DC grids: motivation, feasibility and outstanding issues

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Table of Contents

LIST OF ACRONYMS

AGC	Automatic Generation Control
DCCB	DC circuit breaker
DCG	DC Grid (referring in particular to the offshore HVDC grid and associated offshore wind farms)
DFIG	Doubly-Fed Induction Generator
FCSG	Full-scale frequency Converter Synchronous Generator
FRT	Fault Ride-Through
GS-VSC	Grid-Side VSC (i.e. the onshore converter, connected to the mainland grid)
HVDC	High Voltage Direct Current
LCC	Line commutated converter
MPT	Maximum Power Tracking
MTDC, MT-HVDC	Multi-Terminal HVDC
OWF	Offshore Wind Farm
PCC	Point of Common Coupling
PFCC	Primary Frequency Control Capability
PMSG	Permanent-Magnet Induction Generator
QSS	Quasi Steady-State
SPS	System Protection Scheme
TSO	Transmission System Operator
VSC	Voltage Source Converter
WEC	Wind Energy Converter
WF	Wind Farm
WF-VSC	Wind Farm Side VSC (i.e. the offshore converter, connected to the wind farms)
WT	Wind Turbine

1 INTRODUCTION

Wind energy is already a mainstay of clean power generation in Europe, with over 100GW of capacity installed so far, and another 120GW anticipated by 2020 according to various analysts. Much of this capacity is expected to be installed offshore, as it is a windier and the source is steadier compared to onshore wind energy. Hence, offshore wind has been envisaged as making a critical contribution to Europe’s demand for electrical energy and to minimising the carbon emissions associated with meeting that demand.

It is well understood that installation, operation and maintenance of offshore facilities, whether associated with the generation, collection or transmission of the electrical energy, is extremely expensive and so the most appropriate technologies must be deployed to provide the maximum cost-benefit. For quite long distances offshore, high-voltage direct current (HVDC) transmission is preferred for economic and technical reasons; hence, this technology provides the platform that can be used to enable massive integration of offshore wind farms into AC onshore networks with minimum losses and increased flexibility over power control.

Although no Direct Current Grids (DCG) are operational yet, it has been speculated by many researchers that such grids will provide significant benefits beyond the integration of multiple offshore wind farms dispersed over wide areas into AC onshore grid. In addition to allowing the optimisation of AC and DC transmission infrastructures and offering potential improvements to the reliability and security of supply, DCG are expected to provide additional functionalities and meet key system requirements: wind power transfer function (including smoothing of wind power fluctuations); interconnection function (i.e. use of the DCG to exchange power between AC zones); ancillary services (e.g. voltage support, frequency support to onshore AC grids).

However, DCG also present challenges. For example, security assessment must be specifically addressed to prevent instabilities and cascading outages of the DCG, but also any adverse effect on the mainland AC network.

In spite of those potential benefits, no DCG currently exists, as major barriers still remain. The objective of the “DC Grid” demo is to clarify and overcome some significant barriers, either technological or economic, for example: What controls should be implemented to operate an offshore DCG in a flexible yet robust way (both for the DCG itself, but also the AC network)? Are such controls compatible with the provision of ancillary services for the onshore power system? How to protect the DCG, for which no DC Circuit Breaker (DCCB) is available on the market? What new detection algorithms have to be specifically designed, since those used in AC cannot operate on a DCG? What is the economic viability of a DCG compared to point-to-point DC connections?

These questions were addressed within the DEMO 3 of TWENTIES, shedding new light on offshore DCGs thanks to major achievements (DCCB demonstrator, and the first meshed DCG mock-up with physical cables and protection devices), and new controls and methodologies.

The challenges associated with DCGs connecting offshore wind farms are addressed in DEMO 3 through two work packages:

- Work Package 5 (WP5) is responsible for Research and Development tasks, including: the control and protection strategies of DCGs (for different grid structures) including autonomous power flow controls, ancillary services provided to the AC network and the Fault Ride-Through capability; the impact of the DCG on the AC protections; the economic drivers for the offshore DCG; reliability assessment of different DCG structures. This achievement is the result of a joint effort of WP5 partners: RTE, as Work Package leader, INESC Porto, RSE, University of Strathclyde and UCD.

- Work Package 11 (WP11) brings together RTE (as Work Package leader) and Alstom Grid in contributing to the realisation of two key demonstrators: a DCCB demonstrator, designed and assembled by Alstom Grid, was successfully tested for medium-voltage as a proof of concept, while a high-voltage version is about to be tested (results expected by end 2013). In addition, the first meshed DCG mock-up (with 15 km cables and protection devices) was realized in Université de Lille (as sub-contractor for RTE) to prove the effectiveness and robustness of various control algorithms, both in normal operation and during contingencies. This mock-up was also used to validate innovative DC fault detection algorithms elaborated by G2eLab in Grenoble (as sub-contractor for RTE).

1.1 STRUCTURE OF THE DOCUMENT

This document presents a summary of the main findings of DEMO 3 along with further explanation of those findings. The main findings are summarised in three tables in section 2:

1. a DC grid as a facilitator of power system or electricity market integration of offshore wind farms (Table 2.1);
2. operational performance of DC grids (Table 2.2);
3. Europe-wide impact of DC grids (Table 2.3).

Sections 3 to 5 provide further explanation of the observations made in each of the tables:

- Section 3: in respect of a DC grid as a facilitator of power system or electricity market integration of offshore wind farms;
- Section 4: in respect of operational performance of DC grids;
- Section 5: in respect of the Europe-wide impact of DC grids.

Section 6 reports outcomes from DEMO 3 in respect of Key Performance Indicators. Section 7 presents some recommendations and Section 8 lists some publications that have emerged to date from DEMO 3.

2 SUMMARY OF KEY FINDINGS

The main findings from DEMO 3 are summarised in three tables in this section. In each, a number of considerations or performance criteria are listed in respect of three general types of DC connection of offshore wind farms (OWFs) to one or more onshore AC transmission systems:

1. **Point-to-point connections**, simply connecting an offshore wind farm or cluster of offshore wind farms via HVDC to one location on a single onshore AC transmission system (see Figure 2.1);

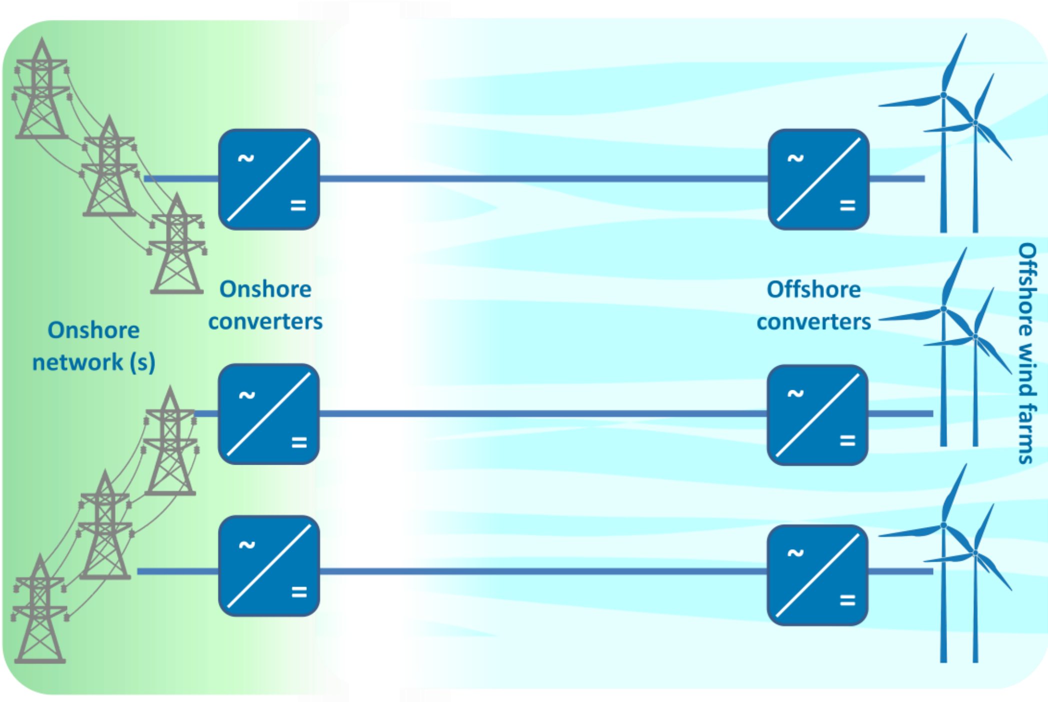


Figure 2.1: Point-to-point connection of offshore wind farms to shore.

2. **Tree-like[1] grids** in which one or more offshore wind farms is connected via a DC grid to one or more AC system onshore location, the DCG not having any possible loop paths within it (see Figure 2.2);

[1] « Tree » refers to the term used in Graph Theory (that is: a connected acyclic and undirected graph). Therefore, the tree-like grids are "trees", while meshed DC grids (including meshed backbones described below) are connected undirected graphs with at least one cycle. For the sake of clarity, we will use shorter and more descriptive terms for DCG typology, rather than the exact Graph Theory ones.

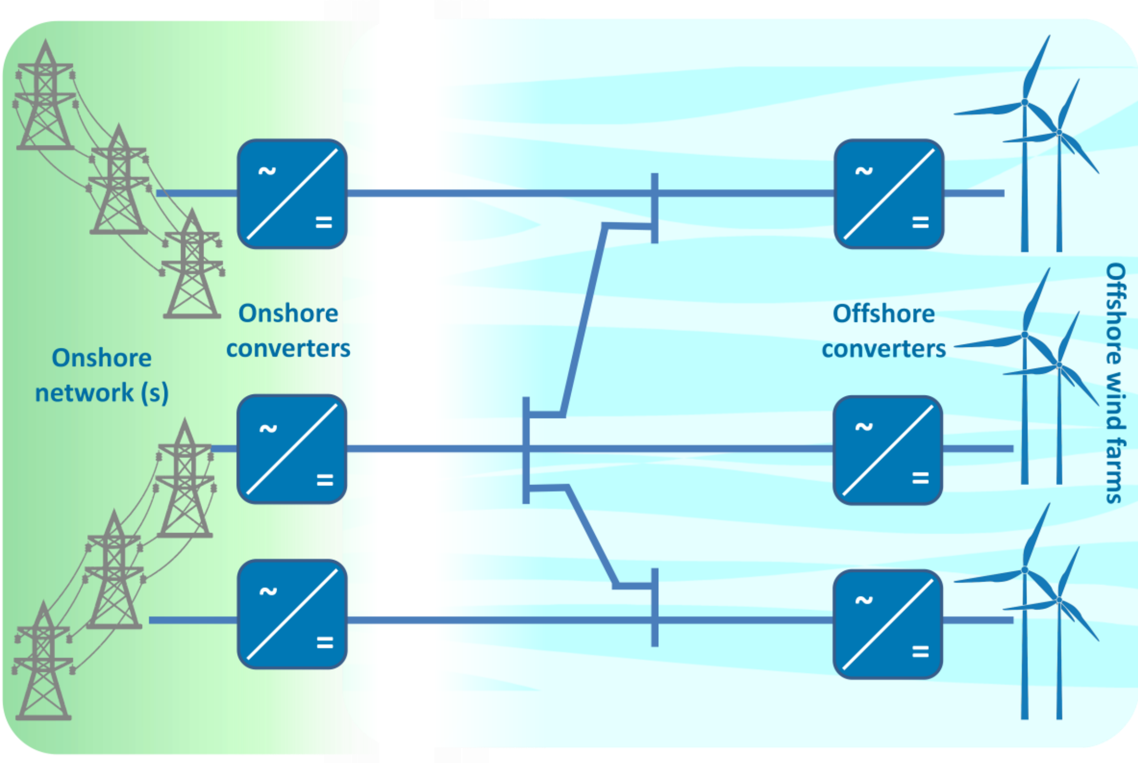


Figure 2.2: Tree-like grid example (also referred to as the "tree-like backbone" in previous deliverables).

3. **Meshed grids** in which offshore wind farms are connected via a DC grid to one or more AC system onshore location; as the DC grid is meshed, there is at least one loop path within it. Two meshed grids were considered in DEMO 3 (see Figure 2.3): a meshed version of the "backbone" layout, and a mixed topology (including both meshed and radial portions of the grid) which was tested in the first meshed DCG mock-up with real cables and protection devices.

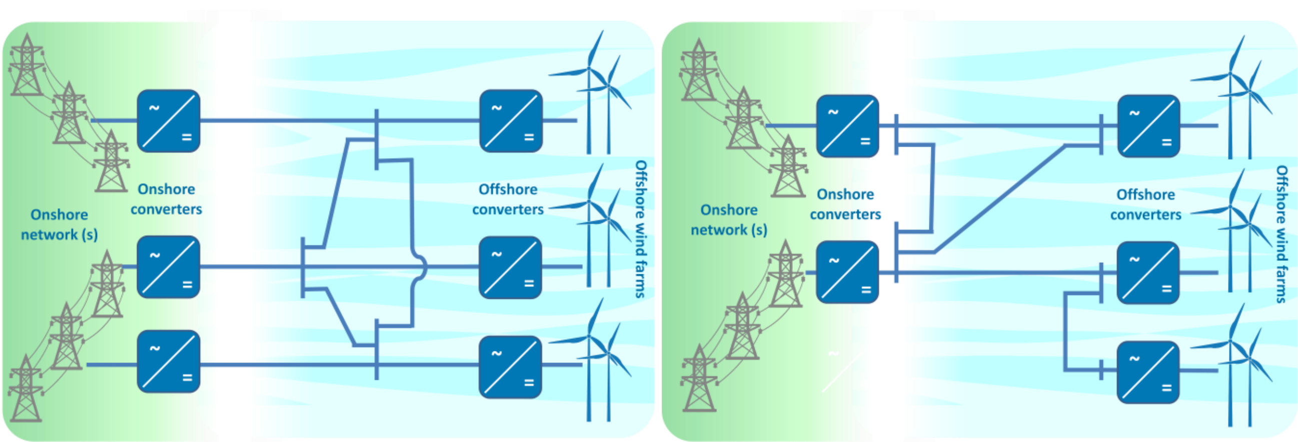


Figure 2.3: Meshed grid examples: a meshed backbone (left) and the DEMO 3 DCG mock-up topology (right).

Strictly speaking, the point-to-point connection case is not a 'DC grid' as such but does nonetheless provide power transfer capability through use of HVDC, and its technical characteristics and costs should be considered and compared with those of the DC grid cases.

As well as providing routes for power transfer from the offshore wind farm(s) to shore, the two grid cases (where there is more than one onshore AC system connection point), may be within the same AC synchronous area or in different AC synchronous areas. In the former case, the DC grid may be said to be 'embedded' within the AC system or to provide power transfer capability *within* the area as a complement to the AC network branches. In the latter case, the DC grid can function as an interconnector *between* the different AC synchronous areas.

The three tables address:

1. a DC grid as a facilitator of power system or electricity market integration of offshore wind farms (Table 2.1);
2. operational performance of DC grids (Table 2.2);
3. Europe-wide impact of DC grids (Table 2.3).

The purpose of the tables is to summarise, quite succinctly, the feasibility of different forms of 'DC grid', to highlight any particular issues and to outline, insofar as the studies within DEMO 3 have been able to quantify them, the potential benefits. However, in providing a short summary, it might not be possible to address a number of important caveats or qualifiers. These are described:

1. in respect of a DC grid as a facilitator of power system or electricity market integration of offshore wind farms, section 3 of this report;
2. in respect of operational performance of DC grids, section 4 of this report;
3. in respect of the Europe-wide impact of DC grids, section 5 of this report.

In addition, sections 3 to 5 point the reader towards other Deliverables of DEMO 3 in which full details of methodology, scenarios and results can be found.

As described in section 1, offshore wind farms have been envisaged as making a critical contribution to Europe's demand for electrical energy through offshore DCGs. However, there are few existing examples of Multi-Terminal DC (MTDC) schemes, all of them being operated using three terminals only. Furthermore, they are onshore ones using LCC technology which is unlikely to be the preferred option for offshore DC grids, and none of them is actually a DCG nor operated in a truly flexible fashion. To develop a DCG requires that a number of technical issues are addressed. While DEMO 3 cannot claim to have fully addressed them all, it is important that sufficient knowledge is gained to establish the theoretical feasibility of DCG in order that further work leading to demonstration and, with successful outcomes, commercial deployment can proceed. With respect to both the feasibility and potential benefits of DCG, readers are encouraged to review all three tables below and to read the discussions in sections 3-5. However, it is recognised that there are a number of different stakeholders with interests in DC grids, e.g.

- wind farm developers and operators;
- transmission system operators (TSOs);
- original equipment manufacturers (OEMs);
- researchers;
- policy makers and investors.

Wind farm developers and operators might particularly consider Table 2.1 and section 3 which seeks to express the findings of DEMO 3 broadly from the perspective of the offshore wind farm. This includes ways in which different system services might be offered by the combination of offshore wind farm and DCG for which the wind farm operators might be remunerated, so enhancing the investment feasibility of the offshore wind development. They might also consider the broader societal context in which a wind farm operates as expressed in Table 2.3 and section 5, which would also be of particular interest to policy makers and investors. TSOs and OEMs responsible for making DC grids finally work safely and reliably may pay particular attention to Table 2.2 and section 4.

Table 2.1: DC grid as a facilitator of power system integration of offshore wind farms

Consideration	Point-to-point connection	Tree-like DC grid	Meshed DC grid
Has the ability to provide an OWF with a choice of onshore market or market zone	No	Subject to detailed DC grid design and overall system operating conditions, yes	Subject to detailed DC grid design and overall system operating conditions, yes
The availability of at least one path from OWF to market in case of a contingency	Low: in case of a bipole scheme with metallic return cable, re-configuration to transmit half power is possible following a single pole fault on a cable or a fault on a converter. Yet, no bipolar scheme exists to date to connect offshore wind farms.	Depending on the capacities of different branches, higher than for point-to-point connection (regardless of the topology: monopole, bipole). However, correct post-fault reconfiguration depends on accurate fault location.	Higher than for the tree-like DCG, but with similar caveats.
The continuity of availability of at least one path from OWF to market	No. Even if metallic returns are used in order to re-configure a bipole DC link following a fault on a converter or a cable, the re-arrangement will lead to at least a short period of unavailability	Provided DC circuit breakers (DCCBs) are installed and DC fault locations can be identified, and depending on the capacities of different branches, higher than for the point-to-point case. (It is less likely that a given OWF is shut down and must be re-started)	Provided DCCBs are installed and DC fault locations can be identified, higher than for the tree-like grid. (It is less likely that a given OWF is shut down and must be re-started)
Has the ability to reduce spillage of wind energy	Depends on the capacity of the HVDC connection relative to that of the OWF, and on the AC system connection point (this is the case irrespective	In general, yes: more than in the point-to-point case.	In general, yes. Opportunities to find routes for transmitting the power and AC networks capable of absorbing the energy increase with the

	of connection type)		network meshing.
Enables the connected OWF(s) to contribute to ancillary services	Yes	Yes	Yes
Enables the connected OWF(s) to contribute to system defence	Yes	Yes	Yes
The DC grid and the connected OWF(s) can contribute to system restoration	Most likely (according to early studies)	Most likely (according to early studies)	Most likely (according to early studies)
What is the limit to OWF capacity on single, contiguous DC grid?	Restricted by cable and converter technology and system primary reserve requirement in AC synchronous area(s) to which it is connected	If DCCBs not used, then total power exported to single AC system synchronous area via one or more terminals is restricted by loss of in-feed due to single contingency and primary reserve of that area. In the case where DCCBs are employed, no limit was established.	

Table 2.2: DC Operational performance of DC grids

Consideration	Point-to-point connection	Tree-like DC grid	Meshed DC grid
Do operations of the DC grid depend on the presence of DC circuit breakers (DCCB)?	No, but maximal power is restricted by cable and converter technology and AC system primary reserve; yet, DCCB could enable faster switching compared to AC breakers.	The total power exported to a single AC system synchronous area via one or more terminals and which might be lost following a single fault event is restricted by the primary reserve of that area. DCCBs can help to limit the loss of infeed due a fault event and enable other branches to continue in service. Without them, the DC grid must be partitioned pre-fault so that clearance of a fault by operation of breakers on the AC side of each terminal of that partition would limit the loss of infeed associated with the fault event.	
Is a DC breaker feasible?	DCCBs are not necessary. The fault current is interrupted by opening breakers on the AC side at each end; reverse blocking capability of new VSC converters could also be considered.	Some classes of DCCB performances (which depend on location, grid and converter design, and operating conditions) are feasible as proved with Alstom's demonstrator (live demo in Villeurbanne). In addition, fast protection algorithms were proven feasible using fast telecoms as proved with the DCG mock-up live demo in Lille.	Idem to the tree-like DCG, but considering similar grid ratings, the duty of the DCCB will necessarily be higher as the grid meshing increases (since stronger and faster fault current would occur).
Is a selective DC fault detection and protection system feasible?	Selective detection is straightforward in a point-to-point connection; AC breakers are commonly used to isolate the DC link.	Innovative and selective algorithms were developed to be efficient for DC cables up to 200 km long. The protection system relies on fast communication. Both selective detection and backup protection were successfully tested on a DCG mock-up (live demo in Lille).	
Can the terminals of the DC grid be coordinated under normal operating conditions and avoid breaches of limits without need for fast communications?	Yes, however "coordination" is simply between the two ends of each point-to-point connection.	Yes: voltage droop control provides global coordination between the converters to accommodate intermittent generation, and ensures system stability for some contingencies without relying on communication. In addition, dedicated droop controls may be designed to implement communication-free,	Yes, as for tree-like DCGs. However, the meshing may require more coordination (with a master control) and additional equipment (such as Power Flow Control devices) to complement the droop control provided by onshore converters and utilize the DC grid in an optimal way.

		predefined power sharing policies, depending on the grid topology.
Which features and services are provided by the DC connection to the AC onshore network?	Wind power transfer; voltage support; inertia emulation; primary frequency control; Fault Ride-Through (FRT) capability	Wind power transfer; interconnection; smoothing of wind power fluctuations; voltage support; inertia emulation; primary frequency control; Fault Ride-Through (FRT) capability; power oscillation damping; power injection redispatching to improve AC system security.
What is the impact on operation of the DC grid of a short-circuit fault on the onshore AC system?	Power transfer from the DC grid will be restricted (depending on the AC voltage dip), leading to possible DC overvoltage.	In contrast to the point-to-point connection case, alternative paths can be used to shift power to AC zones which are less subject to the voltage dip. This mechanism, in addition to the fact that several converter stations should be used to regulate DC voltage, makes it possible to limit or even avoid DC overvoltage. Finally, lower power transfer reduction is expected compared to point-to-point connections.
What is the impact of loss of an onshore converter?	Loss of the whole DC connection.	Possible transient overvoltage on the DC grid may occur. Fast power reduction at wind farm level might be required. In contrast to the point-to-point connection, the DCG is still able to transmit offshore wind power (up to its remaining capacity); this capacity is greater than if wind farms were connected through direct point-to-point connections (with comparable ratings). Depending on the number of remaining onshore converters, the interconnector feature may be partly available.
What is the impact of a DC short-circuit fault?	Loss of the whole DC connection is very likely (unless a bipolar scheme with metallic cable return was adopted, which would enable 50% and 0% remaining transmission capacity for a pole-to-ground and a pole-to-pole fault respectively.)	Loss of all or part of the DC network, depending on the availability and performance of DC protection and DC circuit breakers. If DCCBs are used to isolate the fault, the DCG is able to regain a stable point of operation without interrupting power flows or collapse of DC voltage (voltage droop control ensures system transient stability after fault elimination without relying on communication).
What options are available in respect of different converter designs, and what are the benefits?	All VSC designs are possible: compared to 2-level VSC, multi-level converters have raised VSC efficiency and achievable	Multi-level converters can reduce transient DC fault levels. Alternative (reverse blocking) multi-level converter designs can block AC current contributions to DC faults. Additional protection is required to isolate faulted DCG branches. However investigation is

	voltage ratings but increased size and complexity of converter power electronics.	required to determine interruption times and the impact of such approaches on DC grids and the AC systems.
What impact do different DC structures have on converter and DC breaker stresses?	For converters, the fault current is worst for a fault close to the station and is determined by the converter and coupling transformer inductances. For cables, the transient is composed of an initial discharge of cable and converter capacitance, and a steady state component resulting from AC networks contribution through unblocked converters	Compared to the point-to-point connection case, greater fault currents are likely to be observed as they result from the numerous cables (meshing), and the various AC sources connected to the DCG (both onshore and offshore) A classification of different DC fault currents is proposed, which results in various foreseen DC breaker duties. The design of the demonstrator DCCB is compliant with two of the three identified classes.
What are the limits to inter-operability of different types of converter on the same DC grid?	Studies show that different types of converter can operate together to provide basic control of power flow and satisfactory transient response. However further investigation is required to test inter-operability on a full-scale demonstrator. In addition, converter technology may have a significant impact on DC fault response.	
What is the impact of a DC grid on stability of an AC system to which it is connected?	Reactive power capability of onshore terminals can be used to improve voltage stability of the AC networks during normal operation and AC network faults.	Similar to the point-to-point connection case. In addition: • Small signal stability can also be enhanced through appropriate converter controls. • Inertia and frequency regulation can be provided by appropriate controls. • In a preventive way, AC system stability can be improved by shifting power injections on the mainland AC network.
What is the impact of a DC grid on operation of AC system distance protection?	Protection mis-coordination may occur for existing AC protection close to the onshore converters, whatever the DC transmission structure. This issue was illustrated with the under-reach problem of relay protections (a zone 2 fault which is likely to be viewed in the zone 3 range by a relay, due to the reactive power control of onshore VSC converters.	
How should power be dispatched on different terminals of a	Not relevant	As onshore converters allow controlling the power injected from the DCG into the AC connection points, power could be dispatched according to market rules. Dispatch flexibility is limited by the rating of the DC

DC grid?	cables and converters, as well as by security constraints of both DC and AC grids. The DCG injections could also be used for redispatching in the intra-day markets. In real-time operation, DCG power injections into the AC grid(s) can be adjusted manually, for security reasons, and by automatic systems performing primary frequency regulation of the AC grid(s) and/or accounting for wind power fluctuations.

Table 2.3: Europe -wide impacts of different DC grid designs

Consideration	Point-to-point connection	Tree-like DC grid	Meshed DC grid
The electricity market can choose from which OWF to buy power	No	Subject to detailed DC grid design and overall system operating conditions, yes	
The DC transmission structure can provide inter-area exchange	No	Subject to detailed DC grid design and overall system operating conditions, yes	
The DC transmission structure has multi-use capability, i.e. serves as both OWF connection and interconnector	No	Yes	Yes
The DC transmission structure can reduce spillage of wind energy	Depends on the capacity of the HVDC connection relative to that of the OWF, and on the AC system connection point (this is the case irrespective of connection technology)	In general, yes: more than in the point-to-point case.	
What is the maximum offshore wind power output that can be accommodated?	In respect of the total, it depends on operating conditions across the power system as a whole. In respect of an individual 'DC grid', it is restricted by cable and converter technology and AC system primary reserve	In respect of the total, it depends on operating conditions across the power system as a whole. In respect of an individual DC grid, if DCCBs not used, then the total power exported to single AC system synchronous area via one or more terminals is restricted by loss of in-feed due to a single contingency and the primary reserve of that area	
How much offshore wind energy can the DC transmission structure accommodate?	In respect of the total, it depends on operating conditions across the power system as a whole and how they vary in the course of a year. In respect of an individual DC grid, limited by the capacities of a converter and the cable, but also by the	In respect of the total, it depends on operating conditions across the power system as a whole and how they vary in the course of a year. In respect of an individual DC grid, it depends on the total capacity of each converter and the cable(s) connected to it, and the number of such connections. However, also depends on the export capacities of the AC system locations to which they are connected.	

	capacity of AC network.	
What is the reduction in CO_2 emissions that a DC transmission structure can facilitate?	Provided grid capacity is sufficient, the energy produced by the OWF replaces an equivalent produced by fossil fuelled generation. However, under some circumstances, other limits to operation of the power system prevent utilisation of all the available wind energy (hence there may be a less than 1 to 1 substitution).	Similar to the point-to-point connection, but a DCG will have a wider impact that depends on the nature of AC system and market operation in those areas. In common with point-to-point interconnectors, this impact depends on the nature of AC system operation in those areas and on behaviour of the electricity market. For example, it can facilitate access to cheaper generation in another area or sharing of reserve between areas. However, the carbon impact depends on the emissions characteristics of the cheaper generation.
What is the reduction in the cost of electrical energy in Europe that a DC transmission structure can facilitate?	The overall impact depends, largely, on the prices of fuel and carbon for the replaced fossil fuelled generation relative to the capital, operation and maintenance costs of the OWF and HVDC connections.	The overall impact depends, largely, on the prices of fuel and carbon for the replaced fossil fuelled generation relative to the capital, operation and maintenance costs of the OWF and HVDC connections. A DCG will have a wider impact on the electricity market than the simple replacement of fossil-fuelled generation by wind energy, e.g. by allowing low cost generation in one AC synchronous region to replace higher cost generation in another.

3 DISCUSSION: DC GRID AS A FACILITATOR OF OFFSHORE WIND POWER

As noted in section 2, above, there are three main choices for the provision of offshore transmission network capacity. While the first requirement for such capacity is to bring electrical energy generated by offshore wind farms back to an onshore system where it can be used, different configurations of the network capacity might give other benefits or be more complex to design and operate.

The three main types of 'DC grid' are:

1. "point-to-point connections", not strictly a 'DC grid' but simply connecting an offshore wind farm or cluster of offshore wind farms via HVDC to one location on a single onshore AC transmission system;
2. "Tree-like DC grids" in which one or more offshore wind farms are connected via a DC grid to one or more AC system onshore locations, the DC grid not having any possible loop paths within it;
3. "Meshed DC grids" in which one or more offshore wind farms are connected via a DC grid to one or more AC system onshore locations, the DC grid being meshed, i.e. having at least one possible loop path within it.

Table 2.1 above has summarised the characteristics of the three main types of DC grid in respect of the services or access it can provide to the owner or operator of an offshore wind farm (OWF). The remainder of this section provides some further explanation in respect of those observations.

3.1 GIVING AN OWF A CHOICE OF ONSHORE MARKET OR MARKET ZONE

The simplest design of 'DC grid' to transfer offshore wind power to shore is via a radial connection of a single OWF or a cluster of OWFs to single AC system at a single location. Under current market arrangements, the only electricity market or market zone to which the OWF can, in the first instance, sell its energy or realise income from a renewables support mechanism is the one operating at the location to which the OWF is connected, which might be referred to as the 'home' market. If energy is to be sold into a different market, the OWF owner must procure access rights to an interconnector between the 'home' market and the second market. If a price in a remote market zone is to be obtained rather than the local price, financial transmission rights should have been bought.

In contrast, if the OWF is connected to a DC grid (either tree-like or meshed) and two or more of the terminals are connected into different electricity markets or zones of a single market, the controllability of a DC grid allows power to be directed to a chosen AC system location[2] is subject to the maximum power that can be transmitted via any one terminal (the limit being determined by both the rating of the connection and the capacity of the AC system to which it is connected).

[2] Even though the DC grid provides the physical possibility of directing the power, relevant market access rights would still need to be procured and, if the OWF is in different territorial waters, some arrangement put in place to allow it to realise an income from the renewables support mechanism prevailing in the country in which the chosen AC system destination is located. See, for example, WP16 of TWENTIES for further discussion.

3.2 AVAILABILITY OF AT LEAST ONE PATH FROM OWF TO MARKET IN CASE OF A CONTINGENCY

Normally, the existence of more than one path from an OWF to an electricity market, i.e. the provision of some redundancy in the connection to market, would provide greater availability of access to that market. Thus, in this respect, both types of DC grids considered within DEMO 3 would be expected to perform better than the point-to-point connection case. However, as the capacity of a connected OWF or a cluster of OWFs increases, the limit to the capacity of a voltage source converter (VSC) based monopole (currently around 1GW) dictates, first, that either a second monopole or a bipole is required, and then further monopoles or bipoles. Thus, even with common DC buses, there is at least some degree of redundancy within all three ‘DC grid’ types. Nonetheless, assuming that cables for bipoles or multiple monopoles between common locations are laid close to each other, the grid cases provide a diversity of routes which will be less vulnerable to common mode failures (such as anchor dragging).

When a short-circuit fault occurs somewhere on a DC grid, it must be detected and the fault current interrupted. Ideally, only the affected location would be isolated and other sections of the DC grid would remain in service. However, this depends on both being able to locate where the fault is (far from trivial for a DC system) and activating DC circuit breakers sufficiently quickly. If such localised fault clearance on the DC side is not achieved, the passage of fault current must be interrupted by blocking fault current from the AC side of all terminals of the DC grid. This, in turn, means the loss of all the power being generated on the DC grid or that the DC grid is transferring from one AC system location to another. Provided the total ‘loss of infeed’ experienced by any AC system to which the DC grid is connected is not excessive (see section 3.8 for a discussion on that), this need not be a major problem. Once isolation from the AC side has been achieved and the location of the fault on the DC side identified, that location can be isolated by opening one or more disconnectors (that need not have fault current breaking capability and so should be relatively cheap, simple and small) and the rest of the DC grid re-energised and, on a DC grid, generation and power transfers restarted[3]. Depending on the frequency of occurrence of faults and the time taken to re-start, the annual availability of a path to market for an OWF may still be very high and the average annual cost of the consequential spilled energy so low that investment in expensive, large and highly complex DC circuit breakers is not justified (as long as the rule for the maximal loss of infeed is followed).

The effects of faults within a DC grid are discussed further in sections 3.3, 3.8 and in section 4. DC protection and DC circuit breakers are also discussed in section 4.

3.3 CONTINUITY OF AVAILABILITY OF AT LEAST ONE PATH FROM OWF TO MARKET

It was noted in section 3.2 that, even without DC circuit breakers, the availability of access of an OWF to market can still be quite high, and would generally be expected to be higher for a DC grid than for a point-to-point connection. However, without DC breakers, for faults at particular locations on the DC grid, *continuous* access would be impossible – a fault anywhere on the DC grid would require that the whole DC grid is shut down, even if only temporarily. Thus, provided there are DC breakers at key points on the DC grid and fault locations are successfully and quickly identified, the DC grids will provide continuity of access (contrary to the point-to-point connection case) and, by virtue of having parallel paths *within* the DC gird, the meshed case is better than the unmeshed case.

[3] The level of power transfer that can be achieved following the re-start depends on the design of the DC grid – its layout and the capacity of each branch – and the location of the fault.

3.4 Reducing spillage of wind energy

The extent to which the operator of an OWF is adversely affected by an inability, at any one time, to export all the power that it is capable of generating at that time depends on the prevailing market and renewables support arrangements. For example, if income depends entirely on physical energy produced, then 'spillage' of wind energy (not generating as much as, from the wind farm's perspective, was possible) has a direct financial penalty for the wind farm. On the other hand, if system balancing or network constraints compel the system operator to accept a 'bid' from the wind farm to reduce its output (as in Great Britain (GB) for registered 'balancing mechanism units'), through appropriate pricing of its 'bid', the wind farm operator will be able to more than compensate for any lost income and so would be unaffected by spillage.

There are a number of different possible causes of 'spillage' of wind energy, e.g.:

- the available power transfer capacity on the connection between a wind farm and the main interconnected system is less than the available wind power output;
- there is a constraint on the main interconnected AC system that prevents export of all available power;
- there is a surplus of the total power that could be generated relative either to demand or to system frequency stability limits;
- the scheduling of primary reserve at some minimum level prevents all the available wind power being fully utilised if total generation is not to exceed total demand.

Either of the first two of the above could easily be expected to arise in the event of a planned or unplanned network outage. However, given the very high cost of the connection of offshore wind power, especially at remote locations, the connection may not have been designed to accommodate the absolute maximum power that could be produced by all the connected turbines operating at their rating. Such a design would have been justified if the circumstance of available wind power exceeding the connection capacity occurs so rarely that the value of the spilled energy would be less than the cost of the extra network capacity.

Noting the four possible reasons for wind energy spillage given above, it can be seen that the extent of spillage does not depend solely on the design of the 'DC grid'. However, all other things being equal, a DC grid provides the possibility of exporting either into different AC synchronous systems or different areas of an AC system, meaning that if there are constraints on the operation of one, another could be used.

The collection of power from a geographically dispersed set of OWFs that exhibit some diversity in the level of output at any one time and hence should allow the cost-benefit analysis determining the total connection capacity to shore to be better optimised. In TWENTIES deliverable 5.2a, some analyses were reported in which total wind energy spillage for the whole of Europe was estimated for a particular background of generation capacity and demand and three different designs of network capacity in the North Sea:

1. simple radial connections of new OWF capacity to the nearest shore;
2. simple radial connections of new OWF capacity to the nearest shore along with additional point to point interconnectors between regions around the North Sea;
3. an 'H-like' DC grid in the North Sea.

Although there was insufficient time within the study to optimise the design of the 'H-grid' and make its general characteristics similar to those achieved in case 2, for the particular scenarios studied, both cases 2 and 3 showed a notable reduction in wind spillage compared with case 1.

In addition, TWENTIES deliverable 5.3b illustrates how the meshing of the DCG can be used, thanks to autonomous power flow controls and – if required – Power Flow Control (PFC) devices limit wind spillage in case the grid becomes under-rated compared to the offshore wind generation (for example, following the connection of supplementary wind farms to it). This feature is illustration with an example which shows how wind spillage may be estimated, taking into account wind regimes correlations according to the geographical location of the wind farms.

3.5 CONTRIBUTION TO ANCILLARY SERVICES

There are many important ancillary services traditionally provided by conventional thermal or hydro-based generation units such as voltage and frequency control. Additionally, conventional generation units intrinsically provide inertia to the system, which is a fundamental characteristic in order to assure its stability. The large-scale integration of wind power naturally displaces at least some conventional generation units, thus affecting ancillary services provision and global system security.

A fully operational DCG will play a key role for the creation of AC systems interconnection and to integrate offshore wind farms. The importance of such infrastructure requires its active contribution for ancillary services, namely: (1) fault ride-through (FRT) capability in case of mainland AC faults, (2) primary reserve and inertia emulation and (3) contribution to damping of electromechanical oscillations.

Despite the use of VSC technology in DCG that enables its operation during AC voltage sags, a power balance phenomenon will occur in the DC grid that will culminate in a DC overvoltage. In order to provide FRT capability in DCG, communication-free advanced control functionalities are proposed to be used as a supplementary local control in VSC aiming at active power accommodation that can be achieved following two possible approaches: (1) installing a DC chopper resistor in the DC side of each onshore VSC-HVDC station and (2) the implementation of FRT control mechanisms exploiting a set of coordinated local control rules at the converter stations and wind turbines during grid faults that are responsible for locally accommodating the active power that cannot be delivered to the onshore AC systems. These approaches are described in Deliverable D5.3b.

Large-scale integration of wind energy leads to a displacement of conventional generation units that negatively impacts the behaviour of grid frequency (increases the rate of change of frequency and the absolute frequency deviation) in the aftermath of disturbances, thus affecting the load-generation balance. To mitigate such bottlenecks the possibility of using wind generators to provide primary frequency support and inertia emulation is being requested in some grid codes. The predicted massive integration of OWF contributes to increasing frequency stability related problems in AC systems. Despite it being desirable to enable OWFs connected through DCGs to contribute towards frequency regulation in AC systems, the DC link connections can fully decouple AC areas and offshore stations. Both cost and reliability issues will preclude the development of high speed communication and control centres that should be able to process and communicate real-time information, regarding the core application for frequency control purposes. Additionally, the event of a delay or communication failure can jeopardize the operation of a MTDC network with primary frequency control capability under the solicitation of a disturbed AC system.

In order to overcome the aforementioned difficulties, an innovative approach consists in the identification and development of local controllers to be installed at HVDC-VSC which will autonomously allow the provision of frequency control services. The proposed control strategies make use of a cascading reproduction of AC grid frequency deviations into MTDC voltage variations. Subsequently, MTDC voltage variations are used by the offshore HVDC-VSC for controlling the OWF AC grid frequency. Thus, OWF AC grid frequency variations will be the driving signal for frequency regulation loops to be adopted at the wind generator level. This principle was illustrated in deliverables D5.2b and D5.3b.

The displacement of conventional power plants to accommodate the surplus of wind generation can lead to loss of supplementary damping usually provided by synchronous generators, if they are equipped with power system stabilisers (PSS). Within these circumstances, critical damping levels of inter-area modes of oscillation will occur. Therefore, performing small signal stability analysis of interconnected MTDC-AC systems has become an important task. Moreover, although VSC-HVDC power stations do not participate in the electromechanical modes of oscillation, they can provide additional damping by means of PSS based controllers installed in the active power control loop that are able to modulate active power flows though the DC grid in order to mitigate the effect of oscillatory modes. PSS application to DC grids is presented in Deliverable D5.3b.

3.6 CONTRIBUTION TO SYSTEM DEFENCE

In power systems, load shedding is the most common and effective last-resort remedial control to mitigate voltage instability. Its activation is designed to prevent the occurrence of a voltage collapse. The voltage stability margin may rapidly decline when the system operating point is close to the edge of a voltage collapse. Therefore, load shedding should be activated before the voltage stability margin actually drops to zero.

A HVDC equivalent model for the quasi steady-state (QSS) time scale was developed that meets the accuracy and computational requirements for online stability analysis; the QSS technique has been used extensively in long-term stability analysis, but if necessary, faster DC phenomena can be approximated by their equilibrium conditions during long-term stability analysis to reduce the complexity of system models. Assuming the availability of PMUs, the parameters of this HVDC equivalent model can be identified in real-time by PMU measurements from both VSC stations. During system operations, PMU data involve all dynamic information of VSCs on the AC side, including fast dynamics and controls that are reflected in the time-varying impedances of the HVDC equivalent circuit. Compared with existing HVDC dynamic models, the PMU-based HVDC equivalent circuit greatly simplifies system models with no loss of dynamics of the VSC-HVDC link. Therefore, it is able to analyze long-term stability fast but accurately in an online environment, and is applied to online voltage instability detection for AC grids with HVDC-connected offshore wind generators

Using the proposed HVDC equivalent circuit, a centralized load shedding scheme s proposed to mitigate voltage instability. This algorithm uses the Zbus method to determine the minimal load shedding amount and load shedding location.

The effectiveness of the proposed voltage instability detection and load shedding scheme has been validated by dynamic simulation studies, as described in deliverable D5.3b. These approaches are available to be integrated into the defence system of integrated AC/DC networks. Due to their low computational requirement, the proposed voltage instability detection and load shedding scheme are promising for the online environment.

3.7 CONTRIBUTION TO SYSTEM RESTORATION

The high-level penetration of offshore wind power can dramatically increase loading of the transmission grid. The reduced system stability margin increases the vulnerability of a power system during severe contingencies. It may result in widespread power outages in integrated AC/DC systems following a major disturbance. System restoration after wide-area power outages can be difficult and time-consuming. Generally, the power plant selected as a black-start unit is equipped with small diesel generators that provide its black-start power support. For generators with steam turbines, the required black-start power support can be up to 10% of the capacity of generators for boiler feed-water pumps, boiler forced-draft combustion air blowers, and fuel preparation. It is costly to provide such a large standby capacity at a power station, especially for the oversized diesel generators. With the innovation of wind technologies, the variable-speed wind turbine technology enables the regulation of power factor by absorbing or producing reactive power. Over the last decade, the DFIG has become the dominant technology in the global market for wind generators. Therefore, it is important to evaluate DFIGs as a potential black-start unit to restore AC mainland grids through a HVDC connection.

Compared with the traditional restoration equipment, wind energy can be a valuable asset to significantly lower investment and maintenance cost. The DFIG inherent operation characteristics make it possible for wind farms to serve as a black-start unit for AC system restoration through DC transmission. Early simulation results show that flexible HVDC control can alleviate transient and steady-state overvoltages effectively and provide frequency control before the synchronization of generators; as described in deliverable D5.3b. This would help to reduce the restoration time and smooth the restoration process.

3.8 LIMITS TO OWF CAPACITY ON SINGLE, CONTIGUOUS DC GRID

The phrase ‘single, contiguous DC grid’ is used to mean a DC power island that is electrically continuous before the occurrence of any fault and taking of any consequential action. (The different DC electrical islands might be interconnected but only via an AC system through at least two converters).

On a DC grid that is *not* using DCCBs, the maximum power that could be generated on a single electrical island will be restricted not only by the ratings of individual cables and converters but also by the maximum loss of infeed that could be survived by the AC system to which it is connected were that particular island of the ‘DC grid’ to experience a fault and be isolated. The maximum loss of infeed equals the primary reserve carried on the AC system, with the precise level dependent on a cost-benefit analysis of the cost of additional primary reserve versus the benefit of allowing a higher loss of infeed.

The above considerations set the limit on the maximum power that could be generated on single, contiguous DC grid. However, the installed OWF capacity could be greater than that taking account of expected unavailability of individual turbines, wake effects or, for spatially quite well separated OWFs connected within a single cluster, the likely diversity of output.

An example of a DC grid that does not have DCCBs is shown in Figure 3.1. Each converter is assumed to have a capacity of 1GW. In the operating condition shown, 3GW of power is being generated offshore; 2 GW of that power is being directed to AC synchronous area 1 and 1 GW to AC synchronous area 2. If there were to be a short-circuit fault anywhere on the DC grid, without DC breakers, the passage of current from all of the terminals would need to be blocked. This would result in a loss of infeed to area 1 of 2GW and to area 2 of 1GW. If the primary reserve in the area were only sufficient to compensate for a loss of infeed of 1.32GW (as is currently the case in GB, for example), this would lead to an unacceptable deviation of system frequency in area 1.

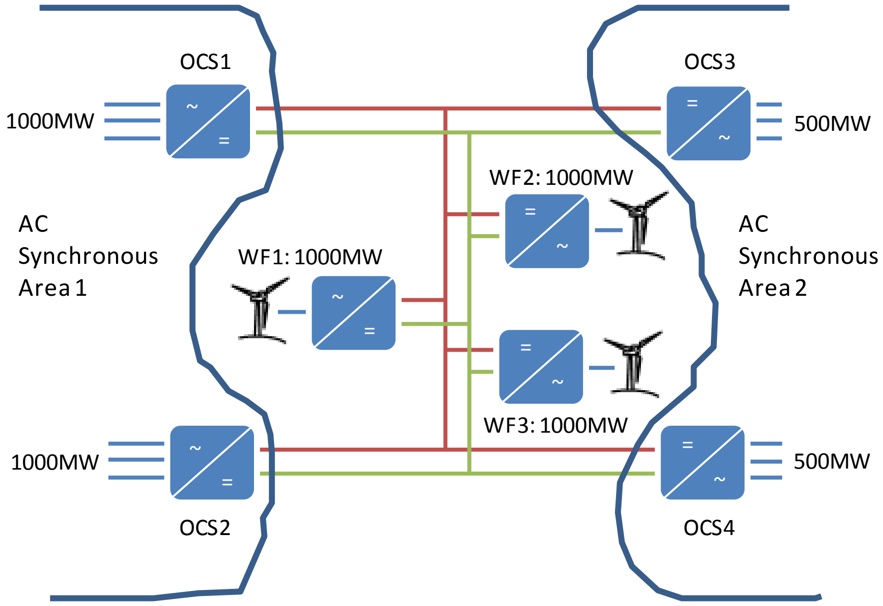


Figure 3.1: Example DC grid and dispatch of power totaling 2GW to area 1 and 1GW to area 2.

Figure 3.2 shows the same DC grid with the DC grid configured in a different way. In particular, disconnectors have been opened pre-fault at location B to separate onshore converters OCS1 and OSC3 plus WF2 from converters OCS2 and OCS4 plus WF1 and WF3. In order to generate 1GW at WF2 and area 1 to receive a total of 2GW and area 2 a total of 1GW, the dispatch of power should be as shown. In this way, two independent contiguous DC grids have been formed.

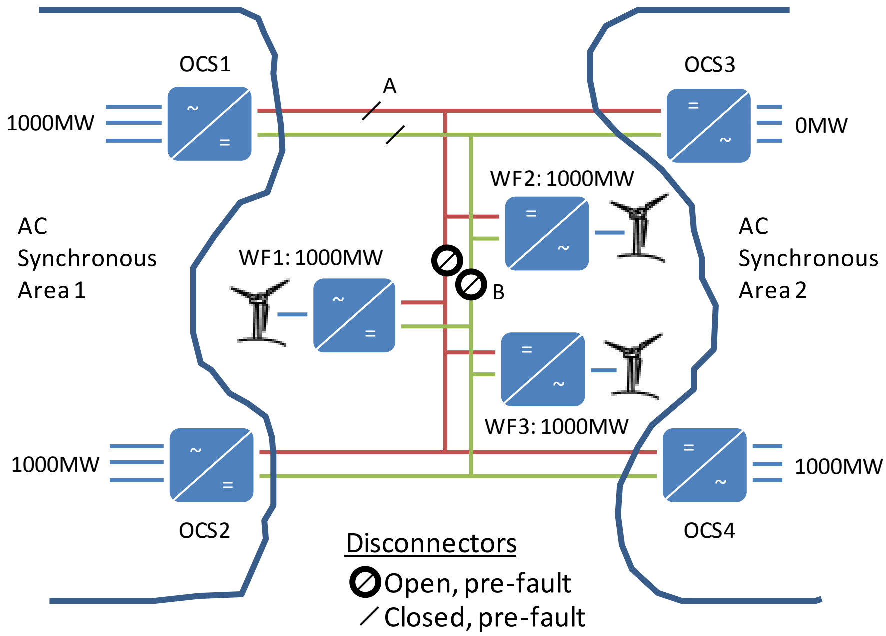


Figure 3.2: Example DC grid with a pre-fault split introduced at location B.

Consider a short circuit fault on the branch connecting OCS1 to location A. In this case, only currents through OCS1 and OCS3 need to be blocked onshore and surplus power from WF2 dissipated. The power flow through OCS2 and OCS4 can continue. This results in a loss of infeed to area 1 of only 1GW (within a GB limit of 1.32GW). Provided the location of the fault can be correctly identified, disconnectors can be opened at location A as in Figure 3.3, and, assuming that the loss of infeed limit in area 2 is at least 2GW, the disconnectors at location B can be closed to provide flexibility in the export of power from WF2. OCS3 can be returned to service and WF2 restarted. (In this case, the total power being generated offshore equals the total remaining onshore converter capacity so the disconnectors at location B could have been left open).

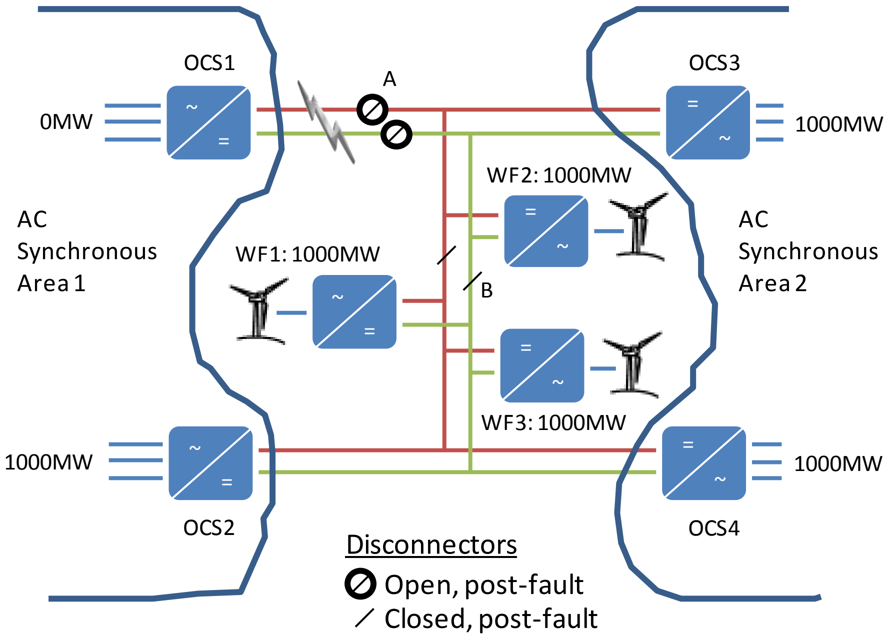


Figure 3.3: post-fault reconfiguration of the example DC grid.

Figure 3.4 shows the same system with DCCBs installed. In this case, provided DC protection correctly identifies the location of the fault and the DCCBs operate successfully, it would not have been necessary to partition the DC grid pre-fault. Only OCS1 would be disconnected and the power from WF2 could have flowed continuously, without interruption. However, the value of this continuous operation (equating to the cost of the interruption in the case without DCCBs) should be compared with the cost of the DCCBs.

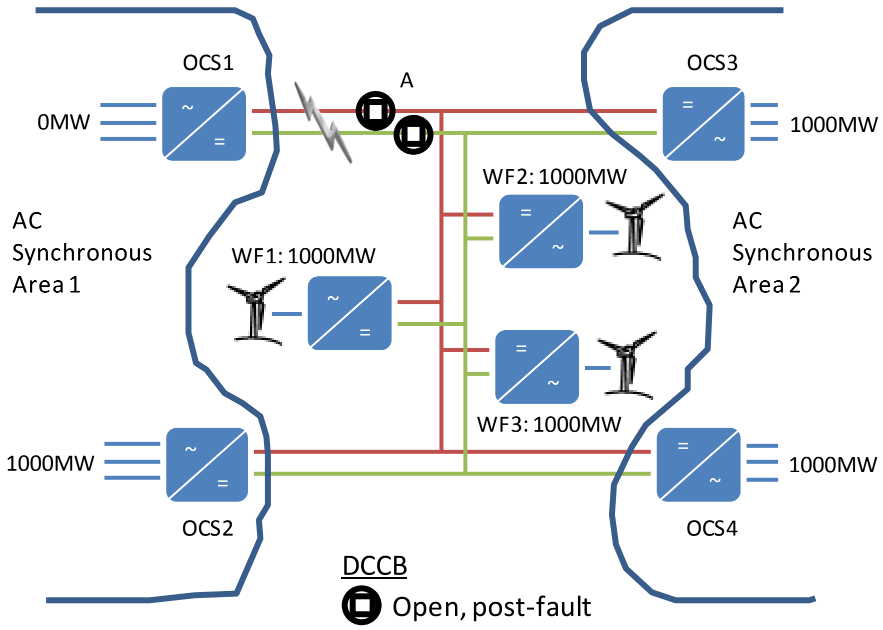


Figure 3.4: Example DC with DCCBs at location A that succeed in clearing a fault between OSC1 and location A.

The main benefit of a meshed DC grid is the availability of a parallel path in the event of a fault on one branch. This would allow transfer of at least some power to be continuous but only if faults can be located and isolated on the DC side. This, in turn, depends on installation and successful operation of DCCBs. The limit to operation is then determined by the power flow condition (how much power is being transferred into each AC system to which the DC grid is connected), the location of the DCCBs and the impact of any one fault outage. This impact in terms of loss of power transfer into any one AC system must be less than the loss of infeed limit for that system.

See further discussion on DCCBs in section 4.

4 Discussion: Operation of a DC grid

Table 2.2 summarised the main findings of DEMO 3 in respect of the operational performance of a DC grid and its technical feasibility.

This section presents some discussion around those findings.

4.1 Dependency on DC circuit breakers

One common assumption is that the operation of a 'DC grid' will only be possible if DC circuit breakers (DCCB) are developed and included in the grid. Although it is not genuinely a 'DC grid' as such, the point-to-point connection case does not depend on the availability and operation of DCCB, as can be seen from the operation of existing two-terminal HVDC interconnectors.

In respect of future DC grids, if a DCCB is not used, a fault anywhere on the DC grid must be cleared by operation of circuit breakers on the AC side of all terminals. In this case, all export from the DC grid or power transfer through it will be interrupted. This will cause OWFs operating on the DC grid to shut down but will also impact on the AC power systems receiving power from the DC grid. However, these AC systems are already operated with the expectation that some level of 'loss of infeed' will be experienced from time to time and some amount of primary reserve will be carried to ensure that the AC system frequency does not go outside of limits as a consequence of a loss of infeed event. Thus, the total power exported by a DC grid to any one AC system synchronous area via one or more terminals should be restricted to the level of the primary reserve of that area, though what that level of reserve is should be determined by a cost-benefit analysis comparing the cost of reducing the level of loss of infeed risk with that of carrying additional reserve. (See section 3.8 for further discussion and an example).

Reverse blocking converters are a feasible extension to existing multi-level converters. This could allow rapid interruption of the current from the AC side and clearing of the DC fault under zero voltage/current. Interruption of the network could be of short duration and OWFs may be able to ride through. However, reverse blocking converters can introduce additional losses over existing multi-level converters. Contrary to DCCBs which could isolate any faulty section of a DCG (assuming they are located at each end of the DC cables), converters with reverse blocking capability would lead to temporary resume power transmission (in the absence of DCCBs), in order to isolate the fault (using disconnectors, for instance) before switching to N-1 operation. Therefore, this strategy would be less flexible than using DCCBs.

If the benefits of a meshed DC grid (as distinct from one that is not meshed) are to be realised in terms of continuity of supply following faults in certain locations (see section 3.3), DCCBs and sufficiently accurate fault identification and location are essential. However, it is also the case that the performance required of a DCCB depends on where a fault occurs, the design both of the grid and the converters at each terminal, and operating conditions both on and offshore.

For further discussion on DCCBs, see sections 4.2, 4.10 and 6.1.

4.2 Feasibility of a DC circuit breaker

The feasibility of a DC circuit breaker was assessed thanks to two evidences in DEMO 3:

1. A medium voltage mock-up
2. The high voltage demonstrator

Both, medium voltage mock-up and demonstrator have the same scheme and operate in the same way. The difference is that each of the branches in the high voltage demonstrator has more elements connected in series to withstand the higher voltage. Details of the scheme and operation can be found in deliverable D11.3 and are not reproduced here.

The feasibility test consisted in the interruption of a sinusoidal current well before its natural current zero under a voltage of few tens of kV (medium voltage range). The rate of rise of current was 3.2 A/µs. Figure 4.1 shows the result of such an interruption test. To protect the mock-up and the source in case of non-clearance the test circuit is an oscillating one consisting of a precharged capacitor bank, inductor and the DCCB mock-up connected in series. If the DCCB stays in conducting mode the 'prospective current' is obtained. This is to be compared to the 'interrupted current' which has clearly smaller amplitude and its zero is much earlier than in absence of breaker action. The same test had been performed a few weeks earlier in the presence of RTE and an independent observer. Interruption tests have been performed up to limits of the test lab (Figure 4.2).

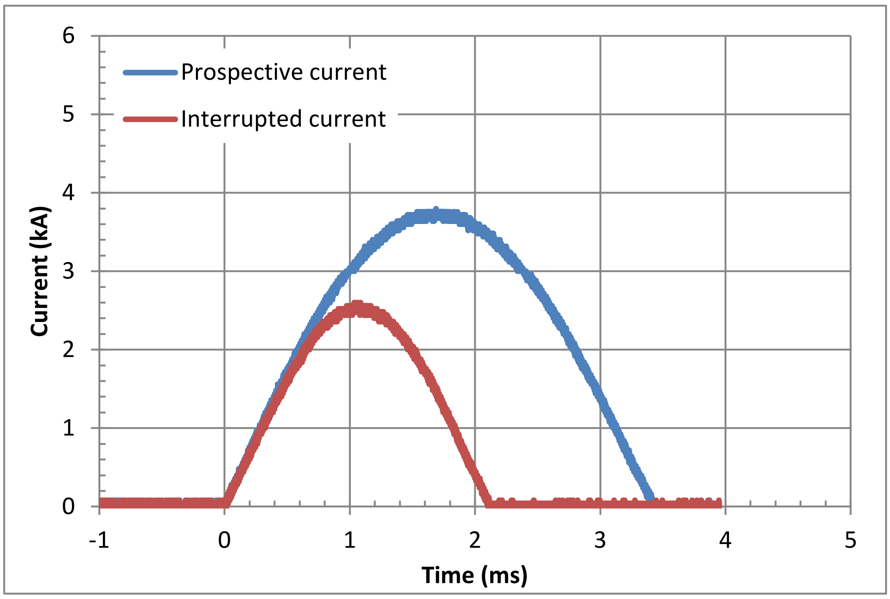


Figure 4.1: Result of the interruption test witnessed on March 21st 2013 by the Technical Reviewer and Technical Committee members. The prospective current (blue curve) is obtained if the DCCB stays closed. The interrupted current (red curve) is the result of the DCCB action if the test is repeated but the DCCB is operated.

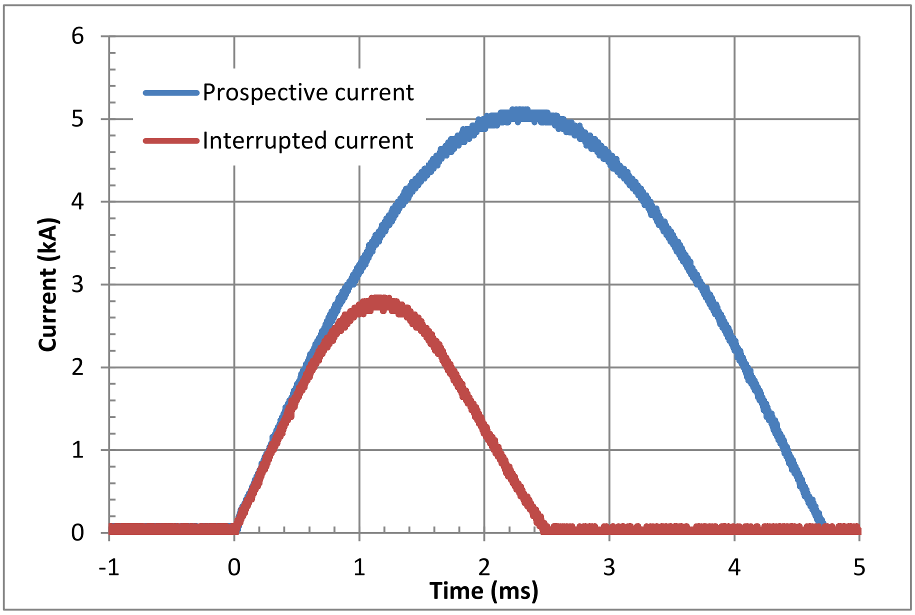


Figure 4.2: Result of a similar interruption test on the mock-up at the limits of the medium voltage test lab.

Later in 2013 the demonstrator will undergo similar interruption tests but at voltages exceeding 100 kV in the lower part of the voltage range used for long distance power transmission. The demonstrator is designed for operation at a rated voltage of 120 kV, but during interruption the voltage will rise transiently to approximately 180 kV. An addendum to both this document and deliverable D11.3 will be provided to complement them with the interruption results observed with this demonstrator.

4.3 FEASIBILITY OF DC GRID PROTECTION

A DC grid needs to be protected against short-circuits. It is very easy to detect the occurrence of a fault (voltage collapse, overcurrent). However, it is more complex to be selective quickly enough to comply with the required fault clearance time and the controllability of the converters. Both pole-to-pole faults and pole-to-ground faults should be cleared. Then, the total delay for clearing the fault (fault detection, plus selectivity algorithm time, plus breaking time of the DCCB) is in the order of some milliseconds. Moreover, unwanted trips of breakers should be avoided in case of a fault on another link as well as in normal operation (like load flow variation or cable connection/disconnection). Finally, backup protection should handle a malfunction of a *main* protection or a breaker failure.

Only simple algorithms can fit the very short delay allowed for fault detection. Overcurrent and undervoltage criteria are robust, but not selective. This is the same for current variation and voltage variation criteria. The simplest selective algorithm is a current differential one, which is based on the comparison of currents at the ends of each device or link. For a substation, a local differential protection can be developed easily. For a DC line, a differential protection needs fast communication (fibre optics typically) between the ends, the disadvantage of which is the communication delay that can be problematic for protecting DC lines longer than 200 km (1 ms transmission delay in fibre optics to be compared with the total 2-3 ms we are allowed to trip the breaker). Finally, on DC links carrying series reactors, algorithms based on the comparison of voltage variation on the sides of the reactor can be imagined, notwithstanding the difficulties associated with fitting the reactors in an evolved DC grid with the overcurrent withstand of breakers.

In the Twenties project, two of these algorithms have been successfully developed, implemented and tested in a hybrid mock-up, combining real cables and converters and real-time simulation :

- A current differential protection
- A backup protection based on current variation combined with a breaker failure detection

4.4 Coordination of the terminals of a DC grid

The role of the DC grid with respect to power transmission is twofold: it must transmit power generated offshore to the AC network; additionally, it may also play the role of an interconnection between different AC onshore zones (for planned power exchanges, for instance). The conjunction of pre-defined and variable power injections over time requires appropriate coordination of power exchanged at each terminal of the DCG, even under normal operation.

The existing point-to-point schemes connecting offshore wind power to shore rely on simple voltage droop controls which enable basic coordination between the two ends of the DC circuit. This control simply ensures power balance, whatever the wind speed.

In the case of a DC grid, the droop principle also ensures the overall balance of power injections during normal operation *for any DC grid topology*. In addition, analyses have highlighted how *dedicated droop controls* could be designed (specifically for appropriate grid topologies, referred to as the “backbone” layouts) to implement predefined coordinated and communication-free behaviours of the grid with regard to power flow; this was illustrated on a tree-like topology and a meshed one, both of which implement either an offshore power mitigation, or direct offshore-to-shore transmission policies (see Deliverable 5.3b chapter 4). Moreover, the examples exhibited illustrate how such controls can be used to set pre-defined power exchanges between different AC onshore zones, regardless of offshore power injections.

Hence, because the overall behaviour of the grid can be securely managed for a variety of topologies (meshed or non-meshed backbones, at least) using appropriate autonomous controls, even with variable wind power and for pre-defined power exchanges between AC zones, telecommunications are only required to ensure optimal operation of the DC grid by adjusting control setpoints from time to time. Therefore, there is no need for fast communication as far as coordination is concerned; furthermore, the voltage droop principle guarantees safe, autonomous operation in the case of communication loss.

In the case of a more complex DCG layout (such as the DCG mock-up, which is partly meshed and partly tree-like) presented in D11.2 and D11.3, communication is required for coordinated control on top of the converters’ autonomous controls; yet, there is no requirement for *fast* communication for normal power flow control in this situation either, as was demonstrated during the live demo with this mock-up.

4.5 Features and services provided by the DC connection to the AC onshore network

Besides integrating multiple offshore wind farms dispersed over a wide area into AC onshore networks, DCGs are expected to contribute to the optimization of AC and DC transmission infrastructures, and to the improvement of the reliability and security of supply of the power system.

In particular, DCGs can provide additional functionalities and meet key system requirements:

- Wind power transfer function (including smoothing of wind power fluctuations),
- Interconnection function (i.e. use of the DCG for exchanging power between different AC areas),
- Ancillary services functions (e.g. voltage support, frequency support to onshore AC grids, etc.),

- Security enhancement (e.g. by offering more degrees of flexibility and control of mainland AC grids).

The power dispatch among DCG terminals should be performed according to market rules accounting for security constraints in AC/DC systems. To this end, steady-state controls provide the transfer and interconnection capabilities of a DCG. Several policies have been analysed in DEMO 3. A new control strategy has been proposed for the DCG backbone topologies by which the power flow is very easy to control from a Dispatch Center, even with superimposed base power exchange between two onshore AC zones.

In addition to the provision of power transfer and interconnection capabilities, which define a certain operating point for the DCG, ancillary services can be provided by the DCG to the AC mainland network: using appropriate controls, the settings of the DCG and associated converter stations can be locally modulated in the short-term in order to provide frequency regulation services to the mainland AC systems (namely primary frequency control and inertial services). Supplementary DCG controls have been described which enable primary frequency control capability without neglecting inertia emulation similarly to conventional AC synchronous generators. Based on an innovative approach, they consist in identifying and developing local controllers to be installed at VSC-HVDC which will autonomously allow the provision of frequency control services, thus getting rid of telecommunication or centralized control which could jeopardize the operation of a DCG (communication failure or delay). The proposed control strategies consist in the use of a cascading reproduction of AC grid frequency deviations into DCG voltage variations. Subsequently, these are used by the offshore VSC-HVDC for controlling the offshore wind farm AC grid frequency. Thus, the offshore wind farm’s AC grid frequency variations will be the driving signal for frequency regulations to be adopted at the wind generator level. It should be emphasized that the corresponding control for onshore VSC converters is fully compatible with the droop control described for steady-state operation.

The redispatching of DCG power injections can also be adopted to improve AC system security taking into account the DC network constraints (e.g. currents in the DC cables, VSC capability curves). The proposed strategies based on the concept of risk allow the risk of high currents in the post-contingency state to be reduced (thus, of incipient cascading mechanisms) while minimizing the redispatching costs or the redispatched power of DCG injections and of conventional generators. The analyses have shown that risk-based control techniques allow the enhancement of operational security exploiting DCG injections to provide improvements with respect to a conventional N-1 security based preventive redispatch.

An important feature affecting DCG operation is the DCG response to AC and DC faults. The comparison of the different policies for onshore converter controls (with or without current limitation, either on d- or q-axis) led to the identification of suitable policies. In particular, the current limiting strategy (which gives priority to the d-axis component of VSC current, i.e., the active power part) is a better option for the DCG since, given the same fault conditions, this strategy contributes to relieve the DC overvoltage by supporting the active power injection. The q-axis strategy provides a higher reactive support to the AC grid during the fault; hence it has a significant impact on the voltage profile on the AC grid and on the measurements of impedance performed by distance relays on the AC lines.

Protection mis-coordination of existing AC protections in the presence of VSC converters was illustrated with the under-reach problem of relay protections (a zone 2 fault which is likely to be viewed in the zone 3 range by a relay, due to the reactive power control of VSC-HVDC). Adaptive distance relays have been introduced to overcome the under-reach problem of relay protection, which ultimately enhances the overall reliability of the protection scheme.

Another important issue regarding DCG response to faults is the need for Fault Ride-Through (FRT) capability in off-shore DC grids, a functionality aimed at accommodating large power imbalances in the DCG due to the faults in the onshore AC or DC grid, or the loss of a large VSC. Different FRT strategies were proposed based on distributed or lumped breaking resistors. This would avoid dangerous overvoltages due to the power imbalance between the power produced by wind plants and the power delivered to the onshore AC system. This problem of power imbalance can be tackled also with SPS (Special Protection Schemes) which partially curtail wind power generation.

The same DCG injections can be used to damp power oscillations in the AC systems by sending stabilizing signals to the controllers of the onshore VSCs.

All those features and ancillary services are presented in deliverable D5.3b (most of them were also introduced in D5.2b).

4.6 Impact of an AC system fault on operation of the DC grid

The anticipated level of offshore WF integration brings new challenges for safe operation of the AC mainland grid. Taking into consideration the security of operation of onshore AC grids and the amount of offshore wind power the DC grid injects into the onshore AC systems, it is anticipated that AC-side fault ride-through (FRT) functionalities will be also required for DC grids. Therefore, the identification and implementation of control strategies to provide AC-side FRT capability in DCGs is a key issue. The FRT capability can be seen as the ability of DCG converters associated with the affected AC area to remain connected to the grid during low voltage periods. The FRT provision can be attained by VSC that are used to establish DC grids. However, proper control strategies must be defined to guarantee that a converter's maximum current is not exceeded during the fault occurrence.

A fault in the onshore AC system, considering the current limits of VSC stations, will cause a significant drop in the power delivered by nearby onshore converters. Therefore, the power not being delivered to the onshore AC grid will cause significant overvoltages in the DC grid. Indeed, under these circumstances, the resulting power imbalance charges the DC circuit capacitors, resulting in a fast increasing DC voltage which may destroy the HVDC equipment if no countermeasures are adopted. Therefore, the maximum time to reduce power in order to prevent over voltages in the DC capacitor banks plays a key role regarding the control strategies to be developed in which the DC voltage control should be as fast and tight as possible.

Decentralized controls fully based on local controllers were designed to be housed at HVDC-VSC stations and at the offshore wind turbines. The local control solutions aim to mitigate the DC voltage rise. The feasibility of the proposed control concepts are extensively demonstrated considering the most typical wind turbine technologies currently available: Doubly Fed Induction Generators (DFIG) and synchronous generators connected to the grid through a full converter. Following the use of the proposed control strategies under different circumstances, it is also demonstrated the avoidance of classical solutions based on the installation of additional equipment such as DC chopper resistors.

To overcome the bottlenecks of communication-based solutions, new control philosophy to assure FRT compliance in MTDC grids were developed and implemented in the control systems of the local VSC-HVDC stations aiming at an effective active power accommodation that can be achieved following two main possible approaches or a combination of them:

- Installing a DC chopper resistor in the DC side of each onshore VSC-HVDC station to dissipate surplus power than cannot be exported. The activation of each DC chopper control strategy is based on a DC voltage threshold that will trigger power dissipation in the resistor. The major advantage of this strategy relies on the fact that wind turbines are not affected by the fault since the DC power balance is achieved through external solutions in relation to the wind farms.
- Implement FRT control methods exploiting coordinated cascaded local control rules of the VSC- HVDC and wind turbine power electronic converters during grid faults, allowing wind turbines to locally accommodate/dissipate the active power that cannot be delivered to the onshore AC systems. The proposed control strategies are based on the fast control of wind turbine power output through offshore grid voltage or frequency control mechanisms.

Following the use of the proposed control strategies it was demonstrated the possibility of avoiding the use of additional Equipment such as DC chopper resistors for FRT compliance in MTDC grids.

4.7 IMPACT OF LOSS OF AN ONSHORE CONVERTER

The sudden loss of an onshore power converter leads to a fast decrease of the power injection capability of the MTDC system to the mainland AC control areas. The resulting effect depends on the global state of operation of the DC grid and on the ability of the remaining converter stations to accommodate the power surplus. However, a severe case will occur regarding an operational scenario where the DC grid is highly loaded. In this case, the sudden loss of a converter results in a DC overvoltage, which needs to be mitigated in order to avoid cascading disconnection of DC grid components. Being a similar effect to the case of an AC mainland fault, similar mitigation strategies can be used in the period immediately following the event. However, it may need to be combined with the use of wind turbine pitch control systems in the case where the remaining structure of the DCG is not able to fully accommodate the offshore wind farms' generated power.

The adoption of DC chopper resistors to mitigate the DC voltage rise following the permanent loss of a HVDC-VSC is not adequate since these devices have a limited energy dissipation capacity. Normally, the maximum energy that a chopper resistor can dissipate is related to the thermal limits of the own resistor and is limited by a thermal protection. Thus, in the case of a permanent loss of an onshore HVDC-VSC and considering that there is not enough margin in the remaining onshore HVDC-VSC to accommodate the power in-feed, an advanced control scheme must assure that the offshore wind power is reduced accordingly.

Therefore, it is necessary to design an advanced control scheme to handle two non-simultaneous objectives. The first objective consists on the capability of fast power dissipation to guarantee the fast DC power equilibrium and maintain DC voltage profile within specific margins. In this case, the exploitation of control strategies based on the fast control of wind turbine power output through offshore grid voltage or frequency control can be used. The second objective consists on the capability of providing power reduction for a larger temporal framework (steady state power reduction), the exploitation of wind turbine pitch regulation capabilities is also required.

Those strategies are described and studied in deliverable D5.3b.

4.8 IMPACT OF A DC SHORT-CIRCUIT FAULT

In the case of a point-to-point connection, there is no clear need for a DC breaker, as, to date, AC circuit breakers are used to isolate the whole DC link. Whether or not a DCCB is used leads to the same consequence for point-to-point connections, since there is no alternative path to transmit offshore power: as offshore point-to-point connections are very likely to be monopolar schemes (a bipolar HVDC link would be unduly expensive considering its footprint –especially offshore –, complexity and the little benefits it may provide), a DC fault (either pole-to-pole or pole-to-ground) will result in loss of the whole point-to-point connection. In the unlikely case of a bipolar scheme with metallic return cable, the remaining transmission capacity would be respectively 50% and 0% for pole-to-ground and pole-to-pole faults.

In the situation of offshore DC grids (tree-like or meshed), a DC short-circuit is a major contingency which would result in the loss of the whole structure in the absence of a DCCB. On the other hand, if the DCG is designed to comply with the constraints which ensure the efficiency of both the DCCB and DC protection algorithms developed in TWENTIES (see section 4.10), such protection equipment would isolate the fault, thus limiting its impact and stopping the rise of the fault current.

As the DC voltage would be disrupted, concurrent action of the onshore converters through voltage droop control is required to regain a stable point of operation without interrupting power flows, as was demonstrated during the live demonstration in Lille on April 3rd 2013. In addition, such controls are autonomous (communication-free) and designed to ensure system transient stability after fault elimination.

4.9 OPTIONS AVAILABLE IN RESPECT OF DIFFERENT CONVERTER DESIGNS FOR A DCG

It is widely accepted that DC grids will be based around voltage source converters connected to a common high voltage DC bus. Converters are required that can operate at suitable voltage levels and power transfer capacity. A particular challenge for HVDC converters is the need to achieve operational voltages well in excess of the ratings of individual power semiconductor devices. To date two basic approaches have been applied to HVDC converters.

Two level converter: Initial implementations of VSC HVDC employed series connected IGBTs to provide a composite high voltage switch. This approach presents challenges for voltage sharing between devices and is constrained in terms of achievable switching frequency/losses. Two level VSC generate a pulse width modulated (PWM) output which allows AC filters to be reduced in size relative to LCC. However, relatively low switching frequency (in the region of 1 kHz) means that power filter size remains significant.

Modular Multi-level Converter (MMC): The MMC achieves high voltage operation though a cell structure with intermediate voltage levels each of which is within the voltage rating of an individual power semiconductor. This cell based topology allows extension of operating voltage without the complication of transient voltage sharing between devices. Multi-level modulation enables synthesis of a low distortion AC output while maintaining low switching loss in the individual IGBTs. These features of the MMC provide improved efficiency and reduced AC filter requirements. A number of variants of the MMC design are proposed; a hybrid approach with series connection of IGBTs can be used to increase cell voltage; the cell circuit (H-Bridge MMC) may be adapted to provide reverse blocking capability.

High voltage VSC converters provide the necessary functionality for offshore wind connection and can facilitate HVDC networks. Filter and VAR compensation requirements are significantly less than for LCC giving a smaller converter footprint which is compatible with offshore installation.

The increased efficiency and suitability for higher DC voltages make multi-level converters (MMC or successor technologies) the most probable candidate for future the HVDC networks. By raising efficiency, the MMC converter will bring down the connection distance at which DC connection becomes preferred. The MMC converter provides improved power quality and a reduction in AC filter requirement. However, this reduction in converter footprint has to be balanced against the additional high voltage capacitors used within each cell. The MMC cell capacitance remains a technical issue particularly in terms of its impact on converter footprint.

Two level converters employ a large capacitor at the DC converter terminals. This capacitor will discharge rapidly into any DC fault causing a large initial fault current which must be withstood by DC network components including any DC breakers. As the DC voltage collapses, this initial fault current sees an additional steady state fault current fed by the AC networks via the anti-parallel diodes of the converter. MMCs have no inherent requirement for a DC link capacitor with energy storage provided within each cell. In the event of a DC side fault, the cell IGBTs may be gated off preventing discharge of the cell capacitance and removing this component of the DC fault transient. Stress on the DC network and circuit breakers is therefore reduced relative to two level VSC. Although capacitor discharge may be prevented, the basic MMC converter does not prevent the AC network from feeding the DC fault. Fault clearance by DC circuit breakers or on the AC side is still required depending on the network configuration. Since the cell capacitors do not discharge into the DC fault, the post fault recharge of a MMC based HVDC connection or network is simplified relative to the two-level implementation.

The basic MMC topology can be extended to provide reverse blocking capability. In this case the converter can prevent both capacitor discharge and AC feed of the DC fault. By blocking the AC connection, the voltage seen by DC circuit breakers can be reduced possibly simplifying DC circuit breaker requirements. This approach introduces additional converter loss and requires a temporary shutdown of the HVDC converter. Further study of the use of reverse blocking converters and acceptable DC fault interruption is required.

4.10 Impact of DC grid design on converters and DC breaker stresses

In the absence of a DC breaker, the major consequence of a DC short-circuit is the dramatic rise of fault current through the DCG in a very short period of time after the fault. As described in deliverable D11.1, this results from various phenomena, namely the discharge of the DC cables (hence the influence of the cables length, the DCG meshing and the value of DC inductances), and the current feeding the fault from onshore and offshore sources; the latter depends on the converter topology (with or without current blocking capability, and considering various smoothing reactor values) and the strength of the various AC networks (including the offshore wind farms). All these parameters affect the severity of a DC fault current resulting from the design of the DC grid:

- Large networks will increase the energy stored in cable capacitance which will discharge into the DC fault.
- The presence of multiple converter stations will provide increased AC infeed which may be concentrated in localised sections of the network.
- Highly meshed networks will lower DC network impedance leading to faster DC voltage collapse and larger line discharge current.

The location of DCCBs will also affect the stress they may be submitted to: a DCCB sited close to a converter station will be subject to similar fault currents as the converter (these are predominantly defined by the design of the converter – typically the internal arm inductance and the inductance of the coupling transformer); the DC grid design therefore has limited impact on the stress seen by the converters and DCCBs connected at their end.

On contrary, DCCBs located at internal DCG nodes (away from the converters) will experience the cable capacitance discharge current and the AC contribution to DC fault current from multiple converters. Therefore, the design of the grid will determine the energy that must be absorbed by the DCCB when interrupting the DC fault current

Different sets of those parameters were considered to identify significant DC fault categories (as detailed in deliverable D11.1); these categories are recalled in the following table.

Table 4.1: DC fault categories for DCCB performance (from deliverable D11.1).

DC fault category	Fault current (amplitude and peak time after fault inception)
Category I	5 kA after 15 ms
Category II	45 kA after 10 ms up to 50 kA after 10 ms
Category III	80 kA after 4 ms, 55 kA after 2.5 ms up to 65 kA after 2 ms

As explained in section 6.5, the effectiveness of a DCCB was established for categories I and II, as the performance of a DC fault detection algorithm for cables no longer than 200km; as long as those constraints are met, no technical “showstopper” was identified which could prevent the design, operation and protection of offshore DC transmission structures.

4.11 Inter-operability of different types of converter on the same DC grid

Studies conducted within TWENTIES have investigated the operation of HVDC networks which employ a mix of converter types under a range of operational conditions. These studies have shown that, although the internal operation of converters types are radically different, their outer control loops can be configured to provide the same system level functionality. These studies indicated interoperability of converters under steady state and dynamic power flows and under AC fault conditions.

Although studies indicate no fundamental limits on compatibility, it should be noted that the design detail of each converter will dictate individual dynamic responses. Where networks are built using a range of technologies it will be necessary for network operators to provide standardised requirements for system level converter behaviour.

More significant interoperability issues may be encountered when DC faults are considered. Two level inverters will give rise to more severe DC fault transients and may incur longer re-energization times than MMC converters. Reverse blocking converters can actively manage the AC input to DC faults; however, this may require the same functionality at all converter stations

4.12 Impact of a DC grid on stability of an AC system

One frequent cause of instability is the lack of damping of the so called electromechanical modes of oscillation, which are related with low frequency (0.1-2Hz) power oscillations that occur among the rotors of synchronous machines, essentially due to some controller settings and due to large power flows through weak transmission lines. It has been demonstrated that wind generation has some impacts on the damping levels of a power system, and that the nature of such impacts depends on factors like wind generation conversion technology or network configuration. Depending on the operating conditions, the integration of wind power may then lead to an improvement or reduction of these damping levels. One of the cases where a reduction of damping can take place is related with a situation where the connection of wind power in one area of the grid, replacing conventional production located in another area, increases the power flows trough weak interconnection lines. This situation may occur in the future, for example, in the north of Europe with the construction of large offshore wind farms. The existence of a large surplus of generation in some areas may in these cases lead to increasing exchanges of power between weakly interconnected grids, giving rise to insufficiently damped oscillations between control areas.

Power system stabilizers (PSS) installed in the excitation of synchronous generators is still one of the most cost effective solutions capable of providing supplementary damping. However, in a system with a large share of wind power production these devices may no longer be capable of providing the necessary additional damping.

The AC/DC converters of off-shore wind farms may be used to introduce damping in a power system since, as synchronous generators, these devices can act as power amplifiers of the auxiliary controllers responsible for adding damping to the electromechanical modes of oscillation. Nevertheless that is not straightforward because these electronic devices are not directly involved in the electromechanical oscillations.

A new Power System Stabilizer (PSS) installed in the AC/DC converter will only be effective to modify a mode of oscillation if that mode is controllable through the injection of power in the bus where connected is connected and, at the same time, the mode is observable in the input signal of the stabilizer. The effectiveness of such a PSS, and consequently the contribution of the converter where it will be installed to the damping of the modes of oscillation, depends on an appropriate choice of the input control signals, architecture of the stabilizer and its domain of actuation regarding the control loops of the AC/DC converter.

It is also well known that the contribution of a PSS to the damping of the electromechanical modes depends significantly of the operating conditions. A solution that provides satisfactory damping for some situations may not lead to adequate results for other scenarios. For this reason it is desirable to find for each PSS a set of parameter values that is capable of producing the desired damping level for all scenarios, or if such value is not possible to accomplish the closest level achievable, for all the operating scenarios of interest. A solution with such characteristics is called a robust solution. In the case of PSS to install in AC/DC converters, robust solutions with the characteristics described before will, of course, also be required. Since these devices add damping in an indirect way, obtaining a robust solution may be quite difficult to achieve.

With the addition of HVDC-connected offshore wind turbines, more control options from the HVDC are provided to enhance the stability of onshore AC grids, such as multi-HVDC active power regulation and reactive power support. They can be applied to damp system oscillations and increase the stability margin. In severe situations, the available HVDC control may prevent system instability and reduce or avoid load shedding. In contrast with conventional AC grids, a higher level of control capability can be provided by the AC grid with HVDC-connected offshore wind turbines for the design of system protection schemes that is intended to reduce or avoid the implementation of the last resort remedial option – load shedding.

As discussed in Section 3.6, an equivalent circuit can be derived from the HVDC QSS model, which is intended for long-term stability analysis. During system operation, flexible HVDC control is reflected in the time-varying impedances of the HVDC equivalent circuit. Based on the Thevenin impedance matching, it is able to perform online voltage instability detection of the integrated AC/DC system. The proposed HVDC equivalent circuit can effectively simplify the system model and improves the computational efficiency for time domain simulations. Numerical simulations are presented in deliverable D5.3b.

AC system stability can also be enhanced in a preventive way, through the redispatching of DCG power injections, when taking into account the DC network constraints (e.g. currents in the DC cables, VSC capability curves). A risk-based strategy (intended to minimize the risk of high currents in the post-contingency state in the AC system) is presented in deliverable D5.3b.

4.13 Impact of a DC grid on operation of AC system distance protection

In an offshore wind HVDC network, the main task of HVDC link is to collect offshore wind power and deliver it to the AC grid. When an AC transmission line close to a onshore converter undergoes a short-circuit fault, the voltage is reduced at the Point of Common Coupling (PCC). This in turn affects voltages and currents of AC transmission grid close to the PCC. Since the capacity of VSC stations is generally large for the offshore power transmission, their impact on the line voltages and currents will be important. It is likely to significantly impact the performance of existing protection schemes on the AC grid, such as distance protections. The basic principle of distance relaying is to measure the apparent impedance using the voltage and current viewed by a relay, which approximately determines the distance between the relay location and fault point during a short-circuit fault. The apparent impedance is compared with pre-set relay operation characteristics to decide whether the fault is within the protected zone. Appropriate time delays are used to allow primary and back-up functions among the distance relays.

Due to the impact of VSC fast control (in the order of milliseconds) on line voltages and currents, the fault distance of a short-circuit fault can be overestimated by its backup relay located on the adjacent line. For instance, it is possible for a Zone 2 fault to be viewed as a Zone 3 event, resulting in mis-coordination between protective relays. If the delayed fault clearance exceeds the critical clearing time (CCT), the system can suffer instability and potentially trigger a sequence of cascading events.

With the growing penetration of offshore wind power, an increasing number of VSC stations will be set up for the integration of offshore wind power. The impact of reactive control from onshore VSC on distance relays on AC grids has become an important subject. The issue of protection mis-coordination protection caused by HVDC control needs to be addressed. In deliverable D5.1, a study proposes an apparent impedance calculation method for identification of potential mis-coordinated relays. By considering reactive power regulation for onshore VSC converters, the Zbus method is used to compute impedances viewed by distance relays. The calculation results are compared with the protection settings to identify mis-coordinated relays. The proposed method proved to provide accurate impedances viewed by distance relays, as was checked with simulations. It can be used by protection/planning engineers to identify protective device settings that need to be adjusted due to HVDC controls.

4.14 Deciding a dispatch of power on different terminals of a DC grid

The initial dispatch of the DCG injections into the AC bulk power system depends on the offshore wind generation profile, combined with considerations of day-ahead market prices and security constraints on the integrated AC/DC system. In fact, the DCG could be connected to different market areas, hence it may be convenient to inject as much power as possible into the market area with the highest price. Limitations come from security constraints of the DC and AC grids under normal and N-1 conditions.

Within DEMO 3, an original framework for risk-based assessment and control of operational security in AC power systems connected to DCGs has been proposed. In particular, indicators based on the concept of risk (defined by the set of possible events i.e. contingencies, their probability of occurrence, and their impact on the integrated system) are used to measure the security level in AC power system operation, and suitable control strategies based on redispatching of both conventional generation and DCG injections are introduced to enhance operational security. The rationale of the proposed strategies is to minimize the overall risk of high currents in the post-contingency state in the AC system, while minimizing either the redispatching costs or the redispatched powers of conventional generation and power injections from the DCG, and taking into account the security constraints of the DCGs involved. The redispatching costs relevant to the different onshore DCG converters are assumed to be defined in the Ancillary Services Market.

The simulations carried out on the test systems showed that:

- DCG injections can help limit congestion on AC systems;
- The higher the number of DCG injections the higher the flexibility of DCG in preventive actions to limit AC system congestion. This implies assuring security on AC systems at lower redispatching costs.

The risk-based assessment and control of operational security in AC power systems connected to a DCG is fully presented in deliverable D5.3b.

5 Discussion: Europe-wide impacts

In this section, some discussion is presented of the observations made in Table 2.3 concerning the potential Europe-wide impacts of DC grids.

5.1 The DC transmission structure as a facilitator of choice among OWFs

Normally, the choice, by an energy purchaser, of which generator to buy energy from is determined by both price and availability. Under similar meteorological conditions, availability of power from an OWF depends on the availability of the physical assets while the price demanded by the OWF owner depends, in a competitive situation, on the generation costs and these, in turn, depend largely on the capital costs. However, they also depend on the extent to which the OWF owner has gained access to financial support for the OWF and the nature of that support, e.g. a feed-in-tariff.

At present, the financial support on offer to OWFs varies from one country's territorial waters to another's though one feature of at least some future DC grids in Europe is likely to be that they connect an OWF located in one country's waters to an energy market or purchaser in another. At present, a theoretical 'statistical exchange' of renewable energy production credits between jurisdictions can take place though it is, to the authors' knowledge, as yet untested. However, the physical connections and controllability of power flows permitted by a DC grid raise the possibility of OWFs competing for financial support from different countries or using different mechanisms to offset costs when quoting a price to the market.

A point-to-point connection connects only one OWF or cluster of OWFs to one AC system location. Any choice with respect to purchase of energy from within that cluster depends on how the cluster is connected and traded but, in general it may be expected to lie within one territorial area.

For a DC grid at any particular time, the extent to which the power available from different OWFs connected to the DC grid can actually be bought within different AC markets or zones depends on the detailed design of the DC grid and the prevailing overall power system operating conditions.

5.2 The DC transmission structure as a facilitator of inter-area exchange

A simple point-to-point connection connects an OWF or cluster of OWFs to a single AC system location and so does not permit transfer of power between different AC synchronous areas or different areas of a single AC synchronous system.

A DC grid with at least two terminals connected to one or more AC grids is not restricted only to bringing power from the OWF(s) to shore. It can also transfer power between different AC synchronous areas or different areas of a single AC synchronous system. As such, it can interconnect different markets or permit power transfer constraints onshore within a single AC system to be bypassed. However, the extent to which this can be done depends on the design of the DC grid and the prevailing operating conditions both offshore and onshore.

5.3 Multiple uses of a DC grid

In some jurisdictions at present, e.g. Great Britain, an HVDC link is classified as just one of the following: a generator connection; part of the 'main interconnected transmission system' (within one single synchronous area); or an 'interconnector' connecting two distinct electricity markets. However, a DC grid might simultaneously serve all these purposes. Part of the business case for development of a DC grid as distinct from a simple connection of an OWF to shore is that, even when wind speeds are low, the physical assets provided as part of the DC grid can still be used and so add value – see section 5.2.

5.4 THE IMPACT OF DC GRID DESIGN ON SPILLAGE OF WIND ENERGY

The effect of 'spillage' of wind energy – the prevention of all the available wind power being fully utilised at all times – on owners or operators of OWFs was outlined in Table 2.1 and discussed in section 3.4. There, it was noted that the financial penalty experienced by the OWF depends on the particular market arrangements in which it is operating. However, in Europe, there is a more general societal concern arising from the desire to reduce carbon emissions which means that spillage of wind energy should be minimised.

In section 3.2, a number of possible reasons for spillage of wind energy have been outlined. It can be seen from those that the extent of spillage does not solely depend on the design of the 'DC grid'. However, all other things being equal, the possibility of exporting either into different AC synchronous systems or different areas of an AC system, meaning that if there are constraints on the operation of one, another could be used.

The collection of power from a geographically dispersed set of OWFs that exhibit some diversity in the level of output at any one time and hence should allow the cost-benefit analysis determining the total connection capacity to shore be better optimised. In TWENTIES deliverable 5.2a, some analyses were reported in which total wind energy spillage for the whole of Europe is estimated for a particular background of generation capacity and demand and three different designs of network capacity in the North Sea:

1. simple radial connections of new OWF capacity to the nearest shore;
2. simple radial connections of new OWF capacity to the nearest shore along with additional point to point interconnectors between regions around the North Sea;
3. an 'H-like' DC grid in the North Sea.

Although the study did not investigate the optimisation of the design of the 'H-grid' and make its general characteristics similar to those achieved in case 2, for the particular scenarios studied, both cases 2 and 3 showed a notable reduction in wind spillage. However, these analyses, which involved simulation of a year of operation of the whole of an integrated European electricity market and quantification of the effects of variability of the power available from different source, did not study the impact of forced outages of network branches.

Further studies concentrated on quantifying the effect on spilled wind energy and electricity prices of unplanned network outages. The results suggest that it is still difficult to make a choice among the available technological solutions: the convenience or otherwise of deploying HVDC multi-terminal systems or DCGs depends on the costs for its realization (not yet clear especially with reference to DC breakers) and on the future evolution of VSC technology. The HVDC technology assumed in this study (± 320 kV, 1200 MW) still seems to provide no significant advantages. Probably, new systems at ± 500 kV with capacity up to 2000 MW could result in more encouraging results as they permit a decrease in the necessary number of offshore platforms and DCCBs. Furthermore, the adopted solution for the meshed topological system has not been optimised in any way: a different meshing pattern may prove more effective even with the already considered case of HVDC 1200 MW sized systems.

5.5 MAXIMUM OFFSHORE WIND POWER OUTPUT

The limit to the total power output that can be accommodated from offshore wind farms at any one moment in time is determined by the following:

- cable and converter ratings;
- the design of the DC grid;
- the loss of infeed consequent to a fault compared with the primary reserve carried on an AC system experiencing that loss of infeed (see section 3.8 for further discussion);
- the dispatch of power to different terminals of the DC grid;
- the operation of the onshore AC system(s) to which the offshore wind capacity is connected.

As was discussed in section 5.4, under certain conditions, at least some available wind power must be 'spilled'.

As a consequence of the many interacting factors, it is not possible to give a single figure for the maximum offshore wind power output that can be accommodated. It is the job of the designer of the offshore grid to take account of the costs and benefits of different designs against a wide range of credible operating conditions. This is a complex task and it has not been the intention of DEMO 3 of TWENTIES to undertake it. Instead, some high level impacts for a small number of feasible DC grid concepts have been sought.

5.6 Maximum offshore wind energy

As was discussed in section 5.5, from a technical point of view, a number of factors contribute to limiting the total power output that can be accommodated from offshore wind farms at any one moment in time. As was discussed in section 5.4, under certain conditions, at least some available wind power must be 'spilled'. The offshore wind energy that can be utilised in the course of a year depends on how system operating conditions vary through that year.

For deliverables D5.2a and D15.2, a number of future generation capacity and demand scenarios were postulated and operation of the European power system simulated. Moreover, the simulation was carried out as a sequence of hours through a year and an attempt made to respect the main limits on operation both of the power system as a whole and individual power stations. However, as was noted in section 5.5, simulation that takes account of all possible limitations of power system operation is not practical so the results obtained for D5.2a and D15.2 must be regarded only as indicative. Nonetheless, using this approach, the impacts of three different designs of network capacity in the North Sea were studied:

1. simple radial connections of new OWF capacity to the nearest shore;
2. simple radial connections of new OWF capacity to the nearest shore along with additional point to point interconnectors between regions around the North Sea;
3. an 'H-like' DC grid in the North Sea.

Although the study did not investigate the optimisation of the design of the 'H-grid' and make its general characteristics similar to those achieved in case 2, for the main generation capacity characteristics summarised in Table 5.1, and Table 5.2 the total wind energy was as shown in Table 5.3 to Table 5.6.

Table 5.1: Total generation capacities in 2020 scenario

	Continental Europe	British Isles	Scandinavia	Total
Coal (GW)	101.2	29.8	9.6	**140.6**
Lignite (GW)	52.5	0.3	1.2	**54.0**
CCGT (GW)	119.0	30.9	4.8	**154.7**
Other Dispatchable fossil fuelled (GW)	86.3	7.9	11.4	**105.7**
Nuclear (GW)	104.1	7.1	12.4	**123.6**
Other Non-Dispatchable Generation (GW)	19.8	2.2	8.0	**30.0**
Reservoir and run-of-river hydro (GW)	98.0	1.7	60.4	**160.1**
Pumped storage (GW - generation)	39.9	3.1	9.1	**52.1**
Onshore wind (GW)	166.0	18.0	9.3	**193.3**
Offshore wind (GW)	12.2	14.9	0.0	**27.1**
Solar (GW)	80.1	2.7	0.0	**82.8**
All generation (GW)	877.1	118.1	126.2	**1121.5**
Peak demand (GW)	*450.0*	*70.0*	*88.0*	
Annual electricity consumption (includes pumping (TWh)	***2779.0***	***396.0***	***493.0***	***3668.0***

Table 5.2: Total generation capacities in 2030 scenario

	Continental Europe	British Isles	Scandinavia	Total
Coal (GW)	101.2	29.8	9.6	**140.6**
Lignite (GW)	52.5	0.3	1.2	**54.0**
CCGT (GW)	119.0	30.9	44.8[1]	**194.7**
Other Dispatchable fossil fuelled (GW)	86.3	7.9	11.4	**105.6**
Nuclear (GW)	72.1	1.2	3.9	**77.2**
Other Non-Dispatchable Generation (GW)	19.8	2.2	8.0	**30.0**
Hydro (GW)	98.0	1.7	60.4	**160.1**
Pumped storage (GW)	39.9	3.1	9.1	**52.1**
Onshore wind (GW)	166.0	18.0	9.3	**193.3**
Offshore wind (GW)	20.1	39.5	1.7	**61.3**
Solar (GW)	160.2	5.4	0.0	**165.6**
All generation (GW)	935.1	140.0	119.4	**1234.5**
Peak demand (GW)	489.1	76.1	95.7	
Annual electricity consumption (includes pumping (TWh)	**3020.7**	**430.4**	**535.9**	**3987.0**

Table 5.3: Wind energy output for 'forward merit order' 2020 scenario

	Absolute energy (TWh)			
	Case 0 no new OWF	**Case 1** radial connection of new OWF	**Case 2** radial connection of new OWF + new point-to-point interconnectors	**Case 3** H-grid
Energy Consumed (including pumping)	3668	3668	3668	3668
Onshore wind	341	340	340	340
New offshore wind	0	74	74	75
Total wind energy	341	414	414	415
Total spilled energy	11	14	13	12
Spilled offshore wind energy	0	1	1	0
Unsupplied Energy[4]	6	6	1	1

Table 5.4: Wind energy output for 'reverse merit order' 2020 scenario

	Absolute energy (TWh)			
	Case 0 no new OWF	**Case 1** radial connection of new OWF	**Case 2** radial connection of new OWF + new point-to-point interconnectors	**Case 3** H-grid
Energy Consumed (including pumping)	3668	3668	3668	3668
Onshore wind	341	340	340	340
New offshore wind	0	73	74	75
Total wind energy	341	413	413	415
Total spilled energy	11	14	14	12
Spilled offshore wind energy	0	2	2	0
Unsupplied Energy[7]	6	6	1	1

[4] Note that the figures for unsupplied energy should be treated with caution given that ANTARES was used in its "economic" mode rather than the "adequacy" mode that would have required a significantly greater number of Monte Carlo simulation years in order to allow the loss of load probability to be estimated with any degree of confidence

Table 5.5: Wind energy output for 'forward merit order' 2030 scenario

	Absolute energy (TWh)			
	Case 0 no new OWF	**Case 1** radial connection of new OWF	**Case 2** radial connection of new OWF + new point-to-point interconnectors	**Case 3** H-grid
Energy Consumed	3987	3987	3987	3987
Onshore wind	342	340	341	341
New offshore wind	0	178	178	186
Total wind energy	342	518	519	527
Total spilled energy	10	24	23	15
Spilled offshore wind energy	0	12	12	5
Unsupplied Energy[7]	10	5	4	3

Table 5.6: Wind energy output for 'reverse merit order' 2030 scenario

	Absolute energy (TWh)			
	Case 0 no new OWF	**Case 1** radial connection of new OWF	**Case 2** radial connection of new OWF + new point-to-point interconnectors	**Case 3** H-grid
Energy Consumed	3987	3987	3987	3987
Onshore wind	342	341	341	342
New offshore wind	0	178	179	186
Total wind energy	342	519	520	527
Total spilled energy	10	23	22	15
Spilled offshore wind energy	0	12	11	4
Unsupplied Energy[7]	10	5	4	3

In respect of individual DC grids and the maximum OWF energy that they can accommodate, the same comment as for capacity applies; the main restrictions are imposed by cable and converter technology, the design of the DC grid and the loss of infeed consequent to a fault compared with the primary reserve carried on an AC system experiencing that loss of infeed (see section 3.8).

5.7 Contribution of a DC grid to reduction of CO_2 emissions

Provided grid capacity – both offshore and onshore – is sufficient, the energy produced by OWFs replaces an equivalent amount produced by fossil fuelled generation and hence reduces CO_2 emissions. However, under some circumstances and for power system operation reasons, not all the available wind energy can be utilised. Thus, as was discussed in section 3.4, at least some available wind power must be 'spilled'. This will require operation of alternative generation. Ideally, this would be flexible renewable generation such as hydro but it may be fossil fuelled.

A DCG will, in general, interconnect different areas of an AC system or different synchronous systems and will have a wider impact than that described above, depending on the nature of AC system operation in those areas and on the behaviour of the electricity market. In particular, within a competitive, single European electricity market, extra interconnection capacity reduces congestion and increases access to the cheapest generation. The impact of this depends on the relative CO_2 emissions characteristics of the generation thus facilitated, and which generators are cheapest in the short-run clearly depends on fuel and carbon prices.

For the main network scenarios described in section 5.6, the generation capacity characteristics summarised in Table 5.1 and 'merit orders' of generation shown in Table 5.7 (and subject to the caveats in section 5.6), the CO_2 emissions were as shown in the Table 5.8.

Table 5.7: Generation 'merit orders' for 2020 and 2030 scenarios

Rank	'Forward'	'Reverse'
1	Nuclear	Nuclear
2	Wind	Wind
3	Hydro	Hydro
4	Lignite	CCGT
5	Coal	Coal
6	CCGT	Lignite
7	OCGT	OCGT
8	Oil	Oil

Table 5.8: Total CO_2 emissions for 2020 and 2030 scenarios

Scenario	Absolute CO_2 emissions (million tonnes)	*Change from Case 0 (million tonnes)*		
	Case 0 no new OWF	**Case 1** radial connection of new OWF	**Case 2** radial connection of new OWF + new point-to-point interconnectors	**Case 3** H-grid
2020 'forward'	1201	*-50*	*-43*	*-44*
2020 'reverse'	829	*-50*	*-55*	*-58*
2030 'forward'	1507	*-101*	*-90*	*-92*
2030 'reverse'	1170	*-128*	*-138*	*-145*

5.8 CONTRIBUTION OF A DC GRID TO REDUCTION OF THE COST OF ELECTRICAL ENERGY

In order to contribute to a reduction in the overall cost of electrical energy, a DC grid should facilitate access to cheaper generation than would otherwise have been the case. However, the reduction in the cost of generation must be greater than the cost of the DC grid for there to be a net benefit.

The extent of the above economic impact depends not only on the design and capacity of the DC grid but also on general electricity market conditions and operational restrictions across the power system as whole. In particular, the economic impact depends on what generation capacity there is of different types, their locations relative to demand and available grid capacity (onshore as well as offshore) and the prices of fuel and carbon. Now that development and operation of generation is, in most of Europe, largely independent of that of the network, future generation capacity is highly uncertain and the identification and development of 'optimal' transmission network capacity not only extremely difficult but also highly dependent on the methods used to quantify risk. Fuel prices, for example, are also extremely uncertain.

Once again, for the main network and generation capacity scenarios postulated in section 5.6, the fuel and carbon price assumptions used are shown in Table 5.9. The assumed costs of components of the DC grids are shown in Table 5.10. They were each annuitised over 20 years at a discount rate of 10%. Once again, although there was no actual optimisation of the design of the 'H-grid' and make its general characteristics similar to those achieved in case 2, the effects of the DC grid designs on total cost of generation were as shown in Table 5.11. (Note that the costs of unsupplied energy are not included in Table 5.11).

Table 5.9: Marginal generation costs for 2020 and 2030 scenarios

Cost contributor	Cost in € / MWh	
	Forward Merit Order	Reverse Merit Order[5]
Nuclear	7	7
Lignite	15	130
Coal / Coal CHP	27	119
CCGT / Gas CHP	40	81
OCGT	62	123
Oil	121	184

[5] Based on underlying fuel price plus a carbon cost of €100 per tonne

Table 5.10: Capital costs of DC grid components

System Element	Capital cost (€m)[6]
3000MW line commutated converter	213
1000MW voltage source converter	135
Platform	70
HVDC 1000MW 500kV Cable per km	0.72
DC 1000MW Circuit Breaker	40

Table 5.11: Annuitised capital costs of DC grid cases 2020 (million euros)

	Case 0 no new OWF	Case 1 radial connection of new OWF	Case 2 radial connection of new OWF + new point-to-point interconnectors	Case 3 H-grid
Offshore network cost excluding DCCB	0	1177	1984	1954
Cost of DCCB	0	0	0	1149
Offshore network cost including DCCB	0	1177	1984	3117

Table 5.12: Annuitised capital costs of DC grid cases 2030 (million euros)

	Case 0 no new OWF	Case 1 radial connection of new OWF	Case 2 radial connection of new OWF + new point-to-point interconnectors	Case 3 H-grid
Offshore network cost excluding DCCB	0	2832	3296	3395
Cost of DCCB	0	0	0	1149
Offshore network cost including DCCB	0	2832	3296	5023

[6] Based on data contained in ENTSO-E Offshore Transmission Technology Report https://www.entsoe.eu/publications/system-development-reports/north-seas-grid-development/

Table 5.13: Total annual costs for 2020 ‘forward’ merit order scenario

Cost item	Absolute cost (million euros)	*Change from case 0 (million euros)*		
	Case 0 no new OWF	**Case 1** radial connection of new OWF	**Case 2** radial connection of new OWF + new point-to-point interconnectors	**Case 3** H-grid
Energy production cost excluding cost of carbon	48568	*-2330*	*-3222*	*-3054*
Spilled energy cost	1145	*214*	*191*	*79*
Carbon cost	25211	*-1056*	*-911*	*-914*
Annualised capital Cost (excl DCCB)	0	*1177*	*1984*	*1954*
Annualised Capital Cost of DCCB	0	*0*	*0*	*1163*
Total cost excluding DCCB	74924	*-1994*	*-1958*	*-1935*
Total cost including DCCB	74924	*-1994*	*-1958*	*-772*

Table 5.14: Total annual costs for 2020 ‘reverse’ merit order scenario

Cost item	Absolute cost (million euros)	*Change from case 0 (million euros)*		
	Case 0 no new OWF	**Case 1** radial connection of new OWF	**Case 2** radial connection of new OWF + new point-to-point interconnectors	**Case 3** H-grid
Energy production cost excluding cost of carbon	59758	-2276	-2872	-2621
Spilled energy cost	1126	301	274	84
Carbon cost	17416	-1052	-1145	-1225
Annualised capital Cost (excl DCCB)	0	1177	1984	1954
Annualised Capital Cost of DCCB	0	0	0	1163
Total cost excluding DCCB	78299	-1850	-1759	-1808
Total cost including DCCB	78299	-1850	-1759	-645

Table 5.15: Total annual costs for 2030 'forward' merit order scenario

Cost item	Absolute cost (million euros)	*Change from case 0 (million euros)*		
	Case 0 no new OWF	**Case 1** radial connection of new OWF	**Case 2** radial connection of new OWF + new point-to-point interconnectors	**Case 3** H-grid
Energy production cost excluding cost of carbon	64556	-6417	-6874	-7276
Spilled energy cost	1024	1383	1282	471
Carbon cost	31643	-2120	-1886	-1929
Annualised capital Cost (excl DCCB)	0	2832	3296	3395
Annualised Capital Cost of DCCB	0	0	0	1628
Total cost excluding DCCB	97224	-4322	-4183	-5339
Total cost including DCCB	97224	-4322	-4183	-3711

Table 5.16: Total annual costs for 2030 'reverse' merit order scenario

Cost item	Absolute cost (million euros)	*Change from case 0 (million euros)*		
	Case 0 no new OWF	**Case 1** radial connection of new OWF	**Case 2** radial connection of new OWF + new point-to-point interconnectors	**Case 3** H-grid
Energy production cost excluding cost of carbon	74635	-5729	-5593	-5834
Spilled energy cost	996	1294	1201	463
Carbon cost	24574	-2677	-2907	-3049
Capital Cost (excl DCCB	0	2832	3296	3395
Capital Cost DCCB	0	0	0	1628
Total excluding DCCB	100205	-4280	-4004	-5026
Total including DCCB	100225	-4280	-4004	-3398

6 KEY PERFORMANCE INDICATORS FOR DEMO 3

Each Demo 3 KPI is detailed in the following subsections (based on the description provided in Section 2.3.2 in deliverable D2.1 « Project Objectives & KPI ») and compared against the actual achievements in WP5 and WP11; the global performance of Demo 3, as measured from the KPI's, is summarized in the following table, while each KPI result is detailed in the following sub-sections (6.1 to 6.5).

Table 6.1: Summary of Demo 3 KPIs.

KPI code	KPI	Description	Target value	Measured value	
D3.1	DC breaker demonstrator performance	C_1: open state C_2: closed state C_3: peak fault reduction C_4: fault current interruption delay	1 or greater 1 or greater 1.21 or greater 1 or greater	1.18 1.23 (for a period twice longer) 2.07-3.19[7] 18-19[7] + successful overload test after the steady state temperature was reached	
D3.2	HVDC grid cases	Number and complexity of basic topologies	At least 3 structures (with 4 terminals or more)	4 structures (comprising 4 to 6 terminals) + the first meshed DCG mock-up (with 15 km cables and protection)	
D3.3	Technologies for offshore DCG and wind turbines	Number of technologies and converters	2 technologies and 2 kinds of converters at least	9 different technologies, including 4 types of converters	
D3.4	Off-shore wind integration in the economic analysis	Number of geographical areas Installed capacity	3 40 GW	**By 2020** 3 27.1 GW	**By 2030** 4 61.3 GW
D3.5	Power transmission through the HVDC grid under contingency	% of the power transmitted in normal conditions	10% or more (by steps of 10 %)	50% or more (depending on the DCG topology) for grids designed to comply with DC fault categories I and II. Yet, secure operation cannot be guaranteed for extremely large and complex	

[7] Those figures were obtained during the March 21st 2013 live demonstration witnessed by the TWENTIES Technical Committee and the Technical Reviewer. Complementary tests will be performed by the end of 2013 on a full-scale demonstrator, at high voltage level (180 kV).

conditions	grids (category III) given currently foreseen technological advances.

6.1 KPI D3.1 - DC BREAKER DEMONSTRATOR PERFORMANCE

An indicator composed of four aspects relating to the three basic states of the breaker (open, closed and operating) is proposed. Hence, the KPI is a four dimensional vector: (C1; C2; C3; C4)

- C_1 is meant to measure how "strong" the DCCB will be in open state.
  This is quantified using the value of the lightning impulse withstand voltage (also known as BIL, or Basic Insulation Level) according to IEC 60060-1 between terminals and earth. Therefore, the normalized component C_1 for this KPI is:

  $$C_1 = \text{Peak of "Prospective" lightning impulse withstand} / 650\text{kV}$$

- The second component measures how "strong" the DCCB will be in closed state.
  This is quantified using the value of the DC current that can flow through the closed breaker without damage. Based on common practice for AC CB tests, this can be measured at low voltage since the dielectric withstand is already assessed with previous component C_1.

  The normalised KPI component C_2 is:

  $$C_2 = \text{Rated current conduction (for 1 min)} / 3000\text{Adc}$$

- The third component indicates what harm can be avoided using a DCCB.
  This can be quantified by comparing the forces the DCG equipment should withstand in case of a fault with and without the protective action of the Demo 3 DCCB. As it is commonly agreed that forces on transmission equipment are proportional to the square of the current, this indicator, which corresponds to the peak force reduction ratio, is computed as the ratio of the peak currents squared.
  The normalised KPI component C_3 for this KPI is:

  $$C_3 = (\text{Peak of prospective fault current without protective action})^2 / (\text{Peak of fault current with DEMO 3 object})^2$$

- The C_4 component assesses how fast the DCCB can interrupt a fault current.
  The interruption duration (i.e. the duration from trip order until current interruption) is compared to 40ms, a duration that is reached by fast AC breakers.

  The normalised KPI component C_4 is:

  $$C_4 = 40\text{ms} / \text{interruption duration}$$

6.1.1 EXPECTED PERFORMANCE

Initial performance

As no commercial DC current breaker existed at the beginning of the project, the start value is:

$$C_1 = 0;\ C_2 = 0;\ C_3 = 1;\ C_4 \text{ is undefined.}$$

Target performance

The target value expected at the beginning of the project is:

$$C_1 = 1;\ C_2 = 1;\ C_3 = 1.1^2 = 1.21;\ C_4 = 1.$$

6.1.2 MEASURED PERFORMANCE

The dielectric withstand when the circuit-breaker is in open position was tested with a Lightning Impulse Withstand Voltage test. The peak voltage that was withstood is **766 kV**. The tests were witnessed by RTE and an independent observer in December 2012.

$$\mathbf{C_1 = 766/650 = 1.18}$$

The current conduction in closed state was tested beyond the second requirement (C_2) as depicted in Figure 6.1 (test performed on January 8th, 2013):

- First the short time withstand current of 3676 A during 2 minutes was demonstrated successfully (Figure 6.2). This result validated higher performance than targeted for C_2 :

$$\mathbf{C_2 = 3676/3000 = 1.23 \text{ (during twice the expected test period)}}$$

- In addition, the thermal management was tested by recording **at the rated current level (1500 A) the steady state temperature that turned out to be well below the limits indicated in AC Breaker standards**.
- Even after reaching the steady state temperature, the demonstrator was able to withstand **overload conditions of 2045 A during 20 minutes without showing any distress** (see Figure 6.1).

The tests were witnessed by RTE and an independent observer on January 08th, 2013.

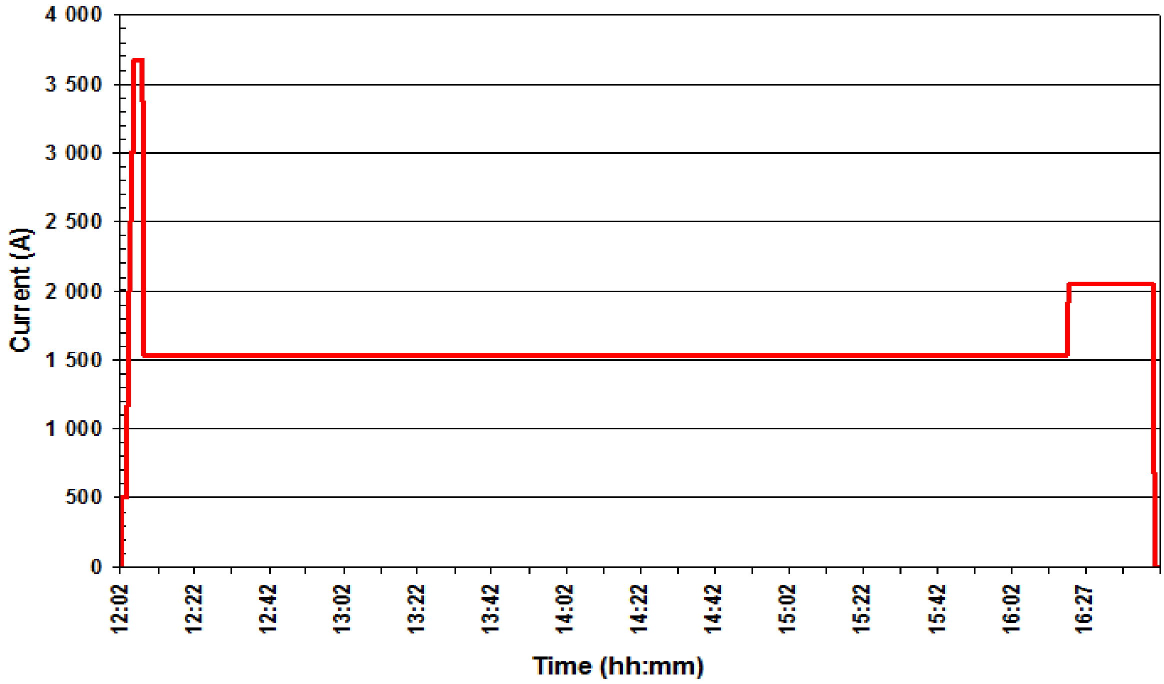


Figure 6.1: Current through the demonstrator as a function of time. The two-minute peak withstand current test is on the left. Steady state conditions were reached during the centre part. The 20-minute overcurrent test is on the right.

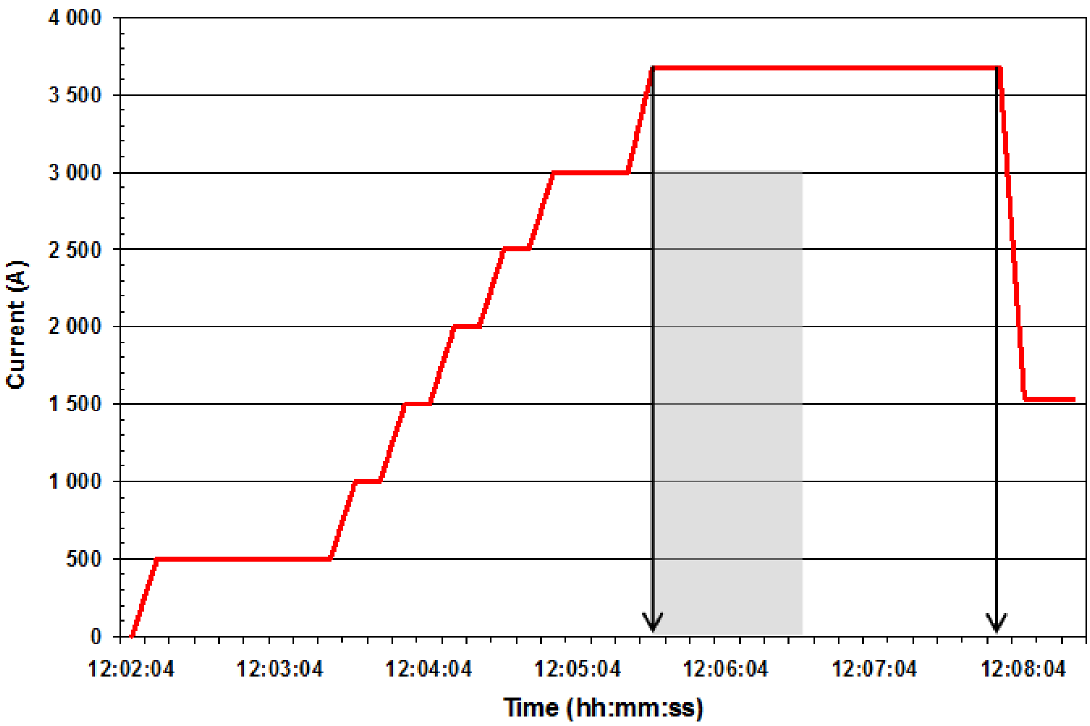


Figure 6.2: The 1-minute peak current test. The grey area shows the duration of 1 minute and the current of 3000 A necessary to obtain a KPI value of C_2 = 1.

On March 21st, 2013 the Twenties Technical Committee and the Twenties Technical Reviewer witnessed power feasibility tests performed on a medium voltage mock-up in Alstom Grid's test laboratory. Interruption tests were demonstrated for two protective current peak values (both were based on a 3.2 A/µs current rise) with the results shown in Table 6.2):

Table 6.2: Test results from March 21st, 2013.

Test results from March 21st, 2013 Both around 3.2 A/µs	Peak of prospective current	Peak of interrupted current	C_3	Interruption time	C_4	Figure
In presence of invited TC members & TR	3.6 kA	2.5 kA	2.07	2.1 ms	19	Figure 4.1
At the limits of the test lab	5.0 kA	2.8 kA	3.19	2.2 ms	18	Figure 4.2

Another test, also witnessed by an independent observer, will be performed in December 2013 on the full-scale demonstrator, at high voltage level (180 kV) that is comparable and not too far from existing voltages of HVDC links.

6.2 KPI D3.2 – DC GRID CASES

This indicator quantifies the number and complexity (in terms of terminal number) of topologies investigated during the project.

6.2.1 EXPECTED PERFORMANCE

Initial performance

At the beginning the project, no offshore DC grid existed. Some aspects where considered in sparse studies (using simulation only), but no specific DCG layout was extensively analyzed (e.g. in the light of ancillary services provided to the AC system, controls design, and protection).

Hence, the state of the art for connecting offshore wind farms to shore using DC transmission is one single structure, the point-to-point connection, which connects 2 terminals (simple HVDC link).

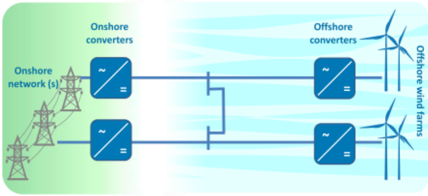
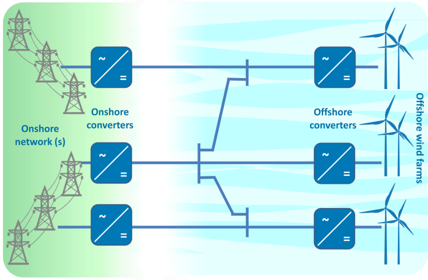
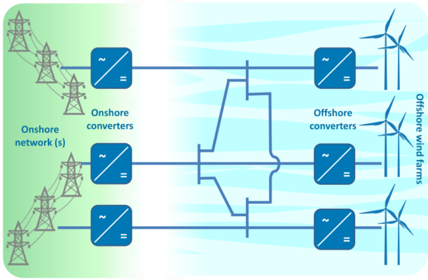
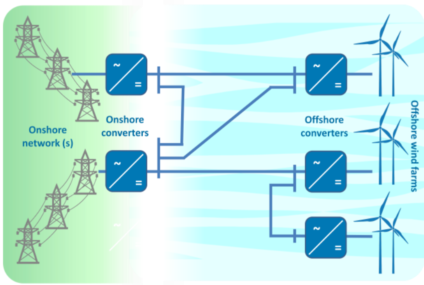
Target performance

The objective of Demo 3 is to provide a wide coverage of the above mentioned aspects of a DCG for at least 3 layouts (for instance: star, ring, backbone), each one comprising 4 to 10 terminals, including various connections to the AC grid.

6.2.2 MEASURED PERFORMANCE

The following four topologies depicted in Table 6.3 were analyzed and considered from the perspectives of provision of ancillary services, controls and protection.

Table 6.3: DC grid topologies covered in Demo 3.

Topology name	Layout	Mainly considered in deliverable
'H' grid (4 terminals)		D5.1 and D5.2b
Tree-like backbone (6 terminals)		D5.2b and D5.3
Meshed backbone (6 terminals)		D5.2b and D5.3
Five-terminal grid (5 terminals)		D11.1, D11.2 and D11.3

All of the four DC grid layouts analyzed in Demo 3 comprise at least four terminals (4 to 6). The structures considered were either tree-like graphs ('H' and tree-like backbone topologies), meshed grids (meshed backbone), or mixed layouts (some portions of the five-terminal grid are meshed, others not).

In addition to the four structures which led to extensive simulations, **the first DCG mock-up (with 15 km of physical cables and protection devices) was designed and tested**, as illustrated during a live demonstration in Lille on 2013 April 3rd, thanks to a joint collaboration with L2EP (Lille) and G2Elab (Grenoble) laboratories. This small scale hybrid mock-up enabled the experimental assessment of various controls embedded in the converters and designed for this DCG (master-slave, voltage droop, and coordinated control), thus proving their viability and robustness using Hardware-in-the-loop (HIL) on both actual and simulated equipment.

6.3 KPI D3.3 – Technologies for offshore DCG and wind turbines

The design of control and protection schemes for different DC grids will strongly depend on the HVDC technology: Voltage Source Converters (VSC) now comes in different breeds (2-level, 3-level, multi-level, with IGBTs gathered in half or full bridge) or Line-Commutated Converters (LCC). Furthermore, other equipment, such as wind turbines, should be considered in their technological aspects.

This KPI will reflect the number of technology and converter breeds taken into account during the project.

6.3.1 Expected performance

Initial performance

Not relevant.

Target performance

Two technologies and two types of converters should be considered, at least.

6.3.2 Measured performance

Table 6.4 below shows the various technologies considered in Demo 3, ranging from already existing ones (some breeds of HVDC converters, for instance) to devices or concepts which appeared during the project lifetime (DC breaker, Power Flow Control Device).

Table 6.4: Technologies considered in Demo 3.

Category	Technology	Mainly considered in deliverable
Thyristor-based HVDC converters	LCC (Line commutated converter) and CCC (capacitor commutated converter) converters	D5.1 D5.3b
IGBT-based HVDC converters	Two-level and neutral-point clamped (NPC) VSC converters	D5.1 D5.3b
	Two-switch and full-bridge modular multilevel (M2C) converters	D5.1 D5.3b
	Hybrid multilevel converters (with series H-bridge cells in AC side / with M2C cells connected across DC link)	D5.1 D5.3b
Wind turbines	Doubly fed induction generators (DFIG) and Full-scale frequency converter synchronous generators (FCSG) wind turbines	D5.1 D5.3b
DC grid protection	Special Protection Scheme (SPS)	D5.1 D5.2b

	DC Circuit Breaker (DCCB)	D11.1 D11.2 D11.3
	DC chopper	D5.2b D5.3b
Others	Power Flow Controlling (PFC) device	D5.3b

All above technologies (except the DCCB, which resulted in a physical demonstrator) led to detailed descriptions and, if relevant, to simulations to assess their behaviour in case of a contingency.

As the frontier between different technologies is sometimes extremely fine (which is the reason why some of them, such as LCC and CCC converters, are grouped together in Table 6.4), the clustering into types of converters and technologies may result in various groups. Based on Table 6.4, **we consider the following result for this KPI: 9 different technologies, including 4 types of HVDC converters.**

6.4 KPI D3.4 - Off-shore wind integration in the economic analysis

This indicator reflects both the number of geographical areas and installed capacity of offshore wind generation considered in economic studies in Demo 3.

6.4.1 Expected performance

Initial performance

Considering the existing and planned projects at the beginning of the project, the initial amount of offshore power connected to shore is 2 GW; this refers to North Sea projects exclusively.

Target performance

For economic studies, at least 40 GW of offshore generation and 3 geographical scenarios were expected to be considered in Demo 3.

6.4.2 Measured performance

The drivers analysis aimed at quantifying the economic benefits of different offshore network topologies, considered offshore wind capacity at two future points in time. **In 2020 a total of 27.1GW of new offshore wind generation capacity was added in three regions**; the North Sea, the English Channel and Western Scotland / Irish Sea. **In 2030, a further 34.2GW of offshore wind capacity was added giving a total of new capacity equal to 61.3GW; in the 2030 case, some of the additional capacity was added in a fourth region**, the Norwegian Sea. The level of offshore wind capacity included in each time frame was based on a proprietary source and has been corroborated with other independent analysis carried out by other work package groups within TWENTIES. The putative nodes representing wind generation hubs and the 4 sea regions are shown in Figure 6.3.

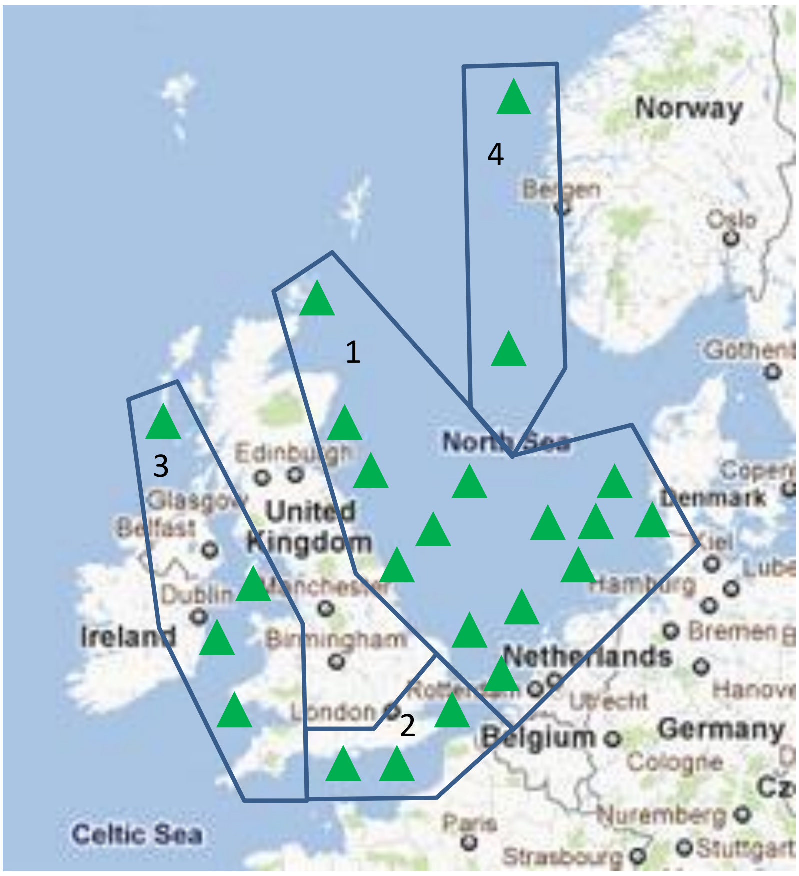


Figure 6.3: Putative wind generation hubs and offshore regions modelled.

The main results from the drivers analysis have been presented in deliverables D5.2a and D15.2 but some of the key conclusions in respect of the KPIs 15.TF2.1 to 15.TF2.3 (see Table 6.5) are repeated here for completeness. In particular, they show the volume of energy production that can be realised from the additional offshore wind generation capacity in the aforementioned 4 areas.

Table 6.5: WP15 KPIs relating to WP5.

KPI.15.TF2.1	Amount of offshore renewable energy that could be securely transmitted by the new HVDC network, [GWh/year]
KPI.15.TF2.2	Ratio between the expected benefit to the system for integrating this energy from of offshore renewable power in the system, and the expected incurred cost to deploy the new components, [Euro / Euro]
KPI.15.TF2.3	CO_2 emissions that could be avoided in Europe 2020 due to this offshore renewable power, [tonne CO_2/year].

The main results relevant to the above KPIs are summarised in Table 6.6 and Table 6.7 below which show the costs and CO_2 emissions for different network topologies, generation merit orders and demand scenarios in 2020 and 2030 respectively.

Table 6.6: Summary of results of 2020 case with 27.1 GW of new offshore wind generation capacity.

	Case 0 – no new OWF	Case 1 – radial connection of new OWF	Case 2 – radial connection of new OWF + new point-to-point interconnectors	Case 3 – H-grid
TWh of new offshore wind production	0	74	74	75
Europe-wide CO_2 emissions from 'forward' merit order electricity production (million tonnes)	1201	1150	1157	1157
Europe-wide CO_2 emissions from 'reverse' merit order electricity production (million tonnes)	829	779	775	771
Total cost of 'forward' merit order electricity production and annualised offshore grid capital cost (million euros)	49713	48775	48666	49855
Total cost of 'reverse' merit order electricity production and annualised offshore grid capital cost (million euros)	60883	60085	60269	61463

Table 6.7: Summary of results of 2030 case with 61.3 GW of new offshore wind generation capacity.

	Case 0 – no new OWF	Case 1 – radial connection of new OWF	Case 2 – radial connection of new OWF + new point-to-point interconnectors	Case 3 – H-grid
TWh of new offshore wind production	0	178	178	186
Europe-wide CO_2 emissions from 'forward' merit order electricity production (million tonnes)	1507	1406	1417	1415
Europe-wide CO_2 emissions from 'reverse' merit order electricity production (million tonnes)	1170	1043	1032	1025
Total cost of 'forward' merit order electricity production and annualised capital cost of offshore grid (million euros)	65580	63379	63283	62170
Total cost of 'reverse' merit order electricity production and annualised capital cost of offshore grid (million euros)	75631	74028	74535	73655

<u>Notes for Table 6.6 and Table 6.7:</u>

- *"Forward" merit order is lignite, coal gas (lowest to highest marginal cost); "reverse" order is gas, coal, lignite*
- *Total CO_2 and costs depend on assumptions made about non-wind generation capacity, generation production costs, market arrangements and network capacity and costs of new offshore network capacity.*
- *Costs do not include costs of: networks within OWF or connecting OWF to offshore hubs; DC breakers; CO_2 costs; unsupplied energy; costs of financial support to renewables.*
- *Design of offshore network has not been optimised.*

From these, the following summary conclusions are drawn:

- It has not been possible from these studies to identify a clear preference in 2020 for an H-grid multi-terminal offshore network when compared with radial connections of wind power from offshore hubs to shore plus point-to-point interconnectors.
- However, the design of the H-grid has not been optimised, and the results for 2030 show clear benefits if the costs of DC breakers are neglected.
- The CO_2 reduction benefits arising from a reversal of the merit order of fossil fuelled generation are significant when compared with those directly associated with the development of offshore wind capacity.
- Questions related to the amount of offshore renewable energy that can be accommodated, the cost benefit of different options for doing so and the CO_2 impact depend on a large number of factors, among them:
    - the installed renewable generation capacity;
    - the power network capacity;
    - the variability of the available renewable power and the demand for electricity and how that variability is managed, which depends on the power network capacity, the characteristics of other generation and on market arrangements for the trading of energy and the provision of ancillary services;
    - relative prices and availability of different generators.

In consequence, the results should be approached with due caution. Moreover, optimisation of the offshore network design for a particular generation and demand background should be the subject of extensive further work. Still more work would be required to identify a design that is robust in light of uncertainty regarding the future generation and demand background.

An issue not fully explored here is the cost of DC circuit breakers and the sensitivity of the overall cost-benefit of a multi-terminal grid to that cost and the number of DC breakers used. However, an initial analysis suggests that the cost of a DC breaker should be less than around 10 million € per unit if an H-grid in which they are widely deployed is not to become unduly expensive.

6.5 KPI D3.5 – POWER TRANSMISSION THROUGH THE DC GRID UNDER CONTINGENCY CONDITIONS

This KPI reflects the resilience of a DCG (for a given technology and appropriate control and protection schemes), that is, its ability to deliver some power after a contingency has occurred (N-1 cable, N-1 converter, DC short-circuit).

It is expressed in % of the power transmitted in normal conditions.

6.5.1 EXPECTED PERFORMANCE

Initial performance

As all existing offshore DC connections are point-to-point, a major contingency such as a fault on a DC cable or on a converter will lead to the complete shutdown of the connection, with no power transmission capacity until the fault is cleared. The initial state is therefore 0%, as all the connected generation is lost simultaneously.

Target performance

One of the expected benefits of using DC grids (with several onshore terminals) rather than point-to-point connections is to guarantee – provided the appropriate technology, controls, earthing and protection – the existence of a remaining path to transmit power following a fault. Hence, though not fully quantified, the target performance should assess that a contingency does not result in a complete loss of power.

Since the definition of a quantified target value was not possible at the beginning of the project (all the more as it depends on the achievements for the DCCB demonstrator, the objective for this target was to assess the maximal achievable value of transmitted power after a fault occurrence (10%, 20%, or more).

6.5.2 MEASURED PERFORMANCE

As illustrated in simulations (deliverable D5.2b and D11.1), the most severe contingency (with respect to remaining power transmission capacity after a fault) is the loss of an onshore converter or the loss of a cable (especially when the faulty cable is the only connection between an onshore converter and the rest of the DCG).

To limit the impact of such contingencies on the healthy part of the DCG, or even isolate the fault, several algorithms, controls and equipments were developed in Demo 3:

- A DCCB was designed and successfully tested
- Protection algorithms (for DC fault detection) were developed and tested on a DCG mock-up
- Converter controls based on voltage-droop control were developed and validated on the DCG mock-up
- Fault ride-through (FRT) capability provision based on a set of controls was described and simulated. As explained in deliverable D5.3b, FRT capability can also be enhanced using DC choppers.

Therefore, KPI D3.5 is related to the assessment of these techniques and technologies. However, quantifying the maximal achievable value of transmitted power after a fault occurrence is not possible in a general manner, as it also depends on the DCG topology and the number and capacities of terminals, amongst other factors. For the sake of clarity, it is assumed here that all converters have similar ratings, while all DC cables are rated so that there is no overload during normal operation of the DCG; in addition, only DC grids with at least two onshore terminals are considered. Those assumptions are consistent with the four DCG topologies that were studied in Demo 3 (KPI D3.2).

Since the effectiveness of a DCCB was established for significant classes of faults in Demo 3 (categories I and II, in Table 4.1, page 37), and also the performance of an innovative DC fault detection algorithm (for cables no longer than 200km), no technical “showstopper” appeared that could prevent the design and operation of DC grids (complying to those categories) which include protection systems able to isolate faults.

Therefore, these recent developments in Demo 3 guarantee that **the maximal achievable value of transmitted power after a fault occurrence is 50% at least for networks designed to comply with categories I and II**: indeed, this figure is achieved for the worst case scenario (the loss of an onshore converter or the loss of the only cable between an onshore converter and the rest of the DCG) following fault clearance thanks to the DCCB, and assuming there are only two onshore converters. Obviously, this figure increases with the number, n, of onshore terminals ($\frac{n-1}{n}$ %).

However, the DCG protection technology exhibited in Demo 3 is not enough to prevent the complete grid shutdown for category III fault (see Table 4.1 on page 37). Therefore, it should be highlighted that, **to date, secure operation cannot be guaranteed yet for extremely large and complex grids, given currently foreseen technological advances.**

7 CONCLUSIONS AND RECOMMENDATIONS FOR FURTHER WORK

The DEMO 3 activities provided and demonstrated key building blocks for designing future HVDC networks which can be securely operated and integrated into existing AC systems. Investigations covered a significant range of security related issues, from the stable and reliable steady state operation to the detection, elimination of and recovery from large perturbations like DC faults. The requirements for specific equipment and systems like master DCG controllers, DCCBs and associated protection schemes were characterized in simulations and through a laboratory test mock-up. These requirements were based on current technological advances, especially through the large scale demonstration test of a DCCB, and through operation of the first meshed DCG mock-up with physical cables and protection devices. Finally, the benefits and impacts of meshed DCGs were studied in the context of the North Sea area, in comparison with the current approach of radial connection of wind farms.

Recognizing that future offshore DCGs would probably be built stepwise, the DEMO 3 activities distinguished three stages beyond radial connection of wind farms:

A first stage with small backbone-shaped DCGs (Figure 7.1) which can be readily constructed and extended with currently available technologies, without specific equipment or systems like DCCBs or master DCG controllers.

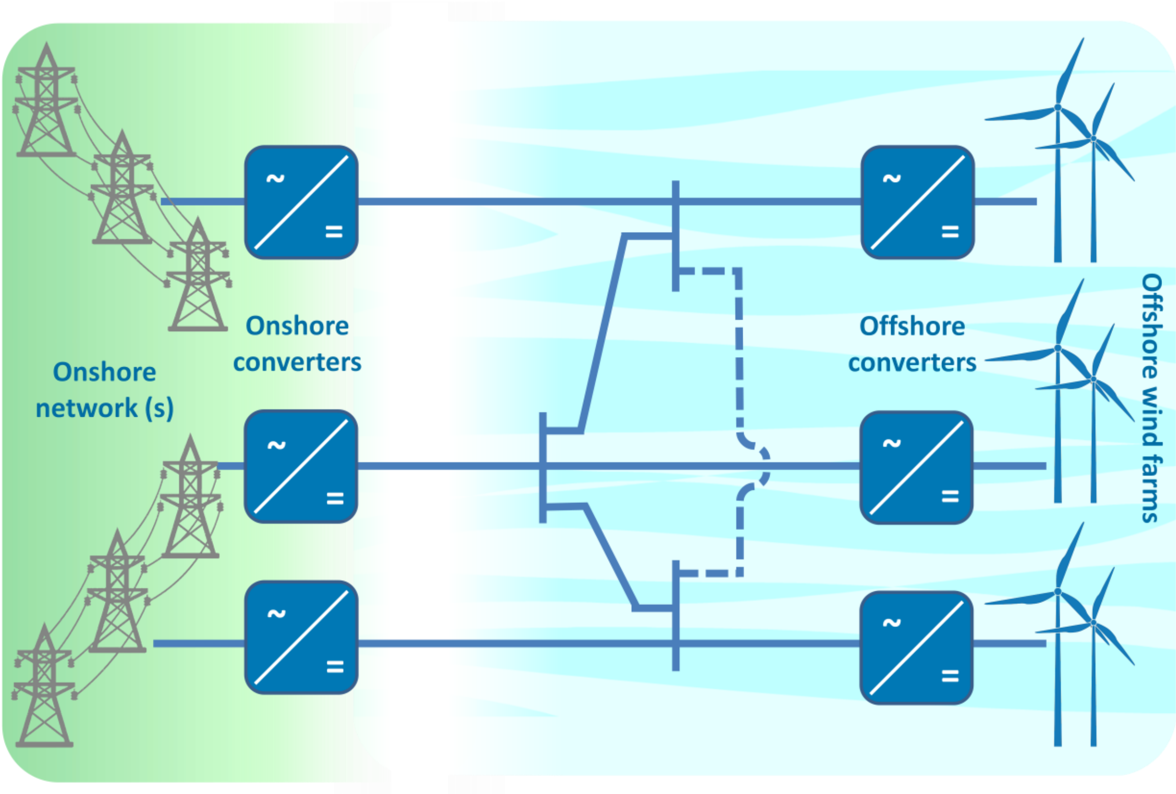


Figure 7.1: Tree-like (plain lines) and meshed (plain and dashed lines) DC backbone examples.

Autonomous controls for both the DCG converters and the offshore wind turbines were exhibited, which demonstrated that flexible power flow control in normal and disturbed conditions, ancillary services provided to the AC mainland network (voltage support, primary frequency control, inertia emulation, Power System Stabilizer), and Fault Ride-Through capacity can be provided by such DCGs using local measurements only.

For this initial stage, fault clearance would then involve de-energizing the complete network from the onshore AC grid. Therefore the maximum power infeed from these networks must remain below acceptable values for such events, for example a few GW (depending on the primary reserve of the synchronous zone the DCG is connected to).

An intermediate stage with simple meshed networks by 2020, for which specific equipment or systems such as a master DCG controller would be required in addition to controls for the backbone structures. To establish these requirements and assess the operation of such networks, a representative network topology with five VSC terminals was first used in simulation. In a second stage, the various controls embedded in the converters (master-slave, voltage droop, and coordinated control) were experimentally validated through the grid behaviour, using a scaled down five-terminal mock-up (Figure 7.2).

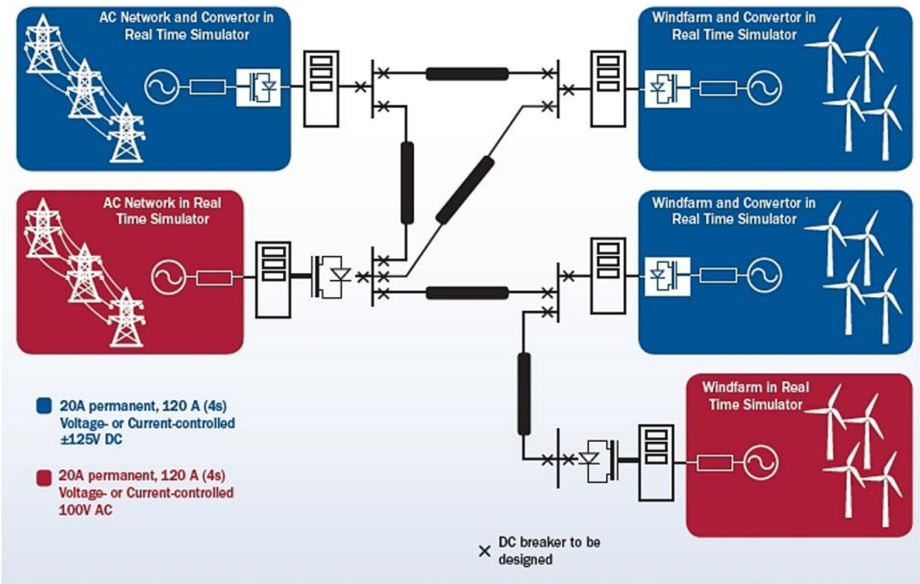


Figure 7.2: DCG mock-up using Hardware In the Loop (HIL) on actual and simulated equipment.

In the case of a DC fault, the rate of rise and amplitude of the fault current are dramatic. Therefore, a protection system based on DCCBs is required to selectively detect and clear DC faults, as the loss of the complete DCG would not be acceptable. Three different classes of requirements were identified for the duty of DCCBs, depending on the ratings of the grid, but also the portions of the grid to be protected. Two of them are met by the performance of the fast switch-type DCCB demonstrator (Figure 7.3) which was designed to meet their stringent fault current interruption and speed requirements at acceptable cost, as witnessed by an independent observer and the EC Technical Reviewer.

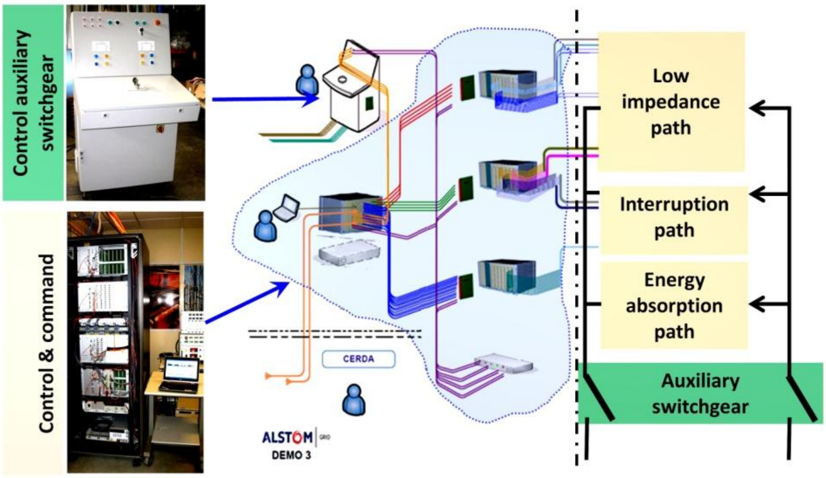


Figure 7.3: DCCB demonstrator architecture.

Fault clearing time constraints required the development of rapid and selective protection schemes using optical fibres. Based on differential overcurrent relays, this was shown to be effective for cable distances no longer than about 200 km. It was validated experimentally on the DCG mock-up, where opening orders are sent in less than three milliseconds.

A final stage with complex meshed DCGs (by 2030 or later), for which secure operation cannot be yet guaranteed given currently foreseen technological advances.

Economic analysis focused on comparing possible DCG topologies (radial, point-to-point interconnectors, multi-terminal, or meshed) in line with the development of offshore wind generation in the North Sea, based on the long-term planning methods used by European TSOs. It was quantitatively established that DCGs use underwater cable capacities more effectively than radial connection schemes to feed offshore wind power back to the continent, with the additional benefit of interconnecting energy production areas at the European scale. The DCG can also implement beneficial functions for operating the onshore AC grids connected to it, which were not assessed in the framework of the study: improved AC security margins through appropriate power injections via the onshore DCG terminals; ancillary services like voltage control, frequency support, synthetic inertia or damping of inter-area oscillations; black-start restoration of the AC system from the offshore grid.

Global cost benefit comparisons between radial connection and DCG schemes were carried out while varying parameters like the cost of CO_2 emissions, of new DC technology (including the DCCB) and cable capacities. From this analysis there is no clear advantage or disadvantage between the studied schemes. Grid schemes are more costly in terms of investment but provide added benefits for operation and remain competitive overall. At the 2020 or 2030 horizon, other uncertainties like regulation criteria on structural adequacy of the European generation mix could also play a significant role in the balance.

7.1 Recommendations for further work

The TWENTIES DEMO 3 activities could be complemented by future testing of a low-scale DCG demonstrator, focusing on interoperability of multi-vendor components (including innovative VSC converters such as full-bridge topology), as a necessary step toward future standardization. This should also permit the testing of available DCCB components in real conditions (integrating the full protection chain, from detection to complete fault isolation).

In addition to such a demonstrator, further real-time simulations are required to include an AC network, the DCG and wind farms, for time scales ranging from microseconds to seconds in order to assess the protection and controls compatibility for the equipment in these three sub-systems.

Last, better visibility on CO_2 emission and DC equipment costs is required to assess the economic viability of future DCGs and their financing.

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Project full title: Transmission system operation with large penetration of Wind and other renewable Electricity sources in Networks by means of innovative Tools and Integrated Energy Solutions

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