2024 TECHNICAL UPDATE

Recommendations for Planning Criteria and Performance Standards for HVDC

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3002030801

Technical Update, July 2024

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ACKNOWLEDGMENTS

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This report describes research sponsored by EPRI. EPRI would like to acknowledge the support of Southwest Power Pool.

EPRI would like to thank the following individuals from Southwest Power Pool (SPP) for their valuable participation and contribution during this project:

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Doug Bowman
Sunny Raheem
Sherri Maxey

This publication is a corporate document that should be cited in the literature in the following manner: *Recommendations for Planning Criteria and Performance Standards for HVDC.* EPRI, Palo Alto, CA: 2024. 3002030801.

ABSTRACT

The number of high-voltage direct current (HVDC) transmission systems has been steadily increasing worldwide in the last decade, driven primarily by the need to enable large power transfers over long distances, improve the connectivity of regions within the power, and facilitate the interconnection of a large amount of both onshore and offshore renewable generation.

As new HVDC systems are developed, designed, and installed, it is crucial to ensure that their impact meets the requirement of the AC transmission system over the project's lifetime. To accomplish this goal, it is critical to have a robust set of performance standards and study and model requirements.

This project aims to develop a set of criteria and performance metrics to evaluate the integration of HVDC transmission projects. The recommended standards and requirements focus on the following two areas: A) Recommendations for planning and performance criteria for HVDC systems, and B) Recommendations on model requirements and simulation tools. These recommendations are based on a comprehensive benchmarking analysis of various grid codes for HVDC system requirements performed by EPRI as part of this effort.

This project was supported by Southwest Power Pool (SPP). SPP has been evaluating several new HVDC project requests in its territory and has recognized the need to review and expand the planning criteria to include specific provisions for HVDC projects. Therefore, the recommended planning and performance criteria developed in this project are expected to be considered by SPP when reviewing interconnection studies of new HVDC facilities.

Keywords

HVDC Systems
Grid Codes
HVDC planning studies
HVDC design studies
HVDC Models

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1 INTRODUCTION

1.1 Background, Objective, and Scope

In the last decade, there has been a steadily increased demand worldwide for high-voltage direct current (HVDC) transmission systems, driven primarily by the need to enable large power transfers over long distances as well as to improve the connectivity of regions within the power grid. HVDC is an economical and technically efficient choice for long-haul transmission projects, but long-haul connection is not the only application that favors this technology. HVDC is the preferred option for underwater cables of modest length, the integration of large amounts of offshore wind generation, the supply of offshore oil rigs, and, in some cases, the infeed of large urban centers.

HVDC systems have unique, beneficial, and powerful features that are incorporated into their hardware and high-speed control systems. Key benefits include fast regulation of active and reactive power and inclusion of modulations such as frequency and power system dampers. They also have some features that need careful management, such as issues related to power quality, system stability, active and reactive power control, and response to AC and DC faults. As new HVDC systems are developed, designed, and installed, it is important to ensure that their impact meets the requirement of the AC transmission system over the project's lifetime. To accomplish this goal, it is critical to have a robust set of performance standards and study and model requirements.

In previous work related to this project[1], EPRI performed a benchmarking analysis of various grid codes for HVDC system requirements. The review included five United States entities and eleven entities from the rest of the world. The entities in the rest of the world included eight from Europe and three from Asia-Pacific. The analysis focused on aspects of operation performance, interaction with the AC grid, and planning criteria, including modeling and simulation tools.

Based on the outcome of that work, this project aims to develop a set of recommended criteria and performance metrics to evaluate the integration of HVDC transmission projects. The recommended standards and requirements focus on the following two areas:

A) *Recommendation for planning and performance criteria for HVDC systems*.
This comprises a set of recommended criteria and performance metrics to evaluate the integration of HVDC transmission projects in the bulk power system.

B) Recommendations on model requirements and simulation tools.
This part includes guidelines regarding the models and simulation tools that should be used in the different parts and stages of HVDC planning and interconnection studies,

[1] *Recommendations for Planning Criteria and Performance Standards for HVDC:* EPRI, Palo Alto, CA: 2023. 3002030801

and recommendations regarding responsibilities for the development, provision, and validation of models.

The project was primarily sponsored by Southwest Power Pool (SPP), which has been evaluating several new HVDC project requests in its territory. Furthermore, due to SPP's further expansion of membership and services into the Western Interconnection, HVDC projects are expected to continue to evolve in planning processes. The needs for HVDC solutions are mainly driven by the evolving characteristics of the bulk power system in SPP's footprint, where renewable generation, predominantly wind and now solar, is projected to grow significantly over the current levels.

The existing SPP Planning Criteria primarily focus on AC and do not address study requirements for HVDC interconnections. Therefore, SPP staff have recognized the need to review and expand the planning criteria to include specific provisions for HVDC projects and have started work in this direction. The recommended planning and performance criteria developed in this project are expected to be considered by SPP when reviewing interconnection studies of new HVDC facilities.

1.2 IEEE 2800-2022

The IEEE 2800-2022 standard [2] is referenced throughout this document. The scope of IEEE 2800-2022 is limited to only those converters of a gen-tie HVDC system (as shown in Figure 1(c)), especially the transmission connected converter. However, some of the requirements could be applicable to converters of other HVDC systems, such as those of an embedded or a tie-line. For example, the ride through requirements, in Section 7 of IEEE 2800-2022 are applied to what the standard describes in its Figure 2 as the converter at the point of connection. This is transmission connected converter shown in Figure 1(c) of this document. These requirements could be applied to other converter topologies such as the Tie Line HVDC system shown in Figure 1(a) of this document.

In this report, any IEEE2800-2022 requirement described or referred applies to all HVDC systems and their converters, unless a specific exception is noted in the text of this report.

1.3 Summary of Terms

Different jurisdictions can use different terms to describe similar concepts. The terms adopted in this report are:

AC Grid	The AC system that a converter is connected to. Could be either an AC transmission system, or a remote gen-tie AC system.
AC Tie-line	An AC cable or overhead line that connects the local converter station to the existing AC transmission system.
AC Transmission System	The wide area AC high voltage transmission system.
Active Control	Control of active power along the HVDC system.
As build EMT model (of the HVDC system)	A EMT model of the HVDC system that is completed after the HVDC Vendor's detailed design studies and updated after commissioning. This model will be representative of the installed equipment.
As build RMS model (of the HVDC system)	An RMS model of the HVDC system that is completed after the HVDC Vendor's detailed design studies and updated after commissioning. This model will be representative of the installed equipment.
Bumpless transition	A bumpless transition or transfer, is a mode transition of the HVDC system's control system. Examples of transitions include change from reactive power control to AC voltage control; or from a converter switching from export to import active power. A Bumpless transition means that from the measurement of active power, reactive power, and harmonic content at the connection point, it is not possible to ascertain that a mode transition has occurred. For example, for a transition from export to import active power, beyond the obvious change in active power direction, there should be no other artifacts, or bumps in the active power or reactive power at the transition point.
Connection Agreement	An agreement between an HVDC owner and a SO to allow the connection of a HVDC system to an AC Transmission System. It may contain specific technical requirements for the HVDC system.
Connection Point(s)	Point(s) at which the HVDC system is connected to an AC transmission system. In this document, the connection point is defined as the point within the existing AC Transmission System as shown in Figure 2. In [2] this is called the point of interconnection.

Converter driven stability	Converter driven stability (or instability) as described in [3] and is those interactions involving grid connection power electronic converters, including IBRs and HVDC systems,
DC line	The cable(s) or overhead line(s) (OHL) between the converter stations of an HVDC system.
Deionization time	The time required for dispersion of ionized air after a fault is cleared so that the arc will not re-strike on re-energization
Distant resonances	Sub synchronous resonances which do cross the zero-impedance line, described in [4]. This implies the resonance is electrically far away.
Embedded HVDC system	An HVDC system where the converters are connected to different areas of the same AC transmission system (see Figure 1(b)).
EMT	Electromagnetic transient model of the power system; software examples include PSCAD/EMTDC EMTP, PowerFactory.
Export Active Power	This is active power exporting energy from the AC transmission system to the DC system. In this case the local converter would act in rectification mode.
Factory Acceptance Testing	In the context of the control and protection system of an HVDC system, this is test of the control and protection system, in the HVDC vendor's factory whilst connected to a real time replica of the power system.
Full-bridge sub-module	A VSC HVDC system that uses a converter with full-bridge sub-modules. This type of converter can create a counter voltage that can be used to extinguish a DC line fault.
Gen-tie HVDC system	An HVDC system, used for connecting between a remote gen-tie AC system and an AC transmission system (see Figure 1(c)).
Grid Code Document	A document written by an authority for an AC transmission system, detailing the rules of how that system is operated, and the requirements thereof. In addition to documents titled Grid Code, this includes guidance notes, or other documents that might be called grid codes, but have a similar role in that they contain rules on how a system should be operated.
Half bridge sub-module	A VSC HVDC system that uses a converter with half-bridge sub-modules. A half-bridge sub-module converter will effectively act like a diode-bridge during a DC side fault, and the fault must be cleared by opening the AC side breaker.

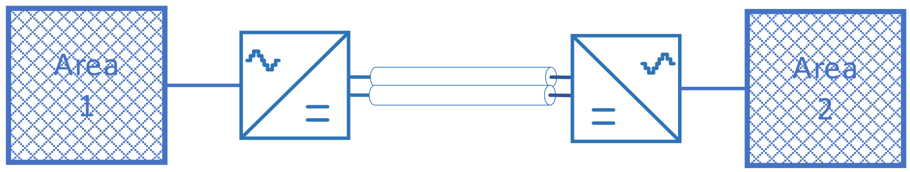
HVDC Converter	All equipment for converting between AC and DC power. Including control equipment, auxiliary systems, and related equipment such as transformers, and filters.
HVDC Equipment	Any piece of equipment that is part of an HVDC converter.
HVDC Owner	The entity that will develop the HVDC system
HVDC System	The converter stations and DC line(s).
HVDC Vendor	The company that provides the electrical, control and other power system equipment at each converter stations.
IBR	Inverter Based Resource
Import Active Power	This is active power imported energy from the DC system to the AC transmission system. In this case the local converter would act in inverter mode.
LCC	Line Commutated Converter
Local Converter	The converter of the HVDC system in the AC grid of interest.
Maximum Current	In line with note 3 of IEEE2800 [2] definition for maximum current ac, Imax
MMC	Modular Multi level Converter. These can be built using either half-bridge sub-modules, or full-bridge sub-modules. Half bridge sub module converters are usually used but require the AC breaker to be opened for a DC line fault.
Other End Converter	A converter of the HVDC system, not in the AC grid of interest.
Pmin	For LCC systems, the minimum power order that the HVDC system can transmit. Below, this level faulty or incorrect operation of the HVDC system could occur.
Preliminary EMT model (of the HVDC system)	A EMT model of the HVDC system that is completed before the HVDC Vendor’s detailed design studies.
Preliminary RMS model (of the HVDC system)	An RMS model of the HVDC system that is completed before the HVDC Vendor’s detailed design studies.
Rated Apparent Power	The MVA rating of the HVDC converter at its Connection Point.

Reduced voltage restart	For some HVDC systems that have an overhead line that is in a polluted environment restarting at a reduced voltage maybe possible. Restarting at a reduced DC voltage may allow operation when a restart at full rated DC voltage creates a fault. Typically, this type of restart is only expected to be possible in full-bridge VSC systems, or LCC HVDC systems.
Remote	For a gen-tie HVDC system, Figure 1(c), remote from the point of view of the AC transmission system, is equipment at the other end of the HVDC system.
Remote Gen-Tie AC System	The AC grid on which remote gen-tie generators and the remote gen-tie converter are connected, in a gen-tie HVDC system. (see Figure 1(c)).
Remote Gen-Tie Converter,	A converter of a gen-tie HVDC system, within a remote gen-tie AC grid (see Figure 1(c)). This will normally operate as a rectifier.
Remote Gen-Tie Generator(s)	Generator(s) within a remote gen-tie AC grid (see Figure 1(c)).
Restart	A return to active power transmission after a DC side fault has been cleared.
Rise-time	The time taken to go from 10% to 90% as per the IEEE dictionary definitions. [5]
RMS model (also known as a phasor domain model)	A model that is accurate for electromechanical modelling, power flow, and can also be used for short circuit calculations of the power system. Software examples include PSS/E PSLF, PowerFactory, PowerWorld. In some references this is called a phasor domain model, as in footnote 137 of [2].
RoCoF	Rate of Change of Frequency, the gradient of the AC grid's frequency during a transient.
RTS	Real time simulator model of the power system. These EMT models are used for Hardware in the loop modelling of HVDC systems. Examples include: RTDS, and OPAL-RT.
System Operator/Owner (SO)	The operator or owner of an AC transmission system. In this document, this means all of the various forms of these entities that are involved with the ownership and operator of AC transmission systems that are used in the various power systems of the world; i.e. Independent System Operators (ISO), Regional Transmission Organization (RTO), System Operator (SO), Transmission System Operators (TSO), Asset Owner (AO), Transmission Owner (TO).

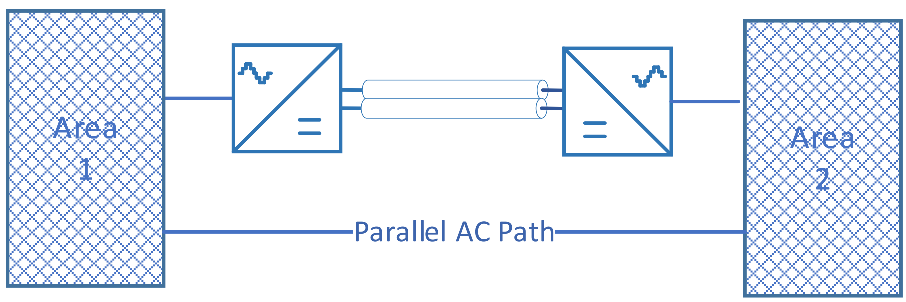
Tie Line HVDC System	An HVDC system that connects between AC transmission systems in different synchronous areas. (see Figure 1(a)).
Thévenin Model (TM)	A simple model of an AC transmission system, where the model consists of a voltage source, and an impedance. The size of the impedance is determined by the fault level of the AC transmission system. A larger impedance has a lower short fault level; this indicates that the AC transmission system is weaker. A smaller impedance has a higher short fault level this indicates that the AC transmission system is stronger.
TOV	Temporary Over Voltage
Transmission Connected Converter	A converter connected to an AC transmission system. (see Figure 1(a) for two examples of transmission connected converters).
UVRT (or LVRT)	Under Voltage Ride Through, normally associated with an AC fault in the AC transmission system. This is type of ride through is also known in some references as low voltage ride through (LVRT) or fault ride through (FRT).
Voltage Droop	An aspect of a voltage controller that linear reduces or increase the reactive power at the point of connection depending on how far the actual voltage at the point of connection is from the controller's reference voltage.
VSC	Voltage Source Converter

1.4 HVDC Configurations

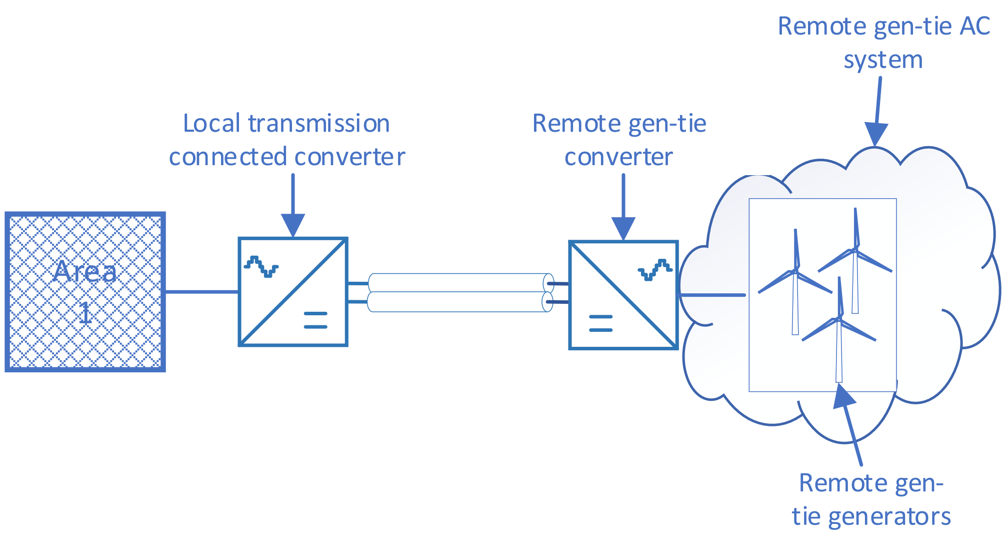
Several key configurations for HVDC are discussed in this report, they are summarized below.



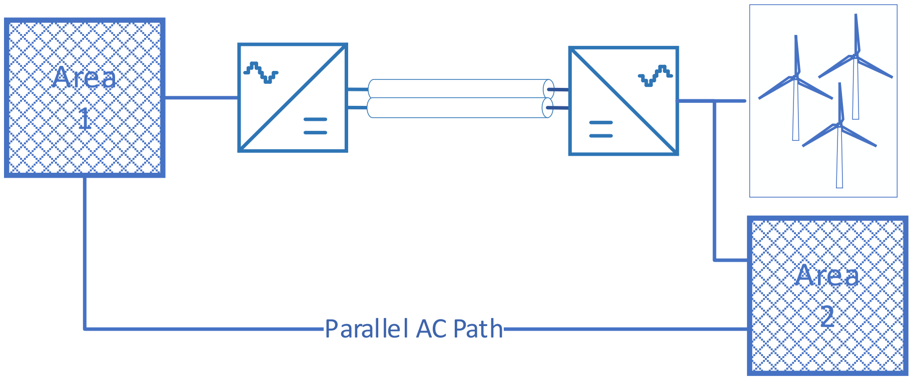
(a) Tie Line HVDC system. Transmission connected HVDC system, between different synchronous systems. Both of the HVDC converters are considered to be transmission connected converters.



(b) Embedded HVDC system, Transmission connected HVDC system within the same synchronous system. Both of the HVDC converters are considered to be transmission connected converters.



(c) Gen-Tie HVDC system. The converter connected to Area 1 is a transmission connected converter ,whilst the converter connected to Area 2 is a remote gen-tie converter.



(d) Gen-Tie HVDC system, with AC tie-line to AC system. The two areas may be in the same synchronous system. Both of the HVDC converters are considered to be transmission connected converters.

Figure 1. Different HVDC configurations

1.4.1 Connection Point

The connection point is the point where the HVDC system connects to the existing AC transmission system. If an AC tie-line is required to connect the local converter to the existing AC transmission system, then the AC tie-line is considered part of the HVDC system.

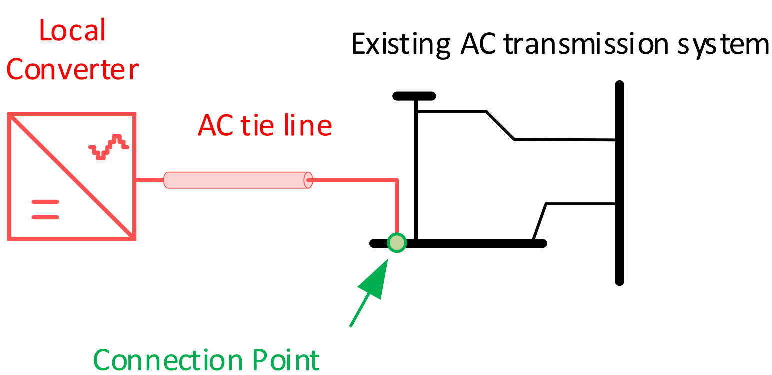


Figure 2. Connection Point

2 RECOMMENDATIONS FOR PLANNING CRITERIA AND PERFORMANCE CRITERIA FOR HVDC PROJECTS

In this section recommendations on performance requirements for HVDC system is presented. The requirements cover the following areas:

Table 1. Summary of performance standard aspects to be considered for an HVDC

Aspect	Description
Reactive Power and Voltage Control	Reactive power requirements of HVDC converters.
Active power control	Response time to follow power orders and power-reversals.
Frequency Ride-through and Control	Frequency ride through requirements and frequency controller requirements
Stability and other oscillations	Requirements related to stability, including small signal stability and sub-synchronous resonance. Stability definitions align as close as possible to those taken in the recent IEEE stability classification paper [3]. These includes requirements related to converter driven stability issues.
Under Voltage Fault Ride Through	Fault ride through, including: • under-voltage ride through curve that the converter must remain connected for • active power recovery curves • current injection during faults
Temporary Over-voltage	An over-voltage criterion the converter must either remain connected or suppress.
Emergency Power controls and other site-specific requirements	Run-backs and power-limits, normally triggered by a signal from within an AC grid.
Power Quality	Requirements on power quality, including harmonics, voltage unbalance, and voltage steps
Power system restoration	Requirements on HVDC systems to be included in power system restoration.
Grid Forming controls	Grid-Forming Control requirements

2.1 Writing Style

These recommendations should be considered *boilerplate* text that can be used within a grid code document with minimal changes. The verb "*shall* " is used for the obligatory and compulsory requirements of the HVDC owner, whilst the verb "*will* " is used for those undertakings the system operator would perform.

Expected changes are:

- The authority, i.e., who would publish and maintain the grid code, is referred in the text as the *system operator*. This would need to be changed to the actual term the authority refers to itself. In some cases, in addition to a system operator, there will also be AC transmission owner that will also be the authority on some parts of the code.
- If the system operator is within a FERC or NERC planning region, during the planning studies, then the HVDC owner will be responsible for facility owner identification of the desired corresponding FERC (TSP, TO, GO, etc.) and NERC responsible entity (BA, RC, PC, TP, TOP, etc.) with corresponding evaluations to identify the impacts to each.
- For some aspects it is assumed that the requirements for a HVDC system, would be no different to those of other connections, such as IBRs and synchronous generators. In these cases, it is expected that this *boilerplate* text would be updated to refer to these existing requirements. In these cases, curly brackets and italics are used, to highlight the text which should be either; replaced with a reference to existing requirements, or the text checked if it aligns with existing requirements. Examples include:

  For a transmission connected converters the nominal voltage range shall be *{the existing requirements for synchronous machines and IBRs.}*

  For a transmission connected VSC converters the reactive inductive and capacitive limits shall have the capability to inject and absorb a minimum reactive power defined by $|Q| \geq$ *{0.3287 × active power rating}*.

- Some specific references are made to NERC standards and SPP requirements, if the actual grid code is used outside NERC or SPP regions, then those references should be removed.
- In this document the term grid code is used. Other terms commonly used are network rules, interconnection requirements etc. The appropriate term should be used.
- The *boilerplate* text uses the terms in this document's glossary, if alternative terms are used by a system operator, these should be replaced with the alternative term.

2.2 Coordination with other System Operators

If the HVDC system is within two operational areas, then the HVDC owner, must design and study the HVDC system to meet the requirements of both system operators. If these requirements are contradictory, then the HVDC owner will work with both system operators to resolve the contradictions.

2.3 Remote Gen-Tie Converters, Generators, and AC systems

There are no direct requirements on the remote gen-tie converters, generators, and AC systems (see Figure 1(c)), such as voltage ranges or reactive power requirements. It has been left up to the owners of the HVDC system and the gen-tie generators to determine these aspects. There are, however, indirect requirements. For example, the energy for the frequency controller of the HVDC system, is likely to come from the remote gen-tie generators, so the performance of the remote gen-tie generators shall be adequate to ensure the HVDC system is able to meet its frequency performance requirements.

2.4 Reactive Power and Voltage Requirements and Control

HVDC converters can adjust their reactive power output to control voltage. Either by switching filter banks in the case of an LCC, or directly supplying reactive power in the case of a VSC.

2.4.1 Voltage Range at Connection Point

The voltage range at the connection point is the range at which the converter should expect voltages at its AC connection point. This is the range in which the standard active and reactive power controls act. For deviations outside this range, a converter shall meet the UVRT requirements described in Section 2.8 or the TOV requirements described in Section 2.10.

How should the voltage range for converters align with other equipment in the AC grid such as synchronous machines, and IBRs? Assume the same normal operating range, to ensure no additional requirements on switchgear rating etc.

1. Beyond the normal operating range at each voltage, is there any need for an extended range (which may be short-term i.e. such as 15, 30 or 60 mins)? How does a short-term rating impact HVDC system equipment rating? Short term voltage ratings are not recommended as it is expected there is minimal rating impact on a converter compared to a converter rated for the same voltage rating, but continuously. In any case in this document the recommendation is to use the same requirements as the existing requirements for SM and IBRs, if these requirements have short term ratings, then they would also be applied to HVDC systems.
2. Should a range be declared for remote-end converters that is different to that of transmission connected converter? The remote end converter range is not specified as detailed as described in Section 2.3.

2.4-1 For a transmission connected converters the nominal voltage range shall be (the existing requirements for synchronous machines and IBRs [6].

2.4.2 Reactive Power Capability

Reactive power capability for VSC HVDC converters is normally defined in terms of the active power rating of the converter, and the voltage range at which it applies. The voltage droop curve is considered in determining the reactive power requirement.

1. How should the reactive range be coordinated with the voltage range? EPRI has suggested an alternative to IEEE2800, as per Clause 2.4-3. IEEE2800 has quite a large droop range, that is not common for VSC converters.

2. How should control features like droop be incorporated in the reactive range? Have been incorporated into the polygon of Clause 2.4-3
3. Should the rating be based on export, import MWs (or should the range change as the HVDC system changes direction)? Export (if it can), otherwise import as defined in 2.4-2.
4. Should a rectangle or complex polygon be used? Should areas, such as the upper-right (capacitive vars, high voltage) and lower-left (inductive vars low voltage) be incorporated in the reactive range, as these may increase converter cost, but may not be important for operation of the AC grids? Polygon has been used as per Clause 2.4-3
5. What requirement should LCC HVDC systems have? Should an LCC converter be required to install dynamic reactive power devices such as an SVC or a STATCOM to align with the VSC requirements? Or should the need for a dynamic device be driven by a study examining an issue such as TOV (see Section 2.10)? The base requirement is +/- 5% as per the Singaporean code, however as per 2.4-6 studies may show an increased need (including dynamic reactive power).
6. How do the requirements align with synchronous machines, and IBRs? The same, as 2.4-2.
7. If there are voltage issues at a proposed HVDC systems connection point, does a process need to be included to encouraging/requiring a larger reactive range that standard? This has been allowed for in 2.4-7

2.4-2 For a transmission connected VSC converters the reactive inductive and capacitive limits shall have the capability to inject and absorb a minimum reactive power defined by $|Q| \geq$ {0.3287 × active power rating}.

2.4.2(a) For

- tie-line VSC HVDC systems, as illustrated in Figure 1(a),
- for embedded HVDC systems, as illustrated in Figure 1(b), and
- for the Area 1 VSC converter VSC HVDC system, with AC tie-line to an AC system, as illustrated in Figure 1(d);

the reactive power rating is be based on greater of, the maximum export active power rating and the maximum import active power rating at the connection point.

2.4-2(b) For gen-tie VSC HVDC systems, as illustrated in Figure 1(c), for the transmission connected converter the reactive power rating is be based on the maximum import active power at the connection point.

2.4-2(c) For gen-tie VSC HVDC system, with AC tie-line to an AC system, as illustrated in Figure 1(d). The reactive power rating for the Area 2 converter is based on the greater of, the maximum export active power rating and the maximum import active power rating of the VSC HVDC converter.

2.4-2(d) The reactive power capability shall be met across the full active power range of the transmission connected converter at the connection points for VSC HVDC systems, as illustrated in Figure 1(a), (b) and (c) and for the Area 1 converter of Figure 1(d).

2.4-2(e) The reactive power capability shall be met across the active power range of the converter for the Area 2 VSC HVDC system illustrated in Figure 1(d).

2.4-3 The reactive power capability shall be as per Figure 8 and Table 4 of IEEE2800-2022 [2] except that the point V2, is at 0.95p.u.

2.4-4 In cases where active power transmission on the HVDC system is not available, the system operator shall notify the HVDC owner if the VSC HVDC converter will have the capability for a STATCOM mode of operation. This will be part of the project specific requirements of Section 2.15. The STATCOM mode of operation will have both voltage control, as per 2.4-8(a) and reactive power operation, as per 2.4-8(b). It shall meet the requirements defined in 2.4.1,2.4.2, 2.8 and 2.10

2.4-5 For HVDC systems that use LCC converters, the converter shall have the capability to keep within *{+/-5%}* of the rated active power of the HVDC converter across its active power range and meet the harmonic requirements of Section 2.12.

2.4-6 The planning and feasibility studies (Section 3.4) may show that a reactive power capacity beyond the requirements of 2.4-2 or 2.4-5 are required. For LCC system's that may include the need for dynamic reactive power devices for active power recovery (as per clause 2.8-10), or TOV suppression (as per clauses 2.10-1 and 2.10-5).

2.4-7 The HVDC owner may offer to increase the reactive power capacity beyond the capacity requirements of 2.4-2,2.4-5 or 2.4-6 to meet an existing voltage stability issue within the AC transmission system (i.e. a pre-existing voltage stability issue in the AC transmission system, that is not caused by the HVDC system). If this offer is agreed to by the system operator it will become part of the project specific requirements as per Section 2.15.

2.4.3 Voltage and Reactive Power Control

2.4-8 Transmission connected VSC converters shall have the following three modes of operation:

2.4-8(a) Control of voltage at the connection point

2.4-8(b) Reactive power exchange at the connection point

2.4-8(c) Control of power factor at the connection point

2.4-9 The modes of operation in clause 2.4-8 shall keep the VSC converter within the operating region defined in clause 2.4-3, and meet the requirements defined in Section 5.2 of IEEE2800-2022 [2].

2.4-10 The accuracy of the reactive power setpoint shall be *{as per existing requirements for IBRs and synchronous generators or the accuracy that can be expected when the following accuracy class equipment is used 0.15s CTs* [7], *0.15 VTs* [7], *and a 0.2 accuracy class transducers. (whichever is smaller)*.

2.4-11 The accuracy of the voltage setpoint shall be *{as per existing requirements for IBRs and synchronous generators or 0.15 VTs* [7], *and 0.2 accuracy class transducers (whichever is smaller)*.

2.4-12 The accuracy of the power factor controller *{as per existing requirements for IBRs and synchronous generators or accuracy derived from the reactive and active power accuracy requirements of clause 2.4-10 and 2.5-2*.

2.4-13 The reactive power shall be metered *{as per existing requirements for IBRs and synchronous generator*s [8]

2.4-14 The voltage controller shall have an adjustable droop, the range shall be from *{1% to 10%, in 1% steps}*. The default value is 4%.

2.4-15 The transmission connected LCC converter's reactive power controller (RPC), shall allow the reactive power to be controlled at the connection point. Whilst the priority will be ensuring enough filters are connected to meet the power quality requirements (as per Section 2.12), additional filters can be switched in to meet a reactive power set-point of the RPC.

> 2.4-15(a) In some situations, the reactive power setpoint maybe unobtainable, for example due to the higher priority filtering requirements, or additional filters not being available. In these cases, the RPC will meet the reactive power set-point as best as it can.

2.4-16 Speed of response and other performance requirements for the voltage, power-factor and reactive power requirements are included in Section 2.7.

2.5 Active Power Control

1. What speed of response time should be used for power orders? Are there existing response times for synchronous machines, and IBRs that should be considered? Boilerplate clause has been included, Clause 2.5-1.
2. What ramp-rate requirement should be used for power orders? Boilerplate clause has been included, Clause 2.5-3
3. Should the ramp-rate be a capability limit of the HVDC system, which maybe much greater than the system limit? Clause 2.5-3 is considered a capability limit, whilst there is a separate operational ramp-rate defined in clause 182.5-5 The operational limit would be checked with system studies, but during the lifetime of the project this operational limit maybe increased (to another limit within the capability limits).
4. Do studies need to be performed to determine the system limits? Yes, as per clause 2.5-5

5. Is ramp-rate an operational system limit, that the system operator could change over time, and should not be defined in the grid-code? Clause 2.5-3 is considered a capability limit, whilst there is a separate operational ramp-rate defined in clause 2.5-5
6. How should the requirements on active power control speed of response be coordinated with emergency power controls (see Section 2.11)? Is there a need to specify a priority order for controllers that effect active power (i.e. normal power orders, emergency power controls, frequency controls etc.). See discussion in Section 2.11.
7. Is there a restriction of the maximum size of P_{min} for LCC HVDC systems? Yes, 5% as per clause 2.5-8. However, this could be adjusted depending on the outcome of energization studies.
8. What accuracy requirements are required of the actual power transmitted, compared to the ordered power? Use standard system operator requirements, as per Clause 2.5-2.
9. At which point within the HVDC system is the power order defined at? For Gen-tie as per IEEE2800-2022 standard (see clause 2.5-10), for other a project specific requirement (see clause 2.5-11)
10. What co-ordination is required with neighboring system operators for cross boundary HVDC system when issuing a dispatch instruction? Assumed this is taken account of as part of the global requirement, referenced in Section 2.2
11. Is a dedicated AGC control needed, which differs from an ordinary dispatch instruction? Project specific requirement as per Clause 2.5-14.
12. What settings on the active power controller (and other controllers within the HVDC system) be able to be adjusted remotely by the system operator? Project specific requirement as per Clause 2.5-13.
13. Are any special requirements needed in the grid code for passing through zero, such as specify no dwell time, or impact on the voltage controller? Yes, see clause 2.5-9(a).

2.5-1 After receiving a power order from the system operator, the HVDC system ramps to the new power order at the operational ramp-rate, as per clause 2.5-7. The HVDC system shall reach the new power order within a 1s envelop of a perfectly executed ramp[2] (see Figure 3).

[2] For example, if at 10:10:00 (hh:mm:ss) an HVDC system receives a power order to increase power from an existing setpoint of 200MW to a new setpoint of 300MW, and has an operational ramp-rate of 50MW/min, then a perfectly executed ramp would finish at exactly 10:12:00. So, in this case, the requirement would be achieved if the new setpoint of 300MW was achieved between 10:11:59 and 10:12:01

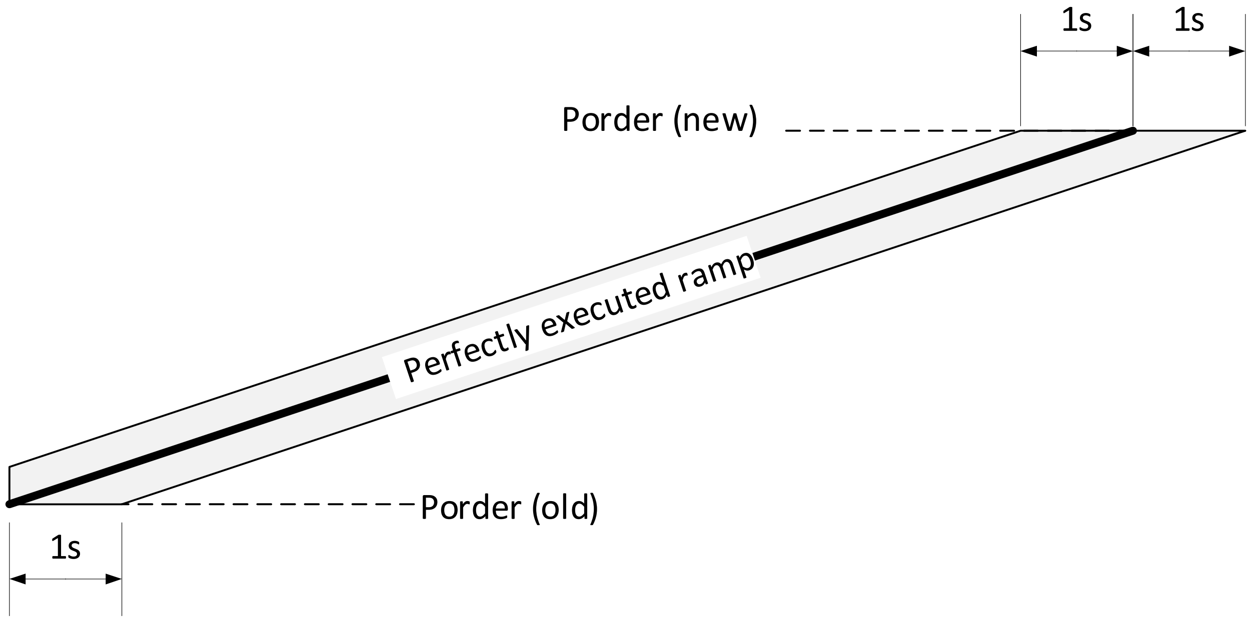


Figure 3. Ramp execution requirement. This figure shows a perfectly executed ramp, and the 1s envelop around it which the HVDC system power order must remain.

2.5-1(a) If a disturbance occurs during the ramp, such as a fault, a tap-changer action, or a switching action, then deviations outside the envelop are allowed. This includes actions from modulation controls such as frequency controllers. After the disturbance has finished the HVDC shall return to within the envelop. This is illustrated in Figure 4.

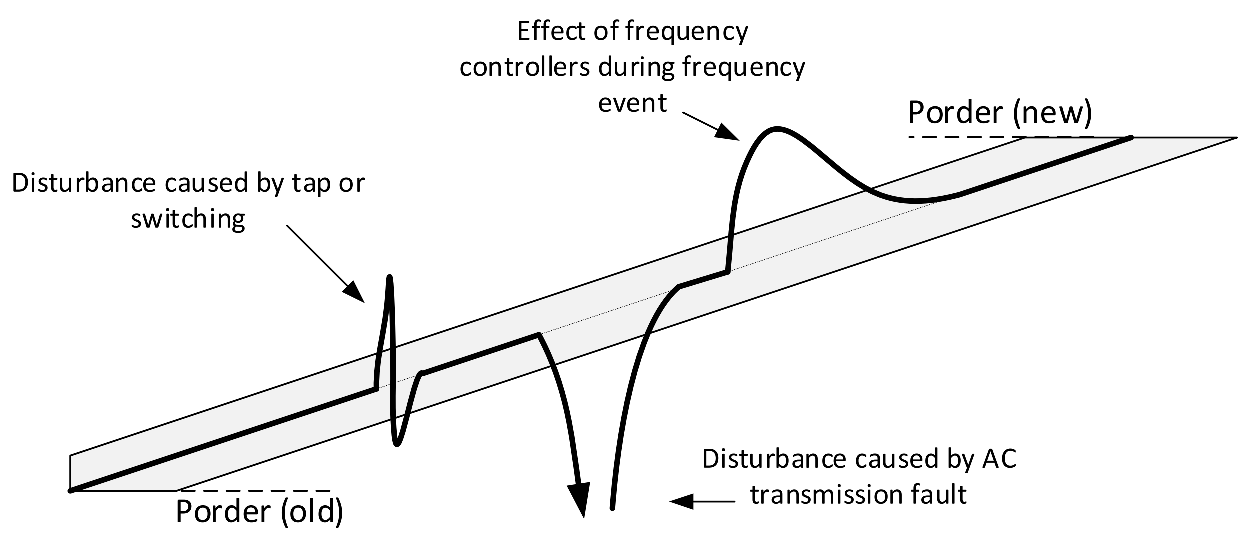


Figure 4. Ramp execution during disturbances (not drawn to scale).

2.5-2 The accuracy of the active power setpoint shall be {as per existing requirements for IBRs and synchronous generators or the accuracy that can be expected when the following accuracy class equipment is used 0.15s CTs [7], 0.15 VTs [7], and a 0.2 accuracy class transducers, (whichever is smaller)}. The active power shall be metered {as per existing requirements for IBRs and synchronous generators [8]. These accuracy requirements shall also apply to modulations that adjust the active power, such as the frequency controllers.

2.5-3 The HVDC system shall be capable of meeting the following ramp-rate {100 MW/min}.

2.5-4 The ramp-rate shall be adjustable at 1 MW/min steps.

2.5-5 The ramp-rate capability of the active power controller will be confirmed in the design studies of Section 3.5.3.

2.5-6 The active power limits of the HVDC system will be investigated in the planning studies of Section 3.4

2.5-7 The operational ramp-rate limit will be determined by the system operator but will be less than or equal to the capability requirement in Section 2.5-1. During the lifetime of the project, it may be necessary to update this ramp rate limit. The ramp-rate is bi-directional, i.e., the same value for ramping towards full export is used for ramping towards full import.

2.5-8 For LCC HVDC systems, the P_{min} shall be no less than {5%} of the active power rating of the converter.

2.5-9 VSC HVDC systems shall have a P_{min} of 0MW.

> 2.5-9(a) For a VSC HVDC system, power reversals (i.e. transitioning from export to import active power transition), shall be:

- bumpless (see glossary),
- have no dwell-time at zero when ramping through a P_{min},
- have no effect on other controls, such as voltage and reactive power controls (see Section 2.4.3), frequency controls (see Section 2.6.2), and stability controls (see Section 2.7).

2.5-10 For gen-tie HVDC systems, as illustrated in Figure 1(c), the active power of the HVDC system is defined at the connection point, in line with Section 4.2.2 of IEEE2800-2022 [2].

2.5-11 For other HVDC systems, the point(s) at which active power control point of an HVDC system is defined is a project specific requirement.

2.5-12 If a disturbance in the power system occurs, such as a DC fault, frequency event, UVRT, etc., then unless an emergency power control is triggered, no active power ramp should be halted, and the active power control shall still ramp to the required post-disturbance power order.

2.5-13T he ability for the system operator to adjust active power settings, such as ramp-rate shall be a project specific requirement as per Section 2.15.

2.5-14 The ability of the system operator to send an external active modulation signal, such as an AGC signal shall be a project specific requirement as per Section 2.15.

2.5-15 For gen-tie HVDC system, some of the active power requirements maybe performed by the remote get-tie generators, instead of the HVDC system itself. Co-ordination between the HVDC-system and generators is a design decision for the HVDC owner. Details of the co-ordination method will be described in the power system models (as described in Section 4).

2.6 Frequency Ride-through and Control

Two aspects to frequency are considered:

- The ability of the HVDC system to ride-through a frequency event
- The response of the HVDC system to support the network frequency by modulating its active power.

2.6.1 Frequency Ride Through

A frequency ride through criteria is described as:

- the ride through requirements for frequency deviations from nominal, for extreme frequencies these are time limited.
- A RoCoF ride-through requirement.

1. What frequency range should be selected for Transmission and Remote-End converters? As per the IEEE2800-2022 requirements, specified in 2.6.1.
2. What RoCoF requirement should be set? How should this align with other plant such as synchronous machines? How should RoCoF be defined (i.e. is averaged over a time interval)? As per the IEEE2800-2022 requirements, specified in 2.6-3.
3. How should this range be aligned with other plant such as synchronous machines, and IBRs? Should it be the most onerous as per the recommendation in European HVDC code. The IEEE2800 limits are much wider than the NERC eastern and western limits in PRC-024-3, so we have gone with the IEEE2800 limits for VSCs. For VSC HVDC system this is not expected to have a great cost impact. For LCCs there may be a cost impact so we gone with the PRC-024-3 levels.
4. Does the proposed range have an impact on plant rating/cost? The IEEE2800-2022 requirements are wide, however, is note expected to be an issue for VSC HVDC systems. For LCCs there may be a cost impact, so we gone with the PRC-024-3 levels.
5. Is there a requirement for a phase angle change ride through? As per clause 2.6-4

2.6-1 For frequency deviations, an VSC-HVDC converter shall meet the frequency ride through requirements of Section 7.3.2 of IEEE 2800-2022 [2] in its connected AC transmission system.

2.6-2 For frequency deviations, an LCC-HVDC converter shall meet the frequency ride through requirements of PRC-024-3 [9].

2.6-3 HVDC systems shall meet RoCoF ride through requirements of Section 7.3.2.3.5 of IEEE 2800-2022 [2] in its connected AC transmission system.

2.6-4 Shall meet the Voltage phase angle changes requirements of Section 7.3.2.4 of IEEE 2800-2022 [2] in its connected AC transmission system.

2.6.2 Frequency Control

Frequency controls are modulations used to alter the active power of an HVDC system to regulate an AC system's frequency.

1. What are the minimum performance levels required by frequency controls? As per IEEE 2800-2022
2. Does the grid code include minimum standards? Is there a market in place for faster acting responses? Minimum standards in line with NERC requirements
3. As frequency services may change in the future, how should participants be encouraged to have flexible controllers which have potential greater performance that today's controllers? IEEE 2800-2022 does include a range of settings for future proofing.
4. Should the system operator be able to adjust control variables (droop, power limits, etc.) remotely? Project specific requirement as per Clause 2.5-13
5. For remote gen-tie generators, should a signal be provided from the HVDC system so that they can response to transmission system frequency deviations? This is part of IEEE 2800-2022 but exact details are left to the HVDC owner 2.6-10
6. Are frequency controls only required in remote-end HVDC systems, and transmission connected schemes that connect the HVDC system between different synchronous areas? Or, should frequency controls be included for embedded HVDC systems in case of a system split, or power system restoration? They should be included in the control system, but only activated if a split occurs (which is also the case for power system restoration), as detailed in

2.6-5 The HVDC system shall have primary and fast frequency capability in-line with both Section 6 of IEEE 2800-2022 [2] NERC requirements and *{system operator requirements}*.

2.6-6 The accuracy of the measurement of frequency for frequency control shall be in line with Section 4.4 of IEEE2800-2022 [2], i.e., 0.01Hz.

2.6-7 If the HVDC system's active power controls have the capability of power-reversals, then the frequency controls can also cause a power reversal. For example, a VSC tie-line HVDC system is exporting 50MW from an AC transmission system, the frequency in that system drops such that the frequency controller requests 100MW of active power. This would cause the HVDC system to undergo a power reversal and change to importing 50MW to the AC transmission system.

2.6-8 For tie-line HVDC systems, as illustrated in Figure 1(a), the frequency controls shall have settings to enable/disable the frequency control individual at each AC system. It shall be possible to enable frequency control enabled simultaneously in several AC systems as per a bidirectional frequency controller. The HVDC owner shall work with the system operators to determine how the frequency control will act if both AC system's frequency require regulation at the same time. At least the following cases shall be considered:

Table 2. Tie-Line frequency combinations

Case	System Freq 1	System Freq 2
1	No event	Under-Frequency
2	No event	Over-Frequency
3	Under-Frequency	Under-Frequency
4	Under-Frequency	Over-Frequency
5	Over-Frequency	Under-Frequency
6	Over-Frequency	Over-Frequency
7	Under-Frequency	No event
8	Over-Frequency	No event

2.6-9 For embedded HVDC systems, as illustrated in Figure 1(b), frequency control shall be included. These controls are expected to only be activated if the AC systems connected to each converter are no longer synchronous (i.e. there has been a system split or during power system restoration). When to active these controls is a project specific requirement as listed in Section 2.15.

2.6-10 For gen-tie HVDC systems, as illustrated in Figure 1(c) the remote gen-tie generators are included in the frequency controller response, however the co-ordination between the HVDC-system and generators is a design decision for the HVDC owner. Details of the co-ordination method will be described in the power system models (as described in Section 4).

> 2.6-10(a) For fast frequency responses, then the response should comply with the requirements of Section 6.2 of IEEE 2800-2022 [2].

2.6-11 For gen-tie HVDC systems, with AC tie-line to an AC system, as illustrated in Figure 1(d). The following is required:

> 2.6-11(a) If the two AC systems are in different synchronous areas the frequency controls shall act as per 2.6-8.

> 2.6-11(b) If the two AC systems are synchronous then the frequency controls shall be as per 2.6-9.

2.6-12 For fast frequency response there are several different possible implementations, such as those discussed in Annex K of IEEE 2800-2022 [2]. The HVDC Owner will work with the system operator to determine the most effective implementation as per the studies defined in Section 3.4.3[3].

2.6-13 The settings of the controllers shall have flexibility, as described in Section 6 of IEEE 2800-2022 [2]. The HVDC owner shall test the controllers on a range of settings during the dynamic performance studies. After the design performance studies, initial settings will be selected for operation by the system operator. During the lifetime of the project, it may be necessary to update theses settings from time-to-time. The HVDC owner and the system operator will work together to determine these changes.

2.6-14 The use of the frequency controls complies with system operator's *{operation manuals for activation frequency controls}*.

2.7 Stability and Other Oscillations

The stability criteria include

- Inclusion of a power system damping (POD) control for damping of power system oscillations, these are the power system oscillations described as small signal in [10]
- Sub-synchronous torsional interaction (SSTI) damping, for the damping of torsional interactions. These oscillations may occur between a fast-acting device like an HVDC system, and a mechanical system like a turbine generator.
- Converter driven stability, one of many classes of fast and slow stability involving converters and their controllers. Some of these interactions may occur between neighboring converters [3].
- Step response criteria for main controllers such as voltage and frequency controllers.

1. What stability classes are of interest? Power oscillations (transient), SSO, and converter driven [3]. Steady state voltage is part of the planning/feasibility studies, whilst the dynamic performance will also specify study of transient stability.
2. Most codes cover sub-synchronous torsional interaction, will there be nearby series capacitors that will need requirements to be included covering sub-synchronous control interactions? Both are intended to be covered in the screening and detailed studies. It should be noted that currently SPP does not have series capacitors within their area.
3. Will a definition of what constitutes adequate damping be included in the requirements? How should this align with existing damping criteria that are already in the grid code? IEE2800-2022 definitions have been used for step response; the dynamic performance studies reference existing rotor-angle damping requirements.
4. Is a damping requirement for slower oscillations (such as power and sub-synchronous) appropriate with higher frequency oscillations that may occur with some aspects of

[3] A recommended starting point for these discussions is the controller K.2.1 in [2], this is a controller with a response that is proportional to the frequency deviation.

converter driven stability? So far only that high-frequency oscillations must be damped has been included.

5. Will a performance criterion, i.e. damping ratio, settling time, etc., be defined for step responses? IEE2800-2022 definitions have been used.
6. How will these align with the study requirements outline in Section 3? Specific studies are required for SSO, and converter driven. Steady state voltage is part of the planning/feasibility studies, whilst the dynamic performance will also study transient stability (which may result in POD tuning) and transient voltage stability.

2.7-1 A power oscillation damping (POD) capability shall be included, the settings and the structure of how this capability is implemented shall be agreed between the system operator and the HVDC Owner. The settings may in part be influenced by the findings of the dynamic performance study described in Section 3.4.3.

2.7-2 The HVDC system shall damp sub-synchronous oscillations (SSO). The HVDC owner will undertake screening studies and detailed studies as described in Sections 3.4.5 and 3.5.7.

2.7-3 The HVDC system shall not adversely interact with other third-party devices or the system operator power system, and any oscillations shall be damped. The HVDC owner will undertake screening studies, and detailed studies as described in Sections 3.4.6 and 3.5.8 to design the HVDC system so that it does not cause converter driven instability as described in [3].

2.7-4 The HVDC system's controllers shall meet the performance requirements specified in IEEE2800-2022 [2]

2.7-4(a) VSC HVDC systems voltage controller shall meet Table 5 of IEEE2800-2022. The step response speed of the voltage controller to either step change in the system voltage and the connection point, or voltage set point changes shall be 1s. The system operator may allow a slower response time if system studies show a slower time is needed for either grid strength, compatibility with other local voltage control devices, or overshoot requirements.

2.7-4(b) The reactive power and power-factor controllers shall have a damping ratio of 0.3 or better for step-responses. The speed of the reactive power and power-factor controllers to step changes in set point shall be 1s. The system operator may allow a slower response time if system studies show a slower time is needed either for grid strength, compatibility with local voltage control devices, or overshoot requirements.

2.7-4 (c) primary frequency controller shall meet the default requirements (or better) Table 8 of IEEE2800-2022

2.7-4(d) The fast frequency controller shall meet the settling band and damping ratio default requirements (or better) of Table 8 of IEEE2800-2022

2.7-4 (e) The current injection controller shall meet the requirements of Table 13 of IEEE 2800-2022 [2] for *all other IBR units*

2.7-4(f) Additionally, all controllers shall meet the system operator's specific requirements (*specific system operator requirements*, [11]).

2.7-4(g) If the requirements of 2.7-4 cause noncompliance with another requirements, such as 2.7-3. then the HVDC Owner shall work with the system operator to agree on a compromise.

2.7-5 During the lifetime of the project, it may be necessary to carry out further stability or oscillatory studies from time-to-time. This need could be driven by the installation of third-party equipment near the HVDC system, or as the results of an observed event. If further studies are needed the HVDC owner will support system operator's requirements for new studies and/or provide information to other third parties to carryout stability studies. The results of the study may require modifications to the HVDC system controllers.

2.8 Under Voltage Fault Ride Through

Under voltage fault ride through is the ability of an HVDC converter to remain connected, during and after an AC system fault. There are several aspects to fault-ride through:

- Requirements to ride-through i.e., not trip or block for a fault. This is normally specified as a voltage-time curve, often called an Under Voltage-Ride Through (UVRT) curve, showing the worst-case expected voltage dip from a fault.
- Active power recovery curve, after-fault clearance, a requirement stating how fast the HVDC must return to its pre-fault power level.
- Current injection can be required during a fault to both support the AC voltage and provide fault current for protection schemes. Often this is a reactive current injection requirement.

2.8.1 Under-voltage Ride Through Curve

The under-voltage ride through curve is the dip in voltage caused by a fault, that the converter should remain connected for. Outside this curve, the converter may be able to take other actions, such as block or trip.

1. Expected breaker opening times (should this consider back-up protection times?) Assumed to be part of the IEEE 2800-2022 requirement which for the most onerous voltage dips requires ride-through times of up to 320ms.
2. Do the UVRTs for other plants, such as synchronous machines, and IBRs need to be considered Synchronous machines as per NERC, and IEEE 2800-2022 has for IBR, so IBR and HVDC systems will be aligned.
3. What action should the HVDC converter take if the criteria is breached? Are there any extended criteria for auxiliary system ride through? Part of the IEEE 2800-2022 requirement assumes robust auxiliary systems, and HVDC system can trip if outside the UVRT criteria.

4. Is there a separate blocking criterion, i.e. the HVDC converter can block, but will deblock when voltage recovers? Covered in Section 2.8-18.
5. What speed should the voltage rise time be before nominal voltage is restored? Are there any fault records or simulations that can be used to estimate this? This is taken account of in Annex D of IEEE 2800-2022.
6. How should the criteria apply to asymmetric faults? It's implied that this is the case in IEEE 2800-2022, and repeated in 2.8-2
7. Will the URVT criteria be able to be met by manufacturers? Whilst the IEEE2800-2022 is more onerous that most, as shown in Figure 3-7 of [1], as the IEEE2800-2022 standard was created with industry input it is not expected to be unable to be met by HVDC vendors.
8. What operating point should the URVT compliance be checked for (i.e. fault level, pre-fault active and reactive power output etc.)? Refer to Section 3 (studies section).
9. How many repeat under-voltage events should be included in the criteria? Repeated ride through maybe caused by auto reclose. As per the description of 2.8-6 IEEE 2800-2022, some exceptions exist for gen-tie generators which will be handled on a case-by-case basis.
10. What criteria should be considered for remote gen-tie converters? For remote-end converters there may be a limitation due to thermal ratings of elements such as DC choppers for repeated ride through attempts. As per the description of 2.8-6 IEEE 2800-2022, some exceptions exist for gen-tie generators which will be handled on a case-by-case basis.

2.8-1 For UVRT, an HVDC converter shall meet the requirements Section 7.2.2.1 of IEEE 2800-2022 [2] for ride-through of under-voltages in its connected AC transmission system. The ride-through voltages are detailed in Table 12 of IEEE 2800-2022[4].

2.8-2 UVRT is required for both faults balanced and unbalanced voltage deviations of Table 12 of IEEE 2800-2022.

2.8-3 During the UVRT, a VSC-HVDC converter shall inject reactive current as described in Section 2.8-11.

2.8-4 For under-voltages more onerous that what is defined 2.8-1 the converter protection shall align with Section 9 (specifically Section 9.3) of IEEE 2800-2022 [2].

2.8-5 For under voltages below 0.1, i.e., the conditions of the last row of Table 12 of IEEE 2800-2022 mandatory operation is required. The system operator may agree to relax this to permissive operation, if this requirement causes stability issues, or is too onerous for the HVDC system to achieve. However, system operator approval is needed for permissive operation.

[4] Note, the IEEE2800-2022 standard includes an annex, Annex D, on how to interpret the ride through requirement.

2.8-6 The HVDC systems shall meet the requirements of Section 7.2.2.4 of IEEE 2800-2022 [2] for consecutive voltage ride through. Gen-Tie HVDC systems (as shown in Figure 1c) can apply for an exception to these requirements (due to DC chopper limitations). This expectation is only for that configuration, not other configurations such as Tie-Line, Embedded HVDC systems[5], or Gen-tie HVDC systems with an AC tie-line. Any exception shall require agreement by the system operator.

2.8.2 Active Power Recovery (APR)

The active power recovery requirement determines how fast the HVDC system should restore power transmission after a fault has been cleared.

1. When should the active power recovery start, i.e. fault clearance, or voltage restoration above a certain level? After voltage restoration to the normal operating range, as per IEEE 2800-2022.
2. What speed should the active power be restored at? Can it be deliberately slowed to aid AC system stability? Allowed for in Section 2.8-8.
3. Is there an initial restoration level (such as 90% of pre-fault power), before an additional time for full restoration? 90% after 500ms, 100% after 1s.
4. What damping criterion, overshoot criteria, should any oscillations have? See section 2.7.
5. Are there any grid issues, such as transient stability which requires a certain recovery time? Refer to Section 3 (studies section).
6. Will the recovery criteria be able to be met by manufacturers? Is a slower recovery allowed under low short circuit conditions? 500ms is in-line with EU requirements, so is not expected to cause issues.
7. What operating point is compliance for the recover criteria checked for? Refer to Section 3 (studies section).

2.8-7 The active power recovery begins when the AC system voltage at the point of connection is restored to within its normal operating range (i.e. the range defined in Section 2.4.3).

2.8-8 The active power recovery time is faster than *{500ms}*. This is the minimum level of recovery performance that must be demonstrated for compliance. At this point 90% of pre-disturbance active power must be restored. After an additional *{500ms}* (i.e. *{1000ms}* after voltage restoration) 100% of active power must be restored.

2.8-9 For stability it may be desirable to reduce the rate of active power recovery. Any reduction of the recovery time from the default value shall be based on a mutual agreement between the HVDC owner and the system operator. The recovery time shall be configurable within the range of *{0.5s to 10s}*.

[5] Note, the IEEE2800-2022 standard includes an annex, Annex M, that has further details on the exception.

2.8-10 For LCC systems, dynamic reactive power (via a device such as a STATCOM or SVC) may need to be installed by the HVDC owner to meet the active power recovery requirements.

2.8.3 Current Injection During Faults

With the development of VSCs, HVDC systems can provide reactive (and sometimes active) fault current. This injection of current is used to both trigger AC protection and support the power system.

1. At what voltage level should current injection begin? Default behavior is described in 2.8-15, an option for project specific behavior is described in 2.8-16.
2. What co-ordination should occur between standard voltage control, and reactive injection? Will this affect the voltage-vs-current curve as per ECC 6.3.16.1.2? Details of the co-ordination is an HVDC owner issue, but it must be smooth (as described in 2.8-17) and there shall not be UV or TOV caused by the injection (as described in 2.8-18).
3. What allowances should be considered for when the fault is cleared to avoid a temporary over-voltage? This could include temporary blocking. Temporary blocking is allowed but only with approval as described in 2.8-18
4. Should consideration be given to inductive current injection for temporary over-voltages (also discussed in Section 2.10)? Yes, as per 2.8-11.
5. How should the converter inject current during unbalanced faults, shall it inject a component of negative sequence current? Yes, as per 2.8-11 (included in 7.2.2.3.4 of IEEE2800-2022).
6. Should a priority be given to reactive current over active current? Default is reactive as per 2.8-15, but an option for project specific behavior is described in 2.8-16
7. At what speed should reactive current be injected? As per Section 7.2.2.3.5 of IEEE 2800-2022, as described in 2.8-12.
8. What damping criterion should any oscillations have? As per Section 7.2.2.3.5 of IEEE 2800-2022, as described in 2.8-12.
9. Are there any grid issues, such as protection which requires a certain injection time or magnitude? For speed the values in 7.2.2.3.5 of IEEE 2800-2022 seem reasonable for vendors achieve, faster values maybe difficult. Going beyond 1p.u. may also cause additional cost. There are some European studies that suggest 1.4 maybe desirable especially for GFC, we assume any need for extra current will be found during the system studies (see Clause 28).
10. Will the criteria be able to be met by manufacturers? Speed and magnitude values seem reasonable, when compared with what was found in other jurisdictions [1].
11. What operating point is compliance with the criteria checked for? Checked in both the dynamic performance studies 3.4.3, and the fault ride through studies 3.5.5.
12. What allowances are made for LCC converters? LCCs are not required to inject, as per 2.8-19.

2.8-11 During both an under-voltage and an over-voltage; a VSC converter shall inject current to support the power system. The requirements of this current injection controller are as described in Section 7.2.2.3.4 of IEEE 2800-2022 [2].

2.8-12 The current injection controller shall meet the requirements of Section 7.2.2.3.5 of IEEE 2800-2022 [2] for all other IBR units.

2.8-13 The maximum current AC (i.e. the current injected into a fault), description in Section 3.1 of IEEE 2800-2022, shall be determined from the maximum rated apparent power of the VSC converter at its connection point.

2.8-14 System studies may reveal a need for higher injection current, to mitigate a power system issue caused by the HVDC system's connection to the AC transmission system.

2.8-15 The following strategy will be used by each VSC converter's current injection controller:

> 2.8-15(a) The VSC converter shall prioritized reactive current as per the definition of prioritized reactive current in IEEE 2800-2022.
>
> 2.8-15(b) For UVRT, the VSC converter shall inject maximum current when the retained voltage is *{0.5p.u}*. or lower.
>
> 2.8-15(c) For TOV, the VSC converter shall absorb maximum current when the retained voltage is *{1.15p.u}* or greater.
>
> 2.8-15(d) The VSC converter shall inject negative-sequence reactive current of *{50%}* of its maximum current rating when the terminal negative-sequence voltage is greater than or equal to *{25%}* of nominal voltage

2.8-16 The default behavior of 2.8-15 may be replaced by a project specific requirement. This could be identified during the feasibility, planning or design stages of the project to develop an VSC-HVDC system. The HVDC owner will either be informed of these changes by the system operator or the HVDC owner can request changes for the system operator's consideration for approval.

2.8-17 The current injection controller shall be coordinated with the active power controller, and the voltage/reactive/power factor controller described in Section 2.4.3. There shall be a smooth transition between these controllers that act in the normal voltage range, and the performance described in 2.8-15.

2.8-18 Upon fault clearance the current injection controller shall neither cause an over-voltage (if it was acting to boost voltage during an UVRT) or an under-voltage (if it was acting to reduce voltage during a TOV). Short temporary blocking of up to two cycles of the VSC maybe allowed to avoid these post-fault clearance issues, however temporary blocking requires the system operator's approval.

> 2.8-18(a) For this clause an over-voltage is defined as per the requirements of Section 2.10.

2.8-18(b) For this clause an under voltage is a deviation below 0.9p.u.

2.8-19 HVDC systems that uses LCC converters are not required to inject current during AC side faults.

2.9 DC Faults

A DC side fault is a fault between the converters of an HVDC system. For systems that use cables, the likelihood of a DC side fault is rare, and if it occurs it normally requires a system shutdown to determine the cause of the fault. This could take days, or even weeks to investigate, and repair. For OHL DC systems: lightning strikes, fires, pollution etc. can cause a DC side fault. In these systems, after the fault is cleared, the HVDC system will normally automatically re-energized the DC system and return to the pre-fault power level.

1. Is DC fault recovery a requirement only for HVDC systems that use DC overhead line? Yes, DC cables (and faults within the converter station) are exempt, as described in 2.9-8.
2. What is the recovery time (to recovery to pre-fault transfer)? Are multiple re-start attempts allowed? If the converter technology allows can a reduced voltage re-start attempt be allowed? Restart time is from 200ms to 1500ms, 200ms is default but can be extended to 1500ms if a system impact study shows no issues as described in 2.9-3 and 2.9-4. Reduced voltage restart should occur if the equipment allows, as described in 2.9-8)
3. Are there any project specific requirements which would determine the recovery time? Yes, as described in 2.9-4.
4. Will there be any differences in transmission connected, or remote-end converters? No.
5. How should the criteria align with the under-voltage ride through active power recovery criteria? 200ms is faster than what is in the UVRT recovery, but it is believed 200ms is possible from other projects. Additionally, a deionization time is also allowed.
6. Will the recovery criteria be able to be met by manufacturers? Can allowances be made for slower recovery for different converter technology types? Restart times are based on reference papers, and knowledge of existing schemes. The range of times from 200ms to 1500ms as described in 2.9-4 allows for different technology.
7. Should DC faults be considered a contingency in planning and design studies? Yes covered in Section 3.2
8. Is there are requirement for a minimum standard for lightning protection? Is there an AC standard for EHV lines that should be used? 2.9-9

2.9-1 For a circuit with OHL the HVDC system shall restart after a temporary DC side faults on the OHL lines.

2.9-2 The HVDC system shall act to extinguish the fault current that flows into the temporary DC side fault.

2.9-3 The active power restoration time is the time from the fault inception to restoration of 100% of active power transfer. This time shall be 200ms and exclude a deionization time.

2.9-4 The active power restoration time can be increased up to 1500ms for equipment that is not able to achieve the requirements of clause 2.9-3[6] but only if the AC system performance is still met as per the dynamic performance study (as discussed in Section 3.4.3). Increasing the restoration time requires approval from the system operator.

2.9-5 The deionization time occurs after the fault is extinguished by the HVDC system, but before the HVDC attempts to restart and restore active power transfer. The deionization time shall be settable between 50ms and 1000ms, the default setting is 100ms. The owner of the HVDC system, and the system operator will agree on the operational deionization setting, and it could be increased or decreased during the lifetime of the HVDC system.

2.9-6 The HVDC owners may attempt multiple restart attempts following a failed initial restart. These restart attempts are permissible given all the following conditions are met:

> 2.9-6(a)HVDC equipment can perform multiple restarts following a failed initial restart attempt.
>
> 2.9-6(b) The site-specific details of the multiple restart attempts shall be examined by the system operator who will determine if multiple restarts shall be used.
>
> 2.9-6(c) For subsequent restart attempts following a failed initial restart, the HVDC system shall extinguish the fault current again, wait a further deionization time and try a further full voltage restart.

2.9-7 If the HVDC system equipment allows for reduced voltage operation a reduced voltage restart shall be attempted after all failed voltage restarts.

2.9-8 For DC side faults, either within the converter stations or on any section of DC cable, then a restart is not required. If the HVDC system uses both OHL and Cables, then the HVDC system's protection shall automatically determine if a fault has occurred on a cable or OHL section. Restart is only required for faults on the OHL sections.

2.9-9 The DC OHL shall be built to the following standard *{if no DC standard exists, then then an AC standard of a similar voltage could be used}.*

2.10 Temporary Over-voltage

Power frequency Temporary Over Voltages (TOV) can occur if a large inductive load is tripped. LCC HVDC systems can generate a TOV if the converters temporarily stop transmitting active power (i.e. due to a line fault, or other end fault). In this case no reactive power is absorbed by

[6] This includes converters that exclusively use half-bridge sub-modules, 2-level, and 3-level converters.

the converters, but the converters filters remain connected so generate a TOV. TOV are most onerous where the LCC systems has a low short circuit ratio [12].

1. Is there any existing TOV criteria that should be adopted? Yes, will adopt IEEE 2800-2022 for the VSCs, and the NERC PRC-024-3 for LCCs. There may be an existing LCC near the location of an VSC, in which case the TOVs that this may generate are used in place of the IEEE 2800-2022 curve.
2. Should the requirement be a ride-through, or performance criteria? For VSC it's a ride-through, for LCCs it's a performance.
3. Will there be differences in the criteria for LCC and VSC converters? See answers to 1 and 2 above.
4. Will there be any differences in transmission connected, or remote-end converters? Only transmissions connected is considered in the requirements as per Section 11.
5. Should a current injection criterion be included for suppression of TOVs, i.e. should inductive current be injected to suppress the TOV? Yes, covered in 2.8-11 and in 2.10-3.
6. Is an instantaneous transient voltage requirement needed**?** No, assumed this is a design issue for the HVDC owner.

2.10-1 For TOVs, an HVDC converter shall meet the requirements Section 7.2.2.1 of IEEE 2800-2022 [2] for ride-through of over-voltages in its connected AC transmission system. The ride-through voltages are detailed in Table 12 of IEEE 2800-2022.

2.10-2 If an HVDC converter is sited near a LCC converter,[7] then the system operator will investigate if that LCC has an event that could produce a TOV that is more onerous than those defined in 2.10-1. In these cases, the system operator will determine a project specific TOV requirement that will replace that defined in 2.10-1.

2.10-3 During a TOV, a VSC-HVDC converter shall absorb reactive current as described in Section 2.8-11.

2.10-4 The HVDC converter shall not trip, and only block for the situation defined in 2.8-18. For TOVs more onerous that what is defined 2.10-1 the converter protection shall align with Section 9 (specifically Section 9.3) of IEEE 2800-2022 [2].

2.10-5 LCC HVDC converters shall not generate a TOV greater than that defined in NERC PRC-024-3 [9] for internal faults in the HVDC system, or faults in any connected AC system.

[7] TOVs are mainly expected to be generated by LCC converters when transmission is temporarily paused, such as an other-end fault. In this case, the reactive power absorbed by the converters is reduced, and the surplus reactive power generated by filter banks creates a TOV.

2.11 Emergency Power Controls (EPC) and Other Site-specific Requirements

Emergency power controls (EPC) are modifications to the active power order of an HVDC system. Emergency Power Controls are normally included to manage a known issue in the power system, where a modification in the HVDC system's power order would be beneficial.

1. Are there known power system issues where EPC controls are required? Are these general requirements or project specific requirements? Expected to be project specific, allowed for in Clause 2.11-1
2. Are there special emergency assistance EPCs needed for HVDC systems between regions, or would these be dispatched via other means (i.e. normal power order dispatch or AGC controls etc.)? Project specific requirement
3. What type of EPC controls are required, and what ramp-rate required by the EPC control? Should the ramp-rate be a capability limit of the HVDC system, which maybe much greater than the system limit? For project specific EPC the type will be part of the design. For the additional EPCs of Clause 2.11-2, they shall be flexible and triggered by a remotes signal from the system operator. The ramp-rate capability is based on the power reversal speed of European HVDC code, but the practical limit will be checked in the EPC design studies, as per Clause 2.11-4
4. In addition to EPCs for known issues, should there be an additional requirement for EPCs to be include for use at a future date if new issues are identified that an EPC could manage? What flexibility in type, parameters and triggering should be included in these additional EPC controls? Allowed for in Clause 2.11-2
5. Should a specific power reversal EPC control be required, or should this be treated as a performance requirement on an EPC ramp-rate? Capability has been included that aligns with the European HVDC code, but the practical limit will be checked in the EPC design studies, as per Clause 2.11-4
6. How should the requirements on emergency power controls speed of response be coordinated with the active power control (see Section 2.4.3)? Will be determined during project design as per Clause 2.11-5
7. What settings of the EPC shall be able to be adjusted remotely by the system operator? Expected to be project specific, allowed for in Clause 2.11-2

2.11-1 Specific requirements for EPC maybe determined either in the studies outlined in Chapter 3, or part of the project specific requirements of Section 2.15.

2.11-2 The HVDC system shall at each converter station include five configurable emergency power controls. These EPC controls are for future use. They shall:

2.11-2(a) Be selectable as either power-limits, run-back/run-ups, or delta-run-backs types.

2.11-2(b) Have selectable settings, i.e. MW size, or set-point, ramp-rate speed, and/or armed/dis-armed

2.11-2(c) These EPC will be triggered by a remote signal from the system operator. The details of how the signal is sent to the HVDC control system, and what settings can be adjusted remotely, will be part of the project specific requirements of Section 2.15.

2.11-3 If the HVDC system is capable of power-reversal, then the EPC can also allow a power reversal.

2.11-4 The EPC controls will be capable of the following ramp/rate speed:

2.11-4(a) For HVDC systems that allow a power-reversal, the maximum ramp-rate from full export to full import (or full import to full export) will be 2s. The system operator may agree to increase this time, if the HVDC system is required to carry out tap changer action to (or in the case of LCC systems, filter switching) for this change in active power.

2.11-4(b) For HVDC systems that do not allow power-reversal, the maximum ramp-rate from Pmin to maximum active power will be 1s. The system operator may agree to increase this time, if the HVDC system is required to carry out tap changer action to (or in the case of LCC systems, filter switching) for this change in active power.

2.11-4(c) the practical limit the HVDC system can perform (given the short circuit level of the AC system) will confirmed during the design studies of Section 3.5.1.

2.11-5 The priority of an EPC controller with other controllers, such as active power controls, other EPCs, and frequency controls shall be agreed between the HVDC owner and system operator during the design of the HVDC system control and protection.

2.11-6 For gen-tie HVDC system, some of the emergency power control actions may be performed by the remote get-tie generators, instead of the HVDC system itself. Co-ordination between the HVDC-system and generators is a design decision for the HVDC owner. Details of the co-ordination method will be described in the power system models (as described in Section 4).

2.12 Power Quality

Power quality requirements have been defined for three issues:

- Harmonics distortion, the allowable level of voltage distortion and/or amplification that the converter can cause.
- Voltage unbalanced, the level of negative sequence that the HVDC converter must remain connected for.
- Voltage step, the maximum step in AC voltage equipment in the HVDC converter can cause when it is energized.

1. What power quality requirements should be included in the grid code, and what should be left to a project's connection agreement? The code will just reference the existing the system operator requirements, however there is expected to be project specific performance levels as detailed in 1.1-1.
2. Should there be special requirements for HVDC converters, or should they be treated like any other connections? Assume the requirements are similar to other devices such as IBR, as detailed in 2.12-1.
3. What standards should be referenced? Existing standard, as detailed in 2.12-1.
4. Are there both performance requirements, and rating (i.e., withstand) requirements? There are both performances as per clause 1.1-1 and compatibility requirements as per clause 2.12-1.
5. How should allocation of harmonic distortion between the current project, and an allowance for future projects be handled? Or should amplification factors be used? As per existing harmonic requirements.
6. Are inter-harmonics an issue? This is included in 1.1-1. There is guidance in Cigre TB754 [13] on this topic.
7. What are the power quality requirements of a remote-end converter station? Not in system operator's scope.
8. What monitoring requirements are required? What standards are referenced for measurement? Assume this is covered in system operator's existing harmonic requirements. IEEE2800-2022 has some details here.
9. What data is required from the TSO to be given to the connection for power quality design studies? Defined in the Section 3.5.6.
10. What allowances should be made for changes in the network conditions across a project's lifetime (i.e. changes in the AC Grid's harmonic impedance, and the background impedance)? Defined in the Section 3.5.6

2.12-1 The harmonic power quality requirements of transmission connected converters shall meet the levels described in IEC 61000 [14]. Background levels, including the method to determine them, is a project specific requirement.

2.12-2 Voltage unbalance compatibility levels shall meet the requirements detailed in *{existing standard used for IBR etc.}*

2.12-3 The HVDC owner will complete a harmonic design study as detailed in Section 3.5.6 to ensure compliance with the levels specified 2.12-1.

2.12-4 The HVDC owner shall be responsible for ensuring compatibility with other parties for induced effects, such as telephone interference, and radiated emissions caused by the installation of the HVDC system.

2.12-5 The HVDC owner shall install monitoring equipment as per *{existing standard used for IBR etc.}.*

2.12-6 The energization of any device of an HVDC converter shall meet the voltage step requirements detailed in *{existing standard used for IBR etc.}.*

2.12-6(a) An energization study will be performed during the design phase, as detailed in Section 3.5.6, to ensure compliance with these requirements.

2.12-6(b) This includes the energization of any AC circuits that are installed between the HVDC converter station and the connection point.

2.12-6(c) Energization of any shunt elements, such as filter banks.

2.12-6(d) Energization of the converter transformer, and the converter.

2.13 Power System Restoration (Black Start)

A power system restoration service is the ability of an HVDC system to energize one of its AC systems if an AC system has had a total system shutdown. Often this is described as the HVDC system having black-start capability. A typical strategy when using an HVDC system is after for energization is:

- to energize the transmission system to a large generator, and re-start that generator.

This creates a small power-island around the HVDC system. The power island around the HVDC system is expanded, by adding new generators and loads. Eventually the HVDC system's power island, is synchronized to a neighboring power-island. A typical power system restoration is shown in Figure 5.

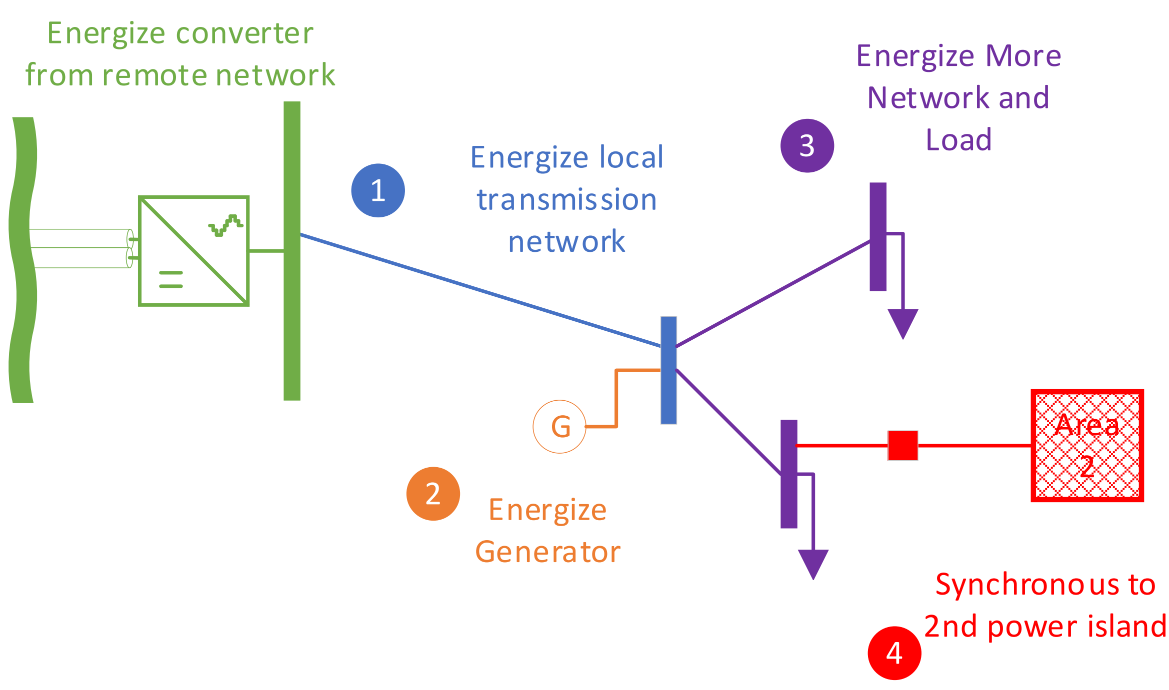


Figure 5. Example of a power-system restoration

1. Are there existing restoration requirements for other plant? Not known.
2. Is restoration an optional (a service paid for by the SO) or mandatory requirement? Not known.
3. Is there a minimum start-up time requirement, including mobilization to site? This will be a project level requirement as per clause 2.13-1.
4. Are requirements such as block size, number of restarts etc. required to be defined within the grid-code? This will be a project level requirement as per clause 2.13-1.. Partly, it will be determined during the restoration studies as per clause 2.13-1(g).
5. If the other end converter is in another system operator's area, what agreement needs to be made with that system operator? Assumed this is taken account of as part of the global requirement, referenced in Section 2.2.
6. What are the resilience requirements of the auxiliary systems? Should this be at full-load, stand-by, can energy from the HVDC system contribute to this? Is the HVDC system allowed to automatically energize its local busbar, after a system shutdown? This will be a project level requirement as per clause 2.13-1Partly, it will be determined during the restoration studies as per clause 2.13-1(g).
7. What testing at commissioning and at regular intervals is required? What testing of the communication system is required between the HVDC system, and the system operator and asset owner control center? This will be a project level requirement as per clause 2.13-1Partly, it will be determined during the restoration studies as per clause 2.13-1(g).
8. What simulations, including restoration path simulations are needed? What strategy will be used to shift the HVDC system from a special restoration mode of operation to the normal mode of operation? Will be determined in the restoration studies as per clause 2.13-1(g).
9. Will the AC protection that is used in normal operation be valid for power system restoration? Will be determined included in the restoration studies as per clause 2.13-1(g).

2.13-1 The connection agreement may require power system restoration services to System Operator. Specific requirements will specified in this agreement, however, it will include the following items.

2.13-1(a) Ready for energization time. This is the maximum time after a blackout has occurred that the local converter of the HVDC system is ready to perform a power system restoration. If the site is required to be staffed, this mobilization time will be included in this time.

2.13-1(b) Start-up time. Once the HVDC system is ready for energization, what time it takes for the HVDC system energize the connection point of the AC transmission system.

2.13-1(c) Any reliance requirements of the auxiliary system, such as:

- The time the local converter's auxiliary system must be solely providing the power demands of the local converter station.

- How the auxiliary system is powered after energization of the local converter.

2.13-1(d) Any commissioning, or regular testing requirements of the power system restoration process. This will include testing requirements of the auxiliary system.

2.13-1(e) The maximum load block size.

2.13-1(f) The number of repeated energizations attempts that are possible over a defined interval.

2.13-1(g) A power system restoration study as outline in Section 3.5.9.

2.14 Grid Forming Controls

Grid forming controls are likely to be useful in networks with low fault level or low inertia, where grid following controls may have some issues.

1. Are grid forming controls required? Are there known network conditions that may require their use? Has been left as a project specific requirement, either one that is identified during the studies, or potentially the vendor may require their use a low short circuit levels.
2. Should a performance-based approach, based on synchrons machine performance be used to define a grid forming control? Performance base is defined in 2.14-2, the details at this stage are difficult define, and there are at least two Cigre working groups looking at this issue. In light of this, the requirements have been left as a project specific requirement that will use the industry consensus of the day to determine what these requirements are.

2.14-1 Grid forming controls may be required either; to improve the power system performance or to allow operation of the converters under onerous system conditions – such as low short circuit levels. The identification that grid forming controls are needed may occur during planning studies, or the HVDC vendor may indicate they are needed to meet the HVDC system's performance requirements.

2.14-2 If grid forming controls are required, the HVDC owner will agree with the system operator on how this mode of operation should be included during the studies of Section 3.

2.14-3 They shall also be tested to ensure they meet a minimum performance requirement. The requirements will be outlined in the project specific requirements (as per Section 2.15). However, they will include:

2.14-3(a) Frequency and RoCof response requirements

2.14-3(b) Response to phase-jumps

2.14-3(c) Response to voltage jumps

2.14-3(d) Response to AC balanced and unbalanced faults

2.14-3(e) Response to DC side faults (if OHL lines are used)

These studies are undertaken during the design phase.

2.14-4 The requirements for grid forming controls are not currently universally agreed upon. The project specific requirements of Clause 2.14-2 will use the latest requirements concepts from organizations such as IEEE, Cigre and NERC.

2.15 Project/Topology Specific Requirements

There may be specific requirements for a project, that could depend on where the project is installed, or some other feature that is not specifically covered by the requirements of this document. These specific requirements may come from the results of system studies. Examples include:

- The point at which active power is controlled, i.e. at the connection point, or the mid-point of the DC circuit of the HVDC system.
- Control points available to the system operator, such as remote active power point control, ramp-rates, etc.
- Measurement points available to the system operator.
- Special modulation signals such as AGC inputs.
- Special requirements to include controls and studies for parallel operation of an embedded HVDC system with an AC system. This could include controls for power-sharing between the HVDC system and the AC system, specific EPC controls, when to operate frequency controls.
- The current injection strategy during faults may need to be adjusted from the standard requirements detailed in Section 2.8.3. This may include an increased magnitude, or a different voltage level related to when maximum current is injected, or a different requirement about negative sequence injection during unbalanced faults.
- The frequency controls may need modification to the meet requirements outline in Section 2.6.2. This could be to align with the frequency control requirements of another RTO/ISO.
- Specific requirements related to AC protection, including study requirements, and input data. This could include data associated with AC protection in the AC transmission system.
- Reactive power capability requirements beyond those of Section 2.4.2.
- If STATCOM capability is required at a converter.
- Special requirements related to signal communications to and from the system operator.
- Special requirements related to power system restoration.
- Project specific background harmonic levels, including the method to determine them, for harmonics, including inter-harmonics.

- Commissioning tests to prove one or more specific controller.
- Further requirements around converter driven stability issues.
- Transient fault recorder requirements, that comply with the requirements of Section 11 of IEEE 2800-2022 [2]

3 RECOMMENDATIONS ON STUDIES

During the development and connection of an HVDC system, three stages of studies are required as depicted in Figure 6.

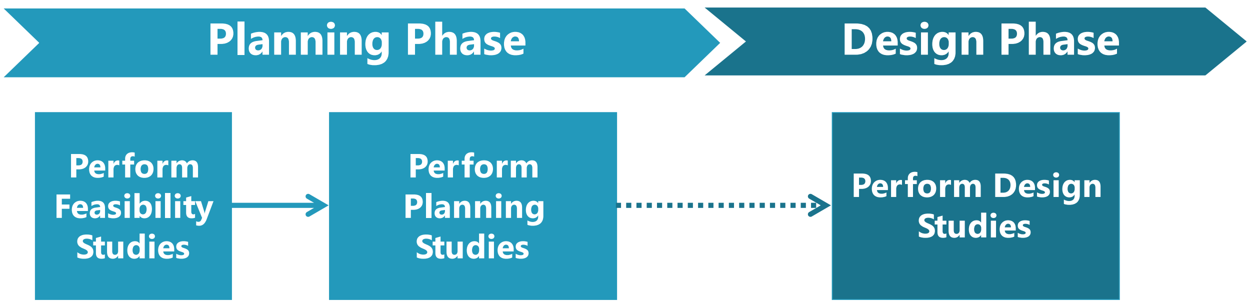


Figure 6. Study stages

The recommend requirement for studies that the HVDC system owner should carryout, with support from their HVDC vendor, for each stage are listed in Table 3. The table includes the study title, the power system model(s) required to perform the study, and at what stage of the project's development the study will be carried out.

Table 3. Summary of recommend HVDC studies

What stage of a project they are carried out, and what software and models are used. Note DNM is detailed network model as outline in Section 4.1 and Thévenin models (TM) is a model based on short circuit level as outline in Section 1.1.

Section	Study Title	Power System Model	Stage		
			Feasibility	Planning	Design
3.4.1	Thermal Overload	DNM – RMS	✓	✓	
3.4.2	Voltage Stability	DNM – RMS	✓	✓	
3.4.3	Dynamic performance	DNM – RMS and EMT	✓	✓	✓
3.4.4	Short circuit duty	DNM – RMS		✓	
3.4.5	Sub Synchronous Oscillation - Screening	DNM – RMS		✓	
3.4.6	Control system interaction studies - Screening	DNM – RMS		✓	
3.5.1	Emergency power control	TM - EMT			✓
3.5.2	Active and reactive power capability confirmation	N/A			✓

Section	Study Title	Power System Model	Stage		
			Feasibility	Planning	Design
3.5.3	Active and reactive power controller study	TM – EMT/RMS[8]			✓
3.5.4	Grid Forming Controllers Study	DNM-EMT and TM -EMT/RMS			✓
3.5.5	Fault Ride Through	TM - EMT/RMS			✓
3.5.6	Power Quality	Impedance Model			✓
3.5.7	Sub Synchronous Oscillation - Detailed	DNM-EMT			✓
3.5.8	Converter driven stability - Detailed	DNM-EMT and TM -EMT			✓
3.5.9	Power System Restoration	DNM-EMT			✓
4.1.6	Network Model Verification	RTS/EMT/RMS		✓	✓
5.2	HVDC Model Verification	RTS/EMT/RMS		✓	✓

Whilst Table 3 and Figure 6 show at what stage of the project's development the studies are expected to occur, there may be some deviations. For example:

- If during the design phase, material changes are made that effect the validity of studies carried out during feasibility or planning stage – then these studies would need to be repeated. Note, the dynamic performance study shall be carried out during all three stages of a project.
- The HVDC vendor, may carryout preliminary design studies before project award, to gain confidence that their offer can meet the performance requirements. Likewise, the HVDC owner may also require some design studies to be carried out during contract award, to ensure their vendor can meet the performance requirements.
- Whilst Figure 6 shows the study stages being carried out in sequence, some parts can be carried out concurrently if the system operator approves.

3.1 Study Documentation

Each study shall have a study report which at a minimum will include:

- Description of the models used in the study

[8] Note, the rms studies for those described in Sections 3.5.3 3.5.4 and 3.5.5 are for the model verification purposes as described in Section 5.2.

- Description on the simulation cases used in the study
- Commentary on the study results, and an evaluation on whether the performance requirements have been met.
- Graphs depicting the results of each simulation, using a signal list agreed with the system operator. The graphs will include any applicable performance criteria (such as active power recovery, injection current criteria etc.).
- Raw results files for each simulation, using simulation formats such as *.out, or *.psout

The HVDC owner, may cover more than one area of study defined in Table 3 in a particular report.

3.2 Contingencies, Faults and Operation Points

The studies for the HVDC system shall be carried out for a range of contingencies, faults, and operating points. This section contains a non-exhaustive list of what shall be considered, however there maybe project specific requirements that are not listed here. Additionally, the HVDC system operator may agree to exclude some combinations for some studies.

Contingencies

For studies that use a detailed network model the following AC transmission system contingency will be included:

- The base case, i.e. the model with no contingencies
- NERC planning events [15]
- For SSO a higher level of contingency is used (as described in Section 3.4.5).

Each planning event will be simulated for the set of AC system faults described below.

AC system Faults – Detailed Network Models

For studies that use a detailed network model the following AC fault types will be used:

- Fault types include in the NERC planning events [15]. These faults are applied at all converter stations of the HVDC system, i.e. for example in Figure 1(a), this would be both at the Area 1 and Area 2 connection points .

AC system Faults – Thévenin model

For studies that use a Thévenin model the following AC fault types will be used:

- Three phase, phase-to-phase and single-phase faults (at different fault impedance). Faults are applied at all converter stations of the HVDC system, i.e. for example in Figure 1(a), this would be both at the Area 1 and Area 2 connection points.
- Faults with and without auto-reclosure

- Delayed and normal protection time clearances.
- Three phase and unbalanced faults, frequency events, simulated by adjusting the voltage of the Thévenin source.

DC system faults

For studies that use both a short circuit model and a detailed network model, the following DC fault types will be used:

- Pole and pole-to-pole faults at the terminations and mid points of a section of OHL line
- Pole and pole to pole faults, at the terminations of cable system
- Pole faults at the mid-points of cable systems
- The loss of a pole without an AC or DC transmission fault, i.e. as would occur due to a protective action like a cooling system fault, or fire system alarm[9].
- The loss of two poles of a bi-pole system without a fault an AC or DC transmission fault, i.e. as would occur due to a protective action such as an issue in the neutral point of the bipole system.

Figure 7 shows an example of where DC side faults would be applied for an HVDC system, with both an OHL section, and a cable section.

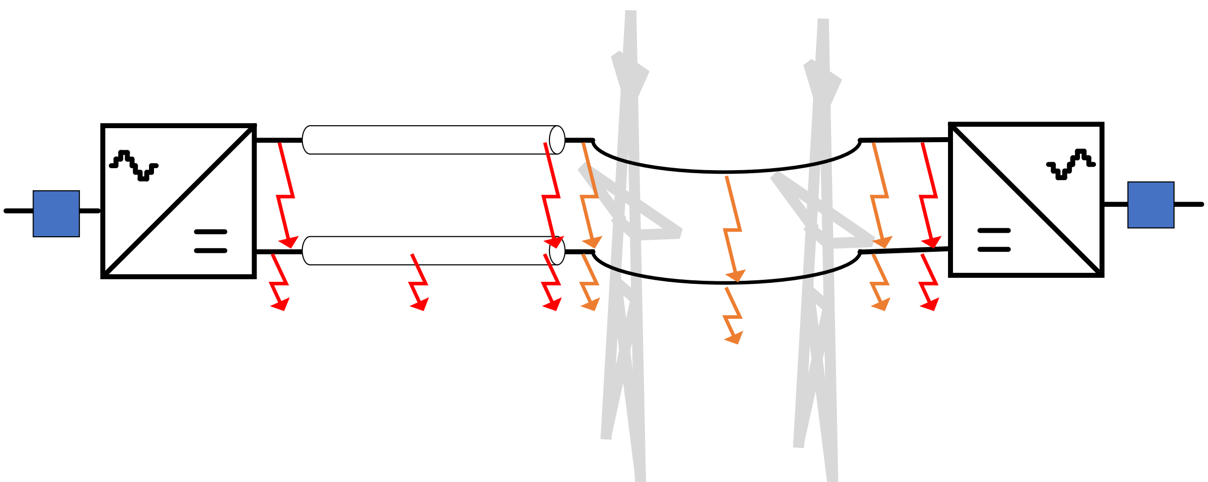


Figure 7. Example of DC fault locations (permanent faults in red, temporary faults in orange).

OHL DC faults would be both permanent, and temporary simulated using the de-ionization time specified in Clause 2.9-5.

[9] Note: it is not expected that auxiliary systems like the cooling system and fire system be explicitly modelled, just the protective action (i.e. trip) that an auxiliary system might trigger.

If there are other nearby HVDC system(s), the response of the HVDC system under development shall also be checked for DC side faults on these nearby HVDC system(s), or AC faults at the remote AC transmission system of the LCC system.

Operating Points

Each study shall be repeated under different modes of operation. Whilst these modes will be project specific, it is expected to include at least:

- Variations in active power setpoint including P_{min}, maximum export, and maximum import, STATCOM mode (if available) and other critical active power setpoints.
- Any internal modes or settings, such as converter transformer tap-changer setting that may have an impact on the response of the HVDC system.
- Steady state voltage range.
- Frequency controls, i.e. not-active, primary controls, fast controls.
- Oscillatory damping controls, including power-oscillation, or synchronous oscillation controls.
- Reactive power and voltage controllers, i.e. power-factor, reactive power, and voltage control.
- Grid forming mode either active or inactive
- DC side control mode of the local converter, such as DC voltage control or active power control
- Single pole, and bi-pole operation if single pole operation is available.

3.3 General Inclusion of Requirements

Whilst a study may have a specific requirement that it is designed to study, the HVDC system is still required to meet all other performance requirements. For example, when evaluating the AC transmission system performance during the dynamic performance study of Section 3.4.3, the HVDC system must meet the active power recovery requirements specified in Section 2.8.2, when recovering from a fault.

3.4 Planning and Feasibility Studies

The planning and feasibility studies are carried out before the HVDC system design has been finalized, they may use a preliminary or even generic model of the HVDC system as described in Section 5.

A key aim of the planning studies, as discussed in Section 2.1, is identifying impacts of the HVDC system on the AC transmission system. If the system operator is within a FERC or NERC planning region, then the HVDC owner will be responsible for facility owner identification of the desired corresponding FERC (TSP, TO, GO, etc.) and NERC responsible entity (BA, RC, PC, TP, TOP, etc.) with corresponding evaluations to identify the impacts to each.

3.4.1 Thermal Overload

A thermal study is undertaken to ensure that the equipment in the AC transmission system is not overload by the altered power flows caused by the project. These studies are carried out using the detailed network load flow models supplied by the system operator, as described in Section 4.1. The thermal studies will be first carried out in the feasibility stage and updated if required in the planning stage. The thermal studies will be assessed against the operating points, network contingencies, and faults outline in Section 3.2. These studies are carried out using the detailed network models supplied by the system operator, as described in Section 4.1. The thermal ratings of the equipment in the AC transmission network, will be *{the system operators' standard thermal requirements for connections}.*

The mitigations for thermal overloads will be determined by examining Pre- and Post-project loading to evaluate the incremental impact of the Project.

3.4.2 Voltage Stability (steady state)

This study is undertaken to ensure that the voltage stability of the AC transmission system is not compromised by the project. The voltage stability studies will be first carried out in the feasibility stage and updated if required in the planning stage. The voltage studies will be assessed for the full set of dispatches, network contingencies, and faults outline in Section 3.2. These studies are carried out using the detailed network model supplied by the system operator, as described in Section 4.1. The studies shall be undertaken using *{the system operators standard voltage stability requirements for connections}.*

For non-converged power flow solutions that are determined to be caused by lack of voltage support, appropriate transmission support will be identified to mitigate the constraint.

The mitigations for voltage stability issues will be determined by examining Pre- and Post-project loading to evaluate the incremental impact of the Project.

3.4.3 Dynamic performance

The dynamic performance study is used to ensure the performance of the AC transmission system is not compromised by the project. These studies are carried out using the detailed network model supplied by the system operator, as described in Section 4.1.

The studies will be first carried out in the feasibility stage using an RMS dynamic model of both the HVDC system and the AC transmission system, and then repeated in the planning stage using a EMT HVDC system model, with an EMT network model.

The models in the feasibility and planning stages will allow the provisional assessment of the impact of the project on the dynamic performance criteria of the AC transmission system. It is however noted, that the HVDC system models are preliminary, and that increased performance could be expected after the HVDC system is tuned during the design phase. In most cases the feasibility and planning results should meet the dynamic performance criteria of the AC transmission system. The system operator may make some exceptions to meeting the criteria at the feasibility and planning, but only if assurance is given that this exception will be corrected during the design stages.

The studies shall also be repeated in the design stage with both the as-built HVDC RMS (and the RMS network model) and the as-built EMT model (with the EMT network model). The main purpose of the as-built HVDC-RMS studies is for model verification of the RMS model with the EMT model (see Section 5.2).

The performance of the AC transmission system will be assessed against *{the system operator's dynamic criteria for the AC transmission system* [11]*}*. Areas covered include:

- Frequency
- Voltage Recovery
- Transient Stability
- Ramping
- Energization

and the NERC requirements [15]

The performance will be assessed for the full set of dispatches, network contingencies, and faults outline in Section 3.2.

The mitigations for transient stability will be determined by examining pre- and post-project loading to evaluate the incremental impact of the project. Mitigations could include a power oscillation damping control, or an emergency power control.

Pole-to-pole faults, and the bi-pole fault shall be simulated, determining if any mitigations to reduce the impact of these events shall be determined by the system operator.

Frequency

After a full or partial outage of the HVDC system, the frequency shall remain within the boundary of NERC PRC-024-3 [9].

Additionally, the frequency control response of the HVDC system, will be confirmed testing with both tripping a large generator station in the AC transmission system, and a large load in the AC transmission system. These tests will be carried out with both the primary and fast frequency control defined in clause 2.6-5. The HVDC owner, will work with the system operator to determine a range of possible parameters for these controls.

Voltage Recovery

After a fault, the bus voltages on the AC transmission system, shall meet the {*the system operator's voltage recovery criteria* [11] }

For LCC systems TOV's after temporary or permanent loss of transmission on the HVDC system, either with or without a fault shall comply with the requirements around TOV, including clause 2.10-5.

Rotor Angle Damping

After a fault, machine rotor angles shall meet the requirements in the latest version of {*the system operator's transient stability criteria* [11] }

Ramping study

Determine the maximum ramping rate that can be achieved in the power system.

Energization

Simulation of the energization of the HVDC system, including simulating the sequence in which AC tie-lines, filters, other reactive devices and converters are deblocked..

3.4.4 Short circuit study

A short circuit duty study will be used to check the impact of the HVDC systems' converters on the fault levels of the AC transmission system.

The studies will be first carried out in the planning stage using an RMS network model.

The impact of the project on short circuits will be examining pre- and post-project loading to evaluate the incremental impact and determine if any mitigations are required. The study will comply with the requirements of [15].

3.4.5 Sub Synchronous Oscillation – Screening

Sub-synchronous oscillation screening studies shall be carried out for each converter of the HVDC system. The two types of SSO that shall be screened for are (as defined in [4]):

- Sub synchronous resonance – torsional interaction against a device (SSR-TI-D). A converter control system may excite the mode of a synchronous machine's turbine.
- Power electronic device interaction – against a network (SSCI-N). A converter control system may interact with the resonances in a network, especially a network with series capacitors.

The class of SSO control interactions between multiple devices (SSCI-D), is considered as part of Section 3.4.6.

UIF screening for SSR-TI-D

The screening method for this class of SSO is to calculate the unit interaction factor (UIF) [16] between all generators in the detailed network model, and the HVDC system's converters. In undertaking this calculation:

- The general formula for UIF, Equation 4-4 of [4], shall be used.
- It shall be calculated each of the detailed network for contingencies up to N-5.
- If series compensation is within the detailed network model, then UIF calculations shall not be used, and an alternative method such as radiality factors must be used. The use of the alternative method requires approval from the system operator.

All UIF above 0.1 (for an LCC converter), or 0.01 (for a VSC converter) shall be selected for detailed analysis (as per Section 3.5.7). Additionally, the system operator can select one or more cases for detailed analysis (even if the case's UIF is below the thresholds described previously). If no cases breach the threshold, then the system operator will select some of the worse cases for detailed analysis.

Network impedance scan for screening for SSCI-N

Impedance frequency scans of the detailed networks from each connection point of the HVDC system shall be used to identify possible network resonances in the sub-synchronous range. This is described as the electrical grid scan in Section 4.2.3 of [4]. These scans are used to assess if there are resonances in the network which the HVDC system's control system may interact with.

Depending on what type of element (i.e. if there are third-party power electronic devices etc.), then either a passive network scan (as described in Section 4.2.4 of [4] as the hybrid solution), or a more detailed calculation (as described in Section 4.2.3.3 of [4]) shall be used. Scans shall be undertaken in each of the detailed network (in EMT) for contingencies up to N-5.

Network with a parallel or series resonance that cross from positive to negative reactance (i.e. the reactance is changing from capacitive to inductive, or inductive to capacitive) shall be selected for detailed analysis (as per Section 3.5.7). Additionally, the system operator can select one or more cases for detailed analysis that are so called *distant resonances*. If only *distant resonances* are observed, then the system operator will selected a group of cases with resonant frequencies the span the observed range.

3.4.6 Converter driven stability studies – Screening

The study of converter driven stability is a developing field of research. A recent IEEE paper on stability [3] classifications, identifies several types of converter driven stability issues:

1. Interaction with passive system components.
2. Converters in proximity with each other may have interactions
3. Converters in weak grids, may have low frequency oscillations.
4. Converter PLLs may have issues with synchronization after large disturbances
5. There may be stability issues related to power transfer limits

To screen for the above issues, the following two screening methods shall be used:

- Short Circuit Ratio (SCR). A short circuit ratio of 2 or less, may indicate weak network converter stability issues. It is noted though that the SCR indicator tends to become less relevant in converter-dominated systems. This screening method, may identify issues, 3,4,5.
- The weighted Infeed Interaction Factor (wMIIF) [17] . For the modified interaction factor, if the ratio between converters is less than 15%: the risk of interactions is considered low. This screening method may identify issue 2[10].

The results of the two screening methods shall be used to identified operating points where control system interaction maybe an issue, and what third party devices may interact with the converters of the new HVDC system.

The SCR and wMIIF can be calculated using the RMS load flow and dynamic model provided by the system operator as described in Section 4.1. In calculating these ratios:

- The SCR ratio shall be calculated for all contingencies described in Section 3.2
- The wMIIF shall be calculated between the converters of the HVDC system, and all other converters (such as those of IBRs, FACTS devices, and other HVDC converters), also for the contingencies described in Section 3.2.

Other studies, such as the dynamic performance studies carried out in the design phase, described in Section 3.4.3 may reveal some of the issues listed above.

As research in this area is developing these methods maybe replaced in the project specific requirements with more complex methods such as [18].

3.5 Design Studies

The design studies, unless otherwise stated, are carried out using the EMT short circuit models (as described in Section 4.1.6). The studies that use the EMT Thévenin source will be performed both; during factory acceptance testing, and with the as built EMT model. Additionally, 3.5.3, 3.5.4 and 3.5.5 are also carried out with the RMS model. The first aim of the design studies is to check compliance of the actual control and protection meet the performance requirements, the second aim is check that the EMT and RMS models have the same response.

As noted in Section 3.4.3, during the design phase, the dynamic performance studies carried out during the feasibility/planning stage are repeated during the design phase with the as build RMS and EMT models.

[10] If series compensation is within the detailed network model, then the wMIIF calculations shall not be used, and an alternative method such as radiality factors should be used. The use of the alternative method requires approval from the system operator.

3.5.1 Emergency power control

The emergency power control study is used to check the design of the HVDC system against EPC performance requirements of Section 2.11.

The studies will at a minimum:

- Check the functionality of all EPC controls, including ones required for the project (as per Clause 2.11-1) and those for future proofing (as per Clause 2.11-2).
- Check the ramp-speed capability of the EPC controls for:
  - A ramp from full export to full import
  - A ramp from P_{min} to full export
  - A ramp from P_{min} to full import
  - A 10%, and a 30% rated power EPC of the HVDC converter from full export
  - A 10%, and a 30% rated power EPC of the HVDC converter from full import

If an EPC is needed to mitigate an issue in the AC Transmission system, then this will be studied during the dynamic performance study.

3.5.2 Active power and reactive power capability study

A report outlining the active and reactive power capability of the converter:

- The capability is defined at the connection point
- Confirm the active power capability.
- The steady state capability shall be defined across the range of operating points described in 3.2
- For VSC systems confirm the reactive power capability (as defined in Section 2.4.2).
- Accounting for any internal operating points, such as converter tap-changer position, that would impact the capability.
- The current injection capacity for UVRT and TOV, including how the converter would respond to unbalanced faults.

The information for this study would expect to be derived from the HVDC system vendor's main circuit report.

3.5.3 Active power and reactive power controller study

The active and reactive power study is used to check the design of the HVDC system against performance requirements of Section 2.4 and 2.5. This study is carried out using short circuit models.

The active power studies will at a minimum:

- Check the functionality of the active power controller. This will include checking set point changes and changes in ramp-speeds.
- Confirm the ramp-speed capability of the active power controls for:
  - A ramp from full export to full import
  - A ramp from full import to full export

Reactive power, voltage controller and power-factor controller study for VSC HVDC systems

The reactive power, voltage controller, and power-factor controller studies will at a minimum:

- Check the functionality of the three controllers. This will include checking set point changes, changes in ramp-speeds, changes in droop settings, transition between control modes.
- Check the voltage controller response to set-point changes:
- voltage reference steps of +/- 1% and +/- 2% and the default droop
- Check the three different reactive power controllers to change in the Thévenin source voltage:
  - voltage steps of +/- 1% and +/- 2%

Reactive power controller study for LCC systems

This design study is for HVDC systems, with LCC converters, and will replace the reactive power studies above which are for VSC HVDC systems. The reactive power controller study is used to check the design of an LCC HVDC system against performance requirements of Section 2.4.

The studies will at a minimum:

- Check the functionality of the RPC controls
- Confirm the RPC can switch filters to meet the reactive power requirements of Section 2.4-5:
  - An active power ramp from full export to full import
  - An active power ramp from full import to full export

3.5.4 Grid Forming controller study

This design study is for HVDC systems, with grid forming controls. These studies will meet the project specific requirements for performance of grid forming controls as 2.14-3.

In addition to the specific studies for testing the performance of grid forming control, converters with grid forming control maybe active in other studies. In these cases, as per clause 2.14-2, how to include the controls in effected studies will be agreed between the HVDC owner and the system operator.

In some cases, grid forming controllers maybe needed at low fault levels. For these cases, new power system models maybe (including short circuit models) at the boundary where grid forming controls are required. At these boundary points, both grid-following and grid-forming controls are needed.

3.5.5 Fault Ride Through

The fault ride through studies are to check the response of the HVDC system to:

- frequency ride through (and frequency controller response), as per the requirements of Section 2.6
- under voltage ride through (including active power recovery, and current injection) as per the requirements of Section 2.8
- temporary over voltage ride through (including active power recovery, and current injection) as per the requirements of Section 2.10
- DC faults, for the operating points and DC fault types outlined in Section

The fault ride through studies complements the dynamic performance studies described in Section 3.4.3. The fault ride through studies has a focus on ride through at the extreme range of the performance requirements, whilst the dynamic performance focuses on the actual expected response of the AC transmission system.

For each study, if trip actions are needed to protect the converter equipment for an event more onerous than the ride through criteria (as per Clauses 2.8-4 and Clause 2.10-4) then these protections and their settings will be explained within the fault ride through report. The explanation will including what equipment is required to be protected, and for what reason.

Frequency Ride Through Study

The studies will at a minimum:

- Check the functionality of the frequency controls, including prioritizing in the case of tie-line HVDC systems (as per clause 2.6-8).
- Confirm the ride through capability of the HVDC system to the ride through requirements of Section 2.6.1. This will be checked by adjusting the frequency of the Thévenin source of the short circuit model, to follow the upper and lower ride through envelops defined in clause 2.6-1.
- The initial rise/drop in frequency will be in-line with the RoCof requirements of clause 2.6-3.
- The ride through study will be repeated for a range of controller settings for both the primary and fast frequency controller.

Under voltage ride through study

The studies will at a minimum:

- Check the functionality of the control and protection, including current injection controls, and the active power recovery.
- Confirm the under-voltage ride through capability of the HVDC system to requirements of Section 2.8. This will be checked by adjusting the voltage of the Thévenin source of the short circuit model to:
  - The full low voltage envelops described by Table 12 of IEEE2800-2022 [2] (as depicted below in Figure 8)

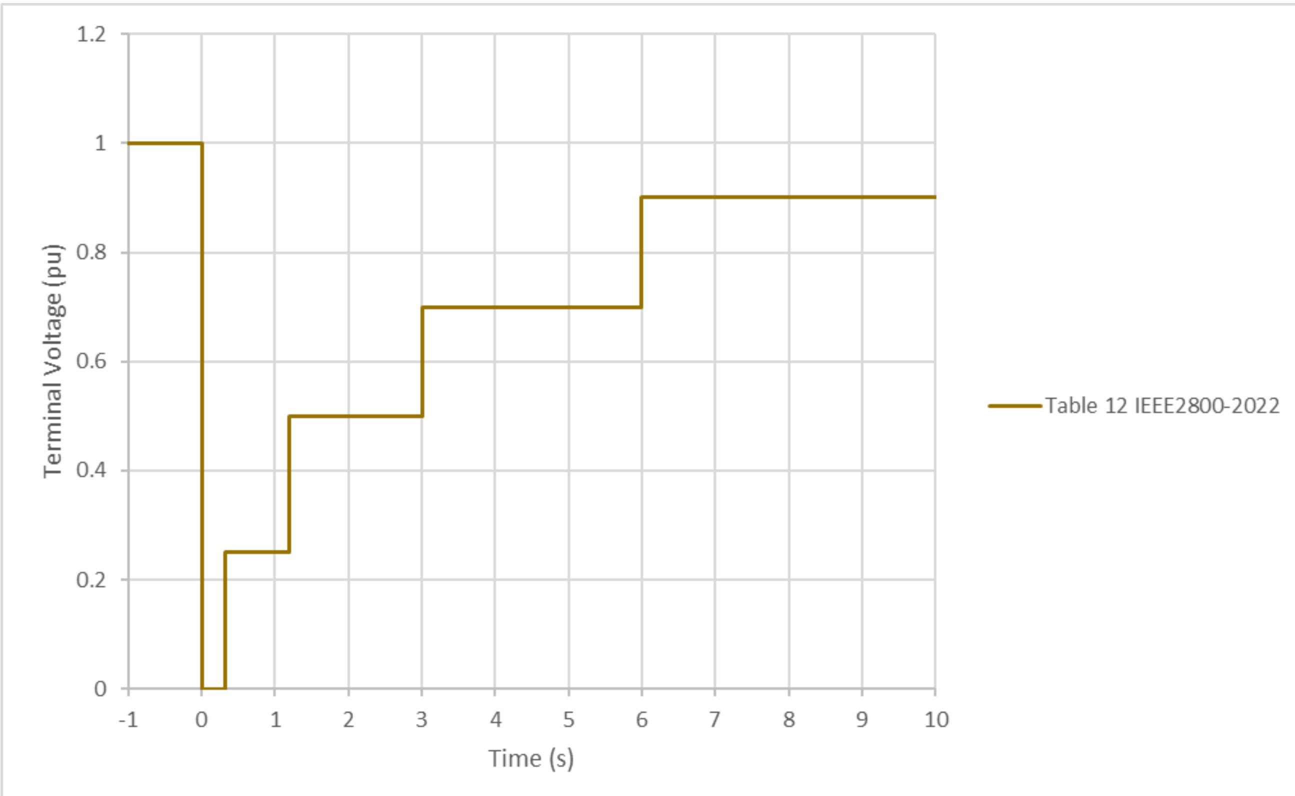


Figure 8. Outer under-voltage ride through envelops

  - At each of the four breakpoints in Table 12 of IEEE2800-2022 [2] (i.e. 0.7, 0.5, 0.24 and 0.1), with two events that are half of the minimum ride through time, and occur within 5s of each other (as depicted below in Figure 9).

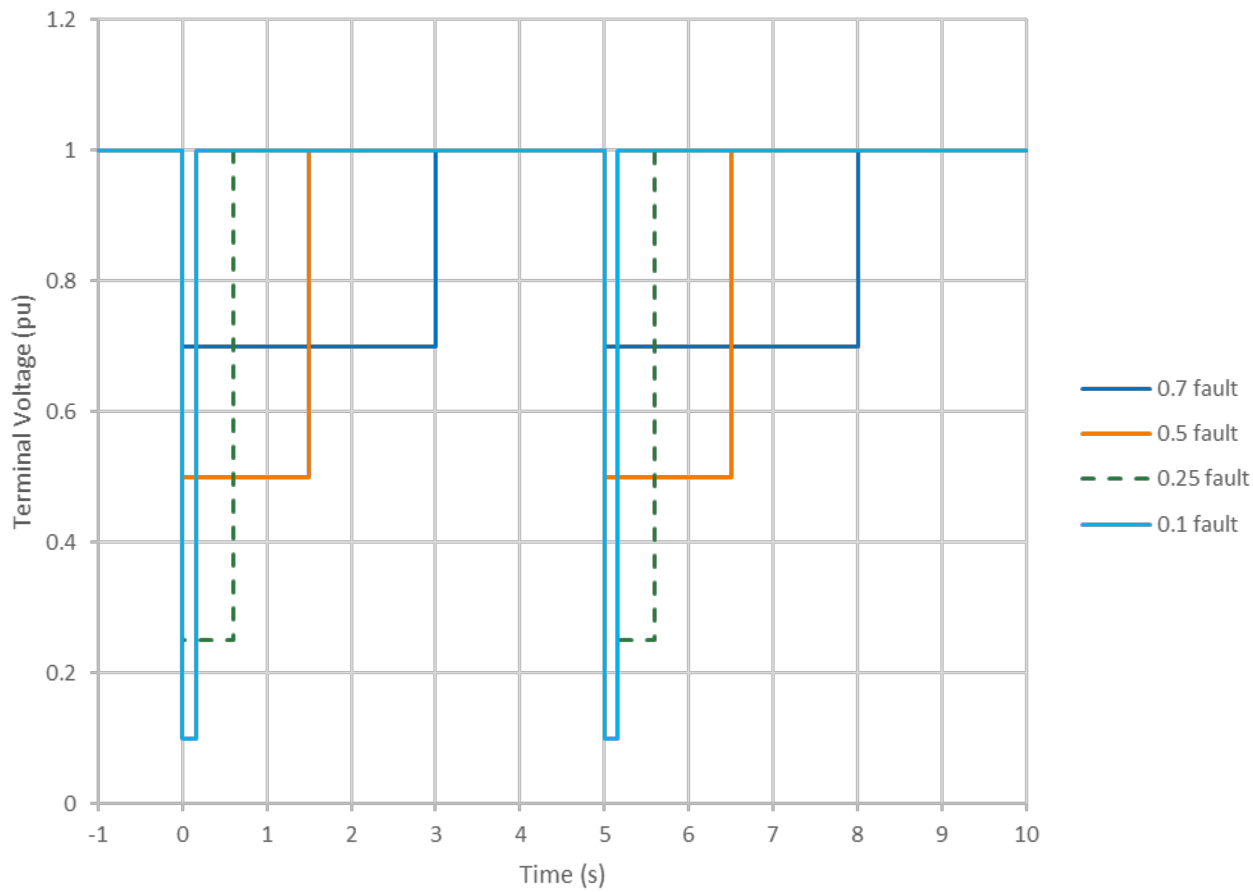


Figure 9. Break-point under-voltage ride through envelopes.

- The under-voltage ride through test will be carried out for balanced (all three phases follow the ride-through characteristic) and unbalanced (one or two phases follow the ride through characteristic).

Over voltage ride through study

The studies will at a minimum:

- Check the functionality of the control and protection, including current injection controls, and the active power recovery.
- Confirm the over-voltage ride through capability of the HVDC system to requirements of Section 2.102.8. This will be checked by adjusting the voltage of the Thévenin source of the short circuit model to:
  - The full over-voltage envelops described by Table 12 of IEEE2800-2022 [2] (as depicted below in Figure 10)

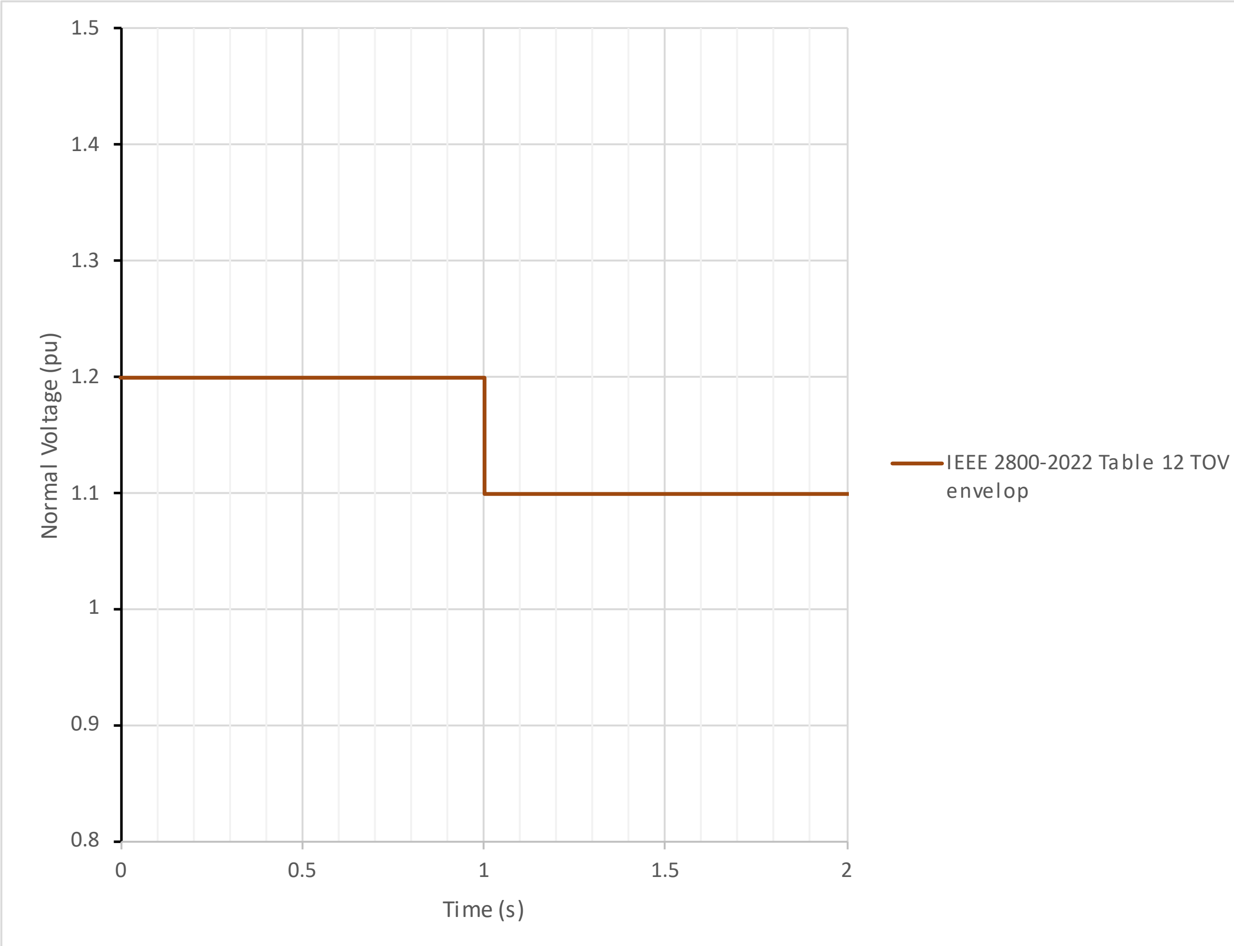


Figure 10. TOV ride through characteristic

- The TOV ride through test will be carried out for balanced (all three phases follow the ride-through characteristic) and unbalanced (one or two phases follow the ride through characteristic).

Under-voltage followed by an over voltage

Some HVDC systems, may be susceptible to an under-voltage followed by an over-voltage. One scenario that this could occurs is when a new VSC HVDC system is sited next to a large existing LCC HVDC system.

These studies will be carried out if an existing LCC system is considered close to the new HVDC system, as per the converter driven screening studies described in Section 3.4.6. The studies will at a minimum:

- Check the functionality of the control and protection, including current injection controls, and the active power recovery.

- Confirm the combined under-voltage and over-voltage ride through capability of the HVDC system to requirements of Section 2.8 and 2.10. This will be checked by adjusting the voltage of the Thévenin source of the short circuit model to:
  - The under-voltage events of Figure 9 followed by a TOV of Figure 10. These combined events are depicted below in Figure 11.
- Alternatively, instead of the curves of Figure 11, if a detailed model of the existing LCC system exists, and with system operator approval, this study can be carried out as part of the dynamic performance studies.

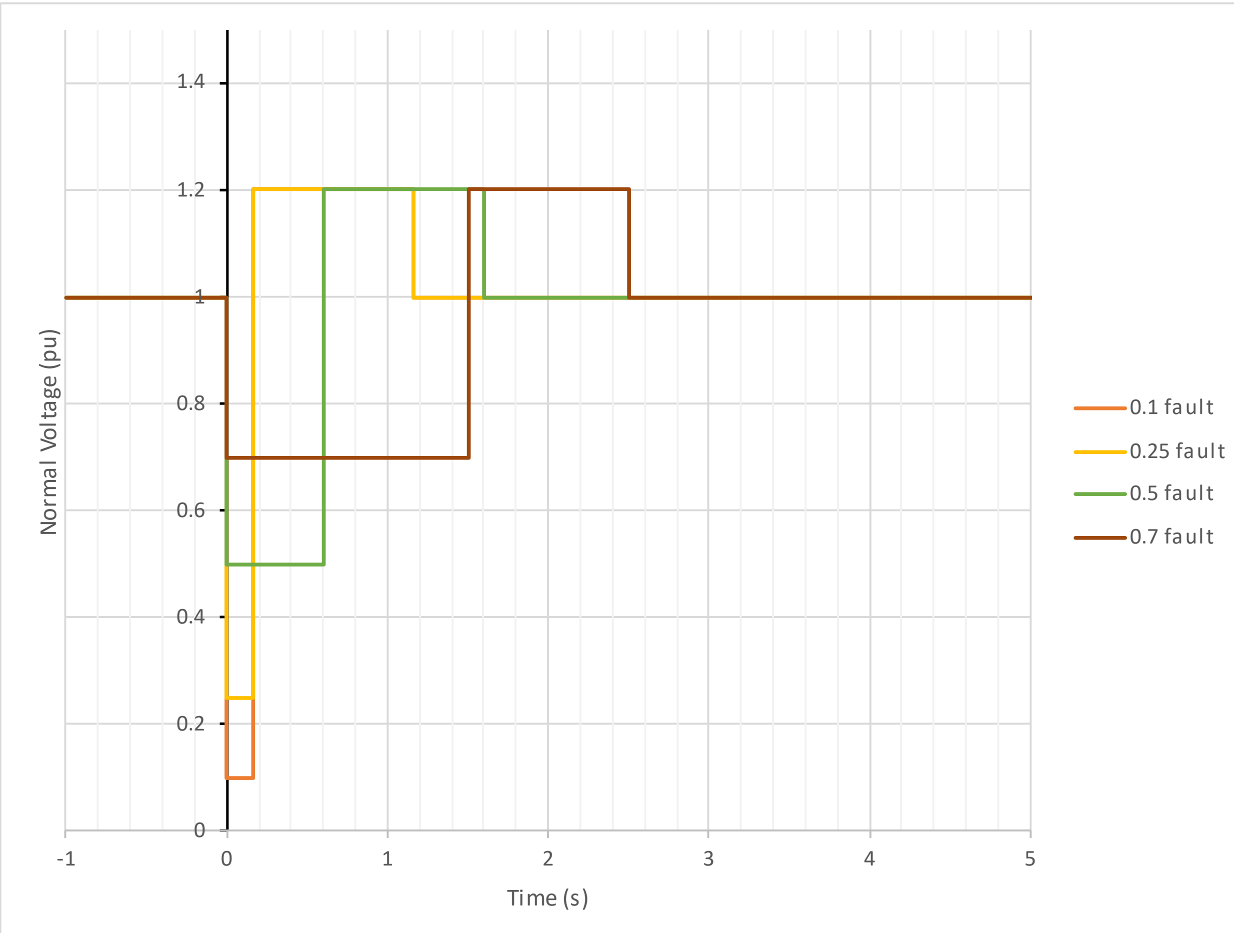


Figure 11. UVRT and TOV combined

DC faults

The DC faults will be applied as described in Section 3.2.

3.5.6 Power Quality Studies

The HVDC owner will carry out a power quality studies to confirm compliance with the requirements of Section 2.12 for both performance and compatibility.

- A harmonic performance study will use the impedance data as per Section 3.5.6, for confirming the performance levels in Clause 1.1-1 have been met.
- A study will be performed to show that the converter equipment, and protection will meet the compatibility requirements of Section 2.12. This is expected to be in the form of a desktop study summarizing the HVDC vendor designs carried out to meet the compatibility requirements.
- An energization study to confirm energization of any equipment will meet the voltage step criteria as per Clause 2.12-6. This will be an EMT study using a Thévenin.
- Confirmation that the HVDC system can operate under-unbalanced conditions, as per Clause 2.12-2. This will be a EMT study using a Thévenin, where the Thévenin source will be used to create voltage unbalance at the connection point.

3.5.7 Sub Synchronous Oscillation – Detailed

For the two classes of SSO the following requirements shall be met.

Detailed study for SSR-TI-D

For detailed analysis of sub synchronous resonance – torsional interaction against a device (SSR-TI-D) the following requirements shall be met:

For each case selected for detailed study,

- The electrical damping curves of the generator shall be calculated. This will be presented as graph showing electrical damping of the generator vs frequency (as per Figure 5-4 of [4]) and include bars showing the damping of the generator for each mode.
- A time-domain study in EMT, showing the response of the HVDC system to appropriate system events, such as step changes in active power.

The damping graphs and the EMT time domain studies, shall be calculated with and without the HVDC system for each case. The calculation will be repeated for a range of different operating points, and modes of operation of the HVDC system. When making a comparison of the damping with and without the HVDC system, the generator shall use a similar operating point.

Both the electrical damping curves and the time domain modelling shall be calculated using the detailed network EMT models (models shall comply with the guidance of Section 5.1.2 of [4]). .

If either;

- the electrical damping curves show negative damping close to a known mechanical mode of the generator,

- or, the time domain simulations show insufficient damping of oscillations.

then, a sub synchronous damping control (SSDC) or some other modification shall be made so that sufficient damping exists.

The cases that require migrations shall have updated damping curves and time-domain analysis to show the impact of the modifications.

Detailed study for SSCI-N

For detailed analysis of sub synchronous control interactions with the network

1. For each case selected for detailed screening, the network impedance calculations will be updated if any additional third-party models have been provided.
2. Using a device frequency scan, the source impedance of each of the HVDC system's converters is calculated. This shall be for a range of different operating points, and modes of operation of the HVDC system.
3. The network and device impedances scans are combined using either; the source-load impedance method, or the impedance network-based method. The combined impedance is used to determine stability, as describe in Section 4.2.3.3 of [4].
4. If the cases are unstable, then modification shall be made to the HVDC control system so that stability is created.
5. Any mitigations shall be proven with time-domain analysis in EMT, showing the mitigation provides stability.

3.5.8 Converter Driven stability – Detailed

If the screening studies show that a converter driven stability is an issue, the system operator and the HVDC owner will work together with effected third parties, to determine how to resolve any issues. For a control system interaction issue, this could take the form of:

1. A EMT study incorporating models of the HVDC system, third party systems, and a detailed system network model.
2. Faults, and other events (such a line switching) to determine if an interaction can occur.
3. Repeating the study for a range of different operating points, and modes of operation of the HVDC system and the third-party equipment.

For a weak network issue, the study may involve testing the HVDC converter in a similar manner to a grid forming converter. If a grid forming mode of operation is suggested, then the weak network studies will be part of the grid forming studies, of Section 3.5.4.

3.5.9 Power system restoration study

A power system restoration study is required to determine if the HVDC system can perform restoration of the power system, the study shall:

- Use data from the detailed network model to model the AC transmission system
- Be performed in EMT
- Model one or more restoration scenarios (i.e. cranking paths), including:
  - energization of other generation,
  - energization of load
  - synchronization from the power island around the HVDC system to neighboring power systems
  - switching from any special power restoration mode to a grid following mode of operation.
- Including of AC transmission system protection models, as per the system operator's requirements.

In addition to the EMT simulations, the study shall,

- Check the functionality of the power system restoration mode shall be confirmed during factory acceptance testing.
- Provide information on the specific restoration requirements that are described in Clause 2.13-1.
- Undertake a detailed SSR-TI-D study (as described in Section 3.5.7) for all synchronous generators which are energized by the HVDC system during restoration.
- Undertake a detailed converter driven stability study (as described in Section 3.5.8) for all converters which are energized by the HVDC system during restoration.
- A communication plan will be created with the system operator, to detail how the system operator will communicate to the system operator during a power system restoration.

3.6 Project Specific Studies

As per the requirement of 2.15, there may be project specific studies. These studies could be an addition to one of the existing studies, or an entirely new study. The studies maybe required in one or more of the project stages.

4 RECOMMENDATIONS ON NETWORK MODELS SUPPLIED BY THE SYSTEM OPERATOR

The power system models are used to represent the AC transmission systems. Different studies require different aspects of the power system to be modelled, so more than one type of model is needed. The models can be classed into three categories:

- Detailed network models, these models are realistic models of the power system model, including models of power system elements such as; transmission lines, transformers, generators, FACTs devices, shunt devices, loads, and other HVDC systems.
- Thévenin equivalent or similar to model the power system.
- Frequency dependent impedance loci used for harmonic power quality studies.

4.1 Detailed Network Models

Detailed network models of the AC transmission system will be provided by the system operator to support the HVDC owner's studies (including feasibility, planning and design stages). The models have the following features:

- RMS format for both load-flow and dynamic studies
- Unbalanced data will also be provided.
- The models will comply with the NERC requirements of [15]
- Different dispatches such as Summer, Winter peak. The exact dispatches to use are a project specific requirement.

4.1.1 New Generation and Retirements

New generations with executed interconnection agreements which are not already included in the base case and are within close electrical proximity and relevant to the study area will be added to the cases, as agreed upon by the affected parties. The cases will be updated to reflect announced generation retirements, as agreed upon by the affected parties. The new generation with executed interconnection agreements to be added to the cases will be dispatched per guidance from the affected parties.

4.1.2 Other networks

If the AC transmission system needs to be integrated with a model of the power system operated by another area, then the HVDC owner will work with both system operators to determine how best to integrate these models.

4.1.3 EMT network models

The HVDC owner shall use the RMS models from the system operator to develop electromagnetic transient models of the network in EMT. In developing these network models:

- The EMT model can use a reduced AC power system model. The reduced AC system model contains two parts; a retained AC model of the power system near each of the HVDC converters, and an AC equivalent to model the rest of the power. A verification between the reduced AC model and full model is required (as described in Section 4.1.6).
- If either the SSO screening study (see Section 3.4.5) or the converter driven screening study (see Section 3.4.6) show that a third-party system may have an interaction, then it must be included in the retained AC model of the power system.
- The EMT model can use co-simulation, to model the local network around the converter in EMT, and the rest of the network in RMS. A verification between the co-simulation model and full model is required (as described in Section 4.1.6).

4.1.4 Third party EMT models

If EMT models of nearby third-part plant are required for control interaction, sub-synchronous oscillation studies or for another purpose, then the system operator will request the data from the third parties, and co-ordinate between the third-party. and the HVDC owner.

If turbine models are required (for SSR-TI-D) studies, then the system operator will work with third party to provide a model of the generator and its turbine. The system operator will try and obtain data similar to that described in Appendix A of [19], but this is not guaranteed.

For some studies AC Transmission System information more detailed than what is provide by the system operator in their RMS models maybe required. In this case the third party would be the transmission system owner. This could be for studies beyond the scope of the studies described in this document, such as insulation co-ordination. The system operator will request the data from the third parties, and co-ordinate between the third-party. and the HVDC owner.

In all cases where third party data is required and requested by the system operator, the system operator will neither; guarantee the accuracy of the third-party data nor that the request will be responded to by the third party. Additionally, inaccurate third-party data, or lack of third-party data will not modify any of the requirements contained in this document.

4.1.5 Models of remote gen-tie generator(s)

In the case of gen-tie HVDC system, such as those in either Figure 1(c) or 1(d), then the HVDC owner will be solely responsible for ensuring the accuracy of the gen-tie generators.

4.1.6 Network Model Verification

The network model verification is used to compare the different detailed models, i.e. the original RMS models provided by the system operator, against their EMT equivalents developed as per Section 4.1.3. The comparison should include the AC faults (for detailed network models) described in 3.2.

The system operator will review the results of the network verification and determine if the match is adequate. The results will show the response of the various models are similar. If there are large differences, an explanation will be given, stating why an acceptable difference exists (i.e. an acceptable difference would be a known difference in how different simulation programs model various aspects of the power system).

To allow easy comparison; curves of the same quantities from the different simulators shall be plotted together.

4.1.7 Remedial action system, protection models and other power restoration data

Data and or models, for existing remedial action system, and protection systems that maybe impacted by the HVDC system may be provided.

If the HVDC system is able to provide power system restoration services, additional data shall be provided as outline in Section 3.5.9.

4.2 Thévenin Models (TM)

A Thévenin model, is a model of the power system represented as a voltage source behind an impedance. For the study of synchrons machines, the model is sometime referred to a single machine infinite bus (SMIB) system.

Short circuit data will be provided by the system operator, this will cover balanced and unbalanced faults, and include network X/R ratios. This data will cover the expected range of short circuits each converter station of the HVDC system can expect to operate. There will be at least maximum and minimum short circuit cases. The minimum short circuit level will exclude the level during power system restoration, where the short circuit level will be close to zero.

Studies that are performed with Thévenin models s will be carried out across the set of provided data. For example, for a tie-line HVDC system, if both minimum and maximum short circuit models are provided by the system operator at both converter stations of an embedded HVDC system, then any study that is required to use a Thévenin would be performed using the following variants:

- Area 1 minimum short circuit level, Area 2 minimum short circuit level
- Area 1 minimum short circuit level, Area 2 maximum short circuit level
- Area 1 maximum short circuit level, Area 2 minimum short circuit level
- Area 1 maximum short circuit level, Area 2 maximum short circuit level

Thévenin models can be built by the HVDC owner on multiple platforms, including in RMS, EMT, and the replica power system used during factory acceptance testing.

4.2.1 Alternative to Thévenin model

Instead of using a Thévenin model, the System Operator may allow the HVDC owner to use the detailed network model to carry out those studies where a Thévenin model is required in this document. However, the use of the detailed network model for this purpose can only be done with system operator's approval.

4.3 Impedance Data for Harmonic Studies

The system operator will provide network data for carrying out the HVDC owner's harmonic studies, as describe in Section 4.1. The HVDC owner will use this data to create impedance loci between 2^{nd} and 50^{th} harmonic, although this range maybe extended if the system operator believes it is necessary for a specific project. The impedance loci will be used in the harmonic power quality studies.

5 RECOMMENDATIONS ON MODEL REQUIREMENTS AND SIMULATION TOOLS

5.1

1. What type of models are required, short-circuit load-flow, RMS, EMT, and harmonic? At this stage, we've gone with load-flow and RMS, and EMT.
2. What functionality should the models have, required control and protection, required input/output data, required adjustable settings? Enough functionality to repeat the studies.
3. What simulation software should the models be built for? In addition to off-line modelling does the system operator require any on-line models to be used for control room security assessments (such as TSAT). So far RMS and EMT have been selected.
4. What requirements should be included for updates? This could be either update to match changes in the HVDC system plant, or the SO progressing to a new version of simulation software. This is covered in Section 5.3
5. What verification requirements are necessary? Should the models be verified against site tests, and/or factor acceptance testing? Are there any specific requirements for transient fault recording (TFR) or phasor measurement units (PMU) that should be installed as part of the project to provide site data to the SO? This is covered in Section 5.2
6. **What allowances will be made for vendor IP issues?** The HVDC owner is expected to be able to supply information for other third parties as outlined in Clause 2.7-5.
7. What documentation is expected to be provided with the models? Covered in [20]

5.1-1 The preliminary RMS model of the HVDC system that was used in the feasibility studies, shall be issued to the system operator. The model shall be issued at the same time the feasibility studies are issued, and feasibility studies shall not be considered accepted until the system operator is able to review this model.

5.1-2 The preliminary EMT model of the HVDC system that was used in the planning studies, shall be issued to the system operator. The model shall be issued at the same time the planning studies are issued, and planning studies shall not be considered accepted until the system operator is able to review this model.

5.1-3 The preliminary EMT model shall be issued with a preliminary verification report, as described in Section 5.2.

5.1-4 After the EMT and RMS model of the HVDC system that was used in the design studies (i.e. those defined in Section 3.5), shall be issued to the system operator. This model, called the as-built model, shall be issued at the end of factory testing of the HVDC control system. The design studies shall not be considered accepted until the system operator is able to review this model. If changes to the HVDC system happen during the commissioning of the HVDC system, then those changes shall be included in an updated as-built model and issued to the system operator, delivered at the end of commissioning.

5.1-5 The as build EMT and RMS model shall be issued with a verification report, as described in Section 5.2.

5.1-6 Each EMT model shall meet the requirements of the latest version the system operator(s) {*Electromagnetic Transient (EMT) Model Requirements for Inverter-Based Resource Interconnection.* [20]} and NERC requirements.

5.1-7 The EMT model shall additionally meet the following requirements:

> 5.1-7(a) Can be used to exactly recreate all the EMT simulation cases of Chapter 3
>
> 5.1-7(b) Black boxing of control and protection is allowed, however high-level controllers (i.e., any of the controls specially mentioned in this documents) settings and references shall be adjustable.
>
> 5.1-7(c) Black boxing of primary equipment is not allowed; i.e. transformers, valves, arresters, filter banks etc. Primary equipment can be model using standard library components that are correctly parameterized (this differs from the requirement of [20])
>
> 5.1-7(d) If protection trips the HVDC system, the protective element(s) that trip shall be indicated.
>
> 5.1-7(e) If the HVDC system can restart after a DC line fault. The de-ionization time shall be settable.
>
> 5.1-7(f) DC line circuits shall be modelled using frequency dependent phase models. Circuits of different poles shall be included in the same model (i.e. to include coupling effects).
>
> 5.1-7(g) For a VSC HVDC system model the preliminary converter shall be either an average model or a detailed model, i.e. described as an EMT Type 4 or 5 model in [21]
>
> 5.1-7(h) For a VSC HVDC system model the as built converter shall be a detailed equivalent model, i.e. described as an EMT Type 4 model in [21]
>
> 5.1-7(i) For an LCC HVDC system, valves shall be modelled using thyristor components or 6-pulse bridge components.

5.1.8 The RMS model shall be accurate for short circuit studies, load-flow studies and dynamic studies. It shall comply with the *{system operators requirements for RMS models}* and NERC requirements

5.2 HVDC Model Verification

The model verification study is used to verify that the RMS and EMT models provided to system operator are true representations of the HVDC system. Verifications are required at:

- Planning stage, comparing the response of the preliminary models of the RMS and EMT HVDC system models.
- The design stage, comparing the response of the as-built models of the RMS and EMT HVDC system models, with the actual control and protection used during the factory acceptance testing.

The models will show the response of the various models are similar. If there are large differences, an explanation will be given, stating why an acceptable difference exists (i.e. an acceptable difference would be a known difference in how different simulation programs model various aspects of the power system).

The model verification report shall use existing simulations, including:

- dynamic performance study of Section 3.4.3,
- the active and reactive power studies of Section 3.5.3
- if grid forming controls are included, the studies of Section 3.5.4
- the fault ride through studies of Section 3.5.5.

To allow easy comparison; curves of the same quantities from the different simulations shall be plotted together.

The verification shall comply with the latest NERC standards.

5.3 Update After System Events

If during operation of the HVDC system an AC or DC faults or event (i.e. from the lists described in Section 3.2) occurs that is either:

- not replicated by the as-built models
- or the response is not in line with the performance requirements.

The HVDC owner will investigate and correct either the as built model or update the control system so the response meets the performance requirements. If the controls are updated, the HVDC owner will also update the as-built models, and issue new models to the system operator, and update any design studies that are affected by the changes.

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