grid related to local DC voltage. The small squares are the steady-state operating points of the converters [CIGRE Technical Brochure No 533 [25]]

Figure 4-5 shows an example of a dead-band droop control of DC voltage versus power for five converters A, B, C, D and E connected to a DC grid. The small squares are the steady-state operation points for the five converters related to the local DC voltage at the converter location. Thus, the difference in voltage is the voltage drop of the DC power lines in the DC grid. Converter B is the converter selected for DC voltage control mode while the other operates in active power control mode. For the rectifiers D and E it is shown that the voltage is limited to, and not exceeding, the allowed rated voltage. The voltage will always be highest at a rectifier.

Additional comments to Figure 4-5:

1) The sum of the current to all converters shall be zero. Thus the total current of the rectifiers is equal to the total current of the inverters.

2) The power/current limitations of the converter combined with the power limitations of its connected AC network are shown as vertical lines.

3) The horizontal lines at +10 kV represent maximum allowed DC voltage for operation.

4) The converter in DC voltage control mode has a dead-band in power. This is the horizontal part of the characteristic for converter B.

5) The converters in active power control mode have a dead-band in DC voltage. This is the short vertical part of the characteristics at the operation points of converter A, C, D and E.

6) The sloping part of the characteristics represents the droop characteristic.

The power sharing and the DC voltage at disturbances are defined by:

7) The power dead-band for the converter in DC voltage control mode.

8) The voltage dead-band for the converters in active power control mode.

9) The two droop constants for each converter.

10) The limitations in power/current and over voltage for each converter.

A converter in islanded network operation or in frequency control should be represented as a constant power characteristic, independent of DC voltage level, in Figure 4-5. For an islanded wind park all Dynamic Braking Devices may temporarily assist to keep the DC voltage down until either the power output from the wind park is reduced or the HVDC Grid Controller has lowered the DC voltage in the DC grid by updating the DC voltage reference to the DC voltage controlling converter.

b) Defining the Converter Characteristics:

The power, current and voltage limits of a converter are normally defined by local conditions, which should be informed to the DC grid master control.

Based on the DC grid dispatch, the DC voltage profile of the grid and known restrictions and limitations the DC grid master control defines the following settings:

1) the DC voltage reference set-points for all converters;

2) the power order for the converters in active power control mode;

3) the dead-band in power and DC voltage respectively, before activating the droop characteristic, for each individual converter;

4) the droop constants for each individual converter;

5) the DC grid master control may also order more stringent limitations than the limitation due to local conditions.

4.6.2.4 Block diagram for droop control with dead-band

The droop control with dead-band is implemented locally in each converter. Thus, it will assist the DC grid at disturbances in the event of a temporary interruption of communication to the HVDC Grid Controller. Figure 4-6 shows the block diagram for droop control with dead-band used for each power controlling converter.

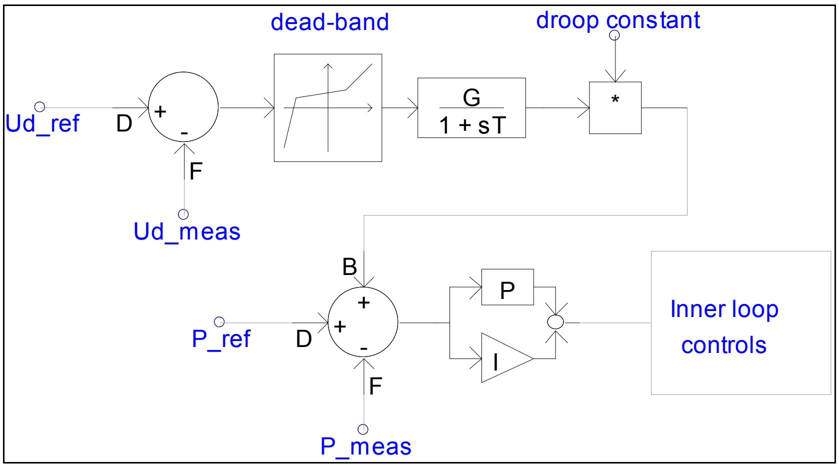


Figure 4-6 — Block diagram for droop control with dead-band as used in power controlling converters

Figure 4-7 shows the block diagram for droop control with dead-band used for the DC voltage controlling converter:

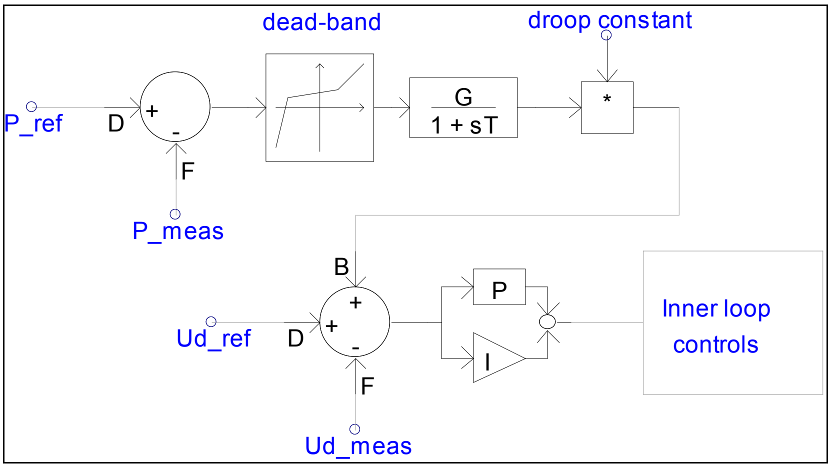


Figure 4-7 — Block diagram for droop control with dead-band used for the DC voltage controlling converter

4.6.3 Voltage-Current Droop

4.6.3.1 Control of the HVDC Grid Voltage

A method of multi-terminal converter control is to make each converter independent so that each converter has its own target power and no individual converter is solely responsible for DC voltage control. This is, therefore, similar to multiple loads and generators operating in parallel in AC systems, where the addition of parallel generators and loads is common practice.

By allowing each converter in a HVDC Grid System to independently adjust its terminal DC voltage following a DC voltage/DC current characteristic, such as that shown in Figure 4-8, a load flow can be achieved which satisfies the overall dispatch energy balance [15]. However, unlike in a conventional point-to-point HVDC scheme, where the power flow across the DC link is precisely controlled by the operator or the HVDC Grid Controller, the power at any node in a HVDC Grid System, where each converter has autonomous control, cannot be precisely defined. This is the same as with an AC system where the load flow changes to balance the generation capability with the load demand without having absolute control over the flow of energy around the circuit. In the following diagrams

Import is defined as power flowing from the converter in to the DC Grid (i.e. Rectification) whilst Export as power flowing from the DC Grid into the converter (i.e. Inversion).

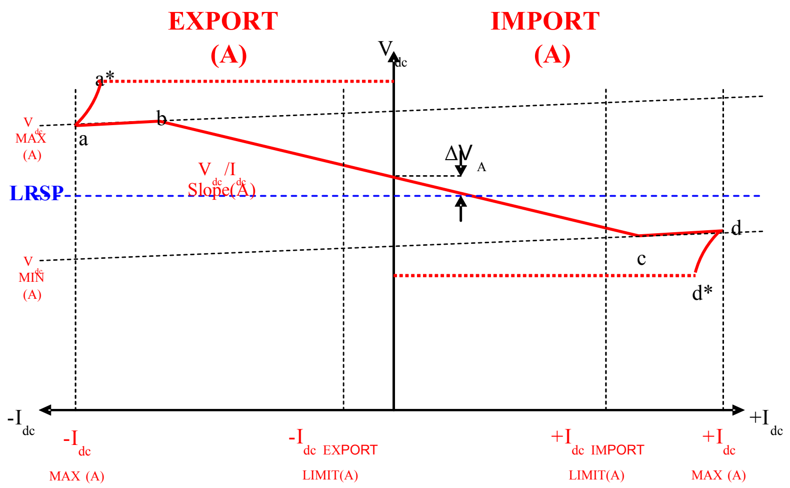


Figure 4-8 — An HVDC converter slope control characteristic

Each converter within the HVDC Grid System is given a ‘Load Reference Set Point’ (LRSP) equivalent to a load reference set point within an AC system. However, unlike in an AC system where this load reference set point is a target AC frequency across the network, for the HVDC Grid System the load reference set point represents the target no-load DC voltage for the converter.

The main part of the characteristic (bc) is a DC voltage/DC current characteristic. Unlike an AC generator, the DC characteristic is extended into the region of exporting power, that is power flow out of the dc system (inverter operation). At zero power the characteristic will nominally be set at the LRSP, see Figure 4-8. The LRSP is the nominal operating voltage for the entire DC grid system and is set by the Dispatch Centre. The LRSP given to each station will reflect the power flow and the assumed DC system resistance. It is only a “nominal” voltage; the actual voltage at any point in the system will be determined by the power flow, power direction and the various DC system conductor resistances. The characteristic (bc) will be moved up or down the DC voltage axis (ΔV) to determine the power flow out of, or into each converter.

Other characteristics are necessary for safe operation of the converter. Whilst the main characteristic (bc) can be moved up or down the DC voltage axis the equipment shall be kept within safe operating limits at all times. It is therefore expected that, as part of the DC “grid code”, a maximum and minimum operating voltage will be set.

Transient, or short-term, operation outside these limits could be permitted but with restrictions on the allowable DC current. The converter will have a DC current limit in both the export (aa*) and import (dd*) operating modes; these need not be the same value of DC current. In the event of the AC system connected to the converter having a surplus or deficit of real power resulting in a change in the AC system voltage it may be necessary to use some of the total current capacity of the converter to provide reactive power control to the AC terminal thereby reducing the available DC capability.

4.6.3.2 HVDC Grid Common Control Block

A basic Converter Station Controller could have a basic structure as shown in Figure 4-9.

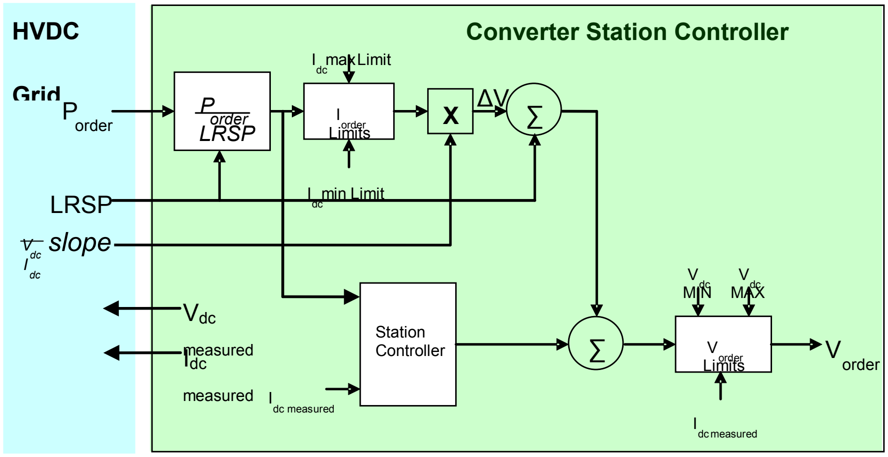


Figure 4-9 — A basic controller for DC converter in a HVDC Grid System

The HVDC Grid Controller would have the overall responsibility for determining the economic operation of the DC grid with changing generation and load conditions.

4.6.3.3 Converter Interaction

Figure 4-10 to Figure 4-14 below illustrate a simple two terminal HVDC Grid System. In this example the DC resistance of the grid system is ignored and the assumption is made that the two converters are of identical ratings and characteristics.

The determination of power flow and power flow direction is by the relative position of the two characteristics. The interception of the two characteristics is the operating point (OP) for the system and determines the DC voltage and the DC current, hence, the DC power transfer, in the case of Figure 4-10, the DC power transfer is zero. Increasing the offset on the converter's Voltage characteristic (ΔV) will move the operating point to the right as shown in Figure 4-11, that is, the power flows from converter A to B.

By reversing the sign of the voltage offset (ΔV) at the two stations the operating point will move further to the left and power transfer is now from B to A, Figure 4-14.

Changes to the transferred power could be made in two fundamentally different ways; Dispatch control or unilateral control.

Under dispatch control the Operators or the HVDC Grid Controller will change the Power orders to both converters simultaneously. This would move the operating point along the LRSP to the new required power as shown in Figure 4-12.

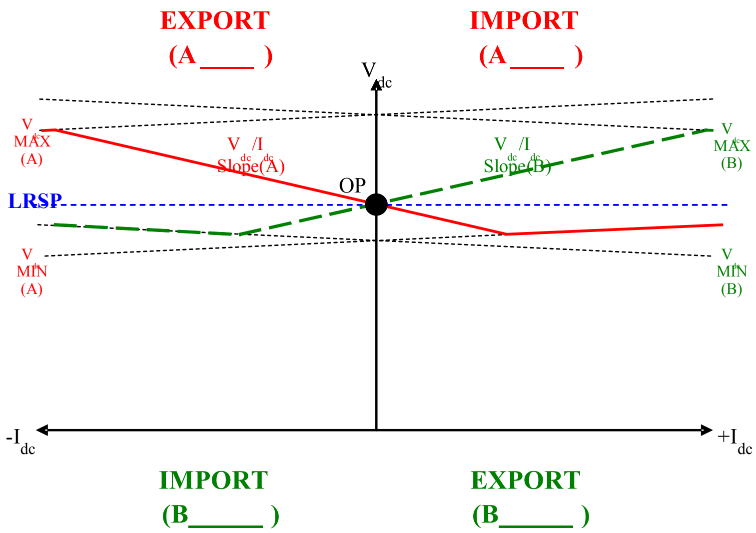


Figure 4-10 — A Two-terminal HVDC Grid System with zero power flow

Unilateral control action, as its name implies, is where individual converters can change their power orders without recourse to the system operators or HVDC Grid Controller respectively. For example, if the importing station is station B, and station B reverts to power control at a different power order, perhaps as a result of loss of generation in its associated AC system, then its voltage offset (ΔV_B) would be increased and its voltage characteristic moved down the Vdc axis. The operating point (OP) would move to the right (OP2) and the transferred power would be increased. However, the operating point would move below the LRSP, Figure 4-13. Under these conditions the scheme is no longer 'optimized' in terms of the losses within the system.

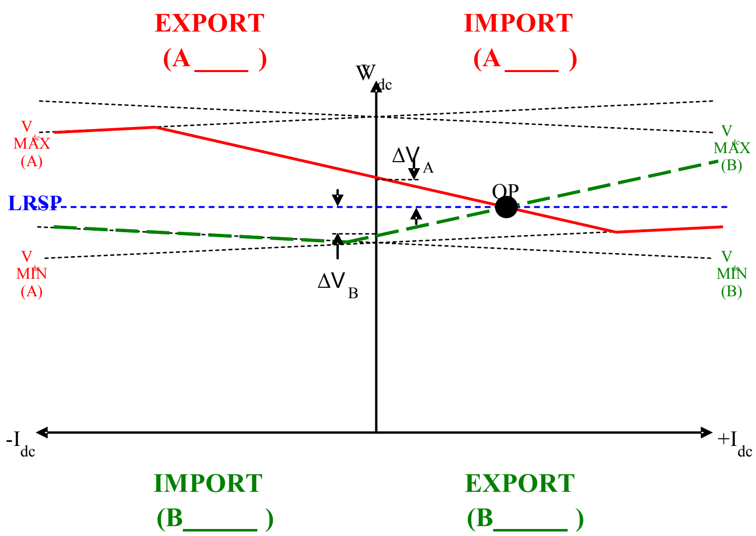


Figure 4-11 — A Two-terminal HVDC Grid System with power flow A to B

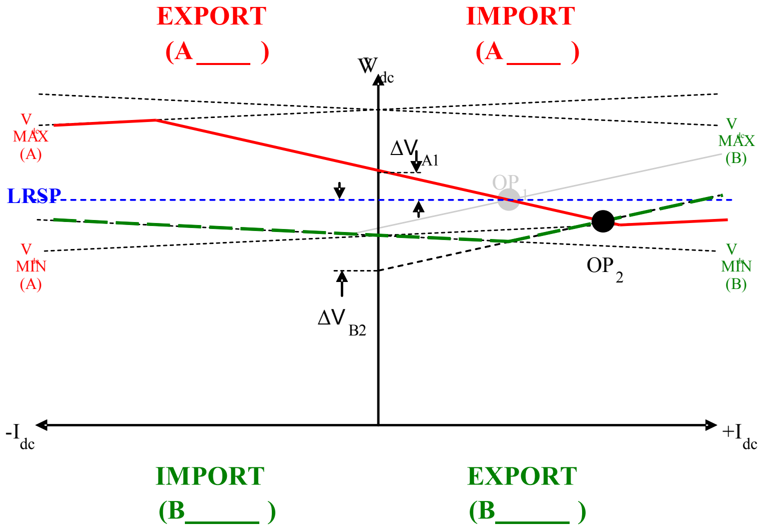


Figure 4-12 — Increased demand at Converter B

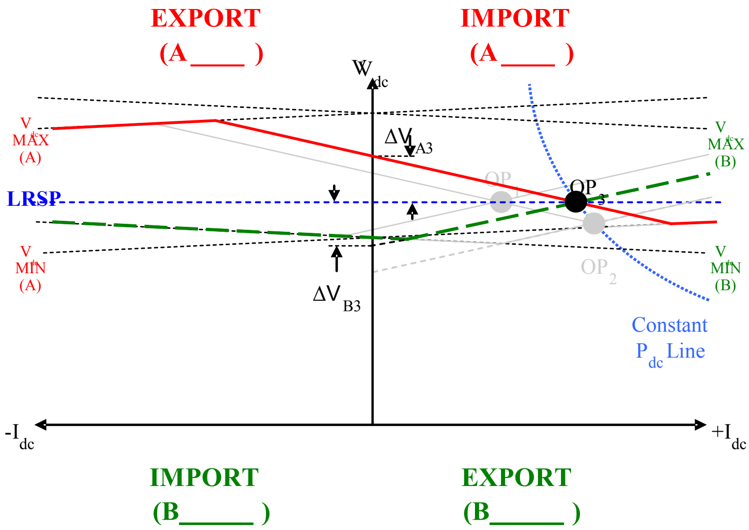


Figure 4-13 — HVDC Grid Controller optimization of the DC load flow

If this operating condition persists the HVDC Grid Controller could then send a new power order to Converter A in order to compensate for the increased demand. Converter A's control system would respond to this by moving its voltage characteristic up (increasing ΔV_A) and thus moving the operating point along a constant power characteristic back to the LRSP (OP3), Figure 4-13. In this manner the operating DC Voltage can be "maximized", and consequently the DC current "minimized" for the whole HVDC Grid System and overall losses reduced.

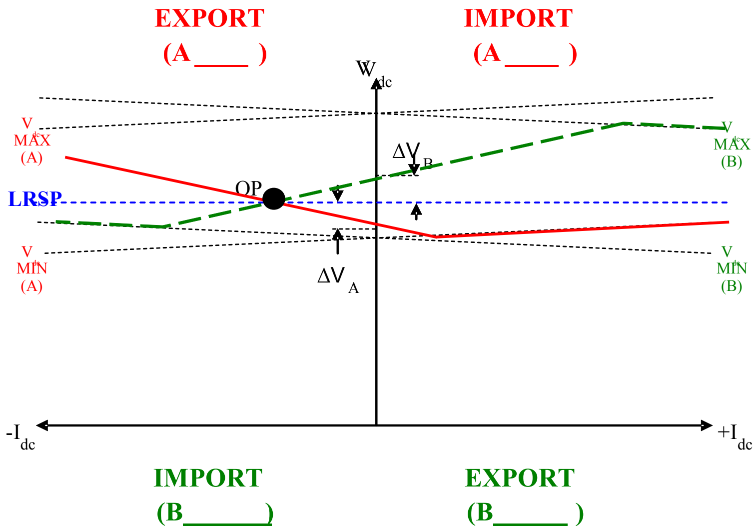


Figure 4-14 — A Two-terminal HVDC Grid System with power flow B to A

Considering a more extreme example of, say, a load rejection in the receiving AC system, the transferred DC power could be reversed. Initially the operating point would be above the LRSP until station A responds by reversing the sign of its offset voltage (ΔV_A), Figure 4-14.

In each case the above makes the assumption that the changes required were within the capabilities of both converter stations.

4.6.3.4 Power Flow Control

The target power flow across the HVDC Grid System is defined by the HVDC Grid Controller in the same way as the power flow of an AC system is controlled. However, an important aspect of this HVDC grid control concept is that the HVDC Grid Controller only exerts a slow control on the DC link, providing export and import power orders to the nodes within the HVDC Grid System in order to meet the desired load flow. Dynamic control, as previously discussed, is autonomous at each converter.

4.6.3.5 Voltage Optimizer

Following changes to the load flow of the HVDC Grid System no node may actually be operating at the maximum steady-state DC voltage. Consequently, the transmission losses will not be optimized, as, to achieve a desired power flow across the network; the DC current shall be higher than it would be if the operating DC voltage was at a higher value. It will therefore be of economic benefit to allow the HVDC Grid Controller to adjust the LRSP of the HVDC Grid System in order to maximize the operating DC voltage.

The HVDC Grid Controller can, periodically, receive from each Converter Station Controller connected to the HVDC Grid System the local operating DC voltage. When the HVDC Grid System has been operating under a steady-state load flow for a predefined time and there are no known new load dispatches about to be issued then the load HVDC Grid Controller could issue a new LRSP and LRSP ramp rate to all of the Converter Station Controllers. This new LRSP should be such that the node which was operating at the highest voltage prior to the change is raised to some higher voltage up to the maximum steady-state DC voltage. In the event of a change of dispatch requirements during an LRSP ramp the HVDC Grid Controller should have the capability of sending a ‘stop LRSP ramp’ signal to all Converter Station Controllers.

4.6.4 Voltage-Power Droop — Control of the HVDC Grid Voltage

Figure 4-15 shows a HVDC Grid System consisting of three stations. The system is used as the reference to describe the voltage-power droop control.

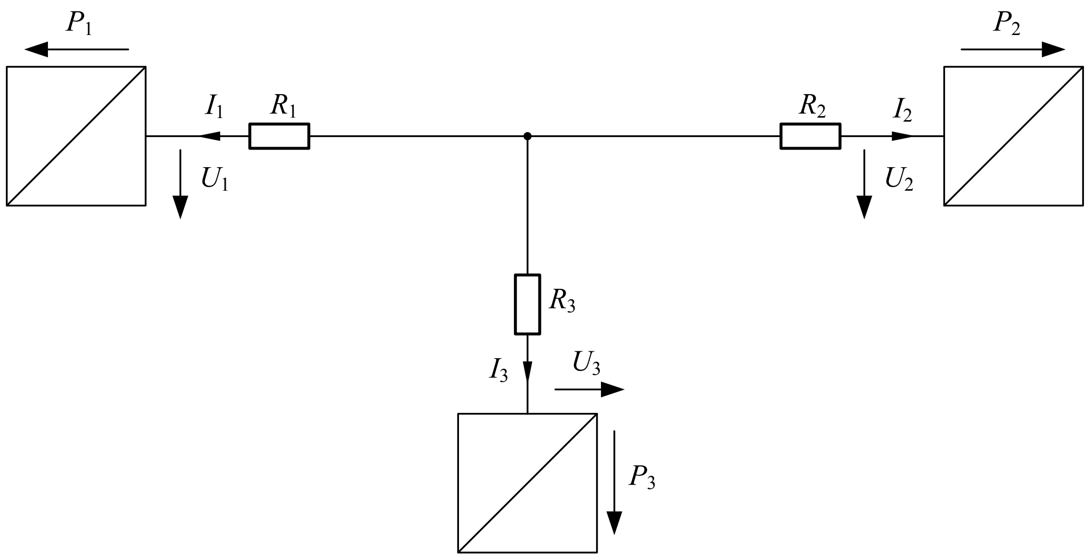


Figure 4-15 — Schematic drawing of a HVDC Grid System illustrating the power, voltage and current measurement as applied for Formulae (4-1), (4-2) and (4-3)

The steady-state operating point of DC voltage and DC power of each station is described by the following equation:

$$P_\nu = P_{0\nu} + k_\nu \cdot \left(U_\nu - U_{0\nu}\right) \text{ with } \nu = 1{,}2{,}3 \tag{4-1}$$

where

- ν is the Station Number
- P is the Active Power
- P_0 is the Active Power Reference
- U is the DC Voltage
- $U_{0\nu}$ is the DC Voltage Reference
- k is the Weighting Factor of DC Voltage Control

The active power reference, DC voltage reference and weighting factor are the set values which can be defined by the system operator or at the converter control level. Note that the active power measurement and the DC current measurement are counted positive in the direction to its respective converter station. The control overview of a station is shown in Figure 4-16.

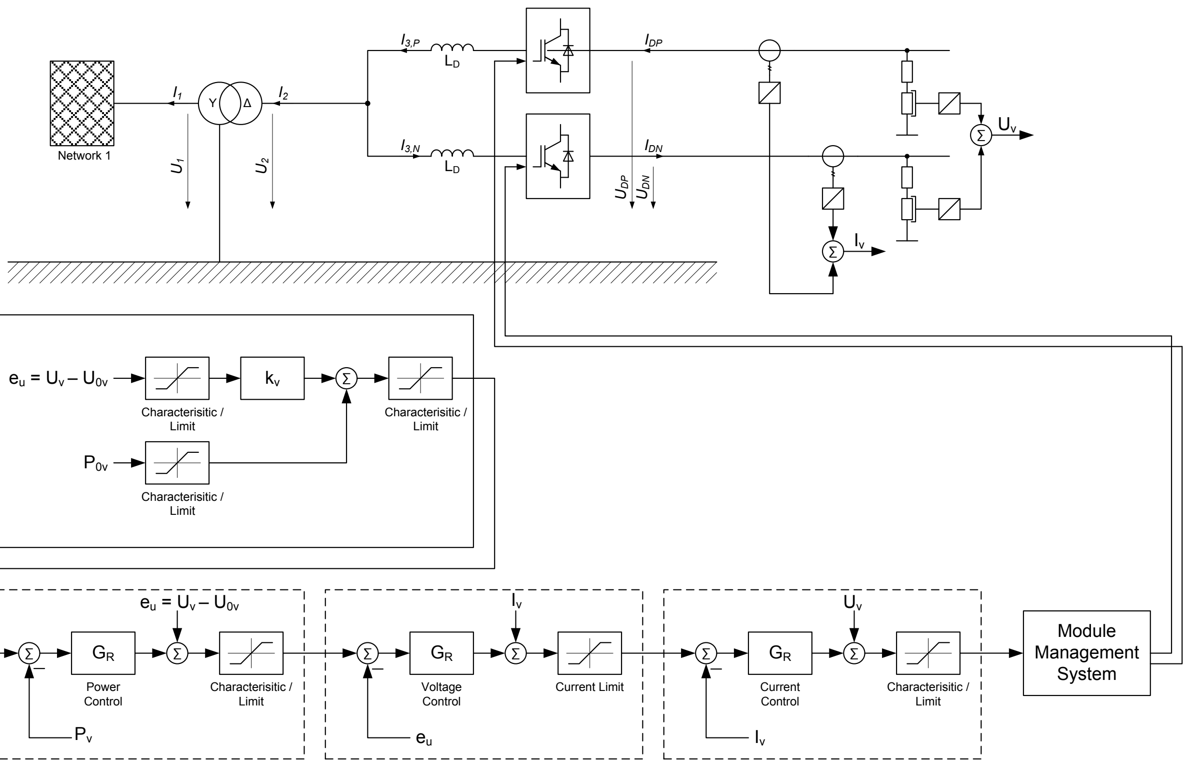


Figure 4-16 — Overview of a Converter Station Controller

From Formula (4-1), the DC voltage can be written as the function of DC current as shown in Formula (4-2):

$$U_{\nu} = \frac{P_{0\nu} - k_{\nu} \cdot U_{0\nu}}{I_{\nu} - k_{\nu}} \tag{4-2}$$

Figure 4-17 shows the voltage-current characteristic of the HVDC Converter Station Controller for different set values P_0. The solid line shows the control characteristic of active power. The dashed line shows a rectangular hyperbolic characteristic according to the following equation, which uses a pure P-control:

$$U_{\nu} = \frac{P_{0\nu}}{I_{\nu}} \tag{4-3}$$

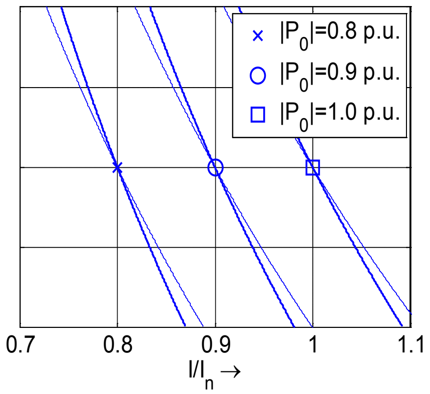


Figure 4-17 — Voltage-Current Characteristic of the HVDC Converter Station Controller

The chosen control characteristic allows a flexible weighting regarding to the DC voltage support via the parameter k_v. For example, if the exporting converter is operating at full load and for any reason the DC voltage increases, the converter control with $k_v > 0$ reacts with a current reduction. The current reduction is greater than that of a pure P-control. The corresponding inverters (with $k_v > 0$) react with an increase of the current, with both effects supporting the voltage stability.

Figure 4-18 shows the control characteristic for the extreme values $k_v = 0$ (pure P-control) and $k_v \to \infty$ (pure U-control). Through the parameter k_v an arbitrary characteristic can be selected between the depicted lines.

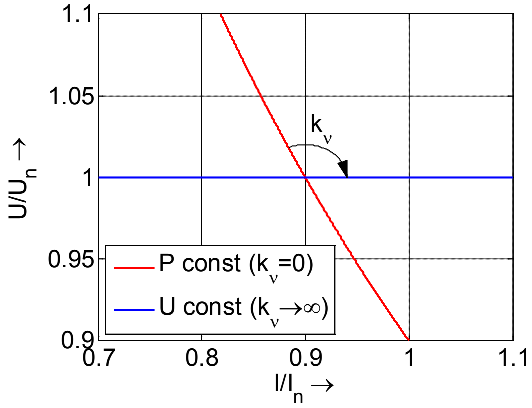


Figure 4-18 — Control Characteristic for $k_v = 0$ and $k_v \to \infty$

A practical Converter Station Controller has to maintain additional boundaries as shown in Figure 4-19. The DC voltage requires to be kept between U_{min} and U_{max}, the active power between P_{min} and P_{max} and the DC current within Imax limits for steady-state operation.

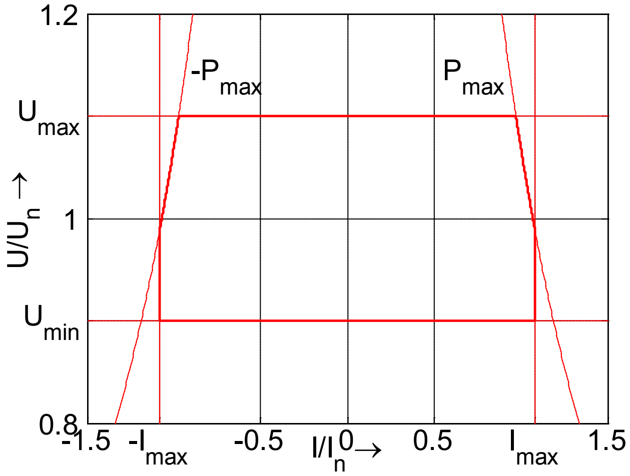


Figure 4-19 — Operating Boundaries for Control

It can be seen that this control concept is independent from the network topology. Therefore, when the transmission lines are added or removed in the future, this control concept is still applicable. Moreover, this control is capable of operating with the delay or loss of communication.

As the above explained concept the operating point of the system shown in Figure 4-15 is shown in Figure 4-20.

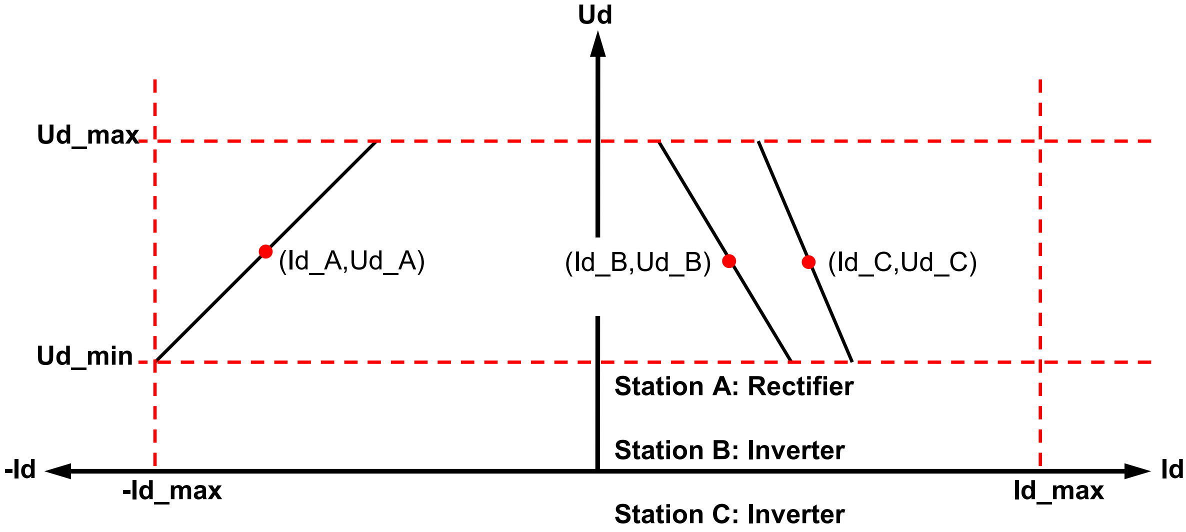


Figure 4-20 — Ud-Id Diagram of a HVDC Grid System

4.7 Benchmark Simulations of Control Concepts

4.7.1 Case Study

Benchmark simulations have been carried out with the following objectives:

- to demonstrate the behaviour of the different HVDC Grid control concepts “Voltage-Power Droop together with Deadbands” (VPDDC), “Voltage-Current Droop” (VCD) and “Voltage-Power Droop” (VPD);

- to investigate possible limitations in combining the different control concepts within one DC circuit;
- to indentify interfaces between the different control concepts and future steps for standardization of HVDC Grid controls.

The configuration and the grid parameters used in the benchmark simulations are shown in Figure 4-21 and Figure 4-22.

The Step responses, power reversal and trip of converters have been investigated. The following control limitations were applied:

- all converter stations had to keep a to given power limit for import and export operation;
- the DC voltage operating band was set to 288 kV ≤ Udc ≤ 320 kV.

Table 4-2 lists the individual benchmark cases analysed.

With the VCD and VPD control concepts, all converter stations contribute to the voltage control according to their respective droop characteristic. The VPDDB control concept normally uses one dedicated station to control the DC voltage. In the present study, terminal C was defined to take this role.

Cases 8 and 10 are described in the following paragraphs; the complete results of the simulations are given in Annex A. Case 8 shows a load rejection in terminal A, case 10 shows a load rejection in terminal C.

For all cases, the AC systems were represented as a voltage source without impedance (infinite short circuit power).

4.7.2 Results

In this subclause, the simulation results for Cases 8 and 10 are presented. The value U shows the DC voltage, I the DC current and P shows the power on the DC side in each station.

Figure 4-23 shows the steady-state values reached after disconnection of terminal A (Case 8).

Figure 4-24 shows the steady-state values reached after disconnection of terminal C (Case 10).

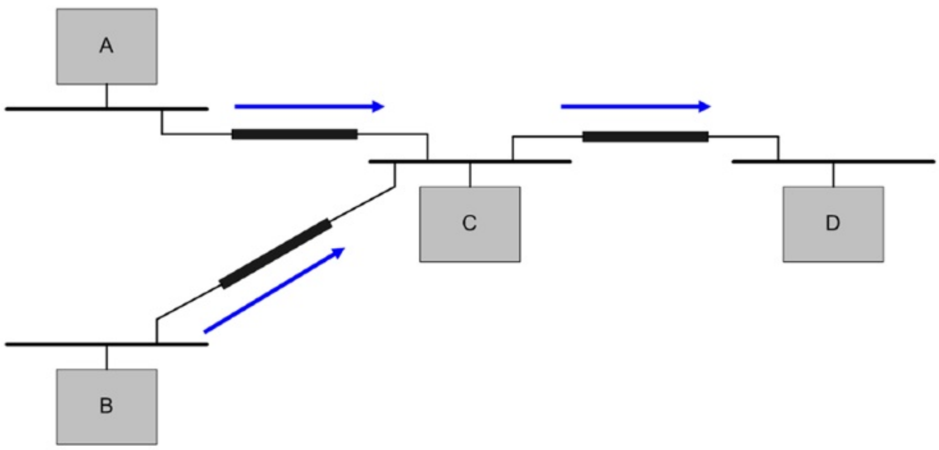


Figure 4-21 — Benchmark Model

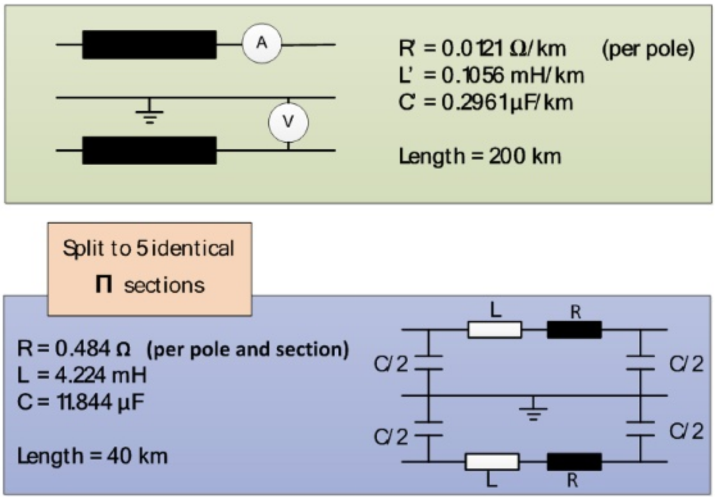


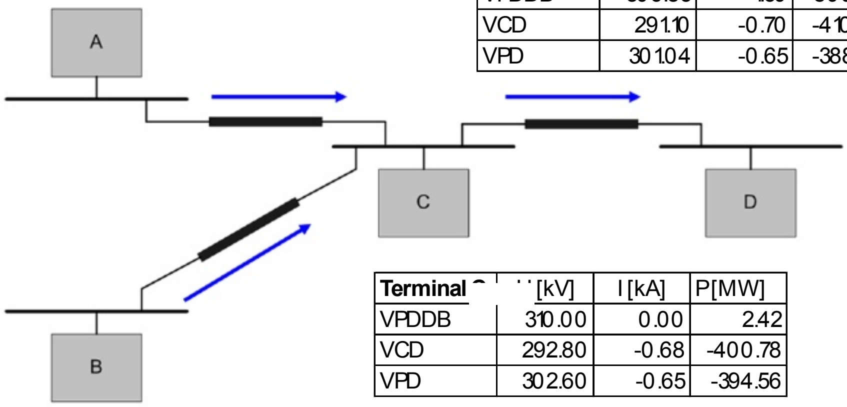
Figure 4-22 — Benchmark grid parameters

Table 4-2 — Benchmark cases

Case	**Pre-Condition**				**Post-Condition**				**Note**
	P_A	**P_B**	**P_C**	**P_D**	**P_A**	**P_B**	**P_C**	**P_D**	
8	800	800	−775	−800	0	?	?	?	**Load Rejection:** Trip Station A
10	800	800	−775	−800	?	?	0	?	**Load Rejection:** Trip Station C

Terminal A	U [kV]	I [kA]	P[MW]
VPDDB	310.00	0.00	0.00
VCD	292.80	0.00	0.00
VPD	288.00	0.00	-0.01

Terminal D	U [kV]	I [kA]	P[MW]
VPDDB	306.85	-1.30	-800.20
VCD	291.10	-0.70	-410.09
VPD	301.04	-0.65	-388.49



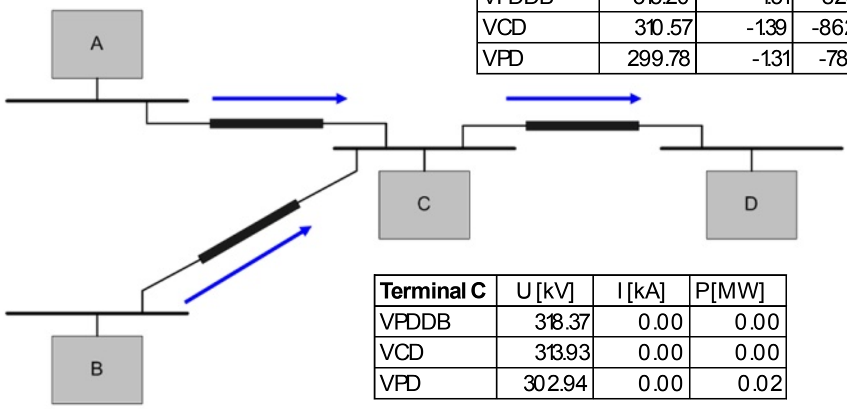
Terminal C	U [kV]	I [kA]	P[MW]
VPDDB	310.00	0.00	2.42
VCD	292.80	-0.68	-400.78
VPD	302.60	-0.65	-394.56

Terminal B	U [kV]	I [kA]	P[MW]
VPDDB	313.15	1.30	814.18
VCD	296.16	1.39	822.61
VPD	305.74	1.30	793.22

Figure 4-23 — Case 8 – Steady State after disconnection of Station A

Terminal A	U [kV]	I [kA]	P[MW]
VPDDB	319.96	0.66	419.15
VCD	315.61	0.69	438.26
VPD	304.52	0.65	397.97

Terminal D	U [kV]	I [kA]	P[MW]
VPDDB	315.20	-1.31	-825.83
VCD	310.57	-1.39	-862.62
VPD	299.78	-1.31	-783.57



Terminal C	U [kV]	I [kA]	P[MW]
VPDDB	318.37	0.00	0.00
VCD	313.93	0.00	0.00
VPD	302.94	0.00	0.02

Terminal B	U [kV]	I [kA]	P[MW]
VPDDB	319.96	0.66	419.15
VCD	315.61	0.69	438.36
VPD	304.52	0.65	397.97

Figure 4-24 — Case 10 – Steady State values after disconnection of Station C

4.7.3 Conclusions

The behaviour of the three different control concepts is stable and well-damped. All control limits are maintained in steady-state, even though short-term overcurrent and over voltages could occur.

Nevertheless, there exist some differences between the behaviour of the three control concepts. The initial converter voltages were not identical for each of the control methods studied. In practice the use of the same HVDC Grid Controller would have given the same initial operating conditions for the different control methods.

The voltage controlling terminal in the Voltage-Power Droop together with Dead Band (VPDDB) control has a significant influence. Depending on the size of the power dead band, the voltage controlling terminal can compensate all disturbances in the HVDC Grid System. Case 10 shows that VPDDB works also without the voltage control terminal. In such a case it behaves similar to the other control strategies.

In the Voltage-Current Droop and Voltage-Power Droop control the terminals start compensating according to their droop constants for the disturbances in the grid. Therefore the imbalances are divided to different terminals. This process lasts until one or more terminals reach their voltage and/or current limits. There after the remaining terminals compensate the remaining imbalances.

4.7.4 Interoperability

There will always be one HVDC Grid Controller. The HVDC Grid Controller will be required to issue different signals depending on the control concept chosen for a converter station and the communication to the different Converter Station Controllers needs to be coordinated.

The benchmark simulation for the different control concepts shows differences in response to a disturbance in the grid. No obvious instability was detected during this study although no mathematical proof for stability can be given by this study.

5 Short-Circuit Currents and Earthing

5.1 General

The probability and frequency of occurrence of short-circuits depends on the nature of the installed equipment (e.g. type of overhead lines or cables) and earthing whereas the amplitude and duration of the current will be influenced by the system design and the control of the converter station. Furthermore these attributes will also influence the steady-state and dynamic characteristics of the short-circuit current.

In general the conditions after the initiation of short-circuits will be largely influenced by:

- the type of converters. There are converters that can control fault currents like the Line Commutated Converter (LCC) or the Full Bridge Voltage Sourced Converter (FB VSC), while others cannot control fault currents, like the Half Bridge Voltage Sourced Converter (HB VSC);

- HVDC Circuit Breakers. Circuit breaker concepts are under development for fast selective fault clearing in HVDC networks and have been presented during the 2011 Cigré Symposium [16];

- the earthing of the DC circuit in case of line-to-earth short-circuits.

The damping of the discharge current is influenced by the resistance of the short-circuit path where the resistance is dependent upon the frequency of the oscillation.

5.2 Calculation of Short-Circuit Currents in HVDC Grid Systems

Short-circuit currents flowing in a DC network will expose the installed DC components to time dependent stresses. In general, the maximum short-circuit currents have to be considered for the assessment of mechanical and thermal stresses, whereas the minimum short-circuit current is relevant for the setting of the system protection. The amplitude of the minimum and maximum currents depends on the topology and the operation of the system as well as on the components of the short-circuit path.

The calculation methods are to be developed by the responsible IEC-Working Group 73.1 “Short-Circuit Calculation”, whereas this Working Group is required to define the basic conditions to perform the calculation and the assessment of the results for the selection of the DC components.

The short-circuit currents at a fault location consist of three different parts:

- discharging of lines (overhead lines and cables) (5.3.2);
- discharging of filters/capacitors (5.3.3);
- contribution of the converter stations (5.3.4).

Whereas the third part can be changed by the type of converters selected and in some cases by the control system of the converter stations, the other parts depend mainly on the total capacitances within the HVDC Grid System (line lengths, configuration of overhead lines and cables, ratings of filters/capacitors).

The current contribution of the converter stations depends on the AC network, type of converter and the system earthing of the HVDC network. Two types of IGBT based converters are currently considered:

- Half Bridge Voltage Sourced Converters (VSC HB);
- Full Bridge Voltage Sourced Converters (VSC FB).

The short-circuit current is influenced greatly by the system earthing. The basics of earthing are discussed in 5.3.5.

The peak value of the discharging current is influenced and reduced by the impedance behaviour of the short-circuit path. The impedance has to be calculated taking the frequency of the short-circuit current into consideration.

Depending on the topology of the systems, the following types of short-circuit currents should be considered:

- line-to-earth short-circuit,
- line-to-line short-circuit,
- line-to-line short-circuit with earth connection.

In general, the amplitude of the short-circuit current depends on the earthing of the system. The following steps have to be considered in detail for the determination of short-circuit currents:

- selection of a typical HVDC Grid System (topology), including earthing and component values (information Subclause 3.2, “Planning Criteria for Topologies”) will determine the maximum/minimum short-circuit current;
- configuration of overhead lines and cables (resistance, reactance and capacitance for the calculation of minimum and maximum short-circuit currents);
- definition of system components which contribute to the short-circuit currents (filters, capacitors, etc.);

- behaviour of converters during a short-circuit: current depending on the fault time (control of the converter stations), impedance of the converter station (AC reactor and transformer impedance);
- operating conditions (voltage, current, power flow) of DC systems (information Subclause 4.2.3.2, Steady State Load Flow Control);
- definition of fault types (single or multiple pole);
- definition of different types of DC short-circuit currents (peak current, breaking current, steady-state short-circuit current, thermal equivalent current) for the selection of the system components;
- specification of typical values of short-circuit currents (fixed values);
- stress of circuit-breakers during and after fault clearing (breaking current, transient recovery voltage).

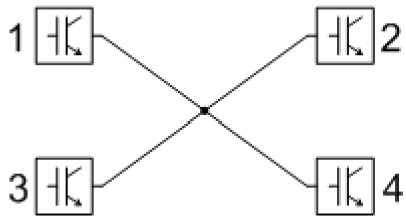
5.3 Network Topologies and their Influence on Short-Circuit Currents

5.3.1 Influence of DC Network Structure

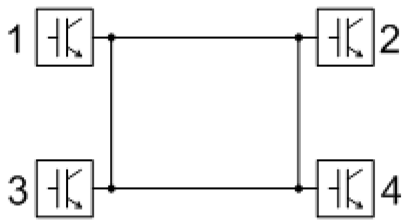
The network topology will influence the behaviour of the short circuit current. The basic network topologies are:

- point-to-point connection, Figure 5-1 a);
- radial structure, Figure 5-1 b);
- meshed grid, Figure 5-1 c).

a) Point-to-point connection



b) Radial structure



c) Meshed grid

Figure 5-1 — Topologies of HVDC Grid Systems

The network structure itself has a significant impact on the maximum possible amplitude of the short-circuit current (fault level) within an HVDC network. Generally the overall behaviour corresponds to AC network structures and the maximum amplitude of the short-circuit current rises for a higher number of converter stations.

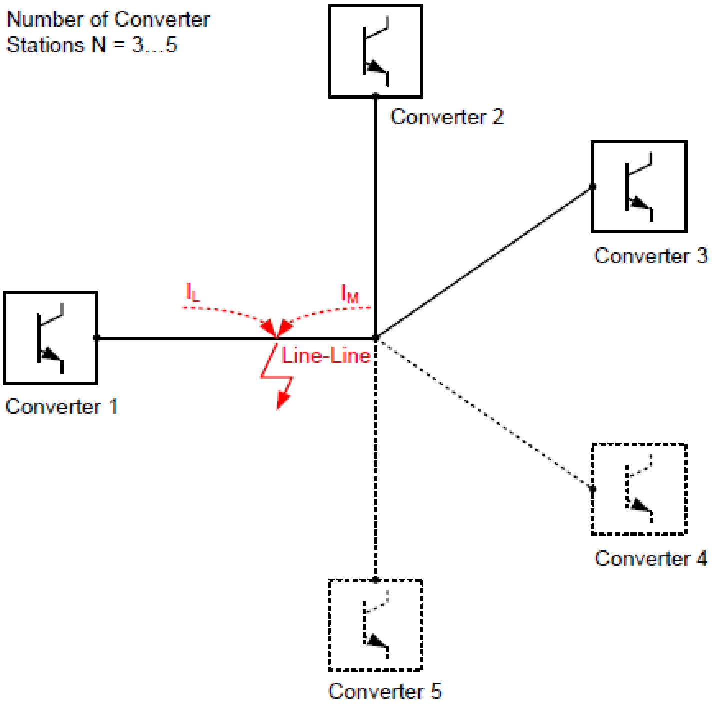


Figure 5-2 — Short-circuit current in a radial network topology with a variable number of converter stations

Figure 5-2 shows a radial network topology for a variable number of HVDC converter stations. The maximum amplitude of the short-circuit current within the HVDC Grid System is evaluated. It is assumed that the length of all DC lines is identical. A line-to-line short-circuit is considered at the remote end of the line connecting converter station 1 with the DC line interconnection point. The short-circuit currents flowing from both sides, towards the fault location, are identified.

Maximum line short-circuit current I_L and maximum short-circuit current I_M from DC line interconnection point are calculated according to Formulae (5-1) and (5-2):

$$I_L = I_C \cdot K_D \tag{5-1}$$

$$I_M = \sum_{i=2}^{N} \left(I_{ci} * K_{Di} \right) \tag{5-2}$$

where

I_{ci} is the maximum short-circuit current contribution of converter i (steady-state);

K_{Di} is the DC cable i damping (reduction factor);

N is the number of converter stations.

The maximum amplitude of short-circuit current contributions of the individual converter I_C depends on the following factors:

- AC grid short-circuit impedance;
- converter transformer;
- converter type (see 4.3.5);

- converter parameters (e.g. IGBT, thyristors, control system).

In general both I_L and I_M have to be determined for rating of the equipment, e.g. a DC circuit-breaker: The calculated I_M according to Formula (5-2) has to be used to determine the rating of the equipment associated with the converter, whereas for the substation bus rating, the sum of the current (I_L + I_M) according to Figure 5-2 has to be taken into consideration.

Depending on the topology of a HVDC Grid System the resultant short-circuit current can be higher in a meshed system in comparison to a radial system.

5.3.2 Influence of Line Discharge

This section deals with the discharge of DC lines in case of a short-circuit between lines and earth, the contribution of converters and DC capacitors are not considered. The relevant network topologies are illustrated in Figure 5-1.

Figure 5-3 shows the resultant short-circuit current in case of a fault between line conductor and earth. A DC cable is assumed to have its shield earthed at the sending and the receiving end. Furthermore the cable length is taken into consideration as this affects the oscillation of the current.

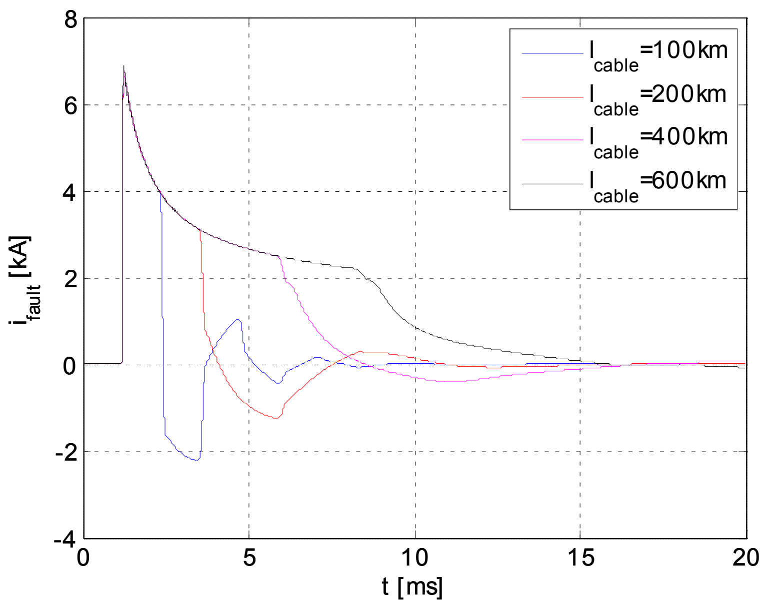


Figure 5-3 — Example of Short-circuit current for a line-to-earth fault (earthed cable shield and point-to-point connection)

The following effects can be derived from Figure 5-3:

- The initial peak current can be estimated by using the surge impedance of the line. In the example case, the current return path (earth and cable shield) has to be taken into consideration. According to Figure 5-3, the peak short-circuit-current is calculated to be 6,9 kA, based on a Voltage U_{DC} = 200 kV and a surge impedance of the cable Z_c = 28,8 Ω.

- For relatively short line lengths, the influence of the reflected wave (reaching the fault location after two times the propagation time corresponding to the line length) is obvious due to the reflection factor of r = −1 at the fault location.

An overhead line would lead to a somewhat different result to that of a cable. The higher surge impedance of an overhead line gives a corresponding reduction in the first peak of the short circuit current. Moreover, the surge propagation speed of overhead lines is higher than those of cables; this is due to the dielectric constant of air compared to the insulation material of cables.

A DC line consisting of a combination of a cable and an overhead line can give rise to a particular short-circuit current waveform depending upon the exact line configuration. If a fault occurs on the cable, the discharge current coming from the side of the overhead line behaves similar to the case where the cable is open-ended (due to the relatively high values of the surge impedance). If the fault occurs on the overhead line instead, the reflection factor at the overhead line/cable interface is positive and relatively high, resulting in a short-circuit current that builds up with every subsequent reflection. The effect is stronger for shorter overhead line sections between the fault and the cable. This is illustrated in Figure 5-4.

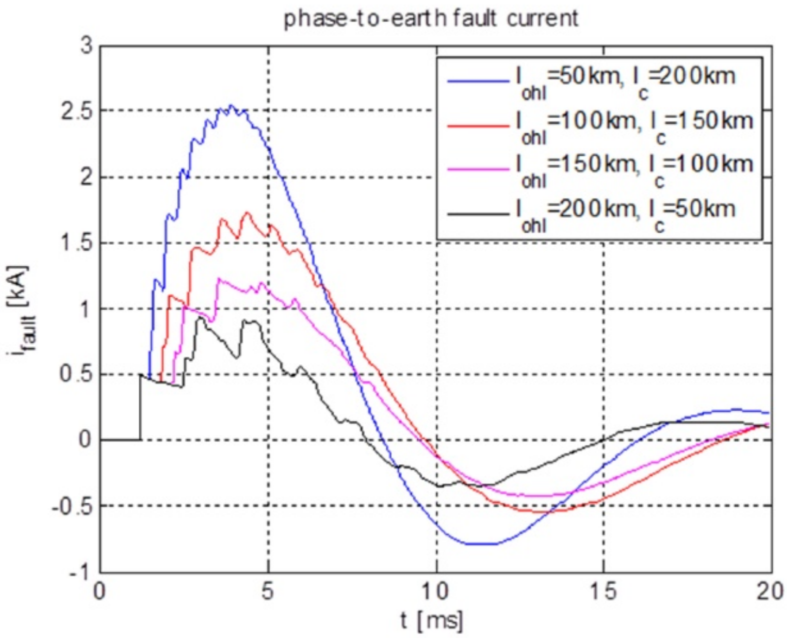


Figure 5-4 — Example of Short-circuit current in case of a line-to-earth fault at an overhead line for a combined overhead line/cable connection (earthed cable shield and point-to-point connection)

Additionally, the following influence the amplitude and the shape of the short-circuit currents and consequently have to be taken into consideration:

- The line length influences the frequency of the discharge.
- The resistance of the short-circuit path is influenced by the frequency (skin effect) and in consequence, the amplitude of the current is reduced and the oscillation is damped.
- The current return has to be considered depending on the fault type, e.g. via earth in case of an overhead line or via cable shield and earth in case of a cable system. The total loop impedance is influenced by the frequency of the discharge.

5.3.3 Influence of Capacitors

Figure 5-5 shows the equivalent circuit of a capacitor which contributes to the short-circuit current.

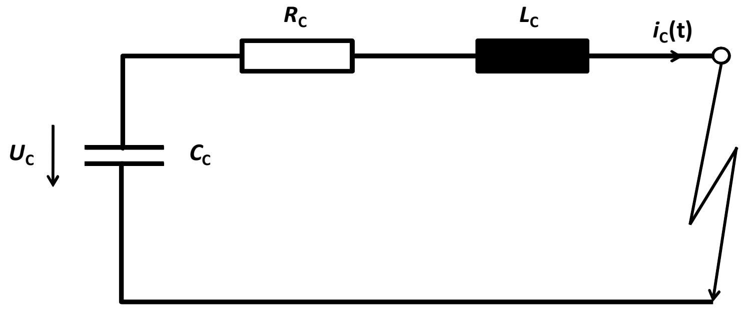


Figure 5-5 — Equivalent circuit of a capacitor bank

The capacitor bank is represented by a RLC-circuit with the resistance (R_c) and inductance (L_c) of the capacitor (C_c). The analytic solution of the discharge current can be calculated according to Formula (5-3):

$$i_C(t) \approx \frac{U_C}{L \cdot \omega_0} \cdot e^{-\delta \cdot t} \cdot \sin(\omega_0 \cdot t) \qquad (5\text{-}3)$$

where

$\omega_0^2 >> \delta^2$

where

ω_0 is the eigenfrequency of the circuit;

δ is the damping time constant $\left(= R/(2 \cdot L_C)\right)$.

Figure 5-6 represents the transient behaviour of the discharge current in the case of a short-circuit across the terminals of a capacitor. The discharge current has a sinusoidal behaviour with an exponential component. In case of larger capacitor values the oscillating characteristic is suppressed and only the first half cycle of the sine wave is apparent. In Figure 5-6, the short-circuit occurs directly at the terminals of the capacitors, the parameters are: U_{DC} = 100 kV; C_C = 500 µF; R_C = 2,4 mΩ; L_C = 35,4 nH.

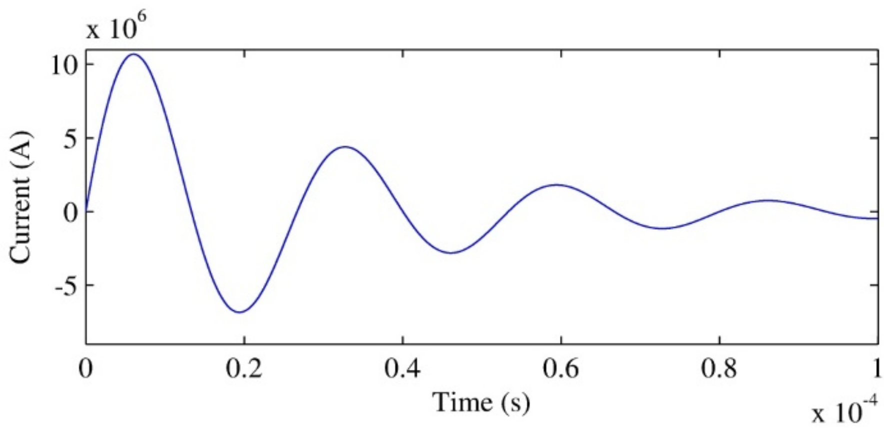


Figure 5-6 — Example of the Contribution of a capacitor to a short-circuit current

5.3.4 Contribution of Converter Stations

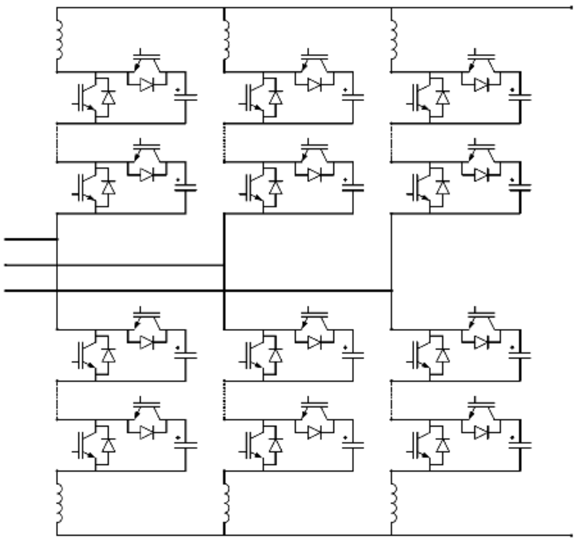
The Study Group considered two different types of VSCs for VSC transmission systems today:

- modular Multilevel Converter Half Bridge type (MMC HB, Figure 5-7 a));
- modular Multilevel Converter Full Bridge type (MMC FB, Figure 5-7 b)).

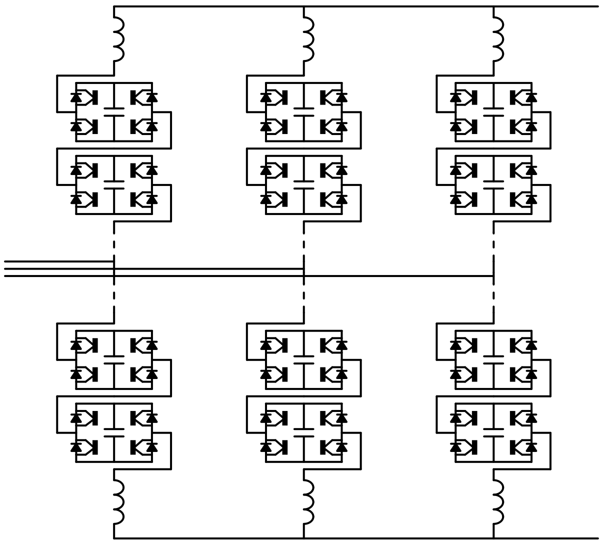
The two types of converters result in different characteristic short-circuit behaviour of the HVDC Grid System. While, in all VSCs, the IGBTs are typically blocked in case of a short-circuit fault, half bridge type MMCs behave differently compared to full bridge type MMCs. The free-wheeling diodes in the half bridge converters becoming uncontrolled rectifier bridges and feed a DC side short-circuit from the AC system. This is not the case in full bridge type MMCs where the IGBT diodes are in series with module capacitors. On blocking the IGBT's the fault current will flow through the transformer and converter valve reactance and all of the limb modules with their diodes in series with the module capacitor. However the combined module capacitor voltage polarity is in opposition to, and greater than that of, the peak AC system voltage, and will therefore oppose, and reduce, the current flow through the module to zero. It should be noted that the fault current flowing in the DC system is energy stored in the system inductance and this will be transferred to the module capacitors during the blocking process. This produces an increase in the module capacitor voltage which has to be considered in the design of the full bridge type MMC module.

The full bridge converter can resume power flow when the faulted equipment has been disconnected and isolated from the remaining (healthy) sections of the grid.

A full description of the behaviour of a full bridge type MMCs is given in [17].



a) MMC Half Bridge (MMC HB)



b) MMC Full Bridge (MMC FB)

Figure 5-7 — Current Types of converters

For the calculation of the short-circuit current the equivalent circuit according to Figure 5-8 can be used. The parameters R_{AC} and X_{AC} represent the impedance of the AC system, including the AC networks, power transformer, and the converter (including reactors). The typical X/R ratio of converter station is in the range of X/R = 60 – 75. The resistance R_{DC} and the inductance L_{DC} represent the parameters of the converter and the DC smoothing reactor (DC system).

In general the steady-state short-circuit current I_{kDC} on the converter DC side can be calculated according to Formula (5-4) [18]:

$$I_{kDC} = \lambda_{DC} \cdot \frac{3 \cdot \sqrt{2}}{\pi} \cdot \frac{c \cdot U_n}{\sqrt{3} \cdot Z_{AC}} \cdot \frac{U_{rTLV}}{U_{rTHV}} \quad (5\text{-}4)$$

where

U_{rTLV}/U_{rTHV} is the transformer voltage ratio;

Z_{AC} is the impedance of the AC system;

λ_{DC} is the factor, depending on the relationships R_{AC}/X_{AC} and R_{DC}/R_{AC} [18];

c is the voltage factor according to EN 60909-0 [19];

U_n is the nominal system voltage of the AC system.

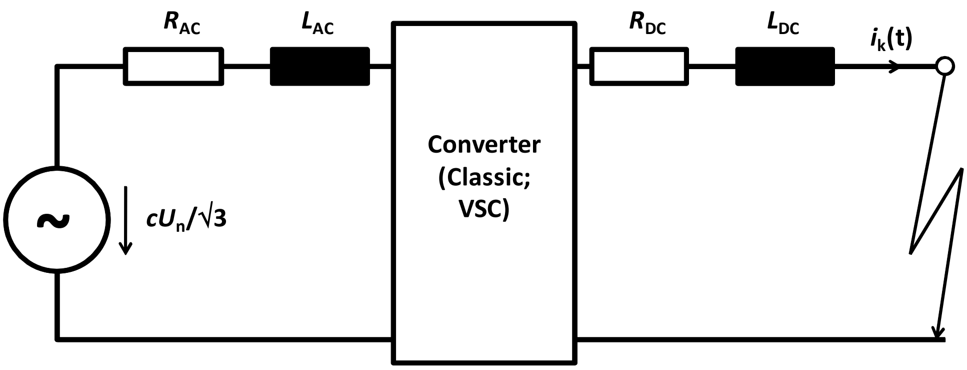


Figure 5-8 — Equivalent circuit of the converter for the short-circuit calculation

The examples described above consider monopolar configurations. Typical short circuit current wave shapes are shown in Figure 5-9 and Figure 5-10 and described in the following paragraphs.

– **Half Bridge Type MMC:**

In case of a short-circuit current the IGBTs in this type of VSCs are blocked, as soon as a corresponding threshold of the valve current is exceeded. This results in the short-circuit current being fed by the free-wheeling diode bridge of the converter. In this case the VSC-converter behaves like a three-phase bridge equipped with diodes or an uncontrolled Thyristors bridge. The DC capacitors of the converters remain charged and do not contribute to the short-circuit current.

Figure 5-9 shows the final current behaviour in case of a short-circuit. The Parameters of the simulated case are: U_{DC} = 100 kV; U_{T1}/U_{T2} = 120 kV/62 kV; S_r = 600 MVA.

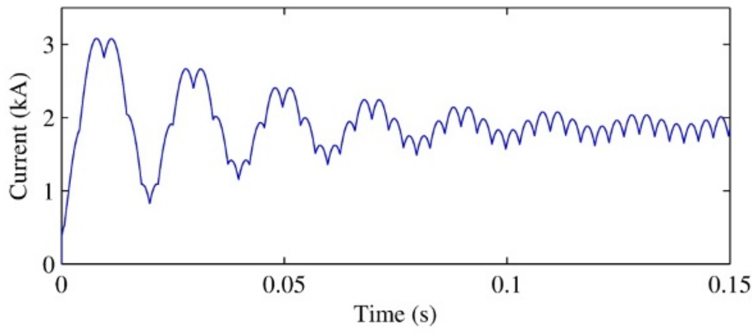


Figure 5-9 — DC side short-circuit current of a MCC Half Bridge type Converter [20]

– **Full Bridge Type MMC:**

Figure 5-10 shows a DC terminal to ground fault at the rectifier converter. A full bridge converter can successfully block high fault currents. The parameters for the simulated case are: P_{DC} = 600 MW; U_{DC} = ± 300 kV.

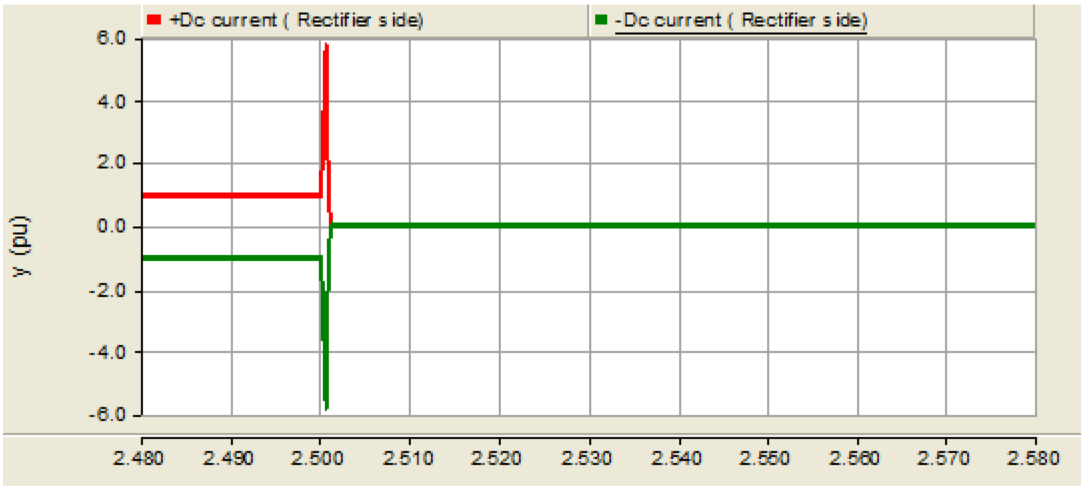


Figure 5-10 — DC side short-circuit current of a MMC Full Bridge type converter

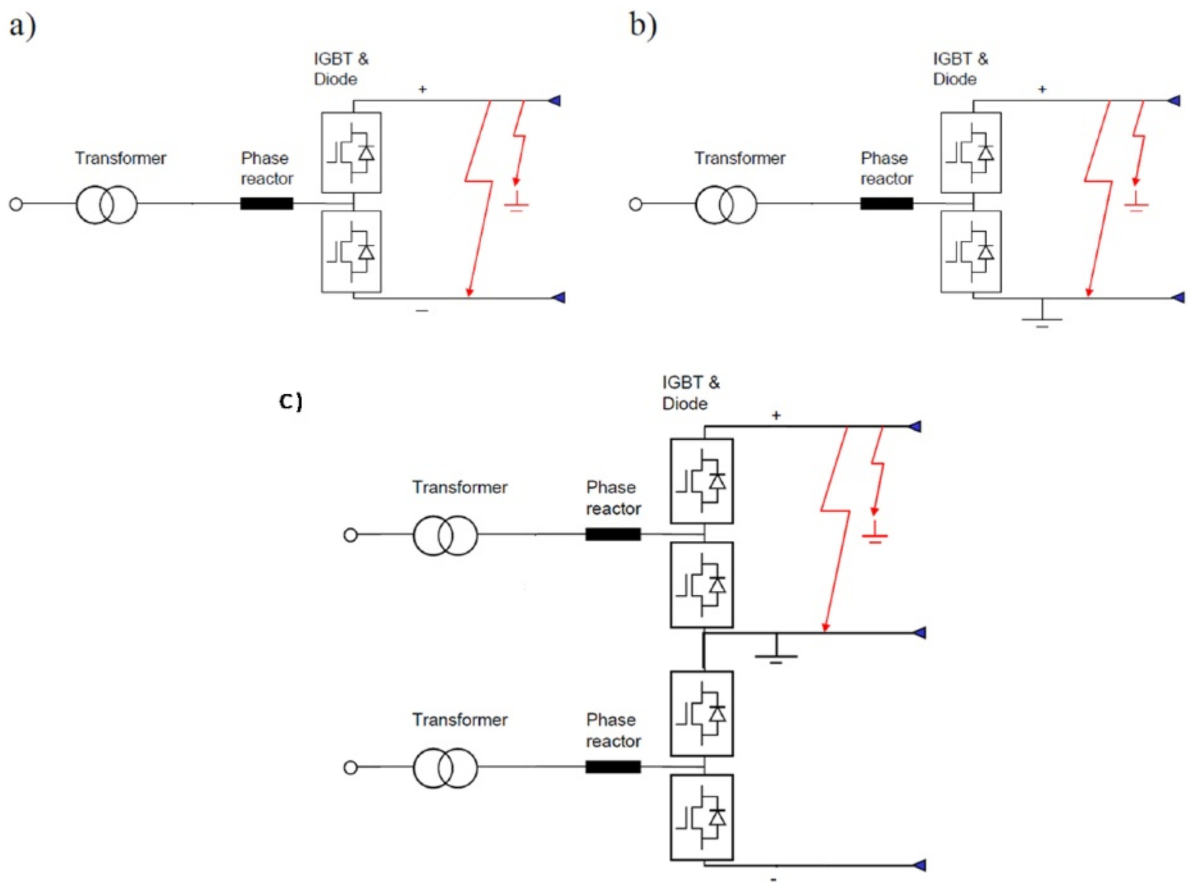
Further information concerning the fault behaviour of Full Bridge Type MMC is given in Annex B.

5.3.5 Methods of Earthing

The methods of earthing will influence the short-circuit current, if the earthing system is involved in the short circuit path. With respect to earthing, the following types of networks are considered:

- Symmetric Monopole;
- Asymmetric Monopole;
- Bipole.

In principle different grounding schemes of the converter bridge are possible, as shown in Figure 5-11.



Key

a) symmetric monopole

b) asymmetric monopole

c) bipole configuration

Figure 5-11 — DC line fault cases and grounding methods of the DC circuit

Depending on the grounding system different effects can be observed and these influence the short-circuit current:

- If the midpoint is isolated (symmetrical configuration of the DC side, Figure 5-11 a)), high short-circuit currents will flow in event of pole-to-pole faults. Single pole-to-ground faults will result in lower short circuit currents determined by the grounding impedance, which will be typically high ohmic in this configuration. Without any countermeasures, single pole-to-ground faults will result in a DC voltage unbalance causing the un-faulted pole being charged to twice the normal operating voltage. Full Bridge type MMCs can prevent this by appropriate control of the converters.

- In case of asymmetric configurations, faults between pole-to-pole and pole-to-ground will produce high short circuit currents. Asymmetric configurations correspond to low impedance grounding (Figure 5-11 b) and c)).

5.4 Secondary Conditions for Calculating the Maximum/Minimum Short-Circuit Current

The following secondary conditions have to be taken into consideration to evaluate the maximum or minimum short circuit-current in DC networks:

a) maximum short-circuit current:

1) system configuration and maximum contribution from converter stations and DC network feeders which lead to the maximum value of short-circuit current at the short-circuit location, or for accepted sectioning of the network to control the short-circuit current;

2) voltage factor c_{max} of the AC network shall be applied, see Formula (5-4);

3) maximum operational voltage of the DC network (the tap-changer position of the converter transformer is included);

4) when equivalent impedances Z_{AC} are used to represent external networks, the minimum equivalent short-circuit impedance shall be used which corresponds to the maximum short-circuit current contribution from the network feeders;

5) resistance R_L of lines (overhead lines and cables) are to be introduced at a temperature of 20 °C;

b) minimum short-circuit current:

1) system configuration and minimum contribution from converter stations and DC network feeders which lead to the minimum value of short-circuit current at the short-circuit location;

2) voltage factor c_{min} of the AC network shall be applied, see Formula (5-4);

3) minimum operational voltage of the DC network (the tap-changer position of the converter station transformer is included);

4) when equivalent impedances Z_{AC} are used to represent external networks, the maximum equivalent short-circuit impedance corresponding to the minimum short-circuit current contribution from the network feeders shall be used;

5) resistances R_L of lines (overhead lines and cables) at the temperature at the end of the short-circuit shall be introduced.

5.5 Calculation of the Total Short-Circuit Current (Super Position Method)

A complete calculation of the short-circuit currents provides details of the time variation of the currents at the short-circuit location, from the initiation of the short circuit to its end. The total short-circuit current at the short-circuit location may be the result of the contribution of several different sources. Due to many variations of current and the nonlinearity of equipment, such calculations can only be performed by numerical means. Consequently only calculation of characteristic quantities is dealt with.

With reference to Bibliographical Entry [18], Figure 5-12 shows the standard approximation function which covers the different current variations.

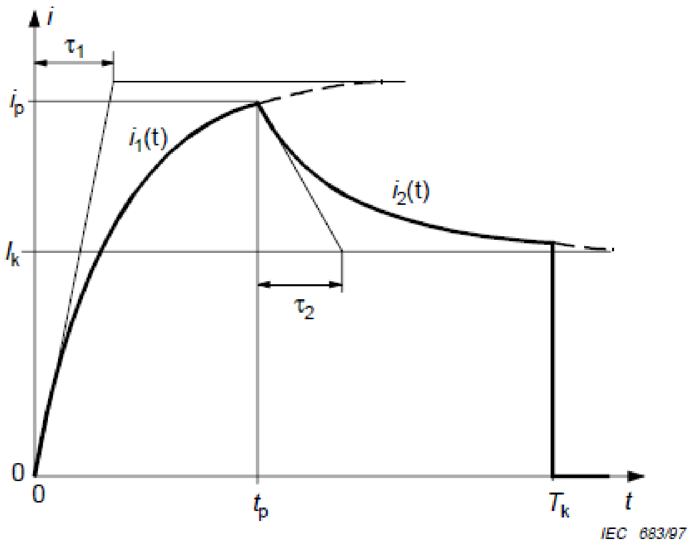


Figure 5-12 — Standard approximation function according to [18]

According to Figure 5-12, the following parameters can be defined:

I_k is the quasi steady-state short-circuit current;

i_p is the peak short-circuit current;

T_k is the short-circuit duration;

t_p is the time to peak;

τ_1 is the rise-time constant;

τ_2 is the decay-time constant.

By calculating the characteristic quantities for the time variation of the short-circuit current according to Figure 5-12, the mechanical and thermal short-circuit stresses can be ascertained.

5.6 Reduction of Short-Circuit Currents

The short-circuit current in HVDC Grid Systems can be reduced by several planning measures, for example:

- Clearing of meshed systems (Figure 5-13 a)): In this case the total HVDC Grid System will be separated into separate DC circuits, which are connected to different busbars. Consequently, the short-circuit current is only limited to one system.

- Current limiting reactors (Figure 5-13 b)): If a current limiting reactor is installed the rate of rise of the short circuit current (di/dt) is reduced. The disadvantage is that the resistance of the reactor will give additional power losses and the TRV (Transient Recovery Voltage) is increased in case of a short-circuit current interruption by a DC circuit-breaker depending on the fault location. The maximum size of the reactor will be determined by the dynamic requirements of the system and the rating of the equipment.

- High speed decoupling (Figure 5-13 c)): The busbars should be separated by a high speed device before the maximum (peak) current occurs. The high speed decoupling will mainly reduce the short-circuit current of the converters whereas the line discharge current should not be influenced due to the current shape (e.g. Figure 5-3). Consequently the design of each of the dc subsystems has to be performed according to the maximum partial short-circuit current of each system.

- HVDC link (Figure 5-13 d)): The contribution to a short-circuit current of a connected HVDC Grid System is controlled by the type of converters, e.g. MMC Full Bridge.

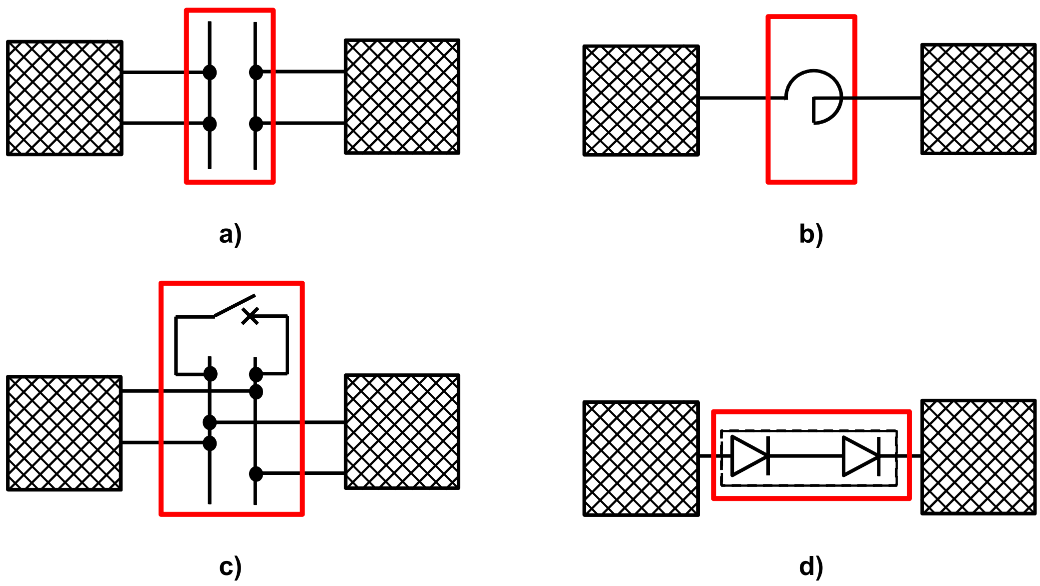


Figure 5.13 — Measures to reduce short-circuit currents (Single line diagrams)
a) system separation
b) current limiting reactor
c) high-speed decoupling
d) HVDC link

6 Principles of HVDC Grid Protection

6.1 General

All protection systems need to be selective and operate for a fault within its protective zone as well as not operate for faults outside its protective zone. A HVDC Grid System consisting of several converters requires greater emphasis for selectivity in the DC protection than a transmission system with two stations. The selectivity is required to allow both identification and subsequent removal of a faulty part and to permit continued operation of the remainder of the HVDC Grid System. The protection system is therefore dependent upon the configuration of the HVDC Grid System, including earthing principles, and the need for separation.

In designing and specifying the protection system the following points have to be considered in detail:

- selection of typical DC systems (layout), including earthing, overhead lines and cables;
- behaviour of converters for earth faults and short circuits;
- operating conditions of DC systems (voltage, current, power flow);
- definition of fault types (converter faults, AC faults or DC system faults);
- benefits of DC circuit-breakers for fault clearing;
- impact from communication.

6.2 HVDC Grid System

The HVDC Grid System consists of a number of HVDC converters connected to a common DC circuit (Figure 6-1). The DC circuit consists of cables and/or overhead lines, DC switchgear and other DC components. The DC switchgear can have either DC breaking capability or only a disconnecting function.

The DC protections are dependent upon the specific requirements on the isolation and selectivity of the system following a fault. The following requirements should be defined by the HVDC Grid System operator(s):

- no requirements on fast dynamic isolation;
- with requirements on fast dynamic isolation.

Dynamic isolation is defined here as isolation of a faulty DC section without interrupting operation on other parts of the HVDC Grid System. See Figure 6-1 below. Where there are no requirements on fast dynamic isolation a temporary stop is accepted for manual control of reconfiguration of the HVDC Grid System after a fault.

Conventional converter protections and breakers can be used to detect and isolate converter faults for most of the faults that can occur in the DC converter and connected AC system. The primary concern regarding protections in a HVDC Grid System is the response to earth faults in the DC System.

A DC side earth fault on cables could be caused by mechanical damage from ship anchors or trawlers in offshore environments and by construction excavation for land installations. Faults due to these causes or internal cable insulation failures, are rare events in cable systems. However, flashovers on overhead lines, which can be caused by thunderstorms and lightning strikes, could be more frequent. For systems not requiring fast dynamic isolations, conventional DC side protections and isolation breakers can be used to detect and isolate also DC side earth faults.

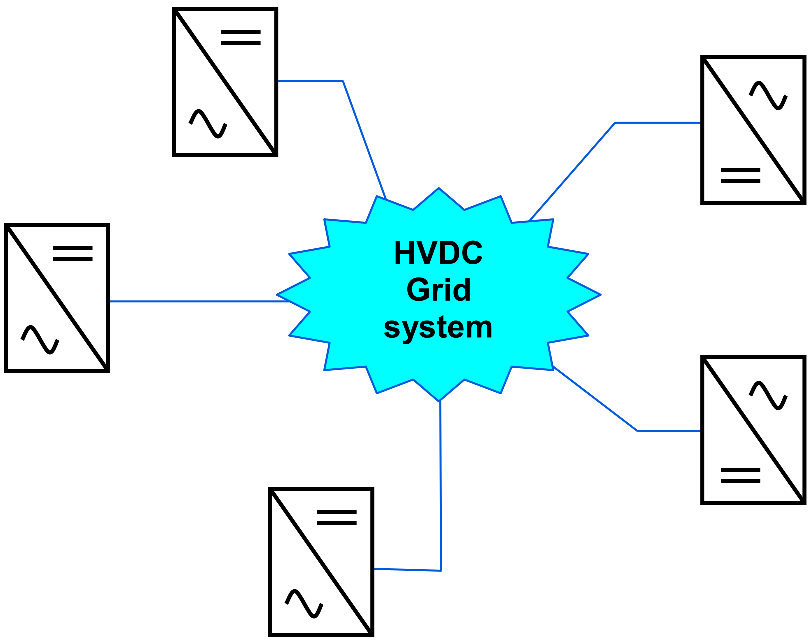


Figure 6-1 — Principle structure of a HVDC Grid System

A method to categorize the requirement on fast dynamic isolation following DC side earth faults is to analyse the acceptable outage times, i.e. the time from fault to recovery of power transfer: This has to be defined by the operators of the AC systems connected to the DC system. Typical categories are illustrated in Table 6-1.

Table 6-1 — Fault isolation time and breaking device type required

Fault isolation time	Breaking device type needed
< few ms	Fast dynamic isolation is needed.
< 100 ms	Mechanical HVDC breakers are needed.
< few sec	Conventional AC breakers are needed. The term High Speed Switches are often used.

The HVDC Grid System can either be asymmetrical (low impedance earthed) or symmetrical (high ohmic earthed or capacitively earthed). In case it is an asymmetrical system monopolar or bipolar operation is possible. A bipolar system should, from a protection point of view be treated as two separate monopolar systems, i.e. be as independent as possible. The protection concepts described in this section are applicable both for symmetrical as well as asymmetrical systems.

6.3 AC/DC Converter

6.3.1 General

There are different design topologies for VSC converter, or the VSC converter can be complemented with additional components, which could give the converter different behaviour during a fault clearing action. The basic concept of HVDC Grid System protections described in this section does not depend on the type of VSC converter but the speed of detection and interruption. However, clearance and speed of recovery may be affected. Furthermore, the amplitude of fault currents and over voltages are dependent on the topology and earthing of the converters.

The typical configurations are:

- VSC Converters based on half bridge topology (with an inherent uncontrolled diode bridge). Fault currents are cleared by the AC breakers of all converters;
- VSC Converters based on half bridge topology with a HVDC breaker in series with the converter. Fault currents on the DC side are cleared by the HVDC breaker;
- VSC Converters based on full bridge topology with the ability to extinguish, or control, fault current by control action.

Each of the converters connected in a HVDC Grid System shall have its own independent set of protections. In this context the converter is defined as having a single point of common connection (PCC DC) to the DC grid, similar to a point of common connection on the AC side (PCC AC) per pole if applicable, i.e. no DC switchgear is included in the converter. The only DC switchgear expected to be part of the converter is an isolation switch, other switchgear is defined as being part of the DC system.

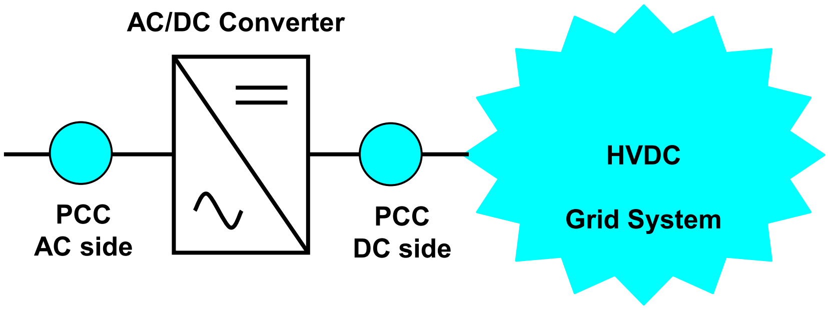


Figure 6-2 — Definition of the Points of Common Connection on the AC and DC side

The requirements on the converter and its control and protection system can be summarized as follows:

- the converter protections should be able to distinguish between internal converter faults and HVDC Grid System including other converter faults and AC system faults;
- with the exception of DC earth faults, the converter should be self-protected, i.e. it should not rely on the HVDC Grid System's protection;
- the converter should self-protect against AC system faults;
- a converter DC isolation failure scheme should be implemented;
- with the exception of power transfer capability, the HVDC Grid System should not, be affected by a fault in the AC network connected to a converter.

With the exception of the isolation failure scheme, the above requirements should be independent of communication with the HVDC Grid System or other converters.

6.3.2 DC System

The HVDC Grid System consists of:

a) HVDC Transmission System;

   1) cables;

   2) overhead lines;

b) HVDC switchyard, which could be connected as a:

   1) single bus;

   2) double bus.

The HVDC Grid System can be connected in different network configurations:

- meshed networks;
- radial systems;
- a combination of the above.

6.3.3 HVDC Switchyard

The HVDC switchyard can include:

a) HVDC breakers:

   1) mechanical HVDC breakers;

   2) semiconductor based HVDC breakers (breaking device is a semiconductor, e.g. IGBT valve);

   3) hybrid HVDC breakers (combination of mechanical and semiconductor breaking device);

b) disconnecting breakers:

   1) high speed switches (i.e. mechanical breakers);

   2) disconnectors;

c) measurement equipment, earthing switches and arresters.

6.3.4 HVDC System without Fast Dynamic Isolation

If there are no requirements for dynamic isolation, or the fault clearance times are considered long, conventional DC converter protections will be sufficient for all kinds of DC systems. An earth fault in the DC system will be detected by the converter protections and clear the fault by blocking the respective converter and open the connected AC circuit breaker. Thereby the fault will be cleared and, after a period of time, the DC system will be available and ready for starting the recovery sequence.

By measuring the direction of fault currents on each section ends on the DC system and sending this information to an earth fault location identification system, the faulty section or converter has to be identified before the fault current is interrupted by all connected DC converters. Determining the fault location is (equal to demands on the isolation itself) not time critical and can be done during or even after the fault clearing in the earth fault location identification system. Once the faulted section has been identified it can be isolated and a restart of the healthy part of the HVDC Grid System can take place. If the earth fault location identification system is out of service, the identification and recovery sequence has to be carried out manually by the DC system operators. The restoration of the grid could take minutes if conventional disconnectors are used or less than a few seconds if high speed switches (HSS) are used.

An alternative method to clearing faults in the DC system, is to use conventional mechanical HVDC breakers instead of opening the converters AC breakers. The basic principle will be the same but the outage time can be made shorter (<100 ms) as the fault can be isolated by opening only the breakers adjacent to the affected equipment. Another benefit is that the HVDC breaker has a capability to interrupt any trapped inductive current.

The re-energization sequence is initiated by the system operators once the connected AC systems are ready. However re-energization of the healthy HVDC Grid System will give rise to converter inrush currents which need to be considered. Including pre-insertion resistors on the connecting breakers is one method to limit the inrush currents.

6.3.5 HVDC System with Fast Dynamic Isolation

Fast dynamic isolation, which has the capability to isolate the faulty section from the remaining healthy HVDC Grid System, requires fast DC breaking devices with operating times of a few milliseconds. The DC breaking devices can be DC Circuit Breakers or VSC with fault current blocking capability in combination with fast disconnecting switches (HSS).

The protection operating time requirement is normally faster than can be achieved with communication. Therefore the system should work without communication and this imposes special requirements on the protection system to handle selectivity on the HVDC Grid System. However if the HVDC Grid System is connected in one physical location, i.e. a star connection, conventional DC protections should be sufficient.

6.4 DC Protection

6.4.1 General

The protective clearance and tripping of a fault has three important purposes:

a) to minimize hazard to personnel;

b) to minimize disturbance to operation;

c) to minimizing the risk of damage of equipment and buildings.

The safety aspect a) will always have the highest priority.

The higher the power transfer of the system is, the higher is the priority for b) to minimize the consequences to operation. The cost of outages could be significant and this should be evaluated based on the likelihood for the faults and the expected outage times. Consequently, the availability of spares is important as this will impact upon the outage time.

6.4.2 DC Converter Protections

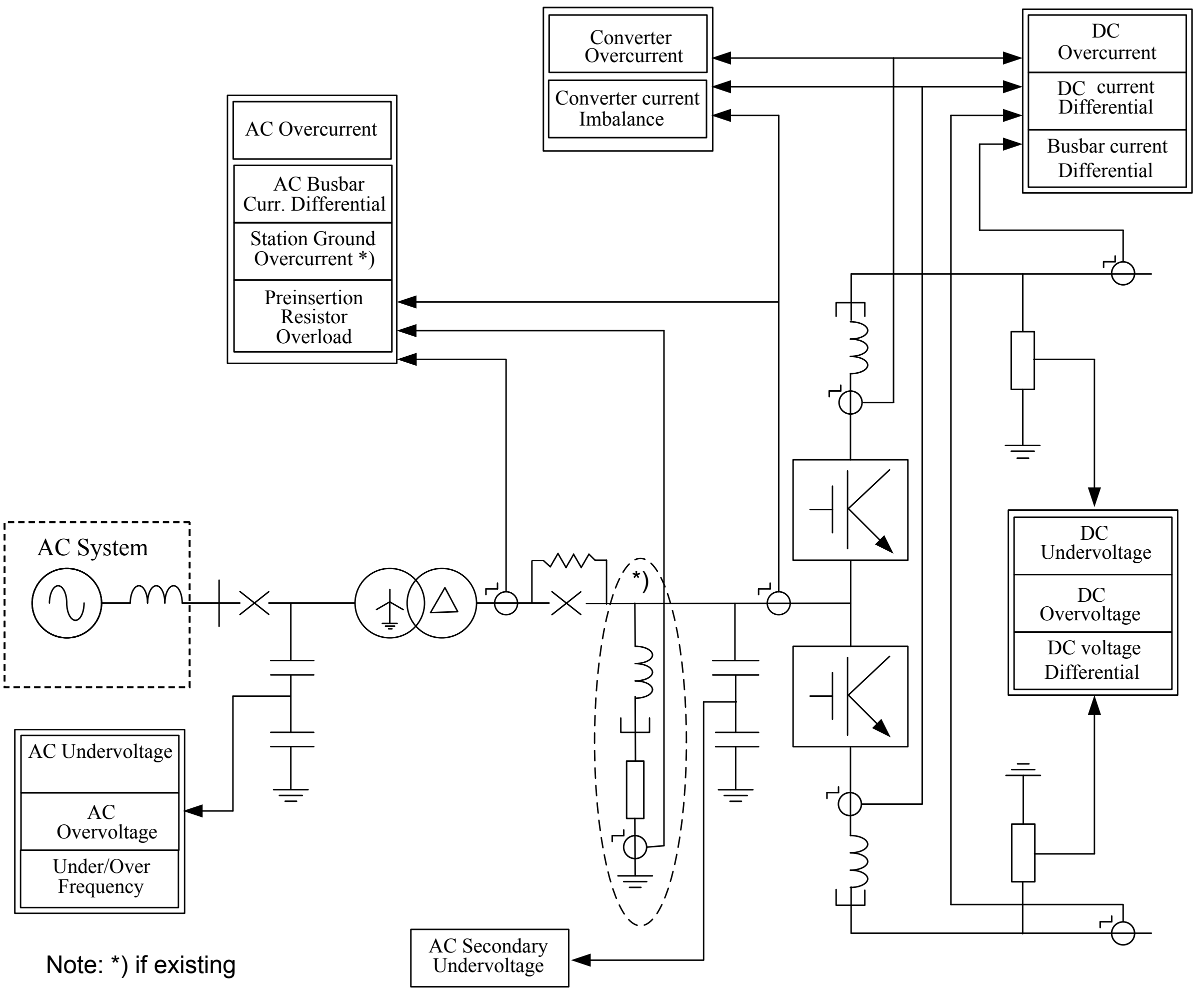
Figure 6-3 shows a typical protection scheme for a symmetrical monopole VSC Converter. An asymmetrical converter will have the same principle set of protections with the DC unbalance taken into consideration in the protective algorithms in the AC and DC voltage protections.

Bipolar schemes are normally designed to have as independent protection systems between the poles as possible and will be virtually the same as two asymmetric monopoles. In some cases, common equipment such as an electrode line may require separate protection systems.

In general it is expected that all faults within a converter will be detected by two different protections; that is, all protections have a back-up protection with a different operating principle and using different transducers as far as is practicable.

The converter protections are divided into two subgroups:

- those related to the HVDC Grid System; where settings primarily come from the HVDC Grid System and are coordinated with other converters;
- those related to individual converter design.



Note: *) if existing

Figure 6-3 — Typical Protections System for a symmetrical monopole VSC Converter

Typical protections comprise of:

a) Converter zone, coordinated from the HVDC Grid System:

1) DC Line Voltage Unbalance Protection:

   Objective to detect deviations between positive and negative DC line voltage to ground;

2) DC Line Overvoltage Protection:

   Objective to detect overvoltage in either the positive and negative DC line voltage to ground;

3) DC Undervoltage Protection:

   Objective to detect undervoltage in either the positive and negative DC line voltage to ground;

b) Converter zone, coordinated by the converter design:

1) DC Overcurrent Protection:

   Objective to detect overcurrent in the DC link;

2) DC Current Differential Protection:

Objective to detect ground faults on the DC side of the converter or within the converter circuit up to the converter transformer;

3) Busbar Current Differential Protection:

   Objective to detect deviations between the sum of converter arm currents and the DC current at positive and negative DC busbars;

4) Asymmetry Protection:

   Objective to detect the persistent presence of fundamental voltage caused by, for example, single phase to ground faults between the transformer and the converter;

5) Converter / Valve Reactor Overcurrent Protection:

   Objective to detect overcurrent in any of the six converter limbs;

6) AC Secondary / Limb Current Differential Protection:

   Objective to detect faults between the converter transformer and the limb reactors (including the limb reactors);

7) AC Secondary Undervoltage Protection:

   Objective to detect undervoltages on the AC side of the converter;

8) Pre-Insertion Resistor Over Dissipation Protection:

   Objective to detect high energy dissipation through the pre-insertion resistor;

c) AC Network zone:

1) AC Undervoltage Protection:

   Objective to detect long duration AC system faults;

2) AC Overvoltage Protection:

   Objective to detect AC system overvoltage outside the specified envelope;

3) Under/over Frequency Protection:

   Objective to detect under- and over-frequency of the AC system.

The operation of any of the above protections will initiate a block and trip of the converter.

Other protection functions associated with the primary equipment (e.g. converter transformer) are considered to be practically identical to the equivalent protections on transmission schemes.

6.4.3 Protective Shut Down of a Converter

The procedure at trip of a converter is:

a) block of the converter;

b) opening of the converter AC breaker;

c) isolation of the converter DC pole, applicable poles.

6.4.4 DC System Protections

The basic HVDC system protection, normally applicable in a transmission scheme with two stations, may include a DC over/under voltage detection based on DC voltage measurement. The detection may be combined with a DC current measurement giving the fault current flow direction and indicating fault location. In a typical two station transmission system this can be used to differentiate between converter and HVDC Grid System faults.

If there are no specific requirements on dynamic isolation this concept will be sufficient for all kinds of HVDC Grid Systems. However the speed of operation of the protections, including measuring and isolation equipment, shall be coordinated with the rating of the converter.

6.4.5 DC Equipment Protections

DC equipment protection is normally based on differential protection methods, that is comparing the measured current on both sides of the component. It is important that the protection is fast compared to the HVDC Grid System protection and DC converter protection. Furthermore, the speed of the DC equipment protection is important in case of symmetrical monopole schemes as the fault currents are caused by transient discharge of the DC system and are of limited duration.

The measuring range of current measuring equipment has to be carefully selected to coordinate with the expected through-fault currents to avoid false operation of the differential protection for faults outside its own protective zone.

In case of DC equipment in a central node of a HVDC Grid System current measuring equipment may be necessary for sensing the fault current direction in order to selectively isolate the faulted section.

6.5 Clearance of Earth Faults

6.5.1 Clearance of a DC Pole-to-Earth Fault

In a scheme with symmetric monopoles, a DC pole-to-earth fault will not result in large short circuit currents. The earth fault currents are only due to cable capacitance and DC capacitor discharge. However, depending on the VSC technology, the earth fault can result in overvoltage on the healthy pole and will affect the entire HVDC Grid System. HVDC Grid Systems comprising of Full Bridge can prevent this overvoltage by appropriate control of the converter.

For minimizing the overvoltage stress on the healthy pole it is important that the DC pole-to-earth fault is cleared as fast as possible. The overvoltage and the voltage unbalance will be detected independently by the DC voltage protection in all stations connected to the faulted pole. This protection will block the connected converters and trip their AC side converter breakers. The time between fault detection and breaker tripping, is the only opportunity to use fault current magnitude and direction to determine the fault location.

In HVDC Grid Systems not having the voltage limiting function of Full Bridge type converters available, surge arresters complemented with an active DC voltage limiter (i.e. Dynamic Braking Device), if available, can be used to limit the amplitude and duration of the overvoltage on the healthy pole. Thereafter, the faulty equipment will be disconnected.

After the fault is cleared, the DC voltage in the two poles are unbalanced and need to be re-balanced before the remaining system can come back to full operation. Dynamic Braking Device, if available, can be utilized for re-balancing of the DC voltage of the two poles after clearance of a DC pole earth fault, For asymmetrical systems a DC pole-to-earth fault will result in an overcurrent, fed from the AC system, similar to that of a pole-to-pole short circuit described below.

6.5.2 Clearance of a Pole-to Pole Short Circuit

A pole-to-pole earth fault will generate an overcurrent. In addition to the cable discharge currents, Half Bridge Type MMCs will feed a short-circuit current, via their internal freewheeling diodes, which is characterized by the short circuit power level of the connected AC systems.

The effects of the short circuit will propagate throughout the HVDC Grid system rapidly with low voltage being independently detected by the protection systems at all connected converters. The converter protections will take appropriate actions, tripping of the converter AC breaker, HVDC breaker, or use fault blocking capability of converters, if available. Thereafter the faulty equipment can be disconnected either manually or by a control sequence.

6.5.3 Clearance of a Converter side AC Phase-to-Earth Fault

In the event of an AC phase to earth fault on the converter side of a symmetrical monopole scheme (F1 in Figure 6-4) over-voltages will be imposed on both poles. This is due to charging both poles to the peak value of the phase to phase AC voltage via the diodes in the healthy phases.

The charging current is limited by the impedance of the AC network, the transformer and the phase reactors. The time constant for the pole overvoltage thus depends on the AC side impedances and the impedance/capacitance of the DC side. Eventually, the pole overvoltages are limited by the converter pole arresters.

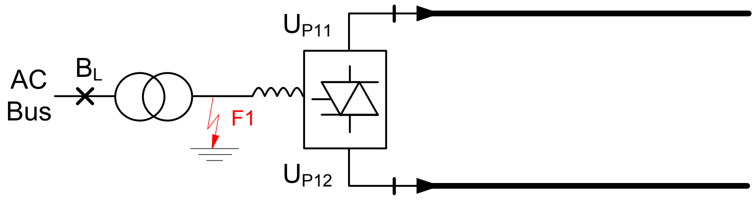


Figure 6-4 — Clearance of converter side AC phase to earth fault by breaker BL

If the fault occurs in a converter including a Dynamic Braking Device, it may be possible to control the DC voltage until the AC breaker of the faulty converter is tripped. The effects of the fault would thus not be imposed on other converters. When the DC voltage is restored to the normal value, the faulty converter is disconnected by opening of both poles of the converter DC pole disconnectors. If the voltage is not restored the other converter protection systems will detect an overvoltage and block and trip their respective converter. Consequentially the complete HVDC Grid system will be tripped.

In case the fault occurs in the converter that does not have a Dynamic Braking Device or any other means to control the DC voltage, all connected converters will be subjected to a DC overvoltage which will be detected by their converter protection systems which will initiate a block and trip of their respective converter.

In an asymmetric monopole or bipolar HVDC Grid System an AC converter bus fault will not be transferred to the DC side voltages. Hence the fault will be seen as a load rejection on the DC side.

7 Functional Specifications

7.1 General

Based on a long year history of HVDC transmission functional specifications are available for equipment and systems of point-to-point links [21]. The following chapters are intended to give guideline to the specification of components specifically for operation in HVDC Grid Systems. These specifications may complement existing documents for point-to-point links adding requirements specific for HVDC Grid System applications.

The present version of the Functional Specifications is seen as a starting point including the findings of the Study Group as available. Reference is made to the technical chapters of this report, where appropriate. Items needing further elaboration are listed as New Work Item Proposals (NWIP) for CLC/TC 8X.

7.2 AC/DC Converter Stations

7.2.1 DC System Characteristics

7.2.1.1 Voltages

The converter shall be capable of operating within the range of DC voltages specified below under steady-state, dynamic and transient conditions. In designing the converter to operate within the specified voltage range, account shall be taken of the required static control settings including voltage reference values, dead bands and droop characteristics as appropriate. Consideration shall be given to the resistive voltage differences arising in the DC circuit under all allowable load flow conditions. The voltage differences are dependent on the resistances of the DC transmission circuits and the magnitude and direction of the currents flowing in them.

It shall be demonstrated by means of dynamic simulations that the required dynamic operating range of the converter is within the range specified below under worst case conditions of speed of response to varying power orders and abrupt load changes. The simulations shall take account of the inductances of the transmission lines and any additional reactors.

It shall be demonstrated by means of transient system studies that the transient DC voltage operating range remains within the range specified below under the worst foreseeable conditions of switching of transmission lines or lightning strikes.

Procedures to derive the operating range of voltage under steady-state, dynamic and transient conditions are elaborated in Clause 4, Principles of DC Load Flow.

Nominal System voltage	kV	_____
Normal Operating voltage range		
maximum continuous	kV	_____
minimum continuous	kV	_____
Extreme Operating voltage range		
maximum continuous	kV	_____
minimum continuous	kV	_____
Stepwise Definition of Temporary Voltage Profile		
Temporary Overvoltage		

< ….. ms	p.u.	_____
< ….. ms	p.u.	_____
< ….. ms	p.u.	_____
< ….. ms	p.u.	_____
> 1 s	p.u.	_____

Temporary Undervoltage

< ….. ms	p.u.	_____
< …... ms	p.u.	_____
< ….. ms	p.u.	_____
< ….. ms	p.u.	_____
> 1 s	p.u.	_____

If there are repetitive events to be considered, this should be stated.

7.2.1.2 Short-Circuit Characteristics

The converter design shall be capable of withstanding the short-circuit current duties specified.

The design relevant current waveform characteristics should be specified by the owner based on the information detailed in Clause 5, Short-Circuit Currents and Earthing.

This includes the short-circuit current characteristics including peak, breaking, steady-state, thermal equivalent currents driven by the DC network.

7.2.1.3 Insulation Levels

LIWL [a]	kV	_____
SIWL [b]	kV	_____

[a] Lightning Impulse Withstand Level.

[b] Switching Impulse Withstand Level.

7.2.1.4 Specific Creepage Distances

DC Equipment	mm/kV	_____

7.2.1.5 Harmonic Voltage Distortion

The converter design shall ensure that the transmission system comprising the new AC/DC converter station operates stably in the entire frequency range. The system stability shall be demonstrated by performing network simulations.

In principle the procedure for designing an AC/DC converter station with respect to harmonics existing prior to the installation of the new equipment (pre-existing harmonics) does not differ from the practice for AC systems.

7.2.1.6 Control Interaction

DC networks are driven by power electronic converters. Power electronics in general have nonlinear voltage-current characteristics. Therefore, the principles of superposition can be applied with limitations only.

It is recommended to design the system considering different levels of detail.

- In high level approach, dominant frequencies existing in the HVDC Grid shall be identified by simulations or measurements, if the system already exists. DC network harmonic impedances shall be calculated for all relevant network conditions. Harmonic voltage levels and network harmonic impedances shall be specified allowing measures to be taken to avoid critical resonance conditions.

- In a more detailed approach, time domain simulations shall be carried out investigating possible interactions between the individual converters including their controls. Appropriate transient models of the existing converters shall be provided allowing measures to be taken to avoid control instabilities.

7.2.1.7 Network Stability Equivalents

The converter design shall ensure that the transmission system comprising the HVDC Grid System together with the connected AC system(s) remains stable. The static and dynamic system stability shall be demonstrated by performing network simulations. Models of the existing HVDC Grid System as well as adjacent AC systems shall be provided to allow the required simulations to be carried out.

The static system stability shall be demonstrated by means of load flow calculations using a detailed model of the HVDC Grid System and the connected AC system(s). Models of the new converter stations shall include voltage/current operating characteristics with their respective limitations.

The dynamic system stability shall be demonstrated by means of simulations using a detailed model of the HVDC Grid System and the connected AC system(s) including the representation of the dynamic behaviour of new converters and machines in the AC system(s). Critical modes of oscillation shall be identified.

A report shall be provided detailing the simulations performed and identifying control measures where necessary. Appropriate countermeasures may include dedicated damping control algorithms applied to converter controls.

Suitably detailed models of the new converter including the control system shall be provided.

7.2.1.8 System Grounding

Solidly grounded		_____
Grounded via Impedance	Ohm	_____

7.2.2 Operational Modes

7.2.2.1 Concept of Fault Clearing

The concept of fault clearing is described in Clause 5, Short-Circuit Currents and Earthing. The requirements with regard to acceptable outage times for a DC fault, i.e. the time from fault to recovery of power transfer shall be specified as given in the following table:

Table 7-1 — Fault isolation time and switching device type required

Fault isolation time	Required switching device type
< few ms	Fast dynamic isolation
< 100 ms	Mechanical HVDC breakers
< few s	Conventional AC breakers (‘high speed switches’)

It shall be specified whether the converter is required to be capable of blocking DC fault currents.

7.2.2.2 Operational Modes and Operational Options

The different operational modes that are feasible with VSC HVDCAC/DC converters are described in Clause 4, Principles of DC Load Flow.

The required control mode(s) for each converter shall be specified as follows:

Power	□ yes / □ no
DC voltage	□ yes / □ no
Frequency	□ yes / □ no
Reactive power	□ yes / □ no
AC voltage	□ yes / □ no

a) <u>Black Start Capability:</u>

The black-start procedure of AC or HVDC Grid Systems may include three main sequences:

1) energization, i.e. where the voltage and frequency in an AC system and DC voltage in a HVDC Grid System are to be settled from a state with absent voltage within isolated system areas.

2) resynchronization and Reconnection, i.e. where the system areas with settled voltage (and frequency) are synchronized by voltage and frequency in an AC system and DC-voltage in a HVDC Grid Systems and interconnected.

3) final recovery, i.e. where the Area Grid Controllers[1] (AGC) in an AC system and the HVDC Grid Controller in a HVDC Grid System are taking over as in normal operation conditions of the interconnected transmission system.

For AC and HVDC Grid Systems, the system operator should prepare the black-start procedure including:

4) grid split-up into areas,

5) units participating in the black-start within each area with further specifications of the frequency leaders in an AC system and the DC voltage leaders in a HVDC Grid System,

6) resynchronization leaders in an AC system and in a HVDC Grid System.

b) Fault Ride Through and DC System Reconfiguration Requirements:

Fault ride through and post-fault reconfiguration of the DC system are described in 3.3.4, Network Behaviour during Faults.

Deionization times and restart DC voltages for HVDC systems which include overhead lines are as follows:

	Deionization Time	**Restart DC Voltage**
	(ms)	(pu)
1. Restart	_____	_____
2. Restart	_____	_____
3. Restart	_____	_____

c) Energy absorption capability (Dynamic Braking Device):

For an islanded wind park an energy absorption unit, e.g. Dynamic Braking device, might temporary assist to keep the DC voltage down. The energy absorption unit can also assist in temporarily lowering the overvoltage of a DC pole after a DC short circuit, as described in 5.3.5, Clearance of a DC Pole-to-Earth Fault.

The required energy absorption capability shall be designed based on the system requirements. It should be stated whether the converter has energy absorption capability. The operating principle of such apparatus shall be described including whether the operation can be performed step-less over the whole power range or step-wise.

1) Area Grid Controllers (AGC) - In AC systems such controllers are also called the load-frequency controllers (LFC). The function of these controllers is keeping the balance between the given system and neighbouring systems with activation of available reserves in deviations.

A specification of such apparatuses may include the following characteristics:

TECHNICAL DATA

Item	Description	Unit	Value
1	**Nominal Resistance**	**Ω**	
1.1	Tolerance of resistance at ambient temperature	%	
1.2	Maximum resistance tolerance at full energy capacity	%	
2	**di/dt limiting reactors (if any)**	**mH**	
	Maximum Inductance	**µH**	
3	**Voltage, DC**		
3.1	Maximum rating voltage across resistor	kV	
3.2	Maximum voltage across resistor for energy calculation	kV	
4	**Energy**		
4.1	Maximum impulse energy, during repeated impulses	MJ	
4.2	Duration of energy impulse	S	
5	**Lightning impulse minimum withstand level***		
5.1	- High voltage terminal to earth	kV	
5.2	- Across resistor	kV	
6	**Switching impulse withstand level**		
6.1	- Across resistor	kV	
7	**Power frequency test voltage, rms value**	**kV**	
8	**Protection class**	**IP**	

Proposed Tests:

Cold ohmic resistance value measured at d.c. Hot ohmic resistance value are calculated from the measured voltage and current values.

Energy impulse temperature rise test at voltage and current necessary at very short energy impulses to demonstrate the maximum temperatures of the parts forming the complete resistor are not exceeded at the end of the test.

7.2.2.3 Short-Circuit Current Contribution of Converter Station

The short circuit current contribution of the converter station is described in 5.3.4, Contribution of Converter Stations.

The short-circuit currents contributed by a converter station shall meet the following requirements:

Maximum peak current	___kA
Maximum di/dt	___As^{-1}
Minimum duration of short circuit current	___s
Maximum recovery voltage	___kV
Minimum/maximum impedances	___/___Ω
Minimum short-ciruit current	kA

7.2.2.4 DC Side Harmonic Performance Requirements

The converter design shall comply with harmonic compatibility levels.

In principle the procedure to design an AC/DC converter station with respect to self-generated harmonics does not differ from the practice for DC point-to-point or AC systems.

It should be noted, that DC networks are driven by power electronic converters. Power electronics in general have nonlinear voltage-current characteristics. Therefore, the principles of superposition can be applied with limitations only.

It is recommended to design the system considering different levels of detail.

- In a high level approach, characteristic harmonics generated by the converter, if any, shall be stated. Network harmonic impedances shall be specified, allowing the new equipment to be designed keeping the harmonic compatibility level at its Point of Common Connection to the HVDC Grid System. Similarly, harmonic coupling impedances shall be specified, allowing the new equipment to be designed keeping the harmonic compatibility levels at defined points within the HVDC Grid System

- In a more detailed approach, the studies as described under 7.2.1.5, Harmonic Voltage Distortion shall be carried out.

7.2.2.5 Insulation Coordination

Voltage withstand requirements, insulator creepage distances and clearances in air for HVDC converter equipment as well as the location, protective levels and energy handling requirements of the required surge arresters should be determined by means of an insulation coordination study in accordance with the procedures given in IEC 60071-5 [22] and the guidance given in ELECTRA No 96 [23] and CIGRE Technical Brochure No 34 [24]. Indicative ratios of required impulse withstand voltage to impulse protective level are given in Table 9 of IEC 60071-5:201X [22].

7.2.2.6 Converter Control and Protection

High reliability of the control and protection system shall be guaranteed with a redundant and fault-tolerant design.

a) <u>Power Flow Control:</u>

Each converter shall be equipped with a control system that has been designed to operate satisfactorily under normal as well as abnormal system conditions.

The control system shall manage the transmission of power between the converters of a DC system. It shall ensure that the power imported to the DC system and the power exported from the DC system remain balanced at all times and that the DC voltage of the DC system be maintained within the range specified in 7.2.1.1, Voltages. The control functions shall be differentiated into Converter Station Controls and HVDC Grid Controls as described in 4.2, Structure of Load Flow Controls.

The Converter Station Controller shall control the real power and reactive power at the converter AC terminals with response times typically in the range of microseconds to milliseconds. The following control targets may be specified:

1) Active power:

    i) active power flow;

    ii) AC system frequency;

    iii) DC voltage;

2) Reactive power:

    i) reactive power exchange with the AC network;

    ii) AC voltage.

The Converter Station Controller shall obtain measured signals from its own converter station and receive status signals from the HVDC Grid Controller. Loss of external telecommunication should lead to the power flowing being interrupted.

The Converter Station Controller shall coordinate with the DC and AC networks by pre-determined characteristics such as fixed reference points or droop characteristics and shall be equipped with voltage limiting and current limiting functions. It shall send status and measured signals to the HVDC grid controller.

The HVDC Grid Controller shall govern the HVDC Grid System operation. It shall receive status and measured signals from the converter station controllers and use the signals to optimize the power flow within the DC network according to pre-defined rules. It shall provide the converter station controllers with their control characteristics and reference values.

The HVDC Grid Controller shall provide the interface to the system operators with indications of the status and power flow of each converter station.

A back-up HVDC Grid controller shall be provided to be located at a different physical location to the main HVDC grid controller to ensure continuity of grid control functions in case of major events such as fire damage or complete loss of telecommunications to an area.

b) <u>Active Power (Ref. 4.3.3, Active Power (PDC) and Frequency (f) Controlling Stations):</u>

The active power control can have the following functionalities:

1) Permitting power import into the DC circuit, power export out of the DC circuit or both

2) Providing adjustable, from 0 % to 100 % of the specified power rating.

3) Providing fast reversal of power

4) Power ramping following a given power order. The power ramping shall occur automatically at a specified rate of change (MW/minute) until a given final value is reached. The control commands shall be absolute values and shall comprise:

1. Order value (MW)) Resolution: ______

2. Ramp Rate (MW/min)) Minimum: __Maximum: ______

3. Initiation command

4. Start/ Stop power ramp command

5) A power Run Up/ Run Back function to be used in case of disturbances of the grid to increase or decrease the amount of transferred active power. The number of Run Ups and Run Backs shall be specified.

c) <u>U/f Control Mode (Ref. 4.3.3, Active Power (PDC) and Frequency (f) Controlling Stations):</u>

U/f Control Mode required □ yes / □ no

d) <u>Stabilization of the AC System:</u>

1) <u>Modulation Control:</u>

Modulation control shall be superimposed on the normal power control so that oscillations in the AC network can be damped. Possible torsional oscillations as well as converter interactions should be considered.

2) <u>Limitation Controls:</u>

Power run-back and run-up functions shall be provided based on the inputs from the AC system. Binary signals derived from the AC system state changes shall be used to execute a run-back or run-up. Run-backs shall be utilized to stabilize the AC system upon sudden loss of an infeed at the Rectifier or loss of export at the inverter.

An AC Voltage Limit Control shall be implemented as an emergency function. This emergency function shall initiate a fixed DC power reduction at a predefined AC undervoltage level.

e) <u>Operator Control:</u>

Operation of the HVDC system shall be altered flexibly by selection of different system settings. A wide degree of freedom shall exist with regard to the order in which the operator can issue commands.

Basic control settings applicable to the HVDC Grid Controller or the Converter Station controller respectively should be defined with respect to:

1) automatic/manual control;

2) local/remote control.

f) <u>Telecommunication System (3.3.6, The Role of Communication):</u>

The telecommunication system shall ensure proper communication between the HVDC Grid Controller and the Converter Station.

g) <u>System Protection (Clause 6):</u>

DC Control, Protection and Measuring Equipment

The design of the control and protection system shall be flexible to enable changes required by application development. A computer based control system shall be used.

The control and protection system shall ensure correct behaviour during normal operation of the HVDC with complete redundancy to ensure a safe shut down and isolation of the faulty equipment.

7.2.3 Testing and Commissioning

7.2.3.1 General Requirements

All equipment within the scope of supply of the Contractor shall be comprehensively tested in order to demonstrate that they meet the specified requirements and fulfil the guarantees.

The tests shall include the following:

- factory tests;
- pre-commissioning and sub-system tests;
- system and acceptance tests:

7.2.3.2 Factory Tests

All individual components shall, without any additional cost to the Purchaser, be subjected to manufacturing tests according to specified standards and references.

Type tests shall be performed on one unit of each design with the specific design and rating used for this project. Type tests proved by certified test reports on tests previously performed on a component with similar design and rating may be accepted as type tests.

All type and routine tests to be carried out shall be witnessed by an authorized inspecting engineer, unless permission to proceed with the test in his absence has been obtained from the Purchaser.

7.2.3.3 Site Tests

a) Pre-commissioning tests:

The pre-commissioning tests shall be carried out on all items of equipment and shall ensure that the equipment has sustained no damage in transit, has been properly installed in the field, is safe to energize, load or start-up and will perform and operate as designed.

b) Sub-system tests:

After successful completion of the pre-commissioning tests all independent sub-systems shall be energized or started up in order to prove that a group of components will work satisfactorily together as a functional unit.

c) Station system tests:

After the successful completion of the sub-system tests, station system tests shall be performed. These tests involve energizing with primary power and will usually affect the AC and HVDC Grid system.

d) System tests:

After successful completion of the station system tests, system tests shall be performed. The programme of system tests shall include tests to check coordination of the HVDC Grid Controller and the Converter Station Control and Protection with all required telecommunication circuits in operation During system tests final adjustments for satisfactory operation shall be made.

e) Acceptance tests:

After the satisfactory completion of the system tests, the acceptance tests shall be carried out to prove that the overall Converter Stations meets the specified performance. It is recognized that many of the acceptance tests will have been carried out as part of the system tests. Repetition of these tests will not be required.

f) Operation:

As soon system and acceptance tests are completed, the Contractor shall advise the Owner that the equipment is ready for service and that commercial operation can be started.

During the first _____ weeks Contractor's commissioning engineer will be available in order to support the owner.

7.3 HVDC breaker

7.3.1 System Requirements

A detailed system specification of a HVDC breaker applicable to a HVDC Grid System requires knowledge of the HVDC Grid System configuration, the design and protection of the HVDC switchyard, representative cable and HVDC line models, definition of the converter topology in the HVDC Grid System and its grounding and insulation coordination in order to understand the electrical operating environment. For a generic HVDC Grid System, technical assessment of the system requirements of a HVDC breaker can be made on rules of thumb based on worst case conditions.

7.3.2 System Functions

The HVDC breaker shall be able to interrupt fault currents in both current directions and provide means for self-protection and supervision.

7.3.3 Interfaces and Overall Architecture

The HVDC breaker shall provide an interface to the control and protection system of the HVDC Grid System.

7.3.4 Service Requirements

It shall be possible to perform maintenance on the HVDC breaker without affecting power transmission of the surrounding HVDC Grid System.

7.3.5 Technical System Requirements

The general system requirements are specified. The HVDC breaker system composition depends on the HVDC breaker type, e.g. semiconductor, mechanical or hybrid. This will influence the requirements to be specified for the individual HVDC breaker system components, such as measurement system, arrester banks, etc. Since it is beyond the scope of these guidelines to describe all possible HVDC breaker designs, component specifications are excluded here. However these will in a real project be similar to standard product specifications.

Table 7-2 — HVDC breaker system requirements

Nominal DC grid voltage	**kV_{DC}**	
1 Current and voltage ratings during normal operation		
1.1 Nominal current	A_{DC}	
1.2 Maximum continuous current	A_{DC}	
1.3 Maximum continuous voltage to ground, Vmax	kV_{DC}	
1.4 Max. temporary overvoltage to ground (1/0,2 s)	kV_{DC}	
1.5 Switching impulse withstand level to ground (SIWL)	kV_{Peak}	
1.6 Lightning impulse withstand level to ground (LIWL)	kV_{Peak}	
1.7 Steady-state voltage across open breaker		
1.3 Maximum continuous voltage across open breaker, Vmax	kV_{DC}	
1.4 Max. temporary overvoltage across open breaker (1/0,2 s)	kV_{DC}	
1.8 Switching impulse withstand level across open breaker (SIWL)	kV_{Peak}	
1.9 Lightning impulse withstand level across open breaker (LIWL)	kV_{Peak}	
2 Voltage and current stress across poles for faults, current breaking, close duties and open contacts		
2.1 Breaking current level (typical / max. at breaking time instance of ___ ms)	kA_{Peak}	/
2.2 Maximum voltage to ground, Vmax for __s	kV_{DC}	
2.3 Peak withstand current	kA	
2.4 Rated short circuit duration [a]	s	
2.3 Maximum transient voltage during fault breaking, 1,5*Vmax for ms, SIPL	kV_{Peak}	
2.4 Maximum transient voltage during load current transfer breaking, (1/4)* SIPL	kV_{Peak}	
2.5 Cable charging in rush current	kA	

2.6 Cable charging, no of closing operations	-	
2.7 Load current temporary overload capability (current and duration)	kA s	
3 General requirements		
3.1 Operating time from fault until open	ms	
3.2 Operation, reclosing for overhead lines (OH) only	Cycle	
3.2 Closing time	ms	
3.3 Maximum consecutive cycles		
3.4 Cycle time		
3.5 Number of operations, total/load/fault (OHL)		
3.6 Minimum time for protection algorithm	ms	
3.7 Minimum creepage to ground	mm/kV	
3.8 Ambient conditions	°C, kPa, etc	
3.9 Energization time	ms	
3.10 On load losses at nominal voltage and current	kW	
[a] The waveform of the short time short-circuit may need to be specified, should it deviate substantially from e.g. a 50/60Hz major loop.		

Annex A
(informative)

HVDC – Grid Control Study

The input data for the benchmark model and the cases are defined in 4.7.

Appendix – Case 08:

Case 08 Voltage [kV]

		Initial Value	Final Value	Change
VPDDB	Terminal A	313,09	310,00	−3,09
	Terminal B	313,09	313,15	0,06
	Terminal C	310,00	310,00	0,00
	Terminal D	306,85	306,85	0,00
VCD	Terminal A	30419	292,80	−11,39
	Terminal B	304,19	296,16	−8,03
	Terminal C	301,01	292,80	−8,21
	Terminal D	297,76	291,10	−6,66
VPD	Terminal A	305,35	288,00	−17,35
	Terminal B	305,35	305,74	0,39
	Terminal C	302,20	302,60	0,40
	Terminal D	299,00	301,04	2,04

Case 08 Current [kA]

		Initial Value	Final Value	Change
VPDDB	Terminal A	1,28	0,00	−1,28
	Terminal B	1,28	1,30	0,02
	Terminal C	−1,25	0,00	1,26
	Terminal D	−1,30	−1,30	0,00
VCD	Terminal A	1,32	0,00	−1,32
	Terminal B	1,32	1,39	0,07
	Terminal C	−1,29	−0,68	0,60

	Terminal D	−1,34	−0,70	0,64
VPD	Terminal A	1,30	0,00	−1,30
	Terminal B	1,30	1,30	0,00
	Terminal C	−1,28	−0,65	0,62
	Terminal D	−1,31	−0,65	0,66

Case 08 Power [MW]

		Initial Value	Final Value	Change
VPDDB	Terminal A	800,00	0.00	−800,00
	Terminal B	800,00	814,18	14,18
	Terminal C	−775,98	2,42	778,39
	Terminal D	−800,00	−800,20	−0,20
VCD	Terminal A	800,13	0,00	−800,13
	Terminal B	800,32	822,61	22,29
	Terminal C	−774,96	−400,78	374,17
	Terminal D	−800,01	−410,09	389,92
VPD	Terminal A	790,89	−0,01	−790,90
	Terminal B	790,89	793,22	2,33
	Terminal C	−771,03	−394,56	376,47
	Terminal D	−782,16	−388,49	393,67

Case 8 – Voltage values

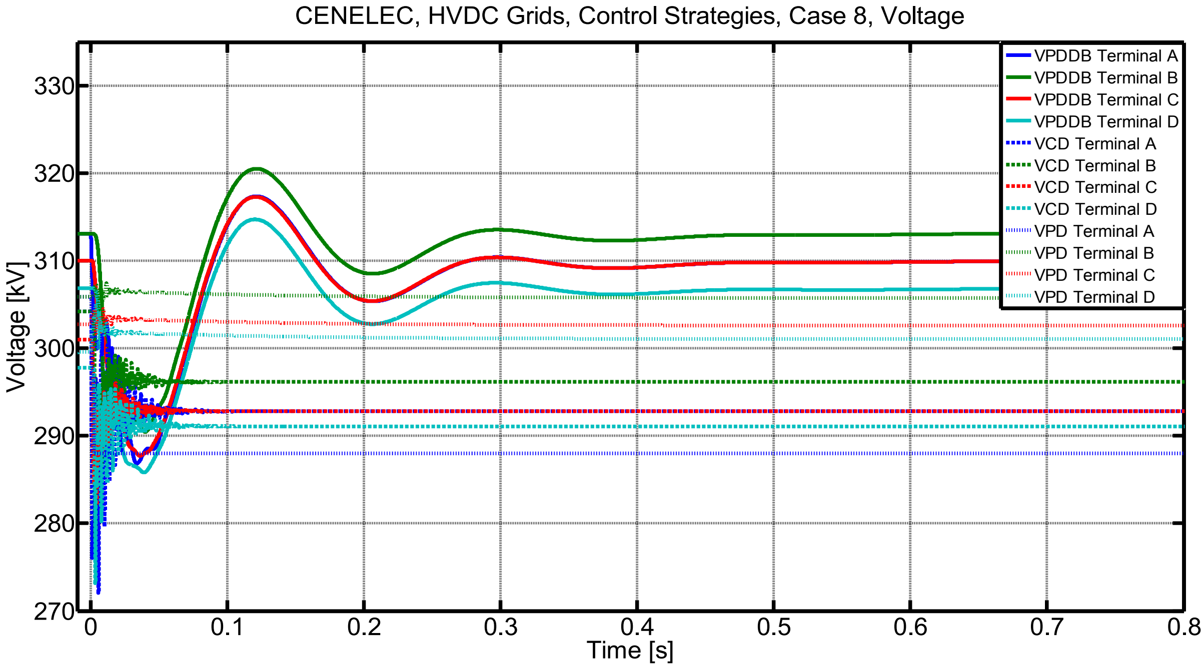


Figure A.1 — Case 8 voltage values

Case 8 – Current values

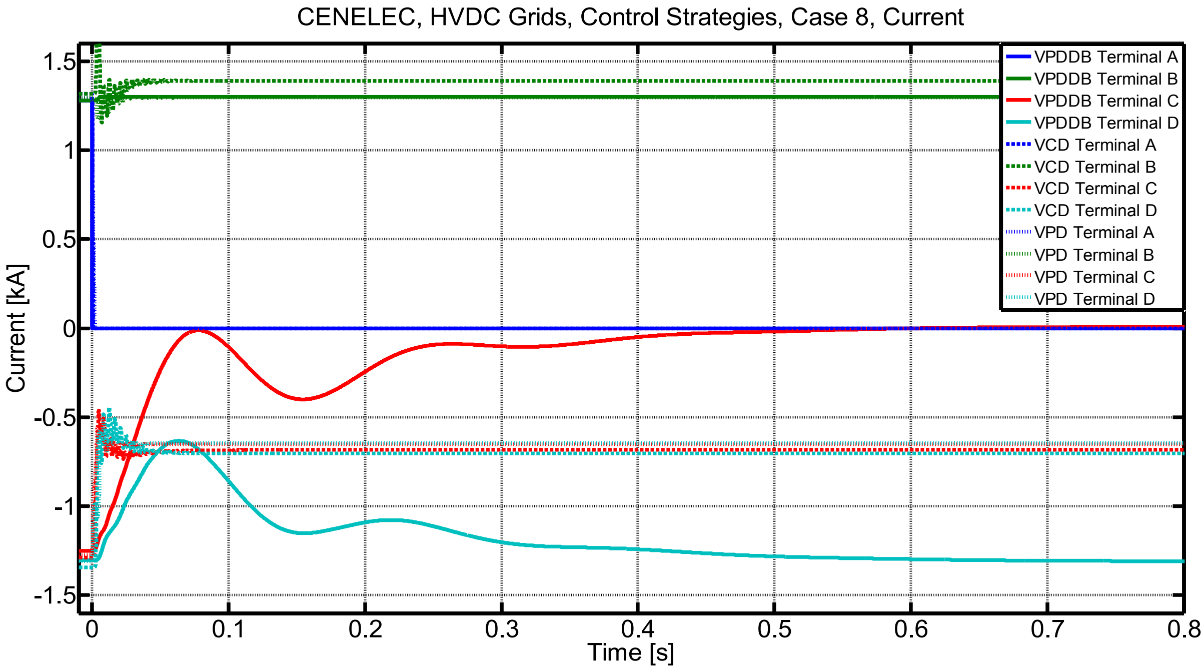


Figure A.2 — Case 8 current values

Case 8 – Power values

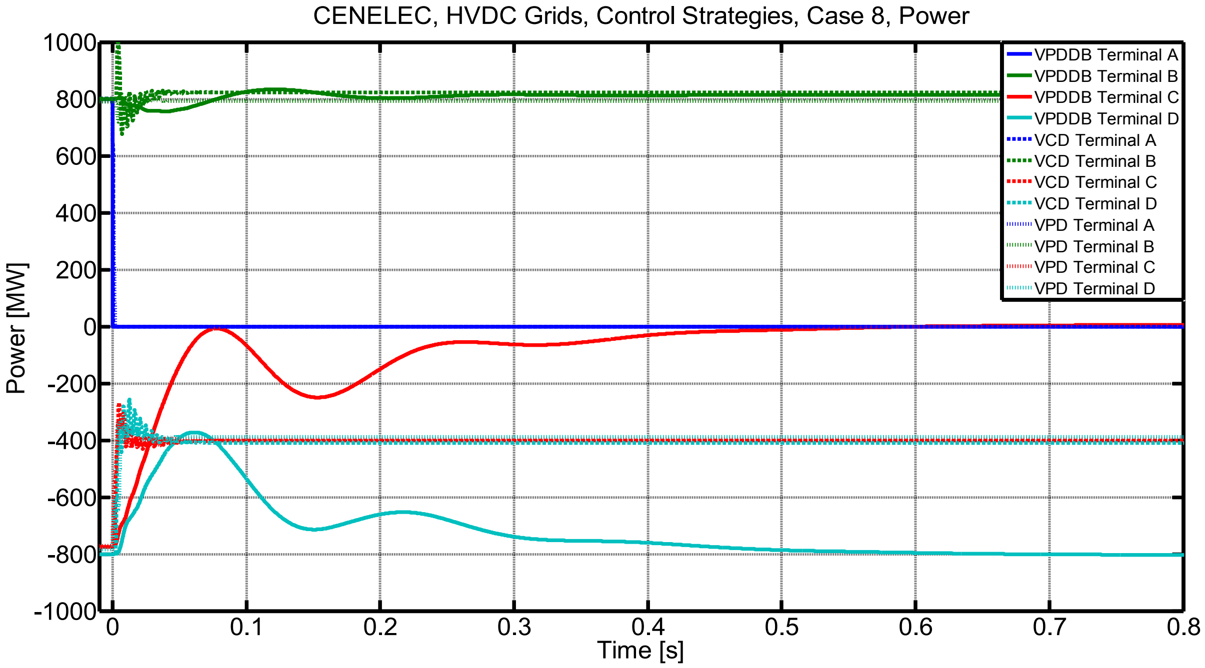


Figure A.3 — Case 8 power values

Appendix Case 10:

Case 10		Voltage [kV]		
		Initial Value	Final Value	Change
VPDDB	Terminal A	313,09	319,96	6,87
	Terminal B	313,09	319,96	6,87
	Terminal C	310,00	318,37	8,37
	Terminal D	306,85	315,20	8,36
VCD	Terminal A	304,19	315,61	11,42
	Terminal B	304,19	315,61	11,42
	Terminal C	301,01	313,93	12,92
	Terminal D	297,76	310,57	12,81
VPD	Terminal A	305,35	304,52	−0,83
	Terminal B	305,35	304,52	−0,83
	Terminal C	302,20	302,94	0,74
	Terminal D	299,00	299,78	0,77

Case 10		Current [kA]		
		Initial Value	Final Value	Change
VPDDB	Terminal A	1,28	0,66	−0,62
	Terminal B	1,28	0,66	−0,62
	Terminal C	−1,25	0,00	1,25
	Terminal D	−1,30	−1,31	−0,01
VCD	Terminal A	1,32	0,69	−0,62
	Terminal B	1,32	0,69	−0,62
	Terminal C	−1,29	0,00	1,29
	Terminal D	−1,34	−1,39	−0,05
VPD	Terminal A	1,30	0,65	−0,64
	Terminal B	1,30	0,65	−0,64
	Terminal C	−1,28	0,00	1,28
	Terminal D	−1,31	−1,31	0,00

Case 10		Power [MW]		
		Initial Value	Final Value	Change
VPDDB	Terminal A	800,00	419,15	−380,85
	Terminal B	800,00	419,15	−380,85
	Terminal C	−775,98	0,00	775,98
	Terminal D	−800,00	−825,83	−25,83
VCD	Terminal A	800,13	438,26	−361,87
	Terminal B	800,32	438,36	−361,96
	Terminal C	−774,96	0,00	774,96
	Terminal D	−800,01	−862,62	−62,61
VPD	Terminal A	790,88	397,97	−392,91
	Terminal B	790,88	397,97	−392,91
	Terminal C	−771,03	0,02	771,05
	Terminal D	−782,15	−783,57	−1,42

Case 10 – Voltage values

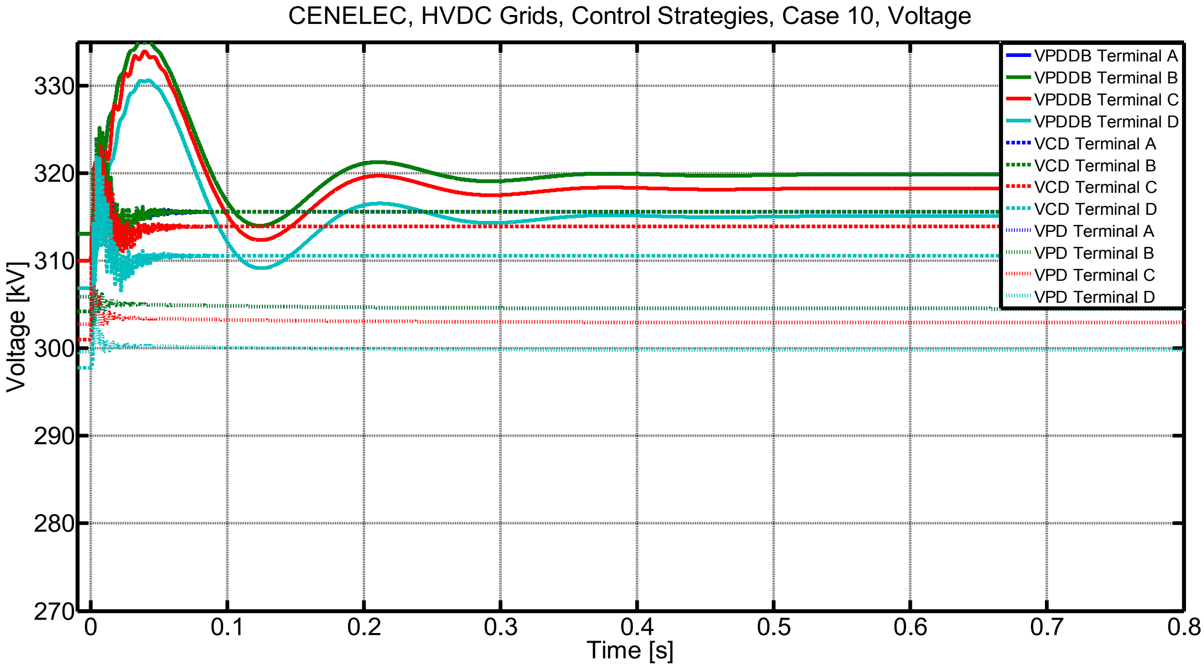


Figure A.4 — Case 10 voltage values

Case 10 – Current values

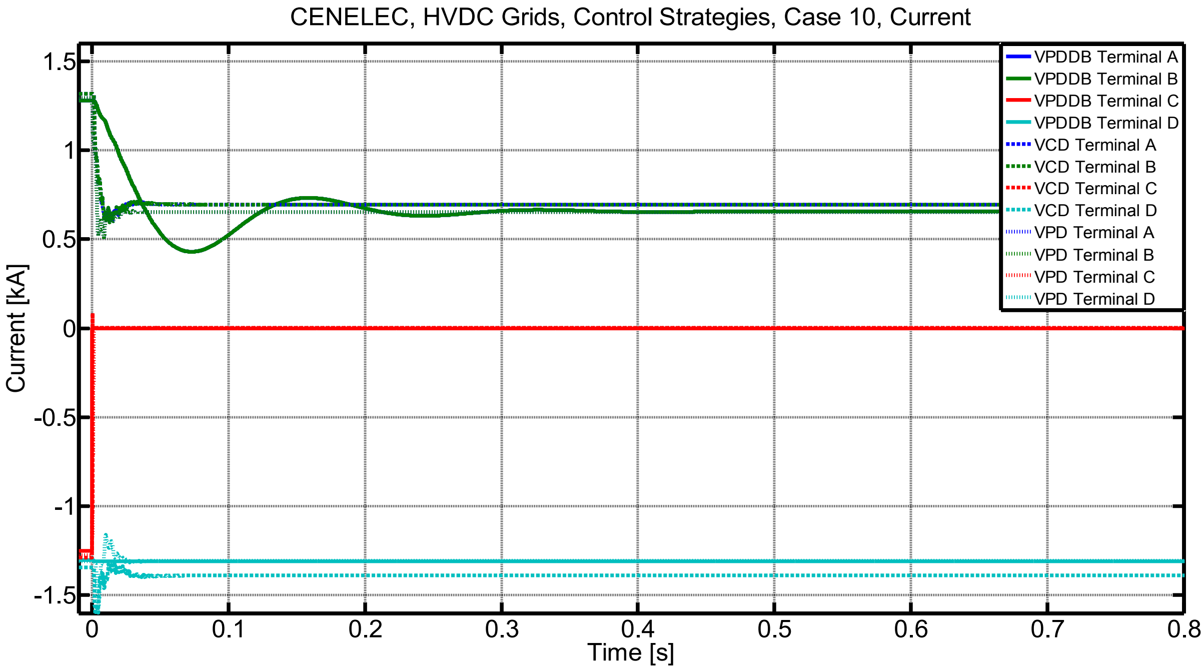


Figure A.5 — Case 10 current values

Case 10 – Power values

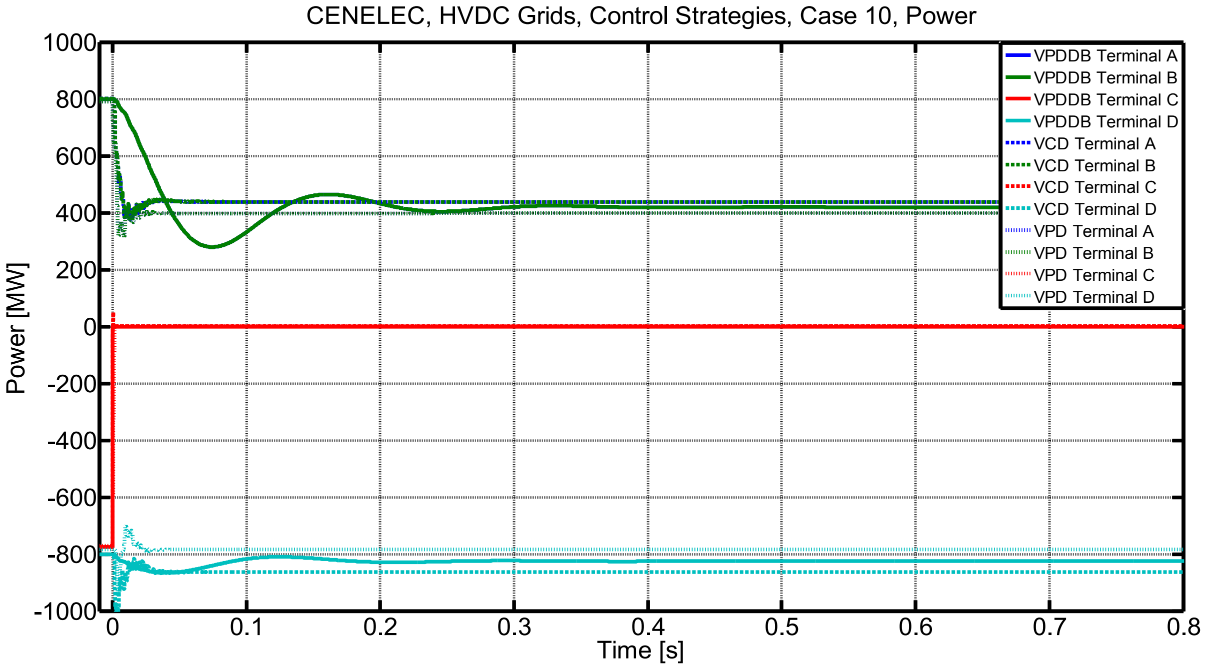


Figure A.6 — Case 10 power values

Annex B
(informative)

Fault Behaviour of Full Bridge Type MMC

B.1 Introduction

This report is based on a simulation study (PSCAD/EMTDC) into the response of a Full Bridge Voltage Sourced Converter (VSC) to DC circuit faults. The study considered faults across the converter terminals and between one terminal and ground at either end of a DC transmission scheme.

In this study both converters are connected to independent AC sources via transformers with delta (Δ) connected secondary windings.

B.2 Test Results

The simulation model was based on a simple symmetrical monopolar VSC scheme with a 200 km cable between the two stations.

The converters were Full Bridge type Modular Multilevel Converters (MMC), as shown in Figure B.1, with the following parameters:-

Number of modules per valve	=	100
Module capacitance	=	2,5 mF
Valve Reactance	=	50 mH
Protection detection/operating time	=	500 us

The assumed data for the DC system was:

Rated DC Power (Pdc)	=	600 MW
Rated DC Voltage (Vdc)	=	±300 kVdc
Rated DC Current (Idc)	=	1 kAdc
Cable length	=	200 km
Cable Capacitance	=	59,2 uF
Cable Inductance	=	21,12 mH
Cable Resistance	=	2,42 Ω

B.3 DC to DC Terminal Faults

Figures B.2 and B.3 respectively show DC to DC terminal fault at the rectifier converter and inverter converter.

In Figure B.2 a), at the rectifier converter, the DC voltage collapses to zero at the fault application and the rectifier converter DC current surges from the steady-state 1,0 p.u. to approximately 6 p.u. The exact value of the converter current is determined by the total series inductance comprising of the AC system impedance, the transformer reactance and the limb reactance. The duration of the high DC current surge is approximately 1 ms (although this is scheme dependent).

Figure B.2 b) shows the inverter response to the fault at the rectifier terminal. The principal difference is the oscillations in the DC terminal voltages due to the DC cables between the converter terminals and the fault. The frequency of oscillation and the decay time of the oscillations are determined by the cable parameters.

Figures B.3 a) and B.3 b) show a fault between the inverter converter DC terminals. Superficially the response is similar to that of Figures B.2 a) and B.2 b).

B.4 DC Terminal to Ground Faults

Figures B.4 and B.5 respectively show DC terminal to ground fault at the rectifier converter and inverter converter.

In each case it would be expected that on fault application, the “un-faulted” cable voltage would rise to approximately twice the rated voltage (2 p.u.) i.e. 600 kV. However, with suitable protection systems able to quickly block the converters, the un-faulted cable voltage can be left at approximately rated voltage.

In Figures B.6 a) and B.6 b), a fault has been applied to the inverter converter positive terminal and the protection systems at both converters has been disabled. In this example the “un-faulted” cable voltage does rise towards twice the rated voltage however the step change top the cable voltage causes additional oscillations at the cable natural frequency resulting in peak DC cable voltages of approximately three times the rated voltage. In practice this transient over voltage would be limited by cable surge arrestors to a more realistic value (typically 1,8 p.u.).

B.5 Conclusion

A VSC Converter implemented using full bridge modules can successfully block high fault currents associated with DC terminal short circuits. In addition a full bridge VSC converter can also prevent over-voltages occurring on the unfaulted cables/lines when the other terminal is grounded.

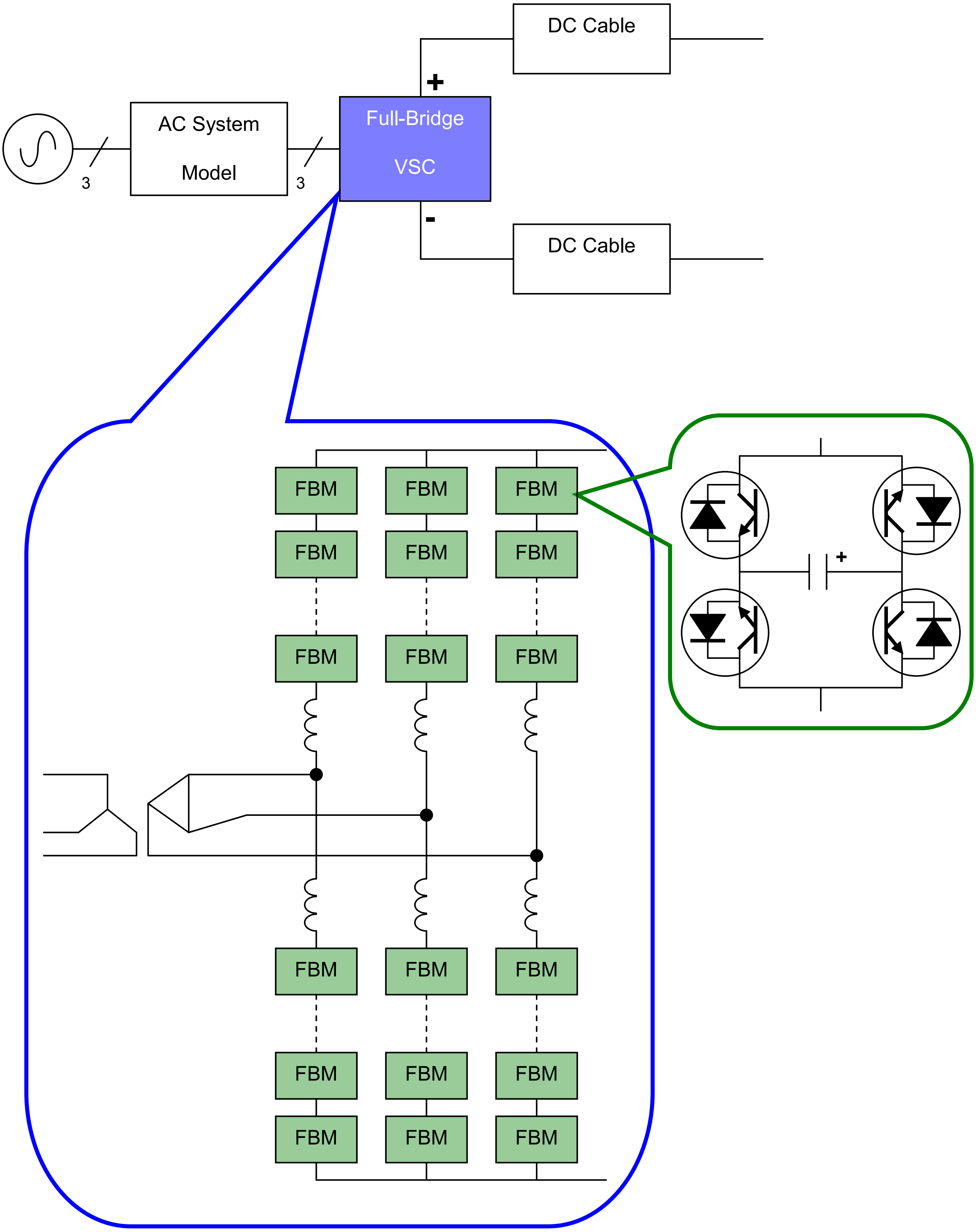
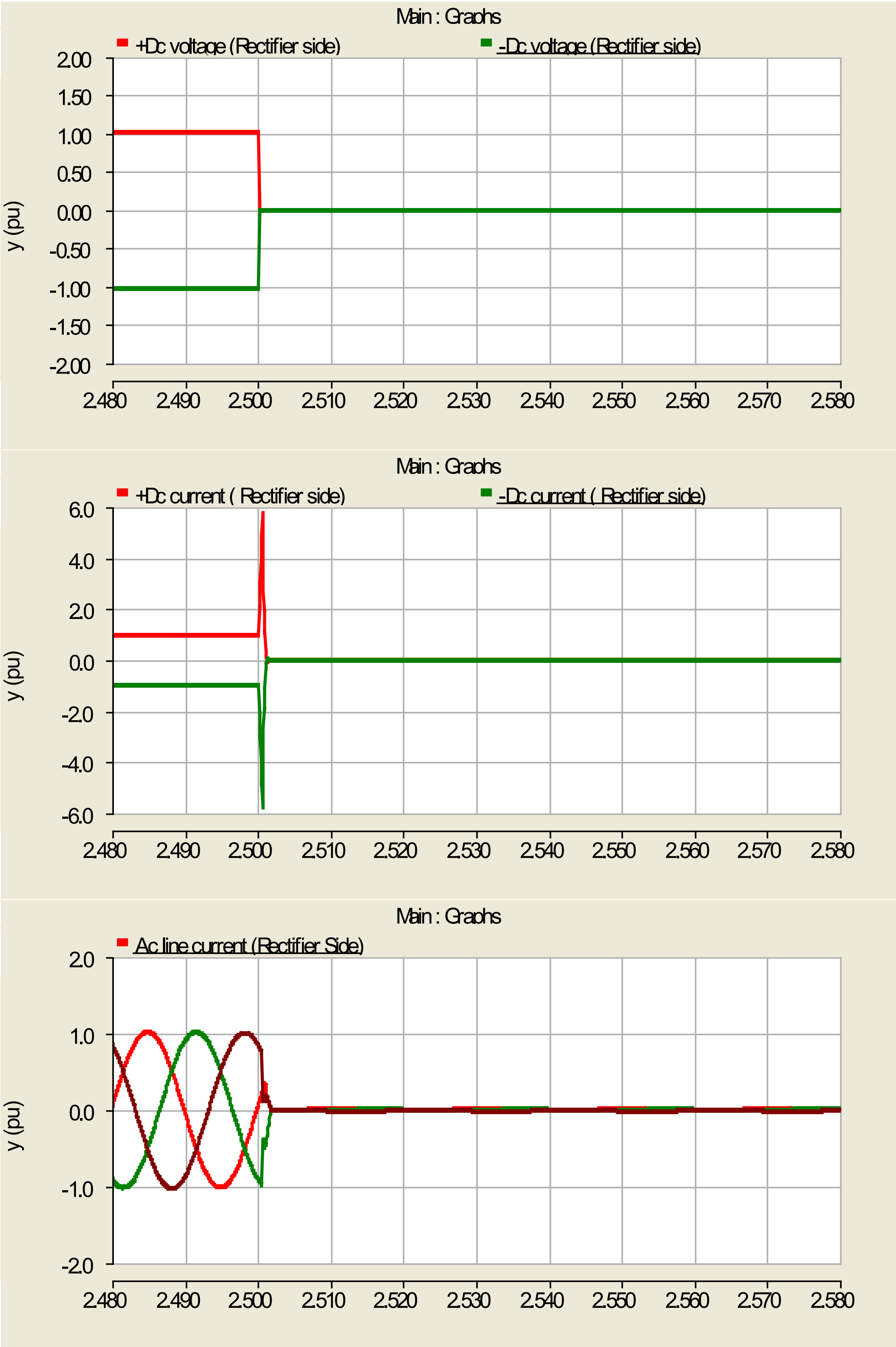
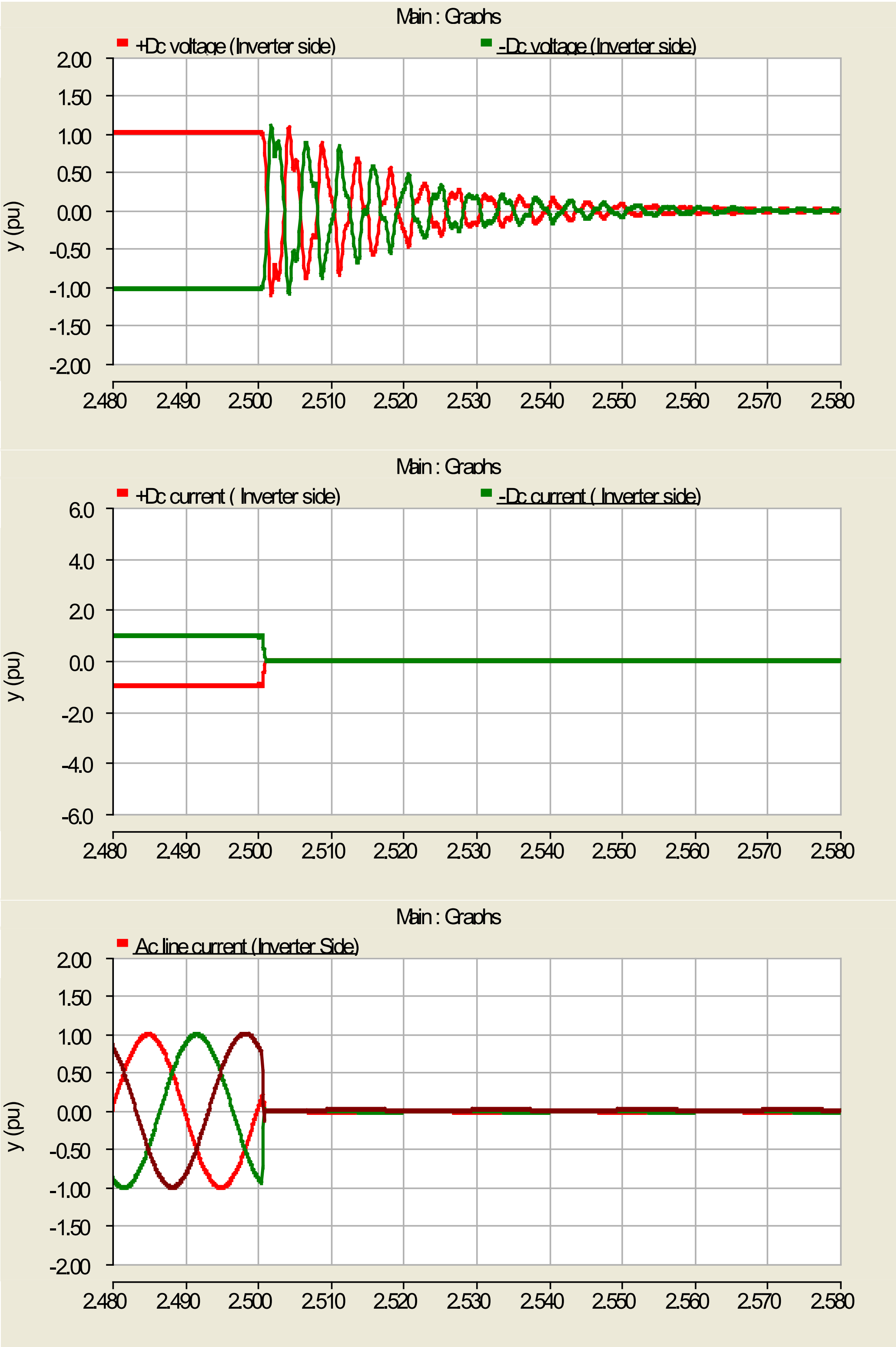


Figure B.1 — Multi-Modular Full Bridge Voltage Source Converter



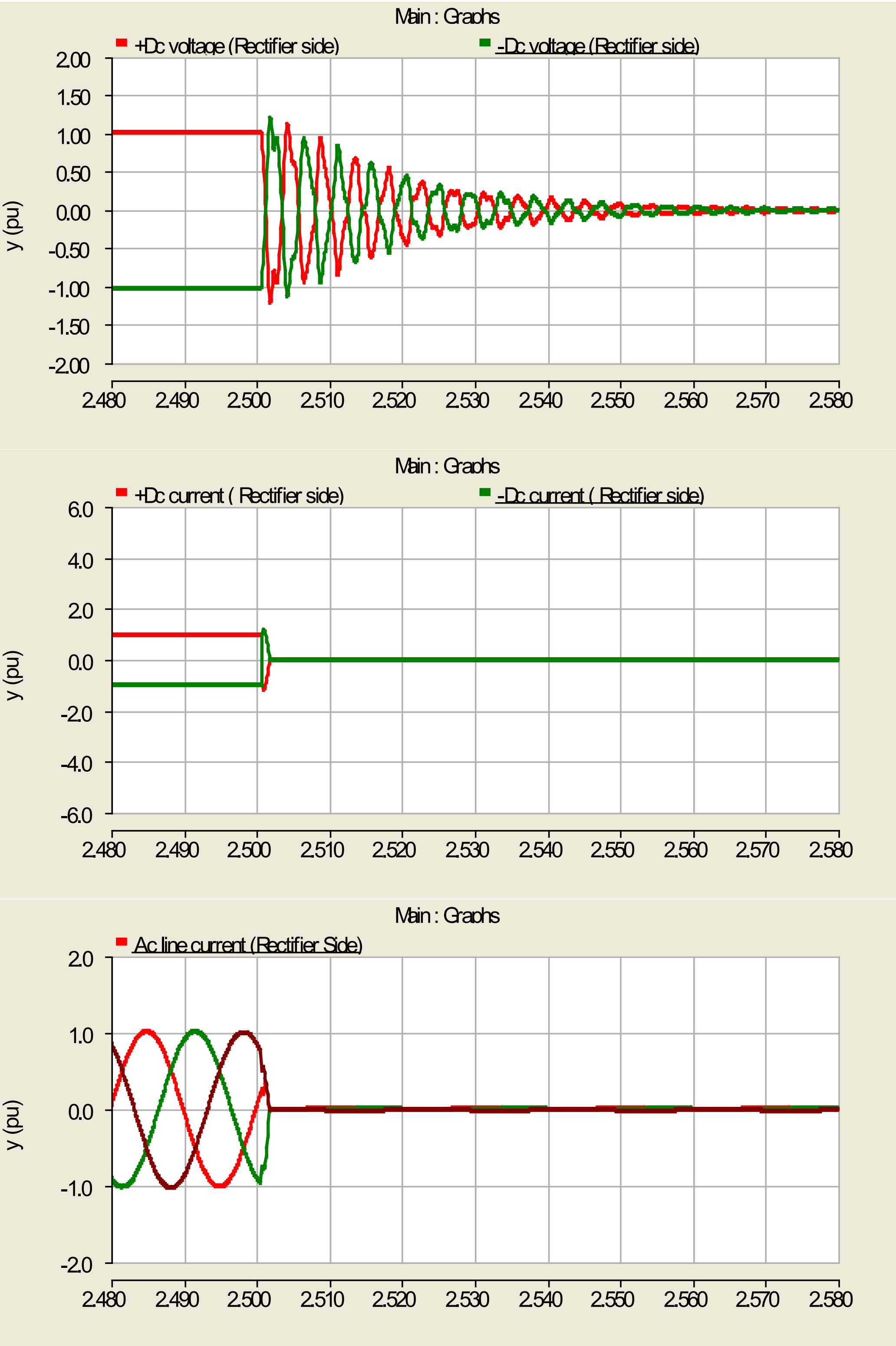
a) Rectifier End

Figure B.2 *(continued)*



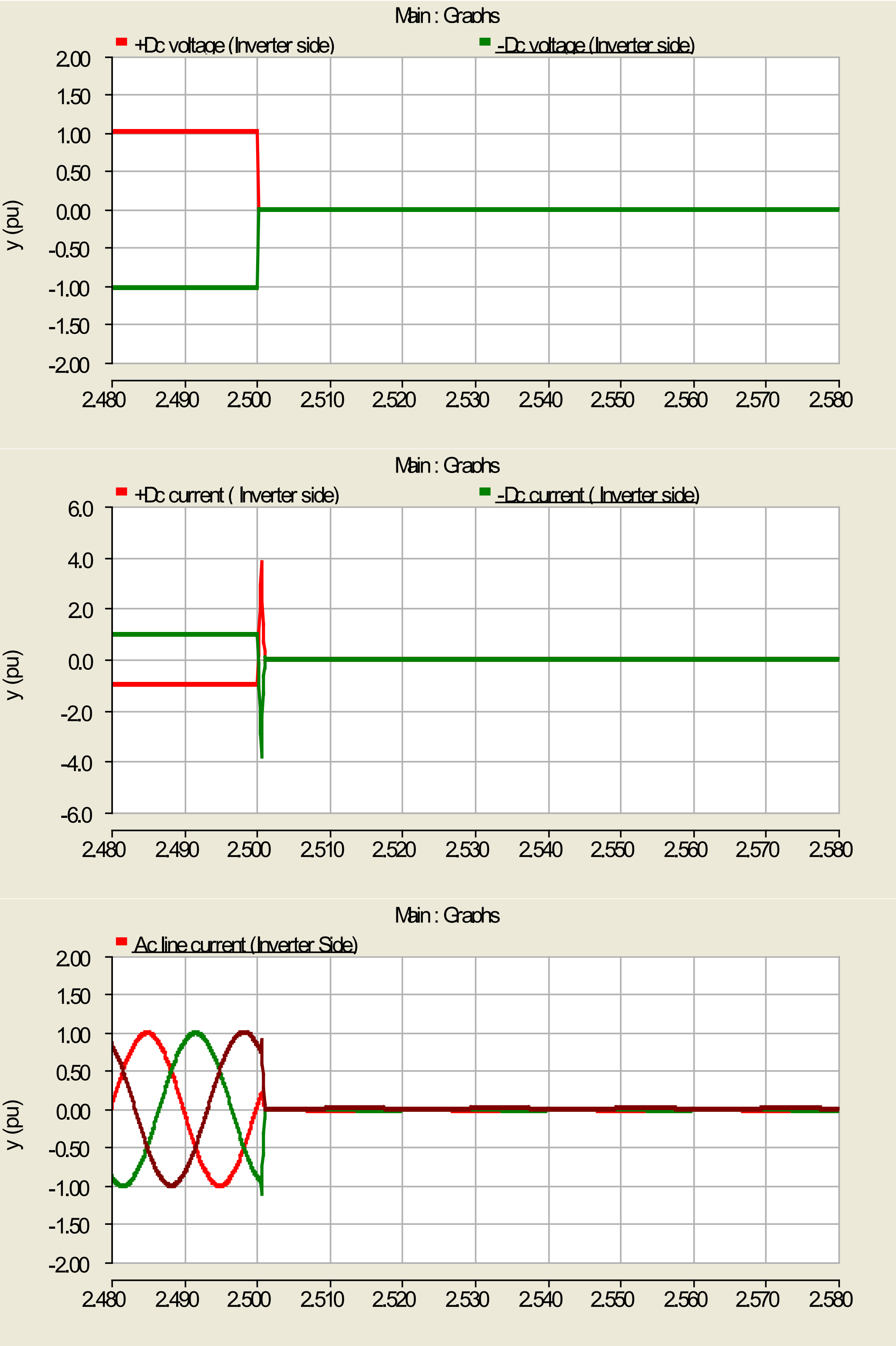
b) Inverter End

Figure B.2 — DC to DC fault at Rectifier



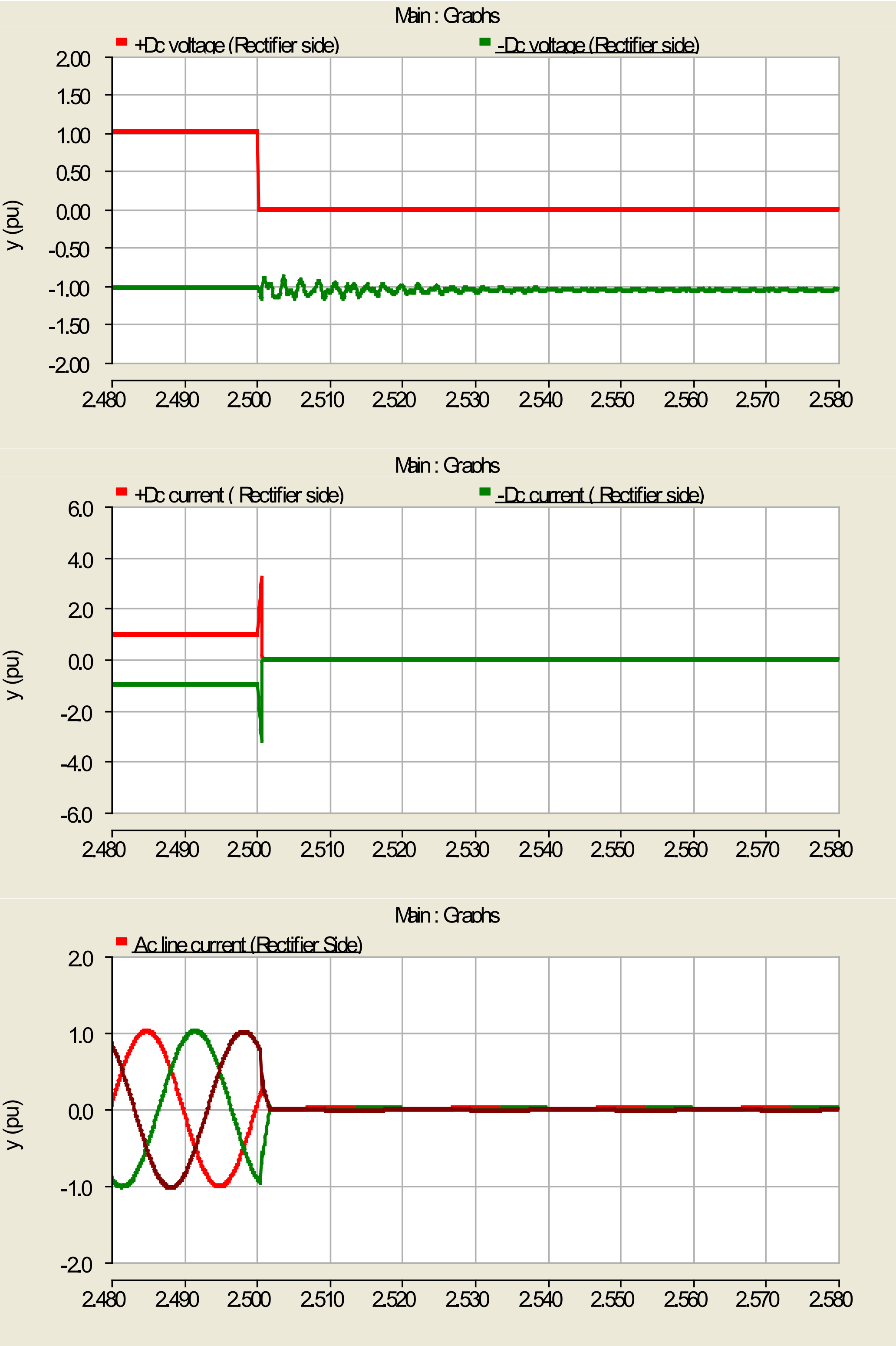
a) Rectifier End

Figure B.3 *(continued)*



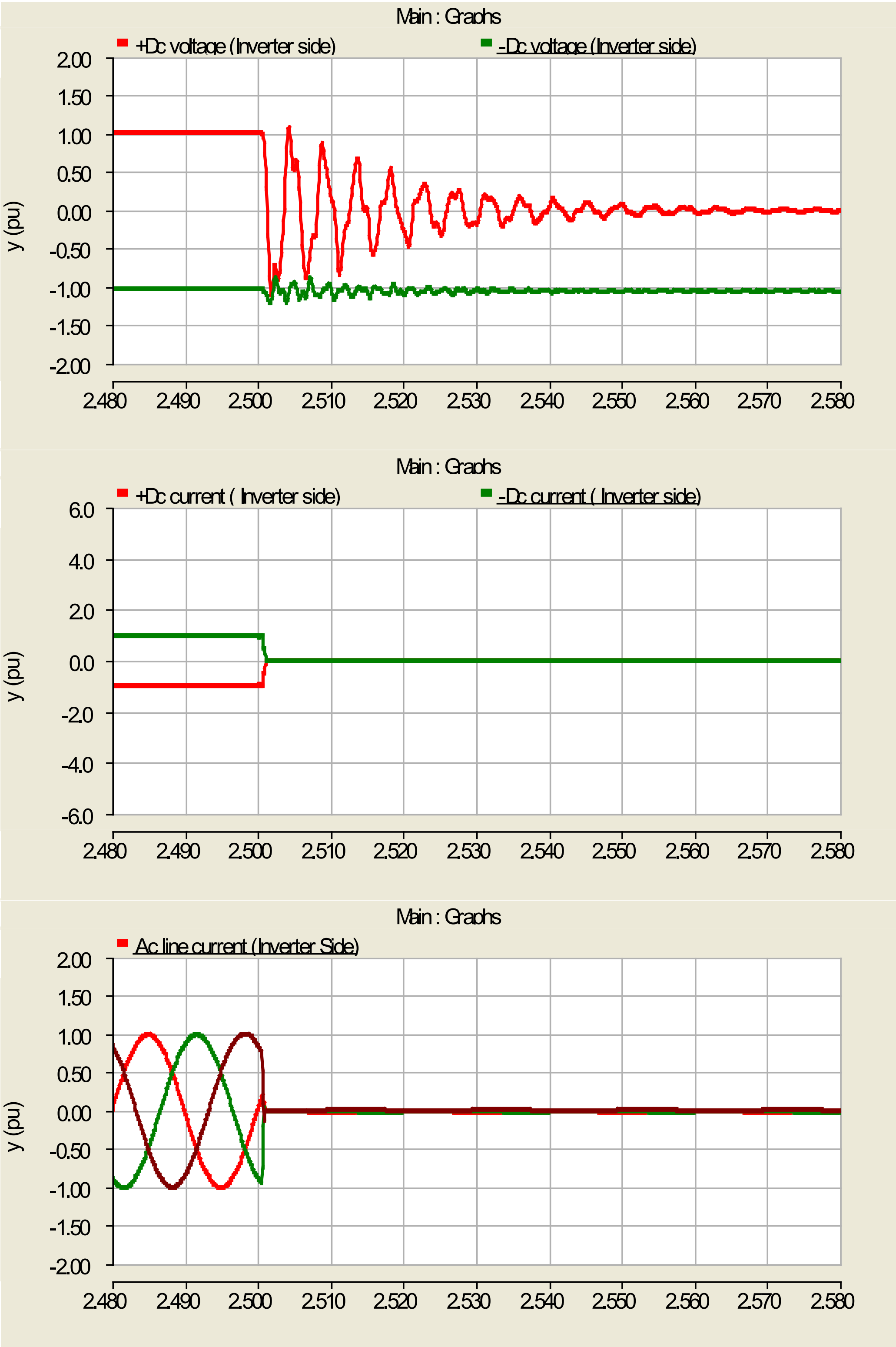
b) Inverter End

Figure B.3 — DC to DC fault at Inverter



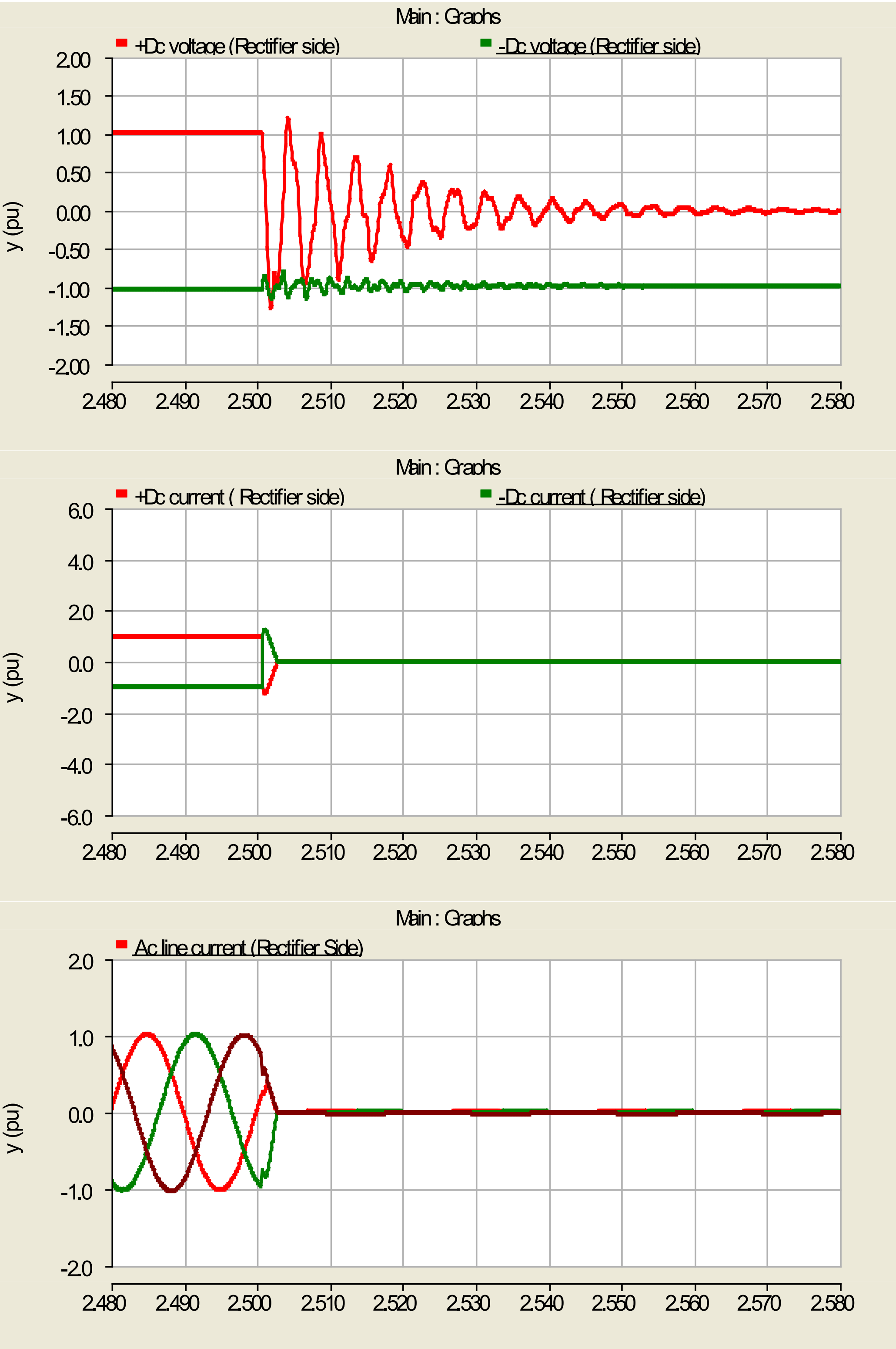
a) Rectifier End

Figure B.4 *(continued)*



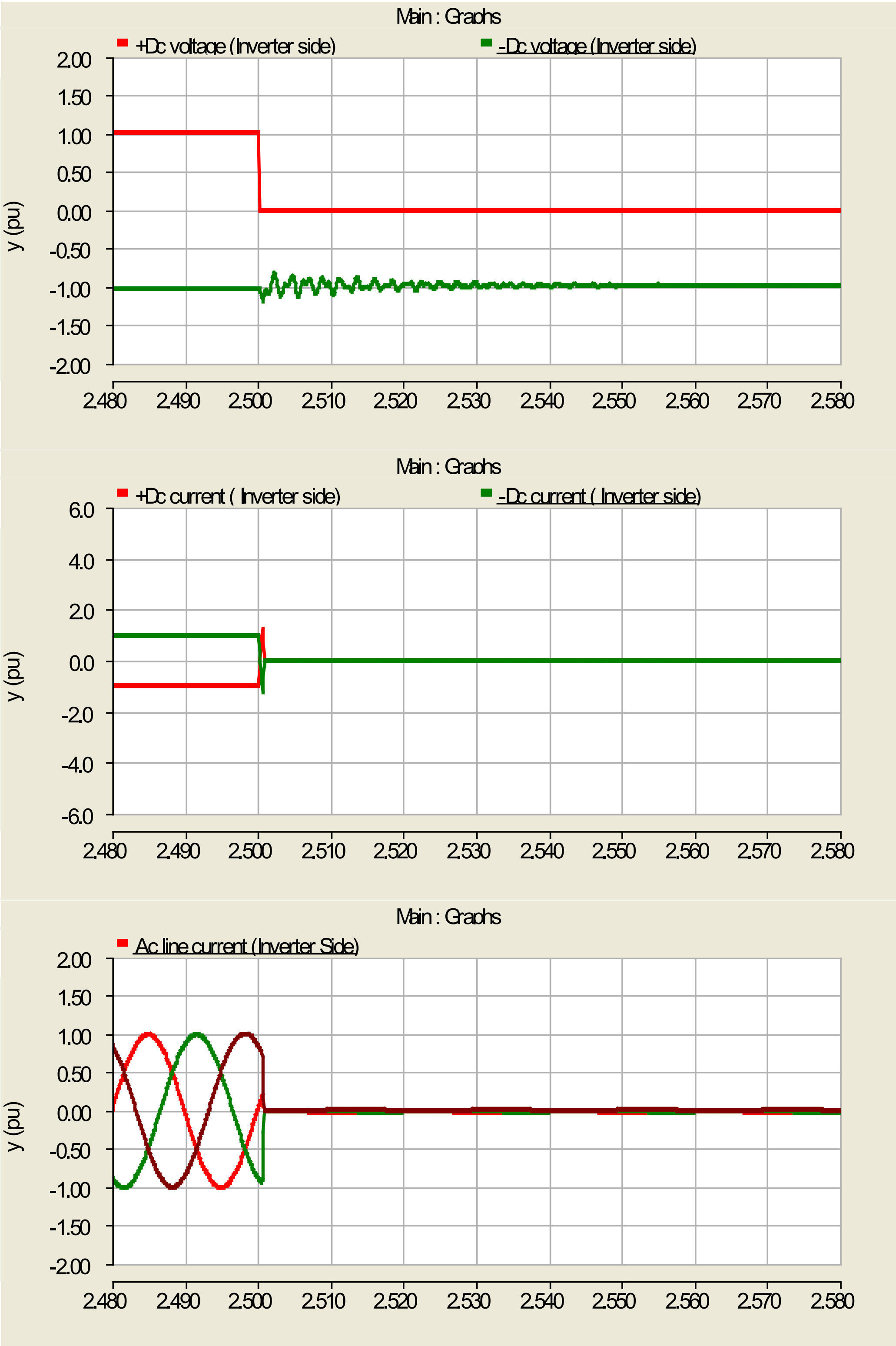
b) Inverter End

Figure B.4 — DC to Ground fault at Rectifier



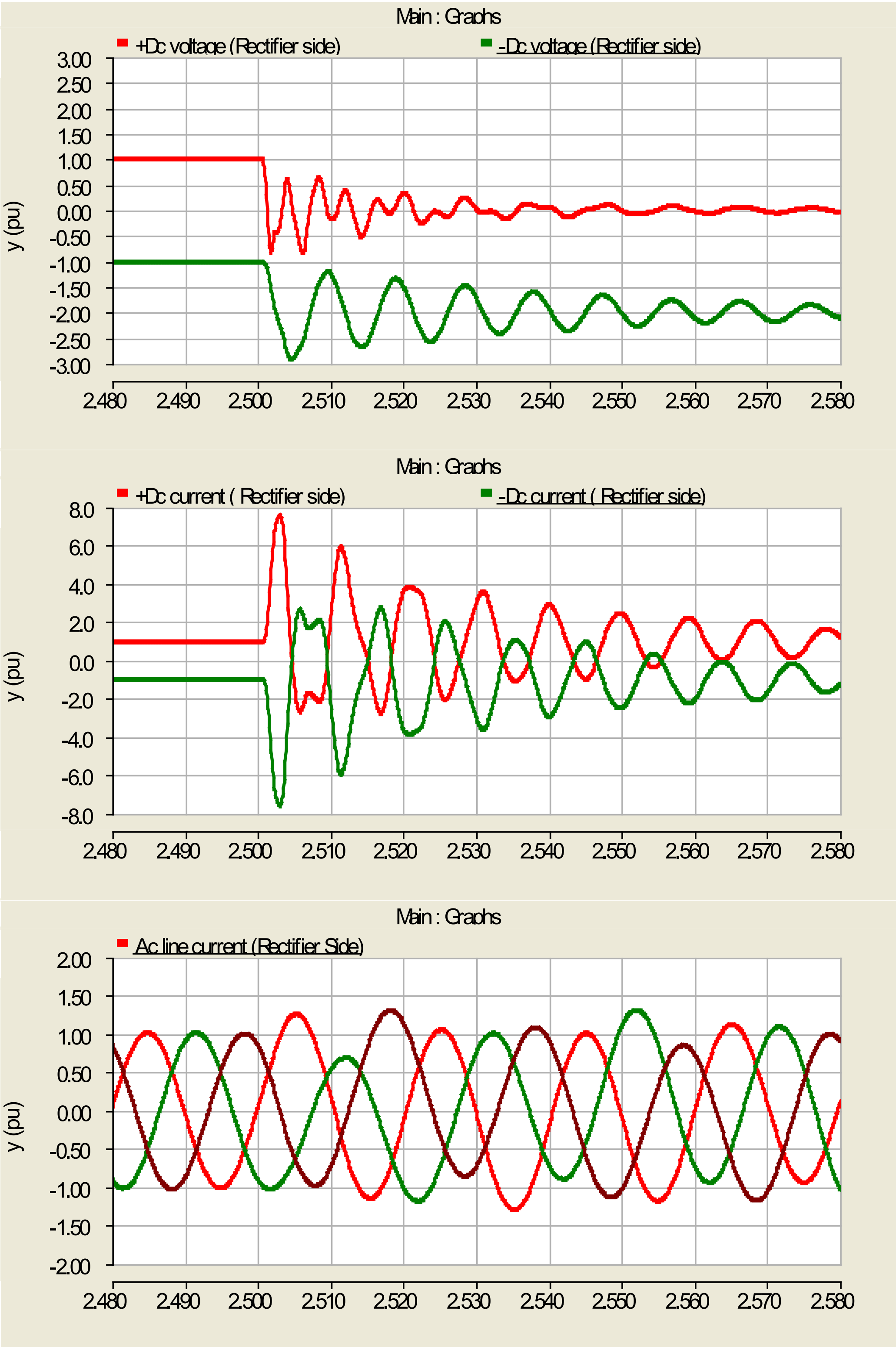
a) Rectifier End

Figure B.5 *(continued)*



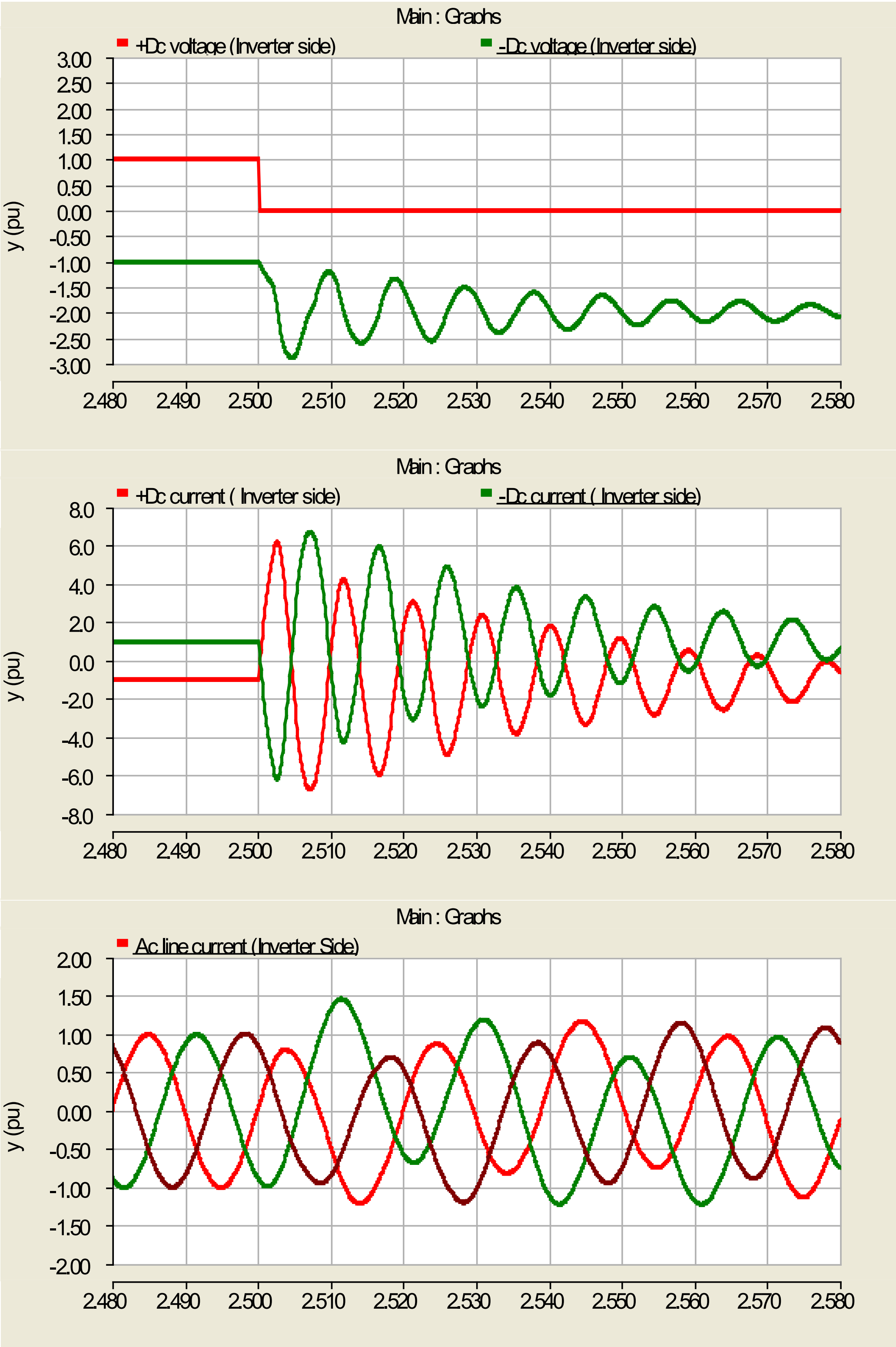
b) Inverter End

Figure B.5 — DC to Ground fault at Inverter



a) Rectifier End

Figure B.6 *(continued)*



b) Inverter

Figure B.6 — DC to Ground fault at Inverter (No Converter Protection Action)

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