Deliverable 1.3: Synthesis of available studies on offshore meshed HVDC grids

PROMOTioN – Progress on Meshed HVDC Offshore Transmission Networks
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EXECUTIVE SUMMARY

Several previous studies have already addressed the development of offshore meshed HVDC grids and the associated technical challenges and regulatory and financial barriers. The PROMOTioN “Progress on Meshed HVDC Offshore Transmission Networks” project builds on those studies, in order to address a number of the remaining barriers for the implementation of offshore grids including: high cost of connection for wind resources, security and robustness of the grid, international regulations and access to financial resources. The aims of this deliverable (D1.3), which forms part of work package 1 (WP1), are the synthetization of existing studies relevant for the project, and the justification of PROMOTioN scope of work in respect to current barriers and gaps. Therefore, this report intends to provide a state-of-the-art picture of the offshore meshed HVDC grids.

A fundamental ingredient to unlock the full potential of Europe’s offshore resources in the North Seas (North Sea, Irish Sea, English Channel, Skagerrak Strait and Kattegat Bay) is the demonstration of the cost effectiveness of a solution to harness these resources. Numerous roadmaps have been proposed in the past decade for the development of an offshore meshed grid in the North Seas. Exact geographical scopes, methodologies and assumptions can differ strongly from one study to another. Moreover, very different levels of details are used to model power systems: from macro-levels, modelling only transfer capacities between hubs, to node-breaker models. Nevertheless, some trends emerge from the analysis of these past roadmaps. Firstly, it is unlikely that the final solution consists of a single large interconnected offshore grid: roadmaps usually come up with several offshore grids not connected together by DC branches. Secondly, complex offshore topologies (i.e. radial multi-terminal and meshed grids) appear to be cost-efficient only for scenarios considering both a high offshore wind generating capacity and numerous offshore hubs to collect this energy (geographical spreading). Otherwise, purely radial configurations stay the most economical way to collect wind energy. It must also be noted that offshore mixed AC/DC grids can be relevant from an economic point of view in some cases. Finally, the economical advantage of complex offshore topologies such as radial multi-terminal and meshed grids can only be demonstrated when the overall grid structure is optimized.

The development of HVDC grids based on VSC and Diode Rectifier Units (DRU) converter technologies introduces new operation and control challenges to maintain the stability of the offshore DC grid, the offshore AC grids connecting wind power plants, and the onshore AC grid. A first issue is the steady-state control of the DC grid to maintain voltages across the grid in an acceptable range, but several kinds of dynamic instabilities could occur as well. For example, the massive integration of converters based on power electronics in the grid introduces new possible interactions between components and the literature shows that this can lead to new resonance phenomena between the converters, either within the DC grid, or through the AC grid. Moreover, developping an offshore HVDC grid in the North Seas will not be done in one step: it is expected that the offshore grid will be developed over several decades, following the development of offshore wind generation. Consequently, several technologies will be integrated, from different manufacturers. The interoperability of converters in such offshore grids remains an open question. The connection of OWFs to the main onshore grid

through HVDC systems also leads to small islanded offshore AC grids dominated by cables and power electronics (i.e. there is no synchronous generator to provide an inherently stabilising source of inertia). If wind turbines and HVDC converters are not properly operated, instabilities could occur, as has already been observed in the BorWin1 HVDC system connecting an offshore wind farm to the shore in Germany. In this case, unexpected harmonics issues occurred, leading to the outage of the HVDC system when converters entered into resonance with the offshore AC grid natural frequencies. The introduction of the DRU leads to new phenomena and the appropriate control of converters and wind power plants in that context is still unknown, in particular when the connection of wind turbines from different vendors must be enabled.

Similarly to AC grids, faults can occur on transmission elements in a DC grid. Consequently, DC grid protection systems must be able to detect and isolate faults and minimize their negative impacts. In a point-to-point HVDC system, it is usually sufficient to open circuit breakers on the AC side to isolate the fault. The problem is much more difficult for complex DC grid topologies such as radial multi-terminal and meshed grids, because, depending on the protection philosophy, there is the need for selective fault detection and clearing. Moreover, a speed requirement is expected for the fault detection and identification in these complex DC grid topologies, such that the faulty element can be disconnected before the current increases beyond the acceptable limits of the system. Numerous HVDC grid protection schemes have been proposed by academia and industry, but they remain at the theoretical level with no practical implementation having been made so far. The literature shows that there is no final consensus on the protection schemes that will be the most suitable for practical implementation. Indeed, no single basic protection principle fulfills all the requirements needed for meshed HVDC grids. Protection systems must thus combine several basic protection principles to perform as required. Another challenge to isolate faults is the development of adequate DC circuit breakers (DCCBs) which must interrupt the fault current quickly, due to the high rate of rise of fault current in DC grids (which is limited only by the resistive part of cables). Additionally, a sufficient means of generating a current zero or an appropriate counter voltage is also required in DCCBs because there is no natural zero crossing of fault current to extinguish the arc, as exists in conventional AC circuit breakers,. If adequate technological concepts already exist for DCCBs (e.g. resonant DCCB, solid-state DCCB, hybrid DCCB) no practical installation exists at this moment. A main barrier for the deployment of DCCBs is the lack of detailed data on the behavior of DCCBs and their interaction with their electric environment. In particular, it is difficult to compare devices from the different manufacturers because they have varying characteristics and they were not compared on the basis of standardized methodologies.

Finally, a number of regulatory and financial barriers are also hampering a large scale deployment of meshed HVDC grids. A vast amount of studies have been done regarding the regulation of financing of transnational infrastructures such as a meshed offshore grid. However, some topics are not fully covered. For example, the amount of literature on the financing mechanisms for such an infrastructure is still limited. Moreover, there is no unanimity on the way to alleviate regulatory and financial barriers: several reports propose different and sometimes conflicting recommandations to attain transnational infrastructure development. Thus, even if progress has been made, there is not yet a definite international regulatory and financial framework for an offshore grid in the North Seas.

LIST OF ACRONYMS

ACRONYM	MEANING
ACER	Agency for Cooperation of Energy Regulators
CBA	Cost Benefit Analysis
CBCA	Cross Border Cost Allocation
CCC	Capacity Commutated Converters
CEF	Connecting Europe Facility
CP	Consenting Procedures
CSC	Current Source Converter
D	Deliverable
DA	Day-Ahead
DCCB	Direct Current Circuit Breaker
DCG	DC grids
DC OPF	Direct Current Optimal Power Flow
DRU	Diode Rectifier Unit
EIA	Environmental Impact Assessment
ENTSO-E	European Network of Transmission System Operators for Electricity
EU RED	European Renewable Energy Directive
FG	Framework Guideline
FRT	Fault Ride Through
HVDC	High Voltage Direct Current
IC	Interconnection
ID	Intra-Day
ISLES	Irish-Scottish Links on Energy Study
LCC	Line Commutated Converter
MMC	Modular Multilevel Converter
MOG	Meshed Offshore Grid

MS	Member State
MSP	Marine Spatial Planning
NC	Network Code
NGET	National Grid Electricity Transmission
NRA	National Regulatory Authority
NSCOGI	North Seas Countries' Offshore Grid Initiative
OfTO	Offshore Transmission Owner
ORG	Offshore Renewable Generation
OWF	Offshore Wind Farm
OWG	Offshore Wind Generation
OWPP	Offshore Wind Power Plant
PCI	Project of Common Interest
PROMOTioN	Progress on Meshed HVDC Offshore Transmission Networks
PSST	Power System Simulation Tool
RES	Renewable Energy Sources
SO	System Operator
SPS	Special Protection Scheme
SPV	Special Purpose Vehicle
TSO	Transmission System Operator
TYNDP	Ten Year Network Development Plan
VSC	Voltage Source Converter
WTG	Wind Turbine Generator
WP	Work Package
WPP	Wind Power Plant

CONTENT

1 INTRODUCTION

Several previous studies have already addressed the development of offshore meshed HVDC grids and the associated technical challenges and regulatory and financial barriers. The PROMOTioN "Progress on Meshed HVDC Offshore Transmission Networks" project builds on those studies, in order to address a number of the remaining barriers for the implementation of offshore grids including: high cost of connection for wind resources, security and robustness of the grid, international regulations and access to financial resources. The aims of this deliverable (D1.3), which forms part of work package 1 (WP1), are the synthetization of existing studies relevant for the project, and the justification of PROMOTioN scope of work in respect to current barriers and gaps. Therefore, this report intends to provide a state-of-the-art picture of the offshore meshed HVDC grids.

When speaking about offshore HVDC grids, the first emerging question deals with the grid topology: how wind farms and countries are likely to be connected together? Fundamental grid topologies are presented in D1.1 and developed in D1.4. Several studies (e.g. Twenties, ISLES, NSCOGI, etc.) already developed roadmaps for the North Seas using the different fundamental grid topologies. Therefore, the first step of the literature review will be the analysis of those studies to understand how offshore grids can be planned and to identify under which circumstances a certain fundamental topology is likely to be implemented. This is done in Chapter 2, "System planning and grid topologies".

The rest of this report is organized according to the four project pathways: converters, protection systems, circuit breakers, and finance & regulation. The first project pathway ("Converters") investigates the operability of future HVDC grids, focusing on the practical utilization of new ways in connecting offshore wind resources based on different converter technologies (specifically DRU and VSC converters). This project pathway consists of two main components. The first component is the study of interoperability and the controllability of converters, during both normal operation and fault conditions, for the different fundamental topologies. The second component is the study of the interoperability of wind turbine and wind power plant controls with the converters (DR and VSC converters) connecting the wind power plants to the DC network. In line with these two components of the first project pathway, studies on the interaction between converters and the system is reviewed in Chapter 3, and studies on interactions between wind turbine generators and converters is reviewed in Chapter 4. The second project pathway ("Protection systems") aims at developing and demonstrating the most appropriate DC grid protection methodologies for the various fundamental grid topologies. Consequently, studies on DC grid protection systems are reviewed in Chapter 5. The third project pathway ("Circuit breakers") will pave the way for commercial deployment of circuit breakers for HVDC systems. Therefore, Chapter 6 reviews design options for HVDC circuit breakers and their current performances. Finally, the fourth project pathway ("Finance & Regulation") will investigate aspects regarding regulatory regimes and financing arrangements for offshore grids. Chapter 7 shows that numerous studies already addressed regulatory and financial barriers, but many questions remain unsolved, in particular for meshed topologies.

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Three specific appendices are also included in this report. Appendix A summarizes the assumptions that were made in previous studies on technologies, costs and reliability of components, in order to define values that will be used in the beginning of the PROMOTioN project. Appendix B will help the PROMOTioN consortium to quantify requirements defined in D1.1 by gathering values that were used in previous studies. Appendix C contains an exhaustive list of summaries of the works done in the framework of the Medow project that could be of interest for the PROMOTioN project.

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2 SYSTEM PLANNING AND GRID TOPOLOGIES

A fundamental ingredient to unlock the full potential of Europe's offshore resources in the North Seas is the demonstration of the cost effectiveness of a solution to harness these resources. In this document, the definition of the "North Seas" is aligned with the one of NSCOGI: it refers to the North Sea, the Irish Sea, the English Channel, Skagerrak Strait, and Kattegat Bay [1]. As shown in D1.1, several fundamental grid topologies, from radial to meshed solutions, can be used for the development of an offshore HVDC grid. Different grid design strategies, using these fundamental topologies have been already proposed and their economic viability has been assessed in various studies. The purpose of this Chapter is to review previous works that proposed roadmaps and master plans for the development of an offshore grid in the North Seas. Methodologies will be reviewed briefly[1], but grid design strategies previously proposed and results of the assessment of economic viability will be detailed. Potential gaps are identified in this Chapter, as well as necessary input data to derive a roadmap. Assumption on technologies, costs and reliability of components are summarized in Appendix A.

It should be noted that the North Seas region actually gathers two non-connected maritime areas: the North Sea, the English Channel, Skagerrak Strait, and Kattegat Bay, which can be called the "extended North Sea", on one side, and the Irish Sea, the straits of Moyle and around the western coastal waters of Scotland, which can be called "extended Irish Sea" on the other side. For the sake of clarity, previous studies are divided in two groups according to this geographical division: Section 2.1 analyzes previous studies that focused on the development of an offshore grid in the extended North Sea (mainly WindSpeed, OffshoreGrid, NSCOGI and Twenties) and Section 2.3 analyzes previous studies that dealt on the extended Irish Sea (mainly ISLES I and ISLES II). Finally, Section 2.4 will conclude on the methodologies used for planning offshore grids and on the topologies that were already proposed.

2.1 OFFSHORE GRID IN THE EXTENDED NORTH SEA

The interest in offshore wind energy in the North Sea rose in the nineties [2] but only radial (point-to-point) connections were initially considered. The development of an offshore grid with possible radial multi-terminal and meshed parts started to be studied in the years after 2000.

2.1.1 WINDSPEED PROJECT

The WindSpeed project, launched in 2008, was one of the first major studies on the development of an offshore grid in the North Sea. The aim of that project was to address the large scale planning and deployment of offshore wind energy in the Central and Southern North Sea between 2020 and 2030. The final roadmap was presented in June 2011. Two main scenarios are analyzed: *In the Deep* and *Grand Design*. The *In the Deep*

[1] Planning methodologies will be detailed in D1.6.

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scenario reflects a bottom-up approach to spatial planning of offshore wind farms, with a priority given for clusters of wind farms far from the shore (near to shore priority is given to existing sea use functions and nature conservation). The *Grand Design* scenario reflects a unified top-down approach to spatial planning of offshore wind farms with a compromise between wind-use of North Sea and other uses. The installed wind offshore capacity is around 53 GW in the *In the Deep* scenario and 81 and 88 GW in the two variants of the *Grand Design* scenario [3]. For each scenario, the grid topology was optimized based on the Net-Op tool developed by SINTEF Energy Research: the sum of the investment cost and the operational cost is minimized. In that tool, the constraints imposed by the grid are modeled with a transportation model[2], which limits the accuracy of the analysis in the case of a meshed grid if the power flows on each individual HVDC link are not controllable. The capacity expansion planning considers several possible operating states in order to have a good statistical description of the wind and solar power and load fluctuations. However, outages of transmission system elements are not considered. Moreover, only the target year 2030 was analysed and the optimal sequence of investments was not computed. The area analyzed is the Central and Southern North Sea with all neighboring countries (Norway, Denmark, Netherlands, Belgium, and United Kingdom). The offshore clusters and the grid of each country are represented by different nodes. Figure 2.1 shows the optimal configurations for the *In the Deep* scenario and for the *Grand Design* scenario. The *Grand Design* scenario leads to more grid investments but also to a larger reduction in operational costs, compared to the *In the Deep* scenario, as a consequence of a higher installed capacity of offshore wind. It results to a total net benefit of approximately €120 billion over the lifetime (30 years). However, both grid configurations have meshed parts and radial multi-terminal parts. The net benefit compared to a purely radial system is not computed.

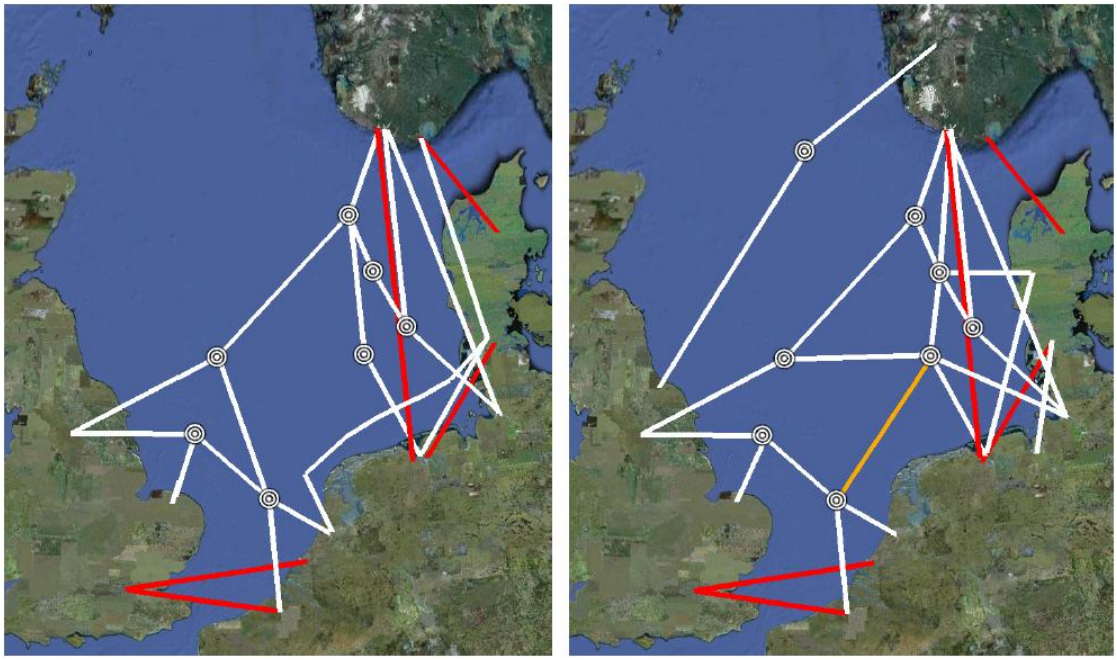

Figure 2.1. Offshore grid configurations in the WindSpeed project [3].

[2] In a transportation model, power can be transferred through the grid wherever there is free capacity, under the constraint of transfer capacity between nodes, but Kirchhoff's laws are not considered.

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2.1.2 OFFSHOREGRID AND NORTHSEAGRID PROJECTS

In parallel to the WindSpeed project, the OffshoreGrid project was launched in 2009 to perform an in-depth analysis of how to build a cost-efficient grid in the North Seas and in the Baltic Sea. The final report was delivered in October 2011 [4]. Two different methodologies for the design of an overall offshore grid were studied: the *Direct Design* approach and the *Split Design* approach. The *Direct Design* approach favors high-capacity direct interconnections between countries, and then develops integrated solutions and meshed links. On the contrary, the *Split Design* approach favors lower-cost interconnectors by splitting wind farm connections in order to connect them to two shores (radial-multiterminal topology), and then develops integrated solutions and meshed links. Contrary to the WindSpeed project, the topology is not optimised by a global optimisation problem. Instead, the economic advantage of possible integrated solutions is tested on a case-by-case basis. The economic analysis is performed on the basis of the SINTEF Power System Simulation Tool (PSST) [5]. PSST combines a market model with a model of the European electricity grid, and assumes a perfect market with nodal pricing: the electricity generation dispatch for each hour of the year is found by minimizing the generation cost. The market simulation is based on a DC OPF, which leads to realistic results for power flows on the various branches. However, outages of transmission system elements are not considered. In that study, the total offshore wind capacity installed in Northern Europe is expected to be approximately 116 GW in 2030 with 76 GW in the North Sea. Figure 2.2 shows the grid topology obtained in the *Direct Design* scenario while Figure 2.3 shows the grid topology obtained in the *Split Design* scenario. The topology is purely radial multi-terminal in the Direct Design approach. It is also quasi-entirely the case in the Split Design approach, but a DC loop is also present in the grid. Net benefits brought by an integrated solution over a lifetime of 25 years are around €14 billion for the *Direct Design* and around €11 billion for the *Split Design*.

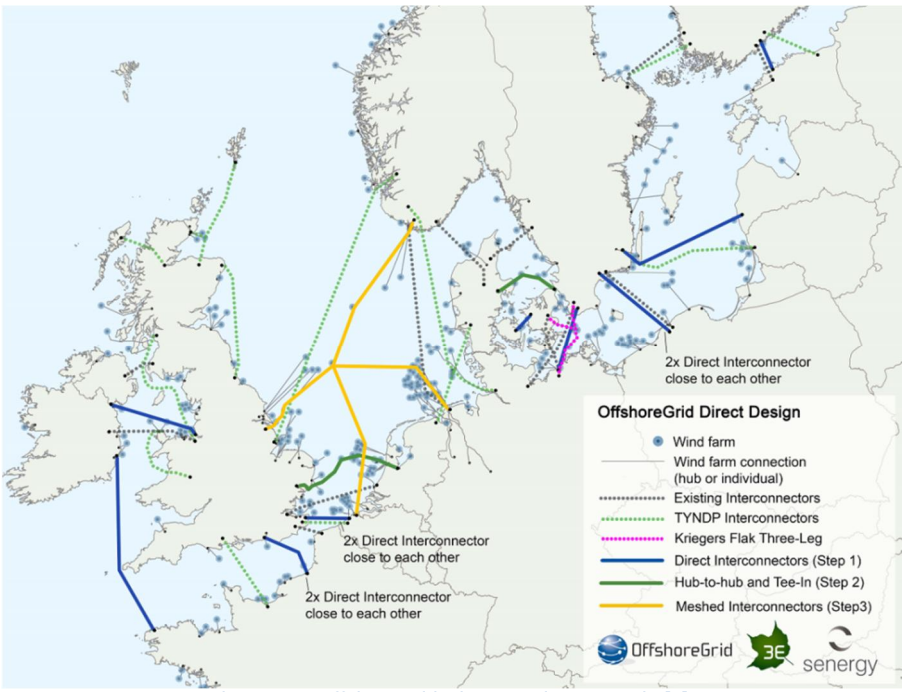

Figure 2.2. OffshoreGrid Direct Design scenario [4].

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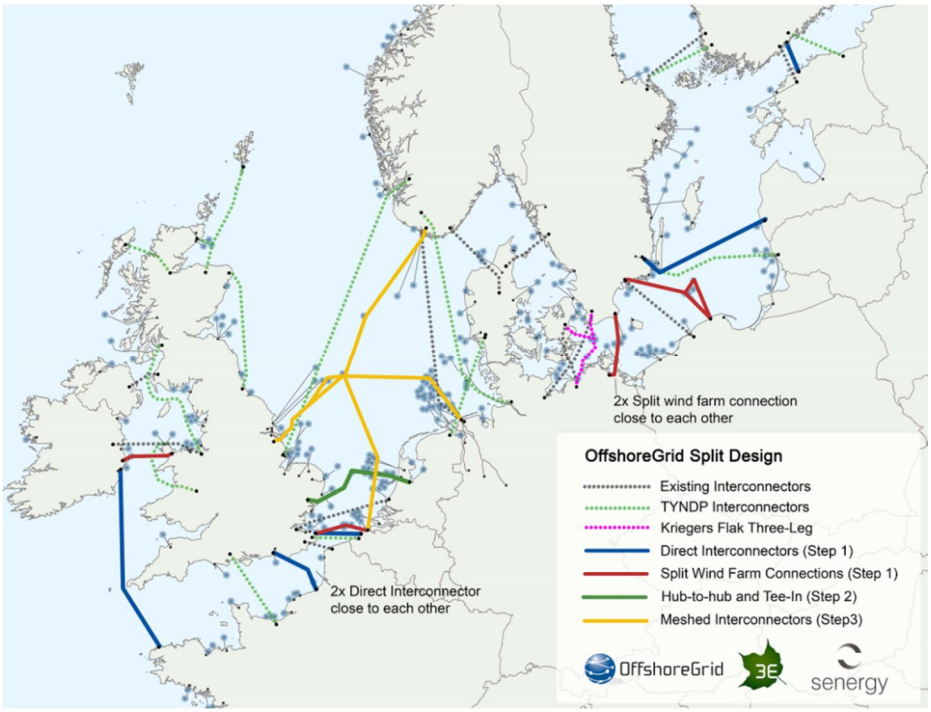

Figure 2.3. OffshoreGrid Split Design scenario [4].

The NorthSeaGrid project, carried out between April 2013 and April 2015, aimed to investigate why the interconnectors integrating offshore wind energy proposed by the OffshoreGrid project are not developed today, despite their economic advantage [6]. The NorthSeaGrid project focused on three case studies for an offshore interconnection integrating offshore wind energy, located in the North Sea, as shown in Figure 2.4: *German Bight*, *Benelux-UK* and *UK-NO*. For each study case, two configurations are studied: the base solution and the integrated solution. The base solution corresponds to the point-to-point offshore wind farms and interconnectors topology, while the integrated solution corresponds to more “meshed” configurations (either radial multi-terminal or mixed AC/DC offshore grids). In the *German Bight* study case, two wind farms are considered in the German part of the North Sea, as shown in Figure 2.5. In the base solution, they are both connected directly and only to Germany by HVDC cables, and a HVDC interconnector connects the Netherlands and Denmark. In the integrated solution, one wind farm is connected directly to both the Netherlands and Germany by HVDC cables, the other one is connected to Denmark by a HVDC cable and there is a hub-to-hub HVDC interconnection between the two wind farms. The resulting topology is radial multi-terminal. In the *Benelux-UK* study case, two wind farms are considered in the Belgium part of the North Sea, and one wind farm is considered in the Dutch part of the North Sea, as shown in Figure 2.6. In the base solution, these wind farms are connected directly and radially to the corresponding country by AC cables, and a HVDC interconnector connects Belgium and the United Kingdom. The two Belgian windfarms are connected together by an AC cable. One Belgian wind farm is connected to Belgium by two AC cables and to the United Kingdom by a HVDC cable. The other Belgian wind farm is connected to the Dutch wind farm by an AC cable and to the Netherlands by a HVDC cable. In the *UK-NO* study case, six wind farms are considered in the British part of the North Sea, as shown in Figure 2.11. In

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the base solution, these wind farms are connected directly and radially to the United Kingdom, by HVDC cables, and a HVDC interconnector connects the United Kingdom and Norway. To improve the reliability, wind farms are connected two by two by AC cables, normally open. In the integrated solution, a meshed offshore AC grid is formed by the connection of offshore wind farms together. This meshed offshore AC grid is then connected to the United Kingdom by four point-to-point HVDC cables and to both United Kingdom and Norway by a HVDC multi-terminal cable. The resulting topology is a hybrid AC/DC network.

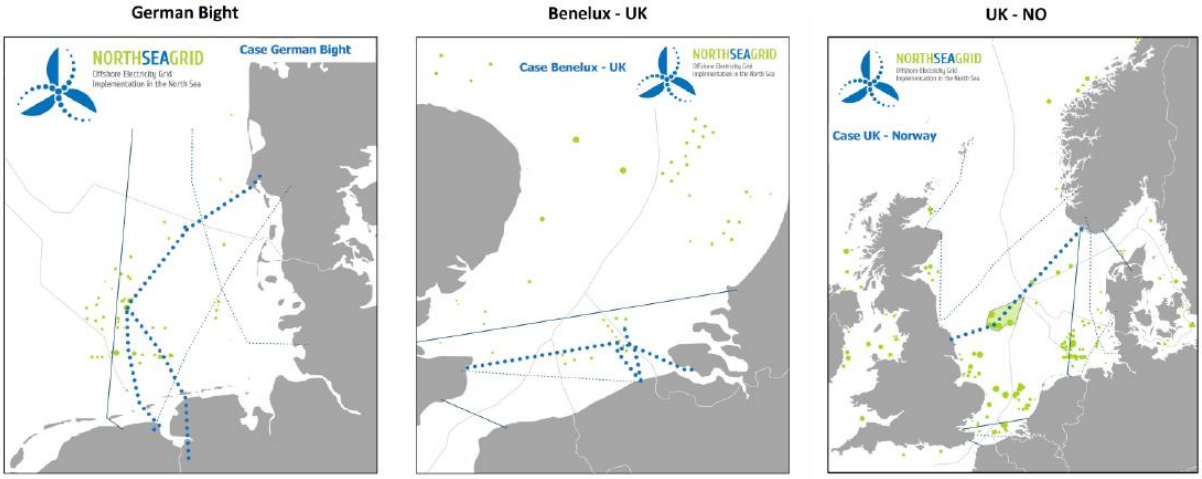

Figure 2.4. NorthSeaGrid study cases [6].

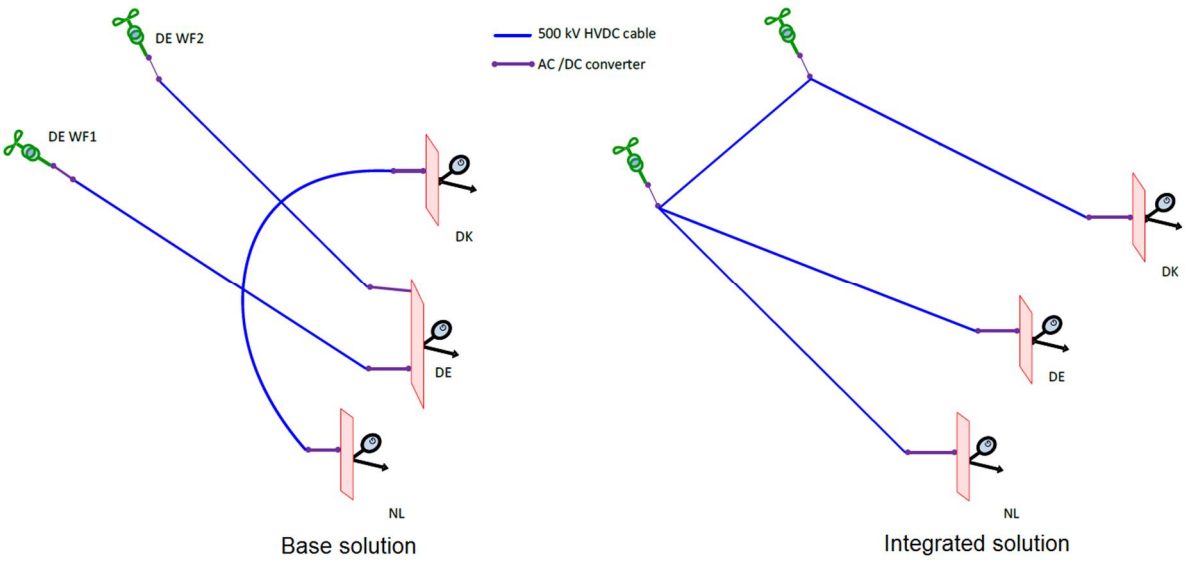

Figure 2.5. NorthSeaGrid German Bight study case [6].

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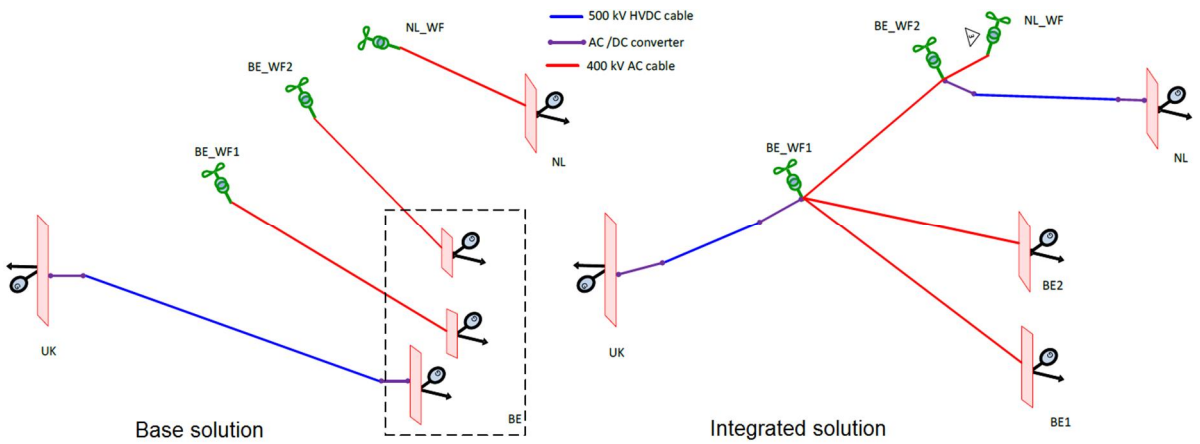

Figure 2.6. NorthSeaGrid Benelux-UK study case [6].

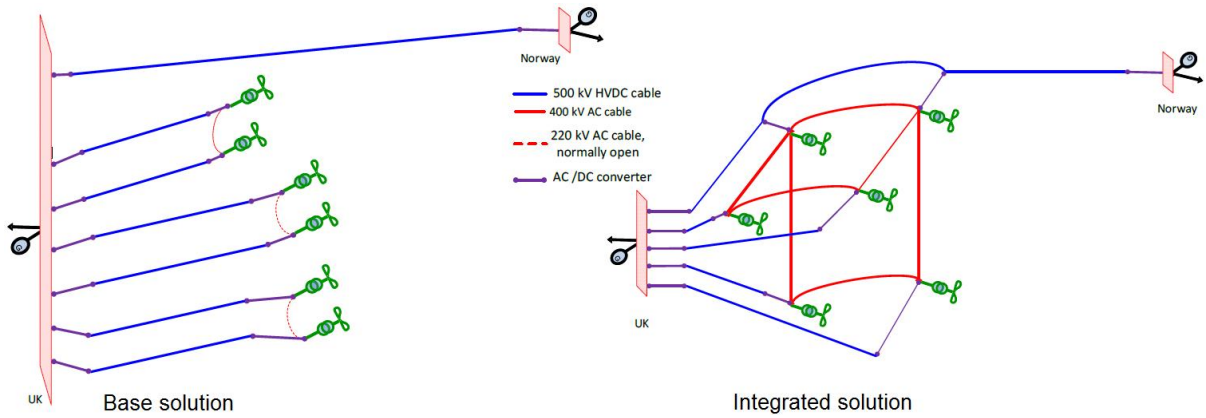

Figure 2.7. NorthSeaGrid UK-NO study case [6].

2.1.3 TWENTIES PROJECT

Following the WindSpeed project and the OffshoreGrid project, the Twenties project also studied offshore grid design in the North Seas. The general aim of the Twenties project (2010-2013) was the demonstration of the benefits and impacts of several critical technologies required to respond to the increasing share of renewable in the pan-European transmission network by 2020 and beyond. A section of the Twenties project was dedicated to studying the potential benefits of different offshore grid configurations [7]. In particular, a radial multi-terminal grid (called H-grid) was compared to a point-to-point connection of offshore wind farms combined with interconnectors between countries, in terms of cost and benefits, for the years 2020 and 2030. The installed offshore capacity is supposed to be approximately 25 GW in 2020 and 61 GW in 2030. The 106 planned wind farms are concentrated on 22 sites. Figure 2.8 shows the proposed point-to-point connection of offshore wind farms combined with interconnectors between countries and the proposed radial multi-terminal grid. The main idea of this radial multi-terminal grid was to combine interregional interconnectors with the connection from wind farm to shore, such that the network that interconnects all the offshore nodes has a minimal length, the offshore nodes are connected to a minimum of two other nodes (when possible) and the interregion transfer capability of the meshed grid case is at least the same as in the case with radial connection of offshore wind farms and

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interconnectors. Consequently, the resulting configuration is not an economic optimum, in contrast to the WindSpeed project. The study considered the technology of the offshore HVDC transmission system to be of VSC type, symmetrical bipolar without electrodes or a dedicated metallic return, at a bipolar level of ±320 kV, double converter of 600 MW each, and double cable with a transmission capacity equal to 1200 MW for the pair of HVDC cables. The economic and reliability (adequacy) analysis have been achieved on the basis of the ANTARES tool developed by RTE and the REMARK tool developed by RSE [7] [8]. These two tools are based on sequential Monte Carlo simulations of the behavior of the power system (power dispatch, RES curtailment and load shedding). Results showed that the radial multi-terminal topology was not economically viable compared to the radial+interconnectors topology. However, it must be reminded that the radial multi-terminal topology was not the result of an economic optimization. Therefore, the results are inconclusive, even if they show that creating the business case for offshore grids is challenging. It was also emphazised in that study that the cost of DC breakers will be a critical factor for the economic viability of integrated solutions.

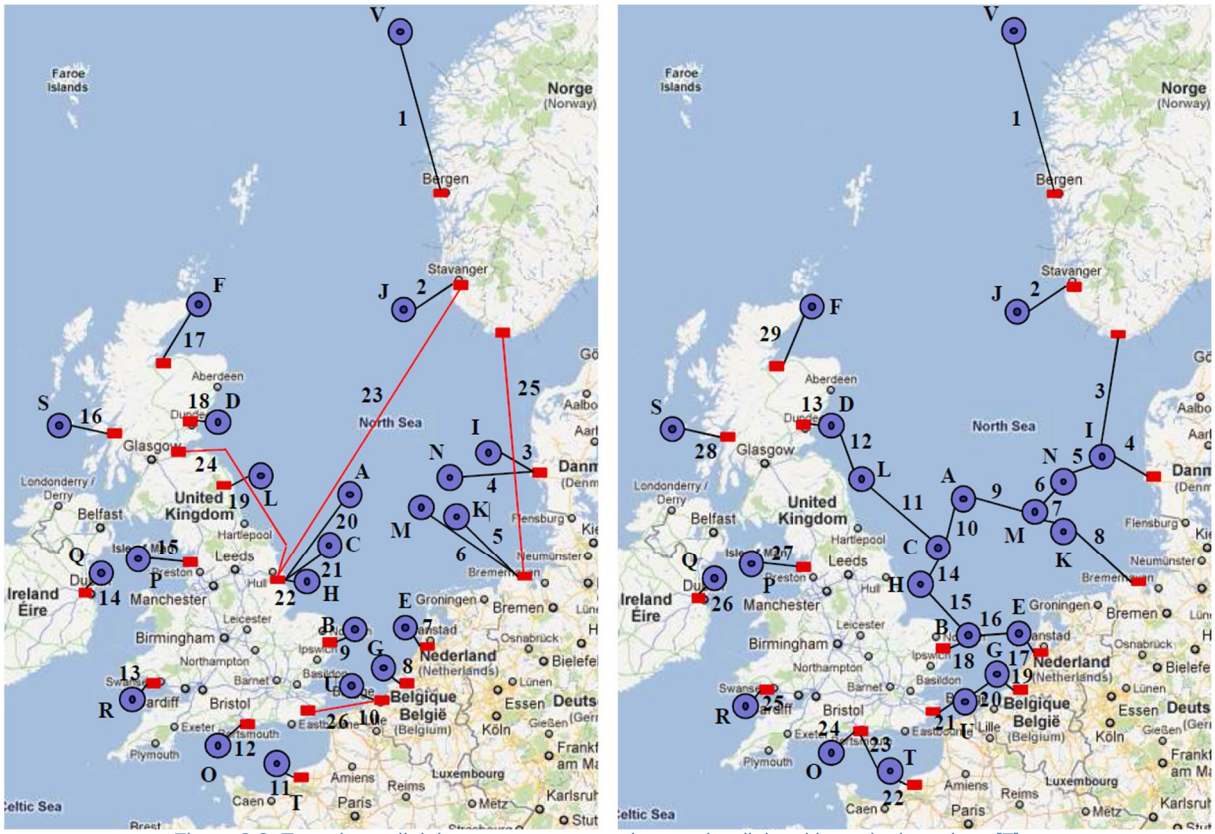

Figure 2.8. Twenties radial+interconnectors topology and radial multi-terminal topology [7].

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2.1.4 NSCOGI STUDY

On December 3, 2010, a Memorandum of Understanding (MoU) was signed by the 10 countries[3] around the North Seas represented by their energy ministries, supported by their Transmission System Operators (TSOs), their regulators and the European Commission together forming the North Seas Countries' Offshore Grid Initiative (NSCOGI). The global purpose of NSCOGI is to evaluate and facilitate coordinated development of a possible offshore grid in the North Seas that maximises the efficient and economic use of those renewable sources and infrastructure investments. For that purpose, three working groups were created: WG1 "Grid configuration and integration issues", WG2 "Market and regulation", and WG3 "Permitting and authorization".

In particular, in parallel of the Twenties project, the WG1 of NSCOGI studied the costs and the benefits brought by two grid designs: a radial design (i.e. point-to-point connection of offshore wind farms combined with interconnectors between countries) and an integrated design (meshed and/or radial multi-terminal) [1]. The year 2030 is chosen as reference, with two scenarios for the offshore wind generation: 56 GW in the reference scenario, and 117 GW in the RES+ scenario. Figure 2.9 and Figure 2.10 show the results for the reference scenario and the RES+ scenario, respectively. For each kind of network design, the topology is optimised based on an approach similar to the OffshoreGrid project: the sum of the investment cost and the operational cost is minimized. The capacity expansion planning considers also several possible operating states (40) in order to have a good statistical description of the wind and solar power and load fluctuations. However, there are two main differences compared to the OffshoreGrid project: the optimisation programme is based on a specific list of new grid link candidates (and not on generic costs between hubs), and DC power flow equations are considered (instead of a transportation model). A detailed analysis of the benefits is then performed through the parallel use of three market simulators (Antares, PowerSym4 and PROMOD IV). They all simulate the electricity market behavior for a one year period in hourly time steps. In general, each country is represented as a single market node (except for Denmark and Luxemburg), and the Net Transfer Capacities (NTCs) set the limit for commercial exchanges between market nodes. The way the meshed offshore grid is modeled in these market simulations is not described. The analysis showed that in the reference scenario (limited development of the offshore wind generation) the integrated solution is slightly better (net benefits are higher by approximately €80 million per year), from an economic point of view, than the radial one, but in the RES+ case (important development of the offshore wind generation), the meshed solution appears to be much better.

[3] Belgium, Denmark, France, Germany, Ireland, Luxemburg, The Netherlands, Norway, Sweden, and the United Kingdom

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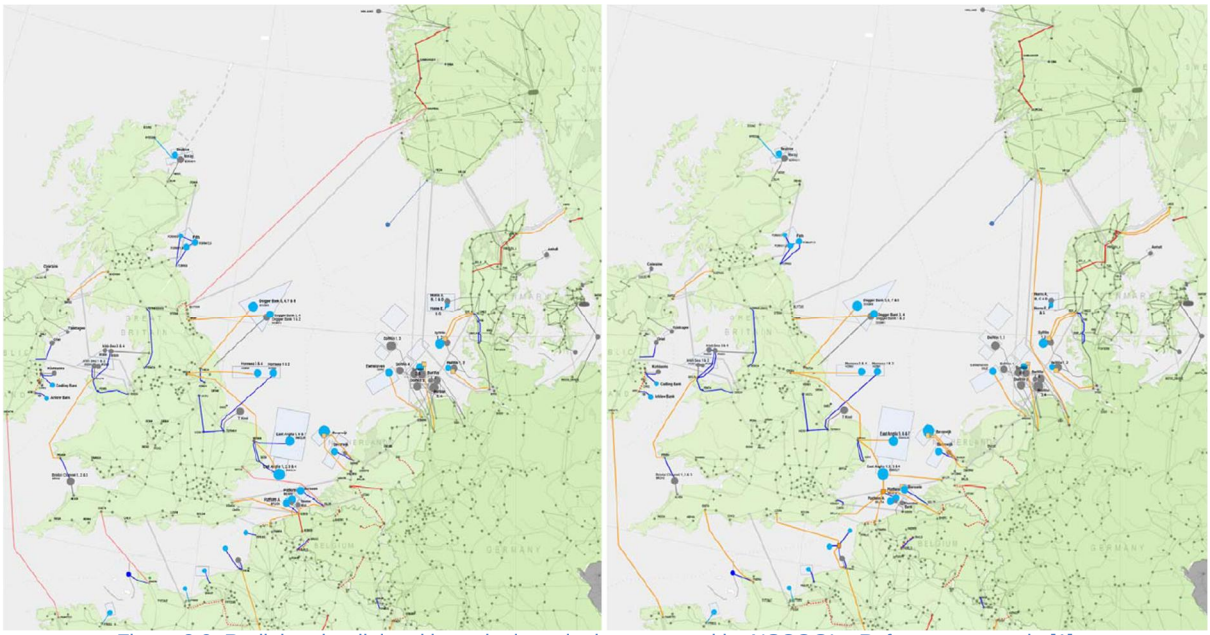

Figure 2.9. Radial and radial multi-terminal topologies proposed by NSCOGI – Reference scenario [1].

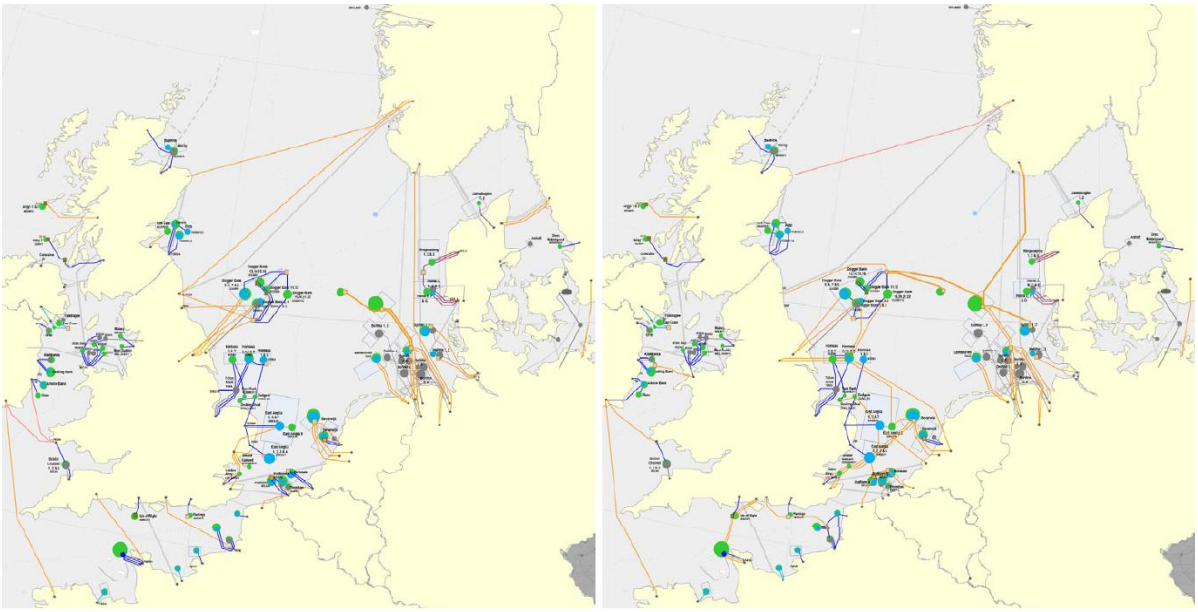

Figure 2.10. Radial and meshed topologies proposed by NSCOGI – RES+ scenario [1].

2.1.5 TRACTEBEL/ECOFYS/PWC STUDY FOR THE EUROPEAN COMMISSION

Following the NSCOGI study, the European Commission mandated in 2013 Tractebel, Ecofys and PwC to study the benefits of a meshed offshore grid in the North Seas [9]. The goal of that study was to assess the full suite of potential benefits of such a grid at time horizon 2030 for three different load/generation scenarios in Europe: ENTSO-E Vision 4 (of the TYNDP 2014) scenario (Scenario 1), PRIMES reference scenario (Scenario 2), and NSCOGI reference scenario (Scenario 3). The total offshore wind installed capacities are respectively 111 GW, 70 GW and 56 GW. For each scenario, the offshore grid development is optimized under two sets of

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constraints: the offshore grid must be purely radial, or the offshore grid can be meshed. The optimisation is done using a method very similar to the one of the WindSpeed study: the sum of the investment cost and the operational cost is minimized, based on the analysis of several possible operating states and using a transportation model. Once the topology is optimized, benefits are evaluated through the use of a market simulator (SCANNER), simulating the electricity market behavior for a one year period in hourly time steps. In general, each country is represented as a single market node, and the Net Transfer Capacities (NTCs) set the limit for commercial exchanges between market nodes. Figure 2.11 shows the optimal offshore grid, when meshed connections are allowed, for each scenario. However, no scenario results in a meshed topology, according to the definition provided in D1.1 of PROMOTioN: the resulting topologies are radial and radial multi-terminal. In scenario 1, there is an HVDC loop near Norway (triangle), but the choice was made to use two different DC nodes on the Norwegian shore, so it does not lead to a meshed topology. The study shows that the coordinated network development leads to an infrastructure investment cost €4.9 to €10.3 billion higher, but it results to annual savings between €1.5 and €5.1 billion.

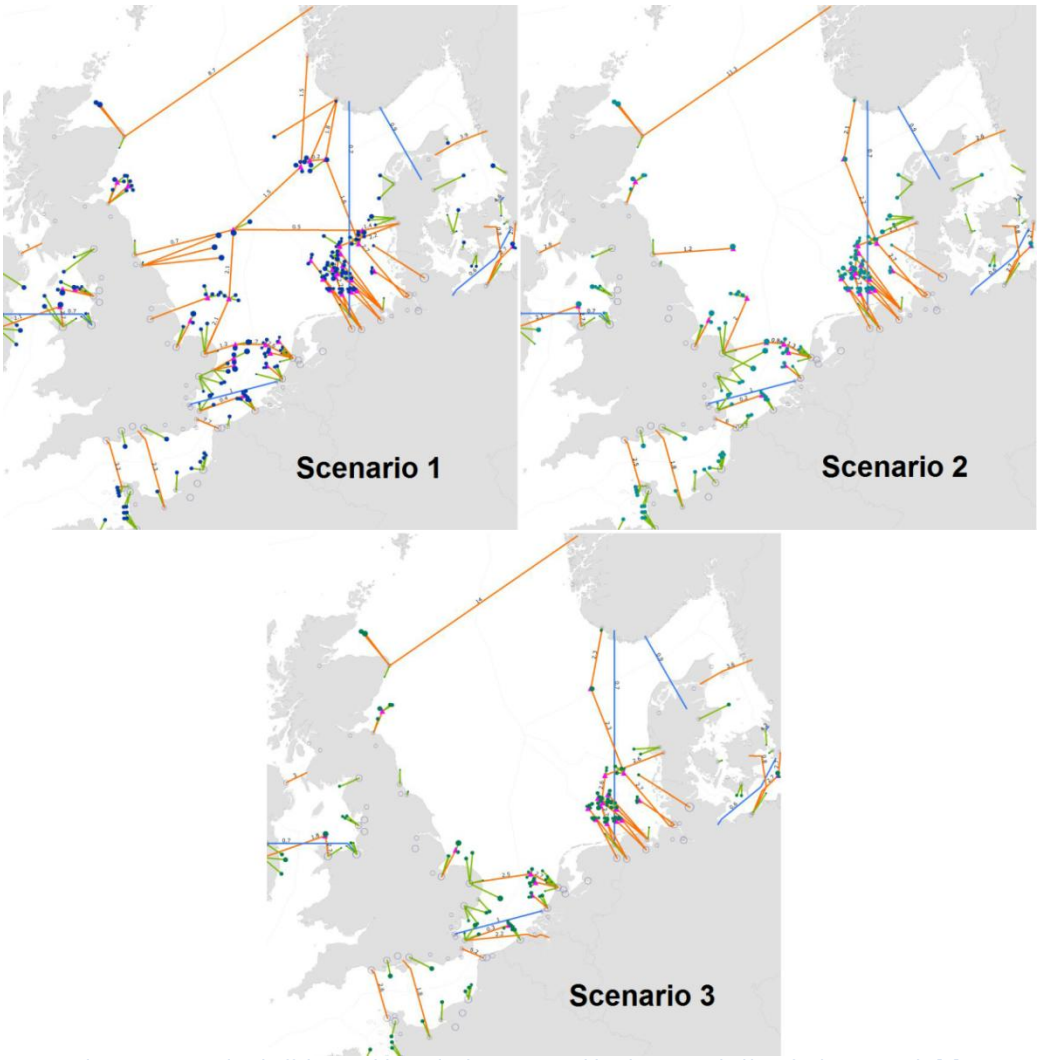

Figure 2.11. Optimal offshore grid topologies proposed by the Tractebel/Ecofys/PWC study [9].

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2.1.6 E-HIGHWAY 2050 PROJECT

From 2013 to 2015, the e-Highway2050 project aimed at developing a methodology to support the planning of the Pan-European Transmission Network (focusing on 2020 to 2050), to ensure the reliable delivery of renewable electricity and pan-European market integration. The focus was thus not especially on the North Seas, but the development of an offshore grid in the North Sea was studied in a simplified way as well. That study was performed on a simplified grid model, with around a hundred macro-nodes in Europe (representing areas) connected together by macro-lines (representing transfer capacities between areas), as shown in Figure 2.12 [10]. In particular, there are 11 offshore nodes in the North Sea, representing numerous wind farms which can be connected to each other by various topologies.

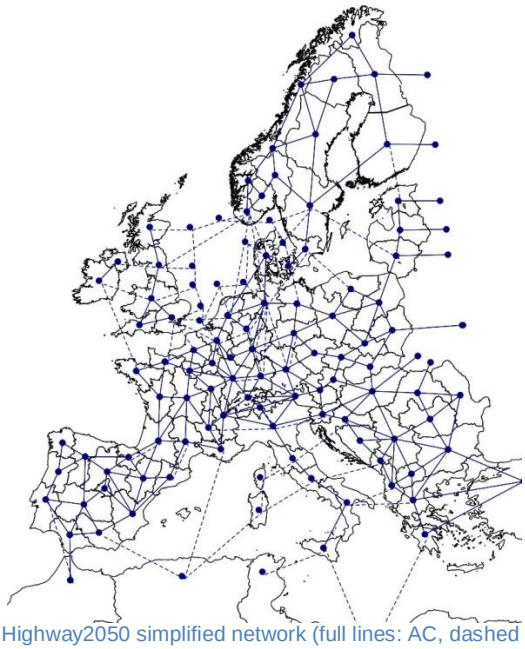

Figure 2.12. E-Highway2050 simplified network (full lines: AC, dashed lines: DC) [10].

Five contrasting scenarios for the generation mix in 2050 were studied: 100% RES (115 GW of wind generation in the North Sea), Large Scale RES (103 GW), Big & Market (76 GW), Fossil Fuel and Nuclear (40 GW), and Small & Local (15 GW). The analysis was performed on a simplified model of the European network made of one hundred zones, computed from the 2030 grid foreseen by ENTSOE in the TYDNP 2014. Starting from this basis, the topology for each scenario in 2050 is then optimised based on a transmission expansion planning problem, similarly to what was done in WindSpeed project, in the NSCOGI study and in Tractebel/Ecofys/PwC study for the European commission. Figure 2.13 presents the grid reinforcements identified in the North in each of the five 2050 scenarios. In all scenarios, part of North Sea wind generation is brought to continental Europe to solve unsupplied demand and optimize thermal redispatch. However, several paths are possible to reach the same purpose, in particular because some offshore clusters with huge volumes of wind power are not close to clusters in deficit of energy (e.g. the offshore cluster near west Denmark is interesting for providing energy to north continental Europe rather than Denmark which does not need it). The optimal choice between those possible paths requires a detailed analysis of the costs, including detailed technologies and possible routes, which was not in scope of the e-Highway 2050 project. Moreover, the planning of arrival of the different wind

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farms could impact the optimal choice (e.g. if farm A is connected to the continent through farm B, then farm B should be built before or at worst at the same moment) and the e-Highway 2050 did not consider the temporal evolution of the grid.

The reinforcements of radial links Norway offshore cluster - Norway in 100% RES and Sweden offshore cluster – Sweden in Large Scale RES and Fossil fuel & nuclear aim at collecting North Sea wind generation for continental Europe (through onshore Norway and Sweden clusters). Part of North Sea wind generation is brought to UK in all scenarios. In 100% RES and Small & Local, it mainly helps UK which faces risk of shortage or lacks of competitive energy, while in the other scenarios it is further transmitted through UK to continental West Europe. The total volumes of reinforcement in North Sea ranges between [7GW, 65GW], consistent with wind installed capacity in North Sea for each scenario. Maximum radial flows occur in winter (when load factor of wind power are maximum).

As a conclusion, it should be noted that the e-Highway2050 project could not demonstrate the interest of a "meshed grid" as such in the North Sea, but this result could be due to specific assumptions used, in particular the limited number of nodes. What was highlighted is that some areas will face huge excess of generation in case of significant deployment of wind generation: UK, Denmark and Scandinavia. These areas and their offshore farms need to be connected to areas in deficit of energy in continental Europe (Belgium, Germany, and Netherlands). For example, one could even imagine connecting some offshore farms in Norway only to Germany and not to Norway at all. The interest to realize such connection directly or to "stop" in different farms to collect power all the way long depends on the detailed location of the farms, the price of the different components and the timing of development of the farms. In some cases, alternative routes through the land are also possible (through Denmark or through UK). The costs and socio-environmental constraints of the different options should then be compared in detail as well. These detailed assessments were not possible within e-Higwhay2050.

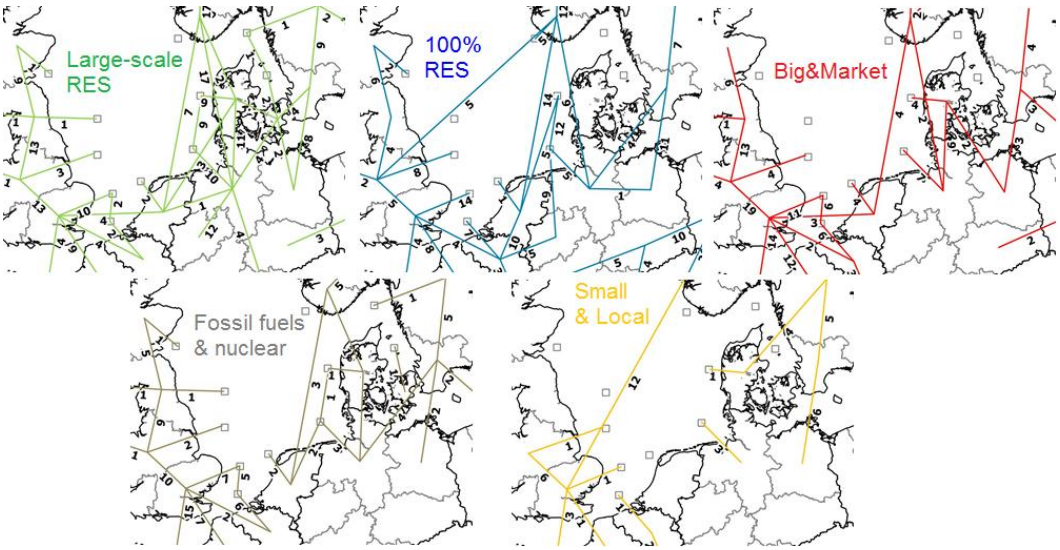

Figure 2.13. E-Highway2050 results for the North Sea (values indicate transfer capacities in GW) [10].

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2.1.7 ENTSO-E TYNDP

ENTSO-E published every other year a Ten-Year Network Development Plan (TYNDP). The aim of the TYNDP is to present and assess all relevant pan-European projects within the pan-European transmission electricity network. The last version of the TYNDP, the TYNDP2016, was published in June 2016 [11]. A part of that TYNDP is devoted to the North Seas region. However, the development of an offshore grid is not studied by the TYNDP: the focus is on development of point-to-point interconnectors between the North Seas' countries, as shown in Figure 2.14. Nevertheless, the possibility of grouping several HVDC branches into a single radial multi-terminal HVDC system with a hub in Denmark (installed inland and not offshore) is studied from an economic point of view, as shown in Figure 2.15. This case study is detailed in [12]. It is concluded that the total capitalized cost reduction should be in a range from €95 million to €161 million (depending on several factors, including grid reinforcements), but that the result is indicative, volatile to energy and equipment prices.

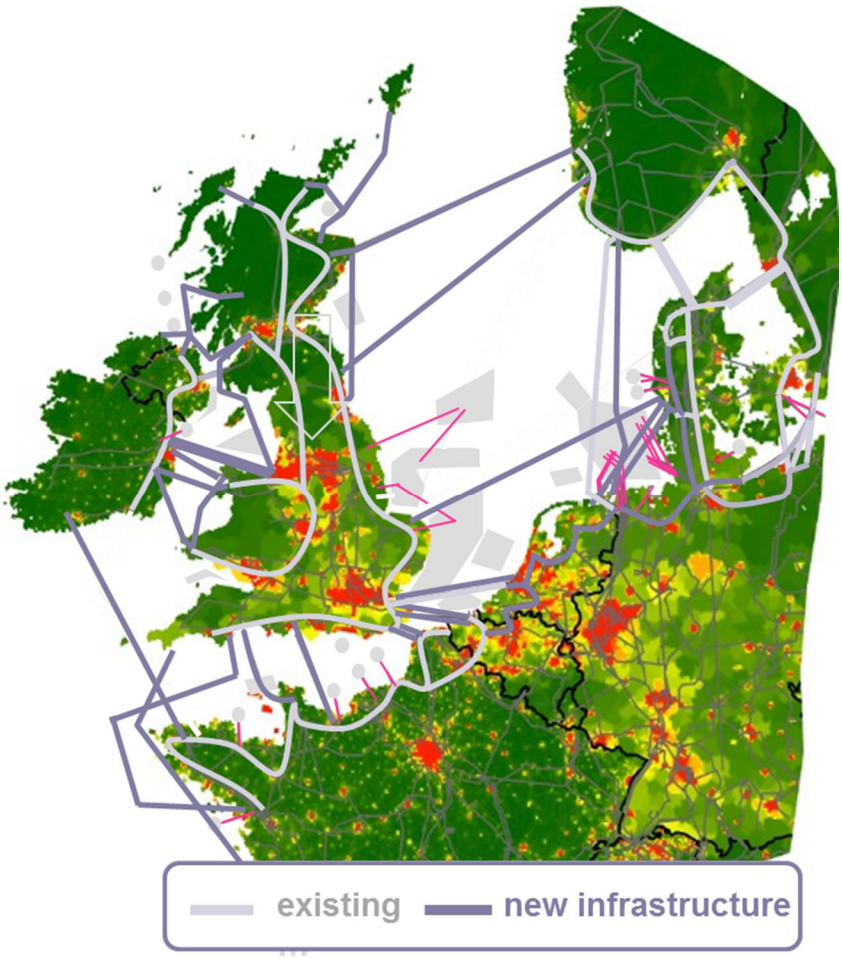

Figure 2.14. TYNDP Northern Seas Offshore Grid Infrastructure 2030 - General Concept [11].

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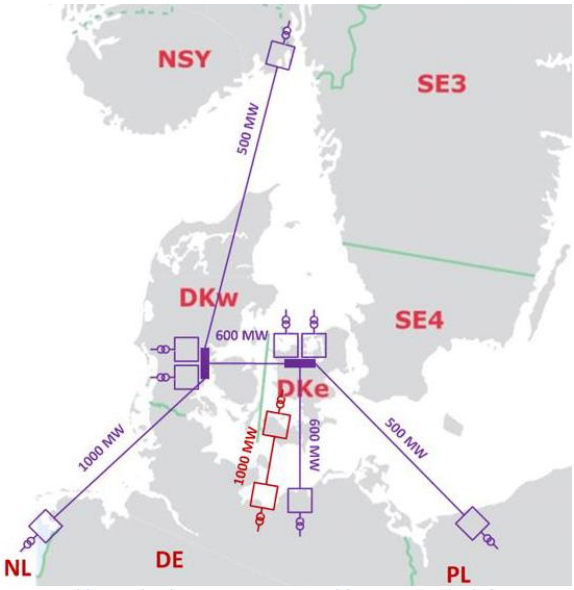

Figure 2.15. Multi-terminal HVDC system with a HVDC hub in Denmark [13].

2.2 OFFSHORE GRID IN THE EXTENDED IRISH SEA

2.2.1 EIRGRID OFFSHORE GRID STUDY

In 2011, EirGrid conducted a study on the need to develop an offshore grid in the Irish Sea [14]. Three offshore wind generation scenarios at the horizon 2030 are developed. The maximum offshore generating capacity in the Irish Sea considered by 2030 is 5.3 GW. For each generation scenario, the offshore grid topology and reinforcements in the onshore grid are optimized on the basis of a formal optimal transmission expansion planning problem, to minimize the combined cost of power production and network development. The development of the grid is analysed for three target years: 2020, 2025 and 2030. In this way, the commissioning schedule of the new transmission elements can be drafted. The methodology followed is very similar to the NSCOGI study: the capacity expansion planning considers several possible operating states in order to have a good statistical description of possible contingencies (pre-defined list) and of wind power and load fluctuations, the optimisation programme is based on a specific list of new grid link candidates, as shown in Figure 2.16, and DC power flow equations are considered. A detailed analysis of the generation cost and the adequacy is then performed through the use of a market simulator (REMARK). Additionnaly, detailed network studies (e.g. static and dynamic security) are performed to ensure the viability of the optimal transmission expansion planning solutions. Figure 2.17 shows the results for the scenario with the higher amount of wind generation and the higher amount of offshore generation sites.

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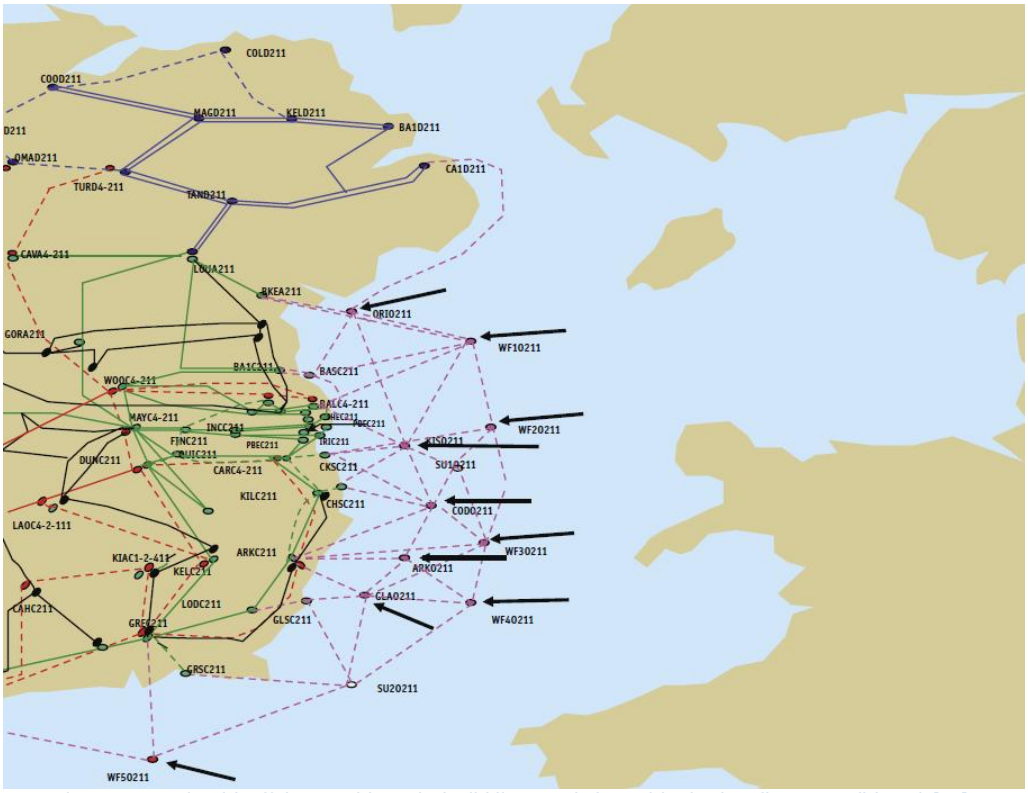

Figure 2.16. EirGrid Offshore Grid Study (solid lines: existing grid – broken lines: candidates) [14].

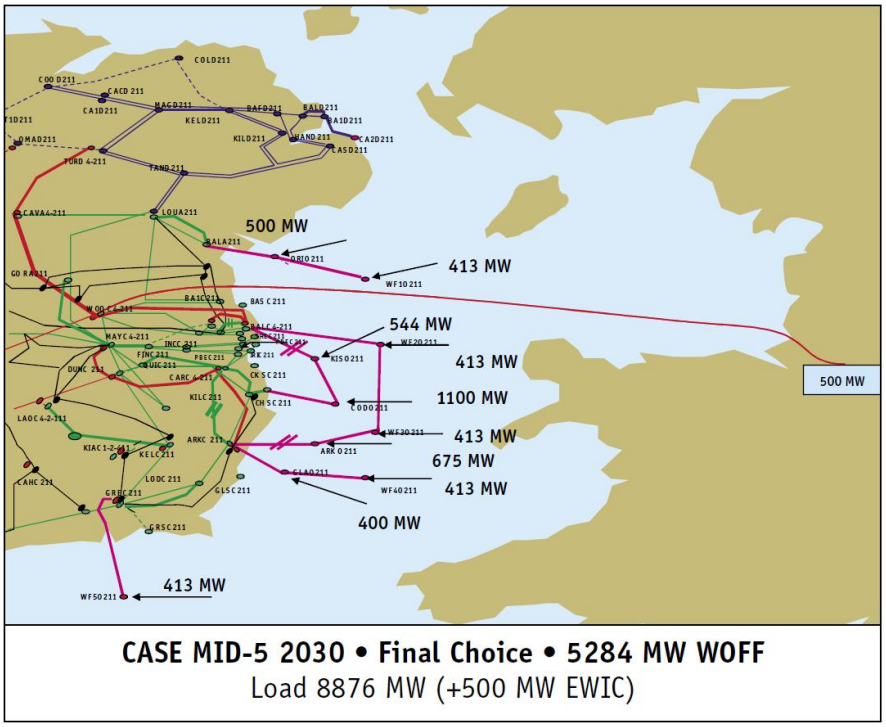

Figure 2.17. EirGrid Offshore Grid Study results for 'MID10' scenario in 2030 [14].

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2.2.2 ISLES

The Irish-Scottish Links on Energy Study (ISLES) was a project commissioned by the governments of Scotland, Northern Ireland and Ireland, published in 2012, that “investigated in detail the opportunities and challenges in developing a cross-jurisdictional offshore transmission network that connects large-scale offshore marine generation, provides for enhanced interconnection and facilitates additional onshore grid and electricity market benefits” [15]. The maximum resource potential of the ISLES study zone is outlined in Figure 2.18 and was estimated to include 12.1 GW of offshore wind and 4.0 GW of wave and tidal potential. However, the focus of the ISLES investigation was on assessing early viability so a timeframe was set so that any proposals should be capable of being delivered with an initial development date of “circa 2020”. As such, two distinct development concepts were articulated with a “Nothern ISLES” concept, comprising 2.3 GW of offshore generation capacity and providing interconnection capacity between the Irish and GB markets (via Northern Ireland and Scotland), defined as the “primary development scenario for testing the ISLES thesis”. A second “Southern ISLES” concept, comprising 3.4 GW of offshore generation and providing interconnection between the Irish and GB markets (Via Ireland and Wales) was defined to “test the sensitivity of certain key aspects of ISLES in more detail, specifically interconnection”. The concepts are not devised as detailed or finalised engineering solutions but rather as a means to test the feasibility of coordinated, cross-jurisdictional, multi-terminal offshore grid designs. The designs proposed for the Northern ISLES and for the Southern ISLES are not optimised formally through an optimization problem, but an engineering judgment is used to shape the offshore grid. Such an approach is possible because the size of the system is small. For the Northern ISLES concept, this engineering judgment leads to two transmission options that are compared.

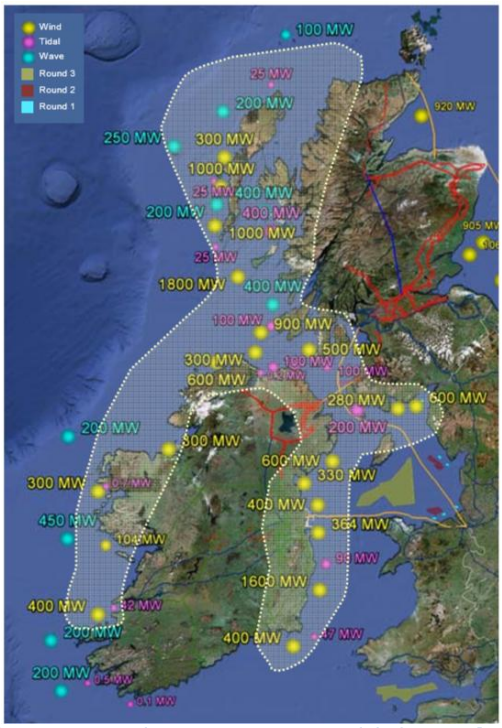

Figure 2.18. Maximum Resource potential of ISLES [15].

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The Northern ISLES concept comprises a number of interconnected 500 MW and 1000 MW HVDC links and facilitates approximately 500 MW of firm interconnection from the Irish transmission system to GB on top of providing a route to market for 2.3 GW of offshore generation capacity as shown in Figure 2.19 [16]. The HVDC network topology consists of three multi-terminal HVDC links and three offshore HVDC hubs platforms (Argyll, Coleraine, Coolkeragh). Voltage source converter technology is proposed as it "should be 'bankable' technology for multi-terminal offshore applications at the capacity required for ISLES, based on industry trends towards 2020". A key feature of the proposed design is that the hubs allow for reconfiguration of the network in the event of fault or maintenance conditions but do not require the use of "untested" HVDC circuit breakers. All offshore wind generation is connected via VSC converters with links up to 1000 MW and all at ±300 kV. It is deemed important that a common voltage is defined and specified at the very first phase of a project build-out to facilitate an integrated HVDC network, to avoid the need for additional cost and losses of DC-DC conversion. Multi-terminal VSC links of three and four terminals are considered in the Northern ISLES concept however it is expected that grids with more than four terminals could be achievable by 2020. The basic network configuration of a four-terminal link is given in Figure 2.20 whereby two offshore wind farms and two onshore stations are connected through a central hub with one onshore converter used to control power export. The Northern ISLES concept proposes the use of three distinct multi-terminal links connected together at a number of switching hubs to allow grid reconfiguration in the event of planned or unplanned equipment outages. However, the grid reconfiguration process is done without DC circuit breakers so the whole of the affected multi-terminal grid section would first need to be shut down, including the wind farms connected to that grid section, before the outage is isolated and the healthy grid sections reconnected. This process would likely take at least some minutes but from the perspective of transmission adequacy a short term outage would represent only a small loss of total generation output. A study of the adequacy of the proposed Northern ISLES grid concept was undertaken to assess the impact of different N-1 outage situations in terms of export capability and constrained generation, but the impact of that in terms of lost energy or monetary value is not assessed in detail and there is no comparison with other grid options, for example a set up that relies on radial links to shore and does not allow for grid reconfiguration, to determine the value of building in the redundancy that exists in the Northern ISLES concept. Note that an attempt to assess the value of redundancy in offshore HVDC systems has been made in other studies [17].

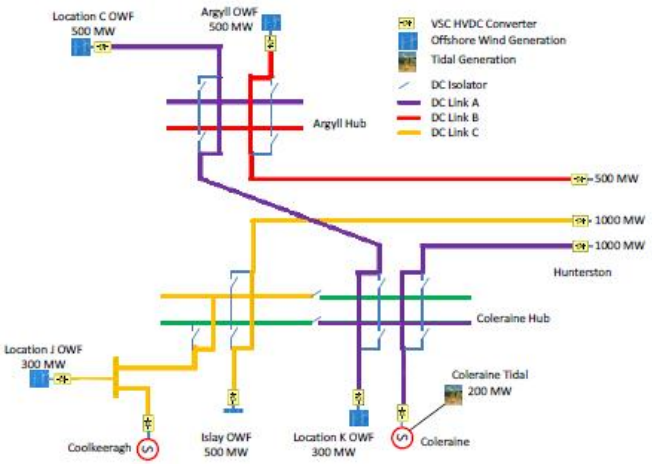

Figure 2.19. Northern ISLES concept [16].

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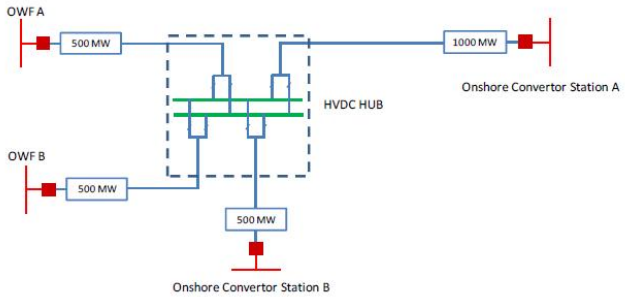

Figure 2.20. Configuration of typical multi-terminal HVDC link in ISLES [16].

The Southern ISLES concept comprises a multi-terminal HVDC backbone running down the east coast of Ireland with a number of 500 MW and 1000 MW VSC HVDC links to shore. In total 3.4 GW of proposed offshore generation are proposed with 3 GW (1000 MW secure) of interconnection between the Irish and GB systems as shown in Figure 2.21. Like the Northern ISLES concept, Southern ISLES is proposed with HVDC switching hubs that facilitate reconfiguration to accommodate operational and maintenance requirements without the need for HVDC circuit breakers.

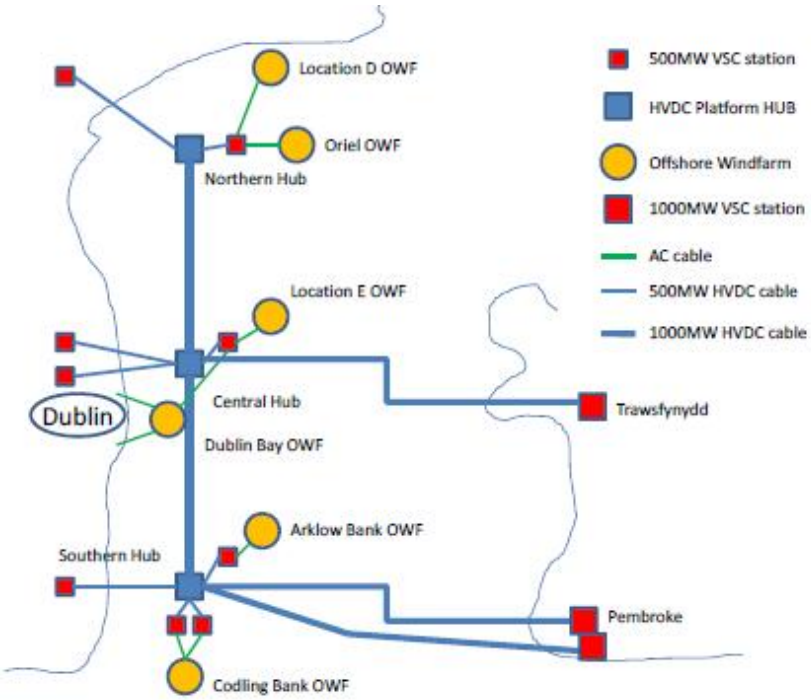

Figure 2.21. Southern ISLES concept [15].

The total combined CAPEX for the Northern and Southern ISLES concepts is found to be in the order of £5.6 billion or circa £1million/MW of offshore network capacity. It corresponds to a cost potentially 15-20% higher than comparable stand-alone projects which might be developed under the UK government's Round 3 Offshore Wind Development process. However, increased development costs can be offset through a variety of economic and market benefits. In particular, ISLES combines interconnection and generation, and a case can

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be made that this could result in synergistic benefits by increasing the utilisation of the network. In the case of Southern ISLES specifically, approx. £170m per annum of savings are possible overall, mostly attributable to the All-Island market.

2.3 DISCUSSION

Numerous roadmaps have been proposed in the past decade for the development of an offshore meshed grid in the North Seas. Exact geographical scopes, methodologies and assumptions can differ strongly from one study to another. Moreover, very different levels of details are used to model power systems: the WindSpeed project stays at a macro-level, modelling only transfer capacities between hubs, while the ISLES study goes down to a node-breaker model. Consequently, it is meaningless to compare directly final maps. Nevertheless, some trends emerge from the analysis of these past roadmaps. Firstly, it is unlikely to have one big connected offshore grid: roadmaps usually come up with several offshore grids not connected together by DC branches. Secondly, complex offshore topologies (i.e. radial multi-terminal and meshed grids) appear to be cost-efficient only for scenarios considering both a high offshore wind generating capacity and numerous offshore hubs to collect this energy (geographical spreading). Otherwise, purely radial configurations stay the most economical way to collect wind energy. It must also be noted that offshore mixed AC/DC grids can be relevant from an economic point of view in some cases, as demonstrated by the NorthSeaGrid project. Finally, the economical advantage of complex offshore topologies such as radial multi-terminal and meshed grids can only be demonstrated when the overall grid structure is optimized: results from Twenties are inconclusive because the proposed radial multi-terminal topology is not the result of an economic optimization. Nevertheless, even when the grid structure is optimized through an optimal transmission expansion planning problem, the economic viability of the result must be checked *a posteriori*, because the optimization of the grid structure relies on simplifying assumptions (e.g. a small number of possible load/generation patterns are considered). Note that, at the exception of the EirGrid Offshore Grid Study, all studies studied a specific point in time and the optimal grid structure at that moment: the way the grid could evolve between now and then is not studied. In contrast, the EirGrid Offshore Grid Study considered two intermediate time steps to draft the commissioning schedule of the new transmission elements.

The PROMOTioN project aims at estimating how an offshore grid in the North Seas could be developed in the upcoming years and decades. To understand the technological needs (e.g. the need for DC circuit breakers), it is particularly important to know how, where, when and why complex offshore topologies such as radial multi-terminal and meshed grids will appear in the North Seas. If previous studies brought some answers, they are still partial, in particular about the chronological evolutions of such offshore grids (i.e. the successive steps towards a radial multi-terminal or a meshed grid). The PROMOTioN project will build on methodologies and assumptions developed and used by previous studies to propose an offshore grid expansion plan for the North Seas. In particular, a draft roadmap taking into account the development pace of offshore wind energy up to 2030 will be derived in D1.6, and a deployment plan for European future offshore grid development will be produced by WP12.

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3 OPERATION OF CONVERTERS IN DC GRIDS

The development of HVDC grids based on VSC and DRU converter technologies introduces new operation and control challenges. Offshore HVDC grids can impact the stability of the onshore AC grids, but the control of the HVDC grid itself is also challenging. Since the introduction of the VSC technology, several works have studied these problems. However, previous studies made use of assumptions that are not always suited to the objectives of the PROMOTioN project. For instance, the operation and control of grids based on VSC and DRU converters is not yet fully mastered. The objective of this Chapter is to review previous works that studied the operation and control of HVDC grids (especially of integrated structures like radial multi-terminal and meshed grids), in order to identify remaining issues that must be addressed before the development of offshore grids in the North Seas. Note that this Chapter does not deal with the specific problem of interactions between OWFs and converters: it will be addressed in Chapter 4.

This Chapter is organized according to the main issues that arise in the operation and control of HVDC grids. First, Section 3.1 reviews previous studies that focused on the steady-state control of such grids. Then, Section 3.2 focuses on dynamic stability issues. Because enabling a smooth, “plug-and-play” interoperabilty of converters in large-scale realization stages is one important aim of PROMOTioN, studies addressing the interoperability of converters are reviewed in Section 3.3. Finally, Section 3.4 concludes.

3.1 STEADY-STATE OPERATION AND CONTROL

The first complexity that arises in radial multi-terminal and meshed HVDC grids is their steady-state control: an operating point that fulfils the operational limits (e.g. voltage limits, power ratings of equipment) must exist under normal conditions, and a new steady-state must also exist after possible disturbances that could arise in the grid (e.g. change in the offshore wind generation or loss of a cable or a converter). In a point-to-point connection between two synchronous or asynchronous areas, one converter usually controls the DC current the while the other one controls the DC voltage [18]. Similarly, the offshore converter of an HVDC system connecting radially an OWF to an onshore AC grid controls the DC current such that the wind generation is entirely evacuated (for any value of the wind generation), while the onshore converter controls the DC voltage. In a system with two converters, such as strategy ensures that an operating point exists. However, this strategy cannot be applied directly in radial multi-terminal and meshed grids. For example the simultaneous control of currents by several converters at fixed values can lead to the non-existence of an operating point. A specific strategy to control the voltage across the system, or to share the power between converters, must thus be used. Indeed, the voltage differences throughout the system directly dictate the power flow through the lines and a power imbalance in a DC grid is reflected in the DC voltages in the grid [19]. The most common strategies are based on the voltage droop control: a proportional relationship is used between the DC voltage and the DC current or the DC power.

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This question of steady-state control of offshore DC grids was in particular extensively studied by the Twenties project, in particular in Deliverable D5.2b [20]. For controlling the DC grid at least one of the onshore converters should control the DC voltage like it is done in point-to-point connections. However, if only one converter contols the DC voltage, in case of the loss of this converter, another converter has to control the DC voltage. Having more than one DC voltage regulator in a system connected to a strong AC system, which includes extra capacity to divert power from a faulty terminal, is thus critical for the steady-state control of DC grids. As a result it was concluded that the voltage regulation should be implemented at all onshore converters at the same time, but with a dedicated voltage droop control (power flow sharing policy). This would mean that the onshore converter could either control the reactive power injected to the AC network or the AC voltage at the PCC. The proposed voltage droop control had the goal of balancing the generation demand variation in the DC grid. Converters worked independently of each other and adjusted their terminal DC voltage according to a DC voltage/DC current (V-I) or DC voltage/DC power slope characteristic. The proposed V-I droop characteristic (negative slope) for onshore VSC indicated an increase in the current inflow when the DC voltage was stepped down. This behaviour corresponded only to physical characteristics like the Kirchhoff's law. In contrast droop characteristics with a positive slope needed control regulators with control loops so that they are able to stabilise the system by compensating the natural reaction to a disturbance. However, the conventional P-V droop was considered limited. Consequently, an alternative P-V droop control for the H-topology was presented. It was stressed that the absolute value of the slope has a big impact on the load flow. By tuning the slope parameter the power exchange between the AC grids could be influenced: congestions (or very stressed grid conditions) on the AC systems can be relieved by shifting power from one onshore converter to another onshore VSC of a DC grid. Therefore, it was found out that DC grid injections can help solve congestions on AC systems connected to a DC grid.

In Twenties Deliverable D5.3b [21], the impacts of an extension of the DC grid were further analysed with respect to the power flow control. The conclusions drawn were as follows, when considering a direct point-to-point injection as the power sharing policy. Extending the initial H-grid (a simple non-meshed topology) has no impact on the voltage droop control and associated sets of parameters and little impact on the existing voltage droop control when considering a control optimised for wind power mitigation. In general it was found out that the power flow sharing policy is an independent parameter (which is used to compute the appropriate voltage droop slope depending on the voltage), while the power exchange is set using the voltage reference. The study also stressed the importance of verifying the operational reference values since the defined control strategies can only be effective if operational working conditions are not violated. It is pointed out that in contrast to point-to-point HVDC links the maximum DC voltage can only occur at one converter, other converters must operate at lower set points. As a result, the authors recommended a P-V droop dedicated to the H-topology where the slope is automatically adapted. Benefits from this control were said to be the reduction of the global DC voltage deviation when having fluctuation in wind power infeed. This was done by controlling the voltage beyond the converter connection point instead of controlling the voltage at the connection point. In conclusion it was stated that this new droop control could avoid DC voltage deviations on the overall DC grid and provide each onshore converter with the power infeed of the closest wind farm. This was done by controlling the DC voltage in the "center" of the grid to a constant value. Also a power exchange between two onshore zones could be executed.

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Note that, in studied topologies, the number of offshore wind farms is equal to the number of offshore converters.

If the Twenties project studied voltage droop controls for specific topologies ("H-grid" and several specific extensions), subsequent works addressed the issue of steady-state control in a more general way. For example, ref. [22] analysed the influence of the converter droop settings and the DC grid network topology on the power sharing, and ref. [23] proposed a methodology for establishing droop constants for a variant of power drooped against DC voltage (pilot voltage droop control). Alternatively, ref. [24] proposed the use of an automatic dispatcher controller to adjust the voltage references at DC terminals in a centralized way. The droop adjustments are thus performed at the dispatcher center (rather than at each of the terminals). Additionnaly, in the framework of the MEDOW project[4], a method for finding the optimal DC voltage in a HVDC grid was introduced in [25], based on power flows and line resistances.

The MEDOW project studied other issues related to the steady-state operation and control of mixed AC/DC grids. Ref. [26] investigated the limitations on the power flow transfer through a VSC-HVDC system connected to a weak grid. First, the impact of the angle and voltage stability limits and the VSC rating has been examined. Then, the power transfer capability curves of a VSC connected to a very weak grid with a Short-Circuit Ratio (SCR) of 1.1 by means of a so-called "L-interface" (i.e. the converter is connected to the AC system through a purely inductive element) were calculated. Finally, the impact of providing additional reactive power (Q) support has been investigated through utilizing a shunt capacitor at the connection point. It has been shown that an additional Q-support of 0.2 p.u. can maintain the transfer of full power without the need for oversizing the VSC.

Still in the framework of the MEDOW project, grid power flow impact on the on-state losses of the modular multilevel converter was studied: in [27], the on-state mode of the half-bridge cell semiconductors with respect to the active/ reactive power flow conditions of the MMC has been analysed. The MMC-HVDC INELFE project[5] model was adopted to perform the converter analysis and simulations. It is shown that the lower switch of the half-bridge cell is responsible for the majority of the on-state losses of the converter. The paper has analyzed the average number of semiconductor devices on the on-state mode based on the active/reactive power flow ratio at the PCC. The description of the methodology adopted was sub-sequentially followed by the analysis of the INELFE HVDC case study. It has concluded that the active/ reactive power flow ratio has a relevant impact on average number of diodes and IGBTs that are in the on-state modes in the corresponding stack. It was emphasized that the MMC is more efficient during the rectifier than the inverter operation mode. Moreover, during the unity power factor operation, the on-state losses of the semiconductors is higher than if reactive power flow exists at the PCC, having the nominal current magnitude unchanged.

[4] MEDOW is a Marie Skłodowska-Curie Initial Training Network (ITN) running from the 1st of April 2013 to the 31st of March 2017. It aims at contributing to the integration of offshore wind power into the onshore AC grids in European countries and for the European offshore grid. Its network works towards sharing complementary expertise, infrastructure and facilities for the training of the next generation of top-quality researchers in this field.
[5] The INELFE project is the HVDC VSC interconnection between Spain and France commissionned in 2015.

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3.2 DYNAMIC STABILITY OF MIXED AC/DC GRIDS

Once the existence of an operating point fulfilling the operational limits is proven, the stability of this operating point must be ensured. The dynamic stability is twofold: the system must stay stable for small disturbances (intrinsic stability), but must also remain stable following the occurrence of AC and DC faults or of others large disturbances. In particular, an offshore grid in the North Seas must have an adequate Fault-Ride-Through (FRT) capability in case of an AC fault near an onshore converter. The offshore grid and its converters must thus be operated to ensure system stability and good speed of responses [18].

This section summarized previous works that have already been carried out in the framework of the Twenties project, the MEDOW project and the OffshoreDC project[6] on these issues.

3.2.1 INTRINSIC STABILITY

Low-frequency oscillations

A first problem related the the intrinsic stability that could arise in power systems is the angular instability: low-frequency oscillations could occur. The Twenties project studied the occurrence of this phenomon in mixed AC/DC grids. In the Twenties Deliverable 5.2b [20], a study to improve the small signal stability of AC systems with DC grids was carried out. It was found out that the connection of large offshore DC grids to AC power transmission systems changes significantly the operating conditions of the latter, impacting system small signal stability. This is due to the replacement of conventional power plants, which leads to a decrease of the damping provided by synchronous generators equipped with PSS; furthermore, power injections from the DC grid may increase power flows through weak transmission lines interconnecting two areas of control in the absence of appropriate AC reinforcement. Hence, critical damping levels of inter-area modes of oscillation may occur. To prevent such risks, the study concluded that small signal stability analysis of interconnected DC-AC systems is required, all the more since VSC converters can provide additional damping by means of PSS-based supplementary voltage controls [28].

Converter interactions

The massive integration of converters based on power electronics in the grid introduces new possible interactions between components and could thus lead to new resonance phenomena. These resonance phenomena can either occur within the DC grid (DC-side resonances), between the converter stations and the transmission cables, or through the AC grid. Because these control interactions and interferences between converters can lead to stability issues, they must be studied and mitigated.

The DC-side resonances have been studied in the framework of the OffshoreDC project, ref. [29] thoroughly investigated transients and interactions in a two-terminal VSC-HVDC system, shown in Figure 3.1. The system

[6] The OffshoreDC project aimed at aimed the development of the VSC-HVDC technology for future large-scale offshore grids, supporting a standardised and commercial development of the technology, and improving the opportunities for the technology to support power system integration of large-scale offshore wind power.

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was modelled as a SISO feedback system. The AC grids were assumed to be infinitely strong and were thus modelled as voltage sources. As the IGBTs were expected to experience high voltages, it was assumed that their capacitances level off at higher voltages. Two different methods were utilized to assess the closed-loop stability of the complete system: the *Passivity* analysis, focusing on the related passivity properties of the transfer functions at critical frequencies, and the *Net-damping criterion* approach. In the area of Multi-terminal HVDC, a first droop-based controller was proposed for cases where a VSC station has to maintain its designated power flow after unexpected contingencies in the grid, while maintaining voltage-droop characteristics during transients in the grid. A second droop-based controller was proposed for MTDC grids where a droop-controlled station requires a very high droop constant. In order to study various dynamic behaviours of HVDC transmission systems, a dynamic simulation model was developed. The *Passivity* analysis showed satisfactory results as long as the transfer functions were stable. However, once the latter was not valid, the passivity approach could no longer be used. The *Net-damping criterion* approach did not have this complication and proved to be a superior tool in analysing the stability of the system and deriving useful results. The absolute amount of net-damping in the system measured at the frequency where the Nyquist plot crosses the real axis closest to -1 was found to be directly related to the existence of poorly-damped dominant poles and their damping factor. A net-damping approaching zero at that frequency indicates the existence of poorly-damped poles with constantly decreasing damping factor. Tested in a five-terminal MTDC, the first proposed droop-based controller showed a better performance than that of a conventional PI-based power controller. Tested in a four-terminal MTDC, the second proposed droop-based controller showed the same steady-state performance as a conventional droop controller (as desired). However, it provided a smooth power and direct-voltage reaction from the stations that used it, compared to the conventional control that even exhibited poorly-damped oscillations. Simulations showed that the modelled MMC was able to continue operating with even a high loss of submodules. The work supports the derivation of requirement specifications of components in a MTDC network by means of simulations and calculations. It demonstrates the ability to control complex multi-terminal HVDC topologies in case of severe power variations occurring in the DC grid. Moreover, it contributes to a deeper understanding of the transient behaviour of the MTDC grid during a pole-to-ground fault on both the AC and DC sides and analyses the influencing parameters.

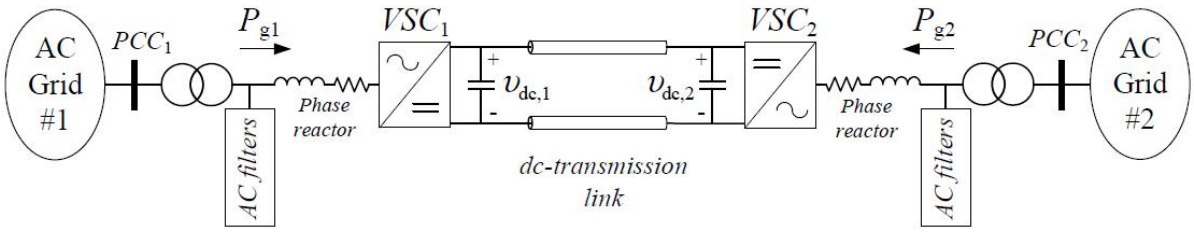

Figure 3.1. Two-terminal VSC-HVDC system [29].

MEDOW project studied the analysis of control interactions of VSC converters through the AC grid have been studied [30] [31]. These two works focused on the system with two converters shown in Figure 3.2, composed by two converters, two AC networks and a transmission line. In both works, the transfer function of the closed-loop system was studied in the frequency domain by using an impedance-based approach, and the role of the transmission line and impact of the AC system strength were evaluated. The impedance-based approach was

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expanded for including both converters, including the modelling of the converters control. Frequency-domain methods allow the detection of potential points of instability, and its expansion is not as complex as those of time-domain methods. In [30], numerical results showed that the stability of a converter is weakened when a parallel converter is connected: a reduction of the phase margin occurs. In others words, the relative stability of one converter is deteriorated due to interactions from the other converter. This deterioration is bigger when the transmission line between the two converters is small: the phase margin decreases when the line length decreases. Results showed also that the deterioration of stability is bigger when the AC systems are weak: the phase margin decreases when the equivalent grid impedances Z_1 and Z_2 in Figure 3.2 increases. Note that, for the specific model studied in [30], equivalent grid impedances Z_1 and Z_2 have larger impacts on the influence between converters than the transmission line between the two converters. Therefore, the need of considering all the dynamics is more important in weaker systems. In [31], the same methodology is used, but slightly more detailed converter models with a different set of parameters are used, and the analysis is extended to a wider bandwith of frequencies. Additionnaly, a time-domain validation of the impedance-based results, using an EMT simulation (Simulink/SimPowerSystems software tool), is performed. Confirming the results of [30], ref. [31] shows that stability issues are encountered in the multi-infeed power system studied, when new oscillatory modes appear in high frequencies close to the control bandwidth. Indeed, when the two subsystems are interconnected by the transmission line, poorly damped oscillatory modes appear above the fundamental frequency, corresponding to resonances between the network and the converter. Instabilities arise when these low-damped resonances coincide with negative-conductance regions in the connected converters. Note that a low *X/R* ratio increases the damping of resonances in the power system and thus improves the stability. It was shown that, when resonances in the system are beyond the control bandwidth, the model reduction of a converter to its phase reactor can provide a first indication of the resultant resonances. However, if high-frequency modes are located within the control bandwidth, a correct stability assessment needs an inclusion of the control dynamics in the converter model.

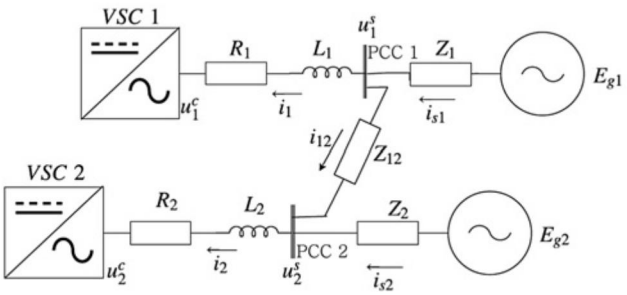

Figure 3.2. System with two multi-infeed VSCs [31].

Subsynchronous resonances

Subsynchronous resonances (SSR) can occur in series-compensated grids when natural oscillation frequencies of the synchronous generators resonate with oscillation modes of the transmission system. This dynamic phenomenon can be affected by the HVDC VSC converters, but could also be mitigated with an appropriate control of the converters. Several works thus studied the properties of SSR in mixed AC/DC systems, in particular in the framework of the MEDOW project.

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A first work [32] analysed the subsynchronous oscillatory stability of series-compensated integrated AC/DC transmission systems with point-to-point VSC-based HVDC links. This work studied a particular type of SSR, torsional interactions. Two test systems were studied: an adaptation of the IEEE First Benchmark Model (FBM) for SSR studies that includes a VSC-HVDC link as shown in Figure 3.3, and a simplified model of the 2020 Great Britain (GB) mainland power system, reinforced with onshore series compensation and offshore submarine VSC-HVDC transmission. The simplified model of the 2020 GB system makes use of network equivalents for the three main generation areas: England and Wales, Southern Scotland and Northern Scotland. SSRs are studied for each system by performing both an eigenvalue analysis (Matlab), on the basis of a detailed linearized state-space dynamic model, and a time-domain simulations (PSCAD/EMTDC). For the two test systems, the PSCAD simulation results match well with the results obtained through the eigenvalue analysis in MATLAB. Results for the IEEE FBM show that the addition of the VSC HVDC link attenuates the amplitude of the torsional oscillations, but increases the range of series compensation percentage over which SSR will occur. On the contrary, in the simplified 2020 GB power system model, the addition of the VSC HVDC link tends to decrease the damping of oscillations.

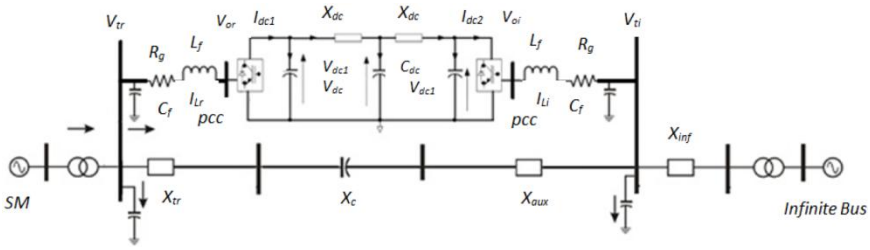

Figure 3.3. IEEE FBM with VSC-HVDC [32].

If ref. [32] showed that the direct impact on SSR of VSC-HVDC integration without dedicated control is not obvious, a second work of the same authors studied the possibility of controlling the VSC-HVDC in order to damp SSR [33]. The proposed damping scheme is embedded in a VSC-HVDC station as an auxiliary control loop. It employs modal filters to identify SSR upon occurrence and then injects currents at the corresponding subsynchronous frequency to damp it. The effectiveness of the scheme was assessed through the methods developed in [32]: eigenvalue analysis in Matlab using the linearized state-space modelling of the system, and time domain simulations performed using PSCAD/EMTDC. The methodology was also applied on the IEEE FBM with VSC-HVDC. The results show that the proposed scheme effectively damps SSR irrespectively of the torsional mode being excited. If the torsional modes of the shaft of a synchronous generator are known, the design of the proposed damping scheme can be easily carried out. The SSR damping controller proposed in this work is effective for a broad series compensation range.

3.2.2 FAULT ANALYSIS

Within the scope of the Twenties project, six simulations with different objectives were also carried out in Deliverable 5.2b [20] to evaluate the transient stability of the DC grid. For this purpose an “H-like” DC grid was modelled in DigSilent Powerfactory and connected at its PCC to a modified 39 bus New England test system

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representing the AC onshore grid. Two 33kVAC collector systems connected the two wind farms to the DC grid. The presented simulations showed that in case of an AC fault close to the PCC of the DC grid, very high DC over voltages occurred due to the power mismatch. By giving priority to the d-axis current the over voltages could be reduced but were still unacceptably high. However, it was stated that q-axis priority will contribute to a higher reactive power support to the AC grid.

Another issue addressed within the Twenties project is the Fault Ride-Through (FRT) capability of offshore wind farms. Due to large scale integration of offshore wind energy, offshore wind farms are required to stay connected to the grid in case of low voltages in order not to jeopardize system stability. It is assumed that FRT capability will also be required for DC grids. Due to this a voltage over time profile was defined indicating the contingencies in which tripping is not allowed. This curve differed with respect to the various grid codes of the TSOs. Nevertheless, FRT capability always relates to the fact that the power which cannot be injected to the grid due to voltage sag needs to be absorbed in another way in order to maintain stability of the generators. In order to do that it was pointed out that the main issue is the resulting overvoltage in the DC-link capacitor which can be counteracted by using DC choppers. However, it was important to reduce the active power within a certain time limit so over voltages were avoided. One solution investigated was to install DC choppers at the onshore converters which were able to dissipate power within the converter's ratings. This solution was regarded effective but costly.

3.2.3 FREQUENCY STABILITY

The Twenties project also studied the frequency stability of AC onshore grids. Due to the integration of huge amounts of wind energy, it was assumed that the generation by conventional power plants might be reduced. As a result it was pointed out that frequency deviations might increase. Solutions requiring dedicated communication were rejected due to reliability issues. Therefore the use of local controllers which can provide autonomous frequency control services was proposed. This strategy was implemented by reproducing the AC grid frequency deviations into DC grid voltage deviations. Later on these deviations could be recognized by the offshore wind farm converters to control the wind farm AC grid frequency and provide frequency support. Since the DC grid voltage deviations were also recognized by the converters of healthy AC synchronous zones, the converters' active power operation point will be affected as well. According to the project findings this impact on the power flow will also help to mitigate the frequency deviation in the disturbed synchronous zone.

3.3 INTEROPERABILITY OF CONVERTERS

Developping an offshore HVDC grid in the North Seas will not be done in one step: it is expected that the offshore grid will be developed along several decades, following the development of offshore wind generation. Consequently, several technologies will be integrated, from different manufacturers. In particular, it is expected that not only the VSC technology will be part of the offshore grid, but also the DRU technology. Therefore, it is crucial to ensure the interoperability of different converter types. This question of interoperability is in the scope of two major European R&D projects: a past project, Twenties, and an ongoing project, Best Paths.

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Twenties project found out that different converter types can work together under steady state, dynamic power flows and under AC fault conditions. This is due to the fact that the outer control loop of different converter types can be set up to provide the same functionality on the system level. However, when subjected to DC faults two level converters will cause more severe DC transients when converters are blocked which may be an issue regarding interoperability [28]. Since in most cases converters will not be blocked due to the protection system responses will be the same. Additionaly, in [20], a comparison of different VSC converters was carried out. The main results are reproduced in Figure 3.4 and in Figure 3.5[7]. The Twenties project points out that for future work the interoperability of multi-vendor components, especially full-bridge converters needs to be investigated in order to establish standardization. Indeed, short time constants and high controllability at the converters lead to complex interaction with different connected AC systems such as the Wind farm islands and the mainland grid. Coordination is said to be fundamental to ensure overall system stability.

	Two-level converter	*NPC converter*	*Two-switch modular converter*	*H-bridge modular converter*
Reactive power capability	Limited only by available DC link voltage	Limited by available DC link plus DC offset for capacitor voltage balancing	Limited only by available DC link voltage plus arm inductances	Limited only by available DC link voltage plus arm inductances
Bidirectional power flow	100% in both direction	100% in both direction achievable, but subject to modulation index margin for capacitor voltage balancing	100% in both direction	100% in both direction
AC filters and interfacing reactors	Relatively large AC filters	Relatively large AC filters	AC filter and interfacing reactors could be eliminated	AC filter and interfacing reactors could be eliminated
Conversion losses	Very high (mostly switching losses)	High (mostly switching losses)	Low (mostly on-state losses)	Moderate (mostly on-state losses)
AC fault ride-through capability	Excellent	Excellent, but in bi-polar configuration case with DC link neutral-point grounded, AC side filters and interfacing transformer neutral-point in converter side must be grounded.	excellent	excellent
DC fault ride-through capability	Poor	Poor	Good	Better

Figure 3.4. Global comparison between two-level, neutral point clamped and two-switch and H-bridge modular multilevel converters [20].

	Hybrid cascaded converter	*Alternative arm modular converter*
Control complexity	Complex, and requires synchronization of the two-level main bridge modulation with that of the series active power filter (H-bridge cells) to minimize the spikes in the converter output voltage, hence reduce AC filter size.	Relatively simply, but requires proper current commutation between the upper arm and lower arms in order to reduce semiconductor losses, and devices current stresses.
Reactive power capability	Could generate larger reactive power than the alternative arm modular converter, because it uses the actual DC link voltage and H-bridge cell capacitors as virtual DC to extend converter P-Q envelope in over-excitation region.	Reactive power in over-excitation is less than that of the hybrid cascaded converter, and is limited by the available DC link voltage plus arm inductances
Bidirectional power flow	100% in both direction	100% in both direction
AC filters	Small AC filter required to attenuate low energy spikes from the converter output voltage (see Fig. 2f).	AC filter could be eliminated, because converter transformer leakage inductance is sufficient to attenuate the high frequency harmonics from the converter output voltage.
Conversion losses	High (predominantly on-state losses)	Low
AC fault ride-through capability	Excellent	Excellent
DC fault ride-through capability	Good	Good

Figure 3.5. Comparison between hybrid cascaded and alternative arm modular multilevel converters

[7] Note that not all of these topologies are commercially available (and may not be commercially available in a near future neither).

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One goal of the Best Paths project, the goal of DEMO #2, is to study the interoperability of multi-terminal HVDC arrangement based on VSC technology (especially on MMC), and to issue recommendations both for specification and hardware control implementation which would ensure maximum interoperability for multi-vendor solutions [34]. For this purpose, a step-by-step approach will be followed. First, a set of HVDC system topologies will be defined, on the basis of three fundamental topologies, representative of the basic elementary bricks of future complex HVDC systems: radial, radial multi-terminal with three terminals, and meshed with three terminals. Figure 3.6 shows these three fundamental topologies. Several variants of these fundamental topologies will be studied: connection to strong AC networks, to weak ones and to offshore wind farms; converters in close electric vicinity or connected to different AC networks; etc. In parallel, functional specifications describing the requirements and expected behavior for various conditions (normal operation, during and after a fault, and during special sequences) will be defined, and manufacturers will adapt their VSC converter models and controllers to meet these specifications. These models will be tested individually first by offline simulations (EMTP-RV) in single-vendor point-to-point configurations to validate them against the specification. Once this verification is done, VSC converter models and controllers will be tested by offline simulations in the multi-vendor configurations initially defined to detect potential interoperability issues (either at the interface between manufacturers, or between an external master control and the converters, or caused by inappropriate behavior if the specifications are not fully adequate). Offline simulations will allow improvement of the initial specifications, in order to address interoperability issues. Then, thanks to refined specifications, real-time simulations based on converters control replicas (exact hardware implementations of the manufacturers current control system solutions) will exhibit both the improvement achieved based on the experience gained during offline simulation and the new interoperability issues that could appear for real DC systems. On this basis, recommendations for the ENTSO-E and standardization bodies will be issued.

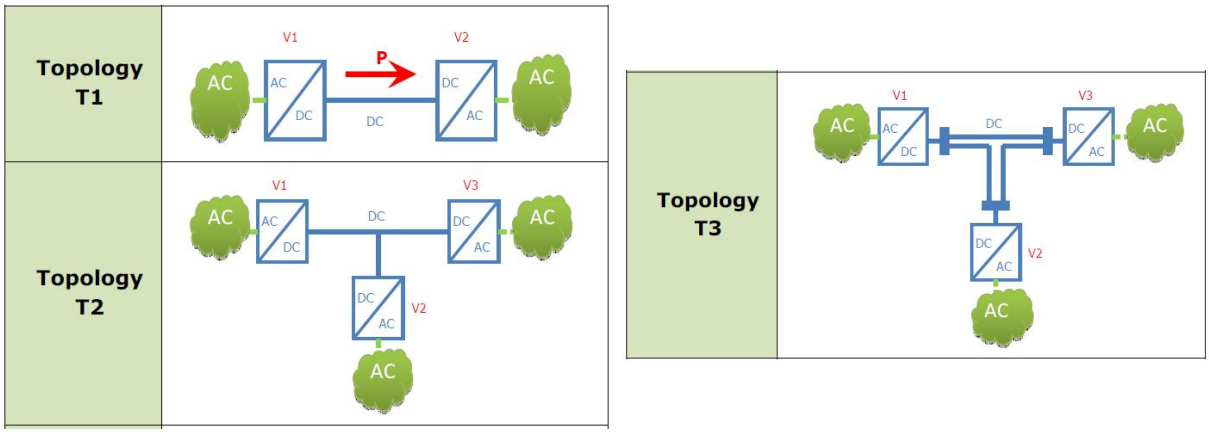

Figure 3.6. Best Paths Demo 2 topologies [34].

3.4 DISCUSSION

The impact of the different study results for PROMOTioN is related to the point in time the study was conducted. Therefore the studies will be discussed in chronological order.

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The Twenties study was one of the first bigger studies on offshore HVDC grids, which included a lot of topics. One important field of study was the effects of grid extensions on the droop control implemented for grid control. It was tested on the extension of the so-called “H-topology” through different extension schemes and illustrated that the power flow control used (droop control) does not have to be changed for most extensions. For the so called Pentagon layout an additional power flow control device was introduced. Based on the simulations of an unmeshed multi-terminal grid the conclusion was drawn that a well-designed multi-vendor DC grid could be operated reliably during all network conditions, including survival from the AC and DC network faults. Due to the variety of topics and the early stage of the investigations, not all topics were investigated at a high level of details. Moreover, the technology has evolved drastically in the last few years and assumptions that were used may not still be fully relevant. For example, only two-level VSC converters were included in the study and it now is expected that mainly MMC converters will be used in a meshed offshore grid. No vendor-specific-controls were used. Faults considered were transients, which are not relevant for an offshore grid based on undersea cables (i.e. faults are expected to be mostly permanent). Topologies studied were very specific. Consequently, the model set-up in the framework of the PROMOTioN project, in particular within WP2, will be more extensive as steady-state, RMS and EMT simulations will be conducted with more advanced models, the expected converter technologies for an offshore grid in the North Seas (i.e. MMC-VSC and DRU), and using different grids and scenario set-up. Another topic addressed in the Twenties project was small signal stability. The corresponding study concluded that properly designed PSS based controllers for onshore converters are effective solutions for providing additional damping to the inter-area electromechanical modes of oscillation, assuring stable AC network operations and enhancing the system dynamic performance. Furthermore, a suitable operation of the whole system ranging from wind turbine via the HVDC connection to the onshore grid was assessed. This included the translation of the onshore grid frequency deviations into the offshore grid to adjust the injected power accordingly. This holistic approach might be beneficial for future system operation.

The OffshoreDC project analysed transients and interactions in VSC-HVDC systems. It contributes to a deeper understanding of the transient behaviour in MTDC grids during a pole-to-ground fault on both the AC and DC side. For analysing the stability of the MTDC systems the Net-damping criterion approach was used and proved to be a superior tool. Therefore it might be a relevant tool for PROMOTioN and especially WP2. Furthermore two new droop controllers for MTDC systems were proposed, which showed better performances than conventional PI-based power controllers.

The main goal of the Best Paths project is to analyse multi-vendor interoperability of multi-terminal HVDC arrangement based on VSC technology. Although the scopes of the two projects are strongly differentiated, this analysis of converter interoperabilities in Best Paths is close to the first pathway of PROMOTioN on converters. Because the project is on going, PROMOTioN cannot build directly on the Best Paths results, but the lessons learnt from Best Paths will be considered in PROMOTioN as they are published. In particular, results of Best Paths will be used for harmonization of HVDC grid requirements (WP11) and development of deployment plan (WP12).

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4 INTERACTIONS BETWEEN WIND TURBINE GENERATORS AND CONVERTERS

The connection of OWFs to the main onshore grid through HVDC systems leads to small islanded offshore AC grids dominated by cables and without any rotating mass establishing a physical binding of active power and frequency (i.e. synchronous generators). It means that the frequency in the offshore AC grid is completely controlled by the offshore converter, independently of the active power balance. Consequently, if wind turbines and HVDC converters are not properly operated, instabilities could occur. For example, unexpected harmonics issues occurred in the BorWin1 HVDC system (based on two-level VSC converters) connecting an offshore wind farm to the shore in Germany, which led to the outage of the HVDC system: converters entered into resonance with the offshore AC grid natural frequencies [35]. The purpose of this chapter is to review previous works that studied the interoperability of the wind turbine and wind power plant controls with HVDC systems. Note that this chapter does not deal with the operation and control of HVDC grids: it is addressed in the previous chapter.

Most of the previous works have studied the interactions between wind turbine generators and voltage source converters (VSCs). These are reviewed first in Section 4.1, which is subdivided according to the main connection requirements and ancillary services. Section 4.2 reviews previous studies on interactions between wind turbine generators and diode rectifiers. The identified barriers and gaps are discussed in Section 4.3, and Section 4.4 concludes.

4.1 VOLTAGE SOURCE CONVERTER STUDIES

4.1.1 ASSUMPTIONS

In Twenties Deliverable 5.2b [20], doubly-fed induction generators (DFIGs) and permanent-magnet synchronous generators (PMSGs) were considered as the two main WT technologies. Converters were modelled as two-level converters because the authors believe that these are the most mature technologies, and different possible configurations are in most cases equivalent with respect to grid stability. Furthermore, OWPPs were assumed to be always connected to an offshore AC grid. The offshore converters were assumed to act as AC voltage sources: setting the AC-side voltage magnitude and frequency. Thus, they cannot control the direct-current (DC) voltages at the connection points but they transmit all the available wind power.

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In the OffshoreDC project [36][8], the OWPPs were assumed to be based on type 4 (full-scale converter) WTs (full-converter generators, FCGs). For power system services, OWPPs were assumed to be seen as lumped units (like any other power station), so that the services must be delivered at the OWPP point of connection as a lumped, coordinated response. Hence, the services can be implemented at plant control level. The DC-voltage control signal was assumed to be directly input to the OWPP as a power reference and fed forward to the dispatcher, to avoid delays due to the power controller.

In the MEDOW project[9], the studied wind turbines have been mainly type 4 offshore WTs. A single aggregated WT model has usually been considered to represent each complete WPP, and therefore the response of each WT for faults within a WPP has generally not been analysed. The WT models have been mostly adopted from the IEC 61400-27-1 standard.

In Twenties Deliverable 5.2b [20], it was recommended to model the WPP converter by a current control-based approach instead of an infinite bus model (this would overestimate the performance of the converter resulting in excessive reactive power support). This model allows the limitation of currents. Priority was given to the q-axis part of the current to provide voltage support of the weak AC offshore island.

4.1.2 FREQUENCY/ACTIVE POWER CONTROL

From a power system service perspective, active power from OWPPs can be used to either provide frequency control to an AC grid (or multiple AC grids) or for maintaining the voltage in the DC grid. Several studies, in both the OffshoreDC and MEDOW projects have looked at frequency control – mainly inertia-based fast frequency response.

A coordinated MTDC-converter control was proposed in [37] [38], in which frequency and DC-voltage droops are used at an onshore converter terminal and, at the same time, the corresponding onshore (AC grid) frequency is communicated to an offshore converter terminal to modulate its OWPP's power output. To enhance the frequency stability of a weak AC grid following a disturbance in power balance, a communication-less method for obtaining inertial response from a VSC-HVDC-connected WPP was proposed and verified experimentally, with laboratory components having ratings in the range of 20 kVA. The emulation of the inertial response from the VSC-HVDC-connected WPP was done by implementing additional controls on the VSC-converter terminals. On the converter connected to the (weak) AC grid, the control relates DC voltage to changes in system frequency. Furthermore, the WPP converter control relates DC voltage changes to changes

[8] The OffshoreDC project aimed at driving the development of the VSC-HVDC technology for future large-scale offshore grids, supporting a standardised and commercial development of the technology, and improving the opportunities for the technology to support power system integration of large-scale offshore wind power.
[9] MEDOW is a Marie Skłodowska-Curie Initial Training Network (ITN) running from the 1st of April 2013 to the 31st of March 2017. It aims at contributing to the integration of offshore wind power into the onshore AC grids in European countries and for the European offshore grid. Its network works towards sharing complementary expertise, infrastructure and facilities for the training of the next generation of top-quality researchers in this field.

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in the electrical torque reference in the WTs. In this way, a coupling of the WTs' inertia to the weak grid is obtained.

The comparison of the communication-based and coordinated frequency controls highlighted that, for the given case, the communication-based scheme can be used without significantly affecting the performance. As the WPP is connected to only one grid in the given case, all the power produced by the WPP flows into that grid, and any power flow change at the wind farm terminal is reflected in the power flowing into the AC grid. However, the two control methods have different results if the WPP is connected to AC grids through an MTDC grid. Moreover, ramp rates (used to protect the WT system – mainly its mechanical part – from excessive stress) might pose a limit to the delivery of such control. When inertial control or fast droop response is needed, ramp-rate limiters may limit the initial frequency response. This is an especially important issue as the share of wind power grows and frequency control requirements become more dynamically demanding. Other factors that limit the active participation of current OWPPs in frequency control are:

- poor economic incentive to deliver the service due to favourable energy price as compared to regulation power price
- insufficient accuracy of wind speed prediction to guarantee safe estimation of available regulation power and energy

In [39], a description of the modelling and control of a PMSG with a fully rated VSC were reviewed for OWPP applications, and its inertial frequency response capability was presented through two methodologies: inertial coupling and step response. The presented simulation and experimental results are consistent and demonstrate the possibility of reducing the rate of change of frequency, but also show the recovery energy problem in restoring the rotor's initial speed. The inertial coupling methodology provides a synthetic inertia with the same dynamic response as the natural inertia, but the addition of a derivative term can destabilise the system. On the other hand, the step response methodology has the advantage of avoiding the derivate term, but it can cause mechanical stress in the shaft when the additional torque is enabled or disabled.

The frequency support characteristics of multiterminal HVDC (MTDC) systems based on modular multilevel converters (MMCs) were analysed in [40], using the energy transferred from the MMCs' capacitance, WTs' rotating masses and other AC systems. A generic formulation of an equivalent synthetic inertia constant was proposed to determine the energy transferred from the MTDC scheme. In the 3-terminal MMC-HVDC system studied, the electrostatic power extracted from the MTDC system's capacitance increases when the values of the cell capacitances or the synchronous machines' synthetic inertia constants increase. As the response from the DC capacitance is faster than that of the other energy sources, the initial energy extracted from it is larger. Such fast support helps to limit the main AC grid's rate of change of frequency. After some time, the contribution from other energy sources becomes larger than that of the DC capacitors. Moreover, active power transferred from other onshore AC grids helps to contain the frequency deviation of the main AC grid. These frequency support capabilities of MMC-MTDC systems will prevent unintended tripping of the main AC grids' protection relays, reduce the required frequency response levels and satisfy grid code requirements.

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In [41], a coordinated fast primary frequency control (FPFC) was investigated for OWPPs integrated to two surrounding onshore AC power systems through a three terminal VSC-HVDC system. The FPFC produces a power reference to the OWPP based on the frequency deviation and its rate of change measured in the offshore AC grid. The power system frequency is significantly improved with the FPFC. However, second frequency and DC voltage (more important for the stability of the offshore grid itself) dips are observed once the OWPPs stop providing frequency control. This phenomenon is predominant at below rated wind speeds due to the higher reduction of the active power output from the WTs after having provided frequency support. The rate and magnitude of the second frequency and DC grid voltage dips can be minimised with the help of an active-power ramp rate limiter. The OWPPs' FPFC, particularly with the ramp rate limiter, reduces the burden on the other converter and AC grid participating in frequency control.

In [42], an improved fast frequency controller (FFC) for WPPs was proposed. The controller produces an additional temporary overloading active-power reference based on the frequency deviation and the rate of change of frequency. Two different control options were proposed and the dynamics of the WTs were analysed at different wind speeds. Contrary to standard controllers proposed in literature, the FFC gains were optimised for different wind speeds over the whole wind speed range and considering the limitations and dynamics of the WTs. Two options for temporary frequency control implementations from WPPs were analysed and compared. By optimising the FFC gains, the response is improved over the whole wind speed range, while stability is still ensured. To improve the WTs' frequency response, the gains can be adapted in advance, based on the very short-term average wind speed forecast, over the whole wind speed range. The controller's performance can be improved if the frequency-initiated power reference is based on the actual power output (Option 2) instead of the constant pre-overloading power output of the WTs (Option 1).

A coordinated control methodology was proposed and demonstrated in [43] for effectively providing ancillary services to AC and DC grids from OWPPs connected through a MTDC network, without any conflict of interest between each service. For the onshore frequency control, the proposed control strategy involves a coordinated control mechanism based on DC-voltage regulation at the onshore converter and frequency regulation at the offshore converter. For onshore AC fault ride-through, and DC grid voltage control, the control strategy involves regulating the offshore AC grid frequency according to the DC-voltage variation. The scheme involves only local measurements, avoiding the need for communication infrastructure and increasing the reliability of the control system. It is recommended to down-regulate the WPPs to have some power reserves. During faults in the DC grid, it may not be advisable for the WPPs' to contribute with more power to the DC grid. Hence, the proposed coordinated control scheme should be coordinated with the DC grid's protection settings.

The limitations for delivery of DC-voltage control from OWPPs are much more restrictive than for frequency control. This is due to HVDC grids storing a quantity of energy that is 10–100 times smaller than in usual AC grids, because of the limited energy storage of the DC capacitance as compared to rotating masses associated with synchronous machines (SMs). This makes the delivery of fast DC-voltage control much more challenging than that of frequency control, as the DC-voltage in HVDC grids changes much more quickly than the frequency in usual (onshore) AC grids. The proposed way to implement such a challenging task at a plant level may not be

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the most effective one. Distributed controllers nearer to the converters may be necessary to provide the required dynamic performance. This is particularly true for higher wind power penetration in the DC grid, but this may be a plausible scenario if large offshore grids evacuating wind power become a reality [37] [38].

4.1.3 AC VOLTAGE/REACTIVE POWER CONTROL

A coordinated reactive power control (CRPC) was presented in [44] for a HVDC-connected cluster of OWPPs. The cluster's reactive power reference is generated by an optimisation algorithm that aims at minimum active power loss in the offshore AC Grid. For each optimal reactive power set point, the OWPP cluster controller generates reactive power references for each WPP, which in turn send the AC voltage or reactive-power references to the associated WTs based on their available reactive power margin. With the CRPC, a WT terminal fault does not affect the voltage profile and power flow in the offshore grid but affects only the faulted cable voltage and its power flow. The WT collector cable fault can affect the voltage profile and power flow to some extent, but it may be improved by additional reactive power support from the non-faulted WPPs. The export cable fault affects the power flow and voltage profile of the offshore grid. The WT's voltage ride-through (VRT) controllers generate the maximum possible reactive current as the voltages at their terminals deviate much from their nominal values. Hence, they contribute with the maximum possible reactive power during voltage dips and consume reactive power following the fault to limit the high voltage in the offshore AC Grid.

A coordinated voltage control scheme (CVCS) was proposed in [44], [45] to enhance the steady-state and the VRT performance of a cluster of OWPPs connected to a VSC-HVDC system, while minimising the losses. The proposed CVCS generates-reactive power references, which are distributed to the individual WTs and the HVDC offshore converter based on participation factors and the WTs' available reactive power margin. In doing so, it integrates individual local voltage/reactive-power control of WTs and of the HVDC converter, with the secondary voltage controller at the offshore grid level. This secondary voltage controller controls the voltage at the pilot bus: the bus with the highest short circuit capacity in the offshore AC grid. By maintaining the voltage level at the pilot bus, which reflects the voltage variations of the entire offshore zone, the voltage profile of the offshore grid is indirectly maintained. During fault clearance, the CVCS limits the temporary peak overvoltage at the point of common coupling. This will be beneficial for overvoltage protection under partial/full HVDC load rejections, resulted from the blocking of the converter due to the action of protection system. In case of communication failures, the individual WTs operate in voltage/reactive control mode within their operational limits.

The CVCS considers the network sensitivity and therefore effectively and efficiently utilises the available reactive power sources. It also improves the voltage stability margin of the offshore AC grid. The participation factors ensure proper distribution of reactive power to each WPP and WTs within the WPPs based on their voltage sensitivity with respect to the pilot bus. This avoids excessive voltage rise at WTs located far from the AC collector substation. Such method leads to the minimisation of the risk of undesired effects, particularly overvoltage at the terminals of WTs located far away from the AC collector substation, by dispatching lower reactive power references compared with the ones nearer to the substation.

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It is usually assumed that the offshore HVDC converter will control the offshore AC system, but little work has been done on how to do so. Two control options for offshore HVDC converters in offshore AC island networks hosting WPPs were analysed in [38]. Table 4.1 presents a comparison of them.

CONTROL OPTION	ADVANTAGES	DISADVANTAGES
Nested voltage-current control	• Automatic current control capability • Slightly better performance in network with multiple HVDC converters and WPPs	• Hard tuning at no-load • Performance dependence on connected capacitance • Performance dependence on active power from WPP • Need for dedicated capacitance (space and weight) to solve above two issues
Voltage-oriented control	• Straightforward tuning at no-load • Simplicity (only one control loop required in normal conditions) • Independence of connected capacitance • Independence of active power from WPP	• No automatic current control capability (need for dedicated protective scheme) • Slightly worse performance in networks with multiple HVDC converters and WPPs

Table 4.1. Summary of the control options assessment [38].

The voltage-oriented control option should be used for offshore HVDC converters in offshore AC island networks hosting WPPs. However, a complete assessment requires a more extensive analysis. In particular, short circuit faults and other heavily non-linear events such as energisation and de-energisation must be analysed before a final choice can be made.

The connection of an onshore HVDC terminal to weak AC networks was also studied in [38]. It was shown that a weak AC network's non-linear characteristic in the Q-V plane may give rise to a non-constant contribution of the HVDC station's voltage control to the small-disturbance short circuit power of the AC network it is connected to. When the onshore AC voltage control and the OWPP's operation are not decoupled, the prioritisation of reactive power in heavily stressed power systems undergoing possible voltage collapse is crucial. For equal sharing of the load by the two sides, the HVDC converter reaches its current limit and hence voltage control capability as the load increases. The prioritisation strategy of the current under such conditions has an influence on the long-term voltage profile of the system (P-V curves). Using a vector prioritisation for the current rather than prioritising active current is beneficial for the voltage stability period, as the active power limit where the voltage stability is lost is larger. Coordination between the TSO and OWPP/HVDC operator is crucial to maintaining mutually beneficial system integrity.

To reduce the overall system losses in a system with HVDC-connected WPPs while respecting operational restrictions on voltage, reactive power capability of the converters and current limitations, an optimal power flow (OPF) was implemented in [46]. The WTs and HVDC converter mutually share the reactive power injection in the offshore WPP grid. The converter, transformer, filter and cable losses are the main sources of power losses for the reactive power allocation optimisation. The loss reduction by optimal reactive-power allocation correlates with the sum of active power injections by the WTs and is independent of the wind direction bin. The wind

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direction influences the individual reactive-power injection, while the reactive-power exchange at the point of common coupling (PCC) depends on the total active-power production. The highest reactive-power injections are made by the individual turbines, which are either close to the PCC and/or have a high annual active-power production.

When faults occur and the produced active power can no longer be exported, the DC voltage level increases. Such surplus active power must be dissipated to prevent the DC overvoltage level from exceeding a certain value (e.g. specified by the manufacturers of the switching devices). In order to dissipate the active power, the possibility of using already existing WT DC choppers was investigated in [20], instead of installing DC choppers at the onshore converters. A control scheme that translates onshore voltage drops to offshore AC grid under voltages was proposed. This solution was regarded as feasible because no new high power DC choppers need to be installed at the onshore converters.

To enable MTDC grid fault ride-through (FRT) capability for AC side faults, communication-free advanced control functionalities were proposed in [21]. Such functionalities are to be used as a supplementary local control in converters, to accommodate active power according to two possible approaches: (1) installing a DC chopper resistor in the DC side of each onshore converter, and (2) the implementation of FRT control mechanisms exploiting a set of coordinated local control rules at the converter stations and wind turbines. The assessment of DC grid operation under loss of an onshore HVDC-VSC confirmed that the active power reduction scheme through AC offshore frequency increase is able to cope with situations of permanent loss of an onshore converter. Additionally, the results suggest that the traditional power reduction scheme through turbine pitch control is not sufficiently fast to ensure that the DC voltage does not overreach the maximum admissible value. On the other hand, the mixed strategy with chopper resistors to assure the initial post-fault power dissipation, and the pitch control to assure the permanent power reduction after chopper disconnection, copes with this specific situation, presenting a satisfactory response. For optimal MTDC grid FRT capability for AC side faults, a combination of the proposed functionalities is advised. Additional research efforts are needed for effectively dimensioning a solution that exploits all the considered alternatives.

Methods for preventing DC overvoltage in MTDC networks were analysed and compared in [47]. Power reduction sharing among offshore wind farms using the different control signals was analysed. Two power-reduction control methods, based on voltage reduction or frequency increase, were proposed for OWPPs with type 4 WTs and a MTDC transmission system. The two proposed methods were also compared with another method that uses a DC-chopper resistor. Simulation and experiments were carried out to evaluate the control systems. Simulation and experimental results under various faults demonstrated the feasibility of the power reduction controllers. The DC chopper resistor method is simple and needs only a local control signal. It can achieve better control performance than the proposed power reduction methods but with extra cost and equipment size. On the other hand, the proposed power reduction methods, based on voltage reduction or frequency increase, remove the need for fast communication between the offshore converters and WTs. They also do not require extra equipment to implement the control schemes.

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4.1.4 RESTORATION

The usage of the offshore DCG and wind turbines is proposed in [21] as an alternative option for system restoration after a blackout. The underlying idea is that wind energy can significantly lower investment and maintenance cost (compared to the traditional restoration equipment). The required control strategies of HVDC-connected offshore wind generators during the black-start process have been analysed. The reported simulation cases show that fast HVDC reactive power control can effectively alleviate transient and steady-state overvoltage during system restoration. It helps to reduce the restoration time and smooth the restoration process.

4.1.5 POWER OSCILLATION DAMPING

The contribution OWPPs can give to the enhancement of small-signal stability was analysed in [38], [48]. Guidelines to tune the parameters of the power-oscillation-damping (POD) controller on static sources were generated, after emphasising the need to account for excitation systems (ESs) and automatic voltage regulators (AVRs) in small-signal analysis. The implementation on HVDC-connected WPPs was successfully tested on a dynamic simulation tool. Moreover, limiting factors for the delivery of this feature from WPPs were discussed. Finally, experimental validation work was performed at the National Renewable Energy Laboratory in the United States.

4.2 DIODE RECTIFIER STUDIES

In addition to the projects listed above, there are studies from the PROMOTioN partners, Siemens [49], [50], [51] and Polytechnic University of Valencia (UPV) [52], [53], [54], on Diode-Rectifier Unit (DRU) connection of offshore Wind Power Plants (OWPPs), which is one of the three key technologies in the PROMOTioN project. In these studies, the main objective is to enable the power flow from the OWPP through the offshore DRU to the onshore VSC-HVDC terminal. The focus is to equip the offshore WTs with the necessary control algorithms, since the DRU cannot form the offshore voltage, as opposed to the existing VSC solution.

4.2.1 ASSUMPTIONS

The main assumption made in the studies is that the WTs will be able to create the offshore network voltage and generate and enable power flow through the DRU, via only software (control algorithm) changes in the WTs (i.e. without any hardware upgrades or additional sizing). However, studies from Siemens assumed an AC connection parallel to the HVDC transmission line (DRU-offshore & VSC-onshore), whereas this so-called umbilical AC line is considered to be connected during start-up of the offshore network and disconnected afterwards.

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4.2.2 MAIN RESULTS

The idea of DRU-connected OWPP has so far been studied via offline simulations and hardware-in-the-loop (HIL) real-time digital simulations by both Siemens and UPV. Results from both of the groups showed that it is possible to operate the OWPP with the DRU such that the newly developed wind turbine algorithms are able to create and regulate the offshore voltage and frequency and perform maximum power point tracking for a range of investigated cases including: low wind, start-up, and active-power control. Additionally, it is shown that the proposed structure with the DRU can survive onshore and offshore AC and DC fault situations, such that the OWPP and the HVDC line can ride through these disturbances.

4.3 IDENTIFICATION OF BARRIERS AND GAPS

As presented in the above listed studies, there are several barriers in front of the offshore wind deployment. One of the main barriers is the lack of interoperability between WT and HVDC and DC cable vendors, which prevents optimized solutions being implemented in an easy way. It is considered that the existing system level components are not yet plug & play, such that each installation requires its own analysis and design. Owing to the dependencies between the HVDC and OWPP vendors, many issues are being addressed separately and independently e.g. harmonics and resonance problems within the offshore AC network. Additionally, it has been identified that the communication (e.g. from the onshore grid to the offshore WTs) requirements of the HVDC and OWPP manufacturers should be investigated in collaboration with the TSOs, especially for the provision of ancillary services and FRT for onshore faults. For instance, the solution with communication of the fault to the offshore WTs via modulation of the offshore AC voltage or frequency (by the offshore VSC-HVDC) needs to be verified with all of the parties (OWPP and HVDC vendors, and TSOs).

As mentioned in almost all of the previous projects, an important barrier for studies of the interaction between offshore WTs and HVDC converters is the difficulty of real (or large) scale testing. As opposed to many other onshore cases, it is not always possible to test and verify developments for the offshore WTs without installing on the offshore site. This adds risk and hence prevents developments.

Another identified barrier, which can be considered as both technical and bureaucratic, is the lack of generally accepted offshore grid codes. The ENTSO-E grid code for DC-connected OWPPs is a reflection of onshore requirements, which is creating possibly unnecessary challenge for the OWPPs and might be preventing cost-effectiveness of the offshore systems. Additionally, the lack of consensus on scenarios of power flow control via meshed offshore grids (MOGs) to onshore grids creates ambiguity for the development of OWPP control schemes, so that the support from OWPPs cannot be fully exploited.

Despite the interest in MTDC solutions in Europe, most installations are point to point. Only a few offshore installations include several WPPs connected to a common HVDC grid and there are no existing meshed structures. This means that possible challenges in the interaction of OWPPs with MOGs are hidden for now, due to the lack of experience with MOGs.

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An important barrier for the development of control solutions (e.g. ancillary services) for the OWPPs is immature economic considerations for the provision of ancillary services, such as the lack of payment schemes. Moreover, an inherent barrier is the intermittent characteristic of the wind power, which hinders for instance reliable frequency support from OWPPs.

In addition to the abovementioned barriers, there are other severe barriers for HVDC solutions using the DRU technology, as it is yet to be demonstrated in existing offshore WTs.

In addition to these barriers, some gaps have been identified within the scope of the abovementioned projects. For instance, coordination with TSOs regarding response from HVDC-connected WPPs (such as prioritisation between active- and reactive-power capacities from the onshore HVDC terminal) is missing in the previous studies. Cost-optimised offshore topologies (e.g. decreasing the amount of power electronic components in the WTs) have been proposed and analysed but have not been verified. Clear requirements from OWPPs are not established yet. For instance, detailed requirement (e.g. offshore asymmetrical fault response) analyses for OWPPs have not been performed. Such analyses would contribute to the establishment of grid code requirements. A reference guideline for the tuning of offshore networks (OWPPs and HVDC converters) is missing in the area, as is an extensive analysis of offshore voltage control (e.g. robustness against resonances). For the recently developed DRU technology, analyses of DRU-HVDC operation within MOGs are yet to be performed.

4.4 DISCUSSION

PROMOTioN will tackle most of the identified barriers and gaps, mainly considering the DRU-HVDC concept. Interoperability is one of the main areas of interest in WP3 e.g., enabling the connection of WTs from different vendors to the DRUs. WP3 will also focus on the standardisation of the WTs' response (based on the specified requirements). The development of standard electrical models will also contribute to interoperability. Development of compliance assesment procedures for offshore WTs and WPPs will indirectly help to improve collaborative studies between OWPP and HVDC developers. In WP3, the provision of ancillary services by OWPPs through MOGs will be investigated. Additionally, the effective use of OWPPs and MOGs in supporting the restoration of onshore AC grids (black start) will be considered in the scope of WP3.

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5 DC GRID PROTECTION SYSTEMS

Similarly to AC grids, faults can occur on transmission elements in a DC grid. Consequently, DC grid protection systems must be able to detect and isolate faulted parts to minimize the negative impacts of these faults. In a point-to-point HVDC system adequate protection systems for DC faults are simple, because selectivity is not an issue (i.e. if there is a fault on the system, the overall system must be isolated[10]). The problem is much more difficult for complex DC grid topologies such as radial multi-terminal and meshed grids, because depending on the protection philosophy there is the need for selective fault detection and clearing. Moreover, a speed requirement is expected for the fault detection and identification in these complex DC grid topologies, such that the faulty element can be disconnected before the current increases beyond the acceptable limits of the system (e.g. safe operating area of IGBTs and cables) or the DCCB short-circuit breaking current capability. However, requirements on the protection systems used depend on the protection philosophy chosen for the DC grid. This Chapter reviews the main protection philosophies, the major requirements imposed on DC grid protection systesms, algorithms previously proposed to detect and locate faults in DC grids and emphasizes current limitations of these algorithms. Note that the review of breaking technologies to isolate faulty elements is performed in the Chapter 6 and is thus not discussed here. This Chapter is organized as follows. In Section 5.1, three protection philosophies are identified together with the six main requirements which are used to assess the related performances. Because faults in DC grids can occur on DC branches, but also on DC busbars, Section 5.2 reviews protection strategies to detect and locate faults on DC lines and Section 5.3 reviews protection strategies to detect and locate faults on DC busbars. Finally, Section 5.4 concludes.

5.1 DC PROTECTION PHILOSOPHIES AND REQUIREMENTS

Three types of protection philosophies can be defined [55]:

- Selective protection philosophy: each element of the grid can be individually disconnected in case of fault on this element;
- Partially selective protection philosophy: a zone of the DC grid is disconnected in case of at least one faulty element inside this zone;
- Non-selective protection philosophy: the whole DC grid is disconnected in case of at least one faulty element inside that system.

The choice of the adequate philosophy is a compromise between the portion of the grid and its generation and load that is accepted to be lost in case of failure and the cost of the fault current eliminating equipment together with its control system. For radial multi terminal and meshed DC grids, a priori the first two philosophies are preferred. The fault detection and identification must be fast, such that the faulty element can be disconnected before the current increases beyond the acceptable limits of the system (e.g. safe operating area of IGBTs and

[10] Note that, in case of pole to ground fault in a LCC-based bipolar point-to-point HVDC system, only the faulted pole can be disconnected for continued operation of the healthy pole through ground return [64].

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cables) or the DCCB short-circuit breaking current capability. For smaller systems it might still be an option to shut down the whole DC system by clearing the fault using the AC breakers, although this is not the main focus of PROMOTioN.

Six main requirements on DC grid protection systems are usually defined [56] [57] [58]:

- Sensitivity: accurate detection of any fault occurring on the grid (including high impedance faults),
- Selectivity: a protection system should only operate in case of fault, and just if the fault is located in its own coverage domain (discrimination of the faulty device),
- Speed: the fault current must be interrupted before it can damage equipment, or before it can no longer be interrupted by the circuit breakers in case of selective or partially selective philosophy, or before it can entail the loss of system stability,
- Reliability: reliable operation and a backup system in case of failure of the primary protection system,
- Robustness: ability to detect faults in normal mode as well as in degraded mode (unavailability of some cables, devices or components), and to discriminate faults from any other operation occurring (setpoint changes, topological changes)
- Seamless: after clearing the fault, the remaining part of the system should continue operating securely

5.2 LINE PROTECTION SYSTEMS

The detection and the localization of faults can be achieved via two alternative approaches: utilizing only local measurements (no communication), which is called a single-ended detection, or utilizing measured values or signals communicated from other terminals in addition to local measurements, which is called double-ended detection [59]. For the sake of clarity, the analysis of protection strategies is based on this classification. In the terminology of the International Electrotechnical Commission (IEC), the related protections are called respectively non-unit and unit protections.

5.1.1 NON-UNIT PROTECTION DETECTION STRATEGIES

In AC systems, two single-ended detection strategies are widely used: *overcurrent protections* and *distance protections*. Distance protections are used as primary protection systems for faults in meshed AC systems, while overcurrent protections are used as primary protection systems in radial AC systems and as back-up protection systems for faults in meshed AC systems. The latter are also used to protect equipment in case of unacceptable working conditions. The same methods have been studied for HVDC grids. Specifically for HVDC grids, protection algorithms based on current and voltage derivatives, travelling waves and artificial intelligence techniques have been proposed[11].

[11] Note that some of these protection algorithms are also studied for AC grids (distribution systems).

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Overcurrent and undervoltage protection systems

An overcurrent relay sends a trip signal to the circuit breaker when the current exceeds a predefined threshold (with a directional criterion), usually after a delay. In the framework of the Twenties project, it has been shown that the overcurrent protection cannot always fulfil the selectivity requirement in DC grids [60]. Similarly to the overcurrent, a simple criterion based on an abnormally low DC voltage could be used (undervoltage protection). However, it appears unsuitable due to a relatively slow decrease after fault occurrence and no possibility for selectivity [59].

Distance protection systems

Even if distance protections are widely used in AC grids, the Twenties project reached the conclusion that they are not suitable for DC grids [56]. A distance protection measures the distance to the fault by computing the apparent impedance, the ratio between the voltage and the current. Note that this ratio reflects effectively the distance to the fault only in steady-state conditions. In an HVAC grid, the apparent impedance is mainly due to the inductive part of the cable or the line. But, in an HVDC grid, under stationary conditions, this apparent impedance is only due to the resistive part of the cable or the line, as shown in Figure 5.1, which is very weak. It is indeed necessary to wait for stabilized currents and voltages to be able to compute the apparent impedance: otherwise the computation would be disturbed by the fault wave propagation or possible reaction of converters [56]. Therefore, a small measurement error or a non-negligible fault resistance can cause a huge distance error. Moreover, waiting for the steady-state conditions entails a trip signal delay much larger than the delay to clear the fault according to the DCCB's capability.

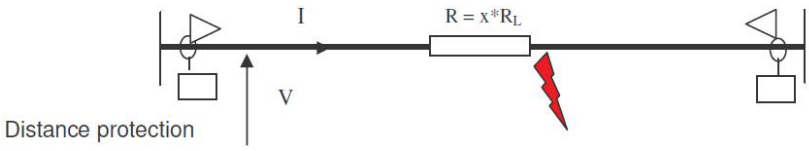

Figure 5.1. Operating principle of a distance protection [56].

Current and voltage derivative protection systems

Single-ended protection strategies can be also based on the DC-current derivative or the DC-voltage derivative: a trip order is sent when the current derivative is larger than a threshold, in the first case, or when the voltage derivative is lower than a threshold, in the second case. However, the scientific literature is inconclusive about the selectivity. Based on simulations for a meshed HVDC grid with 2-level VSC converters [60], the Twenties project concluded that these strategies suffer from a lack of selectivity [61]. On the other side, [59] concluded that single-ended protection strategies based either on the current derivative or the voltage derivative are suited to protect a radial multi-terminal HVDC grid with MMC VSC converters: selectivity can be obtained for faults on most of the cable lengths, except when a fault occurs close to a terminal. Another recent work [62] concluded that single-ended detection strategies based on the current derivative cannot be (significantly) more selective than the ones based on undervoltage, while the ones based on the voltage derivative measured on the line side of FCL inductors can lead to selectivity.

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It is also possible to combine criteria on the current derivative and on the voltage derivative in a “Voltage Derivative Supervised Current Derivative” (VDSCD) protection algorithm to enhance the performance [63]. A fourth protection strategy is based on derivatives: the transient based fault protection algorithm sends a trip order if the product of the current derivative by the voltage derivative is negative and below a certain threshold for a specific period of time [63].

Travelling wave protection systems

The traveling wave protection is a new type of protections and only few aspects are presented in the frame of the present report. Its algorithm is based on the measurement of the magnitude and/or polarity of the current waves (or the voltage waves), initiated by faults [64]. The current wave cannot be measured directly, but can be computed based on the DC-current, the DC-voltage and the characteristic impedance of the line. This method has a good selectivity for HVDC systems for homogeneous branches (e.g. only cables) [64], but the faulty section identification is more difficult for mixed branches combining overhead lines and underground cables [65]. Moreover, it is vulnerable to interference signals and needs a (very) high sampling rate to be accurate [65]. Travelling-wave based fault-location detection methods can be improved by using signal processing techniques. The most popular one is the wavelet analysis, which is well suited to detect abrupt, local changes in a signal [66]. However, a detection method based only on current wavelet coefficients for fault detection causes a lack of selectivity and this detection method must be combined with others to reach a satisfying accuracy [66].

Artificial intelligence techniques

A final category of single-ended detection methods is based on artificial intelligence techniques such as machine learning. For example, in the framework of the Medow project, [67] proposed a Fault Detection and Identification (FDI) method for HVDC grids based on a K Nearest Neighbors (KNN) algorithm. The proposed FDI algorithm utilizes only current measurements to identify the protection zone of the DC grid where the DC fault occurs. It has been claimed in [67] that in contrast to the previously studied data-based methods in literature, the proposed algorithm uses features obtained from current rather than voltage measurements. The FDI algorithms which are based on voltage measurements also require the measurements obtained from current sensors to distinguish between faults on DC transmission lines and bus terminals. This paper also presented a detailed model of an optical current transducer (OCT) and investigated how the accuracy and speed of the proposed FDI algorithm is impacted by i) measurement noise and ii) sampling frequency. The proposed algorithm has been applied to a four-terminal HVDC grid. The current measurements provided to the relays are obtained from elaborately modelled OCTs. Study results show that the proposed algorithm can detect faults at DC transmission lines and converter bus terminals and identifies the protection zone where the fault occurs (bus terminal or transmission line). The performance of the FDI algorithm does not degrade in case of various measurement noises, i.e., optical, electronics unit, and quantization. Nevertheless, the usual drawback of artificial intelligence techniques occurs: a large amount of training efforts are needed to reach satisfactory results.

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5.1.2 UNIT PROTECTION DETECTION STRATEGIES

The selectivity of some single-ended protection systems can be improved by communication of the protection with the protection of the opposite end. On the other side, selectivity can also be achieved by using double-ended detection strategies. In any case, the communication delay between extremities decreases the speed. Indeed, even if fiber optic transmission is very fast (approximately 1 ms for 200-km cables), the emission and reception relays that are also required increase the communication time by 2 ms [56]. Moreover, the reliability of the protection system is dependent on the telecommunication's system availability.

Differential protection system

In the world of AC systems, current differential protection systems are widely used. The main principle is to measure and compare currents at the two line ends. If their algebraic sum is larger than a threshold during a time larger than a pick-up delay, it indicates that there is a fault on the line and a tripping order is sent to the circuit breaker [56]. The pick-up delay is necessary because the assumption that, in absence of a fault, the algebraic sum is approximately equal to zero (i.e. equal to losses on the cable) is true only in steady-state conditions. Because it is not acceptable to wait for steady-state conditions in an HVDC grid, adapted versions of differential protection must be used [19]. In particular, in the framework of the Twenties project, a modification of the basic differential current principle has been modified to become a traveling-based criterion, which takes into account the transient behavior of a DC grid under fault conditions, shown in Figure 5.2. A selective threshold enables the fault detection for the faulty link. If small enough, the threshold is exceeded at the front transient arrival. To avoid unwanted trippings of healthy link protections, a negative threshold is added to detect the first negative front. This negative front defines the fact that the fault is exterior to the link. The over-passing of this threshold will imply the blocking of the tripping order, for a duration time corresponding to the fault clearing process time. Therefore, the selectivity is ensured, except for short links (i.e. shorter than 1 km) [61]. The major constraint of this protection scheme is the required communication path and the delay it implies on the treatment of the signals due to the propagation speed of the data that may limit the length of the cable to which this principle is applicable. This limit is estimated in the range of 180 km. GPS synchronization, accurate parameters of HVDC lines, high sampling rate and communication speed are needed, which is costly [65]. However, this principle is the best way to selectively clear high resistance faults.

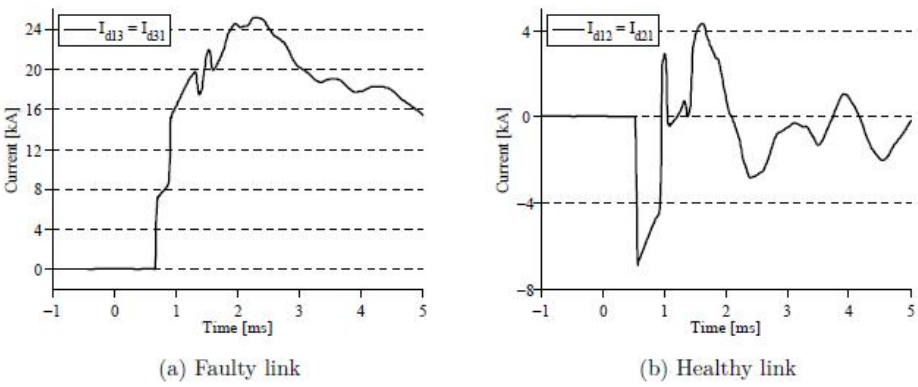

Figure 5.2. Transient behaviour of the differential current [60].

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Directional protection system

The directional comparison protection combines information about the current direction at both ends with local measurements to detect a fault: a trip order is sent to the circuit breaker only if local measurements indicate the presence of a fault on the protected branch (e.g. through the overcurrent criterion) and if the protection system at the other end detects also a fault on that branch. Because of the simplicity of the information to be communicated, it should be faster and more robust than the differential protection principle, but the transmission issues are the same [56]. A variant of the directional criterion based on the first current wave front after a fault is presented in [60].

5.1.3 DETECTION STRATEGIES USING THE COMBINATION OF BOTH TECHNIQUES

The literature shows that protection systems must combine several basic protection principles to perform as required. For example, the protection system proposed in [60] combines a differential current algorithm and a voltage differential algorithm and the protection system proposed in [66] makes use of a 2-out-of-3 voting system based on voltage wavelet coefficients, current wavelet coefficients and voltage derivative/magnitude.

The combination of basic principles to reach a protection system satisfying all the requirements is also the choice done in Demo 1 of the Best Paths project. In that case, the protection system consists of two layers:

- The first layer is based on a single-ended detection strategy (no communication between the terminals), the current derivative strategy, to ensure fast detection of low impedance faults. Indeed, communications between terminals in a multi-terminal HVDC grid introduce delays that may not be compatible with the extremely high current gradients that are a consequence of the low impedance present in the current paths in this kind of grid. Inductive Fault Current Limiters (FCLs) are installed at each end of the HVDC cables to ensure fault selectivity. The simulation results show that this first protection layer can detect faults between 0.01 Ω and 100 Ω with the applied settings. In general, a higher value for the FCL impedance is beneficial for the selectivity, simplifies the setting of the thresholds and makes it possible to detect faults with higher impedances, but also leads to higher installation costs.
- The second layer is based on a double-ended protection strategy, the differential protection strategy, to ensure detection of high impedance faults: a drawback of communication-less protection schemes is that they are unable to detect relatively high impedance faults. Using this technique, faults with impedance up to about 400 Ω should be detected. Note that the Demo 1 of the Best Paths project does not aim at studying the development of protection systems for meshed HVDC grids, but that it aims at proving that OWFs can be connected through radial multi-terminal systems.

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5.3 BUSBAR PROTECTION SYSTEMS

In the framework of the Twenties project, busbar differential protection has been studied [61] [60]. The differential current is the absolute value of the algebraic sum of currents entering/leaving the busbar. When the differential current exceeds a threshold, strictly higher than zero to account for measurement errors, a tripping order is sent to each DCCB of the busbar. Because all measurements are done in a unique substation, there is no need for telecommunication, and thus the fundamental problem of differential protection systems for cables is avoided. Therefore, the Twenties project concluded that the differential protection is an appropriate principle for busbar protection in DC grids [61].

Note that DCCBs may be unidirectional, which implies that, in that case, DCCBs used to clear busbar faults are different than DCCBs used to clear line faults. For example, in [68], a protection strategy for multi-terminal HVDC grids based on unidirectional breaking devices has been discussed and assessed. The performance of unidirectional protection strategy has been examined under different fault scenarios in a four-terminal MMC-HVDC grid model. Furthermore, the impacts of unidirectional protection strategy on the power converters and also the current interruption and surge arrester ratings of the DC circuit breakers (DCCBs) have been discussed. The paper concluded that unidirectional DCCBs are technically attractive for application in MTDC grids due to lower capital and operational costs. A comparison study of different parameters for DCCBs implies that the current rating of DCCBs and the size of surge arresters are not necessarily different for the bidirectional and unidirectional strategies. However, the impact of suggested strategy on all converters of the grid, particularly the converters with shorter connections between them should be analysed. In order to avoid blocking of the MMCs at non-fault buses, an increase in the size of the smoothing reactor or DCCB limiting inductor might be required.

5.4 CONCLUSIONS

As shown in previous sections, numerous HVDC grid protection schemes have been proposed by academia and industry, but they remain at the theoretical level with no practical implementation having been made so far. Some of the schemes rely on locally measured quantities (non-unit protections), while others require measured data from two points (unit protections). The latter are slower, but could offer more selectivity and are able to detect high impedance faults. The literature shows that there is no final consensus on the protection schemes that will be the most suitable for practical implementation. Indeed, no single basic protection principle fulfills all the requirements needed for meshed HVDC grids. Protection systems must thus combine several basic protection principles to perform as required

The PROMOTioN project (specifically: WP4 and WP9) will thus compare the various theoretical approaches that have been reported in the literature, in order to select the best ones for HVDC grids and to bring them to ready-to-be-implemented approaches, including detailed descriptions of equipment requirements. It is expected that different grid topologies and different grid sizes will result in different requirements (e.g. loss of power infeed) and different preferential grid protection philosophies. Therefore, a multipurpose Intelligent Electronic Device

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(IED) will be developed to test the different methods with different system configurations and different fault current interruption methodologies. This assures a multi-vendor compatible protection method. This breakthrough will remove one of the critical barriers for the realization of large meshed HVDC grids. The multi-vendor approach will allow HVDC grid protection systems to be “plug-and-play”.

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6 HVDC CIRCUIT BREAKER PERFORMANCE

6.1 INTRODUCTION

There are a number of challenges associated with fault management in HVDC grids which make the development of HVDC circuit breakers (DCCBs) challenging. In traditional AC systems impedance is dominated by the reactive component but in a HVDC grid only the relatively small resistive component of impedance is present which leads to significantly higher fault current magnitudes and a low voltage level across the grid for faults in a DC system. Voltage Source Converters are blocked if voltage drops to around 80-90% of nominal value which can lead to the loss of the entire DC grid for any DC fault [18]. To avoid this and to limit the size of fault current that needs to be interrupted it is normally assumed that HVDC circuit breakers should be capable of operating at much faster speeds than traditional AC circuit breakers. The exact requirements for DCCBs vary depending on the network design and the type of converters that are deployed. If half bridge MMC VSC converters are to be used, as is often envisaged for multi-terminal and meshed offshore grids, then in the event of a DC side fault the converters would block their IGBT switches under localised overcurrent protection. The VSCs then become uncontrolled diode bridges which allow fault current to feed into the DC grid from the connected AC systems. In such a scenario the standard expectation is that DC faults should be cleared within 3-5ms to avoid converter tripping [18] [69]. If the rate of rise of current in a particular DC grid is very high then it may well be necessary to have even faster breaking times to minimise the peak fault current that needs to be interrupted, depending on the limitations of the DCCB technology used. If full bridge MMC VSC converters are used then it is possible to block or limit the fault current in the DC grid which would significantly reduce the required performance of DC side protection. This option however comes at the cost of additional semiconductor components in the converter.

Another key distinction in DC systems compared with AC systems is that there is no natural zero crossing of fault current which means that extinguishing the arc, which forms when the conducting path is physically broken by a traditional mechanical circuit breaker, is a non-trivial task, especially at the voltage and current levels expected within an offshore DC grid. Therefore, DCCBs need to generate a current zero crossing to extinguish the arc in a mechanical breaker or block current flow by alternative means, for example, by building a large enough counter voltage through the use of power electronic devices. DCCBs also need to dissipate the large amount of energy that is stored in the system inductance. Therefore, it is clear that DCCB designs are necessarily more complex and more costly than their AC equivalent.

6.2 DESIGN OPTIONS

Mechanical DCCBs are commercially established and presently available at low DC voltage ratings of around 1-3 kV [18]. At these voltage levels it is possible to employ current limiting methods to reduce the current to a low enough level for arc extinction without the need to force a current zero crossing, however such designs have not

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been scaled to high voltage and extra-high voltage and are thus inadequate for use in HVDC systems of the scale proposed in the PROMOTioN project, working at several hundreds of kV [69] [70]. The three main design concepts that have been developed for delivery of high voltage DCCBs are discussed below.

6.2.1 RESONANT HVDC CIRCUIT BREAKER

The first concept that has been proposed for HVDC applications is the resonant HVDC circuit breaker. A resonant circuit is used in conjunction with the simple mechanical circuit breaker to force the zero crossing with the typical design consisting of three separate paths as shown in Figure 6.1.

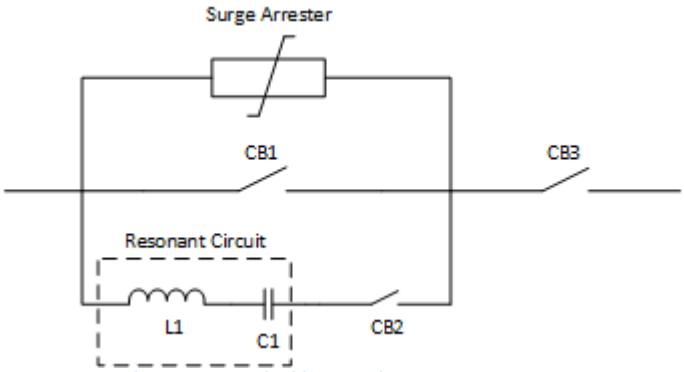

Figure 6.1. Typical layout of a resonant DCCB.

The on state conducting path consists of a low loss main mechanical circuit breaker, CB1, which along with CB2 can be similar in nature to an AC circuit breaker. Upon fault detection the normally closed CB1 is opened and an arc is formed, immediately after which the normally open CB2 is closed. This initiates the resonant circuit containing L1 and C1 which generates an oscillating AC current which is superimposed onto the main DC current and acts to generate a current zero crossing which extinguishes the arc. After interruption the current commutates to the surge arrester path which dissipates the residual energy stored in the system inductances and allows final isolation at current zero via the opening of the normally closed disconnecting switch CB3. There are two alternative designs for the resonant breaker using either passive or active methods. In the passive option, CB2 is not required and the oscillation generated in the resonant circuit is self-excited and grows gradually to a value large enough to create a current zero crossing. In the active option additional circuitry allows the capacitor to be pre-charged and maximum resonance amplitude is reached immediately after CB2 is closed leading to a faster zero current crossing. Active resonance designs can also be classified as active current injection devices. In many cases a series reactor is also present to limit the rise of current into the DCCB and stresses on components but it is desirable for the size and cost of this to be minimised. The faster the circuit breaker action, the smaller the required reactor so there is a trade-off between component parameters, reactor value, breaker performance and total cost [71].

Resonant DCCBs are relatively low cost compared with options that rely on power electronics and have low losses but their main drawback is operating time which is dominated by the speed of the mechanical contacts and until recently has typically been in the range of 30-40ms. This is significantly slower than the required

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interruption speed of 5ms or less expected for DCCBs in multi-terminal or meshed grids which means they have generally been considered unsuitable for this application. More recently developments have been made to speed up the operation of the mechanical contacts [72] which allows for the design of fast mechanical breakers with operating speeds in the range of 5-10ms which more closely approaches the requirements of DC grids. Both ABB and Mitsubishi have successfully demonstrated fast mechanical DCCB prototypes at scale with ABBs demonstration, for example, operating at 80kV system voltage, 10kA fault current and with an interruption time of 5ms [71] [73].

6.2.2 SOLID-STATE HVDC CIRCUIT BREAKER

A solution that has been proposed to meet the requirement of fast operating time is that of a solid-state DCCB. This would consist solely of semi-conductor devices placed in the current path. Figure 6.2 shows the basic principle behind the solid state DCCB where the semi-conductor devices operate in the main current path with energy absorbing surge arresters in parallel.

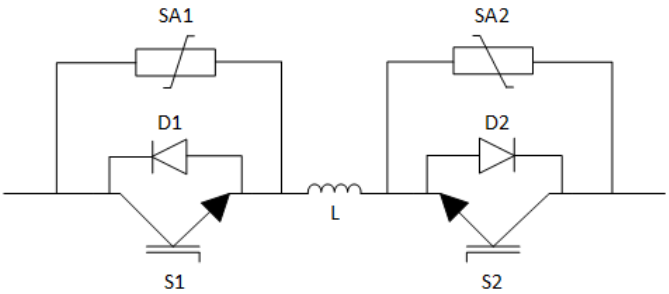

Figure 6.2. Basic layout of bi-directional solid state DCCB (adapted from [18]).

The typical solid-state arrangement essentially consists of two inverter valves of reverse polarity rated at full DC network voltage via the combination of series and parallel stacked IGBT semi-conductors. The clear advantage of the solid-state system is that total operation times could be 1ms or less and so this is presently the only available option which can comfortably meet the proposed requirements of VSC based DC grids [70] [74]. This is due to the fast response nature (microsecond range) of the semi-conductors on detection of fault current which leaves the external protection coordination logic as the dominant component of the overall operating time.

It is expected that for bi-directional capability the semi-conductor requirement for a solid-state DCCB is equivalent to one third of that required in a full VSC converter station [18] [69]. However, the breaker would not require any of the additional filtering, transformer, switchgear and controls that are required in the converter so its overall size would be significantly less than a full converter station but likely still considerable in its own right. Given the large cost associated with VSC converter stations the cost of semi-conductor based DCCBs is also likely to be significant, especially in the context of a large offshore grid where the number of desired DCCBs might be high.

Another drawback of solid-state DCCBs is that the conducting mode resistance is in the order of mΩ compared with μΩ for a resonant DCCB system meaning high on-state losses are present which are typically expected to

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be around 30% of the losses associated with a full VSC converter station [74] [75]. Therefore, the use of solid state DCCBs throughout a large DC grid would have a considerable impact on the final deliverable energy within the system and the financial implications of that could be significant so to date mainly alternative design concepts have been commercially pursued. However, it should be noted that new design concepts continue to be investigated at research level with some showing evidence that costs and losses could be reduced. For example, a new topology concept for a solid-state DCCB was proposed in the MEDOW project which uses pre-charged capacitors for soft-switching. Simulations of the proposed design suggest interruption times of less than 300µs could be achieved which limits the surge voltage and in turn reduces the semi-conductor requirement and therefore the cost and losses of the DCCB [76].

6.2.3 HYBRID HVDC CIRCUIT BREAKER

To eliminate the high on-state losses associated with the solid-state DCCB a number of hybrid DCCB concepts have recently been proposed and prototypes tested [75] [77] [78] by a number of leading manufacturers. These look to merge the requirements of fast response time and low on-state losses. There are a number of variations on the design but the main concept behind each is that the main semi-conductor valves are removed from the normal conducting path of the breaker. One possible design concept is shown in Figure 6.3. The main conducting path consists of an auxiliary DC breaker semiconductor valve and a mechanical breaker or fast disconnector. The auxiliary valve is rated to the voltage drop across the main DCCB valve under fault current which is typically only 3-4kV which means the on-state losses of the main conducting path are reduced to a small percentage of those associated with the solid-state design option. In normal operation the main DCCB valve is open but no current flows due to its large internal impedance.

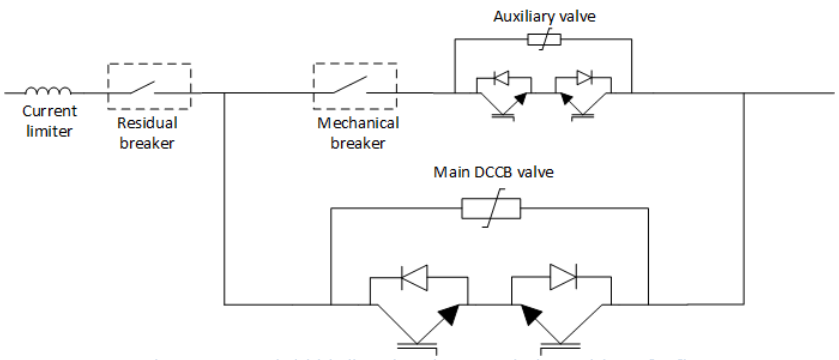

Figure 6.3. Hybrid bi-directional DCCB (adapted from [75]).

In the event of a DC fault the auxiliary valve opens which commutates current to the alternative path with the main DCCB valve. The mechanical breaker, likely to be made up of several series connected mechanical isolators, then opens to isolate the auxiliary valve before the main valve opens to interrupt the full fault current, as in the solid state breaker design, with the fault energy being dissipated in the surge arresters. The residual breaker can finally be opened to protect the arrester banks from thermal overload and provide long term isolation if required.

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Additional benefits of the hybrid breaker are derived from the fact that the main DCCB valve does not conduct nominal current so is in cold state before utilisation. This reduces the cooling requirements of the system and increases the maximum interrupting capability for the same amount of semiconductor devices. It is also possible to operate hybrid DCCBs in a fault current limiting mode to control fault current without danger of a DC branch unnecessarily tripping although this requires higher rated components.

Through the use of fast mechanical breaker technology and the high speed of commutation and fault blocking within the semiconductor devices, hybrid breaker designs have been tested and demonstrated to scale for operating times of 2-3ms which brings them within the range where they could be suitable for deployment in multi-terminal DC grids. The main drawback to the hybrid design is that it essentially maintains the same level of semiconductor equipment as the solid state option so remains a high cost solution with a significant footprint.

6.3 SUMMARY OF CURRENT CAPABILITIES

DCCB development is a fast growing field with a number of design options from various vendors still under development. Some designs are still in R&D phase while several vendors have conducted large scale tests on prototype designs but as yet no full scale DCCB for multi-terminal DC grid application has been implemented or made commercially available, although it is expected that the technology will be available if and when required. Table 6.1 looks to summarise the current development status of all DCCB design options.

It is evident that the most advanced developments thus far have been focused upon two design options is particular. Three vendors have produced and tested largescale prototype variations on the hybrid DCCB topology whilst two have tested large scale prototypes of a fast active resonance DCCB topology. It is expected that the first full scale implementation of DCCBs in an operational multi-terminal HVDC grid will be in CEPRI's onshore five-terminal overhead line Zhoushan project due for completion in 2018 [78] [79]. The current speed capabilities of the different DCCB design options are broadly outlined in Figure 6.4.

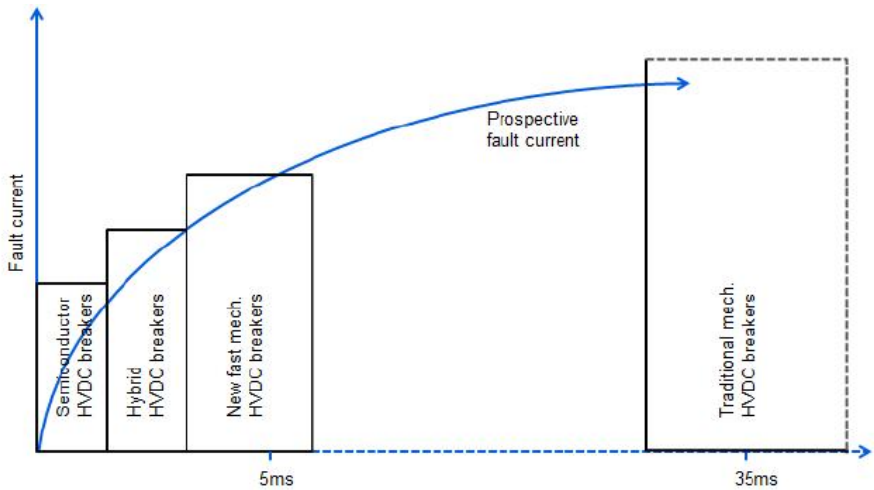

Figure 6.4. Existing and suggested DCCB concepts: breaking speed vs required fault current capability [71].

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Development status of DCCB design options			
BREAKER TYPE	VENDOR	PUBLICLY REPORTED TESTING	COMMENTS
Hybrid	ABB	Yes – 80kV	Uses standard hybrid design as outlined in Figure 6.3. Designed with modular rating of 80kV for suitability in 320kV grid. In 2011 a single 80kV breaker cell prototype was successfully tested for breaking current of 9kA at 120kV assuming breaker operation within 2ms for a HVDC grid with 3.5kA/s fault current rise. [75]
	Alstom	Yes – 120kV	A 120kV hybrid breaker demonstrator was developed as part of the 'Twenties' project in 2013. Uses standard hybrid principle but the auxiliary branch consists of two time delaying branches (which maintain low impedance while mechanical switch opens) and an extinguishing branch (which along with surge arrestors force the current to zero). In testing, fault current peak of 5.2kA at 160kV was broken with first action in 2.2ms and full interruption in 5.3ms. [77] [80]
	CEPRI	Yes – 200kV	Uses standard hybrid design with full-bridge semiconductor topology for main DCCB valve. Designed with modular voltage rating of 50kV, in 2014 a 4 module 200kV prototype was tested for 2kA rated current and was found to successfully break >15kA fault current at transient voltage of 75kV per cell in 3ms so is suitable for grids with up to 5kA/s fault current rise. Likely to be implemented in full scale Zhoushan multi-terminal HVDC project due in 2018. [78] [79]
Resonant DCCB (active design)	ABB	Yes – 80kV	An 80kV demonstration module was developed to test an active resonance based mechanical DCCB design. Fault current interruption of between 2 and 10.5kA was successfully demonstrated with interruption time within 5ms. This option is low cost and approaches the speed of hybrid designs. [71]
	Hyosung	Yes – low voltage	A fast interruption resonant breaker design with active current injection has been proposed. A low voltage prototype was developed to test the feasibility of the design which saw a main breaker clearing time of 2ms for 5kA peak current and a withstand voltage of 4.4kV. [81]
	Mitsubishi	Yes	An active resonance based breaker which utilises a vacuum circuit breaker (VCB) as main interrupter has been tested in the context of investigating application of the VCB. The scheme can typically interrupt in 8-10ms and breaking currents between 4kA and 16 kA were tested. No published data is yet available which focuses solely on the development of the DCCB performance. [73]
	SciBreak	No	A new company, formed in 2014, with an as yet unpublished DCCB design concept. The design is "based on a combination of mechanical breaking elements and power electronics". Lab tests have proven a scaled version can break currents up to 1.6kA.[12]

Table 6.1. Status of existing DCCB design options.

[12] http://scibreak.com/index.html

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6.4 PERFORMANCE EXPECTATIONS AND GAPS

As discussed to some extent in previous sections there are no settled performance expectations for DC breakers as the final requirements for any given DCCB implementation will depend on a number of other factors including the size and rating of the HVDC grid, the type of converters that are used and the level of current limiting reactors deployed on the system. The size and rating of any future offshore grids will be dependent on the generation resources and demand centres that are being connected within the project and can be viewed as a fixed parameter once a project is decided upon. However, the converter design and the size of the deployed reactors on the grid are design choices and will greatly influence the performance requirements of DCCBs within the grid. Therefore, there are a number of trade-offs to be made between the size, cost and performance of all these components before a finalised HVDC grid design and protection philosophy can be implemented.

A number of sources have however published estimates as to the probable expected requirements of DCCBs based on certain assumptions. For example, in the absence of fault blocking converters and if it is assumed that voltage on the DC network should be kept above 80-90% of nominal value so as to avoid blocking and loss of the terminal, then DC faults in general should be cleared within 3-5 ms [18] [69]. For DC grids of the scale and distance proposed in the North Seas the rate of rise of current might imply that an even shorter breaking time is required such that the current breaking capability of existing technologies is not exceeded. For example the working assumption in many of the DCCB demonstrations to date is that operation time should be in the region of 2-3 ms [75] [77] [78] based on limiting the rise of fault current within acceptable bounds.

If fault current blocking converters are to be deployed then these could be used in a number of ways that either help to relax the requirements of the DCCBs or remove the need for them altogether. If full bridge converters are deployed to block fault current entirely it would be possible to make use of simple and cheap resonant breakers for fault isolation. Such a philosophy implies loss of the whole DC grid for 50-100ms which may be tolerated by the connected AC systems for small DC grids but is unlikely to be acceptable for large DC grids [69]. Another option is to use full bridge converters in a fault limiting mode which has the potential to reduce the overall duty placed on the DCCBs, allowing for slower operation and potentially lower cost solutions. It should be noted that use of full bridge converters comes at the expense of increased semiconductor devices which inherently add to the cost, size and losses in the whole DC system so benefits are likely restricted to operational considerations.

As there is no final agreed settlement on the expected performance requirements of DCCBs it is difficult to assess exactly what gaps need to be filled in future development efforts. However it clear that developers are focused on improving on a number of key performance elements for DCCBs including speed of operation, peak fault current capability and cost minimisation. It can be said that solid state circuit breakers meet all expected requirements but are high cost and have high losses. Hybrid breakers have been proven to operate at speeds that are compatible with offshore HVDC grid implementation and are low loss but remain a high cost option.

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New fast acting active resonance based DCCBs are low cost, low loss and have demonstrated breaking times that are approaching those required for HVDC grids and could already be used in some applications.

The detailed work of WP5 and WP6 within the PROMOTioN project will seek to address the existing uncertainties relating to the characterization of performance expectations for DCCBs before testing a number of proposed technology options through detailed modelling analysis, real-time simulation and finally kV scale hardware demonstrations.

6.5 MODELLING OF HVDC CIRCUIT BREAKERS

Modelling and simulation of DCCBs is an important step in the process of both understanding performance characterisitcs in the context of DC grid operation and developing suitable design concepts that can then be tested at scale. The development of suitably advanced DCCB models has been limited to date with much of the recent literature using simplified models. In [74], the DCCB is modelled as a simple time delayed switch whereas in [62] [82], a simplified approach that considers the commutation process from the auxiliary branch to the main branch of a hybrid breaker concept is applied. In [83], a series reactor is incorporated with an ideal switch to model the DCCB. It is noted in [84] that such simplified methods are not suitable to fully represent a range of DCCB performance factors including: subsystem parameters, dynamics, component limits, internal control limitations and interlocks, self protection or active current limiting operation of breakers.

In [84], an effort is made to develop an elementary model of hybrid DCCBs (which are the most advanced in terms of readiness for deployment in DC grids and also the most complex to model) for use in transmission level grid protection and transient studies. The model aims to accurately represent the opening sequence and closing sequence of the DCCB taking into account the coordinated control and interlocking of the four constituent subunits of the hybrid breaker (main and auxiliary semiconductor valves and two mechanical switches) and includes an option to model the DCCB in fault current limiting mode. Models for both unidirectional and bidirectional DCCBs are developed and a schematic representation of a unidirectional DCCB and its associated internal control logic is given in Figure 6.5 Mechanical switches are modelled as ideal switches with residual current. The auxiliary valve is modelled as a single IGBT which mimics the on-state resistance of the 3x3 matrix of nine IGBTs which are typically used in reality. Likewise the main valve is modelled as a single IGBT with appropriate parameters calculated. The model includes a number of hierarchies of protection with the failure of the normal operation grid level protection being supplemented with back-up from both self-protection (which initiates if the line current reaches destructive levels) and driver-level protection (each individual IGBT is tripped if the collector-emitter voltage is higher than a threshold).

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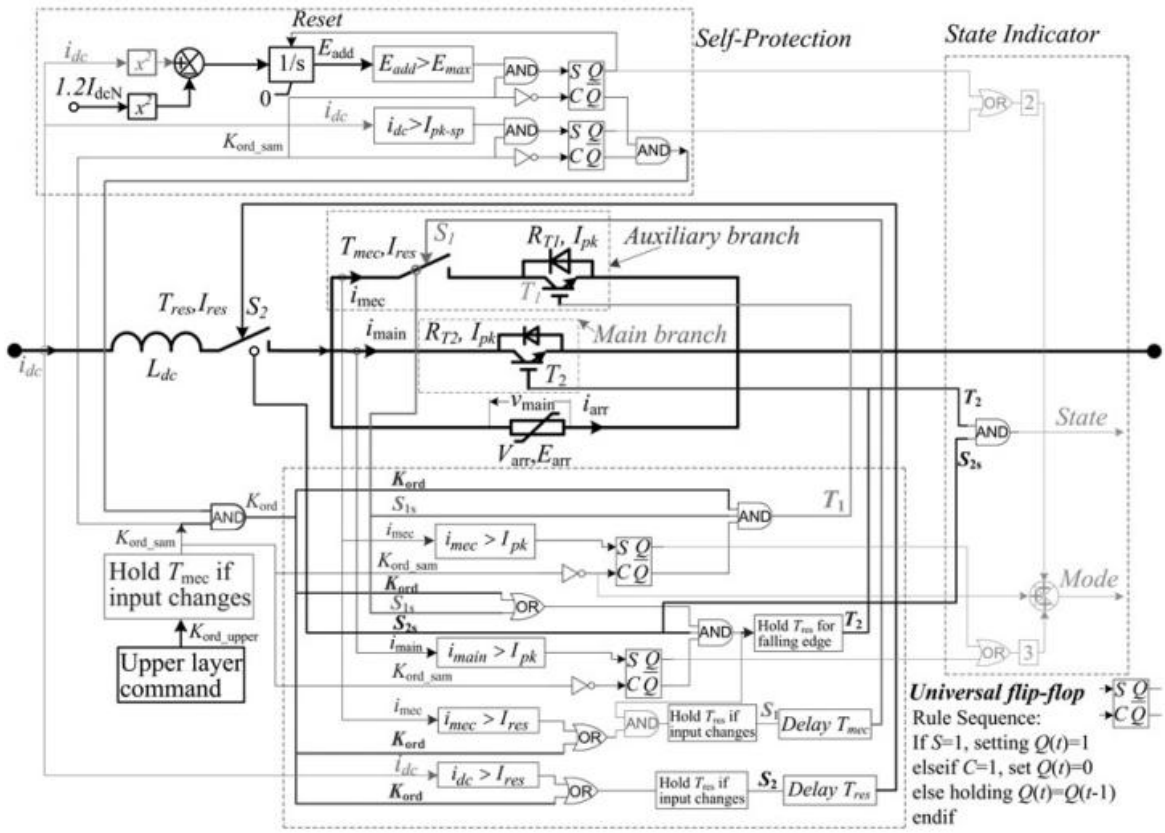

Figure 6.5. DCCB structure and control system of hybrid DCCB [84]

In fault current limiting mode the main branch of the DCCB is divided into four cells as shown in Figure 6.6 in line with ABBs representation in [85]. The principle of operation in fault current limiting mode is for the DCCB to act as a chopper so as to limit the DC fault current by controlling some cells to an OFF state whilst others are switched ON to adjust the counter voltage depending on the current magnitude. A suitable controller that enables the DCCB to limit fault current whilst evenly distributing the absorbed energy among the arrestors is also proposed.

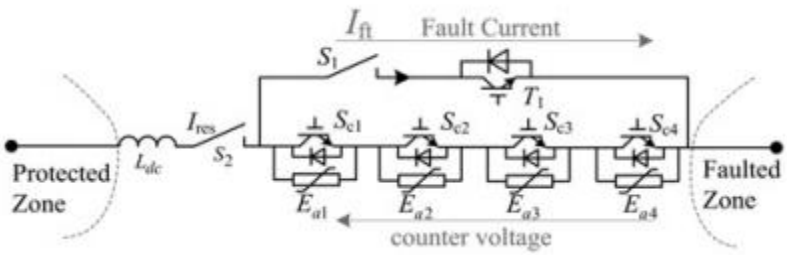

Figure 6.6. Operating principle of DCCB with four cells in current limiting mode [84]

The DCCB models are verified in a test system using EMTP-RV under a number of key operating conditions including normal opening, self protection, closing under rated DC current, re-closing into a DC fault and current limiting. Sufficient operation was observed in all cases and for the current limiting mode a comparison was made with experimental results reported in [85] and good matching was observed to verify the functionality of the models.

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The PROMOTioN project will look to develop and expand upon the exisiting recent developments in DCCB modelling. Work Package 6 will include a focus on DCCB model development for both hybrid and mechanical DCCBs with an initial focus on more detailed and accurate offline system level models that incorporate proactive breaking and fault current limiting modes to feed into the studies being done in WP4 and WP5. Detailed component level real time models will then be developed to feed into WP9 and WP10 and provide the basis for development of hardware prototypes.

6.6 TESTING AND DEMONSTRATION OF HVDC CIRCUIT BREAKERS

Given the pace of development of DCCBs it is crucial that effective means of performance verification under realistic operating conditions can be demonstrated. As has been shown, a small number of DCCB concepts have been tested at large scale prototype level and there is ongoing research into the development of test circuits for demonstration of DCCBs. This section gives an overview of the testing methods that have been utilized to date and a review of latest research in the area outlining the strengths and weaknesses of different design options.

6.6.1 RECENT TESTING METHODS

A number of the demonstrations of the most recently developed DCCB designs have used test circuits based on charged capacitor banks combined with current limiting reactors to test performance [78] [86]. An example is shown in Figure 6.7 where the capacitor bank C1, supplied by a DC source, builds up the desired DC voltage level. The spark gap Q5 initiates the short circuit fault while reactor L1 controls the fault current rise rate. Verification tests of internal components such as the IGBTs used in the load commutation switch and main breaker valve and the ultra-fast mechanical disconnector, were also performed separately.

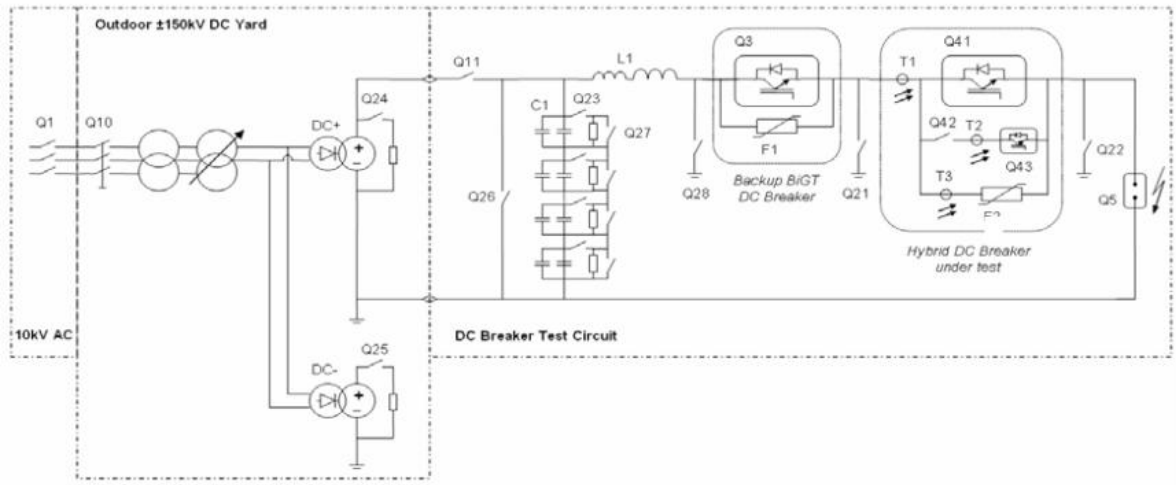

Figure 6.7. ABB hybrid DCCB test circuit [86].

The Twenties project offers the most detailed publicly available review of test procedures carried out on a large scale HVDC circuit breaker to date. In the framework of that European project, a series of tests were performed

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to investigate the performance of Alstom's 120kV hybrid DCCB prototype, rated for a nominal DC current of 1500 A. Four main expectations were defined for a DCCB: it must be able to withstand high voltages in open state, it must be able to conduct high currents in closed state, it must be able to interrupt DC current and do this in a short timeframe [80]. For these tests, Alstom used a test circuit consisting of two L-C circuits, one with low frequency (32Hz) to represent nominal load current and one at high frequency (66Hz) to represent the system under fault conditions as shown in Figure 6.8 [87] [88]. Both these methods produce an AC current waveform which in the rising phase can be used to represent the rate of rise of DC fault current.

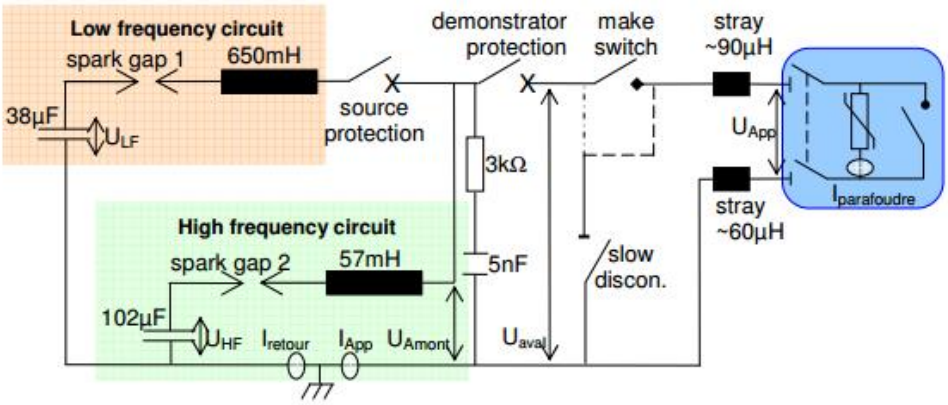

Figure 6.8. Alstom hybrid DCCB test circuit [88].

The ability to withstand high voltages in open state is evaluated through a lightning impulse standard test following the standard IEC60060-1. A subassembly of the demonstrator whose function it is to isolate it from the rest of the network is subjected to series of 15 high voltage surges with a rise-time of 1.2 µs and a half peak time of 50 µs. Surges with positive and negative polarities are applied. The disconnector withstood voltages over 763 kV which exceeds the 650 kV value that was required. The test procedure used to evaluate the ability to conduct high currents followed in essence the standard IEC622714-1. It was demonstrated that the DCCB was able to withstand a current of 3676 A during 2 minutes, which exceeded expectations. Finally, it was demonstrated that the hybrid DCCB prototype was able to interrupt a fault current of 5285 A in 5.3 ms.

Mitsubishi have also developed two separate methods for testing the performance of an active resonance type DCCB as shown in Figure 6.9 [73]. The first method uses an AC current source short circuit generator to produce an AC waveform which is then interrupted at peak value to test the DCCB and is the same method that is used in [71]. The second, charged reactor, method uses a pre-charged capacitor as a power source. When SW1 is closed a resonant current is generated and when this reaches first current peak SW1 is opened and SW2 closed allowing the L-R discharge to create an approximation of a DC current which can then be interrupted by the DCCB.

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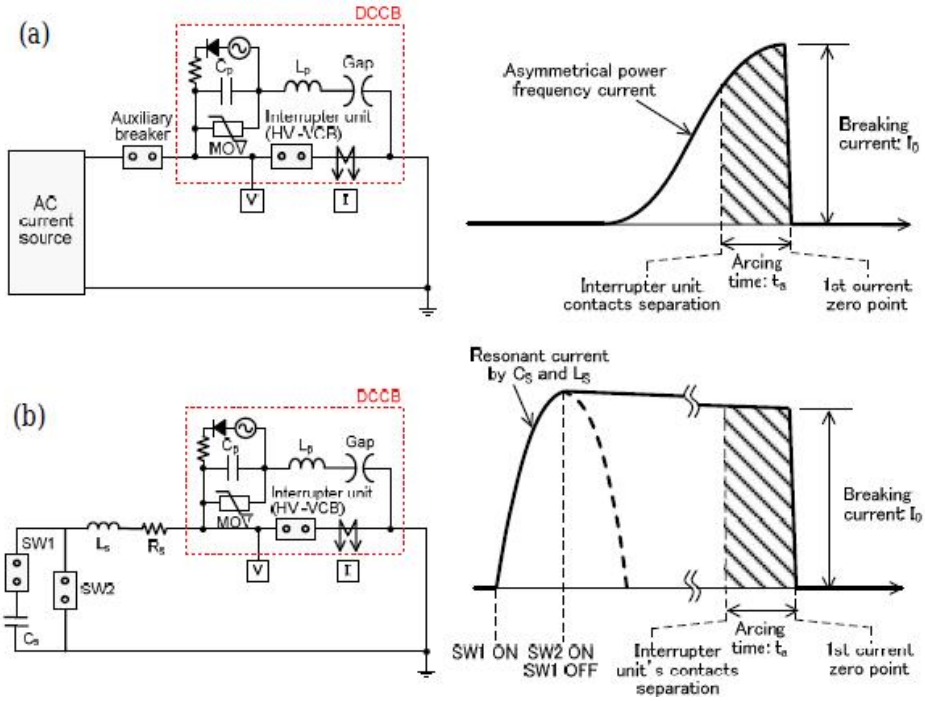

Figure 6.9. Mitsubishi test circuits and current waveforms for a) Power frequency peak current method b) charged reactor method [73].

6.6.2 LATEST RESEARCH ON TESTING METHODS FOR DCCBS

It is noted in [89] that all of the test circuits outlined in the previous section have the capability to demonstrate interruption at a "local" current zero i.e. a current zero in the DCCBs interrupter unit. However, this only allows demonstration of one stage of the fault removal process as interruption of the system's current is not demonstrated. To demonstrate the complete process counter voltage creation and energy absorption characteristic also have to be tested.

In light of this, deliverables within PROMOTioN Task 5.1 have investigated the high level requirements of test circuits for DCCBs, to ensure sufficient stress is applied, with the findings described as follows in [89] [90]:

- Produce a fast rising current that increases to a value up to the rated interruption current,
- Have sufficient energy stored in its lumped reactance that corresponds to the magnetic energy stored in practical grids,
- Stress the HVDC CB with nominal and constant voltage during the energy dissipation phase of the interruption process and afterwards.

To protect the test DCCB from damage in the event of failed operation the test circuit should also be able to interrupt the test current rapidly and independently after the prospective interruption time has elapsed. It is also noted that the test circuit does not necessarily need to be capable of producing constant DC current as in a practical DC grid the rising DC fault current should be detected and cleared well before steady state is reached.

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In the same study, a number of test circuit options for DCCBs are discussed and analyzed through simulation and compared against an ideal DC source which theoretically imposes upper limits on the requirements of test circuits. The three methods which are tested against each other are the charged capacitor, charged reactor and AC short circuit generator methods which have already been highlighted in existing test set-ups. Simulation results looked at the circuit current, source voltage and energy absorption under each test circuit with results given in Figure 6.10.

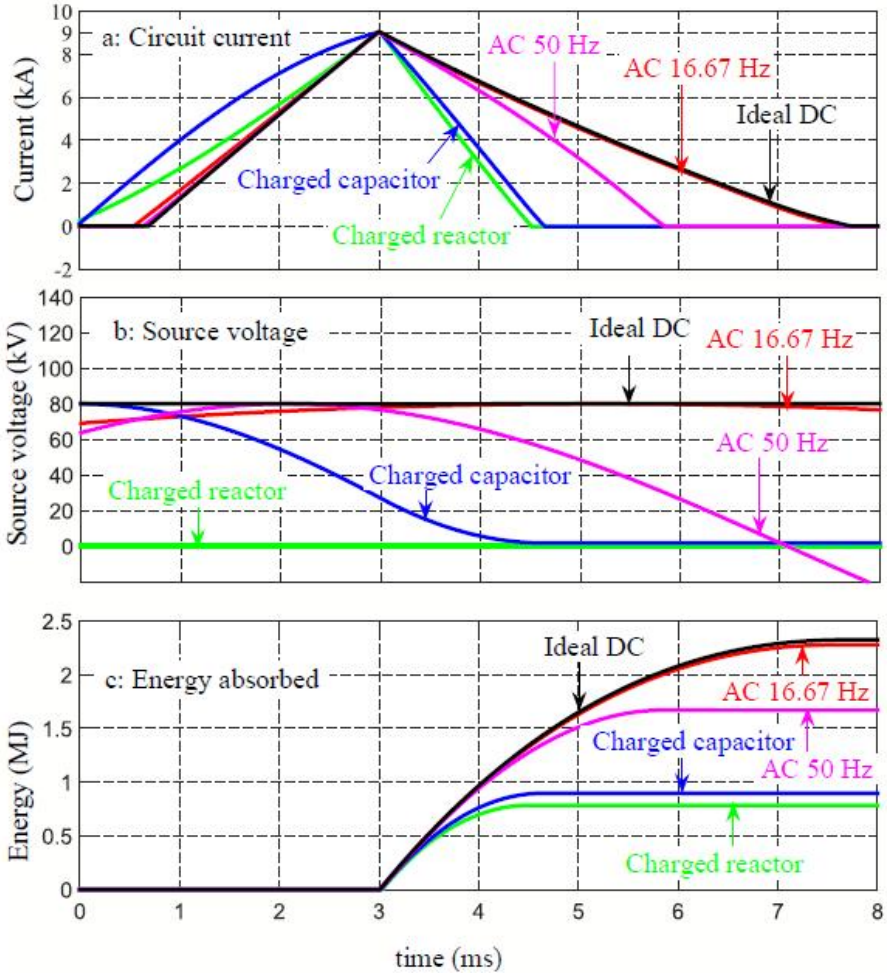

Figure 6.10. Simulated comparison of DCCB test circuit options [90].

It is found that although all options sufficiently generate a peak current for interruption by the breaker, there are significant differences in the energy absorption phase and time to clear the fault. The energy dissipated in the DCCB during the current suppression phase, after initial fault interruption, is a function of the energy stored in the reactor and the contribution from the source. In the charged reactor option there is no intrinsic voltage source present which means the only energy dissipated is that stored in the reactor which means this method does not mimic the voltage stress and energy absorption characteristics required of DCCBs in reality. Similarly, in the charged capacitor methodology a large portion of the charge on the capacitor is already lost before the energy absorption phase which means the energy contribution from source in this technique is also insufficient.

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Test circuits using an AC short-circuit generator are found to offer much better performance in this area, especially at low frequency. At 50Hz the method is an improvement on the other two options but sufficient thermal stress is still lacking whereas the simulations show that when using a frequency of 16.7Hz the source voltage is maintained throughout the fault clearance process and the absorbed energy is close to ideal. A qualitative summary of the three options is given in Table 6.2.

	AC SHORT CIRCUIT GENERATOR	CHARGED REACTOR	CHARGED CAPACITIOR
Features	• Power supplied by short circuit generators • Frequency and making angle can be controlled	• Test supplied by discharge of magnetic energy in the reactor	• Test supplied by discharge of electric energy stored in capacitor banks
Strenghts	• Simple construction and testing procedure • Sufficient voltage and current stress can be achieved • Several generators and step-up transformers can be combined to achieve high voltage and power • Can provide sufficient energy at low frequency	• Quasi-DC current can be obtained for a relatively longer period	• di/dt and maximum current can be controlled by current limiting reactor
Limitations	• Short circuit power reduces with frequency • Special step-up transformers are required • Requires special protection to avoid damage in case TO fails to interrupt	• Lacks intrinsic voltage stress • Requires large and high quality reactors for sufficient energy storage • Rate of decay of current is affected by circuit resistance	• Large capacitor and inductor are required for low frequency • Energy from source is minimum because of decay of charge across the capacitor

Table 6.2. Summary of test circuit options for DCCBs.

6.7 POSITIONING OF PROMOTION PROJECT

If adequate technological concepts already exist for DCCBs, no practical installation exists at this moment. A main barrier for the deployment of DCCBs is the lack of detailed data on the behavior of DCCBs and their interaction with their electric environment. In particular, it is difficult to compare devices from the different manufacturers (ABB, Mitsubishi and Alstom) because they have varying characteristics and they were not compared on the basis of standardized methodologies. The third technology pathway of PROMOTioN will demonstrate the performance of existing DCCB prototypes, by using standardized tests which will allow characterization of different devices into compatibility classes. As no standard test methodologies exist for the moment, WP5 and WP6 will develop new test methodologies while ensuring the agreement of the relevant stakeholders. Finally, WP10 will test the (prototype) breakers in the test facilities of DNV-GL (KEMA).

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7 REGULATION AND FINANCING

Technical barriers described in previous chapters are not the only issues preventing the development of a meshed offshore grid: a number of regulatory and financial barriers are also hampering a large scale deployment of meshed HVDC grids. For instance, offshore grid assets are still developed in Europe by means of bilateral agreement between national governments. Point-to-point connection corridors are constructed, while no multilateral assets are planned. Although 10 countries signed a Memorandum of Understanding in 2010 in the framework of NSCOGI, until today, the positions of the 10 countries involved are different, obstructing offshore grid development. One of the initiatives to overcome these barriers is the recent political declaration on energy cooperation between the North Seas Countries (Belgium, Denmark, France, Germany, Ireland, Luxembourg, the Netherlands, Norway and Sweden). This political declaration and action plan aims at facilitating the building of missing electricity links to reach a further integration of energy markets.

Also within the PROMOTioN project, one of the aims is to consider regulatory and financial aspects of a meshed offshore grid. A separate work package (WP7), called “Regulation and Financing” is dedicated to that. While the focus of this work package is on the development of an EU legal, economic and financial framework, the focus of this deliverable is on existing literature. Previous works have already studied policy, legal and regulatory barriers in developing transnational infrastructures (such as a meshed offshore HVDC grid), and have investigated the needs for European legal and economic frameworks to support the deployment of offshore grids. The purpose of this Chapter is to review existing studies on the regulatory and financial aspects of offshore grids, to act as a starting point for PROMOTioN’s WP7. While the focus of this deliverable is on existing literature, PROMOTioN’s WP7 will use this background knowledge in the development of an EU legal, economic and financial framework.

The Chapter is divided in several Sections. Before going into a deeper discussion, first an overview of the reviewed documents and topics is provided in Section 7.1. This allows the reader to easily detect which documents provide information regarding particular regulatory or financial matters. Afterwards, in the following Sections 7.2-7.7, the regulatory and financial reports from the main European projects are discussed. These include reviews of deliverables from Twenties, ISLES, NSCOGI and E-Highway 2050. Additionally, the main observations from the PhD thesis of H.K. Müller on the legal framework for offshore grids and from the EC report on regulatory matters for offshore grid development are provided. Apart from the reviews of the main documents, some other relevant sources are highlighted and briefly presented in Section 7.8. Finally, Section 7.9 provides a concluding discussion.

Apart from the reviewed documents, other relevant reports regarding regulation and finance of offshore meshed grids are available in literature. Nevertheless, this chapter aimed at selecting the most relevant and recent ones. Also note that this chapter doesn’t aim at providing an exhaustive overview of all reports. The focus is on

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including the key elements of each. For deeper insights, a deeper look on the original documents is recommended. Therefore, references are clearly stated throughout this Chapter.

Also note that being a relatively large market area entirely surrounded by sea, developments concerning GB are clearly important in relation to the pace, nature and volume of offshore grid developments in Europe and have been cited in a number of the reports reviewed here. In addition, Northern Ireland is a part of the UK but not part of the GB electricity system or market. (It is part of the Single Electricity Market and synchronous area on the island of Ireland). However, in June 2016, a national referendum of voters in the UK gave a result that recommended that the UK leaves the European Union. At the time of writing of this report, it is not known what effect this will have on electricity market, generation and network developments in GB and Northern Ireland. Although policy makers in the UK are keen to maintain trading links with the rest of Europe, including for energy, it may nevertheless be noted that changes are possible, e.g. in respect of adherence to European processes for pricing of electricity, harmonisation of codes, priority access for renewables, exchange of renewables credits, mutual support for security of supply and sharing of reserve and common rules on environmental protection. Meanwhile, it may also be noted that some countries that are not members of the European Union are full participants in electricity industry harmonisation initiatives, e.g. Norway, and that countries that are neither in the European Union nor the European Economic Area are interconnected with the main European power system, e.g. Turkey.

7.1 OVERVIEW OF REVIEWED DOCUMENTS AND TOPICS REGARDING REGULATION AND FINANCE

This Section provides an overview of all documents reviewed and of all topics handled regarding regulation and finance. Table 7.1 and Table 7.2 list the main topics, which are discussed in each document that is reviewed. This allows the reader to gain an overview of which reviews are relevant to particular topics of interest. It is important to note that some reports aim at providing a general overview of regulation and finance for transnational infrastructure (e.g. the technical report for the European commission titled “study on regulatory matters concerning the development of the North Sea offshore energy potential”, Jan. 2016), while others focus on one or several specific topics (e.g. the NSCOGI study entitled “Market arrangements under the virtual case study, “published in 2012).

The definition of these topics partly follows from the non-functional requirements as defined within Deliverable 1.1. In accordance with this deliverable, the relevant topics are split in four categories: energy policy aspects, legal and regulatory aspects, financial-economic aspects and market aspects. Each of these aspects contains several relevant topics regarding regulation and financing. Note that, while the topics follow from the non-functional requirements, some modifications to the list are made.

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Topics / Reports	Twenties-D17.1 [91]	Twenties-D17.2 [92]	NSCOGI-WG2D1 [93]	NSCOGI-WG2D2 [94]	NSCOGI-WG2D5 [95]	NSCOGI-WG3D2 [96]	NSCOGI-WG2D3 [97]	NSCOGI-WG2D3DP [98]	ISLESI [99]	ISLESII [100], [101], [102], [103], [104], [105]	Müller, 2015 [106]	e-High-D5.1 [107]	EC, Jan. 2016 [108]
Energy Policy Aspects										X	X		X
Political commitment of policy makers											X		X
Contribution to the IEM and other EU objectives (SoS, Emissions, etc.)										X	X		X
Legal and regulatory aspects	X	X	X	X	X	X	X	X	X	X	X	X	X
International regulation											X		X
European regulation			X		X						X		X
National regulation			X								X		X
Convergence between regulatory levels (int., EU, nat.)			X								X		X
Legal def. for integrated offshore transmission infrastructures			X	X							X		X
Interaction national onshore transmission regulation & requirements			X	X						X	X		X
Coordinated cross-border/EU design of the MOG			X	X						X	X	X	X
Permitting and planning requirements(incl. MSP, CP)	X	X	X	X		X					X		X
Ownership and the interfaces between different asset owners			X	X					X		X	X	X
Rules on liability and compensation				X					X		X		X
National renewable support schemes			X	X							X		X
Priority grid access/Priority dispatch			X		X			X		X	X		X
Connection requirements			X								X		X
Connection & Operational Charges			X		X		X				X		X
Interoperability and standardization	X	X									X		
Common standards, e.g. environmental and HSE	X	X									X		
Financial-economic aspects			X				X		X	X	X	X	X
Cost and benefits of the investments							X		X	X			X
Cost allocation method across EU MS/beneficiaries			X				X			X	X	X	X
Cost recovery/revenue schemes													X
Financing of investments			X				X				X		X
Investment incentives ((non-)financial)							X		X	X			X
Instruments to attract debt and equity capital									X	X			X
(Joint) investor participation and funding mechanisms									X	X		X	X
Market aspects			X	X	X			X	X		X	X	X
Generation capacity and interconnection usage (capacity allocation, congest. manag.)			X	X	X			X			X		X
Operation & Balancing			X	X							X		X
Ancillary services			X								X	X	X
Trading and auction rules					X			X	X		X	X	X

Table 7.1. Overview of topics covered in each of the main European project reports

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Topics / Reports	Think, Jan. 2012 [109]	EWEA, Oct. 2014 [110]	E3G, April 2015 [111]	NSG; 2015 [112]	FLOW, Dec. 2015 [113]
Energy Policy Aspects			X		X
Political commitment of policy makers			X		X
Contribution to the IEM and other EU objectives (SoS, Emissions, etc.)					
Legal and regulatory aspects	X	X	X	X	X
International regulation					
European regulation		X	X	X	X
National regulation	X	X	X	X	X
Convergence between regulatory levels (int., EU, nat.)					
Legal def. for integrated offshore transmission infrastructures				X	
Interaction national onshore transmission regulations & requirements.	X				
Coordinated cross-border/EU design of the MOG	X	X	X	X	X
Permitting and planning requirements					
Ownership and the interfaces between different asset owners				X	
Rules on liability and compensation				X	
National renewable support schemes	X			X	
Priority grid access/Priority dispatch				X	
Connection requirements				X	
Connection & Operational Charges				X	
Interoperability and standardization					
Common standards, e.g. environmental and HSE					
Financial-economic aspects	X	X	X	X	X
Cost and benefits of the investments	X			X	
Cost allocation method across EU MS/beneficiaries	X			X	
Cost recovery/revenue schemes	X			X	
Financing of investments	X	X	X		X
Investment incentives ((non-)financial)	X	X			X
Instruments to attract debt and equity capital		X	X		
(Joint) investor participation and funding mechanisms		X	X		X
Market aspects			X	X	
Generation capacity and interconnection usage (capacity allocation, cong. manag.)			X	X	
Operation & Balancing				X	
Ancillary services				X	
Trading and auction rules			X	X	

Table 7.2. Overview of topics covered in other relevant documents regarding regulation and finance

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7.2 TWENTIES PROJECT

WP7 of Twenties analysed the challenges currently being faced when obtaining permits and consents from regulatory, spatial planning and environmental bodies for offshore interconnector projects. It led to two main deliverables: D17.1 "Offshore interconnectors: challenges and carriers for barriers for consenting" in 2012 [91], and D17.2 "Reframing planning and permitting for offshore interconnectors" in 2013 [92].

7.2.1 DELIVERABLE 17.1

Key takeaways of Twenties D17.1 [91]

- *"Conflicts with environmental protection interests are the single most critical factor for the success of a project and a key reason for delays."*
- *"The different consenting procedures of international authorities can substantially delay the development of projects."*

D17.1 of Twenties [91] presents the results of a study that analyses ten interconnector projects[13] from the North Sea and the Baltic Sea (NorNed, BritNed, Cobra Cable, E-W Interconnector, Skagerrak 4, Estlink 2, Nordbalt, Moray Firth, Fenno-Skan 2 & Kontek) to identify the major barriers for offshore interconnections in Europe when it comes to obtaining planning consent acceptance for location of cables and stations. The study also evaluates the challenges and best practical lessons on the internal project organization between two partner TSOs when preparing for permits and consent. The study was mainly based on interviews with relevant contact people from the TSOs involved in the projects.

Existing barriers

- The process of achieving permits from the relevant authorities is a challenge to all interconnector projects.
- The consenting process differs amongst countries, impeding collaboration. Some countries manage the consenting process with just one or a few competent authorities, whereas other countries ask the TSO to interact directly with all the authorities given in the land/sea use and environmental legislation (preferred option).
- The aspects of time and predictability are important parameters. The consenting process in the shortest case is about 18 months, whereas it takes more than four years in the longest case. This is naturally a drain on project resources and may inhibit the realization of some projects. Therefore, some cases are at risk of being cancelled due to a prolonged development phase.
- The willingness of competent authorities to make preliminary indications of accepting a project is highly important. In some cases, the project management has added extra length to the route in order to

[13] The projects were selected to cover a range of countries for which the planning process is well under way or completed, but the projects commissionned before 2000 are omitted because legislation at that time was different.

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avoid disputed permits. In other cases, competent authorities tend not to appreciate the overall societal importance of ICs as constituting a vital part of the European renewable energy strategy. However, in most cases the dialogue is sound and gives the project developers a guarantee of project feasibility.

- The challenges seem bigger at land than on sea. Only very few cases are delayed due to consenting on sea, whereas the processes on land often cause delays and redesigns. A most critical factor is the consenting of overhead lines, but also consenting of converter stations in rural areas pose a challenge to the project developers.
- The consenting by environmental authorities proves to be among the most critical aspects. While most legislation derives from EU directives, national practices differ substantially. These differences are accentuated in interconnector projects that are subject to an EIA process in the one country and not in the other. Practical assessments of potential adverse impacts also vary between countries. In general, it seems that lack of common practices for environmental assessments and consenting is one of the key challenges to offshore interconnector projects.
- The Environmental Impact Assessment (EIA) processes differ from one country to the next. Generally, a well-managed EIA process is not delaying the consenting process substantially. The problems occur when route design and the managing of public hearing and opposition is inadequately prepared. Furthermore, there is a risk of delays if the control of the project design is fully taken over by environmental authorities, who are not under time pressure and for whom the economic advantage solutions carries less weight. The land use conflicts at the part of the interconnector located on land is another set of barriers. In some countries, the Natura 2000 restrictions are issues of major concern. The potentially cumbersome process may lead to an 'escape route' by circumventing these areas, even though the overall environmental impact is, in fact, less pronounced if the protected area is crossed. Better documentation of the adverse environmental impact of the cable and installation techniques may contribute to reducing the barriers.
- The directly affected citizens and the dialogue with the civic society, in general, is a key issue. Most of the interaction is regulated by law and the public opinion is integrated in spatial planning and EIA public hearing procedures. The public opinion and the ‘Not in My Backyard’ resistance to projects is well known. Cases involving construction of overhead lines come out having the biggest challenges. In addition, cable routes through nature protected sites and construction of large converter buildings pose a challenge when local acceptance is to be achieved. In case of resistance by landowners, the available options for continuing the project by force, differs from country to country. In some countries, the TSO is authorized to compulsory purchase, whereas the legal framework, in especially the new EU Member States, does not provide the TSO with such legal instruments. Cases reveal that land owner acceptance of routing can be very critical in such countries.
- In reality, only overhead lines and the converter stations are subjects for major criticism from private stakeholders (landowners, public or private interest groups). The absence of expropriation rights of TSOs in some new EU Member States is a concrete barrier, which has to be taken into account. The public appeal of permits and consent is another factor that may inflict uncertainty and time delays on the projects. Here, the TSO may contribute by making sure that stipulated procedures and legal provisions are observed.

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- The private stakeholders have a very strong influence, especially when observing citizens' and private organizations' privilege to appeal decisions made by competent authorities. The appeal processes are typically as long as, or sometimes even longer than, the initial procedure for consenting and permitting. In this way, an extra year or more can easily be added to the consenting process. Some TSOs include an environmental court review into the project timetable right from the start.
- Project organization comes out as another potential barrier to a successful interconnector project. It is found that inappropriate project organization contributes to the major part of time and budget overruns.
- Offshore interconnector projects are highly complex covering two countries plus any possible transit country. The project design is an iterative process between the technical experts working on technical design and procurements, whereas the legal team tests for permissible solution and prepares for the environmental assessments etc.
- Project teams are pressurized by the technical innovations and strict public regulations. Thus, the overall challenge is to manage project development in a dynamic setting.

Recommendations

- There is a need for creating better awareness among environmental specialists and authorities that modern offshore interconnector projects only leave a limited footprint on nature. The TSOs and technology providers have to better document the limited adverse environmental effects of cables in different seabed and land structures.
- Transnational standards for documenting interconnector projects and recognizing the environmental assessments across countries would simplify the consenting process.
- Effective stakeholder management eases and smoothes the consenting process by reducing risks in terms of time, money and uncertainty on the project. Before going public, the project needs to clarify the public necessity of the interconnector and to take into account all social benefits in order to achieve social acceptance.
- A well-structured internal project organisation and the co-operation between the partner TSOs are key contributors to ensuring a cost effective consenting process. A multi-disciplinary approach is needed, when experts on spatial planning, environmental impact assessments etc. are increasingly integrated in project development at an early stage of the project. They will remain part of the design phase until the planning consent and the licensing to construct the interconnector is received.

7.2.2 DELIVERABLE 17.2

Key takeaways of Twenties D17.2 [92]

- *"A well-organized plan to deal with international authorities is key to construct a HVDC link avoiding delays."*
- *"There is a need of defining cooperation agreements among the planning and permitting authorities from the European member countries."*

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D17.2 of Twenties [92] provides a synthesis of seven background reports from the WP17 of Twenties, including D17.1, to identify the barriers to the planning and permitting of offshore interconnectors and to propose ways of mitigating these barriers. The studies considered the following phases of an offshore interconnector project: pre-feasibility, feasibility, development, construction and O&M. In order to study projects that require permits in more than one country, a virtual test case named TRIFFID was used. It represents an interconnector system with multiple landing points in Netherlands, Germany and Denmark with a link to an offshore wind farm. TRIFFID considers issues like ownership, congestion management and capacity allocation and other technical issues.

Existing barriers

- The development consenting and permitting process is currently detached in national procedures with shortcomings on cross-border issues and permitting efficiency. The risk is that the scope of studies is becoming too wide and too comprehensive.
- Cables need to cross waterways under the authority of water and shipping authorities. The lack of standards for undertaking and evaluating risks can result in detours in cable routes.
- One of the main issues is the duration of the permitting procedures. This is due to the highly unintegrated administrative practices in relation to the involvement of various public authorities and their different responsibilities. Factors having a negative effect are also a lack of transparency and manageability, and the interdependence of processes.
- The EIA Directive appears to be the environmental framework associated with the most legal barriers. These challenges relate in particular to change and an increase in legal requirements, confusion about the level of detail and scope of the environmental documentation, significant discrepancies and the poor quality of the data.

Recommendations

- A common road map for EIA studies should be applied and shared practices for scoping of studies and documentation prepared.
- Cooperation agreements with national planning authorities must be entered into to facilitate overall and holistic evaluation of the cable route design.
- The cable technologies and impacts are very similar from one project to the next. The repetitive work adds to the cost of permitting without giving additional information. It is possible to determine best available cable technologies and installation methods. A transnational body must serve as the focal point for authorities and scientists to select best available technologies and to determine their impacts. Reference studies on environmental effects of selected installation and cable technology should be endorsed a relevant transnational and neutral body. In order to keep up with innovation, the list of best available installation and cable technologies can be regularly updated.
- Current route screening by planning authorities is typically part of a full EIA in which many route variants are surveyed in detail and conclusions are given after a long period. It is proposed to only locate key landing points and crossing points with waterways etc. in maritime spatial plans. More

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weight should be assigned to cable project interests when balancing them against the conflicting interest of the seabed.

- A model reference case for scoping, undertaking and evaluating shipping risk studies should be prepared.
- The key documents to be used by authorities and stakeholders during the process of planning consent and permitting should be standardised.
- The TSOs should be involved as a project developer in drafting background studies and finding responses to challenges concerning routing and other aspects during the EIA and spatial planning.
- The national planning authorities and TSOs need to consider the complexity of onshore planning and permitting at a very early stage in the planning process. Onshore cable routing and converter building call for accurate planning and strong coordination with stakeholders.
- Lobby for national and EU interests in the development of interconnectors.
- Establish a database of research on the most common issues regarding interconnectors.
- Initiate a public affairs campaign to explain the demand for and necessity of offshore interconnectors in combination with offshore grid.
- With regard to the use of EU influence, it is seen as beneficial to assemble an “EU project team” to help projects emphasise EU interests. Specific projects can obtain support from this unit.
- Creation of one-stop shops. This would mean that there would only be one single authority responsible for handling one single permitting procedure. Moreover, this single authority would also have specialised knowledge. Another solution could be to define maximum durations, and parallel handling of processes could also contribute to reducing the barrier. Yet one must be aware of the fact that one-stop shops are national, which means that there would still be issues regarding cross-border projects, which would often be the case in relation to offshore interconnectors.

7.3 NSCOGI STUDIES

Besides the offshore grid planning study described in section 2.1.4, the NSCOGI published several deliverables related to regulation and financing, which are summarized here in chronological order:

- WG2, Deliverable 1: Incompatibility of national market and regulatory regimes, January 2012 [93].
- WG2, Deliverable 2: Recommendations for guiding principles for the development of integrated offshore cross border infrastructure, Nov. 2012 [94].
- WG2, Deliverable 5: Market arrangements under the virtual case study, Nov. 2012 [95].
- WG3, Deliverable 2: Procedural guidelines as a recommendation to the national competent authorities, Nov. 2012 [96].
- WG2, Deliverable 3: Cost allocation for hybrid infrastructures, July 2014 [97].
- WG2, Discussion paper: Integrated offshore networks and electricity target model, July 2014 [98].

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7.3.1 WG2, D1 – "INCOMPATIBILITY OF NATIONAL MARKET AND REGULATORY REGIMES"

Key takeaways of D1 of NSCOGI WG2 [93]

- *"The Third Package[14] is interpreted in different ways by the different member countries, leading to different regulatory regimes for the same network elements".*
- *"Existing national regulatory regimes can limit the development and operation of integrated offshore grids, as these are not designed in this perspective".*

The deliverable 1 of WG2 [93] examines the existing European and national regulatory regimes for offshore grid and offshore generation development and points out the main regulatory barriers. Several topics are covered, such as planning, financing, construction, ownership, operation and balancing, support schemes, grid access regimes, connection requirements and connection and operational charges. Moreover, the deliverable lists relevant EU legislation, such as the EU Renewable Energy Directive (RED) and the Third Energy Package.

The EU RED allows member states (MSs) to develop their own national renewable support mechanisms, leading to different mechanisms among MSs. Moreover, it provides a flexibility mechanism with which a MS can support RES outside its national boundary. Finally, the EU RED also defines priority access. The latter entails a "connect and manage" connection regime, a limited exposure and participation in national balancing, and a guaranteed single buyer model for RES. It also defines that, subject to system security constraints, TSOs must give priority to generating installations using RES and that grid and market-related operational measures must be used to minimize curtailment of electricity produced from RES. The second relevant EU legislation is the EU Third Energy Package. This package envisions the creation of a single internal energy market. To accomplish this, framework guidelines, network codes, and also requirements on ownership unbundling are envisioned. The latter leads to different offshore asset ownership regimes among the MSs due to a different interpretation of the unbundling requirements (offshore grid network can be part of the transmission system or of the grid connection).

For planning, financing, construction, and ownership, the responsibility lays in general with the TSO. For the financing of meshed offshore grids, offshore assets and subsequent reinforcements of the onshore grids are typically socialized through the grid access tariff, yet exceptions exist (UK). For the offshore grid connecting a renewable generator, the financing depends on the legal status in the country. Nevertheless, in general, radial connections are considered as grid connections while the connections of hubs are seen as transmission architecture. Again, several exceptions exist. Regarding ownership, interconnectors are typically in hands of the national TSOs while radial connections are in some countries owned by the generation developer. Note that a particular regime with merchant developers and Offshore Transmission Owners (OfTO) exists in the UK.

[14] European Union's Third Energy Package (2009) is legislative package for an internal gas and electricity market in the European Union. Amongst others, it aims at unbundling energy suppliers from network operators and at cross-border cooperation between transmission system operators.

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For operation and cross border balancing, EU legislation aims at harmonizing approaches between its MSs. Nevertheless, national differences remain. Examples are the rules on cross border procurement, imbalance settlement, etc.

As mentioned before, the EU RED allows for national mechanisms to support the realization of renewable energy targets. As a result, support schemes between MSs differ. Moreover, the grid access regime differs amongst MSs. Two approaches can generally be distinguished in this perspective: the “connect and manage” approach and the “invest and connect” approach. For connection and onshore reinforcement cost charges, the offshore portion is usually paid by the generator (exception: Germany), while for the onshore reinforcement this largely depends on the country. Regarding system operation and balancing cost charges, most countries charge the offshore generation similarly compared to onshore generation. For grid connection requirements, offshore generators are rarely expected to provide ancillary services although France and Great Britain impose some reactive power requirements.

Existing barriers

- Existing national regulatory regimes can limit the development and operation of integrated offshore grids, as these are not designed in this perspective.
- Lack of harmonization of interoperability for operation and balancing.
- The Third Package is interpreted in different ways by the different member countries, leading to different regulatory regimes for the same network elements.
- No coordination for support schemes for RES, grid access regimes, connection and onshore reinforcement cost charges, system operation and balancing costs charges, grid connection requirements.
- Due to differences in support schemes, connection regimes and charging policies, it may be difficult to provide a genuine business case for investment in offshore generation that is part of an integrated offshore grid. Moreover, the decision on the country to which charging, connection, and support regimes apply, also necessitates an appropriate allocation of costs for the on- and offshore transmission reinforcements as well as the use of system costs. Finally, existing national differences may lead to investments in suboptimal areas.

Recommendations

- Countries should be stimulated to share their emerging thinking on coordinated offshore development in order to limit different technical designs.
- A methodology should be developed in order to allocate costs for offshore transmission assets, onshore reinforcements and the use of the system between the different countries.
- An enhanced cooperation for grid planning and construction is needed.
- While planned EU network codes (NCs) and framework guidelines (FGs) are benefiting cooperation between countries, issues related to offshore grid development should gain specific attention.

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7.3.2 WG2, D2 – "RECOMMANDATIONS FOR GUIDING PRINCIPLES FOR THE DEVELOPMENT OF INTEGRATED OFFSHORE BORDER INFRASTRUCTURE"

Key takeaways of D2 of NSCOGI W2 [94]

- *"National approaches don't necessarily need to be harmonized but they do need to be compatible in order for such an approach to work",*
- *"Barriers are not insurmountable",*
- *"There is currently no regulatory regime in Europe which provides an explicit regulatory framework for the development of 'hybrid' assets."*

The deliverable 2 of WG2 [94] builds further on deliverable WG2, D1. In this perspective, recommendations to overcome regulatory barriers are suggested. These recommendations distinguish between design, planning, construction, system operation, renewable support schemes, ownership, and system charges.

Recommendations

- Design: development of a framework within which all developers can cooperate to understand network needs, overall system needs, long-term government plans, bankability, etc.
- Planning: in order to reach legal certainty, it is key to have predictable decision making and efficient processing of planning and permitting procedures.
- Construction: upfront clarity should exist on which party bears the risk in relation to any delays in construction.
- Operation: in general the TSO should take responsibility for operation of the assets on its territory.
- Renewable support: A common model for MS cooperation should be applied. Additionally a MoU between MSs on the allocation of costs and benefits could be signed.

7.3.3 WG2, D5 – "MARKET ARRANGEMENTS UNDER THE VIRTUAL CASE STUDY"

Key takeaways of D5 of NSCOGI WG2 [95]

- *"An offshore wind generator (OWG) should be allowed to bid into a national market, even when connected to several ones"*
- *"The OWG should be prioritized in case of congestion between OWG generation and cross-border trade on the same asset, even when this leads to decreased day ahead interconnection capacities".*
- *"The OWG should be charged for the asset connection in the same way as radially connected OWG. It should not need to buy interconnection capacities to get access to the market into which it is to bid".*
- *"Capacities not used by the OWG should be accessible to all market participants as interconnection capacities".*

The deliverable 5 of WG2 [95] investigated the implications of market coupling for offshore renewable generators (ORG), focusing on the day ahead timeframe. Hereby, the principles following from the Renewables

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directive (priority access and priority dispatch) and third energy package (congestion management guidelines and EU target model) are considered. To assess the implications of market coupling, two models (also referred to as virtual cases (VC)) are considered: VC1 (the basic model) and VC2 (a variation). An illustration for both methods is provided in Figure 7.1 and in Figure 7.2.

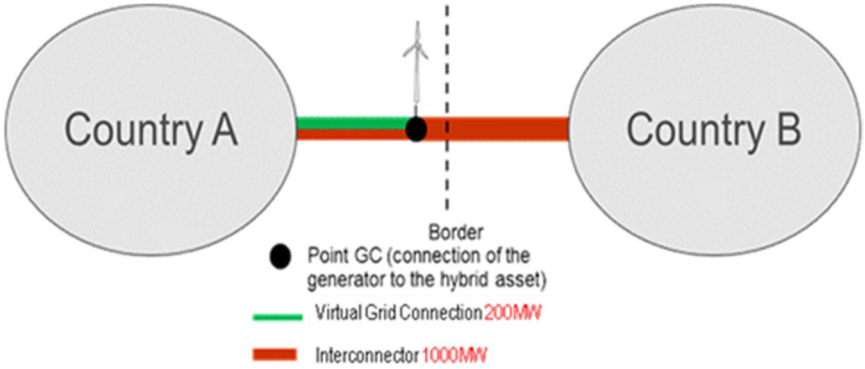

Figure 7.1. Virtual Case 1, basic model [95].

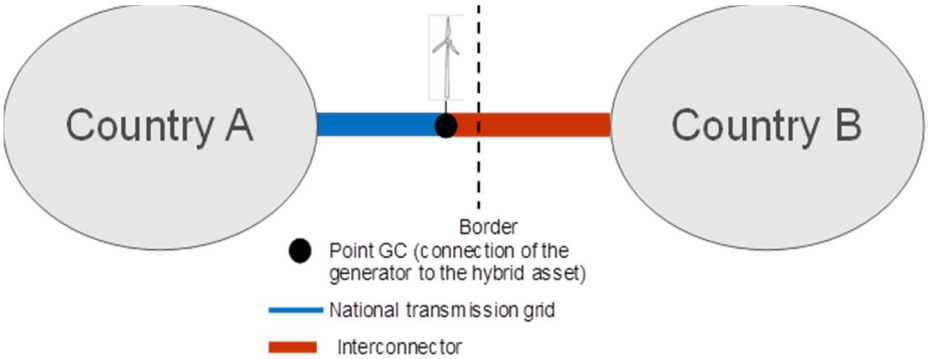

Figure 7.2. Virtual Case 2, variant model [95].

For the first VC (VC1), a hybrid interconnection between two countries is considered. An OWG is attached to the IC. Specific to VC1 is that the connection from the point where the generator is connected to country A is partly defined as virtual grid connection (equalling the OWF capacity) and partly as interconnection. For this VC, three different options are considered and discussed. For option 1, the OWG bids in the national hub and is treated as any other trader in hub A. No conflicts regarding priority access, congestion management, non-discrimination and cost efficiency occur in case the flow on the interconnection goes from A to B. Nevertheless, in case the line is congested from hub B to A, difficulties arise. In this perspective the generation from the OWG could be curtailed and compensated, yet this is not compatible with the renewable directive and can lead to difficulties for member states to meet its renewable objectives. Moreover, the compensation mechanism for such cases is not defined and this could lead to higher total generation costs. Another way is for the OWG to participate in the long-term market and pay for access. Yet, also with this solution difficulties arise as it exposes the OWG to market risk which the radially connected generation doesn't face. A last way is to have priority dispatch with reservation of variable capacity on the IC. For option 2, a floating hub is assigned for the OWG. In

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other words, for every hour the OWG can choose to bid in zone A or B. This is typically the one with the highest price. No justification is found for providing the OWG with such privilege as it discriminates against the other market participants. For option 3, a separate hub for the OWG is created. Also this option can be considered as discriminatory because the OWG will receive the lowest price of both bidding zones in any case.

For the second virtual case (VC2), the link between the connection of the OWG to the IC and the country A is defined as part of the national transmission grid. In other words, no hybrid status of this asset occurs. For VC2, one option is considered (option 4), in which the OWG bids in its national hub and the OWG is treated as any other trader in hub A. NSCOGI showed that the conclusions for this option are similar to the ones of option 1.

The deliverable concluded that options 1 and 4 seem to be the best solutions for market arrangements. Nevertheless, future work on the impact of the different classification of assets is needed. It is also concluded that it is vital to ensure that the same connection/access charges are paid by OWGs connected to hybrid assets, as are paid by OWGs with radial/regular connections. Different options are available to this end: payment priority access, sale of long term capacity rights, or the OWG could be constrained to preserve IC capacities.

7.3.4 WG3, D2 – "PROCEDURAL GUIDELINES AS RECOMMENDATION TO THE NATIONAL COMPETENT AUTHORITIES"

The deliverable 2 of WG3, working group about permitting and authorization, focusses on procedural guidelines which apply to cross-border projects in which at least two signatory countries are involved [96]. Nevertheless, the guidelines may also be applicable for exclusively national projects. The target groups of the document are the planning bodies and permitting authorities.

Recommendations

- Each national authorized planning and permitting authority should publish a manual of planning and permitting procedures. It should include an elaborated description of these procedures required for granting permits for the building and operation of offshore electricity infrastructure projects. These procedures should be accessible for TSOs and other stakeholders.
- When no legal instruments and tools such as maritime spatial planning are available, an overview should be provided defining all planned and existing areas which are identified as protected or dedicated to specific uses. In case several authorities are responsible, a close consultation process between them is recommended.
- Each competent national authority should provide information to support efficient and effective information for the applicant, other authorities, stakeholders and the public.
- Standardisation of procedures is key.
- The creation of a glossary is useful to provide common understanding.

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7.3.5 WG2, D3 – "COST ALLOCATION FOR HYBRID INFRASTRUCTURES"

Key takeaways of D3 of NSCOGI WG2 [97]

- *"Different costs allocation methods have different strengths and weaknesses".*
- *"The majority of methods studied ensure lower costs for all stakeholders (incentive value), yet no method guarantees higher net benefits for TSOs in every possible case".*
- *"ORGs should not contribute to reinforcement costs".*
- *"For the connection of an ORG to an interconnector, only basing reallocation on congestion rent could be more suitable than basing reallocation also on surplus".*

The D3 of WG2 [97] focusses on how the costs and benefits of the offshore hybrid assets can be shared, focusing on an offshore renewable generator connected to an interconnector (T-in connection). Different methods are proposed and for each the advantages and disadvantages are listed. Note that the deliverable assumes a specific market arrangement and asset classification for the hybrid asset.

This deliverable is complementary with ACER's recommendation No 07/2013 on cross border cost allocation (CBCA). Note that this recommendation focusses on projects of common coupling with a negative cost benefit analysis for at least one of the hosting members. Contrary, this deliverable focusses on hybrid offshore projects for which the cost benefit analysis of the hybrid solution is more positive than the stand-alone solution.

Following the Renewable Energy Directive (RED) priority access and dispatch of RES is assumed. Moreover, based on the congestion management guidelines and the EU target model following from the Third Energy Package, it is assumed that electricity flows according to the price differentials between markets and that cross-border flows are not reduced in order to solve internal congestion. Two asset classifications are considered and referred to as virtual cases. In virtual case 1 (VC1), the line between the ORG and country A is classified partly as virtual grid connection and partly as interconnector. In virtual case 2 (VC2), the link between the ORG and country A is defined as national transmission system. Connection between the ORG and country B is classified as an IC. For both cases, the ORG is assumed to bid in its national bidding zone (zone A). Both virtual cases are presented in Figure 7.1 and Figure 7.2 (see section 7.3.3).

When the line is congested from bidding zone B to bidding zone A an issue occurs as the ORG priority over cross border flows can lead to decreased day ahead interconnection capabilities. The prioritization of the generation from the ORG over the cross-border flows in the direction of imports can have several implications. First of all, although the ORG could attain the same benefits, its connection costs could be considerably lower compared to a radial connection. For the TSOs, the congestion rent and the social surplus resulting from the interconnection is lowered. Nevertheless, the TSO from the importing country may save reinforcement costs on the onshore grid compared to radial interconnection. Second, apart from the TSOs and the ORG, the country in which the ORG is located receives benefits in terms of a contribution to renewable targets and an additional generation capacity. Contrary, the other country (and TSO) doesn't receive additional benefit to compensate the potential loss. Therefore, with conventional cost allocation (50-50), the other country has no immediate interest

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in accepting the ORG's connection and in developing a hybrid infrastructure. In this perspective, an efficient cost allocation mechanism is required in which the ORG could pay for its priority access and its used or reserved transmission capacity.

Note that the order of development can raise problems of free riding and first mover disadvantage as those arriving late would possibly only pay incremental costs. Three scenarios are possible as shown in Figure 7.3.

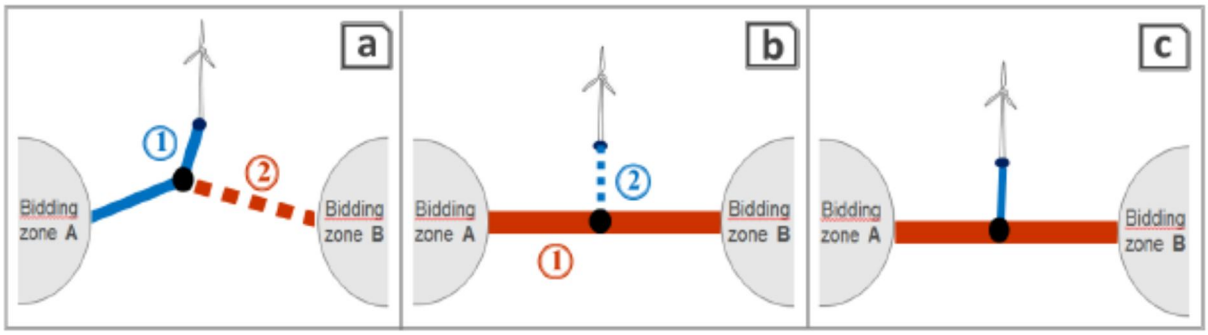

Figure 7.3. Three scenarios for the order of development of a hybrid grid [97].

In the Scenario A, the IC is built after the ORG. In this case, no particular cost issues seem to occur. The ORG is treated similarly than any other radially connected ORG. Moreover, the TSOs benefit from lower investment costs. The only issue could be potential reinforcement costs of the existing line between zone A and the wind generator. This could be either shared amongst the TSOs or fully covered by TSO A when the cable is classified as offshore transmission grid (VC2). In scenario B, the ORG is built after the IC. This changes the role of the IC and modifies its business plan as previously highlighted. Therefore, IC owners could be allowed to refuse a T-in connection. Finally, in Scenario C, the ORG and the IC are constructed at the same time. Similar issues to Scenario B occur, although the cost allocation is decided ex-ante in this case. Note that for the three scenarios, the risk of stakeholders dropping out of the project and therefore of the project being delayed is higher in Scenario C.

To overcome the cost-benefit issues created in Scenario B and C, the deliverable presents several cost allocation methods based on the proportional to stand-alone cost method, the Louderback's method, the Shapley value method, the min/max contribution method, and the proportional to benefits method. Each of these methods is assessed according to different criteria (incentive value, costs-incentive, no unfair discrimination, horizontal/vertical consistency, compatibility with legal frameworks, reinforcement cost allocation between TSOs, complexity and feasibility, adaptability, and allocation between stakeholders).

Apart from costs, benefits can also be shared amongst parties. It should be noted that congestion rent can only be shared between TSOs while surplus benefits cannot be shared. The ORG also doesn't share its benefits resulting from selling generation. When the ORG gets priority access leading to decreased day ahead interconnection capabilities, a contribution of the ORG could be needed to pay for this access. While the TSO of the importing country could see its investment costs reduced, the TSO of the exporting country could lose part of its congestion rent and surplus. Therefore, an appropriate congestion rent allocation between TSOs could be installed.

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Existing barriers

- No general cost allocation methodology is present for integrated hybrid offshore projects
- Priority of generation from the ORG over cross-border flow can have several detrimental implications if not compensated by means of an appropriate cost allocation method.

Recommendations

- No cost allocation method is preferable over the other. This should be evaluated on a case-by-case basis.
- Reallocation of benefits between TSOs should be based on the congestion rent, not on the surplus.
- ORGs should not contribute to reinforcement costs as ORGs are not charged for reinforcement costs in any NSCOGI country

7.3.6 WG2, D3 – "DISCUSSION PAPER: INTEGRATED OFFSHORE NETWORKS AND ELECTRICITY TARGET MODEL"

Key takeaways of NSCOGI discussion paper [98]

- *"Bidding zones should be consistent across all timeframes (forward, day ahead (DA), intraday (ID)".*
- *"Bidding zone configurations for ORGs could evolve over time".*
- *"ORG should be charged for asset connection in the same way as radially connected ORG".*
- *"ORGs should not be required to purchase transmission rights to access markets".*
- *"For ID, the own bidding zone may be a viable option. Nevertheless, there does not appear to be any difference with bidding in the national bidding zone of the country".*
- *"For the forward market, in general, the use of long term transmission rights providing ORG with access to cross border capacity is not recommended. Nevertheless, transmission rights could be an efficient approach to manage the risk of congestion costs for an ORG located within its own bidding zone and a potentially and efficient means of renewables trading across the internal market".*

This discussion paper [98] discusses the market arrangements to facilitate trading from across simple hybrid offshore structures. The paper assesses the impact of ORG distinguishing between three markets with a different trading timeframes, namely the Day Ahead (DA) Market, the intraday (ID) market, and the forward market. For the DA market, the conclusions from the market arrangement paper (WG2, D5) are repeated. These include that, even when the ORG is connected to several bidding zones, it should be allowed to bid into only one. Moreover, when a hybrid interconnection is congested, the ORG should get priority in a way consistent with the national approach for other RES connected. And finally, the ORG should be charged for the asset connection similarly to a radially connected ORG. Building further on the market arrangement paper, this paper notes that the option of creating a separate bidding zone for the ORG is an option worth considering. For the ID market, the paper notes that the inclusion of ORG should follow the principles of priority access and

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priority dispatch and the EU target model (continuous implicit trading via single matching algorithm). In the case the ORG can bid in its national bidding zone, no conflict with these principles is found when the IC is not congested in the direction of the national bidding zone of the ORG. Nevertheless, when the IC is congested in this direction, an issue can occur as the ORG doesn't have access anymore to its national bidding zone. Several routes exist to overcome this issue: the ORG can be constrained and compensated, the ORG pays for access to IC (although this is conflicting with the EU target model), or priority dispatch with reservation of variable capacity on the IC. Apart from the case of the ORG bidding in its national zone, it is also possible to create a separate bidding zone for the ORG. Nevertheless, no tangible advantage for the ORG is found in this case. For the forward market, NSCOGI doesn't recommend the use of long term transmission rights. Nevertheless, it could be an efficient approach to manage the risk of congestion costs for an ORG located within its own bidding zone and potentially an efficient means of renewables trading across the internal market.

Existing barriers

- In general, conflict between ORG generation and cross-border trade on the same congested asset.
- For the intraday market, when the IC is congested in the direction of the national bidding zone of the ORG, the ORG doesn't have access anymore to its national bidding zone.

Recommendations

- For DA, the creation of an own bidding zone should also be considered.
- Bidding zones should be consistent across all timeframes.
- ORG should be charged for asset connection in the same way as radially connected ORG.
- ORGs should not be required to purchase transmission rights to access markets.
- For the forward market, in general, the use of long term transmission rights providing ORG with access to cross border capacity is not recommended.

7.4 ISLES

7.4.1 ISLES I

Key takeaways of ISLES I [99]

- *"Several barriers exist for implementation of both a "Business as usual" model which follows existing frameworks as far as possible and a "stand alone market" model where all offshore generators are part of a separate market that trades with the two onshore systems."*
- *"A third "Hybrid" method is therefore recommended which includes offshore wind generation in the Republic of Ireland as part of the GB market."*
- *"Innovative thinking will be required to tackle the existing regulatory barriers to building cross jurisdictional offshore grids."*

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The ISLES study investigated the feasibility of building cross border offshore grids with the dual purpose of providing interconnection between the islands of Ireland and Britain and enabling market access for potential offshore renewable generation projects. Through its cross-jurisdictional report [99], it identified that the creation of an integrated, cross-jurisdictional offshore network would raise a series of complex market and regulatory challenges. A shortlist of the key issues to be addressed, to facilitate an ISLES type grid was outlined as follows:

- The need to define a regulatory and legal framework acceptable to all the jurisdictions affected
- The legal and regulatory status of interconnectors, and how a network which combines the characteristics of generator connection and interconnection would be treated by each jurisdiction
- Subsidy models, and how subsidies could be aligned and/or modified to drive market behaviours to meet the needs of each jurisdiction
- The mechanisms for funding and remunerating strategic network build with incremental development of assets over a period of time. A subset of this is the development of network charging models and agreement over how costs are socialised into the host markets
- The evolving impact of EU legislation, given current uncertainties about how certain elements might be interpreted, particularly in the GB context

Assuming that there is an underlying economic rationale for the ISLES project the aim of the investigation was to determine whether a regulatory framework can be developed that will “make it sufficiently attractive to all the relevant market stakeholders to be viable”. The fundamental issue for an offshore network is where the jurisdictional boundaries are drawn and four different boundary types were identified as follows:

- Legal/Jurisdictional boundaries: generally corresponds to national borders.
- Market Boundaries: need not be aligned with national boundaries (in case of ISLES the single Irish market already covers two territories).
- System Operations Boundaries: can be different to national/market boundaries and also possible that operator can operate networks which it does not own.
- Ownership boundaries: the owner of the transmission asset is not necessarily the operator e.g. in GB OFTO regime offshore networks owned by separate entity but operated by National Grid.

Existing barriers

With the above distinctions in mind, two potential regulatory models, representing plausible pathways forward as determined by project stakeholders, were initially examined in detail to gauge the barriers to implementation.

<u>Model 1 – Business as Usual</u>

This assumes that the ISLES project would be accommodated within the existing regulatory and market structures of the countries involved. Offshore assets in the waters of both Northern Ireland and Republic of Ireland are governed by the market rules of the all-island Irish market (SEM) and those in GB waters are governed by GB market rules. A conceptual picture is given in Figure 7.4. A notional boundary is drawn between the two markets which is approximately contiguous with the marine boundary. The assumption is that National Grid Electricity Transmission (NGET) would act as system operator for the assets under its jurisdiction

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and that EIRGRID (or SONI) would perform the role for the all-island grid. The interconnection owner/operator would, however, need to be defined as under existing GB law the owner/operator could not be NGET.

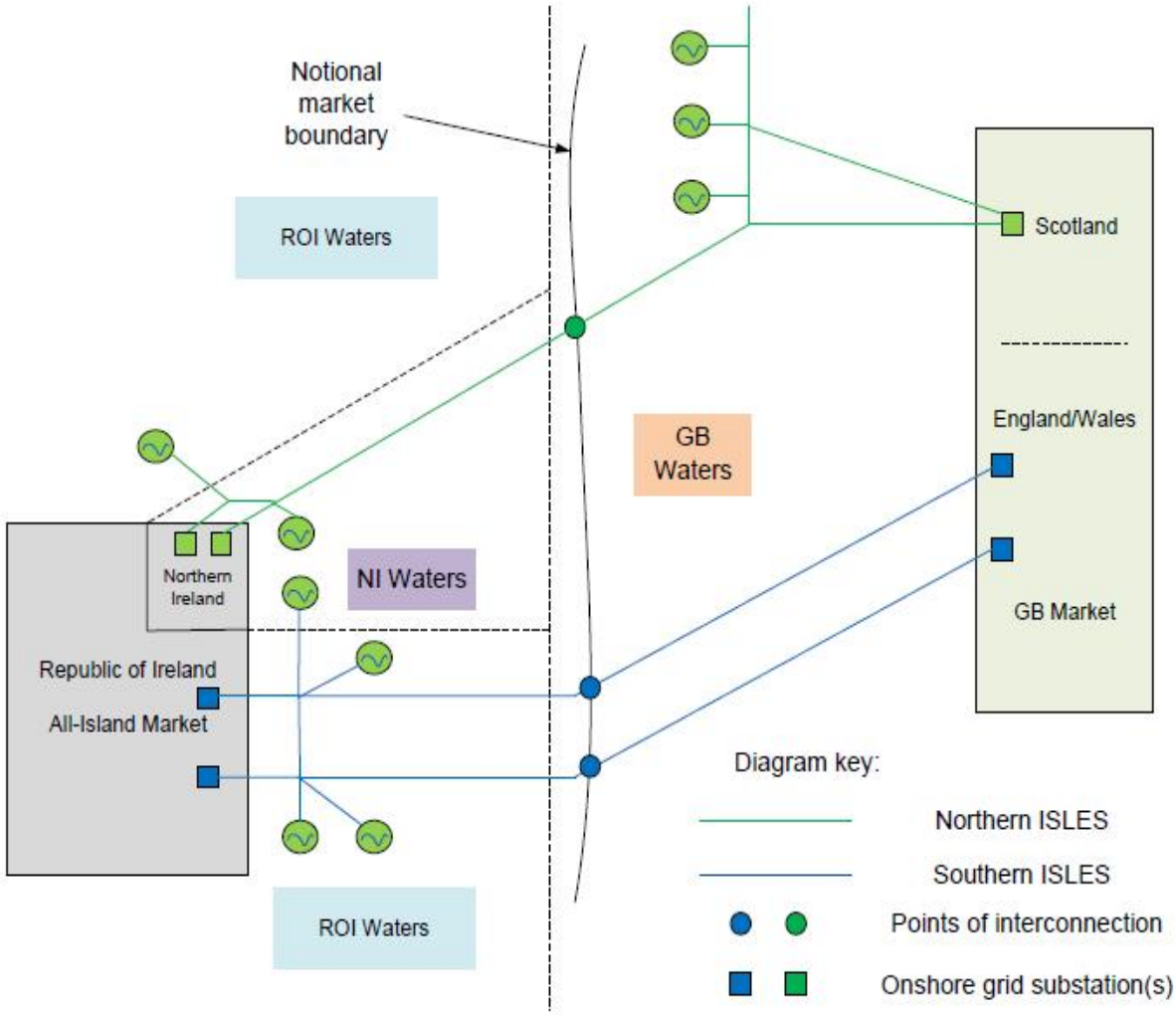

Figure 7.4. Regulatory Scenario 1 "Business as Usual" [99].

Model 2 – ISLES as a stand-alone market

An alternative view is that a specific regime needs to be developed to cater for offshore projects of this type. A number of conflicts however arise when considering a standalone market option. Firstly the approach would lead to the creation of multiple ISLES interconnectors to GB and it would be very difficult to define in practice what is an interconnector and what is a transmission asset as this approach “runs contrary to the very concept of an integrated network”. In addition, if a separate System Operator (SO) exists for this set of assets, it could reconcile power flows to/from the onshore SOs, but would be operating in direct competition with existing interconnectors, which are operated on a fundamentally different commercial basis.

A decision would also have to be taken about who the market operator was for the offshore assets. An approach could be envisaged where the Irish and Northern Irish generation remains in the all-Island market and GB generation remains in BETTA (British Electricity Trading and Transmission Arrangements). However, this

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then raises questions about which market bears the cost of renewable subsidies for given generators. Some academic comment has suggested harmonisation of subsidies for trans-national projects, to avoid the mismatches and skewed incentives which would otherwise result from different generators having different commercial drivers. This is deemed politically unworkable for ISLES however.

To explore the issues and test the boundaries of what might be possible and/or workable, the model that was envisaged is the creation of a standalone market operator trading power with both the GB and Irish markets. In this arrangement all the transmission assets and generation assets connected to them will be part of this new market structure. The boundaries of this standalone market will be at the onshore (or offshore) points of connection with the two existing markets as illustrated in Figure 7.5.

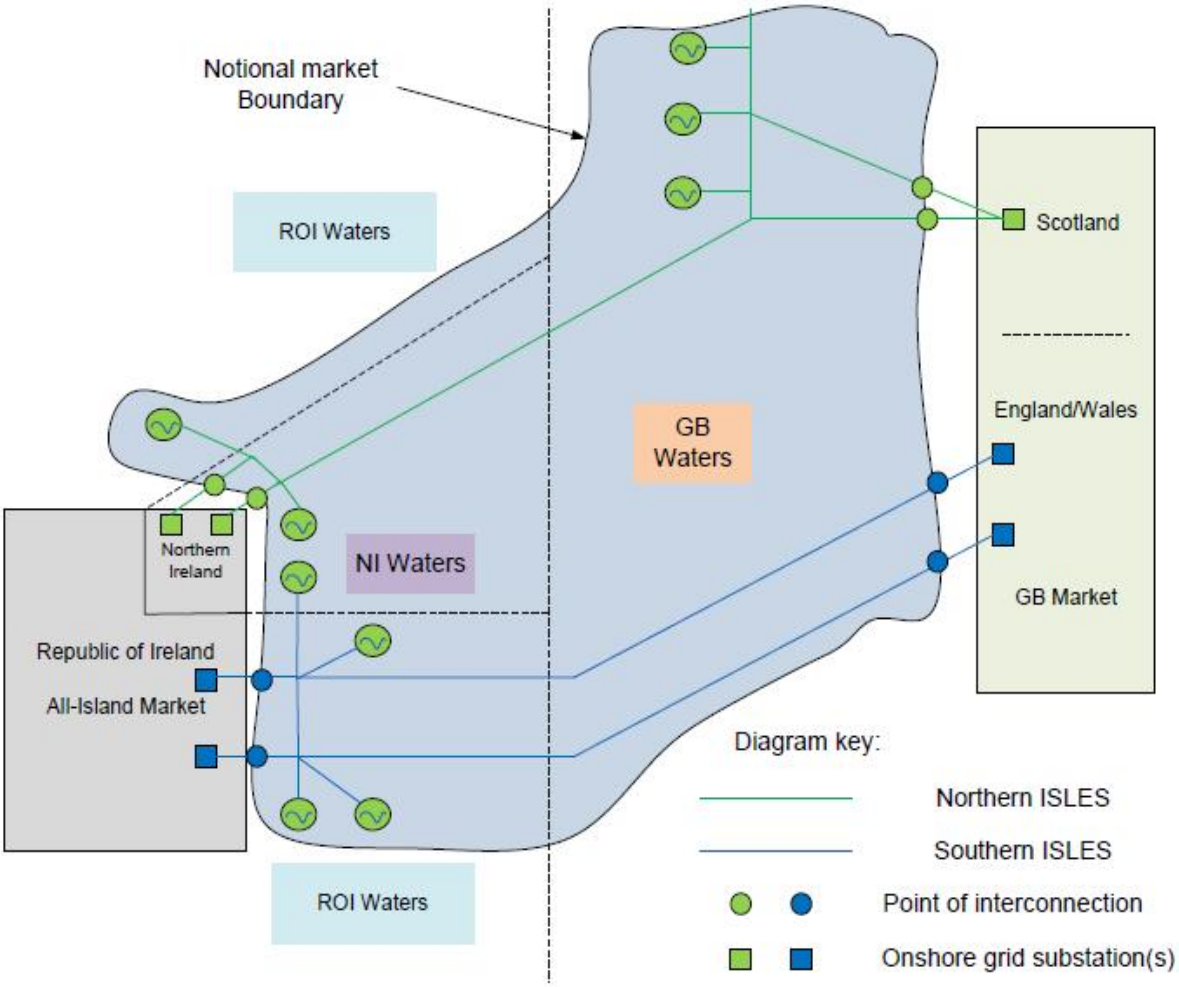

Figure 7.5. Regulatory Scenario 2, ISLES as a standalone market [99].

Comparison of Models

A detailed analysis of the issues relating to each regulatory model including the institutional framework, ownership and financing, market arrangements and subsidy mechanisms was made and a qualitative comparison of the two options is outlined below. It is clear both options contain significant barriers. Note that the third option “hybrid scenario” will be discussed within the next subsection.

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Criterion	Regulatory Scenario 1 "business as usual"	Regulatory Scenario 2 "integrated regulatory concept"	Hybrid Scenario
Degree of complexity in developing from status quo	LOW – this is an evolutionary 'line of least resistance' approach	HIGH – significant policy changes and sovereignty questions	MEDIUM – main complexity centres around generators in Ireland participating in GB market, and the related sovereignty issues
Risk of EU legal challenge	MEDIUM – robust provided that SEM and GB markets evolve in a compliant manner, although there are pre-existing issues (e.g. relating to the Moyle I/C) which need to be solved	MEDIUM – this arrangement raises a number of relatively complex questions of principle which would need to be resolved.	MEDIUM – robust provided that SEM and GB markets evolve in a compliant manner, although there are pre-existing issues which need to be solved
Difficulty in financing network	HIGH – some assets (in GB) would follow already established models but business case for build of anticipatory capacity is not clear, the current legal confusion around Interconnection would also be perceived as regulatory risk.	MEDIUM/HIGH – this is a new regime but if clearly defined could be workable, the issue will be justifying discrete investment decisions where the benefits are cumulative. The viability of this solution may be dependent on how the project is packaged and presented to the investment community.	LOW/MEDIUM – aligns more closely with existing financing mechanisms for offshore network and interconnection
Difficulty in financing generation projects	MEDIUM – projects in Scottish territorial waters would proceed on similar basis to OFTO, significant commercial barriers for generation in Ireland and particularly in NI.	MEDIUM/HIGH – generators would have nervousness about a new, unfamiliar market & subsidy regime, and the associated regulatory risk.	LOW/MEDIUM – UK as per OFTO regime, RoI would need legislative change – awarding subsidies to all developers will facilitate private sector understanding of project risk/reward
Misalignments in treatment of generation resource across jurisdictions	HIGH – significant issues for any project whose business case hinges on cross-border sales of energy	MEDIUM – common approach means ISLES resources would be treated equally, although there may be misalignment with other developments (e.g. Round 3).	LOW – all generation is treated as part of GB market
Likely level of resistance from existing stakeholders	LOW – this is the evolutionary scenario	MEDIUM – Level of resistance will depend heavily on the details of how this scheme would work	UNKNOWN, but several stakeholder felt this type of approach represents a pragmatic solution.

Table 7.3. Comparative analysis of regulatory models

An alternative 'hybrid' scenario was developed in an attempt to mitigate some of the major barriers identified in each of the first two models.

<u>Model 3 – The 'Hybrid' Scenario</u>

The model was developed as an interpretation of the policy aspirations of stakeholders in all jurisdictions and aimed to:

- Solve or mitigate problems identified by stakeholders, rather than exacerbating them
- Interpret the current 'direction of travel' of thinking in the jurisdictions involved and the EU, so that it can be seen to be a logical transition from existing thinking rather than a more radical (and potentially risky) step change
- Create a model which incentivises the markets to achieve their RE policy goals, at the same time maintaining economically rational behaviour

Due to system stability constraints a limit will soon be reached whereby not all of the intermittent generation in Ireland can be dispatched. This could coincide with surplus wind energy and depressed wholesale prices. The GB market is approximately ten times larger so the economic value of selling wind energy into the GB market will remain high for much higher levels of absolute wind generation build. Therefore, most or all resources in the ISLES area may need to build their business case on selling to the GB market.

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Further to this, the smaller all-island Irish market will have generally higher wholesale prices than GB. This inherently leads to a business case for increased interconnection, at least until interconnection is at a level where price coupling between the markets is very close.

The ISLES network therefore needs to present:

- An opportunity for generators in all the jurisdictions to sell into the GB market on a commercially viable basis, such that they can compete against other alternative projects in GB waters
- An opportunity to use network capacity at times of low wind to sell thermal energy from the GB market into the SEM, decreasing energy costs to Irish and Northern Irish consumers.

The hybrid scenario, as outlined below, is therefore designed as a regime which facilitates energy sale to GB and increases interconnection to the SEM.

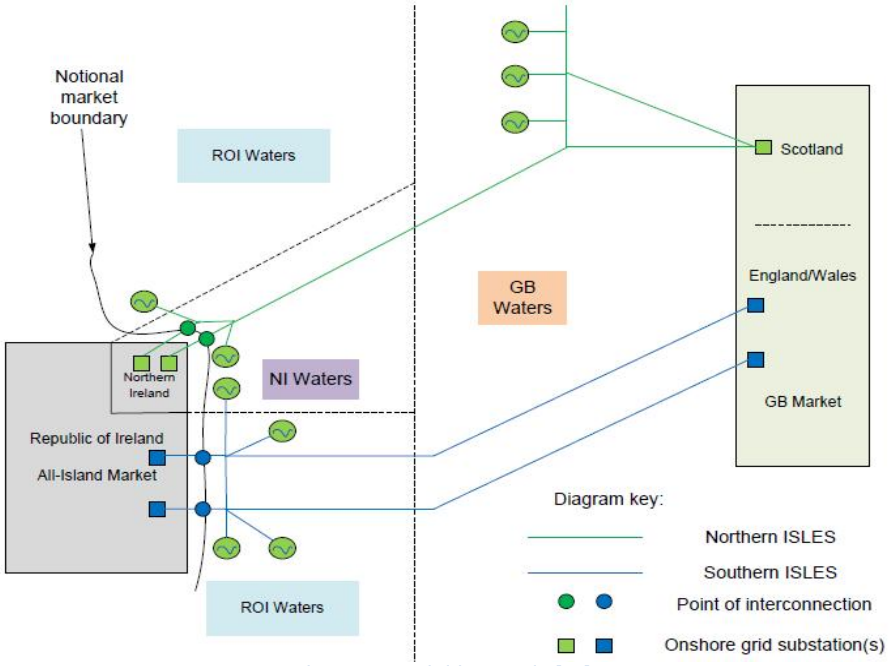

Figure 7.6. Hybrid scenario [99].

In this scenario all generation assets are considered part of the GB market. The offshore network assets are dealt with on the same basis as GB waters, except that cable connection to Ireland would be treated as interconnection. The hybrid solution could be viewed as radical because generators in Irish waters would be part of the GB market and could earn subsidy from GB customers. The scenario does also introduce sovereignty issues for the RoI, including public acceptance of generation being built to serve another country and allocation of corporation tax. From the UK perspective it would require the UK government to see enough value in the project to accept the entire subsidy burden for generation based in another countries jurisdiction. The hybrid model was subjected to the same extensive analysis as the first two and the summarised conclusions are shown alongside those of the other regulatory models in Table 7.3.

Note that ISLES I did not study the possibility of market convergence between the GB and Irish markets but did comment that the hybrid scenario in particular would lend itself to being extended to a 'converged' scenario where both the GB and all-island system could be operated as one control area. This could be a similar set-up

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to Nord Pool with 'market splitting' allowing for regional pricing zones. The hybrid scenario boundary could be the point where the market splitting occurs. This arrangement could mitigate or even remove the issues around generation in one country's waters being part of another's market set-up.

7.4.2 ISLES II

Key takeaways of ISLES II [100] [101] [102] [103] [104] [105]

Three key principles are outlined to help address existing regulatory barriers:

- Embedding risk mitigation mechanisms
- Placing generation at the forefront of the regulatory framework
- Demonstrating commitment to a pragmatic policy approach

In ISLES II the Network Regulation and Market Alignment Study [103] and five associated sub reports make a number of recommendations aimed at addressing existing barriers that hinder development of multiple-use, cross-jurisdictional offshore networks. With some minor modifications, the ISLES II project investigates broadly similar development scenarios to those outlined in the Northern and Southern ISLES examples of the ISLES I study with an updated timescale of 2030 for project completion. A number of illustrative examples of the types of co-ordination opportunities that could arise in the ISLES zone (as sub-systems or staged development of the wider system) are outlined in Figure 7.7.

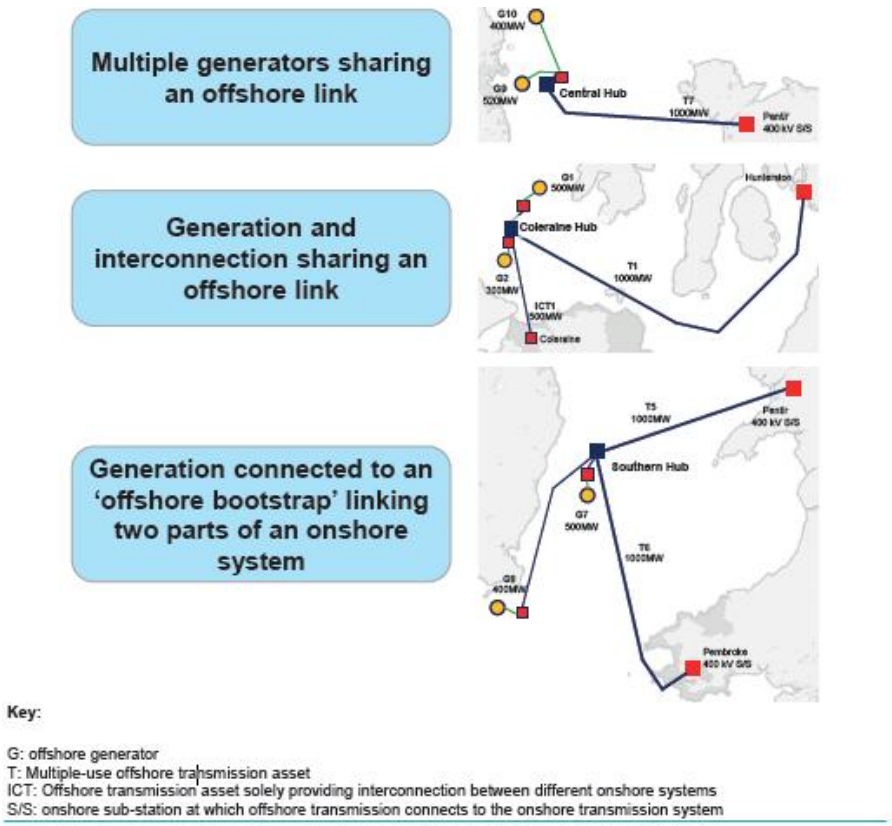

Figure 7.7. Examples of multiple us, cross-jurisdictional offshore network assets [103]

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A number of benefits of multiple-use offshore networks are identified as outlined in Figure 7.8, one of which the ability to reduce the capital costs of particular offshore windfarm projects. The ISLES II study investigated 10 potential offshore wind farm developments in total, 6 of which had lower capital costs in a co-ordinated scenario when compared against being built with direct links to shore. Figure 7.9 shows the potential benefits of co-ordination are largest in terms of reduction of required support level for smaller generation projects and it is found that this is especially true when sharing a link with a much larger project. This is due to the economies of scale offered in offshore transmission network construction, which mean that for example a 1 GW link could be around 15% cheaper than the cost of two 500 MW links of the same length.

Direct benefits for the delivery of a project	Wider energy system benefits	Support for wider policy goals
• Lower offshore network costs • Improved reliability of offshore network • Lower cost funding of projects	• Increased market to market capacity • Increased onshore transmission capacity • Provision of connection options for future offshore generation development	• Consistent with a more integrated European electricity market • Supply chain benefits (e.g. installation, O&M) • Provision of grid access for emerging generation technologies • Reduced number of landing points

Figure 7.8. Benefits of multiple-use offshore transmission network assets [103]

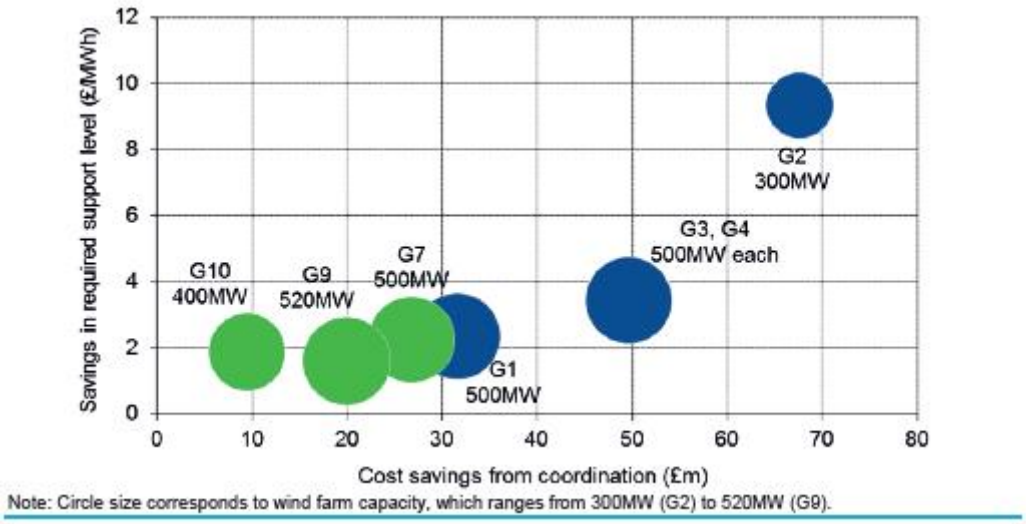

Figure 7.9. CAPEX savings of connecting to multiple-use networks rather than sole-use links for selected ISLES Generators [103]

In terms of improved reliability the ISLES II project found that having multiple routes to shore can significantly boost the commercial case for the offshore windfarm by reducing the expected lost output due to long term cable faults in particular. A specific comparison was made between an 'interconnected radials' example with 2 GW generation connected to two landing points via two interconnected 1 GW links and a case with a separate 1 GW link for each 1GW of offshore generation. It was found that the estimated average net-benefit of the co-

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ordinated solution equated to a reduction in required renewable support of around £1/MWh. Thus the benefit is relatively small but still large enough to drive coordination where low cost opportunities exist.

Another direct benefit of shared offshore network assets are the potential for access to central funding sources, for example having the status of Project of Common Interest (PCI) allows projects to apply for direct grants under the EU's Connecting Europe Facility (CEF). There is uncertainty as to the level of funding that will be available in future but under current rules "EU support can exceed 50% of the eligible costs for studies and works in exceptional circumstances, linked to major social benefits of the project. If the specified conditions are met, the CEF grant can cover up to 75% of the costs for works". It was estimated that, if 50% of capital costs of the multiple use offshore network assets were covered by such grants, the average reduction in required renewable support would be £7/MWh. If however, European support was limited to lower cost funding, rather than capital grants, then the reduction in renewable support is around £3/MWh. These are significant savings but could be much larger if the grants were applicable to funding of offshore generation assets which account for 70% of the total cost of ISLES.

Wider energy sector benefits of the proposed ISLES grid are found to include:

- Increased market-market capacity resulting in lower annual wholesale electricity prices, reduction in costs of thermal generation, lower CO2 emission, fewer thermal generation start-ups and higher average capture prices for Irish onshore wind farms. Benefits mainly accrue to Irish system in ISLES example compared with No ISLES development path and figures relate to 2030.
- Reinforcing of onshore networks: e.g. Bootstrap between two points of the same system which avoids need for onshore reinforcement which can often be subject to long planning delays.
- Opportunities to utilise non-firm offshore network capacity. A higher opportunity arises when offshore wind farms output have lower correlation with onshore wind. This reduces significantly reduce the level of curtailment of onshore Irish wind assets

The final set of benefits identified for a coordinated ISLES grid is its implications on wider policy goals as identified in Figure 7.8, which include facilitation of supply chain benefits.

Existing barriers

Two main regulatory barriers are identified:

<u>Barrier 1: Coordinated benefits not factored into network investment decisions</u>

Existing regulatory regimes are defined for assets with only one of the following uses:

- Offshore transmission (offshore generation directly connected to onshore network in same jurisdiction)
- Interconnection (direct connection of different onshore electricity markets)
- Onshore transmission (connecting two different points of the same onshore network via offshore assets)

There are different types of licenses for each particular use and there is no framework within the ISLES jurisdictions for development of network assets with multiple uses.

Through public workshops and bilateral meetings with stakeholders a number of clear risks for sharing network assets were identified:

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- Need for policy-maker and regulatory buy-in to support the development of novel regulatory arrangements to support coordinated offshore network development.
- Lack of clarity over scope of public funding to support coordinated projects involving connection of offshore generation.
- Need for fall-back arrangements if the other project(s) sharing the assets are not taken forward – for example, will the remaining project be committed to taking forward the shared network development on its own, or will it have to restart the project development process? (E.g. consenting for a single-user set of offshore transmission assets). This risk is enhanced given the emphasis on the importance of competitive allocation of renewable support in the new European guidelines for renewable support schemes10. These changes have increased the perception of development risk for new renewable generation assets. It has also led to projects being worried about other projects gaining disproportionately from coordination, and hence getting an advantage in the competitive allocation process.
- Possibility of delays being introduced in the development timelines of other project(s), which then holds up the remaining projects. This could include the regulatory funding process for generation or transmission assets.
- Risk of losing firm access to the offshore network capacity in the future – for example if priority is given to market to market flows as part of the implementation of the European Target Model for electricity.

Risk has important knock on effects on the cost of private finance and it is estimated that the support required by an ISLES generator increases by £7/MWh for every 1% increase in required return.

Barrier 2: Differences between jurisdictions

A number of boundary issues arise when considering cross-jurisdictional network assets, such as:

- differences in regulatory treatment of generation and offshore transmission;
- boundaries between different wholesale markets; and
- lack of mechanisms for cross-border trading of renewables in the ISLES zone.

Differences in regulatory arrangements between jurisdictions include issues such as licensing, funding, regulatory oversight and operational rules and responsibilities. For the ISLES project one of the key issues is that much of the generation development business case relies upon having access to the much larger GB market, even if not located within the jurisdiction of the UK government and so eligible of UK renewable support mechanisms.

Recommendations

Three key principles are set out for regulatory and support arrangements along with suggested next steps or actions towards delivering on these principles.

Principle 1: Embedding risk-mitigation mechanisms

Risk mitigation mechanisms would not be designed to eliminate risk but alter the balance of risk between individual projects and consumers. By shifting balance of risk towards consumers, it removes the barrier of asymmetric risk profiles being the burden of individual projects and could facilitate the key early stage

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developers to invest the effort to lay the foundation for a coordinated grid. The mechanisms must address two main risks as follows:

- The failure of projects planning to share assets
    - Risk of developer paying more for stranded shared assets than they would for own dedicated assets.
- Connection of additional users to an offshore network
    - Risk for operational projects that new projects could curtail their access rights.

Action 1: Embedding risk mitigation mechanisms

Mechanisms to mitigate the risks of coordination over different project timescales include a framework for:

- facilitating regulatory continuity over the whole lifetime of individual projects
    - for example a transmission asset licensed under the offshore transmission regime should be given the opportunity to retain its existing licensing and regulatory regime, even after interconnection connects to it.
- protecting individual project development timelines
    - if design changes to offshore network are needed due to certain projects not moving ahead, under current rules the consenting and licensing application process would have to be re-started. A means of incorporating greater flexibility is needed
- allocating costs and benefits of the development of shared assets; and
    - mechanisms for consumer underwriting of incremental co-ordination costs are required and could be delivered via transmission charging or by linking the level of renewable support to the offshore network costs
- allowing different users access to transport electricity across shared network
    - ensure that market-market capacity does not reduce the commercial rights for offshore generators

Principle 2: Placing generation at the forefront of the regulatory framework

Regulatory and market arrangements should support phased incremental development of generation and offshore network assets. The minimum requirement for the policy framework is that it should encourage first projects to develop in a way that facilitates rather than hinders later co-ordination developments but the encouragement for co-ordination should not be to the extent that it stifles development of the initial generation projects. Funding for renewable generation should therefore be clearly separable from the funding of the incremental costs of co-ordination.

Action 2: Placing generation at the forefront of the regulatory framework

Main actions for governments include:

- Engaging with developers of live projects in the ISLES zone to maintain a good understanding of highest priority regulatory issues for near-term developments
    - E.g. Engage with potential core developers of co-ordinated network to see how they can be encouraged to support co-ordination rather than seeking to build individual assets
- Participating in a multi-national group such as the North Seas Countries Offshore Grid Initiative (NSCOGI) that is focused on monitoring and influencing individual policy initiatives
- Exploring the interaction between competitive allocation and co-ordinated development

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- A joint initiative between governments to award a particular sum of renewable support to generation projects in a defined area could reduce the likelihood of withdrawal of projects involved in coordinated network development.

Principle 3: Adopting pragmatic approach to policy-making

A common set of regulatory policies and legal arrangements that enables all efficient co-ordination is not feasible in the time required to facilitate development of early co-ordination efforts. A set of pragmatic arrangements that enables a high proportion of co-ordination through ad hoc arrangements are a more realistic means of achieving key goals. Such arrangements should also build on existing regulatory framework as much as possible rather than seeking a complete overhaul of existing policy and over time they could be codified into a more formal, wide ranging set of rules.

Action 3: Demonstrating commitment to pragmatic policy approach

To demonstrate commitment to a pragmatic policy approach, the governments could sign a joint document, such as a Memorandum of Understanding.

Developing workable arrangements also includes a pragmatic approach to decide which jurisdictions are involved in which decisions – for example, Irish bodies should be involved in discussions on the arrangements for Northern ISLES developments related to cross-zonal capacity. Although the developments are outside its jurisdiction, additional market to market capacity could benefit Ireland, and any arrangements may be seen as setting a precedent for developments in the Southern ISLES.

7.5 PHD THESIS OF H. MÜLLER

Key takeaways of the PhD thesis of H. Müller [106]

- *"A transnational offshore grid will not be developed under the current legal framework as established under international law, EU law and national law".*
- *"The EU does not have a competency under the EU Treaties to require Member States to develop a transnational grid".*
- *"Many reports suggest simplified solutions such as aligning national support schemes, harmonising grid rules, appointing a single TSO or establishing a single body being responsible for overall network planning. I argue that these suggestions are not feasible as they do not sufficiently take into consideration the legal context of international and EU law as well as the choices made under national law".*
- *"Certain legal agreements need to be made now to allow for the connection of infrastructure to other countries at a later stage".*
- *"An offshore grid will not be built as such but will rather evolve from the clustering of offshore hubs and the connection of offshore wind farms with multiple countries".*
- *"North Sea states will only cooperate and adopt the required legal changes if they benefit from it".*

This PhD thesis [106] assesses existing legal frameworks relevant in the view of offshore grid development. In this perspective, distinction is made between international law, European Union law and national law. It includes

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the current legal and regulatory barriers for the transnational offshore grid development. In order to overcome these barriers, recommendations are made.

As most offshore grids in the North Seas will be mainly located outside the territory of the coastal states, the starting point for the legal assessment is the international law of the sea. The main agreement in this perspective is the 1982 United Nations Convention on the Law of the Sea (UNCLOS), impacting the basic provisions concerning states' rights and duties in the North Sea. It determines that the coastal states have the sovereign right over the cables to connect offshore wind farms to its national transmission grid. Moreover, all states are free to lay cables. Nevertheless, the clustering of wind farms or the construction and operation of hybrid grids is not foreseen in this convention. Following the international level, the relevance of EU law is analysed. It is concluded that while EU's competences regarding the development of a transnational grid are limited, several relevant competences regarding offshore wind energy development and its related transmission cables are present. Nevertheless, existing EU law fails to regulate the clustering of wind farms or the development of hybrid grids. Moreover, uncertainty regarding the applicability of existing EU laws could hamper development. Finally, also national law is evaluated. To this end, four coastal states (DE, DK, NL, and the UK) are selected. Within these states a clear trend towards a more coordinated approach is seen in different stages. At a first stage, cables towards offshore wind farms fall under the responsibility of the wind farm developers. Afterwards, as distances and sizes increase, park-to-shore cables become a separate activity. At a third stage, TSOs become responsible to cluster multiple wind farms via offshore hubs. While this is currently the case in Germany, other coastal states need to follow. Finally, in the future, cross-border projects should be established which combine the connection of offshore wind farms with interconnection between the coastal states.

These different layers of legal frameworks (international, European, national) are assessed considering different options for the connection of offshore wind farms. Four options are assessed, namely:

1. Radial connection of offshore wind farms.
    a. Offshore wind farm, park-to-shore cable.
    b. Interconnector, point-to-point.
2. Clustering of offshore wind farms via offshore hubs.
3. Connection of offshore wind farms with two or more countries (Hybrid projects).
    a. One wind farm connected directly to two countries.
    b. Multiple wind farms connected directly to two countries.
    c. One wind farm connected to an interconnection cable (T-in)
    d. Multiple wind farms connected to an interconnection cable (T-in)
4. Connection of offshore wind farms into a meshed offshore grid.

The graphical representations of the (sub)options are provided in Figure 7.10, Figure 7.11, Figure 7.12, and Figure 7.13. Note that, currently, the approach remains to connect offshore wind farms by means of an individual park-to-shore cable.

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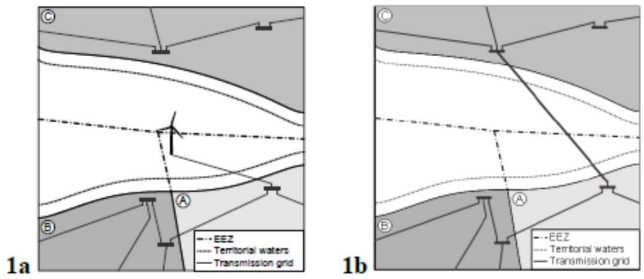

Figure 7.10. Option 1: Radial connection of offshore wind farms and point to point interconnection

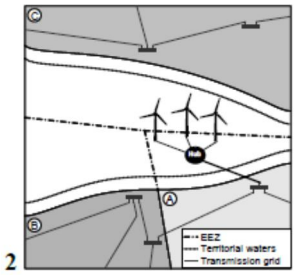

Figure 7.11. Option 2: Clustering of offshore wind farms via offshore hubs.

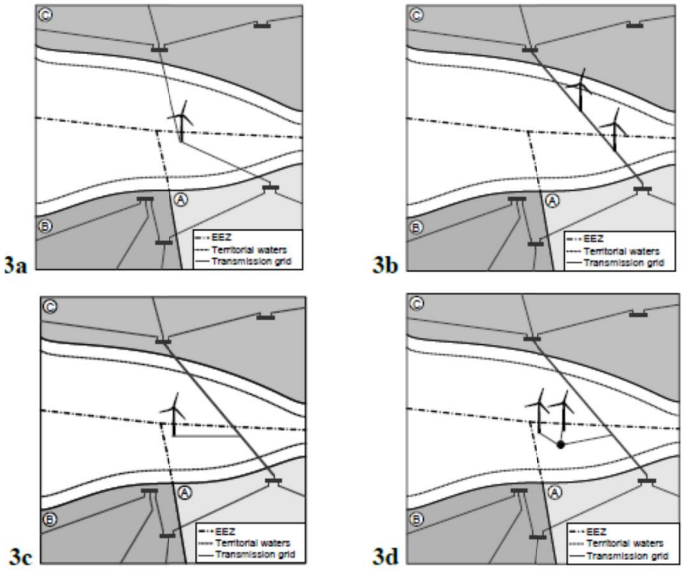

Figure 7.12. Option 3: Connection of offshore wind farms with two or more countries.

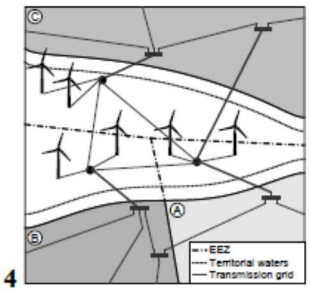

Figure 7.13. Option 4: Connection of offshore wind farms into a meshed offshore grid.

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Existing barriers

- While the role of national exploitation of offshore wind energy is covered by the regional regime under UNCLOS, alternative options (e.g. the connection of offshore wind farms to interconnectors) don't fall within this regime.
- While UNCLOS doesn't impede the development of more coordinated offshore projects, no clear guidance is provided.
- The EU objectives regarding the promotion of RES and the facilitation of an internal energy market can be conflicting, limiting the development of cross-border offshore wind farms.
- The application possibilities of EU law to the exclusive economic zone (EEZ) are limited.
- Within the EEZ, it is less clear on who carries the jurisdiction over interconnector cables.
- No EU regulation exists regarding the clustering of wind farms and the development of hybrid projects. Moreover, existing rules could lead to uncertainty in this perspective.
- For clustering projects, a lack of coordination between the development of offshore wind farms and related offshore infrastructure exists. Moreover, the regulatory and financing regimes are covered by uncertainty.
- For hybrid projects, existing uncertainty regarding definitions and responsibilities exists. Moreover, the incentives for relevant actors are not sufficient to engage in these projects. Finally, the national support schemes remain limited to national projects.

Recommendations

- Develop a more coordinated regional method to limit the impact on the other users of the sea.
- For clustering, first national Offshore Infrastructure Plans should be developed. Afterwards, the TSOs should be obliged to identify beneficial clustering projects. The projects should fall under an adapted legal framework, after approval from the start by the NRA.
- For hybrid projects, a similar recommendation compared to clustering is made. First, national Offshore Infrastructure Plans should be defined after which the TSO identifies beneficial projects. After approval of the NRA, an alternative legal framework is applied.
- It is suggested to apply a separate alternative legal framework, only for hybrid projects. This exclusive framework should limit the impact on existing legal frameworks and on the internal energy market.

7.6 E-HIGHWAY 2050

Key takeaways of e-Highway 2050 D5.1 [107]

- *"To evolve towards a more coordinated, European-wide grid expansion planning process, interaction with national plans, is the efficient way to correctly and timely identify main bottlenecks and related projects."*
- *"An efficient degree of coordination shall be maintained between TSOs and potential third-party transmission asset owners in those circumstances and scenarios where these two types of asset*

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owners co-exist. Going forward, there should be no blunt evolution towards favouring a more diversified set of asset owners as a way of ensuring that investments are forthcoming."

- *"Two main aspects contribute to the success of financing the projected 2050 transmission network: the availability of diversified sources of financing and the determination of a risk commensurate return which ensures efficient investment signals."*
- *"Cost allocation of grid reinforcements and flexibility deployed for grid purposes should be coordinated once feasibility studies indicate positive results. Network costs should be allocated as far as possible by applying the beneficiary pays principle."*
- *"A well-functioning market and technical operation design should entail three key aspects: efficient transmission capacity utilization; integrated market operation and strong cooperation of security management. "*

In view of the evolution of the European grid architectures up to 2050, potential adaptations to the current regulatory framework to realise these projected grid architectures might be necessary. The European grid will by 2050 inevitably be more interconnected than today, spanning more countries and transporting even more energy from distant production centres to diverse consumption areas. In order to face the challenges for such grid architecture realisation, a set of key governance principles has been elaborated by means of best practices derived from worldwide experiences, which can be considered for future European regulation. Five key governance principles are considered and discussed in what follows.

The first governance principle is based on a further strive for more coordinated grid planning. The current approach adopted for grid planning at European level has already been evolving from a purely bottom-up process at national level towards a more centralised and European shared approach. This evolution is supported by the work carried out by ENTSO-E in the TYNDP definition process, which combines top-down planning elements with a bottom-up approach. Such an approach allows taking into account the local knowledge of the regional and national networks and their specifics and investment needs. Moving forward, this evolution towards a more centralised approach is to be further supported, whilst at the same time ensuring that the bottom-up and national elements remain a key part of European grid planning. This evolution towards a more coordinated, European-wide grid expansion planning process, interacting with national ones, is considered as the efficient way to correctly and timely identify main grid bottlenecks and related infrastructure projects. Identifying these is a necessary first step in their realisation, in order to evolve towards a truly interconnected European network.

The second governance principle aims at an efficient scheme of network construction and ownership. Both the allowed investment costs and the rate of return for these investments shall be approved by regulatory authorities and are subject to oversight at European level. Only if local TSOs are not able to deliver the required investments within a pre-specified time for reasons within their control, auctions open to TSOs and reliable third parties, may take place to allocate the ownership of assets. If there is insufficient competition, ownership of the asset should, by default, be allocated to the local TSO; ensuring in all cases that an adequate remuneration is provided. The rationale behind network construction auctions is that, by promoting competition amongst

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potential providers of equipment and installation services, a more efficient pricing and deployment of investments would be enabled, leading to benefits to society as a whole. This provision builds upon current European regulation, which already foresees the possibility of organizing tenders when TSOs are not able to timely deliver a PCI. In those cases where third-party private partners are allowed to own network assets, regulatory authorities should monitor the financing and operating capabilities of these entities to ensure an appropriate development, operation and maintenance of their transmission assets, equivalent to the TSOs. Fostering the internationalization and increase in scale of private network owners should enhance these capabilities. However, given that the internationalization and merger of private owners may decrease the level of competition among these and TSOs in transmission auctions; this should be monitored by regulatory authorities.

Thirdly, the financing conditions should be continuously improved. One of the key challenges to ensuring a swift project realisation is providing the necessary financing conditions for the transmission network owners to finance the construction of infrastructure. Public sector support and rate-adders for strategic projects could push the project forward by financial stimuli throughout the most risky project phases, but may be insufficient to overcome the entire challenge. To provide the correct signal for transmission network investment, it is fundamental to create a fair, stable and predictable risk-reward mechanism which takes into account the different life-cycle stages of an infrastructure project. This implies that regulatory regimes should provide a forward-looking, long-term commitment and provide clarity to limit regulatory risk for investors. Whenever a fair and commensurate risk-reward mechanism is ensured, in a stable context with regulatory comfort for the conditions, there should be no barrier to a timely project realisation. Fall-back solutions in case of failure of timely delivery of the project for reasons lying under the control of the TSO should however be foreseen.

The fourth governance principle aims at an appropriate and fair cost allocation of network investments. Given that costs and benefits of network investments will be increasingly spread out over several countries, further coordinated cost allocation of grid reinforcements is foreseen for projects having a cross-border impact. To this aim, a unique, robust and binding methodology should be developed for cross-border cost allocation (CBCA). Furthermore, the higher complexity of electricity systems by 2050, characterized by higher shares of RES and more variable electricity demand (electric vehicles, heat pumps), implies a higher diversity of costs and benefits incurred by network users on the system. Since network charging structures currently often take a typical average situation as point of departure, increasing gaps between network charges and true costs of network users for the grid are observed. This results in a lack of incentives to generators and loads for optimal use of the network in many member states. Consequently, network costs could be allocated as far as possible by applying the “beneficiary pays” principle, which is theoretically the most appropriate, but could be difficult to implement. In any case, the future mechanism should provide efficient economic signals to all network users, both generation and demand. Likewise, when RES becomes a mainstream technology, RES network costs should no longer be socialized through priority access or dispatch, but allocated to RES facilities that benefit from them. Cost components that cannot be indisputably allocated to a specific (group of) stakeholder(s) and reliability network costs (‘N-1’ costs) should however remain to be socialized.

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The final governance principle entails the objective of more coordinated system operation. As for system operation aspects, further coordination between actors and integration of market mechanisms needs to take place. First and foremost, there is a clear need to complete the internal energy market and to ensure regional market integration in all time-frames (forward, day ahead, intraday and real-time). The recent implementation of the flow-based mechanism serves as an example for the future in that regard. Related to that is the bidding zone configuration, which should be, as long as zonal transmission capacity allocation is pursued, configured in a way which corresponds to real network bottlenecks.

Furthermore, it will be crucial to incentivise market actors to ensure correct and rational behaviour in order to tackle ever-increasing system security aspects. Well-designed balancing markets are a key requirement and electricity markets should contain a well-defined resource adequacy objective. These objectives should be defined on a more regional basis. If they lead to the elaboration of capacity markets, then they should be deployed in a way compatible with the European wide energy market. In addition, and to deal with the high share of renewable generation, further regional security monitoring and control mechanisms closer to real-time over larger geographical areas are put forward. Finally, integrated systems will require further information exchange and harmonization of procedures by means of common tools, data and processes among TSOs to deal with the variable and uncertain cross-border power flows.

Existing barriers

- In the short term, and as long as there is no sufficient consensus on the appropriateness of the method for the computation and allocation of benefits of reinforcements to affected countries, multilateral CBCAs should not be applied as the base case and only be applied in exceptional cases. In the long term, multilateral cross-border cost allocation agreements should be applied on a wider scale, if (an updated) feasibility study indicates positive results.
- Locational Marginal Pricing results in price spikes during capacity scarcity, and it increases the risk of price volatility for network users. Therefore, the implementation of locational marginal pricing is often accompanied by risk hedging instruments, such as financial transmission rights (FTR). However, it has to be recognized that the nodal market design is not in line with the current market design embedded in the European network guidelines which are based on a zonal approach. Therefore, the nodal design, which seems the best solution from a theoretical point of view, faces several barriers towards its practical implementation in the European context.

Recommendations

- The expansion of the cross-border transmission grid in Europe shall be coordinated centrally following a combined top-down and bottom-up approach, taking into account the needs and requirements of the countries involved through close cooperation with the national TSOs. If possible, uncertainty about the future evolution and operation of the system should be adequately represented.
- Cross-border investment proposals should be assessed and approved centrally, by European institutions with executive powers, in accordance with Member States, while respecting national authorization procedures

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- As a base case, network construction auctions for regulated cross-border assets shall be conducted by TSOs to determine which company should construct the asset and provide the related installation services. The winning tender of these auctions (bid) shall be used to compute the allowed revenue of asset owners, i.e. the local TSOs.
- Economies of scale in grid development are to be encouraged.
- The role of the public authorities as investment enabler should be strengthened by setting up stable, long-term oriented regulation, and by promoting assistance to create innovative financing tools for attracting diverse financing sources at low cost.
- Improved risk management tools should bring down the cost of transmission network investments. This includes a common risk evaluation for cross-border projects and a common risk management tool. In addition, a separate cost of capital determination mechanism could be used for low risk assets within the regulated asset base.
- Cost allocation of grid reinforcements and flexibility deployed for grid purposes should be coordinated as soon as possible once feasibility studies indicate positive results.
- Network costs should be allocated as far as possible by applying the beneficiary pays principle. Cost components that cannot be indisputably allocated to a specific country or (group of) stakeholder(s), should however be socialized.
- It should be further assessed whether a system of Locational Marginal Pricing (LMP) could increase efficiency of transmission capacity allocation in the European electricity system. As long as zonal transmission capacity allocation is pursued however, bidding zones should be configured in an adaptive way which corresponds with network bottlenecks
- Regional energy market integration should be pursued in all time frames, incl. on the day ahead, intraday and balancing market. Variable renewable generation requires well-designed balancing markets, as well as a well-defined adequacy objective. Market design should allow old and new technologies to compete to provide energy, ancillary services and capacity to the system
- Interconnected power systems with high share of intermittent renewable generation require regional security monitoring and control mechanisms closer to real-time, and over larger geographical areas. Regional approaches to define reliability should be considered

7.7 TRACTEBEL/ECOFYS/PWC STUDY FOR THE EUROPEAN COMMISSION

Key takeaways of the "Study on regulatory matters concerning the development of the North and Irish Sea offshore energy potential" [108]

- "Need for strong political commitment of all parties" (NSCOGI was a good starting point, but additional commitment is required).
- "Need for a common policy driver to incentivize coordination among market players and align individual objectives" (e.g. common targets for a RES share at European level by 2030).
- "Need for clear allocation of main responsibilities about the financing, construction and operation activities".

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- "Need to establish a stepwise approach where grid assets development precedes and the deployment of RES generation follows".

To enhance offshore grid development, the "Study on regulatory matters concerning the development of the North and Irish Sea offshore energy potential" realized by Tractebel, Ecofys and PWC for the European Commission (DG Ener) [108] aims at identifying and understanding the existing regulatory barriers obstructing offshore grid development. Apart from the barriers, it aims at developing a set of workable models and identifying and sequencing the legal, regulatory and policy activities to implement the suitable regulatory models.

Fifteen potential regulatory barriers are identified. An overview is provided in Figure 7.14. Note that each potential barrier is assigned to one of the following categories: grid connection, offshore RES plant operation, grid operation, power market, administrative process, cost allocation. Moreover, the size of each barrier is identified as small, medium, or large. Finally, it is described whether the barrier relates more to the grid and/or RES part of the hybrid asset. Figure 7.14 shows that most barriers have only a small or medium impact on the development of an offshore meshed hybrid network. Another observation is that most barriers are related to the RES development rather than to the grid development. It is also mentioned that grid development carries lower risk of leading to stranded assets since the grid would be used for market purposes in all cases. Three main barriers are considered in the table:

- Distribution of costs and benefits: While the investment in a hybrid IC could bring large benefits resulting from increased cross border capacity and the enablement of offshore RES integration, it remains costly and risky. Taking this into account, an appropriate distribution of the costs should be in line with the distribution of the expected benefits. Nevertheless, the quantification of these poses considerable challenges.
- Differences in national RES support schemes: While international cooperation frameworks exist on a high level, no offshore RES plants that connect and sell electricity to more than one country currently exist.
- Differences in national responsibility of balancing: Apart from the RES support scheme, also the balancing responsibility influences the business case of the RES plant. The payment of imbalance penalties and the potential remuneration of balancing power are two examples.

Apart from the three main barriers, several medium sized barriers are identified. An example of such a barrier is the financing of offshore assets. This is due to the relatively inexperienced environment and the uncertainties (which can be reduced by decreasing the other barriers).

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Category	Barrier	Size	Grid or RES
Grid connection	1. Grid access responsibility	Medium	RES
	2. Priority grid connection	Small	Grid/RES
	3. Onshore connection rules	Medium	RES
Offshore RES plant operation	4. Balancing responsibility	Large	RES
	5. Requirements to provide grid services	Small	RES
	6. RES support schemes	Large	RES
Grid operation	7. Priority dispatch regulation	Small	RES
	8. Cross border capacity allocation and congestion management	Medium	Grid
Power market	9. Gate closure time and settlement period	Small	RES
	10. Market integration	Small	Grid and RES
Administrative process	11. Marine spatial planning	Small	Grid and RES
	12. Consenting procedures	Medium	Grid and RES
Cost allocation	13. Financing offshore assets	Medium	Grid and RES
	14. Grid connection costs	Small	RES
	15. Distribution of costs and benefits	Large	Grid

= *Small* = *Medium* = *Large*

Figure 7.14. Overview of barriers' evaluation [108].

Nine measures are identified which are designed to tackle the main regulatory barriers and to enhance coordinated development of the offshore grid potential. Each measure is assessed against its effectiveness, efficiency, and feasibility. The 9 measures are divided in 6 categories:

- Measures to minimize risk of stranded assets: The first measure to minimize this risk is to enhance the planning cooperation among the national ministries by defining and validating a common action plan. This is a voluntary bottom-up approach which envisages the signing of a Memorandum of Understanding by the national governments. Preferably, this action plan is binding and applied at the national level, while supervised and controlled by ENTSO-E and the NRAs. The second measure is the coordination for constructing and operating infrastructure assets of national TSOs. This voluntary cooperation should start from agreed technical rules and is set between the TSO and the project developer. It aims at increasing interoperability, the reduction of administrative costs (regarding marine spatial planning and consenting procedures) and allocate responsibilities among stakeholders. The NRA should verify the correct involvement of all relevant stakeholders.
- Measures to ensure the proper distribution of costs and benefits among the involved stakeholders: This entails mainly the measure to set up an overarching cooperation framework for the distribution of costs and benefits. Note that compared to the two voluntary approaches as previously discussed, this measure sets up a new regulatory regime. In this regime, national governments are empowered to set up an overarching cooperation framework defining a cross-border cost allocation (CBCA) mechanism

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and to revise the national framework to enable it. The recommendation of ACER for the CBCA can be a starting point. The benefit of this is that it remains relatively easy to implement and it can be country specific. NRAs should implement it on a national level, while ACER has the responsibility to monitor implementation on the international level.

- Measures to reduce the differences in national regimes regarding the RES support schemes: In order to establish a common instrument for supporting and avoiding competition between countries, a two-step approach is suggested. In the short term, a voluntary approach to set a support scheme based on the geographical borders as defined by the Exclusive Economic Zones (EEZ). In other words, the ORG receives the support from the country where it is physically located, independent from the country to which the generated power flows. To compensate the country that pays the support to the ORG but doesn't receive its power, a balancing regime should be set up. In the long term, a new regional regulatory regime could be put in place which replaces the national support schemes. Nevertheless, it is foreseen that such a regional scheme could trigger low stakeholders' acceptance as the national regime needs to be amended.
- Measures to minimize the balancing responsibility issues: the main measure in this perspective is to create appropriate bidding zones for the offshore grid. Again, a two-stage approach is suggested starting with a voluntary step and ending with a new regulatory regime. In the voluntary step in the short term, home country bidding zones are established which include the ORG in the national market zones. These ORG are treated similarly than other generators in these national zones. In the second step, new bidding zones are created. Consequently, the ORGs do not belong to any national price zone but constitute a supply only market zone.
- Measures to enhance the financing framework for the development of the offshore project: A first measure in this perspective consists of a two-step approach to finance grid assets. Hereby, identifying a more specific international framework for the cost recovery of investments. Again two stages are considered. In the voluntary and short term stage, a harmonized and coordinated framework for cost recovery of investments is defined. This should incentivize anticipatory investments. Afterwards, a new regulatory framework could be set up in which a regional fund is constructed to attract financial sources and private capitals aiming to increase the financial investments in hybrid IC projects. A second measure aims to build international cooperation for marine spatial planning (MSP) and consenting procedures (CP) by establishing a Regional Administrative Secretariat by national governments. This secretariat should support project developers and TSOs in the fulfilment of all the administrative procedures. It could follow a Memorandum of Understanding between national governments. The NRAs and ACER could monitor.
- Measures impacting all barriers identified: Two measures are part of this category. The first measure aims for the allocation of the regulatory responsibility. The aim is for North and Irish Sea NRAs to cooperate towards a shared interest. Hereby, national governments are responsible for the governance of cooperation at the regional level by a Memorandum of Understanding while ACER becomes responsible for the implementation. A second measure in this category entails the set-up of pilot projects. By means of non-legislative initiatives, these pilot projects aim at stimulating international cooperation and at gaining hands-on experience regarding regulatory constraints.

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7.8 OTHER RELEVANT SOURCES REGARDING REGULATION AND FINANCING

While the focus of this regulatory and financial analysis is mainly on the projects discussed in the previous sections, some other relevant mentions regarding regulation and financing are briefly discussed in what follows. The documents considered are ranked chronologically. Note that this overview is not exhaustive and that a more complete analysis will be performed within WP7. For each source, the main content is highlighted. When relevant takeaways, barriers or recommendations are discussed in these sources, these are also included in what follows.

7.8.1 THINK, EUI: OFFSHORE GRIDS: TOWARDS A LEAST REGRET EU POLICY, JAN. 2012

Report 7 of the THINK project [109] provides policy recommendations for the EC on offshore grid development considering both standalone lines and combined solutions. Five main barriers were identified which alter the development of offshore grids:

- National regulatory frames for transmission investment are not aligned.
- National renewable support schemes differ.
- A multitude of stakeholders is involved which results in winners and losers.
- Typical R&D market failures.
- Sequential decision process in a context of uncertainty and irreversibility.

For each barrier, a corresponding recommendation is provided:

- Harmonize regulatory frames taking into account planning, competition, and beneficiaries pay principles.
- Harmonize renewable support schemes.
- Facilitate ex-ante allocation of costs and benefits.
- Speed up technology development.
- Adapt the community-wide transmission planning to offshore grids.

7.8.2 EWEA POSITION PAPER

In a position paper called “Developing a shovel-ready offshore grid in the North Seas – why public support is needed” [110], EWEA (now WindEurope) highlighted in 2014 the reasons why developing a North Seas offshore grid should be part of the upcoming EC €300 billion public-private investment programme to revive the European economy. To this end it lists some key barriers for offshore grid development:

- Need for a substantial increase of public support.
- Development of offshore resource in the North Seas is still a national responsibility. Moreover, national regulations differ and no regional cooperation is found.
- Although initiatives such as NSCOGI take place, financial and regulatory barriers persist.
- Technical barriers are relevant from a financing perspective (e.g. Regulators are reluctant to reflect HVDC-VSC technology in an adjusted return on investments for the TSO).

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- Broader political obstacles due to national interests (e.g. interconnection Norway to continental Europe).

It provided also two main recommendations: political coordination and financial support are keys, and EU level public funding must be ensured to help leverage capital from institutional investors and industry.

7.8.3 E3G BRIEFING PAPER

Key takeaways of the E3G briefing paper on the North Seas grid [111]

- *"Over 100 billion is due to be invested in electricity transmission networks in the North Seas region over the next 15 years".*
- *"Pervasive policy and regulatory risks keep escalating costs".*
- *"A lack of coordination on grid design, development and finance implies that system costs will be between €25 and €75 billion higher over the next 25 years".*

In a briefing paper called "Delivering the North Seas grid, towards a regional free trade of electricity", E3G proposed in April 2015 to the Energy Ministers of the North Seas region to take action by agreeing on a new mandate and electricity strategy for the development of the North Seas grid. Indeed, it claimed that different governments in the North-Seas region were failing to push investments effectively as no forward-looking regional electricity strategy is available, and that financing sources for coordinated offshore grid development were holding back due to regulatory and political risks. It argued that the Commission should propose a strategic roadmap which sets a clear timeline for identification and implementation of priority projects, by creating a dedicated project team which could broker a ministerial-level agreement regarding grid development, finance and market design:

- Strategy coordination, legal framework, and regional network development: The project team should broker an International Agreement following a shared strategy between energy ministers. This should set clear objectives for the exploitation of offshore wind resources and for the development of the offshore grid. Moreover, it should allow the creation of a regulatory institution. This institution should keep oversight of the strategic network design and have the authority to evaluate and approve future investment plans.
- Financing through a Special Purpose Vehicle (SPV): The project team should establish a dedicated investment platform to increase the availability of private sector capital. Such a platform is necessary to decrease the political and regulatory risk and as a consequence to lower the cost of capital by increasing visibility and the scaling up of projects.
- Market design: a 'North Seas renewables free trade zone' should be brokered allowing renewables to freely trade across different borders.

Apart from the objectives for the dedicated project team, the document highlights the benefits that can arise from optimized grid infrastructure. These include energy security, competitiveness, industrial development, and environmental benefits.

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7.8.4 NORTHSEAGRID PROJECT

Key takeaways oft he NorthSeaGrid project on regulation and financing issues [112]

- *"Conventional methods to allocate the costs and benefits of cross-border projects sometimes result in highly unbalanced outcomes, making it less likely that concerned countries decide to build such projects. Instead, the so-called 'Positive Net Benefit Differential' methods should be applied consistently as a pivotal point of departure for negotiations on the financial closure of investments in cross-border (integrated) offshore infrastructures. "*

Apart from the techno-economic analysis of three case studies (German Bight, Benelux – UK, and UK-NO) detailed in section 2.1.2, the NorthSeaGrid project also assesses financial and regulatory barriers related to these case studies and it provides recommendations and solutions for these barriers [112]. For each of these three cases the costs and benefits are calculated and a qualitative risk analysis is performed. Afterwards these costs and benefits are allocated by means of a CBCA. For the costs, three cross-border allocation methods were tested: the conventional method (50-50 rule), the Louderback method, and the positive net benefit differential. Results show that the latter one is preferred.

The barriers are divided in four categories: support schemes, grid access, OWF operation and grid operation. Hereby, the grid access category is further split into grid access responsibility, connection design, priority grid connection and definition connection to shore. The OWF operation category is further split in balancing responsibility and ancillary services. Finally, grid operation is split into transmission charges, priority feed-in, cross-border capacity allocation, gate closure time and imbalance prices. Note that these subcategories are assessed for the three cases shown in Figure 2.4 (German Bight, Benelux-UK, UK-NO). The identified barriers are:

- Support schemes: When participation in the support schemes of other countries is viable, the level of remuneration can strongly affect the preferred feed-in direction of the OWF. This could lead to congestion towards the country with the highest remuneration.
- Grid access responsibility: a barrier arises when an OWF located in the EEZ of country A has to be connected to country B. In this case, the responsibility could be denied by both TSOs.
- Connection design (hub versus radial): Years in advance, the location of the cables and converter stations are planned, especially for hub design. If an OWF gets connected to an interconnector, it could lead to a decreased use of the hub design, resulting in stranded investments.
- Priority grid connection: Due to country differences regarding priority grid access, it could be the case that the OWF gets connected to one country (priority) but that the connection to the other is delayed as no priority is in place. This could limit the total feed-in of the OWF. In such a case, liability and compensation should be clearly defined.
- Definition connection to shore: this is not a barrier in all 3 cases as the four countries involved all define the connection to shore as part of the transmission system or as part of the OWF.

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- Balancing responsibility: different rules amongst different countries could lead to unequal treatment of the OWF operators, leading to uncertainty for potential investors.
- Ancillary services: OWFs that feed into multiple countries can only provide one type of LVRT capabilities. If the LVRT requirements for these countries differ, a barrier can rise.
- Transmission charges: if transmission charges differ between countries, congestion towards countries with the lowest charges could occur.
- Priority feed-in: differences between country rules regarding priority feed-in and compensation mechanisms for curtailment.
- Cross-border capacity allocation: this doesn't seem to be a major barrier. Coordination amongst countries is needed however.
- Gate closure times (Intraday): different gate closure times can result in a distortion of competition.
- Imbalance price: A uniform imbalance price between countries does not seem necessary, as the imbalance payments are also driven by national supply and demand characteristics.

Note that some of these barriers are (partly) covered by existing European legislation. The remaining barriers include the grid access responsibility and the connection design. Also the barriers regarding transmission charges, priority feed-in, and support schemes remain partly open.

The related recommandations are:

- Regarding the remuneration for renewable generators: the generation should receive the remuneration of the country in which it is located, irrespective to which country is connected. Compensation mechanisms between the affected countries are set up to attain a fair cost distribution. Finally, a compensation mechanism should be installed to ensure that the country supporting the generation also receives the credits for it.
- A redesign of national support schemes could facilitate offshore generation development.
- Regarding the grid access responsibility for the connection of an OWF located in the EEZ of country A and connected to country B, a European TSO fund is proposed which is funded by all TSOs. An offshore north-sea grid development plan should be established (by ENTSO-E and verified by ACER). This plan should maximize social welfare and the development is financed by the European fund.
- Grid connection: this barrier could be best addressed via an inclusion into the network codes.
- Transmission charges: corrections should be agreed on a bilateral level.
- Priority feed-in and compensation of curtailed production: the latter aspect is not yet included in European regulation. A possibility is to start compensation as soon as a certain level of annual curtailment is reached.

7.8.5 FLOW PROJECT: TOWARD A TRANSNATIONAL NORTH SEA MESHED GRID, DEC. 2015

Key takeaways [113]

- *"Despite varying perspectives of organizations, they generally agree that a meshed transnational grid serves best the objectives of economic and technical efficiency, security of supply, integration of the European energy market, and integration of Offshore Wind (OSW) in the European grid."*

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This document [113] reviews the perspectives of several instances (the European Union, the Offshore Grid Project, the North Seas Countries Grid Initiative, ENTSO-E, and Greenpeace) on transnational meshed grid development. It focusses on existing international legal frameworks and national laws and regulations regarding grid construction and subsidy schemes. It also highlights these existing uncertainties with illustrations from the Kriegers Flak and COBRA project. The report argues that although the reports reviewed are written by organisations with different interests, they all conclude that a meshed grid can lead to economic and technical benefits compared to point-to-point solutions. However, current practice shows that OSW facilities are still radially connected. This follows from short term targets regarding the 2020 objectives and from regulation as the international and European framework for transnational grids is uncertain. As radial connections often fall within existing national legal and regulatory frameworks, this path is easier for TSOs to realize. Nevertheless, this brings higher costs and also harms the subsea environment due to the need for a higher amount of cables.

Several barriers for the development of a transnational meshed grid are discussed:

- Incompatible international legal structures. UNCLOS formalizes the territorial boundaries of coastal states at 12 nautical miles, while the Exclusive Economic Zone (EEZ) is set to 200 nautical miles. In territorial waters the coastal states have exclusive sovereign rights. In the EEZ, coastal states have sovereign rights for the exploitation of natural resources including wind and for the protection of the environment. While other countries have the legal right to lay transit submarine cables in another's EEZ, the EEZ's respective coastal state has the legal jurisdiction to authorize and regulate construction, building and operation of structures. Regarding OSW, UNCLOS' legal structure is uncertain. Four different options can be considered. In the first, the OSW farm is constructed within a state's own EEZ. In this case no problems occur as the complete jurisdiction falls with the coastal state. In the second option, the OSW is constructed in country 1 but connected to the onshore grid of country 2. In option 3 the OSW is connected to an interconnector in country 2. In option 4, a transnational offshore transmission network is envisioned in which multiple states are involved. Note that for options 2 to 4 considerable uncertainty exists.
- Incompatible national energy laws. As TSOs have different mandates and subsidy/incentive schemes, currently transnational coordination seems difficult to achieve due to the complexity.
- Lack of EU regulatory guidance as international law, EU and national legal and regulatory frameworks are incompatible
- Varying technology configurations of national offshore networks can limit future grid integration.
- Uncertainties for TSOs, wind farm developers and operators.
- States still need to put coordinated solutions on their agenda. Currently, they are still following national targets.

Apart from barriers, also recommendations for transnational meshed grid development are discussed:

- Agreement in view of interoperability and standardization.
- New regulation for offshore networks is needed.
- Reassess unbundling laws for offshore developments

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- As OSW develops, instead of developing new offshore regulations considering the national level, aim at coordinating regulatory regimes internationally.
- Regional treaties, established within the current legal framework, could be useful to stimulate coordination of an offshore grid. The establishment of a single regulatory authority is suggested in various studies.
- A joint subsidy scheme could foster coordinated development
- Priority grid access policies for RES should be reassessed.
- Creating EU exemption policies for OSW could incentivize coordinated development.

7.8.6 OTHERS

Apart from the studies as listed above, some other relevant studies and projects provide information regarding regulation and finance. Some examples are the following:

- OffshoreGrid focused on offshore electricity grid infrastructure in Europe. This techno-economic study, running from 2009 to 2011, provides a deep analysis of costs and benefits from different offshore grids. Due to the early publication date of the final deliverable (2011) and due to the limited focus on regulation, this report is not covered in this Chapter of D1.3.
- Seanergy 2020 focused on marine spatial planning (MSP). This project ran from 2010 to 2012 and assessed existing national MSP practices, international MSP practices, and the challenges and opportunities of moving from national to a transnational MSP approach. Note that these aspects are partly covered in the studies above. Nevertheless, for a detailed overview, Seanergy 2020 provides the necessary information.
- The report on “The structuring and financing of energy infrastructure projects, financing gaps and recommendations regarding the new TEN-E financial instrument” written by Roland Berger for the European Commssion in 2011 [114] discusses three main topics: the structure (volumes, financing structure, sources, and financing capacity) of energy transmission investments, the financing challenges, and the measures and instruments to overcome these challenges. The document considers transmission investments in general, but the barriers and recommendations are also relevant for offshore transmission investments.
- A. Henriot, “Financing investment in the European electricity transmission network: Consequences on long-term sustainability of the TSOs financial structure,” Energy Policy, 2013 [115] : This paper assesses the ability of European TSOs to meet the substantial investment need for the electricity transmission grid for the next 20 years. To this end, several alternative financing strategies are assessed. The analysis shows that given the current evolution of transmission tariffs only half of the planned investments can be funded. This document focusses on transmission in general, but results are also linked to the investment in offshore transmission.
- K. Bell et al., “Considerations in design of an offshore network,” Cigré session, 2014: In this paper, apart from engineering and economic issues, regulatory issues regarding offshore networks are discussed. These include the role and responsibilities of transmission owners and the sharing of costs and benefits.

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- In 2014, the ENTSO-E Working Group Economic Framework published a policy paper on “Fostering Electricity transmission investments to achieve Europe´s energy goals: Towards a future-looking regulation” [116]. In this paper, ENTSO-E aims to identify barriers for TSOs regarding transmission investments.In particular, the insufficient coordination of regulatory frameworks between EU-countries and the lack of attention on the financeability aspect of transmission investment are pointed out as two main barriers. It also provides recommendations for national and European policy makers and regulators. ENTSO-E proposes a toolkit with regulatory instruments which can be used by policy makers to create an appropriate regulatory framework for TSOs.
- EC, Study on comparative review of investment conditions for electricity and gas transmission system operators in the EU, 2015: This report assesses the balance between the investment requirements and financing capabilities of European TSOs. In this perspective, it is investigated whether TSOs are able to realize new projects and how these new projects will impact the balance sheet. Different financing sources are hereby considered and the potential impact on the transmission tariff is examined. Note that the focus of this document is both on gas and electricity and that it covers both onshore and offshore projects.

7.9 DISCUSSION

This chapter provides an overview of key reports regarding the regulation and financing of transnational infrastructures (such as a meshed offshore grid). To this end, several recent reports are reviewed in depth. These include amongst others the main European projects such as TWENTIES, ISLES, NSCOGI, E-highways, and the EC report on regulatory matters for offshore grid development. The important elements of each report are highlighted in this chapter, distinguishing between the key takeaways, the main content, the existing barriers, and the recommendations. The purpose of the reviews is to provide an overview of the state-of-the-art regulatory and financial aspects. This can be used as a starting point for other work packages of the PROMOTioN project such as WP7: Regulation and Finance.

Five general observations can be derived from the literature review:

- First, the literature review showed that the amount of aspects covered within the regulatory and financial framework for transnational infrastructures is vast. Therefore, several categories were defined starting from the non-functional requirements of D1.1. Hereby, distinction is made between energy policy aspects, legal and regulatory aspects, financial-economic aspects and market aspects. For each category, several topics are defined. Reviewing the reports, it was observed that some reports provided a detailed analysis on a few specific topics, while others aimed at providing a global overview of regulation and finance.
- Second, the literature review showed that some topics are already better covered by existing literature than others. For example, although barriers remain, various reports exist which focus on consenting and planning of offshore infrastructure. On the contrary, the amount of literature on the financing mechanisms for offshore meshed grid is still limited, while this is a considerable barrier for

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development. Although general literature on the financing of cross-border projects is available, dedicated documents for meshed offshore infrastructure is partly lacking.

- Third, the review also revealed that regarding some topics, alignment between the different reports exists. An example is that offshore wind farms should be charged for the asset connection in the same way as radially connected wind farms. Another example is the recommendation to assign clear responsibilities and liabilities for project delays.
- Fourth, although in general the barriers and recommendations align between the different reports, several reports propose different and sometimes conflicting recommendations to attain transnational infrastructure development. While several reports recommend to align national support schemes, to appoint a single TSO or to harmonize grid rules, H.K. Müller states that these solutions are not feasible as they don't account for the legal context of international and EU law as well as for the choices under national law.
- Fifth, it was also shown that over the last years, several perceptions on regulation and finance of transnational infrastructures have changed. This is for example the case for the determination of bidding zones for offshore wind turbines. While in 2012, NSCOGI discarded the creation of a separate bidding zone for offshore renewables, they revised their point of view in 2014 stating that the creation of a separate zone is an option worth considering.

Finally, it can be concluded that, while progress is made, barriers regarding the regulatory and financial aspects of the development of transnational asset remain. While these barriers are not unsurmountable, action has to be taken. The PROMOTioN project is an important step in this direction. Another initiative which could foster development is the recently signed political declaration for closer energy cooperation between the North Seas region countries (including Belgium, Denmark, France, Germany, Ireland, Luxembourg, the Netherlands, Norway and Sweden). This initiative aims at facilitating the cost-effective deployment of offshore RES through voluntary cooperation in four work areas: maritime spatial planning, development & regulation of offshore grids & other infrastructure, support framework & financing, and standardization & technical rules.

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APPENDIX A: ASSUMPTIONS ON TECHNOLOGIES, COSTS AND RELIABILITY OF COMPONENTS

Offshore grid planning studies presented in Chapter 2 used various assumptions on the available HVDC technologies, on expected technological developments, on the costs of HVDC technologies and on their reliability. The purpose of this Appendix is to compare and to analyse these various assumptions. Section A.1 summarizes the assumptions made on technologies. Because the PROMOTioN project will use the most recent information, assumptions are more developed for recent projects and studies. Then, Section A.2 compares the costs used and Section A.3 gathers the assumptions on reliability performances. Note that the purpose of this Appendix is not to provide the current status of technologies. Therefore, this review may not give up-to-date information on available technologies and their costs. An analysis of currently available technologies will be presented in Deliverable 1.6.

A.1 ASSUMPTIONS ON TECHNOLOGIES

A.1.1 WINDSPEED PROJECT

At the moment of the WindSpeed project (2008-2011), the VSC HVDC technology was relatively new. Nevertheless, several VSC HVDC links based on two-level converters were already in service in the beginning of the WindSpeed project, and the first VSC HVDC link based on MMCs, the 400 MW Trans Bay Cable, was commissioned during the project in 2010. Therefore, the WindSpeed project stated that, although existing HVDC multi-terminal systems were based on the CSC technology, the VSC technology was more appropriate for offshore MTDC systems with OWFs. The WindSpeed project made use of 600 MW converters.

The WindSpeed project assumed that mass impregnated cables are used for CSC HVDC links (i.e. oil/paper insulated cables are the only viable cables for CSC), but that, for VSC HVDC links, the normal choice is extruded polymer insulated cables. In both cases, only 600 MW (two poles) cables are used.

The WindSpeed project also assumed that DCCB were needed when using the VSC technology, but there was at that moment a high uncertainty on the cost of such circuit breakers and related switch gear.

A.1.2 OFFSHOREGRID PROJECT

The OffshoreGrid project (2009-2011) considered the possible use of six different HVDC converters: three for CSC converters and three for VSC converters. It was assumed that CSC converters in bipolar configuration were already available in ±150 kV (up to 500 MW), in ±250 kV (up to 1000 MW) and in ±500 kV (up to 2000 MW). In contrast, it was assumed that VSC converters in symmetrical monopolar configuration were already

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available only in ±150 kV (up to 500 MW) and in ±320 kV (up to 1000 MW), but were going to be available in ±500 kV (up to 1000 MW) only after 2020. Similarly, 150-kV and 320-kV XLPE cables were considered to be already available, but 500-kV XLPE cables were assumed to be available only after 2020.

The methodology used on the offshore grid designs has been to use DC fault isolation equipment (such as DCCB) to prevent any power infeed loss to onshore AC transmission systems exceeding the amount of frequency control reserve held by the onshore system. Even if DCCBs were not commercially available at that moment, the OffshoreGrid project assumed thus the availability of adequate DCCBs in the near future, based on discussions with manufacturers.

A.1.3 NORTHSEAGRID PROJECT

The NorthSeaGrid project assumed the availability of ±500 kV VSC converters with a symmetric monopolar configuration and corresponding 500-kV XLPE cables. The availability of DCCB is also assumed.

A.1.4 TWENTIES PROJECT

For the network design studies in the Twenties Project as proposed in [7] mainly 2-level VSC converters have been used. The characteristics were taken from the ABB HVDC Light technology. A bipolar symmetrical configuration with a rated voltage of ±320 kV was chosen. Three possible active power sizes for converters were proposed: 370, 740 and 1110 MW. Three possible sizes of submarine cables were assumed: 300, 1200 and 2400 mm², with capacities up to 662, 1458 and 2170 A, and resistances of 0.0601, 0.0151 and 0.0073 Ω/km. The Twenties project also assumed the availability of appropriate DCCBs. In other deliverables of Twenties which were amongst others related to load flow control and fault scenarios various converter topologies, like half-bridge modular multilevel converters in a symmetrical monopolar configuration etc. were also investigated. [117]

A.1.5 NSCOGI STUDY

In [118], the regional group “North Sea” for the NSCOGI analysed the current HVDC capabilities and the expected developments of offshore transmission technologies. At that moment, in 2011, several VSC links operated in the 400 MW range at ±200 kV and several point-to-point VSC connections in the 800-1000 MW range at ±300 kV or ±320 kV were under construction, but also a 700 MW monopolar link at +500 kV (Skagerrak 4). This implied thus the capability for a 1400 MW VSC HVDC system at ±500 kV. It was then expected that a current rating of IGBTs up to 2000 A would be achievable by 2017, leading to 2000 MW systems at ±500 kV. Nevertheless, the report [118] underlied that the manufacturers needed a signal from the industry that a 2 GW VSC HVDC system is needed in order to actually develop it. The report also emphasized that the development of VSC HVDC systems has raised the possibility of developing a MTDC system where the power flows are not constrained in direction, even if a working VSC multi-terminal HVDC system has not yet been demonstrated. The lack of standardisation among manufacturers was detected as the main challenge to the successful

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development of a multi-terminal HVDC system, as well as the lack of full size demonstration projects. Another detected barrier for the development of MTDC systems was the lack of appropriate DCCBs at that moment.

When [118] was written, the maximum capacity of installed mass impregnated paper cables was 660 MW/cable at 500 kV and the maximum planned capacity of such cables was 800 MW/cable at 500 kV. For this type of cable, the near term achievable rating was assumed to be 1500 MW/cable at 600 kV. For XLPE cables, the maximum installed rating was 200 MW/cable at 200 kV and the maximum planned rating was 500 MW/cable at 320 kV (so 1 GW for a bipolar configuration). For this type of cable, the near term achievable rating was assumed to be 1000 MW/cable at 500 kV (so 2 GW for a bipolar configuration).

A.1.6 E-HIGHWAY2050 PROJECT

In the framework of the e-Highway2050 project, a technological database covering, among others, HVDC was created. For each kind of HVDC technology (i.e. CSC and VSC), a list of critical techno-economic parameters was identified. For each parameter, values were gathered from a literature review and from the expertise of the project partners. Cost and performance trajectories from today to 2050 were then defined. Furthermore research, development and demonstration (RD&D) and standardization needs over the period 2015-2030 were also identified. The main conclusions are summarized in this section.

Transmission losses

Today the losses per VSC station are around 1% of rated power against 0.70% of rated power for CSC. Losses in transformers, reactors and auxiliary losses account for a major part of the losses. They have been reduced (from a level of 3 % in 1999) thanks to three main developments, which are expected to continue in the coming decades:

- Development of semiconductors
- The use of improved topologies
- The modulation principle

As a result by 2050, the losses per VSC station are expected to reach the same values as those of the more mature CSC converter technology, i.e. 0.50% of rated power.

Transmission capacity

Transmission capacity is directly proportional to the voltage and current of the DC-circuit:

- The increase in voltage for the converter posed a challenge before the introduction of the multi-level converter since the converter valve was built on series-connection of IGBTs; the introduction of multi-level converter reduced the switching voltage at each time drastically and became independent from the DC-voltage level. This implies that the overall dielectrical properties do limit the DC-voltage from a converter perspective and all the findings concerning the CSC HVDC development where 800 kV exist can be reused.

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- The current rating is dependent on the development of semiconductors. Today the step from 600 A to 2000 A has been achieved for IGBT technology. CSC installations use thyristors which can be used up to 4-4.5 kA.

As a result, maximum transmission capacity of converters reaches today the following levels:

- CSC technology schemes are now in service at DC voltages up to ±800 kV and power levels up to 8000 MW.
- In the last 15 years the VSC technology capability has risen from some hundreds of MW (e.g. the 330 MW Cross-Sound Cable was commissioned in 2002) to around 1 GW with one symmetric monopole transmission system.

Key challenges for the future are the development of new types of semi-conductors, novel multi-level switching topologies with more parallel components and higher power ratings in operation. More specifically in the shorter term (i.e. the next decade) such HVDC techno-economic challenges will include:

- New types of semiconductors (SiC , diamond, etc.) which will allow the development of new thyristors;
- Development of novel multi-level switching topologies (architecture and switching modes, paralleling components) to enhance transmission capacity.

In a longer run, it is expected that ultra-high voltage DC (UHVDC) will be implemented. Related technological challenges include: air insulation of water cooled thyristor valves, transformer oil/paper insulation, numerical analysis tools to UHVDC designs, etc.

Maximum transmission distance at an acceptable level of losses

The maximum transmission distance for HVDC systems are resulting from techno-economic constraints. Today the maximum installed length of the line/cable is about:

- 2000 km (OHL) and 580 km (cables) for CSC
- 1000 km (OHL) and 300 km (cables) for VSC

At 2050 the maximum length of the line/cable between two nodes of the system is expected to reach 3000 km (OHL) and 1000 Km (cables) both for CSC and VSC. The rationale behind these projections is that the losses in the cable/OHL shall be reasonable, i.e. they have to be tolerable for the complete system. Approximately 10% is considered as acceptable.

A.1.7 ENTSO-E TYNDP2016

A part of the TYNDP2016 [11] details the assumptions on technologies for transmission system used for the proposed network development plan based on the National Grid Ten Year Statement 2015. The TYNDP2016 notes that the largest scheme in service at the moment of writing was the 2×1000 MW, ±320kV INELFE project (France-Spain) and the highest voltage was on the 700 MW Skagerrak Pole 4 project at 500 kV (Norway-Denmark). Furthermore, the North Sea Network (NSN) project at the moment under construction between the UK and Norway will be operated as a bipole at 1400 MW and ±525 kV. Consequently, it was supposed that the VSC technology was already available for converters of 1000 MW and ±320 kV, and for converters of 1400 MW and ±525 kV. Converters of 2500 MW at ±600 kV using the VSC technology are expected to be available for a commissioning no sooner than 2025. Similarly, extruded (XLPE) cables at ±320 kV and ±525 kV were

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considered to be already available, while extruded cables at ±600 kV are expected to be potentially in service after 2025, depending on actual contracts. Mass impregnated cables up to ±600 kV were already available.

A.2 ASSUMPTIONS ON COSTS

The main costs that will be encountered in the development of an offshore grid are the cost of converters, the cost of cables, the cost of offshore platforms and the cost of DCCBs.

A.2.1 COST OF CONVERTERS

Table A.1 compared the costs used for VSC converters in various studies.

VOLTAGE (KV)	POWER (MW)	COST (M€)						
		WINDSPEED	TWENTIES	ISLES	NSCOGI	NORTHSEA GRID	TE/PWC/ ECOFYS	E-HIGHWAY 2050
300/320	300	/	/	44	/	/	/	59
	500	/	/	63	75-92	/	75-92	79
	600	136	/	/	/	/	/	87
	850	/	98-105	/	98-105	/	98-105	111
	1000	/	/	138	/	/	/	125
500	700	/	/	/	/	87-98	/	97
	1000	/	/	/	/	110-128	/	125
	1250	/	121-150	/	121-150	/	121-150	148
	1400	/	/	/	/	130-160	/	162
	2000	/	144-196	/	144-196	/	144-196	218

Table A.1. VSC HVDC converter station costs

A.2.2 COST OF CABLES

Table A.2 compared the costs used for submarine cables in various studies.

VOLTAGE (KV)	POWER (MW)	COST (M€/KM) – INCLUDING INSTALLATION, FOR TWO POLES						
		WINDSPEED	TWENTIES	ISLES	NSCOGI	NORTHSEA GRID	TE/PWC/ ECOFYS	E-HIGHWAY 2050
300/320	300	/	/	0.9	/	/	/	/
	500	/	/	1.1	/	/	/	/
	600	1.2	/	/	/	/	/	/
	700	/	/	/	/	/	/	1.9
	850	/	/	/	1.2-3.0	/	/	/
	1000	/	/	1.9	1.3-3.1	/	2.1	2.6
500	700	/	/	/	/	1.8-2.3	/	/
	1000	/	1.2-1.7	/	1.3-3.3	1.9-2.5	/	/
	1250	/	/	/	1.4-3.3	/	/	/

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	1400	/	/	/	1.4-3.5	2.0-2.6	1.9	/
	2000	/	/	/	1.6-3.6	/	2.3	/

Table A.2. HVDC submarine cable costs

A.2.3 COST OF OFFSHORE PLATFORMS

Table A.3 compared the costs used for offshore platforms in various studies.

WEIGHT (TONNES)	COST (M€)						
	WINDSPEED	TWENTIES	ISLES	NSCOGI	NORTHSEA GRID	TE/PWC/ ECOFYS	E-HIGHWAY 2050
2000	/	/	/	66-91	/	/	/
2500	/	/	/	85-108	/	/	/
3500	/	/	/	129-154	/	/	/
8000	/	/	/	261-324	/	/	/
Not specified	31	70	1-123	/	127-340	66-324	/

Table A.3. Offshore platform costs

A.2.4 COST OF CIRCUIT BREAKERS

Table A.4 compared the costs used for DCCBs in various studies.

RATING (MW)	COST (M€)						
	WINDSPEED	TWENTIES	ISLES	NSCOGI	NORTHSEA GRID	TE/PWC/ ECOFYS	E-HIGHWAY 2050
350	/	/	/	/	10-50	/	/
1000	/	40	/	/	/	/	/
Not specified	40	/	/	/	/	18	/

Table A.4. DCCB costs

A.3 ASSUMPTIONS ON RELIABILITY OF COMPONENTS

Table A.5, Table A.6 and Table A.7 gather the failure rates of cables, the failure rates of others components and the mean time to repair of all components, respectively.

COMPONENT	FAILURE RATE (/100KM.YEAR)						
	WINDSPEED	TWENTIES	ISLES	NSCOGI	NORTHSEA GRID	TE/PWC/ ECOFYS	E-HIGHWAY 2050
Submarine cable	/	0.0998	/	/	0.1114	/	/
Underground cable	/	/	/	/	0.1330	/	/

Table A.5. Failure rates of cables.

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COMPONENT	FAILURE RATE (/YEAR)						
	WINDSPEED	TWENTIES	ISLES	NSCOGI	NORTHSEA GRID	TE/PWC/ ECOFYS	E-HIGHWAY 2050
Converter	/	1.40	/	/	/	/	/
DC circuit breaker	/	0.075	/	/	/	/	/

Table A.6. Failure rates of components.

COMPONENT	MTTR (HOURS)						
	WINDSPEED	TWENTIES	ISLES	NSCOGI	NORTHSEA GRID	TE/PWC/ ECOFYS	E-HIGHWAY 2050
Submarine cable	/	1440	/	/	1440	/	/
Underground cable	/	/	/	/	600	/	/
Offshore converter	/	4.1	/	/	24	/	/
Onshore converter	/	4.1	/	/	4.3	/	/
Offshore DC circuit breaker	/	3	/	/	24	/	/
Onshore DC circuit breaker	/	3	/	/	3	/	/

Table A.7. Mean time to repair of components.

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APPENDIX B: QUANTIFICATION OF REQUIREMENTS

As explained in the introduction, PROMOTioN is based on three technical pathways and on a financing and regulation pathway. All these pathways are necessary to achieve the development of an offshore grid in the North Seas. For this reason, consistency and compatibility of the results of each pathway (and, thus, of each WP) must be ensured. This is one of the objectives of WP1, performed through the definition of a common set of equal requirements for all pathways. This set gathers the requirements that should be met by an offshore grid and the wind farm connected to it. In Deliverable 1.1, the PROMOTioN consortium agreed on a first definition of these requirements. However, the definition at that stage was only qualitiative. The next step is the quantification of these requirements[15]. The quantification has to rely (partially) on previous studies that have already been carried out in the area of offshore grid topologies. Indeed, conclusions that have been reached previously must be used to guarantee the relevance of the chosen values for the defined requirements. The objective of this Appendix is to summarize the relevant information for the quantification process that can be found in previous major studies.

Among the major past studies analysed within Task 1.2 and presented in this deliverable, only the following ones contain relevant information for the quantification process: Twenties, Best Paths and Medow. Twenties is a completed study and all deliverables can thus be analysed. Best Paths is an ongoing study and, at the time of writing, only its deliverable D2.1 is publicly available. Medow is a consistent set of PhD theses and did not result in any global deliverable. Consequently, Medow is excluded in the analysis for the quantification of requirements.

In Deliverable 1.1, it was decided to classify requirements according to the four main areas of interactions that an offshore grid can have:

- The interface between the HVDC offshore grid and the AC onshore grid,
- The interface between the HVDC offshore grid and the offshore generation,
- The interface between the HVDC offshore grid and the offshore consumption,
- The HVDC offshore grid itself (interactions within the grid).

Additional requirements were defined for the behaviour of the overall system in the category “Functional system requirements” and other possible requirements imposed by stakeholders that influence the feasibility of an offshore grid were listed in the category “Non-functional requirements”. Because the quantification of requirements will focus on the functional requirements linked to the main areas of interactions, this Appendix summarizes only relevant information that can be found in Twenties and Best Paths dealing with these

[15] The decided quantification of requirements will be given in Deliverable 1.5

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requirements. The presentation follows the classification proposed in Deliverable 1.1, in particular for the four main areas of interactions.

B.1 REQUIREMENTS LINKED TO THE INTERFACE BETWEEN THE HVDC OFFSHORE GRID AND THE AC ONSHORE GRID

B.1.1 REQUIREMENTS 4.2.1 – REQUIREMENTS FOR ACTIVE POWER CONTROL AND FREQUENCY SUPPORT

Requirement 4.2.1.3 – Requirements related to frequency control

In its Deliverable D5.3b [21], the Twenties project makes use of a relation between onshore AC grid frequency and MTDC voltage for disturbed operation of the AC grid is established by the following formula:

$$V_{DC} = V_{DC}^{0} - k_{fv} \cdot f_{grid}$$

where V_{DC} is the reference value for the DC voltage at the onshore HVDC-VSC, V_{DC}^{0} is the predisturbance DC voltage resulting from the operation of the converter in the normal mode governed by the k_{pv} droop, k_{fv} is the frequency/DC voltage droop and f_{grid} is the frequency of the onshore AC grid to which the converter is connected. Figure B.1 shows the corresponding droop control mechanism. In order to avoid stressing the offshore wind farm, it is suggested that the onshore HVDC-VSC should switch its operation mode from "normal" droop control based only on DC voltage to this one according to a specific frequency dead-band. The value of 20 mHz is suggested.

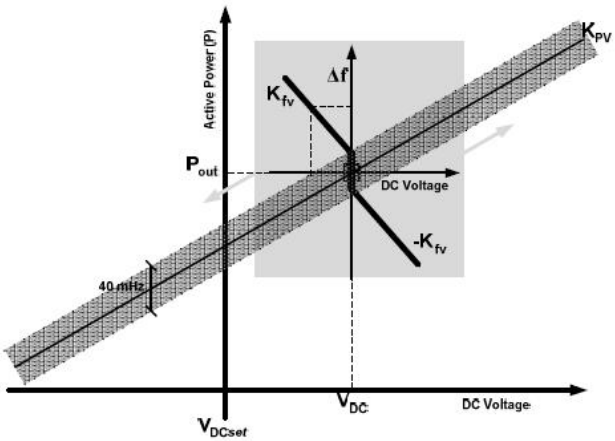

Figure B.1. Droop control mechanisms for HVDC onshore converter stations used in Twenties.

B.1.2 REQUIREMENTS 4.2.2 – REQUIREMENTS FOR REACTIVE POWER CONTROL AND VOLTAGE SUPPORT

Requirement 4.2.2.5 – Priority to active power or reactive power contributions

In its Deliverable D5.2b [20], the Twenties project makes use of the following assumptions for active and reactive power contributions during faults. When the current limiting strategy gives priority to the d-axis component, the limit on i_d is set to 1 pu, and when the current limiting strategy gives priority to the q-axis component, the limit on i_q is set to 0.8 pu. In both cases, the short-term overloading capability of the VSC is equal to 10% (i.e. in the first case, i_q is limited to 0.46 pu, and, in the second case, i_d is limited to 0.76 pu). The time duration of the short-circuit is 100 ms (self-extinguishing short-circuit).

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Requirement 4.2.2.6 – Power quality

In its Deliverable 2.1 [34], the Best Paths project considers that the level of harmonics of AC voltage should be below 10%.

B.1.3 REQUIREMENTS 4.2.3 – REQUIREMENTS FOR FAULT RIDE THROUGH CAPABILITY

Requirement 4.2.3.1 – Fault ride through capability

In its Deliverable 2.1 [34], the Best Paths project considers that each DC converter must remain transiently stable and connected to the system for a three-phase short circuit fault or any unbalanced short circuit fault in the onshore transmission system with a clearance time lower than or equal to 140 ms. There is no detailed information about the origin of this value, but the purpose is to evaluate if the controllers developed during the project fulfil the requirements specified in grid codes.

Requirement 4.2.3.3 – Post-fault active power recovery

In its Deliverable 2.1 [34], the Best Paths project considers that each DC converter must provide at least 90% of the active power available immediately before the fault, upon both clearance of the fault on the onshore transmission system and within 0.5 seconds of the restoration of the voltage at the interface point to within 90% of the nominal. There is no detailed information about the origin of this value, but the purpose is to evaluate if the controllers developed during the project fulfil the requirements specified in grid codes.

In its Deliverable 5.3b [21], the Twenties project states that the grid codes for UK and Ireland impose requirements on wind farms to provide at least 90% of their maximum available active power as quickly as the technology allows and within 1 second of the transmission system recovering to the normal operating range. This statement is directed towards wind farms, but might be used as an indication.

B.1.4 REQUIREMENTS 4.2.4 – REQUIREMENTS FOR CONTROL

Requirement 4.2.4.3 – Power oscillation damping capability

The obtained results in Deliverable 5.3b [21] of Twenties demonstrate that MTDC systems do not participate in the electromechanical modes of oscillation, but when properly designed, PSS based controllers installed in the AC side VSC-HVDC converter stations can contribute for increasing the system damping levels. The following boundaries are set: a minimum damping level of 15 % and a maximum deviation of oscillation frequencies of 5 %.

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B.2 REQUIREMENTS LINKED TO THE INTERFACE BETWEEN THE HVDC OFFSHORE GRID AND THE OFFSHORE GENERATION

B.2.1 REQUIREMENTS 5.1.2 – REQUIREMENTS FOR OFFSHORE WIND FARMS (OWFS), ROBUSTNESS AND CONTROL DURING SHORT-CIRCUIT FAULTS

Requirement 5.1.2.1 – Offshore AC fault-ride-through

Deliverable 5.2b [20] of Twenties defines a general shape of the voltage-time curve defining the region in which wind generators are not allowed to trip is the following, as shown in Figure B.2. Values for different system operators are given in Figure B.3.

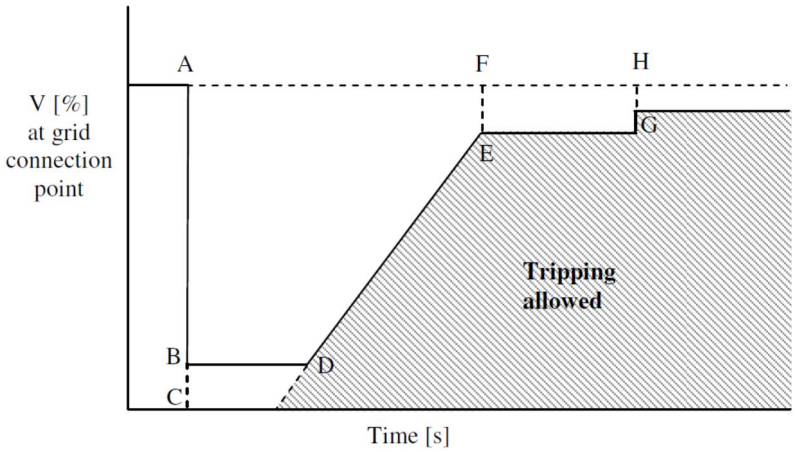

Figure B.2. Generic voltage-time curve used in Twenties.

Grid Code	BC	BD	AF	FE	AH	HG
Denmark	25%	0.1s	0.75s	25%	10s	N.A.
Germany	0%	0.15s	0.15s	30%	0.7s	10%
Ireland	15%	0.625s	3s	10%	N.A.	N.A.
Spain	20%	0.5s	1s	20%	15s	5%
Spain (Canary Islands)	0%	0.5s	1s	20%	15s	5%
UK	0%	0.14s	1.2s	20%	2.5s	15%
Portugal	20%	0.5	1.5s	20%	10s	N.A.

Figure B.3. Values of the generic voltage-time curve used by different system operators.

Requirement 5.1.2.4 – DC fault-ride through

In its Deliverable 2.1 [34], the Best Paths project considers that the maximum power ramp rate solicitation to any WTG to assure Wind Park stability after DC fault is defined to 1 MW/s.

Requirement 5.1.2.5 – Onshore AC fault-ride-through

In its Deliverable 5.2b [20], the Twenties project provides an example showing the time to reach a DC-link overvoltage of 1.2 pu as a function of the power not being delivered to the AC grid (active power drop) in case of a 400 MW VSC-HVDC converter station with 75 µF DC capacitor (see Figure B.4). The maximum time to

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perform the active power accommodation/dissipation in order to avoid the DC voltage to overpass the maximum admissible value, which can be as low as 10 ms for severe faults leading to almost zero active power injection into the AC grid. A cited reference [119] showed that, for a specific test case, OWFs should be able to reduce their power from 50 MW to 0 MW in 24 ms in order to remain connected during the fault.

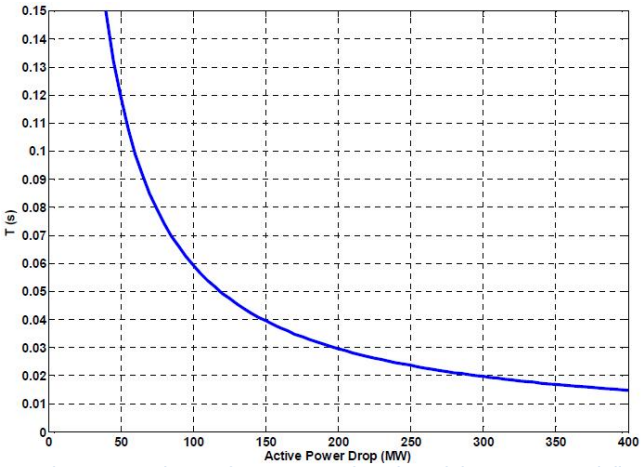

Figure B.4. Time to reach an overvoltage of 1.2 pu as a function of the power not delivered to the AC grid.

B.2.2 REQUIREMENTS 5.1.3 – REQUIREMENTS FOR OFFSHORE WIND FARMS (OWFS), VOLTAGE STABILITY

Requirement 5.1.3.2 – Reactive power control

Deliverable 5.2b [20] of Twenties makes use of a specific law for the reactive power control of offshore wind farms. The additional reactive current to be provided by the OWF follows the law $i_{reactive}=2(1-u)$ where u is the voltage magnitude, with a dead band of ±10% on the voltage, which leads to the following curve shown in Figure B.5. The rise time required for this control is less than 20 ms, while the control must remain activated for 500 ms after the return of the voltage inside the deadband.

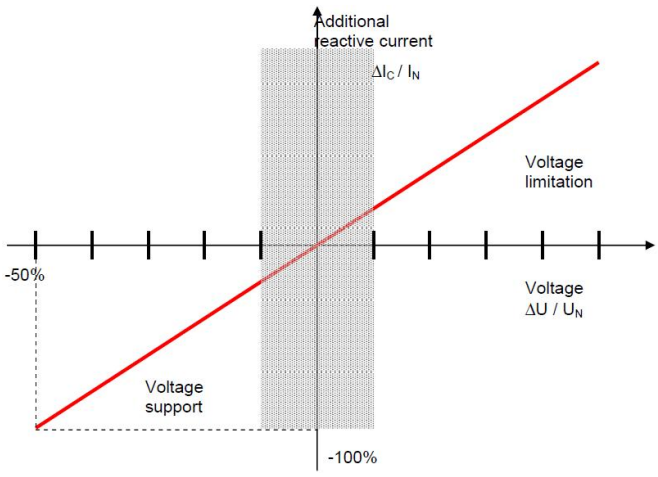

Figure B.5. Control law of reactive power for offshore wind farms.

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B.2.3 REQUIREMENTS 5.2.4 – REQUIREMENTS FOR OFFSHORE HVDC TERMINALS, OFFSHORE START-UP REQUIREMENTS

Requirement 5.2.4.3 – Offshore power quality

In its Deliverable 2.1 [34], the Best Paths project considers that the level of harmonics of AC voltage should be below 10%.

B.3 REQUIREMENTS LINKED TO THE HVDC OFFSHORE GRID ITSELF (INTERACTIONS WITHIN THE GRID)

B.3.1 REQUIREMENTS 7.1.1 – REQUIREMENTS FOR HVDC TERMINALS, OPERATIONAL RANGES

Requirement 7.1.1.1 – HVDC voltage range

In Deliverable 5.3b of Twenties [21], for calculations in a ±320 kV grid the admissible range in steady-state operation was set to [304, 320] kV, e.g. [0.95, 1.0] p.u., but the maximum admissible value in transient conditions was set to 1.2 p.u.

B.3.2 REQUIREMENTS 7.1.2 – REQUIREMENTS FOR HVDC TERMINALS, POWER AND DC VOLTAGE RESPONSE

Requirement 7.1.2.3 – DC voltage response parametrization

The question of DC voltage control was extensively studied in the Twenties project. In Deliverable 5.2b [20], the conventional P-V droop shown in Figure B.6 is first analysed. Values used for the conventional P-V droops are -200 MW/kV, -625 MW/kV and -2000 MW/kV (the nominal voltage is 320 kV and the capacity of converters is 800 MW). For the specific study case presented in Chapter 4 (H-topology, i.e. two wind farms connected radially to two onshore converters, and an additional cable connects these two subsystems), it is noted that the value -625 MW/kV seems the more suitable from a TSO perspective (i.e. each onshore converter gets the power from its associated wind farm and there is no flow on the cable connecting the two subsystems constituted each by an offshore wind farm and on onshore converter). A dedicated P-V droop control, with an automatic computation of the droop parameter, is also proposed in Deliverable 5.2b, but is not detailed here because it is two specific for test systems used in Twenties.

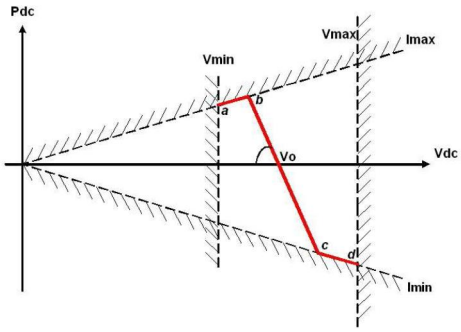

Figure B.6. Control law of DC voltage.

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Similarly, in Deliverable 5.3b of Twenties [21], a voltage droop control is proposed to control the power at the various onshore substations for the specific topologies used in that project. The P-V slope computation (for onshore converters) is as follows:

$$\lambda_i = \frac{G_i}{1 + k_i} \cdot V_{A_i}$$

where

- V_{A_i} is the measured DC voltage at the point of connection,
- k_i is the ratio of active power lost in the ith onshore converter,
- G_i is a parameter depending on the cable admittances.

However, this control strategy is limited to very specific topologies and cannot be extended easily to others.

Finally, in Deliverable 11.3 of Twenties [80], the current control loops dynamics used have a response time of 10 ms (i.e. 10 ms to go from zero power to 95% of the rated apparent power) and the voltage control loops dynamics have a response time of 100 ms.

B.3.3 REQUIREMENTS 7.1.4 – REQUIREMENTS FOR HVDC TERMINALS, BEHAVIOUR DURING SHORT-CIRCUIT FAULTS

Requirement 7.1.4.1 – HVDC terminal response to DC grid faults

In its Deliverable 2.1 [34], the Best Paths project considers that the peak current during a fault should be limited to 3 pu and that the clearance time is limited to 6 ms.

B.3.4 REQUIREMENTS 7.1.6 – REQUIREMENTS FOR HVDC TERMINALS, POWER QUALITY

Requirement 7.1.6 – Power quality

In its Deliverable 2.1 [34], the Best Paths project considers that the ripple of DC voltages should be limited to 2%.

B.3.5 REQUIREMENTS 7.2 – DC GRID PROTECTION AND CONTROL REQUIREMENTS

In PROMOTioN Deliverable 1.1, requirements on DC grid protection systems (including DCCB) were not completely formalized. Therefore, it is not possible at the time of writing to report quantitative values corresponding to requirements on DC grid protection and control. Nevertheless, an important part of the Twenties project was devoted to DC grid protection systems and it is worth summarizing it in this section. Note that the Twenties project was entirely based on 2-level VSC converters.

In Twenties Deliverable 11.2 [61], results of simulations indicate that the diode constraints imply a tripping time between 4 ms and 8 ms for metallic faults, depending on the type of fault and the fault location. That deliverable states also that the protection algorithms have to elaborate in the range 0.5-1.5 ms for metallic faults, and should be able to detect high impedance faults up to (at least) 200 Ω (in the case of high impedance faults, the

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requirement on speed is less stringent). The simulations showed additionnaly that a breaking capability of 17 kA is required when the tripping order is sent after a delay near 1 ms in the studied 120-kV DC grid.

In its Deliverable 11.3 [80] (and its addendum) reporting tests on the Alstom HVDC CB, the Twenties project considered that HVDC circuit breakers must be able to withstand a lightning impulse of 650 kV and that they must be able to conduct twice the nominal current, i.e. twice 1500 A, for a duration of at least 1 minute. Tests showed that the CB prototype was able to withstand lightning impulse voltage of 763 kV, that it was able to withstand a current of 3600 A (2.4x the nominal current) and that it was able to interrupt a peak current of 5.27 kA in 5.3 ms (amount of absorbed energy: 1.2 MJ).

Finally, in its deliverable 5.4 [28], the Twenties project considered that the power transmission through the HVDC grid under contingency should be at least 10% or more.

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APPENDIX C: SUMMARY OF STUDIES AND PAPERS OF MEDOW

MEDOW is a Marie Skłodowska-Curie Initial Training Network (ITN) running from the 1st of April 2013 to the 31st of March 2017. It aims at contributing to the integration of offshore wind power into the onshore AC grids in European countries and for the European offshore grid. Its network works towards sharing complementary expertise, infrastructure and facilities for the training of the next generation of top-quality researchers in this field.

C.1 WORK PACKAGE 2: INVESTIGATION OF VOLTAGE SOURCE CONVERTERS FOR DC GRIDS

C.1.1 OBJECTIVES/SCOPE

This WP investigates various converter configurations used in the same DCG so as to identify the interaction of various converters and grid configurations and to remove obstacles for different converters used in the same DCG. The expertise from industry on HVDC and VSC control is to contribute to the development of effective test platforms.

The WP's key research objectives are:

O4: Design and compare various VSC

O5: Investigate power flow control in DCG

O6: Develop tools for analysing and simulating converter stations

C.1.2 ASSUMPTIONS

The main investigated converters are two level, half bridge MMC, full bridge MMC and mixed MCC VSCs.

C.1.3 MAIN RESULTS

The 2-Level and Half-Bridge and Full-Bridge MMC converter models have been developed and validated in different software platforms. An experimental platform has been assembled and several control methods are being validated. Experimental tests to investigate various types of MMC have been carried out. Some gaps have been identified on economic models, analysis of converters and test of grid configurations.

Modular Multilevel Converter Modeling and Controllers Design

In [120], the operation and control of MMC have been described. The converter current controllers were designed with different bandwidth ranges. Different operating conditions for the controller schemes leading to different responses were evaluated. Simulation results of a 5MW grid connected to the MMC illustrate the good

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dynamic and steady state responses. The steady-state response evaluation was based on the grid current harmonic generation and the voltage ripple at the converter capacitors. The grid currents are characterized by having low harmonic pollution. It has been concluded that increasing the bandwidth of the grid current controllers reduces the harmonic generation in the high frequency harmonics. The grid current controller bandwidth change doesn't have impact on the capacitors voltage ripple. The grid current controllers are fast, being able to change from 0A to the nominal current value in less than 5 electrical grid cycles. The circulating current controller bandwidth has a high impact in the MMC capacitors voltage ripple. The results showed a ripple reduction of 40% by changing the controller bandwidth from 500Hz to 1000Hz. The circulating current controllers with less or equal to 500Hz bandwidth originated some response oscillations due to energy loops control conflicts.

Elimination of MMC Differential Currents via a feedback LTI control system

In [121], one of the drawbacks associated with MMC, that is the creation of a double line frequency current component, has been addressed. This work has described the origin of the double line frequency current and presented a step-by-step stationary reference frame circulating current suppress controller (S-CCSC) as a feedback linear time invariant (LTI) control to cancel out this source of additional losses. The proposed S-CCSC solution was compared to the previously proposed 2ω rotating reference frame CCSC (R-CCSC). Both solutions have shown very fast results, removing almost instantaneously the second harmonic current without leaving any evidence of them in steady state. Moreover, the LTI solution is demonstrated to demand 33% less computational time, which is a clear advantage from a practical application perspective.

Grid power flow impact on the on-state losses of the modular multilevel converter

In [27], the on-state mode of the half-bridge cell semiconductors with in respect to the active/ reactive power flow conditions of the MMC has been analysed. The MMC-HVdc INELFE project model was adopted to perform the converter analysis and simulations. It is shown that the lower switch of the half-bridge cell is responsible for the most of the on-state losses of the converter. The paper has analyzed the average number of semiconductor devices on the on-state mode based on the active/reactive power flow ratio at the PCC. The description of the methodology adopted was sub-sequentially followed by the analysis of the INELFE HVdc case study. It has concluded that the active/ reactive power flow ratio has a relevant impact on average number of diodes and IGBTs that are in the on-state modes in the correspondent stack. It was emphasized that the MMC is more efficient during the rectifier than the inverter operation mode. Moreover, during the unity power factor operation, the on-state losses of the semiconductors is higher than whenever exists reactive power flow flowing at the PCC, having the nominal current magnitude unchanged.

Comparison of Cell Selection Methods for Modular Multilevel Converters

In [122], several algorithms of switching the MMC sub-modules (SMs) that are present in the literature have been analysed addressing different aspects such as: the average switching frequency, magnitude of the capacitor's voltage ripple, and the complexity of the algorithm implementation. The converter simulation over a broad range of operating conditions was presented and discussed. It has been concluded that at nominal conditions, the denominated classic approach minimizes the voltage ripple of the capacitors to 8.1% with the

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cost of a substantial switching frequency (≈ 960 Hz) and power losses (≈ 14 MW). On the other hand, at nominal conditions, if imposed the magnitude of the capacitor's voltage ripple equal to 10%, the Hybrid-CTBsort is the one that curtails the most of the switching events and achieve the minimum average switching frequency for the SMs of 129 Hz. Nonetheless, this last approach results from a combination of two cell selection methods and at each time step continuously sorts the voltages of the capacitors which become difficult to implement on a HVdc-based converter with hundreds of SMs. Finally, the CTBsort sorts out the voltages of the SMs only few times, but retrieves the average switching frequency of 134 Hz, which is slightly higher than the Hybrid-CTBsort method. Different reactive power flows between the converter and the network were taken into account to study the performance of the presented methods. Moreover, the Hybrid-CTBsort and Hybrid-ATBsort obliges slightly less switching occurrences than the CTBsort and ATbsort respectively. Furthermore, the HCTBsort method can compute up to 14% reduction of correspondent switching losses in comparison to the CTBsort method.

Capability curves of a VSC-HVDC connected to a weak AC grid considering stability and power limits

In [26], the limitations on the power flow transfer through a VSC-HVDC system connected to a weak grid have been investigated. First, the impact of the angle and voltage stability limits and the VSC rating has been examined. Then, the power transfer capability curves of a VSC connected to a weak grid with a SCR of 1.1 p.u. by means of an L-interface were calculated. Finally, the impact of providing additional reactive power (Q) support has been investigated through utilizing a capacitor at the connection point. It has been shown that an additional Q-support of 0.2 p.u. can maintain the transfer of full power without the need for oversizing the VSC.

Extension of Power Transmission Capacity in MMC-based HVDC Systems through Dynamic Temperature-Dependent Current Limits

In [123], the extension of the current control loops, used in MMC, to include semiconductors junction temperature as an operational constraint has been proposed. A new controller is added to the inner current loop to modulate the current limits as a function of the temperature, providing an extension of the power transmission capacity without violating the thermal limits of the semiconductors. A numerical method to investigate the operation of converters with temperature-dependent current limits is proposed and the stability of the controller is analysed and validated through simulations under steady and transient operations.

Optimal DC Reference Voltage in HVDC Grids

A method for finding the optimal DC voltage in a HVDC grid was introduced in [25], based on power flows and line resistances. The method was implemented in the open-source software MatACDC and the results were verified by dynamic simulations in DIgSILENT PowerFactory, using a one area DC-voltage restoration controller.

C.1.4 CONCLUSIONS/NEXT STEPS

The test results presented in [25] showed that the introduced method grid is able to calculate the optimal DC-voltage reference in a HVDC. A drawback of the method is that the power flow has to be known to perform the calculation. Thus, its application is limited to scheduling tasks, as changes in the topology and/or power of the

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converters will change the optimal DC-voltage reference. This algorithm can be easily integrated in the DC SCADA/EMS as it would require limited communication.

As to the WP, efforts will be made to cover the gaps identified on economic models, analysis of converters and test of grid configurations, with proper methods used.

C.2 WORK PACKAGE 4: INTERACTIVE AC/DC GRIDS

C.2.1 OBJECTIVES/SCOPE

This WP investigates the interaction between AC and DCGs so as to determine operation requirements (grid codes) for DC and AC grids and to be able to present recommendations for IC strategy. It investigates the contribution of DCG to the electricity market with a view to contributing to reducing the barriers to a single European internal electricity market through the DCG. Key to reaching these objectives is the development of specialised platforms and tools to carry out power flow and stability analysis for both DC and AC grids.

The WP's key research objectives are:

O10: Develop simulation and experimental platforms for the integrated DC/AC system

O11: Investigate impact between AC and DCG

O12: Validate integrated DC/AC systems using simulation and experimental platforms

C.2.2 ASSUMPTIONS

The studied wind turbines (WTs) have been mainly type 4 (full-converter generators, FCGs) offshore WTs. A single aggregated WT model has usually been considered to represent each complete WF/WPP, and therefore the response of each WT for faults within a WF/WPP has generally not been analysed. The WT models have been mostly adopted from the IEC 61400-27-1 standard. Other specific assumptions tend to vary from one project to another.

C.2.3 MAIN RESULTS

All early-stage researchers are now working towards their goals, the first results are being delivered and the first publications have been realised.

Impedance-based stability assessment of parallel VSC HVDC grid connections

In [30], the stability of a system with two converters was analysed. The problem was studied in the frequency domain by using an impedance-based approach. The studied system composed of two converters, two AC networks and a transmission line. The study of the closed-loop response of a system with two converters was challenged, and the role of the transmission line and impact of the AC system strength were evaluated. The

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impedance-based approach was expanded to include both converters, and stability was studied from the closed-loop transfer functions of the complete system.

Preventing DC Over-voltage in Multiterminal HVDC Transmission

Methods for preventing DC overvoltage in multiterminal HVDC (MTDC) networks were analysed and compared in [47]. Power reduction sharing among OWFs using the different control signals was analysed. Two power reduction control methods, based on voltage reduction or frequency increase, were proposed for offshore wind farms with FCGs (type 4 WTs) and a MTDC transmission system. The two proposed methods were also compared with another method that uses a DC-chopper resistor. Simulation and experiments were carried out to evaluate the control systems.

Capability of TCSC on SSR Mitigation

An equivalent circuit of the thyristor-controlled series compensator (TCSC) was used in [124] to better understand how TCSC performs at subsynchronous frequency ranges, so that interactions of the TCSC behaviours and subsynchronous resonance (SSR) components could be viewed individually. The frequency response of the equivalent circuit was obtained, and the effects of the TCSC operation interfered by subsynchronous components were discussed.

Subsynchronous Oscillatory Stability Analysis of an AC/DC Transmission System

In [32], a formal analysis of torsional interactions — a form of subsynchronous resonance (SSR) — were investigated in series-compensated systems featuring HVDC links based on VSCs. Two integrated AC/DC systems were studied. The first one consists of the IEEE First Benchmark Model for SSR studies, upgraded with a point-to-point VSC-based HVDC link. The second system represents a simplified yet upgraded future (2020) Great Britain (GB) power system, where reinforcement is achieved through onshore series compensation and offshore submarine VSC-HVDC transmission. Detailed state-space dynamic models of the systems under study were constructed in MATLAB, and time-domain simulations were carried out in PSCAD to validate them. Stability assessments were carried out in MATLAB using eigenvalue analysis, with results agreeing well with those obtained through time-domain simulations.

A New Coordinated Voltage Control Scheme for Offshore AC Grid of HVDC Connected Offshore Wind Power Plants

A coordinated voltage control scheme (CVCS) was proposed in [125], which enhances the steady-state and the voltage ride-through (VRT) performance of an offshore AC grid. The proposed CVCS generates-reactive power references which are distributed to the individual wind turbines and the HVDC offshore converter based on participation factors and the WTs' available reactive power margin. In doing so, it integrates individual local voltage/reactive-power control of WTs and of the HVDC converter, with the secondary voltage controller at the offshore grid level. This secondary voltage controller controls the voltage at the pilot bus: the bus with the highest short circuit capacity in the offshore AC grid. By maintaining voltage at the pilot bus, which reflects the voltage variations of the entire offshore zone, the voltage profile of the offshore grid is indirectly maintained. A

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detailed model of an 800 MW VSC-HVDC-connected OWPP cluster developed in DIgSILENT PowerFactory was considered in this study.

Active Filtering Based Current Injection Method for Multi Modal SSR Damping in an AC/DC system

A method for extracting subsynchronous components of the current flowing in a transmission line at different series compensation levels was presented in [32]. The proposed damping scheme would be embedded in a VSC-HVDC station as an auxiliary control loop. It employs modal filters to identify subsynchronous resonance (SSR) upon occurrence and then injects currents at the corresponding subsynchronous frequency to damp it. The effectiveness of the scheme was assessed through eigenvalue analysis (following the state-space modelling of the system), in the well-known IEEE First Benchmark Model, which was upgraded with a point-to-point VSC-HVDC link. This AC/DC test system, together with the SSR damping controller, were implemented in PSCAD/EMTDC to perform time domain simulations. Simulations were performed in PSCAD, with the eigenvalue analysis carried out in MATLAB for the small-signal stability assessment of the AC/DC system.

Side-by-side connection of LCC-HVDC links to form a DC grid

The side-by-side connection of LCC links using DC transformers at a geographic crossing point or close proximity between the LCC links was proposed in [126]. The purpose of such a connection is to achieve the benefits of DCG operation by making full use of existing LCC lines without incurring the vast costs of constructing new DC transmission lines. The side-by-side connection was developed using a DC transformer to interconnect two line-commutated converter (LCC) links. The DC transformer was designed for coping with power reversal, temporary DC and AC faults, and reduced voltage operation. The structure and control system of the DC transformer were designed to match the operation of LCC links.

Dynamic Reactive Power Control in Offshore HVDC Connected Wind Power Plants

A coordinated reactive power control (CRPC) was presented in [44] for a HVDC-connected cluster OWPPs. The reactive power reference for the WPP cluster is generated by an optimization algorithm aiming at minimum active power loss in the offshore AC Grid. For each optimal reactive power set point, the OWPP cluster controller generates reactive power references for each WPP, which further send the AC voltage/ reactive power references to the associated WTs based on their available reactive power margin. The impact of faults at different locations in the offshore grid, such as a wind turbine (WT) terminal, collector cable, and export cable, on the dynamic voltage profile of the offshore grid was investigated. Furthermore, the dynamic reactive power contribution from WTs of different WPPs in the cluster for such faults was also studied.

Coordinated Fast Primary Frequency Control from Offshore Wind Power Plants in MTDC System

In [41], a coordinated fast primary frequency control (FPFC) was investigated for offshore wind power plants (OWPPs) integrated with a surrounding onshore AC power system through a three terminal VSC HVDC system. The onshore grid frequency is replicated at the offshore grid through supplementary control blocks located at the onshore and offshore HVDC converters. The proposed FPFC produces a power reference to the OWPP based on the frequency deviation and its rate of change measured in the offshore AC grid. The impact of wind speed variations on the OWPPs' active power output and the dynamics of the wind turbines were also

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discussed. The impact on the power system frequency and DCG voltage of the OWPPs' active power output variation and the associated dynamics of the wind turbines was studied at different wind speeds above and below the rated ones. Moreover, the effect of the OWPPs' active power ramp rate limiters on the power system frequency and DCG voltage was also studied.

Analysis of control interactions in multi-infeed VSC HVDC connections

In [31], the control interactions and interferences in a multi-infeed power system with two converters were studied. This was done in the frequency domain by using an admittance-based stability assessment. Harmonic stability under different network characteristics was addressed.

Coordinated Voltage Control in Offshore HVDC Connected Cluster of Wind Power Plants

A coordinated voltage control scheme (CVCS) was presented in [45] for a cluster of offshore wind power plants connected to a voltage-source converter-based high-voltage direct-current (VSC-HVDC) system. In addition, a control strategy was proposed for improving the voltage ride-through (VRT) capability of WTs for faults in the offshore AC grid, thus leading to improved dynamic voltage profile in such grid. The primary control point of the CVCS is the introduced Pilot Bus, which has the highest short-circuit capacity in the offshore AC grid. During the steady-state operation, the Pilot Bus voltage is controlled by reactive-power references to each WT in the WPP cluster, based on their available reactive power and participation factors. Each participation factor is derived from the dV/dQ sensitivity of a WT bus with respect to the Pilot bus. The Pilot Bus voltage reference is generated by an optimisation algorithm aiming at minimum active power losses in the offshore AC grid. The scheme's effectiveness to provide dynamic reactive power support was demonstrated through faults applied at different locations of the offshore AC grid.

Improved Frequency Control from Wind Power Plants Considering Wind Speed Variation

In [42], an improved fast frequency controller (FFC) for wind power plants (WPPs) was proposed. The controller produces an additional temporary overloading active-power reference based on the frequency deviation and the rate of change of frequency. Two different control options were proposed and the dynamics of the WTs were analysed at different wind speeds. Contrary to standard controllers proposed in literature, the gains of the FFC were optimised for different wind speeds over the whole wind speed range and considering the limitations and dynamics of the WTs. Two options for temporary frequency control implementations from WPPs were analysed and compared. Moreover, the impact of the mechanical, electrical and control limitations at different wind speeds and its effect on the frequency control was discussed.

Coordinated Control Scheme for Ancillary Services from Offshore Wind Power Plants to AC and DC Grids

A coordinated control methodology was proposed and demonstrated in [127] for providing ancillary services to AC and DCG from offshore wind power plants (OWPPs) connected through a multi-terminal HVDC network. For the onshore frequency control, the proposed control strategy involves a coordinated control mechanism based on DC-voltage regulation at the onshore converter and frequency regulation at the offshore converter. For onshore AC fault ride-through, and DCG voltage control, the control strategy involves regulating the offshore AC

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grid frequency according to the DC-voltage variation. The effectiveness of the proposed control scheme was demonstrated through detailed simulations in DIgSILIENT PowerFactory, with a model of a wind power system connected to a 3-terminal HVDC system.

C.2.4 CONCLUSIONS/NEXT STEPS

Impedance-based stability assessment of parallel VSC HVDC grid connections

The impedance-based approach used in [30] is shown to have potential for studying the interactions in larger networks. Simulation results showed that the stability is compromised when a parallel converter is connected. Frequency-domain methods allow the detection of potential points of instability, and its expansion is not as complex as those of time-domain methods. Simulation results revealed the proneness to instability of one converter due to the influence of the other. The relative stability of one converter is deteriorated due to interactions from the other converter. Results showed that shorter lines and higher grid impedances impose limitations in the stability margins and the system is more sensitive under uncertainties. In the studied model, grid impedances have larger impacts on the influence between converters whilst the transmission line has a minor effect. Therefore, interactions between converters are mainly dependant on the strength of the system in such a network topology, and the need of considering all the dynamics is more important in weaker systems.

Preventing DC Overvoltage in Multiterminal HVDC Transmission

Simulation and experimental results under various faults demonstrated the feasibility of the power reduction controllers proposed in [47] to prevent DC overvoltages. The DC-chopper resistor method is simple and needs only local control signal. It can achieve better control performance than the proposed power reduction methods but with extra cost and equipment size. On the other hand, the proposed power reduction methods, based on voltage reduction or frequency increase, remove the need of fast communication between the offshore converters and wind turbines. They also do not require extra equipment to implement the control schemes.

Capability of TCSC on SSR Mitigation

The frequency response of the equivalent circuit used in [124] shows that the thyristor-controlled series compensator (TCSC) has the capability to damp subsynchronous resonance (SSR) if the corresponding behaviour is inductive, but this capability can be deteriorated if the TCSC's firing logic cannot be effectively maintained. This subsynchronous behaviour will be moved if the equivalent inductance is varied, which is related to the dynamics of the thyristor-controlled reactor (TCR). The TCSC's impedance stability is related to its SSR damping performance, as long as its subsynchronous characteristics at the concerned frequency are inductive. However, it is also noted that the dynamics of the TCSC may sometimes turn its behaviour into capacitive, which will lead to a SSR failure. Therefore, a controller that limits the output of the TCSC's apparent reactance or other variables is helpful to improve the SSR performance. The capacitive subsynchronous behaviour has been validated as to amplify SSR problems. However, the comparison between the TCSC and its equivalent circuit shows that, even in the same capacitive conditions, the TCSC's inherent regulation has better impacts on decreasing the slope of oscillations.

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Subsynchronous Oscillatory Stability Analysis of an AC/DC Transmission System

The dynamic modelling and formal analysis approach adopted in [32] allows a detailed understanding of subsynchronous oscillations arising in integrated AC/DC networks. The modelling was performed in such a way that the proposed models are easily scalable to build more complex and detailed networks. As it was shown, the PSCAD simulation results match well with the results obtained through the eigenvalue analysis in MATLAB.

A New Coordinated Voltage Control Scheme for Offshore AC Grid of HVDC Connected Offshore Wind Power Plants

The coordinated voltage control scheme (CVCS) proposed in [125] reduces the active-power losses during steady-state operation and improves the low-voltage ride-through capability of the offshore AC Grid during faults. During fault clearance, the CVCS limits the temporary peak overvoltage at the point of common coupling. This will be beneficial for overvoltage protection under partial/full HVDC load rejections, resulting from the blocking of the converter due to the action of protection system. In case of communication failures, the individual WTs operate in voltage/reactive control mode within their operational limits.

Active Filtering Based Current Injection Method for Multi Modal SSR Damping in an AC/DC system

The results presented in [33] show that the proposed scheme effectively damps subsynchronous resonance (SSR) irrespectively of the torsional mode being excited. If the torsional modes of the shaft of a synchronous generator are known, the design of the proposed damping scheme can be easily carried out. This can be extended to any transmission topology. The eigenvalue analysis and the results obtained through simulations match well. The SSR damping controller proposed in this work is effective for a broad series compensation range. Experimental validation of the proposed method will be considered as future work.

Side-by-side connection of LCC-HVDC links to form a DC grid

The DC transformer proposed in [126] can regulate the power flow flexibly between side-by-side-connected line-commutated converter (LCC) links under normal operation and power reversal condition. Even if one LCC link is in low voltage operation, the DC transformer still works properly and maintains the power in the other link at the desired level. Disturbances caused by DC faults and AC faults are isolated by this DC transformer and the unfaulted link remains in normal operation.

Dynamic Reactive Power Control in Offshore HVDC Connected Wind Power Plants

With the coordinated reactive power control (CRPC) proposed in [44], the WT terminal fault does not impact the voltage profile and power flow in the offshore grid but affects only the faulted cable voltage and its power flow. The WT collector cable fault can affect the voltage profile and power flow to some extent, but it may be improved by additional reactive power support from the non-faulted WPPs. The export cable fault affects the power flow and voltage profile of the offshore grid. The WT voltage ride-through (VRT) controllers generate the maximum possible reactive current as the voltages at their terminals deviate much from their nominal values. Hence, they contribute with the maximum possible reactive power during voltage dips and consume reactive power following the fault to limit the high voltage in the offshore AC Grid.

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Coordinated Fast Primary Frequency Control from Offshore Wind Power Plants in MTDC System

The power system frequency is significantly improved with the OWPPs' coordinated fast primary frequency control (FPFC) proposed in [41]. However, second frequency and DC voltage (more important for the stability of the offshore grid itself) dips are observed once the OWPPs stop providing frequency control. This phenomenon is predominant at below rated wind speeds due to the higher reduction of the active power output from the WTs after having provided frequency support. The rate and magnitude of the second frequency and DCG voltage dips can be minimised with the help of an active power ramp rate limiter. The OWPPs' FPFC, particularly with the ramp rate limiter, reduces the burden on the other converter and AC grid participating in frequency control.

Analysis of control interactions in multi-infeed VSC HVDC connections

Stability issues are encountered in the multi-infeed power system with two converters studied in [31], when new oscillatory modes appear in high frequencies close to the control bandwidth. When these systems are interconnected, poorly damped oscillatory modes appear above the fundamental frequency. These modes correspond to resonances between the network and the converter. Instabilities arise when these low-damped resonances coincide with negative-conductance regions in the connected converters. The model reduction of a converter to its phase reactor can provide a first indication of the resultant resonances. However, resonances in the system can lead to instabilities when appearing within the control bandwidth, thereby implying the necessity to also consider higher-frequency dynamics. If high-frequency modes are located within the control bandwidth, the converter model must include the control dynamics; otherwise, it will lead to an incorrect stability assessment.

Coordinated Voltage Control in Offshore HVDC Connected Cluster of Wind Power Plants

The coordinated voltage control scheme (CVCS) proposed in [45] improves both the steady-state voltage profile and voltage ride-through (VRT) of the offshore AC grid, while minimising the losses. The scheme considers the network sensitivity and therefore effectively and efficiently utilises the available reactive power sources. It also improves the voltage stability margin of the offshore AC grid. The participation factors ensure proper distribution of reactive power to each WPP and WTs within the WPPs based on their voltage sensitivity with respect to the Pilot Bus. Such a method leads to the minimisation of the risk of undesired effects, particularly overvoltage at the terminals of WTs located far away from the AC collector substation, by dispatching lower reactive power references compared with the ones nearer to the substation.

Improved Frequency Control from Wind Power Plants Considering Wind Speed Variation

By optimising the gains of the improved fast frequency controller (FFC) proposed in [42], the response is improved over the whole wind speed range, while stability is still ensured. To improve the WT s' frequency response, the gains can be adapted in advance, based on the very short-term average wind speed forecast, over the whole wind speed range. The controller's performance can be improved if the frequency-initiated power reference is based on the actual power output (Option 2) instead of the constant pre-overloading power output of the WTs (Option 1).

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Coordinated Control Scheme for Ancillary Services from Offshore Wind Power Plants to AC and DC Grids

With the coordinated control strategy proposed in [43], offshore wind power plants (OWPPs) can effectively deliver the ancillary services to DC and AC grids without any conflict of interest between each service. The scheme involves only local measurements, avoiding the need for communication infrastructure and increasing the reliability of the control system. The strategy has good performance, but it also presents some possible practical limitations, which were explained in detail. It is recommended to down-regulate the WPPs to have some power reserves. During faults in the DCG, it may not advisable for the WPPs' to contribute with more power to the DCG. Hence, the proposed coordinated control scheme should be coordinated with the DCG's protection settings.

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