Cardiff University Engagement with the National HVDC Centre: Deliverable D1	Doc. No:
The challenges and problems of HVDC schemes connected to weak grids and its correlation with existing Grid Code specifications.	Issue: Date

	Name and Function	Date
Prepared by:	Dr. Tibin Joseph	25/10/2019
Checked and Approved by:	Dr Carlos Ugalde Loo Prof. Jun Liang	
Authorised by:		

Table of Contents

Executive Summary

AC Grid Codes are well documented and constantly being updated by industry and electricity system operators. However, the deployment of power electronics-based technology into conventional ac power systems brings significant challenges for system operators. As high-voltage direct-current (HVDC) technologies keep developing, the existence of hybrid AC and DC systems may be standard in future power grids. Although HVDC brings flexibility to the system, the control strategies have become more complex. In addition, stability issues brought by a reduced system inertia resulting from the gradual replacement of synchronous machines with HVDC-connected generation are becoming very important—particularly when connected to weak ac grids. Therefore, the compliance of conventional Grid Codes should be settled urgently to tackle operational challenges. In this report, Grid Code requirements on HVDC schemes connected to weak grids are presented. Reactive power and fault ride-through requirements specified by the European Network Code and the Great Britain (GB) Grid Code on HVDC are analyzed in detail. The impact of grid strength on the operational requirements of HVDC systems connected to weak grids and compliance testing are performed through simulation studies conducted on a test system resembling an embedded HVDC link.

The report is made in response to the agreement between National HVDC Centre and Cardiff University on the (GB) Grid Code Compliance project. This report evaluates the existing architecture of grid codes related to HVDC connections (e.g. embedded HVDC links, HVDC interconnectors and HVDC systems for the grid integration of offshore wind farms) and their specification on weak AC grid connection requirements.

From the literature survey conducted to understand the current state-of-the art compliance of HVDC connections to network with declining system strength the following aspects has been identified:

• the existing requirements on HVDC connection to AC grids doesn't provide strict specification on weak grid connection compliance.

• The control aspects of HVDC systems related to weak grid connections are largely academic driven with some manufactures such as ABB using power synchronisation control for this purpose [].

• GB Grid Code requirements place emphasis on frequency management, inertia and short-circuit in-feed, fault ride-through (FRT) and voltage regulation assuming HVDC connections are made to strong ac grids and the guidelines for weak connections are limited.

• EU NC HVDC code managed by ENTSO-e aligns different HVDC connection codes to a single one including system strengths

In this report, the grid code requirements on HVDC schemes are presented and critically reviewed. The challenges are summarized, and possible recommendations for future evaluations are provided.

In a nutshell the following aspects of the existing Grid Code requirements have been detailed and summarised with the key findings and results on:

- The existing requirements on HVDC connection to AC grid
- The key variables needed to be considered while mandating these connections
- Relation and dependencies of grid codes suggested by NC HVDC and National Grid ESO
- Lessons learned from existing isolated grid connection of HVDC's or other DC connected power modules
- Relation between the declining short circuit level and grid codes
- Regional decline of grid strength and prospective connection of HVDC links requiring weak grid control mode capability

Nomenclature

AC	Alternating Current
CM	Caithness-Moray
DC	Direct Current
ECC	European Connection Conditions
ECP	European Compliance Processes
ENTSO-E	European Network of Transmission System Operators for Electricity
ESCR	Effective short-circuit ratio
FRT	Fault Ride-Through
FSM	Frequency Sensitive Mode
GB	Great Britain
HVDC	High Voltage Direct Current
LFSM	Limited Frequency Sensitive Mode
MMC	Modular Multi-level Converters
MW	Mega Watts
MVA	Mega Volt Ampere
NC	Network Code
PLL	Phase Locked Loop
PI	Proportional Integral
PCC	Point of Common Coupling
RoCoF	Rate of Change of Frequency
RPR	Reactive power requirements
SCR	Short-circuit ratio
SCL	Short circuit Level
TSO	Transmission System Operator
VSC	Voltage Source Converter
V_{dc}	DC Voltage
V_{ac}	PCC AC Voltage
P	Active Power
Q	Reactive Power

1. Introduction

1.1 Background and Objective

The increased environmental concerns combined with a higher customer demand have put enormous pressure on the existing AC networks. Network reinforcements are put in place to cope with these challenges. Power electronic-based devices play a vital role in these developments. Among them, high-voltage direct-current (HVDC) is a frontrunner and are installed globally for increasing transmission capacity and reliving bottlenecks [1-3]. Several new HVDC connections (embedded HVDC links, HVDC interconnectors and HVDC systems for grid integration of offshore wind farms) are expected in Great Britain (GB) network by 2030, as shown in Figure. 1. Their successful integration into the existing AC grid will play a critical role in developing a sustainable and resilient GB power system. By 2025 the GB electricity transmission network operator is expected to be completely coal-free and to meet these targets HVDC schemes will play an important role [1-7]. The transition from a fossil-fuel-based to an HVDC rich network is expected with more services and flexibilities being required from HVDC connections [6,7].

The electric power system is a large, complex system involving many entities executing their respective activities and responsibilities. With multi-stakeholders perspective such as the generation, transmission, and distribution licensees, system operators, traders, and other participants in the system, the stakeholders should function in proper co-ordination with each other; they should follow the regulations, standards, and procedures for the safe and reliable operation of the grid. Grid codes provide the basic design criteria and operational rules and responsibilities to be followed by the generating stations, transmission utilities, and distribution utilities. There are many rules and criteria in every grid code which deal with generation, transmission, distribution, protection, metering, maintenance, buying and selling of power, ancillary services, etc. Grid Code documents of varying countries depend on the past practices of its respective electricity sector, the present hierarchical structure of its electricity sector, energy sources available, and it's legal, technical, and commercial aspects etc. It is of paramount importance that the power grids of each member states are integrated through a harmonised/co-ordinated effort of grid codes for smooth, optimal, secure, and reliable power system operations.

1.2 EU Network Codes

A harmonised grid connection code was introduced in 2016, as described in the European Union Commission Regulation *EU 2016/631*, which sets a minimum standard that all member states must adhere to in their respective Grid Codes. This will require some minor changes to some of its members Grid Codes [8]. This standard is a minimum requirement rather than a recommended set of requirements and, typically, national Grid Codes are more exhaustive and more stringent in their allowable ranges for technical parameter ranges (e.g., droop and governor dead bands).

ENTSO-E, The European Network of Transmission System Operators for Electricity describe the EU Network Codes as follows [8]: Network codes are a set of rules drafted by ENTSO-E, with guidance from the Agency for the Cooperation of Energy Regulators (ACER), to facilitate

the harmonisation, integration and efficiency of the European electricity market. Each network code is an integral part of the drive towards completion of the internal energy market, and achieving the European Union's 20-20-20 energy objectives of:

• at least a 40 percent cut in greenhouse gas emissions compared to 1990 levels.

• at least a 27 percent share of renewable energy consumption.

• at least a 27 percent energy savings compared with the business-as-usual scenario.

The EU Network Codes have been under development for several years. They are the first large scale attempt at harmonising international grid codes, with the target of ensuring a coherent regulatory framework for power system operations in all EU member countries. As of 2018, all eight codes have entered into force and have been signed by the EU Commission into European law *(see Table 1).*

Table 1 THE EUROPEAN NETWORK CODE Families [8]

The Network Code (NC) families		
Connection	Operation	Market
Demand Connection Code (DCC) High Voltage Direct Current Connections (HVDC) Requirements for Generators (RfG)	Emergency and Restoration (ER) System Operations (SOGL)	Capacity Allocation & Congestion Management (CACM) Forward Capacity Allocation (FCA) Electricity Balancing (EB)

The EU Network Codes are neither a regional nor international grid code. Most of the EU member countries retain their own grid codes or yet to develop one that must be harmonised with the EU Network Codes within three years of implementation. The Codes themselves are a framework that defines the structure and content of Grid Code documents and the rights and responsibilities of stakeholders (which have been subject to European law since 1998). The Connection and Operations code groups mostly specify the "what", but not the "how" – it is, for example, clearly defined which requirements for generators/source have to be included in the grid code, but specific technical parameters are still the responsibility of each individual TSO or DSO as may be the case. Guidelines on parameters and collections of (current) parameters and values of specific requirements in different countries are included in the Codes.

1.3 Grid Codes and UK Perspective

The GB Grid Code comprises of different sub-codes, such as a Connection Conditions covering both generation and demand), the Demand Response Services, a number of Operating Codes, a Planning Code, a European Compliance Process, the European Connection Conditions, and a number of Balancing Codes [9]. The Grid Code Administrator National Grid ESO defines the Grid Code as: *The technical code for connection and development of the National Electricity Transmission System (NETS).* A more detailed explanation can be found in the Grid Code document and states: "*The Grid Code sets out the operating procedures and*

principles governing the relationship between The Company and all Users of the National Electricity Transmission System, be they Generators, DC Converter owners, Suppliers or Non-Embedded Customers. The Grid Code specifies day-to-day procedures for both planning and operational purposes and covers both normal and exceptional circumstances."

The HVDC Code was introduced through the European Third Energy Package and applies to any HVDC System, HVDC Converters (including Remote End HVDC Converters) and DC Connected Power Park Modules [8-9]. In the GB system, many of the requirements apply equally to HVDC Systems, DC Connected Power Park Modules and Remote End HVDC Connections, which for the purposes of the GB Grid Code have collectively been called HVDC Equipment [9]. These sets of requirements and specifications will facilitate a seamless interconnection of future HVDC links and contribute to the creation of a DC grid in the GB.

Grid Codes, which include both AC and DC grid specifications, are under constant revision in order to reflect the system requirements [6-7, 10]. For instance, the UK government and the regulator (Ofgem) have recently launched a review into existing Grid Codes related to energy systems, aiming to define code governance and administration [10]. On the other hand, GC revisions are constant with monthly review panel meetings Given their vital and strategic role in the GB, Grid Code revisions will impact the requirements for the safe and secure connection of planned HVDC assets. Most of the existing Grid Codes assume HVDC connections are made to a strong AC grid and the guidelines for weak connections are limited [5-7]. This constitutes an important issue demanding attention given the reduced grid strength at different locations of the GB network where multiple in-feed HVDC links either exist or are planned (for example in South-East England and North-East Scotland) [6, 11]. It is expected that the total HVDC installed capacity in the UK will reach 16 GW by 2027 compared to 8 GW present capacity [4]. The HVDC link or interconnectors will contribute to the transition from fossil-fuel based to HVDC-rich network to facilitate the decarbonisation target of electricity network by 2025 [4,7].

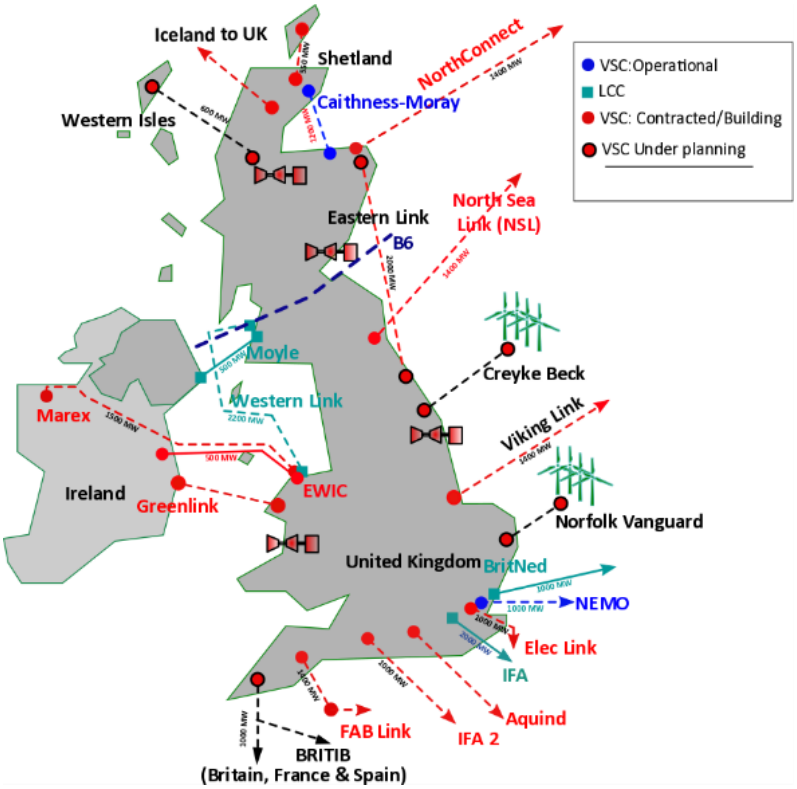


Figure 1. HVDC interconnections of the UK adapted from [1,4].

As depicted in Figure.1 several HVDC schemes (embedded, interconnectors and connection for offshore wind farms) are currently being implemented/under construction. These HVDC connection integrated in close proximity between each other and to existing generating units has to adhere to the connection requirements specified in GB GC. In addition, these installations will bring new operability challenges for the system operator which are not present in the network before such as multi-infeed interactions, controller interactions, subsynchronous oscillations, unstable voltage oscillations, resonance and harmonic interactions to name a few. The current GB GC specify requirements to most of these events such as, stable non-oscillatory voltage control (ECC6.3.8) and SSO damping (ECC6.3.17) (detailed evaluation of GC requirements is outlined in Appendix. I). However, with the proliferation of inverter fed generations and higher capacity HVDC schemes the current GC requirements are non-exhaustive, meaning a relation between system strength and existing specification is lacking. Moreover, as shown in Figure. 1, there are currently two HVDC links embedded in the GB system (Western and CM HVDC link), with Eastern HVDC link being scoped for future. These internal HVDC systems are not captured in the present GB GC, which is significant considering the amount of power flow it manages.

Additional questions also prevail with high penetration of HVDC systems and their instantaneous power import and export requirements, especially when the GB grid is weak. In particular with the integration of offshore wind through HVDC and for multi-terminal infeed's, whether it if feasible to curtail the power import/export, if so how much and from where, and how that affects the security and quality of supply standards (SQSS) limit of 1800 MW (Infrequent Infeed Loss Risk) [SQSS]. These questions are becoming increasingly significant with the GB being connected to neighbouring countries through large HVDC interconnectors.

At present we have 5 such interconnectors in operation, totalling 5000MW of power capacity, with 4 more in construction adding a further 4800MW of capacity. In planning are a further 13 interconnectors, which could provide a further 16,650MW of power capacity. The flexibility of HVDC systems provides a tremendous opportunity to control these large, typically 1000MW to 2000MW each, links to modulate their power automatically in response to variations in system parameters such as frequency and voltage variations. All such power modulations would require agreement with the neighbouring power systems, who would experience the same power modulation and needs to be incorporated in the GC specifications not only in the GB but also in NC HVDC. Beyond that the speed of response of modern digital controlled HVDC schemes is fast enough to allow these large power links to provide the necessary power modulation, i.e. "synthetic inertia", to improve the resilience of the network to the type of event encountered in August 2019 in the GB. It is well known that system strength has been reducing as inverter fed generation has increased, but this event has served to demonstrate the adequacy of connection requirements.

From the existing GC for HVDC schemes, a key requirement will be the provision of active power control and frequency support. This has been highlighted with other general specifications in the ENTSO-E's NC on grid integration of HVDC [8]. This is also highlighted in the GB Grid Code, where the focus is placed on frequency management, inertia and short circuit in feed, and voltage management [9].

However, for the GB system, with multiple HVDC schemes already in place and more in the pipeline, the active power flow requirements in different areas are constrained [6,11]. In addition, given that the replacement of fossil-fuel based generation with HVDC-connected renewables will reduce the GB system strength (represented as short-circuit ratio, SCR). The GB electricity transmission system operator National Grid (National Grid ESO) has identified this scenario and identified the pattern of a general decline of short circuit level (SCL) in the network as shown in Figure . 2 [6]. A considerable amount of decline in the SCL is foreseen in the GB network by 2025, which must be incorporated in the existing Grid Code provisions [6,11].

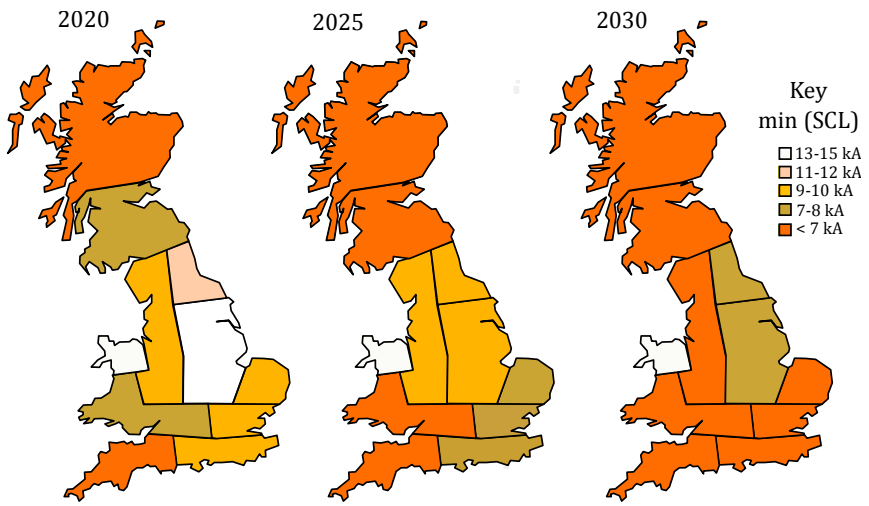


Figure 2. Regional short circuit level in the GB system [4].

1.4 Grid Strength and HVDC connection requirements

To this end, challenging conditions are foreseen to be imposed on HVDC connections in weak areas or regions with declining SCL. On one hand, too negligent requirements may cause reliability or stability issues. However, on the other hand, too onerous requirements can prevent reaching energy policy targets.

Connection of HVDC schemes to AC grids and grid code compliance tests is a topic of research in the past years [12-16]. The compliance of voltage source converter based HVDC schemes to fault ride through (FRT) requirements were reported in [8-10]. A recent EU project developed open source models for grid code compliance tests of HVDC and DC grid and is reported in [15-17]. Articles on the frequency support requirements from HVDC converters were presented in [18-19]. However, in all the cases reported in the literature and in the existing Grid Codes a strong AC system is assumed. The reduction in SCL and thereby the strength of the AC grid where HVDC is connected is not considered. This will be of significant importance in the near future and needs immediate attention with particular focus required for the specifications and tests to be performed and complied in the code.

To address this scenario, it would be beneficial for system operators to specify different power responses of HVDC connecting to areas with different network strength, defined as operational zones or to specify appropriate control responses for HVDC schemes connecting to areas with relatively weak network strengths. Thus, this report will review the specifications and requirements of the existing Grid Codes for HVDC schemes defined in the GB GC and NC HVDC code. In addition, the available control schemes from open literature for HVDC systems will be identified and summarised with particular focus on weak grid connection.

2. THE GRID CODE REQUIREMENTS ON HVDC SCHEMES

2.1 Introduction

The technical specifications in National Grid Codes can be divided into several categories with the main list highlighted below. Specifically, we focus on the grid connection requirements of HVDC systems and DC-connected power park modules as described in the GB Grid Code [9]. This include requirements for:

- Steady-state Operation
  - Active Power Controllability
  - Reactive Power Controllability
  - Voltage/reactive power/power factor control mode
  - Frequency Sensitive modes (FSM, LFSM-O, LFSM-U)
  - steady state short-circuit current calculation
  - Steady-state harmonics
  - Load flow calculation

- Dynamic Operation
  - fault-ride-through capability
  - post fault active power recovery

- fast fault current injection
- frequency restoration control
- power oscillations damping control
- ability to damp sub-synchronous oscillations
- harmonic stability
- black start capability
- protection settings
- fast fault current injection
- fast active power reversal
- fast signal response
- ramping rate modification

A comparison of the HVDC compliance testing/simulations requirements within the GB Grid Code with remarks to the relevant steady-state and dynamic compliance codes as specified are compiled and is provided as an Appendix at the end of this report for more detailed analysis.

2.2 Frequency/Active Power Requirements

Each Power Generating Module (including DC Connected Power Park Modules) and Onshore HVDC Converters at an Onshore HVDC Converter Station must be capable of contributing to frequency control by continuous modulation of active power supplied to the NETS. All onshore and offshore power park modules (PPM) and DC converters at a DC converter station in the GB system, with a registered capacity above 50 MW, must have the capability of participating in frequency control at all times. The settings specified for frequency requirements as outlined in ENTSO-E NC are presented in Table 2, with the modes of operation which they must adhere to outlined as: [9]

- Frequency Sensitive Mode (FSM): in case of over / under frequencies within a limited frequency range
- Limited Frequency Sensitive Mode (LFSM): in case of over / under-frequencies for larger frequency excursions. LFSM is further divided into two:

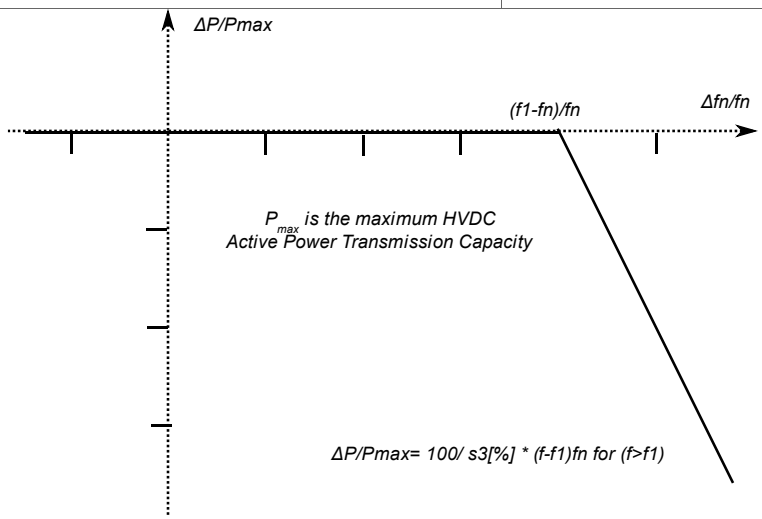
  (a) <u>Limited Frequency Sensitive Mode – Overfrequency (LFSM-O):</u> Each Power Generating Module (including DC Connected Power Park Modules) and HVDC Systems shall be capable of reducing Active Power output in response to Frequency on the Total System when this rises above 50.4Hz

  (b) <u>Limited Frequency Sensitive Mode – Underfrequency (LFSM-U):</u> Each Type C Power Generating Module and Type D Power Generating Module (including DC Connected Power Park Modules) or HVDC Systems operating in Limited Frequency Sensitive Mode shall be capable of increasing Active Power output in response to System Frequency when this falls below 49.5Hz. This is valid only when the converter is importing power into the GB system.

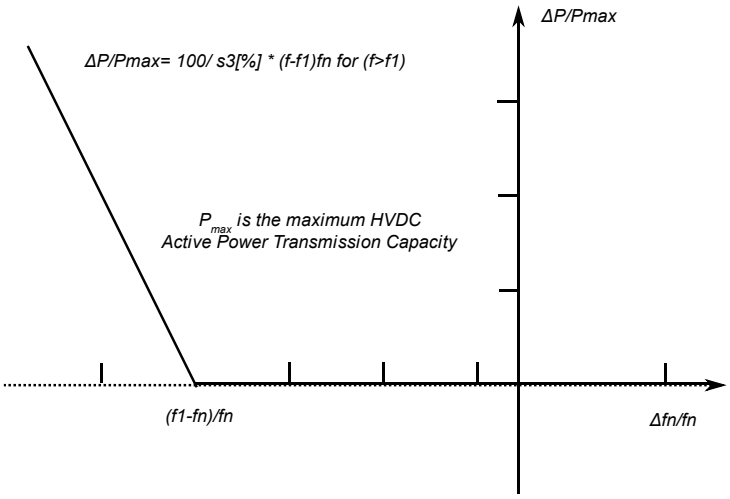
Table 2 Frequency Sensitivity Modes

Frequency Sensitivity Modes

Mode	European Network Code e	NGESO
FSM	0- 0.5 Hz deadband and droop 2%-12% with 1.5%-10% available capacity	0 Hz deadband and 3-5% Droop with 10% available capacity
LFSM-O	Threshold value 50.2Hz - 50.5 Hz. Droop 2%-12%	Threshold value 50.4 Hz, Droop 10%
LFSM-U	Threshold value 49.5 Hz - 49.8 Hz. Droop 2%-12%	Threshold value 49.5 Hz, Droop 10%

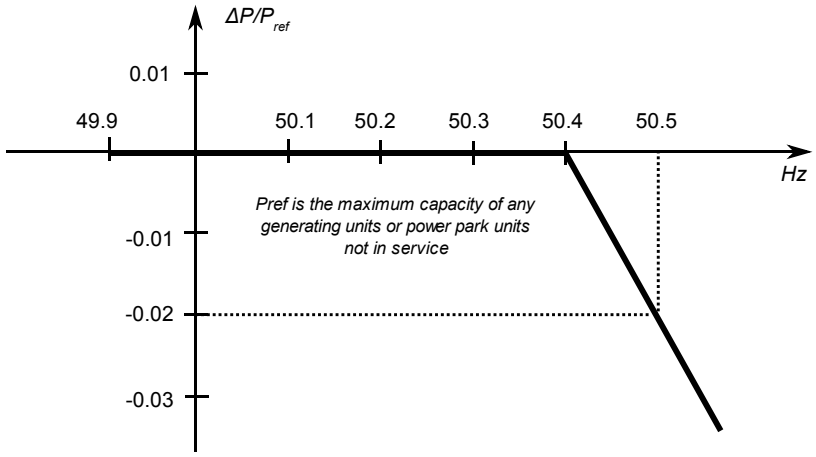


(a)

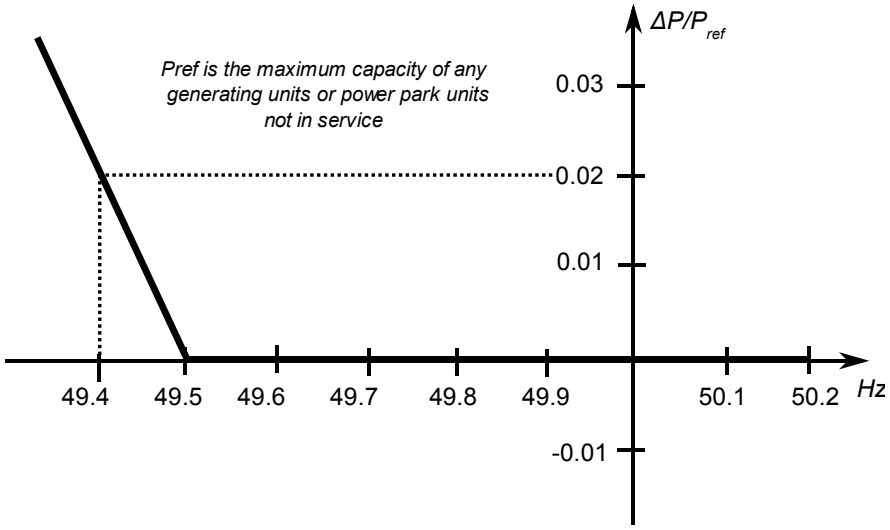


(b)

Figure 3. The active power capacity of an HVDC with the change of frequency; ENTSO-E solution for LFSM.: (a) LFSM-U(b) LFSM-O



(a)

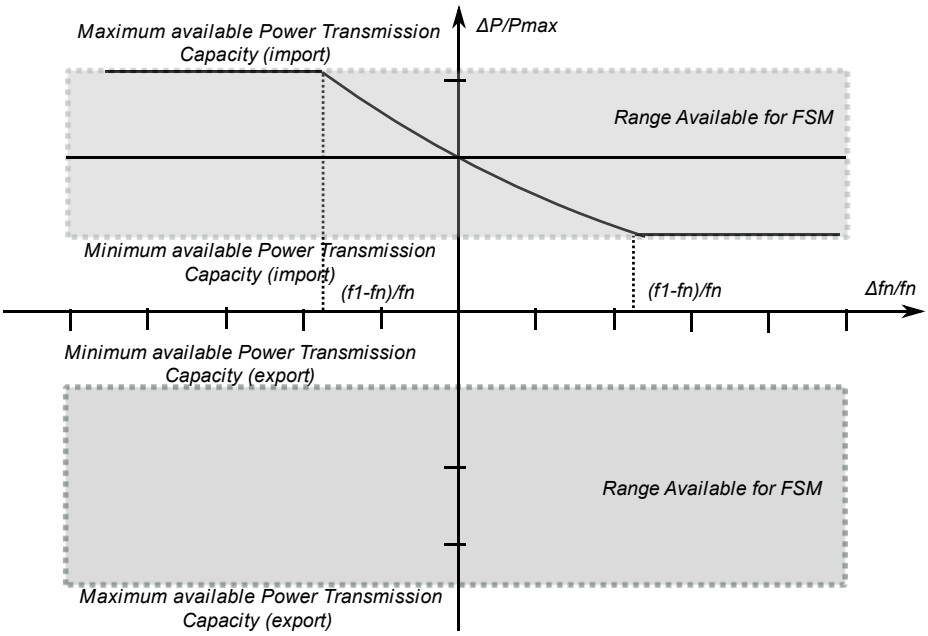


(b)

Figure 4. National Grid Solutions for LFSM; (a) LFSM-U(b) LFSM-O

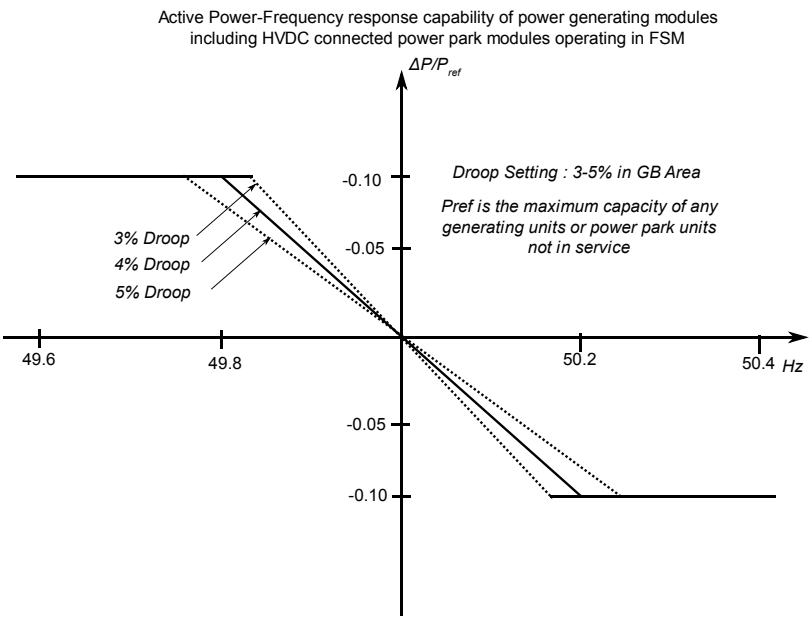
2.2.1 Limited Frequency Sensitive Mode (LFSM)

In the LFSM, the DC converters must be capable of maintaining constant active power for system frequency changes between the ranges of 49.5 to 50.5 Hz. The active power output of converters has to be independent of the system frequency in this range. Also, below 49.5 Hz to 47 Hz, active power drop in the DC converter must not exceed 5%. This applies to all DC converters with the rated capacity both less and greater than 50 MW as shown in Figures 3-4. For DC converters with a power input from the NETS (i.e. exporting power to DC networks), when operating in the LFSM, they must maintain constant active power between 49.5 to 50.5 Hz and their active power input must not drop below 40% for frequency drops below 49.5 Hz. Figures. 3-4 shows the active power capacity of an HVDC according to the frequency variations for both ENTSO-E and GB Grid Code requirements.



(a) European NC HVDC(?) solution.

.



(b) GB Grid Code solution

Figure 5 The available ranges for FSM (a) ENTSO-E (b) GB Grid Code

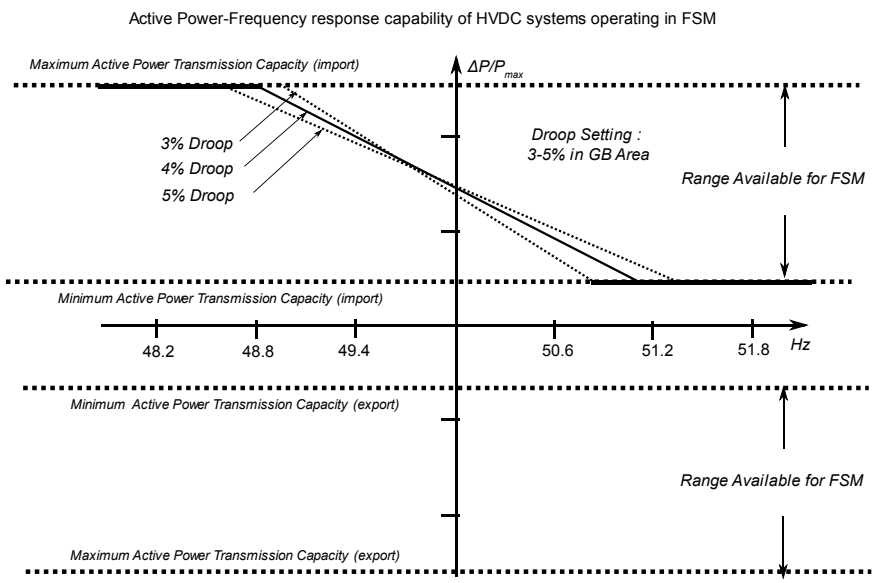


Figure 6 Active Power frequency response capability of a HVDC System operating in FSM.

2.2.2 Frequency Sensitive Mode (FSM)

The generating units or DC converter stations participating in the FSM are considered as providing a system ancillary service. DC converters with a registered capacity greater than 50 MW can participate in this service and are no longer required to operate in the LFSM. In the FSM, HVDC systems and DC connected power plants provide the primary response and/or secondary response and/or high-frequency response. Figures. 5 shows the available ranges for the FSM solution for the ENTSO-E and National Grid specifications. HVDC Systems shall also meet the following minimum requirements: HVDC Systems shall be capable of responding to frequency deviations in each connected AC System by adjusting their Active Power import or export as shown in Figure 6. The HVDC requirements for frequency settings of ENTSO-E and National Grid specifications are provided in Table 2.

Even though the current Grid Code specifies these requirements for the effective participation of HVDC systems in ancillary services, the regulation of frequency in a low system strength scenario is still not fully addressed. Besides the test that needs to be undertaken or considered while devising the HVDC connections for FSM scenarios are also not fully developed. To this end it should be worth mentioning that the review performed here is based on the existing Grid Code requirements and there are many other aspects that needs to be taken into consideration to evaluate the effectiveness of existing FSM mode.

2.3 Voltage and Reactive Power Regulation Requirements

The reactive power requirements of an HVDC system or DC connected power park module can be usually specified using PQ and UQ profiles. Where PQ defines the reactive power requirements as a function of active power and the UQ specifies reactive power requirements as a function of the voltage. These requirements may vary for different values of active power and the voltage at the connection point.

The European NC defines the reactive power requirements in the following way [8]. "The relevant system operator, in coordination with the relevant TSO, shall specify the reactive power capability requirements at the connection points, in the context of varying voltage. The proposal for those requirements shall include a U-Q/P_{max} profile, within the boundary of which the HVDC converter station shall be capable of providing reactive power at its maximum HVDC active power transmission capacity. The U-Q/P_{max} profile shall comply with the following principles:

(a) the U-Q/P_{max} profile shall not exceed the U-Q/P_{max} profile envelope represented by the inner envelope in Figure 7 and does not need to be rectangular;

(b) the dimensions of the U-Q/P_{max} profile envelope shall respect the values established for each synchronous area in Table 3; and

(c) the position of the U-Q/P_{max} profile envelope shall lie within the limits of the fixed outer envelope in Figure 7.

Moreover, the HVDC system shall be capable of moving to any operating point within its U-Q/P_{max} profile in timescales specified by the relevant system operator in coordination with the relevant TSO.

In European NC and GB Grid Code there are three modes of control for DC converters identified while fulfilling the reactive power requirements: AC voltage control mode (Vac), Reactive power control mode (Q) and Power factor control mode. The value of Vac set point is defined in the range from zero to +/-5% of nominal value (reference 1 p.u.). In addition, 90% of Q variation within time t_1 = 0.1-10 s is required for providing effective voltage support, with a settling time of 1 - 60 s [8-9]. The specific requirements for voltage and reactive power regulation are summarised in Table 3 for both R and GB GC.

Table 3 U/Q Requirements

Reactive Power/Voltage Requirements

Mode	ENTSO-e	National Grid
Power Factor	0.95 lead - 0.95 lag	0.95 lead - 0.95 lag
Voltage Range	1.1 p.u. – 0.875 p.u. for voltage (0.225 p.u.)	1.1 p.u. – 0.875 p.u. for voltage (0.225 p.u.)
Maximum range of Q/Pmax	0.95	0.95

The GB GC code specifies: All Onshore Power Park Modules and HVDC Converters at an HVDC Converter Station with a Grid Entry Point or User System Entry Point voltage above 33kV, or Remote End HVDC Converters with an HVDC Interface Point voltage above 33kV, or OTSDUW Plant and Apparatus with an Interface Point voltage above 33kV shall be capable

of satisfying the Reactive Power capability requirements at the Grid Entry Point or User System Entry Point (or Interface Point in the case of OTSDUW Plant and Apparatus, or HVDC Interface Point in the case of a Remote End HVDC Converter Station) as defined in Figure 8 (Figure ECC.6.3.2.4(a)) when operating at maximum capacity.

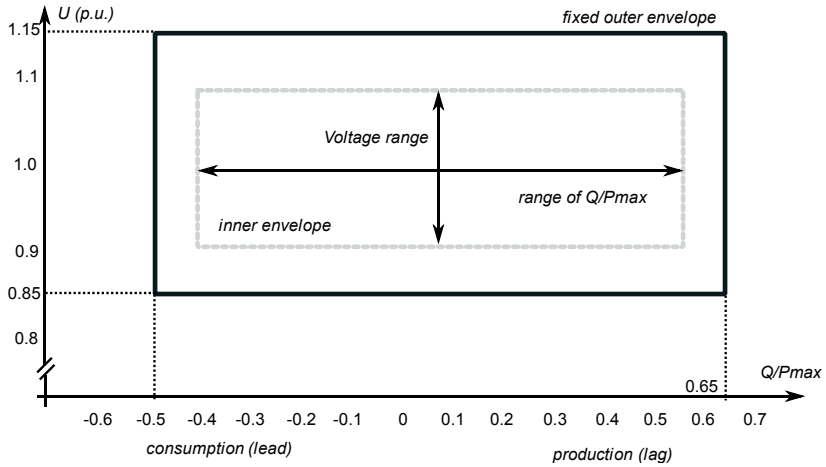


Figure 7 The voltage ranges under different active and reactive power defined by ENTSO-E.

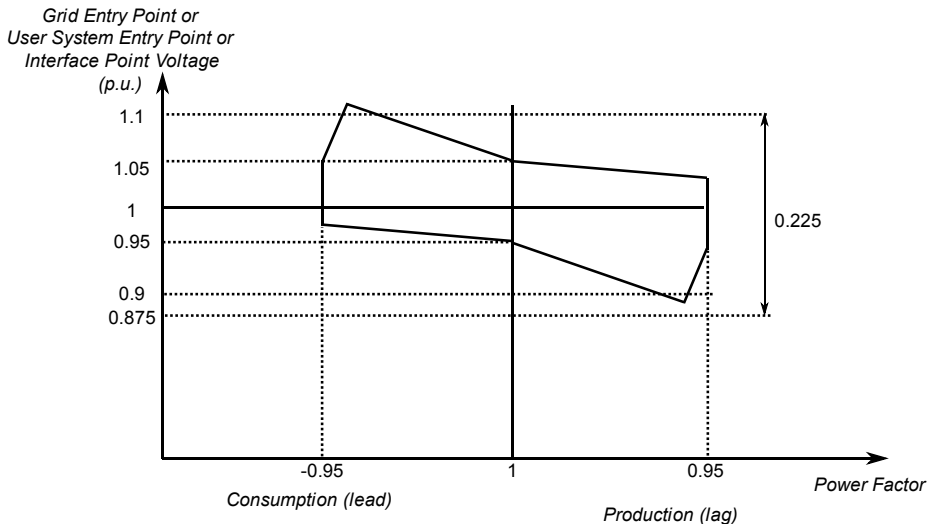


Figure 8 Reactive Power Capability at rated capacity for HVDC

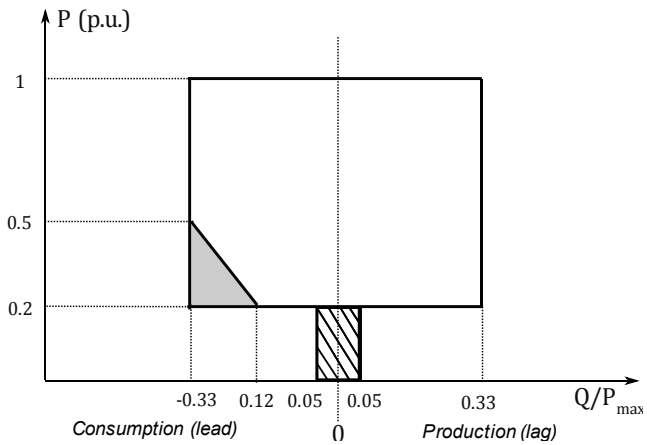


Figure 9 Reactive Capability at nominal AC voltage for GB GC

GB GC ECC.6.3.2.4.4 defines that: All Type C and Type D Power Park Modules, HVDC Converters at an HVDC Converter Station including Remote End HVDC Converters or OTSDUW Plant and Apparatus, shall be capable of satisfying the Reactive Power capability requirements at the Grid Entry Point or User System Entry Point as defined in Figure 9, (Figure ECC.6.3.2.4(c) in GC) when operating below maximum capacity. With all plant in service, the reactive power limits will reduce linearly below 50% active power output as shown in Figure 9 unless the requirement to maintain the reactive power limits defined at maximum capacity under absorbing reactive power conditions down to 20% active power output has been specified by the company. These reactive power limits will be reduced pro-rata to the amount of plant in service. As seen from Figures 7-9 the basic requirements are the operation between 0.95 power factor leading to lagging.

The current Grid Code specifies the voltage and reactive power requirements for the effective participation of HVDCs in system services, however, the regulation of voltages in a low system strength scenario is still not fully addressed. Besides the test that needs to be undertaken or considered while devising the HVDC connections for RPR scenarios are also not fully developed. Besides there are questions like how HVDC does participates in voltage regulation as it gets harder at lower SCL. The clear definition of percentage voltage change or step needs to be provided with respect to power ratio at the PCC. Moreover, the droop characteristic of the steady state control is not mentioned neither post fault dynamic voltage control, for instance, rethinking on the testing that should be performed for Mvar delivery 1sec after a disturbance as in code or may be more important to be testing response earlier than that. To this end it should be worth mentioning that the review performed here is based on the existing Grid Code requirements and there are many other aspects that needs to be taken into consideration to evaluate the effectiveness of existing modes.

2.4 Fault Ride-Through Requirements

ENTSO-E in its Network Code on HVDC Connections sets out clear and objective requirements for HVDC System Owners, DC connected Power Park Module Owners, Network Operators and National Regulatory Authorities in order to contribute to non-discrimination, effective competition and the efficient functioning of the internal electricity market and to ensure system security. The HVDC system shall fulfil the requirements referring to voltage stability, be capable of giving active and reactive support for the AC system. Also, the HVDC system shall have the capability of fault ride through. Therefore, the HVDC system owners should make sure the operation and control of their HVDC system are able to meet all the Network Code [8]. Figure. 10 shows the fault ride-through requirement (critical fault clearance time) of an HVDC converter for user system entry point of HVDC interface point at or above 110 kV as defined in European NC HVDC Regulation (EU) 2016/1477 [8].

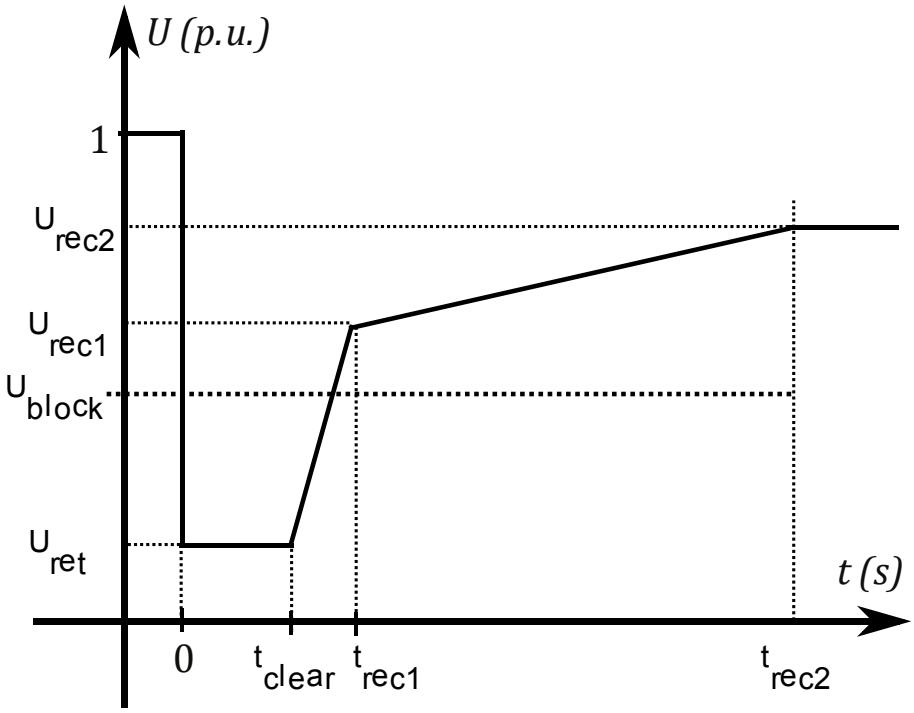


Figure 10. The Fault-ride-through profile of an HVDC converter station European NC solution.

The diagram represents the lower limit of a voltage-against-time profile at the connection point, expressed by the ratio of its actual value and its reference 1 p.u. value in per unit before, during and after a fault. U_{ret} is the retained voltage at the connection point during a fault, t_{clear} is the instant when the fault has been cleared, $U_{rec1}$and t_{rec1} specify a point of lower limits of voltage recovery following fault clearance. U_{block} is the blocking voltage at the connection point. The time values referred to are measured from t_{fault}.

The relevant TSO may specify voltages (U_{block}) at the connection points under specific network conditions whereby the HVDC system is allowed to block. Blocking means remaining connected to the network with no active and reactive power contribution for a time frame that shall be as short as technically feasible, and which shall be agreed between the relevant TSOs and the HVDC system owner. The parameters and time scale is presented in Table 4 for the FRT requirements specified in European NCs

Table 4 Parameters for Figure 6 for the fault-ride-through capability of an HVDC converter station

Voltage parameters [pu]		**Time parameters [seconds]**	
U_{ret}	0.00 – 0.30	t_{clear}	0.14 – 0.25
U_{rec1}	0.25 – 0.85	t_{rec1}	1.5 – 2.5
U_{rec2}	0.85 – 0.90	t_{rec2}	t_{rec1} – 10

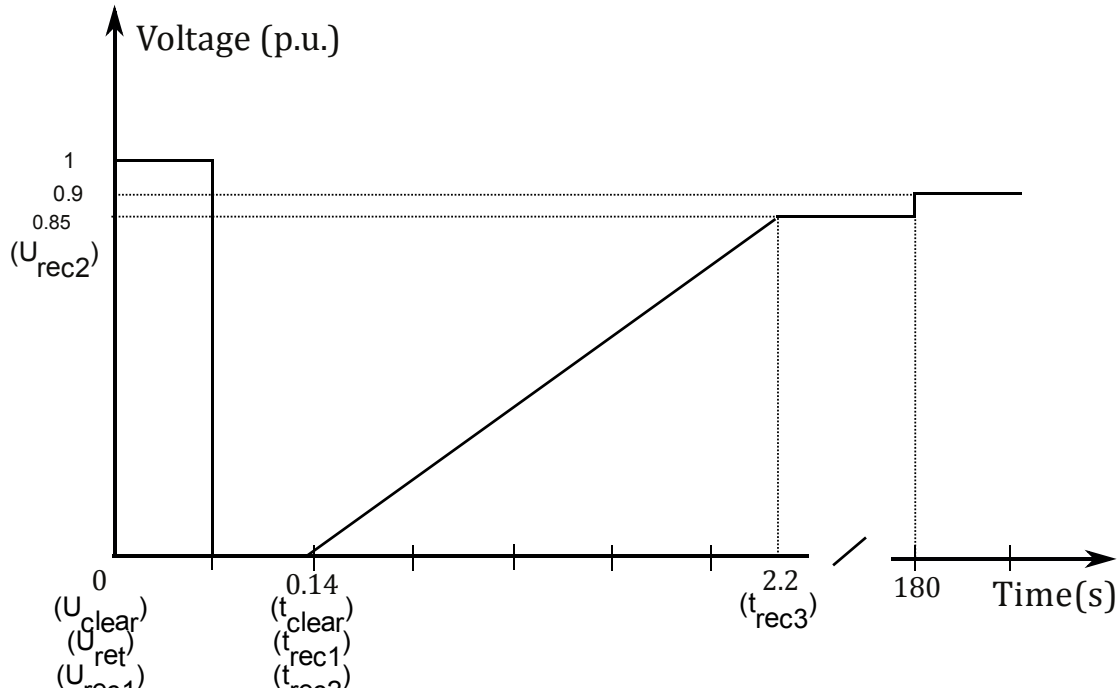


Figure 11 Voltage against time curve applicable to HVDC Systems and Remote End HVDC Converter Stations GB Grid Code

Table 5 Voltage against time parameters applicable to HVDC Systems and Remote End HVDC Converter Stations

Voltage parameters (p.u.)		Time parameters (seconds)	
U_{ret}	0	t_{clear}	0.14
U_{clear}	0	t_{rec1}	0.14
U_{rec1}	0	t_{rec2}	0.14
U_{rec2}	0.85	t_{rec3}	2.2

For the GB Grid Code for FRT requirements, it should be noted that the pre-fault voltage shall be taken to be 1.0 p.u. and the post fault voltage shall not be less than 0.9 p.u. as depicted in Figure 11 as per Grid Code requirements [9]. The GB Grid Code FRT requirements also specifies fault duration beyond 140ms, as shown in Figure 12. The required ride through time for a given voltage for eg: a voltage level of 80% nominal value at 1.2s and 85% at 2.5s is tolerated for a longer duration of faults. Besides, during fault the priority is given to reactive power to support the voltage over the active power and minimum active power at during a voltage drop to generate maximum reactive current is allowed in the National and European Grid Codes.

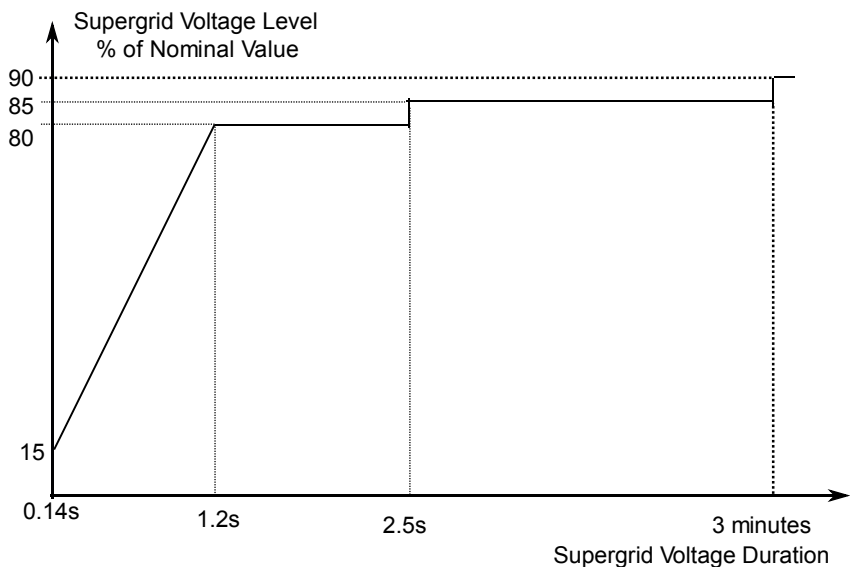


Figure 12 Fault ride through requirments longer than 140ms

The current Grid Code specifies the FRT requirements for the effective connection of HVDCs, however, the behaviour in a low system strength scenario is still not fully addressed. Besides the testing that needs to be undertaken or considered while devising the HVDC connections for FRT scenarios are also not fully developed. Besides there are questions like how HVDC behave during a fault and afterwards using the existing control schemes as it gets harder at lower SCL. The clear definition on the need for 100% active power capability 500ms after a fault clearance and voltage>0.9p.u. is needed to be satisfied as defined in requirement (ECC6.3.17). Besides, for fast fault injection of reactive current during a fault but nothing specifying exactly what reactive current strategy is covered thereafter. Besides, the nature and requirements on temporary over voltage (TOV) is not included in the standard but that in satisfying FRT is of importance as converter is subjected to overvoltage, some which may be driven by its control strategy. None of that is tested in existing code.

2.5 DC connected Power Plants/Modules Requirements

The requirements for DC connected wind parks are reported in Articles 20 to 22 of "Network Code on requirements for grid connection of generators"[8]. Similar to the previous specifications, the focus is on frequency, voltage and fault ride through capabilities [8]. In the GB Grid Code requirements for DC connected power plant are the same as those for HVDC systems as discussed in the previous sections. However, a major difference lies in the FRT requirements. From the existing regulation, priority must be given to reactive power support (thus, active power can go to zero during the fault period). For GB Grid Code, during the fault period the DC converter must deliver at least an active power proportional to residual voltage [8-9]. Even though this is included in the Codes, how the residual voltage influence the behaviour of control design when SCL at different connection point varies is an area which needs clarification on the Gird Code for effective design of HVDC control system.

3. COMPARISON OF FREQUENCY AND VOLTAGE AT STEADY-STATE OPERATION REQUIREMENTS OF HVDC SCHEMES: EUROPEAN NETWORK CODES AND GB GRID CODE

A summary of the Grid Code Requirements for five countries is provided in Table 6. with the focus of voltage and frequency specifications. It can be found that for all the systems with HVDC connection the frequency range or tolerance is stricter and requires to operate continually in the range 49 Hz – 51 Hz, implying the requirements only allows 1-2 Hz deviation from the nominal value (see Table 6(a)). The GB Grid Code defines this for HVDC systems and remote end HVDC converter stations in Table ECC.6.1.2.2 and states the range as the "minimum time periods HVDC Systems and Remote End HVDC Converter Stations shall be able to operate for different frequencies deviating from a nominal value without disconnecting from the NETS" [9].

The operating range of voltages specified in different countries Grid Code requirements as shown in Table 6(b) shows a continues operation in between 0.9 p.u.-1.1p.u. In general, it is often found that there is a 10%–15% voltage band in which the systems operate most of the time. The voltage range for the GB Grid stated in Grid Code document Table ECC.6.1.4.3(b) defines the band as "minimum time periods for which a Remote End HVDC Converter shall be capable of operating for different voltages deviating from reference 1pu without disconnecting from the network where the nominal voltage base is from 300kV up to and including 400 kV and also applied to new HVDC connections [9].

To this end it should be noted that the current Codes do not say frequency and voltage excursions happen in isolation. The HVDC in this case is required to remain connected for both a voltage and frequency depression happening at the same time. What problems might that represent for HVDC and the grid at large, besides, the requirements for test considering performance for a simultaneous frequency and voltage depression in the grid code is not defined anywhere. In addition, what challenges might result from those tests if it was conducted and the specification of test needs to be covered as well.

Table 6 The Requirement of Frequency and Voltage in Different Countries for HVDC connections [8, 9]

(a) Frequency Requirements

F (Hz)	UK	Spain	France	Germany	Nordic	
53						3 min
52	20 min				5 s	
51.5	90 min and 30s	Continuous	30 min	Continuous		
51	Continuous		Continuous		Continuous	
50						
49						
48	90 min and 30s		30 min		30 min	
47.5		3s				
47	60 s					

(b) Voltage Requirement for HVDC coennections [8, 9]

V (p.u.)	UK	Spain	France	Germany	Nordic
1.2		0.05s-1s			
1.15	15 min	15 min		30 min	
1.115		1 h			
1.1		Continuous	5 min	Continuous	1 h
1.05	Continuous		Continuous		Continuous
1					
0.95					
0.9			90 min	2 h	
0.875	60 min	3 h			1 h
0.85		30 min			
0.8			Variable		

From the Tables it should be noted that different requirements exist in different parts of the world for HVDC. However, what might this mean for HVDC if they are meeting different power ramping and voltage requirements in different countries- and whether both of these requirements can be respected or do the present conflicts/ impact performance is an open question form the existing work.

4. GRID STRENGTH

System strength is defined as the ability of the power system to preserve and control the voltage at any given location in the grid, both during steady-state and following a disturbance. It dictates the rate at which voltage recovers following changes in power flow. In traditional grids, this is defined as fault level and is provided by synchronous generators. However, with the gradual phasing out of these machines with grid following non-synchronous generations (NSG) a significantly lower and different contribution towards fault level is envisaged. Any fault at this level causes a significant impact not only on the voltages but also on system inertia as well. Thus, system strength at a given location is proportional to the fault level at that location and inversely proportional to effective inverter penetration seen at that location. Besides, system strength is also a function of grid events, its severity and on the stability of NSG. This causes sudden and wide-area sustained voltage and power oscillations after a severe fault. In considering a converter dominated grid, a range of measures can be used to defined network strength. Of these, only short circuit ratio (SCR) can be defined from the data provided as standard at the time of any connection being a ratio between the short circuit power of the network and the power capability of the NSG. In our previous project, I have developed a regional SCR to define regional decline of short circuit level for the next 20 years so as to define connection requirements for HVDC connections. Besides when considering the system strength, synchronisation and control of inverters in NSG play a vital part in defining the requirements. A phase- locked loop is used to follow the grid voltage which could be compromised with reduced system strength as also shown from our previous study (please see attached document). To overcome these other forms of grid synchronisation, for instance, grid forming controllers could be used [20-21].

As discussed previously the decline of SCL in different regions of the GB network poses operability challenges to the system operator. To consider these impacts a brief section on grid strength is discussed with the units required to identify the strength of the grid. In the IEEE 1204 standard a weak AC power grid is defined using two characteristics, which includes both static and dynamic indicators.

Within the context of HVDC connections to an ac grid, the well-documented and accepted measure for system strength (or weakness) is the SCR. However, numerous indices are used to quantify grid strength. In general, SCR can be defined as the ratio between short-circuit capacity (SCC_{MVA}) from a three-phase line-to-ground fault at a given location in the power system and the rating of the inverter-based resource connected to that location [21]-[24]:

$$SCR = \frac{SCC_{MVA}}{P_{dc}}, \qquad (1)$$

where SCC_{MVA} is the short-circuit capacity in MVA of the ac system including HVDC and P_{dc} is the MW rating of the dc link. It is assumed that sufficient strength at the specific busbar is obtained when the SCR is at least equal to 3 [23], [24]. This requires knowledge of the short-

circuit capacity SCC_{MVA}, which is calculated using the IEC 6090 standard, used for grid planning purposes, defined by [23]:

$$SCC_{MVA} = \sqrt{3} U_{LL} I_{sc} \qquad (2)$$

where U_{LL} is the nominal line-to-line voltage at the point of common coupling (PCC) and I_{sc} is the three-phase short circuit current, defined in turn by

$$I_{sc} = \frac{U_{LL}}{\sqrt{3} Z_{sc}}, \qquad (3)$$

where Z_{sc} is the Thevenin equivalent short-circuit impedance seen from the PCC. SCR can be written in terms of impedance as

$$SCR = \frac{U_{LL}^2}{P_{dc}} . \frac{1}{Z_{sc}} . \qquad (4)$$

It can be observed from (4) that SCR is a function of the short-circuit impedance and is sensitive to the operating conditions in the network. The minimum value of SCR with a rated dc power transmission level must be considered when analyzing the limiting operating conditions and Grid Code requirements.

As a result, the SCC definition is inversely proportional to the p.u impedance. The minimum value of SCC with a rated DC power transmission level must be considered in analysing the limiting operating conditions. The lower the SCC value, the weaker the system, and the greater the interactions between DC and AC systems.

- Strong system: The AC/DC system with SCC values greater than 3,
- Weak system: The AC/DC system with SCC values between 2 and 3,
- Very weak system: The AC/DC system with SCC values less than 2.

Within the context of connecting HVDCs in an AC grid, the well documented and practised aspects for system strength or “weakness” of the grid is short-circuit ratio and there are several indices used to quantify the strength of the grid. In general, SCR is defined as the ratio between short circuit apparent power (SCMVA) from a three-phase line to ground (3LG) fault at a given location in the power system to the rating of the inverter-based resource connected to that location. Since the numerator of the SCR metric is dependent on the specific measurement location, this location is usually stated along with the SCR number [22].

4.1 Comparison of different SCR Methods

There is currently no industry-standard approach to calculate an SCR index of a weak system with high penetrations of wind and solar power plants or other inverter-based resources, such as HVDC. To take into account interaction effects between generating resources and to provide a more accurate system strength index calculation, a better indicator is needed to assess the potential risk of complex instabilities. Several approaches, such as GE’s composite SCR and ERCOT’s weighted SCR methods, have been proposed for calculations of SCR of a weak system with high penetrations of inverter-based resources [23-24]. The low SCR is typically identified and addressed during nonsynchronous generation interconnection studies. The low

SCR can be remedied with system upgrades, such as employment of synchronous condensers; however, synchronous generator retirements, network topology changes, and the addition of inverter-based technologies can manifest into weaker local areas within the bulk power system. A brief description of the available different SCR schemes is provided below with a comparison provided in Table 7.

Weighted Short Circuit Ratio (WSCR): defining operational limits for total transmission of power from inverter-based resources across key power system interfaces.

Composite Short Circuit Ratio (CSCR): estimates the equivalent system impedance seen by multiple inverter-based resources by creating a common medium voltage bus and tying all inverter-based resources of interest together at that common bus

Short Circuit Ratio with Interaction Factors (SCRIF): has been proposed to capture the change in bus voltage at one bus resulting from a change in bus voltage at another bus. Electrically close inverter-based resource buses will have a relatively higher Interaction Factor (IF) than inverter-based resource buses that are electrically separated.

Table 7 SCR Comparison

Comparison of SCR Methods							
Metric		Simple analysis using short circuit program	Accounts for nearby Inverters	Provides common metric across large group of inverters	Accounts for weak electrical coupling between larger plants	Considers non-active converters capacity (STACOM)	Considers individual inverters within a larger plant
SCR	Short Circuit Ratio	++	X	X	X	X	X
CSCR	Composite SCR	+	++	++	X	X	X
WSCR -MW	Weighted SCR using MW	+	++	++	+	X	X
WSCR -MVA	Weighted SCR using MVA	+	++	++	+	++	X
SCRIF	**Short Circuit Ratio with Interaction Factors (SCRIF):**	X	++	X	++	++	++

'X' represents that the metric cannot be applied for the described purpose.
'+' represents that the metric can be applied with some additional effort or processing, or can be applied to a limited extent, and
'++' represents that the metric is easily or directly applied for these purposes.

Table 7 is adapted from [28] in which it is concluded that no single methods is suitable for all studies related to weak grids. The report also infer that only one fault level value for that weak system is required to be provided to a user via the grid code to perform grid connection studies. From current study this conclusion is acceptable for wind or solar PV inverter studies, however,

it should be highlighted that when considering HVDC the conclusion has some flaws. The control scheme of HVDC and the requirements to fully inject power either direction if needed at weak grid connection demands more fault level studies to be performed and tested.

5. GRID CODE REQUIREMENTS FOR HVDC SYSTEMS CONNECTED TO WEAK AC GRIDS: CASE STUDY

5.1 Test System Configuration

The system under investigation is shown in Figure. 13. The system resembles the an embedded HVDC link to transfer around 1,200 MW of additional renewable capacity to connect to the electricity network. The link uses half-bridge modular multi-level converters (MMC) HVDC technology to transmit power through a 113 km subsea cable between converter stations at Grid 1 and 2. MMC model available in the PSCD/EMTDC library is used to build the HVDC converters. The Grid 1 has relatively weak system characteristics, with a wide range of system strengths, with generation at the area dominated by onshore wind. It has been identified from the Caithness-Moray project that the system strength at the point of common coupling (PCC) of the HVDC connection can vary from 1 to 5 GVA over the lifetime of the project [25-26]. The details of the test system and operating modes are outlined in Table 8.

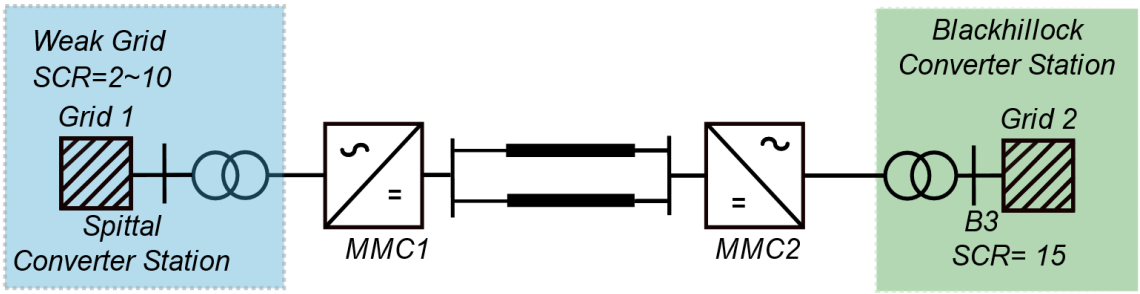


Fig. 13. Embedded HVDC link configuration

Table 8 Operating mode of CM HVDC link

Item	***MMC1***	***MMC2***
Rated Apparent Power (S)	*840 MVA*	*1265 MVA*
Rated Active Power (P)	*±800 MW*	*±1200 MW*
Convertor Nominal DC Voltage	*640 kV (±320 kV)*	*640 kV (±320 kV)*
AC Grid Voltage	*275 kV*	*400 kV*
SCR	*2~10*	*15*
Transformer Reactance	*0.16 p.u.*	*0.16 p.u.*
Control Mode	*P and Q (CM1)* *P and Vac (CM2)*	*Vdc and Q*

Item	MMC1	MMC2
Rated Apparent Power (S)	**840 MVA**	**1265 MVA**
Rated Active Power (P)	**±800 MW**	**±1200 MW**
Convertor Nominal DC Voltage	**640 kV (±320 kV)**	**640 kV (±320 kV)**
AC Grid Voltage	**275 kV**	**400 kV**
SCR	**2~10**	**15**
Transformer Reactance	**0.16 p.u.**	**0.16 p.u.**
Control Mode	**P and Q (CM1)** **P and Vac (CM2)**	**Vdc and Q**

The control scheme of the HVDC link is based on a cascaded structure in a dq reference frame: an outer loop regulates power or dc voltage and an inner loop regulates current [19], [20]. The d-axis reference current is designed either to regulate active power or the dc voltage of the

MMC. The q-axis reference current is designed either to regulate reactive power or the ac voltage of the MMC. More specifically, MMC1 is equipped with an active power and reactive power control mode, while MMC2 regulates dc voltage and reactive power and operates as a slack bus during normal operation.

5.2 Reactive Power and Voltage Support Requirements

Recent adaptations to GB Grid Code demand HVDC connections to contribute to voltage regulation in the system—as conventional power plants do especially when the grid is weak. The reactive power requirements are usually expressed with P-Q diagrams (available active power versus available reactive power) as defined in Section 4.3. Different reactive power requirements (RPR) are summarized in Figure. 14 with respect to the specifications from different countries. In general, at full active power, the converter must be capable of supplying reactive power in the range 0.41 p.u. inductive to 0.48 p.u. capacitive, which corresponds to a power factor from 0.925 lagging to 0.9 leading. The GB Grid Code demand that the HVDC connections and DC connected power plants should be able to provide 0.95 lagging to 0.9 leading reactive power support [9].

RPRs are set for strong grid connection points, where the converter operates with a conventional vector control mode. However, it is well known that vector control does not operate satisfactorily for very weak grids (SCR<2) [22,26]. This will, in turn, cause GB or general? Grid Code compliance issues. Thus, the challenges are twofold; the system operator is required to define a new specification for the RPR at the PCC, and the converter owners need to comply with these requirements through the provision of supplementary or additional control capabilities.

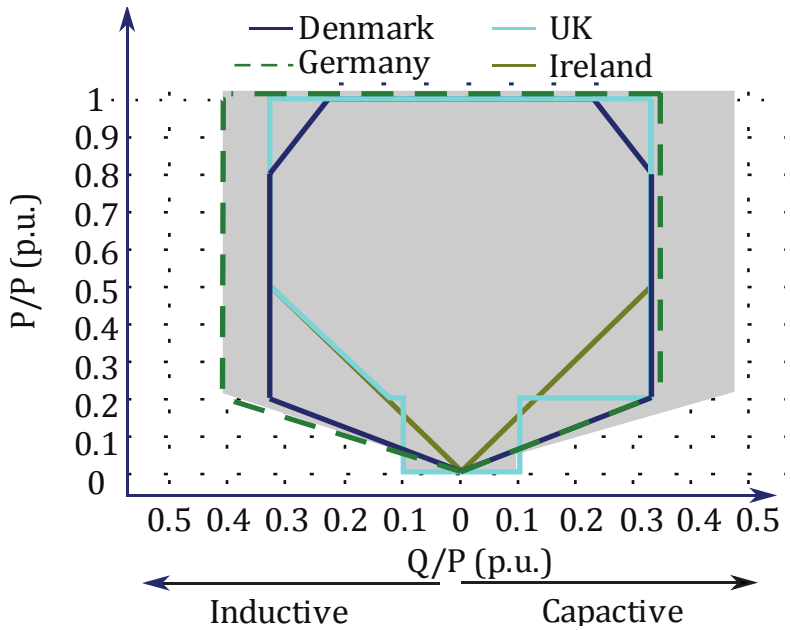


Figure 14 Reactive power requirements of various Grid Codes.

5.3 Simulation results

To study the performance of the HVDC link and its Grid Code compliance in a weak grid condition, the embedded HVDC link (see Fig. 13) has been implemented in PSCAD. Detailed switching MMC models with 40 submodules per arm are used together with their associated control systems. DC cables are represented by frequency dependent models. The ac grids at the ends of the HVDC link are modelled appropriately to represent different grid strengths. Unless stated otherwise, the simulations are started with Grid 1 operating as a strong system, with the value of SCR being reduced at t = 0.5 s into the simulation.

5.3.1 Case Study for reactive power requirements

The ability of the converter connected to a weak grid to meet RPRs is examined for the CM HVDC project as shown in Figure 13. The operation is performed at the Spittal AC grid, which is modelled to represent different grid strength. At t =1 s into the simulation, the power factor is changed from 0.95 (lead) to 0.95 (lag) and the process is reversed at t = 2 s and the results are plotted in Figure 15. The scenario emulated here is assumed as a test case for the reactive power requirements study with respect to power factor change as specified in the GB Grid Code ECC.6.5.5. It should be highlighted that typical voltage step cases such as 3% and 6% as described in the Grid Code is not considered owing to the fact that it might not reveal the RPR compliance in a weak grid connection. A more severe case of 10-12% voltage step is considered here. Two cases were presented and tested here for comparison

- Case-1: Requirement testing for a step change of reactive power set point from -200 MVAr to 200 MVar
- Case-2: Requirement testing for a ramp change of reactive power set point from -200 MVAr to 200 MVar with a 200 ms ramping period.

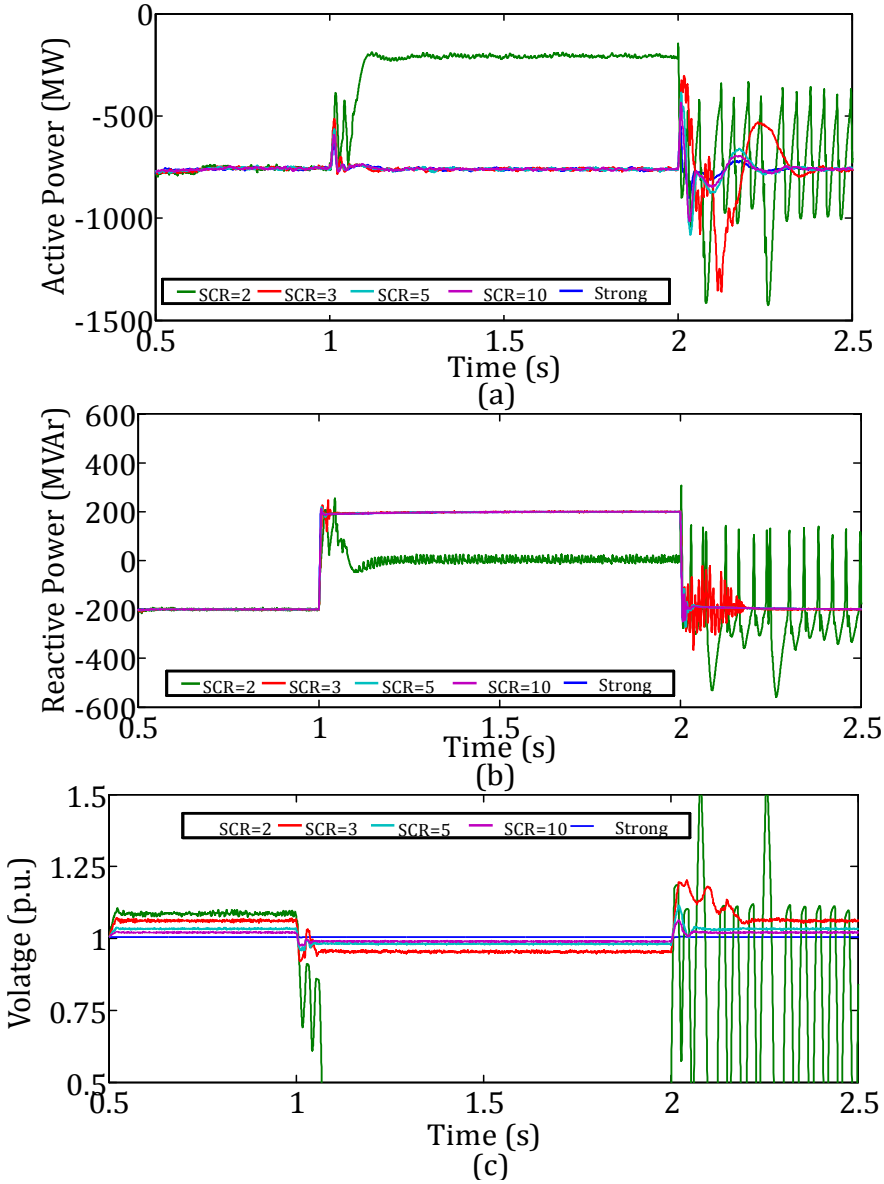
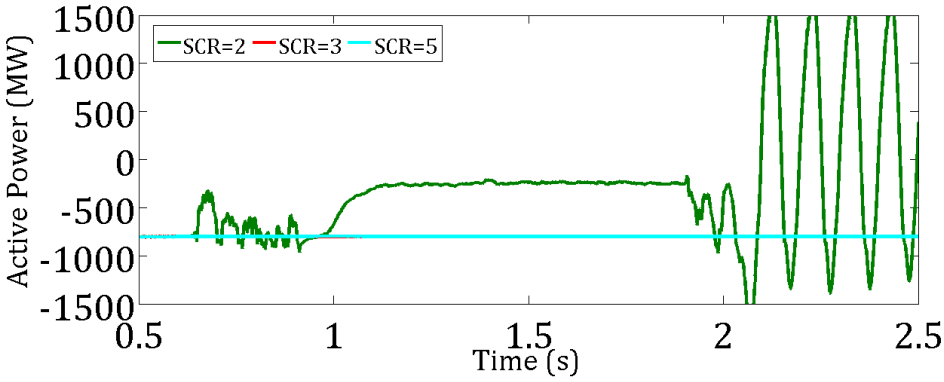
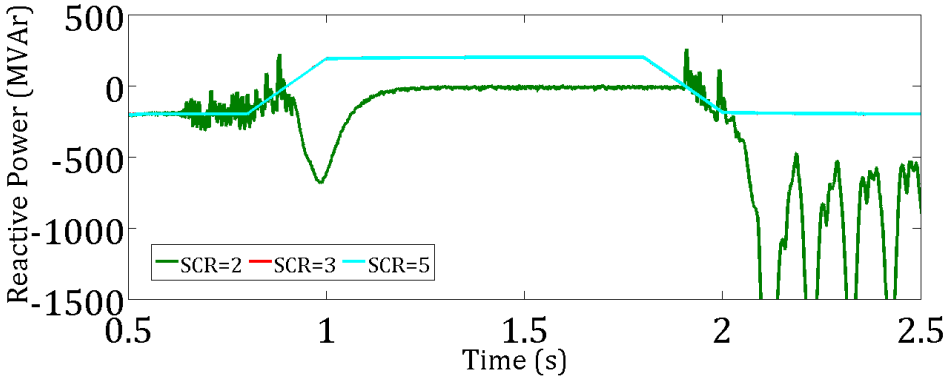


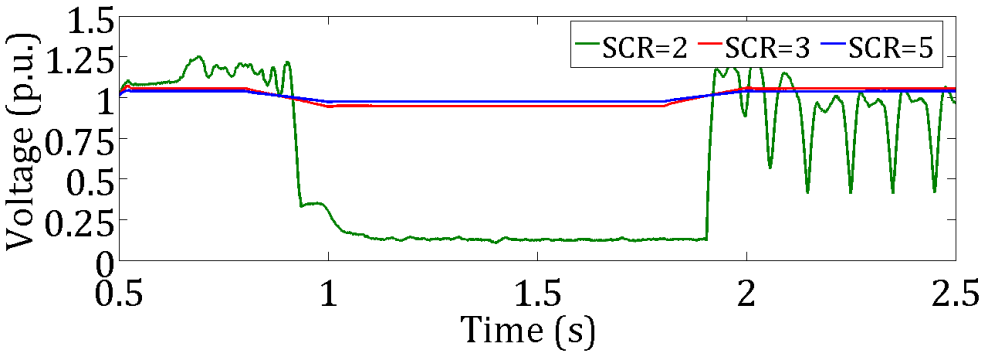
Figure 15 System performance for a range of SCRs for Case 1. (a) Active power; (b) reactive power; (c) PCC voltage.



(a)



(b)



(c)

Figure 16 System performance for a range of SCRs for Case 2. (a) Active power; (b) reactive power; (c) PCC voltage.

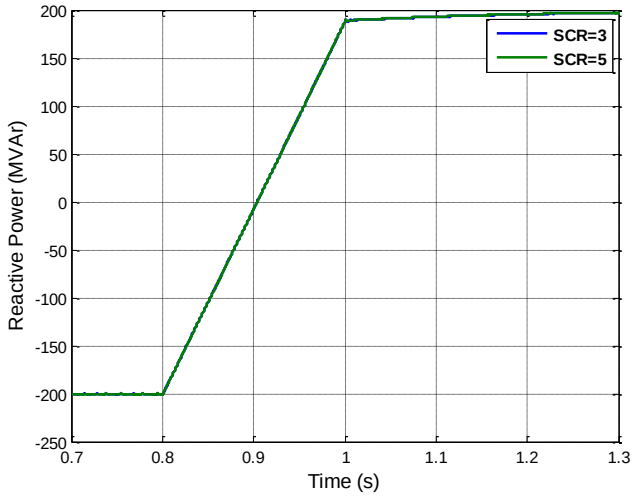


Figure 17 Reactive power ramp period

As can be observed in Figure. 15, for Case-1 the converter is capable of delivering the rated power without any difficulties within the specified range when the grid is strong. However, the power flow through the HVDC link is compromised with reduced SCRs. With the PCC voltage showing marginal stability at SCR = 3 and becomes unstable for low values of SCR. More investigation is required to evaluate the reason behind such occurrences, which will be performed in the later stages of the project. On the other hand, for Case-2 (see Figure 16) with ramping of reactive power (see Figure 17), the voltage stability can be preserved for SCR = 3 compared to Case-1. Ramp rate is another aspect which is needed to be considered when system strength reduces to warrant stable operation, for the case tested here a ramp rate of 200 ms is considered. The instability is also reflected in active and reactive power responses. It can be inferred that stable voltage at converter terminal is required to maintain PLL synchronism and voltage changes are directly linked to system strength and require consideration in Grid Code to maintain system stability and security under weak grid operation. A detailed investigation on the reasons for such converter behaviour is not included in the current study as it is out of the scope of the current work. The work aimed to test the various Grid Code requirements when SCR changes with different control modes.

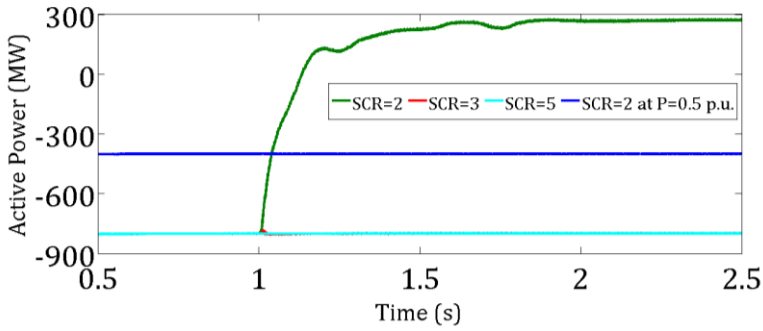
5.3.2 Case Study for reactive power requirements with AC Voltage Control

To investigate the HVDC performance for changes with lower SCR and P-Vac control mode the following case study is performed. The details of the test system and operating modes are outlined in Table 9. The MMC connected to Spittal station (MMC1) is controlled in P-Vac/Q droop control mode as described in Section 4 to test the reactive power compliance.

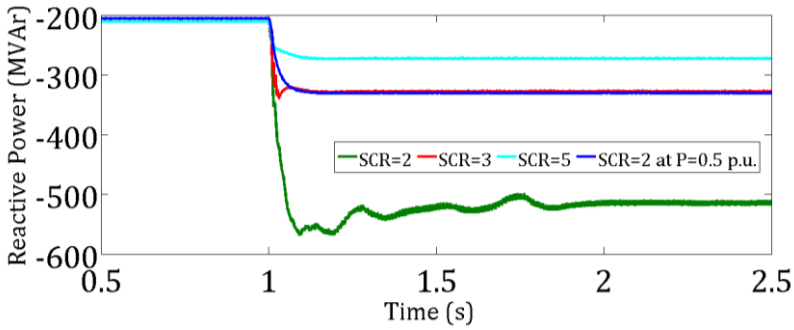
Table 9 Operating Modes for AC Voltage Control Case

Operating Modes	Control Mode 1	Control Mode 2
MMC1	P and Q	P and Vac

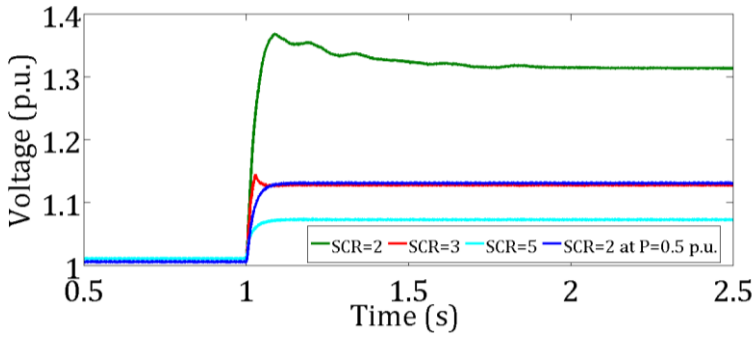
	P= 800 MW; Q= 200 MVAr	P= 800 MW; Vac= 275 kV Q= 200 MVAr
MMC2	Vdc and Q	
	Vdc= 640 kV (±320 kV); Q= 200 MVAr	



(a)



(b)



(c)

Figure 18 System performance for a range of SCRs for Voltage Control mode of MMC1. (a) Active power; (b) reactive power; (c) PCC voltage

The SCR value of AC grid 1 is varied to identify the stable operating condition and grid code compliance. The active power response follows the reference until SCR=3 but loses its control for SCR=2 as shown in Figure 18. However, for reduced power injection (0.5 p.u.) SCR= 2

operation is possible. Compared to the PQ control mode PVac control mode offers stability for lower SCR values. Moreover, it should be noted that QVac and PVac control would be standard for a grid code link.

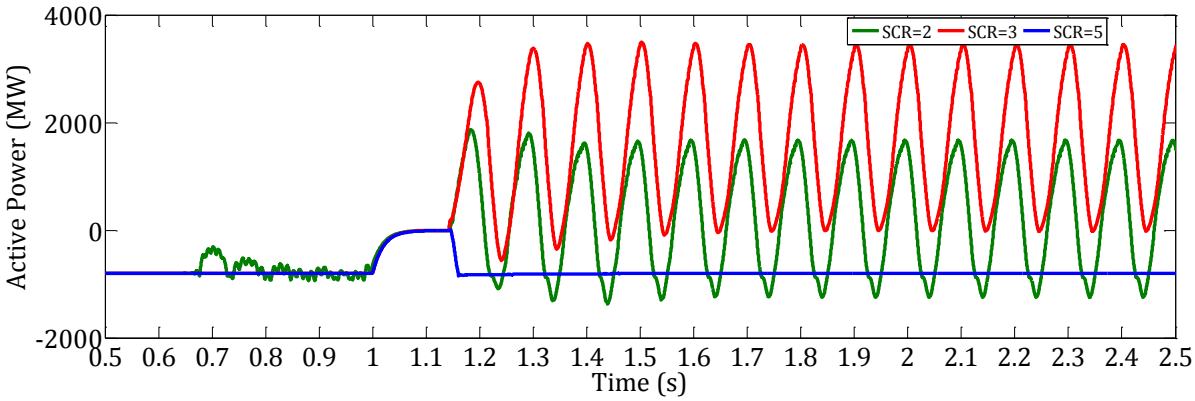
.

5.3.3 Case Study Fault Ride through requirements

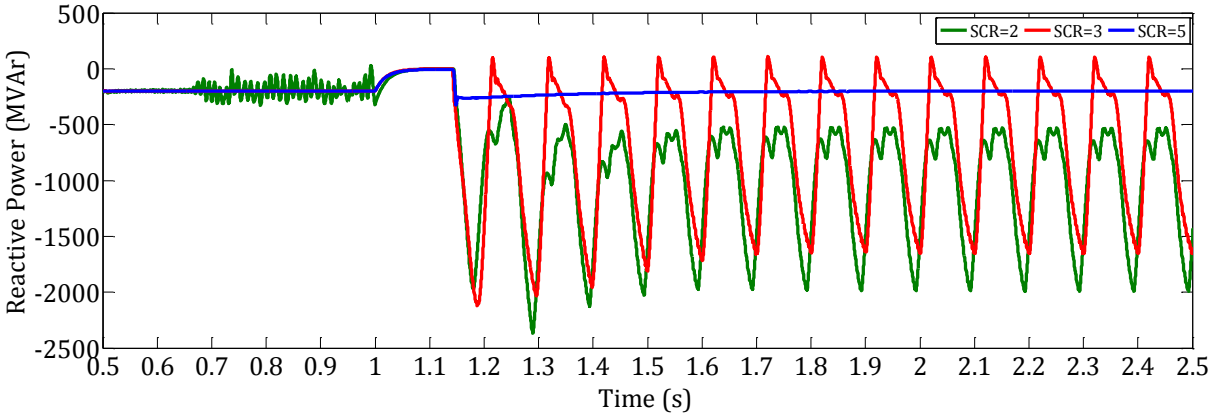
The HVDC performance during FRT and compliance with respect to Grid Codes were investigated using the following case studies

- Case Study 1: FRT testing with a three-phase symmetrical fault applied at Spittal AC grid for 140ms for MMC-1 in control mode-1
- Case Study 1: FRT testing with a three-phase symmetrical fault applied at Spittal AC grid for 140ms for MMC-1 in control mode-2

The active and reactive power responses in Figure 19 reflect stable operation until SCR=3 and voltage instability occurs for a severe fault such as the one tested here in this control mode for higher SCR values. In this, the SCR value of Grid 1 in changed from 10 to a different value at t = 0.7 s to emulate a weak grid. This operation causes oscillations for SCR = 2, as seen in Figs. 20 owing to the impedance change in the grid used to emulate SCR change.. For Case 1, the active and reactive power responses shown in Fig. 20 reflect a stable operation until SCR = 3. However, voltage instability might occur for higher values of SCR (>3), across severe faults, different operating conditions, different HVDC control gains, or different PLL settings (not shown). Such aspects require further investigation.



(a)



(b)

Figure 19 FRT requirements with Control Mode-1 at MMC-1 (a) Active Power; (b) Reactive Power

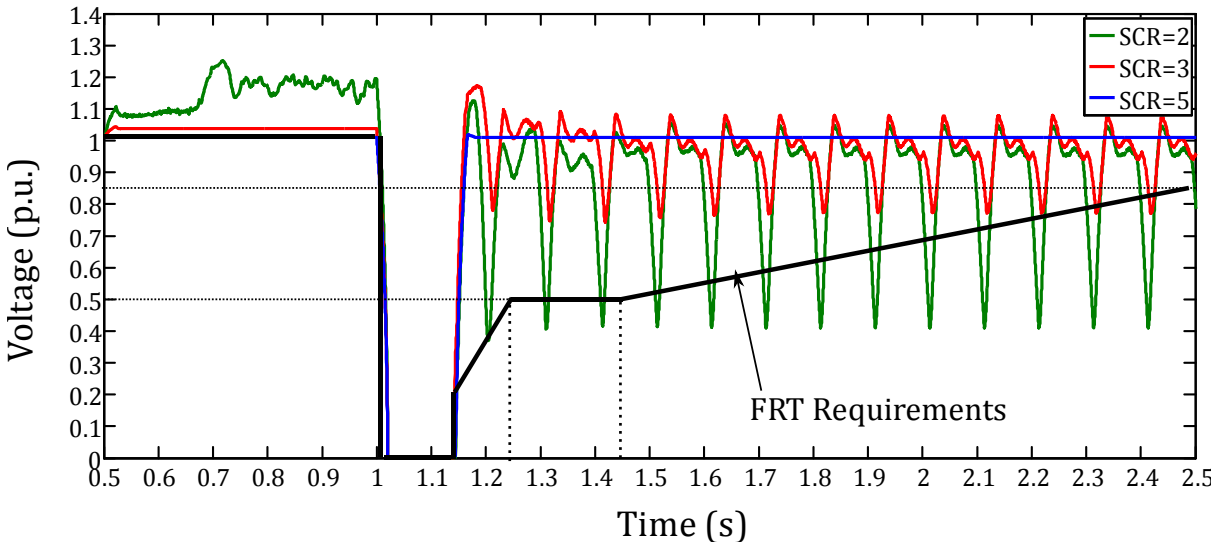
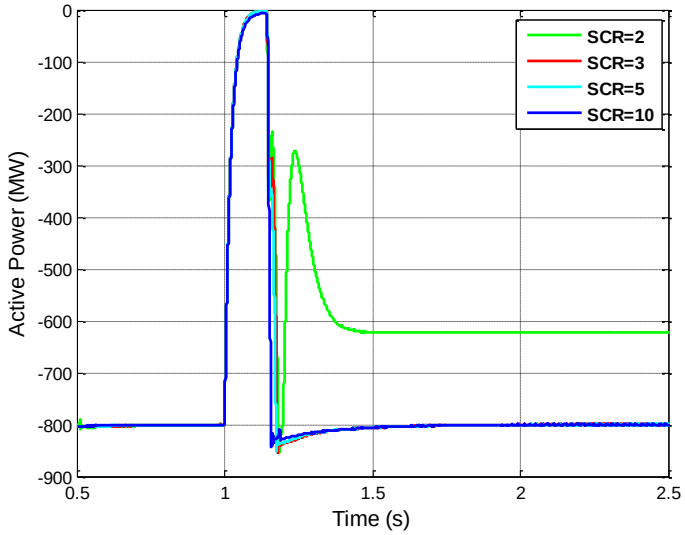


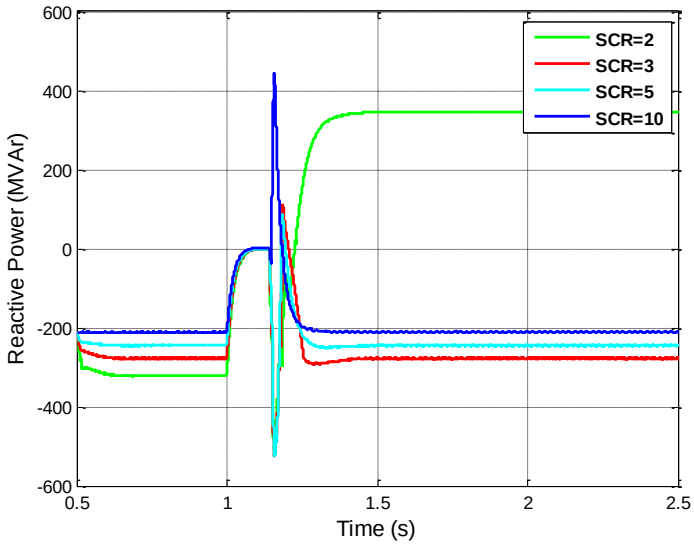
Figure 20 Voltage response for the FRT requirment for Case-1

Figure 20 demonstrates the Fault Ride Through compliance against the requirements of ECC.6.3.15 is detailed in ECP.A.3.5 and ECP.A.6.7 of the GB Grid Code [9]. The post fault profile is above the heavy black line for SCR =5. In this case, the HVDC systems or DC connected power park module must remain connected and stable. However, if the post fault voltage dips below the heavy black line, as seen for SCR=2 in which case the HVDC is permitted to trip. On the other hand, it is important to note that for SCR=5, the post fault voltage didn't cross the requirement curve but for SCR=3 the recovery voltage is unstable causing unforeseen technical difficulties to operate the HVDC systems and DC connected modules.

For Case-2 the active and reactive power responses in Figure 21 reflects stable operation until SCR=3 and voltage instability does not occur for a severe fault such as the one tested here in this control mode for compared to Case-1



(a)



(b)

Figure 21 System performance for FRT requirment at Case-2. (a) Active power; (b) reactive power.

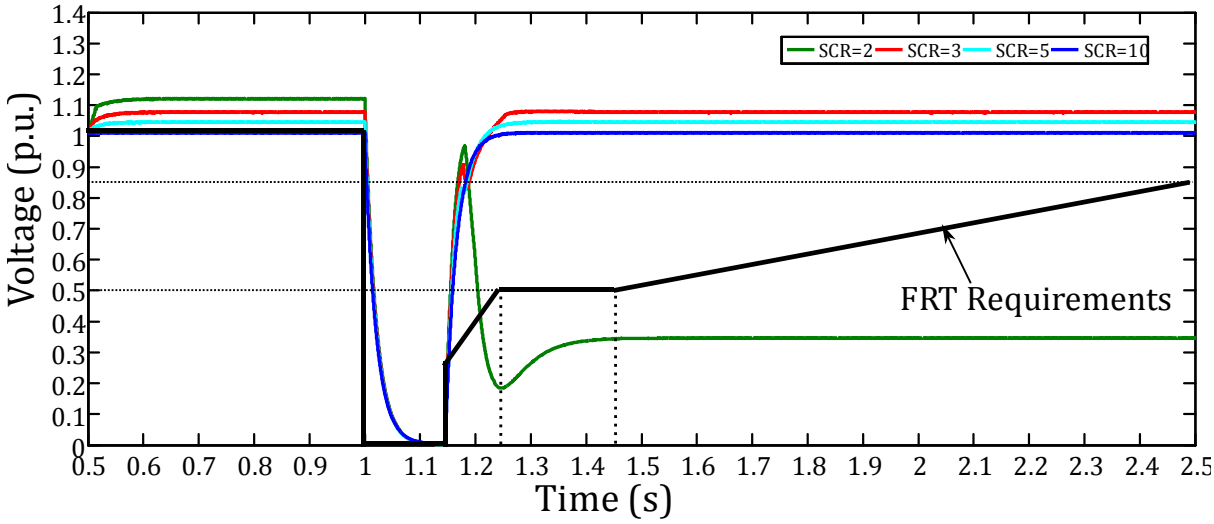


Figure 22 PCC voltage performance for FRT requirment at Case-2

On the other hand, for PVac control mode as shown in Figure 21, the Fault Ride Through compliance against the requirements of ECC.6.3.15 is detailed in ECP.A.3.5 and ECP.A.6.7 of the GB Grid Codes are meet for values of SCR =3. For SCR=2 the post fault voltage dips below the heavy black line, in which case the HVDC is permitted to trip below which the operation is compromised due to the weak grid characteristics. The post fault voltage profile recovers with the clearance of the fault and are well within the requirement until SCR=3 for Case-2 compared to Case-1.

From the case studies performed to evaluate thevHVDC link operation under weak grid scenario for steady-sate and fault conditions the following inferences can be made:

- The reactive power requirements for severe 10-12 % step-change of voltage and existing ramp rate of 200ms for volatge change in weka grid for SCR=3 or less won't comply with esxisting codes when an HVDC connection is considered.
- A more sustained or stable operation can be achieved through ramping the set-points which will reduce the impact on other system parameters
- The AC voltage control mode of operation for different SCR values at weak grid is observed and results were compared to PQ mode of operation, showing the capability of ac volatge to operate stably the HVDC link with same lower SCR level
- For lower SCR values PVac control offers stability compared to PQ control for both steady-state and fault scenarios. A crtical SCR value for stable or marginally stable operation will be evaluted in the next phase of the project

6. POTENTIAL SPECIFICATION OF REQUIREMENTS FOR HVDC SCHEMES CONNECTED TO WEAK AC GRIDS

From the review, analysis and case studies performed the challenges of connecting HVDC schemes and compliance with the existing GC for weak grid scenarios can be summarized as:

- Weak power systems experience significant fluctuations in bus voltages, both in steady-state and dynamic events due to paramterisation and intilization.

- Frequency regulation is primarily troublesome in weak power grids with potential risk of volatge induced frequency dip exits. Strict bands of operation is required when system streghth reduces.

- Transient stability can also be compromised in weak power grids under severe short-circuits. The recovery voltage after fault cases shows non-standard performance and does not comply with requirements on the existing Grid Code

- Under weak grid condition, voltage sensitivity with respect to reactive power is high, which means that the same amount of reactive support (injection or absorption) results in larger voltage deviations due to large source impedance value. A potenial solution lies with re-tuing the converters to compact with steady-state oscilaltion sonce the grid becomes weak.

- Both RoCoF and steady-state frequency deviation following an active power mismatch results in high values, because of low inertia, low regulating capability and relatively large size of inverter-fed generators with respect to the total load.

- Finally, the magnitude of a voltage dip during a fault will be higher at a point with low short-circuit power, i.e. low network strength.

To mitigate such scenarios and to support weak grid operation of HVDC and DC connected power plant modules some of the potential requirements in the future can be identified as:

Fast voltage support: critical for operation of weak AC networks such as offshore wind farms, but also essential to aid recovery of the AC grids from AC faults. Reactive current injection levels supported by a minimum level of active power will be considered in the next phase

Fast power run-back and run-up: Eliminate or reduce active power mismatch (provide retarding power) to limit rotor acceleration of the generators during a network event. This operation can be deducted for HVDC with fast power controllers.

Black start capability: to restore the power to the AC grid following a blackout, and in general to supply passive or weak AC networks.

Synthetic Inertia: A future possible application is controlling the converters of static generators, in order to introduce synthetic inertia in the system. Potential testing and specifications are required to validate such as scheme with HVDC.

Grid Forming Capability: The capability of converters either in HVDC schemes or DC connected power park modules to work as virtual synchronous machines and operate as grid forming sources rather than grid following devices.

7. CONCLUSIONS

HVDC transmission offers distinctive characteristics when compared to conventional HVAC transmission due to its inherent advantages of fast and independent active and reactive power

control, ability to connect weak grids and higher integration of renewables where AC connection is not an option. However, the integration of HVDC systems into weak grids constitutes a challenging task due to the stability problems caused by voltage fluctuations and inability to comply with Grid Code requirements. Whilst AC Grid Code is well documented and is constantly being updated, HVDC grid codes are still being developed top align with the changes in short circuit level. There are synergies in a number of aspects between Grid Code requirements proposed by NC HVDC and NG ESO for HVDC schemes. The frequency bands in the interconnected grid are strict and only allow 1 Hz or 2 Hz deviation for nominal value. However, tripping times are much longer in strong grid cases. The voltage requirements specify a 10%–15% voltage band in which the systems operate all the time. Moreover, it allows tighter variations but with wider trip times as in existing grid codes. The frequency deviation and voltage bands are set for strongly interconnected grids, however, with reduced system strength and larger power inflow through HVDC schemes, specification of grid code requirements needs to be understood well in advance to devise the specifications.

Moreover, after reviewing the European HVDC NC and GB Grid Code for HVDC schemes, a considerable level of flexibility is provided for national TSOs compared to continental level such as the specification of tolerance for RoCoF, set points for active power regulation, and reactive power requirements. However, there are also common grounds for operation modes to harmonise the Grid Codes such as the minimum requirements for voltage regulation at steady-state operation.

An important conclusion from this review, analysis and case study is that with regards to GCs the necessary requirements for regulation of active power, frequency and voltages are in place for HVDC connection to the relatively strong grid. ENTSO-E has been consulting and considering the inclusion of services like synthetic inertia and fast fault current injection into the GC requirements for HVDC connected to a weak grid. On the other hand, it is not yet fully explored in the GB GC.

References

[1] T. Joseph, “Operation and control of voltage source converters in transmission networks for AC system stability enhancement,” *PhD thesis*, Cardiff University, Mar. 2018.

[2] T. Joseph, C. E. Ugalde-Loo, J. Liang and P. F. Coventry, "Asset Management Strategies for Power Electronic Converters in Transmission Networks: Application to Hvdc and FACTS Devices," in *IEEE Access*, vol. 6, pp. 21084-21102, 2018.

[3] G. Li, C. Li and Dirk van Hertem, “HVDC technology overview,” HVDC Grids: For Offshore and Supergrid of the Future, *Wiley-IEEE Press*, Chapter 3, pp.45-76, 2016.

[4] Simon Marshall CM Project stake holder engagement event, National HVDC Centre, March 2019

[5] Simon Marshall and Oluwole Daniel Adeuyi, Grid Code Project Kick-off Meeting National HVDC Centre, May 2019

[6] National Grid, “The System Operability Framework ”, July 2018.

[7] National Grid, “Future Energy Scenarios”, July 2018.

[8] http://eur-lex.europa.eu/legal-content/AUTO/?uri=CELEX:32016R1447&qid=1475684066651&rid=1

[9] National Grid, “The Grid Code”, Issue 5 revision 36, 12 July 2019.

[10] https://www.ofgem.gov.uk/publications-and-updates/energy-codes-review

[11] National Grid ESO, “Stability Pathfinder RFI Technical Performance and Assessment Criteria”.

[12] R. Teixeira Pinto, S. F. Rodrigues, P. Bauer and J. Pierik, "Grid code compliance of VSC-HVDC in offshore multi-terminal DC networks," *IECON 2013 - 39th Annual Conference of the IEEE Industrial Electronics Society*, Vienna, 2013, pp. 2057-2062.

[13] O. A. Giddani, G. P. Adam, O. Anaya-Lara, G. Burt and K. L. Lo, "Control strategies of VSC-HVDC transmission system for wind power integration to meet GB grid code requirements," *SPEEDAM 2010*, Pisa, 2010, pp. 385-390.

[14] M. Ndreko, A. Bucurenciu, M. Popov and M. A. M. M. van der Meijden, "On grid code compliance of offshore mtdc grids: modeling and analysis," *2015 IEEE Eindhoven PowerTech*, Eindhoven, 2015, pp. 1-6.

[15] “Beyond state-of-the-art technologies for power AC corridors and multi-terminal HVDC systems (Best Paths)”, EU Project nr. 612748, http://www.bestpaths-project.eu/.

[16] E. Ciapessoni *et al*., "Assessing the impact of multi-terminal HVDC grids for wind integration on future scenarios of a real-world AC power system using grid code compliant open models," *2017 IEEE Manchester PowerTech*, Manchester, 2017, pp. 1-6.

[17] C. E. Ugalde-Loo *et al*., "Open access simulation toolbox for the grid connection of offshore wind farms using multi-terminal HVDC networks," *13th IET International Conference on AC and DC Power Transmission (ACDC 2017)*, Manchester, 2017, pp. 1-6.

[18] O. D. Adeuyi, M. Cheah-Mane, J. Liang and N. Jenkins, "Fast Frequency Response From Offshore Multiterminal VSC–HVDC Schemes," *IEEE Trans on Power Delivery*, vol. 32, no. 6, Dec. 2017.

[19] Jose, K., Joseph, T., Liang, J., & Ugalde-Loo, C. E. (2018). Auxiliary dead-band controller for the coordination of fast frequency support from multi-terminal HVDC grids and offshore wind farms. *IET Renewable Power Generation*, *12*(13), 1444-1452.

[20] P. Kundur, Power System Stability and Control, McGraw Hill, 1994.

[21] N. R. Chaudhuri, “Integrating Wind Energy to Weak Power Grids using High Voltage Direct Current Technology”, *Springer International Publishing*, April 2019.

[22] IEEE Guide for Planning DC Links Terminating at AC Locations Having Low Short-Circuit Capacities," *IEEE Std 1204-1997* , vol., no., pp.1-216, 21 Jan. 1997

[23] S. Achilles, N. Miller, E. Larsen, J. MacDowell, GE Energy Consulting, "Stable Renewable Plant Voltage and Reactive Power Control," Presented to NERC ERSTF, June 11-12, 2014

[24] Essential Reliability Services Task Force Measures Framework Report, November 2015.

[25] Ryan Tumilty, “Caithness – Moray HVDC System Integration” CM Stake holder engagement event, National HVDC Centre, Glasgow March 2019

[26] Strathclyde Engagement with the UK National HVDC Centre: Phase I Converter and GB Network Modelling, “Offline DC grid model development”, Doc. No. USTRATH-HVDC Centre-P1-003, 2018

[27] L Harnefors, L. Zhang, Method And Control System For Controlling A Voltage Source Converter Using Power-Synchronization Control, ABB Schweiz AG (Baden, CH), May 2019

[28] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Item_4a._Integrating%20_Inverter-Based_Resources_into_Low_Short_Circuit_Strength_Systems_-_2017-11-08-FINAL.pdf

Requirements		according to your national implementation of NC HVDC						
		Is this requirement considered in the compliance process for HVDC	How is this requirement considered in the compliance process?		Is this requirement considered in the compliance process for DC-connected power park modules?	How is this requirement considered in the compliance process?		remarks
			In the context of compliance testing?	In the context of compliance simulation?		In the context of compliance testing?	In the context of compliance simulation?	
Steady-state operation	active power controllability	Yes	☒	☒	Yes	☒	☒	Section of the European Compliance Process (ECP.A.3) describe the simulations studies which need to be carried out before any HVDC Converter Station will be issued an Interim Operational Notification (ION) or ECC.6.3. ECC.6.3.9., PC.A.5.4.3.2, or CC.6.3.3 as applicable
	reactive power capability	Yes	☒	☒	Yes	☒	☒	PC.A.5.4.3, CC.6.3.2. or ECC.6.3.2.4.2 to ECC.6.3.2.4.4 as applicable or ECP.A.7.2, OC5.A.3.4 (Reactive Capability testing for PPM), or CC.6.3.7 as applicable

	1- voltage control mode 2- reactive power control mode 3- power factor control mode	Yes	☒	☒	Yes	☒	☒	PC.A.5.4.3.2, CC.A.7.2.2 , or CC.6.3.8(c) as applicable or ECC.A.7.2.5, ECC.A.7.3, ECC.A.7.4, ECC.A.8.2.2, ECC.A.8.3 or ECC.A.8.4, as applicable or ECC.6.3.8.2, ECC.6.3.8.5.1, ECC.A.6.2.3, ECC.6.5.5 or ECC.6.2.2.9.10.1 as applicable
	steady-state harmonics	Yes	☒	☒	Yes	☒	☒	For harmonic voltage distortion, the process detailed in Stage 3 of Engineering Recommendation G5/4 is applied. For the voltage fluctuation, the principles outlined in Engineering Recommendation P28 are used. The European Connection Conditions ECC.6.1.5 (a) is followed with ECC.6.1.7 for voltage fluctuations. Specific information required for the assessment of harmonic voltage distortion and voltage fluctuation is detailed in Grid Code DRC.6.1.1.
	load flow calculation	Yes	☐	☒	Yes	☐	☒	PC.A.2.5.1(c), PC.A.8.3 (c), ECP. A.3.3.1 to 3.3.3 for HVDC and ECP.A.3.5.2 for Power Park modules
	steady-state short-circuit current calculation	Yes	☐	☒	Yes	☐	☒	PC.A.2.5.3, PC.A.6.6 or DRC.6.1.14 as applicable

	FSM response	Yes	☒	☒	Yes	☒	☒	OC5.A.3.6.4, ECC.6.2.2.9.10.1, ECC.6.2.2.8.3, or ECC.6.3.7 as applicable or ECC.6.3.5.3, ECC.6.3.6.1.2.5, ECP.A.3.6.5 or BC3.5.1 as applicable
	LFSM-O response	Yes	☒	☒	Yes	☒	☒	OC5.A.3.6.4, ECC.6.2.2.9.10.1, ECC.6.2.2.8.3, or ECC.6.3.7 as applicable or ECC.6.3.5.3, ECC.6.3.6.1.2.5, ECP.A.3.6.5 or BC3.5.1 as applicable
	LFSM-U response	Yes	☒	☒	Yes	☒	☒	OC5.A.3.6.4, ECC.6.2.2.9.10.1, ECC.6.2.2.8.3, or **ECC.6.3.7 as applicable or ECC.6.3.5.3, ECC.6.3.6.1.2.5, ECP.A.3.6.5 or BC3.5.1 as applicable**
Dynamic Operation	ramping rate modification	Yes	☒	☒	Yes	☒	☒	OC5.A.3.6. give the ramps and step frequency injection tests required at different loading levels or ECC.6.2.2.11, BC2.7.1, BC5.3.1, ECC.6.3.6.1.2.4, ECC.6.3.15 and ECC.6.3.6.1.2.2 as applicable
	black start capability	Yes	☒	☒	Yes	☒	☒	ECC.6.3.5, ECC.6.1.2 or ECC.6.1.4 applicable with the OC5 tests include the Black Start Test procedure.
	frequency restoration control	Yes	☒	☒	Yes	☒	☒	BC 5.1 or ECC.6.3.14 as applicable

	fast signal response	?	☐	☐	Yes	☐	☐	More clarification on the type of signal and test requirements are needed to answer this question as there are many instances on signal responses in the Grid Code: for example, real-time continuous signal for frequency measurement (CC.6.3.7), response to current or voltage signal tests (CC 6.6)
	fast fault current injection	Yes	☒	☒	Yes	☒	☒	CC.6.3.15, CC.A.4.A or CC.A.4.B as applicable or ECC.6.3.15, ECC.6.3.16, ECC.A.4. or ECC.A.4EC as applicable
	fault-ride-through capability	Yes	☒	☒	Yes	☒	☒	CC.6.3.15, CC.A.4.A or CC.A.4.B as applicable or ECC.6.3.15, ECC.6.3.16, ECC.A.4. or ECC.A.4EC as applicable
	post fault active power recovery	Yes	☒	☒	Yes	☒	☒	Each DC Converter shall be designed to meet the Active Power recovery characteristics as detailed in CC.6.3.15
	power oscillations damping control	Yes	☒	☒	Yes	☒	☒	CC.A.6.2.5, ECC.6.3.17, ECC.6.2.2.9.10.1 or ECP.A.3.8.2 as applicable and the terms of the Bilateral Agreement.
	fast active power reversal	Yes	☒	☒	Yes	☒	☒	ECC.6.3.6.1.2.2 States: The requirements for fast Active Power reversal (if required) shall be specified by The Company or through ECC.6.5.6.6, ECC.6.5.6.7 as applicable.
	capability of providing synthetic inertia	No idea	☐	☐	No idea	☐	☐	Nothing specified up to the grid code Issue 5 revision 36, 12 July 2019

	Simulation of transient behaviour (in the event of switching-in conditions, sudden voltage changes at the network connection point, Switching-off conditions and load shedding)	Yes	☒	☒	Yes	☒	☒	The Grid Code CC.A.6.2.4, CC.A.7.2.3.1, CC.6.3.15.1 sets out a number of criteria for acceptable transient voltage response. OC5.A.3.5, **PC.A.6.2, PC.A.5.4, or PC.A.6.1 as applicable or ECC.6.2.2.9.4, ECC.6.3.15.11, ECC.6.3.16, ECC.A.6.2.4 or ECC.A.4 as applicable**
	ability to damp sub-synchronous oscillations	Yes	☒	☒	Yes	☒	☒	ECC.6.3.17.2.6, ECC.6.2.2.9.10.1, CC.6.3.16 or ECC.6.1.9 as applicable
	harmonic stability	Yes	☒	☒	Yes	☒	☒	CC.6.1.5(a) or ECC.6.1.5(a) as applicable Depends on the Harmonic Assessment Information as defined in IEC 61400-21 (2001)).
	protection	Yes	☒	☒	Yes	☒	☒	ECC.6.3.13, ECC.6.3.15, ECC.6.3.16, or ECC.7.5.1 as applicable or CP.6.3.1, CP.8.5.6, or CP.A.3.6.3 as applicable or ECP.6.3.3.1, ECP.8.5.6, or ECP.A.3.6.2 as applicable, PC.A.5.4.3.2, and PC.A.5.4.2(f), PC.A.6.3 for protection system as applicable In addition, under the section ECC.6.2.2.2 of European Connection Conditions, the HVDC System Owner must meet a set of minimum protection requirements

These requirements are based on the GB Grid Code, Issue 5 revision 36, 12 July 2019. Definitions for the terminology used within this document can be found in the Grid Code Glossary and Definitions.