Programme Area: Energy Storage and Distribution

Project: Offshore Connection 1

Title: Multiple Offshore Connection Report

Abstract:

Building on the Individual Connection Report (with which this report should be read), it identifies and assesses options for network architectures for the connection of multiple offshore renewable energy farms – to shore and to each other. Again, it describes the associated challenges and technology development opportunities (to augment those in the earlier reports). Section 7 summarises the conclusions regarding optimum architectures, including in respect of the use of Gas Insulated Lines and of national / international interconnectors, and identifies further technology development opportunities.

Context:

This project examined the specific challenges and opportunities arising from the connection of offshore energy to the UK grid system and considered the impact of large-scale offshore development. It also looked into the novel electrical system designs and control strategies that could be developed to collect, manage and transmit energy back to shore and identified and assessed innovative technology solutions to these issues and quantified their benefits. The research was delivered by Sinclair Knight Merz, a leading projects firm with global capability in strategic consulting, engineering and project delivery. The project was completed in 2010.

Offshore Connection Project

MULTI-TERMINAL OFFSHORE CONNECTION ARCHITECTURES REPORT

Final

■ 23rd July 2010

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Contents

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1. Introduction

1.1. Project Outline

The Energy Technologies Institute (ETI) has engaged Sinclair Knight Merz (SKM) to identify the opportunity for the development of innovative solutions for the collection of electrical energy from individual and multiple offshore renewable energy farms, and the transportation of bulk electrical energy from these offshore farms to the onshore power system.

The work is being carried out to allow the ETI to focus their subsequent research, development activities and funding initiatives on technologies that will increase energy efficiency, reduce greenhouse gas emissions, and help achieve energy and climate goals.

The study being undertaken by SKM comprises of four main tasks that will enable the required project outcomes to be delivered:

1. Offshore renewable scenarios – to define the timeline of the expected volumes of offshore renewable generation capacities, an important aspect to allow the quantification of the potential benefits of future technology development opportunities. In addition, as indicated in the Statement of Work paragraph 2.2, this task will produce matrices that outline key variables that will allow the generalisation of a range of potential wind, wave, and tidal developments. These matrices will further be used to define a number of specific development cases for analysis in the subsequent project tasks.
2. State of the art of offshore network technologies – establishment of the current state of the art of offshore network technologies and their prospective future development path (through discussions with equipment manufacturers and suppliers), including an assessment of technical and financial characteristics.
3. Analysis at individual farm level – identification of the challenges and resultant technology opportunities (based on the state of the art review) that could arise in respect of the connection of individual large-scale offshore wind or marine energy farms to the UK grid system, and provision of recommendations for connection solutions worthy of further development and analysis.
4. Analysis at multiple farm level – building on the analysis at individual farm level, evaluation of the optimal architecture(s) that could be developed to collect, manage and transmit back to shore the electrical energy produced by multiple, large-scale offshore renewable energy farms.

1.2. Multi-terminal Approach

The aim of this Multiple Offshore Farm Connection Architectures Study is to determine potential architectures for connection of multiple offshore energy farms, identify criteria to assess these architectures and then to apply selected architectures to the six sites identified in the original ETI RfP for the Offshore Connection Project. The output of the previous SKM State of the Art report and the subsequent results of the Individual Offshore Connection Architecture Studies have been used to not only describe the baseline "point to point" solutions architecture, but to enable the detailed analysis of the multiple connection architectures. These architectures have been studied at a high level mainly using DIgSILENT verified Excel based spreadsheets to enable the appropriate range of technical and economic factors to be assessed and conclusions reached as to the potential for technology development opportunities.

1.2.1. Modelling

For the detailed assessment of the technical performance and economic attributes of the connection architectures the work already completed within the Individual Offshore Connections Architecture studies has been used as the main input. The baseline of "point to point" connection architectures for all technologies considered has been used to assess the potential range of multiple architectures.

Initial assessment of architectures was undertaken utilising assessment criteria which have been developed based on the previous stages of the project and additional SKM expertise.

1.2.2. Assessment Criteria

The initial, mainly qualitative, assessment criteria used to refine the potential number of multiple offshore farm connections were as follows:

- Connection capacity
- Capital cost
- Reliability
- Availability
- Operating costs
- Efficiency
- Environmental impact
- Technology availability
- Control issues
- Construction issues
- Project risk

- Compliance with equipment/grid system standards
- European market impact

Additional factors were subsequently added for:

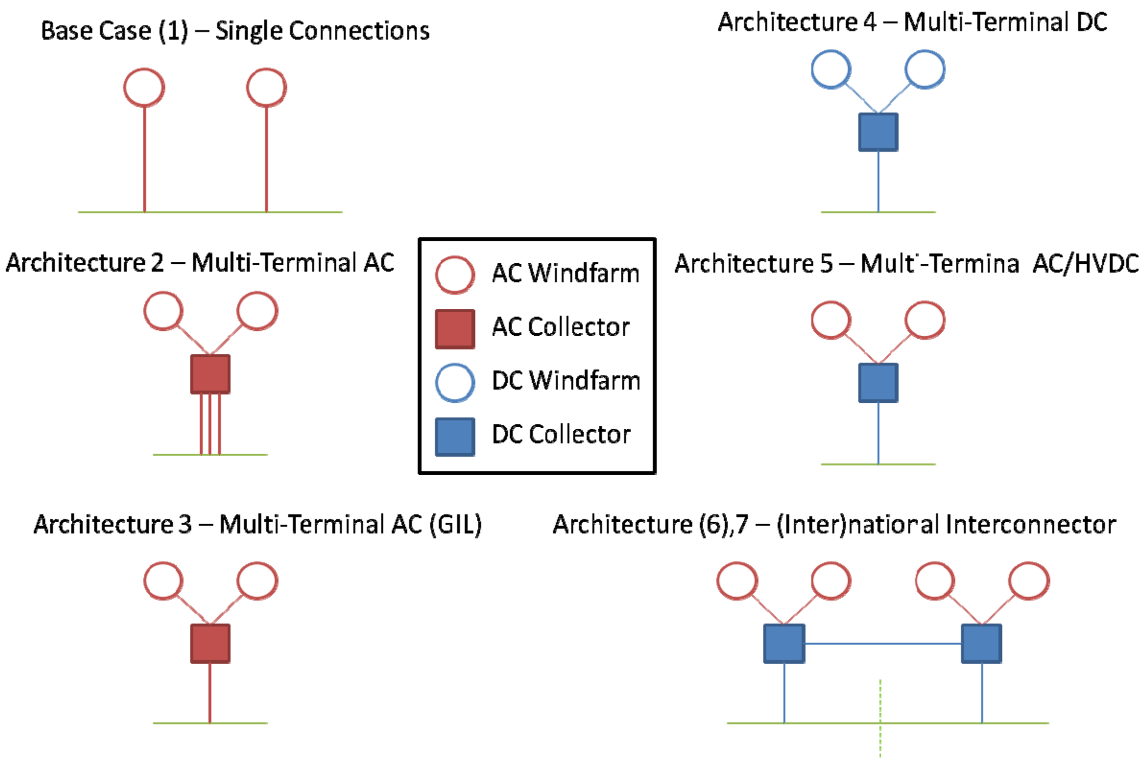
- Provision of auxiliary power
- Extensibility

The conclusion regarding these additional factors was that they did not significantly impact on the overall assessment of the various multiple connections architectures that were considered from a technology perspective. Of course the application of the technologies to specific developments will require detailed consideration of all the above issues, but the choice of technology will not significantly impact on the importance of these additional factors.

1.2.3. Connection Technologies

In determining the range of potential connection architectures the full range of technologies identified in the State of the Art Review and developed in the Individual Offshore Connection Architecture studies were considered, including where appropriate the impact of intra-array technologies as is discussed in the following sections and illustrated in Figure 1.

- **Figure 1 Representation of Basic technology architectures**



1.2.3.1. Full AC Technologies

Present UK offshore renewable energy farms have been developed using full AC arrangements for both intra-array collection and export. Hence this defines not only the base case of point to point (Architecture 1) connections but also for the multi-terminal options of Architecture 2, Multi-terminal AC and Architecture 3, Multi-Terminal AC with GIL.

AC intra-array is realised with 33kV although this has little impact at the multi-terminal / multi-farm level.

1.2.3.2. AC and HVDC Technologies

As identified in previous reports HVDC is the preferred export option above 90km/1000MW. So for Multi-terminal Architecture 5, 6 and 7 the combination of AC collector and DC export is considered.

Architecture 5 considers a straightforward multi-terminal AC/DC architecture whilst Architecture 6 considers a national interconnector or “Bootstrap” arrangement. Architecture 7 is similar to Architecture 6 except that here the “Bootstrap” is an international interconnector which has additional considerations compared to a national connection.

1.2.3.3. Full DC Technologies

Within the Individual Offshore Connection Architectures study it was identified that there were two possible arrangements for full DC architectures, these being the series and parallel systems.

It was concluded in the Individual Offshore Connection Architectures report that the parallel system was not economically viable; hence it is not considered in this multi-terminal study.

The series system is considered in Architecture 4.

1.2.4. Summary of Connection Architectures to be assessed

Architectures studied are illustrated in Figure1 and detailed below.

1.2.4.1. AC-AC

1. Base case point to point, AC collection (33kV) and export (220kV cable).
2. Multi-terminal, AC collection (33kV) and export (220kV cables).
3. Multi-terminal, AC collection (33kV) and export (280kV GIL).

1.2.4.2. DC-DC

4. Multi-terminal, DC collection in series with direct export.

1.2.4.3. AC-DC

5. Multi-terminal, AC collection (33kV) and DC export.
6. Multi-terminal, AC collection (33kV) and DC export in conjunction with national bootstrap.
7. Multi-terminal, AC collection (33kV) and DC export in conjunction with international interconnector.

The choice of DC voltage for DC export is derived from the DC converter and DC cable developments discussed within the State of the Art Technologies report (Reference Fig 33) with 500MW ±150kV, 1000MW ±320kV and 2000MW ±400kV.

The voltage selected for AC interconnections between zones is 220kV based on the optimisation studies that were reported upon within the Individual Architectures report.

1.2.5. Summary of Multi-Terminal Approach

Having applied the assessment criteria outlined in Section 1.2.2 to the generic architectures specified in Section 1.2.4 it was concluded that each architecture should be analysed in detail except for the DC/DC system. This is on the basis that in the series DC architecture the significant benefit is that no converter platform is needed, hence the architecture does not provide any opportunity for a multi-terminal approach. This approach was agreed at Design Review 2 on 23rd March 2010. The main focus points of the studies to be completed in the multi-terminal analysis were agreed as:

- Analysis and comparative assessment of multi-terminal architectures using the 6 sites in Figure 2 which is extracted from the ETI RfP.
- Any additional control system requirements associated with multi-terminal architectures.
- Any additional onshore grid impacts associated with multi-terminal architectures.
- High level assessment on European markets of multi-terminal architectures.

Of course the overall aim of these studies will be to identify technology development opportunities which could accelerate the progress of the most attractive and technically suitable future connection architectures.

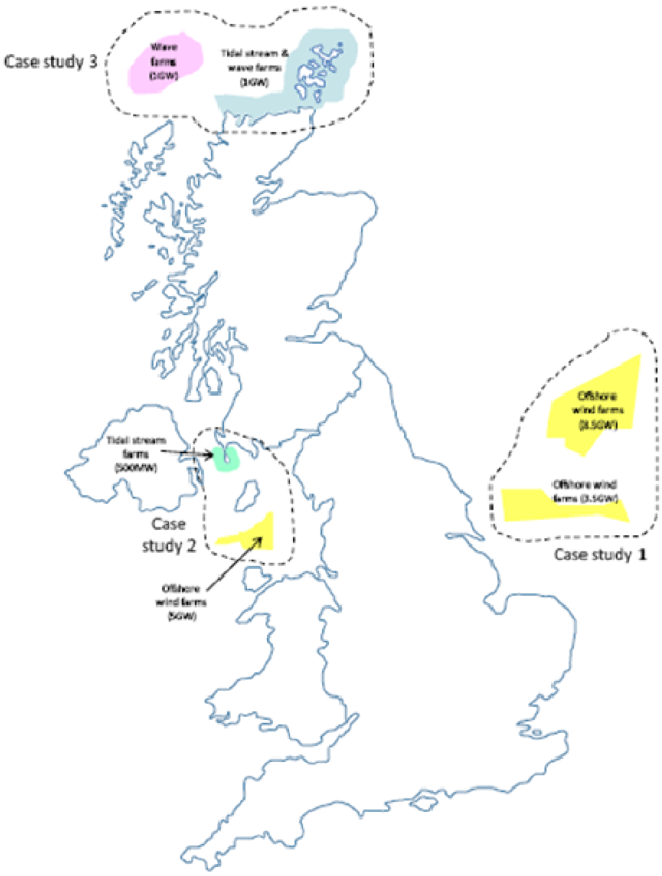
Table 1 shows how the individual Development Scenarios identified in The Generation Scenarios report are covered by the Study Groups used within this multi-terminal architectures study.

Table 1 Linkage Between Generation Scenarios and Study groups

Generation Scenarios	Study Group 1	Study Group 2	Study Group 3	Study Group 4
Distributed Smaller Wind farm Up to 1000 MW			X	
Large Wind farms Up to 2000 MW	X	X		
Very large Wind farms Up to 5000 MW	X	X		
Small Marine 20 MW				X
Medium Wave 150 MW				X
Large Tidal 500 MW				X

- ## Figure 2 Offshore Development Cases

Appendix C – Offshore Farm Connection Case Studies (for Work Package 2)



The following three offshore renewable energy farm case studies apply for this Request for Proposals:

1) The connection of 12 GW of offshore wind farms off the east coast of England (Dogger Bank plus Hornsea). The offshore connection points are between 80 km and 250 km from the shoreline.
2) The connection of 5 GW of offshore wind farms in the Irish Sea (40-100 km from the shoreline), combined with 500 MW of tidal stream energy farms off the south-west coats of Scotland (10-20 km from the shoreline).
3) The connection of 1 GW of tidal stream and wave farms in the Pentland Firth area, combined with 1 GW of wave energy farms to the north of the Isle of Lewis (50-100 km from the shoreline).

2. Methodology

2.1. Technical Model

Technical spreadsheet models for each architecture variation (design) have been primarily built to assess availability. Mean Time between Failure (MTBF) and Mean Time to Repair (MTTR) data was sourced from a range of documents including supplier literature, past project experience and Cigre reports. Where data was only available for onshore equipment the MTBF and MTTR have been adjusted to reflect the offshore environment as detailed in (Appendix A). All connection designs, with the exception of Design 25, are rated at 100% installed generating capacity; Design 25 investigates the potential of de-rating export connections. For all HVDC multi-terminal designs only VSC has been considered due to the issues discussed at length in the State of the Art Report and Individual Offshore Connection Architectures Report including practical issues such as size and technical issues such as control. LCC HVDC has only been assumed for the point to point national/international interconnection where there is no requirement for an offshore converter.

2.2. Availability

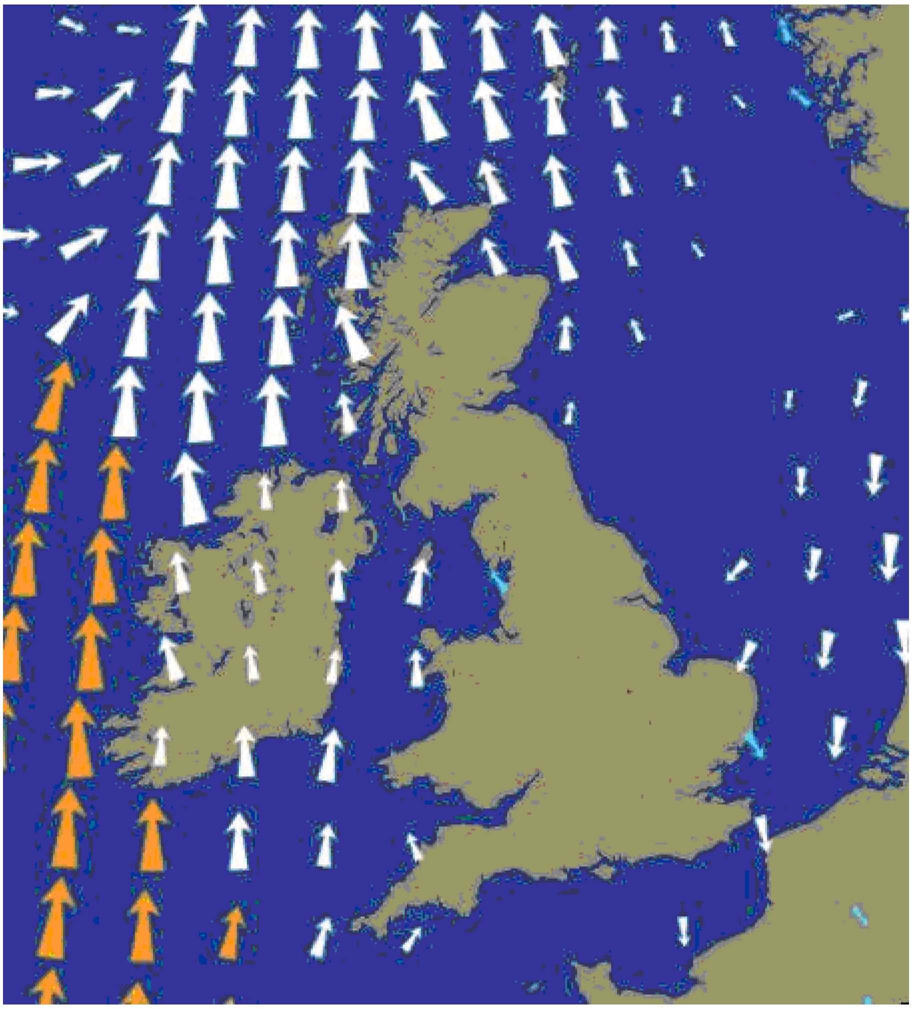
Availability is defined as the percentage of power exported compared to the total power it would have been possible to have exported. Unavailability refers to the percentage power lost due to outage. Unavailability is predicted using known equipment reliability including average failure rates (also expressed as MTBF) of equipment and known Mean Times to Repair. Also taken into account is the percentage of possible output capacity lost for each given failure. For this reason series equipment will have relatively poor availability as the loss of a single piece of equipment would incur the total loss of all export. Parallel equipment will have generally good availability as the loss of a single piece of equipment will incur only a part loss of export capacity.

A simplified spreadsheet model has been used to assess comparative availability between architectures. To account for the varying output and low load factor of renewable generation, availability has been calculated for a range of generator outputs. By taking availability figures at a range of generator outputs and weighting them relative to the percentage of time the development would spend at each output capacity (based upon an indicative offshore farm output) an average is reached. This average better represents the effect of export outages to the generator. An example of this would be if the loss of a piece of equipment reduces the export capacity to 50% rated, when an offshore farm is operating at less than 50% capacity (likely given a usual load factor of around 40%) the actual availability as experienced by the generator is 100%. By weighting the average availability as described this effect is taken into account. OFTO (Offshore Transmission Owners) effect has been considered separately.

Consideration was given to the use of source diversity to strengthen the case for interconnection.

For wind and wave it was concluded that whilst there is potentially large diversity across the UK (see Figure 3) due to weather patterns, as the area of interest becomes more focused there becomes significantly less diversity at a local level. Therefore within Study Groups, where distances of interconnections are relatively short, wind/wave diversity was not considered as it would not have any material impact on the conclusions drawn on interconnection architectures

- **Figure 3 Typical UK Wind Map (Source BBC)**



For National/International interconnectors this is discussed in Section 4.1.9.

2.3. Financial Model

The financial assessment of the various multi-terminal architectures is primarily built upon the capital and operating costs of the architecture and the cost of lost generator revenue (based on the average availabilities calculated for the given architectures). Penalties and credits earned through the OFTO revenue stream have been considered separately. From a comparison of the above aspects for various architectures the advantages, disadvantages and likely optimum designs have been highlighted.

Capital costs utilised throughout this study are the same as those generated for the Individual Offshore Connections Architectures report and is briefly repeated here for clarity. A database of unit costs was collated from a number of sources including internal SKM databases, sub consultants and the interview activities carried out as part of the State of the Art Technologies Report and was further reviewed following the recently published National Grid ODIS report[1]. All costs are based on present day values and losses have been capitalised by assigning a value to each unit of power loss (£/MWh) and also the period of time (years) over which the discount rate will operate.

Lost generator revenue has been calculated based on the following parameters.

- Value of Losses £105/MWh[2]
- Capitalisation Period 20 Years
- Discount Rate 10%
- Load Factor 40%

It is also worth relating the figure of £105/MWh used for losses with the current wholesale price of energy of £45/MWh which could of course be added to with ROC's (Renewable Obligation Certificates) which are valued around £50/MWh per ROC.

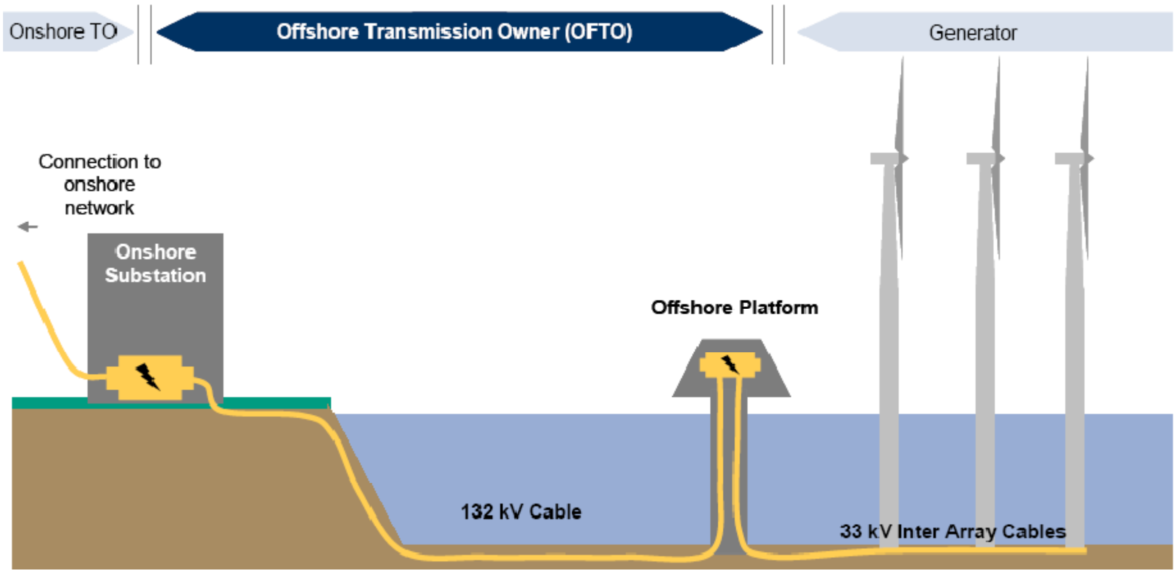
2.4. OFTO Revenue Scheme

The economic model highlighted above is used for capital cost analysis and cost of losses. The charging and revenue models for generators and OFTO's is complex recognising the regulatory and investment aspects that need to be covered.

It is assumed that the boundaries between Generators, OFTO and TO (Transmission Operator) will follow the transmission model outlined in Figure 4.

[1] National Grid, 'Transmission Networks: Offshore Development Information Statement', December 2009
[2] Typical figure used by Developer in assessing offshore renewable cost of losses for Round 2 projects

- **Figure 4 Generator, OFTO and TO Boundaries[3] ©Crown Copyright**

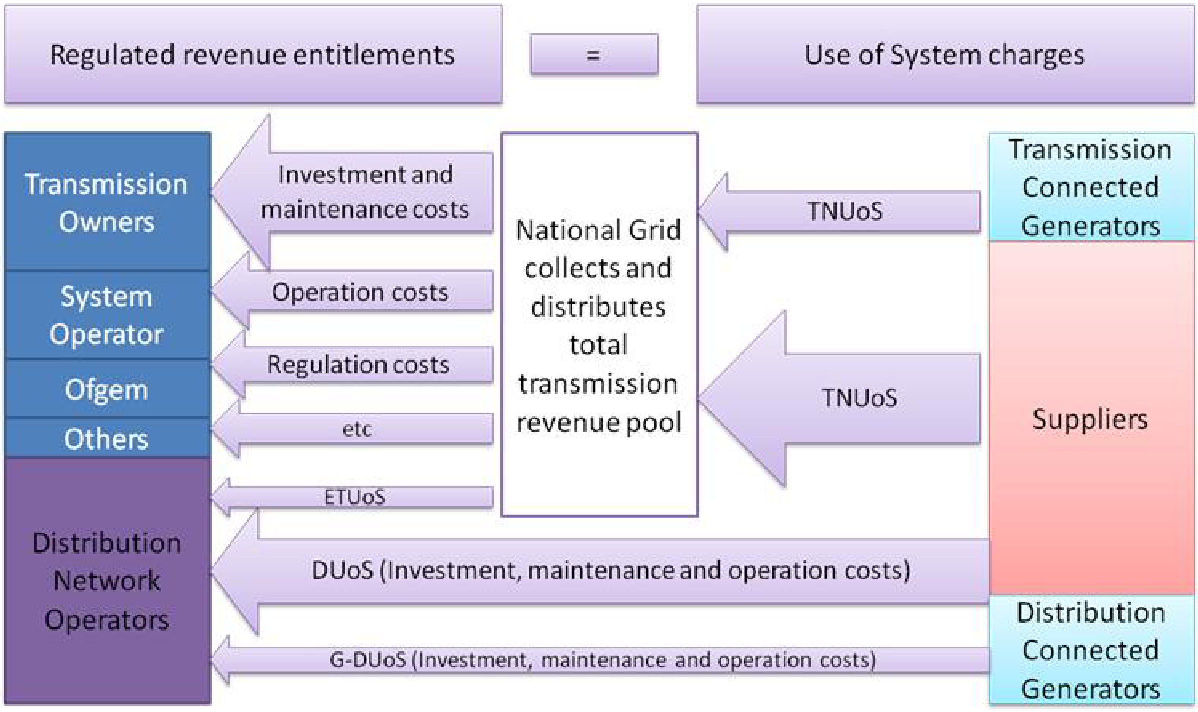


Network operators, both onshore and offshore have revenues regulated by Ofgem with onshore transmission, distribution and system operators having revenues set through 5 year price control reviews. OFTO revenues are set through a 20 year price control being established through a tender process. All network users pay Use of System Charges with Transmission Use of System charges to National Grid and Distribution Use of System charges to the appropriate DNO where a distribution connection is provided.

The system is shown diagrammatically in Figure 5 to illustrate the relationship between the System Operator, OFTO and generator.

[3] Ofgem, 'UK Offshore Transmission Investment Opportunity', July 2009 http://www.ofgem.gov.uk/Networks/offtrans/rott/Documents1/Generic%20and%20project%20specific%20Preliminary%20Information%20Memorandums%20for%20offshore%20electricity%20transmission%20transitional%20projects.pdf

- **Figure 5 Charging Overview**



The Ofgem OFTO revenue scheme is a specific economic analysis designed to incentivise offshore transmission owners to provide a reliable connection and is calculated on availability rates. This scheme is presented in further detail in section 3 'OFTO Regime' however below is a summary of the relevant parameters taken from the published 'Generic OFTO Special License Conditions':

- Target Availability 98%
- Penalty/Credit Earning Rate 2.5% for 1% change in Availability
- Collar Availability 94%
- Maximum Penalty beyond Collar 10%

The Base Revenue Asset Payment is a figure that will be established for each project based on the current OFTO tendering process for transitional projects and the enduring process which is yet to be established. The base revenue payment being primarily established on capital costs of the connection, operating and maintenance costs for the OFTO, costs of decommissioning plus additional costs such as insurance and the critical IRR (Internal Rate of Return) required by an individual OFTO. In the subsequent analysis a range of Base Revenue Asset Payments have been assumed for comparison with the costs of constrained generation.

2.5. Approach

All technical modelling has been carried out at a level of detail appropriate for the studies undertaken and has been primarily based on spreadsheet analysis for costs and availability. All studies are based on simplistic designs and generalised offshore farm output characteristics, as such the results are intended only for comparative analysis to highlight trends and potential optimum solutions.

Financial modelling has been carried out to a degree of detail necessary for the study being undertaken and is intended to be a high level comparative tool highlighting cost trends and indicating optimal solutions. It is not intended to be an accurate capital expenditure model which is not possible given the nature of the studies.

Understanding of the OFTO regime and how this will impact on revenue streams with multi-terminal offshore connections has been studied. This involves a combination of both the technical and economic analysis of the architectures to give a high level comparison. It is however not intended to quantify full OFTO revenue streams for each architecture over the 20 year operating period, as this is not appropriate.

3. OFTO Regime

The Offshore Transmission Owners (OFTO) regime relates to the new regulatory structure for offshore transmission networks that has been developed by Ofgem and the British Government. It is designed to encourage investment in new offshore assets in a long-term, low-risk regime.

3.1. Revenue Stream

The OFTO revenue stream is the backbone of the regime and represents the financial incentives and penalties which face an investor operating as an OFTO. The scheme is built upon a number of streams outlined by Ofgem as seen in Figure 6:

- **Figure 6 OFTO Revenue Stream[4] ©Crown Copyright**

Base revenue	The revenue stream bid by the successful OFTO adjusted following the determination of the final transfer value.
Pass through costs	Limited and efficiently incurred costs which the OFTO could not have been reasonably expected to foresee prior to the commencement of the revenue stream and which may be passed through by way of an increase in the revenue stream. Scope defined ex ante.
Incremental Utilisation Revenue Adjustment	This is an uplift in the OFTO's revenue where it provides, without investment, transmission capacity over and above what it was contractually required to provide at license grant
Incremental Investment Revenue Adjustment	An uplift which may be granted to cover efficient CAPEX investment of up to 20% of the Final Transfer Value in providing extra transmission capacity when requested to do so by the NETSO.
Correction Factor	An adjustment to the OFTO revenue where the previous year it over or under recovered against the use of system charges.
Performance incentive	A penalty of up to 10% of the previous year's base revenue which can be deducted from the OFTO's revenue where the OFTO under performs against its availability target incentive. A banking mechanism allows the OFTO to accrue credits which allow it manage this risk between years and can provide upside revenues.

For the purpose of this investigation it is the performance incentive which will be of most interest. The performance incentive relates to the credits or conversely, penalties, which the OFTO can accrue over the 20 year operating period based on the offshore transmission networks availability.

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[4] Guidance Notes: OFTO Generic Special Licence Conditions (v.0.5) http://www.ofgem.gov.uk/Networks/offtrans/rott/Documents1/Guidance%20note%20on%20version%200.5%20of%20the%20special%20licence%20conditions.pdf

3.1.1. Performance Incentive

The performance incentive is aimed at ensuring the OFTO can provide the most reliable connection possible, with as few outages as can be reasonably expected. This incentive therefore becomes of significant interest in a multi-terminal system whereby reliability and redundancy could be affected and hence have greatest impact on the revenue stream. Calculation of the performance of the system is based around availability which is the product of an item of equipments mean failure and repair rates. The OFTO target for availability for any given operating month is set at 98% and relates to the actual transmitted power compared to the potential transmitted power should there be no outages.

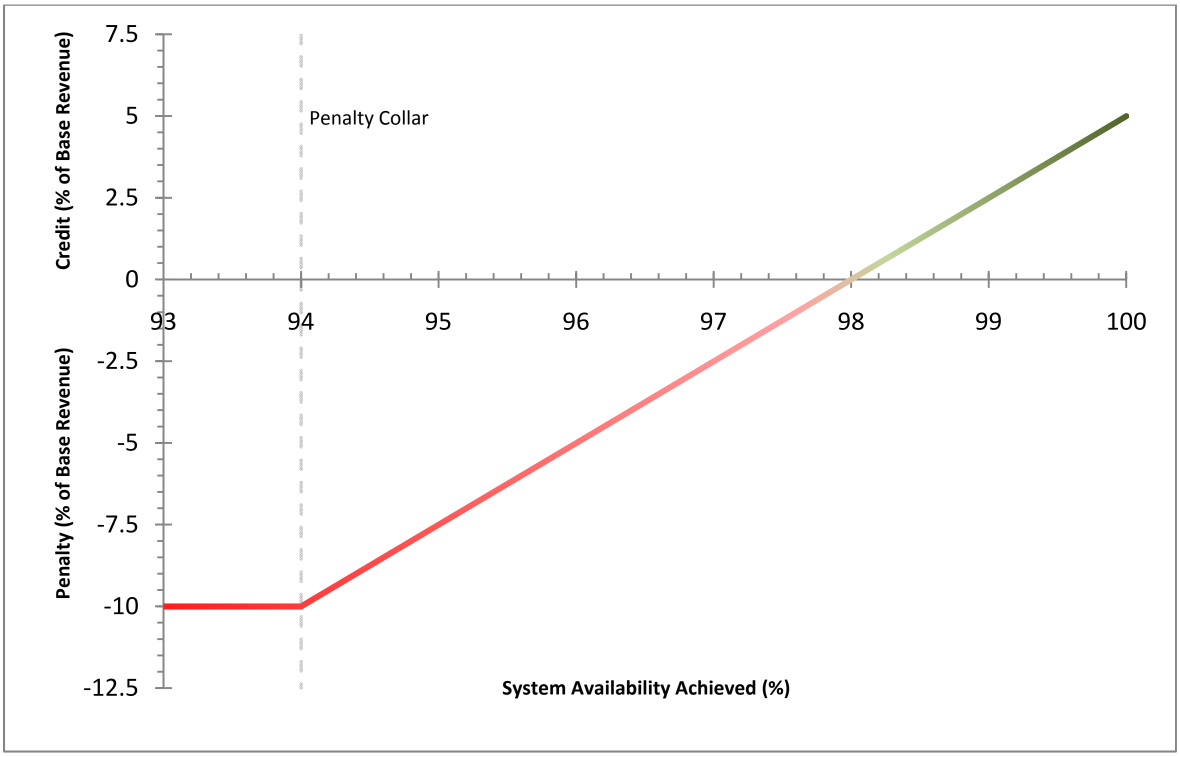
The basis of the financial aspect of the performance incentive is based around whether availability is greater than, or less than the target of 98%. For months with availability greater than 98% the OFTO can accrue credits as a reward for providing a reliable connection. For months with availability less than 98% an increasing penalty is issued which is capped at 10% of the OFTO's base revenue should availability drop below 94%. The aim is for the OFTO to accrue credits in normal operation (over 98% availability) which can be used to pay penalties following large scale unplanned outages.

Figure 7 below illustrates how the system availability achieved for a month impacts on the base revenue of the OFTO due to the performance incentive scheme. The relationship can be seen to be linear with the penalty collar capping achieved availabilities of less than 94% to a 10% penalty. Hence for every 1% change in availability, the OFTO can expect a penalty or credit of 2.5% of their base revenue.

The base revenue is the annual revenue that the OFTO bid to win the tender and for recent round 3 projects this can be seen in the region of £30m for developments of 1000MW size[5]. With such large revenue streams, the performance incentive percentage can become a large issue if the OFTO is consistently paying penalties. There may be opportunities to increase capital expenditure of additional equipment to increase system reliability which may be a more economically sound investment in the long term operation of the system.

[5] Based on revenue stream example of £22.69/kW for 80MW offshore development and scaled accordingly

▪ **Figure 7 OFTO Performance Incentive Scheme**



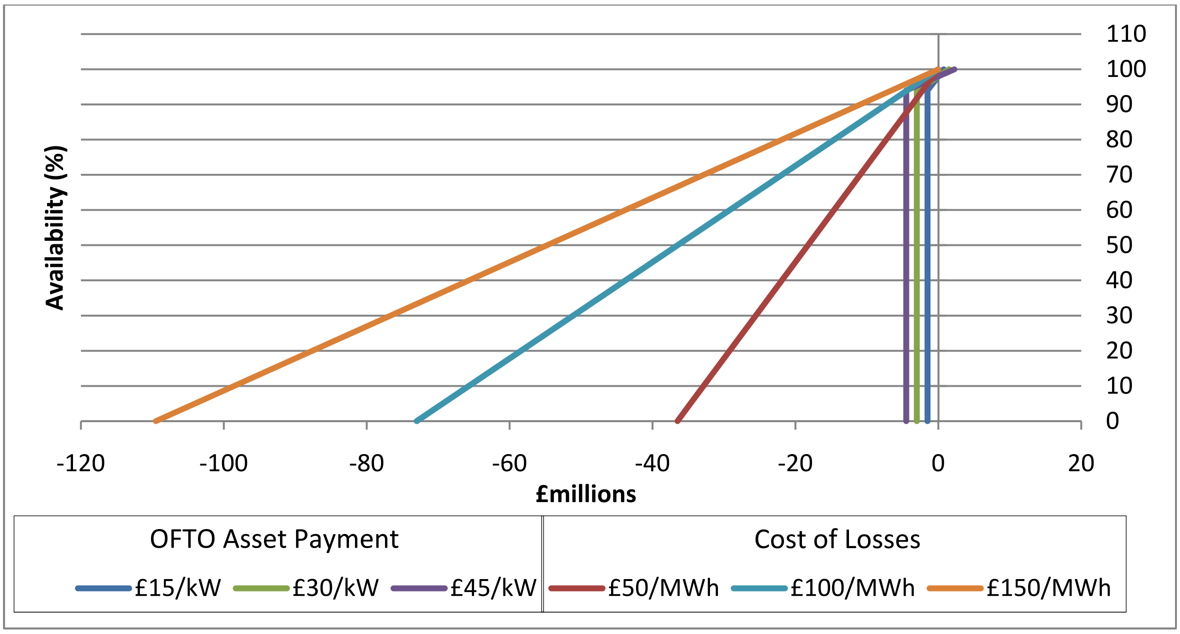
Although the performance incentive payments will be calculated on a monthly basis in practice, it is possible to average this over a year, or even a 20 year operation period which has been quoted in the OFTO guidance documentation. 'Hence planned and unplanned outages should occur, on average over the 20 year revenue period, over no more than about 2% of the total MWh for this 20 year revenue period'[4].

This approach provides a useful method of highlighting the potential impact of different multi-terminal architectures based on an average availability over an annual period. If this is greater than 98% then it can be seen that the architecture will most likely end the 20 year period in credit. If however, the average availability is less than 98% then it will be necessary to calculate the potential cost of penalties to the OFTO and assess whether these architectures are economically viable.

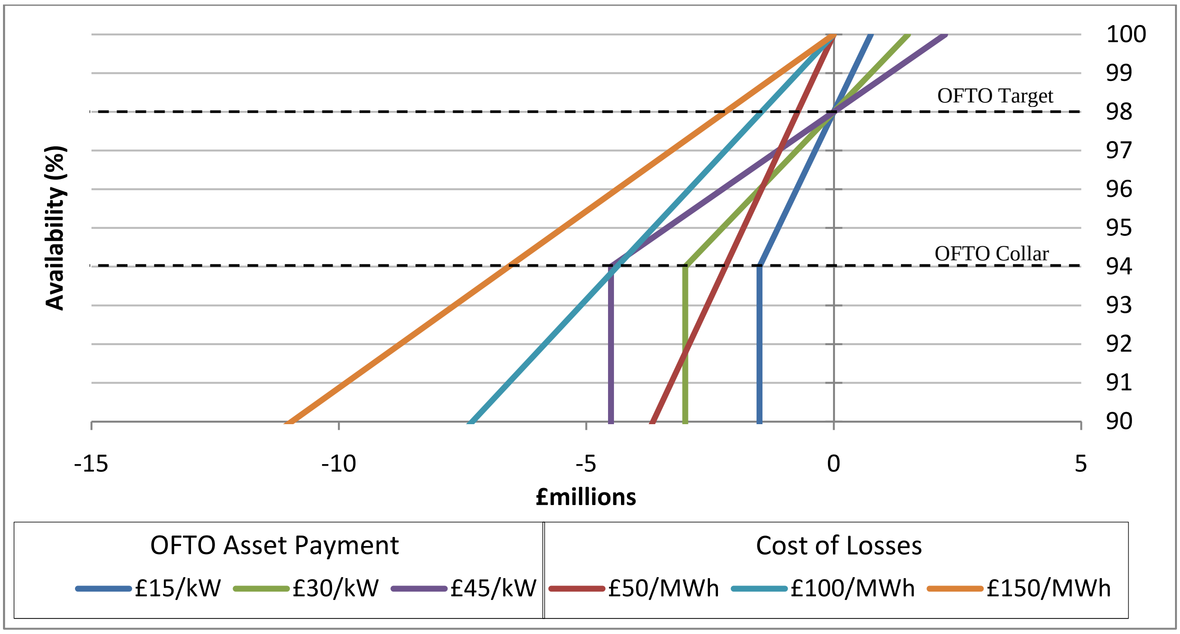
3.2. Cost of Lost Generation

The OFTO revenue scheme is a regime to incentivise the transmission system operator to provide a reliable connection from the offshore energy farm to shore. The OFTO scheme does not however cover the physical cost of losses when availability is below 100%. This cost is seen as potential revenue which cannot be collected due to outages and is not capped at availabilities less than 94% as seen by the OFTO regime. Figure 8 and Figure 9 below illustrate the differences between the magnitudes of the OFTO revenue stream and the physical cost of lost generation. The example utilises a 1000MW offshore development size and costs are given on an average monthly basis of 730 hours.

- **Figure 8 Cost of Lost Generation and OFTO Performance Inventive**



- **Figure 9 Focus on OFTO Performance Incentive Range**

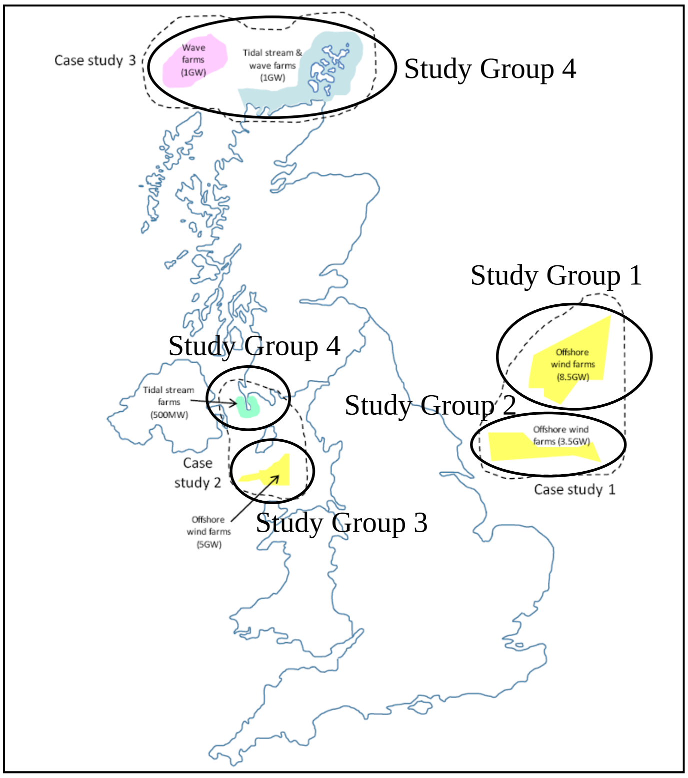


As the cost of lost generation is not capped at 94% availability, it can be seen that this cost has a significant impact over the costs incurred by the OFTO regime. A range of cost of losses and OFTO base revenue streams above and below those stated in the economic methodology were chosen to illustrate the lack of sensitivity in these results and the main impact that the cost of losses has even with a range of values.

4. Financial Assessment

To assess the financial implications of multi-terminal and interconnected architectures it has been necessary to define a limited range of case studies as discussed in Section 1.2.5. The developments within the Case Studies have been divided into Study Groups of similar parameters (i.e. distance from shore, development capacity, etc.) as shown in Figure 10.

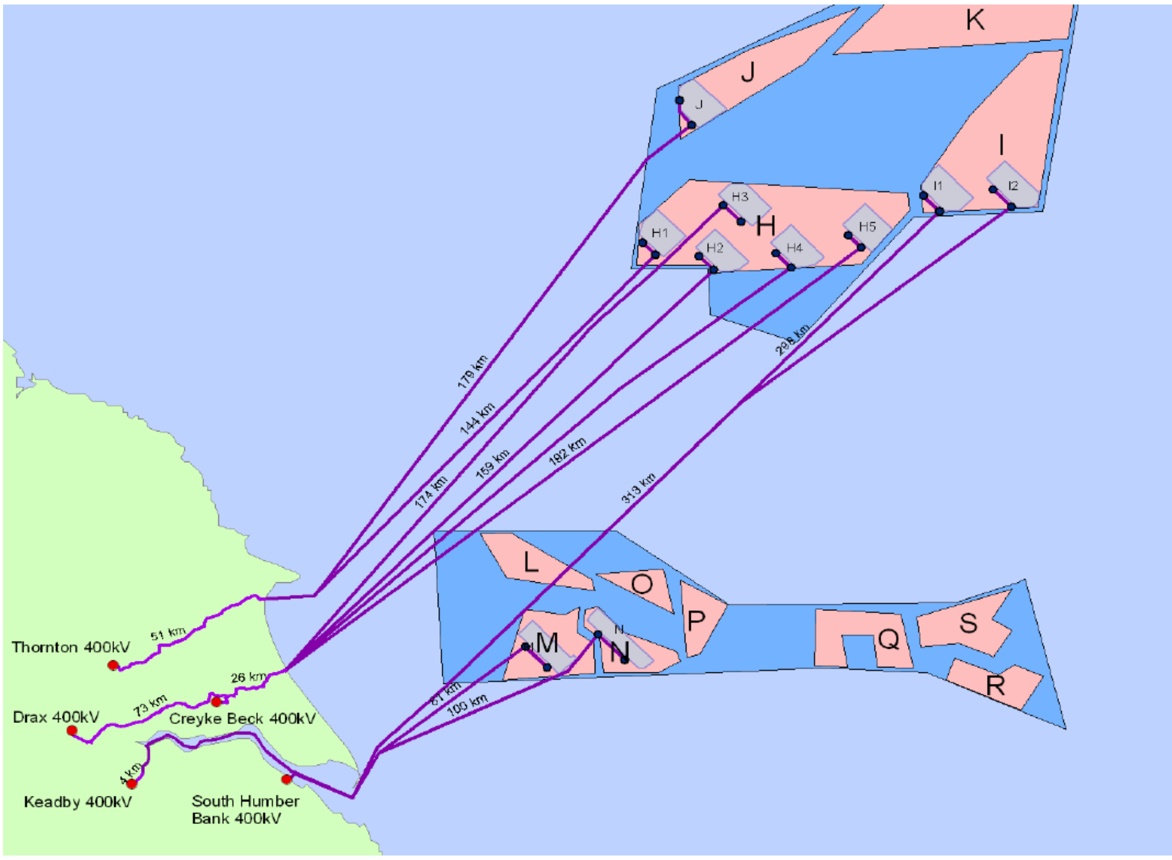
- **Figure 10 Study Groups Relation to Case Studies**



4.1.1. Study Group 1 Architecture Summary

Case Study 1 is arguably the most significant as it encompasses the greatest total capacity at the greatest distance from shore where it is expected multi-terminal and interconnections could have the greatest impact. Case Study 1 is comprised of 1000MW blocks of wind generation in the Round three zones of Dogger Bank and Hornsea positioned as indicated in Figure 11.

■ **Figure 11 Case Study 1[6]**



The majority of Case Study 1 is too far from shore to be connected using AC so only HVDC and GIL have been investigated. The case study parameters have been used to define general connection and interconnection distances as well as development numbers and capacities for Study Groups 1 and 2 representing the two development zones within the Case Study. As Dogger Bank represents the main part of Case Study 1 it has been considered in the most detail.

Initial studies have been carried out to assess the relative advantages of different HVDC architectures and interconnection capacities.

The basic parameters for initial studies hereafter referred to as Study Group 1 have been defined according to the distribution of wind farms closest to shore in the Dogger Bank zone.

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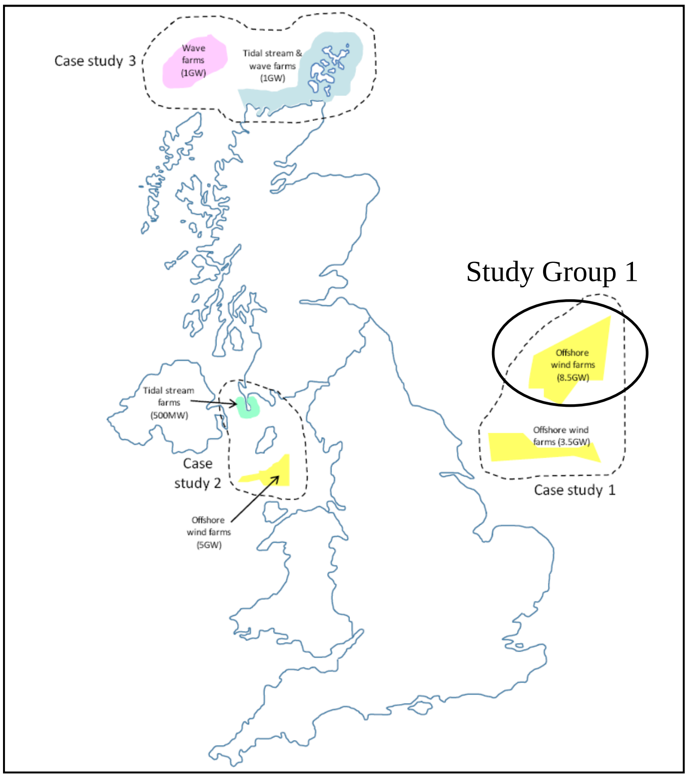
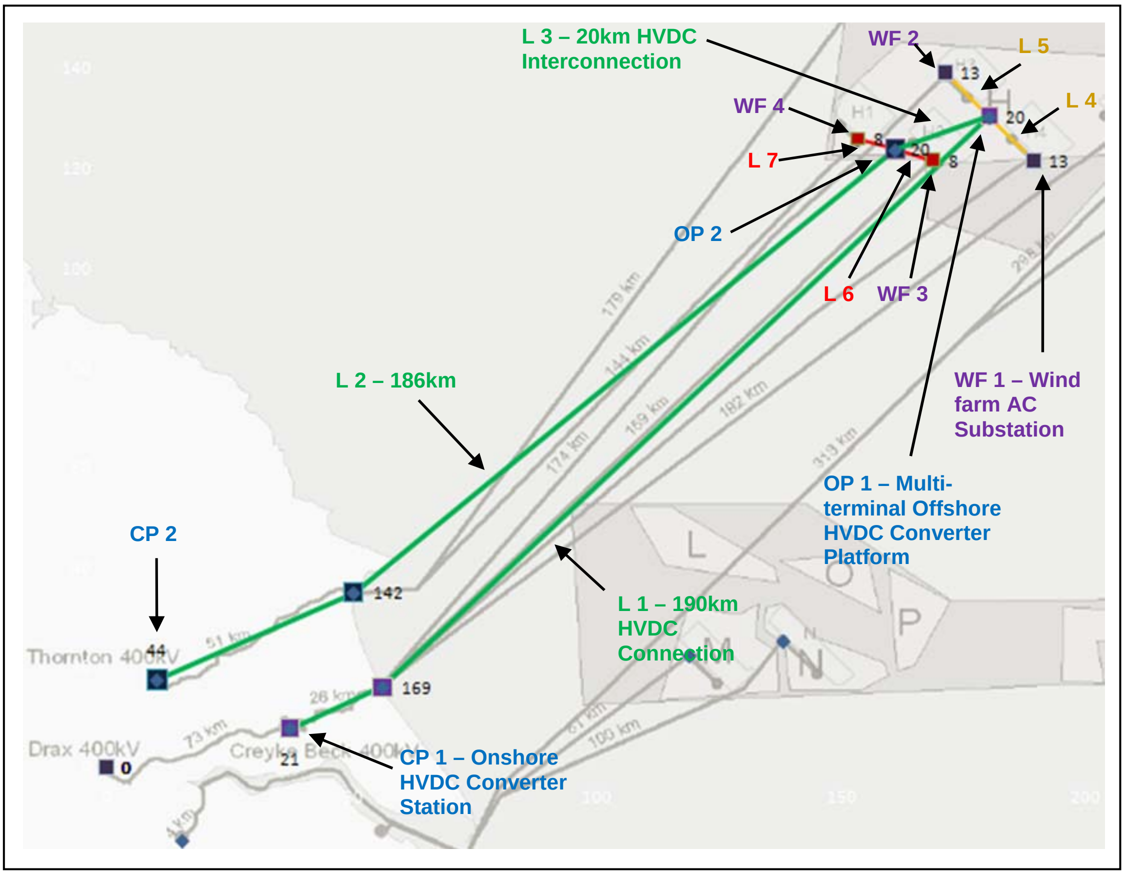
6 "The Crown Estate, Round 3 Offshore Wind Farm Connection Study", By National Grid and Econnect, 2009

- **Figure 12 Study Group 1 Relation to Case Studies**

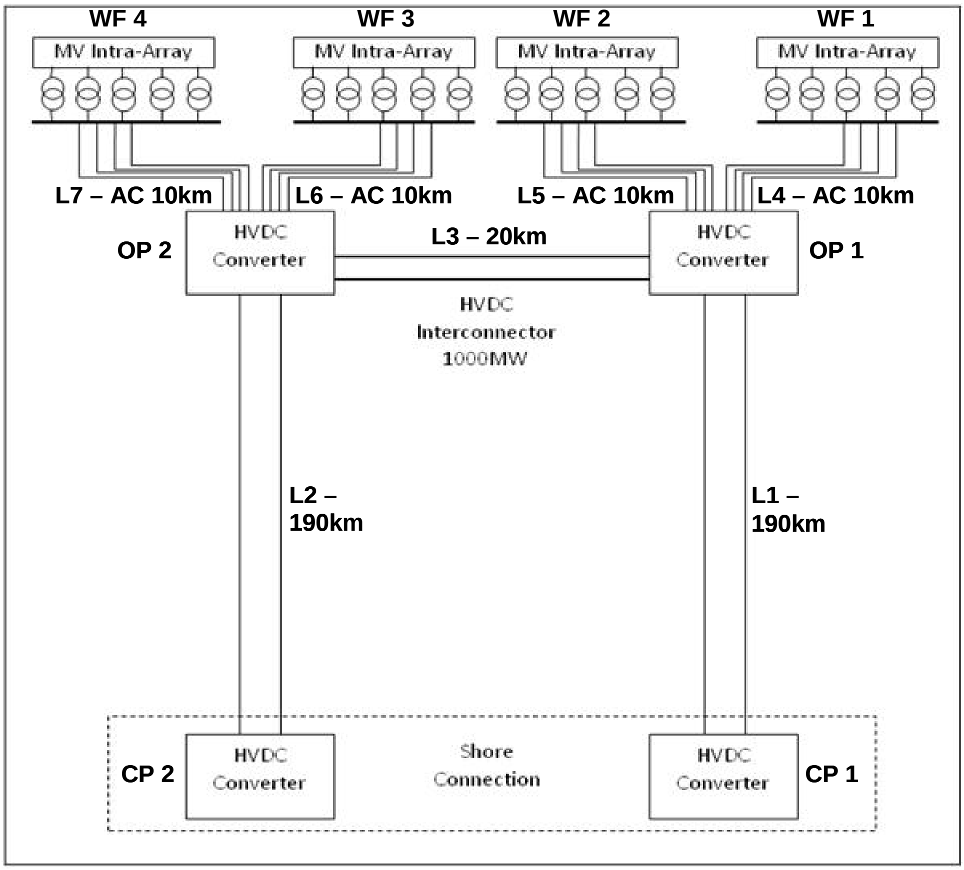


The basic parameters are as shown in Figure 13 then generalised and applied to architecture SLDs (Single Line Diagrams) as shown in Figure 14.

- **Figure 13 Geographical Design Representation**



- **Figure 14 Simplified Design SLD**



All designs in Study Group 1 utilise the same general layout and connection distances as summarised in Table 2, SLD representations of all designs are included in Appendix C with the design shown in Figure 14 relating to Design 5.

- **Table 2 Study Group 1 Design Summary**

Design Number	Name	Description
1	1000MW HVDC Point to Point Connection	1 x 1000MW Development 0.5km 1000MW AC Connection from AC Substation to HVDC Converter Platform 1 x 1000MW HVDC Offshore Converter Platform 1 x 1000MW, 190km, Bipole HVDC Cable Connection to shore 1 x 1000MW HVDC Onshore Converter Station
2	1000MW HVDC Split Connection	1 x 1000MW Development 0.5km 1000MW AC Connection from AC Substation to HVDC Converter Platforms 2 x 500MW HVDC Offshore Converter Platforms 2 x 500MW, 190km, Bipole HVDC Cable Connections to

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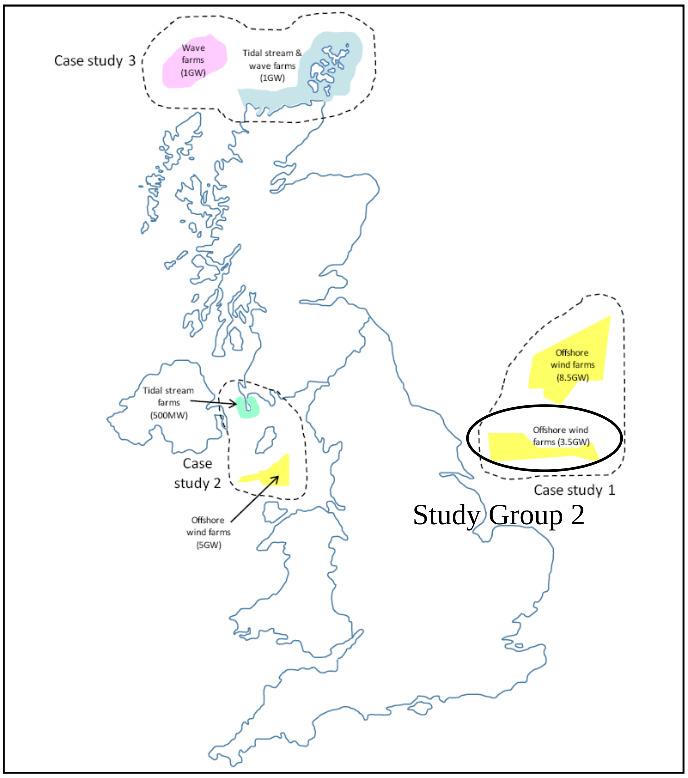
Design Number	Name	Description
		shore 2 x 500MW HVDC Onshore Converter Stations
3	1000MW HVDC Switched Connection	1 x 1000MW Development 0.5km 1000MW AC Connection from AC Substation to HVDC Converter Platform 2 x 500MW HVDC Offshore Converters in Bipole configuration 1 x 1000MW, 190km, Bipole HVDC Cable Connection to shore with switching arrangement facilitating the bypass of either one of the two converters. 2 x 500MW HVDC Onshore Converters in Bipole configuration.
4	2000MW Multi-terminal Point to Point HVDC Connection	2 x 1000MW Developments 2 x 1000MW 10km AC Connections from AC Substations to HVDC Converter Platform 1 x 2000MW HVDC Offshore Converter Platform 1 x 2000MW, 190km, HVDC Bipole Cable Connection to shore 1 x 2000MW HVDC Onshore Converter Station
5	4000MW Dual HVDC Connection with 1000MW HVDC Interconnection	4 x 1000MW Developments 4 x 1000MW 10km AC Connections From AC Substations to HVDC Converter Platforms 2 x 2000MW HVDC Offshore Converter Platforms 1 x 1000MW, 20km, HVDC Bipole interconnection between converter platforms 2 x 2000MW, 190km, HVDC Bipole Cable Connections to shore 2 x 2000MW Onshore Converter Stations
6	4000MW Dual HVDC Connection with 500MW AC Interconnection	As Study 5 with a 500MW AC Interconnection replacing the 1000MW HVDC Interconnection
7	4000MW Dual HVDC Connection with 750MW AC Interconnection	As Study 5 with a 750MW AC Interconnection replacing the 1000MW HVDC Interconnection
8	4000MW Dual HVDC Connection with 1000MW AC Interconnection	As Study 5 with a 1000MW AC Interconnection replacing the 1000MW HVDC Interconnection
9	4000MW Dual HVDC Connection with 1250MW AC Interconnection	As Study 5 with a 1250MW AC Interconnection replacing the 1000MW HVDC Interconnection

4.1.2. Study Group 2 Design Summary

Study Group 2 consists of further studies intended to support those carried out in Study Group 1 by applying the same general designs to the Hornsea development zone significantly closer to shore than Dogger Bank.

Figure 15 Study Group 2 Relation to Case Studies



The Hornsea zone is expected to be composed of 1000MW developments as with the Dogger Bank zone however there is a limit of around 3.5GW and a connection distance of only around 90km. The distribution of developments within the zone is comparable to Dogger Bank.

Table 3 Study Group 2 Design Summary

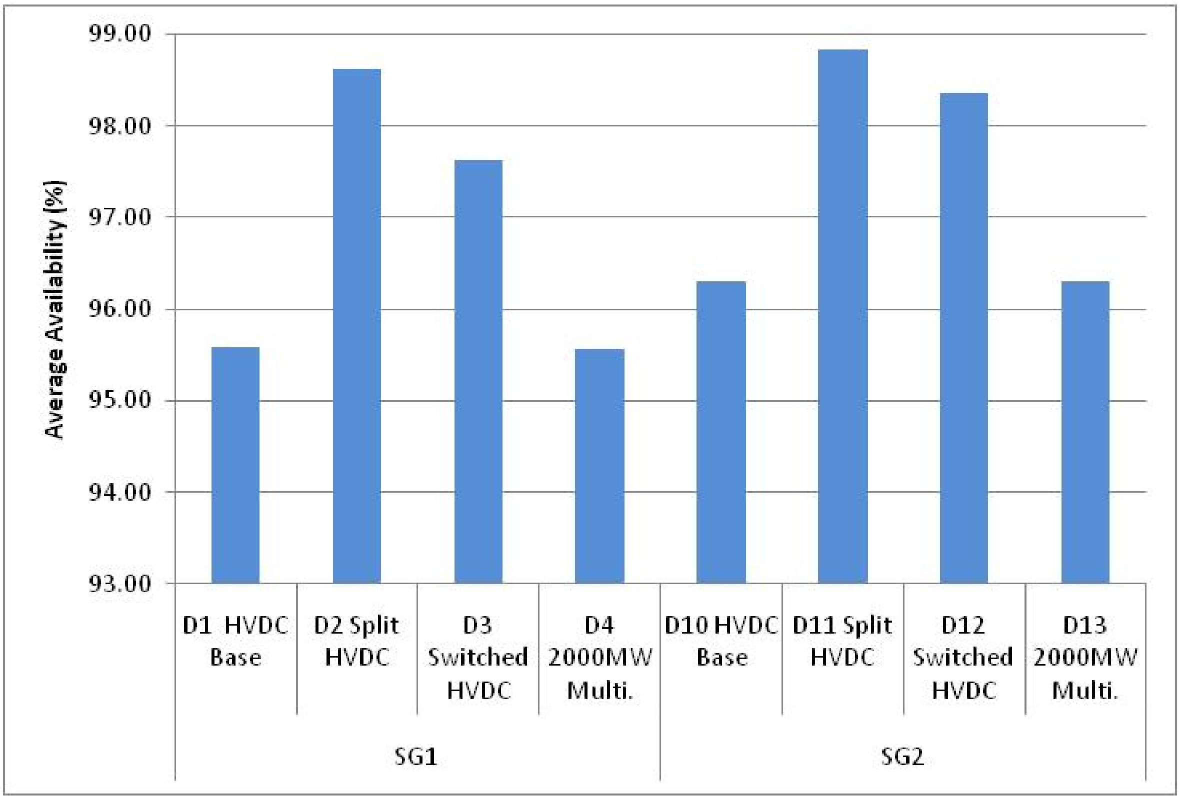
Design Number	Name	Description
10	1000MW HVDC Point to Point Connection	1 x 1000MW Development 0.5km 1000MW AC Connection from AC Substation to HVDC Converter Platform 1 x 1000MW HVDC Offshore Converter Platform 1 x 1000MW, 90km, Bipole HVDC Cable Connection to shore 1 x 1000MW HVDC Onshore Converter Station
11	1000MW HVDC Split Connection	1 x 1000MW Development 0.5km 1000MW AC Connection from AC Substation to HVDC Converter Platforms 2 x 500MW HVDC Offshore Converter Platforms 2 x 500MW, 90km, Bipole HVDC Cable Connections to shore 2 x 500MW HVDC Onshore Converter Stations
12	1000MW HVDC Switched	1 x 1000MW Development

Design Number	Name	Description
	Connection	0.5km 1000MW AC Connection from AC Substation to HVDC Converter Platform 2 x 500MW HVDC Offshore Converters in Bipole configuration 1 x 1000MW, 90km, Bipole HVDC Cable Connection to shore with switching arrangement facilitating the bypass of either one of the two converters. 2 x 500MW HVDC Onshore Converters in Bipole configuration.
13	2000MW Multi-terminal Point to Point HVDC Connection	2 x 1000MW Developments 2 x 1000MW 10km AC Connections from AC Substations to HVDC Converter Platform 1 x 2000MW HVDC Offshore Converter Platform 1 x 2000MW, 90km, HVDC Bipole Cable Connection to shore 1 x 2000MW HVDC Onshore Converter Station
14	2000MW Dual HVDC Connection with 250MW AC Interconnection	2 x 1000MW Developments 2 x 1000MW 10km AC Connections From AC Substations to HVDC Converter Platforms 2 x 1000MW HVDC Offshore Converter Platforms 1 x 250MW, 20km, AC interconnection between HVAC bus bars 2 x 1000MW, 90km, HVDC Bipole Cable Connections to shore 2 x 1000MW Onshore Converter Stations
15	2000MW Dual HVDC Connection with 500MW AC Interconnection	As Study 14 with a 500MW AC Interconnection replacing the 250MW AC Interconnection
16	2000MW Dual HVDC Connection with 750MW AC Interconnection	As Study 14 with a 750MW AC Interconnection replacing the 250MW AC Interconnection

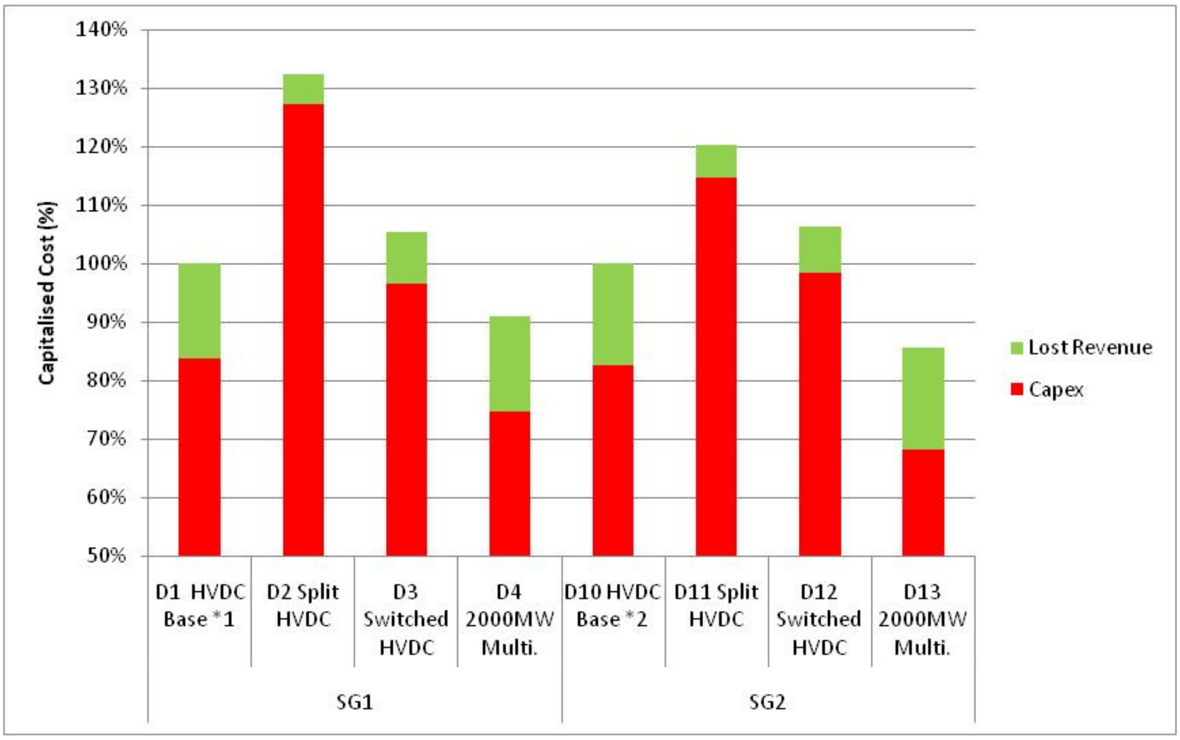
4.1.3. Study Group 1 and 2 Results

Compared initially are HVDC connection arrangements that assume a single 1000MW development with dedicated connection. The base case (D1 and D10) is a single converter bipole arrangement, this is compared with a dual bipole 500MW connection (D2 and D11), and a switched bipole arrangement (dual HVDC converter stations in a bipole arrangement and a single bipole cable connection) (D3 and D12). A comparison is also provided for a multi-terminal option (D4 and D13). Capitalised costs are given as percentages of the base cases as indicated in the figures.

- **Figure 16 Average Design Availability**



▪ **Figure 17 Comparative Design Costs**



*1 – Indicative cost of base, £850m[7]

*2 – Indicative cost of base, £660m

Figure 16 and Figure 17 show the relative advantages of the given HVDC designs. It is clear from Figure 16 that either split or switched DC designs provide significant availability improvements, which in turn provide significant revenue savings to the generator, however these savings are outweighed by the additional capex incurred. The switched arrangement shows promise as the availability increase is significant compared to relatively modest increase in capex. The resulting increase in cost is only 5% overall which could very easily become a cost reduction, should energy prices increase or converter costs decrease as would be expected as the VSC technology matures and becomes more widely used. Multi-terminal designs provide near identical availability to multiple point to point connections though with significant savings in capex and hence an overall cost saving.

Though single connections to shore are shown to be more financially viable than multiple connections this is only possible up to a given capacity assumed to be around 2000MW due to technical and SQSS limitations.

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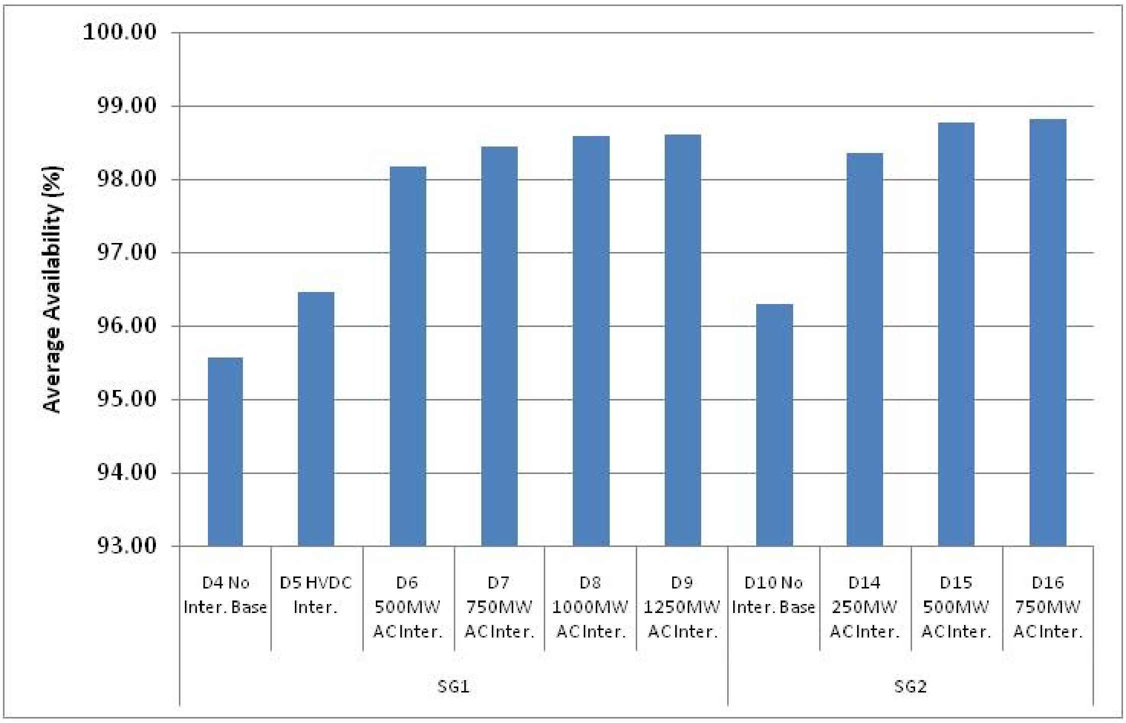
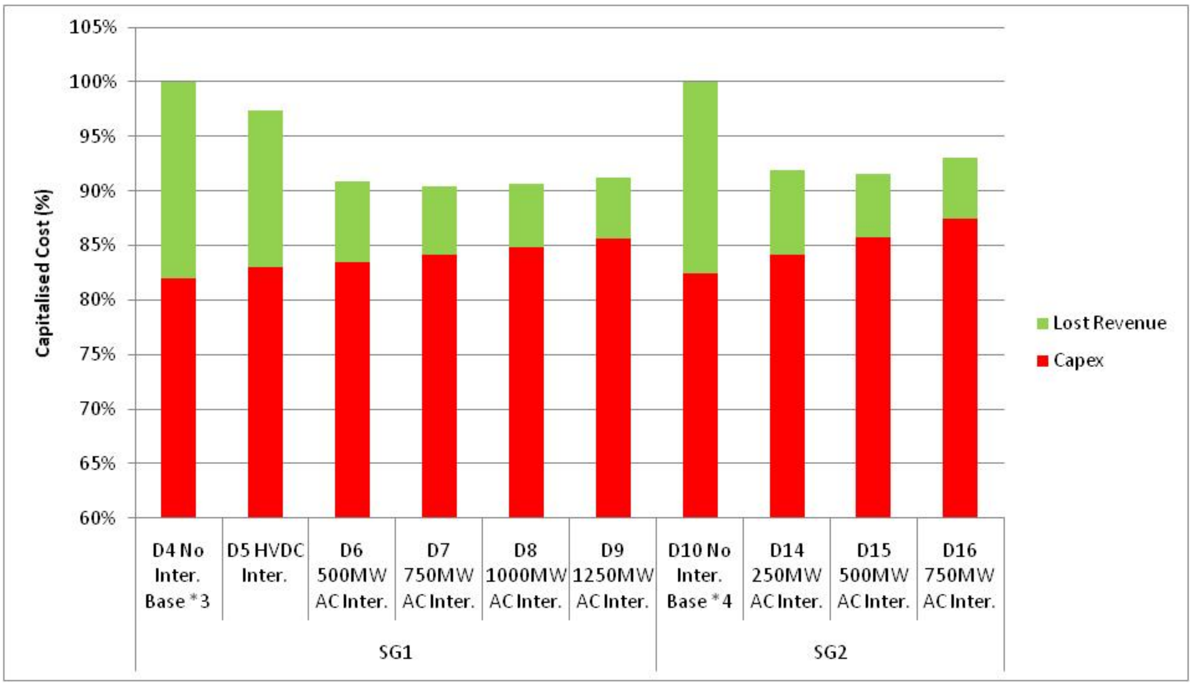
[7] Indicative costs are for comparative purposes only based on the generalisations and assumptions described for this project and are therefore not intended as an accurate estimate of specific connection costs.

- **Figure 18 Average Design Availability**



- **Figure 19 Comparative Design Costs**



*3 – Indicative cost of base, £3,090m

*4 – Indicative cost of base, £1,320m

Figure 18 and Figure 19 show the relative advantages of AC and HVDC interconnectors. In all instances an interconnector is financially attractive compared to no interconnector, this is due to the significant increases in availability and the resulting savings in revenue compared to modest additional capex. Architecture D16 is significantly more expensive than the other interconnection options due to 25% of the installed capacity being the maximum power that will flow though the interconnector given that the export circuits are rated at 100% capacity. Above 25% the savings in revenue are only due to an increase in the number of interconnection cables effectively providing N-1 security on the interconnection, these modest savings are outweighed by the increase in capital cost and as such lower capacity interconnectors are preferable. This effect is greater in Study Group 2 as the connection distance is much shorter and consequently the percentage increase in capex due to the interconnector, greater. The size of the interconnector proves to be optimum at around 20% of the total connection power, over that capacity the additional capex is not justified by savings in revenue.

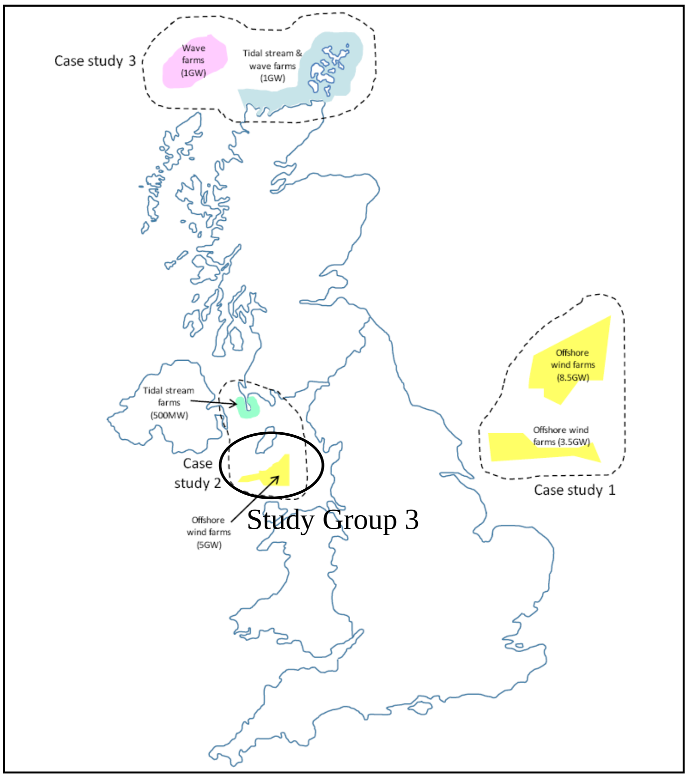
Hence it is concluded that for these architectures an AC interconnection of HVDC converter platforms is more effective than applying an HVDC multi-terminal architecture due to the relatively short distances involved and ease through which AC interconnection can be achieved.

Potential interconnection between the Dogger and Hornsea developments are possible which, due to the significant distances involved, would best be achieved with a DC interconnector. Such an architecture would thus be similar to the National/International interconnector case that will be discussed in Section 4.1.9 where the benefits a such interconnection are evaluated.

4.1.4. Study Group 3 Design Summary

Case Study 3 consists of a potential capacity of 5000MW of offshore wind assumed to be developed in blocks of around 1000MW in the Irish Sea as illustrated in Figure 20.

Figure 20 Study Group 3 Relation to Case Studies



The connection distances range between 50km and 100km and at the greatest distances it is likely HVDC will be utilised; however as this has already been covered in Study Groups 1 and 2 it will not be considered in this Study Group to allow assessment of other technologies. With the shorter connections, AC is likely to be the preferred connection method and has been considered here in Study Group 3. An average connection distance of 80km has been used. This along with Study Groups 1 and 2 covers all wind farm elements of Case Studies 1, 2 and 3 and the bulk of the potential generation capacity.

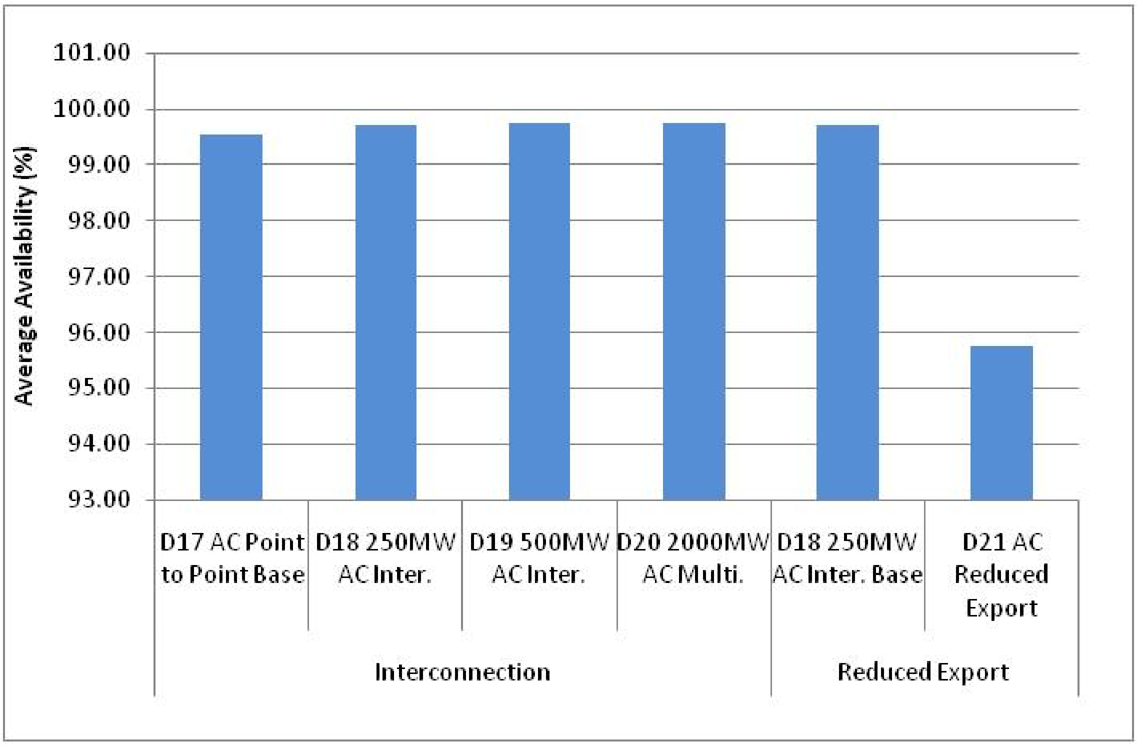
Table 4 Study Group 3 Design Summary

Design Number	Name	Description
17	1000MW AC Point to Point Connection	1 x 1000MW Development 80km 1000MW AC Connection from AC Substation to shore
18	2000MW Dual AC Connection with 250MW AC interconnector	2 x 1000MW Development 2 x 80km 1000MW AC Connection from AC Substation to shore 1 x 250MW AC Interconnection
19	2000MW Dual AC Connection with 500MW AC interconnector	As Study 18 with a 500MW AC Interconnection replacing the 250MW AC Interconnection
20	2000MW Multi-terminal Point to	2 x 1000MW Developments

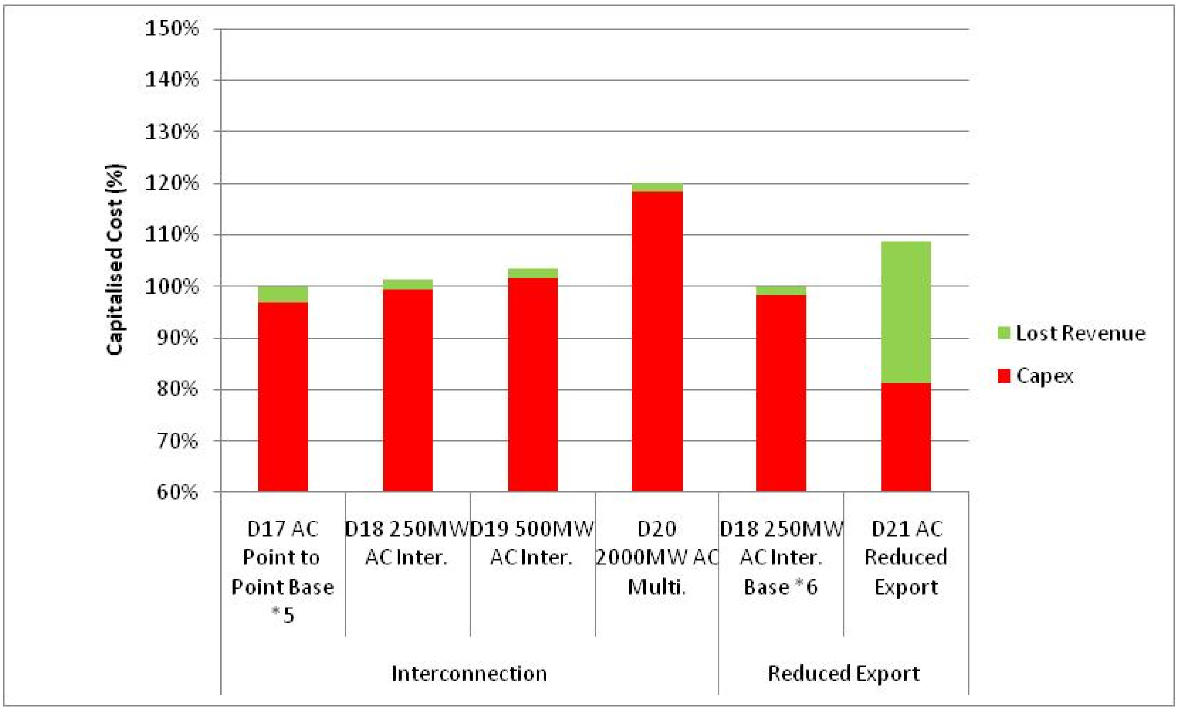
Design Number	Name	Description
	Point AC Connection	2 x 10km, 1000MW AC connection to AC Switching Station 1 x 2000MW AC Switching Station 80km 2000MW AC Connection from AC Substation to shore
21	1500MW Dual AC Connection servicing 2000MW of generation with 250MW AC interconnector	2 x 1000MW Development 2 x 80km 750MW AC Connection from AC Substation to shore 1 x 250MW AC Interconnection

4.1.5. Study Group 3 Results

- **Figure 21 Average Design Availability**



- **Figure 22 Comparative Design Costs**



*5 – Indicative cost of base, £945m

*6 – Indicative cost of base, £955m

Figure 21 and Figure 22 show that interconnections on AC connected developments are of no real value, availability does increase however due to the connection being composed of multiple AC circuits by technical necessity the availability is already high without the interconnection. The result is that the additional cost of the interconnection is not offset by a reduction in revenue losses.

Also demonstrated is that a reduction of export capacity to 75% installed capacity although resulting in a significant capex saving incurs a much larger increase in lost revenue making it unattractive. This is of course assuming that large scale offshore storage is not economically viable as previously concluded in the Individual Offshore Connection Architectures report.

4.1.6. Study Group 4 Design Summary

The remaining capacity described in the case studies is wave and tidal located in relatively small zones close to shore.

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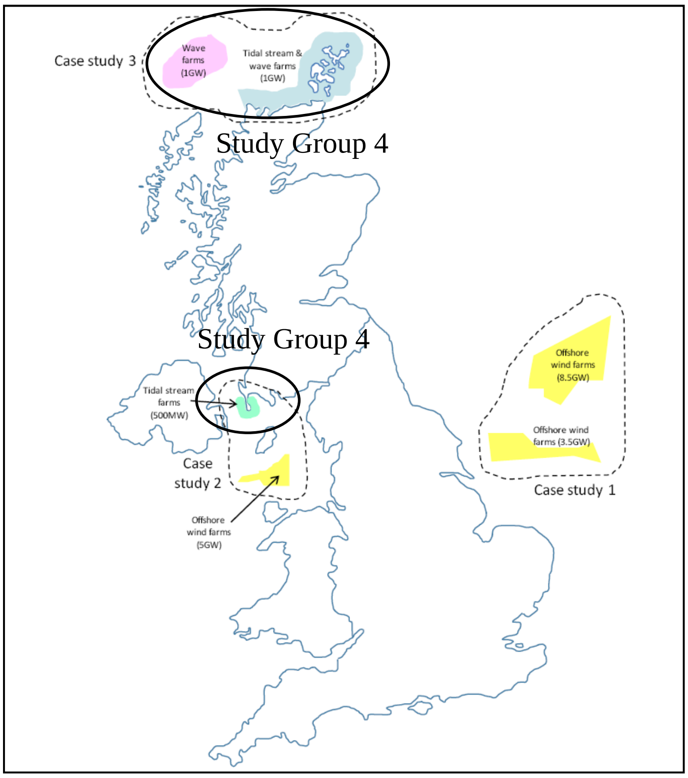
- **Figure 23 Study Group 4 Relation to Case Studies**



Due to the close proximity to shore only AC has been considered with point to point connections compared to multi-terminal with two options being considered. Firstly 500MW total capacity with an average connection distance of 20km and 20MW blocks of generation connected either as multiple 20MW point to point connections or a single 500MW multi-terminal connection. Secondly a 1000MW total capacity with an average connection distance of 80km and generation blocks of 100MW, either as multiple 100MW point to point connections or as a single 1000MW multi-terminal connection (interconnection between 1000MW zones not being viable due to the closeness to shore).

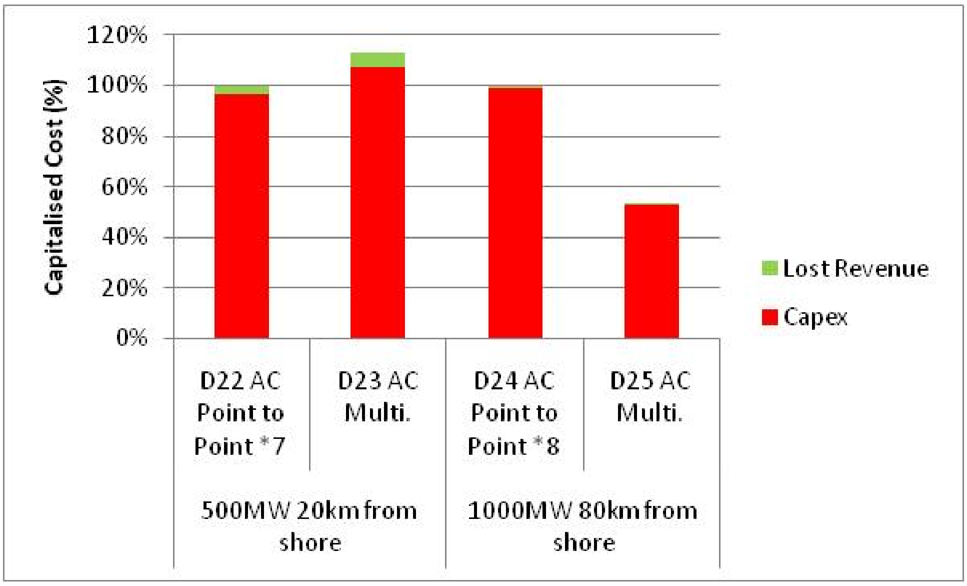
- **Table 5 Study Group 4 Design Summary**

Design Number	Name	Description
22	20MW AC Point to Point Connection	1 x 20MW Development 1 x 20km 20MW AC Connection from Development to shore
23	500MW Multi-terminal Point to Point AC Connection	25 x 20MW Developments 25 x 5km 20MW AC Connection from Development to AC Substation 1 x 500MW AC Substation 1 x 500MW AC connection to shore

Design Number	Name	Description
24	100MW AC Point to Point Connection	1 x 100MW Development 1 x 80km 100MW AC Connection to shore
25	1000MW Multi-terminal Point to Point AC Connection	10 x 100MW Developments 10 x 10km 100MW AC Connection from Development to AC Substation 1 x 80km 1000MW AC connection to shore

4.1.7. Study Group 4 Results

- **Figure 24 Comparative Design Costs**



*7 – Indicative cost of base, £130m

*8 – Indicative cost of base, £1,685m

Figure 24 shows the marked difference between small capacity developments close to shore and larger capacity developments further from shore. Close to shore, multi-terminal is not financially attractive due to the very short connection distance, however further from shore multi-terminal is clearly the preferred option due to significant capex savings. The revenue is not significant to the result in either option so the type of generation is not significant. The “tipping point”from point to point to the multi-terminal approach described in Figure 50 and Figure 52 occurs at approximately 25km for both 500 and 1000MW developments, where 25km is the total connection distance.

4.1.8. GIL

The Individual Offshore Connections Architectures Report concluded that there is only potential cost benefit for GIL when used for very high capacity bulk export using single circuit connection.

Assuming a 4000MW single circuit connection the average availability of the connection is likely to be as low as 93%. Over 20 years this could amount to a lost revenue value of around £1,000m and would not be acceptable as a design option. When combined with the numerous technical and practical issues relating to GIL it is unlikely that it will be an attractive option in the near future.

4.1.9. National/International Interconnector

One potential design variation is to combine an offshore farm connection with a national or international interconnection, the low load factor of the offshore farm could be exploited to obtain a higher capacity national/international interconnector for the same cost.

The combined design in Figure 25 has been compared to a combination of single 350km 1000MW HVDC national/international interconnection shown in Figure 26 and a single 90km point to point 2000MW multi-terminal HVDC connection (Design 13).

- **Table 6 National/International Interconnector Results**

	Separate Connections	Combined Connection
Offshore farm Export Availability	96.2	97.2
Capital Cost (£m)	1,630	1,740

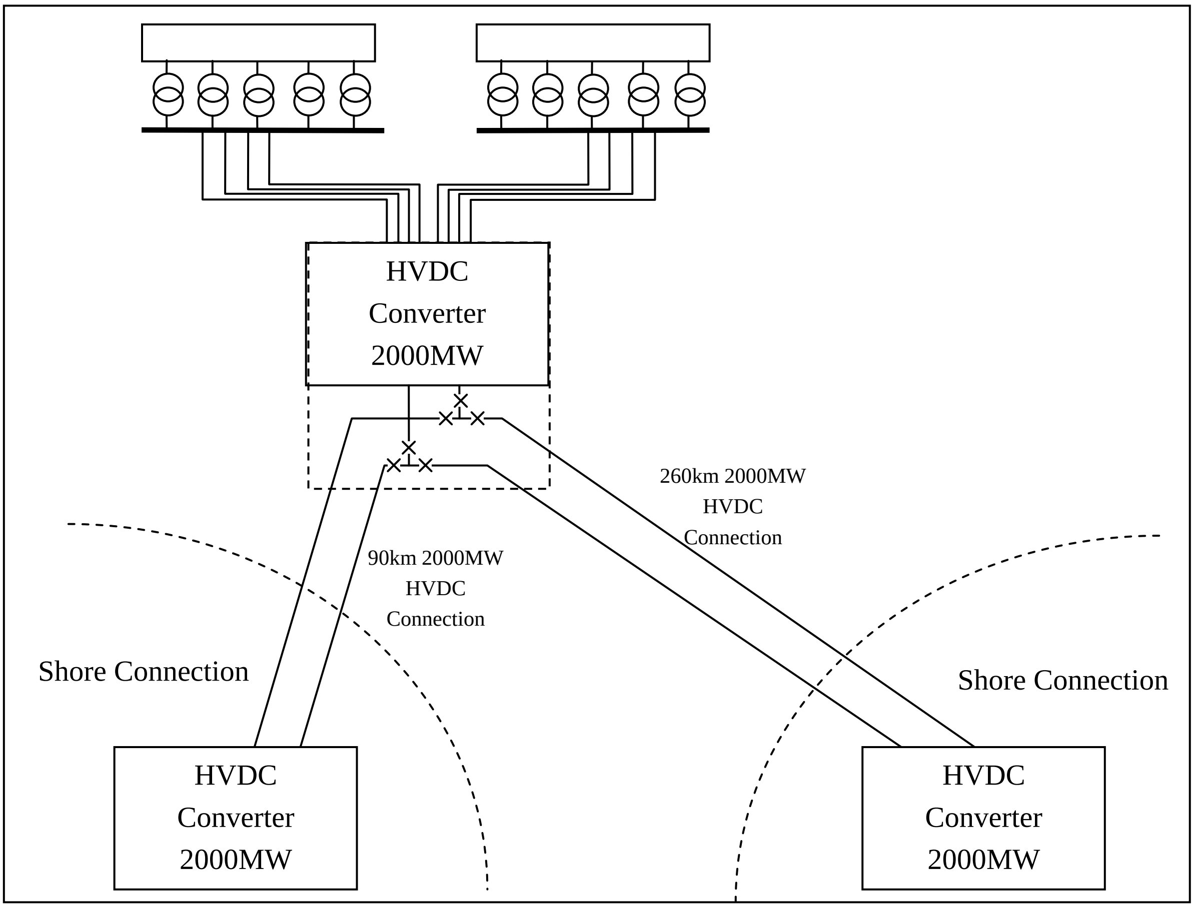
The combined design results in an increase in average availability for the offshore farm of around 1% relating to a saving of around £70m over 20 years as well as facilitating an average national/international interconnection of around 1200MW. This is at the cost of only around a £110m or 6% increase in capex. These results show that this type of combined design could be attractive to both offshore developers and transmission grid operators.

For Design 13 there would be little opportunity for additional consideration of wind diversity across the 2000MW wind farms. However, a further option, whilst electrically similar, could provide opportunities for additional influence by wind diversity would be when two separate 1000MW wind farms were connected at each end of the interconnector. In such an architecture the influence of wind diversity would be much stronger and could provide further justification for such an arrangement. To study the implications of such an arrangement would require not only assumptions to be made concerning the location of the wind farms and diversity factors for the wind, but also the financial treatment of potentially two independent developers who under normal circumstances would be providing generation to different countries.

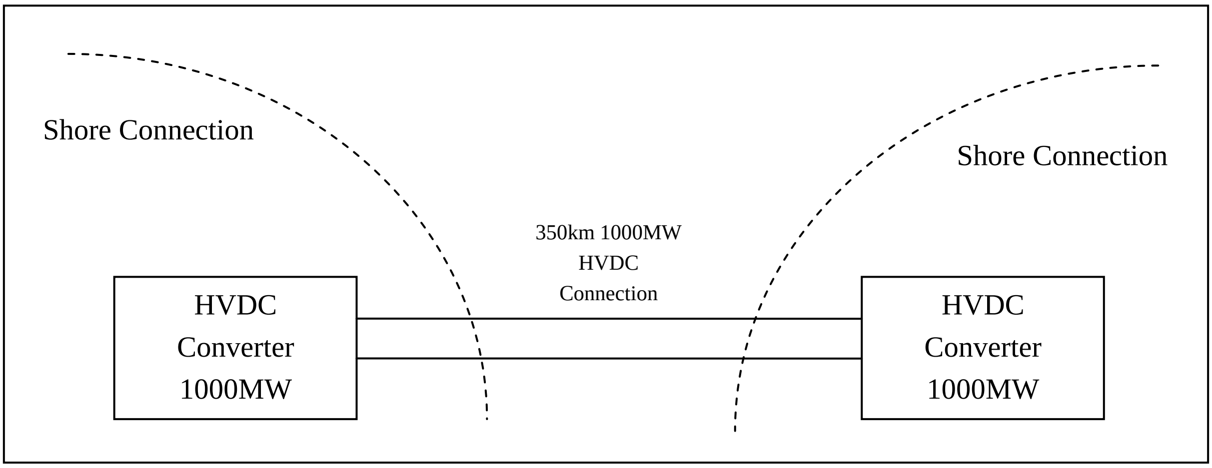
There is no technical difference between national and international interconnectors so the result is equally valid for both; additional aspects associated with international interconnectors have been covered in Section 5.2.

International interconnectors provide additional requirements in terms of Grid Code compliance differences between countries but this is not seen as a significant issue and is already addressed for existing interconnectors.

- **Figure 25 Combined Wind farm and National/International Interconnection Design Diagram**



- **Figure 26 National/International Interconnection Design Diagram**



5. Other Factors

5.1. Control issues

The purpose of this section of the report is to identify any additional control system requirements associated with multi-terminal architectures based on the technologies and architectures studied and identify specific potential areas for technology development.

It should be remembered that studies were undertaken to assess the impact of different connection architectures on Grid Code and SQSS issues within the previous Individual Architectures report to ensure that basic architectures would be able to comply with Grid Code and SQSS requirements. Additional Fault Ride Through and Harmonic Distortion studies have not been performed for this Multi-Terminal Architectures study on the basis that it is clear that the generator characteristics themselves dominate Grid Code compliance issues and that fundamentally the architectures studied here are application of modules which are already considered not to raise additional issues or challenges with regard to dynamic generator control.

Consideration here is focused on the control issues arising from the interconnection of architectures identified; hence these are concentrated on export systems being controlled by OFTO's and not the requirements on specific generation operators.

Further information for Generators is included in Section 5.3 of the Individual Architectures report including explanation of requirements of The Guidance Notes for Power Park Developers[8] published by National Grid which gives an overview of the preferred connection process Generators may follow to achieve the Operational Notification required to allow Generators to synchronise and export power onto the transmission system.

5.1.1. AC Multi-terminal and Interconnections

For the AC multi-terminal and interconnected systems described in this report there are no specific additional control issues that have been identified. Standard AC control technologies and strategies would be appropriate for such architectures.

5.1.2. HVDC Multi-terminal and Interconnections

In terms of multi terminal HVDC architectures it has been assumed that VSC technology is most appropriate for consideration due to:

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[8] Guidance Notes For Power Park Developers September 2008 Issue 2

- The VSC does not require a commutation voltage from the network in order to operate satisfactorily. The VSC can operate continuously at any power flow. The performance of a LCC converter depends on the short circuit level at its terminals. In a multi-terminal system the terminal with the lowest short circuit ratio determines the performance of the DC multi terminal system. The performance of a VSC scheme does not depend to the same extent on the short circuit level.
- A VSC does not suffer commutation failures. A commutation failure results in a collapse of the dc voltage, which stops power transmission until all terminals have restarted. This takes longer than in a two terminal scheme.
- A VSC Transmission converter station is much more compact than the equivalent LCC HVDC converter

Hence only control issues for VSC technologies are considered here. In summary there are two control issues that have to be addressed when considering multi-terminal VSC systems.

The first issue concerns the control of the power flow between the various HVDC stations whilst maintaining the DC voltage on the system.

Secondly there is a need to cope with DC side faults caused by cables or other system components.

Currently there are very few multi-terminal HVDC systems in operation however there are now systems planned and perhaps the Kriegers Flak[9] project is the most ambitious with six parallel VSC converters operating together.

The above issues will be discussed in turn.

5.1.2.1. Multi-Terminal Control

When considering control of VSC converters[10] there are two levels of technology that need to be considered.

The first is the control within the VSC system to generate the firing pulses of the VSC itself. This “inner” controller uses reference values produced by the “outer” loop controller

Whilst references can be found[11] as to the philosophy of these inner controllers they are dependent on the specific technology of the VSC converter and closely guarded by the supplier. There is therefore no opportunity or need for ETI to assist technology development in this area.

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[9] E. S. K. V. E. Transmission, An Analysis of Offshore Grid Connection at Kriegers Flak in the Baltic Sea, 2009

[10] W. L. K. R. L. Hendriks, G. C. Paap, Control of a multi-terminal VSC transmission scheme for connecting offshore wind farms, 2008, IEEE

For the "outer" controllers there are different approaches which have been proposed for multi-terminal offshore developments, as would be expected in line with the main suppliers who are able to offer VSC technologies. Of course this situation is not dissimilar to LCC technology where initially projects involving mixing of converters between suppliers were uncommon, it is now becoming more accepted that such cooperation is possible and of course this will be possible on VSC multi-terminal systems.

Further work is required however and CIGRE Study Committee B4 has recently suggested[12] that additional studies are needed in the areas of:

- The design and performance of multi-terminal HVDC schemes with more than five terminals.
- The control of HVDC schemes during system dynamics in networks with low inertia.

However it does not appear that the control of VSC based HVDC systems is a barrier to the application and implementation of this technology to realise multi-terminal systems and on this basis the potential role for ETI as a facilitator of technology development is limited.

5.1.2.2. Protection and DC Breakers

When a fault occurs on a DC multi-terminal system, it has to be isolated from all the current sources in order to be extinguished. Depending how the isolation is done will determine the extent to which the fault impacts on the operation of the grid. Ideally, as with an AC system the operational impact of a fault should be to protect and isolate the faulty section leaving the healthy parts undisturbed.

Isolation can be done in a number of ways.

- Isolating the DC grid by breakers on the AC side is the lowest cost options as AC breaker have to be applied anyway for the protection of the AC grid. However such AC breakers would have to isolate the complete grid leading to a long interruption time whilst the DC grid is re-established. Hence such a system is not considered viable.
- Second solution is to use DC breakers at each station to isolate the DC grid. In this way, the service interruption time will be reduced but dependent on fault location interruption of healthy circuits will still result.
- Final option is to apply DC breakers which can be located at the termination of each line/cable. This is the most costly solution in terms of numbers of DC breakers but ensures minimum

[11] Control and Protection philosophy of a multi-terminal HVDC connection, A.Tadese, G.Schoore Aalborg university
[12] CIGRE Brochure 370 Integration of Large Scale Wind Generation using HVDC and Power Electronics

disruption to supplies and replicates the philosophy applied to AC systems. Such a system seems the most likely to predominate.

The fault detection system for such a protection system will not cause any onerous requirements from a technology perspective and can be achieved based on current state of the art systems. Discrimination of a fault condition from transient or other phenomena and fault location to ensure rapid fault isolation can be confidently achieved based on locally accessible measurement points without the need for more complex communication connections. As multi-terminal systems grow it is not anticipated that such a philosophy will create significant problems.

The requirement, technology and development opportunities for DC breakers were identified in the previous State of the Art Technologies report prepared as part of this project. The studies completed in this multi-terminal approach confirm the views expressed during the State of the Art consultations with suppliers and subsequent studies.

5.2. Impact on European Market

The impact on the European market is only applicable to the design which utilises an international interconnector whereby co-operation between two or more countries are required, each with differing onshore power systems. A current international interconnector design has been proposed for the Krieger's Flak offshore wind development site[13] and would include three separate developments from Germany, Sweden and Denmark. Some of the highlighted issues from this report and which are relevant to any international interconnector are summarised below:

- Significant co-ordination and commitment required between developers, OFTO's, regulators, authorities and politicians
- Reinforcements of onshore grids in multiple countries required
- Regulatory issues relating to whether a design of this type is treat as an offshore grid connection of offshore power or an international interconnector. Assumptions have been made that such a design would be subject to EU regulation (EC) No. 1228/2003 concerning cross-border exchange of electricity.
- Energy trading across the interconnector would need to be regulated and this could potentially be handled by the European Market Coupling Company (EMCC), however answers would need to be made on how the transmission capacity for trade is calculated.
- Due to the intermittent nature of offshore power there will often be times where the forecasted and actual offshore power productions do not balance. This balancing and trade of system

[13] Energinet.dk, Svenska Kraftnät, Vattenfall Europe Transmission, 'An Analysis of Offshore Grid Connection at Kriegers Flak in the Baltic Sea', May 2009

services would increase the efficiency and advantages of such a design but it is a complex matter to build such a market between multiple countries.

Essentially, with an international interconnector utilising an offshore energy farm there would need to be substantial co-operation between all countries involved due to differences in operation, ownership, regulation and energy trading. However the advantages could allow a much more efficient use of the offshore energy farm production and facilitate further interconnection of the UK grid to Europe and the wider power network.

Quantification of such advantages is beyond the scope of this study and would be very dependent on the negotiation of the ownership, regulation and trading arrangements. Such negotiations would not be expected to be determined on technology issues but by political and economic factors. Two specific benefits that would be explored would be:

- During periods with low winds the interconnector may be used for power trading between the interconnected countries.
- Power flow from the offshore farm will be distributed between two countries and thus the necessity for onshore network reinforcements could be reduced.

Even when viewed at a high level it is clear that the potential beneficiaries from such arrangements may be complex and the commercial evaluation of such factors would not be straightforward.

Nevertheless the potential benefits of an international interconnector discussed in Section 4.1.9 are sufficient to suggest that there is merit is this option being studied further with the requirement to study specific interconnector projects rather than the generic studies completed here.

5.3. Technology Availability and Construction Issues

The requirements for multi-terminal architectures do not appear to raise any additional technology availability and construction issues compared to what has been identified previously.

Main issues are the increase in capacity of VSC HVDC technology at higher power levels and the associated XLPE cable technology.

Of course throughout this part of the study MTBF and MTTR figures have been used for the different technology aspects and it is accepted that in a fully offshore operating environment these figures are not yet based on extensive operating experience. Hence providing application designs which can achieve the necessary reliability figures may yet prove to be the most significant challenge, rather than the availability of the technology in the market.

5.4. Onshore Grid Compliance

As was described in the Individual Offshore Connection Architectures report, onshore grid compliance issues will primarily be associated with the maximum allowable infeed loss as described in National Electricity Transmission System Security and Quality of Supply Standard (NETS SQSS) which details how for offshore energy farms:

- With HVDC connections, the allowable infeed loss risk is currently 1000 MW (normal infeed loss risk) due to faults or outages of the HVDC converter, and 1320 MW (infrequent infeed loss risk) due to faults or outages of HVDC cable transmission circuit.
- With AC connections, the allowable infeed loss risk due to a transformer fault or outage is currently 50% of the offshore grid entry capacity up to a maximum of the normal infeed loss risk (1000 MW), and 1320 MW (infrequent infeed loss risk) due to faults or outages of the HVAC cable transmission circuit.

As the size of individual connections are unchanged in this study as those carried out in the previous report there will be no additional direct impact on Grid Code compliance. It has been assumed that in the longer term increases in infrequent infeed loss limits might become possible with onshore network developments and possible increased levels of interconnection. However, it is clear that the development of future single infeed loss limits will be a significant factor in determining the size, technology and applicability of multi-terminal approaches to offshore connection architectures.

No material Grid Code compliance differences have been identified for the multi-terminal architectures identified here and also significantly the offshore architecture itself does not impact significantly on the onshore grid design. However, the total capacities of offshore development, connection points and phasing will have significant implications for the design of the onshore grid as will be discussed in section 5.5

It is understood that the currently proposed changes to the single loss limits are driven by the capacities of the next generation of nuclear power stations which will operate at a high load factor. Offshore wind and wave generation operates at much lower load factors and it should be questioned as to be whether the same infeed losses should apply.

5.5. Onshore Grid Design

The focus of these studies has been to assess the designs of different offshore connection architectures and clearly this does not extend to the design considerations for the onshore network. However, various aspects of the offshore architecture need to be considered for the design of the onshore network.

5.5.1. Generation Capacity

The generation scenarios outlined in the Generation Scenarios report considered potential offshore generation capacities of over 40GW by 2050 and more recent announcements suggest that even higher figures may be considered.

The implications of such a requirement have been considered by various studies including that produced by the ENSG[14] (Electricity Networks Strategy Group) that outlines potential onshore transmission system reinforcements required to accommodate up to 25GW of offshore wind farm generation by 2020. The reinforcements identified are linked to specific developments and specific connection points and are thus dependent on these factors. However the actual connection architecture and technology does not impact on the conclusions of such a study, providing that the connection points are unchanged.

5.5.2. Connection Point

Within onshore reinforcement studies such as ENSG[12] assumptions are made concerning connection points and the need to not only reinforce the transmission system but also provide new transmission substations or extensions to existing substations. Invariably this will require new overhead line to be built onshore, a process which is lengthy and involves an uncertain outcome. However for direct connection to the onshore AC grid, such developments are necessary and due to the scale of generation capacity to be connected will involve significant development.

Within these multi-terminal connection architectures considered assumptions have been made concerning the likely maximum sizes of single connections to shore, these being limited by technology and System Quality and Security Standard limits. These are generally in line with assumptions made in other studies and hence this does not have any significant impact on the implications for onshore connection points.

5.5.3. Connection Architecture and Technology

The final consideration for onshore grid design is the potential impact of the architecture and technology used for the connection to shore.

The majority of close to shore (<100km) connections are envisaged to be AC connections as discussed within the Individual Offshore Connection Architectures report. For an AC connection it is likely that the most effective connection onto the onshore grid will be via an existing or newly provided AC transmission substation. With an HVDC connection another option becomes possible which is for a “deep” HVDC connection.

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[14] ENSG ‘Our Electricity Transmission Network: A Vision for 2020’

For an HVDC connection architecture it is possible to provide additional cable connection length without problems occurring of the transmission length becoming unviable. For AC connections the 100km connection distance limit is the total length of the export cable, so if the onshore connection point is 25km from shore, the limit of subsea cable is 75km giving the 100km total. For HVDC the total length of offshore and onshore cable is not limited which means that potentially onshore connection points deep inland could be considered.

The main advantage of such a deep connection being that no additional overhead line may be necessary if existing capacity onshore can be identified for direct cable connection. Of course a local HVDC converter would also be required to be located at the connection point.

Providing an underground HVDC cable route compared to an additional AC overhead line might provide significant opportunities in terms of project delivery timescale and also provide the facility to connect to parts of the onshore grid which allow better onward transmission of the energy, perhaps at a location where existing onshore generation has been removed.

Hence the choice of connection architecture and technology could provide additional options for the design of the onshore grid.

5.6. Extensibility

Extensibility was considered as a factor when evaluating potential connection architectures and is made up of two components.

5.6.1. Intra Zone

Within a generation zone there is of course a first need to establish a transmission connection at either HVDC or HVAC.

For HVDC the full connection capacity would have to be established from the outset, hence for this reason HVDC connection architecture does not provide an easily extensible system.

For an HVAC system, potentially with more individual cables to shore, it is easier to envisage a staged approach with fewer elements and system capacity needing to be provided from the start of the development. Subsequent generation capacity could be provided with additional cable circuits providing that the basic infrastructure (particularly the offshore substation platform was provided with the capability to be easily extended).

5.6.2. Inter Zone

Between zones or indeed to add a complete additional zone there is essentially no difference between an HVDC and HVAC architecture. This is due primarily to the fact that for HVDC it has been demonstrated in Section 4 that the optimum means of interconnecting HVDC zones is via an AC link. For HVAC connected zones the conclusion being that interconnection cannot be justified, hence the need for inter zone extensions is unlikely to be justified.

5.7. Environmental Issues

The environmental issues involved with wind turbines are well documented with respect to bird issues as well as sound and sight impacts. The scope of this work however is based around the connection architecture and therefore the environmental impact is primarily around the laying of long distance subsea cables and to a lesser amount the size and scale of the offshore platforms required for a multi-terminal architecture.

With respect to the offshore platforms it will be of greatest cost benefit to locate these within the centre of offshore farm zones rather than outside of the perimeter of the zone. For this reason it can be expected that the platforms would be included in the Environmental Impact Assessment (EIA) of the entire designated wind farm zone and would expect little additional opposition compared to that of the overall offshore farm.

In contrast the export cables will be required to span long distances from shore to platform and in an interconnected architecture, from platform to platform. Dependent on the technology used will determine the level of environmental impact based on width of channel required to lay the connection and the technique for installing the cable. On this basis, HVDC cables will provide the lowest environmental impact as their high capacity allows few cables to be laid resulting in a thin channel. In comparison an AC solution may require multiple parallel cables to achieve the necessary capacity, resulting in a wide channel which could have significant environmental implications. In addition an AC solution may require intermittent offshore reactive compensation platforms dependent on the technology used and this could have a further impact. Finally a GIL solution, although providing a narrow channel through high capacity cables may require a tunnel structure to be developed should seabed laying not be possible. Tunnelling long distances may have significant environmental impacts, especially due to the undulating terrain of the seabed.

5.8. Auxiliary Power

In the same way that onshore substations and networks need auxiliary systems to ensure functionality of the network, similar systems are necessary for offshore architectures. A major consideration here is the provision of auxiliary power.

Auxiliary power, when links to shore have been lost, is critical. Many secondary system functions require AC and DC power to provide continued operation of safety systems, control and protection and communications. Additionally when no primary energy source is available or during maintenance periods then turbines will have power requirements to keep their electrical and environmental equipment running.

Designs of offshore substations include sources of auxiliary power, typically diesel stand by generation. The capacity and running time requirements being determined not only by the characteristics of the offshore farm but also choices made by the operator of the offshore farm itself. For onshore systems auxiliary power provision is likely to cover all equipment needs (essential and also non-essential), for offshore it is likely that a more selective approach will be taken.

Typically a period of time will be chosen which might enable supplementary generation to be brought offshore on a barge or vessel, if the disconnection time was envisaged to be lengthy.

Whilst the design and philosophy of such auxiliary power systems is beyond the scope of this study a question that has to be addressed is the potential impact of auxiliary power on the connection architecture.

Firstly it is clear that for an individually connected offshore farm the consequences of an export cable failure can be much more significant, particularly if only a single cable is utilised. For offshore farms with multi-terminal connections then the risk of a complete loss of connection is significantly reduced and therefore the auxiliary power systems can be considered accordingly.

Secondly is the technology of equipment to be used for the export connection. Due to the nature of the HVDC converters for an HVDC connection it is considered that auxiliary power requirements will be more onerous than for an equivalent AC connection. The provision of auxiliary power still remaining a very small proportion of the total cost of a connection system.

As far as the turbine generators themselves, the auxiliary power requirements are determined by the generator characteristics and not the connection architectures.

From the above and the detailed studies which have been completed on various connection architectures it is concluded that the connection architecture itself will have a direct impact on the provision of auxiliary power systems but that the provision of auxiliary power is not a significant factor when evaluating possible system architectures. Provision of auxiliary power is an important design aspect but when compared to the scope of design, engineering and cost for offshore connections it is a small part of the scope.

6. Conclusions

6.1. Financial Assessment Summary

6.1.1. Study Groups 1 and 2

The designs investigated in Study Group 1 and 2 indicate that where a single HVDC connection is possible it is the most financially attractive due to the significant capital cost saving over the installation of a second HVDC link. Switched DC arrangements show potential for savings however this would hinge on the energy markets and development of VSC converters. It is expected that a single HVDC connection is unlikely to increase beyond 2000MW due to both technical and SQSS limitations however interconnecting HVDC offshore nodes at either HVDC or AC provides revenue savings which outweigh the additional capital expenditure. The saving offered by interconnections increases with distance from shore however even at 90km, the minimum distance HVDC is likely to be financially attractive at, interconnecting can provide significant savings. The capacity of the interconnection only needs to be a proportion of the total installed capacity, around 20% has shown to provide optimum results however this will be dependent on the specific design of the interconnection, output characteristic of the development, and the capacity of the shore connection. AC interconnections provide the optimum saving due to significantly greater increase in availability compared to HVDC as the HVDC converters themselves have a significant unavailability.

6.1.2. Study Group 3

For high capacity AC connections such as those investigated in Study Group 3 there are inherently a high number of connection circuits providing a high availability and thus making interconnection or multi-terminal designs unattractive. Further a reduction of export capacity significant enough to impact on capex is likely to result in an increase in lost revenue which makes the option unattractive.

6.1.3. Study Group 4

The application of multi-terminal architecture to marine developments as investigated in Study Group 4 will be dependent on specific details on a case by case basis. By its nature tidal generation is close to shore where it has been shown that multi-terminal is less attractive due to the short connection distance. Wave generation further from shore has shown to be more attractive for multi-terminal application. There was a marked difference between small capacity developments close to shore and larger capacity developments further from shore. Close to shore multi-terminal is not financially attractive due to the very short connection distance, however further from shore multi-terminal is clearly the preferred option due to significant capex savings. The revenue is not significant to the result in either option so the type of generation is not significant. An opportunity for further study may be to establish the "tipping point" distance between point to point and multi-terminal for such developments with project specific details at a later stage when such project details become available.

6.1.4. GIL

GIL has been shown to potentially have a very low availability which would make it an unacceptable design option and as such we would not recommend significant investment in that area. Further the very high capacity of the connection would cause significant impact to the onshore grid, it may be necessary to split the connection onshore to spread the impact over a larger area at increased cost. This issue is not expected to arise with AC or HVDC as the individual connections are of reasonable capacities. HVDC is expected to have the least impact on the onshore grid given the potential for deep connections however AC connections may require close to shore network reinforcements. It should be noted that the studies performed for GIL were based on assumptions due to limited real data however the conclusions derived are not influenced by the assumptions made with the most significant element determining the calculated availability figures for GIL being the capacity of the individual connections.

6.1.5. National/International Interconnector

Combined national/international interconnectors with offshore farm connections have been shown to be potentially attractive and as such may warrant further study. As previously identified for HVDC multi-terminal systems, HVDC switchgear and control solutions would be required for such national and international interconnector arrangements. Whilst the specific switchgear and circuit breaker devices are not presently available they could be developed as discussed in the State of the Art Technologies report.

6.2. OFTO

Penalties incurred as part of the OFTO regime are expected to be only a fraction of the cost related to lost energy and as such are not expected to be a leading factor considered in export architecture design.

6.3. Technology Development Opportunities

The basic conclusions are that the technology opportunities identified in the State of the Art Network Technologies report are still valid. However some further comments can be made:

- Once again the importance of HVDC technologies has been emphasised. Reinforcing all comments made previously in respect of HVDC technologies.

- Whilst technically feasible to provide single GIL connections of very high capacity, these are not attractive from an availability or economic perspective, hence does not warrant further consideration
- Offshore storage has not been considered as part of the assessment of multiple connections; however it is assumed that the points that were valid for individual architectures would still apply for the multiple connections approach.
- The importance of technology and architecture in determining connection availability has been extensively studied in this report. Technology development opportunities that arise from this analysis are all those associated with improving connection availability, some of these have been included previously but additional factors can also be added.
- Assumptions made concerning the progression of future single infeed loss limits will be a significant factor in determining the size, technology and applicability of multi-terminal approaches to offshore connection architectures. It is understood that the currently proposed changes to the single loss limits are driven by the capacities of the next generation of nuclear power stations which will operate at a high load factor. Offshore wind and wave generation operates at much lower load factors and it should be questioned as to be whether the same infeed losses should apply.

The technology development opportunities identified in addition to those within Table 18 of the State of the Art Technologies report are detailed in Table 7.

- **Table 7 Additional Technology Development Opportunities**

Technology Area	Potential Benefit of Technology	Development Need	Potential ETI Input
Offshore equipment reliability	Improvement in availability figures	Establishing and improvement of equipment availability figures	Initiate studies to establish reliability figures as experience is built up and identify improvement areas.
Offshore connection availability	Improvement in availability figures	Improve offshore repair and maintenance procedures and access to equipment	Study proposed repair and maintenance procedures and optimise. Include offshore access issues.
Offshore equipment failure rate	Detailed and accurate equipment failure rates in offshore environment to provide better calculation of availability for offshore architectures	Improved methods and frequency of assessing failure rates of equipment in offshore environment.	Initiate studies into assessing the impact of equipment failure rate in an offshore environment.
Single loss of infeed limits	To allow increased capacity single connections and promote multi-terminal approach	Studies to determine options to enable increase of SQSS limits and potential implications	Sponsor studies
Interconnectors	Can realise financial and other benefits for	Detailed studies of particular interconnectors	Discuss within SAG to assess whether project

Technology Area	Potential Benefit of Technology	Development Need	Potential ETI Input
	stakeholders	in conjunction with specific generation developments, potentially at both ends of interconnector	could be viable and with real information.
VSC multi-terminal control	To facilitate potential VSC multi-terminal applications	Is VSC multi-terminal control a potential technology implementation constraint	Verify findings of this study that VSC control will NOT constrain implementation of technology
VSC Automated Switched Architecture	Minimise impact of faulted converter	Use of circuit breakers offshore to automatically switch out faulted converters	Study concept and developments required

Appendix A Equipment Reliability

A.1 Switchgear

Onshore switchgear comprising principally of GIS has an MTBF of 0.005 per annum and an MTTR of 5 days[15]. Assuming that the repair can be undertaken offshore using a readily available personnel and general purpose workboats then it is estimated by SKM that an offshore MTTR will be 10 days with no change to MTBF. It could be argued that for offshore applications the MTBF for GIS will be lower compared to onshore, however there is currently no experience which can be used to support such a view.

A.2 Transformers

The 120MVA 132/33kV has forced air cooling (AF) and a 21 position on-load tap changer, all of which contribute to the overall availability of the transformer.

In an onshore environment a power transformer with on-load tap changer and forced air (AF) cooling will have an MTBF of 0.05 per annum and an MTTR of 5 days[16] assuming that the fault involves auxiliary equipment and can be repaired in-situ. Assuming that the repair can be undertaken offshore using a readily available personnel and general purpose workboats then it is estimated that an offshore MTTR will be 10 days.

A small proportion of transformer faults involve the windings and/or the magnetic core that cannot be repaired in situ and it will be necessary to remove the transformer for replacement or repair in a manufacturer's works where removal, transportation and repair times can be significant. The MTBF for faults requiring replacement or a back to works repair is 0.006 per annum[16] or once every 167 years and although this is a low probability event it could happen once within the lifetime of typical transmission assets. In an offshore environment the MTBF will be the same as for onshore transformers but the MTTR will be dependent on:

a) The availability of suitable vessels with cranes able to lift and deliver the transformer to a suitable port for transit to the manufacturer's works. Assuming a suitable vessel can be diverted for a few days to remove the failed transformer from the platform then the time for this operation should not have a significant impact on the MTTR. An allowance of 5 days mobilisation plus a 2 day lift and transit to port has been estimated for this activity. A further 2 day transit and lift has been estimated for the transformer replacement.

[15] Derived from "Report on the Second International Survey on High Voltage Gas Insulated Substations (GIS) Service Experience", CIGRE WG 23.02, February 2000

[16] Derived from Section 2.3, Forced Outage Performance of Transmission Equipment, Canadian Electricity Association, May 2002.

b) The location of the manufacturers works. It is assumed that the transformer can be repaired in a UK facility and that it will take 3 days to transport the transformer from the port to the works with a further 3 days for the return journey. However it should be noted that there is only one transformer supplier who has a facility in the UK for works repair.

c) The availability of a repair slot in the manufacturer's works and the nature and extent of the internal transformer fault that may not be apparent until the transformer is de-tanked and inspected. Slot availability and repair times could result in MTTRs ranging from 6 weeks to 6 months and a MTTR of 12 weeks has been assumed.

d) Transformer commissioning and testing is estimated to take 3 days.

e) A weather contingency of 5 days has been estimated to cover delays to the offshore operations.

Taking the above into account the overall MTTR for a transformer return to works repair is set out in Table 8 below.

Table 8 Offshore Transformer MTTR

Activity	Duration Days
Mobilisation of repair vessel to site	5
Removal of transformer and transit to port facility	2
Transit port facility to factory	3
Factory repair	84
Transit factory to port facility	3
Transit to site and replacement of transformer	2
Transformer tests	3
Weather contingency	5
Total	**107**

The overall MTTR could be significantly reduced by the provision of a spare transformer though this is only likely to be financially viable in a situation where multiple developments use a standard transformer.

A.3 Sub-sea Cables

The MTBF of subsea cables is high provided cable installation and burial has been completed in a satisfactorily manner and regular surveys are undertaken along route to check on the cable condition and undertake remedial work where required. The overall MTBF for an XLPE subsea cable is approximately 0.0705/100cct.km/year[17]. AC and HVDC are assumed to be comparable.

The MTTR of a subsea cable is dependent on the availability of a cable repair kit, a suitable repair vessel and support spread and further dependant on a suitable weather window. There are few

[17] CIGRE Brochure 379, WG B1.10, April 2009

statistics on which to base MTTRs other than the recent cable fault on the HVDC connector between England and France took 83 days to repair[18], 40% of which was attributable to weather down time. Accordingly the SKM estimate of the MTTR for a fault on a subsea cable is set out in Table 9 below.

▪ **Table 9 Subsea cable MTTR**

Activity	Duration Days
Mobilisation of repair vessel to site	10
Surveying, de-trenching and recovery of cable	5
Repair and testing of cable	10
Lay-down, reburial and surveying	5
Weather contingency	10
Total	**40**

The MTTR of 40 days is considered by SKM to be representative for a cable repair in water depths of 30m where a number of suitable vessels can be equipped to undertake the repair.

A.4 HVDC

SKM estimates the unavailability of an onshore VSC HVDC converter station to be as shown below in Table 10.

▪ **Table 10 HVDC Converter Station Unavailability Breakdown**

Equipment	Failure Rate / Annum	MTBF (Years)	MTTR (Hours)	Unavailability (%)
HVAC Filters	0.074	14	16	0.014
HVAC Switchgear	0.005	200	16	0.001
Converter Transformer Replacement	0.006	167	504	0.035
Converter Transformer Repair	0.050	20	25	0.014
HVAC / HVDC Converter	1.500	0.7	9	0.154
			Total	0.217%

Assuming a converter pair the unavailability will be 0.434%. This aligns with industry quoted values including an ABB estimate[19] for an onshore VSC converter pair forced unavailability of 0.3-0.5%. An offshore converter station is assumed to have the same failure rates. Offshore MTTR

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[18] Offshore Repair of the IFA 2000 Cross-Channel Link, Electra 213, April 2004

[19] ABB Typical Values, available on 07 April 2010 Online at: http://www.abb.com/industries/ap/db0003db004333/44d898c82113672fc12574ab00419037.aspx

will be significantly larger given the requirement for repair crews to be mobilised to site. SKM estimates the mobilisation time to be 5 days and assume that spare switchgear, filter, and converter equipment will be stored offshore. The only exception is Transformer replacement, it is assumed that given the import of the transformers and the long lead times for a replacement that a spare transformer will be available. Time to transport the spare transformer and crew to the platform is estimated to be 10 days. Given the described changes to MTTR, offshore unavailability is estimated as shown below in Table 11.

- **Table 11 Offshore Converter Station Unavailability Breakdown**

Equipment	Failure Rate / Annum	MTBF (Years)	MTTR (Hours)	Unavailability (%)
HVAC Filters	0.074	14	16	0.115
HVAC Switchgear	0.005	20	16	0.008
Converter Transformer Replacement	0.006	167	744	0.051
Converter Transformer Repair	0.050	20	25	0.137
HVAC / HVDC Converter	1.500	0.7	9	2.209
			Total	2.519%

A.5 GIL

There is relatively little GIL data in this area for long connections and no subsea examples. The most extensive reference[20] quotes 0.2 major failures per annum per 100km of three phase GIL. MTTR is even less known given a lack of experience. SKM estimate for the purposes of this study that tunnel installed GIL will have an MTTR approximately 25% that of cables reflecting the ease of access. For direct submarine GIL there are no developed techniques and SKM estimates that the MTTR will be approximately 150% that of cable reflecting a more complex repair technique.

A.6 Scheduled Maintenance

A.6.1 AC Asset Scheduled Unavailability

Scheduled AC asset unavailability is assumed to include the aspects set out in Table 12.

- **Table 12 Transmission Asset Maintenance Requirements**

Item	Routine Maintenance	Interval (years)	Overhauls etc	Interval (years)
OSP Steelwork	Inspection, minor remediation of paintwork etc	1	Major repainting of containers and structural steel	5
OSP Cathodic Protection	Inspect, replace as required	3	-	
OSP Diesel Generator	Refuel, lubricate, test run	1	Exchange of worn parts	5

[20] CIGRE Brochure 351 "Application of Long High Capacity GIL"

Item	Routine Maintenance	Interval (years)	Overhauls etc	Interval (years)
OSP HV Switchgear	Test operation	2	None	-
Power Transformer	Lubricate fans, tap changer mechanism, remedy paintwork, inspect gaskets, bushings, cable terminations	2	Oil regeneration, major paint jobs	5
OSP Auxiliary Systems	Inspect panels, change lamps in navaids, rooms etc, check and change filters in HVAC, lubricate, clean, routine test protection	1	Replace batteries and/or electronic equipment	10
OSP General	Start diesel generator, clean, tidy up, inspect accommodation & emergency provisions etc	0.2	None	-
Subsea Cable	Burial inspection	2	Reburial due to sea bed migration	5
Transition joint and onshore cable	None	-	Review of other parties work along route	10
132kV 64MVAr Shunt Reactor	Inspect gaskets, bushings, cable terminations	1	Remedy paintwork, regenerate oil	10
Harmonic Filter	Inspect components, cable terminations	1	None	
Onshore Auxiliary Systems	Inspect panels, change lamps, check and change filters in HVAC, lubricate, clean, routine test protection	1	Replace batteries and/or electronic equipment	10

The unavailability due to the above aspects is assumed to be as follows;

- Routine maintenance allowance of 3 x 8 hour (i.e.1 day) outage over a 2 year period per AC Offshore Platform.
- Power Transformer maintenance overhaul allowance of 5 days every 5 years per transformer.

A.6.2 HVDC Asset Scheduled Unavailability

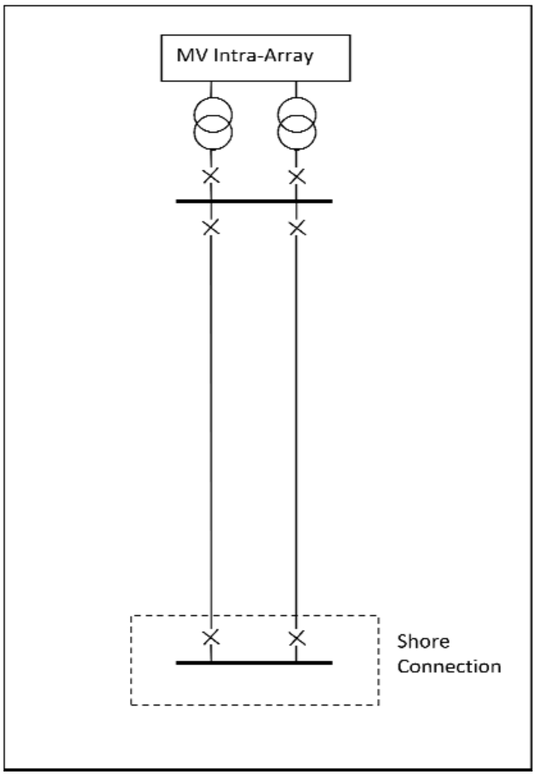
HVDC converter pair Unavailability is quoted by ABB as <4%[21] and in the absence of any other information we have applied a frequency of 1.2 times a year and duration of 1 day to produce an estimated unavailability of 0.33%.

HVDC cables are assumed to have a maintenance requirement matching AC cables.

[21] ABB Typical Values, available on 07 April 2010 Online at: http://www.abb.com/industries/ap/db0003db004333/44d898c82113672fc12574ab00419037.aspx

Appendix B Example of Availability Application

The following simplistic example demonstrates the application of the availability calculation and subsequent further assumptions.



- **Figure 27 AC Connection Example**

Point to Point AC Connection

- 2 Export Transformers rated at 50% total generation.
- 2 Export Circuits Rated at 50% total generation.
- 60km subsea cable connection.
- No significant onshore cabling.
- Switchgear provided as shown in Figure 27.

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■ **Table 13 Example Availability Table 100% Generation Output**

Unavailability due to unplanned outages

Notes	Units	Equipment	Failure Rate	MTTR Days	Unavailability (per Unit)	% Tot.	Available Capacity %
Transformer	2	In-situ Offshore Transformer	0.1	10	0.00137	10	50%
Transformer	2	BTWR Offshore Transformer	0.012	107	0.001759	13	50%
Overlap 1	1	Planned Tx Outage	0.2	5	0.000205	2	50%
Overlap 1	1	In-situ Offshore Transformer	0.05	10			
Overlap 2	1	Planned Tx Outage	0.2	5	0.000205	2	50%
Overlap 2	1	In-situ Offshore Transformer	0.05	10			
Transformer	2	Offshore Switchgear	0.01	10	0.000137	1	50%
Subsea Cabling	2	Sub-sea cable	0.0846	40	0.004636	35	50%
Subsea Cabling	60	SS Cable / km	0.0423	0	0	0	0%
Subsea Cabling	2	Offshore Switchgear	0.01	10	0.000137	1	50%
Subsea Cabling	2	Onshore Switchgear	0.01	5	6.85E-05	1	50%
Reactive Comp	1	Onshore Shunt Reactor	0.05	5	0.000685	5	0%
				Total	0.009201	69	

Scheduled Maintenance

	2	Planned Tx Outage	0.4	5	0.00274	21	50%
	1	Routine Maintenance	0.5	1	0.00137	10	0%
				Total	0.00411	31	
				Total	0.013311	100	
				Availability	**98.67**	**%**	

The above total availability of 98.67% is greater than the OFTO required 98%, this assumes a generator output of 100% continuous. This in itself confirms the likelihood of OFTO compliance.

The average Availability would in fact be greater. An example would be if the generator is outputting 50% rated capacity, the Available Capacity percentages would increase from 50 to 100% for the majority of aspects as they are arranged in parallel so the loss of any one aspect would result in no loss of export. Routine Maintenance has been assumed to remain at 0% as it is assumed the full substation is lost (dependent on design maintenance section by section may be possible), and overlap failures which would reduce to 0%. Overlap failures are a special case as they deal with the possibility of multiple losses at a time. The Available capacity input is not the capacity remaining given the two losses it is the additional loss of capacity given the second loss. If having a transformer out of service for maintenance results in 50% available capacity, and the loss of the second due to an unplanned outage results in 0% available capacity then the value input for the overlap is only the difference of 50%. If the farm is generating at 50% then the transformer out for maintenance results in an available capacity of 100% where as the unplanned loss of the second transformer still results in an available capacity of 0%, the difference is therefore 100% and the value input 100% - 100% = 0%.

By taking availability figures at a range of generator outputs and weighting them relative to the percentage of time the development would spend at each output capacity an average is reached.

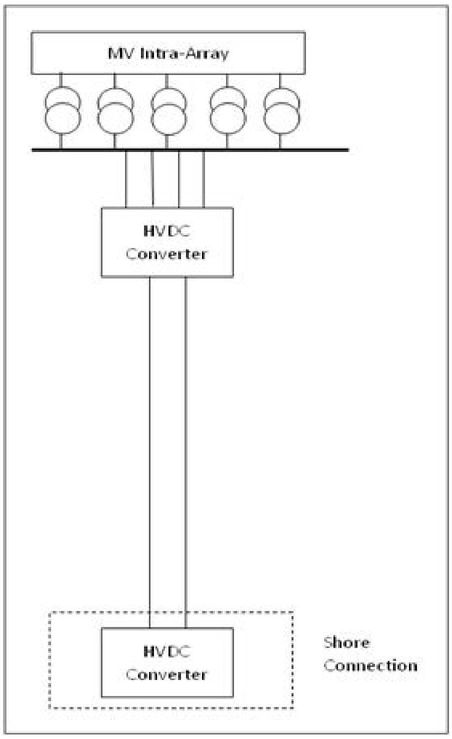
Overlaps included are the most significant given probability and impact.

From the example calculation it is clear that switchgear has negligible impact and so has been omitted from further studies for reasons of simplicity.

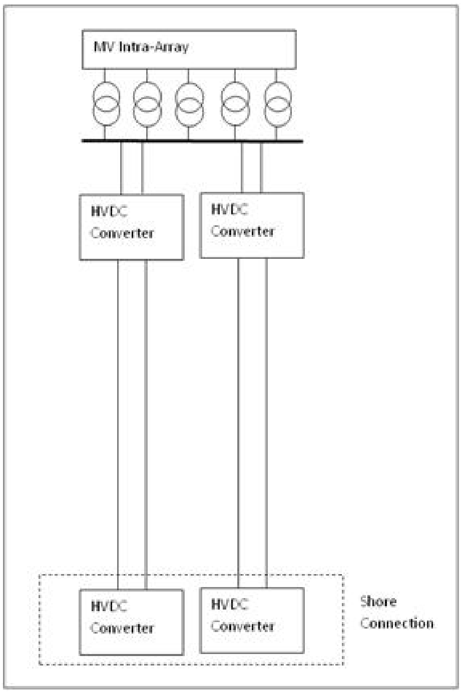
The availability prediction method here is simplified and for comparative purposes only based upon an indicative offshore farm output and a simplified design.

Appendix C Design Diagrams

- **Figure 28 Design 1**



- **Figure 29 Design 2**



- **Figure 30 Design 3**

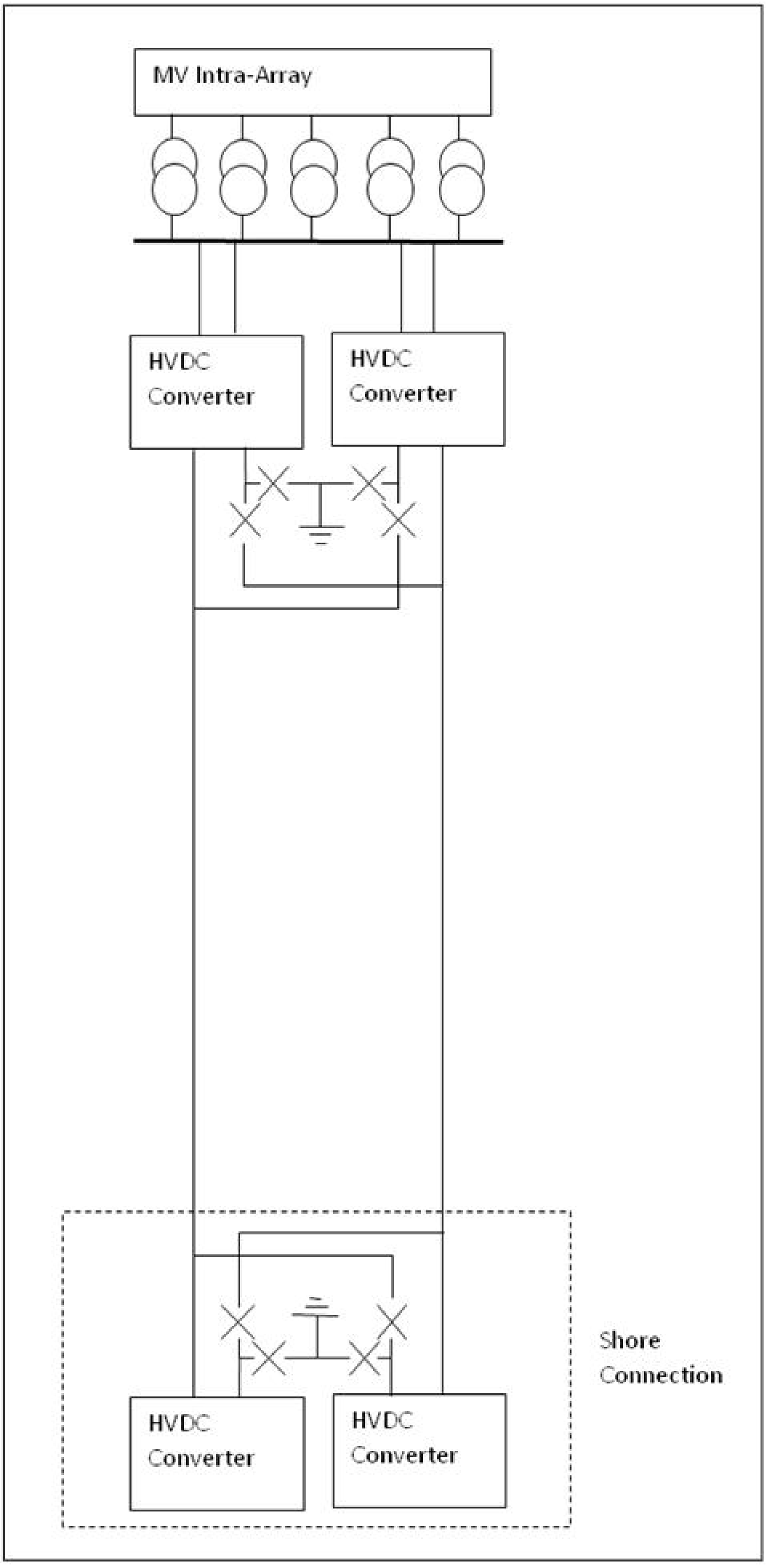


Figure 31 Design 4

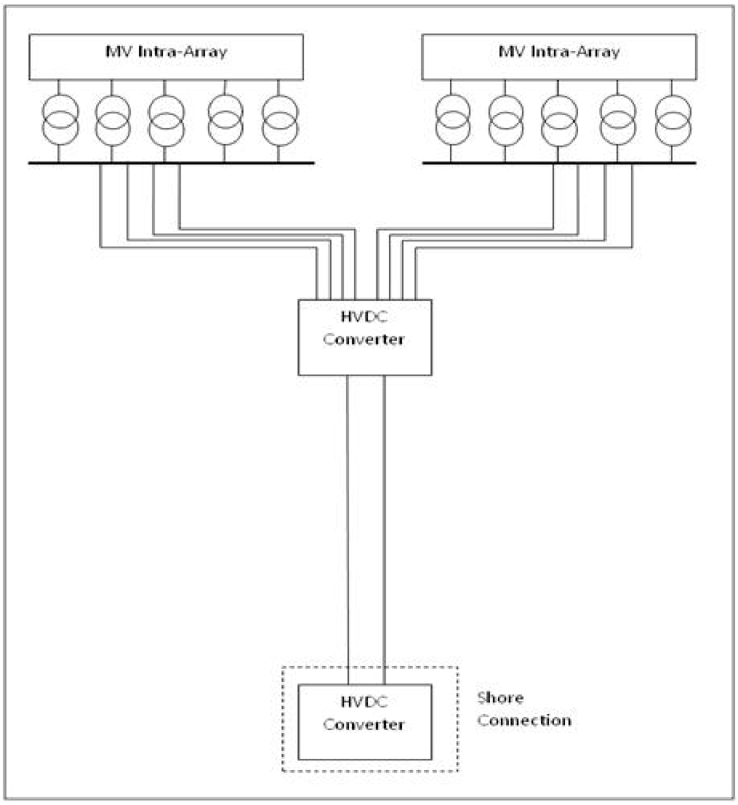
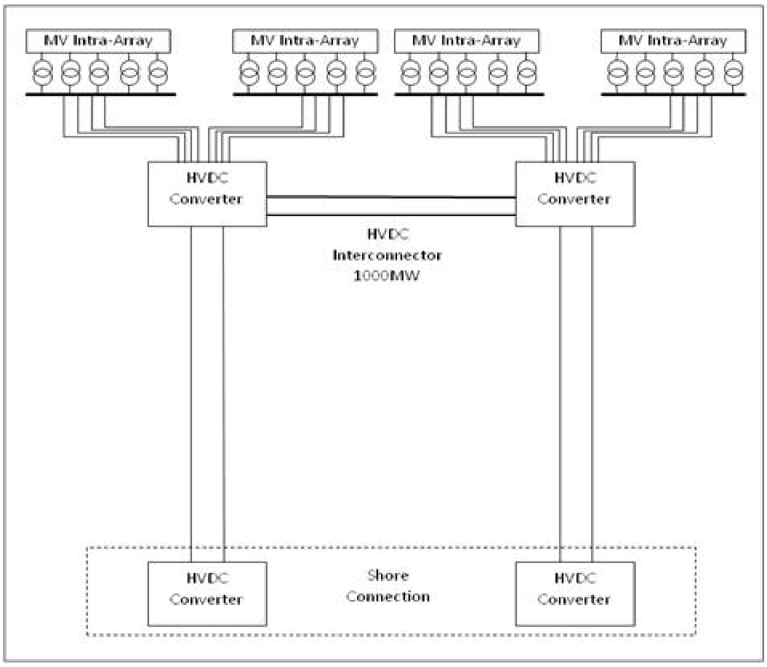
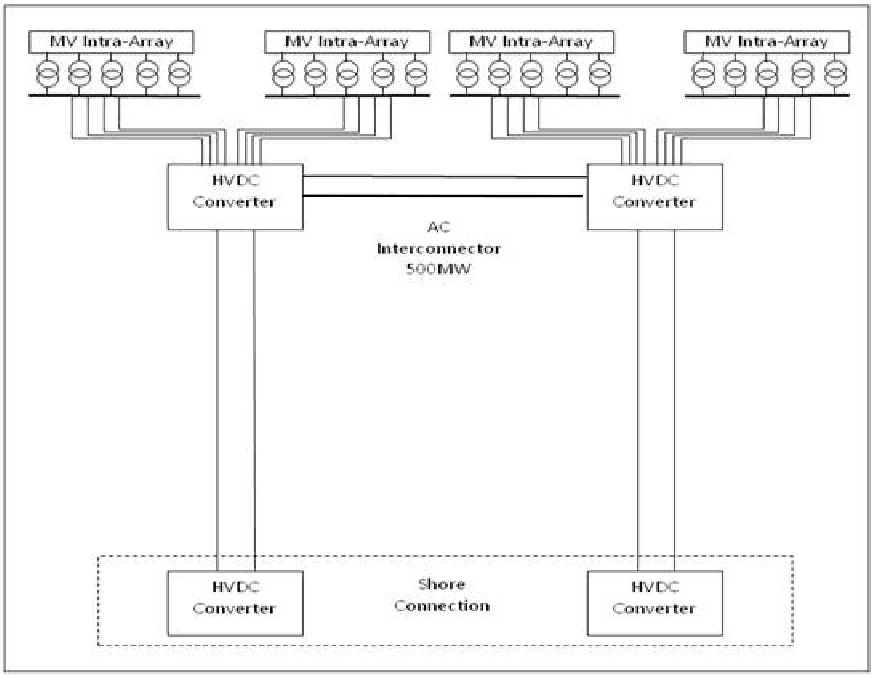


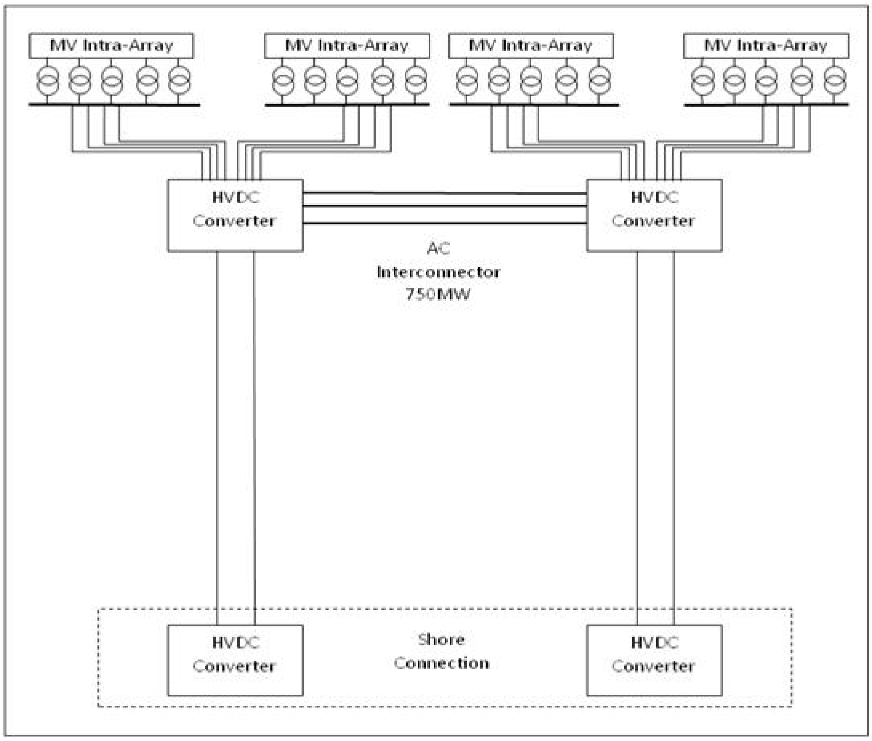
Figure 32 Design 5



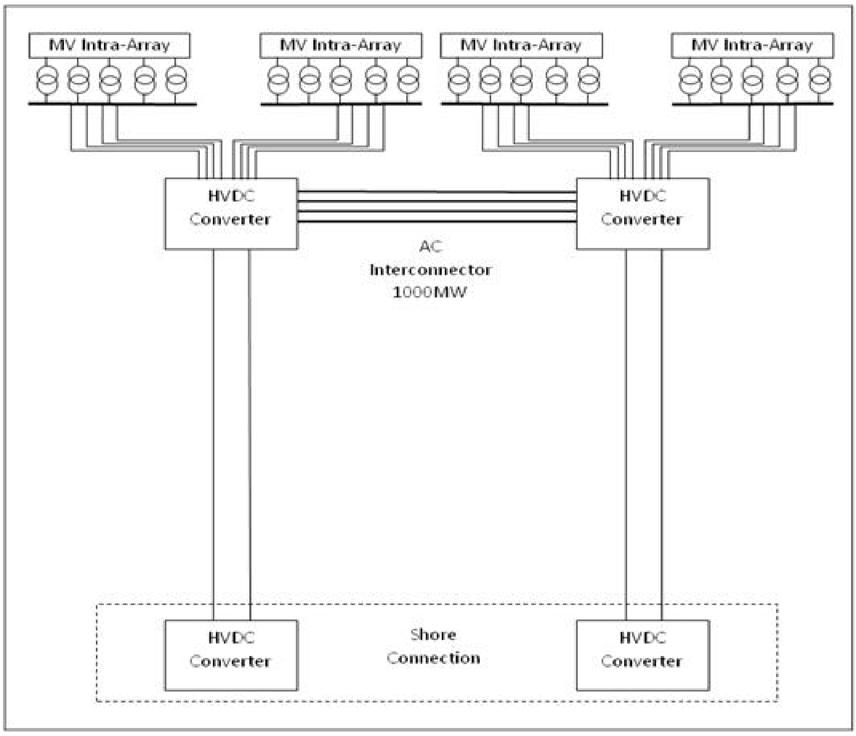
- **Figure 33 Design 6**



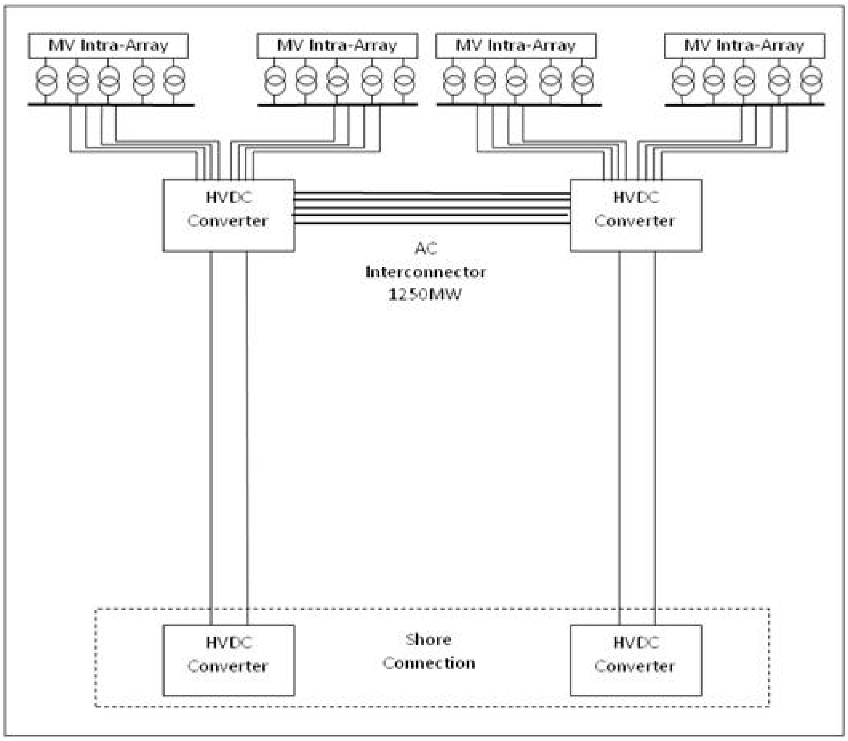
- **Figure 34 Design 7**



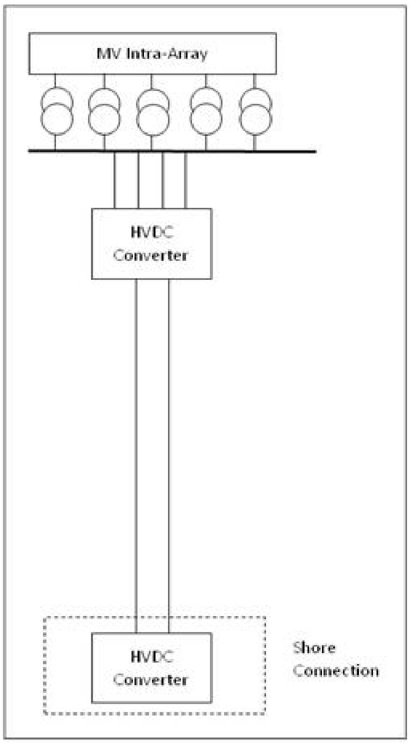
- **Figure 35 Design 8**



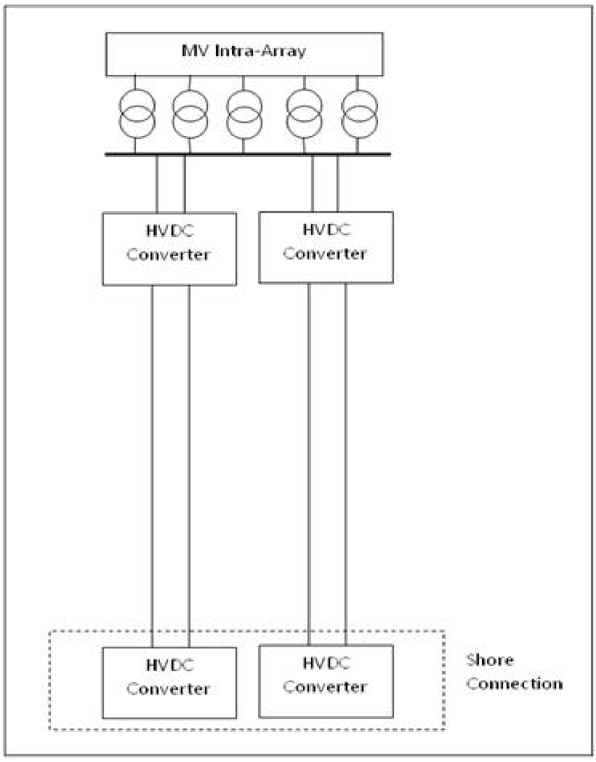
- **Figure 36 Design 9**



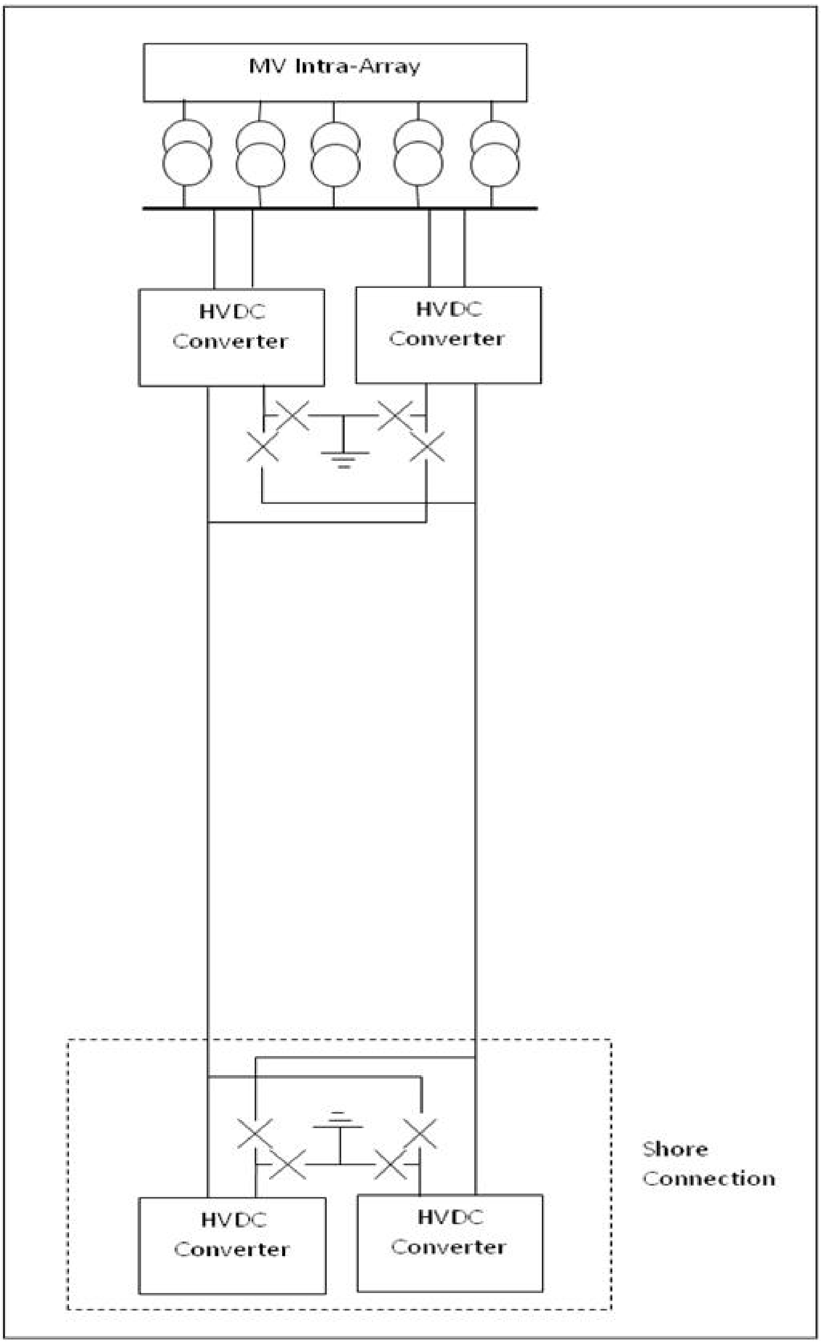
- **Figure 37 Design 10**



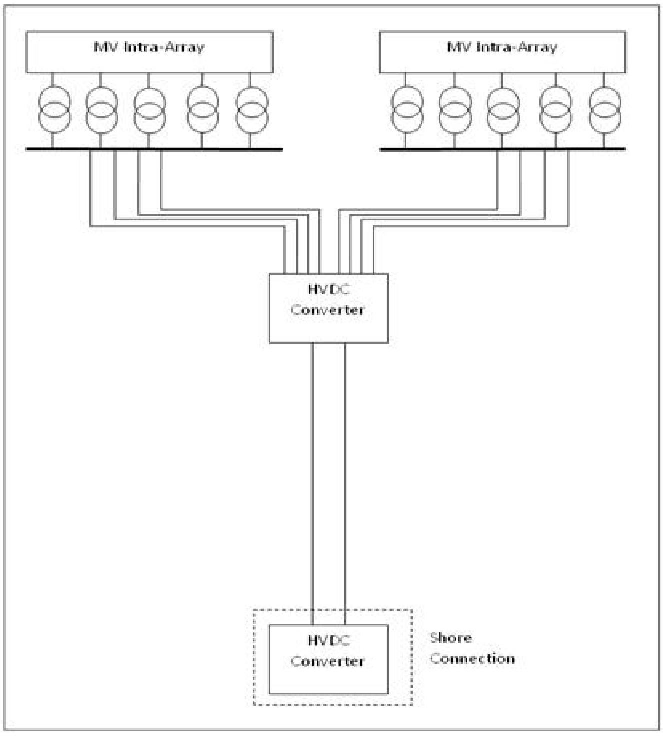
- **Figure 38 Design 11**



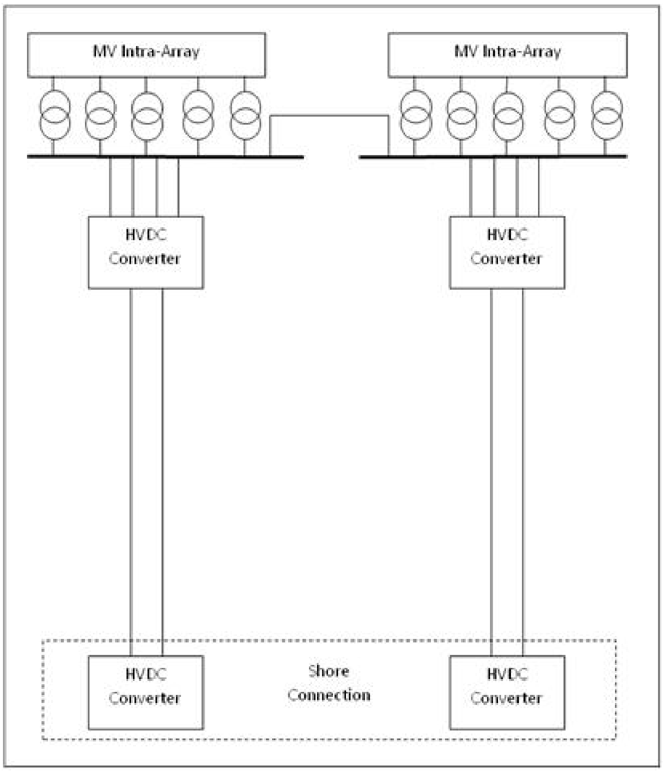
- **Figure 39 Design 12**



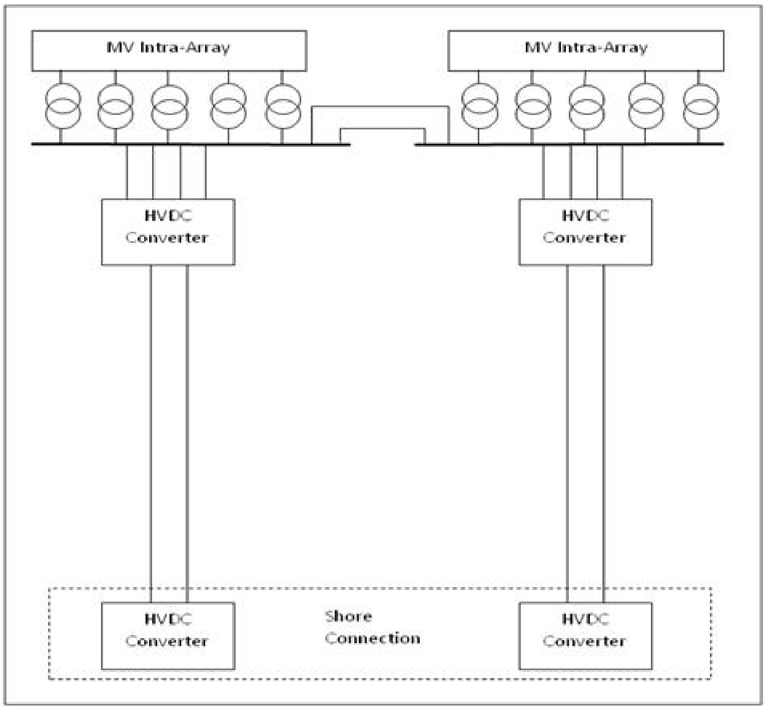
- **Figure 40 Design 13**



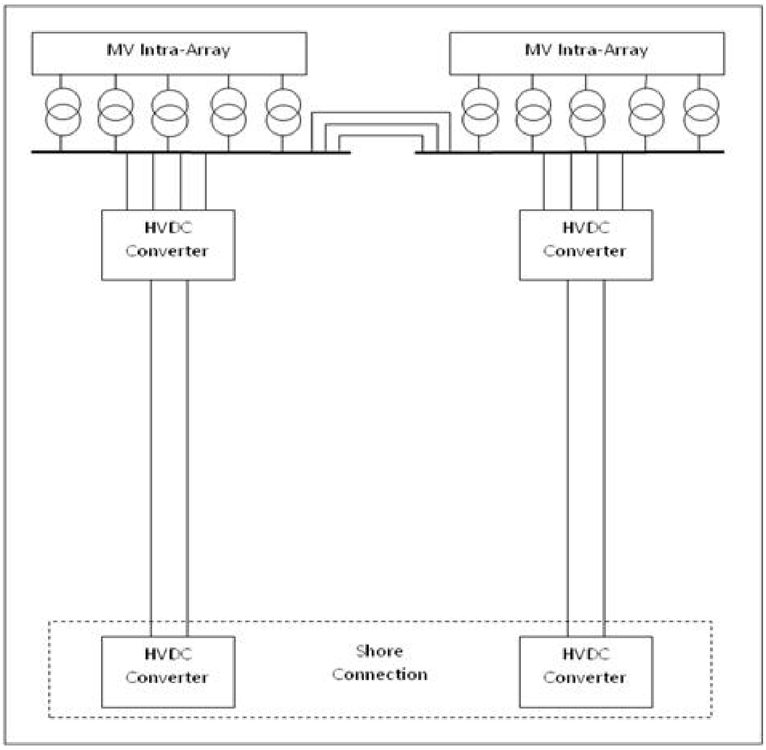
- **Figure 41 Design 14**



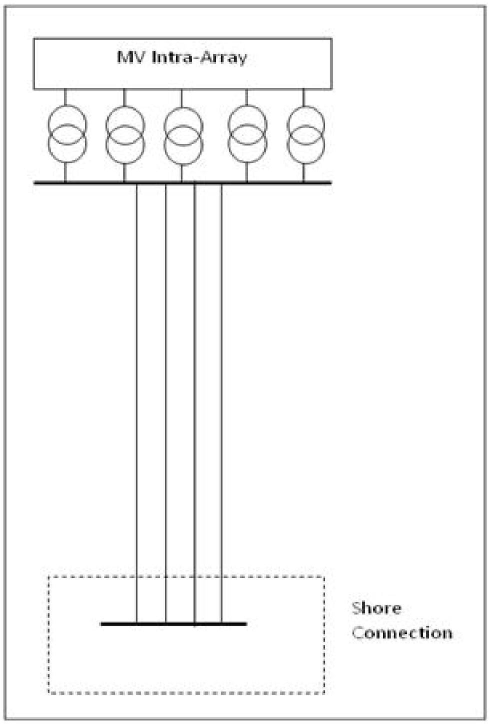
- **Figure 42 Design 15**



- **Figure 43 Design 16**



- **Figure 44 Design 17**



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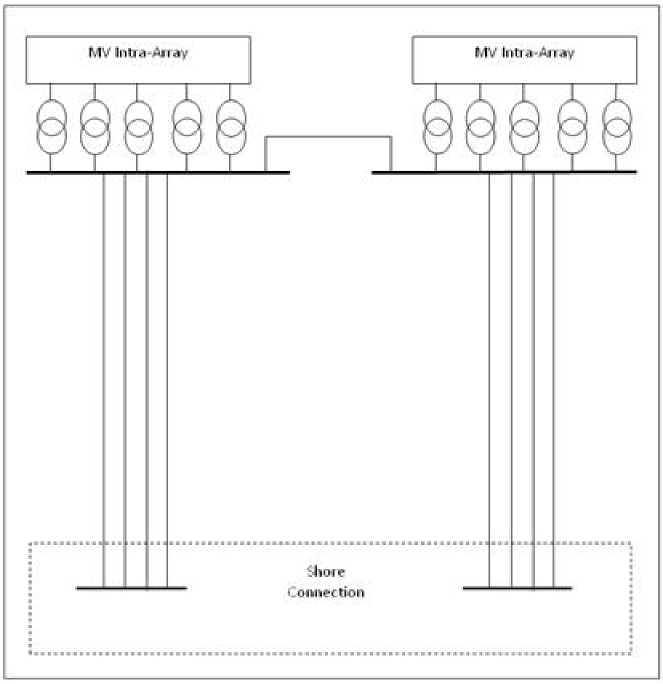
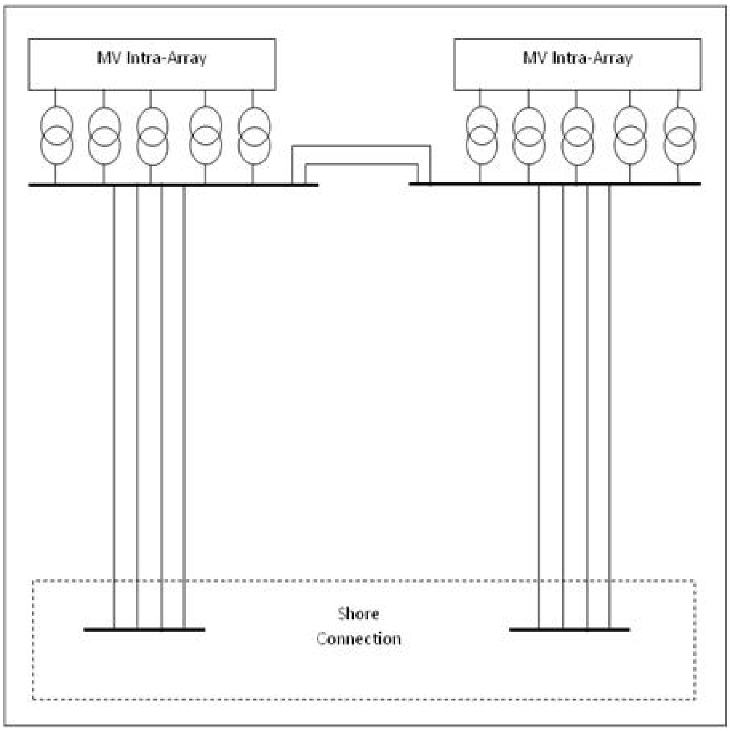
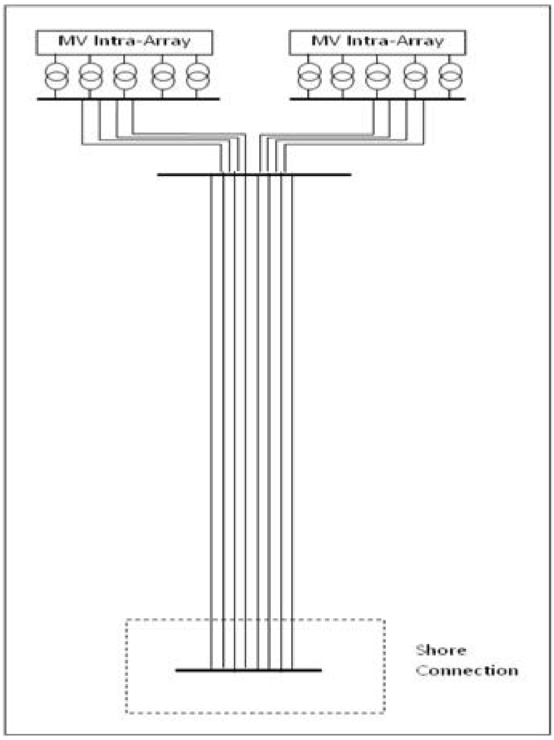
▪ Figure 45 Design 18



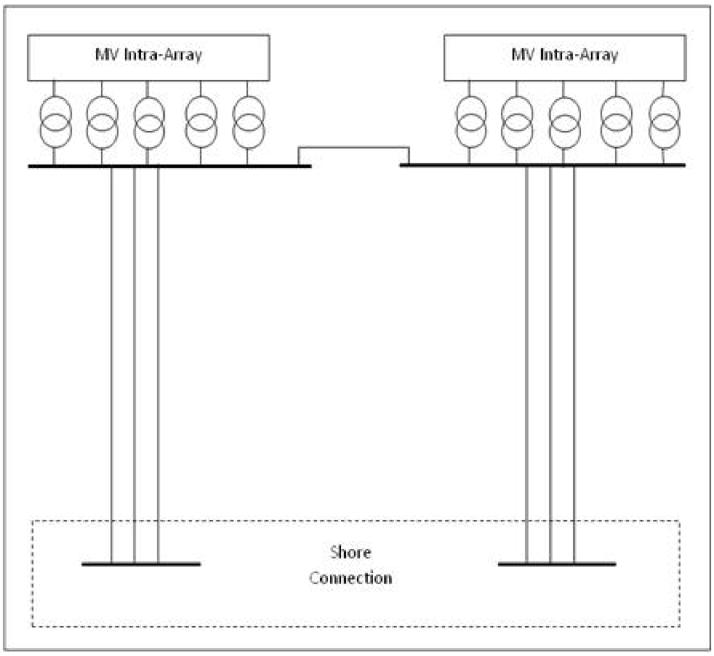
▪ Figure 46 Design 19



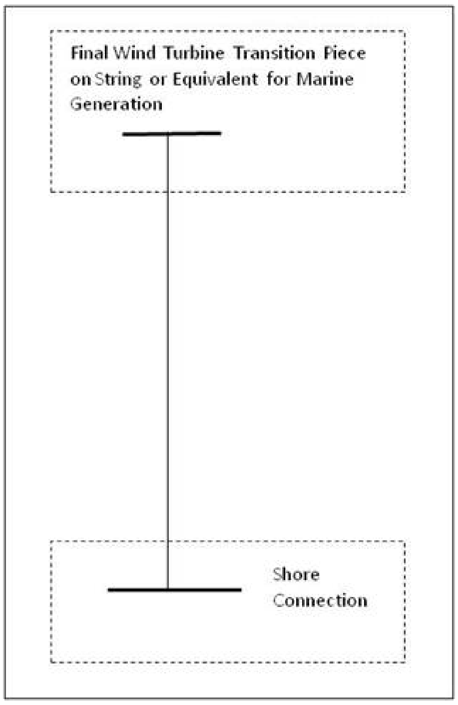
- **Figure 47 Design 20**



- **Figure 48 Design 21**



■ **Figure 49 Design 22**



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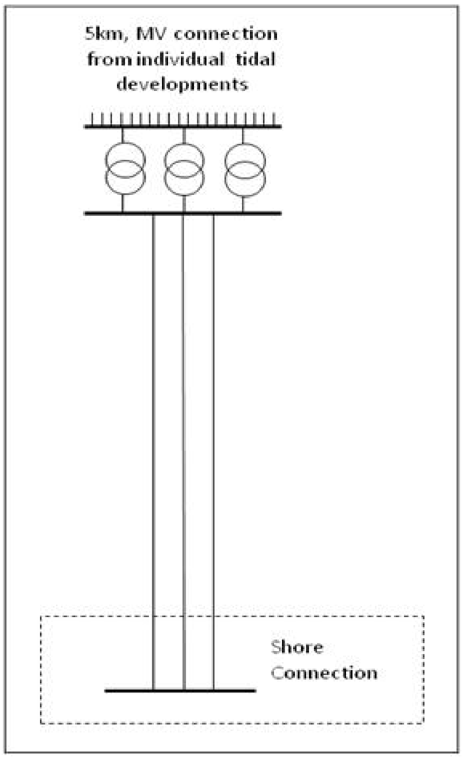
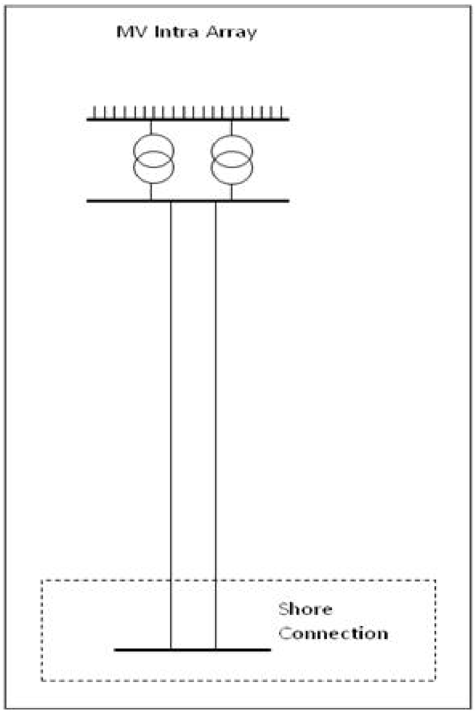
■ **Figure 50 Design 23**



- **Figure 51 Design 24**



- **Figure 52 Design 25**