European Network of
Transmission System Operators
for Electricity

NC HVDC

CALL FOR STAKEHOLDER INPUT

JOINTLY PUBLISHED WITH THE “NC HVDC – PRELIMINARY SCOPE”

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1 INTRODUCTION

1.1 PURPOSE

The Network Code on HVDC connections (NC HVDC) will cover a highly technical, relatively new and increasingly important subject. ENTSO-E wishes to understand the views of a broad range of stakeholders at each stage of developing the network code. As a first step in this process, this document provides interested parties with information on the context for and scope of the HVDC network code and calls for evidence to inform the way we develop the code. As such this document complements the "NC HVDC - Preliminary Scope" which interested parties are advised to read together with this document.

This Call for Stakeholder Input is addressed to all parties with an interest in High Voltage Direct Current (HVDC) technology and DC connected Power Park Modules. It provides information on the intended scope of the forthcoming NC HVDC with an explanation of its context. Further information on the general development process of this code can be found on the ENTSO-E website[1].

The aim is to define and discuss the challenges related to HVDC connections, DC connected Power Park Modules and the principles of associated possible requirements. A range of questions are stated and stakeholders are encouraged to feed back their views thereby supporting the development from the scoping document through to the draft Network Code. In order to encourage a structured exchange ENTSO-E has set out a series of HVDC related topics and questions in this document, often directly related to the "NC HVDC – Preliminary Scope".

ENTSO-E welcomes all possible input - in the form of motivated views and/or specific data – that stakeholders may provide, via reply to consultations@entsoe.eu by 7 June 2013. All feedback received by this date will be assessed by ENTSO-E and made publically available on the ENTSO-E website.

1.2 BACKGROUND

1.2.1 EUROPEAN NETWORK CODE DEVELOPMENT

The upcoming NC HVDC covers a specific area in a wider portfolio of network codes on electricity. The NC HVDC is the ninth code developed by ENTSO-E[2]. Key messages on the need for European wide network codes and an overview of how these interact between each other, are linked with other European energy roadmaps, and benefit European energy consumers, are given in the ENTSO-E paper "*European Network Code Development: The importance of network codes in delivering a secure, competitive and low carbon European electricity market*" [1]. This section sketches some of the messages most relevant for the NC HVDC.

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[1] https://www.entsoe.eu/major-projects/network-code-development/high-voltage-direct-current/

[2] https://www.entsoe.eu/major-projects/network-code-development/

What are the network codes?

Network Codes are sets of rules which apply to one or more part of the electricity sector. The need for them was identified during the course of developing the Third legislative package and Regulation (EC) 714/2009 sets out the areas in which network codes will be developed and a process for developing them.

Europe's energy policy objectives

Europe's trio of energy policy goals – ensuring security of supply, promoting the decarbonisation of the energy sector and creating competitive, liquid markets which benefit consumers – is well known.

More interconnected networks and markets: The electricity system is becoming increasingly interconnected and the electricity market is becoming much more pan-European. This provides opportunities for generators to sell into different markets, based on price signals, and gives consumers a greater choice over who they buy energy from.

Increases in cross-border flows: A natural consequence of bigger markets and the siting of fluctuating generation further away from the consumption centres are much greater levels of cross-border and long-distance power flows. These flows require careful management by TSOs and require greater coordination between grid operators in planning infrastructure developments, in designing markets and in operating the system – given the significant influence such flows can have on the operation of the system in real time.

A changing role for network users: The changes in generation portfolio and operational challenges discussed above are creating a change in the role of network users. It is becoming increasingly important that all types of users (i.e. generation, demand, distribution networks, and interconnections) play an active role in providing the capabilities and services which are needed to maintain the security of the pan European transmission system.

Creating stronger, more robust and smarter networks: Without a robust transmission system, none of the trio of energy policy objectives will be achieved. Europe's networks will need to change significantly in the coming years, with much greater levels of interconnection and the probable extension of networks offshore, using a greater proportion of HVDC technology. They will also need to adapt to much more active distribution networks and to greater customer participation.

Ensuring closer cooperation between TSOs: TSOs are working more and more closely together (building on a tradition of doing so for over 60 years) to make better use of existing assets and build on the very high levels of security of supply enjoyed to date. More advanced and coordinated operational planning procedures are being implemented by many TSOs through multi TSO coordination initiatives (and through regional market coupling initiatives). TSOs are also developing systems for coordinating balancing and remedial actions where system issues exist and enhancing real time data exchange (e.g. via the ENTSO-E Awareness System).

The network codes under development: Investment decisions taken now will affect the power system for the next decades. The European energy system of 2020 is being built today and the foundations of the European energy system of 2050 are being conceived. As such, there is a need to make sure that all users are aware of the capabilities which their facilities will be required to provide – recognising both the need for all parties to make a contribution to security of supply and the high cost of imposing requirements retrospectively. The grid connection codes therefore seek to set proportionate connection requirements for all parties connecting to transmission networks (including generators, demand customers and HVDC connections). A stable set of connection rules also provides a framework within which operational and market rules can be developed.

The system operation network codes will provide a solid basis for coordinated and secure real time system operation across Europe while market related network codes aim at creating a relatively simple set of market rules which can promote effective competition, minimise risk for all parties (particularly renewable generators who will benefit from markets close to real time) and give incentives for market players to act in a way which is supportive to the efficient operation of the system and minimise costs. All of them need to be developed in light of the connection requirements established in connection related network codes:

HVDC	Sets requirements for HVDC connections and DC connected generation.
Load Frequency Control & Reserves	Provides for the coordination and technical specification of load frequency control processes and specifies the levels of reserves (back-up) which TSOs need to hold and specifies where they need to be held.
Balancing	Sets rules to define the roles and responsibilities of TSOs and market parties to procure and exchange balancing products to balance the system from day ahead to real time in the most efficient way. It also includes financial principles for the payment of these services.
Requirements for Generators	Sets requirements which new generators connecting to the network (both distribution and transmission) – and existing generators (in very limited cases) - will need to meet, as well as responsibilities on TSOs and Distribution Network Operators.
Operational Security	Sets common rules for ensuring the operational security of the pan European power system.

The European electricity system is going through a period of unprecedented change. The generation mix is changing fundamentally, the potential for the demand side to become much more involved is vast and the market is becoming genuinely pan European. For Europe to achieve its trio of objectives of ensuring and enhancing security of supply; creating competitive markets; and facilitating the transition to a low carbon economy there will need to be a significant change in the role of network users, of Distribution System Operators and of Transmission System Operators.

However, network codes will impact on all parties active in the energy sector and will lead to considerable change in existing practices. ENTSO-E recognises the importance of engaging with a wide range of stakeholders to ensure that these impacts are understood and that as broad a range of views as possible are reflected in the network code development and is seeking to structure processes to allow this to occur.

Through a transparent approach, collaborative method of working and shared objectives we are confident that the network codes can deliver real benefits in realising each of Europe's energy goals.

1.2.2 NC HVDC STARTING POINT

This Network Code is referred to in full as the "Network Code on HVDC Connections and DC Connected Power Park Modules" (NC HVDC). The NC HVDC will be developed based on ACER's Framework Guidelines on Electricity Grid

Connections (FG) [2]. It forms part of the ENTSO-E work programme 2012 [3] through Q1/2014, subject to a mandate letter from the EC [4].

The preliminary scope of this network code to be developed is set out in [5]. The scope document sets out the initial thoughts by outlining each of the individual requirements planned to be included in the NC HVDC a draft of which is expected to be formally consulted on by the end of 2013. Obtaining stakeholders opinions on this list of requirements is the main purpose of this Call for Stakeholder Input document. This planned NC HVDC will be the third connection code in line with the FG [2]. The two connection codes preceding the NC HVDC are the “Requirements for Grid Connection Applicable to all Generators” (RfG) and “Network Code on Demand Connection” (DCC). A fourth network code on Connection Procedures, also founded in the same FG [2], may follow at a later date still to be defined in the work programme.

The existing cover of HVDC requirements in national grid codes is varied. A few countries already have codes in force or are in process of developing codes. This is not the case in the majority of countries. Many countries have at present no HVDC applications and therefore have had no reason for such coverage. The application of HVDC to compliment the hitherto dominant electricity transmission technology of High Voltage Alternating Current is expected to expand greatly in the years and decades ahead. The reasons for the expected rapid expansion in HVDC applications include the larger power transfers over longer distances and the connection to shore of very large offshore RES installations. This strengthens the view of ENTSO-E and the wider industry to pursue European-wide requirements which may be further specified at national level or based on the needs in specific projects.

1.3 CHALLENGES AHEAD RELEVANT TO HVDC REQUIREMENTS

1.3.1 CONTEXT

HVDC technology will increasingly be used in the coming years to develop interconnections between different TSOs or 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. To that end, extensive active power controllability is needed. Automatic control modes are especially needed for exchanging balancing energy resulting from the activation of cross-border frequency containment and restoration reserve. The NC HVDC will define the minimum standards and requirements needed for achieving these goals related to market integration.

The conventional task for HVDC is bulk transfer of large volumes of energy over long distances. Additionally, HVDC has been used like a firewall in its back-to-back connection of large AC transmission systems. These tasks will remain a major focus supplemented by the task of HVDC in the world of offshore power, so far predominantly associated with wind. As the proportion of electrical power transmitted by HVDC to the vicinity of major load centres increases, the characteristics of HVDC including its responses to fast system changes under disturbed conditions increases in importance in two ways. In the first place this relates to its own robustness to disturbances, the ability to continue to deliver the power. This is particularly important considering the size of most of the HVDC schemes. Secondly, as HVDC displaces direct AC connection of generation, the ability of the HVDC system to “pass on” quickly and in a controlled manner the dynamic support from another system or from generation becomes increasingly important to deliver stable operation and hence security of supply.

Security of the system cannot be ensured without considering the technical capabilities of all users. Historically large synchronous generation facilities have formed the backbone of providing technical capabilities. The energy system is changing rapidly especially with the massive integration of RES (wind generators, PV installations) in the European electricity network. At a European level this is illustrated in the Ten Year Network Development Plan (TYNDP 2012) issued by

ENTSO-E [6]. In relation to the longer time horizon, on 8 March 2011 the European Commission issued "A Roadmap for moving to a competitive low carbon economy in 2050" [7].

The HVDC technology itself is developing rapidly. In particular the branch of it called Voltage Sourced Converters (VSC). As illustrated at a December 2012 International HVDC Conference (IET's ACDC2012) [8] with the statement in a workshop on VSC that since the first VSC installation there had been a fundamental change of configuration for every second VSC project. In contrast with the emerging HVDC VSC technology and the associated HVDC Grids, the alternative HVDC technology using Line Commutated Converters (LCC) is a mature technology, applied with large capacity in relative low numbers.

It is important that the development of the NC HVDC supports the development of this important technology (VSC). In this context CIGRE issued in December 2012 a WG report (WG B4-52) [9] concluding that DC Grids are feasible. Another CIGRE group (WG B4-56) is working on connection requirements for meshed DC Grids whose report is expected end of 2013 or early 2014. This group is further considering to recommend adoption of standard DC voltages, similar to how 400kV is a standard voltage in Europe for AC. In a DC Grid it will eventually become possible to have a Connection Point directly at HVDC (connection to a DC busbar).

Operating conditions with the highest RES injection (typically in windy / sunny conditions with moderate demand) present major system challenges, particularly where the high RES penetration extends to a total control area or even more if covering a total synchronous area. The main answer to this is to increase the controllability and the flexibility of all power system elements to deliver a power system which can react and cope better with the volatility of RES [10]. The three main new or expanded technical challenges ahead related to stable operation of the power systems are:

- Frequency management with reduced inertia in synchronous area or even in each control area;
- Voltage management in areas remote from main centres of RES installations during times of high RES production when conventional generation, which has traditionally provided this service, being displaced; and
- Fault level (system strength) management in context of rapid changes from high system strength during low RES production to extreme low system strength during high RES production, when synchronous generation is displaced (not operating).

Questions:

1.1. Do you have comments on the role of HVDC links as outlined in the document referred to in section 1.2, entitled „The Importance of network codes in delivering a secure, competitive and low carbon European electricity market" which sets out the non-technical explanation of all the network codes & their interactions, or on section 1.3?

In particular,

- Do you believe that operating with higher RES penetrations and consequently higher shares of non-synchronous generation will create additional challenges of operation? If yes, do you foresee any additional operational challenges you believe beyond those outlined above? If not, please provide your reasoning. See also section 3.5 focused on "weak systems".
- What is your view on the expectation that HVDC will have to contribute to services previously provided by synchronous generators including the 3 items defined in section 1.3.1?

1.4 GUIDING PRINCIPLES

1.4.1 WHY DC?

Efficient and reliable power transmission grids are one prerequisite to support EU energy targets and to achieve the political goals of a low-carbon energy system. The way the power system has to be designed and operated must be consistent with these paramount targets and poses new challenges for TSOs. The future power system must:

- Facilitate the integration of RES, partially located far away from load centres (e.g. offshore wind parks)
- Manage huge cross-border power flows caused by the pan-European electrical energy trade.
- Achieve both targets with minimal impact on environment and at least costs.

An efficient technology choice to achieve these targets is based on economics and technical performance. In general the choice is between AC and DC transmission. Thereby a comparison between these technologies leads to following areas of application for DC transmission [2]:

- Distance: Long–distance, bulk power transmission is often more economic by HVDC
- Environmental constraints: The corridor needed to transmit a certain amount of power is considerably less for HVDC compared to AC.
- Overhead line versus cable: The charging current of AC cables requires well distributed reactive power compensation means. Therefore, for long cables (e.g. subsea cables) AC is usually not economic compared to a DC solution.
- Asynchronous interconnection: AC systems operating at different frequencies or using independent frequency control systems can only be coupled by HVDC.
- Control and stabilization of power flows: HVDC systems in an integrated power system may enhance the overall system performance and system security.

In the view of the above mentioned challenges and requirements for a future power system, DC transmission is expected to become increasingly important.

1.4.2 HVDC AND ITS ROLE FOR "SMARTER" TRANSMISSION

Modern HVDC transmission offers advanced performance, as they can control active and reactive power independently. The first HVDC connected wind farms in the North Sea demonstrate that latest HVDC transmission is also able to control the frequency of islanded AC networks and to supply weak networks. If well planned and designed, these features offer remarkable flexibility:

- Future fast changes in power flows in situations resulting from the change in generation pattern could be handled more securely by the operator. Additional reactive power (particularly conveniently available inherently from VSC technology) would stabilize the voltage profile.
- The controllable active power flow can be used to minimize losses and to overcome bottlenecks by distributing the power flow in an optimal way, making the fullest use of all circuits.
- In emergency situations, e.g. partial black outs or islanding of networks, the HVDC scheme could increase stability margins or reenergize or stabilize an island.

At present HVDC systems provide predominantly point to point power transfers. It is envisaged that DC grids (meshed DC systems) will gradually emerge for some applications, initially as a new emerging technology and eventually as a proven technology. One important step needed in this context for the TSO to further develop future HVDC systems is the interoperability of different vendors and the ability to integrate individual projects into the existing system. In this respect, the NC HVDC is expected in the future to play an important role [11]. Future revisions of the NC HVDC are expected to bring these aspects forward as the DC grid technology moves into implementation.

2 GENERAL APPROACH TO NC HVDC

2.1 STRUCTURE

The guiding principle of the NC HVDC is to develop requirements for high-voltage DC links and the DC grid connection of Power Park Modules, from the perspective of maintaining, preserving and restoring the security of the interconnected electricity transmission and distribution systems with a high level of reliability and quality in order to facilitate the functioning of the EU-internal electricity market now and in the future.

The main principles for drafting this code are provided in ACER's framework guidelines and are given in the "NC HVDC Preliminary Scope" [5]. The principles of the scope of the NC HVDC are the main focus of this chapter, while the content of the scope is the focus of Chapter 3.

Existing national grid codes are varied in terms of their coverage of HVDC requirements. Many countries have no code for HVDC (e.g. due to absence of applications) while other countries have or are in the process of establishing such national code requirements either within the national code or in appendices documents. It is therefore challenging but crucial to distinguish at a European level what is an existing and what is a new requirement.

2.2 APPLICATIONS OF HVDC AND DC CONNECTED POWER PARK MODULES

According to ACER's FG, "*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*".

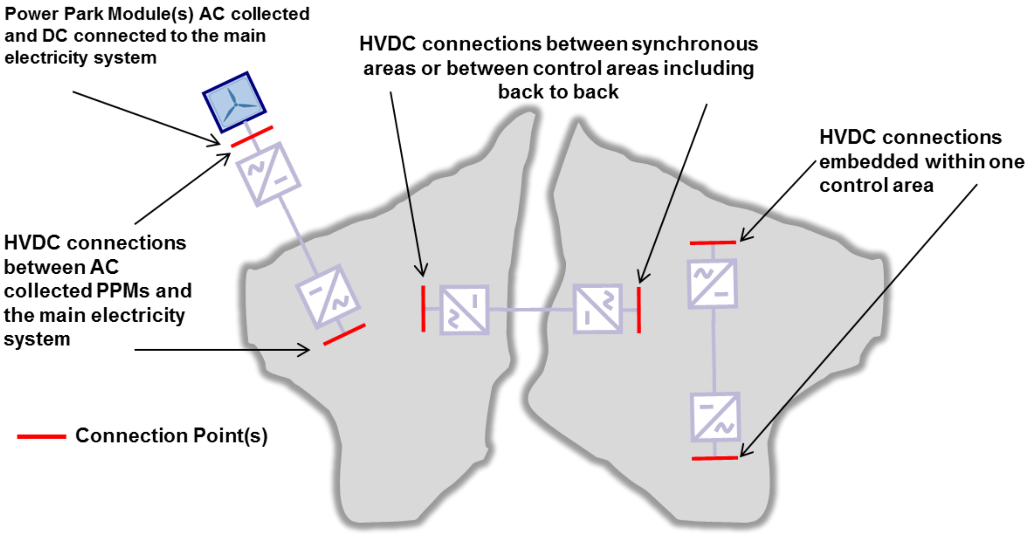
A major challenge of the HVDC code is consequently to answer to the central question "Who are the Significant Grid Users?" in order to define unambiguously the field of application of the code.

The FG gives a general definition of the Significant Grid Users. They define 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, ENTSO-E proposes that in the NC HVDC the following HVDC configurations are considered as Significant Grid Users:

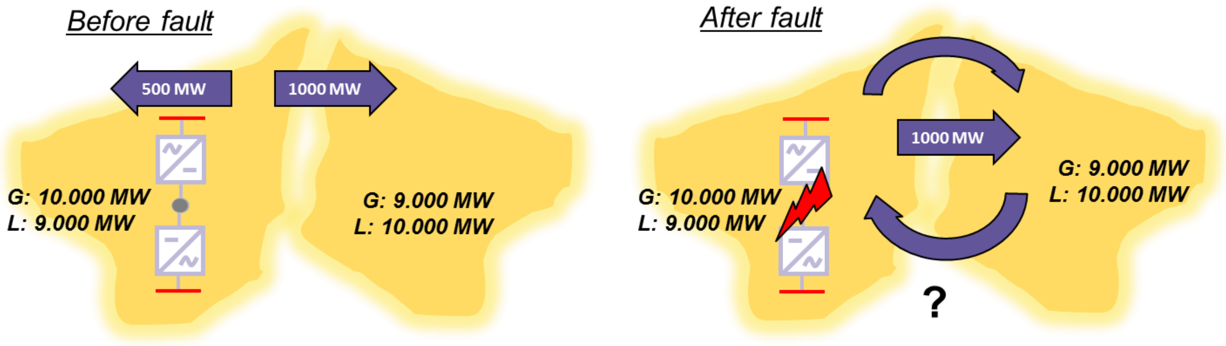
- HVDC connections between synchronous areas or between control areas, including back to back;
- HVDC connections to Power Park Modules;
- HVDC connections embedded within one control area and connected at transmission system voltage level. Connections at an AC voltage below transmission system voltage, as specified at national level, can be covered as Significant Grid Users if a cross-border impact is demonstrated by the relevant TSO and approved by the NRA;
- All Power Park Modules that are AC collected and DC connected to the main electricity system at any AC transmission voltage.

The following picture illustrates the above mentioned different ways HVDC is envisaged to be used as well as the location of the connection points of the HVDC and the AC system. These connection points form the physical interface between the systems thus the performance requirements are usually defined related to this connection points.



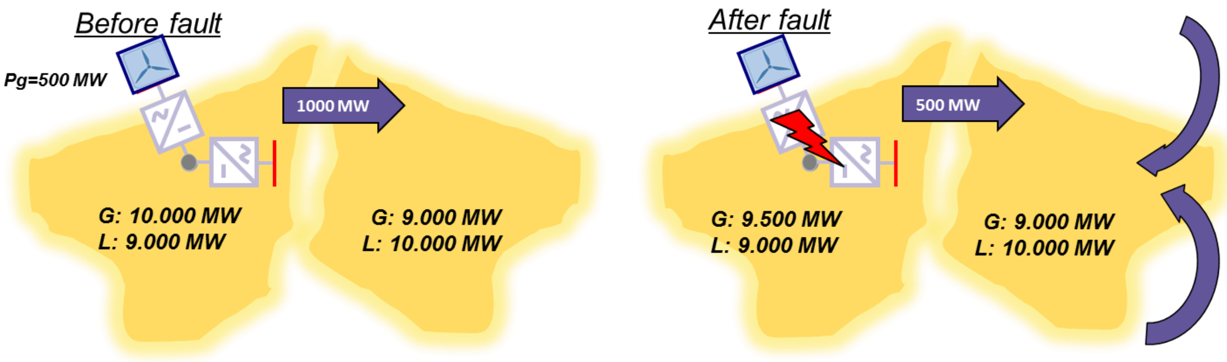
Example 1: HVDC transmission system across control areas

An HVDC transmission system with AC/DC terminals across multiple synchronous areas or control areas, has a cross border impact due to the fact that a fault on the HVDC system causes the change of flows between control areas. Therefore these schemes are deemed to be Significant Grid Users.



Example 2: Embedded HVDC transmission system within single control area

Large HVDC connections embedded within one control area can also have significant cross-border impact. For instance, the loss of an internal HVDC link can modify the distribution of cross-border flows and consequently have impact on the power flow in neighbouring control areas. All HVDC connections embedded in AC transmission systems have such a potential impact on cross-border flows.



Example 3: HVDC generation collection system within one control area

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 a fault on the HVDC system causes the change of flows between control areas. However it is important to recall that cross-border issues are not only based on active power exchange in tie lines but are also related to the technical capabilities of all the users playing a critical part in system security. Therefore the requirements will improve robustness to face disturbances, to help to prevent any large disturbance and to facilitate restoration of the system after a collapse. 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.

Therefore, 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 technical standardisation shall be regarded as “cross-border network issues and market integration issues”. The option to apply the NC HVDC to most, if not all, HVDC links has the following advantages:

- The scenario that a TSO owned HVDC link could be transferred to another party during its lifetime is realistic. The application of the code enables to guarantee that these links comply with appropriate minimum standards and requirements.
- Application of the NC HVDC to TSO assets ensures non-discrimination across Europe compared to third party projects.
- In case the HVDC link to AC collected and DC connected Power Park Modules (e.g. offshore wind farms connected by HVDC) is owned by the TSO, application with the NC HVDC ensures a non-discriminatory approach towards these generating units in which the HVDC link is owned either by the Power Generating Facility Owner or by a third party.

HVDC configurations resulting from emerging technologies without expected operational development in the next ten years such as connection of meshed DC network or DC collection of offshore Power Park Modules are proposed to be considered out of the scope of the NC HVDC at present, with possible inclusion in future amendments once the technology matures.

In the previous connection codes (Requirement for Generators (RfG), Demand Connection Code (DCC)), the network codes provide an extensive but transparent and non-discriminatory process before they could be considered applicable to existing users. A Cost-Benefit Analysis showing the socio-economic benefits and cost of the proposal has to be carried out and the report will be subject to a public consultation. Finally the TSO sends the proposal on the applicability of the requirement, including the outcome of the consultation, to the relevant national regulatory authority for approval. ENTSO-E considers that this approach to the NC HVDC is relevant.

Question:

2.2.1. What is your view on the broad extent of the scope covering HVDC connections and DC connected Power Park Modules applications?

In particular, what is your view on

- the identified Significant Grid Users (with respect to the NC HVDC requirements)?
- the defined Connection Points?

2.2.2. Do you know of projects under development concerning applications not covered in the scope, such as meshed DC networks or DC collection networks for Power Park Modules ? Do you agree with the proposal of excluding these configurations from the scope of the current version of the NC HVDC until these technologies have emerged?

2.2.3. Do you agree that the NC HVDC could only apply retrospectively to existing facilities in line with the approach developed in previous RfG and DCC codes?

2.3 CLASSIFICATION OF THE REQUIREMENTS

For each requirement, the NC HVDC will provide a classification into exhaustive or non–exhaustive, and mandatory or non-mandatory requirements:

- **Non-mandatory** requirements leave a choice at national/regional level about including the specific requirements. This typically covers aspects which may not be essential everywhere.
- **Mandatory** requirements are to be implemented throughout Europe.
- **Non-exhaustive** requirements leave certain details of a requirement to be further specified at a national level. This is often focused on parameters. The national choice may be limited by a parameter range defined at European level within which the national parameter must be set.
- **Exhaustive** requirements define all details of a requirement.

Some examples of requirements proposed to be exhaustive and non-exhaustive are given in Section 3.2. on ”HVDC Performance requirements”.

These classifications are introduced to give an optimal balance of cross-border relevant functionalities that should be fully specified at European level and those where further specifications are best made locally to be fit for purpose at the lowest cost. The proposed classifications follow the same principle used in the preceding network codes on RfG and DCC.

Furthermore, network codes as referred to in Regulation (EC) 714/2009 only cover aspects with cross-border relevance and supporting market integration. Other capabilities needed for efficient and cost-effective operation of the national power system shall be defined in national regulation.

Finally, when a requirement is defined as non-mandatory, its application will need to be judged in each national context. Where it can be demonstrated as justified and cost-effective, it will be included as a requirement. This justification may imply Cost Based Analysis (CBA), particularly if the requirement is both significant and new. For this quantitative information from grid users is needed, in particular with respect to the cost of capabilities, preferably as percentage of total cost. ENTSO-E proposes to collect most of this information to avoid excessive duplication. For this reason, stakeholder[s] can be requested in this document to provide any cost-based information that is relevant to the later national assessment of the need and justification for application of possible non-mandatory requirements.

Questions on scope and classification of requirements:

2.3.1 Do you have comments on the principles outlined above with respect to mandatory, non-mandatory, exhaustive and non-exhaustive aspects?

2.4 SUSTAINABILITY OF THE REQUIREMENTS OF THE NC HVDC

An appendix to this document illustrates in HVDC context how the challenges are expected to arise and vary in a range of countries. The appendix is organised into sub-sections covering the main 3 applications, namely interconnectors (7.2), embedded links (7.3) and DC connected PPMs (7.4). These illustrate the critical nature of defining adequate performance capabilities for the HVDC systems in the light of fast evolving electrical systems. The rapid change of the energy systems in terms of location of generation and the growing part of volatile renewables mostly connected by power electronics introduced major challenges to the TSOs.

Questions on sustainability of the NC HVDC:

2.4.1 Do you have any comments about the best time to include performance requirements to fit the more challenging conditions for HVDC in light of the rapid system changes, e.g. due to a large amount of renewables?

2.4.2 Can you provide cost-related information or cost-related examples for exploiting or not exploiting the flexibility of the emerging new HVDC technology?

2.5 TECHNOLOGY NEUTRALITY

The objective of the NC is to define the minimum requirements needed to ensure reliable operation of connections and to maintain the security of the systems. Integration of RES and development of the European market will have impacts on the minimum required capabilities of the HVDC. The proposed NC HVDC should reach these objectives while giving room for research, development and better solutions thus enabling provider entities to propose innovative solutions for the future. Therefore, ENTSO-E believes that requirements defined in the NC should be performance based and technology neutral.

Questions based on the technology Neutral Approach:

2.5.1 It is not expected to have separate LCC and VSC requirements. Please detail problems, if any, you may have with this intent to focus on technology neutral performance requirements?

2.5.2 Do you believe any requirements proposed in the preliminary scope have a major technology selection implication? Please provide cost-related information or technical specification to support your argument.

2.6 MULTI-VENDOR ISSUES IN HVDC APPLICATIONS

To be able to create substantial HVDC integrated systems, not only multi-terminal HVDC systems, but also applications allowing to build meshed grids (so called “HVDC Grids”) are needed, the latter not yet existing. The Technical Brochure of CIGRE WG B4-52 “Feasibility of HVDC grids” [9] concludes that this emerging technology is indeed feasible.

From a practical point of view HVDC Grids are probably only viable if the converter terminals for a developing system can be delivered by a range of manufacturers and function well together. To make a success of HVDC grids, collaboration (e.g. for control and protection) and exchange of essential information is expected to be critical.

Questions regarding multi-vendor issues:

2.6.1 What is your view on the need for multi-vendor arrangements to facilitate HVDC grid development? Do you believe such requirements should be included in the initial issue of NC HVDC?

2.6.2 What level of openness is required to make multi-vendor HVDC practical, including predictable stable performance under dynamic disturbances including faults?

2.6.3 What kind of possibilities do you see to establish the necessary data and model exchange needed to design any multi-vendor systems?

3 REQUIREMENTS OF NC HVDC IN LIGHT OF FUTURE CHALLENGES

3.1 INCREMENTAL COST OF HVDC CAPABILITIES

In relation to the proposed requirements, set out in the “Preliminary Scope” document for the NC HVDC, it is important to establish both the feasibility of the capabilities proposed (if not immediately, from when) as well as the per unit cost sensitivity in relation to the total cost of the facility. ENTSO-E believes that in most cases this should be expressed in terms of the total converter valve facility or Power Park Module. In some cases other parts such as the cable system may be a more appropriate basis for the per unit cost.

Question:

3.1.1 What are the requirements in the Preliminary Scope with the largest cost implications? Please identify, for individual items as far as practical, the following

- the cost percentage expressed in terms of the total cost (e.g. of the converter valve) of the five most costly requirements;
- the split in the cost of R&D and production costs for each system delivered; and
- any other items with cost implications greater than 0.1% of the total facility.

3.2 HVDC PERFORMANCE REQUIREMENTS

ENTSO-E proposes in the preliminary scope that performance requirements can be defined in general for HVDC systems at the AC connection points. It also states that meshed DC Grids are out of scope at present.

Questions regarding the definition of requirements:

3.2.1 Do you agree with the feasibility of ensuring reliable operation of connections and of maintaining the security of the system using performance requirements specified at the AC connection points? Please provide your rationale.

3.2.2 Do you agree with leaving meshed DC Grids out of scope of the NC HVDC at present, implying in the meantime that requirements will be set at a national level or on a per project basis initially while this technology emerges in the coming years?

3.2.1 Requirements for Active Power Control and Frequency Support

Please consider the requirements in Section 3.1.1 items i. to ix in the Preliminary Scope.

For a proper operation of the power system, frequency shall be statically and dynamically stable across a synchronous area and across all its voltage levels. Deviations of frequency from its nominal value indicate generation-load imbalances which have to be eliminated in order to guarantee a stable frequency across the electric system. The European TSOs are responsible for this frequency control and for maintaining frequency quality within pre-defined quality criteria. The Network Code on Load Frequency Control & Reserves will provide the coordination and technical specification of load-frequency control processes and specifies the levels for different classes of reserves which TSOs need to hold. The generating units, with their ability to vary their active power output when a frequency deviation occurs, as well as the other users connected to power system are required to contribute to frequency control or at least to frequency stabilisation. To that end, the connection codes set requirements for new facilities connected to the power systems.

HVDC systems do not generate any active power within the converter stations. They rather transmit electricity from one end to the other in a controlled and accurate manner. Hence, HVDC systems are required to be flexible and robust in order to manage system frequency. In context of system inertia there may be a limited exception in the sense that stored capacitive energy in the DC link could be used for some 100ms, possibly up to few seconds.

Frequency deviations from 50.0 Hz can immediately affect HVDC converters and Power Generating Modules. In case of generation-demand imbalances and increasing frequency deviation, it is necessary to avoid subsequent, uncoordinated HVDC converters tripping by defining its range of operation and control as far as technically feasible. These measures are required to protect the system power balance during normal demand changes and during emergency situations. This capability needs to exist in both directions.

The following paragraphs give some examples of exhaustive and non-exhaustive frequency requirements.

Frequency ranges

HVDC converters should at least match the same capability as defined in the Network Code for Requirement for Generators in article 8(1)a). This requirement is intended to be mandatory and exhaustive. Within a synchronous area this could otherwise be applied in an inconsistent manner and potentially adversely affect system security. Frequency range and time period values may differ for each synchronous area.

HVDC converters should withstand wider frequency ranges than generating units (no interaction with rotating masses). In case of network splitting, in which some isolated parts can experience large frequency deviations, system operation will be easier if TSOs can rely on HVDC connections even though generation has partly or totally tripped. Information is requested for acceptable frequency ranges beyond thresholds defined for generating units and their cost implication, e.g. out to 45 – 55 Hz.

Rate of change of frequency withstand capability

HVDC converters should at least match the same capability as defined for generators (via Network Code for Requirement for Generators, Article 8(1)b)). This is needed to maintain coordination of generators and HVDC systems and avoid sub-sequent unwanted tripping. Feedback about the highest practical value of df/dt and associated cost implications would be useful to define this requirement and whether it should be exhaustive or not.

Active power controllability; control range and ramp rates

The management of variability and uncertainty is critical for the secure operation of a power system with high levels of variable generation and HVDC schemes. HVDC converters have the inherent capability to control within a few hundred milliseconds active power. In some cases, TSOs need fast active power control. For instance, in case of a nearby contingency that results in limited power transmission, the HVDC system shall be capable of decreasing its power output in order to solve overloads on the nearby network (‘fast run back’). On the other hand, in case of tripping of another parallel HVDC or AC circuit, the HVDC system shall be capable of increasing its power flow up to the nominal operation power in order to overtake the net flow (‘fast run up’). This requirement is proposed to be non-exhaustive, giving the opportunity to add certain detailed requirements at a national level or project base.

TSOs require HVDC links to be capable to contribute to market integration by supporting the development of cross-border exchange of energy and reserve. To that end, extensive active power controllability is needed. Automatic control modes are especially needed for exchanging balancing energy resulting from the activation of cross-border frequency containment and restoration reserve. This requirement is also proposed to be non-exhaustive, giving the opportunity to add certain detailed requirements at a national level.

Ramp values for the active power control may be different and fixed or adjustable depending on power system needs, protection settings and topology, so as this value or a range of the values, when adjustable, should be agreed between TSO / facility owner and manufacturer. This requirement is proposed to be mandatory and non-exhaustive.

Frequency sensitivity and frequency control requirements

HVDC systems are required to be flexible to modify their active power flow during frequency excursions to maintain system frequency stability. Frequency deviations of a synchronous area can be reduced by a smooth reduction of the active power output of HVDC converters in case of high frequencies and by a smooth increase in case of low frequencies.

This requirement is proposed to be mandatory and non-exhaustive to allow provisions for different ramp rates, gains, droop values, deadbands, static and dynamic reserve during operational time frames. Different values could be envisaged at national level depending on reserve requirement, generation, control structure and system characteristics at both ends of the HVDC connector. Schemes and settings of the different control devices of the HVDC system shall be coordinated and agreed between the relevant TSOs at both ends of the HVDC connector. In some cases those could be disabled to operate the HVDC system at fixed power.

The capability is mandatory. However, for the case of an embedded link within a synchronous interconnected AC network, these requirements could be non-mandatory because any change of active power will affect the power share between the HVDC link and the parallel paths with no direct impact on frequency. The capability may be required by the TSO during a contingency situation such as system separation between two control areas or power restoration.

Synthetic inertia capability

System synchronous inertia fundamentally affects how fast and how far the frequency drops or increases during an energy imbalance, being the rate of change of frequency and the frequency turning point (lowest or highest). With high penetration of non-synchronous generation, power electronic devices and HVDC links connected to the grid, system inertia tends to reduce, favouring frequency excursions and higher rate of change of frequency. This might trigger rate-of-change-of-frequency-type of loss of mains protection and some consider risks of transient stability issues (lack of synchronising torque). This will result in a fundamental change under both steady state and transient condition of the power system.

Fast-acting response (inertial-emulation or synthetic inertial capability) can serve to allow more, HVDC links, and non-synchronous generation from renewable energy sources. HVDC converters can provide synthetic inertial capability if required by implementing the control in its whole structure. Reliable and useful measurement of rate of change of frequency is a substantial challenge, due to angular movement between generators when disturbed. Inertia emulation could therefore work against its intended purpose when not designed with great care.

This requirement capability is power system dependent and will change with the needs of each system and synchronous area as well as with the system development over time, i.e. substituting conventional, synchronous generation with non-synchronous generation. Therefore, this requirement is intended to be non-mandatory and non-exhaustive.

Maximum loss of active power

Losing active power due to the tripping of an HVDC interconnector or HVDC connected Power Park Modules may endanger system stability as frequency deviates immediately. As HVDC links may transmit significant amount of power between synchronous and control area, it is necessary to define a maximum largest single loss infeed in order to avoid wide scale system instability due to the tripping of an element of the HVDC link. Responsibility for providing stable system frequency is assigned to all TSOs in the synchronous area. Frequency containment is under existing system operation and market regimes a joint responsibility distributed among all TSOs in the synchronous area while frequency restoration is a local responsibility only of the imbalanced TSO. Each TSO is consequently responsible for the procurement of appropriate amount of operational reserves according to the rules defined by the Network Code on Load Frequency Control & Reserves. These reserves (frequency containment and restoration reserve) are sized to mitigate against, at a minimum, the loss of the biggest facility in the synchronous zone or control area. HVDC connections can have a power capacity higher than the biggest generating units connected to the transmission system. This aspect may be subject to adjustment under other codes (LFC&R and Balancing), e.g. from more sharing. If they are not designed to avoid the loss of their full capacity in case of unexpected outage, TSOs shall have to increase accordingly the amount of operational reserves, resulting increasing costs to be covered by all grid users.

Limiting the maximum loss of active power in case of HVDC facility outage enables the TSO therefore to operate the network in a safe way without increasing the costs of frequency reserve, justifying inclusion of requirements in the NC HVDC.

This size of the largest loss of active power allowed for is one of the main criteria for dimensioning the reserve, both for the entire synchronous zone and for the various control areas, according to the Network Code LFC&R. This requirement is proposed to be mandatory and non-exhaustive in order to give to each TSO the possibility to optimise this size according to its own dimensioning parameters.

Questions on Active Power Control and Frequency Support:

3.2.3 Do you have comments on the requirements outlined in 3.1.1., items i. to ix. of the Preliminary Scope?

In particular, what is your view on the following:

- *frequency withstand capabilities*: Should this be wider than those defined for generating units (e.g. extended to 45 – 55 Hz). What are the associated cost implications expected?
- *rates of change of frequency* : higher rates of change of frequency are being experienced in the smaller synchronous areas, indication rates as high as 1Hz/s may need to be specified (item ii.). What are the highest acceptable values for rate of change of frequency (df/dt) and associated cost implications?
- *control and ramp rates* (item iii.).
- *synthetic inertia capability* (item iv.): Can the concept of e.g. “Inertia Emulation Control Strategy for VSC using stored capacitive energy on the DC link deliver a contribution to system inertia” [12]**Error! Reference source not found.**. be made to work for practical, e.g. 1000MW, VSC HVDC systems? What is the likely per unit cost increase for the VSC valve to deliver for example H=3s?

3.2.4 What is your view related to the ENTSO-E analysis that social welfare will be increased by adding equipment to the largest HVDC facilities in order to limit the loss of power, thus avoiding an increase in costs of operational reserves?

3.2.5 If such additional equipment is required, please specify the corresponding cost expressed in terms of the total cost of the HVDC link?

3.2.2 Requirements for Reactive Power Control and Voltage Support

Please consider the requirements in Section 3.1.2 items i. to vi in the Preliminary Scope [5].

The need for a stable voltage is another prerequisite for a proper operation of the power systems. It is important that HVDC systems have extensive capabilities to support voltage. HVDC converters are expected to contribute to system security by remaining operational when voltage is varying within the normal and emergency voltage ranges defined by the TSOs (See also Network Code on Operational Security) and also deliver specified relief to the system such as being expected to contribute to system security by facilitating voltage control and fault level management.

Voltage ranges

HVDC converters should at least match the same capability as defined in the Network Code for Requirement for Generators, article 11(2). This is needed to maintain coordination among generators and HVDC systems and avoid subsequent unwanted trip. This requirement is intended to be mandatory and exhaustive otherwise voltage thresholds within a synchronous area may be applied in an inconsistent manner and potentially affect system security. Voltage range values may differ for each synchronous area.

Questions on Reactive Power Control and Voltage Support:

3.2.6 Do you have comments on the requirements outlined in 3.1.2., items i. to vi. in the Preliminary Scope?

3.2.7 How do the requirements related to reactive power impact the design and costs of the converter stations?

3.2.3 Requirement for Fault-Ride-Through

Please consider the requirements in Section 3.1.3 items i. to iii in the Preliminary Scope [5].

Due to their importance for the future power transmission system HVDC systems must have a high availability in terms of active and reactive power exchange with the AC side. Fault ride through capability starts with the ability of a HVDC converter to remain transiently stable and connected to the system for a nearby fault or voltage dip

In case of DC side faults the admissible interruption times in particular depends on the realization of the DC transmission path connecting the converter stations. To interconnect adjacent synchronous systems often either a back to back HVDC station or underwater cables are utilized. For long distance onshore bulk power transmission the choice is between overhead lines, underground cables or a mixture of the two. Underground cables are considered the favoured alternative for environmentally sensitive areas. The increased difficulty in obtaining permits for new transmission overhead lines and routes leads to solutions attempting to enhance the transmission capability of existing lines. To this aim either a full or a partial conversion of AC lines to DC might be considered as an attractive approach.

The requirements that will be demanded from the HVDC system depend on the foreseen type of transmission path. Overhead lines are subject to atmospheric disturbances (lightning strikes; line swinging during windy weather conditions etc.) posing high requirements on the frequency and admissible duration of automatic reclosing sequences in case of DC link short circuits. To maintain the security of supply a high reliability and robustness comparable to today's AC system performance must be ensured in this regard. In the case of parallel operation of AC and DC lines running on the same tower even higher requirements on the HVDC system result due to the probability of intersystem failures. On the other hand, if the transmission path is realized as underground cable, limited requirements to mitigate DC link short circuits might apply. In general a cable failure leads to time consuming repair times and fast recovery times for active power are not possible at all. Nevertheless there might be high demands with respect to reactive power support. Independent of system performance requirements the protection of the HVDC system against any kind of overloading must be assured for all specified fault scenarios.

Questions based requirement for fault-ride-through and interruption times in case of DC side faults

3.2.8 Do you have comments on the requirements outlined in Section 3.1.3., items i. to iii. in the Preliminary Scope?

3.2.9 Do you see any technical challenge to comply with fault ride through requirements (e.g. with respect to fault duration?)

3.2.10 Should anything specifically be added to bring out the aspect of fault-ride through capability of wind farms and nearby located converters?

3.2.11 Can you share any specific experience or associated data you may have on the restoration and recovery time of HVDC connections?

3.2.12 Depending on the DC transmission path realization, which technical solutions do you suggest to mitigate DC short circuits, i.e. to minimize interruption times with respect to the AC side connection point, and to comply with the above mentioned requirements? In your response, please also specify the following:

- Which interruption times can be achieved with these technical solutions? (in terms of active power recovery and Statcom functionality)
- Do you see any design limitations regarding the frequency and duration of automatic reclosing sequences?
- How do you evaluate the costs to develop / to adapt the equipment properly? What are the main cost drivers?

3.2.4 Requirement for Control

Please consider the requirements in Section 3.1.4 items i. to vii in the Preliminary Scope.

HVDC transmission can be fitted more readily than AC to a gradual expansion plan for transfer of power. AC transmission often has to be built from the start with a high capacity to maintain stability, but DC can be tailored to discrete stages. Expansion of existing HVDC systems will naturally result in a more complex network with an increase in the number of multi-vendor converters in the same area. Therefore, requirements for cooperation and coordination of control systems designed and built by different vendors should be set up to allow expandability of network in the future.

The requirements related to the converter control could be classified into the following categories:

Interaction with the AC system / Control performance to enhance AC system performance

The requirements shall ensure that at first any adverse effect on the AC system or on any grid user is avoided (e.g. excitation of torsional stress on nearby generators). Further on the capabilities of HVDC converters to enhance the overall AC system performance and to contribute to its security shall be utilized, e.g. through Power Oscillation Damping contribution to the AC system dynamic stability (small signal). This will become more and more important in the future power system (e.g. due to reduction of conventional generation units otherwise providing ancillary services).

Interaction between Power Electronic Equipment

The requirements shall ensure that there is no adverse interaction between different power electronic equipment (e.g. between HVDC converters, between Power Park Modules and HVDC converters etc). This aspect is especially important if the grid is dominated by power electronic equipment and therefore likely to operate with low short circuit levels (e.g. connection of (offshore) wind parks via HVDC)

Robust control of multi-terminal schemes

Besides point-to-point connections also multi-terminal schemes might be foreseen in future. In this regard the requirements shall ensure that multi-terminal schemes work together in a robust and safe way.

The interactions between AC and DC systems are quite complex and variable in nature. Taking the short circuit ratio value on the AC system is a simplified approach to evaluate these interactions. However, as non-synchronous generation becomes dominant, this concept may no longer hold entirely true, due to dominance of design based choices rather than machine characteristics. The minimum short-circuit ratio at AC connection points is an important aspect for the functioning of the HVDC schemes. This is well established for LCC based HVDC schemes, but at the ACDC2012 international conference in December 2012 (VSC workshop) [8] this was shown to be a major issue also for the performance of VSC type HVDC schemes. In this regard also the changeover between control modes might have to be considered if the short-circuit ratio can change significantly in consequence of contingencies.

Questions based on requirement for control:

3.2.13 Do you have comments on the requirements outlined in 3.1.4., items i. to vii. in the Preliminary Scope?

3.2.14 How do different control functionalities to enhance AC system performance (e.g. POD control, SSRD control) affect the design and costs of the converter?

3.2.15 Which kind of control interaction between power electronic equipment (e.g. between PPM and HVDC links in an offshore connection scheme) might occur? Which did you experience? Which mitigation measures do you see?

3.2.16 Do you believe that the different control strategies could lead to problems with coordination of these devices if they are produced by different manufacturers? In your opinion, are there any other ways that HVDC controllers can contribute to the system stability, such as damping power oscillations, between two synchronous areas with active/reactive power control? Is there any practical way to reduce the effect of fault to remote locations? In your point of view, is there any other performance requirement that should be included in this section?

3.2.5 Requirement for Protection Devices and Settings

Please consider the requirements in Section 3.1.5 items i. to v in the Preliminary Scope.

Questions based on requirement for control and protection:

3.2.17 Do you have comments on the requirements outlined in 3.1.5., items i. to v. in the Preliminary Scope?

3.2.6 Requirements for Power System Restoration

Please consider the requirements in Section 3.1.6 items i. to ii in the Preliminary Scope.

Both black start capability and the capability to operate in isolated, weak networks might be required from the HVDC system. For instance in case of a regional blackout the HVDC system could support the affected area via the converter station that is connected to the healthy part of the system. In this regard HVDC can play an important role to minimize down times and to energise the system as quickly as possible. Coordination is needed with other equipment in the affected area (protection, dispersed generation etc.)

Questions based on requirement for control and protection:

3.2.18 Do you have comments on the requirements outlined in 3.1.6., items i. to ii. in the Preliminary Scope?

3.2.19 Please comment on the role that HVDC can play to support the power system operation?

3.3 DC CONNECTED POWER PARK MODULE PERFORMANCE REQUIREMENTS

Please consider the principles of Section 3.2 in the Preliminary Scope [5]. These requirements will mostly apply to offshore generation. Consideration is needed to match the requirement of the PPM and the offshore AC system with the requirements of the HVDC link. The requirements for the offshore PPM need to recognise the different characteristics of the offshore AC island system, having no system strength from synchronous generation. Communication from the main interconnected system to the offshore facility can be provided indirectly via system state variables, for example frequency, or via a separate communication channel.

Questions based on Power Park Modules:

3.3.1 What is your view of defining requirements at both ends of a HVDC link as well as at the connection point of the PPMs?

3.3.2 Frequency support onshore can be achieved either via direct communication of the onshore frequency to the PPM or alternatively indirectly by the HVDC system driving the offshore AC frequency. What is your preference and why?

3.4 DEVELOPMENT OF ADDITIONAL SERVICES FOR WEAK SYSTEMS

With increasing capacities of RES, the likelihood for operation of a synchronous area or at least a control area with at times very high percentage Non-Synchronous Generation (NSG) increases, as described for varies countries in the Appendix (Section 7). In the extreme case the total demand may be covered by supply from converter based technology (PPM and HVDC connections). In general NSG results in lower fault levels. A family of challenges are related to operation with less system strength:

- Potential commutation failures of LCC, the conventional type of HVDC. Traditionally LCC schemes required a fault level in MVA of at least 3 times the MVA rating of the HVDC link.
- High harmonics. If minimum fault level in operation is much lower than the fault level used in the design, then unexpected high harmonics may appear. As a rough measure if the fault level is halved, the harmonic voltage distortion will double. Also, the NSG will have replaced the synchronous generators, which are traditionally a major sink for harmonics. Harmonic designs therefore may need to be reviewed.
- High Negative Phase Sequence (NPS or 3 phase unbalance) voltages. Again the synchronous generators as major sink for NPS are being displaced by NSG which do not perform similarly as a sink.
- Larger voltage steps, e.g. when switching capacitors or reactors on the network in order to control the system voltage.
- New challenges for Transmission Protection Systems in which the protection systems have to distinguish between fault currents and load current of similar magnitude.

The technical requirements of the HVDC systems can contribute to an extent to ameliorate the above problems by delivering very fast fault current contributions at least to their current ratings, even if this initially is 2-3 times lower than the current (sub-transient) contribution from the displaced synchronous generation would have been. The possibility of the HVDC valves having to deliver more novel services are explored next. Although these services may not be included in the first issue of NC HVDC, it is important to establish the approximate cost sensitivity for such requirements where this is known, in order that they can be introduced initially on a project basis or national basis, where they are initially needed. The alternative for some of the systems having the greatest percentage NSG may otherwise result in less desirable actions, such as replacing RES in operation with synchronous generators or cause a system technical based ceiling on RES installed capacity. There have already been cases when oil-based fossil fuel generation was operated under high wind conditions in order to achieve stable operation of the HVDC systems (avoid commutation failures).

HVDC valves (VSC types) are known to be able to be designed to absorb both harmonics and NPS currents by presenting impedances to harmonics and NPS voltages or alternatively or additionally providing active attenuation. Information is requested from manufacturers of HVDC valves about ability and timing of readiness to deliver such capabilities. Relative cost in terms of the percentage of total valve cost for adding various volumes of such capabilities is critically important.

In context of short circuit current contribution it is also important to have manufacturers' information of how fast this can be delivered. In this context the protection need case is ideally 5 ms but certainly not slower than 20ms.

Additionally, when the RES production is low and therefore the synchronous generators are connected with consequent high fault current contribution (close to the safe limit of switchgear), could the HVDC valve fault current contribution be curtailed. An option is making it subject to a signal from the TSO: In state 1 "low system fault level, provide max fault current" and in state 2 "high system fault level, provide no or min fault current". Again what are the cost implications, for the R&D activity and would there be any costs to implement this once developed?

ENTSO-E would like to ask the following focused specifically on the HVDC valve manufacturers (supported by R&D community):

Questions:

3.4.1 Do you have comments on above regarding harmonic and NPS capabilities (with particular attention to the following issues)?

- when such capabilities could be made available; and
- what would be the harmonic absorption/NPS volume / cost relationship in pu cost for the valve?

How fast (ms) can your fault current capability be delivered and what is the per unit capability?

- could the fault current delivery be made conditional on a received signal? If yes, at what per unit cost could such a conditional capability be provided?

3.5 INFORMATION EXCHANGE AND COORDINATION

The preliminary scope defines the objectives of an adequate and coordinated information exchange between network operators and HVDC system and DC connected offshore PPM owners. These requirements enable the TSOs to operate the electric system in an efficient and minimum cost manner.

The ENTSO-E proposal for drafting these requirements on information exchange and coordination is to use similar principles as those used in the previous connection codes (generation, demand).

3.6 COMPLIANCE & DEROGATION

The preliminary scope proposes for compliance and derogation criteria similar principles as in the previous connection codes (generation, demand).

The question whether the code is applied to existing HVDC link is a major one. In the previous connection codes (generation, demand), ENTSO-E has proposed an approach where a national TSO could initiate and carry out to its end a procedure of applicability. In that case, a Cost-Benefit Analysis showing the socio-economic benefits and cost of the proposal has to be carried out and the report will be subject to a public consultation. Finally The TSO sends the proposal on the applicability of the requirement, including the outcome of the consultation, to the relevant national regulatory authority for approval.

ENTSO-E considers that the extension of this approach to the NC HVDC is relevant.

Questions

3.6.1 Do you agree to extend to HVDC code the approach developed in previous RfG and DCC code for the conditions of application of the code to existing facilities, as well as the possibility of derogation procedures?

4 NEXT STEPS

The energy system is changing rapidly, especially with the massive integration of RES. This requires a new framework to cope with the challenges ahead. All participants of the energy market are faced with significant changes and the implementation of new processes and technologies. In line with the principles laid out in ACER's Framework Guidelines on Electricity Grid Connections, the Network Code for "HVDC Connections and DC connected Power Park Modules" will have to break new ground to help to accomplish this task on a European level. In comparison to other network codes and standards that are to a large extent based on existing rules and procedures, the NC HVDC will contain significant new requirements.

As a consequence, ENTSO-E conducts this "Call for Stakeholder Input" to collect opinions on the main new topics proposed, seeking to identify the most economic and efficient solutions to take forward.

The consultation on the questions stated in this document will be open for one month until 7 June 2013. ENTSO-E will use the answers received as guidance to further develop the NC HVDC.

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6 ABBREVIATIONS

AC	Alternating Current
ACER	Agency for the Cooperation of Energy Regulators
CA	Control Area
CBA	cost-benefit analysis
CIGRE	International Council on Large Energy Systems
CP	Connection Point
DC	Direct Current
DCC	Demand Connection Code
EC	European Commission
ENTSO-E	European Network of Transmission System Operators for Electricity
FACTS	Flexible AC Transmission Systems
FG	Framework Guidelines
H	system inertia constant
HVDC	High Voltage Direct Current
IEEE	Institute of Electrical and Electronic Engineers
IET	Institution of Engineering & Technology
LCC	Line-commutated converter
NC	Network Code
NPS	Negative Phase Sequence
NSG	non-synchronous generation
PCC	power control characteristics
PPM	Power Park Module
PV	photovoltaic
RES	Renewable Energy Sources
RfG	Requirements for Generators (network code)
SA	Synchronous Area
TSO	Transmission System Operator
TYNDP	Ten-Year Network Development Plan
VSC	Voltage-sourced converter
WG	Working Group

7 APPENDIX: HVDC TECHNOLOGY TO COVER REGION SPECIFIC AND EUROPE-WIDE SYSTEM NEEDS

7.1 GENERAL

This appendix illustrates how global challenges and local system needs result in specific considerations to choose HVDC solutions in several European countries. The interconnected European electricity system has emerged from the interconnection of national grids that were designed for power transport from generating units to loads comparatively close to each other. Moreover, the power to be transported by the grid used to be rather predictable. Today, the situation has changed: different types of connections between TSOs are not only needed for mutual help in emergencies, but rather to enable a European-wide market for electricity, leading to significant cross-border flows. Another factor in this region causing power transports over longer distances is the growing share of renewables often concentrated in areas far from load centres.

The interconnection with HVDC can be realized in three different ways:

1. To connect two or more Synchronous Areas (SA) to each other. The HVDC link is considered a significant grid user at all connection points.
2. To provide a transfer capability inside a single synchronous area, called embedded HVDC. The parallel operation of the HVDC with HVAC can encompassing a single TSO control area or 2 or more control areas.
3. To connect remote generations to the main AC network. The HVDC connection may or may not be part of the generation facility.

The interconnection ratio is shown in figure 7.1. This reflects the % interconnection capability compared to installed power capacity for each country. A significant improvement is expected to be achieved between 2011 and 2020. This should be seen in context of the objective agreed in March 2002 by the EU Council in Barcelona (10% of the installed power capacity).

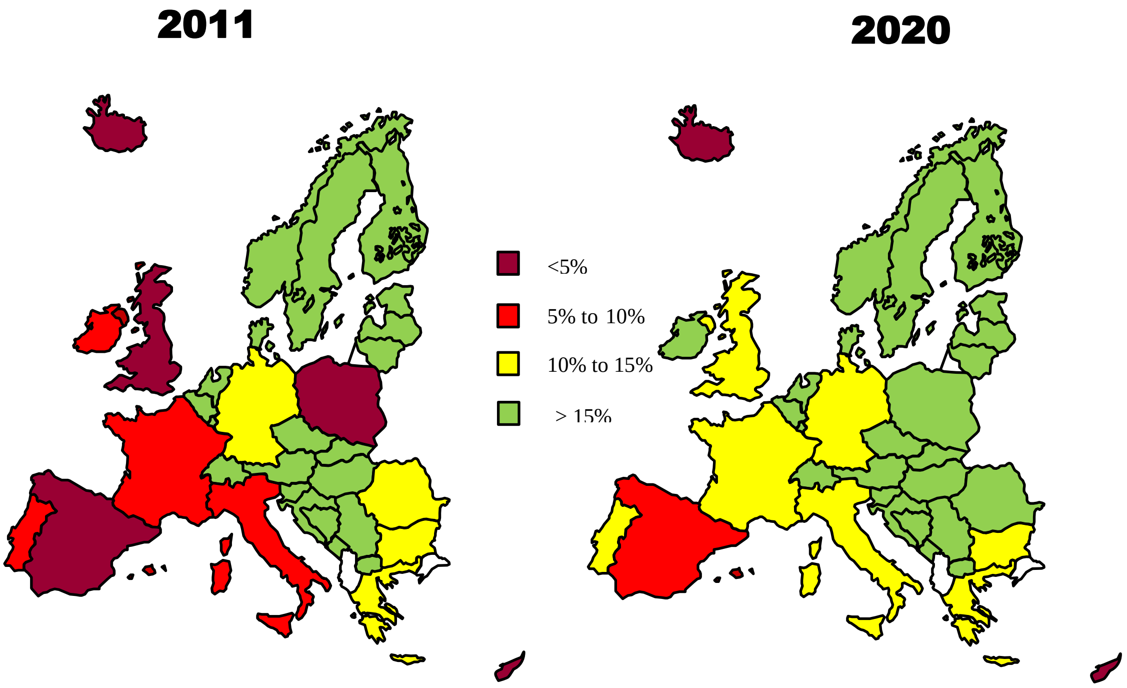


Figure 7.1: Interconnection ratios of ENTSO-E countries

In its 2030 vision, published in 2012, the North Sea Countries' Offshore Grid Initiative [13] presented the possibility of an integrated future combining in particular 1 and 3 from above:

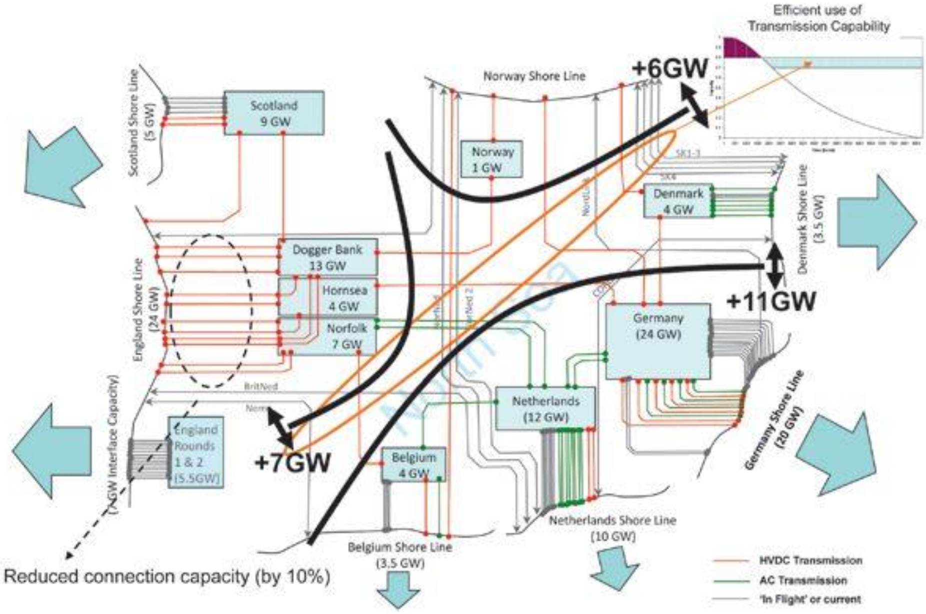


Figure 7.2: Integrated grid vision for the North Sea [13]

7.2 HVDC INTERCONNECTORS BETWEEN SYNCHRONOUS AREAS

HVDC capabilities for large scale power transfers over long distances and to connect two separate AC systems makes it an attractive technology to expand the geographical area able to trade. Interconnection of power systems may offer important technical, economic and environmental advantages such as: reduction of the necessary reserve capacity in the system by reserve sharing, improving reliability and supply security, improving load factor by increasing load diversity and reducing the losses facilitating an optimised system operation.

The strengths of fast and full power controllability, without the need for a common frequency, with stable operation across the full power rating, improved dynamic performance in the AC systems by modulating transmitted power, transmission of scheduled power independent of system conditions in the AC systems together makes HVDC an attractive option.

In the following paragraphs different examples from different European HVDC interconnectors are presented. Sample information is provided by TSOs.

7.2.1 IRELAND

EirGrid, the Transmission System Operator of Ireland, and SONI the Transmission System Operator in Northern Ireland play an active part on several work streams to understand immediate and future needs of the interconnected European electric transmission grid with associated challenges to connect HVDC technology and renewable power generation. Ireland is aiming for a 40% energy target from renewable energy by 2020, much of which will come from wind farms. Transmission infrastructure and interconnection has been identified as a key enabler to achieve such a challenging target and better integrated market. It is imperative that requirements to connect into the onshore transmission system are as well defined and understood as possible for both HVDC and wind generation power park modules users.

The island of Ireland transmission system is currently connected to Great Britain via two independent 500 MW High Voltage Direct Current (HVDC) links. They are the Moyle interconnector built as dual monopole with line commutated technology between Scotland and Northern Ireland, and the East-West interconnector (EWIC), between the Republic of Ireland and Wales, built as symmetrical monopole with voltage source converter technology.

Following detailed studies it has been found that it would not be prudent to operate the Island of Ireland system with more than 50% of the instantaneous penetration coming from the combined sources of wind energy and HVDC (System Non-Synchronous Penetration, SNSP). For more details of the broad range of system technical challenges regarding very high penetration of Renewable Energy, see references [14],[15], [16],[17],[18] and [19]

The main limiting factor is the high ratio of largest infeed to system inertia and the resultant high rates of change of frequency experienced, for the loss of the largest generation/infeed. However mitigation strategies are possible, allowing in the best case up to 75% levels of non-synchronous technologies. Beyond 75% the lack of synchronous torque in the system after fault clearance shows a significant deterioration of transient stability of the synchronous generators. From the island of Ireland perspective increased export capability was found to mitigate curtailment of renewable energy and therefore facilitating energy policy objectives. It is also worth noting that a high import scenario increases SNSP levels, as imports on a HVDC link are non-synchronous.

Looking at the 2020 or 2050 timeframe, additional challenges come into play such as controllability and observability of embedded generation, DSO/TSO Mvar control coordination, low short circuit contribution during faults and associated protection detection, harmonic resonance and control interaction. Ultimately the TSO will be endeavouring to maintain system security with all the above challenges.

An exchange of power between the System Operators (SOs) could assist in alleviating system security issues by reducing the total generation capacity required to maintain security of supply. An example of this would be the ability to increase interconnector imports, or reduce exports, during a capacity shortfall scenario when system margins are reduced where load shedding would otherwise be required.

In Ireland, the Single Energy Market (SEM) requires SO counter trading on the interconnectors after Gate Closure in advance of the re-dispatch of price taking generation. So by trading to reduce interconnector imports, or increase exports, curtailment of priority dispatch generation in SEM can be reduced or avoided. This is an interesting use of HVDC interconnection services to manage wind power generation and increase capacity for cross-border trade.

Moyle and EWIC have the technical capability to facilitate automatic flow changes to provide reserve to either power system which they are connected into. EWIC also has the capability to provide a Black Start service. Delivery of these services relies on the exchange of energy from one transmission system to the other. In the case of the Power Reserve service, automatic increases or decreases in interconnector power flows are initiated by frequency events on either system.

This service only utilises any spare capacity on the interconnector so it does not interfere with the capacity offered to the market, nor does it interface with the real time position of traders in the event that the service is triggered. In the event of a Black Start of either system, power would be supplied from the healthy system to the system being restored. The power exchanged between one system and another to deliver these services is commercially settled as an SO trade.

Studies undertaken jointly by the transmission system operator EirGrid in Ireland, NGET in GB and RTE in France have demonstrated the benefits of greater interconnectivity between the Irish transmission system and transmission systems of Great Britain and France.

Figure 7.3 illustrates new interconnection projects using HVDC technology being investigated or built.

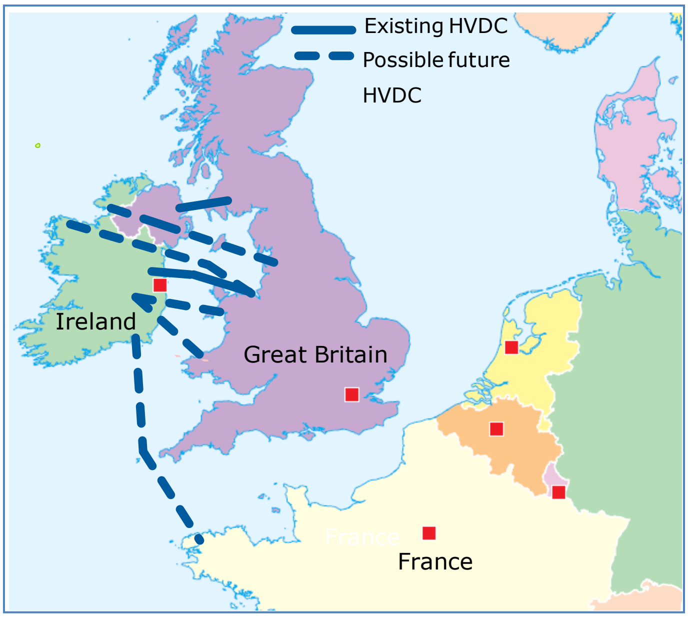


Figure 7.3 Potential HVDC connections to the Ireland transmission system.

The following developments have been proposed and are being considered as potential projects of common interest:

Further new point-to-point interconnection (a third and possibly a fourth HVDC link) between Ireland and Great Britain.

MAREX (Mayo Atlantic Renewable Energy Export): MAREX is a storage and transmission project to deliver electricity from Ireland to UK

In addition, EirGrid and RTE are considering the viability of an Ireland-France interconnector.

The governments of Ireland and the UK have signed a Memorandum of Understanding (MoU) to cooperate on how the two systems might be further integrated. It is expected that the outcome of this joint approach, in the form of intergovernmental agreement early 2014, will provide greater clarity as to which of the above projects progresses to construction.

7.2.2 GREAT BRITAIN

The GB synchronous system is connected to France with a 2GW link, to Netherlands with a 1GW link and to Ireland with two 0.5GW links. Further links mainly driven by expected major expansion in wind generation capacity are likely to at least double this capacity. For locations of these, see the system diagram in Section 7.4.2. Future developments are shown in the 2012 Electricity Ten Year Statement (ETYS, see [21]), which includes connections to Belgium, Norway, France and Denmark.

In Scotland there are a number of HVDC planned projects in context of the islands to the North and West. This includes planned connect ion to the separate ac system in Shetland in 2018 and for the Western Isles an HVDC link is planned to connect an AC system which in 2016 is planned to be operated with the ac link to the mainland open (disconnected). In contrast parallel AC / DC connection are planned in 2019 and 2021 to the Orkney Isles.

Technical requirements for HVDC are in GB an integral part of the Grid Code.

7.2.3 DENMARK

The case of Denmark illustrates the variety of HVDC applications covering all of interconnectors, embedded links and offshore wind.

The international connections are a precondition for constructing a well-functioning international market, which is a precondition for an efficient transition to renewable energy. Through long-term grid planning, Energinet.dk targets the expansions of the international connections which are the most socio-economically efficient. The same applies to the internal grid where Energinet.dk works on strengthening the grid at transmission level.

The development of the international connections will be based on the socio-economic cost-benefit analyses and on the international outlook in the area.

Figure 7.4 Launched initiatives and planned future international connections

Figure 7.4 illustrates the initiatives where Energinet.dk is planning new projects for which investment decision is needed in the course of the coming two to four years. Furthermore, more possible long-term projects are also illustrated, e.g. the optimum solution regarding an offshore grid in the North Sea has not been determined yet.

Energinet.dk's analysis shows that it will be socio-economically efficient with a diversified expansion of interchange capacity on international connections by further approx. 2 000MW by year 2020.

7.2.4 SPAIN

Spain is a sparsely interconnected power system with similar interconnection ratios as UK and Ireland which is far from the objective agreed in March 2002 by the EU Council in Barcelona (10% of the installed power capacity). The result is a congested border in both directions, with the corresponding decrease of security of supply, RES integration limitation and hampering on the process of union to the European Internal Electricity Market. See Figure 7.1 comparing 2011 and 2020 interconnectivity, identifying Spain as still relatively weakly connected in 2020.

During the 90´s there were several attempts of reinforcements of the interconnection infrastructure between France and Spain but they were rejected for political reasons, and it was in 2007 when a new interconnection project was boosted, with the final recommendation of the European Coordinator "A solution in HVDC totally undergrounded for the cross border section between Baixas and Santa Llogaia, with a terrestrial route and using as far as possible existing infrastructures within a determined area". Independently of the final result, this decision intuitively reveals that next Spanish interconnections also are expected to consider HVDC technology. As these developments cover HVDC in parallel with HVAC this is further described as embedded connections and hence covered in section 7.3.4.

An HVDC link was commissioned in 2012 within the Spanish Control Area, the ROMULO interconnector (former COMETA) between the Spanish peninsular power system and Mallorca, the main island of the Balearic archipelago. The system consists of a two bipolar HVDC cables and a metal return cable, with a total capacity of 400 MW and in LCC technology and mainly submarine.

The EC EIP (Energy Infrastructure Package) contains three projects of HVDC links between Spain and UK. These are within the list of projects to be submitted to be considered as potential Projects of Common Interest in energy infrastructure (Electricity): HVDC submarine link Spain - Great Britain (2025, promoted by Red Eléctrica de España); Britain-Iberia ("BRITIB") Interconnector Project (2017, Transmission Capital); Galicia Iberian Renewable Energy Export (GIBREX) (2020, promoted by Organic Power Ltd.).

7.2.5 BALTIC

In the Baltic region, the HVDC interconnections are considered as the possibility to connect the region to Nordic and Poland and therefore increase the security of supply, and to develop the Baltic electricity market. Currently there is in operation one VSC type HVDC interconnector, with capacity of 350 MW, between Finland and Estonia (and one LCC type HVDC interconnector with capacity of 600 MW between Poland and Sweden). In order to increase the transfer capacity between synchronous areas of Baltic, Nordic and Central Europe different plans exist. Currently a second interconnector between Finland and Estonia, Estlink 2 – 650 MW, is being built and is expected to be in operation in the beginning of 2014 (Figure 7.5). This project is driven by market development and one third of it is financed by EU. In addition, there are two other HVDC projects considered, i.e. NordBalt interconnector between Sweden and Lithuania (Figure 7.5) and LitPol back-to-back interconnector between Lithuania and Poland. It is expected that the LitPol link could be in operation in 2015 and the NordBalt after 2014. In the future it is expected that the off-shore wind power may impact on the development of HVDC links in the Baltics.

Figure 7.5. Planned interconnections in the Baltic Sea area

7.3 EMBEDDED HVDC LINKS

7.3.1 FRANCE

France, in the geographical crossroads of the European networks, is impacted by the strong evolutions which affect the nearby countries such as Germany, Spain or Italy. The impact of the withdrawal of the nuclear generating units in Germany and the development of distributed renewable energies, coupled with the evolution of the French energy mix, require the increase of the "breath" allowed by the interconnections. HVDC technology will be used to increase capacities with Spain, including using sea cables in the Atlantic Ocean, with Italy, as well as the strengthening of the cross-Channel connection planned for the 2030 horizon.

The transmission network will continue to enable interregional transits and to facilitate the mutual assistance between the French regions, following the example of AC "safety nets" committed in Brittany and in region of Provence-Alpes-Côte d'Azur. With the replacement of old power plants, in particular thermal plants, and the development of the renewable energies, the amplitude and the volatility of flows will increase, in particular between the North and the South of France. Besides the modernization and reconstruction of AC overhead lines already committed or planned, RTE suggests creating a new electric DC link by the Mediterranean Sea - between Languedoc and Provence.

Other decisions will also be to set from 2013, at the end of the national debate on energy, to face challenges beyond 2022, a date following which the transformation of the electric landscape is going to accelerate, with a possible significant change of geographical distribution of the power plants. Important investments will be necessary to rebalance the French electricity network. Among these are the restructuring of the Massif Central network, the strengthening of the network in the East of France as well as between Normandy and the South of Paris. Part of these investments will also be realised with HVDC technology, especially sections crossing dense urban areas.

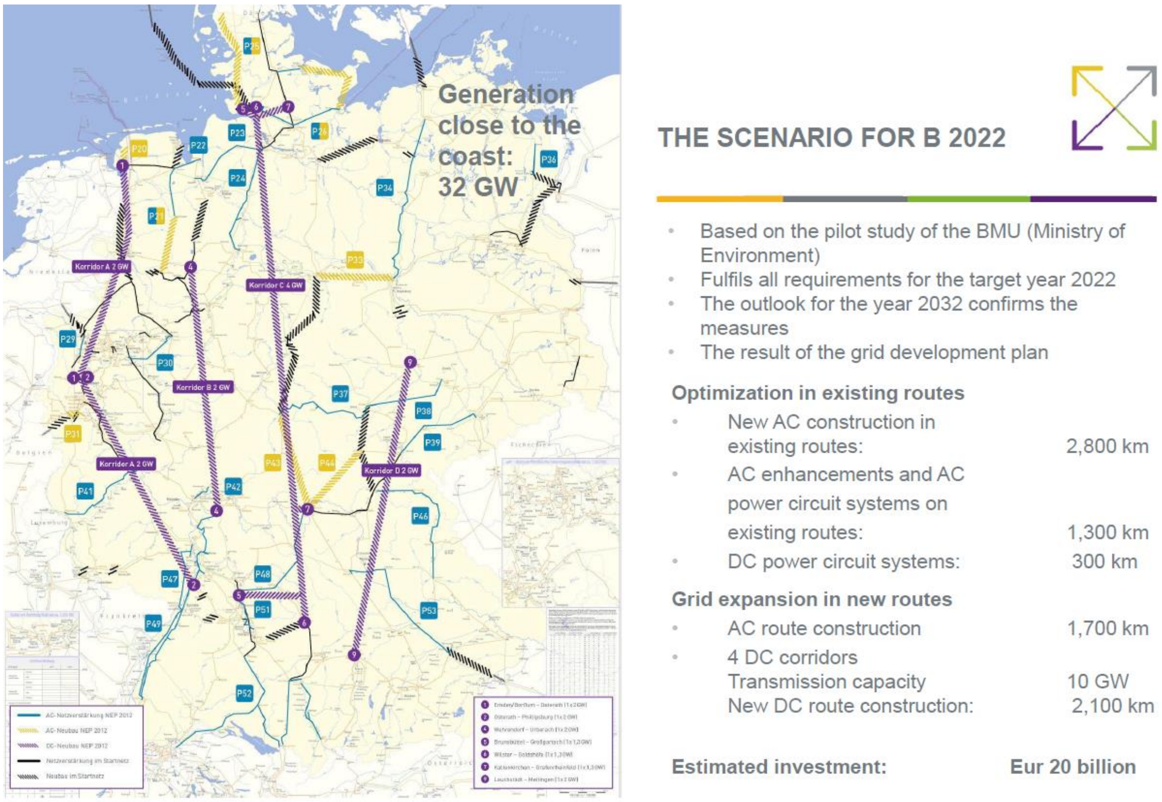
In the next 10 years HVDC technology will take an increasing place in RTE's investments with the building of 800 to 1000 km of new underground or submarine HVDC links, representing about one third of the length of very high-voltage connections which will need to be built or to be strengthened.

7.3.2 GERMANY

The four German Transmission System Operators have submitted in close cooperation a joint National Grid Development Plan (NEP 2012) to the National Regulatory Authority (NRA) on 15th August 2012. The draft of the NEP 2012 was consulted during a public consultation process initiated by the TSOs and afterwards by the NRA. The NEP 2012 consists of all effective measures in order to optimize, to reinforce and to strengthen the German transmission network. All need cases were supported from the energy sector point of view by the NRA. All projects have to be realized in the next ten years in order to maintain power system reliability and security. The grid extensions include 4 trendsetting HVDC corridors (Overlay High-Voltage grid) throughout Germany.

The integration of renewable energies and the development of a European electricity market were taken into consideration, with respect to the stipulated parameters relating to the efficient use of energy. Grid optimisation and enhancement measures were prioritised vis-à-vis new routes. There appears to be a significant and nationwide need for development. In this case, the emphasis is on the high-capacity North-South connections. In the case of lead scenario B, it will be necessary to implement network enhancements and optimisations along a length of 4,400 km in the existing routes by 2022. The construction of new routes spans a length of 1,700 km. The HVDC transmission corridors are approximately 2,100 km long. They have a transmission capacity of 10 GW in the North-South direction. The expansion of the transmission network will require a total investment of ca. € 20 billion over the next ten years.

The assumptions contained in scenario B 2022 are based on the pilot study carried out by the Federal Environment Ministry (BMU) in 2010. This scenario was also examined with respect to a forecast for the target year 2032 (scenario B 2032), in order to determine how well the grid expansion measures can hold up over the long term. Scenario B satisfies all the requirements for the year 2022.The grid expansion that results from scenario B 2022 illustrates the result of the grid development plan. The associated projects are progressing through consultation.



THE SCENARIO FOR B 2022

- Based on the pilot study of the BMU (Ministry of Environment)
- Fulfils all requirements for the target year 2022
- The outlook for the year 2032 confirms the measures
- The result of the grid development plan

Optimization in existing routes

New AC construction in existing routes:	2,800 km
AC enhancements and AC power circuit systems on existing routes:	1,300 km
DC power circuit systems:	300 km

Grid expansion in new routes

AC route construction	1,700 km
4 DC corridors	
Transmission capacity	10 GW
New DC route construction:	2,100 km

Estimated investment: **Eur 20 billion**

Figure 7.6: Grid Reinforcement measures NEP-B2022 including 4 HVDC corridors

Together with the expansion of the 400-kV HVAC network, high voltage direct current (HVDC) connections are envisaged for the high transmission requirements along the North-South direction. HVDC facilitate a low-loss transfer across large distances. HVDC also stabilise HVAC network if used in conjunction with modern technology. It is expected the embedded HVDC links will provide measures to better operate and secure the system. The capability of these links is important in order to face the future challenges.

With high levels of RES penetration, system security can be maintained at lower costs if there is more interconnection capacity between TSOs. This can be achieved by HVDC links. Technical rules are required to meet certain performance criteria necessary for this role in order to make the technologies capable for the system needs for both today and the future. The combined deployment of DC and AC technologies, as recommended in the NEP, makes it possible to collectively optimise the transmission network for the supply-related tasks, which have grown in historic proportions. It shall also make it possible to meet future transport-related requirements, with respect to network stability, economic efficiency and utilisation of space.

7.3.3 ITALY

Terna, the Italian Transmission System Operator, owns and operates the following HVDC systems connected on the Italian control area:

- 3-terminal HVDC system connecting Sardinia (IT), Corsica (FR) and Italian mainland; in operation since the 1960s; rated power is 300 MW;
- HVDC Galatina (IT) - Arachthos (GR), in operation since 2001; rated power is 500 MW

- HVDC Latina (IT mainland) – Fiumesanto (IT Sardinia) - SA.PE.I., in operation since 2009, rated power is 1.000 MW in bi-pole;

The future of HVDCs in the Transmission System is also demonstrated by projects in development in Italy, where Terna is building two HVDC border projects between Italy and France (1.000 MW Piossasco – Grand'Ile) and between Italy and Montenegro (1.000 MW Villanova – Kotor) in addition to two other HVDC border projects on the CH-IT and on SI-IT borders which are in permitting phase. In addition to the above mentioned projects are two HVDC projects in the form of merchant line initiatives on the Switzerland-Italy and Albania-Italy borders, both of them in permitting phase.

Terna has recognised the significance of connection regulation for an HVDC system for these new transmission technologies in fast development. Without HVDC technical rules and adequate specifications at the connection node the operation of the national transmission system could be jeopardised, even the security of the system itself. Compared to the conventional HVAC system, the HVDC can offer "smart" services (e.g. power flows control) more than HVAC lines.

The Italian HVDC connection code, at its 2nd release, is now in force and it defines the non-discriminative rules to allow the connection on the grid of all HVDC system aiming to guarantee and preserve the system security in the real time normal and emergency conditions. The HVDC connection code must have an overview on the future conditions of the network when the penetration at highest level of renewable energy could reduce the ancillary services provided to the grid.

Terna, as TSO responsible of the Italian Transmission Network operation, is involved in the process of HVDC "design" in order to have the best HVDC performances and the Italian HVDC connection code defines the following field of requirements:

- Network data on the connection node of the AC/DC conversion stations;
- Performances by the HVDC system
- Studies and documentations required
- Nominal conditions for the system component designing
- Main requirements for the HVAC section of AC/DC conversion stations
- Tests and operation commissioning

The Italian HVDC connections code endeavours to preserve the system security taking into account that new types of HVDCs can be designed for stable operation of the network. HVDC can offer services beyond that provided by conventional AC overhead line. How much more depends upon the choice of HVDC technology. Without studies of the HVDC operation the system security could be at risk. The Italian connection code ensures an exchange of technical information between manufactures, TSO and private owner of HVDC.

The Italian HVDC connections code does not impact on the existing HVDC. Benefits from changes must be evaluated by the TSO in order to avoid costs that are not supported by improvements in the performances of the network.

7.3.4 SPAIN

Section 7.2.3 reveals that the next Spanish interconnections are expected to consider HVDC technology, in parallel with HVAC connections, i.e. embedded HVDC. The HVDC link is the INELFE project, and it constitutes a major project in the world regarding VSC technology with two independent bipoles with a rating of 1000 MW each.

In the long term planning of the Spanish power system, HVDC links are still contemplated in order to increase the total transfer capacity:

Within the ENTSO-E Ten Year Network Development Plan (TYNDP) [6] a new France-Spain submarine interconnector is contemplated as project of pan-European and regional relevance in the Central South West Region (2017-2022).

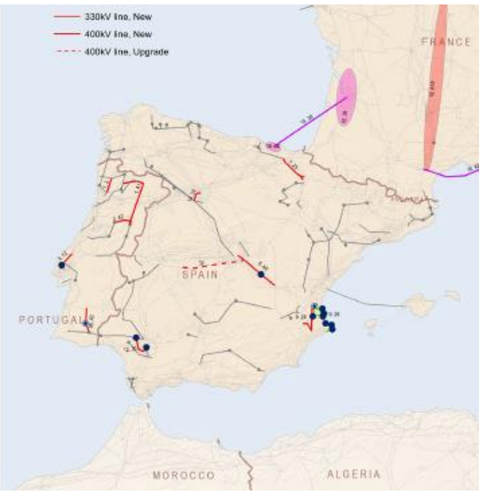


Figure 7.7: TYNDP 2012 projects in the CSW region

At present there is not a specific regulation in Spain applying exclusively to HVDC connections. However, technical requirements of these infrastructure projects have been set individually within the technical specifications of each project. To date HVDC systems have only been of interest for the Spanish TSO.

7.3.5 GREAT BRITAIN

The first embedded HVDC link is under construction linking Scotland and England in parallel with 4 existing HVAC circuits (which use two double circuit HVAC overhead lines). This West Coast HVDC link is routed via the Irish Sea with a massive 2,200MW and a further significant overload capability (measured in hours). This link is using LCC technology. See presentation A1.1 at the IET ACDC2012 conference [8].

Another four embedded schemes are included in the Gone Green 2030 network plan, These are all sea links located on the North East – Scottish coast as well as on the Welsh coast. They may well end up as multi-terminal projects, i.e. HVDC Grids. See diagram 7.10 in Section 7.4.2.

7.3.6 SWEDEN-NORWAY – A FIRST IN DC GRIDS?

A first example of an HVDC Grid is the South-West Scheme under development, linking Southern Sweden with Central Sweden as stage 1. In stage 2 a T-connection is planned to be made with an HVDC connection branching off to deliver a link to Norway. This 3-ended HVDC proposal embedded in the HVAC system was described at the IET ACDC2012 conference [8], see presentation A1.5.

7.4 DC CONNECTED POWER PARK MODULES

7.4.1 IRELAND

Some envisaged projects are

- ISLES (Irish Scottish Links on Energy Study): Offshore interconnected electricity grid based on renewable resources (wind, wave and tidal).
- Interconnection associated with proposed renewable energy export projects. For example, the Greenwire Interconnector project and the Energy Bridge interconnection project, both proposed to connect between Ireland and Great Britain.
- Natural Hydro Energy Strategic Energy Infrastructure: Large scale pumped storage schemes on the Irish West Coast interconnected by High Voltage DC cables to the Irish and UK grid systems.

The cost of offshore networks using HVDC technologies is significantly higher than those of onshore networks or AC offshore technologies. Consequently, DC technology is only economically viable over long distances. In the case of offshore cable networks this has been calculated in the “Offshore Grid study” as being higher than c.60km. Also long aggregate lengths of EHV AC cables have a number of technical issues favouring the use of DC cables.

A fundamental aspect of DC connected PPMs is to examine whether this generation could trigger an AC or DC offshore network built either ‘Meshed’, with parallel circuit or ‘Radial’ with a series of links from collection points for offshore generation power transfer directly to onshore networks.

The analysis performed in Ireland has shown that neither AC nor DC is exclusively selected but rather a mixed approach with the cost of the two technologies dictating heavily their use. The shorter links are predominately AC; however in some applications the use of DC technology could be used to control power and postpone the network investment. Almost every development to a transmission network has an interaction with the existing network. The level of this interaction and the resulting impact defines whether the development is symbiotic in nature. The results of the study carried out in Ireland show that reinforcement onshore is required for the introduction of generation offshore. This is not purely as a result of the need to strengthen the path from the offshore generation into the network to load demand centres, but also to provide routes through the onshore networks to other parts of the offshore network for bulk power transfer (for example to export to another country). Consequently both onshore and offshore networks are symbiotic in nature, i.e. they assist one another and hybrid network using DC and AC thereby minimise the overall development requirements. See reference [22].

7.4.2 GREAT BRITAIN

National Grid published in September 2012 energy scenarios covering all main forms of energy from the present through to 2050 [22]. This document covers three separate scenarios of which the central scenario called is “Gone Green” and is designed to just meet the targets of EU (202020) related to UK (15% RES of all energy or about 30% of electricity) and UK (80% CO2 reduction by 2050 underwritten by law). In addition to the 3 scenarios the transmission contracted position for new generation is also listed. The contracted position significantly exceeds all three scenarios, even the high scenario called “Accelerated Growth”.

The installed electricity capacity up to 2030 in the central scenario, Gone Green is shown below and the key RES parameters are:

- 2020: 30GW Wind (Demand: 68GW max, 23GW min)
- 2030: 55GW Wind (Demand: 79GW max, 26GW min)

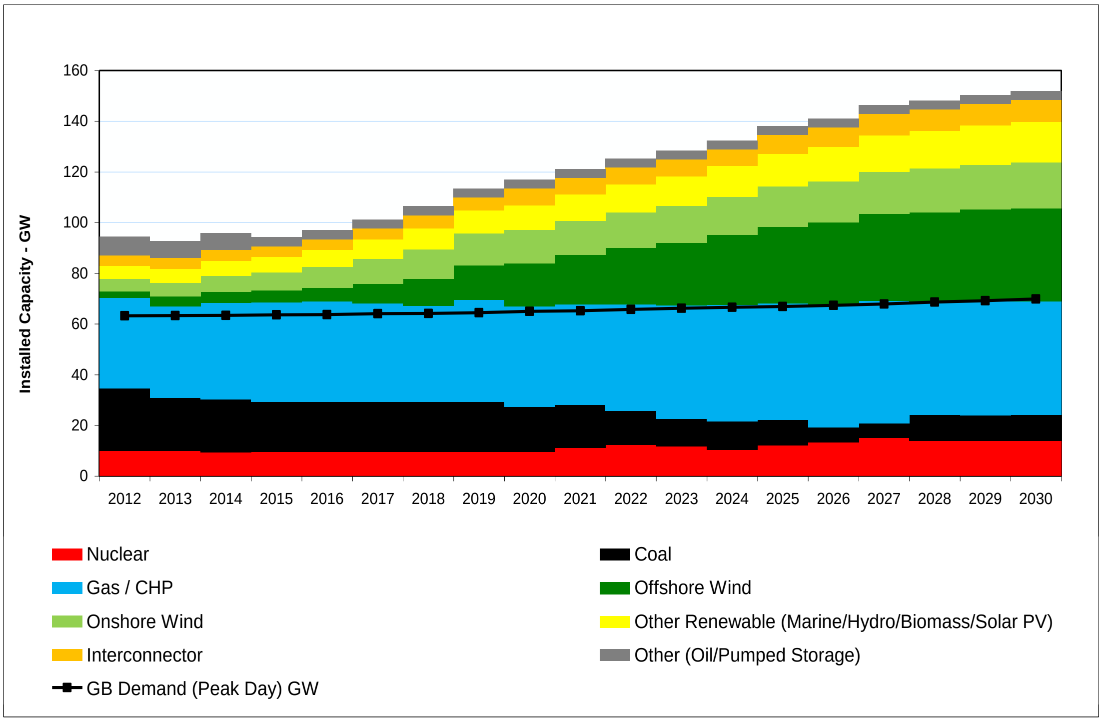


Figure 7.8: Installed capacity per generation type – "Gone Green" scerario

The above developments in installed capacity (GW) show that the maximum demand can approximately be met either by traditional generation (nuclear and fossil based (the latter moving towards fitting CCS)) all synchronous or by RES based generation, nearly entirely non-synchronous generation. Supplying the demand from a predominantly Non-Synchronous Generation (NSG) is a major system technical challenge, increasing as the % NSG potentially moves from 50% towards 100% of the total synchronous system demand and even beyond. This also has significant implications on the requirements of the HVDC systems which may be connecting more than half of this power.

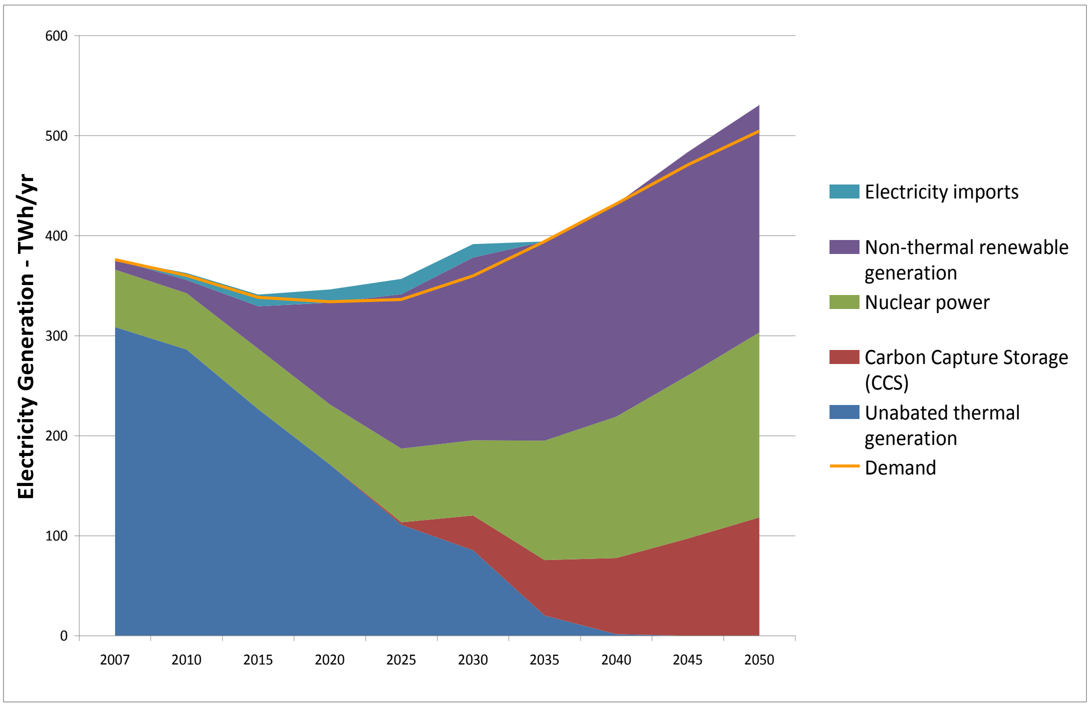


Figure 7.9: Generation technology shares of electrical energy production (TWh) to 2050 in Gone Green scenario

National Grid has published its Electricity Ten Year Statement (ETYS) [21]. This covers the network developments expected over the next 20 years for each of the scenarios as well as describing in outline in chapter 4 some of the system technical challenges.

The middle scenario "Gone Green" designed to just meet environmental targets contains about 35 HVDC installations by 2030, of which about 25 installations relate to connection of offshore wind generation. The Gone Green scenario for 2030 indicates significant hours in the year in which wind production exceeds the total demand of the GB synchronous area, unless constrained off.

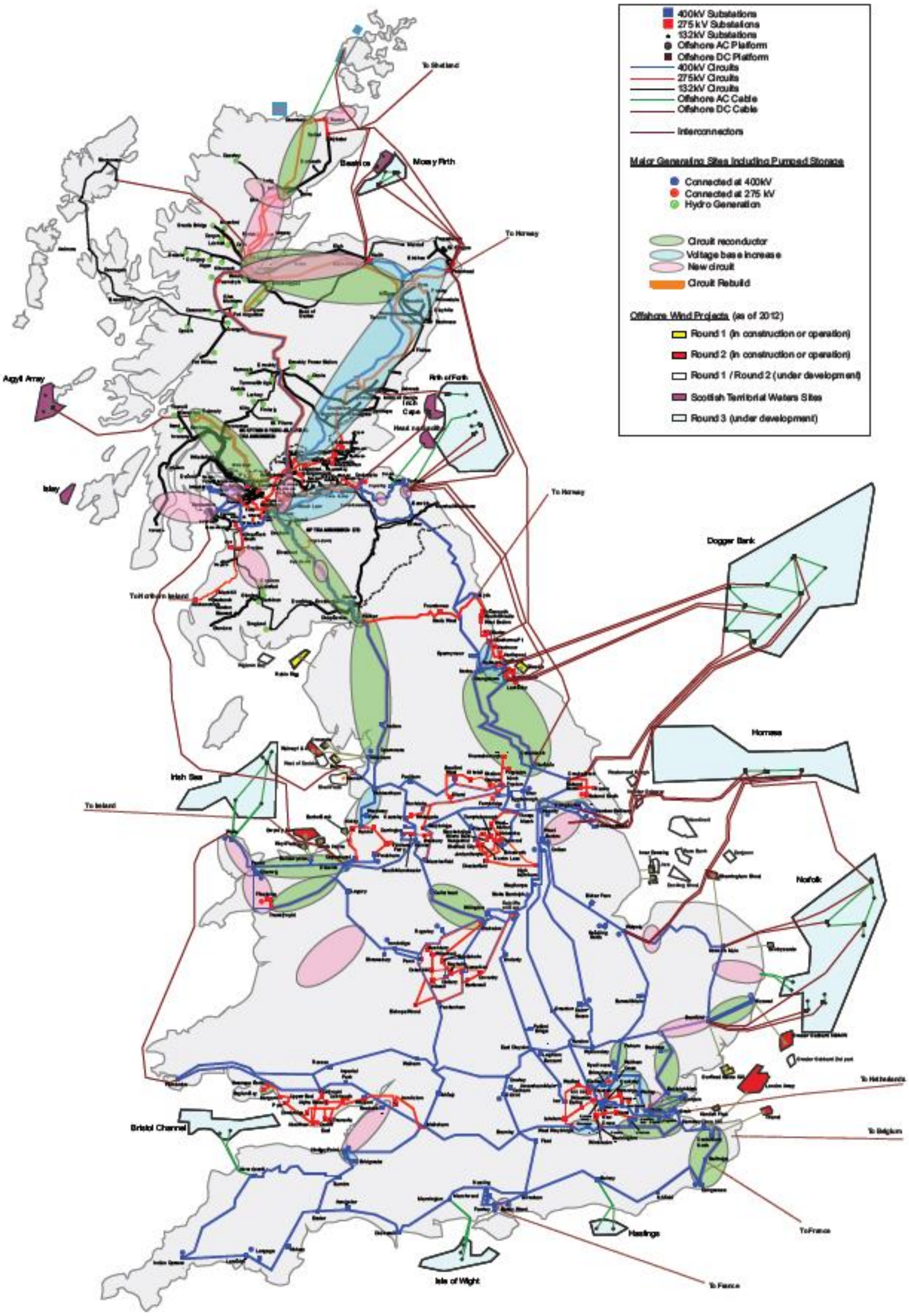


Figure 7.10: Network development plans up to 2030 – "Gone Green" scenario

The system challenges include a dramatic reduction in total GB system inertia. This is illustrated for the period up to 2030 for the Gone Green scenario, for the case of 70% production (compared to installed capacity). It can be seen that unless action is taken with new requirements the total system inertia for GB falls from typically 250GVAs to the range of 50-100GVAs for the more challenging conditions in 2030. This change will make it very challenging to deal with the planned largest loss of 1800MW (from April 2014).

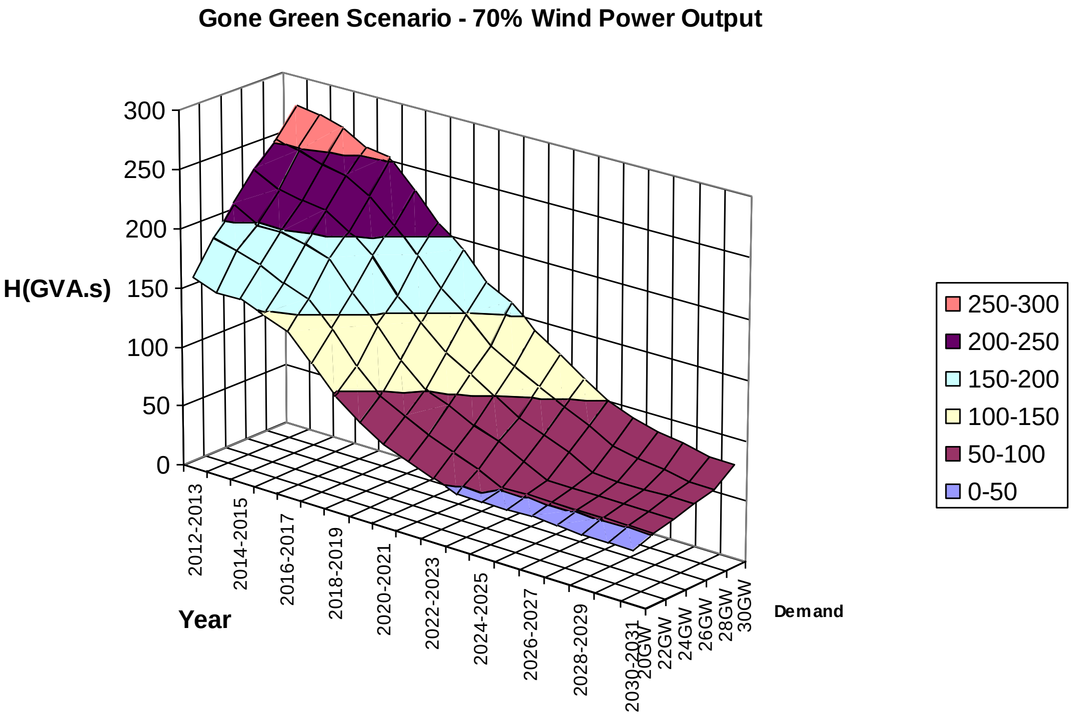


Figure 7.11: System inertia vs demand values – "Gone green" scenario

To improve the low total system inertia, it is important that all forms of generation, including that presented to the system via HVDC connections deliver a form of inertia contribution. An IEEE Transactions on Power Systems publication [12] by Jiebei Zhu, Campbell D Booth, Grain P Adam, Andrew J Roscoe and Chris G Bright entitled „Inertia Emulation Control Strategy for VSC-HVDC Transmission Systems" demonstrates that this may be possible from HVDC systems from release of capacitive energy in the DC link of VSC HVDC systems. If the suggested H=3s can be delivered economically in practical full scale systems, this could make a major contribution, even if sustained for a period shorter than the 8s described in this paper.

7.4.3 DENMARK

The transformation of the Danish power system to a power system in which 50 per cent of the electricity consumption is covered by wind power assumes that the infrastructure must be strengthened both nationally as well as internationally and that there are efficient international electricity markets. Added to that, the energy systems must be more integrated in order for the transformation to be socio-economically efficient.

Energinet.dk analysis continues to follow the development of the balance between the electricity consumption and production (wind in particular) in order to secure the implementation of the necessary infrastructure investments and adjustments in market design. In addition, Energinet.dk continues to estimate the need to change the incentive to keep the necessary production capacity, in case the development changes in relation to Energinet.dk's expectations.

The three core challenges to be handled in 2020:

- Wind power must be used more efficiently in the periods with larger wind power production than consumption.
- The Danish electricity consumption must also cover the situations and the periods without wind.
- Consumption and production must match, ie so-called balancing of consumption and production must take place. The challenge is that the amount of energy to be balanced largely corresponds with the Danish energy consumption when it is at its highest (peak consumption).

In order to meet these challenges in an efficient way, it is necessary that the other areas of the energy system (heat, gas and transport) are also included in order to provide flexibility in the power system. However, the majority of the flexibility lies within the power system itself until 2020. This flexibility until 2020 is primarily achieved by:

- Strong national infrastructure
- Strong international connections
- Effective international markets
- Domestic production resources

Denmark is generally well-integrated with the rest of Europe, but due to the increasing renewable energy, it requires expansion to the surrounding countries. However, it is a challenge that many of these countries do not always have the same incentive to establish connections with Denmark, as Denmark has. The design of the Danish energy system and the ambitious political objectives of integration of renewable energy entails that connections will often be profitable for Denmark before they are profitable for the surrounding countries.

By 2020, about 50 per cent of the Danish electricity consumption will be covered by wind power. Through long-term planning, the electricity infrastructure will be developed concurrently with the expansion of the planned offshore wind farms, near-shore wind turbines as well as new and larger onshore wind turbines. In the period 2017-2020, the power connection of two new offshore wind farms, Krigers Flak and Horns Rev 3 will be commissioned. Besides the two large-scale offshore wind farms at a total of 1,000MW, Energinet.dk expects to connect at least 500MW near-shore wind turbines towards 2020 as well as some of the new 1,800MW new onshore wind turbines that were decided in the energy agreement. Some of the new onshore wind turbines will replace old ones. It is expected that the total net expansion with wind power will be approx. 2,000MW towards 2020.

7.4.4 THE NETHERLANDS

With respect to the future system developments relevant to HVDC in the Netherlands a clear distinction between the short and longer term has to be made.

Although the Netherlands intend to fulfil their obligations towards the EU policy to increase the use of RES, the bulk of the electricity is currently produced by conventional energy sources. There is a tendency to concentrate new power plants at coastal locations, which requires reinforcements in the high voltage AC grid. Cost benefit analysis have shown that for the Dutch grid, with relatively short distances in a strong meshed grid, HVDC is not the most efficient solution.

In the long term, two developments can be distinguished. On the one hand it is expected that new cross border submarine HVDC connections to North Sea countries are a serious option to create new possibilities of the penetration of RES and will create new market opportunities. On the other hand, improved and new HVDC technologies will make the connection of far away large offshore wind farms feasible.

In both cases, onshore converter stations will connect to the main AC onshore infrastructure, and will therefore be electrically close to conventional power plants and electrically close to other onshore converter stations.

These future developments will, in the Netherlands, increase the need for a focus and understanding on several issues like:

- The interaction between different HVDC converters, between HVDC converters and conventional power plants;
- the interaction of protection and control between AC and DC grid;
- the use of additional capabilities of VSC converters, for instance with respect to reactive power and voltage control;
- the short circuit behaviour of the converter stations.

Besides the above mentioned developments, cross border impact of German HVDC development plans on the Dutch power system will need to be investigated.

7.4.5 GERMANY

Renewable energy and especially offshore wind will play a major role in Germany’s future energy system. This requires, in addition to fundamental change of the onshore transmission grid, measures to connect the offshore wind farms to the onshore system. The resulting technical challenges entail innovative technologies and concepts.

Figure 7.12: Offshore Wind Farms and Grid Connection Systems in the German North Sea

For the German North Sea the connection of the Offshore Wind Farms will be mainly done by using HVDC systems. This was found to be the most economical solution taking into account the total cost of ownership bearing in mind the amount of installed power and the long distance between the Wind Farm cluster and the suitable onshore connection point. As a result, each individual cluster is operated as a single isolated network consisting of mainly power electronic devices. Consequently, the operational performance differs significantly from the classical system, e.g.:

- In such networks there is no physical link between the frequency and the balance of generation and demand.
- During network faults the short circuit currents do not differ significantly from the operational currents
- The harmonics distortion of the voltage is not currently causing any issues in the EHV system. However, in future this could be a concern because of an increasing amount of power electronic devices as well as the lower fault levels in the AC systems.

As a result, the future Grid Code has to tackle new topics besides the existing requirements.