PROMOTioN
PROGRESS ON MESHED HVDC OFFSHORE TRANSMISSION NETWORKS

Deliverable 1.6: Draft roadmap and reference offshore grid expansion plan

PROMOTioN – Progress on Meshed HVDC Offshore Transmission Networks
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EXECUTIVE SUMMARY

This report develops a draft offshore grid expansion roadmap for the evacuation of offshore wind energy during the decade 2020-2030 in the North Sea. For that purpose, the grid structure is optimized from an economic point of view along that decade, such that all the expected offshore wind energy can be evacuated while considering the development pace of offshore wind farms. Two cases are compared. In the first case, only individual and radial connections of offshore wind farms are allowed. In the second case, the coordinated development of connections of offshore wind farms is envisaged. For the coordinated development, provisional planning criteria are drafted, and in particular a specific interpretation of the N-1 security rule for offshore grids is proposed. That second case leads to radial connections of some offshore wind farms, to radial multi-terminals, and to meshed HVDC grid structures. The economic viability of these coordinated connections of offshore wind farms is then studied by comparing the costs and the benefits of the two cases. Note that, in both cases, the grid design does not consider power exchanges between different countries, but these exchanges are valued in the estimation of the benefits.

This preliminary analysis allows drawing several conclusions. Firstly, the HVDC circuit breakers' capabilities and costs will drastically impact the business case of coordinated solutions such as meshed grids. Two technologies could be part of an HVDC grid: mechanical and hybrid circuit breakers. Mechanical circuit breakers are expected to be much cheaper than hybrid circuit breakers, but they might have to be used only in conjunction with full-bridge VSCs. If hybrid circuit breakers are needed, the offshore grid will probably integrate only offshore wind farms far from the shore (i.e. significantly more than 100 km). Secondly, the technical capabilities and the cost of DRUs could also significantly impact the likely development of offshore grids. Indeed, DRUs are expected to have a low cost compared to equivalent VSCs, but they might be limited to purely radial connections of offshore wind farms. Under that specific set of assumptions, radial connections will keep an economic advantage compared to meshed grids. On the contrary, if DRUs can be integrated as well in coordinated solutions such as meshed grids, these coordinated solutions will equally benefit from that cost reduction. Thirdly, the limitations of the onshore grid in terms of hosting capacity could strongly impact the grid topology: it might be cost-effective to extend the HVDC grid up to load areas, instead of connecting offshore wind farms to the closest onshore connection point. Finally, there are a number of uncertainties about the way the grid will be operated (e.g. security rules, market rules). The business case of a meshed offshore grid could also be strongly impacted by the operational constraints.

The proposed approach has nevertheless currently several limitations that will have to be overcome in the final reference offshore grid expansion plan under development within PROMOTioN's Work Package 12. In particular, it is expected that the HVAC technology will still play a major role in the connection of offshore wind farms, either to group them in clusters of critical size before connecting them to the onshore grid through an HVDC system, or to connect them directly to the shores in HVAC if the distance is limited.

LIST OF ACRONYMS

ACRONYM	MEANING
ATC	Available Transfer Capacity
CBA	Cost-Benefit Analysis
CB	Circuit Breaker
DCCB	HVDC Circuit Breaker
DRU	Diode Rectifier Unit
EHV	Extra High Voltage
ENTSO-E	European Network of Transmission System Operators for Electricity
GCS	Generation Cost Savings
GSK	Generation Shift Key
MC	Monte Carlo
MINLP	Mixed Integer Non Linear Program
NPV	Net Present Value
NTC	Net Transfer Capacity
OHL	Overhead Line
OTEP	Optimal Transmission Expansion Planning
RES	Renewable Energy Sources
TYNDP	Ten-Year Network Development Plan
VSC	Voltage Source Converter
WP	Work Package

CONTENT

1 INTRODUCTION

1.1 A ROADMAP FOR THE EVACUATION OF OFFSHORE WIND ENERGY

Several challenges must be addressed in order to develop meshed offshore grids in the North Seas[1] connecting offshore wind farms and North Seas countries[2]. Key components must be sufficiently mature to realise such a development. The regulatory frameworks of the European Union and the North Seas countries must also facilitate it from a legal perspective, which is addressed in PROMOTioN's Work Package 7. Once these two prerequisites are met, an offshore grid development plan fulfilling the technical and the legal requirements must be designed. Finally, on the basis of an estimation of the costs and the benefits (including their distributions among the different stakeholders and countries), a financial plan must be established to determine the capital sums required.

A comprehensive roadmap for the development of meshed offshore grids in the North Seas must address these challenges. Most of them are currently addressed by dedicated Work Packages (WPs) within the PROMOTioN project, with the exception of the grid development plan. Although the purpose of this project is not to provide an actual grid development for the North Seas, it is nevertheless crucial to base the analysis on a realistic example of such a plan, referred to here as a reference offshore grid expansion plan. The objective of this report is the initial development (and application) of a methodology to provide a reference offshore grid expansion plan, given the development pace of offshore wind farms in the North Seas. This reference offshore grid expansion plan will be revised within WP12 and consolidated with the outputs of the other WPs into a full comprehensive roadmap.

1.2 OBJECTIVE OF THIS REPORT

This report thus intends to derive a draft offshore grid development roadmap for the evacuation of offshore wind energy, including a detailed study considering the economic viability of an offshore grid in the North Seas. In addition, this report will present the corresponding reference offshore grid expansion plan. Note that a meshed offshore grid could be used for both the evacuation of offshore wind energy and to exchange energy between different countries. The study of the economic viability will consider both aspects, but the sizing of the grid presented in this report will be based mainly on the evacuation of offshore wind energy.

As detailed in PROMOTioN's D1.3 "Synthesis of available studies on offshore meshed HVDC grids" [1], numerous roadmaps for the development of a meshed offshore grid in the North Seas have been already

[1] The "North Seas" in this document refers to the North Sea, the Irish Sea, the English Channel, Skagerrak and Kattegat, in line with the one of NSCOGI.
[2] The "North Seas countries" in this document refers to the signatories of the "North Seas Countries' Offshore Grid Initiative Memorandum of Understanding (2010)", i.e. Belgium, Denmark, France, Germany, Ireland, Luxembourg, the Netherlands, Norway, Sweden and United Kingdom.

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proposed in the past decade. These roadmaps demonstrated that coordinated topologies (i.e. radial multi-terminal and meshed topologies) can bring substantial benefits when i) the overall offshore grid structure is optimized, ii) there is a high offshore wind generating capacity and iii) there are numerous offshore hubs to collect this energy (geographical spreading). However, the proposed topologies were optimized for a single point in time (e.g. for 2030) and did not indicate how offshore grid topologies are likely to evolve from radial structures to meshed structures. Moreover, because the topologies were developed at a macro level, their technical feasibility cannot be studied easily.

The purpose of this draft roadmap finds its roots in the objectives of the overall PROMOTioN project itself. PROMOTioN aims at alleviating the remaining technical, economic, financial and regulatory barriers hampering the deployment of meshed offshore HVDC grids in the North Seas. Consequently, PROMOTioN will conclude at its end (within WP12) about the technical feasibility, the economic viability and the fundability of meshed offshore HVDC grids. In order to do so, there are several prerequisites. In particular, the factors impacting the grid topology as well as the costs vs. benefits of meshed offshore HVDC grids must be identified and quantified. Moreover, all relevant technical, financial and regulatory questions must be covered and the results of the different PROMOTioN's WPs must be consistent.

The objective of PROMOTioN's Task 1.4 is therefore to develop a report developing a draft roadmap and reference offshore grid expansion plan and computer demonstration tool. It will take into account the development pace of offshore wind, technical and economic factors, and business case to assess the viability and an initial roadmap with an interactive visualisation. In addition to this report, the computer demonstration tool is thus also part of Deliverable 1.6. An overview of this computer demonstration tool is available in Appendix D. Note that refinement of the tool is expected to be required at the delivery of the draft roadmap for it to be able to be used for the demonstration of the final roadmap in WP12.

To keep the modelling complexity manageable for this draft roadmap, the timeline of the modelling is up to 2030: this will later be extended for the final roadmap in WP12 towards 2050. By optimizing the grid structure from an economic point of view, the main circumstances under which a certain fundamental topology is likely to be implemented will be identified and the impact of costs on the topology will be studied. Note that these topologies will not be optimized for a single point in time, as it was the case for previous roadmaps, but over the time horizon 2020-2030[3]. By this way, a likely development of offshore grid topologies can be estimated as well. On the basis of optimized topologies, the economic viability of offshore grids will be investigated. Additionally, this report aims to raise the main technical questions that must be answered by the PROMOTioN project to allow the planning of a meshed offshore grid, and to provide realistic topologies of offshore grids to the different WPs to allow them to address these questions.

[3] The development of topologies up to 2030 should be seen as an intermediate step on the way to a long-term perspective (e.g. 2050) that will be discussed in WP12.

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Note that, in order to draft realistic offshore grid topologies, it is necessary to define a set of technical criteria that need to be fulfilled by the offshore HVDC grid. Planning criteria are well defined for onshore grids (e.g. N-1 security criterion), however this is not the case for offshore HVDC grids: there is no standard guideline to plan such a grid. The first part of this report is thus devoted to the drafting of planning criteria for an offshore grid.

1.1 STRUCTURE OF THIS REPORT

The structure of the document is the following. Chapter 2 details the context, the scope, and summarizes the main assumptions. Chapter 3 provides a preliminary discussion on potential planning criteria. These planning criteria will be further refined during the PROMOTioN project. Chapter 4 develops the methodology followed to actually generate offshore grid topologies and to estimate their economic viability. Chapter 5 presents the results, in particular the reference offshore grid development plan and sensitivity analyses. Finally, chapter 6 concludes and issues recommendations for the next steps. Additionally, appendix A details the assumptions used to get these results, appendix B shows the development of the reference grid year per year, and appendix C lists the open research questions raised during this pre-feasibility study that should be answered during the PROMOTioN project.

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2 CONTEXT, SCOPE AND MAIN ASSUMPTIONS

The PROMOTioN project aims to alleviate the remaining barriers hampering the development of meshed offshore grids in the European North Seas (North Sea, Irish Sea, English Channel, Skagerrak Strait and Kattegat Bay). As shown in PROMOTioN's D1.3 [1], the need for such offshore grid in the North Seas is expected to begin in the decade 2020-2030, but should increase strongly after. In general, the European Union is currently looking up to 2050 for its energy policy. As this report presents a preliminary exercise, the scope will be limited to the North Sea during the decade 2020-2030. Furthermore, it is considered that interconnectors and offshore wind farms connections already existing or that will be commissioned by 2020 cannot be part of a meshed offshore grid, because they were not designed in that way (e.g. different voltage levels are used).

PROMOTioN's D1.4 [2] establishes a reference scenario for potential installed wind capacities in the North Seas and for load/generation of surrounding countries for the period 2020-2050, with intermediate milestones in 2030 and 2040. This reference scenario is based on the Vision 3 of the ENTSO-E TYNDP2016 for 2030. In the North Sea itself, 37 GW of offshore wind is expected to be commissioned between 2020 and 2030 with approximately half in the United Kingdom, as shown in Table 2.1. These global figures can be translated in concrete projects using the 4-C-Offshore wind database containing detailed information on individual projects (geographical location, target wind farm size, current development status), similarly to what is done in [3]. Figure 2.1 shows the individual projects considered in this draft roadmap. According to the development status, commissioning dates were assumed in order to have a smooth evolution of the installed wind capacity between 2020 and 2030.

Country	Offshore wind generation
Belgium	1,700 MW
The Netherlands	4,444 MW
France	3,005 MW
Germany	7,389 MW
Denmark	1,310 MW
United Kingdom	19,360 MW

Table 2.1. Offshore wind generation expected to be installed between 2020 and 2030 in the North Sea [2].

Because DC/DC converters are not expected to be available in a short future for Extra-High-Voltage (i.e. above 245 kV) applications, a homogenous voltage level will have to be chosen for the development of offshore grids in the short term. The adequate voltage level for the North Sea is currently unclear, but it is expected that it will be above 300 kV. Given the current technical capabilities, the offshore grid expansion plan will be developed for two different voltage levels: 320 kV and 525 kV. These voltage levels are in line with the recommendations of the Cigré Joint Working Group B4/C1.65: for point-to-point connections, a voltage of 320 kV is recommended for a transfer of power between 0.5 and 1.0 GW and a voltage of 500 kV is recommended for a transfer of power

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between 1.5 and 3.0 GW [4]. Offshore wind farms expected by 2030 in the North Sea will have capacities between several hundred of MWs and a couple of GWs.

Figure 2.1. Map of offshore wind farms considered commissioned between 2020 and 2030.

For the analysis of the economic viability, a model of the European transmission system is also needed. This model is built from the ENTSO-E TYNDP2016 data.

Detailed assumptions made in the context of this draft roadmap are described in Appendix A. In addition, because there is no known formal planning criteria existing for offshore HVDC grids, and because planning criteria could affect the CBA, chapter 2 details a first proposition of planning criteria for an offshore grid.

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3 PLANNING CRITERIA FOR AN OFFSHORE GRID

As explained in the introduction, the approach that will be followed to draft the initial roadmap for the evacuation of offshore renewable generation and to generate the offshore grid expansion plan is the one that of the power transmission system planner. In that context, information on generation sources (in particular offshore wind energy) and on loads is treated as a known input through one or several scenarios[4]. Planning a transmission power system consists in finding the most economical way to develop the system while being able to satisfy components operational limits and maintaining an acceptable reliability level. The set of constraints that must be fulfilled by the planned power transmission system defines the planning criteria. Transmission planning criteria typically cover (but not limited to)

- System states and the contingencies (including faults) to study,
- Acceptable system operating limits in normal operation (pre-contingency) and post-contingency states,
- Acceptable response of the system to outages and to fault disturbances.

The security analysis is traditionally based on deterministic criteria (i.e. the system must ride through the postulated secured contingencies while staying within acceptable operating conditions). However, the need to use probabilistic criteria (i.e. a risk of problems is acceptable but must be below a given threshold) to complement (or replace) deterministic criteria is rising. This is in particularly relevant for a part of the interconnected European transmission system, which connects a significant amount of installed wind capacity to the system.

For onshore grids, conventional transmission planning criteria have been established at national, regional or utility level. Although they differ in implementation aspects, the overall philosophy is the same. In particular, there are common trends on the system states to analyse (peak and off-peak load), the contingencies to consider (N-1, exceptional contingencies and, sometimes, N-2 contingencies), the analyses that must be performed (static and dynamic), etc. In other words, a standard envelope does exist for planning criteria for a traditional onshore grid. This is not the case for meshed offshore HVDC grids: no planning criterion formally exists for that kind of grid. Nevertheless, the development of coordinated solutions for the evacuation of offshore wind energy in the North Seas will need the establishment of planning criteria for offshore grid. The purpose of this chapter is to provide a preliminary discussion on potential planning criteria for an offshore grid. This preliminary discussion will be enriched throughout the PROMOTioN project.

This chapter is organized as follows. In order to build planning criteria for an offshore grid based on existing planning criteria for traditional onshore grids, section 3.1 reviews existing planning criteria. Because an HVDC offshore grid can be viewed as an extension of existing HVDC offshore wind farms connections and of existing HVDC interconnectors, section 3.2 will analyse the planning criteria that are used to plan these connections and

[4] Several scenarios can be used to characterize uncertainties on the actual evolution of the load and generation.

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interconnectors. Finally, on that basis, section 3.3 discusses a first proposal of planning criteria for offshore HVDC grids that could be applied to purely radial, radial multi-terminal and meshed structures.

3.1 REVIEW OF PLANNING CRITERIA FOR AN ONSHORE GRID

Although their formal organizations in different countries differ, the planning criteria can be classified according to the following categories:

- Requirements on the system performance under normal conditions,
- Requirements on the system performance following a single contingency,
- Requirements on the system performance following several or extreme contingencies.

This section is organized according to that classification.

3.1.1. SYSTEM PERFORMANCE UNDER NORMAL CONDITIONS

The planning criteria have first to ensure that the transmission power system can accommodate the load and the generation under normal conditions while satisfying operational limits and being stable. In planning, the system is said to be under “normal conditions” typically when all generation and transmission facilities are available[5]. To cover the possible range of operating conditions, system peak load and system off-peak load are usually analysed. The massive integration of renewable energy sources leads nevertheless to critical operating conditions not covered by these two conditions. Therefore, other critical conditions can also be analysed. For all conditions studied, the power transmission system must accommodate the power flows given by the economic dispatch (or another credible dispatch) of generating units, without load shedding, with power flows through transmission elements within normal (continuous) ratings and voltages at nodes within specific bounds (typically between 0.95 pu and 1.05 pu for AC grids). The intrinsic stability can be ensured by imposing a criterion on eigenvalues (angular small-signal stability). The planned power system must also be such that the maximum short-circuit currents are below the ratings of circuit breakers.

3.1.2. SYSTEM PERFORMANCE FOLLOWING A SINGLE CONTINGENCY

Constraints linked to the system performance following a single contingency are often called “N-1 security criterion”. A single contingency can be defined as the trip of a single network element (e.g. single transmission circuit, generator, reactive compensator) that cannot be predicted in advance. Transmission systems are typically planned such that a single contingency occurring at system peak or off-peak load does not endanger the system security:

- The system must stay electrically stable (e.g. voltage stability, angular stability, frequency stability),
- Loss of load (i.e. load shedding) is not allowed,

[5] Note that, in some cases, states with elements in planned maintenance can also represent the system under normal conditions.

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- No uncontrolled cascading outage is allowed (but the disconnection of a generator radially connected, or an action of an automatic Remedial Action Scheme is allowed),
- Electrical variables (e.g. power flows, voltages) must be within emergency operating limits (e.g. between 0.9 pu and 1.1 pu for voltages in AC grids, depending on the voltage level) or normal (continuous) operating limits (depending on the specific implementation) just after the contingency,
- When electrical variables are allowed to be outside the normal operating range just after the contingency (i.e. when they are allowed to be within emergency ratings), it is often imposed that they should be able to go back to normal (continuous) operating limits after system adjustments.

Planning criteria detail usually the types of contingencies to consider, the types of faults (e.g. single-phase and three-phase faults) to analyse in the stability analysis, the method to perform the stability analysis, the allowed operating limits, etc.

3.1.3. SYSTEM PERFORMANCE FOLLOWING SEVERAL OR EXTREME CONTINGENCIES

If the analysis of the system performances under normal conditions and following a single contingency are standard procedures during the planning stage, this is not the case for the analysis of the system performance following several or extreme contingencies. Nevertheless, it is included in planning criteria for various countries. The general purpose is to check that contingencies more severe than the ones covered by the N-1 security criterion, but nevertheless with a non-negligible likelihood, do not entail unacceptable consequences. The events considered can be:

- Busbar fault (exceptional contingency),
- Two successive contingencies (N-1-1),
- Two simultaneous contingencies (N-2) due to a common mode failure (e.g. failure of a tower supporting several circuits),
- Fault with delayed clearing,
- Etc.

Requirements on the system performance following several or extreme contingencies differ from one country to another, but, usually, the system must remain stable and load shedding can be allowed under specific conditions. If these requirements are still mainly deterministic, it should be noted that the NERC standard TPL-004 requires the transmission planner to evaluate the risks and consequences for a number of extreme contingencies, which implies a probabilistic security assessment.

3.2 ANALYSIS OF EXISTING PLANNING CRITERIA FOR HVDC OFFSHORE WIND FARM CONNECTIONS AND HVDC INTERCONNECTIONS

Because HVDC offshore wind farm connections are part of the transmission system, the philosophy behind planning criteria stays the same as that for onshore grids: any HVDC offshore windfarm connection must accommodate the generation under normal conditions (i.e. when all transmission facilities of the connection are available) while satisfying operational limits and being stable, and a single contingency cannot endanger the system security of the onshore grid (N-1 security). However, as the HVDC offshore windfarm connections

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connect almost exclusively generation to onshore grids, and they do not connect loads (at the exception of the auxiliary equipment that consumes electrical power), implementation details differ. In particular, it is not relevant to perform the analysis for peak and off-peak load conditions. In the case of an offshore wind farm connection, the analysis is done at the nominal capacity of the wind farm (i.e. peak generation). Note that the N-1 security criterion for the connection of an offshore wind farm does not mean that the generated offshore wind energy must still be evacuated after a single contingency. It means that a single contingency cannot lead to an unacceptable disturbance in the onshore grid, such as a load shedding.

In Europe, the Commission Regulation (EU) 2016/1447 establishing a “Network code on requirements for grid connection of high voltage direct current systems and direct current-connected power park modules” (26 August 2016) establishes a list of planning criteria for HVDC offshore wind farm connections, but that list is not specific because the various points have to be detailed by each TSO. Nevertheless, article 17 on the maximum loss of power infeed is important for the planning of an HVDC offshore wind farm connection: the first paragraph states that “an HVDC system shall be configured in such a way that its loss of active power injection in a synchronous area shall be limited to a value specified by the relevant TSOs for their respective load frequency control area, based on the HVDC system’s impact on the power system”. This is further analysed and discussed in PROMOTioN’s deliverables 1.1 and 1.5. In particular, these deliverables argue that “the time dimension must be considered and differentiation between temporary and permanent losses of power must be made”. Deliverable 1.5 proposes a quantification of the acceptable loss of active power injection for each synchronous zone relevant for the North Seas (Continental Europe, Nordic, Great Britain, Ireland and Northern Ireland), corresponding to the reference incident. Note that article 17 of Commission Regulation (EU) 2016/1447 lacks clarity, because the contingencies that must be considered for this requirement (e.g. single contingencies) are not specified.

Article 17 of the Commission Regulation (EU) 2016/1447 applies also to HVDC interconnectors between different synchronous areas. It implies that the capacity of a circuit of an interconnector between synchronous area A and synchronous area B (with A≠B) is limited to the minimum between the maximum loss of active power injection allowed in area A and the maximum loss of active power injection allowed in area B.

3.3 PROPOSITION OF PLANNING CRITERIA FOR AN OFFSHORE GRID

This section proposes a first draft of planning criteria that will have to be analysed further during the PROMOTioN project such that refined criteria can be proposed in the Deployment Plan at the end of the project. These provisional planning criteria established here are limited to system performance under normal conditions and following a single contingency (i.e. the two main standard categories of requirements). An additional discussion on planning criteria for DC grids can be found in the Cigré Technical Brochure 657 [5].

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3.3.1. SYSTEM PERFORMANCE UNDER NORMAL CONDITIONS

The planning criteria of an offshore grid have to first ensure that the offshore grid can accommodate the offshore load and the offshore generation under normal conditions while satisfying operational limits and being stable. It is proposed to consider, in planning, that the offshore grid is under “normal conditions” when all converters and transmission facilities are available (similarly to onshore grid).

It is then necessary to define the specific operating conditions that must be studied at the planning stage. These selected operating conditions should somehow cover all the possible range of operating conditions of the offshore grid. Because the offshore peak load (e.g. offshore oil/gas platforms) is expected to be much lower than the installed offshore generating capacity, the peak load is not expected to be a critical condition. On the contrary, the peak generation is expected to be a critical condition. It is thus proposed to analyse the peak generation, when all offshore wind generators produce at their nominal rating (i.e. maximum power output). Contrary to the AC grids, the off-peak generation (i.e. when no offshore wind generator produces power) is not expected to be a critical condition in an HVDC grid[6]. Therefore, these provisional planning criteria propose to limit the analysis to the offshore peak generation. Note that, in a radial multi-terminal or a meshed grid, the generation level does not lead uniquely to the power flows in the grid: the set-points of onshore converters also impact these power flows.

Finally, the operational limits must be defined. For AC grids, there are two sets of operational limits considered in the planning stage in steady-state analysis: thermal limits and voltage limits. It is proposed to have the same for offshore HVDC grids. The requirement is straightforward for power flows through transmission elements: under normal conditions, power flows must be below the normal (continuous) rating (no overload). For voltages at nodes, the requirement is more complex, because there is no standard value for acceptable voltages within an HVDC grid. Nevertheless, PROMOTioN’s D1.5 states that “HVDC terminal shall be capable of normal operation in a voltage range around the nominal voltage, for instance ± 5% of the nominal DC link voltage (0.95 pu – 1.05 pu)”. Therefore, it is proposed to require as a planning criterion that, under normal conditions, voltages at all nodes must be between 0.95 pu and 1.05 pu.

The proposed planning criteria for the system performance under normal conditions can be summarized as follows. When all HVDC transmission elements are available and all offshore wind generators are at their maximum (nominal) power output, it must be possible to set the onshore converters such that power flows within HVDC transmission elements are below the normal (continuous) rating and that voltages at all nodes of the offshore HVDC grid are between 0.95 pu and 1.05 pu.

[6] That will have to be confirmed by WP2.

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3.3.2. SYSTEM PERFORMANCE FOLLOWING A SINGLE CONTINGENCY

The pre-contingency state to consider for the analysis of the system performance following a single contingency is the one considered for the analysis of the system performance under normal conditions: the peak generation (i.e. all offshore wind generators are at their maximum power output) with all HVDC transmission elements available. It is proposed to consider as single contingency the loss of a converter, the loss of a cable with or without a fault and the loss of an overhead line (OHL)[7] with or without a fault. PROMOTioN's D4.1 lists the faults that could occur in an HVDC grid. It is proposed to include in the N-1 contingency analysis the "faults which need to be considered by the (main) protection system" according to that deliverable (first category of faults): pole–to-ground cable faults (permanent), pole-to-ground OHL faults (transient and permanent) and pole-to-pole OHL fault (transient). The second category of faults, considered by D4.1 as are not necessarily covered by the (main) protection system but whose detection and clearing should not lead to unacceptable damages, could be considered as exceptional contingencies (i.e. pole-to-pole cable fault, pole-to-pole OHL fault (permanent), pole-to-metallic return fault, pole-to-pole busbar, fault and pole-to-ground busbar fault). Similar to AC grids, the requirements on the system performance following a single (N-1) contingency are proposed to be the following:

1. The system must stay electrically stable[8],
2. No uncontrolled cascading outage is allowed (but the disconnection of an offshore wind farm radially connected, or an action of an automatic Remedial Action Scheme is allowed),
3. Electrical variables (e.g. power flows, voltages) must be within emergency operating limits just after the contingency, once the automatic voltage droops of converter controller have stabilized the system, and they should go back to normal (continuous) operating limits after system adjustments.
4. The permanent losses of power infeed into the onshore grids must be below the values defined by the requirements defined in PROMOTioN's D1.5 [6], reproduced in Table 3.1. Note that, in Europe, a sharing of the frequency containment reserve between the different synchronous zones is possible, which means that the overall frequency containment reserve can be less than the sum of the individual reference incidents. It is therefore proposed to interpret that requirement as follows. Following a single contingency, the loss of power infeed for a specific zone must be below the reference incident of that zone, and the global loss of power infeed in all zones must be below the maximum value of all the reference incidents in the various zones (i.e. 3000 MW in this case)[9].

Synchronous zone	Reference incident
Continental Europe	3,000 MW
Nordic	1,350 MW
Great Britain	1,800 MW
Ireland and Northern Ireland	Up to 500 MW

Table 3.1. Summary of the reference incidents in Europe [6].

[7] Overhead lines might be used to connect onshore converters to the offshore grid.
[8] The onshore AC grid must remain electrically stable according to the standard criteria. For an offshore HVDC grid, these stability criteria must be defined. Note that some parts of the HVDC grid could be fully disconnected after the fault occurrence and re-energized after the fault clearing.
[9] It is thus based on the conservative assumption that all frequency containment reserves are mutualized within Europe.

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4 METHODOLOGY TO GENERATE OFFSHORE GRID TOPOLOGIES

The optimal development (from an economic point of view) of a transmission system while considering all the planning criteria is an extremely complicated challenge that is usually broken down into successive simplified sub-tasks. It would be not only intractable to try to tackle transmission system planning with a single optimization problem, but it would also be irrelevant. Indeed, several considerations, in particular for environmental and social aspects, cannot be quantitatively modelled (e.g. through a mathematical constraint). Nevertheless, to be as close as possible to the best solution, the different sub-problems must be solved in a consistent and coordinated way. The purpose of this Chapter is to develop a methodology to generate the offshore grid topologies similar to methodologies used for traditional power system planning. In particular, a pragmatic approach based on decomposition in several sub-problems is adopted. This Chapter is organized as follows. Section 4.1 review transmission planning methodologies for both onshore and offshore grids. Section 4.2 presents the overall approach. Sections 4.3-4.5 detail then the methodologies developed to solve the successive sub-problems.

4.1 LITERATURE REVIEW

The question of the optimal development of an offshore grid is somehow similar to the general problem of Optimal Transmission Expansion Planning (OTEP) already developed in the literature on traditional (AC) onshore grids, with the major difference that the purpose of the grid expansion is not the same. Indeed, onshore grids are usually planned to supply the power demand at an economic cost, while offshore grids must be planned to evacuate the offshore power generation and to exchange power between countries at an economic cost.

The OTEP problem consists of determining the optimal transmission capacities that should be installed (or not) between the nodes of the grid. Early applications of OTEP techniques on real grids can at least be traced back to the 1970s [7]. Since then, considerable work for traditional (AC) onshore grids has been performed in that field, differing in the level of details considered and approximations done. Indeed, trade-offs must be made between the relevance of the mathematical model developed and the possibility to actually solve it. These details and approximations can be classified along three main streams:

1. The way transmission capacities between nodes are defined: either in a continuous fashion [8] [9] or in a discrete fashion [10] [11]. Because real lines or cables have discrete ratings, the second one is closer to reality, but needs the introduction of binary (or integer) variables in the optimisation problem, that complicates the numerical resolution of that problem.
2. The way the time horizon is considered: either only a specific target year is considered (the model implicitly assumes that all years are similar to that target year) [11], or a planning period comprising several years or

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several decades is considered [8]. In the first case, optimal investments are found but not their optimal commissioning dates, while the second case also optimises the commissioning dates. That second case provides more information to the planner and guarantees that the planned grid satisfies the planning criteria for each year, but leads to larger optimization problems much more difficult to solve.

3. The way the power system is modelled. The simplest way is the so-called transportation model [8]. In such a model, power can be transferred through the grid wherever there is free capacity, under the constraint of transfer capacity between nodes. Kirchhoff's current laws are enforced, but Kirchhoff's voltage laws are not considered. When Kirchhoff's voltage laws can play a significant role in congestions (in particular in meshed grids), the power flow equations must be used, either through their linearized version [11] or their complete version [12] [13]. The consideration of Kirchhoff's voltage laws in the optimization problem complicates the numerical resolution of that problem.

Note that, when transmission capacities between nodes are defined in a continuous fashion, only a transportation model can be used. On the other hand, the combined use of discrete transmission capacities and the complete version of the power flows equations leads to MINLP optimization problems that are numerically challenging to solve. The choice of the level of details considered and approximations done is then of paramount importance in order to have a meaningful optimization problem that could be actually solved.

If the OTEP was initially developed for onshore (AC) grids, several works adapted it to the case of offshore (HVDC) grids [14] [15] [16] [17] [18]. However, to the best of the authors' knowledge, existing works for offshore grids optimize only the grid topology for a specific target year: no time evolution is considered. In the context of offshore wind energy evacuation, the time evolution is of paramount importance: offshore wind farms are developing progressively. It is thus not sufficient to know what infrastructure must be installed within a long time period, but it is also crucial to know when each element must be commissioned, so that the offshore grid is viable and fulfils operational criteria at every moment. Additionally, power flow equations within the HVDC grid are usually not considered. The methodology developed in this chapter aims to overcome the usual limitations by developing a pragmatic approach to generate offshore grid topologies.

4.2 PROPOSED APPROACH

The general question that an approach to generate offshore grid topologies must try to address can be defined as follows: *Given the location, generating capacity and commissioning dates of future offshore wind farms, and the evolution of the load and generation mixes in the relevant countries, what is the best way to develop an offshore grid to connect the offshore wind farms and the relevant countries together?* Such a question is extremely difficult to answer, especially because it would be intractable to solve a single optimization problem taking into account every single aspect of the problem. The approach proposed here is inspired by the classical decomposition of the transmission expansion planning problem in three phases that is used for traditional AC grids:

1. Determination of the global transmission and interconnection needs on the principal axes of the network (i.e. between major hubs of the network),

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2. Elaboration of an actual grid expansion plan(s) on the basis of these global needs, such that this plan fulfils the technical requirements,
3. Detailed assessment of the costs, the benefits and the economic viability of the resulting grid expansion plan(s).

This approach leads to tractable successive problems. Note that it does not result in the true optimal grid, but it should result in a close-to-the-optimum solution.

The first step, the determination of the global transmission and interconnection needs, can be formulated as an OTEP problem with simplification of the technical constraints to consider. Finding an optimal transmission expansion planning implies the definition of an objective function: the planning is “optimal” when the value of the objective function is minimal. As explained in the literature review in previous section, the objective function in an OTEP problem represents typically the cost, but there is no unique approach about the costs components to consider. The cost must include at least the CAPEX, i.e. the investment cost linked to new transmission assets. In addition to that, some models include also an estimation of the OPEX, i.e. the generation cost and, potentially, the load shedding cost (if load shedding is allowed). The consideration of the OPEX is more complex, not systematic and depends on the planning philosophy. Because the main purpose of the draft roadmap presented in this report is to evacuate offshore wind energy, the chosen objective function corresponds to the offshore grid infrastructure cost (i.e. CAPEX) only: the offshore grid must be able to evacuate the offshore wind energy at the lowest infrastructure cost. However, as stated in the introduction, the purpose of an offshore grid can be also to allow exchange of energy between different countries. That part of the benefit is not valued in the objective function used to size the grid in this draft roadmap, but could nevertheless impact the structure of an actual offshore grid in the North Seas. PROMOTioN’s WP12 will study the impact of international power flows on the offshore grid structure. In summary, the first step finds the global transmission needs by solving a multi-time-steps OTEP problem such that the offshore wind energy can be evacuated at the lowest investment cost. Section 4.3 details the approach followed for that purpose.

Once the global transmission and interconnection needs have been determined, the design of the offshore grid must be refined such that it is technically viable and, in particular, it meets the planning criteria. The methodology followed to reach a more detailed design is explained in section 4.4.

Finally, the economic viability and the level of adequacy of generated offshore grid topologies must be evaluated by assessing more precisely the benefits brought by the grid, especially the generation cost savings. The probabilistic approach that will be followed for that purpose is described in section 4.5.

4.3 OPTIMAL TRANSMISSION EXPANSION PLANNING

As detailed in the literature review section, there is no unique formulation of the OTEP problems. Before writing down the mathematical formulation, it appears thus important to define the features that must be considered by the optimization problem:

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- To be closer to the reality and to have meaningful results, the transmission capacities between HVDC nodes will be defined here in a discrete fashion, corresponding to the different possible ratings of HVDC circuits. Note that, in a symmetric monopolar or in a bipolar configuration, the rating of a circuit is twice the rating of a cable.
- In order to not only estimate ideal target structures at a single point in time, but also to estimate how an offshore grid could evolve over a time period, the OTEP problem will be formulated as a multi time-steps optimization problem.
- A transportation model will be used to model power flows in the grid.

Given these features, the problem can be defined in a way very similar to previous formulations, as shown in section 4.3.1. However, a significant difference between our situation and traditional OTEP problems is that we cannot take advantage of any existing network. Indeed, OTEP formulations were traditionally developed for the expansion of existing grids, with a limited number of candidate circuits reinforcing critical areas or corridors of the grid identified beforehand. Therefore, even if studied networks could have several hundreds of nodes, the number of candidate circuits is usually limited to several tens. The case of the development of a meshed offshore grid in the North Seas translates in almost a “greenfield” from a power system point of view (i.e. only few existing connections far from the shore). It is thus not possible to execute a “first pass” in the network to identify the few most suitable locations for investment and thereby reduce the number of candidate circuits. Nevertheless, it would be intractable to consider as candidate circuits each direct connection between any pair of nodes. Indeed, the number of binary variables is proportional to the number of candidate circuits and MIP problems do not scale well to a large number of binary variables. Consequently, a pragmatic approach is needed to identify appropriate candidate circuits. This approach is described in section 4.3.2.

4.3.1. MATHEMATICAL FORMULATION

The following indices, sets, variables and parameters will be used to formalize the OTEP problem:

- **Indices and sets**
  - $t \in [1, T]$: Index and set of years
  - $k \in K$: Index and set of HVDC circuits
  - $n_w \in N_w$: Index and set of offshore nodes
  - $n_c \in N_c$: Index and the set of onshore nodes (connection points of the offshore grid on the shores)
  - $n \in N = N_w \cup N_c$: Index and set of nodes (offshore and onshore)
- **Variables**
  - $x_{k,t}$: Binary variable indicating the presence or not of HVDC circuit k during year t
  - $y_{n_w,t}$: Binary variable indicating the presence or not of candidate offshore substation at node n_w during year t
  - $p^f_{k,t}$: Power flow in HVDC circuit k for the peak offshore wind generation during year t [p.u.]
  - $p^l_{n_c,t}$: Power evacuated from the offshore grid at the onshore node n_c during year t [p.u.]
- **Parameters**

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- T: Number of years in the planning horizon
- P_k: Maximum power flow in HVDC circuit k
- P_{n_c}: Maximum power evacuation (hosting capacity) at onshore node n_c
- P_{n_w}: Peak offshore production at offshore node n_w
- $I_{n,k}$: Incidence matrix whose elements are equal to 1 if the HVDC circuit k starts at node n, -1 if it ends at node n, and 0 otherwise
- $\gamma_{k,t}$: Discounted cost of HVDC circuit k at year t
- $\delta_{n_{w,t}}$: Discounted cost of an offshore substation at node $n_w$at year t
- M: Sufficiently high number needed to express the need of offshore substations in a linear way, chosen at 200 for this study
- ρ: Actualization rate
- τ: Lifetime of a DC circuit, in years

On the basis of these notations, the optimization problem can be formulated as follows.

$$\min \sum_{k\in K} \sum_{t\in[1,T]} \gamma_{k,t}(x_{k,t} - x_{k,t-1}) + \sum_{n\in N} \sum_{t\in[1,T]} \delta_{n,t}(y_{n,t} - y_{n,t-1}) \tag{1}$$

such that

$$\sum_{k\in K} I_{n_w,k}\, p^f_{k,t} \;=\; P_{n_w}\; \forall n_w, t \tag{2}$$

$$\sum_{k\in K} I_{n_c,k}\, p^f_{k,t} \;+\; p^l_{n_c,t} = 0\; \forall n_c, t \tag{3}$$

$$0 \le p^l_{n_c,t} \le P_{n_c}\; \forall n_c, t \tag{4}$$

$$-\, x_{k,t}\, P_k \le p^f_{k,t} \le x_{k,t}\, P_k \forall k, t \tag{5}$$

$$x_{k,t} \ge x_{k,t-1}\; \forall k, t \tag{6}$$

$$\sum_{k\in K} |I_{n_w,k}|\, x_{k,t} - 1 \le M\, y_{n_w,t}\;\; \forall n_w, t \tag{7}$$

$$y_{n_w,t} \ge y_{n_w,t-1}\; \forall n_w, t \tag{8}$$

Equation (1) describes the objective function to minimize, the actualized total investment cost. This investment cost is the sum of the costs of the HVDC circuit and of the costs of the offshore substations. Note that the cost of converters and circuit breakers is not considered in that objective function. For each year, the sum comprises the cost of circuits commissioned that year. Indeed, as $x_{k,t}$ represents the existence of line k at year t, $x_{k,t} - x_{k,t-1}$ gives whether line k was installed at year t or not (with $x_{k,0} = 0$). The same rationale applies for the substations. Equation (2) enforces the power balance at offshore nodes: the peak offshore production at offshore node n_w must be entirely evacuated by HVDC circuits connected to that node. Equation (3) enforces the power balance at onshore nodes: the algebraic sum of power flows on HVDC circuits connected to the onshore node n_c must be absorbed by HVDC converters connected to that onshore node. Equation (4) limits the power that must be absorbed by an onshore node to the hosting capacity of the onshore grid. Equation (5) constraints the power flow through HVDC circuits to their nominal rating. Equation (6) indicates that once a

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HVDC circuit has been commissioned, it cannot be decommissioned later on[10]. Equation (7) enforces the commissioning of an offshore substation at the offshore node n_w if more than one HVDC circuit is connected to that offshore node. Finally, equation (8) indicates that once an offshore substation has been commissioned, it cannot be decommissioned later on.

4.3.2. IMPLEMENTATION DETAILS

The typical chosen scenario consists of 72 offshore nodes and 32 onshore nodes, potentially connected by 4 different types of cables over a planning horizon of 11 years (from 2020 to 2030, boundaries included). If every connection between any pair of nodes was considered, the resulting problem would have 235664 binary variables related to lines only. It appears that such a problem cannot be solved with state-of-the-art algorithms on usual computing facilities in a reasonable amount of time. Fortunately, most of these connections do not make sense, as mostly neighbours will be connected to each other. Therefore, we can limit our set of candidate lines to the ones connecting closest neighbours. In our implementation, we included all connections from an offshore node to its 5 closest neighbours, plus the closest onshore node. It results in 256 candidate connections for the North Sea, represented in Figure 4.1. On that figure, blue dots represent onshore substations, while red dots represent offshore wind farms (axes in km). The candidate topology has a disconnected structure (i.e. several parts not connected together by candidate circuits), allowing further decomposition of the problem. However, the resulting problems for some of the parts remain intractable. Therefore one final simplification is made: the time horizon is split in slices of 4 years, reducing the number of variable in each optimisation problem. Values used in the optimization problem are given in Appendix A.

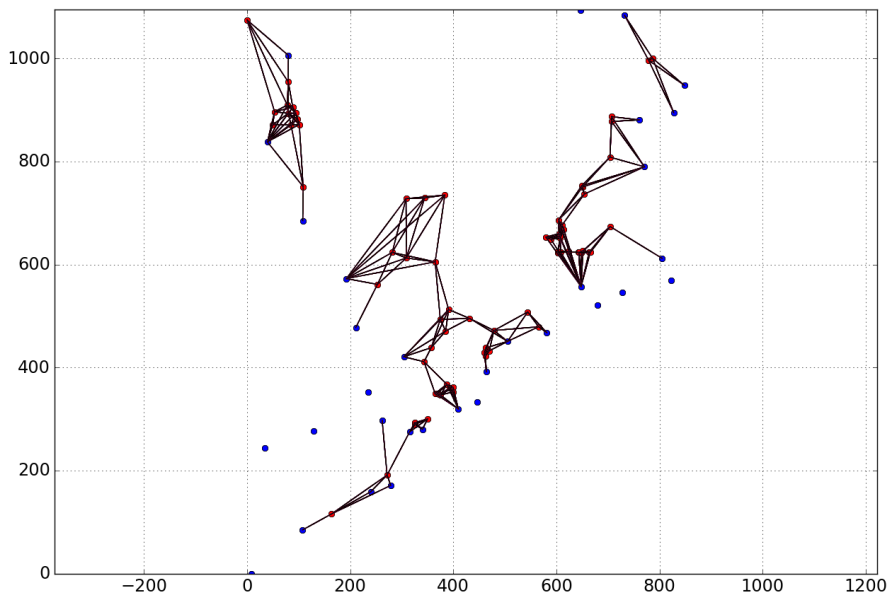

Figure 4.1. Candidate circuits in the OTEP problem.

[10] In theory, a circuit or a substation could be decommissioned, but with a specific cost that is not considered in the model as it stands: considering that $x_{k,t}$ could be lower than $x_{k,t-1}$ would lead to a negative cost in the objective function which is unrealistic.

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4.4 DETAILED DESIGN

The optimization problem formulated in previous section will lead to the selection of the candidate circuits that have to be commissioned in order to evacuate all the offshore wind energy at the lowest cost. However, some simplifications were made in the mathematical formulation. One of them is the negligence of the Kirchhoff's voltage law: a transportation model was used. Consequently, the technical viability of the proposed solution while considering the full power flow equations must be checked and adaptions must be made if the solution of the OTEP problem does not comply with the planning criteria. Solving the power flow equations for the offshore HVDC grids is thus the first step of the technical analysis. Power flow equations for HVDC grids will be used for that purpose, as described in [19]. Moreover, the optimization problem focuses on the topology and does not consider converters and circuit breakers. A more detailed technical analysis is needed to determine which converters can be used and where DCCBs are needed.

4.4.1. ASSUMPTIONS

- **Constrained power flow**

The OTEP results are converted to a readable file format which provides the network topology and the active power injection at each offshore windfarm. However, this does not uniquely define the power flow in the grid. The power flow problem is solved in order to assess whether the topology proposed by the OTEP algorithm is actually able to evacuate all the wind energy produced by the offshore windfarms. Therefore, the flow on each DC line is constrained by the DC line rating. The converters control and set-points are adjusted in order to find at least one operating point able to evacuate all the wind energy without overloading of DC lines or converters.

The N-1 security criterion is not fully considered in this draft roadmap. There are too many uncertainties regarding converter controls and acceptable criteria for a meshed offshore DC grid to present a comprehensive analysis. The N-1 cases considered here assess whether there is an acceptable post contingent steady-state operating point. It is assumed that it is acceptable to lose a power infeed to the AC grid smaller than the value shown in Table 3.1. It is also assumed that each converter can change its set-point in order to avoid overloads on the remaining lines. In operation, it is expected that the meshed DC grid could be composed of:

- A non-linear local controller which avoids the overload and over-/under-voltage of equipment,
- A master dispatch controller which optimizes the N-1 load flow.

This report only evaluates the use of the non-linear local controller. Therefore, wind curtailment is allowed in N-1 as long as the reduced injection to the AC system is acceptable. The N-1 contingencies are limited to line outages and converter outages. DC bus outages are not considered in the N-1 contingency list. The N-1 post-contingent load flow is evaluated after every single contingency.

- **DC bus configuration**

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Each DC bus is modelled as a solid bus. In reality, it is expected that DCCBs on a DC bus can be used similarly to AC CBs on an AC bus. However, it needs to be confirmed whether DCCB can be used to split a bus following a bus fault. It also needs to be confirmed whether there are limitations on DCCBs regarding short-circuit current or maximum power infeed that can be connected to a single CB. The detailed design of each DC bus and the number of DCCBs required will have an impact on the OTEP results. It is assumed in this study that DCCBs can be used similarly to AC CBs (i.e. to clear DC bus faults and to discriminate faults on really short lines).

4.4.2. IMPLEMENTATION DETAILS

- **Meshed HVDC network equations**

For this particular study, we are almost exclusively interested in the DC part of the equations. Therefore, each offshore windfarm AC network is represented by an individual equivalent machine, and each onshore converter station is represented by a separate equivalent load. The onshore AC network connections are not represented but a maximum hosting capacity is defined for each onshore converter. It is assumed that the AC network is able to cope with this hosting capacity value. Note that strong limitations could come from the hosting capacity of the AC grid and, for that reason, it is not necessarily the best solution to connect offshore wind farms to the closest onshore connection point.

The converters are assumed to be bipolar VSC converters. Note that the following equations stay valid for VSC in symmetrical monopole configuration. Each converter has two degrees of freedom, because the converter voltage on the AC side can be controlled in amplitude and phase. The degrees of freedom can be used to simultaneously satisfy two criteria [20]:

$$P_{ac} = P_{ref} \text{ and } U_{ac} = U_{ref} \tag{9}$$

$$P_{ac} = P_{ref} \text{ and } Q_{ac} = Q_{ref} \tag{10}$$

$$P_{ac} = P_{ref} \text{ and } cos\varphi = (cos\varphi)_{ref} \tag{11}$$

Where the index *ac* refers to the AC side of the converter and *ref* is the set-point of the controller. When the converters are coupled by means of a DC network, one degree of freedom is lost as far as active power setpoints are concerned. This is because the total active power entering the converters must equal the total active power leaving the converters (minus the losses). In other words: there is no energy storage in the DC network. This is mathematically expressed as:

$$\sum_{i=1}^{n} P_i = P_{loss}$$

This means that one converter needs to balance the power and cannot freely choose the active power setpoint. In analogy to AC systems, we call this converter the 'slack converter'. Note that the slack converter will not directly regulate the active power but the DC voltage. Similarly to AC grids, the choice of the slack converter is

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not crucial in system studies when the power imbalance to absorb by this slack is small. However, when the power imbalance is non-negligible, the choice of the slack could impact the results and a “distributed slack converter” (i.e. several converters acting as slack together) might have to be used to provide meaningful results. The degrees of freedom of the slack converter can thus be used in the following way:

$$U_{dc} = U_{dcref} \text{ and } U_{ac} = U_{ref} \tag{12}$$

$$U_{dc} = U_{dcref} \text{ and } Q_{ac} = Q_{ref} \tag{13}$$

$$U_{dc} = U_{dcref} \text{ and } cos\varphi = (cos\varphi)_{ref} \tag{14}$$

Where the index ac refers to the AC side of the converter, dc refers to the DC side of the converter and ref is the set-point of the controller.

For the DC network side equations, the simplified example shown in Figure 4.2 illustrates how the current on each line is calculated in a meshed DC network.

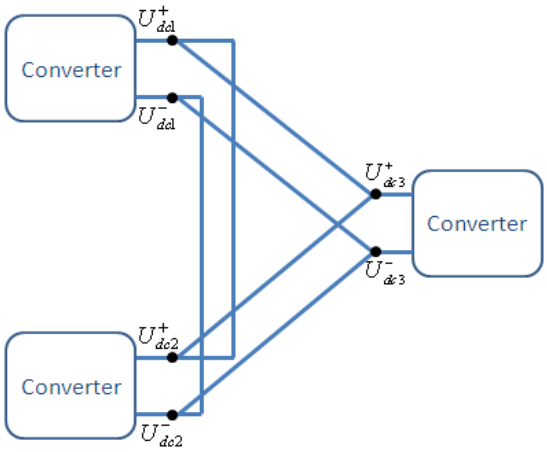

Figure 4.2. Example of HVDC meshed network.

Illustration of DC network equations in symmetrical monopole configuration:

$$I^+_{dc1} = \frac{U^+_{dc1} - U^+_{dc3}}{R_{13}} + \frac{U^+_{dc1} - U^+_{dc2}}{R_{12}}$$
$$I^-_{dc1} = \frac{U^-_{dc1} - U^-_{dc3}}{R_{13}} + \frac{U^-_{dc1} - U^-_{dc2}}{R_{12}} \tag{15}$$

$$I^+_{dc2} = \frac{U^+_{dc2} - U^+_{dc3}}{R_{23}} + \frac{U^+_{dc2} - U^+_{dc1}}{R_{12}}$$
$$I^-_{dc2} = \frac{U^-_{dc2} - U^-_{dc3}}{R_{23}} + \frac{U^-_{dc2} - U^-_{dc1}}{R_{12}} \tag{16}$$

$$I^+_{dc3} = \frac{U^+_{dc3} - U^+_{dc1}}{R_{13}} + \frac{U^+_{dc3} - U^+_{dc2}}{R_{23}} \tag{17}$$

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$$I_{dc3}^{-} = \frac{U_{dc3}^{-} - U_{dc1}^{-}}{R_{13}} + \frac{U_{dc3}^{-} - U_{dc2}^{-}}{R_{23}}$$

Where I_{dc} is the DC current and U_{dc} the DC voltage. The subscript + or – indicates the positive and negative poles of the converter.

Note that no DC/DC converters were used in this analysis: the same nominal voltage is thus assumed on the whole meshed HVDC grid.

- **Interface OTEP → Detailed Design**

The OTEP algorithm provides a file which describes the topology, cable rating, converter rating and windfarms generation. The topology is provided for each year from 2020 to 2030 and for multiple scenarios.

Offshore windfarms

Each offshore windfarm is modelled as a single equivalent machine which produces an active power equal to the installed wind capacity, in line with the planning criteria (i.e. offshore peak generation must be analysed). This equivalent machine is connected to a VSC converter station composed of converter transformers, two VSC converters in bipolar configuration.

HVDC hub

An offshore converter station where more than one DC line/cable is connected is called a DC hub. No particular control is used at the HVDC hub. If one windfarm is connected to the hub, the converter control is set to active power control, similarly to all the others windfarm converter stations.

Onshore converter stations

Each onshore converter station is connected to an equivalent machine (which absorbs or injects active power). The converter station can import or export active power up to a pre-defined hosting capacity value. For the analysis in N state, all but one converter station are in active power control mode. The remaining converter station is in voltage control model and acts as a slack bus when there is only one slack bus[11]. For the analysis in N-1, there is an iterative process that evaluates the steady state voltage deviation at each DC bus pre and post-contingency. Based on this voltage deviation, the active power set-point is increased (or decreased) at the corresponding converter.

4.4.3. SUMMARY

Need for a common file exchange

It was quickly identified that an interface was needed between the OTEP algorithm and a power system simulation software. From the point of view of a planning engineer, the network design has to be evaluated by analysing the flows for a given set of scenarios. One major difficulty is that load flow results will be different

[11] As explained earlier, a distributed slack bus can also be used.

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depending not only on the scenario but also on the converter controls and set-points. In other words, fixing the generation does not uniquely define the load flow. To mitigate this problem, a coordinated planning among the involved TSOs could be required and some information about the converter controls will have to be exchanged. It is therefore suggested to use a common file format for coordinated planning and operation of a meshed HVDC network in the North Seas. The complexity of the meshed HVDC network is highly dependent on the exchange of information and coordination between the different actors. It has been shown in this study that an adequate use of the HVDC converter controls could be used to evacuate all the offshore wind energy with the proposed topologies.

Contingency analysis results are dependent on HVDC control and protection philosophy

Theoretically, HVDC converters have the ability to quickly adjust the flows on DC lines to avoid the overload of the remaining lines following a contingency. Therefore, there is more flexibility in fast post-contingent actions than in the AC network. A voltage droop control could be used to mitigate post-contingency over- and under-voltage problems. Overloads could also be mitigated by integrating dedicated controls to the adequate converter. Therefore, by considering that converters have the ability to perform remedial actions and that loss of power infeed to the AC network is acceptable, the N-1 simulation results do suggest to reinforce the proposed network topology. The main outcome of the N-1 analysis is that the rating and number of parallel cables should be carefully considered. Transient simulations have not been performed. It is also assumed that DC CBs perform properly and are able to discriminate faults, even DC bus faults and faults on short DC lines.

Ratings of parallels cable must be carefully considered

Initially, the OTEP topology proposed to reinforce successively HVDC cables over the years. For example, the OTEP might suggest using first a 1200 MW cables for the first expansion stage and then a parallel with 800 MW cable for a second expansion stage. This could happen because the OTEP algorithm does not consider the Kirchoff's voltage law. Obviously, the current is not split according the rating but according to the cable resistance and the cable capacity might be limited below the installed rating. Note that from our simulations, the maximum cable overload for parallel cables having different ratings was around 5%. It is therefore concluded that a careful design should be sufficient to mitigate this.

4.5 ANALYSIS OF THE ECONOMIC VIABILITY

This section presents the methodology for evaluating the economic viability of the optimized offshore grids in the North Sea. To assess the economic viability, we need estimation of the costs on one side, and of the benefits on the other side. Costs are directly deduced from the previous steps, because they correspond to the infrastructure costs. Benefits valued for transmission projects are usually the generation cost savings that correspond to the change in the socio-economic welfare. Indeed, reinforcing the transmission system can alleviate congestions, and can thus allow a more efficient use of generating units (i.e. a more economic dispatch). Estimating the benefits brought by transmission projects, and in particular by an offshore grid, requires thus to estimate the annual (variable) cost of generation. The latter is estimated usually through a

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market study. Market studies are used to simulate the dispatch of generating units by mimicking perfect market behaviour.

The first part of the analysis of the economic viability is thus the development of a market model detailed enough to optimize the hourly evacuation of the offshore wind generation along a year, as well as the exchanges through the meshed offshore grid, within the electricity market of the North Sea's countries. On the other hand, the market model needs to be simple and easy to apply to different grid topologies and target years. The perimeter of the model is limited to the North Sea's countries.

Once the economic benefits have been estimated by the market study, they must be compared to the costs to evaluate the economic viability. The second part of the analysis consists thus in defining a cost-benefit analysis methodology suited for the evaluation of the economic viability of the meshed offshore grid. As for the market model, this methodology shall strike a balance between being applicable iteratively to several target years and a meaningful quantification of the economic benefits or barriers associated to the development of the offshore grid.

4.5.1. MARKET STUDY

Market studies aim at simulating the steady-state behaviour of a power system (i.e. the dispatch of generating units, the potential activation of demand response, the potential shedding of loads in case of lack of generation), in order to estimate economic and adequacy indicators. In order to lead to relevant results, market studies must try to mimic the way the system is operated and they must thus consider operating rules of the power system, including market constraints.

In that context, the transmission power system can be represented in various ways: through a single node (copper plate model), through multi area, or through a detailed grid model. In a multi-area model, the power system is decomposed in different market (bidding) areas with the assumption that no (major) congestion occurs within an area (internal grid constraints are neglected). Power exchanges between areas can be considered in two different ways: in ATC-based (or NTC-based) market studies, Kirchhoff's voltage law is completely neglected and the power exchanges between market areas are limited by the ATCs (or the NTCs). It corresponds to the market organization that was in place in continental Europe just before the implementation of the Flow-Based market coupling in 2015, and remains the market organization in several parts of Europe. Note that such an ATC-based multi area market model is also used in market studies performed for the ENTSO-E TYNDP. The alternative way to consider power exchanges between areas in a multi-area model is through a flow-based representation. In that case, the linearized version of power flow equations is used to limit the power exchanges between areas but generic assumptions are made on the power dispatch within each area through Generation Shift Keys (GSKs). Finally, in a detailed grid model, power flow equations are considered in detail, without any notion of area. The linearized version of these equations (DC power flow) is generally used.

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Simulating the behaviour of a power system in the presence of hydro dams, storage and demand response is not straightforward. For this reason, different models exist, translated in different software tools. For drafting this roadmap, the market study will be carried out through the use of the SCANNER software tool developed by Tractebel, which optimizes the behaviour of the electricity market for a one year period in hourly time steps. SCANNER is characterized by a sequential Monte Carlo simulator of generation and transmission systems. Monte Carlo (MC) simulation is used to extract random forced outages of generating units and transmission elements and the stochastic behaviour of RES. For each hour of a year, operating costs are optimized under operating constraints (e.g. thermal rating of transmission elements). For each Monte Carlo year, a scenario on the overall studied year is generated by sampling the uncertainties linked to random outages and stochastic behaviour of RES, and the economic dispatch of the generators is then carried out by minimizing their operating cost for three different time horizons, in a progressive manner.

Modelling uncertainties

Two kinds of uncertainties are stochastically modelled by SCANNER: random forced outages of generating units and transmission elements, and the stochastic behaviour of RES and hydrological inflows. Both planned and unplanned outages of generating units are sampled by SCANNER, on the basis of probability laws (Weibull laws) describing the times to failures and the times to repair. The drawback of this assumption is the lack of seasonality for the planned maintenances. The stochastic behaviour of RES is managed by providing different hourly wind and solar profiles to the tool. Several regions can be modelled, each with their own wind/solar potential. If several hourly profiles are provided for a same region (e.g. for accounting for the annual variability), SCANNER samples one of them for each Monte Carlo simulation.

Minimizing the operating cost

Once the Monte Carlo scenario is defined for the selected year, SCANNER performs the economic dispatch of the generators by minimizing the operating cost in three steps:

- The first step is the annual allocation of hydrological resources.
- The second step is the daily unit commitment of generators, performed in day-ahead.
- The third step is the intraday economic dispatch.

The annual allocation of hydrological resources optimizes the amounts of hydroelectricity that will be used during each week of the year by minimizing the total operating cost during the overall year. Different time granularities can be used, but each week is usually represented as a single point in time.

The daily day-ahead unit commitment of generators optimizes the commitment of thermal generators by minimizing the total operating cost during one week. In this optimization problem, the time granularity is one hour, RES generations and load demands are supposed to be perfectly known and dynamic constraints on thermal units are considered (minimum/maximum output levels, minimum up and down times, maximum ramping rates). Constraints on hydrological resources coming from the annual allocation are enforced.

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However, having a hard constraint on the use of hydrological resources in the day-ahead unit commitment, or in the intraday economic dispatch, leads to two main drawbacks:

- An unanticipated surplus of RES will be spilled instead of being stored,
- An unanticipated shortage of generation will lead to load-shedding even if an additional use of hydroelectricity could avoid that.

The issue is tackled by converting these hard constraints into soft constraints through the use of virtual costs. SCANNER is thus based on a soft constraint on the use of hydrological resources: virtual costs (penalties) are associated with the potential deviation between the actual use and the planned use. If the level of reservoirs is lower (e.g. due to unexpected unavailability of thermal units that entails a higher need of hydro generation) than previously defined, a malus [€/MWh] is applied: a deviation on the use of hydrological resources is preferred to load shedding. On the other hand, if the level of the reservoir is higher than expected (because of higher renewable production) a bonus [€/MWh] is used: a deviation on the use of hydrological resources is preferred to the curtailment of RES. However, those virtual costs have the drawback of affecting the marginal costs when deviation occurs and therefore affect the average zonal costs and the social welfare. The occurrence of this deviation is monitored and, if necessary, a posterior adjustment of the electricity marginal cost in the area affected can be implemented.

The intraday economic dispatch optimizes the generation of each generating unit by minimizing the total operating cost for each hour, considering maximum output levels and maximum ramping rates. The curtailment of wind and solar power generation is the amount of available energy not actually used.

Note that the network model (i.e. single node, multi-area model, model based on the linearized version of the power flow equations) used to solve the optimization problem can be different at each step of the simulation.

4.5.2. COST BENEFIT ANALYSIS

The results of the market optimization is then analysed through a simplified cost-benefit analysis (CBA). The benefits of transmission infrastructures such as offshore meshed grids can be numerous. For example, the ENTSO-E guideline for CBA of grid development projects [21] list the security of supply (adequacy to meet demand and system stability), the increase of the socio-economic welfare, the improved RES integration, the decrease of losses, the decrease of CO_2 emissions. Other benefits might be generation investment cost savings, competition benefits, etc. However, this draft roadmap will perform only a simplified CBA by focusing on the increase of the socio-economic welfare equivalent to the Generation Cost Saving (GCS) when the load is considered as inflexible (which is the case in the market study performed in this draft roadmap). Note that guidelines for CBA of offshore meshed grids should be established within WP7 and a more detailed CBA should be performed within WP12 on the basis of these guidelines. The variable cost of generation is expected to be lower for the meshed case compared to the radial case, even if the wind energy generated along the year is the same for both, for two reasons: the actual evacuated wind energy might not be the same due to outages of elements (i.e. the meshed solution provides redundancy) and the actual generation cost might be lower in the meshed case due to commercial exchanges between countries. For the studied year, the economic benefit is

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thus calculated from the reduction in total variable generation costs in the study perimeter, associated to the optimized meshed offshore grid with respect to the radial configuration, as summarized below:

$$\text{Generation Cost Saving [M€]} = \text{Total Generation Cost}_{\text{opt.meshed}}\ [\text{M€}] - \text{Total Generation Cost}_{\text{radial}}\ [\text{M€}]$$

The advantage of using the GCS indicator is its direct quantification of the contribution of the optimized meshed offshore topologies to the integration of the offshore wind energy into the North Sea's electricity markets. The underlying assumption associated to this indicator is the inelasticity of demand to the price. In pre-feasibility studies, this simplification is acceptable.

The investment cost (CAPEX) is then compared to the GCS value. To ease the comparison between investments in different years, both the GCS and the CAPEX are actualized using a single discount rate for the whole period and perimeter studied. For each studied topology, the economic surplus is calculated by subtracting the actualized investment costs from the actualized GCS.

In later stages of the PROMOTioN project, more than one possible development path will be conceived and analysed over a longer time period. Each development path will consist of a series of couples, each one composed of a target year and a configuration. The CBA methodology can be extended to provide the Net Present Value of each studied path, as the sum of the actualized economic surplus of each couple (year, configuration).

In conclusion, this simplified CBA methodology allows a straightforward but meaningful assessment of the economic viability of the optimized offshore grid topology, providing also the flexibility required to assess various development paths.

4.5.3. IMPLEMENTATION DETAILS

In the framework of the draft roadmap, the economic viability of the optimized offshore grid will be assessed for the year 2030, considered as a meaningful sample year to raise open questions and problems to be tackled during the course of the project. Nevertheless, the methodology hereby developed is meant to be applied seamlessly to longer time periods.

A reference scenario for potential installed wind capacities in the Northern Seas and the load/generation of surrounding countries is defined in PROMOTioN's Deliverable 1.4 [2]. In particular, for 2030, the Vision 3 "National Green Transition" of the ENTSO-E TYNPD 2016 has been selected as reference. The available market modelling data of the TYNDP 2016 (i.e. net generating capacities, generation basic models, fuel and CO_2 prices, NTCs and demand hourly profiles) will thus be used for the simulation of target year 2030. Details on load and installed capacity are reported in Appendix A.2.

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A key factor impacting the results of the market studies is the network model chosen. As explained in section 4.5.1, the model should correspond to the market design. The approach followed by the ENTSO-E TYNDP is the use of a multi-area model consistent with the current organization of the European power market[12]: nearly each country is considered as a single market area (some countries are divided into several market areas), and power flows between market areas are limited by the corresponding NTCs. The consideration of a meshed offshore grid in the North Seas is not straightforward in the market simulation, in particular because there is neither a clear market design nor clear operating rules yet. For example, each current national bidding area could include the corresponding national part of the meshed offshore grid, or a unique market area could be created for the meshed offshore grid, etc. This draft roadmap will make use of the ENTSO-E approach (i.e. ATC-based multi-area model) for everything outside the meshed offshore grid (i.e. onshore grid, onshore load and generation, offshore generation not part of the meshed offshore grid), but will use a detailed grid model for the meshed offshore grid. In that way, the maximum benefits brought by the meshed offshore grid will be estimated. Consequently, the offshore wind farms that are part of the meshed offshore grid are modelled singularly and connected to the mainland and to each other through branches representing the actual optimized grid topology and sizing. These inputs are obtained from the results of the optimal transmission expansion planning and the detailed design phases.

The market study will be limited to the meshed offshore grid and the countries surrounding the North Sea. The countries included in the perimeter of the studies[13] and the corresponding market areas are following:

- Belgium (BE)
- Germany (DE)
- Denmark (DKW and DKE)[14]
- France (FR)
- The Netherlands (NL)
- Norway (NO)
- Sweden (SE)
- Great Britain (UK)

Several wind profile sets have been defined. Each set is associated to a cluster of offshore wind farms geographically close together. Eleven different clusters have been established, using a distance-based clustering algorithm to identify the coordinates of each cluster's centre (centroid) and the wind farms associated to it. The selected algorithm implements a Mean-Shift clustering methodology, consisting in a mode-seeking algorithm for clustering data points based on their density in the metric space. This methodology is extensively described in [22]. This approach has been chosen for the following advantages it provides over other clustering algorithms:

[12] With the following difference: the multi-area model of the TYNDP makes currently use of an ATC-based representation of the market, and not a flow-based representation.
[13] The GCS is thus related to the variable costs of the generation in these countries.
[14] The subdivision of the Danish system into two regions, Denmark West (DKW) and Denmark-East (DKE) corresponds to the fact that they are connected in an asynchronous way through an HVDC interconnection and follows the same approach adopted by ENTSO-E for the TYNDP.

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- It is able to identify clusters with arbitrary shapes;
- The number of clusters is not pre-determined by the user. The algorithm identifies the number of clusters and their centroids based on regions with higher point concentration (modes).

The assumption on the wind profiles reduces the complexity of the economic optimization problem while still keeping different generation patterns within the offshore grid.

The optimised offshore grid will be superimposed on the existing and planned interconnections across the North Sea described in the ENTSO-E TYNDP2016. The development of these interconnectors affects the energy exchanges on the offshore grid. Hence, particular attention has been dedicated to the assumptions on the NTCs between the countries interconnected across the North Sea, which have been assessed on a case by case basis, taking into account the status of each interconnection project. Only the interconnection projects with low degree of uncertainty have been considered in the market model. Following the classification adopted by ENTSO-E for the TYNDP, only the mid-term projects have been taken into account, i.e. the ones in an advanced stage of development and foreseen to be commissioned around 2020. The long-term and future projects, expected to be commissioned by 2030 or in early stages of development, have been neglected. The resulting NTC values are close to the 2020 expected progress value of the TYNDP 2016 with minor variation. The list of the interconnection projects in the North Sea considered in the study, as well as the list of the ones not considered, is presented in Appendix A.

The NTCs representing the mainland interconnections correspond to the 2030 reference capacities of the TYNDP 2016. The complete list of reference transmission capacities between each country, including the North Sea's interconnections, is presented as well in Appendix A.

For the first two steps of the optimization, annual and day-ahead, an economic dispatch problem is solved considering the limits imposed by the NTCs but disregarding Kirchhoff's voltage law (i.e. a transportation model is used). Unit commitment is neglected in this preliminary analysis to reduce simulation times in order to achieve results with statistical significance over a range of draft topologies. This assumption will be reviewed in later stages of the project. The intraday optimization is solved through a multi-temporal OPF, representing more closely the physical power flows in the offshore grid (use of a linearized version of the power flow equations), but keeping a transportation model for onshore grids. This approach allows the identification and quantification of eventual offshore grid constraints.

The cost benefit analysis methodology described in the previous paragraph is applied to process the results of the economic optimization. For the purpose, the investment cost (CAPEX) of the optimized offshore grid, calculated in the detailed design phase, is opposed to the GCS value. To ease the comparison between investments in different years, both the GCS and the CAPEX are actualized using the single discount rate adopted by ENTSO-E in the Guidelines for CBA analysis of Grid Development Projects [21]. In particular, a rate of 4% for a 25-year lifetime with a residual value of zero is used [21]. For this draft roadmap, only the year 2030 is analysed to provide an indication of the expected magnitude of the benefits and identify eventual issues to be tackled before simulating longer time periods.

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5 RESULTING DRAFT TOPOLOGIES

This Chapter presents the results of the application of the methodology described in the previous Chapter to the North Sea for the decade 2020-2030. The draft topologies and the related investment costs are presented in the following paragraphs. Note that the optimization problem itself considers only two categories of costs, cables and platform extensions, while additional costs related to converters and circuit breakers are considered as well in the overall cost estimation. Finally, the results of the CBA applied are presented and discussed.

The resulting draft topologies are classified as reference coordinated solutions, characterized by meshed offshore grids, and reference radial solutions, where all offshore wind farms are connected radially to the mainland. It is relevant to list beforehand the assumptions underlying the computation of the investment costs, which have been calculated considering three different sets of hypotheses representing different stances on the commercial availability of key technologies:

- **Base Case**: the base case reflects a conservative approach regarding technological development in the field of mechanical DC Circuit Breakers (DCCBs) and Diode-Rectifier Units (DRU) converters, both considered commercially unavailable by 2030;
- **Variant 1**: this variant assumes the availability of DRU converters for radial connections of offshore wind farms (only) but not of mechanical DC CBs. This particular future favours the radial topologies over the coordinated meshed solutions;
- **Variant 2**: this variant assumes the unavailability of DRU converters and the availability of mechanical DCCBs. This future favours the coordinated meshed topologies over radial solutions;
- **Variant 3**: this variant assumes the availability of DRU converters for radial connections of offshore wind farms (only) and the availability of mechanical DCCBs. This future favours the coordinated meshed topologies over radial solutions;

The complete list of hypotheses underlying each case is reported in Table 5.1.

#	Hypothesis	Base Case	Variant 1	Variant 2	Variant 3
1	Commercial availability of DRU converters	✗	✓	✗	✓
2	Commercial availability of Mechanical DCCBs	✗	✗	✓	✓
3	DCCB installed only where a single contingency leads to a loss of power infeed in the AC network higher than the reference incident of that zone	✓	✓	✓	✓
4	Platform extensions for DC hubs (>1 cable)	✓	✓	✓	✓
5	Neglected costs to expand onshore substations	✓	✓	✓	✓

Table 5.1. List of hypotheses for the computation of investment costs.

Hypotheses 1 and 2 characterize the different cases. The first hypothesis considers a future scenario where DRU converter technology may or may not be mature enough to be implemented for the radial connection of offshore wind farms. Note that there is currently an uncertainty about the technical capabilities of DRUs: if it

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would be possible to use it in purely radial point-to-point connection of offshore wind farms, it is unknown if it can be used in meshed grids. That uncertainty will be alleviated by PROMOTioN's WP2, and the conservative assumption that it can be used only it in purely radial point-to-point connection of offshore wind farms is used in this report. The commercial availability of DRUs has limited effects on the investment costs of the coordinated solutions where radial connections are limited in number. On the other hand, if DRU are assumed unavailable, all converters are considered to be VSC, both for radial and meshed topologies.

The second hypothesis concerns the commercial availability of mechanical DCCB. For the purpose of the economic feasibility study, Hybrid DCCBs are assumed to be the default technology. However, the hybrid design bears high cost due to the amount of semiconductor equipment. A significant reduction of costs could be achieved by implementing mechanical DCCBs, substantially cheaper than hybrid solutions. Mechanical DCCBs, while commercially established for low DC voltage ratings, have yet to be scaled for high voltage and extra-high voltage applications. Since DCCBs are not strictly required for purely radial point-to-point connections of offshore wind farms (assuming that the capacity of a single windfarm is lower than the maximum loss-of-power-infeed allowed), only the coordinated solution will benefit from the cheaper mechanical technology. That's why the commercial availability of mechanical DC CBs characterizes the pro-meshed case.

The impact of DCCBs on the investment costs is directly related to the philosophy behind the protection system. For the economic feasibility studies, simplified assumptions (Hypothesis 3) have been taken to select the lines where DCCBs should be installed and consequently estimate the number of units required. Generally, DCCBs are implemented only on those cables that, if subject to fault, would cause a potential loss of power infeed in the onshore AC zone higher than the reference incident of that zone (see section 3.3.2). That's the case for most of the cables considered in the coordinated solutions, with the exception of the offshore grids in front of the Danish shores (connected to the mainland via Endrup, Idomlund and Ferslev, see section 5.2).

Preliminary hypotheses have been made on the configuration of busbars. Considering each onshore bus to be composed of a single bar not only would be unrealistic but it will substantially increase the number of DC CBs required. Multiple onshore busbars reduce the need of DCCBs. Decoupling the busbars confines the effect of a single contingency to smaller parts of the offshore grid, limiting the potential loss of power infeed and thus the need of DCCBs. For example, Figure 5.1 shows the topology of the offshore grid connected to Torness and Norton in Great Britain. If the onshore substation of Torness is equipped with a single DC busbar, the loss of a single DC cable connected to Torness would cause a potential loss of power infeed in the mainland network higher than the reference incident considered for UK (1800 MW). Therefore, each DC cable would need to be protected with DCCBs (24 units). Decoupling the onshore DC busbar in Point A reduces the need of DCCBs to 12 units by limiting the maximum loss of power infeed on the second busbar (from Seagreen Delta to Blyth) to a value below the reference incident. An additional decoupling in Point B further reduces the need of DCCBs to 6 units (from Inch Cape to Seagreen Alpha).

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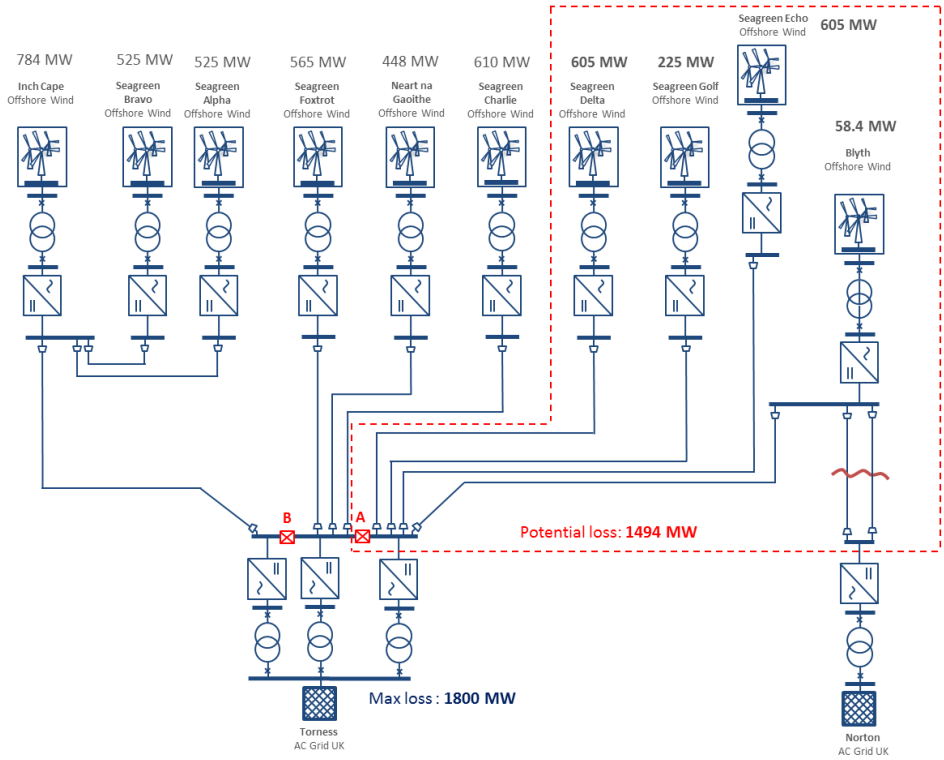

Figure 5.1. Potential loss of power infeed in UK mainland grid with decoupled DC busbar in Torness (Point A).

For computing the investment costs, onshore decoupled busbars have been considered where beneficial effects could be gained by the isolation of part of the offshore grid.

Hypotheses 4 and 5 are common to all cases. In particular, if more than one cable connects an offshore wind farm to another node of the meshed offshore grid or to the mainland, an additional offshore platform is foreseen to accommodate the DC bus (Hypothesis 4). Moreover, the costs associated to the expansion of the onshore substations to accommodate the converters are not taken into account (Hypothesis 5).

The unitary costs (per km or per unit) used to compute the investment costs and related hypotheses are reported in Appendix A.1.2.

5.1 REFERENCE RADIAL SOLUTIONS

The reference radial solutions were obtained by connecting radially the offshore wind farms to the closest national onshore connection points, while satisfying the hosting capacity of the onshore grid. Figure 5.2 and Figure 5.3 show these reference radial solutions in 2030 for the two voltage levels used, 320 kV and 525 kV, respectively. Because all offshore wind farms are connected radially and directly to onshore connection nodes, differences are hardly noticeable: capacities of cables are not exactly the same, and two circuits are sometimes needed for the 320-kV solution, while only one circuit is needed for each wind farm for the 525-kV solution.

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The breakdown of the investment costs associated to the reference radial solutions for each set of hypotheses is presented in Table 5.2. As expected, 320 kV reference configurations have a lower investment cost compared to the 525 kV solutions. The difference is marked by the lower cable costs due to the lower ratings of 320 kV submarine HVDC cables. This result also indicates that the offshore wind generating capacity could be evacuated by the radial topology at 320 kV with limited recourse to parallel cables. Note that, in the 525 kV case, all windfarms can be connected through a single circuit (pair of cables), which avoids the investment in offshore platforms.

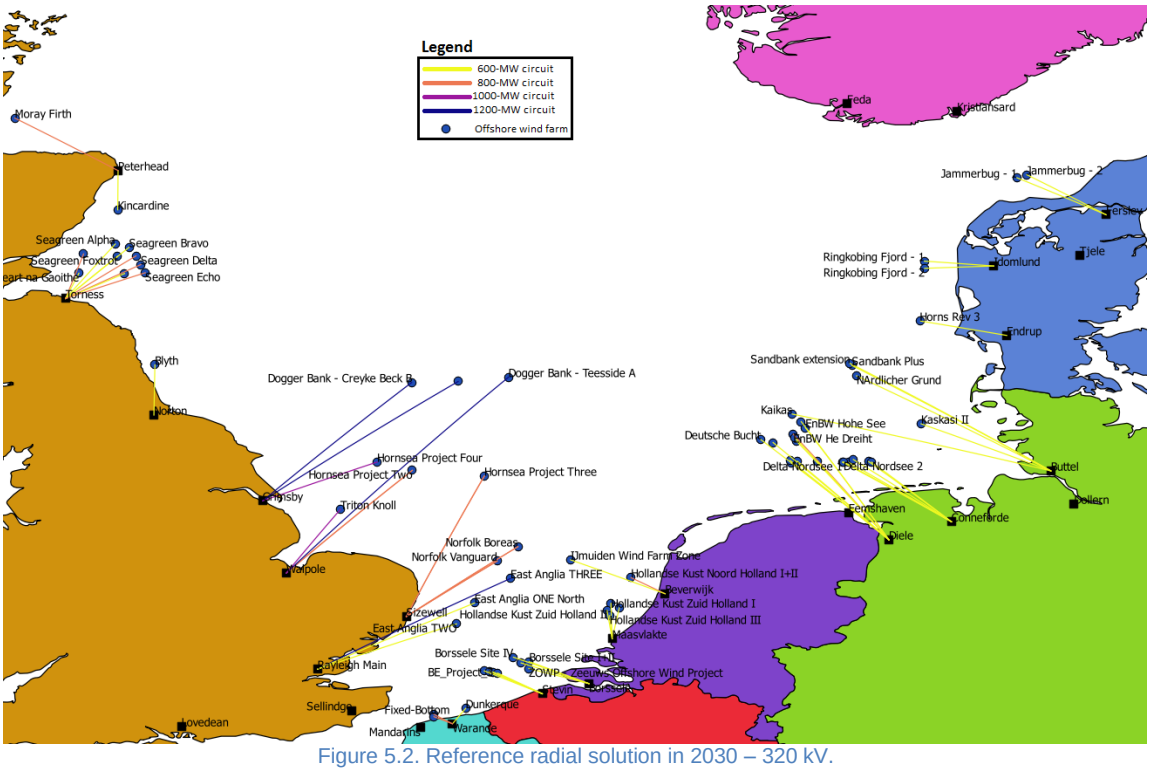

Figure 5.2. Reference radial solution in 2030 – 320 kV.

The availability of DRU (Variant 1) leads to the possibility to connect offshore wind farms through a system with an offshore DRU and an onshore traditional VSC. Relying on the assumption that the commissioning of an offshore DRU instead of an offshore VSC could lead to a cost reduction of one third (as developed in appendix A), the reduction in the converter costs would be approximately €4 billion. However, because of the low strength of the rationales behind the DRU cost assumptions (section A.1.2), that value must be taken with care. Note that assumptions on circuit breakers does not factor into the investment cost for radial solutions.

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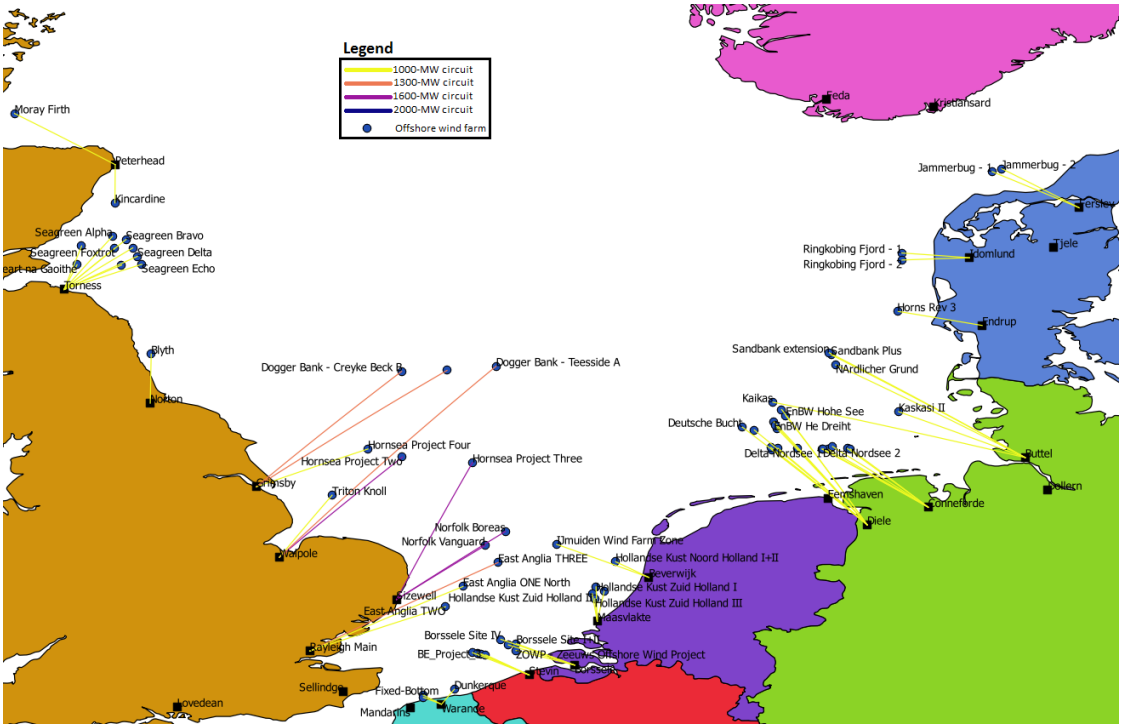

Figure 5.3. Reference radial solution in 2030 – 525 kV.

Equipment Cost [M€]	Base Case		Variant 1		Variant 2		Variant 3	
	Radial Solution 320 kV	Radial Solution 525 kV	Radial Solution 320 kV	Radial Solution 525 kV	Radial Solution 320 kV	Radial Solution 525 kV	Radial Solution 320 kV	Radial Solution 525 kV
Offshore VSC Converters (incl. platforms)	11,880	12,000	0	0	11,880	12,000	0	0
Offshore DRU Converters (incl. platforms)	0	0	7,901	7,986	0	0	7,901	7,986
Onshore VSC Converters	6,160	6,160	6,160	6,160	6,160	6,160	6,160	6,160
Submarine HVDC Cables	9,122	10,962	9,122	10,962	9,122	10,962	9,122	10,962
Offshore platform extensions	120	0	120	0	120	0	120	0
DC Circuit Breakers	0	0	0	0	0	0	0	0
Total CAPEX	**27,282**	**29,122**	**23,303**	**25,108**	**27,282**	**29,122**	**23,303**	**25,108**

Table 5.2. Total investment cost (M€) at the horizon 2030 of the reference radial configurations.

5.2 REFERENCE COORDINATED SOLUTIONS

The reference coordinated solutions were obtained by applying the methodology described in Chapter 4. Figure 5.4 and Figure 5.5 show these reference coordinated solutions in 2030 for the two voltage levels used, 320 kV and 525 kV, respectively. The temporal evolution of these coordinated solutions is presented in Appendix B.

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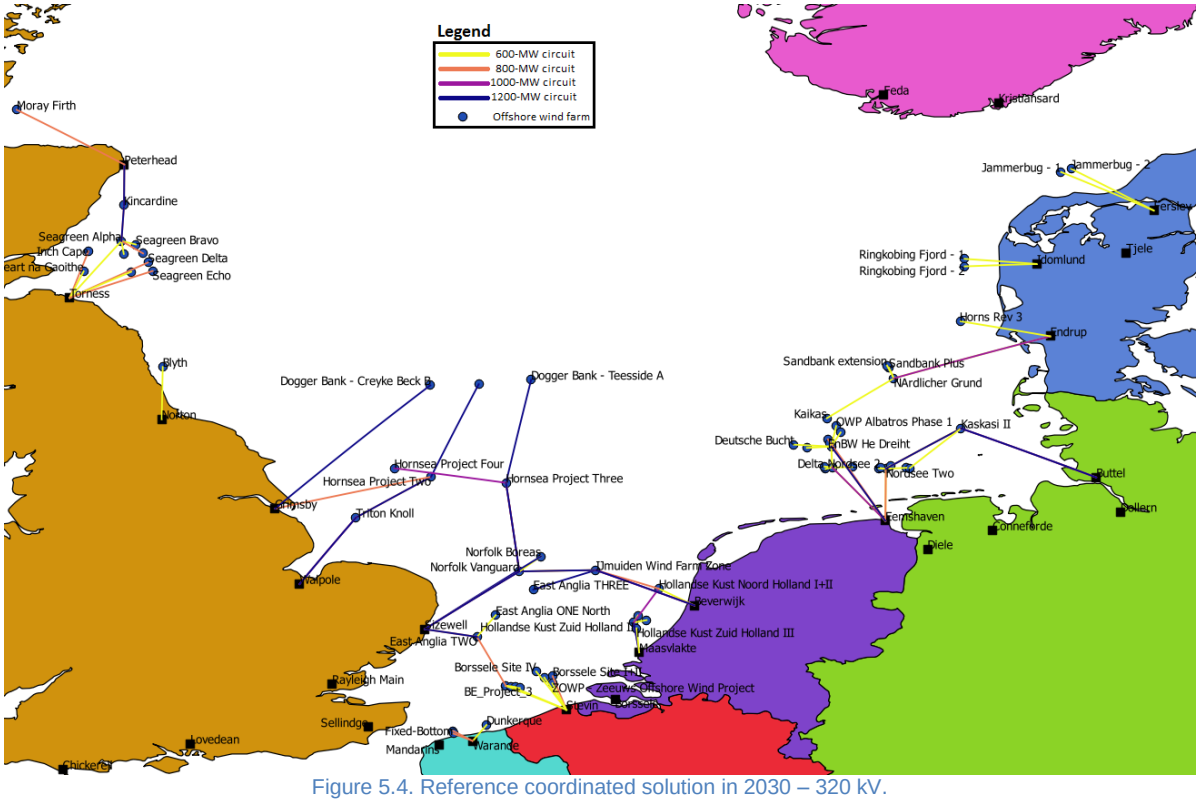

Figure 5.4. Reference coordinated solution in 2030 – 320 kV.

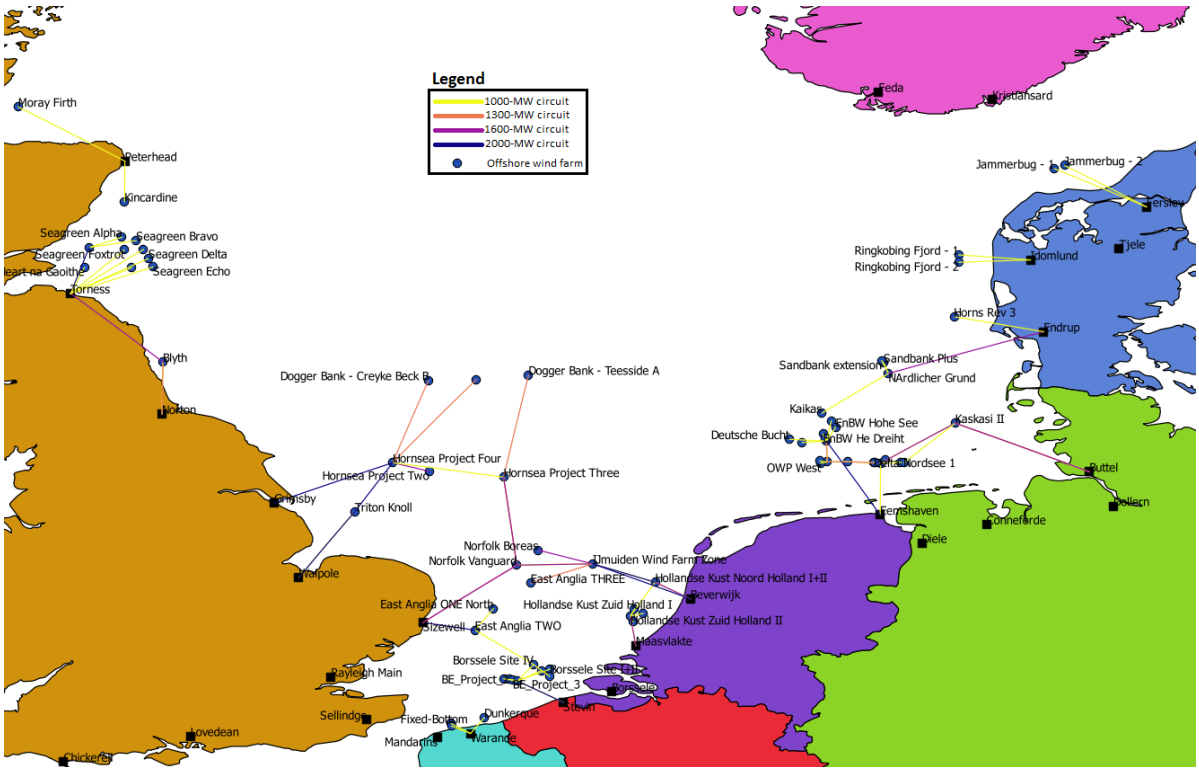

Figure 5.5. Reference coordinated solution in 2030 – 525 kV.

The investment costs associated to the reference coordinated solutions are presented in Table 5.3

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Equipment Cost [M€]	Base Case		Variant 1		Variant 2		Variant 3	
	Meshed Offshore Grid 320 kV	Meshed Offshore Grid 525 kV	Meshed Offshore Grid 320 kV	Meshed Offshore Grid 525 kV	Meshed Offshore Grid 320 kV	Meshed Offshore Grid 525 kV	Meshed Offshore Grid 320 kV	Meshed Offshore Grid 525 kV
Offshore VSC Converters (incl. platforms)	11,880	12,000	3,260	3,300	11,880	12,000	3,260	3,300
Offshore DRU Converters (incl. platforms)	0	0	5,732	5,789	0	0	5,732	5,789
Onshore VSC Converters	5,160	4,870	5,160	4,870	5,160	4,870	5,160	4,870
Submarine HVDC Cable	8,318	8,194	8,318	8,194	8,318	8,194	8,318	8,194
Offshore platform extensions	510	570	510	570	510	570	510	570
DC Circuit Breakers	5,616	8,366	5,616	8,366	127	179	127	179
Total CAPEX	**31,484**	**34,000**	**28,596**	**31,089**	**25,994**	**25,813**	**23,107**	**22,902**

Table 5.3. Total investment cost (M€) at the horizon 2030 of the reference coordinated configurations.

For the coordinated solutions, the most relevant cost element is represented by the converters, followed by DCCBs and submarine cables. On the total investment costs, the difference between the 525 kV and 320 kV solutions is marked mostly by the hybrid DCCBs (Base Case and Variant 1), whose cost is higher in the 525 kV configurations due to the higher voltage and ratings of the cables. Given a comparable number of breakers in both solutions (142 in the 525 kV network and 146 in the 320 kV one), it must be noted that the average cost of a DCCB in the 525 kV solution is approximately 45% higher than the average cost in the 320 kV solution due to an higher average rating. Because it is assumed that DRUs can be used only for offshore wind farms connected radially (point-to-point) to the shores, the savings allowed by the availability of DRUs for the coordinated configurations are lower than the savings obtained in the radial configurations. Indeed, approximately one fourth of the offshore wind capacity is integrated in radial multi-terminal or meshed grids and must stay connected through a VSC in the set of assumptions used. It means that the savings applies on only three fourths of the offshore converter, and are thus about €3 billion (instead of about €4 billion for the purely radial configurations). Note that the assumption that DRUs can be used only for offshore wind farms connected radially (point-to-point) to the shores is not yet validated or invalidated by simulations, but PROMOTioN's Work Package 2 is studying that.

The introduction of mechanical DCCBs (Variant 2) reduces significantly the weight of the breakers on the total investment costs, marking a €5-8 billion difference between the Base Case and Variant 2, depending on the voltage level. In Variant 2, the difference of investment costs between the 525 kV and the 320 kV is also levelled. A difference is identified in the cost of onshore converters, with the 320 kV solutions having slightly higher cost due to the lower ratings of the 320 kV VSC converters, requiring a higher number of converters with respect to the 525 kV solutions (42 units for the 320 kV solutions against 31 units for the 525 kV ones).

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5.3 COST-BENEFIT ANALYSES

The Cost-Benefit Analysis (CBA) methodology presented in section 4.5.2 is applied to the results of the economic optimization of the reference draft topologies. The CBA quantifies the economic benefits associated to the draft coordinated topologies by comparing their investment costs (CAPEX) against the actualized Generation Cost Savings (GCS), calculated with respect to the relative reference radial solution.

5.3.1. INVESTMENT COSTS

Details on the investment costs associated to each reference topology are presented in the previous paragraphs. Table 5.4 reports a breakdown of the total investment costs.

Total CAPEX [M€]	Meshed Offshore Grid 320 kV	Meshed Offshore Grid 525 kV	Radial Configuration 320 kV	Radial Configuration 525 kV
Base case	31,484	34,000	27,282	29,122
Variant 1	28,596	31,089	23,303	25,108
Variant 2	25,994	25,814	27,282	29,122
Variant 3	23,107	22,902	23,303	25,108

Table 5.4. Comparison of investment costs.

As expected, the investment cost follows the rationale behind the assumptions taken, with the base case being the most conservative across all draft topologies. Some interesting considerations can already be deduced from these results:

- For radial configurations, there is no difference between the Base Case and Variant 2 due to DCCBs being unnecessary in case of purely radial point-to-point connection of the offshore wind farms,
- For meshed configurations, the availability of mechanical DC CBs substantially reduces the investment costs of the meshed offshore grids, marking a €5-8 billion difference between the Base Case and Variant 2, depending on the voltage level,
- The availability of DRU converters (Variant 1) reduces the CAPEX of the radial case by approximately €4 billion. However, also the meshed configurations take advantage of the DRU technology, with a CAPEX reduction of approximately €3 billion,
- The CAPEX of the meshed solution with the mechanical DCCBs in place is comparable with the CAPEX of the radial solution with the DRU in place.

In conclusion, two trends can be identified:

- The commercial availability of DRU will benefit to varying degrees both radial and coordinated solutions;
- The commercial availability of mechanical DC CBs has significant impact on the investment costs of the meshed solutions.

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For the purpose of the CBA, it is assumed that the investment costs are incurred altogether the year before the commissioning of the whole infrastructure. This simplification is acceptable at this stage of the PROMOTioN project.

5.3.2. GENERATION COST SAVINGS

As detailed in section 4.5.2, the Generation Cost Savings (GCS) is the chosen indicator to monetize the variation of the socio-economic welfare following the realization of the meshed offshore grid, in place of a purely radial configuration.

Generation costs are extracted from the results of the economic optimization as the sum of the total fuel cost and total start-up costs of conventional thermal generators. Table 5.5 reports the generation costs for each studied scenario, for the year 2030. The 525 kV configurations, both radial and meshed, are able to evacuate more wind generation than the respective 320 kV solutions. The Generation Cost Savings (GCS) are reported in Table 5.6. The savings generated by the 525 kV and 320 kV configurations appear to be comparable.

	Meshed Offshore Grid 320 kV	Meshed Offshore Grid 525 kV	Radial Configuration 320 kV	Radial Configuration 525 kV
Generation Cost [M€]	14,866	14,891	15,050	15,033

Table 5.5. Generation costs [M€].

	Meshed w.r.t. Radial 320 kV	Meshed w.r.t. Radial 525 kV
Generation Cost Savings [M€]	-184	-142

Table 5.6. Generation cost savings [M€].

5.3.3. RESULTS OF THE COST-BENEFIT ANALYSES

In order to compute the Net Present Value (NPV) of the economic surplus generated by the meshed offshore grid with respect to the reference radial solutions, a time span of 25 years has been considered. The GCS resulting from the economic optimization for year 2030 are assumed as reference value for the whole period under consideration. The results of the CBA for the 525-kV and 320-kV voltage levels are presented in Table 5.7 and Table 5.8, respectively. For both voltage levels, the NPV is positive in the Pro-meshed case, demonstrating the impact of DC CBs' cost on the profitability of the coordinated solutions over the radial ones. The reduction of breakers' cost affects the 525-kV topology to a wider extent with respect to the 320-kV solution, due to the higher ratings of DC CBs required at this voltage level.

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Meshed – Radial 320 kV	ΔCAPEX (M€)	Actualized GCS[16] (M€)	NPV (M€)
Base Case [M€]	4,202	-2,867	-1,335
Variant 1 [M€]	5,293	-2,867	-2,426
Variant 2 [M€]	-1,287	-2,867	4,154
Variant 3 [M€]	-196	-2,867	3,063

Table 5.7. CBA Results for 320-kV solutions.

Meshed – Radial 525 kV	ΔCAPEX[15] (M€)	Actualized GCS[16] (M€)	NPV (M€)
Base Case [M€]	4,878	-2,211	-2,667
Variant 1 [M€]	5,981	-2,211	-3,770
Variant 2 [M€]	-3,308	-2,211	5,519
Variant 3 [M€]	-2,206	-2,211	4,417

Table 5.8. CBA Results for 525 kV solutions.

The main conclusions that can be extracted from these results are the following:

- The business case of the coordinated solutions to evacuate the offshore wind energy is not straightforward, due to the expected high costs of hybrid DCCBs.
- With the set of assumptions used in Variant 1, the business case of purely radial solutions is much better than the one of integrated solutions. It means that the technical capabilities of DRUs and their costs could drastically impact the development of meshed grid: if their costs are much lower than the ones of the VSCs and if they can be used only in purely radial point-to-point connections, the cost of radial solutions will be much lower than the cost of meshed solutions.
- With the set of assumptions used in Variant 2, the business case of the integrated solutions is much better than the one of the radial solutions. It means that the technical capabilities of DCCBs and their costs could drastically impact the development of meshed grid: if DCCBs with a cost negligible to the ones of the converters can be used, the cost of meshed solutions will be much lower than the cost of radial solutions.
- With the set of assumptions used in Variant 3, the business case of the integrated solutions is still better than the one of the radial solutions but less favourable than Variant 2. This case allows a better understanding of the impact of the DRU technology on the profitability of the business cases, assuming mechanical DCCBs will be available. In particular, based on the assumption on DRU costs considered for this preliminary evaluation, the NPV would be reduced of approximately 1 billion, in both the 320 kV and the 525 kV cases, due to the reduced investment costs of the radial reference solutions.

15 Since the CAPEX is concentrated in "year 0", the economic surplus for each subsequent year is equal to the actualized GCS.

16 As reported in §4.5.3, discount rate is 4% throughout the 25 years under consideration.

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6 CONCLUSIONS AND NEXT STEPS

A roadmap for the development of meshed offshore grids in the North Seas must address the various barriers currently hindering that development (e.g. technological barriers, financing & regulatory barriers). Dedicated Work Packages of this PROMOTioN project are dealing with these challenges, but one ingredient of a roadmap is not really addressed by a dedicated Work Package: the development of a grid expansion plan. This report developed thus a first approach to generate offshore grid structures and applied that approach to the North Sea for the decade 2020-2030 to establish a draft offshore grid expansion plan. The following conclusions can be drawn:

- The DCCBs capabilities and costs will drastically impact the business case of coordinated solutions such as meshed grids. If only hybrid DCCBs are technically viable for the voltages and powers present in the offshore grid, only offshore wind farms far from the shore (i.e. significantly more than 100 km) will be part of the offshore grid. On the contrary, if mechanical DCCBs can also be used, offshore wind farms closer to the shore could be integrated as well.
- The technical capabilities and the cost of DRUs could also significantly impact the likely development of offshore grids. Indeed, DRUs are expected to have a low cost compared to equivalent VSCs, but they might be limited to purely radial connections of offshore wind farms. Under that specific set of assumptions, radial connections will keep an economic advantage compared to meshed grids. On the contrary, if DRUs can be integrated as well in coordinated solutions such as meshed grids, these coordinated solutions will equally benefit from that cost reduction.
- The hosting capacity of the onshore grid could strongly impact the grid topology, but they could be increased by onshore grid reinforcements. In the planning stage, it could thus be of paramount importance to consider both the onshore grid and the offshore grid in a coordinated planning,
- There are a number of uncertainties about the way the grid will be operated (e.g. security rules, market rules). The business case could also strongly be impacted by the operational constraints.

However, it is important to remember that the formulation of the grid expansion plan as a mathematical optimization problem presented in this report is a simplification of reality. Therefore the conclusions that are drawn from the analysis are only applicable if the assumptions of the optimization hold. This means that it is not the outcome of the optimization (the grid maps, the final CBA) that is most relevant, but the analysis that underpins it, and the trade-offs that the optimization shows. The objective is to improve the optimization in the next phase of the project in such a way that the outcome of the optimization is also usable as a reference grid. Indeed, the proposed approach currently has several limitations that will have to be overcome in the final reference offshore grid expansion plan under development within PROMOTioN's WP12. In particular, the following points must be emphasized:

- The OTEP problem considered only HVDC connections. However, for short distances, the HVAC technology remains more economical than the HVDC technology. It is thus likely to keep a strong

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development of HVAC technology within or in parallel with an HVDC grid. That should be considered in the OTEP problem.

- Individual connections of offshore wind farms are considered. However, in line with the previous comment, it is likely that offshore wind farms separated by short distances (several tens of kms maximum) will be grouped together (through HVAC) to reach critical cluster sizes and that their energy will be evacuated through a shared HVAC or HVDC connection. That should be considered in the approach.
- The need for DCCBs on some circuits for coordinated solutions was not considered in the OTEP problem. As shown by the results, it could drastically impact the business case and should thus be considered in the initial design of the grid.
- Exchanges of power between different market areas through the offshore grid are not valued in the design of that grid. They could nevertheless strongly impact the business case and should thus be considered.
- The N-1 security criterion is not considered in the OTEP problem, but could impact the topologies and should thus be also considered.
- The assumptions on technology availabilities and on related costs are preliminary and are expected to reflect the expected situation in 2020. A deeper study about expected evolutions should be conducted.
- The optimization problem leaves political decision making out of scope. The following political trade-off impacts the optimization that was not taken into account:
  - Each country could require that wind generated in their economic zone is connected to their onshore grid in such a way that all the offshore wind generation in that economic zone can be evacuated to the corresponding country under normal operating conditions (i.e. no outage). For example, if 6 GW of wind is developed in the economic zone of a country A, a connection of 6 GW to that country A could be required. On the contrary, in the optimization problem as formulated in this report, if it is less expensive to evacuate a part of the totality of that wind energy to a country B, it is possible that the rated capacity of 6 GW is not fully evacuated to country A.
  - The model does not yet separate the contribution of wind evacuation and interconnection. The full benefit is calculated towards the meshed offshore grid. It fully depends on the regulations and market rules who gets what benefit, and this could impact dimensioning of the grid as well as individual business cases.

Moreover, the approach was applied for the decade 2020-2030, but national grid development plans are already being decided for that decade. It means that the effective implementation of a meshed offshore grid will probably occur only after 2030.

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APPENDIX A: ASSUMPTIONS ON COMPONENTS, LOAD, GENERATION AND INITIAL GRID

A.1 OFFSHORE GRID COMPONENTS

This section presents the assumptions done for the different components of the offshore grid. A review of assumptions used in previous studies can be found in PROMOTioN's Deliverable 1.3. Note that assumptions made in this section are supposed to reflect the technologies available in 2020 and their costs, and do not consider an evolution over the decade 2020-2030. In reality, the technologies can improve and their costs decrease. Moreover, costs could depend on volumes. These effects are not considered in this study.

A.1.1. ASSUMPTIONS ON TECHNOLOGIES

Even if DC/DC converters could play a major role in future HVDC grids, they are not part of the scope of the PROMOTioN project. Therefore, a homogenous voltage level has to be chosen for the development of offshore topologies. The main limitation on the voltage level comes from the cables. Several manufacturers can provide XLPE HVDC cables for 525 kV. Note that in June 2016, the Prysmian group announced the successful testing of 600 kV XLPE HVDC cables. The 525 kV is chosen as one reference voltage level. It might nevertheless not be useful to go up to that voltage level. Therefore, the 320 kV is chosen as a second and separate reference voltage level. Consequently, as two different voltage levels were considered (i.e. 320 kV and 525 kV) there are two sets of different assumptions.

For converters, the bipolar configuration is considered as the reference configuration in this draft roadmap. The Caithness Moray HVDC Link under construction is rated at 1200 MW for a monopolar configuration at ±320 kV. This draft roadmap considers this value as the maximum rating of a ±320 kV converter. By keeping the same maximum current, the highest rating for a ±525 kV converter is considered to be 2000 MW[17]. The same assumptions are considered for DCCBs, DRUs and cables. The actual capabilities of DCCBs are still unknown but will be clarified during the PROMOTioN project. For cables, note that there are two poles per circuit, so each pole is rated at half of the total rating.

A.1.2. ASSUMPTIONS ON COSTS

For undersea cables, the overall cost has two main components: cable procurement and cable installation. The installation cost depends on the local conditions, e.g. sea depth and seabed. For the purpose of this draft roadmap, it does not appear necessary to go into a lot of details. Indeed, this draft roadmap aims to perform a

[17] Note that VSCs rated at 3000 MW are available for a voltage of ±640 kV – see for example http://new.abb.com/systems/hvdc/hvdc-light: "In the upper range, the technology now reaches 3,000 MW and ±640 kV".

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prefeasibility study of meshed HVDC grids, and does not intend to provide an actual offshore grid expansion plan with an exact quantification of costs. In addition to cost figures reported in PROMOTioN's Deliverable 1.3, ref. [23] proposes to use a cost of 140 M€/100 km for a cable pair of 1 GW when the voltage is 320 kV. Table A.1 gives the cable costs (including installation, for two poles) used for this draft roadmap. These costs result from a synthesis of the costs reported in previous studies.

VOLTAGE (KV)	RATING (MW)	COST (M€/KM) – INCLUDING INSTALLATION, FOR TWO POLES
		UNDERSEA CABLES
320	600	1.08
	800	1.23
	1000	1.38
	1200	1.53
525	1000	1.48
	1300	1.63
	1600	1.78
	2000	1.93

Table A.1. HVDC submarine cable costs

For converters and circuit breakers, a distinction must be made between onshore and offshore installations. Indeed, offshore installations necessitate a dedicated platform representing a substantial cost. For VSCs themselves, an affine law is adopted, similar to the one proposed by the e-Highway 2050 project. Following the suggestion of [23], a linear law depending on the rating of the converter is adopted for the cost of platforms supporting offshore VSCs. The PROMOTioN project will progress on both mechanical and hybrid DC CBs. The costs of hybrid DC CBs are expected to be higher than those of mechanical DC CBs. For this draft roadmap, the costs of hybrid DC CBs are assumed to be one fourth of the costs of VSCs with the same ratings, in line with what is used in [23]. For offshore hybrid DC CBs, the additional cost due to the dedicated platform is also assumed to be linearly dependent of the rating, with a cost of 0.02 M€/MW, taken from [23]. The cost of mechanical DC CBs is assumed to be at 0.001 M€/MW, with no need of a platform. Finally, it appears much more difficult to make assumptions about the cost of a DRU. Indeed, to the best of the authors' knowledge, the only public information on that topic can be found in Siemens presentations and a press release announcing the DRU in October 2015 [24] [25] [26]. These presentations and press release claimed that the DRU can reduce costs "by more than 30%" [25]. It is however not specified the costs components that are exactly considered: cost components related to the offshore converter only or to the overall HVDC system. It is considered here than the figure on the cost reduction applies only to the offshore converter and its platform, and therefore this component is assumed to cost two thirds of an equivalent VSC (i.e. the cost reduction is 33%). Please note that this relative cost is only an assumption as no cost figures are available from manufacturers or specific projects: it should be further investigated in the PROMOTioN's project.

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Note that cost figures given in this section are supposed to give a reasonable estimation of costs in 2020, but should not be considered as exact numbers due to the large uncertainty and variability affecting costs in this domain. In particular, cost figures are not validated by manufacturers.

VOLTAGE (KV)	RATING (MW)	COST (M€)					
		OFFSHORE VSC (INCL. PLATFORM)	ONSHORE VSC	OFFSHORE HYBRID DC CB (INCL. PLATFORM)	ONSHORE HYBRID DC CB	MECHANICAL DC CB	OFFSHORE DRU (INCL. PLATFORM)
320	600	140	80	32	20	0.6	93
	800	180	100	41	25	0.8	120
	1000	220	120	50	30	1.0	147
	1200	260	140	43	35	1.2	173
525	1000	220	120	50	30	1.0	147
	1300	280	150	64	38	1.3	187
	1600	340	180	77	45	1.6	227
	2000	420	220	95	55	1.7	280

Table A.2. HVDC VSC (bipolar configuration) and hybrid DC CB costs (for two poles)

A.1.3. ASSUMPTIONS ON RELIABILITY

For the purpose of a preliminary economic optimization, submarine HVDC cables have been considered as the only equipment of the offshore grid subject to outages. In line with assumptions presented in PROMOTioN's Deliverable 1.3, for bi-pole configurations, a failure rate of 0.2 faults/100km/year has been assumed to define the time to failure of each HVDC cable. The mean time to repair is assumed to be 1440 hours.

A.2 LOAD AND GENERATION

This section presents the load and the installed capacity considered for the market model at the year 2030. As reported in PROMOTioN's Deliverable 1.4, the available market data in the TYNDP 2016 database (i.e. net generating capacities, generation basic models, fuel and CO2 prices, NTCs and demand hourly profiles) are suited for the simulation of target year 2030. In particular, Vision 3 "National Green Transition" of the TYNPD 2016 has been selected for modelling the net generating capacities and the hourly demand profiles. Aggregated data for load, in peak power and in energy, at 2030 for each country are presented in Table A.3.

Country	Peak Load [GW]	Load [TWh]
France	83.30	479.48
Belgium	12.60	86.10
The Netherlands	19.00	116.20
Germany	78.30	508.73

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Great Britain	63.80	354.18
Norway	25.30	140.15
Denmark West	4.30	24.39
Denmark East	2.80	15.40
Sweden	22.70	130.93

Table A.3. Load in power (peak) and in energy at 2030.

Installed capacity in 2030 is presented in Figure A.1. Note that the offshore wind capacity includes wind farms existing and expected to be commissioned by 2020 in addition to the wind farms part of the meshed offshore grid.

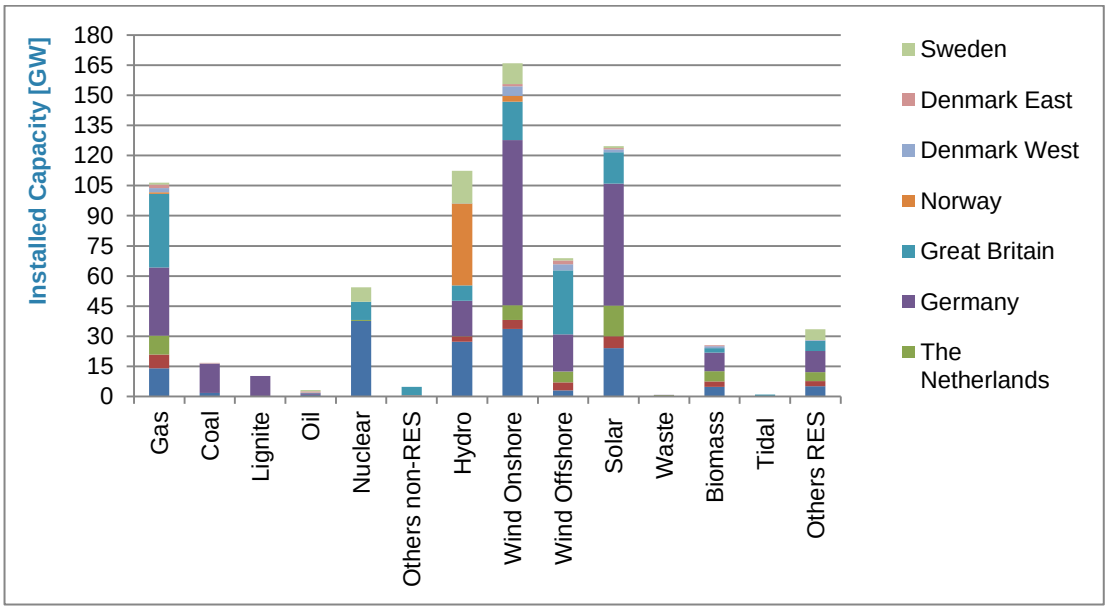

Figure A.1. Installed capacity in 2030.

A.3 INITIAL GRID

The list of the interconnection projects in the North Sea considered in the study is presented in Table A.4.

Name	Interconnected Countries	Capacity [MW]	Existing (01/2017) - Mid-term - Long-term - Future	Comm. Year
Nemo	BE - UK	1000	Mid-term	2019
Kriegers Flak CGS	DE - DKE	400	Mid-term	2018
Kontek	DE - DKE	600	Existing (01/2017)	1995
NordLink	DE - NO	1400	Mid-term	2020
Baltic Cable	DE - SE	615	Existing (01/2017)	1994
DKE - SE 4xAC cables (2x400kV+2x132kV)	DKE - SE	1700/1300	Existing (01/2017)	1985
Viking DKW-GB	DKW - UK	1400	Mid-term	2020
COBRA cable	DKW - NL	700	Mid-term	2019

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Name	Interconnected Countries	Capacity [MW]	Existing (01/2017) - Mid-term - Long-term - Future	Comm. Year
Skagerrak (4 cables)	DKW - NO	1640	Existing (01/2017)	2014
Kontiskan	DKW - SE	740/680	Existing (01/2017)	1988
IFA2	FR - UK	1000	Mid-term	2020
ElecLink	FR - UK	1000	Mid-term	2018
France-Alderney-Britain	FR - UK	1400	Mid-term	2022
BritNed	UK - NL	1000	Existing (01/2017)	2011
Norway-Great Britain NSN	UK - NO	1400	Mid-term	2019
NordNed	NO - NL	700	Existing (01/2017)	2008

Table A.4. Interconnection projects considered for the NTCs across the North Sea.

The only interconnection project included in the model but scheduled to be commissioned after 2020 is the France–Alderney-Britain (FAB) interconnector, for which the procurement process has already started in 2016 and the final approvals are in course of completion [http://www.fablink.net/category/news/].

Table A.5 lists the projects in the North Seas that have not been considered in the definition of the NTCs.

Name	Interconnected Countries	Capacity [MW]	Existing (01/2017) - Mid-term - Future	Comm. Year
2nd interconnector BE - UK	BE - UK	1000	Future	2025
DKE - DE	DE - DKE	600	Future	2030
Kontek-3	DE - DKE	600	Future	>2030
Hansa PowerBridge 1	DE -SE	700	Long-term	2025
Hansa PowerBridge 2	DE -SE	700	Future	2025-2030
COBRA - 2	DKW - NL	700	Future	>2030
Kontiskan 2	DKW - SE	to be determined	Future	2030
AQUIND Interconnector	FR - UK	2000	Future	2020
New UK- NL Interconnector	UK - NL	1000	Future	2030
NorthConnect	UK – NO	1400	Mid-Term	2022

Table A.5. Interconnection projects not considered for the NTCs across the North Sea.

The NTCs representing the mainland interconnections correspond to the 2030 reference capacities of the TYNDP 2016. The complete list of reference transmission capacities between each country, including the North Sea's interconnections, is presented in Table A.6.

Country 1	Country 2	Capacity 1 → 2 [MW]	Capacity 2 → 1 [MW]
BE	DE	1000	1000

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BE	FR	2800	4300
BE	UK	1000	1000
BE	NL	2400	2400
DE	DKE	1000	1000
DE	DKW	3000	3000
DE	FR	4800	4800
DE	NL	5000	5000
DE	NO	1400	1400
DE	SE	615	615
DKE	DKW	600	600
DKE	SE	1700	1300
DKW	UK	1400	1400
DKW	NL	700	700
DKW	NO	1640	1640
DKW	SE	740	680
FR	UK	3400	3400
UK	NL	1000	1000
UK	NO	1400	1400
NL	NO	700	700
NO	SE	3695	3995

Table A.6. NTC between each country in the perimeter of the study.

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APPENDIX B: TEMPORAL EVOLUTION OF THE REFERENCE OFFSHORE GRIDS

B.1 REFERENCE COORDINATED SOLUTION, 320 KV

Figure B.1, Figure B.2, Figure B.3, Figure B.4, Figure B.5, Figure B.6, Figure B.7, Figure B.8, Figure B.9 and Figure B.10 show the temporal evolution of the reference coordinated solution for the voltage level 320 kV, over the time period 2021-2030. Hollow dots indicate offshore wind farms not yet commissioned, while blue dots indicate offshore wind farms in operation. Colour lines between offshore wind farms and onshore substations indicate HVDC circuits commissioned. In the first years, radial and radial multi-terminal structures appear, while meshed structures appear during the second half of the decade. Structures link two asynchronous grids: Continental Europe and Great Britain. Connections appear between Belgium, Netherlands and the United Kingdom. Note that integrated structures appear also between the Netherlands and Germany.

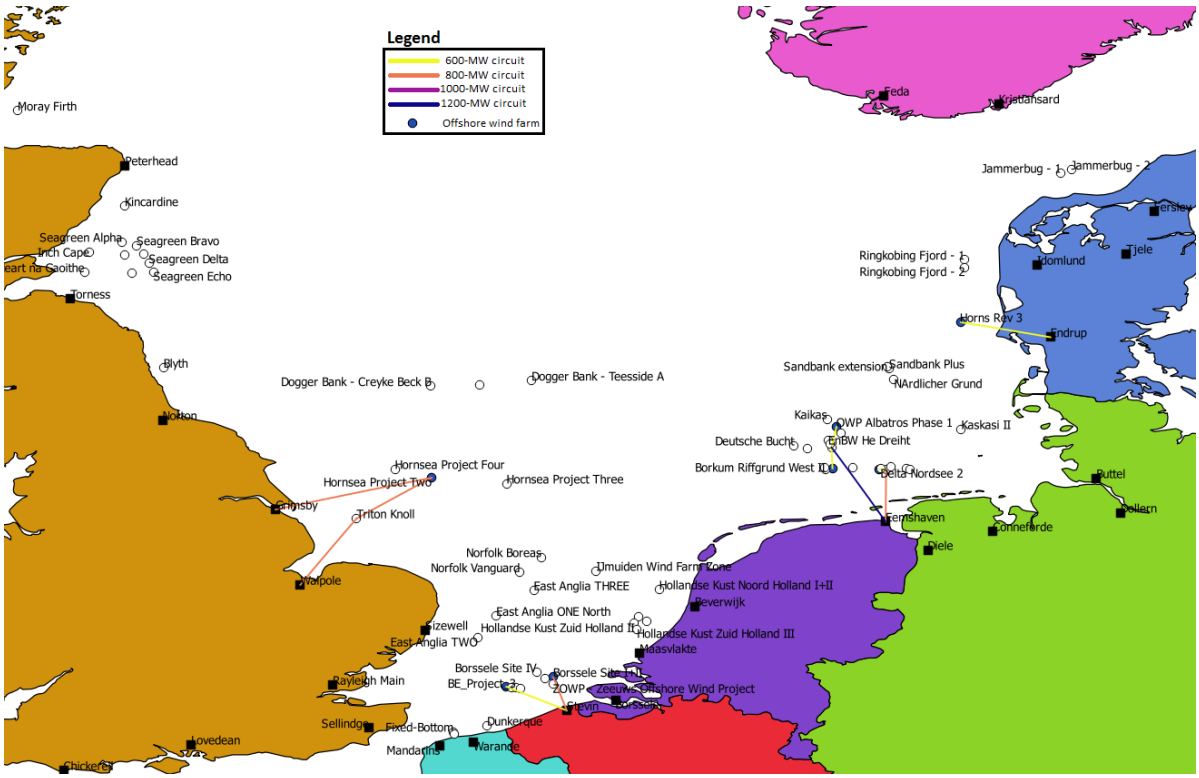

Figure B.1. Reference coordinated solution in 2021 – 320 kV.

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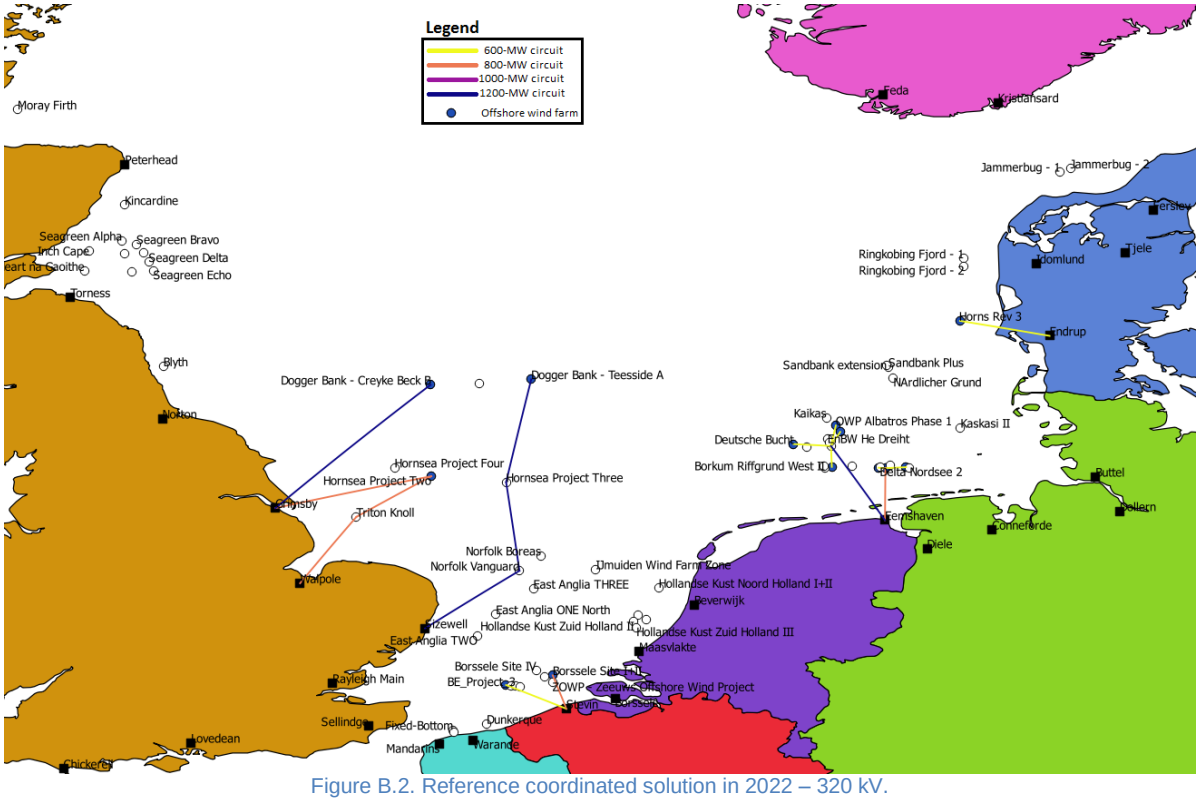

Figure B.2. Reference coordinated solution in 2022 – 320 kV.

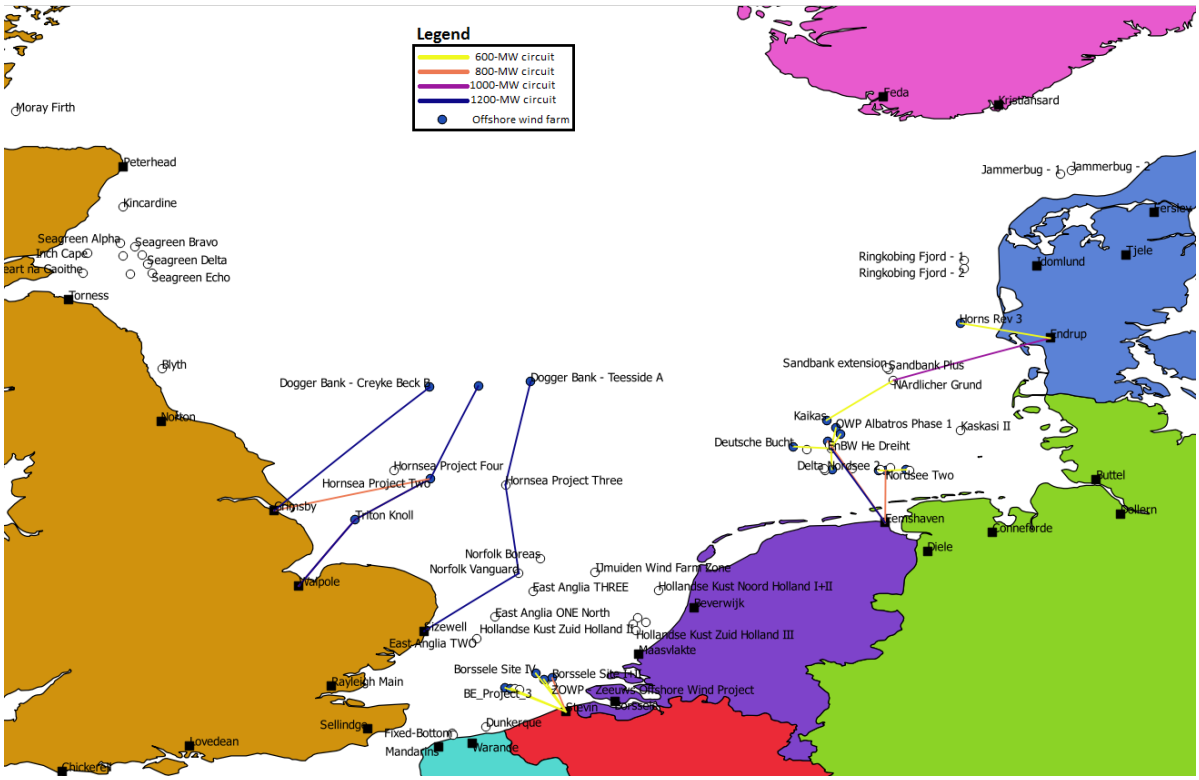

Figure B.3. Reference coordinated solution in 2023 – 320 kV.

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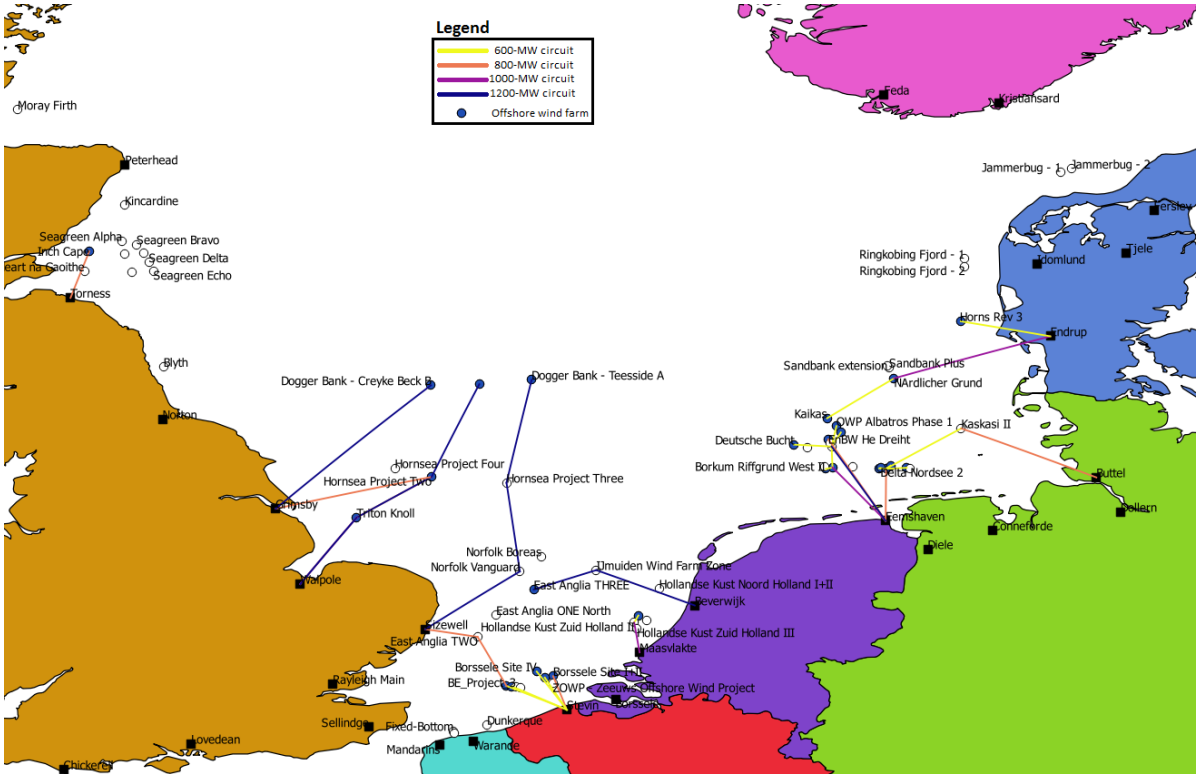

Figure B.4. Reference coordinated solution in 2024 – 320 kV.

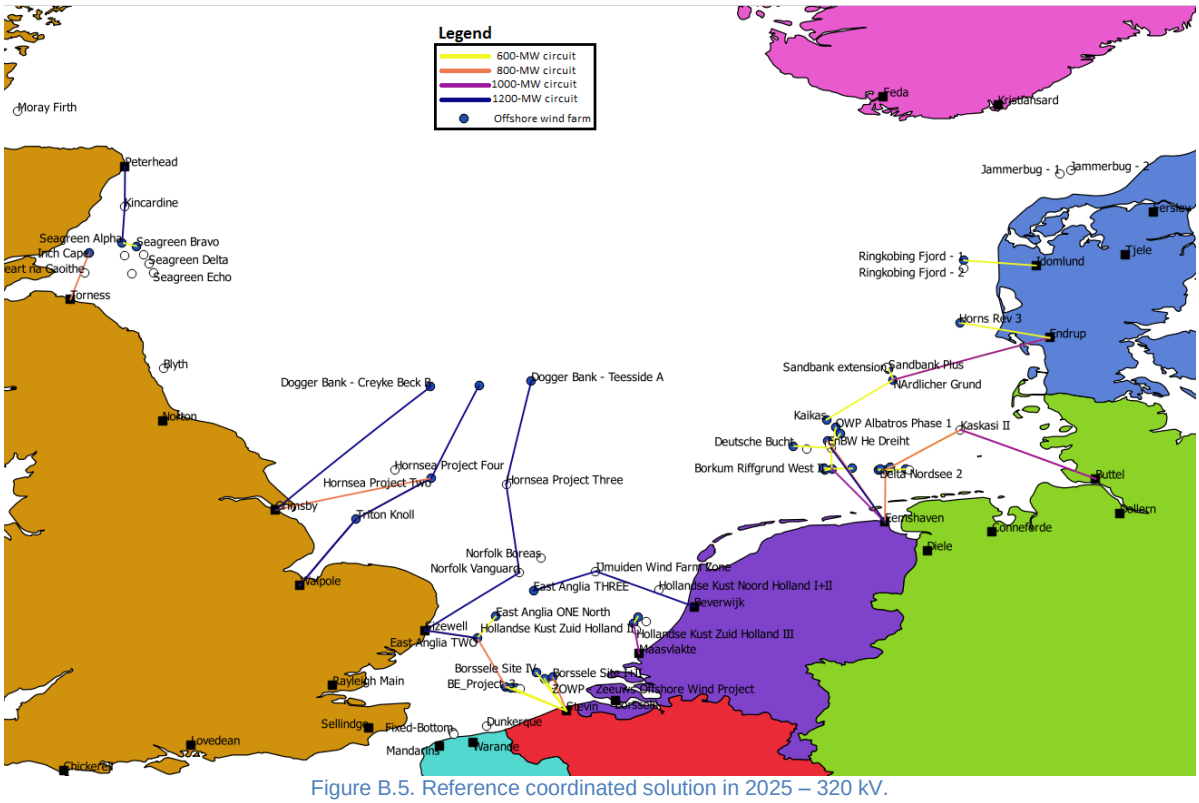

Figure B.5. Reference coordinated solution in 2025 – 320 kV.

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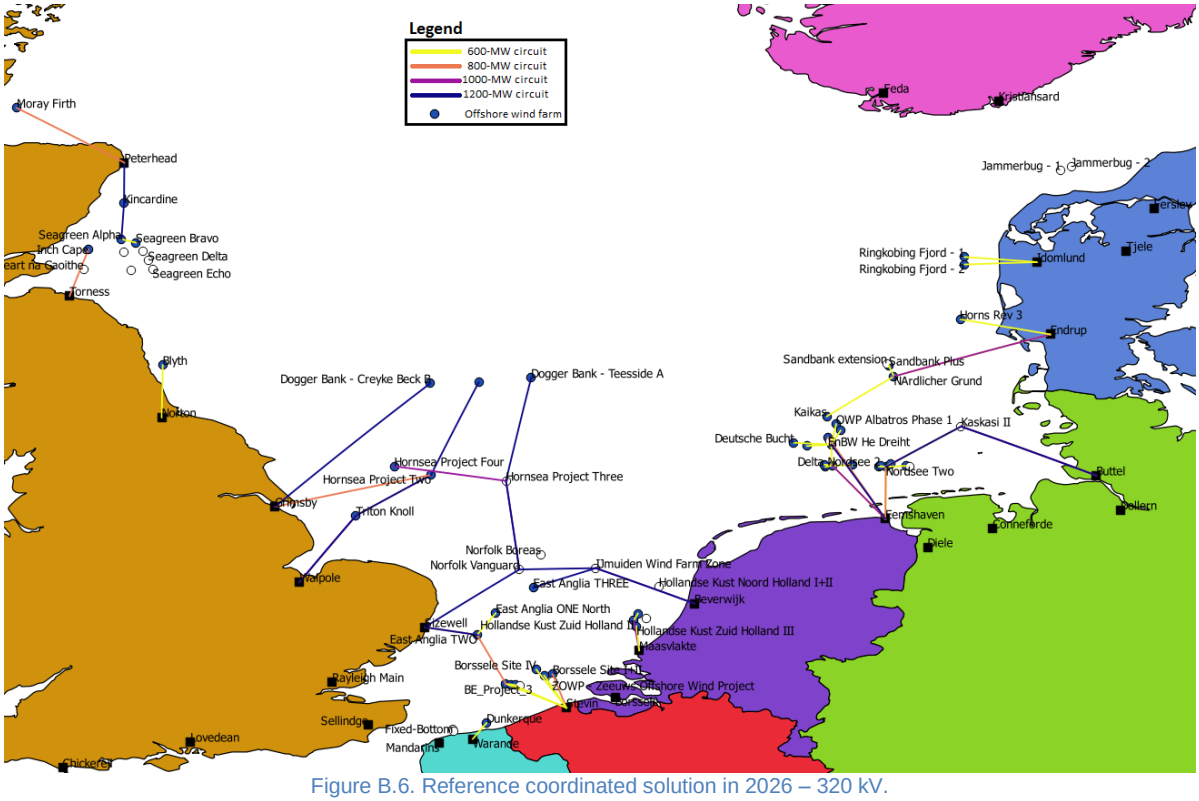

Figure B.6. Reference coordinated solution in 2026 – 320 kV.

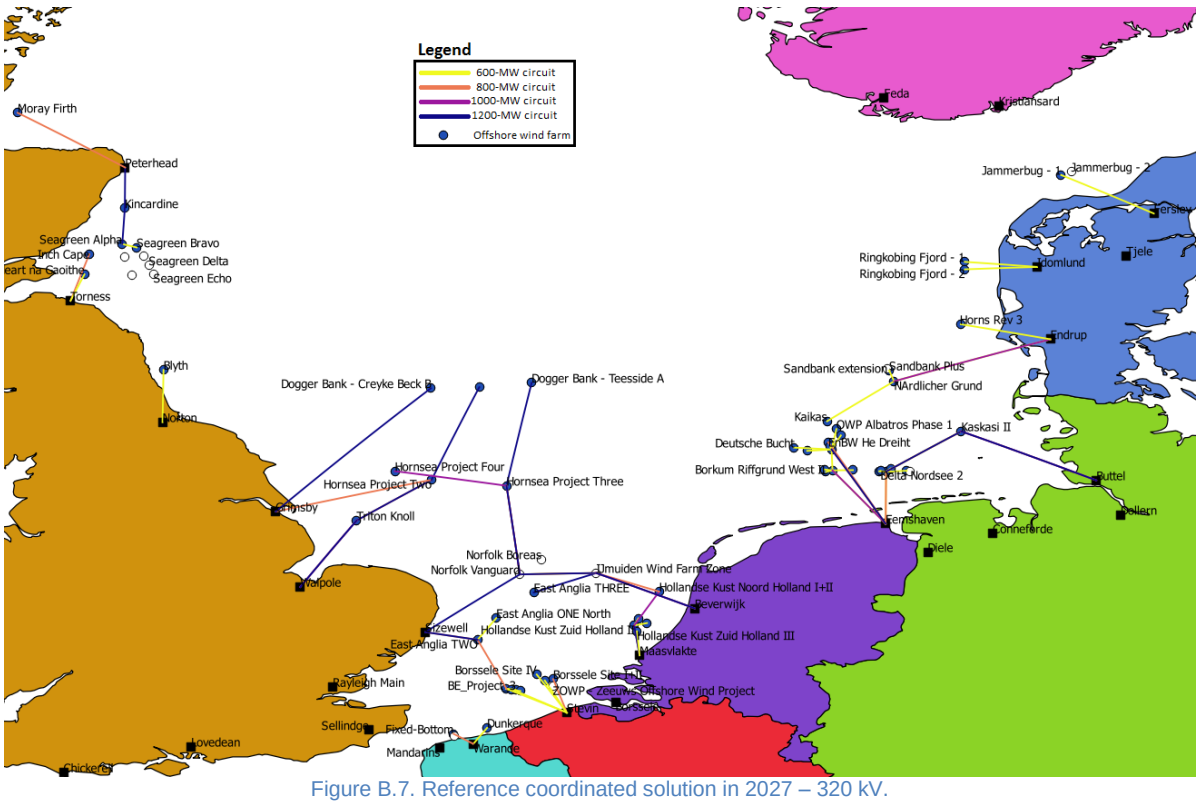

Figure B.7. Reference coordinated solution in 2027 – 320 kV.

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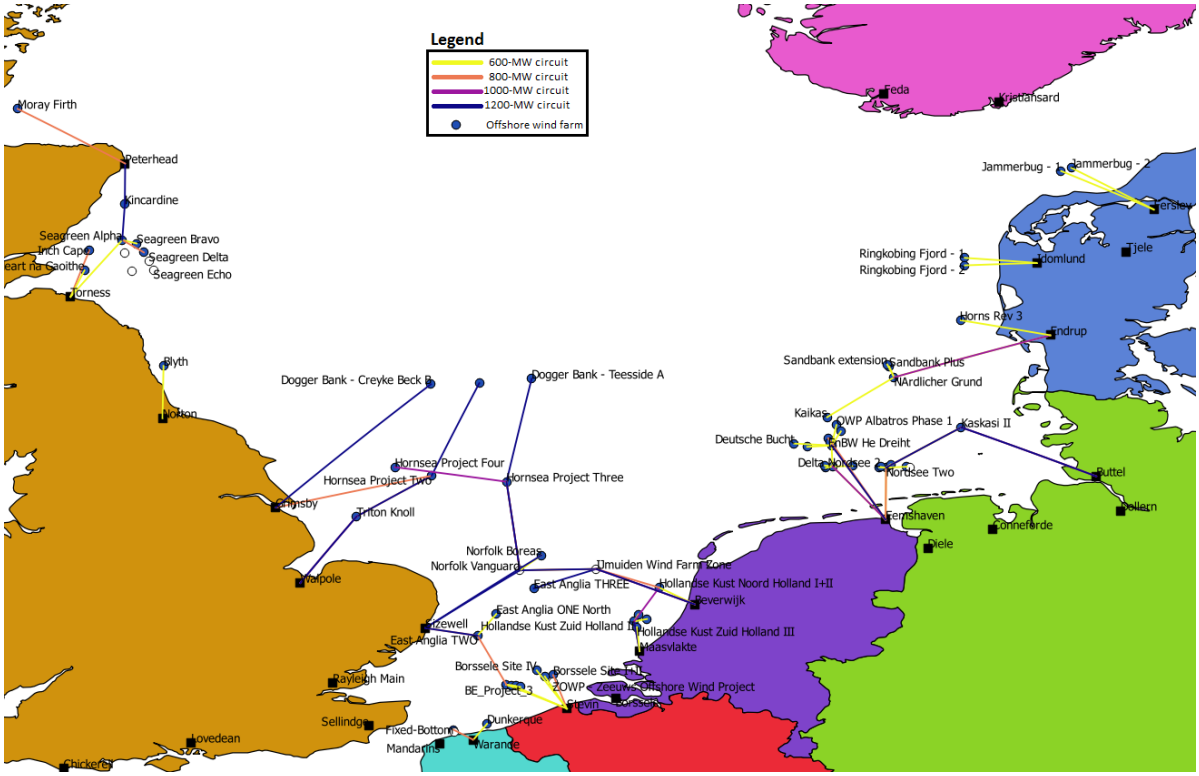

Figure B.8. Reference coordinated solution in 2028 – 320 kV.

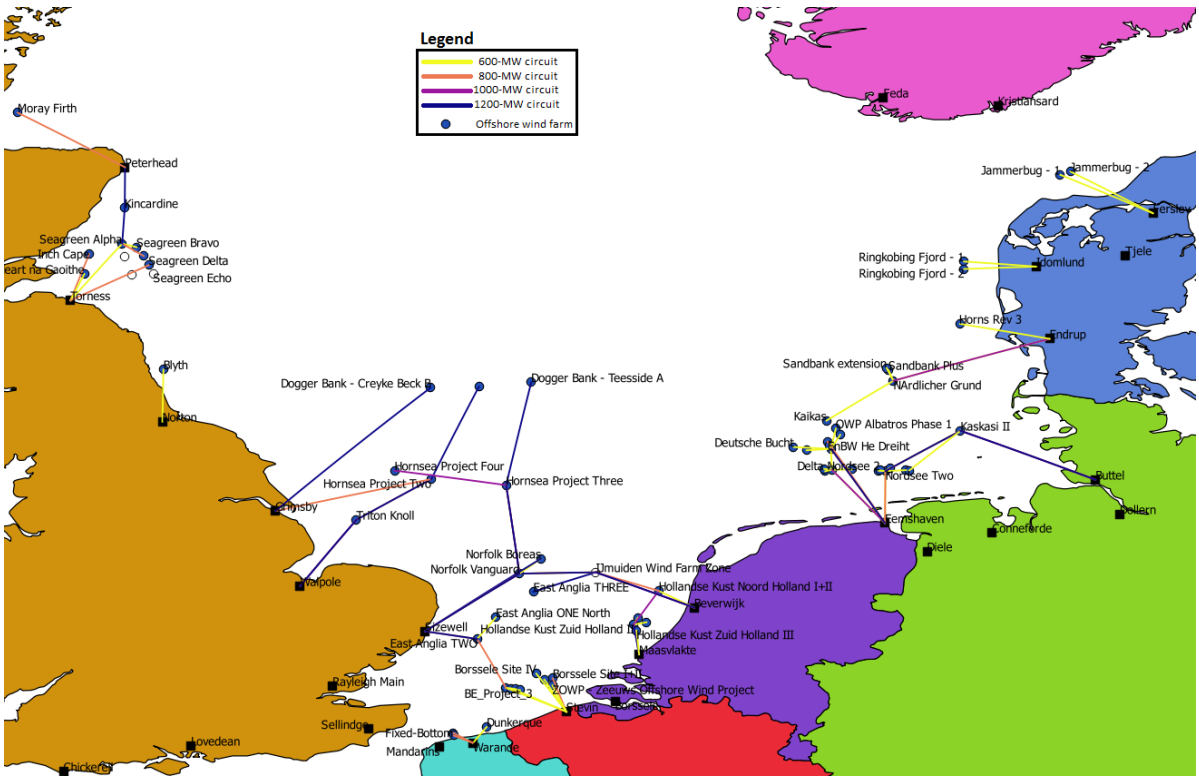

Figure B.9. Reference coordinated solution in 2029 – 320 kV.

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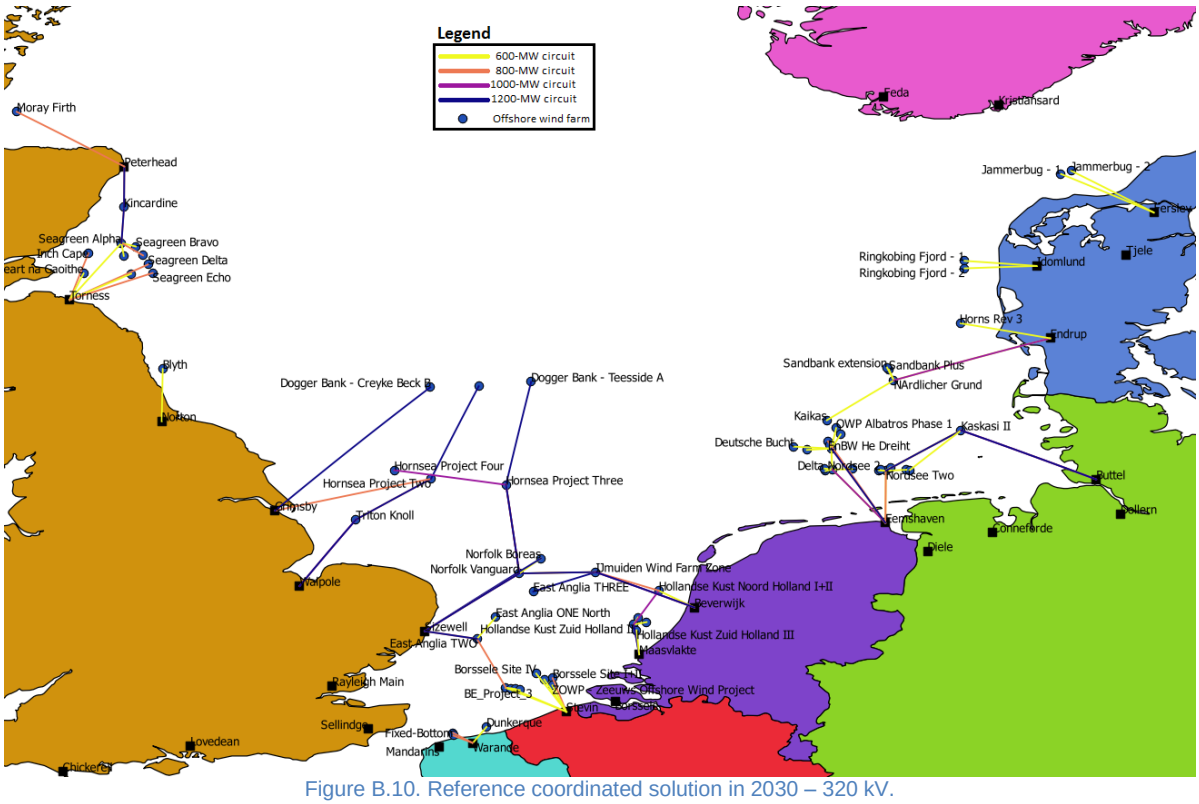

Figure B.10. Reference coordinated solution in 2030 – 320 kV.

B.2 REFERENCE COORDINATED SOLUTION, 525 KV

Figure B.11, Figure B.12, Figure B.13, Figure B.14, Figure B.15, Figure B.16, Figure B.17, Figure B.18, Figure B.19 and Figure B.20 show the temporal evolution of the reference coordinated solution for the voltage level 525 kV, over the time period 2021-2030. Hollow dots indicate offshore wind farms not yet commissioned, while blue dots indicate offshore wind farms in operation. Colour lines between offshore wind farms and onshore substations indicate HVDC circuits commissioned. The behaviour is the same as for the 320-kV voltage level: in the first years, radial and radial multi-terminal structures appear, while meshed structures appear during the second half of the decade.

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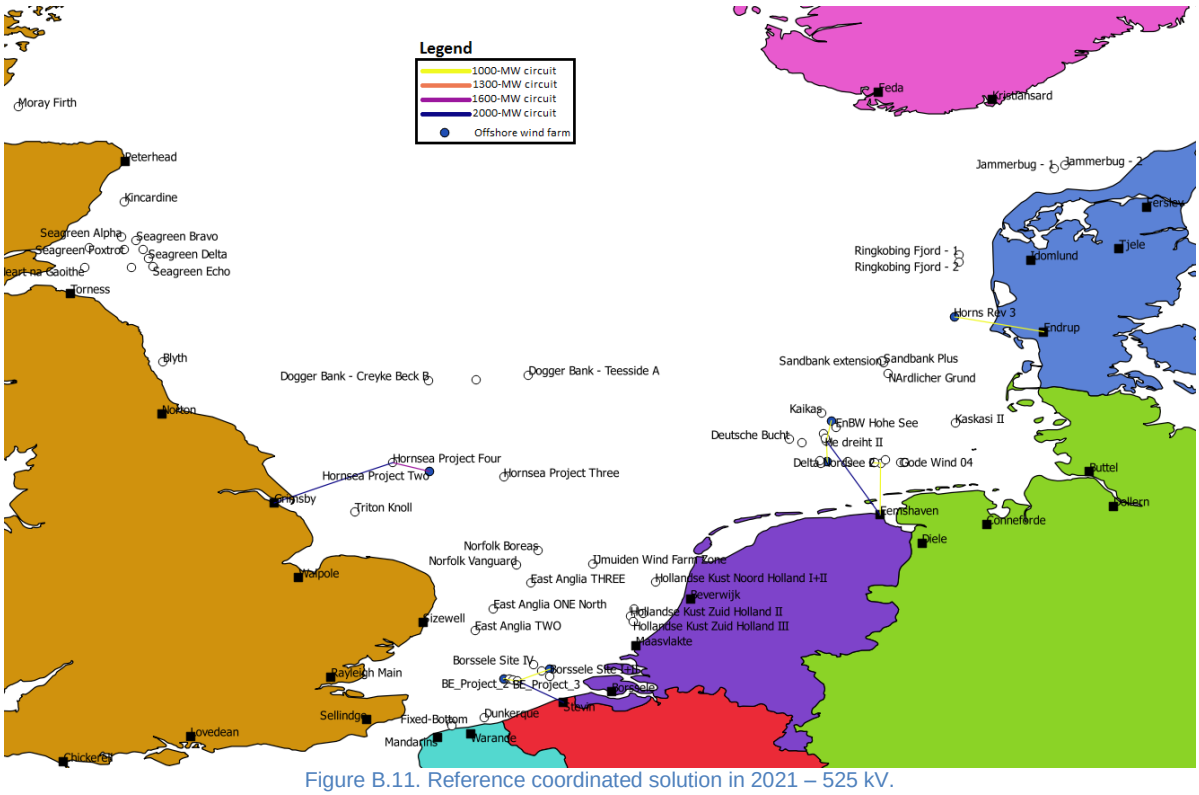

Figure B.11. Reference coordinated solution in 2021 – 525 kV.

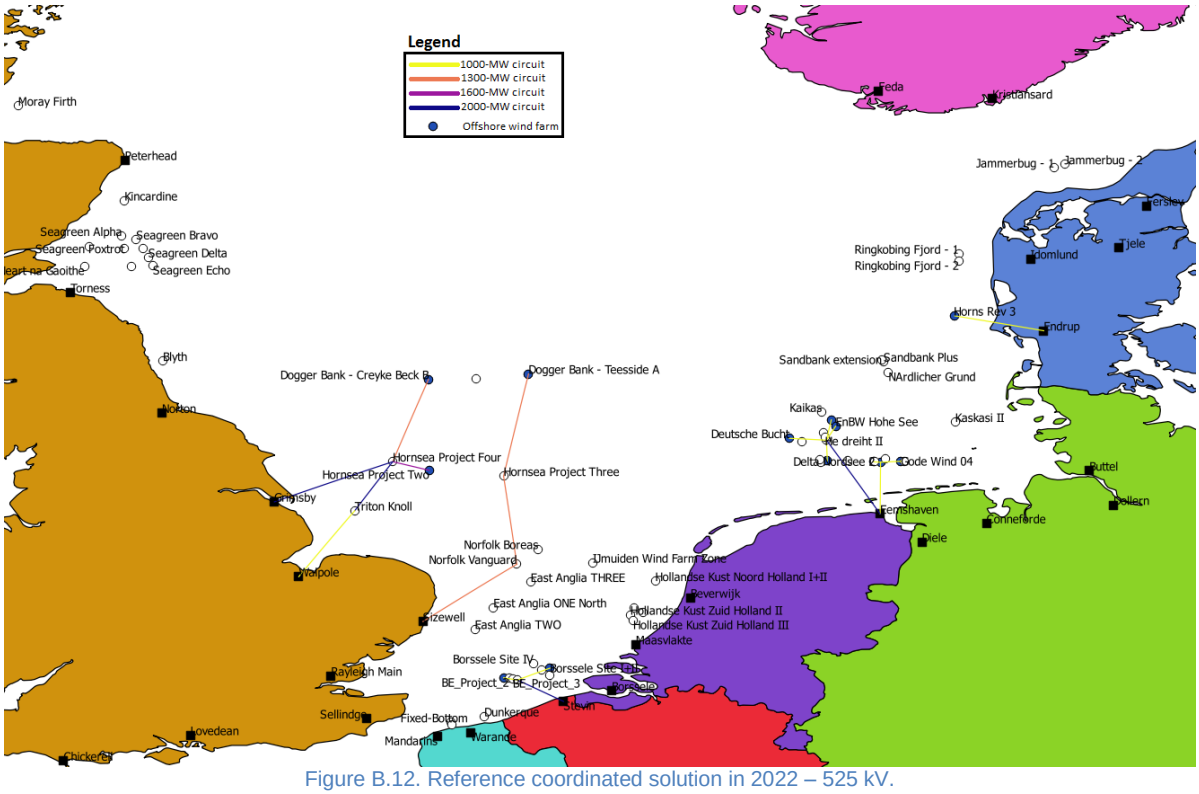

Figure B.12. Reference coordinated solution in 2022 – 525 kV.

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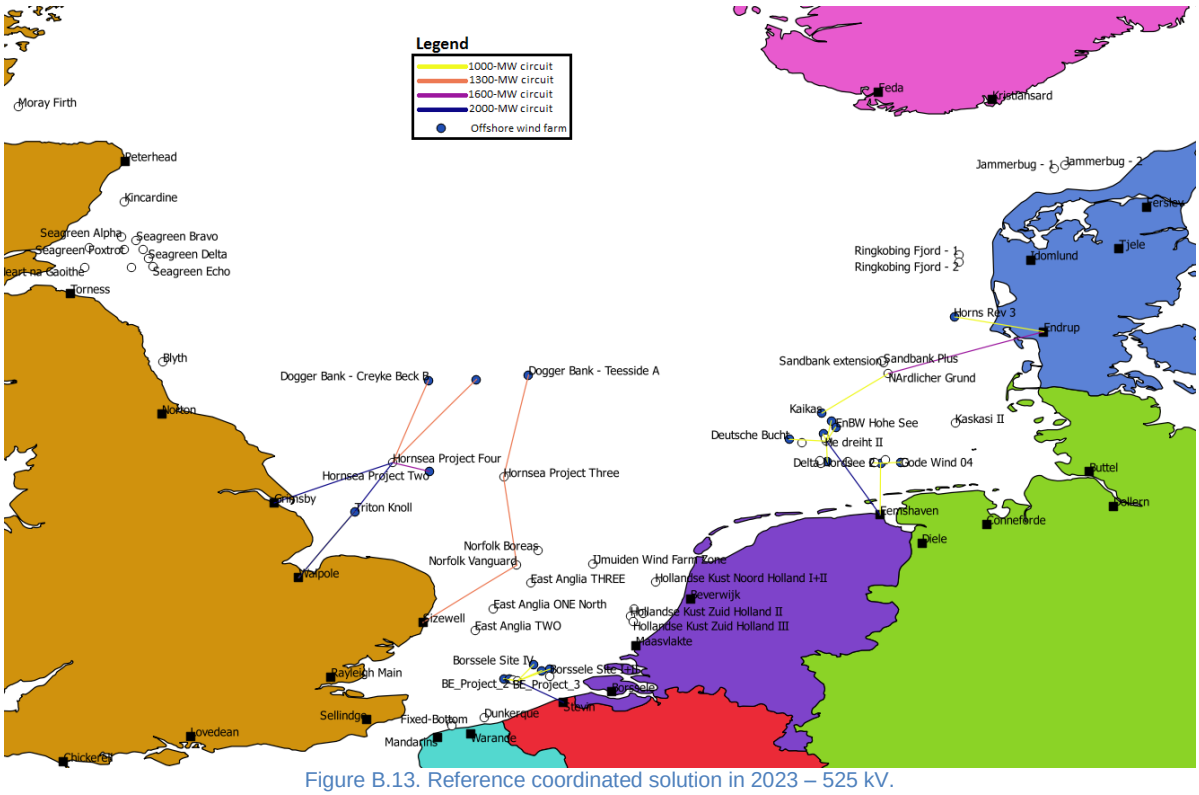

Figure B.13. Reference coordinated solution in 2023 – 525 kV.

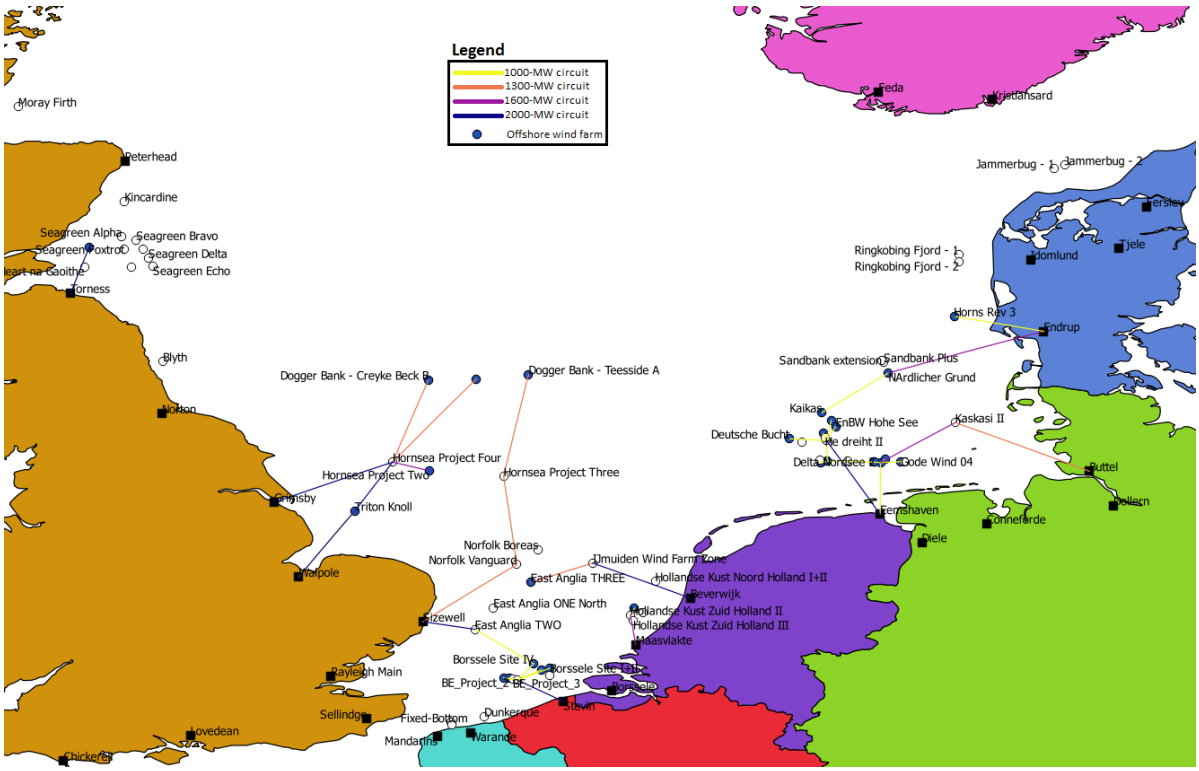

Figure B.14. Reference coordinated solution in 2024 – 525 kV.

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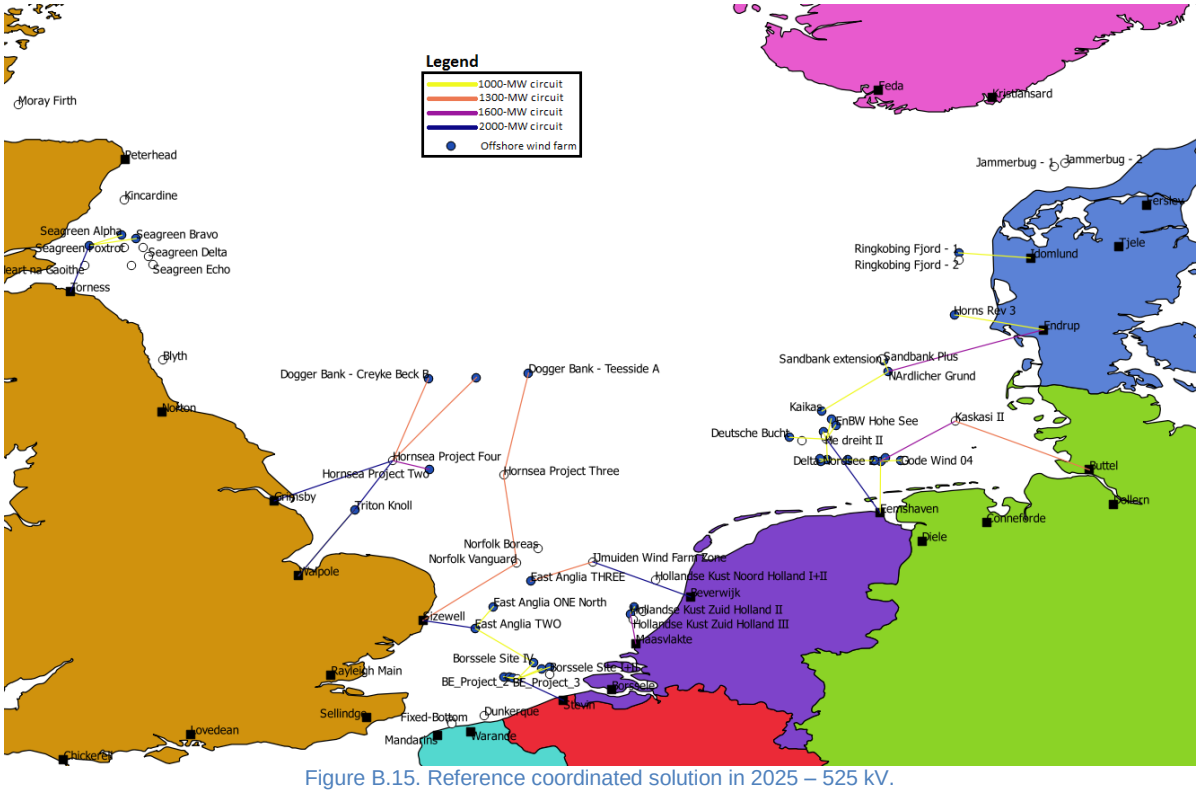

Figure B.15. Reference coordinated solution in 2025 – 525 kV.

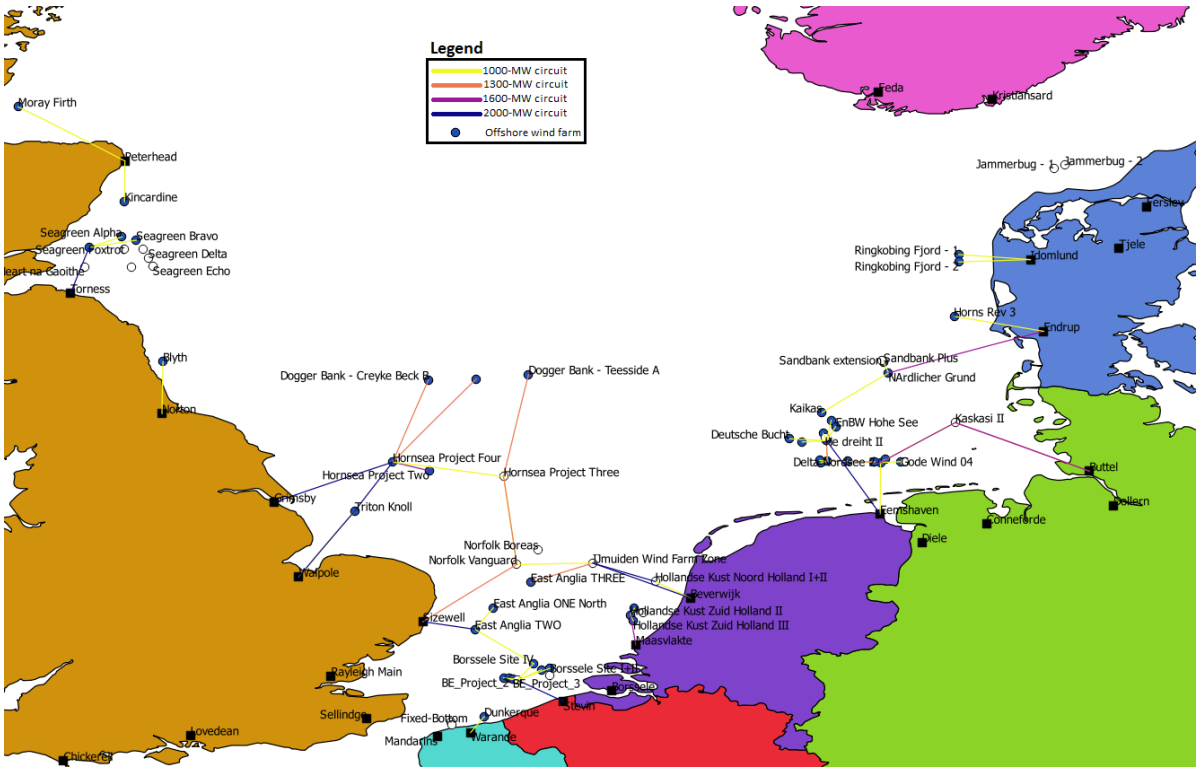

Figure B.16. Reference coordinated solution in 2026 – 525 kV.

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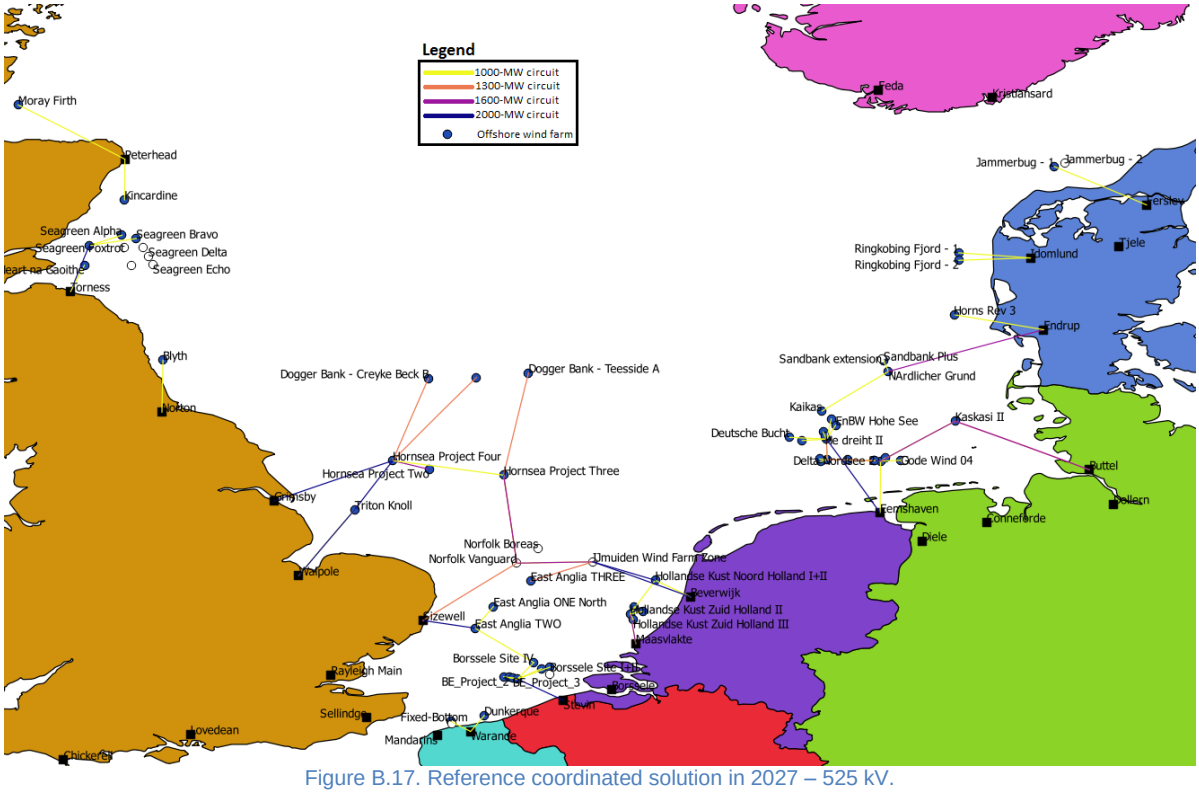

Figure B.17. Reference coordinated solution in 2027 – 525 kV.

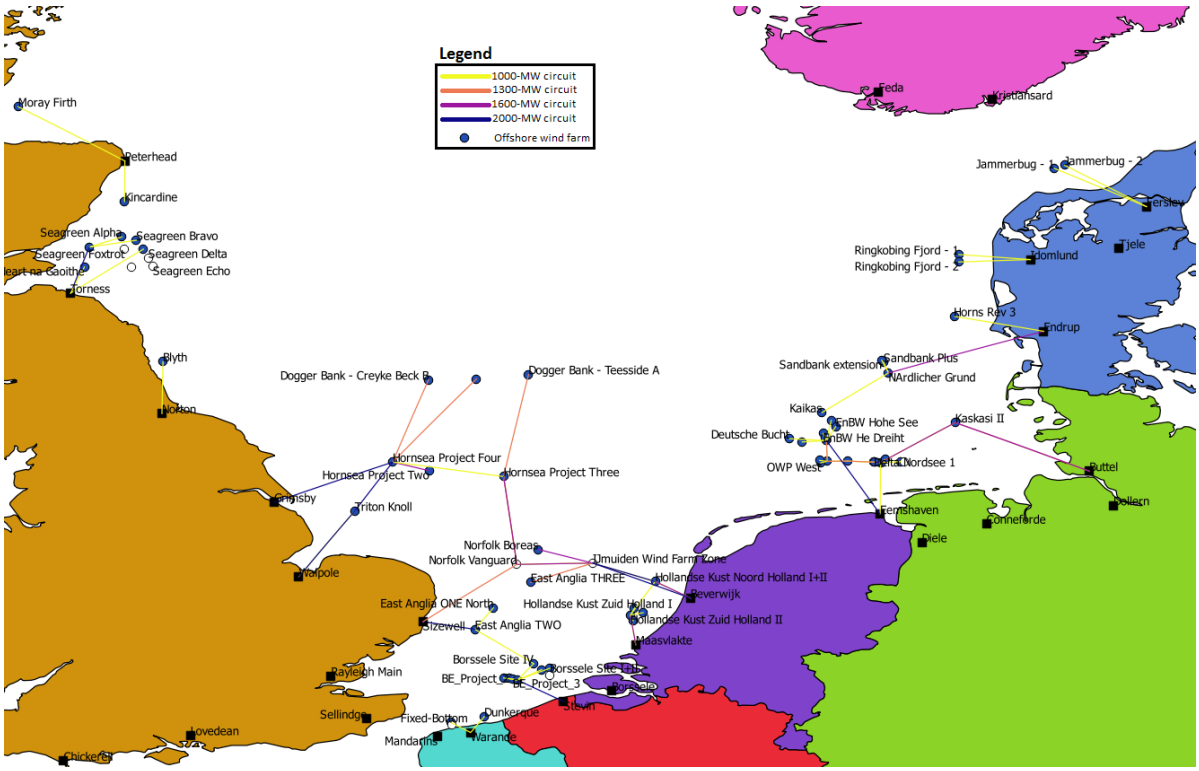

Figure B.18. Reference coordinated solution in 2028 – 525 kV.

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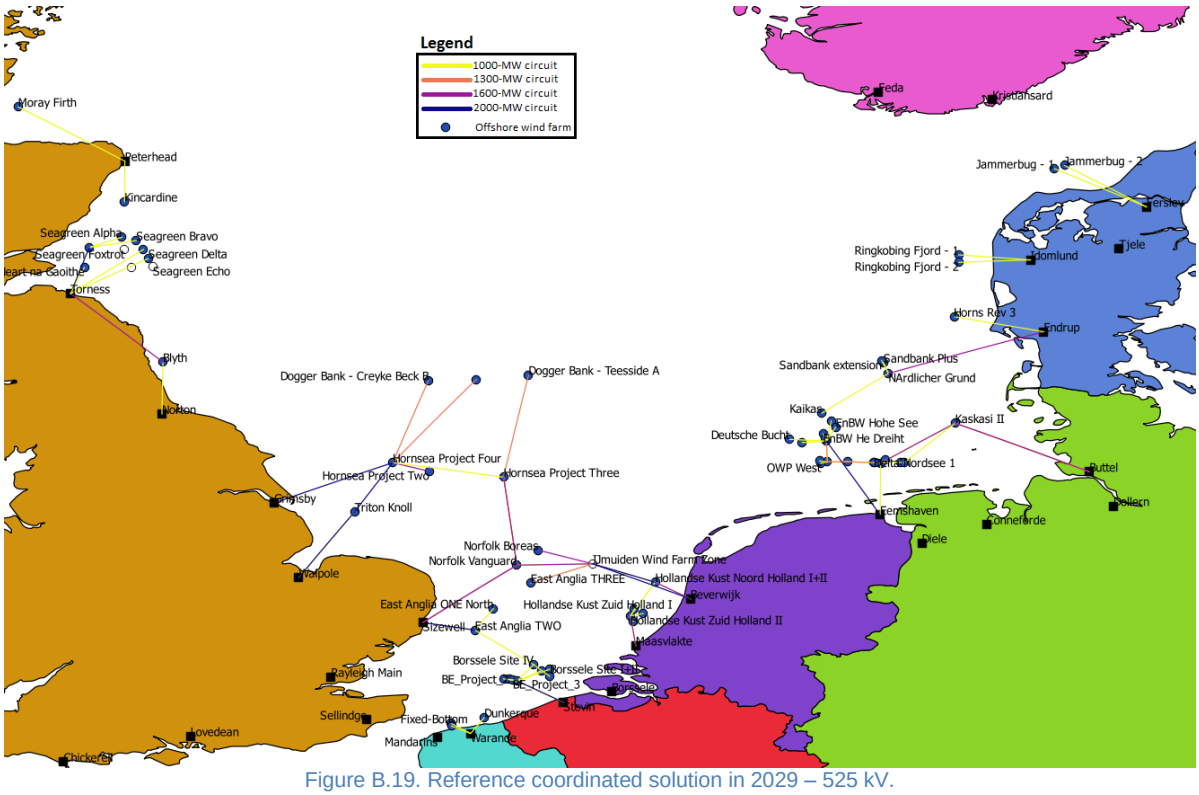

Figure B.19. Reference coordinated solution in 2029 – 525 kV.

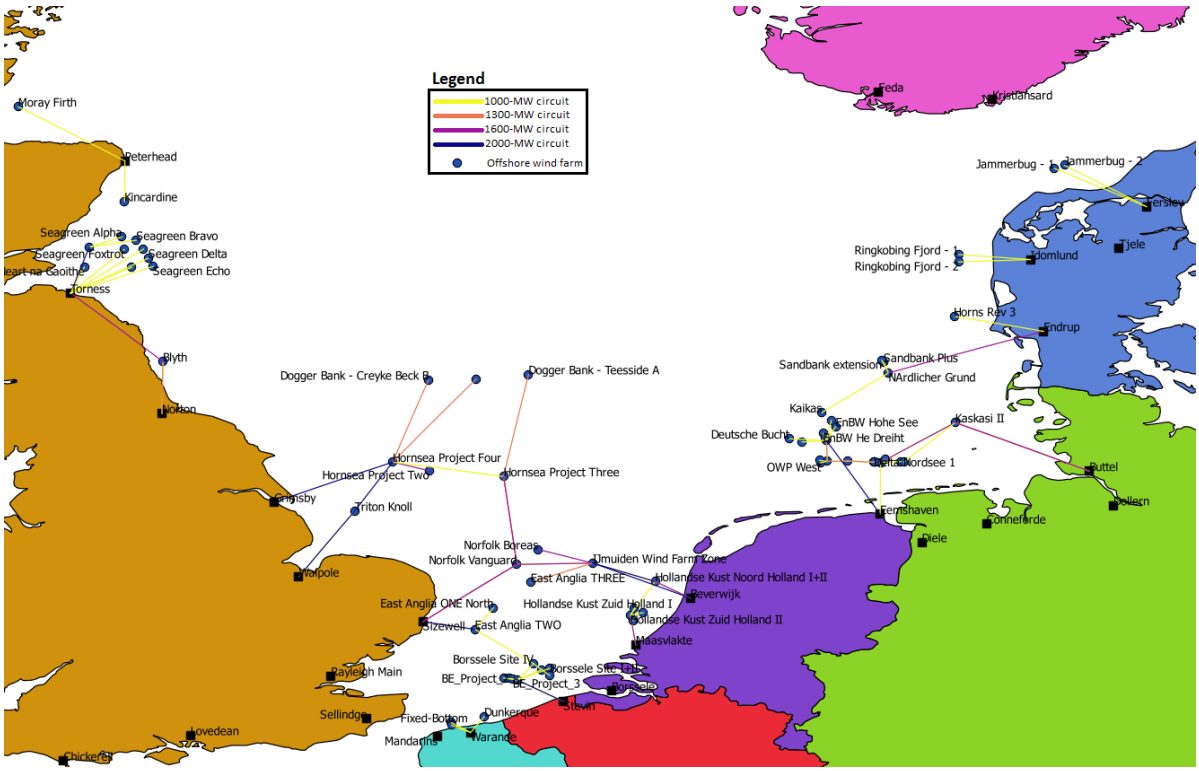

Figure B.20. Reference coordinated solution in 2030 – 525 kV.

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APPENDIX C: OPEN RESEARCH QUESTIONS

C.1 PLANNING CRITERIA

A first attempt to draft planning criteria for an offshore HVDC grid has been made in this deliverable. One major question is linked to the relevance of deterministic criteria. Indeed, the N and N-1 criteria have been initially developed for ensuring a good level of reliability for loads in systems dominated by centralized and dispatchable generating units. The relevance of these deterministic criteria is already questioned for onshore grids in the current energy transition, especially due to the increasing uncertainty of generation induced by intermittent energy sources (e.g. solar, wind) and due to the new power system actors like storage and demand response. Indeed, there is no clear load/generation pattern to analyse. In that context, the collaborative R&D GARPUR project co-funded by the European Commission (7th Framework Programme) aims at developing probabilistic criteria to manage the reliability, in particular in the planning stage. If the relevance of deterministic planning criteria is already questioned for onshore grids, the problem is more stringent for offshore grids. Indeed, the amount of loads is expected to be very small compared to the amount of generation: offshore grids will mainly be used to evacuate offshore wind energy and to trade energy between countries. It means that it is not fully relevant to apply to offshore grids planning criteria developed initially to guarantee a good level of power supply to loads. It appears thus more relevant to base the planning of an offshore grid on probabilistic criteria, in place of or in complement to deterministic criteria.

If deterministic criteria are kept, fully or partially, several points must be addressed. Firstly, the specific operating conditions that must be studied in the N/N-1 analysis must be defined. In this deliverable, the offshore peak generation was considered, but it might not be fully appropriate. Moreover, when the offshore grid comprises several onshore converters, several power flow patterns could be possible, depending on the settings of these converters. Planning criteria should specify the way the power flow pattern to study is obtained. Secondly, the way to study the intrinsic stability of the power system under normal conditions must be defined. Finally, the kind of events/contingencies to consider in an N-1 analysis and the simulations to perform to check the N-1 security must be defined.

The use of probabilistic planning criteria requires the definition of probabilistic metrics. Two different types of metrics could be defined:

- Reliability metrics, in order to quantify directly the adequacy and the security of the grid. In that case, what is considered as the failure of the grid must be precisely defined (e.g. incapacity to evacuate all the offshore energy) to allow the actual quantification of reliability, as well as acceptable values. Note that different failure definitions can be adopted, in order to lead to different reliability metrics.
- Economic metrics, in order to plan the grid in order to optimize the balance between costs and benefits balance.

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Similar to traditional onshore grids, there is no major conceptual challenge for the development of a probabilistic adequacy assessment, but a probabilistic security assessment is not straightforward. Indeed, in case the grid is not secure after a specific initiating event, a proper assessment of the risk necessitates considering potential cascading outage effects.

C.2 TECHNICAL CAPABILITIES OF THE DRU

It is currently unclear in which grid topologies a DRU could be used. If the DRU can only be used for purely radial connection of offshore wind farms, and cannot be used for more complex structures (i.e. radial multi-terminal and meshed grids), the benefits of these complex structures might be insufficient to cover the extra cost due to the need of VSCs. A clear understanding of the DRUs capabilities is thus needed.

C.3 CONTROL

Long-term planning requires making assumptions about power system elements that do not yet exist and are not yet under construction. For traditional onshore grids, this is in particularly the case for future power plants. Indeed, assumptions on the electric machines, on the frequency control, on the voltage control, etc. are needed to verify that the planned power system complies with the planning criteria, in particular the stability criteria and the constraints on the short-circuit levels. Usually, generic models and typical values of parameters are used in the simulations, and it is justified because actual values are close to typical values. For example, the frequency droop parameter of a power plant is typically between 4% and 6%, which means that the frequency stability of a power system can be studied in long-term planning by using values in that range.

For offshore HVDC grids, there are however no “standard values” yet for the different parameters that can be used in control loops. For example, there is no indication of what could be a realistic range for the voltage droop parameter of HVDC converters. The lack of typical values could hamper the planning of offshore HVDC grids. It is thus of the paramount importance to establish a set of standard models and values that could be used in the long-term planning phase.

C.4 SHORT-CIRCUIT CONSTRAINTS

In AC grids, the requirement of having a maximum short-circuit current lower than the circuit breaker capacity can impact significantly the planned topologies. It is expected that the same phenomenon will apply to offshore HVDC grids. A clear understanding of the DC CBs capabilities and the way Fault Current Limiters can be used is needed.

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C.5 MARKET

The way the market is organized can impact drastically the benefits of an offshore grid. Different schemes could be implemented to define the bidding areas (e.g. national bidding areas, offshore bidding areas), and different market models could be used (e.g. ATC-Based, Flow-Based). Moreover, the operating rules (e.g. security constraints) will impact the transfer capacities between the bidding areas. A more precise CBA thus requires an estimation of how the market could be organized for a meshed HVDC offshore grid.

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APPENDIX D: OVERVIEW OF THE INTERACTIVE PRESENTATION TOOL

Figure D.1 shows the interactive presentation tool.

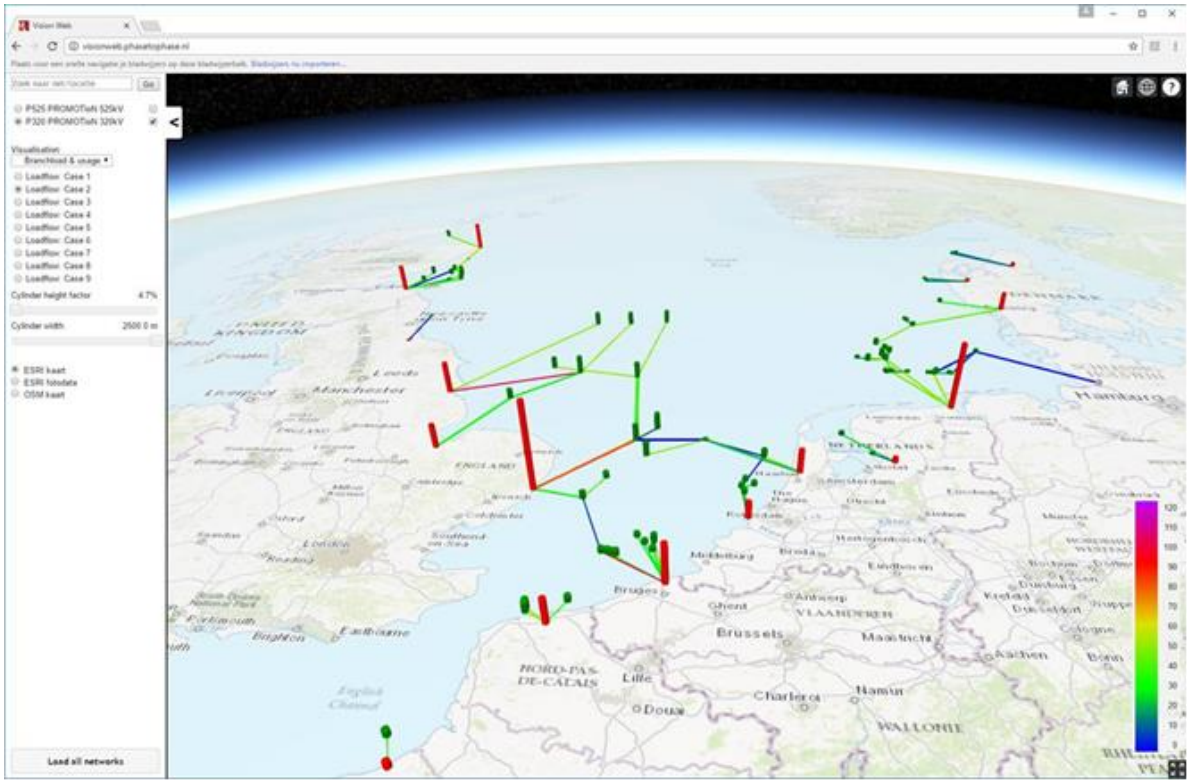

Figure D.1. Overview of the interactive presentation tool.

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