
Network Code for HVDC Connections and DC-connected Power Park Modules

Frequently Asked Questions

30 April 2014

Disclaimer: This document is not legally binding. It only aims at clarifying the content of the Network Code for “HVDC Connections and DC-connected Power Park Modules”. This document is not supplementing the final network code nor can be used as a substitute to it.

List of Frequently Asked Questions

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As used in this paper, the capitalized words and terms have the meaning ascribed to them in the NC HVDC.

Answer to FAQ 1:

What are the “cross-border network issues and market integration issues”?

Regulation (EC) 714/2009 Article 8 (7) defines that “the network codes shall be developed for cross-border network issues and market integration issues and shall be without prejudice to the Member States’ right to establish national network codes which do not affect cross-border trade”.

The terms “cross-border network issues and market integration issues” are not defined by the Regulation. However, ENTSO-E’s understanding of the terms has been derived from the targets of the EC 3rd legislative package for the internal electricity market:

- supporting the completion and functioning of the internal market in electricity and cross-border trade
- facilitating the targets for penetration of renewable generation
- maintaining security of supply

Based on these targets and in the context of the network codes for grid connection, the following interpretation of the terms "cross-border network issues and market integration issues" has been taken as a guiding principle:

The interconnected transmission system establishes the physical backbone of the internal electricity market. TSOs are responsible for maintaining, preserving and restoring security of the interconnected system with a high level of reliability and quality, which in this context is the essence of facilitating cross-border trading.

The technical capabilities of the users play a critical part in system security. TSOs therefore need to establish a minimum set of performance requirements for generators, demand and DC-links connected to their network. The performance requirements include robustness to face disturbances and to help to prevent any large disturbance and to facilitate restoration of the system after a collapse.

Secure system operation is only possible by close cooperation of grid users connected at all voltage levels with the network operators in an appropriate way, because the system behaviour especially in disturbed operating conditions largely depends on the response of grid users in such situations. With respect to system security the transmission system and the grid users need to be considered as one entity. It is therefore of crucial importance that grid users, incl. HVDC Systems and DC-connected Power Park Modules, are able to meet the requirements and to provide the technical capabilities with relevance to system security.

Moreover, harmonization of requirements and standards at a pan-European level (although not an objective in itself) is an important factor that contributes to supply-chain cost benefits and efficient markets for equipment, placing downwards pressure on the cost of the overall system.

To ensure system security within the interconnected transmission system and to provide an adequate security level, a common understanding of these requirements to power generating facilities is essential. **All requirements that contribute to maintaining, preserving and restoring system security in order to facilitate proper functioning of the internal electricity market within and between synchronous areas and to achieving cost efficiencies through harmonization of requirements shall be regarded as “cross-border network issues and market integration issues”.**

Answer to FAQ 2:

What is the relationship between the framework guidelines and network codes – what are the responsibilities of both and what is the process of network code development?

The relationship between framework guidelines and network codes as well as the process for the establishment of network codes are defined by Article 6 of Regulation (EC) 714/2009.

The Agency for the Cooperation of Energy Regulators (ACER), on request of the European Commission (EC), shall submit to EC, within a reasonable period of time not exceeding six months, a non-binding framework guideline. This framework guideline will set out clear and objective principles for the development of network codes, covering cross-border network issues and market integration issues relating to the following areas and taking into account, if appropriate, regional specificities:

- network security and reliability rules including rules for technical transmission reserve capacity for operational network security;
- network connection rules;
- third-party access rules;
- data exchange and settlement rules;
- interoperability rules;
- operational procedures in an emergency;
- capacity-allocation and congestion-management rules;
- rules for trading related to technical and operational provision of network access services and system balancing;
- transparency rules;
- balancing rules including network-related reserve power rules;
- rules regarding harmonized transmission tariff structures including locational signals and inter-transmission system operator compensation rules; and
- energy efficiency regarding electricity networks.

Each framework guideline shall facilitate non-discrimination, effective competition and the efficient functioning of the market.

Based on such a framework guideline the EC shall request ENTSO-E to submit a network code which is in line with the relevant framework guideline to ACER within a reasonable period of time not exceeding 12 months.

If ACER assesses that the network code is in line with the relevant framework guideline, ACER shall recommend the network code to the EC for adoption as European law. The EC will then initiate the comitology process to give the network codes binding legal effect. It is likely that the network codes through the comitology process will become European Union (EU) regulations making the provisions of the network codes applicable in all Member States immediately without further transposition into national legislation.

The main objective of the framework guidelines is to highlight **which** emerging questions/problems should be solved, leaving the approaches on **how** to solve them to the related network code(s). Figure 1 provides an overview on the complete process of framework guideline and network code development.

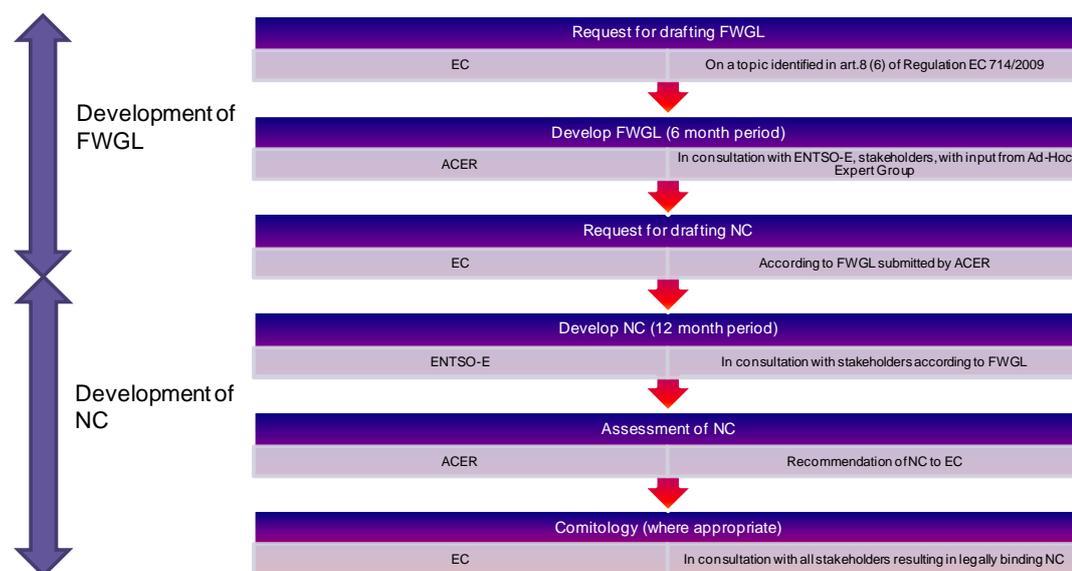


Figure 1: Framework guideline (FWGL) and network code (NC) development process

As reflected in the three year work program¹ which is regularly discussed by EC/ACER/ENTSO-E and consulted upon in the Florence Forum with all key stakeholders in the electricity sector, one or more network code(s) may correspond to a single framework guideline. The ACER framework guidelines on grid connections² were published on 20 July 2011. In total, four codes are anticipated in the coming years: connection of generation, connection of demand, connection of HVDC circuits and connection procedures. The formal twelve month mandate for the network code on HVDC connections started in April 2013, with a request to submit the NC HVDC to ACER by 1 May 2014. The two earlier grid connection codes (on Requirements for Generators, and the Demand Connection Code) are finalized by ENTSO-E, received a recommendation by ACER, and are at present being prepared by the EC for formal comitology with the involvement of Member States. For the fourth network code under these framework guidelines, regarding connection procedures, no starting date has been indicated so far.

In accordance with Article 10 of Regulation (EC) 714/2009, ENTSO-E shall conduct an extensive consultation process while preparing the network codes, at an early stage and in an open and transparent manner, involving all relevant market participants, and, in particular, the organisations representing all stakeholders. That consultation shall also involve national regulatory authorities and other national authorities, supply and generation undertakings, system users including customers, distribution system operators, including relevant industry associations, technical bodies and stakeholder platforms. It shall aim at identifying the views and proposals of all relevant parties during the decision-making process.

All output of the stakeholder interactions (bilateral meetings, workshops, user group meetings) during the formal development period of NC HVDC can be accessed on the ENTSO-E website³.

Most recent information on the development of all NCs can be found on the ENTSO-E website⁴.

¹ http://ec.europa.eu/energy/gas_electricity/codes/codes_en.htm

² http://www.acer.europa.eu/portal/page/portal/ACER_HOME/Public_Docs/Acts%20of%20the%20Agency/Framework%20Guideline/Framework%20Guidelines%20On%20Electricity%20Grid%20Connections/110720_FGC_2011E001_FG_Elec_GrConn_FINAL.pdf

³ <https://www.entsoe.eu/major-projects/network-code-development/high-voltage-direct-current/>

⁴ <https://www.entsoe.eu/major-projects/network-code-development/>

Answer to FAQ 3:

How does this Network Code link to other codes on connection, operation and market integration?

One of main principles in the development of the NC RfG, DCC and NC HVDC is the goal of a consistent set of connection requirements for new generators, demand and DC links, which take into account local system needs and inherent technical capabilities.

Whereas this code details requirements for capabilities, it does not provide answers to operational or market-related issues. These rules can be found within the operational/market network codes, notably NCs Operational Security, Load Frequency Control & Reserves, Electricity Balancing and Emergency and Restoration, or appropriate national rules. It is also emphasised that whereas operational and market codes often reflect present needs, connection codes need to ensure future operational/market rules can be facilitated as well.

The paragraphs below describe some of the most notable interactions of NC HVDC with other Network Codes.

NC Requirements for Generators

NCs HVDC and RfG are closely linked in terms of various processes: national implementation, modernization, operational notification, existing users, users not yet connected, derogations.

More importantly, many of the technical requirements prescribed for DC-connected Power Park Modules are based on, and often explicitly refer to the respective requirement in NC RfG. Additional or different requirements are formulated wherever needed due to the different characteristics of the (offshore) connection point and collection network, or where the inherent capabilities of generating units connected through power electronics can be used. The delivery of certain technical capabilities can be optimised between the PPM and the HVDC link connecting the collection network to the main AC network, as described in e.g. Article 38(2). One key argument for such approach has been the expectation that DC-connected collection grids may in the future be connected via AC-circuits as well (hybrid connection), in which case both RfG and HVDC would become applicable, therefore limiting the differences to wherever necessary for system characteristics is reasonable. Another key argument is the non-discriminatory application of connection requirements to all grid users.

The requirements for HVDC Systems contain similar categories as in RfG, with the additional guiding principle to ensure that HVDC links (similarly to other elements of the transmission network) are the most reliable items of the system, i.e. are the ones withstanding the widest range of parameters (voltage, frequency, etc.) in non-normal situations. This results in somewhat wider ranges to be withstood than for generators, wherever there was no prohibitive cost implication identified.

Demand Connection Code

NC HVDC and DCC are also closely linked in terms of general processes such as national implementation, modernization, operational notification, existing users, users not yet connected and derogations.

NC Operational Security

The technical capability of limiting ramp rates for frequency management reasons (as foreseen in NC OS Article 9(14)) shall be ensured by NC HVDC.

NC OS foresees structural and scheduled information exchange of HVDC interconnectors and the TSOs, HVDC setting the requirement for equipment and standards, while operational codes (i.e. NC OS) addressing the scope of information to be exchanged.

NC Load Frequency Control & Reserves

The NC LFC&R specifically refers to the role of HVDC links in several articles, in particular with regard to the realisation of the imbalance netting process and the cross-border sharing and activation of operational reserves. The inherently available control characteristics of HVDC links shall be utilised for such processes.

The main principle followed, which also determines the interactions with NC LFC&R, is that connection codes should ensure that the necessary technical capability for e.g. active power adjustment, reversal, ramping and limiting as well as the necessary communication infrastructure for receiving such orders is present where needed, while operational codes shall describe the framework and responsibilities with regard to provision of such services, and market codes describe the possible products and commercial aspects. NC LFC&R also prescribes management of total system inertia, utilising the capabilities described in among others the NC HVDC and also defining the consequential conditions required with respect to robustness.

Answer to FAQ 4:

Does the network code apply in non-EU member states or in respect to cross-border issues between a EU member state and a non-EU member state?

It is foreseen that the network codes will be adopted via the comitology process in the format of an EU regulation.

Therefore, they will become binding vis-à-vis non EU-countries in accordance with the following principles.

1. For the non-EU countries which are parties to the EEA Agreement (the European Economic Area Agreement), the EEA Agreement provides for the inclusion of EU legislation that covers the four freedoms — the free movement of goods, services, persons and capital — throughout the 30 EEA States. The Agreement guarantees equal rights and obligations within the Internal Market for citizens and economic operators in the EEA.
As a result of the EEA Agreement, EC law on the four freedoms is incorporated into the domestic law of the participating EFTA States. All new relevant Community legislation is also introduced through the EEA Agreement so that it applies throughout the EEA, ensuring a uniform application of laws relating to the internal market.
As energy legislation covering the functioning of the internal market falls within the scope of the EEA-Agreement, the entire body of future network codes will almost certainly be EEA relevant, and hence be applicable and binding after decision by the EEA Committee and national implementation. The regular implementation procedures will apply.
2. As Switzerland is not a party to the EEA Agreement, the enforceability of the NC transformed into EU Regulation will need to be assessed in the context of the pending negotiations between Switzerland and the EU. However, Swiss law is also based on the principle of subsidiarity. Under this principle, self-regulating measures can be taken by the parties of the sector if they reach the conclusion that these rules should become common understanding of the sector. Based on the subsidiarity principle it is currently considered by the Swiss authorities to introduce under Swiss law, new rules compliant to relevant EU-regulations by the parties of the sector.
3. For the countries that are parties to the Energy Community Treaty, the Ministerial Council of the Energy Community decided on 6 October 2011 that the Contracting Parties shall implement the Third Package by January 2015, at the latest. Moreover, it decided “to start aligning the region’s network codes with those of the European Union without delay”. The network codes will be adopted by the Energy Community upon proposal of the European Commission. The relevant network codes shall be adopted by the Permanent High Level Group. The Energy Community Regulatory Board stressed on 5 September 2013 “the importance to implement the NCs in the Energy Community in a timely and coherent manner in coordination with the European developments.”

The process to be followed in case of an HVDC System connecting points inside and outside the European Union is described in Article 77.

Answer to FAQ 5:

How will ENTSO-E efficiently and transparently perform stakeholder consultation?

The active involvement of all stakeholders, to be reflected in particular through their submission of comments during the formal consultation according to Article of 10 Regulation (EC) 714/2009, is considered to be crucial for the development of the network codes.

All ongoing, scheduled and finished consultations on draft network codes can be accessed at the ENTSO-E web consultation portal⁵.

The reader is referred for further information to the ENTSO-E publication “Consultation process”⁶ and the network code web sections⁷.

In addition to the formal consultation, ENTSO-E involved stakeholders in the NC HVDC development by means of a dedicated NC HVDC User Group, composed of more than 20 European organizations. Several improvements have been made in the draft code based on the discussions throughout the 5 User Group meetings, as well as bilateral meetings, the materials of which are all published on the ENTSO-E website⁸.

Prior to a formal consultation on a full draft network code, ENTSO-E pursued early views on a preliminary scope by means of a “Call for Stakeholder Input” consultation (May 2013). A first draft text of the technical NC HVDC requirements was discussed with the NC HVDC User Group in September 2013. A full draft code, approved by ENTSO-E, has been publicly consulted on during the period 7 November 2013 – 7 January 2014. This consultation resulted in nearly 2500 individual comments, all of which have been assessed by ENTSO-E and which have triggered numerous amendments and clarifications in the final code as submitted to ACER.

All comments as well as ENTSO-E’s responses are publicly available, together with the corresponding arguments. ENTSO-E also indicates how the comments received during the consultation have been taken into consideration and provides reasons where they have not been acted upon. Details can be found in the document “Evaluation of comments”, published together with the final code and supporting documents.

⁵ <https://www.entsoe.eu/news-events/entso-e-consultations/>

⁶ https://www.entsoe.eu/fileadmin/user_upload/library/consultations/110628_Consultation_Process_Description.pdf

⁷ <https://www.entsoe.eu/major-projects/network-code-development/>

⁸ <https://www.entsoe.eu/major-projects/network-code-development/high-voltage-direct-current/>

Answer to FAQ 6:

What is the role of the subsidiarity and proportionality principle in the NC HVDC?

European Network Codes contain a number of non-exhaustive requirements, especially the codes in the grid connection domain. A non-exhaustive requirement within a Network Code does not contain all the information or parameters necessary to apply the requirement and needs further specification at national level. Implementation of Network Codes at a national level comprises making these specifications and decisions to render the non-exhaustive European requirements into exhaustively defined national or project specific rules and to update and amend respective technical regulations (e. g. existing grid codes) accordingly. In order to allow for such an implementation procedure, the NC HVDC introduces a three year period from the date of entry into force until its application.

Typically additional information or parameters are to be provided by the Relevant TSO. In many cases these specifications can be brought forward through an already established process at national level, e.g. grid code review panel, user group, public consultation, regulator or ministry approval. A Network Code itself does not prescribe these national processes, but merely stipulates that they shall be in accordance with the implementation of Directive 2009/72/EC and the principles of transparency, proportionality and non-discrimination, and caters for the involvement of the National Regulatory Authorities. This framework safeguards against unilateral or non-motivated decisions and ensures adequate involvement of stakeholders. Furthermore it allows Member States to continue most established processes, which often are acknowledged by all involved parties and have proven to be successful.

Non-exhaustive requirements have a valid role in a European Network Code because of their impact on security of supply, the integration of renewables or market development. Even as specifications depend on local system conditions, clear benefits exist when the code

- a) ensures that these requirements are specified by the Relevant Network Operator or TSO in all Member States;
- b) enforces a similar terminology and gives the minimum list of parameters and conditions to specify; and
- c) covers compliance and derogations procedures across Europe in a transparent and non-discriminatory manner.

In many cases the Network Codes constrain national provisions from either very loose or extremely onerous implementations. A European Network Code pulls all national codes in the same direction.

Answer to FAQ 7:**Why does the network code not provide for dispute resolutions?**

The settlement of dispute provisions is commonly used for contractual types of relationships which are outside the scope of this network code.

Therefore, in case a dispute regarding the application of a network code provision arises, it shall be referred to national courts - which are the ordinary courts in matters of European Union law - in accordance with national rules. Nevertheless, to ensure the effective and uniform application of European Union legislation, the national courts may, and sometimes must, refer to the Court of Justice and ask it to clarify a point concerning the interpretation of EU law (in the network code provisions).

The Court of Justice's reply takes a form of a judgment and the national court to which it is addressed is, in deciding the dispute before it, bound by the interpretation given and the Court's judgment likewise binds other national courts before which the same problem is raised. It is thus through references for preliminary rulings that any European citizen/ entity can seek clarification of the European Union rules which affect him.

Answer to FAQ 8:**How does a NC on HVDC connection rules relate to equipment standards and planning standards?**

Standards are driven by a need for harmonization to remove trade barriers and cut manufacturing and compliance costs, and aim to define common requirements for products. Network Codes contain connection rules, largely driven by the need to ensure security of supply in a power system undergoing vast changes and define functional capabilities without specifying how these are to be delivered.

The relation between standards and Network Codes has been acknowledged in a recent Memorandum of Understanding, signed by ENTSO-E and CENELEC. This underlines the legal basis of a Network Code and the benefit of standards that give further specifications and are based on the Network Code. Standardisation bodies were represented in the User Group in order to ensure that there is no conflict between the Network Code and existing standards or ones in an advanced stage of development, but rather complement each other.

It is also to be noted that the scope of issues to be covered in a European Network Code is also bound by the applicable Framework Guidelines, see also FAQ 9.

A connection code sets explicit capabilities for a connecting party, whereas a planning standard gives general requirements for the overall long term network development of the grid and overall system performance.

Answer to FAQ 9:

What is the appropriate level of detail and harmonization of the network code?

The level of detail and the scope of the network code are in line with the scope defined by the corresponding framework guidelines provided by ACER which read as follow:

“Furthermore, the network code(s) shall define the requirements on significant grid users in relation to the relevant system parameters contributing to secure system operation, including:

- *Frequency and voltage parameters; (HVDC Article 7 and 16)*
- *Requirements for reactive power; (HVDC Article 18)*
- *Load-frequency control related issues; (HVDC Article 11 and 14)*
- *Short-circuit current; (HVDC Article 17)*
- *Requirements for protection devices and settings; (HVDC Chapter 2 - Section 5)*
- *Fault-ride-through capability; (HVDC Chapter 2 - Section 3)*

(...)

The network code(s) shall set out how the TSO defines the technical requirements related to frequency and active power control and to voltage and reactive power management. Technical rules set at the synchronous system level for operational security shall be in line with these requirements. Those rules shall be aligned as far as technically possible and economically beneficial throughout the EU, irrespective of synchronous area borders.”

The requirements in the network code have a system wide impact; however the appropriate level of detail for each requirement has undergone a case-by-case consideration of its purpose, taking into account the extent of the system-wide impact as a guiding principle. The relevant entity from the perspective of system security is predominantly the synchronous area.

For the requirements with immediate relevance to system security on the level of a synchronous area, besides a common level of methods and principles, common parameters and settings (thresholds, limits) are necessary to achieve a sustainable set of common requirements, since one of the aims of the network code is to align requirements for HVDC throughout Europe to a reasonable extent to preserve system security in a non-discriminatory manner by applying the principle of equitable treatment. Other requirements of the network code are limited to the definition of common methods and principles and the details have to be provided by each TSO at national level (e. g. by explicit thresholds or parameter values). This allows consideration of specific regional system conditions (e. g. areas with different system strength, density of demand or concentration of Power Generating Modules). Therefore the level of detail of the requirements varies and the principles of subsidiarity and proportionality are applied.

It is to be noted that the NC HVDC is specific in the sense that HVDC links have more than one Connection Point. Although all requirements are applicable at a Connection Point, for certain requirements which are non-exhaustive, i.e. parameters are to be defined at a national level, a coordination of these parameters and/or procedures is necessary between the Relevant TSOs and NRAs. The framework of this coordination is emphasized in Article 4(6).

Answer to FAQ 10:

How do the requirements of the code relate to existing regulation and present practices?

1. Summary

Present practices related to the scope of NC HVDC are not as well established as in the case of NC RfG for example. The main reason for this is the relatively low number of existing HVDC numbers (see section 4), which means that relatively few countries have introduced these requirements in their national Grid Codes. Also, of the three application areas⁹, DC connection of PPMs (expected to develop largely offshore) is only just starting and even those few countries with some cover of HVDC aspects have not yet developed this part. In the partial absence of existing National Grid Codes a comparison can still be made against present practices, e.g. by reviewing national or project specifications for the most recent projects.

The NC HVDC in its draft form has been undergoing significant development. Following the formal consultation several changes have been made and are discussed in section 6 of this FAQ. Of these, two changes are of particular relevance in the comparison of the final proposed NC HVDC with existing practices, namely the time reduction applied at the extreme end of the frequency range and the introduced national freedom to reduce the performance requirements at frequencies below 49.0Hz.

With the above background, ENTSO-E concludes that the NC HVDC is broadly in line with existing practices. Where differences are identified following comparison with requirements in individual countries, these are modest. Information is provided below to the reader what these are and then linked through to analysis summarised in the Explanatory Note and further detailed in FAQ 11 “What are the cost implications of significant new requirements in NC HVDC and how are these justified?”

The three most sensitive topics in this comparison and the manner in which they have been dealt with are:

- Application of the principle that backbone HVDC should be at least as resilient as the strongest requirements for generation or demand in NCs RfG and DCC. See the agreed minutes of the 2nd NC HVDC User Group meeting on 11 June 2013 where this principle was fully debated and agreed on. The implications from implementing this principle were identified as significant through consultation and surveys (of TSOs and of manufacturers for consequential cost implications). Subsequent changes, in particular the two referred to above, fine tune these requirements to remove the main cost implications while retaining most of the resilience contribution to security of supply for extreme cases of system disturbance with major customer disconnections.
- Some stakeholders have maintained that they have planned HVDC connected PPM projects for offshore wind which they insist are planned as radial separate connections and that they will remain this way with no interconnections. This is in contrast to a string of initiatives to create an integrated approach for large scale far offshore wind capture. Some of these developers (who maybe plan to develop the HVDC link(s) themselves) request to only be subject to requirements at the Connection Point onshore without anything stipulated in the NC HVDC for the remote end, neither for the remote HVDC Converter nor for the PPM. See consultation feedback (in particular received cover letters) for arguments on this point. This subject is covered in further detail in a FAQ 20 (“What approach is taken regarding purely radial arrangements of PPM connections?”)
- Reactive power is a major cost driving requirement. This applies both onshore and offshore, although it has the greatest potential impact offshore due to the high cost of space / accommodation on platform(s) where it has been suggested by developers to be a full order of magnitude more

⁹ Interconnecting synchronous areas, embedded links, and links connecting Power Park Modules.

costly offshore than onshore. ENTSO-E has therefore taken two key initiatives to limit cost implications. Onshore the reactive power contribution has been made non-mandatory and the national choice of the reactive power range been made wide enough to encompass existing practices. Offshore the reactive power range is down to zero Mvar and is further made flexible to postpone reactive power installations until actual interconnectivity (which causes the need for substantial reactive power range to manage the offshore voltage) is established. Further, a choice allowing optimisation and best use of inherent capabilities is ensured by flexibility to deliver the reactive power either from the remote converter or the PPM, or indeed from the combination of the two.

2. TSO survey comparison based on the November 2013 NC HVDC

Prior to taking account of the post consultation changes to NC HVDC the results of the survey (detailed in section 6) were:

- In 26% of the TSO cases there are no national requirements **and** no existing HVDC systems.
- In 60% the Network Code for HVDC is broadly in line with the actual national requirements / practices (where existing) for the connection of HVDC systems.
- In 14% significant differences exist between the November 2013 version of NC HVDC and existing national requirements for existing HVDC systems.

As highlighted in the Summary and further detailed in subsequent sections, these differences reduce substantially by the post consultation changes made to NC HVDC.

Differences relate to the frequency/voltage withstand capabilities, maximum power reduction at under-frequency and reactive power requirements. Adjustments have subsequently been made to these requirements.

The most significant deviation from existing practices in National Grid Codes and specifications used relates to

- HVDC systems as the back bone of the transmission system with the capability of fast active and reactive power control are expected to be more robust against frequency deviations in order to improve system stability in case of emergency situations. The NC HVDC shall ensure that tripping of HVDC Systems does not occur before tripping of generation or demand connection is allowed (as prescribed in NCs RfG and DCC).
- Offshore requirements for ranges for frequency, voltage and reactive power. However, in the only four applications of HVDC connection of offshore PPMs physically in place by end of 2014, projects here referred to as “existing”, these offshore requirements are already broadly included, with only minor differences.

3. NC HVDC in light of present practices

All ENTSO-E members were requested to complete a survey which comprises:

- Existence of national grid codes or other documents describing connection requirements for HVDC. In countries where some HVDC installations exist or are planned, the survey endeavoured to further establish the potential for deviations by application categories. Only a minority of countries have or plan to have all 3 categories of HVDC applications, namely
 - Interconnectors
 - Embedded HVDC
 - DC Connected PPMs

- An indication is sought whether present grid codes deviate significantly with respect to requirements in the code, with focus on the articles questioned by stakeholders.

The number of HVDC Systems already installed or planned through to 2035 is as given in Figure 1.

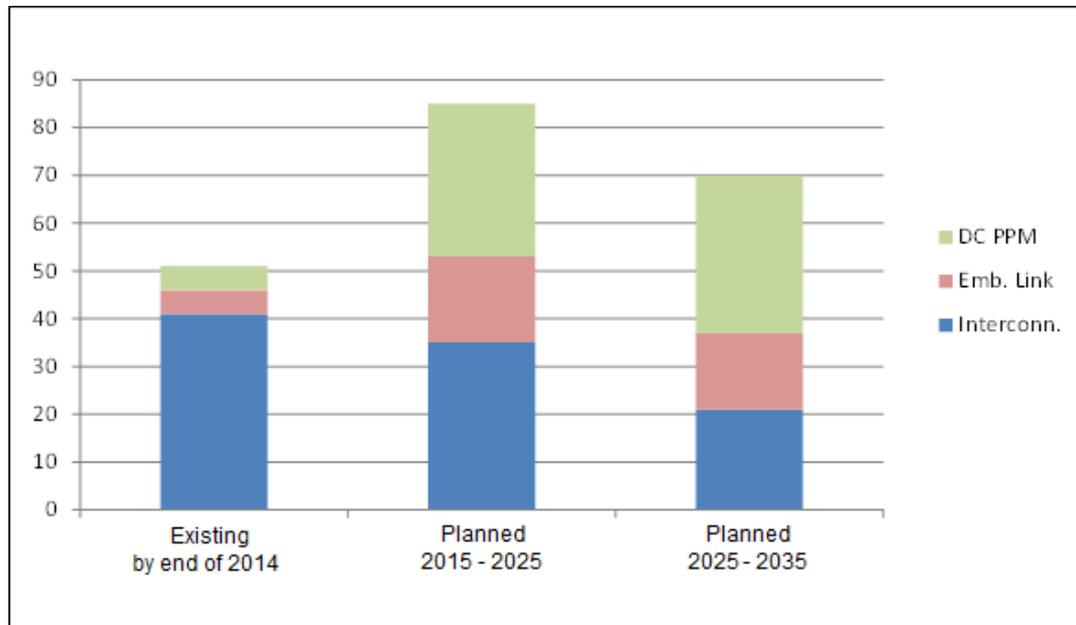


Figure 1: Numbers of HVDC Systems installed and planned

Figure 2 gives a view on how many TSOs have HVDC requirements, either in existing national grid codes or in other documents (e.g. case-specific project specifications).

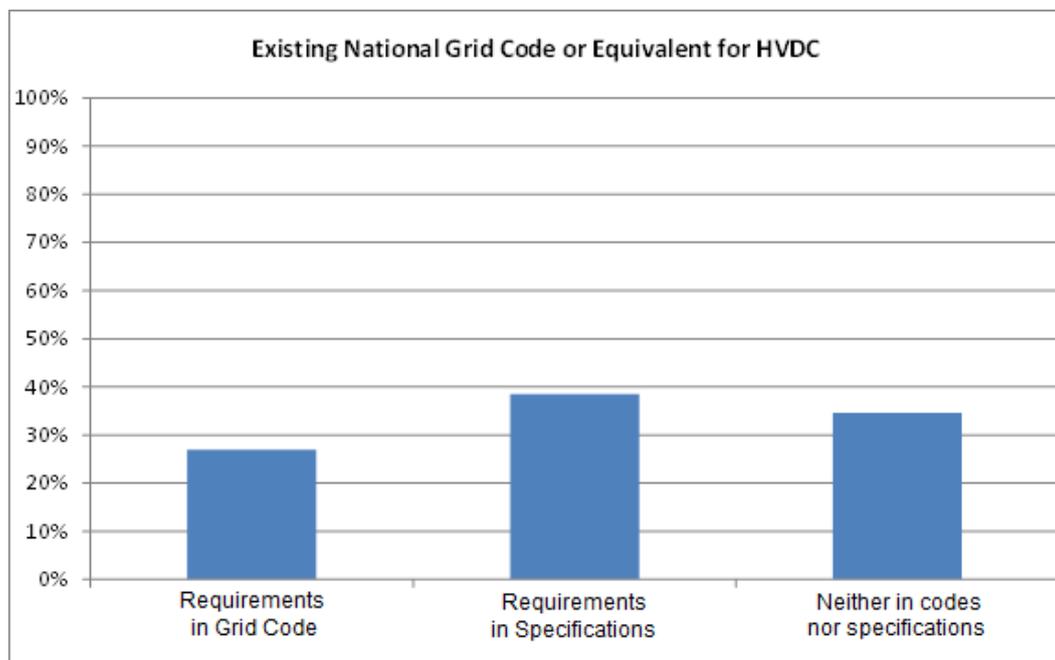


Figure 2: Percentage of TSOs with existing HVDC requirements

The following paragraphs list the key questions on which ENTSO-E members provided further insight, referring to the November version of the NC HVDC.

Frequency range for HVDC links:

Article reference: 7

Will this requirement in a European Regulation after implementation at national level result in a change compared to the present transmission grid code relevant to you?

Based on the consultation version only 13% stated “the requirement will result in a change with significant impact on users and system operators compared to the present grid code”.

Following the change to NC HVDC post consultation of

- reduced duration for extreme frequencies, including 47.0 to 47.5 down from 30 min to 60 seconds.
- national option for reduced performance at frequencies below 49.0Hz

and when combined with cost data from HVDC equipment manufacturers (see FAQ 11), this has in ENTSO-E’s view **moved from significant impact to minor impact**.

The capability of keeping HVDC Systems operating during deviations of system frequency from its nominal value is of crucial importance from the perspective of system security. Significant deviations are likely to occur in case of a major disturbance to the system, which comes along with splits of normally synchronously interconnected areas due to imbalances between generation and demand in the then separated parts of the system. A rise of frequency will occur in case of generation surplus, while lack of generation will result in a drop of frequency. The volume of a frequency deviation not only depends on the amount of imbalance, but also on other conditions / characteristics of the system, such as the generation profile, system inertia, spinning reserve and the frequency response speed. The justification for this requirement is further dealt with in Explanatory Note section 4.1 and in FAQ 23 “Why do HVDC systems have stronger frequency / voltage withstand capabilities than generation and demand?”

Frequency range for PPMs:

Article reference: 37

Will this requirement in a European Regulation after implementation at national level result in a change compared to the present transmission grid code relevant to you?

Based on the Consultation version 10% stated “the requirement will result in a change with significant impact on users and system operators compared to the present grid code”.

Following the change to NC HVDC post consultation of

- reduced duration for extreme frequencies, including 47.0 to 47.5 down from 30 min to 20 seconds.
- national option for reduced performance at frequencies below 49.0Hz

and when combined with the fact that the first HVDC connected PPM projects implemented all have wider rather than narrower frequency requirements specified. This has in ENTSO-E’s view **moved this change from significant impact to no increase in requirement**.

The justification for this requirement is further dealt with in Explanatory Note section 4.1 and also in FAQ 20 “What approach is taken regarding purely radial arrangements of PPM connections?”

Voltage range for HVDC links:

Article reference: 16

Will this requirement in a European Regulation after implementation at national level result in a change compared to the present transmission grid code relevant to you?

The voltage range in the Network Code for HVDC is according to the voltage range in the NC RfG and DCC. The Network Code RfG requires an unlimited time operation capability from 0.9 to 1.05 p.u., which is broadly in line with most present transmission grid codes.

Synchronous Area	Voltage Range (NC HVDC)	Time period for operation (NC HVDC)
Continental Europe	0.85 pu – 1.118 pu	Unlimited
	1.118 pu – 1.15 pu	To be defined by each TSO while respecting Article 4(3), but not less than 20 minutes
Nordic	0.90 pu – 1.05 pu	Unlimited
	1.05 pu – 1.10 pu	60 minutes
Great Britain	0.90 pu – 1.10 pu	Unlimited
Ireland	0.90 pu – 1.118 pu	Unlimited
Baltic	0.85 pu – 1.12 pu	Unlimited
	1.12 pu – 1.15 pu	20 minutes

Table 4 in NC HVDC: This table shows the minimum time periods a HVDC System shall be capable of operating for Voltages deviating from the nominal system value at the Connection Point(s) without disconnecting from the Network. This table applies in case of pu Voltage base values below 300 kV. (Network Code for HVDC from 3 March 2014)

Voltage Range (NC RfG)	Time period for operation (NC RfG)
0.85 pu – 0.90 pu	60 minutes
0.90 pu – 1.118 pu	Unlimited
1.118 pu – 1.15 pu	To be defined by each TSO while respecting the provisions of Article 4(3), but not less than 20 minutes
0.90 pu – 1.05 pu	Unlimited
1.05 pu – 1.10 pu	60 minutes
0.90 pu – 1.10 pu	Unlimited
0.90 pu – 1.118 pu	Unlimited
0.85 pu – 0.90 pu	30 minutes
0.90 pu – 1.12 pu	Unlimited
1.12 pu – 1.15 pu	20 minutes

Table 6.1 in NC RfG: This table shows the minimum time periods a Power Generating Module shall be capable of operating for Voltages deviating from the nominal value at the Connection Point without disconnecting from the Network. (The Voltage base for pu values is from 110 kV to 300 kV (excluding).)

One country mentioned that at the nominal voltages below 132 kV their national requirement define closer voltage range at the connection point than in the Network Code for HVDC. It is expected that few HVDC connections will connect below 132kV to the HVAC systems.

This topic is therefore deemed not to represent any significant increase in requirement.

The wide voltage ranges of the HVDC System operations are very important during "normal" operation to ensure the technical capability of a HVDC System to retain synchronous operation and support the system when local voltage problems occur (e.g. to avoid voltage collapse). Across Europe, tripping of HVDC Systems from the meshed network to protect the HVDC System and equipment and to prepare to contribute to the restoration process is permitted if extreme voltage drops occur. In practice, the setting of these undervoltage protections in terms of nominal grid voltage and time delay should be agreed with the Network Operators. A wide voltage range withstand capability of HVDC Systems is furthermore highly beneficial during the system restoration process when extreme voltage conditions may occur, (e.g. during charging of long lines).

Further information can be found in section 4.2 of the Explanatory Note and in FAQs 21 and 22.

Voltage range PPMs:

Article reference: 38

Will this requirement in a European Regulation after implementation at national level result in a change compared to the present transmission grid code relevant to you?

Based on the consultation version 20% stated “the requirement will result in a change with significant impact on users and system operators compared to the present grid code”.

The most significant deviations are the voltages above 1.12 pu in Table 9 and 1.10 pu in Table 10. They were in excess of IEC standards for the duration specified.

Harmonisation between the PPM requirements of the NC HVDC and NC RfG has since been introduced for cases of “hybrid” integration from DC to AC or from AC to DC, and to ensure non-discriminatory treatment of grid users.

The Tables 9 and 10 have been changed subsequent to consultation.

In Table 9 (for nominal voltage between 110kV and below 300 kV) for voltages above 1.10 pu the time period for operation can now be specified by the Relevant TSO while respecting the provisions of Article 4(3).

In Table 10 (for nominal Voltage between 300 kV and 400 kV) the voltage range was changed to 0.90 to 1.05 pu instead of 0.90 to 1.10 with unlimited time period for operation. Above 1.05 pu the time period for operation can be specified by the Relevant TSO while respecting the provisions of Article 4(3).

In respect of approach to possible purely radial connections, see FAQ 20. See also Explanatory Note section and section 4.2 and FAQ 21.

Referring to the requirement in the final NC HVDC, **all impacts can be estimated as minor.**

Voltage range for remote converters:

Article reference: 38

Will this requirement in a European Regulation after implementation at national level result in a change compared to the present transmission grid code relevant to you?

Based on the consultation version 22% stated “the requirement will result in a change with significant impact on users and system operators compared to the present grid code”.

The most significant deviation was the voltages above 1.12 pu in Table 9 and 1.10 pu in Table 10. They were in excess of IEC standard for the duration specified.

In the post consultation version of the NC HVDC two new Tables (12 and 13 in Article 47) were added especially with the requirements for remote converters.

In the new Table 12 (for nominal Voltage between 110kV and below 300 kV) for voltages above 1.10 pu the time period for operation can now be specified by the Relevant TSO while respecting the provisions of Article 4(3)

In the new Table 13 (for nominal Voltage between 300 kV and 400 kV) the voltage range was changed to 0.90 to 1.05 pu instead of 0.90 to 1.10 with unlimited time period for operation. Above 1.05 pu the time period for operation can be specified by the Relevant TSO while respecting the provisions of Article 4(3)

In respect of approach to possible purely radial connections, see FAQ 20. See also Explanatory Note section and section 4.2 and FAQ 21.

Referring to the final NC HVDC, **all impacts can be estimated as minor.**

Maximum power reduction at under frequency:**Applies to:** HVDC Connections + DC-connected PPMs**Article reference:** 7(1)d**Will this requirement in a European Regulation after implementation at national level result in a change compared to the present transmission grid code relevant to you?**

Based on the consultation version 13% stated “the requirement will result in a change with significant impact on users and system operators compared to the present grid code”.

In this case the question is focused on a national option to reduce the performance requirements. This reduction would have a significant impact for some TSOs.

In Article 7 Frequency ranges the following part was added in the final version of the Network Code:

“The Relevant TSO shall have the right to specify a maximum admissible Active Power output reduction from its operating point if the system Frequency falls below 49 Hz, while respecting the provisions of Article 4(3).”

Further information / justification can be found in FAQ 11 regarding the cost reductions secured.

Taking into account that this topic is concerned with reduction of requirements of the Network Code for HVDC in the sense of the normal use of the word “significant” (normally related to new or additional requirements), the **impact of this topic is not significant**.

Reactive power capability for HVDC links:**Article reference:** 18(1)**Will this requirement in a European Regulation after implementation at national level result in a change compared to the present transmission grid code relevant to you?**

Based on the consultation version 21% stated “the requirement will result in a change with significant impact on users and system operators compared to the present grid code”.

In the November version of the Network Code for HVDC **the reactive power requirement was specified as a national choice with a minimum value of 0.33 pu Q/Pmax** range. Taking account of the absence of inherent reactive power capability of LCC technology, the minimum value has been removed.

Referring to the final NC HVDC, **there is no impact as continuing existing national requirements is facilitated**.

Reactive power capability for PPMs and remote converters:

Article reference: 38(2), 40(2) and 40(3)

Will this requirement in a European Regulation after implementation at national level result in a change compared to the present transmission grid code relevant to you?

Based on the consultation version 11% stated “the requirement will result in a change with significant impact on users and system operators compared to the present grid code”.

There are a lot of TSOs with no reactive power requirements for DC-connected PPMs, reflecting the position prior to consideration of offshore network integration. In the final NC HVDC the “no offshore requirement option” is still possible if there is no foreseen integration in long-term network development plans, although reactive power has to be provided from either the Remote-end HVDC Converter or the PPM if integration becomes a reality.

Regarding the modest existing numbers of PPMs, these all have reactive power requirements compatible with the NC HVDC.

Regarding the only four Remote end Converters connecting offshore PPMs, these all have reactive power requirements compatible with the NC HVDC.

Referring to the final HVDC, **the impact can be estimated as modest.**

The justification for this requirement is further dealt with in Explanatory Note section 4.7 and also in FAQ 20 “What approach is taken regarding purely radial arrangements of PPM connections?” and in FAQs 29 and 31.

Answer to FAQ 11:

What are the cost implications of significant new requirements in NC HVDC and how are these justified?

This FAQ is based on survey returns from converter manufacturers.

The need for information:

To understand the full cost implications of individual requirements, particularly those that have not previously been common, early input was needed from all impacted stakeholders, particularly manufacturers. In its 7th May 2013 “Call for Stakeholder Input” ENTSO-E requested information on this aspect, asking for the 5 requirements in the preliminary NC HVDC scope with the largest impact to be identified and also for any requirement with an impact greater than 0.1% of the total cost of the HVDC Converter Station. However, this first consultation did not result in any quantitative cost information related to the proposed scope items.

ENTSO-E recognises the commercial sensitivity of this aspect and took advice from CENELEC TC8X WG06. A manufacturer survey, bound by an NDA with the ENTSO-E Secretariat, was set out with the objective to only use high level information received from each manufacturer in accordance with the NDA and to ensure that only some high level conclusions, which are not attributable to any one manufacturer, are published.

Manufacturers in CLC TC8X WG06 were also consulted when identifying the topics of significance in context of potential added cost, taking into account what had emerged as controversial requirements in the NC HVDC consultation. In the ENTSO-E survey, the request for cost data is limited to an order of magnitude cost in percentage of a total converter station cost, based on a typical 1000MW project.

The topics of the survey were:

- Frequency ranges and durations
- Power versus frequency
- Low Frequency and High Voltage Combined – Overfluxing
- Reactive Power
- Qualification by Type Testing
- Other Significant Cost Driving Requirements
- Total increase in cost attributable to NC HVDC requirements

Each topic was explored in context of cost implications for the two main HVDC technologies (LCC and VSC), with VSC selected for further split between onshore and offshore. It is not currently anticipated that the LCC technology will be used in converter stations offshore.

For these limited topics the converter manufacturers were requested to identify the additional costs introduced by NC HVDC requirements compared to recent practice. If the size of the project affects the answer significantly, a converter station size of 1000MW was suggested as reference.

Also a rough split of the total additional cost for the converter into development cost component versus production cost component was requested.

The survey and NDA proposal was sent to the HVDC equipment manufacturers participating in the NC HVDC User Group, as well as to T&D Europe and EWEA for possible input from other members.

Out of the HVDC equipment manufacturers who were directly contacted, most replied. Very useful information was obtained on most questions. No manufacturer responded to all questions.

The following sections reflect ENTSO-E's general conclusions from the feedback received on the key questions. Resulting ENTSO-E actions, in particular revisions in the code are described in *italic*.

1. Frequency ranges and durations

Manufacturers: There is significant cost implication linked to the duration at the lowest frequency end of 47-47.5Hz. The feedback further tends to indicate that a time of no more than 60s is critical to avoid additional cost. It is noted that frequency range has the greatest potential for cost increase offshore due to cost related to size and weight for the platform. However, cost implications are lower for VSC technology (anticipated to be the main technology choice offshore) than for LCC technology. The returns tend to indicate that the cost implications are mainly in production costs rather than development costs.

ENTSO-E: *The duration in NC HVDC has been reduced to 60s from the earlier 30min requirement. Therefore the HVDC corridors will only be required to be retained for the short excursions to these low frequencies. The information received tends to indicate that this reduction in duration largely cuts associated costs, while only moderately affecting the aim of the requirement in terms of system security. (Ref. Article 7(1)a)*

2. Power versus frequency

Manufacturers: This explored the possibility of reducing the performance requirement at the lower end of frequencies in a manner similar to NC RfG for some technologies (e.g. CCGTs with lower output at lower speeds). The survey feedback demonstrates that this factor is of similar or even greater importance for cost than the duration. It was indicated that reducing the harmonic performance requirements during extreme frequency excursions could reduce costs.

ENTSO-E: *NC HVDC therefore includes an option to allow at a national level (where such loss of performance would not be excessively detrimental) to introduce a similar reduced performance requirements as allowed in NC RfG. The explicit harmonic performance is not included in the scope of the NC HVDC. This topic related to extreme frequencies may still be relevant to the planned national implementation guideline to supplement standards which may not deliver required clarity for these extreme and rare conditions. (Ref. Article 7(1)d)*

3. Low Frequency and High Voltage Combined – Overfluxing

Manufacturers: In this question the cost implications of the proposed voltage range requirements were compared with requirements specified in recent European projects. Information suggests a variation between no impact for several synchronous areas to a relatively modest total converter station cost implication in other synchronous areas, although responses were not all entirely consistent. The survey returns indicate that cost implication is particularly small when combined with the lower duration conclusion from question 1.

ENTSO-E: *The information received indicates that the importance placed by ENTSO-E on ensuring that the backbone of the network survives in the rare extreme operating conditions of low frequency and high voltage may outweigh the modest cost implications of retaining these requirements.*

4. Reactive Power

Manufacturers: This question covered the cost implications of the varied possible reactive power requirements as consulted on, when compared to virtually no contribution through delivering unity power factor. **The returns indicate that these requirements have the greatest cost implications.** It was suggested that the dynamic reactive power needed offshore is modest and that the wind turbine generator(s) could contribute to this.

It was indicated that deferring installation of reactive power may be impractical offshore due to platform considerations.

ENTSO-E: *This underlines the need to define carefully what is required related closely to actual circumstances (configurations) and to allow freedom to which component(s) provide the capability. The post consultation proposed NC HVDC ensures that requirements are carefully optimised to keep cost to a minimum while ensuring that enough reactive capability is provided to manage the voltage adequately. The importance of voltage management has been demonstrated in question 3. Even though a choice of later addition of equipment is not likely to be a frequent one, due to the very different regulatory and ownership structures across Europe, it cannot be ruled out. Therefore, it is still considered a useful option to retain in the code.*

5. Qualification by Type Testing

This question was intended to explore the cost of performance requirements which may not materially affect primary plant, but lead to developments required in protection and control. Manufacturers suggested this could be captured best by analysing changes in cost of type testing. The question explored two aspects:

- Additional costs due to new requirements
- Reduced cost over time due to greater harmonisation

Manufacturers: Only generic and modest information was received. This indicated a low to moderate cost implication possibly related to extending both test facilities and duration of tests.

It was suggested that cost reduction from a degree of standardisation is not expected.

It was noted that the time factor for the first project could be a problem and become a bottleneck.

ENTSO-E: *The broad implications are noted.*

6. Other Significant Cost Driving Requirements

No additional information beyond that provided to the previous questions was received.

7. Total increase in cost attributable to NC HVDC requirements

No specific return.

Other significant ENTSO-E measures taken to optimise cost implications

Following the consultation, various measures to reduce cost implications and allow for innovations, especially in the relatively new offshore sector, have been established in the NC HVDC. A limited extract of these is given below:

-
- Freedom to select frequency of the offshore AC system, including
 - Different fixed frequency, e.g. 16 2/3Hz – allow converters to be moved onshore
 - Variable frequency of the offshore AC system – allow use of simpler WTGs
 - WTG output at DC with DC collection networks

 - Freedom to optimise delivery of required reactive power to support voltage control offshore
 - Choice between HVDC Converter or PPM or combination - maximise inherent capability
 - Free to defer reactive compensation until actually needed

 - Freedom to vary connection configuration – from simple radial to fully integrated
 - Allow different national regimes and developers choices to be implemented
 - Allow simple radial connections to move ahead where appropriate
 - Fewer parties having to commit at the same time, less risk of stranded assets.

 - Preserve possibility of integration, including possible savings through:
 - Reducing cost of connections
 - Reducing transmission development needed onshore – where environmental issues are greater
 - Sharing resources between projects both in construction and for service

Answer to FAQ 12:**Why does the network code not define certain requirements as paid-for ancillary services?**

The scope of this network code is to define requirements for technical capabilities of HVDC connections which are needed for secure operation of the electricity transmission system. Operational issues are covered in NCs Operational Security (OS) and Load Frequency Control & Reserves (LFC&R). Paid-for ancillary services are broadly defined in NC Electricity Balancing (EB); further specifics (including payments) are to be found in national documents.

One objective of the network code is specifying clearly the necessary technical capabilities in order to enable the industry to consider these features for future HVDC connections and to develop corresponding technical solutions. This approach has been expressively endorsed by the industry, because sufficient time for research and development is needed to be able to deliver the required functionalities. Introducing such capabilities only when the market demands for them is not sustainable as this inherently bears the risk, that at the time the market requests for these capabilities, they are not available and cannot be introduced at short notice causing a substantial risk to the security of the power system due to lack of ancillary services.

It is important to distinguish between mandatory requirements of technical capabilities and the provision of ancillary services based on these capabilities. ENTSO-E agrees with stakeholders, that the provision of ancillary services is basically market-related which needs to be appropriately remunerated. The paid-for ancillary services can be expected to evolve over a longer period of time. The introduction of remuneration provisions are the subject of other Network Codes or arrangements.

Answer to FAQ 13:

Do the requirements have to be considered as “minimum” or “maximum” requirements; what is the understanding of “minimum”/ “maximum” requirements?

“Minimum” relates to the request for defining the minimum set of requirements in the corresponding network code(s) which is necessary in order to achieve the objectives of the framework guidelines and consequently of Regulation (EC) 714/2009. The terms “minimum” (and “maximum” respectively) shall not be understood in the sense of defining minimum (or maximum) values for parameters, thresholds, ranges, etc.

The requirements established in the network code prevail over national provisions when implemented via European Regulation, and if compatible with the provisions in the European network code(s), national codes, standards and regulations which are more detailed or more stringent than the respective European network code(s) should retain their applicability. Nevertheless, additional measures remaining within the scope of the network code can, as a matter of principle, be taken at the national level provided that they do not contradict the provisions of the network code (e.g. if the NC explicitly allows for a parameter to be selected at national level in a prescribed range of values).

The following examples attempt to clarify this principle:

- Example 1: Art 8 - The network code requires that each HVDC System shall be capable of withstanding a rate-of-change-of-frequency up to 2.5Hz/s in any direction.
- It is not admissible to define a value under this minimum limit on a national level, but a value above this limit could be defined by the national (relevant) TSO.
 - Example 2: Art 16 (1)(b) The network code determines the admissible continuous operational voltage range capability for a HVDC system at connection point(s) (minimum operation time periods in case of voltage deviation).
- If wider voltage ranges or longer minimum times for operation are economically and technically feasible, the consent of the HVDC System Owner shall not be unreasonably withheld. Wider Voltage ranges or longer minimum times for operation can be agreed between the Relevant Network Operator (in coordination with the Relevant TSO) and the HVDC System Owner to ensure the best use of the technical capabilities of a HVDC System. The same principle also applies for frequency range capability.

Answer to FAQ 14:

Which terminology is used in this code, and how does it relate to that in other Network Codes, national codes and standards?

The terminology used in NC HVDC corresponds to the general terminology used in other ENTSO-E Network Codes, terminology contained in Article 2 of Directive 2009/72/EC and that of Article 2 of Regulation (EC) N°714/2009. For HVDC related terminology the proposed definitions are in line with IEC 60633 “Terminology for high voltage direct current (HVDC) transmission”.

In order to clarify the definitions used in the code, the below single line diagram is composed. The figure below is based on the configuration of Skagerrak 1, 2 and 3 (LCC) and the coming Skagerrak 4 (VSC). Definitions illustrated are HVDC Converter Unit, HVDC Converter Station, and HVDC System.

DC-connected Power Park Module means a Power Park Module that is connected via one or more Interface Point(s) to one or more HVDC System(s). Unless otherwise stated, Power Park Module referred to in this network code means a DC-connected Power Park Module;

DC-connected Power Park Module Owner means a natural or legal entity owning a DC-connected Power Park Module;

HVDC Converter Station means part of an HVDC System which consists of one or more HVDC Converter Units installed in a single location together with buildings, reactors, filters, reactive power devices, control, monitoring, protective, measuring and auxiliary equipment;

HVDC Converter Unit means a unit comprising one or more converter bridges, together with one or more converter transformers, reactors, converter unit control equipment, essential protective and switching devices and auxiliaries, if any, used for the conversion;

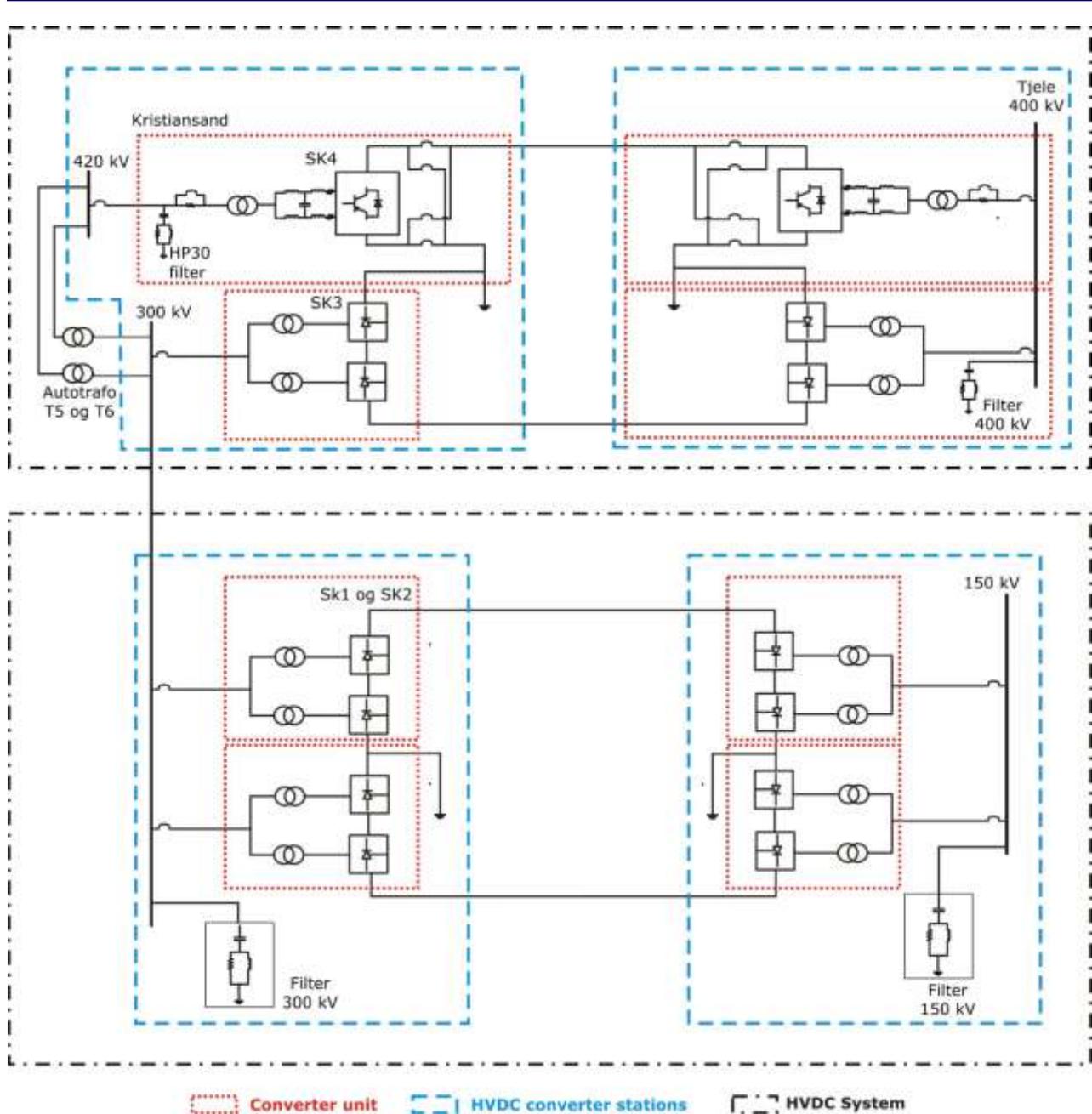
HVDC System means an electrical power system which transfers energy in the form of high-voltage direct current between two or more AC buses. A HVDC System comprises at least two HVDC Converter Stations with DC transmission lines or cables between the HVDC Converter Stations. In case of a back-to-back system the HVDC System comprises only one HVDC Converter Station with direct DC circuit connection between the pair of HVDC Converter Units. A HVDC System has at least two Interface Points;

HVDC System Owner means a natural or legal entity owning a HVDC System;

Interface Point means an AC point in a Network connecting equipment owned by two or more parties (which can be the owner of a Power Generating Module, Demand Facility, Distribution Network or HVDC System) at which technical specifications affecting the performance of the equipment of one or more parties can be prescribed;

Remote-end HVDC Converter Station means a HVDC Converter Station which is synchronously connected via Interface Point(s) to DC-connected Power Park Module(s). For the purpose of this Network Code, in case of back-to-back schemes the requirements for the Remote-end HVDC Converter Station apply at the Interface Point(s) with the DC-connected PPM(s);

Remote-end HVDC Converter Station Owner means a natural or legal entity owning a Remote-end HVDC Converter Station.



Answer to FAQ 15:**Why does the code not make a distinction between LCC and VSC technology?**

HVDC technology will increasingly be used in the coming years to develop interconnections between different TSOs (inter- or intra- synchronous zones) and it is of the utmost importance for these new facilities not only to improve power system security but also to contribute to market integration by supporting the development of cross-border exchange of energy and reserve. From technology perspective mainly two solutions are in use – LCC and VSC technology. The LCC technology has been available for many decades and therefore can be considered as mature whereas the VSC technology can be considered as developing technology and has been on the market for the last ten years, but is still undergoing considerable change.

It is recognized that there are differences between the inherent functionalities of the two technologies but from the perspective of NC HVDC they are considered as a HVDC System connected to the network at a connection point. The requirements stated in the NC HVDC are based on system needs and consider the integrity of the power system, development trends in the future, and security of supply. The objective has been to define the minimum performance requirements needed to ensure reliable operation of connections. The performance requirements are defined in general for HVDC systems at the connection point considering technology neutrality. In the NC HVDC, different requirements are composed based on the viewpoint of mandatory and non-mandatory requirements and exhaustive and non-exhaustive requirements (see Explanatory Note document). Non-mandatory requirements have been applied in a limited number of cases where not all technologies can reasonably deliver a capability. This approach is considered to provide sufficient flexibility to guarantee the technology neutrality and focus on the need for system performance. ENTSO-E has endeavoured to seek the views also of the wider industry (through the NC HVDC User Group) on early drafting of the code as to ensure that the NC HVDC does not prevent future application of any HVDC technology.

Answer to FAQ 16:

Who does the code apply to, at which point and why?

According to ACER's FWGL, "the network code will apply to grid connections for all types of significant grid users already, or to be, connected to the transmission network and other grid user, not deemed to be a significant grid user will not fall under the requirements of the network code".

The FWGL give a general definition of the Significant Grid Users by defining them as "pre-existing grid users and new grid users which are deemed significant on the basis of their impact on the cross border system performance via influence on the control area's security of supply, including provision of ancillary services".

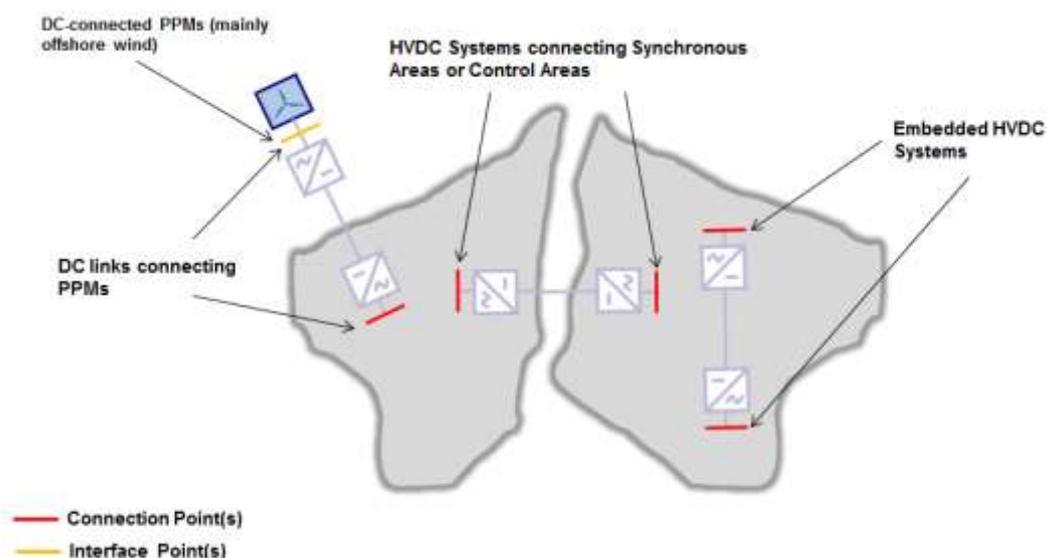
Based on that definition, in the NC HVDC the following HVDC configurations are considered as Significant Grid Users:

- HVDC Systems connecting Synchronous Areas or Control Areas, including back to back schemes;
- HVDC Systems connecting Power Park Modules to the (Transmission or Distribution) Network;
- HVDC Systems embedded within one Control Area and connected to the Transmission Network; and
- HVDC Systems embedded within one Control Area and connected to the Distribution Network, when a cross-border impact (currently or on the longer term) is demonstrated by the Relevant TSO and approved by the NRA.

In addition all Power Park Modules that are AC collected and DC-connected to the main electricity system at any AC voltage (transmission or distribution) are also considered as Significant Grid Users.

The emerging alternative way of connecting individual DC Power Generating Units via MVDC is deemed as not yet adequately mature to be detailed in this NC. Where this choice is made national or local requirements will apply until covered in future issues of NC HVDC.

The following picture illustrates the above mentioned configurations considered in the NC HVDC.



Example 1: Illustration of the Significant Grid Users considered in the NC HVDC and the Connection Points and Interface Point(s) at which the requirements apply.

It is important to note that cross-border issues include the technical capabilities of all the users to contribute to system security. Requirements of this NC will affect robustness to face disturbances; will help to prevent any large disturbance and will facilitate restoration of the system after a collapse.

- It is clear that HVDC systems between control or synchronous areas have, by definition, a cross-border impact.
- HVDC links embedded within one Control Area and connected to the Transmission Network fall within the scope of this NC.
- An HVDC link connected to the distribution system could possibly fall within the scope of applicability of this NC. For such links, however, cross-border impact needs to be demonstrated, taking into account the planned long-term development of the Network.
- An HVDC generation collection system, in which all the AC/DC terminals are connected within a single control area, has a cross border impact due to the fact that it is the interface between the grid and a significant generating units and because its capability will greatly affect the system robustness in case of system faults.

During the development of the NC RfG a principle decision was taken following review of stakeholder comments about offshore to exclude DC connected PPMs from the scope of that code, but to have these covered when developing European connection rules for HVDC Systems at a later stage. These generating units were expected to be significant as per the criteria defined in the NC RfG with a strong link to performance requirements for the HVDC System connecting them to the main power system. The NC HVDC covers therefore both the HVDC System and the remote end PPMs.

The requirements set forth by this Network Code apply primarily to New Significant Users. Aspects regarding exceptional application to Existing HVDC Systems or Existing DC-connected Power Park Modules are covered in FAQ 17.

At which physical point are the technical requirements of the code applicable and why?

Requirements will describe the functional behaviour of the user installation at the Connection Point, which is the physical interface between the user installation and the grid as referred to in the connection agreement.

The illustration above also shows the location of the (AC) Connection Points of the HVDC System to the AC system as well as the (AC) connection points of the Power Park Module to the AC collection system. These connection points form the physical interface with the systems thus the performance requirements are usually defined related to these Connection Points.

As under different national regulatory frameworks the ownership of esp. offshore collection grids and DC links connecting these to the transmission system may vary, as well as change over time, a connection agreement does not in all cases exist for the physical interface described above. In order to ensure comparable technical capabilities in such cases, the notion of Interface Point is defined and referred to where appropriate.

Regarding meshed HVDC grids and DC connection points, see FAQ 19.

Answer to FAQ 17:

How does the code impact existing users?

The European power system is changing rapidly: internal market evolves; Demand Side Response and renewable generation increases; new transmission technologies, such as FACTS (Flexible AC Transmission Systems), HVDC (High Voltage Direct Current) lines, etc. are introduced. In this situation there is an inherent uncertainty in anticipating the needs for power system security throughout the next 20 years. On the other hand, the requirements of this network code will enter into force by means of European legislation, which means that they will be applicable for a rather long time and changes/amendments to them can only be implemented by running through lengthy European legislative procedures. Hence, it is essential to have the possibility to apply network code requirements retroactively to existing users. Such application will be pursued in very particular and reasonable cases and, with all the necessary safeguards to grid users following the principles of ACER's framework guidelines. A consistent approach has also been prescribed in the Demand Connection Code and the NC Requirement for Generators. This process prescribes a thorough cost benefit analysis (based on data contribution from the HVDC System or DC-connected PPM owner), a transparent consultation and final decision by the NRA.

Existing HVDC systems or DC-connected PPMs, which are not covered by the network code, shall continue to be bound by the already existing technical requirements that apply to them pursuant to legislation in force in the respective Member States or contractual arrangements in force. Consequently, existing national/local derogations may remain in force as well, provided that they refer to a requirement not covered by the European network code.

In case of replacement/improvements/modernisation of an existing Significant User Installation, it is required that the replaced/improved/modernised part of the installation is compliant with the requirements of the network code, unless the user applies for a derogation from this obligation and this derogation is granted by the NRA. Indeed, during a replacement/improvements/modernisation the fulfilment of the NC HVDC can be added in the specifications as long as such type of equipment can reasonably fulfil some of the requirements of the NC. As an example, the replacement of the protection system of an existing HVDC link should lead to fulfilling the requirements of the NC related to "Electrical protection schemes and settings" and to "Priority ranking of protection and control". However, the HVDC facility should not for this reason have to fulfil the requirements for "Reactive power capability" (i.e. Article 18) as the change has negligible impact on the reactive power capability of the system.

Answer to FAQ 18:**Why are some generators covered by the NC RfG and some by the NC HVDC?**

The NC RfG defines the requirements for generators connected to Synchronous Areas. This covers the main parts of the European power system and is characterized by a certain amount of rotating masses and a considerable fault current level. In contrast, the scope of this network code is the definition of requirements for HVDC connected Power Park Modules. The absence of synchronous generation in combination with the connection to the main AC system by HVDC results in fully different physical grid conditions of this “small” system. As these systems are fully based on power electronics there is no physical coherence between power balance and frequency.

One objective of the network code is to clearly specify the necessary technical capabilities in order to enable the industry to consider these features for future PPMs and to develop corresponding technical solutions independently from the way of connection, whenever possible and reasonable. This would enable the design of PPM solutions fitting to both markets, i.e. offshore with HVDC and on-/near-shore by AC connection. Therefore, the NC HVDC specifies different requirements from the RfG whenever necessary because of the system specifics and sticks to the known necessities as given by the RfG, if reasonable. This approach was broadly agreed on in the 2nd NC HVDC User Group meeting.

Further, the requirements set in this network code need to be forward looking: the expected mid- and long-term developments need to be taken into account. Even more, the NC should enable and foster future improvement. Thus, the definition should not unnecessarily hinder the future optimisation and flexible extension of the system. Therefore, the code is seeking for common rules to be future-proof and foster enlargements of the systems by, e.g. enabling interconnections in-between different HVDC-platforms offshore. In addition this would be the most flexible way to design HVDC grid connection systems offshore if, as it is the case in some countries, a HVDC grid connection system is not designed together with a PPM within the framework of a single project. Standardization is necessary in order to host multiple offshore PPMs of different design and type of machines. This framework requires a certain degree of standardization, offering the needed flexibility for both parties (HVDC operator and PPM owner). This is needed during planning, project execution and operation as this will also enable flexibility to connect PPMs to different HVDC systems within a cluster in case of the non-availability of the HVDC system originally assigned to.

Answer to FAQ 19:**How are multi-terminal connections and meshed DC grids covered by the code? Is there a roadmap for future amendments of the NC HVDC?**

The NC HVDC focuses on DC transmission grids' point to point connections, as well as extensions to multi-terminal radial connections. Meshed DC grids and DC collection grids are out of the scope of this network code.

At present HVDC systems provide predominantly point to point power transfers. Preliminary studies have concluded that DC Grids are feasible (see CIGRE WG B4-52 report issued in December 2012). Another CIGRE group (WG B4-56) is working on connection requirements for meshed DC Grids whose final report is expected during 2014. It is envisaged that meshed DC grids will gradually emerge for some applications in the future but this technology will need time to develop.

Therefore meshed DC network are considered out of the scope of the present NC HVDC, with possible inclusion in future amendments once the technology matures. Future revisions of the NC HVDC are expected to bring these aspects forward as the DC grid technologies move into implementation.

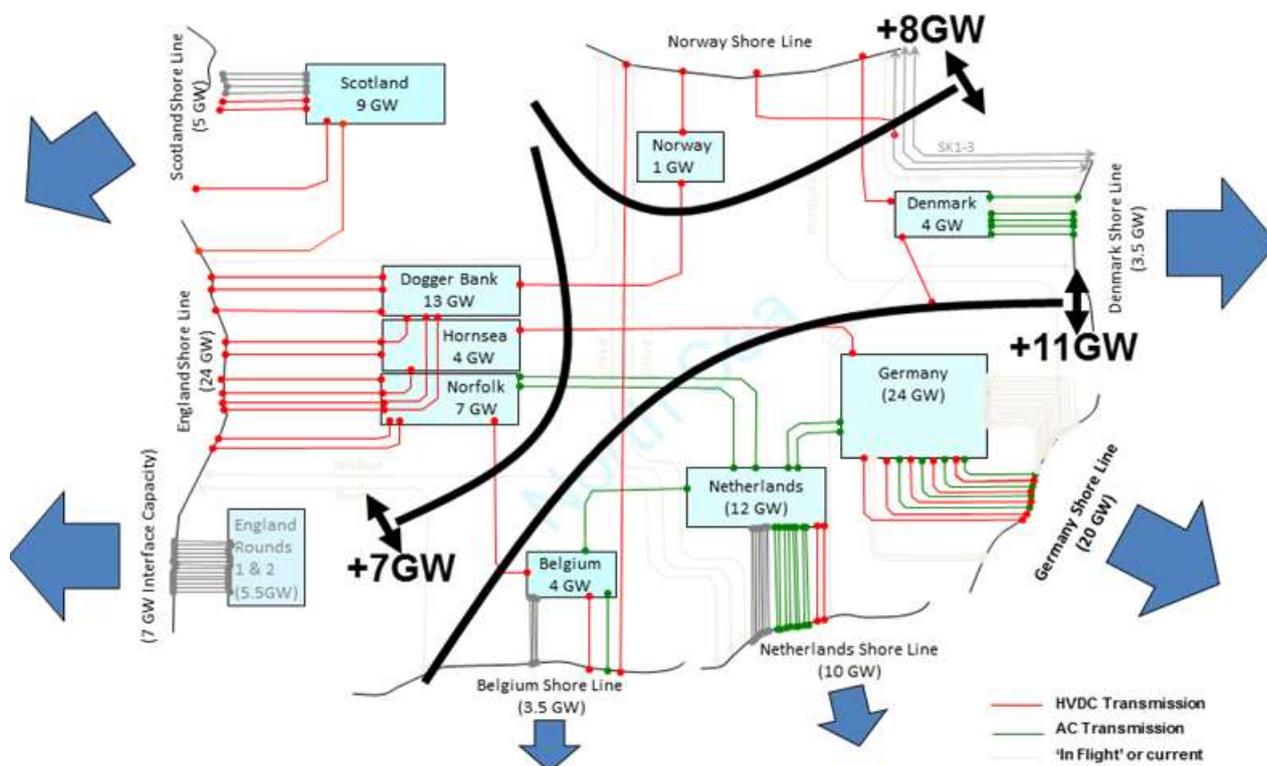
Answer to FAQ 20:

What approach is taken regarding purely radial arrangements of PPM connections?

Background

Some organizations have argued during NC HVDC User Group discussions and in the formal consultation process that there is no prospect of their particular planned radial offshore links ever changing to become part of linked connections of a cluster of Power Park Modules (PPMs) or part of an even more widely integrated offshore network. There should therefore be an option for remote-end requirements that are justified to secure flexibility regarding future integration to not apply to these projects at all. These views have been expressed in context of the offshore sector for HVDC connection of very large and far from shore PPMs.

The above developers' views of a clear pure radial choice are in part balanced by various published development plans, including collated at a European level the Ten Year Network Development Plan (TYNDP). In 2011 ENTSO-E published its concept design for 2030 for the North Sea, replicated below.



Subsequently the governments of the potentially affected states surrounding the North Sea have signed an agreement to cooperate on the North Sea developments. The North Seas Countries' Offshore Grid Initiative (NSCOGI) has emerged in this context as well as various European R&D projects to secure the necessary technological developments to facilitate the option for meshed HVDC networks.

The ENTSO-E R&D Roadmap 2013 -2022¹⁰ covers the broad intent, with more specifics described in the R&D Implementation Plans, the latest covering 2015-2017¹¹.

¹⁰ <https://www.entsoe.eu/index.php?id=918>

At a more practical level a substantial number of HVDC connections built for linking PPMs is already on track. These are being built to service clusters of PPMs at least sharing multiple HVDC link capacities to shore from several separate PPMs within a single cluster. They are also being designed for further interconnections between the clusters, in contrast to the above claimed pure radial intent. The four HVDC links planned to be commissioned by the end of 2014, all have elements of integration and are expected to connect 7 PPMs. Section 3.4 of the NC HVDC Explanatory Note shows that 38 PPMs more are planned to be DC connected between 2015 and 2025 and a further 29 PPMs DC connected between 2026 and 2035. Of the projects ahead of 2025, those commissioning by 2019 and a good number beyond this date (already contracted for their main equipment by about 2018) are all expected to be considered as existing HVDC Converter Stations in context of NC HVDC. These will therefore not be affected by the NC HVDC expectation of allowing for the possibility of clustering and further integrated connection design.

What change is being requested?

An option is requested to allow pure radial HVDC links to PPMs which are not prepared for any level of further interconnection. This could consist of a national option to allow purely radial HVDC connections of PPMs which have the same performance requirements at the onshore point of connection to the main HVAC system, but have lower (or no explicit) offshore requirements. The offshore HVDC converter would

- either have no explicit requirements at all (only being able to support the onshore performance, e.g. frequency response); or
- have lower requirements. In particular an exemption from the principle that HVDC links are seen as part of the “backbone” of the network and should have withstand capabilities (e.g. frequency and voltage ranges) at least up to the highest level of any generation, such that the network under extreme disturbed conditions is always ready to capitalise on generation that remains connected. The motivation for the lower standards is to reduce the cost of the connection.

In ENTSO-E’s view this cost reduction covering voltage and possibly frequency ranges as well as not having the possibility of later provision of reactive power could be in the order of 10% of the converter costs or about 5% of the total HVDC connection costs.

Note that a derogation from future provision for remote-end reactive power capabilities could possibly be granted even under the existing conditions of the NC HVDC, if the development information is judged as there is no possibility of later developments with an association / degree of integration. This is explicitly allowed for under Chapter 3 of the NC HVDC. In any case, as for all NC requirements a transparent explicit derogation process can be pursued at national level.

Considerations

In respect of the above request for an option to allow developments to be prepared in a way which will prevent a future integration into a wider network (e.g. national choice to allow) at least the following considerations need to be made:

- Such option would lead to reduced resilience through lower voltage and frequency ranges – *argument against the option*
 - Most significant during disturbed conditions, when there is a greater risk of loss of links as well as lower readiness to restore quickly

¹¹ <https://www.entsoe.eu/publications/rd-reports/rd-implementation-plan>

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- Experience from the German sector indicates a need to be able to switch over to alternative routes to shore.
 - During these switch-overs the near absence of inertia leads to greater volatility in frequency and also consequential voltage disturbances.
 - Such option would go against the long term multi-national intent of offshore integration – *argument against the option.*
 - Such option goes against equitable treatment of all developers (comparing different offshore projects, as well as comparing onshore/offshore) – *argument against the option.*
 - When costs are assessed:
 - *Arguments in favour of the option:*
 - lower direct installation costs through lower technical standards
 - greater simplicity in financial sign-off (when the offshore developer is directly involved in the offshore transmission build) – less need for coordination between developers
 - *Arguments against the option* because of loss of various cost benefits of integration:
 - Avoiding much more severe onshore transmission construction
 - Reducing onshore environmental impact
 - Sharing of offshore resources from accommodation to auxiliary supplies

Conclusion

Based on a review of the factors listed above, ENTSO-E states that a national option for a lower standard exclusively radial HVDC connection, with no flexibility for future developments, is on balance not warranted as common practice beyond the time when a NC HVDC enters into force.

Answer to FAQ 21:

How should the combined effect of frequency and voltage ranges be interpreted?

For both frequency and voltage required operating ranges are defined in which immediate disconnection of a HVDC System or DC-connected Power Park Module is prohibited due to the deviation of the frequency or the voltage from its nominal value. These requirements as such define the duration that the HVDC System or the generators are required to withstand this deviation. A non-discriminatory behaviour is prescribed from generation and demand. The international standard IEC 60034 (for rotating electrical machines) gives a specific reference to which the NC RfG is aligned. Even as HVDC technology or PPM interfaces may have less difficulty in complying with withstand capabilities, the requirement is aligned with that of synchronous generators. In the IEC Standard 60034-1 these two dimensions (ranges and times) are combined in a single diagram covering both voltage and frequency (see RfG FAQ 19, Figure 1).

- *Why does ENTSO-E not do the same?*

The IEC standard covers requirements at the generator terminals. The network code covers requirements at the Connection Point. Therefore they are very different. The impact of the generator transformer possibly with an on-load tap changer as well the impact of the collection network in the case of a Power Park Module makes up this difference. The network code does not specify the voltage range at the generator terminals.

- *If there is no diagram how should the situation of simultaneous deviation in frequency and voltage be interpreted?*

Each requirement applies on its own. If the specified duration withstand capability is exceeded, then the HVDC System or DC-connected PPM is entitled to trip. If both parameters vary at the same time, the parameter with the shortest duration criterion can initiate the trip.

Example for an HVDC System with Connection Point in the GB Synchronous Area (400 kV):

If 51.7 Hz (frequency limited time operation) and 1.07 p.u (voltage limited time operation) occurs for 10 min, what will happen?

- It is not allowed to trip on frequency, however after 15 min, it would be allowed to trip for voltage (>1.05 for longer than 15 min).

Answer to FAQ 22:

How can an interconnector provide frequency support, including inertia and even contribute synchronising torque?

Change of system frequency depends on the difference between the generated and the consumed power as well as of the inertia of the power system.

Frequency and inertia support can be provided by controlling the active power output of the interconnector, within its ratings, at the point of connection in such a way that imbalance between generation and demand is minimised.

Inertia support can be provided by regulating the power output ΔP_1 from the interconnector in response to a rate of change in the frequency $\partial f / \partial t$ according to $\Delta P_1 = -2H \frac{\partial f}{\partial t}$, where H [s] is the inertia constant. For decreasing frequencies, ΔP_1 is positive. When using rate of change of frequency some care must be taken to filter the measurement such as to avoid undesired activation due to inherent noise.

Frequency support can be provided by regulating the active power output of the interconnector in response to a frequency deviation from its nominal value according to $\Delta P_2 = -K(f_{meas} - f_{nom})$, where K [MW/Hz] is the network power frequency characteristic. For measured frequencies lower than the rated frequency ΔP_2 is positive.

The magnitude of the additional power ΔP_{out} required for inertia and frequency support is the resulting power derived from the inertia response plus the primary frequency response $\Delta P_{out} = \Delta P_1 + \Delta P_2$.

Specific implementation of the control algorithms may depend on the HVDC manufacturer.

Note that an interconnector can at times give frequency support to both the connected systems when the frequencies on the two sides deviate in opposite directions. Conventionally, any frequency support given on one side of the interconnector is based on the acceptance of an equal deviation in imbalance as the additional power which is delivered to the disturbed system.

Recent publications have also demonstrated that for a very short burst of power in an inertial response (only a few seconds required), use of the capacitive stored energy in the DC link may suffice and therefore largely make the inertial response independent of system conditions in the opposite end. This is achieved by allowing the SI controller to vary the DC link voltage by a modest percentage for a short period. A reduction in DC link voltage releases positive SI, acting to reduce $\partial f / \partial t$ following large infeed losses.

Other publications have shown that a SI contribution can be controlled to give a second beneficial effect, namely enhance the synchronising torque. For operation with extreme low & synchronous generation (SG), modelling in Ireland and GB indicate that when in real time for a synchronous area the SG contribution is approx. 25-35% stability problems can arise. A contributory solution allowing higher RES production (with less need for RES constraint actions) can be provided by delivering the synthetic inertia in a smarter manner, contributing synchronising torque. The specified requirement allows this additional functionality to be added, but as this is a recent development, a cautious approach is adopted in the NC HVDC. This requirement is both non-mandatory and non-exhaustive (key parameters to be defined at national / project level). Two further tests are included prior to adoption:

- The need to be demonstrated for a particular country (in context of the conditions in its synchronous area), by forward modelling, e.g. out to 2030.
- The confirmation that the practical manufacturing technology can deliver in accordance with the published research work.

Answer to FAQ 23:**Why do HVDC Systems have stronger frequency/voltage withstand capabilities than generation and demand?**

The capability of operating Power Generating Modules during deviations of the system frequency from its nominal value is of crucial importance from the perspective of system security. Significant deviations are likely to occur in case of a major disturbance to the system, which come along with splits of normally synchronously interconnected areas due to imbalances between generation and demand in the then separated parts of the system. A rise of frequency will occur in case of generation surplus, while lack of generation will result in a drop of frequency. The volume of a frequency deviation not only depends on the amount of imbalance, but also on other conditions / characteristics of the system, such as the generation profile i.e. system inertia, spinning reserve and the frequency response speed. In this sense, the current massive displacement of conventional generation by renewable generation increases frequency sensitivity of the system. In general, smaller systems will usually be exposed to higher frequency deviations than bigger ones. In the same way, peripheral systems which are part of very large systems, such as the interconnected Continental European area, but are weakly interconnected to the main system will be exposed to substantial frequency deviations in case of disturbances that cause the trip of the interconnections with the main interconnected system. Therefore, the capability of operation of HVDC Systems under such frequency conditions is a prerequisite to keep the system “running” in order to be able to continue electricity supply and to restore a secure system state quickly. Moreover HVDC systems as the back-bone of the transmission system with the capability of fast active and reactive power control are expected to be more robust against frequency deviations in order to improve system stability in case of emergency situations. The NC HVDC ensures that tripping of HVDC Systems does not occur before tripping of generation or demand connection is allowed (as prescribed in NC RfG and DCC). The same reasoning is applied for voltage deviations during severe system events.

Answer to FAQ 24:

What does fault-ride-through mean for an HVDC system and how should the requirement be interpreted?

It is crucial for the power system reliability that HVDC Systems remain in stable operation and connected to the network whenever contingencies and secured faults occur on the AC transmission network. The capability of HVDC Systems to remain connected during contingencies and faults in AC networks to which the HVDC System is connected is referred to as “fault ride-through” capability (FRT). Its need in case of embedded generation has been widely demonstrated in research papers and TSO case studies. See also the development of the NC RfG and the ongoing work of CENELEC on embedded generation specifications in this respect.

FRT requirements are based on a voltage-against-time profile at the Connection Point, which reflects the worst voltage variation during a fault and after its clearance (retained voltage during a fault and post-fault voltage recovery) which is to be withstood. HVDC Systems have to stay connected to the grid for voltages above those worst-case conditions, continue stable operation after clearing of faults on the network and continue stable operation in order to assist in system stability.

A number of motivations for this FRT capability are:

- Power systems are designed to withstand a sudden loss of system components i.e. transformers, lines, generation or combinations thereof known as (n-1), (n-2) etc. security, after secured faults. If HVDC Systems connected to healthy circuits do not remain connected and stable during and after a fault, system security may be jeopardized due to a sudden loss of transmission capacity and resulting power imbalance. This possibly entails loss in the system greater than the one the system is designed to withstand.
- If FRT capability is not applied in the HVDC System design their inherent control capability during critical situations is not reliable and the full generation capacity from HVDC connected PPMs can be lost.
- It must be ensured that as a result of a voltage drop and during the voltage recovery phase, the auxiliary and control supplies of the HVDC System do not trip.

In order to ensure a proportional and non-discriminatory application of the FRT requirements of HVDC Systems throughout Europe, the NC HVDC gives a clear frame by which each TSO is obliged to define the pre-fault and post-fault conditions for the fault ride through capability in terms of:

- conditions for the calculation of the pre-fault minimum short circuit capacity at the Connection Point;
- conditions for pre-fault Active and Reactive Power operating point at the Connection Point and Voltage at the Connection Point;
- and conditions for the calculation of the post-fault minimum short circuit capacity at the Connection Point.

The parameter U_{ret} is the voltage during fault duration, and is to be specified by the Relevant TSO to reflect local network conditions. If the fault is of shorter duration than as specified by T_{clear} , the HVDC system is obliged to stay connected. In other words if the fault conditions fall below the specified voltage-against-

time curve, the HVDC system's protection is allowed to trip it by opening its AC breaker at the connection point.

As specified in Figure 6 and Table 7 in the NC HVDC, the blocking of the converter can be allowed subject to TSO decision, which means that active and reactive power contribution is blocked although the HVDC system is still connected to the transmission network. Then, within some determined time after the clearance of the fault (which must be as short as technically feasible) and network voltage restoration, the converter must recover a stable operation point according to the prescribed post-fault network conditions.

The specifications of Figure 6 and Table 7 only apply to symmetrical 3-phase AC faults. Asymmetrical fault conditions and fault ride through capability are to be specified by the Relevant TSO on a case by case basis. DC faults are not specified under this NC. Post-fault active power recovery is separately specified in Article 24.

Answer to FAQ 25:

Which reactive power requirements does the NC HVDC set on HVDC connections?

The NC HVDC defines a set of reactive power requirements that the HVDC converter shall fulfil at the connection point(s). They are written in such a manner that LCC technology is not discriminated against when the TSO(s) consider the specifications of a project. The choice of LCC or VSC technology can be made depending on the network conditions, either actual or planned, costs or other parameters as applicable. Where the requirement cannot be inherently met from LCC converters for example, additional reactive compensation could be installed as well to meet the HVDC System's requirements at the connection point. The requirement is also to be seen in context of reactive power delivery by generation, demand response and other system solutions.

Article 18 ("*Reactive power capability*") defines the rating of the HVDC System in terms of active and reactive power capability in a range of voltage levels. It specifies a capability envelope U-Q/Pmax (illustrated as dotted in Figure 5 of the NC) with a range of consumption and production reactive power supplied at the connection point in the whole range of active power supply of the HVDC System. The relevant TSOs specify, at Maximum HVDC Active Power Transmission Capacity and in the context of varying Voltage, the maximum positive and negative reactive power that could be delivered at the connection point by defining the appropriate range in Table 7 with respect to the inner envelope (which in turn needs to remain within the fixed outer envelope). As the requirement is written, a U-Q/Pmax profile can be specified at national level so as to comply with

- VSC capabilities: PQ-diagram, figure 1 - a 4-quadrant curve within which the VSC HVDC substations must operate; or
- LCC capabilities: PQ-diagram, figure 2 - a band around the P-axis within which the LCC HVDC substation must operate, delta Q is the maximum allowed AC filter size.

The requirement is written in a technology independent manner. If a PQ-diagram like figure 1 is specified it can inherently be obtained by HVDC Converter Units or by LCC HVDC converter Units with additional compensation equipment installed in the HVDC Substation.

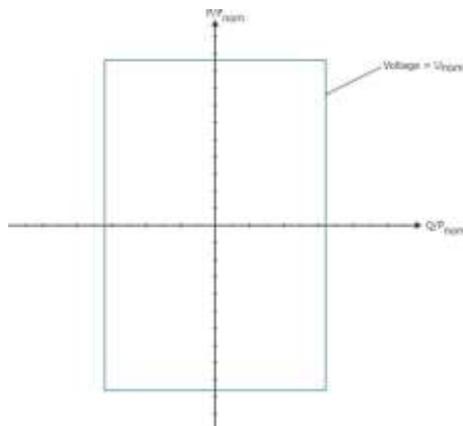


Figure 1: PQ-diagram for a VSC HVDC Converter Unit

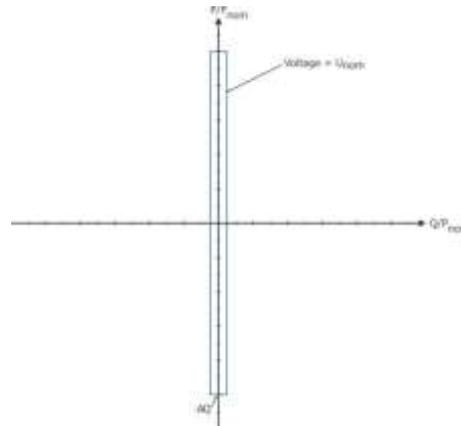


Figure 2: PQ-diagram for a LCC HVDC converter Unit. Delta Q is the maximum AC filter size

Article 19 (“*Reactive power exchanged with the Network*”) concerns the reactive power that the HVDC converter could exchange with the network within the operation at different active power levels, and the reactive power variation ΔQ caused by the HVDC system operation according to the range given by the Relevant TSO. It concerns the design of the filters and additional equipment so as to ensure that the possible reactive power consumption of an HVDC connection does not jeopardize the power system. The second part of the article concerns the design of the bank of capacitors so as not to have undesired voltage transient steps when switching each bank.

Article 20 (“*Reactive power control mode*”) concerns the reactive power control modes aiming to operate the HVDC system as part of the wider power system: Voltage Control mode (HVDC station reactive power output aiming to follow a voltage set-point), Reactive-Power Control mode (HVDC station reactive power output aiming to follow a reactive power set-point) and Power-Factor Control mode (HVDC station reactive power output aiming to follow a Power Factor target). At least two out of these control modes shall be implemented in the HVDC System.

Answer to FAQ 26:**How can the interaction between HVDC converters and other elements of the grid be addressed?**

Where power electronic equipment like HVDC Converter Stations, PPMs, other equipment are connected to a network within close electrical proximity of each other, there is a risk of interaction between them, especially if the network is “weak” with a low short circuit power.

In order to address the interaction, different simulation tools and models of the equipment have to be used depending on the frequency ranges of interest. The phenomena to be investigated cover a broad spectrum such as steady-state phenomena, electromechanical oscillations, small-signal effects, large-signal effects, oscillations, sub-synchronous resonances, electromagnetic transients, high frequencies phenomena and harmonic resonances.

Voltage and power stability of AC networks with HVDC systems should be investigated by evaluation of the capacity of the AC network to exchange the power with the HVDC system. For a single HVDC in-feed the effective short circuit ration, the voltage stability factor and the maximum power curve are general accepted indicators that can be used.

Small signal stability analysis may be used to investigate electromechanical effects. Coordination of controls may be investigated by the use of stability programs and eigenvalue analysis supplemented by transient stability programs and electromagnetic transient programs.

Large signal effect and the effects of nonlinear controls should be investigated in digital real time simulators or in electromagnetic transient programs.

The study of this interaction requires adequate input of data and models. For this purpose the requirement to deliver this input to reasonable extent could also cover existing users (generation, demand or HVDC systems).

Answer to FAQ 27:

Why is power quality included the NC HVDC and why are there no specific standards referred to?

The HVDC System and any associated equipment thereof shall not introduce voltage distortion or fluctuation onto the supply system to which it is connected, beyond the value(s) allowed by the relevant TSO. TSOs may have different harmonic emission standards. It is the TSO's responsibility to ensure that the harmonic level is not infringed when power electronic devices are connected with consequences on the stability of users connected to system.

The NC HVDC sets a requirement on power quality, as well as the DCC and differently to NC RfG because HVDC equipment constitutes a natural source of harmonics and waveform distortion considering the conversion AC/DC and DC/AC. For this reason ENTSO-E argues the application of power quality standards is a cross-border subject in case of the NC HVDC. In addition to the effect that power quality may have within the transmission network, it is a phenomenon that may also affect the distribution network and their users. Feedback from the NC HVDC User Group supported the proposal to include power quality requirements on HVDC Systems in the scope of the code.

The NC HVDC does not set the specific standard for power quality because it is a very local network dependant issue. Also where today some areas may not have power quality related problems, depending on how the demand, generation and topology changes in future, the probability may very well increase. The impact of and the mitigation countermeasures against power quality problems, can be solved through local standards to prevent the cross-border effects on the voltage waveform distortions.

The term power quality is related to the degree of the distortion of the ideal sinusoidal waveform. This waveform distortion can be mathematically analysed to show that it is equivalent to superimposing additional frequency components onto a pure sine wave. These frequencies are harmonics (integer multiples) of the fundamental power system frequency (50Hz) which starts with the fundamental frequency, and can sometimes propagate outwards from nonlinear loads, causing problems elsewhere on the power system. One of the major effects of power system harmonics is that it can increase currents in the network. This is particularly the case for the third harmonic (causing resonance), which causes a sharp increase in the zero sequence current, and therefore increases the current in the neutral conductor or earthings. This effect can require special consideration in the design of HVDC power systems connecting non-linear equipment and components.

In addition to the increased line current, different electrical equipment can suffer the effects from harmonics on the power system connected several kilometres away from the source. For example, electric motors can experience hysteresis loss caused by eddy currents set up in the iron core of the motor. These are proportional to the frequency of the current. Since the harmonics are at higher frequencies, they produce more core loss in a motor than the fundamental frequency would. This results in increased heating of the motor core, which (if excessive) can shorten the life of the motor. The 5th harmonic may cause a counter electromotive force in large grid connected motors which acts in the opposite direction of rotation.

Answer to FAQ 28:

Why is the data model exchange essential?

Data model exchange is essential in general for all the equipment connected to the transmission network, but is even more important in the case of HVDC systems and DC-connected PPMs because of the significant impact that this equipment may have on the network:

- The amount of transmitted power is likely to be higher than in the case of individual devices connected to the transmission network.
- HVDC systems have not the same behaviour patterns as the traditional HVAC assets, so it is essential to have adequate models so as to predict the interaction between the HVDC and HVAC systems. TSO tasks and responsibilities such as planning and operation, continuous evaluation of the power system, scheduling, contingency analysis, transient stability studies, short circuit calculation, electromagnetic transient coordination studies, protection system coordination, etc... would not be possible if the TSO cannot rely on accurate modelling of these network assets.
- In such cases where the owner of the DC-connected PPM and the owner of the HVDC System are different owners, maybe different from the TSO, and maybe involving different manufacturers, it is essential that the TSO has the right to specify the format and conditions of the simulation model in order to guarantee that they are coherent and give the relevant input to conduct these analyses.

The Relevant TSO shall also have the right to specify the format and software platform on which the model is programmed as well as the way to guarantee the availability of the model along the lifetime of the equipment as new software versions are developed continuously. On the other hand, the Relevant TSO has an obligation to confirm and guarantee the confidential nature of the delivered simulation models.

In order to check that the simulation model is accurate, it shall be verified against the real behaviour diagrams of the device, at least by means of the tests carried out within the Compliance chapter of the Network Code. If the simulation results are verified, then the model could be used to evaluate other technical capabilities of the HVDC or DC-connected PPM as stated within the Compliance Simulation requirements of this Network Code.

Data model exchange is essential for every new HVDC connection study. It is also essential that the TSO provides the manufacturer with an accurate and relevant network data so that the HVDC System manufacturer or owner can perform the needed studies, obtain the most reliable results and design the installation according to the given network conditions.

Answer to FAQ 29:**Why does the NC HVDC allow for different requirements compared to those in NC RfG?**

AC collection networks are commonly small synchronous systems, but occasionally with very high imbalance of demand and generation.

In many instances given the expectation that these AC collection networks can be expected to see an increase in AC connections (circuits and grid users) but also in DC connections (circuits which may also be interconnectors). The added AC connections based on previous analysis may also connect these AC collection networks to other AC collection networks or to the larger Synchronous Areas networks. The latter would make the AC collection network an inherent part of a main Synchronous Area.

Therefore, the functional capabilities placed on AC collection networks in many instances are consistent and compatible with those of any other AC network, with the need to manage voltage, frequency, cope with disturbances and facilitate maintenance. Therefore many requirements are identical in nature, and are often future proofed to what can be reasonably be expected to happen over the life of the plant and equipment of the AC collection network and the users connected to them. This includes potential development or modernization of these networks.

However due primarily to the larger imbalance of demand and generation in the AC collection networks and the opposing forces they normally apply to each other to dampen changes on the network, the need to manage frequency and voltage needs to be carefully addressed. The small size of these networks also means that the inherent system strength of the network is lower as well its dampening effects.

Therefore some NC RfG requirements need to be modified or added to account for these phenomena. It should be noted that the NC RfG provides the minimum requirements with the possibility for example in frequency requirements for wider ranges to be required. These are included in part to account for the same effects of system segregation of a larger Synchronous Area which as a result may become very similar in behaviour to an AC collection network.

Answer to FAQ 30:

Which design requirements apply to the AC collection Network of a DC-Connected Power Park Module?

The design requirements that apply to the offshore AC collection network are broadly consistent with those that are AC connected. This includes the requirements for both the DC-Connected Power Park Module[s] and HVDC Converter Unit[s].

Several offshore grid studies¹² where the majority of the DC-Connected Power Park Modules are likely to exist show a natural progression from a radial to an increasingly meshed grid, with connection hubs for multiple users. These networks often act to connect generation and interconnection between AC networks, as well as being symbiotic with the AC networks to which they connect.

As such these networks become part of the main network and their reliability, flexibility and operability is required to be at an equivalent level to any other AC node on the network. It is therefore necessary to require the same functionality from these HVDC systems and DC-connected Power Park Modules.

Onshore DC-Connected Power Park Modules are only likely to be connected at DC given the costs involved if the connection point into the Network is very remote from their location and/or technical difficulties drive a DC decoupled connection (i.e. fault levels, or stability reasons). Therefore any other development in the area is also likely to experience the same restrictions and their connection into the HVDC System is highly likely. Therefore to ensure the non-discriminatory treatment of the connection of any new users to the HVDC System the reliability and quality of supply from the HVDC System should be comparable to the AC Network to which it is connected.

However the NC HVDC also addresses situations where the DC-Connected Power Park Module is connected to a dedicated HVDC System from which:

1. no other user conceivably is going to be connected to;
2. which is unlikely to become part of the meshed network, and;
3. which is unlikely to become part of an interconnection to another AC network or Synchronous Area;

The requirements to provide reactive power may be omitted or reduced (at the owner accepted reduced reliability to the DC-Connected Power Park Module), subject to an agreement with the Owner of the HVDC converter Unit(s). This requirement may only be omitted or reduced where the Relevant TSO is able to demonstrate that:

1. HVDC system is not going to be developed before Reactive Power capability can be retrofitted to the DC-Connected Power Park Module;
2. contractual arrangements are in place to ensure that the Reactive Power capability will be fitted when required for the wider Network.

This approach ensures a balance between non-discrimination of other users on the Network to the joint contribution of all users to Reactive Power provision and enforcing unnecessary capabilities that are not justified by the Relevant TSO on a user.

Other requirements may not be practically and/or cost effectively be retrofitted for example voltage or frequency ranges and must be incorporated in the initial design of the DC-Connected Power Park Module or HVDC System.

¹² http://www.benelux.int/NSCOGI/NSCOGI_WG1_OffshoreGridReport.pdf
<http://www.eirgrid.com/media/EirGrid%20Offshore%20Grid%20Study.pdf>
<http://www.greenpeace.org/sweden/Global/sweden/karnkraft/dokument/2014/0214%20gpi%20E%5BR%5D%20grid%20report%2007%20mr.pdf>

Answer to FAQ 31:**What happens in case the HVDC System is owned and/or operated by another party other than the onshore TSO and the offshore wind farm(s)?**

In this situation the requirements of the NC HVDC will be complied with by the Owner of the HVDC System.

Similarly the requirements for the DC-Connected Power Park Module will be complied with by the Owner of the DC-Connected Power Park Module.

If there is any requirement which requires the contribution of both parties to be met and demonstrated, then the responsibility to demonstrate this requirement will be with the HVDC System Owner as the connecting party to the Relevant TSO for the AC Network which the HVDC System is connecting to.