Programme Area: Energy Storage and Distribution

Project: Offshore Connection 1

Title: Technology State of the Art Report

Abstract:

This report describes the technologies which could be deployed in offshore networks for the collection and export of paths for each technology, and assesses barriers to such development. Section 7 draws conclusions as to which technologies are likely to be most significant, summarises the key issues and identifies opportunities for technology development. These are augmented by subsequent reports.

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

STATE OF THE ART OFFSHORE NETWORK TECHNOLOGY REPORT

- Final
- 15 October 2010

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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. State of the Art Offshore Network Technologies

The purpose of this report is to establish the current state of the art of offshore network technologies and the prospective future technology development paths, as indicated by equipment manufacturers and experts within the industry. The views of these leading industry suppliers and experts have been sought and augmented by SKM's own internal knowledge of prospective future equipment and technology developments for inclusion in this report.

Included within this report are:

- An overview of the offshore equipment considered and a description of the interview process.
- A detailed description of the current state of the art offshore connection equipment physical and technical characteristics, including reliability and performance experience, as well as equipment costings. This latter aspect includes consideration of equipment installation and operational costs as well as an analysis of expected future trends and market impacts.
- A critical review of the expected technological development of key offshore electrical equipment, as predicted by the interviewed suppliers and experts, as well as a description of any perceived barriers to development.

The ultimate aim of this report is to guide the connection architectures and issues investigated in the subsequent tasks of this project. This will be achieved using the technology development maps devised under this task to visualise the "break points" in critical technology developments, as might affect future connection architectures. This will enable the identification of technology development opportunities for the ETI and other stakeholders.

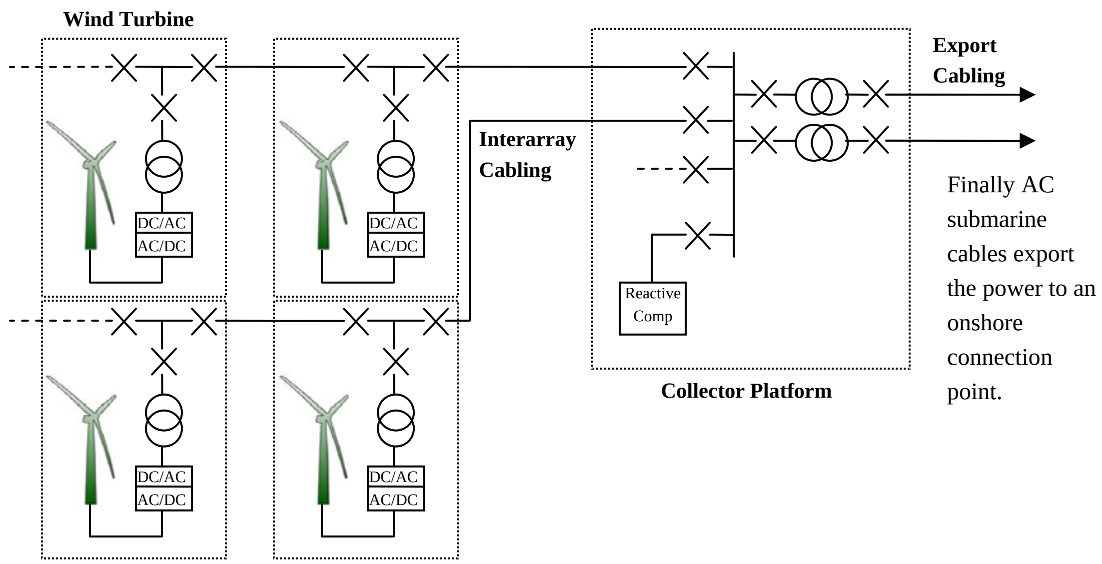
2. Overview of Offshore Renewable Farm Architectures

The connection architectures of offshore renewable farms currently follow a generally uniform design. Generators are collected at a relatively low voltage and stepped up at a central substation for export to shore. With a usual AC collection and AC export design the offshore equipment is as shown in Figure 1 below, all the usual control and protection equipment also applies and varies by application.

▪ **Figure 1 AC/AC Offshore Equipment**

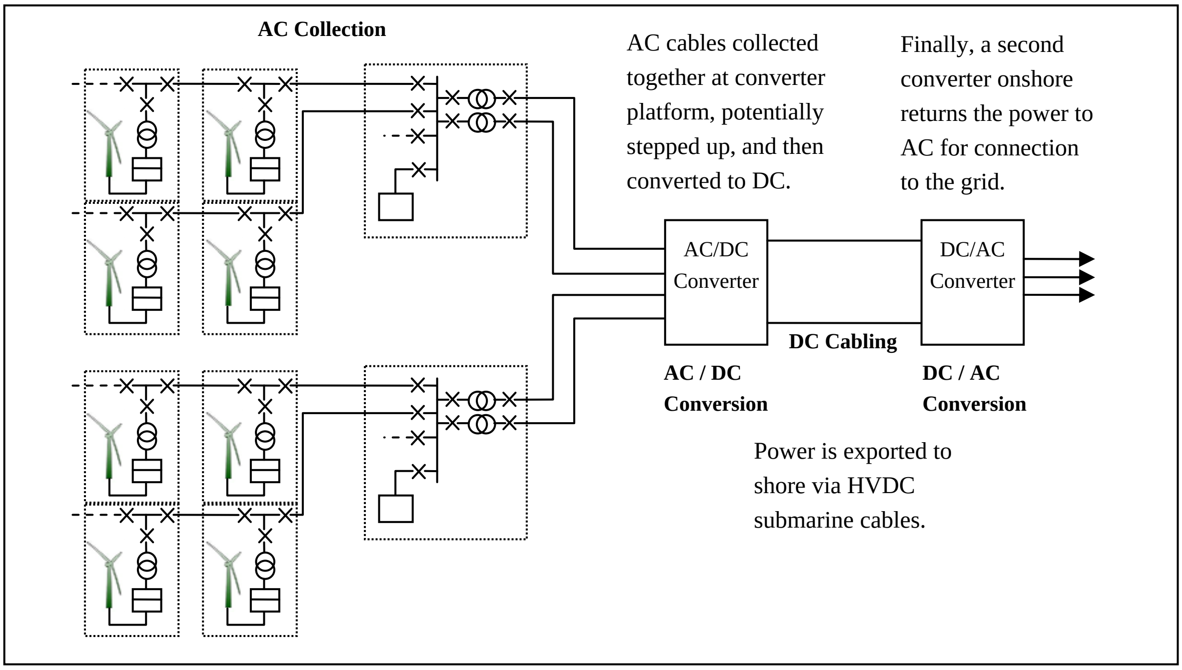
Within each wind turbine with the generator is a back to back converter, step up transformer (e.g. 0.6/33kV), and MV switchgear. Turbines are strung together by interarray submarine cabling at medium voltage (e.g.33kV) and collected together at one or more collector platforms.

Collector platforms are effectively offshore substations consisting of MV switchgear on the wind farm side, step up transformers increasing voltage for export (usually 132 kV), and HV switchgear on the export side. Reactive compensation may also be required depending on design however its location and connection voltage will vary case by case.



With AC collection and HVDC export an extra stage of conversion is required with the inclusion of a converter offshore and onshore (assuming an AC grid connection), this can physically be handled in a number of ways, firstly and simply a converter platform can be added to the AC/AC architecture as shown in Figure 2 below. This option may be most practical when the layout necessitates a number of collection platforms feeding a single converter. Alternatively, the converter and collection platforms can be combined in one; this potentially could negate the intermediate voltage level though this would depend on a number of factors such as the power to be transferred, the transmission voltage and the wind farm connection arrangement. A full description of HVDC equipment and conversion methods is included below in Appendix A and D.

- **Figure 2 AC/DC Offshore Equipment**



A further development option for connection is a DC collection and DC export arrangement. This arrangement obviously negates the need for offshore AC/DC converters, transformers and all AC equipment however requires in their place DC switchgear, cabling, and large DC to DC converters. As this type of connection is not likely to be commercially available for some time the optimum design configuration has not yet been ascertained. That said, the two leading potential designs are known, these being a series or parallel connection, as presented in Figure 3 below. The main advantage of the series connection design is that there is no need for a central DC to DC step-up platform, where as the parallel connection design option provides superior security. Note that switchgear has been omitted from Figure 3 for reasons of clarity.

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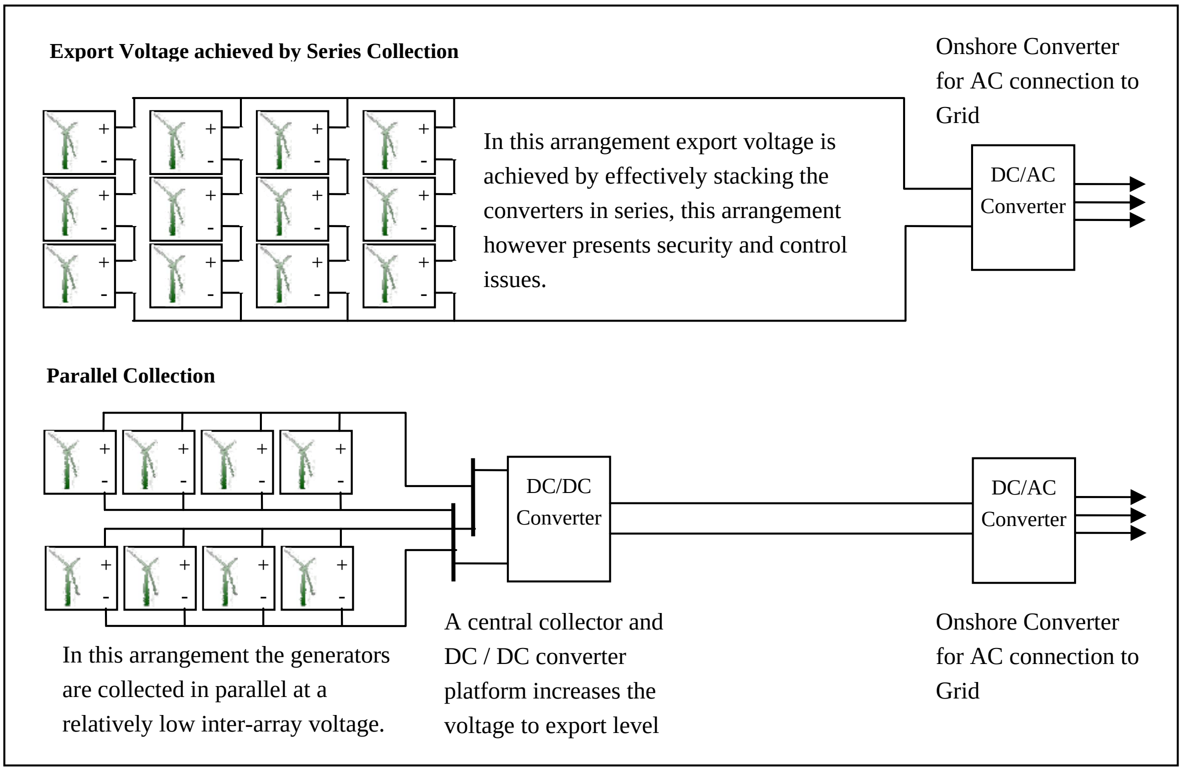
Figure 3 DC/DC Offshore Arrangements



The three arrangements above are drawn with offshore wind farms in mind and assume hundreds of MW's of generation located a significant distance from shore. In the case of wave and tidal generation, in the short term at least, developments will be small and relatively close to shore. In this case as we have seen with early wind farms there is the potential for connection to shore at the inter-array collection voltage, effectively extending the string to a connection point on shore. This will be even more relevant for tidal generation schemes which by the nature of the resource are near to shore. These early developments will not require offshore platforms and will be relevant in the short term only, excluding the possibility of DC implementation though that said they could prove valuable as DC collection pilot projects given their small size and close proximity to shore.

A high level review of the relevant equipment from the inter array switchgear to the export cable has been included in Appendix A for background purposes.

3. Manufacturers Interviews

3.1. Process

Given the pivotal nature of this task to the success of the project as a whole it was split into two stages with a review following the first stage to ensure the lines of inquiry being followed and the quality of information being received were consistent with the requirements of the subsequent tasks.

Stage 1 included contacting key individuals within targeted organisations specifically to gain an overview of the limitations / restrictions / developmental aspects / opportunities that they believe exist with respect to their current offshore electrical equipment offerings.

Stage 1 consisted of a questionnaire as well as direct interviews, the questionnaire was a high level document developed to gauge the general opinions of the supplier over the full range of equipment and issues being considered in this project. The questionnaire was developed and effectively answered in house by SKM to predict the likely responses of the suppliers and plan an interview strategy.

Interviews were intended to be carried out following a response on the questionnaire however given time constraints within the project and time commitment restrictions on the suppliers the questionnaires were often used as discussion guides for the interviews being completed by SKM during and following the interviews. Some of the questionnaires were completed in full by the suppliers following the interview.

A write up of the information collected through Stage 1 was submitted to the ETI for review and discussed face to face at a progress meeting. This assured that the issues raised through the interviews and hence the subjects selected for further investigation at Stage 2 met with the ETI's scope of interest and ultimate influence and avoid wasted effort following up on issues that are not of interest to the ETI.

Stage 2 expanded upon the issues raised in Stage 1 by posing specific questions tailored around the most significant issues to specialists within the Stage 1 organisations, select niche suppliers, and academics. As with Stage 1 both questionnaires and interviews were employed to ascertain the required information but given the more targeted nature of Stage 2 both were not necessarily used for every contact.

Included in Appendix B is a complete list of the responses received as part of the interview processes.

Based on the Stage 1 responses it was agreed that Stage 2 would be focused on the key technology areas of:

- Fire Protection – Low priority
- DC Switchgear – Medium priority
- HVAC Export Cable – Low priority
- HVDC Export Cable – High priority
- AC Collector Cable – High priority
- DC Collector Cable – Medium priority
- HVDC Converters – Medium Priority
- Marinisation of Equipment – General issue
- Future technologies – General issue
- Application of superconducting technologies – General issue

3.2. Participants

3.2.1. Stage 1

Those organisations contacted during Stage 1 of the process were:

- ABB – T&D equipment and systems
- Areva – T&D equipment and systems
- Siemens – T&D equipment and systems
- Prysmian – Cables
- Fluor – Offshore Project Developer
- McNulty's – Offshore Platform Constructor
- SLP – Offshore Platform Constructor
- CCI – Cable Consultant
- Electranix – HVDC Consultant

3.2.2. Stage 2

Those contacted during Stage 2 of the process were:

- ABB – T&D equipment
- Areva – T&D equipment
- Siemens – T&D equipment

- Prysmian – Cables
- CCI – Cable Consultant
- Electranix – HVDC Consultant

Some additional organisations were contacted with specific questions concerning particular technologies and devices, these included.

- NaREC – Marinisation
- Imperial College – Offshore Systems
- Cardiff University – Offshore Systems
- Liverpool University – Circuit Breakers
- EPRI – General technology development
- EVInce – Diamond power electronic devices
- American Superconductors – Superconducting T&D Systems

3.3. Results

Response to our approach in Stage 1 was largely positive, with the majority of contacts providing as much or more time than could be reasonably expected. Mentioned during these initial approaches however was some frustration over a perceived replication of effort which is occurring, notably the accelerator project launched by the Carbon Trust with the aim of cutting offshore wind costs had approached some of the suppliers with similar questions. Subsequently discussions with the Carbon Trust were arranged by the ETI to share learning from various projects.

Notably the organisations/individuals who failed to respond were those with whom SKM did not have personal contacts within, this reinforces the observation made early in the project that personal contacts are vital to the success of a task such as the manufacturers interviews. Despite these issues the outcome of Stage 1 was very positive with clear lines of agreement drawn across the various sources and a resulting robust view of the major issues that should be taken forward into Stage 2.

As with Stage 1, questionnaires were produced for Stage 2 with specific questions posed to the area of expertise of the individuals listed above. In some respects Stage 2 was more difficult to Stage 1 for a number of reasons:

- Quite specific questions have been raised which have increased manufacturer sensitivities with regard to openly discussing technology plans and cost aspects.
- Approaches to technical specialists, in some cases are where personal relationships do not exist or are limited.

- Additional time pressure on respondents due to the lead up towards Christmas holidays.

Hence additional time was allowed to incorporate some comments which were provided after the original deadlines assigned.

On the positive side some interesting input was obtained from sources who were not originally included in the plan, the views provided giving a more balanced outlook on potential technology developments which could influence future implementation of offshore renewables.

3.4. Conclusions

It was identified that engagement of suppliers was essential in determining not only the state of the art of current equipment but to capture views on developments that are likely and could deliver benefits for the implementation of offshore renewables. It was also clear that some filtering was necessary to identify the critical areas of technology so that priorities could be assigned during the more detailed stages of the state of the art review.

The first stage of the process was successful in contacting key individuals within targeted organisations specifically to gain an overview of the limitations / restrictions / developmental aspects / opportunities that they believe existed with respect to their current offshore electrical equipment offerings.

Stage 2 also followed the same format of a questionnaire but with very specific questions to address issues arising from Stage 1 of the process. The response during Stage 2 was not as effective with manufacturers, however by broadening those contacted a potentially wider insight into future technologies was gained. Once again the importance of personal contacts in obtaining any responses was obvious.

It was unfortunate that no response was received from any developer, it is considered however that this has not detracted from the quality of the conclusions based on the information received elsewhere.

The basic state of the art and views on developments are those as provided by respondents with direction being provided by SKM, whereas conclusions reached are based on the additional expertise and analysis of SKM.

4. State of the Art Technology

The description of the State of the Art of offshore connection technology is covered in this Section of the report and also in Section 6.

In this Section, descriptions of the technologies are presented together with some summary physical, performance and cost characteristics. In Section 6 detailed spreadsheets are included for each technology covering physical, performance and cost attributes. In addition to the current state of the art the development of the attributes is then identified for the future with specific milestones for advancement being defined.

Additionally, in Section 6 the information in the individual attribute sheets is used to visualise technology road maps based on the expected development of equipments.

4.1. HVDC Converters and Systems

4.1.1. Overview of Technology and Developments

The general consensus of opinion is that there will be significant developments in HVDC technology over the next 20 years, becoming gradually more cost effective and more compact equipment. There is no limitation currently with regard to application of HVDC to offshore renewables though there are currently very few proven examples. (Voltage Source Converters) VSC's can be rated up to 1800 A, limited by IGBT ratings, at voltages up to 500 kV using mass impregnated cables. There is a trend to use the cheaper extruded cables that are limited to about 250 kV however development is already underway and it is expected that over the next few years this limitation will be alleviated as discussed in Section 4.6.2.5.

A single connection at present could be rated up to 1000 MVA using current technology, and though there is no operating example of this both ABB and Siemens have concept designs for comparable offshore platforms. Given availability requirements it is likely that converters will be limited to around 1000 MVA per unit regardless of technical limitations making current technology fit for purpose into the foreseeable future.

We can expect to see converter capacity and voltage increase steadily over the next 15 years potentially reaching 3000 MVA and 600 kV. Standardisation and the resulting interoperability is expected to develop on a similar timescale with significant multi-terminal applications operational within 15 years. VSC losses are expected to be comparable to (Line Commutated Converter) LCC losses within 10 years given general development of existing technology.

The most likely significant developments for VSC over the considered timeframe are developments with the basic IGBT building blocks. Currently Silicon based devices are used and have been developed to their upper limit of 6.5kV per device whilst thermal performance is significantly limited. Silicon Carbide could potentially achieve ratings of 15kV per device with improved thermal characteristics. Large sums of money are being invested into military applications of Silicon Carbide to reduce the size and weight of devices for total electric drive applications for the American navy. A commercial product for drive applications, assuming the continuation of funding, could be available in 10 years and will no doubt be applied to transmission and distribution applications potentially providing a step reduction in size, weight, and losses. Diamond based materials could however achieve ratings of up to 50kV with better thermal capabilities than Silicon Carbide. Possibly the most promising development is the introduction of such diamond based devices which could potentially result in a further step reduction in converter dimensions, weight, cost, and losses. These devices operate on the principle of injecting electrons into a diamond substrate using field emitting structures embedded in the diamond. This exploits a property almost unique to diamond, which is that although it is a very good electrical insulator, if you can get charge into the material - especially electrons - they will travel through the diamond with very low loss. Since the transport is in the solid state you can manipulate the characteristics (e.g. some fault limitation) by doping the diamond. The result is that potentially by 2015 diamond based devices rated at several hundred amps up to 20 or 30 kV could be available and could mean a reduction in device numbers of up to three quarters in a voltage source converter. However although this technology is proven with relatively small capacity prototypes uptake by major suppliers has been less than enthusiastic.

Another potential development which has been mentioned, although without any specific timescale attached, is filterless converters. As described in Appendix A VSC stations require AC filtering to a greater or lesser extent, recently announced new topologies propose to be completely filterless though there is no information as yet as to any cost benefit and the specifics behind the new technical solution. Footprint saving from such a development would be small but not insignificant at around 7% which could result in small platform and installation cost reduction.

The most significant and consistent message from suppliers with regard to HVDC application has been the need for standardisation. In order for true multi-terminal to be realised standardised voltages must be established for the development of breakers and protection systems to follow. Further, the control of such systems will be difficult to achieve without interoperability standards. Standardisation will be difficult to achieve and will take some years to become established however progresss is being made in this field with IEC (TC115) and the CIGRE B4 study committee. The latter of these is particularly significant as it demonstrates the recognition of the potential role of the CIGRE (International Council on Large Electrical Systems) organisation. Additionally some form of DC Grid Code would be required for connectivity to a DC Grid. It has been noted that if standardisation does not come on stream within 5 to 7 years de-facto standards (from manufacturers own solutions) may begin to be implemented out of necessity.

We have also gauged a significant amount of interest from suppliers with regard to DC collection. Current application of HVDC assumes collection at AC and then conversion at a central converter platform for export to shore. The requirement for AC could be removed entirely, especially given that the WTG's utilise back to back converters already. We have addressed this point by placing enhanced emphasis on DC switchgear and cables. From a converter stand point DC/DC solutions would require large high voltage DC to DC converters for the function currently provided by transformers. Existing DC/DC converters are not geared towards this role, however manufacturers are starting to developments in this area, driven by the requirements of future SmartGrids and offshore DC networks. Generally it has been suggested that suitable converters will begin to become available over the next 7 to 10 years, split into two classes; SmartGrid related converters with voltages from 5 – 25 kV and powers from 1 – 25 MW, and Transmission related converters with voltages from 50 – 300 kV and powers from 40 – 600 MW.

4.1.2. Characteristics

Physical Characteristics

Currently there is little information on the physical characteristics of a large offshore converter stations as there are limited operating examples. Included below are the known characteristics of a moderately sized operating converter (Figure 4) along with a concept design indicative of the operating converter (Figure 5), also included are concept designs for larger converters (Figure 6 and Figure 7). An indicative layout of an onshore 1000 MW VSC block is presented in Figure 8 below, along with an LCC converter station in Figure 9 for comparison. Table 1 provides a summary of dimensions against technology and capacity.

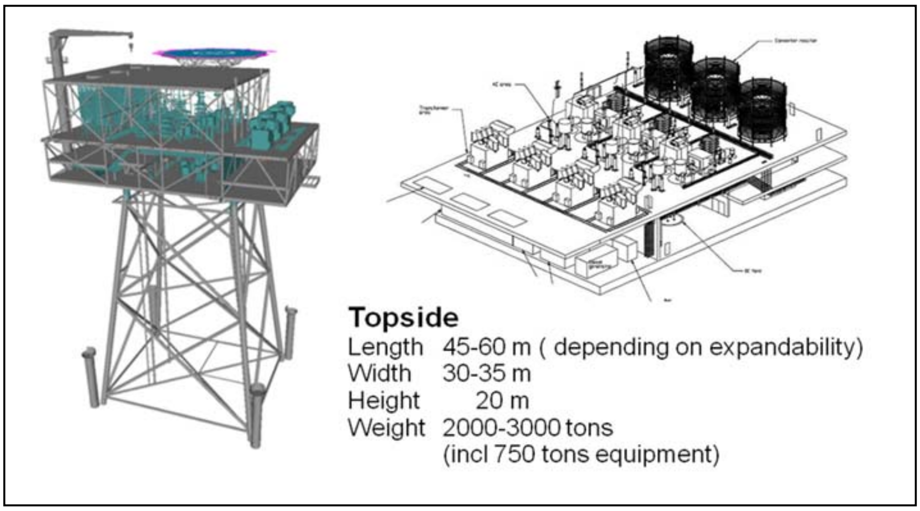
- **Table 1 Summary of Converter Station/Platform Dimensions**

Capacity (MW)	Technology	Length (m)	Width (m)	Height (m)	Weight (Tonnes)
400	VSC (HVDC Light)	45-60	30-35	20	2000-3000 (750 equipment)
750	VSC (HVDC Plus)	45	45	30	5000
1000	VSC (HVDC Light)	60-90	35-40	30-35	5000-7000 (1500-2000 equipment)
500	LCC (HVDC Classic)	240	80		N/A Fence to Fence Dimensions
1000	LCC (HVDC Classic)	450	130		N/A Fence to Fence Dimensions

There are no specific environmental issues regarding the application of HVDC technologies other than the general issues of consideration of electrical losses and the need to ensure that any equipment placed offshore is suitable for the environment.

- **Figure 4 BorWin 1 ±150 kV, 400 MW HVDC Light Platform 3,300 tonnes (Courtesy: ABB [1])**

- **Figure 5 HVDC Light ±150 kV, 400 MW Platform Layout (Courtesy: ABB[2])**



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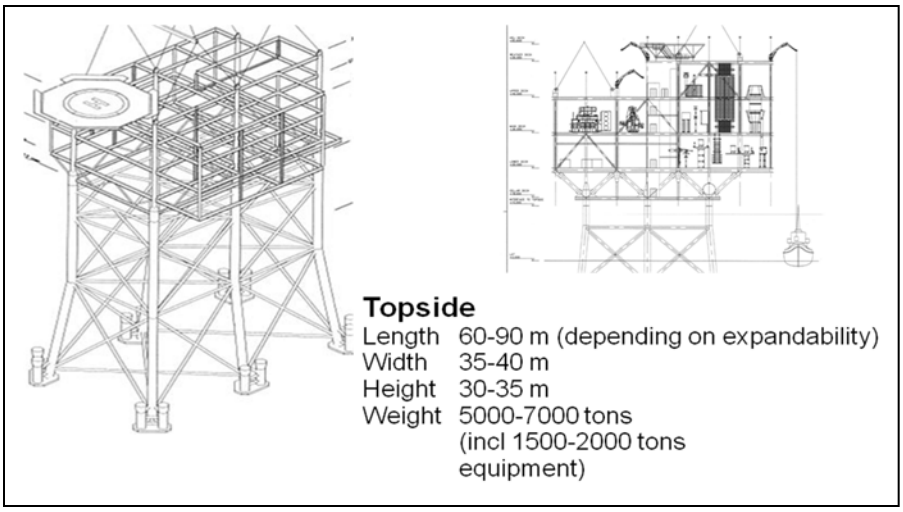
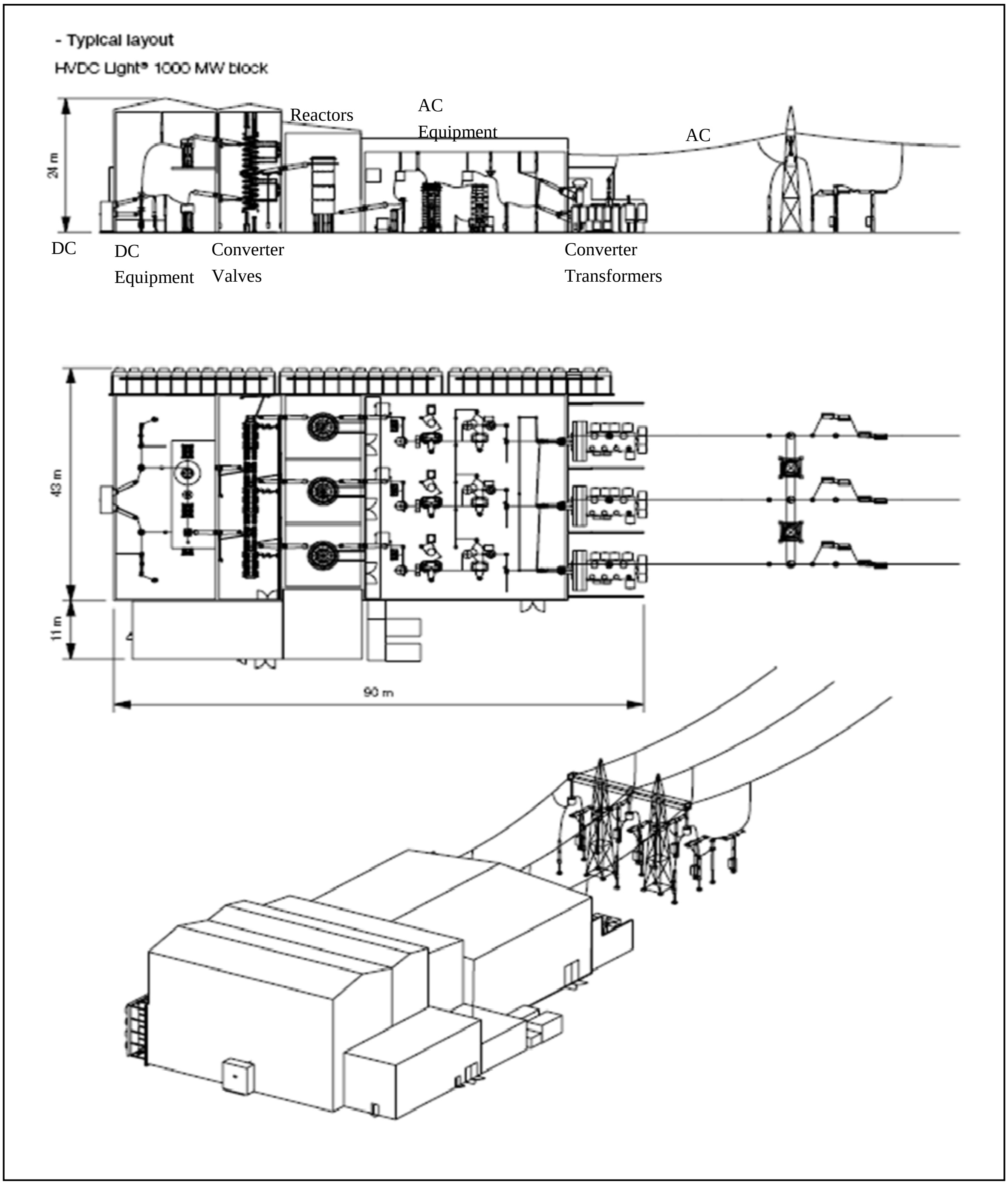
[1] BorWin1 ABB Press Release, December 2009 aspx
[2] HVDC Applications, ABB Power Point Presentation, October 2008, Ref 08MP0823

- **Figure 6 HVDC Light ±300 kV, 1000 MW Platform Layout (Courtesy: ABB[2])**



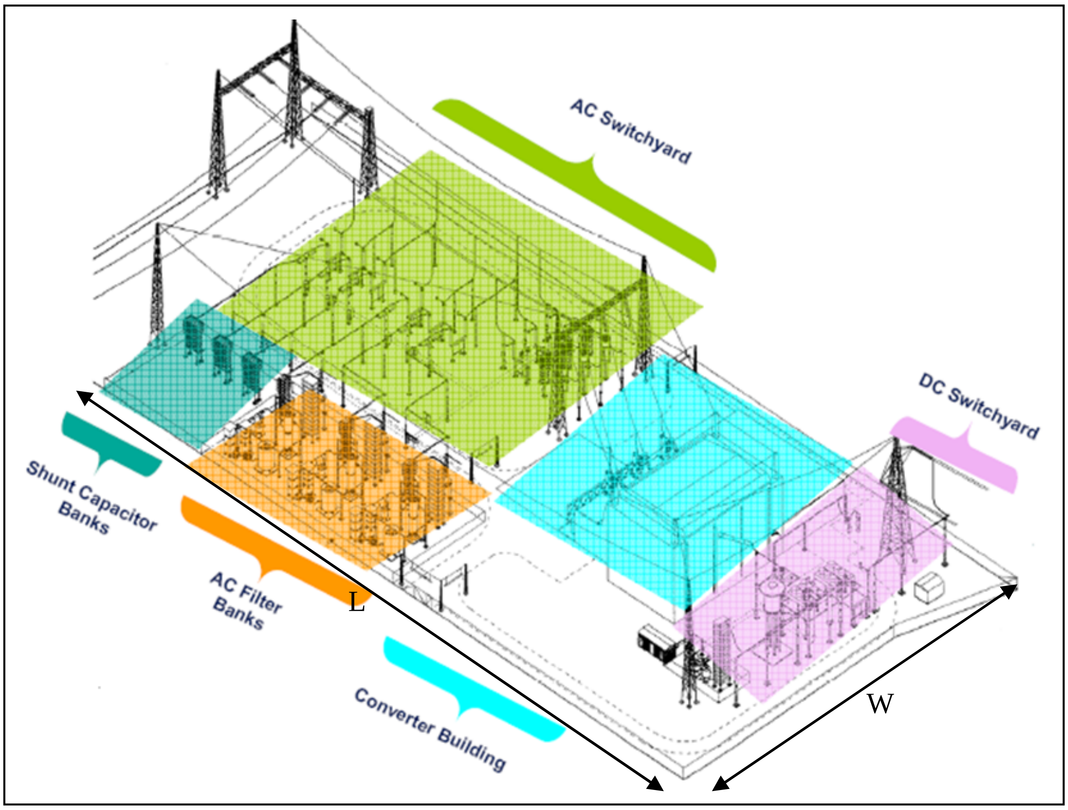
- **Figure 7 HVDC Plus 800 MW Converter Platform (Courtesy : Siemens)**

- **Figure 8 HVDC Light ± 320 kV, 1000 MW Onshore Block (Courtesy: ABB[3])**



[3] "It's time to connect – Technical description of HVDC Light technology", ABB, 2008

- **Figure 9 HVDC Classic (LCC) Layout (Courtesy: ABB[4])**



Converter platform size is very likely to decrease over the next 20 years as the technology develops and evolves. This development is a natural progression of the technology and is unlikely to be a main driver in offshore development. There is however the potential for a step changes in physical dimension and weight with the adoption of filterless converters in the short term, Silicon Carbide devices in the medium term and subsequently Diamond type devices in the longer term which could instantly result in a reduction of converter station size and weight.

Converter platforms are (as with collector platforms) transported to site on a vessel and craned into position atop a prebuilt and installed support structure. Given the relatively small nature of converters compared to other offshore constructions used in the oil and gas industry it is not envisaged that there will be any technical issues with installation for the foreseeable future. The main issue given the volume of platforms (both converter and collector including a great number of wind turbines) that will potentially be built in a relatively short timescale is that there is likely to be a constraint on suitable vessels and trained personnel for installation. This issue will be compounded should there be no adequate co-ordination to maximise resource utilisation.

[4] http://www.abb.com/industries/db0003db004333/453b51c4d7050460c1257482003106c6.aspx?productLanguage=us&country=GB&tabKey=2

Electrical and Operational Characteristics

Presented below in Table 2 are the HVDC converter characteristics which will most significantly affect offshore development along with expected and potential developments over the given timeframes.

- **Table 2 VSC State of the Art and Perceived Developments**

Characteristic	State of the Art	Within 5 Years	Within 10 Years	Within 15 Years	Beyond 15 Years
Converter Capacity MW	1000 Theoretically 500 MW realised	1500	2000	3000	Given availability requirements there is no benefit to larger converter capacities.
Voltage kV	250 - 320 when limited by XLPE cabling [5]	400	500	600	Further development in voltage will be linked to XLPE cables unless conventional cables are used.
Losses %	1.0 to 1.2 Rating (includes Tx losses), 60% Fixed	1.0	= LCC with potential further Significant Reduction due to the adoption of Silicon Carbide Devices	-	Significant reduction
Performance and experience	Given the lack of any significant offshore applications until very recently there is very little information on performance and availability, onshore applications of VSC have availability in excess of 99% however the relevance of onshore information is disputable.				
Availability	>99%				
Interoperability	A lack of any standardisation limits interoperability.		Standardisation established with multi-terminal in build.	Multi-terminal fully operational.	DC networks may begin to replace some AC systems, interoperability akin to that in AC systems.
Development Description		General incremental development	General incremental development Adoption of Silicon Carbide Devices	Development of a standardised multi-terminal system could significantly reduce connection issues	Adoption of Diamond type devices.

4.1.3. Costs

Presented below in Table 3 are representative HVDC offshore converter costs and potential developments over the given timeframes. Please note that costs are indicative and based upon very limited number of published and communicated values. A range of values is presented for capital costs as voltage level and converter size both have an impact on the per MW value.

[5] Mass Impregnated cables could be used with VSC technology but XLPE preferred due to lower costs.

- **Table 3 HVDC Converter VSC Offshore Costs**

Cost Type	State of the Art	Within 5 Years	Within 10 Years	Within 15 Years	Beyond 15 Years
Capital £/MW	150,000 - 225,000 installed	Small reduction	Small reduction	Small reduction	
Installation £/MW	-	Removal of filters reduces station weight and footprint reducing platform and installation cost	Reduction in converter weight due to Silicon Carbide devices resulting in reduction of platform and installation costs	No change	Reduction in converter weight resulting in reduction of platform and installation costs
Operation		Small reduction due to less losses	Small reduction due to less losses	Small reduction due to less losses	Significant reduction in losses leading to reduction in operational costs
Description of developments		General incremental development Introduction of filterless topologies.	General incremental development Introduction of Silicon Carbide Type Devices.	General incremental development	Introduction of diamond type devises

- **Table 4 Comparative Onshore VSC and LCC Costs**[6]

Technology	Installed Cost £/MW
VSC	100,000 - 112,500
LCC	55,000 - 65,000

There is at this point no historic cost trends related with VSC offshore converters due to the lack of operational VSC offshore applications. It is expected that the general cost of offshore converters will fall over time as the technology improves however this is not expected to significantly drive offshore developments.

4.2. Power Transformers

4.2.1. Overview of Technology and Developments

Transformers are a well established piece of equipment, general consensus of opinion has been that there will be no major advances in transformer technology in the foreseeable future that will significantly affect the design or implementation of offshore renewable connections. There has however been some interest in the application of alternative current technologies.

[6] "PJM Interconnection (PATH PROJECT) HVDC Conceptual Study", Black & Veatch, November 2009

Key factors that arose in the discussions with suppliers were:

- Fire protection philosophy and potential impact of insulation system
- Saving weight and resulting impact on platform structures
- Environmental aspects of insulation technology
- Cooling systems and suitability for offshore application
- Marinisation of main and ancillary equipment

Current offshore projects generally use traditional mineral oil immersed transformers with fire protection systems ranging from the very basic provision of containment walls to avoid the spread of the fire while it burns itself out, to integrated fire suppression systems.

To reduce fire risk with regard to the transformer, alternative insulation fluids can be used such as silicone oil or natural and synthetic esters, these fluids offer comparable transformer performance, size, and weight while reducing the fire risk. Predictably however they are also more expensive than mineral oil immersed transformers, - application of these fluids has been limited to around 120 MVA and 245 kV though the technology could be more widely applied if the demand existed. As there is the potential to reduce fire risk given a serious fault, a further question to be considered is whether the platforms will always be unmanned and as such there is the question of fire containment and/or suppression systems being built into the platform and what steps are reasonable to mitigate damage. As platforms become larger and are located further offshore then they may well become manned, when the question of fire protection will become increasingly important. Information on the potential benefits of the technology on fire protection systems is not clear. Indeed, there appear to be inconsistencies in the application of fire protection philosophies on offshore platforms and this has been highlighted as an area where some standardisation would be useful.

Alternatively, fire risk can be completely removed with the application of gas insulated transformers (GIT) which, as with gas insulated switchgear (GIS), use SF_6 in place of the conventional insulating fluid. SF_6 is completely non-flammable and SF_6 transformers are considered non explosive due to SF_6's pressure rise against time characteristics within a large transformer tank volume. Furthermore GIT's are approximately 50% the volume and 85% the weight of oil immersed transformers, and if integrated with GIS a significant substation footprint reduction can be made. Again however GIT's are significantly more expensive than oil immersed transformers athough this can be balanced by other savings such as platform cost, fire fighting systems, fire protection and reliability. GIT's have a more limited record of use both in regards to the number of units and length of operation, however reliability records are excellent and maintenance requirement minimal.

It is important to note that “less- flammable” transformers have already been used primarily in locations where fire or explosion poses risk to life. For example large GIT’s have been used for underground substations in heavily built up and populated areas in Japan where a major fire or explosion could have a devastating effect on life. Offshore platforms are currently, as previously mentioned, completely unmanned during normal operation and as such the only risk that is significantly mitigated is that of damage to the platform in the already highly unlikely event of a fire or during maintenance periods. A further issue affecting the insulating medium is the question of environmental impact. Mineral oil is highly polluting and as such collection in the event of a spill is vital for offshore platforms. Certain “less-flammable” fluids and SF_6 remove the environmental aspect by being biodegradable or in the case of SF_6 a completely harmless (to wildlife) gas, athough as SF_6 is a very potent greenhouse gas research and development of alternate gasses to SF_6 is ongoing but at present there is no viable alternative.

With respect to environmental damage, current offshore projects include in the design containment systems to collect oil spills, which is relatively cheap and sufficient for requirement. There is therefore little incentive to take measures to reduce oil spill risk further though this may change with future legislation demanding further mitigation of environmental risks. Such considerations of legislation may also apply to SF_6 gas where future requirements might make the use of SF_6 gas offshore less attractive. In some countries restrictions have already been placed on the use of SF_6 particularly where solutions exist that overall are considered to have less environmental impact. Life Cycle Assessment techniques may then be required to assess the overall benefits of particular solutions.

Mention has been made to the development of superconducting transformers and although significant in reducing conversion losses or as fault current limiters, their impact on the transmission system as a whole or the direction of developments seems to be very limited. This will be especially evident should, as expected, HVDC become a more prevalent technology or furthermore a move to a fully DC system which would remove the use of transformers entirely. It has been suggested that superconducting transformers will be generally available within 5 years.

Submersible transformers exist and are of use in oil and gas operations for auxiliary power supplies in drilling projects. These transformers are currently of cast-resin design and for very small units. The advantage of utilising a submersible transformer would be to remove the requirement for an offshore platform. This would therefore imply that the application would be for a large step-up power transformer for exporting of power. The costs involved in the design and construction of a sealed and watertight power transformer would likely far outweigh that of an offshore platform, even in deep water. In addition, the installation, maintenance and potential repair of such an item of equipment would be extremely difficult and costly. Such a design may be more viable for very small scale marine developments, however other architectures and design conceptions are likely to be adopted before this concept is realised.

4.2.2. Characteristics

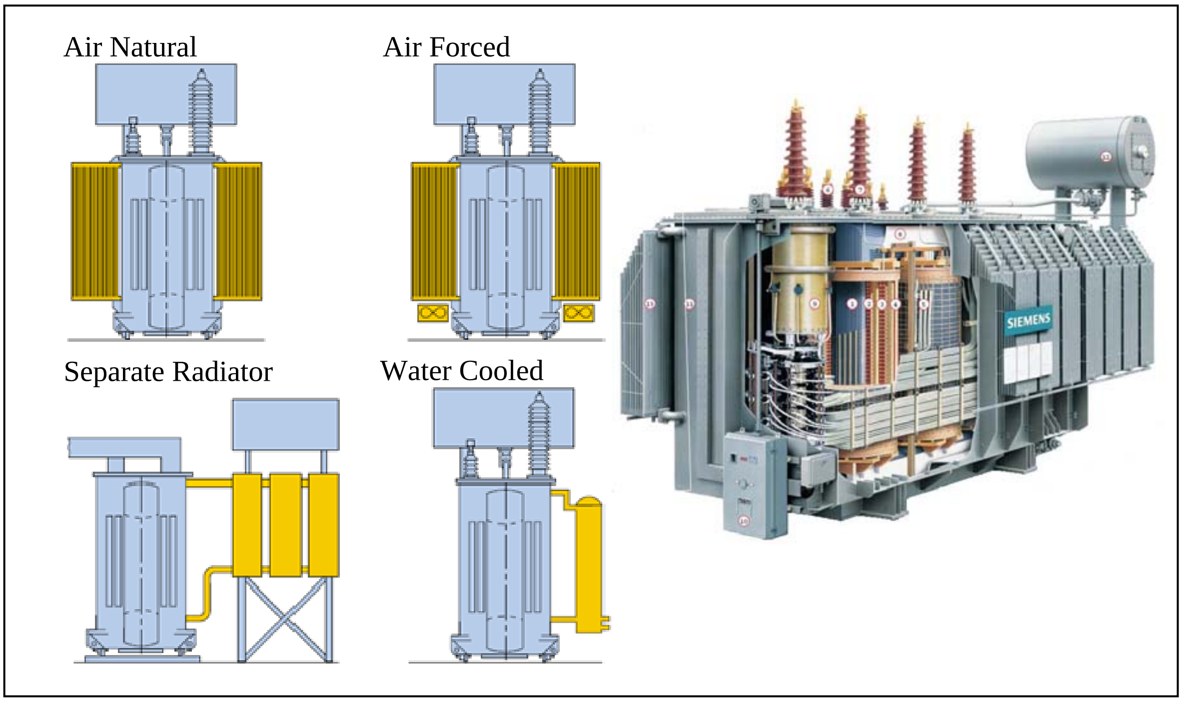
Physical Characteristics

Figure 10 below shows a selection of the most common oil immersed power transformer cooling arrangements, Figure 11 shows a comparative GIT. Indicative dimensions and weights for a range of transformer capacities and insulation types are summarised in Table 5.

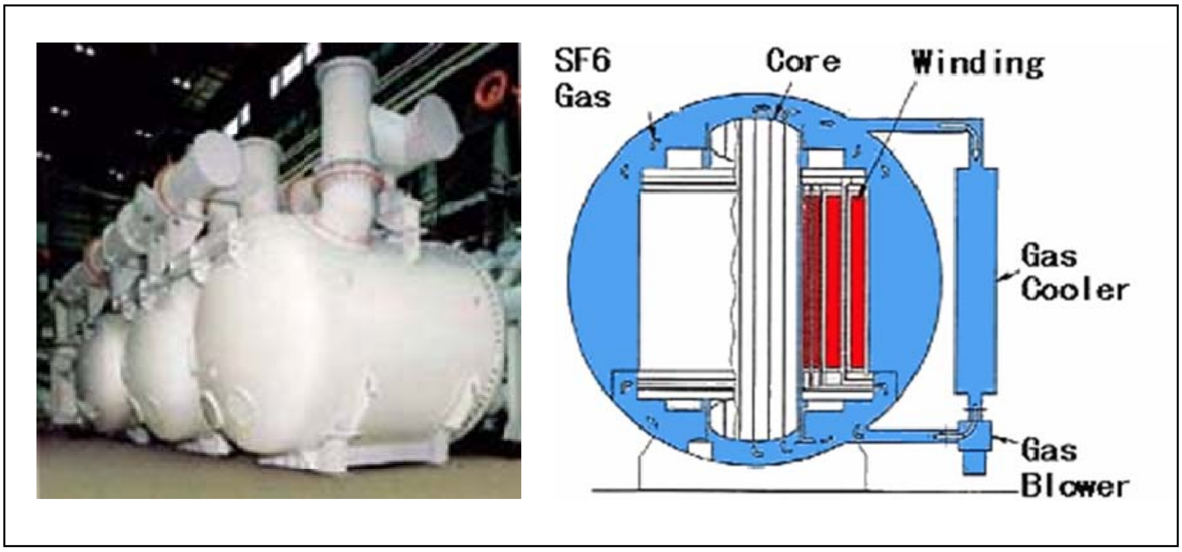
Table 5 Power Transformer Dimensions and Weights

Capacity (MVA)	Type	Length (mm)	Width (mm)	Height (mm)	Weight (kg)
90	33/132 Mineral Oil Filled	6875	4515	5775	106000 With Oil 80000 Without Oil
120	33/132 Mineral Oil Filled	7280 Tx 7460 Radiator	2630 Tx 3070 Radiator	5350 Tx 7000 Radiator	134500 With Oil 93600 Without Oil
180	33/132 Mineral Oil Filled	7676 Tx 6825 Radiator	2205 Tx 3150 Radiator	4620 Tx 7350 Radiator	190000 With Oil 152000 Without Oil
N/A	Synthetic Ester Filled	Comparable to mineral oil, approximately 5% more volume			Approximately 2% more than mineral oil
N/A	Silicon Oil Filled	Comparable to mineral oil, approximately 5% more volume			Approximately 2% more than mineral oil
N/A	Gas Insulated SF^6	Approximately 50% volume of mineral oil immersed			Approximately 85% that of mineral oil

- **Figure 10 Indicative Transformer Arrangements(Courtesy of Siemens[7])**



- **Figure 11 Power GIT Indicative Construction (Courtesy: Toshiba[8])**



[7] "Power Transformers 10 to 100 MVA" Product Brochure, Courtesy Siemens
[8] Toshiba GIT webpage, "http://www.toshiba.co.jp/f-ene/tands/english/trans/l_gas.htm"

Electrical and Operational Characteristics

Table 6 below summarises the characteristics which will most effect offshore development for a range of transformer capacities and insulation mediums.

- **Table 6 Power Transformer Electrical Characteristics**

Characteristic	Mineral Oil (120 MVA) (132/33kV)	Synthetic[9] Ester	Silicon Oil	Gas insulated SF_6
Cooling arrangements	Range of well established arrangements the most common being ONAN (oil natural air natural) ONAF (oil natural air forced) and OFAF (oil forced air forced)	Match mineral oil filled	Match mineral oil filled	Match mineral oil filled
Lifetime Years	40	40+ commercial sources claim extended transformer life	40+ high thermal stability and oxidation requirements could result in extended transformer life	20 years of service recorded with life expected to be well over 30 years
Operation and Maintenance	0.5 periodicy per annum. 5 days duration.	As with mineral oil filled	As with mineral oil filled	Minimal. Almost maintenance free with the exception of cooling system, gas samples required to be taken following energisation, 1 week, 6 months, 1 year, 2 year, 4 year cycle.
Availability	MTBF in situ 0.05, Factory 0.003. MTTR in situ 10, Factory 107.	MTBF factory increased, due to reduced degradation of solid insulation	Comparable	Near perfect record, significantly better than oil immersed however lack of data means there is no available figures for MTBF or MTTR.
Fire and Blast Considerations	The most flammable and explosive of the insulation mediums covered, offshore fire precautions range from none to integrated suppression systems	Classified as less flammable, significantly reduced risk of fire or explosion in the event of a fault	Classified as less flammable, significantly reduced risk of fire or explosion in the event of a fault	Non flammable and classified non explosive
Environmental Considerations	Highly polluting, containment required on platform	Biodegradable, no containment required	Non Biodegradable, containment required	Potent greenhouse gas

[9] Midel Document Library, http://www.midel.com/library.htm

4.2.3. Costs

Table 7 below summarises the capital and offshore installation cost of an indicative power transformer along with comparative costs for a range of installations.

Table 7 Power Transformer Costs

Cost	Mineral Oil (120 MVA)	Synthetic Ester	Silicon Oil	Gas insulated SF_6
Capital	£1,200,000	10% more than mineral oil	More than synthetic ester	200-300% equivalent oil filled transformer cost.
Installation	35% capital assuming installation on platform at construction yard, total installed cost of transformer offshore will be at least double onshore value.			Cheaper than mineral oil

4.3. AC and DC Switchgear

4.3.1. Overview of Technology and Developments

4.3.1.1. AC Switchgear

AC Switchgear is a very well established technology and in most senses could be classed as a commodity item of equipment. Over the past 50 years, switchgear developments have been focused on reducing size, weight and cost of the equipment through new insulation and circuit breaker mediums and at the same time improving reliability and reducing maintenance requirements. In line with this trend and with the responses from manufacturers there is little expected substantial development in AC switchgear in the near future.

There is a wish to optimise the AC voltage level of inter-array cabling to best utilise string length, reliability, availability and losses as turbine sizes increase over time. This could be with the introduction of IEC non-standard voltage levels at which the switchgear must be able to operate. Present switchgear technologies are versatile and can often operate outside of their rated values with little impact on reliability and lifetime so it would be unnecessary to develop new equipment for this scenario.

Present AC switchgear systems utilise SF_6, particularly at voltages of 66kV and above, as the insulating medium to reduce the size and weight of the equipment. Voltages at 33kV and below often still use SF_6 for insulation but utilise vacuum interrupters for the circuit breaking elements. Designs of higher voltage GIS switchgear are available which use vacuum interrupters for interruption and Nitrogen as the insulating medium, but these are typically the size and weight of higher rated equipment which have been de-rated to eliminate SF_6 usage. It has been highlighted by some that due to the environmentally unfriendly nature of the gas that regulation in the future could restrict or even forbid its use. However at present as there is no feasible replacement to the technology, to overcome the issues discussed in Section 4.2, and until an alternative is commercially available it is expected that regulation will focus on the strict controls during handling of the gas more than forbidding its use entirely. The developments of new insulation mediums may have small impacts on switchgear size, weight and costs but operation will be ultimately the same and AC switchgear will continue to be a commodity item and have little impact on influencing the design of offshore network systems.

Basically there are two main types of AC switchgear that are required for current and near term projects. The first of these is the switchgear required at each generating device which is typically of the “secondary” switchgear type. The other is the export switchgear which is required on the offshore substation platform and also on the land based connection point.

Collector Switchgear

The term secondary reflects its role on onshore applications where combinations of circuit breakers and switches (Ring Main Units) are needed in cable connected networks. Early renewable projects utilised standard onshore ring main units (one circuit breaker and two ring switches) based on standard onshore technologies. More recently such ring main units have been adapted with three circuit breakers being used by connecting three separate elements together. This provides increased functionality but is significantly higher cost and also requires a larger footprint.

- **Figure 12 "Secondary" type RMU, 33kV, (Courtesy : ABB[10])**

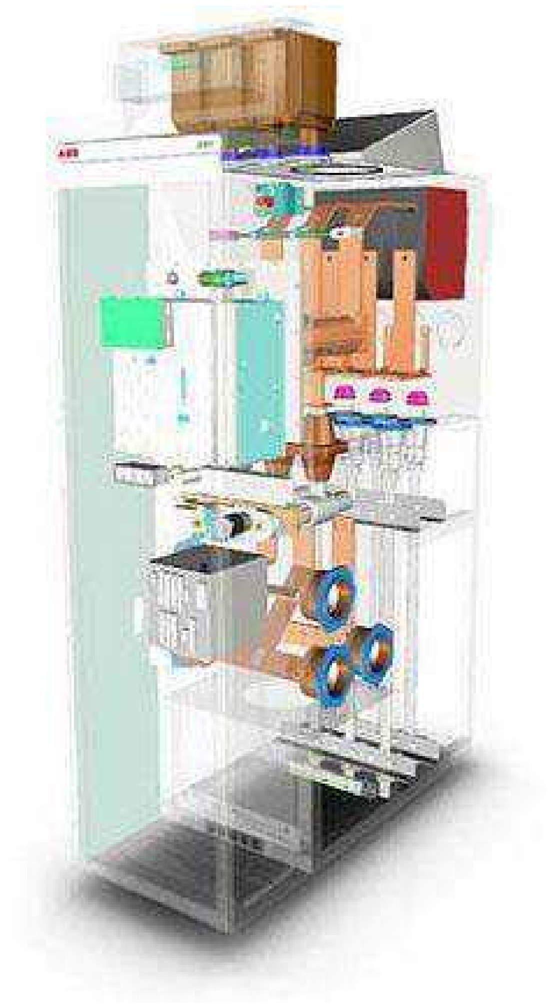


Figure 12 above shows a typical "secondary" type RMU which provides "T" connected 33kV cables and basic 33kV switches. Multiple circuit breaker units can also be connected together as suggested.

Another option is to engineer a specific array switch which provides a circuit breaker and two ring switches with fully automated operation and the benefit of phase segregated GIS construction (see Figure 13 below).

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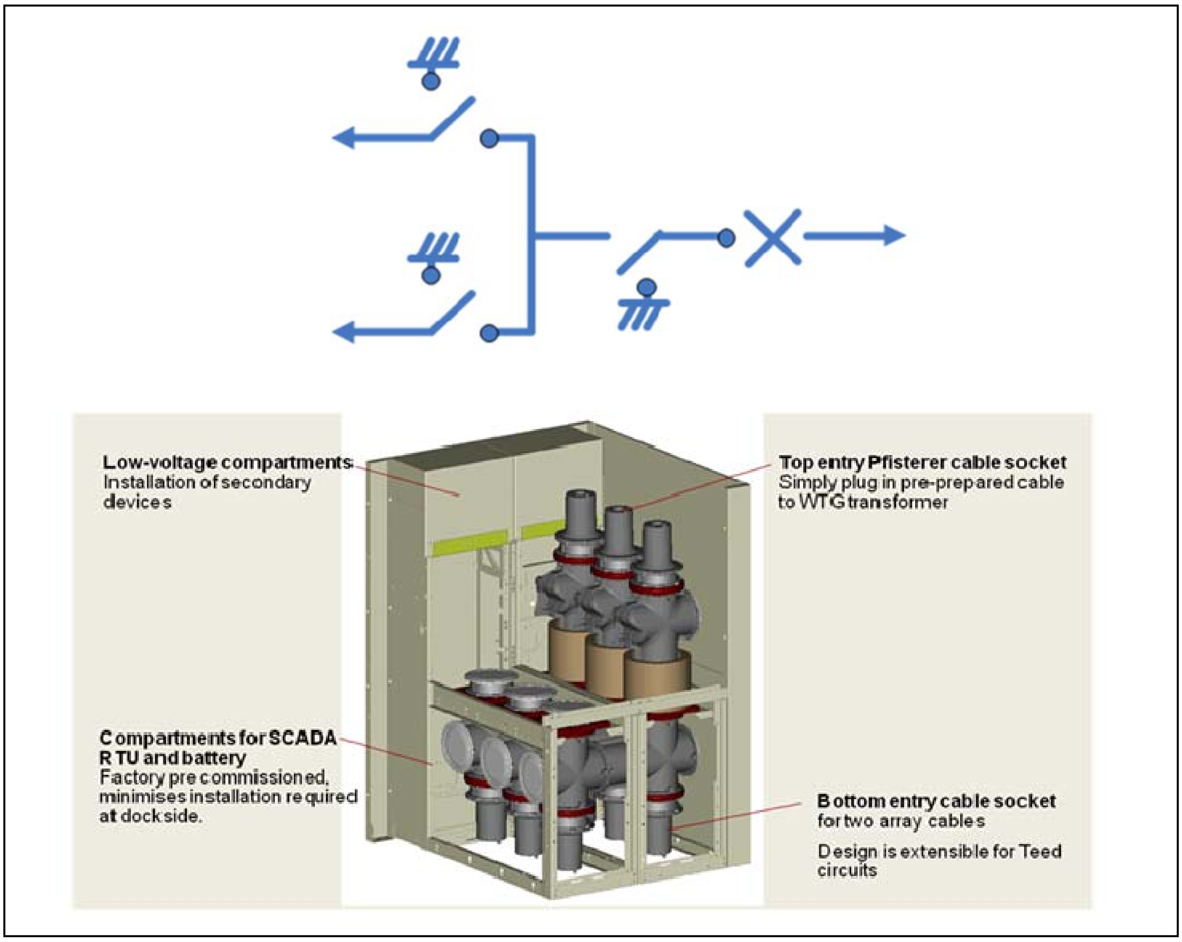
[10] ABB Type ZX1.2 http://www05.abb.com/global/scot/scot235.nsf/veritydisplay/f7670c781803e2d5c12576e90057cd69/$File/ZX1.2_E_2010.pdf

▪ **Figure 13 Array Switch Construction (Courtesy of Siemens)**



The array switch may be mounted in the wind turbine transition piece.

This arrangement offers some application advantages

- Factory condition quality and testing
- No electrical work at dockside
- Minimise offshore work
- In the event of a fault replace individual castings, not whole unit – fits through tower door
- Can be transported offshore with transition piece vertical, or on its side
- Cast aluminium design and removable top box allow overwinter offshore before tower arrives

However the most significant benefits will relate to enhanced reliability provided by the single phase segregation of the GIS type construction. Additionally, for applications where elevated AC voltages may be required it is possible to operate such equipment at 40.5kV and may be possible to achieve higher ratings on standard elements.

Export Switchgear

The second type of switchgear is the export switchgear which is currently rated at 145kV for both offshore and land applications associated with large wind farms. For offshore this is located on a platform and due to space constraints is of the GIS (Gas Insulated Switchgear) type. For onshore applications the voltage and type of equipment used will depend on the application and the potential interconnection with existing onshore substations. Hence MTS (Mixed Technology Switchgear, see Figure 14) GIS (see Figure 15), or AIS (Air Insulated Switchgear, see Figure 16) solutions might be the most appropriate.

In all cases the switchgear used for the AC export system is standard switchgear and developments in switchgear itself are not likely to impact on the implementation of offshore renewables with standard solutions being available for all envisaged offshore requirements.

- **Figure 14 Mixed Technology Switchgear, 550kV, (Courtesy: ABB[11])**

[11]http://www05.abb.com/global/scot/scot245.nsf/veritydisplay/e3beab95cf00a533c12577a500524821/$File/BR_HV-PASS-FAMILY(EN)A_2GJA708398-1008.pdf

- **Figure 15 145kV GIS, Double Busbar Bay with Cable Feeder (Courtesy: ABB[12])**

- **Figure 16 420kV AIS Substation (Courtesy: ABB[13])**

[12] http://www.abb.com/product/db0003db002618/c6e717894cf48393c12577840039fb32.aspx?productLanguage=us&country=GB

4.3.1.2. DC Switchgear

DC switchgear is utilised in many traction applications at relatively low voltage levels, however there are few applications at medium or high voltage levels. This would be required should full multi-terminal HVDC systems or DC inter-array collection systems be fully realised. In terms of HVDC breakers the greatest challenge is dealing with a DC exporting cable fault. Although rare, the faulted cable section requires to be rapidly identified and removed from operation so that the un-faulted cable sections and converters can be quickly restored into service. Some designs of high voltage DC breakers do exist and 500kV DC circuit breakers were tested on the Pacific HVDC Intertie by Bonneville Power Administration as long as 20 years ago, however the re-start time of such equipment are limited. There has been a significant interest in the possibility of utilising a fully DC system for both collection and export. Should a fully DC system be realised then the protection systems employed will also rely on fast-acting DC switchgear at a range of voltage levels.

At present there is no standardisation of DC voltage levels and this would be required before manufacturers can commit to substantial switchgear design and reflects what has been noted in Section 4.1.1 concerning the interoperability of multi-terminal HVDC systems. We have identified that in order for multi-terminal HVDC systems and DC collection systems to be fully realised, fast-acting DC breakers at medium and high voltage levels will require new developments to be completed following standardisation of suitable voltage levels. A market driven development based on standardised DC voltage levels could be realised in 3-5 years.

For AC systems two natural current zeros occur for each cycle, so the challenge for the AC circuit breaker is to extinguish the current flow at current zero and ensure that the voltage withstand capability of the device exceeds the stresses imposed by the recovery voltage of the system. Generally this involves mechanical contacts drawing an arc, which is extinguished at current zero and then establishing a contact gap that can withstand the recovery voltage of the system.

For a DC breaker the challenge is to deal with a situation where there is no natural current zero, therefore the circuit interruption has to be forced using some additional device or system.

Theoretically there are two types of HVDC circuit breaker that could be envisaged, the first is the conventional mechanical solution, the second being the electronic solution. The electronic solution using power electronic switches is potentially much faster than a mechanical solution but would be currently prohibitively expensive and also involve significant electrical losses. Developments in power electronic devices (see Section 4.1) are unlikely to change these problems in the foreseeable future so the mechanical solution seems most realistic to consider.

Whilst there are various circuit breaking mechanisms that have been suggested for HVDC they can be categorised into 3 elements[13], these are:

1) The main contacts
2) The commutation circuit
3) The energy absorber

The main contacts could be provided from a suitably rated conventional AC circuit breaker. Differences are envisaged in the nature of the commutation circuit but the objective, whether it be reverse current injection or active resonance is to establish a current zero at which the current can be interrupted, bringing into play the energy absorption element which limits the recovery of the system voltage as energy is absorbed.

CIGRE has already established the requirements for such an HVDC circuit breaker under normal switching, fault clearance and line/cable switching duties. What would be required next would be for agreement on standardisation issues such as voltage levels such that specific development projects could be undertaken to deliver the theoretical devices envisaged.

The voltage levels selected and the requirements for location of such HVDC devices will determine the packaging required and selection of technology needed for the other DC switchgear elements needed to provide a complete a complete HVDC switchgear solution. The circuit breaker requirement is however seen as the major technical issue, yet to be addressed for DC switchgear.

4.3.2. Characteristics

4.3.2.1. Physical Characteristics

As the switchgear is required to be installed within the turbine tower or on an offshore platform, its size and weight can have an impact. For instance, present 72.5kV switchgear is unable to be located within 3.6MW wind turbine towers due to lack of space to fit the 3 circuit breakers required. However, as turbine size increases, so must the tower and supporting structure which we envisage will allow higher voltage switchgear equipment to be installed with little issue in the future. Included in Table 8 below are known characteristics of 33kV and 132kV switchgear which is currently being utilised in offshore applications. Higher voltage equipment may be utilised in the future to optimise a system with larger turbines hence 72.5kV and 220kV switchgear equipments have also been included. In addition a current DC breaker for traction applications is included to provide some reference on the development of DC breakers at this point and a comparison to AC equipment. All of the equipment is SF_6 insulated to reduce size and weight as much as possible.

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[13] CIGRE Brochure no 114 Circuit Breakers for Meshed Multi-terminal HVDC systems

- **Table 8 AC and DC State of the Art Switchgear Physical Characteristics**

Equipment Name	Operating Voltage	Dimensions L/W/H (m)	Weight
Areva Flusarc 36[14]	36kV AC	0.92/1.226/1.72	1.2T
FujiElectric 72.5kV Compact[15]	72.5kV AC	2.7/1.1/2.3	2.3T
Siemens 8dn8[16]	145kV AC	0.8/0.65/1.2	3.2T
Siemens 8dn9[17]	245kV AC	3.7/1.55/4.1	-
Hawker-Siddeley Lightning[18]	1.5kV DC	1.7/0.5/2.3	0.37T

4.3.2.2. Electrical Characteristics

Presented below are the electrical and maintenance characteristics for the switchgear technologies noted previously. It can be seen from this data that the durability of all the switchgear technologies is extremely high at 10,000-20,000 operations and expected lifetimes of greater than 30 years in all cases. In most cases wind turbine lifetime is restricted to 25 years and this could be further reduced in an offshore environment, hence the switchgear will on average outlive that of the turbine. Maintenance of equipment is extremely costly in an offshore environment due to the difficulty in supplying trained personnel to the site. The switchgear technologies denoted below illustrate maintenance free periods greater than 20 years, again close to that of the lifetime of a turbine and this is consistent across all voltage levels.

It is fair to assume that the lifetime, maintenance and reliability of all switchgear technologies is sufficiently high to be of little concern to impact the offshore system. This further enforces the commodity nature of the equipment, illustrating a ‘fit and forget’ style and hence the lack of drive for any significant developments in the field of AC switchgear, as present technology is sufficiently adequate.

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[14] http://www.areva-td.com/solutions/liblocal/docs/Products/SDS/AREVA_T&D_SDS_Secondary-Distribution-Switchgear_Offer-EN.pdf

[15] http://www.fujielectric.com/company/tech_archives/pdf/45-03/FER-45-03-085-1999.pdf

[16] https://www.energy-portal.siemens.com/static/hq/en/products_solutions/17966_153481_8dn8%20up%20to%20145%20kv.html

[17] https://w3.energy.siemens.com/cms/us/US_Products/Portfolio/HVSystemsupto800kV/Documents/8dn92.pdf

[18] http://www.jocastro.co.za/pdf/Lightning%20NDC%20Switchgear%20March%2004.pdf

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Table 9 AC and DC State of the Art Switchgear Electrical and Maintenance Characteristics

Equipment Name	Operating Voltage	Rated Current	Peak Withstand Current	Short Circuit Break Current	Expected Life	MTBF	Maintenance
Areva Flusarc 36	36kV AC	1.25kA	25kA	20kA	40 years	10,000 Operations	20-25yrs maintenance free, 10,000 operations
FujiElectric 72.5kV Compact	72.5kV AC	2.00kA	31.5kA	20kA	40 years	10,000 Operations	20-25yrs maintenance free. 10,000 operations
Siemens 8dn8	145kV AC	3.15kA	108kA	40kA	40 years	10,000 Operations	20-25yrs maintenance free, 10,000 operations
Siemens 8dn9	245kV AC	4.00kA	135kA	50kA	>50 years	10,000 Operations	25yrs maintenance free 10,000 operations
Hawker-Siddeley Lightning	1.5kV DC	4.00kA	71kA	125kA	>30 years	20,000 Operations	'Fit and Forget', 20,000 operations

Switchgear reliability is normally referenced in MTBF (Mean Time Between Failures) with failures generally following CIGRE definitions where Major Failures is the failure of a component or element to perform one of its specified functions which results in the need for intervention within 30 minutes.[19]

Extensive reliability surveys have been completed for GIS switchgear which is clearly of main interest for this project. Reliability figures are dependent on the voltage class of equipment being considered but averaged figures have been published suggesting MTBF rates for GIS <100kV as being in excess of 1000 years whilst for voltage levels between 100kV and 200kV and indeed up to 300kV figures are approximately 100 years MTBF. Of course individual manufacturers will always claim figures better than the CIGRE results, but to balance such arguments we again have to remember that all the CIGRE figures are for onshore applications and the potential influence of offshore environments has not yet been evaluated.

For the lower voltage equipment (up to 33kV) that will be used on smaller sized projects and within individual wind turbines/generators the same extent of reliability information is not available. Individual manufacturers claim MTBF figures for 11kV and 33kV ring main units

[19] CIGRE Brochure No 150 Second International GIS Experience Survey and Database

between 3000 and 5000 years. However caution is necessary as some reliability data is only for part of a system e.g. the circuit breaker element whilst in the above referenced CIGRE studies the figures cover a complete bay of equipment.

4.3.3. Costs

- **Table 10 Generator Switchgear Costs - 33kV Assumption three element array switch**

Cost Type	State of the Art	Within 5 Years	Within 10 Years	Within 15 Years	Beyond 15 Years
Capital £/switch	115,000	Small reduction	Small reduction	Small reduction	
Installation £/switch	-25% of capital cost	No change	No change	No change	
Operation	Insufficient actual data but assumed 0.5 man days per year for routine and detailed inspections	Small reduction to adaption improvements	Small reduction due to less losses	Small reduction due to less losses	No significant impacts
Description of developments		General incremental development	General incremental development	General incremental development	

- **Table 11 Export Switchgear Costs (145kV GIS)**

Cost Type	State of the Art	Within 5 Years	Within 10 Years	Within 15 Years	Beyond 15 Years
Capital £/bay	350,000	Small reduction	Small reduction	Small reduction	
Installation £/bay	25% of capital cost	No change	No change	No change	
Operation	Insufficient actual data but assumed 0.75 man days per year for routine and detailed inspections.	Small reduction to adaption improvements	Small reduction due to less losses	Small reduction due to less losses	No significant impacts
Description of developments		General incremental development	General incremental development	General incremental development	

4.4. Protection Control and Communications

4.4.1. Overview of Technology and Developments

Protection and control systems architecture and hardware are well established technologies, the introduction of these systems to an offshore environment do not pose a problem to existing proven technology. Modern protection relays have been developed to implement the IEC 61850 protocol, which defines a standard protocol to allow increased interoperability and digital signalling from CTs and VTs, although not in common use IEC 61850 has been implemented in various trial substations in networks across the world.

It is envisaged that advances in protection technology will come in the form of further development in un-conventional CT's and VT's which will allow for space and weight saving to be made within substation equipment. The use of IEC 61850 protocol is being accompanied by the development of 'intelligent' measuring devices, these are designed to give a digital output, which can be fed directly to protection relays via optical fibre communications systems. Many of these advances are currently in development, independent of offshore developments, and although the new technology will impact in offshore substation development it is unlikely to be driven by the increase in offshore activity.

SCADA (Supervision, Control and Data Acquisition) is a computer based system utilised for the local and remote control of plant, and the monitoring, collection and reporting of data for analysis. The acceptance and use of SCADA systems within industry has been due predominantly to the advancement in computer hardware and software technology over the past few decades and latterly, the rapid development of the internet, which has enabled the remote control and monitoring of ever increasing complex processes and systems with the resultant financial benefits to industry i.e. increased production, condition monitoring and prediction of plant failure, reduction in manpower etc). As such it is unlikely that any future developments in SCADA technology will be driven solely by the offshore industry, but the offshore industry will be a beneficiary of these if they are adopted.

SCADA is therefore a fundamental component in the effective operation, control and monitoring of industrial process or systems and is used widely within all major industries. In the offshore renewable sector, SCADA has been utilised predominantly in the offshore wind farms where turbine manufacturers have been developing and manufacturing their own SCADA systems for a number of years. These systems were developed initially for the control and monitoring of the smaller capacity onshore turbines and integrating these into a larger operational system using other manufacturers SCADA equipment proved to be complex due to the limited functionality and inflexibility of the turbine SCADA system. As the industry has moved into the construction of much larger capacity wind farms, the turbine manufacturers have been developing SCADA systems that will allow for easier integration with third party equipment. This should allow the wind farm developers more scope of choice with the number of suppliers and the selection of more technically suitable and robust equipment than may have been previously available. This will allow for more comprehensive data gathering and flexibility of remote control, which given the difficulty of access to offshore platforms will be critical to the successful operation of offshore generation.

The communication of control and monitoring information between the SCADA system and the operational plant in onshore industries has traditionally been by copper cables. With the requirement for increasing amounts of data transmission at higher speeds over greater distances the use of optical fibre cabling is becoming more prevalent. This is also the standard for SCADA communications between the offshore industry platforms and the onshore base, which utilises optical fibre cores installed within the export power cables. Other communication systems in use are UHF and VHF radio, GSM (mobile) and the use of satellite technology. These forms of communication tend to be ‘backup’ systems due to the present limitation of data and speed that these systems can handle when compared with optical fibre cable. As with the development of SCADA, any development in communications systems will tend to be driven by global demands in commercial/industry needs rather than the offshore industry in particular.

Condition Monitoring of transmission and distribution equipment has generally increased in recent years with specific diagnostic techniques being developed for equipment such as transformers, cables and switchgear. Reliable and relatively low cost data acquisition equipment and the ever increasing computational power allows even complex equipment diagnostic informations to be captured, processed and communicated. Condition Monitoring is believed by many to be an important tool in the achievement of reduced failure rates, improved equipment availability and as such it is being applied into the offshore environment, although not universally. Therefore, whilst development of specific monitoring techniques for offshore equipment was not highlighted as a significant need, there is no doubt that increased opportunities will exist for more widespread application of condition monitoring in the future offshore connections environment.

Some concerns were expressed as to whether control, protection and communications equipment was entirely suitable for use even within the normally controlled control room environments within a typical offshore platform. Experience will show whether these concerns are well founded but it seems that others believe that if there are problems then techniques already proven in offshore oil and gas environments could be applied to traditional T&D equipment if necessary.

What has been identified is that there are potential interface issues surrounding the access to information across commercial boundaries given the potential complexities of the regulatory regime. The consensus view was however that these issues are not technical but more related to commercial considerations that are beyond the scope of the current study.

4.5. Reactive Compensation

Reactive compensation is well established equipment and will be required mainly for AC exporting to shore scenarios, the introduction of HVDC and other DC designs will dramatically reduce the amount of reactive compensation required. As these DC technologies are to be introduced in the near future, the focus here on reactive compensation equipment is limited. Any foreseeable reactive compensation requirement can be serviced with existing equipment, suppliers of shunt reactors being able to provide units up to 750 kV and 250 MVAr[20].

At present much of the reactive compensation for offshore developments is held onshore to reduce costs and increase ease of installation. With the OFTO regime it is unclear whether this will introduce a requirement for more of the reactive compensation to be located offshore at the sending end of AC export cabling. Current applications of offshore reactive compensation have been unmodified onshore equipment and the only foreseeable developments will be increased marinisation to prevent the corrosion seen by all offshore equipment and to make the solution more compact and of less weight to save on platform requirements.

With the introduction of HVDC to the majority of future developments the perceived advances of reactive compensation is small and of low priority to manufacturers. For this reason and the aforementioned maturity of the equipment there are no significant developments that could be included in this report.

Whilst not expected to be of major importance to this project it is relevant to note that state of the art reactive compensation is considerably more complex than the aforementioned shunt reactor. SVC’s and STATCOM’s provide variable reactive compensation which can react automatically to system conditions. SVC’s based upon thyristor technology have the longer performance history and have generally higher ratings and larger footprints than STATCOM’s which are based on voltage source converters.

SVC’s have been produced up to 500kV and over 700MVAr and are manufactured by several suppliers including ABB, AREVA, Siemens, Toshiba and Mitsubishi.

STATCOM ratings up to ±100MVAr continuous at 145kV are in service with designs up to 200MVAr available. Suppliers Include: ABB, Areva, AMSC, Hyosung, Mitsubishi, Siemens, and Toshiba.

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[20] “Shunt Reactors, for Medium and High-Voltage Networks”, Brochure, Siemens,

4.5.1. Characteristics

Physical Characteristics

Table 12 summarises typical dimensions and weights for shunt reactors of various voltages and ratings.

- **Table 12 Shunt Reactor Physical Characteristics**

Capacity (MVAr)	Type	Length (mm)	Width (mm)	Height (mm)	Weight (kg)
30-60 Tapped	33 kV 3 phase Gas Insulated	7200	5700	4800	100000
30-60 Tapped	33kV 3 phase Oil Filled	6400 6300 Cooler	3000 3200 Cooler	4250 6600 Cooler	112000
30-60 Tapped	132kV 3 phase Oil Filled	8700			4900

Electrical and Operational Characteristics

Table 13 below summarises relevant reactive compensation electrical and operational characteristics. Given the similarity between shunt reactors and transformers many of the operational characteristics are the same as indicated. Note that the statement 'match transformers' refers to a comparable transformer size and cooling arrangement.

- **Table 13 Shunt Reactor Electrical and Operational Characteristics**

Characteristic	General
Capacities MVar	Up to 250
Voltages kV	Up to 750
Availability	Match Transformers MTTF, and MTTR
Operation and Maintenance	Match transformers
Fire, blast, and environmental Considerations	Match transformers

4.5.2. Costs

- **Table 14 Shunt Reactor Costs**

Cost Type	60 MVAr 33kV Oil	60MVAr 132kV Oil	200MVAr 245kV	SVC	STATCOM
Capital £	3.5M	2M	3M	£1M/MVAr	£0.75M/10Mvar
Installation £	35% capital assuming installation on platform at construction yard	35% capital assuming installation on platform at construction yard	35% capital assuming installation on platform at construction yard	Included in above	Included in Above

4.6. Power Cables

Subsea cabling technologies have arisen as a major driver in the development of offshore renewable generation parks. The sheer volume of cabling required impacts greatly on electrical losses, reliability and installation issues. This includes both the inter-array collection cabling and export to shore cabling. Present designs utilise fully AC technology though it is expected in the near future for HVDC export technology to be widely used with the further introduction of fully DC systems. These advances may be limited or driven by the availability and development of suitable cables. We have therefore highlighted power cabling as a major area for future development.

4.6.1. Superconducting Cables

Limited interest from manufacturers has been seen in respect to the practical use of superconducting cables in offshore environments due to the many technical and economic obstacles for superconducting technologies to overcome onshore before offshore applications could be delivered.

Almost all applications for superconductive cables to date have been commercial trials for AC applications where conventional cables cannot be readily used. An example would be where installation space is restricted , or the thermal environment is poor due to deep installation depth or within close proximity to other heat sources. These applications are short single reel lengths (100m or so) with no joints. The superconducting cable requires additional active equipment which includes:

- Liquid nitrogen pumping plant to maintain cryogenic flow and pressure within the product (internal pressure typically ~20 bar)
- Heat exchanger equipment positioned at short intervals – presently at one or each end of a system
- Pumping and monitoring equipment to maintain the vacuum thermal shield (for a long length cable the vacuum would need to exceed that experienced on the moon)

The use of superconducting cables at AC has the added disadvantage that the critical current level that each superconducting tape can take is reduced due to the alternating magnetic field inducing currents in the non-superconductive cable elements, which in turn produce magnetic fields in a non-normal direction. This significantly reduces the efficiency of the superconductor. This is not critical when replacing small conductor cables with superconducting technology but is for a high current, long length, application which would be seen in an offshore environment.

The maintenance requirements and reliability of super conducting cables have to be considered to be very major challenges when compared to standard cables. A rise in temperature due to loss of vacuum or refrigerant flow would result in the cable losing its superconductivity. Should the cable suffer a third party damage or internal failure it is highly likely to be out of service for "years" due to contamination of the vacuum shield with cryogenic thermal insulation and superconductivity tape elements.

There are current planned applications of superconductor technology in New Mexico, USA which would involve the transfer of 5000MW across a distance of 10-15km with a projected service date of 2014. This is an onshore application and the main complicating factor for offshore superconducting cables is the need for periodic refrigeration stations. This would require the development of subsea coolers and considering the technical difficulties involved in subsea cable laying at present will be a major issue. In addition the relatively low power output of offshore developments at present questions the economics of superconductors and would not be of any significant advantage until developments in the 5GW scale are realised.

It is thus concluded that the technology will be some time (5-10 years) in becoming commercially accepted for short distance onshore applications and will not be suitable for subsea applications at least within the next 30 years due to reliability, installation and unsuitability for long distance transmission. The technology shall not be examined further henceforth due to these restrictions and the viewpoints of cabling consultants and manufacturers.

4.6.2. Overview of Technology and Developments

4.6.2.1. AC Inter-array Power Cables

Present offshore energy farms utilise fully AC systems and the preferred collector voltage is 33kV AC utilising 3 core cables as illustrated in Figure 17. Manufacturers have stressed that future development in AC collector systems will be focused around optimising this voltage to ensure the system is utilised to its full potential coordinated with associated generator ratings. This will become more prevalent as turbine sizes increase and the continued utilisation of 33kV would result in non-optimised string lengths. An optimised voltage level may be a standard or non-standard IEC voltage level and as such will impact on the application of cable developments, whether this is using present cabling modified for purpose or specific cabling and will be a market driven advancement.

If therefore a wind farm were to be optimised for a specific transmission voltage, then a cable could be optimally designed to meet the system requirements. This would be achieved by using the system and transient voltages to govern the power core insulation thickness and the system load current requirements would govern the conductor size. At present typically 11kV and 33kV system voltages have been used to interconnect turbines. Should this be increased to a non-standard voltage level of say 45kV then cable designs would be adjusted accordingly. Manufacturers have stated that cable designs at 40.5kV and 52kV are commercially available but not widely used due to lack of customer demand. It is also noted that cables can be utilised at voltages lower than their design level provided the amount of current does not lead to conductor temperatures in excess of the normal operating limits. This operation will have little impact on life expectancy unless the cable is operated above its maximum voltage for continuous periods. This further illustrates how a range of voltage levels between the standard 33kV and 66kV could be utilised if seen to be a more optimum solution with little implication for cable technology.

- **Figure 17 33kV AC 3-Core Inter-turbine connection cable (Courtesy: ABB)**

The development of medium voltage AC cabling is market driven and primarily based around reducing costs of the product. Little significant change in design or manufacture of the cabling is expected in the near future as the technology is well established. Installing cables offshore is a long and costly process and developments are being made into cable accessories in the aim to reduce these offshore installation times. Some such accessories include J-tube hang-off arrangements and armour clamps to reduce the time taken to assemble components offshore.

4.6.2.2. DC Inter-array Power Cables

There has been notable interest in the possibility of utilising DC as a collector technology as opposed to traditional AC as seen at present. The main driver for this is to reduce the losses seen in the cabling as well as to simplify conversion systems, especially when HVDC is used as an exporting technology. Medium voltage DC cabling is not commercially available at present as there is no market need for such products. However, the technology does exist however to produce cables which can transfer DC power at voltages from 1kV to 200kV utilising extruded dielectrics or paper insulated technologies. Design of these cables would be determined by the following factors:

- Transmission voltage would determine the cable insulation thickness
- Maximum load current would determine the conductor size
- Would need to incorporate a concentric return conductor to minimise magnetic field emissions
- Key technical parameters to be addressed would be:
  - Voltage drop across the length of the cable
  - Thermal Losses
  - Magnetic Field interaction

There are existing operating systems that utilise AC rated cable designs to operate under DC conditions. Examples of this are the HVDC cable links such as Basslink or Swepol link. At these locations one or multiple extruded dielectric earth return conductor cables run alongside the main HVDC cables. These earth return cables are essentially 24kV AC rated cable designs that are operating under DC fields in the range of 4 to 6kV. The cables have to withstand transient excursions and as such the impulse performance requirements tend to govern the amount of insulation required for the application. This illustrates how current AC cabling can be utilised in a DC manner, allowing immediate installation of DC systems if the market requested, though this would be by far a less optimum solution than purpose built DC cabling which can also be achieved with little development.

4.6.2.3. AC Export Power Cables

The choice of export cabling used is determined by the export technology implemented, whether this is HVDC or HVAC. As AC cable lengths increase, the charging current dictated by the capacitance of the cable increases and reaches the point where HVDC becomes the preferred solution. The additional costs associated with HVDC converter equipment becomes smaller than the reactive compensation and associated costs needed for an equivalent AC system. The majority of offshore systems at present in the UK have utilised AC export technologies, traditionally at 132kV. This restriction is mainly due to the relatively short distances involved and the handling and installation issues seen with large export cables due to their physical size and weight. Recent developments have shown that high stress extruded dielectrics have assisted in alleviating some of the manufacturing constraints and these state of the art advances have meant that 220kV cabling is being considered at offshore wind farm locations of West of Duddon Sands in the Irish Sea off the coast of Barrow-in-Furness, UK and Sandbank 24 in the North Sea off the coast of Germany.

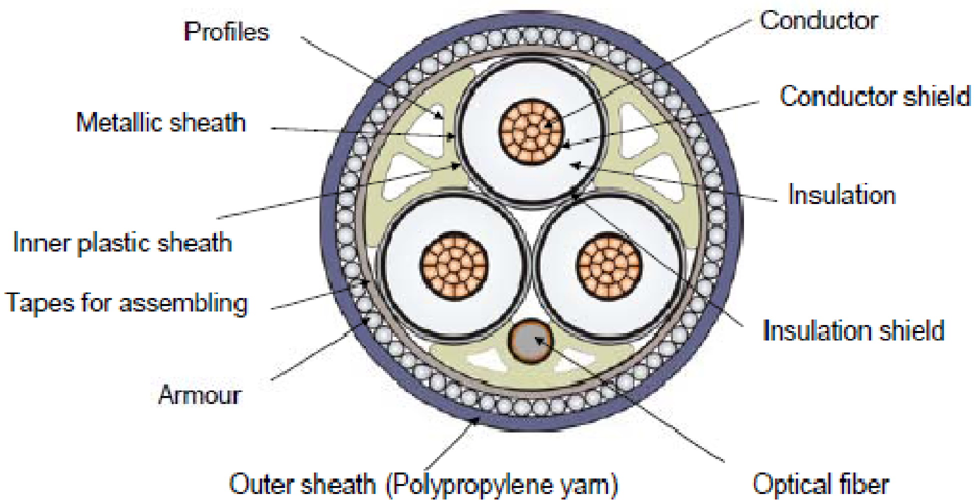
By further increasing the voltage level advantages are seen in reduced losses and increased capacity of the cabling, though the size of transformers and related switchgear also increases whose impact would need to be assessed. At higher voltage levels further emphasis is applied to the cable accessories in terms of flexible factory joints, offshore cable terminations, rigid subsea repair joints and shore landing transition joints due to the installation difficulties of the large cables. At 220kV voltage levels the main barriers are therefore associated with the installation and handling as technology exists to produce the cable and it is assumed that this technology will be more prevalent in the near future.

Further developments could see the introduction of 400kV AC voltage levels as an export cabling technology. Single core extruded dielectric submarine cables are available in the marketplace at 400kV, however schemes which have employed this have generally been short and involve the installation of three phases plus one additional phase which can be utilised in the event of a fault. For long lengths, as would be required to allow this technology to be utilised as an export from an energy farm, the cabling would require to be in a 3-core format. This would require significant developments to be carried out into producing a 3-core cable at this level or a way in laying single core cables in a trefoil arrangement. The 3-core design is preferred due to the added cost of laying three separate cores across long distances. Losses are also higher in a single core formation and the environmental impact of electromagnetic fields (which is significantly reduced in a 3-core format) on marine life is under research and currently inconclusive.[21]If these developments can be realised then power transfer at 400kV could be in the region of 1000MW utilising extruded dielectric technology.

The uptake of the development of 220kV and 400kV AC export cabling will be heavily influenced by the market, the uptake of HVDC and the advantages that such a development can introduce. As HVDC is planned to be extensively used in future applications, manufacturers may choose to focus their efforts on the development of DC cabling and this could restrict the development of HVAC subsea cabling as the demand for HVAC subsea cabling will be greatly reduced.

[21] COWRIE (Collaborative Offshore Wind Energy Research into the Environment) – Electromagnetic Fields Review, July 2005

- **Figure 18 XLPE AC 3-Core Submarine Cable (Courtesy: ABB)**



- **Figure 19 132kV AC 3-Core Submarine Cable (Courtesy: ABB)**

4.6.2.4. Gas Insulated Lines (GIL) for AC export

GIL is an AC transmission system for high and extra high voltage based on coaxial pipes of aluminium with aluminium tubular conductors. The main insulation system is generally a gas mixture of 80% N_2 and 20% SF_6 which allows high power transmission with currents up to 4000A or even up to 6300A at 500kV. The SF_6 content is determined by the Basic Insulation Level required. Potentially for a fully connected system, reduction in BIL levels would be acceptable and the proportion of SF_6 can be reduced or even eliminated. This is significant due to the high greenhouse gas potential of SF_6 and potential of prohibitive use due to regulation in the future. The introduction of GIL on a large scale could see a significant change in the uptake of HVAC as an export technology over HVDC due to the higher power capacity and robust three phase technique which does not demand converter stations.

- **Figure 20 – Cross-section of a GIL (single phase) (Courtesy of Siemens)**

The advantages GIL can provide are low operating losses (some 70% lower than overhead lines), high transmission capacity and low capacitance which will greatly reduce the requirement for reactive compensation which is expected to be a prohibitive factor in the use of traditional HVAC cables. In addition GIL is quoted as having high reliability, maintenance-free construction with a long life-time (>50years) and fire-safe operation.

At present GIL has only been applied to short distance onshore projects, with an offshore feasibility study being carried out by ForWind through funding by the European Commission in the Trans European Energy Networks (TEN-E)[22]. The proposed installation of subsea GIL is similar to the laying of pipelines whereby highly standardized elements are used to install in every spatial direction including vertical. As the installation style is so similar to that of subsea gas pipelines it is assumed that much of these techniques could be employed from knowledge from the gas sector. In addition, by employing GIL there could be significant alleviation on supply chain constraints for traditional subsea cable laying vessels. Low electromagnetic radiation means that GIL can be laid in single phases without being constricted to a trefoil configuration as seen in traditional HVAC

[22] ‘Network of offshore wind farms connected by gas insulated transmission lines?’ Forwind feasibility study, 2008

cabling and their robust design is of added benefit for protection against the offshore environment. The low capacitance of GIL potentially provides better HVAC transmission line for long distance applications compared to HV cables and in some cases with overhead lines.

In the more distant future long distance DC-GIL may be developed in order to reduce costs by utilising steel pipes compared to aluminium required by AC due to induced eddy currents in the enclosure.

Compared to traditional HVAC technologies, GIL shows a high potential in providing an alternative design for an export cable. Low capacitance allows long distance transmission without the need for significant reactive compensation, whilst the insulation medium employed allows high capacities to be achieved with potential high reliability. However the application of the technology subsea is perhaps speculative with many practical issues to overcome, such as gas sealing, conductor continuity and insulating support systems and achieving required levels of cleanliness. Significant issues to be overcome during installation offshore and maintained during operation in a subsea environment. Potentially the installation of GIL could be similar to that of gas pipelines where knowledge from this sector could be applied and the physical characteristics enforce a robust build which benefits the harsh offshore environment, this may warrant further investigation.

- **Figure 21 - Gas Insulated Line laid in tunnel at Geneva Airport (Courtesy of Siemens)**

4.6.2.5. DC Export Power Cables

General consensus across a number of manufacturers and reports has illustrated that HVDC is the preferred export technology for offshore connection distances greater than 70km or for capacities of 1000MW or greater[23]. These limits cover all Round 3 wind farm sites and the majority of future offshore wind developments; hence HVDC progress will be highly significant to support this growth. In order for HVDC technology to reach its potential the exporting cable must advance in line with the converter stations so that one is not a hindrance to the other.

Present state of the art mass impregnated (MIND) DC cables operate at ±500kV with the capacity to deliver 1000MW per pole[24] and developments are centred on new insulation materials and impregnating fluids to enable conductor temperature and voltage level to be increased. Traditionally kraft paper has been used as a cable insulating material and has proved to be a highly reliable product. New developments in laminates that sandwich a polymer film between paper layers, termed Polypropylene Laminate Paper (PPLP)[25] have been successfully trialled. In conjunction with new, more viscous impregnates it is possible for it to achieve some significant advantages of PPLP over MIND cable constructions such as:

- 125-150% increase in power transmission compared to a similar conductor size MI paper cable
- 70% conductor size for the same power rating as an MI paper cable
- Reduction in overall diameter (90% of MI cable)
- 125% increase in impregnation length and hence cable length

In addition to PPLP tapes which are pre-laminated, there are thin paper tapes and discrete polyethylene tapes that have also been used to improve the electrical performance. Polymer films in conjunction with these tapes are being explored to see if a reduction in insulation thickness can be achieved. In terms of developments on insulation impregnates new dielectric fluids are being developed that have improved rheological characteristics to fit the manufacturing and operational requirements for HVDC cable systems. Such dielectric characteristics are to be highly viscous at cable conductor operating temperatures and low viscosity at moderate impregnation temperatures. These advancements will enable an increase in power transfer across an HVDC link without a further increase in cable size. The developments will also aid a reduction in physical size of the cables which will improve the handling and installation difficulties. In addition power transfer

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[23] Rule of thumb and in line with assumptions quoted in 'Electrical Cables Handbook', BICC Cables, 1997
[24] Cigre Paper 21-302 – ABB High Voltage Cable Systems
[25] "Solid DC Submarine Cable Insulated with Polypropylene Laminated Paper (PPLP)" http://global-sei.com/tr/pdf/energy/62-01.pdf

capability can be increased by up to 15% by increasing allowable conductor temperature by 10ºC which can be achieved through the development of new insulation materials and impregnates.

There may be some concerns over the environmental impact of oil impregnated cables in a subsea environment should a severance occur. The compound used in MIND subsea cables is a high viscosity polyisobutylene which is less dense than water so can be displaced in the event of a cable severance. However, the high occupancy of the conductor and the swelling of paper tapes on contact with moisture severely limits the displacement of the compound. At present there are no recorded barriers to their subsea installation and cable consultants are unaware of any cable system being investigated on environmental grounds.

- **Figure 22 1600mm^2 ±500kV MIND HVDC Cable (Courtesy: ABB)**

Manufacturers are highly active developing extruded HVDC cable systems due to the reduced cost and other advantages that this technology can bring. Present voltage levels are limited to ±200kV allowing 300MW per pole due to conductor temperature limitations and poor reliability based on performance in polarity reversal and superimposed impulse conditions. Manufacturers have tested extruded dielectric technology up to ±300kV for VSC HVDC applications and have noted that the incorporation of larger conductor sizes into the cables will allow higher power magnitudes to be transferred. The development into dielectric materials and combinations of screening and insulation materials is expected to continue to increase the levels of electrical stress that the cable can withstand. Key to this is the thermal resistivity characteristics of the dielectrics to determine the extent of stress inversion that can occur when a cable is operating at maximum temperature. Further development of insulation packages along with cable accessories that can withstand high electrical screen stresses will enable the technology to increase in reliability which is crucial in an offshore environment.

- **Figure 23 ±300kV Extruded Dielectric HVDC Cable (Courtesy: ABB)**

4.6.3. Physical Characteristics

The physical characteristics of the cabling have a significant impact on installation in offshore environments. The bending radius of the cable is a factor in the ability to connect into turbine J-tubes and to be wrapped around the laying drum. For smaller inter-array cable sizes it is possible to use barges to lay the cable and these are generally at multiple short lengths, however for large export cables, specialist vessels are required. The introduction of subsea cable jointing is extremely expensive, timely and difficult in an offshore environment and it is preferred to lay long lengths of cable continuously to avoid this. Maximum continuous cable lengths are provided in Table 15 based on data from existing projects.

The total dimensions of the cable are determined primarily by the thickness of the insulation. As the voltage level increases, this level of insulation must also increase which has proven to be of significant restriction as seen in 400kV AC cable where single core cables are only available due to the thickness of insulation making a 3-core cable presently impractical. Developments are focussed on reducing insulation thicknesses to allow easier installation and handling of larger cables as this is a major restricting factor.

Table 15 below outlines physical characteristics for a range of cabling technologies.

- **Table 15 – State of the Art Cabling Physical Characteristics**

Cable Type	Operating Voltage	Maximum Submarine Cross-Sectional Area	Conductor/ Insulation	Max. Length of Cable on Drum	Min. Bending Radius
12kV AC	11kV AC	630mm^2	Cu/XLPE	N/A	1.8m
36kV AC	33kV AC	630mm^2	Cu/XLPE	N/A	2m
72.5kV AC	66kV AC	630mm^2	Cu/XLPE	N/A	2.5m
HVDC Classic	±500kV DC	3300mm^2	MIND	100km on specialist vessel (Basslink)[1]	3m
HVDC Extruded Dielectric	±250kV DC	870mm^2	Cu/extruded dielectric/Pb/PE	7000T	2.4m
145kV AC	132kV AC	1200mm^2	Cu/XLPE/Pb/PE	50km (Greater Gabbard)	3.5m
245kV AC	220kV AC	1000mm^2	Cu/XLPE	50km	3.9m

[1]The turn table of the Giulio Verne vessel used to install the Basslink Cable has a load capacity of 7000 tonnes and a total payload capacity of 8000 tonnes. The weight of the ±500kV 3300mm^2 cable is 70kg/m therefore on paper 100km of monopole cable could be installed in one campaign. If a bundled bipole is being installed then the campaign length would reduce to 50km.

4.6.4. Electrical Characteristics

The electrical characteristics of the cabling are pivotal in ensuring low loss, reliable operation. Substantial development is being carried out to improve insulation packages, thermal characteristics and dielectric materials to increase the reliability and capacity of common cables.

Reliability data has been obtained from the Cigre survey ‘update of service experience of HV underground and submarine cable systems’ for cable systems installed up to the end of 2005. These quoted values can be seen to be slightly optimistic as they are only based on internal defects and do not include external influences which in an offshore environment can be higher with trailing anchors, fishing nets and other aspects.

Table 16 below gives an overview of the electrical characteristic and reliability of a range of state of the art cabling.

- **Table 16 - State of the Art Cabling Electrical Characteristics**

Cable Type	Operating Voltage	Rated Current	Short Circuit Withstand Current	Capacity	Resistance (Ω/km)/ Inductance (mH/km)	Expected Life	Reliability (failures/ 100 cct km/ year)
12kV AC	11kV AC	0.495kA	37.6kA	5.445MVA	0.125/0.28	25 Years	0.0705
36kV AC	33kV AC	0.627kA	47kA	20MVA	0.06/0.31	25 Years	0.0705
72.5kV AC	66kV AC	0.883kA	90kA	38.5MVA	0.04/0.11	25 Years	0.0705
HVDC Classic	±500kV DC	2000A	100kA	1000MW Per Pole	0.0093	40 Years	0.0998
HVDC Extruded Dielectric	±250kV DC	1200A	100kA	300MW Per Pole	0.0203	40 Years	0.067[1]
145kV AC	132kV AC	0.92kA	170kA	210MVA	0.0192/0.25	40 Years	0.0705
245kV AC	220kV AC	0.89kA	141kA	339MVA	0.027/0.19	40 Years	0.067[2]

[1] No reported failures in the survey so a published figure is not available. As manufacturing extrusion technology is similar between HVDC and HVAC cable systems, a figure based on HVAC technology is quoted

[2] Value given is land based reliability as at the time of survey there were no 220kV HVAC subsea cable systems installed.

4.6.5. Costs

Cable capital cost data has been supplied by Cable Consulting International and ranges are given based on the size of conductor used. These have been further verified by in house data and published information relating to major submarine cable supply contract awards such as Nexans and ABB press releases. It is important to illustrate the cable procurement times as this will impact on the time for technologies to be available for introduction into systems.

Table 17 below outlines the capital cost and procurement times for a range of state of the art cabling technologies. Cable capital costs are given for a range of conductor sizes currently in production at a per metre basis.

- **Table 17 – State of the Art Cabling Costs**

Cable Type	Operating Voltage	Capital Cost (per m)	Procurement Time	Losses (W/m)
12kV AC	11kV AC	£130-£610 ($95mm^2$-$630mm^2$)	6-12 Months	96.4 ($185mm^2$)
36kV AC	33kV AC	£130-£610 ($95mm^2$-$630mm^2$)	6-12 Months	86.4 ($300mm^2$)
72.5kV AC	66kV AC	£130-£610	6-12 Months	49.4

Cable Type	Operating Voltage	Capital Cost (per m)	Procurement Time	Losses (W/m)
		($95mm^2$-$630mm^2$)		($630mm^2$)
HVDC Classic	±500kV DC	£300-£360 ($3300mm^2$)	> 2 Years	44.6 ($3300mm^2$ at 2000A)
HVDC Extruded Dielectric	±250kV DC	£400 ($870mm^2$)	1 – 2 Years	35 ($870mm^2$ at 1200A)
145kV AC	132kV AC	£530-£700 ($800mm^2$-$1200mm^2$)	~ 1 Year	61 ($1200mm^2$)
245kV AC	220kV AC	£950 ($1000mm^2$)	~ 1 Year	104 ($1000mm^2$)

Installation costs, particularly for array cables are difficult to quantify simply as a function of length of circuit as the proportion of the total of termination costs are far more significant for short cable lengths. The analysis provided is based on published information relating to Scroby Sands, a 60MW, 30 turbine project with about 40km of 36kV submarine cable, Nysted, a 165.6MW, 72 turbine project with about 45km of 36kV submarine cable and Burbo Bank, a 90MW, 25 turbine project with about 40km of 36kV submarine cable. Analysis of this information indicates that the component of installation cost associated with the length of circuit involved is equivalent to only about £10/m and with the bulk of the installation costs being driven by the number of turbines and corresponding to about £90,000 per turbine.

4.6.6. Power Cable Installation and Maintenance Issues

Due to the considerable volume of cabling which will be required in large energy wind farms the installation and maintenance of this component in the system is critical. As the installations are offshore a number of complications arise with respect to laying the cable, maintenance assessments and repairing faulted cable sections. The offshore environment means the procurement of specific vessels and the time and cost of these actions can be extremely difficult and these are illustrated below.

4.6.6.1. Cable System Installation

Subsea cable system installation costs are primarily governed by the cost of chartering a vessel suitable for the conditions of the installation site and the passage from the cable load out port. Specialist cable laying ships are available with large turntables capable of taking 7000-8000 tonnes of product (e.g. Giulio Verne, Skagerrak and Sea Spider); however the charter fees for these vessels are typically £100k per day.

Dumb barge vessels equipped with turntables are also available for operating in shallower waters. These vessels have to be towed via tugs to the installation site (e.g. UR101, Pontramaris and Henry P Lading). When on station the vessels are propelled by winches attached to kedge anchors that are deployed by anchor handling tugs. These vessels cost typically £75k per day.

The length of time required for a vessel charter depends on:

- Position of the cable load out of port relative to the installation site
- Cable load out time
- Cruising speed of the vessel
- Distance to the installation site
- Cable laying and burial time
- Position of port for demobilisation

The majority of these periods can be accurately determined – however there will be periods when the programme will be interrupted due to adverse weather conditions or unforeseen events such as equipment failure.

Once on station the cable laying time is usually constrained by the cable burial rate. A typical burial speed is in the order of 240m/hour.

Figure 24 Specialist Cable Laying Vessel (Courtesy: ABB)

- **Figure 25 Subsea Cable Laying (Courtesy: ABB)**

- **Figure 26 Cable Laying Drum on specialist vessel (Courtesy: ABB)**

4.6.6.2. Cable System Maintenance

Once installed, protected (via burial) and recorded on nautical charts, a subsea cable system should need very little routine maintenance. A prudent cable system owner would periodically perform a seabed survey (say every 2 years or following a severe storm) to check that the cable is still adequately buried and that there are no significant suspended spans such as a cable crossing a rock or ship wreck. Cable system accessories including cable terminations and bonding equipment would be periodically visually checked for signs of corrosion or leaks. Repeat Time Domain Reflectometry traces would be taken on optical and metallic power cores during routine outages to compare to base line readings taken during installation (Optical TDR and TDR). The cost of these condition assessment checks is minimal.

Significant maintenance would only occur in the event of a cable system failure. Damage to subsea cable systems is generally caused by third party interference such as a ship dragging an anchor in a storm, fishing equipment and trawler beams colliding with the cable. If a cable system has been poorly installed, for example a cable has been laid across a rock outcrop, installed with unsupported spans, installed with a loop or hanging bight, then there could be the opportunity for fatigue mechanisms such as vortex shedding vibration which can lead to premature failure of the product. In these cases it would be necessary to mobilise a repair vessel, suitably decked out, to locate, recover and repair the cable.

4.6.6.3. Cable System Repair

A repair to a subsea cable system is not a trivial undertaking and entails significant amounts of planning, engineering input, marine equipment and strategic cable repair spares. A repair will usually take the following form:

1) The cable fault location is determined from land.
2) A small survey vessel is mobilised, equipped with a remote operating vehicle (ROV) and specialist equipment, to more exactly establish the location of the fault.
3) An engineering scheme to affect the repair is developed and put into action.
4) A suitably sized repair vessel is chartered.
5) Equipment for surveying, deburial, cutting and recovering the damaged cable, jointing, and redeploying the cable is mobilised.
6) The repair vessel is fitted out in port.
7) The vessel mobilises to site, cable location, and recovery to deck begins.
8) The recovered cable is tested to confirm that the damage has been removed.
9) Cable joints (2 off) and a spare length of cable (usually several hundred meters depending on water depth and damage) are inserted. A single repair joint can take between 3 to 5 days to complete.
10) The cable and joints are deployed onto the sea bed.
11) The cable system is tested.
12) The cable is reburied or protected by application of rocks / mattresses.
13) The vessel demobilises back to port.
14) The deck equipment is removed.

Typically the time from failure to repair for a subsea cable system is in the order of 3-6 months and is weather, vessel, equipment and personnel dependent.

The main cost involved in a repair is the charter of a vessel that is suitable for the expected sea conditions and large enough to mount the repair suite and recover the required amount of cable. A repair vessel typically costs in the range of £60 to £100k day - the former being a towed barge that remains in place by the placement of kedge anchors, and the latter being a work boat that holds station using thrusters and differential global positioning system (DGPS). A vessel fit out import typically takes 4 weeks. The time taken to steam to the repair site depends on the distance from the port of mobilisation, sea conditions and cruising speed of the vessel (1-2 days is probably typical around UK waters). The recovery and repair works can take a further 2 – 4 weeks to complete. Demobilisation of the equipment from the vessel usually takes 1 week to complete. The vessel is therefore required for a total period of 8 to 10 weeks with an estimated cost being in the range of £3.5M to £7M.

The reliability of a cable system stems from the manufacturing quality of the cable system and the ability to determine whether defects are present within manufactured cable lengths. Therefore improvements in manufacturer's quality procedures, sampling requirements, test techniques and procedures would assist in the production of more reliable cable systems. There are currently no IEC standards that cover the manufacture of subsea cable systems. CIGRE recognized this and have issued some recommendations on the mechanical and electrical testing of subsea cables. However, the introduction of an international standard covering the design, manufacture, testing and installation of subsea cable systems would therefore assist potential purchasers.

Given the significant costs involved in cable repair and the planned large installed base of cables that will exist in the future it seems that advances in subsea cable systems repair and enhanced reliability are areas for focus for the future. Presently it seems that priority is not being given to these aspects.

The general view is that improvements in cable systems over the next 10 years are likely to be incremental rather than a step function.

4.7. Offshore Platforms

Current designs of offshore platforms for substations are primarily based on the experience of Offshore Fabricators which has been accumulated over many years within the Oil and Gas industries.

Based on initial discussions the design of platform is entirely determined by the size of power to be handled on a single platform which is usually determined itself by other factors such as cable terminations and HVDC system design.

The platforms required by today's state of the art offshore developments are to some extent small in comparison with what has been delivered for these other industries. Typically a substation platform today has a requirement to be around 2000T fixed within a depth of say 40m whilst up to 14,000T has been delivered in fixed depths well over 60m or indeed floating in depths up to 200m. Hence the view of the offshore fabricators is understandably that there aren't any new significant challenges yet to be overcome for the offshore renewable industry.

As was the case for for other equipment areas, there was a strong message that the industry would benefit from some coordination of requirements with uncertainties about project viability and who the customer might be, with detailed design requirements for now and in the future causing offshore fabricators difficulties in assessing future programmes at the moment. Their business is traditionally cyclical and the potentially significant offshore renewable sector could contribute up to 50% of one offshore fabricators total annual business, hence an ability to optimise work flows by overall management of programmes would not only ensure cost effective utilisation of resources but also to ensure that the ageing labour force is kept within the industry at times when other industries e.g. Nuclear are likely to be a potential drain of the labour force. In summary it seems there is a desire for greater visibility of future planning across the offshore connections industry in comparison with other sectors in which offshore platform manufacturers operate.

Work on recording and analysing operating costs for transmission and distribution equipment in the offshore environment is likely to be useful. The point was made that much equipment seems to have simply been put into an offshore environment without much modification and it is yet to be proven what the operating experience offshore is likely to be. The cost of doing anything offshore could be as high as 6 times that of doing it onshore, thus it is likely that there are still many lessons to learn in this area.

Developments in the future of platforms to accommodate HVDC and generally larger platforms are anticipated to require no step change in technology and adaptations of already proven solutions are envisaged instead.

Initiatives to implement industry standards and adopt increased modularisation of design and build would be welcomed but there were no strong thoughts at this stage on specific ideas for research that could be undertaken to resolve outstanding technical issues.

Projects to investigate the potential for submarine collection systems do exist e.g. Wavehub[26] with an initial project with 11kV subsea made cable connections that could be increased to 33kV. Such developments are not considered practical for the very large AC and DC collector and converter platforms envisaged for the larger wind farm projects but may have a role for small marine and wave projects.

4.7.1. Costs

Specific platform costs are directly linked to the weight and depth of water/design of subsea structure required. However, some guidance on typical offshore platform costs (excluding the electrical equipment) would be as follows:

[26] http://www.southwestrda.org.uk/working_for_the_region/key_sw_projects/cornwall__the_isles_of_scilly/wave_hub.aspx

Platform Size (35m depth)	Topside Cost £m	Jacket Cost £m	Installation £m
1200 Tonnes	11	6	8
2000 Tonnes	18	8	9

Future costs could be influenced by the degree of standardisation and modularisation introduced but mainly by commodity and labour rates.

4.8. Cost Trend Analysis and Market Impacts

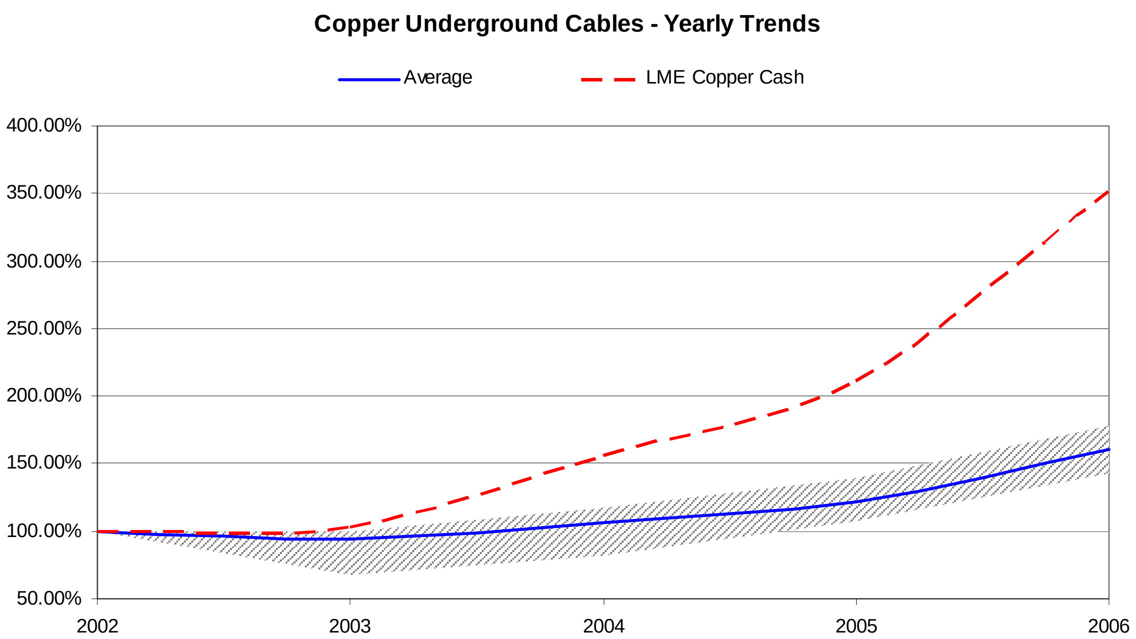
Predicting future cost trends in the timescales considered for this report is difficult to do with any degree of certainty, however we consider two key drivers will influence cost trends over the medium term:

- Commodity prices
- Other market fundamentals

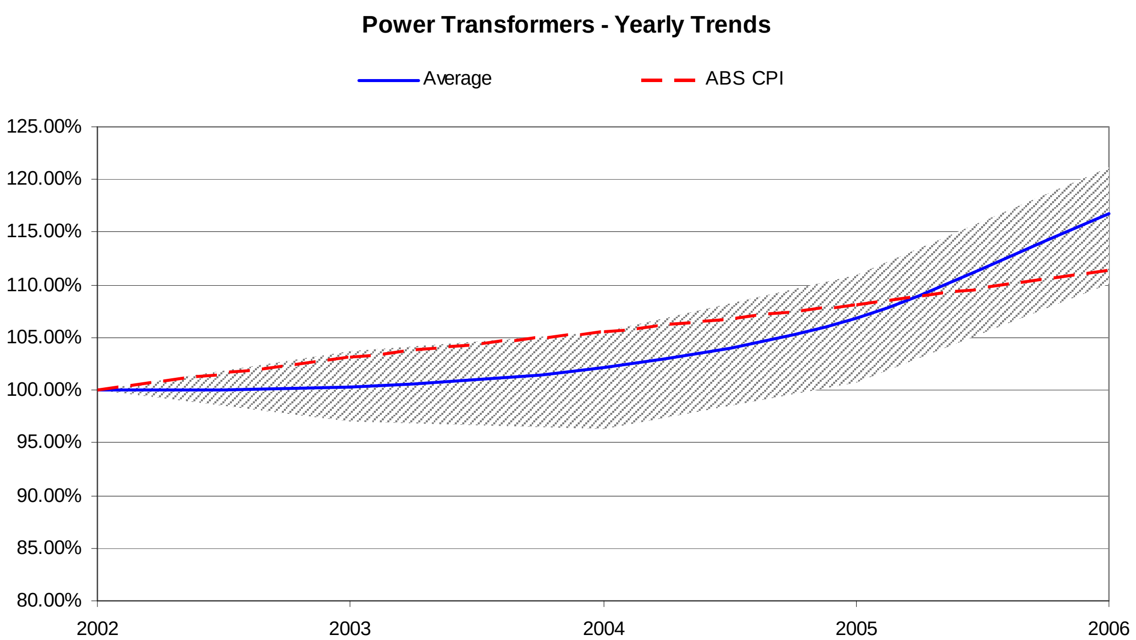
4.8.1. Commodity Prices

For a number of pieces of equipment copper prices are a significant cost component, particularly cables and transformers/ reactors which have high copper content. Figure 27 and Figure 28 below show the clear correlation between rising copper prices and rising cable and transformer prices between 2004 and 2006 – over this period copper core cable prices increased by 46% and transformer prices by 20%. Figure 29 indicates that the effective lag between commodity price rise and equipment price rise for copper and copper cables is substantial at approximately 2 years. All other things being equal, equipment price increases can be estimated with some accuracy based on current and forward commodity prices as well as forecasts produced by sources such as the International Monetary Fund (IMF). Similar correlations exist between other commodities and equipment such as steel and offshore platforms.

- **Figure 27 Copper Core Underground Cable Prices against Copper Prices[27]**



- **Figure 28 Power Transformer Prices against Consumer Price Index[27]**



[27] Information from SKM internal sources

- **Figure 29 Time Lag Between Commodity Price Increases and Equipment Price Increases[27]**

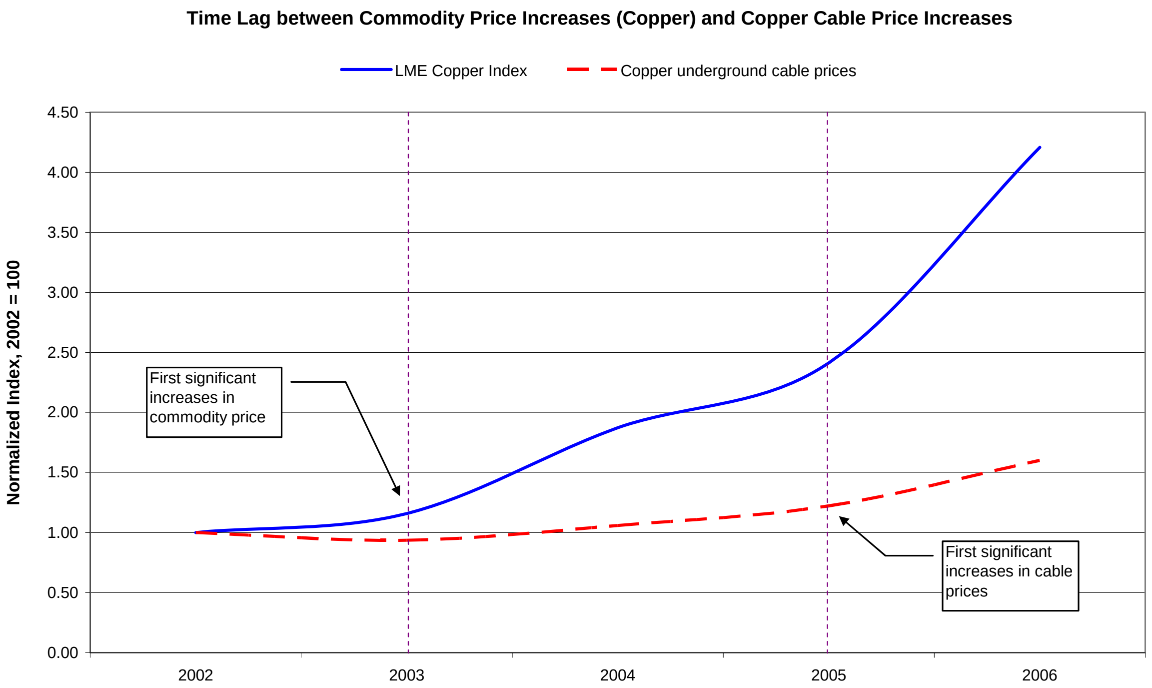
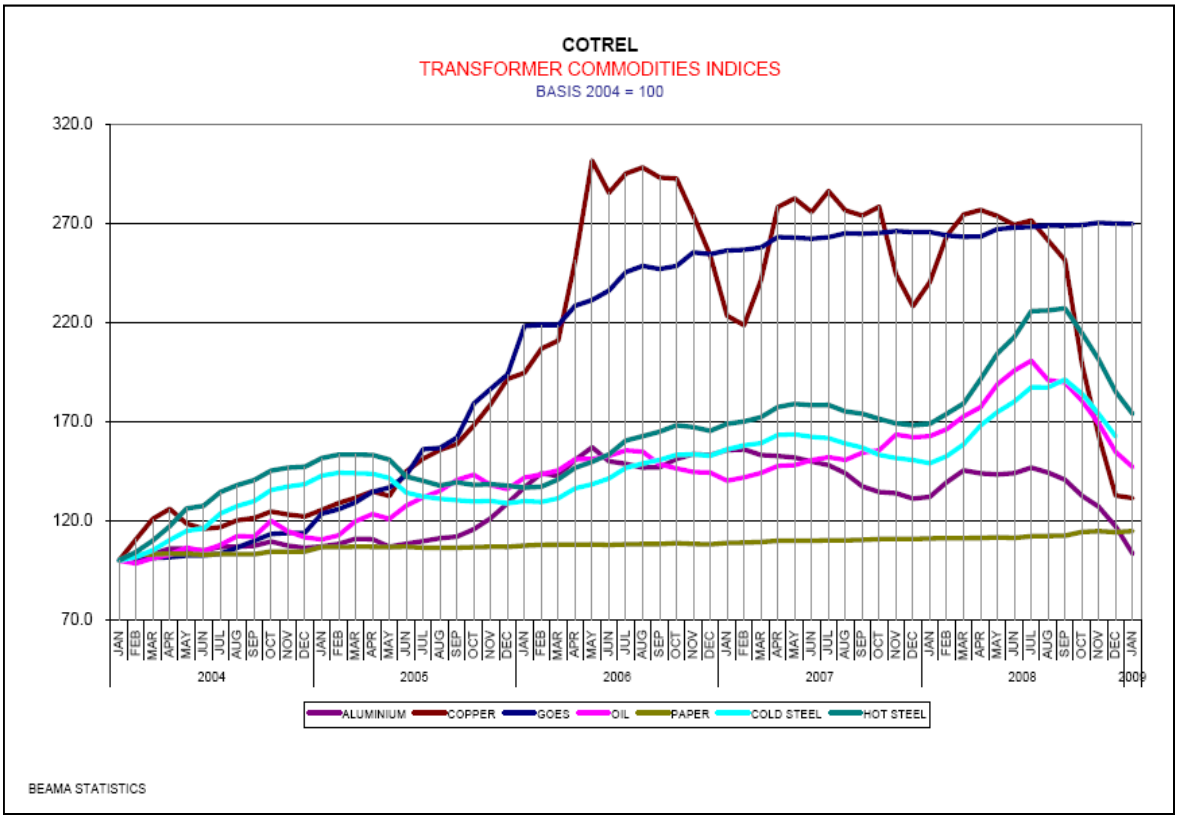


Figure 30 illustrates the change in price of materials made in the manufacturing process of transformers. It is clear that copper and GOES (Grain Oriented Electrical Steel) prices are of the highest order for the majority of the past 6 years. In conjunction, these materials make up the majority of the transformer physical construction with copper used in extensive amounts for windings and GOES for the core. It is therefore fair to say that the cost of each equipment type is dominated by the cost of the main construction material as has been illustrated with the cost of copper and its impact on cabling. This relation can be applied to transformer unit costs and assumed to be relatively in line with copper and GOES costs as seen in Figure 30

▪ **Figure 30 Transformer material commodities indices**[28]



4.8.1.1. Commodity prices – short term base metals index forecast

The following is a short term forecast for the base metal index to provide insight into the range of information and sources tapped for short term forecasting.

Base metal prices have been on the rise in 2009 and are expected to continue increasing into 2010, with prices currently at a 12 month high. Nickel has risen almost 200% from its low at the end of 2008 and zinc has risen 176% and copper almost 110% over the same period.

While there is a certain amount of speculator activity driving prices up on the expectation of improving global economic activity and the impact of a weak dollar, the market fundamentals for base metals are also looking generally positive.

China is particularly important to prices in the base metals sector. As a result of China's share of global base metals consumption is expected to increase in 2010. Organisation for Economic Cooperation and Development OECD demand is also expected to start to increase on the back of

[28] COTREL – Transformer Commodities Indices Jan 2000-Jan 2009

more positive economic news. Historic trends suggest there is a three to six month lag between the turning point in economic leading indicators and any pick-up in metals consumption, so with measures such as new orders rising since lows in December 2008, the timing is looking better for metals demand to increase. In conclusion the base metal demand is likely to remain significant for 2010.

In terms of supply, not all base metals are the same and supply differences are likely to lead to prices rising at different rates for different base metals.

Copper is currently around USD 6,600 per tonne – with prices more than doubling during 2009. The World Bureau of Metals Statistics (WBMS) showed that the global copper market swung to a 71,000-tonne deficit in the January to August period 2009 from a surplus of 10,000 tonnes in the corresponding period of 2008. So the market has been destocking and supplies are running tighter. Combine this with increasing demand and market fundamentals are pointing towards prices increasing in 2010 with some suggesting copper will hit peak levels in 2012/13.

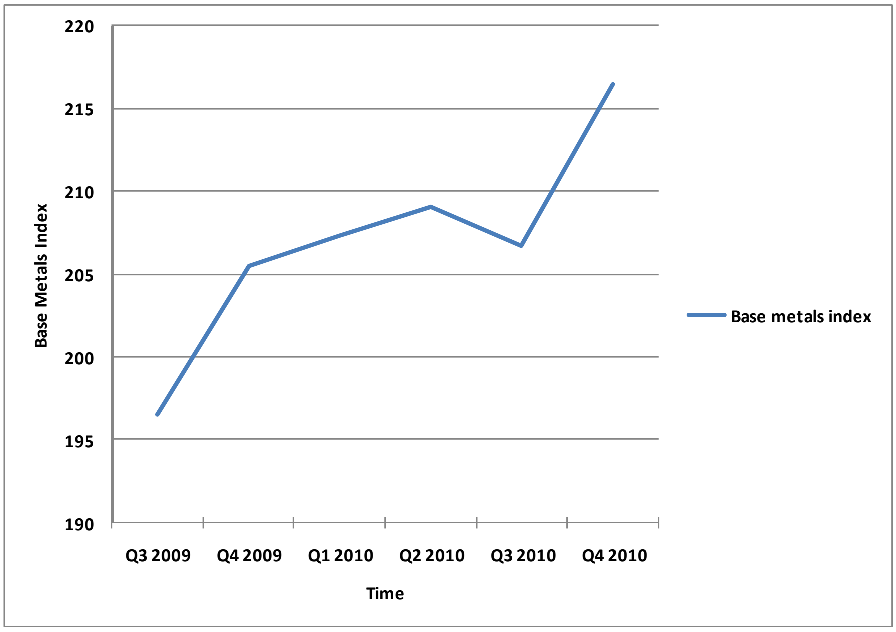
The zinc market is currently in surplus – with relatively high stock levels. However, stock levels are falling. Given the large price rises so far in 2009, market fundamentals suggest that the recent upward movement in zinc prices is likely to be sustained in 2010.

For nickel market fundamentals are also strengthening. Most recent data puts the nickel market in deficit for the first time since February 2008 and consumption is rising.

Aluminium is probably the base metal with the least favourable market fundamentals. LME inventories are at record highs and a lot of production capacity is being restarted to take advantage of current higher prices. Generally the market has a supply overhand and this excess capacity should act to keep a cap on prices.

In view of the above, the consensus is that commodity prices, using the base metals index as a guide, will rise modestly in 2010 with an increase of approximately 10 % from Q3 2009 to Q4 2010. This is illustrated in Figure 31 below.

- **Figure 31 Forecast Base metals index form Q3 2009 to Q4 2010**



4.8.2. Other Market Fundamentals

While commodity prices clearly are a crucial cost component other market fundamentals will also influence costs, these include:

- Supply and demand tightening.
- Technical issues.
- Supply chain constraints

Underlying market supply and demand fundamentals can exacerbate any commodity price rise – illustrated recently in the cost of offshore wind turbines. Together with rising commodity prices the wind turbine industry began to rapidly accelerate after 2005. This expansion began to place strain on the supply/demand balance as demand outstripped supply – leading to upward price pressure.

In terms of technical considerations - technological advancement, including potential 'step changes' in technological design or manufacturing may lead to a reduction in costs over time. Over a shorter time frame economies of scale may also lead to a reduction in costs.

However, set against these downward cost drivers are potential supply chain issues that may lead to upward pressure on prices as demand exceeds supply, particularly in a rapidly expanding sector – again illustrated by recent experience in the offshore wind market. Since 2007 the limited availability of installation vessels has led to a large increase in day rates and the availability of electrical equipment, including transformers and subsea cables, have been in short supply – with upward price pressure for offshore wind turbines resulting.

Therefore, while commodity prices are crucial to the direction of future costs, other market fundamentals can also be of significant importance – particularly in a rapidly expanding industry.

5. Barriers to Development

5.1. Overview

Included in this section is a summary of the issues identified during the interviews held which are not directly technical but were identified as impacting on the potential development of offshore technologies. Although not directly within the scope of the project it is believed to be important that these barriers and issues are captured.

5.2. Supply Chain

Manufacturers have some concerns about areas of the supply chain and some have noted making repeated comments to OFGEM and other bodies around this topic as part of their corporate obligations. A broad feeling is that these points have not been taken on board and a dialogue with customers would be useful. However the point was made that given the regulatory structure being pursued the identification of customers is not straightforward and is a significant difference between the UK and other countries where significant offshore developments are also occurring.

Major bottlenecks in the supply chain for renewable developments over the next 30 years are well documented in the report 'Quantification of Constraints on the Growth of UK Renewable Generating Capacity'[29] carried out by SKM on behalf of BERR. Major constraints to offshore renewable developments in UK waters which can be noted from this report are:

- Wind turbine availability is limited with new orders not likely to be delivered until 2013. In addition, the UK market is far smaller than markets such as the USA and China meaning UK developers are tending to fall to the back of the queue.
- The availability of vessels for the installation of wind turbines is severely limited to two which could be allocated to work full time in UK waters and corresponds to a build rate of 350MW/year. New vessels will cost in the region of £40-50 million each and will take about three years to build.
- The UK currently has no offshore wind turbine manufacturing/assembly capacity and setting up such a plant would take about two years and £15 million to set up.
- The supply of HVAC and HVDC subsea cables is a significant constraint to growth as the UK again has no high voltage sub-sea cable manufacturing capability. Only three suppliers are available within Europe in ABB, Nexans and Prysmian and orders are fully booked for the next 5 years. In addition the manufacturing time from placing an order can range from approximately 1 year for HVAC cables to over 2 years for mass impregnated HVDC cabling.

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[29] Available at http://www.berr.gov.uk/files/file46779.pdf

- Cable installation speed is taken as in the order of 240m/hr. Assuming 15x1000MW wind farms at an average 70km distance from shore are constructed in the next 10 years to meet the 15GW offshore target then cable installation from a single vessel will take 5 years. This is based on bipole HVDC technology being employed, operating in 12 hour shifts with laying and weather windows of half a year.
- In order to alleviate the constraints from high voltage subsea cabling it could be possible to invite an existing European supplier to set up a manufacturing facility within the UK. This would involve the finding of a suitable port location to facilitate loading onto specialist vessels and would take approximately three years to reach production at a cost of £35 million.

As a consequence novel and non-standard offshore designs may find procurement even more difficult as manufacturers focus on production for standard designs. Developments are to be market driven and there will need to be substantial orders in place for manufacturers to justify utilising new technologies and investing up front in additional production facilities.

5.3. Regulatory and Legislative Issues

A significant proportion of the contacts made in the interview process volunteered various comments on the regulatory situation surrounding offshore renewable and all comments were unfavourable in terms of the process and the approaches being taken.

A common response was that the regulatory regime should not have been adopted until some of the fundamental requirements had been established. As a result the optimum technical solutions are being obstructed by a regulatory regime that does not allow some fundamental issues to be addressed.

Contacts identified many technical areas that are uncertain which could be qualified by some up front studies and preparation for adoption of some fundamental standards. It is expected that the work to be done in later stages of the project could significantly contribute to providing background information to allow the overcoming of some of these issues.

Specific standardisation issues raised were DC/AC voltage selection for inter array and export systems and control systems for HVDC systems that allow the necessary exchange of information to allow multi-terminal control, but protect manufacturer's proprietary information.

The approach to fire protection on collector and converter platforms was identified as an area which would benefit from a more uniform industry approach, particularly where the experience of the application of devices such as large mineral oil transformers on offshore platforms is very limited. In such an area the early sharing of experience and interchange of views could benefit the overall development of safer and more environmentally acceptable solutions.

However, the point that was repeated again numerous times was a desperate need for coordination of activities, initiatives and thinking across the offshore renewable sector which would allow more extensive optimisation of efforts and allow all involved to move ahead more rapidly.

We are sure that these themes will be repeated during all stages of the project.

6. Development Case Technology Maps

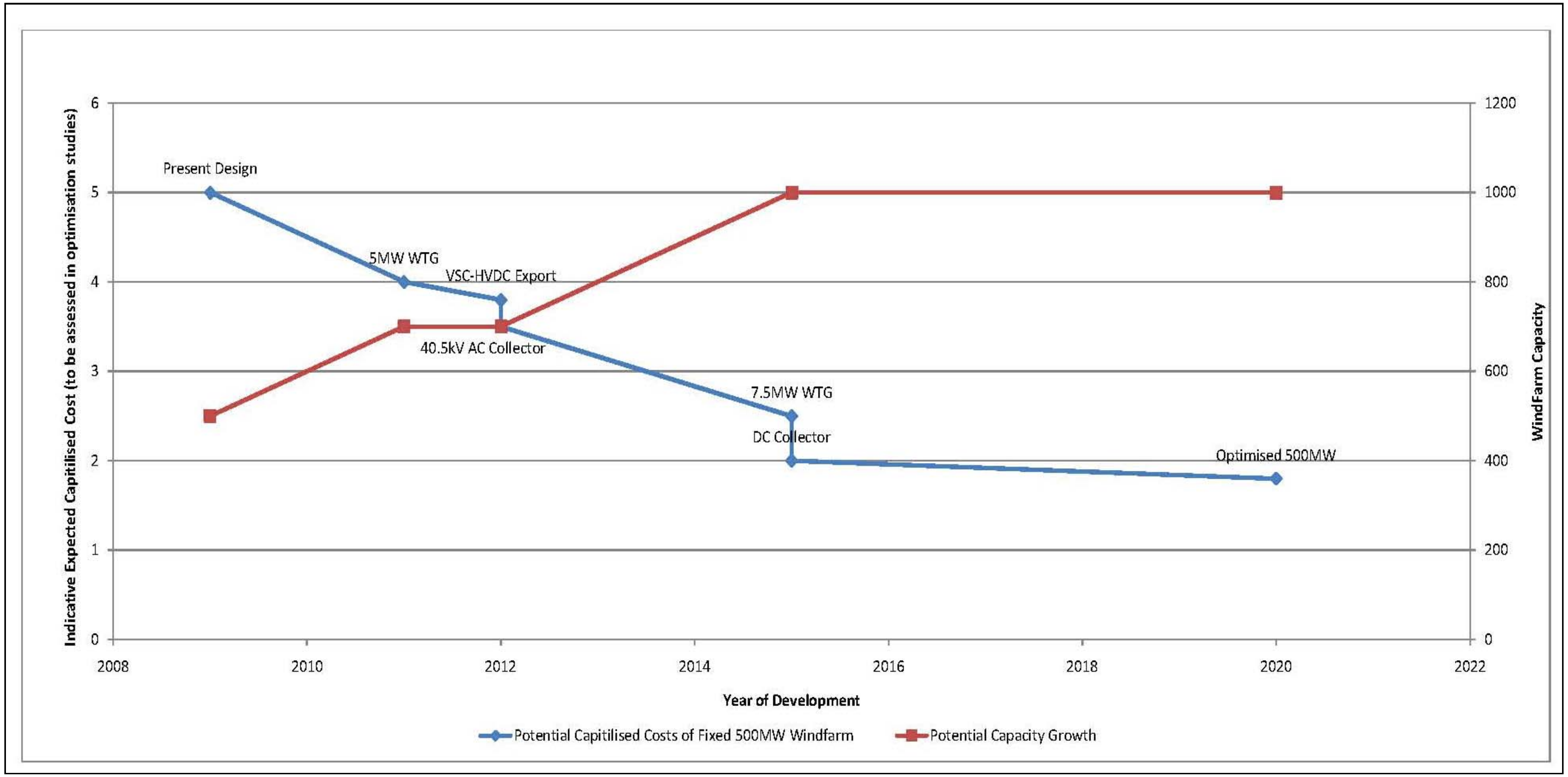
During Stage 1 it was recognised that thought had to be given to how technology developments would be identified, mapped and related to the Specific Development Cases identified in Section 7 of the Offshore Study Scenarios Report. Two tools have started to be used for this process as follows;

a) For each item of equipment an attribute spreadsheet has been developed which identifies all the physical, performance and cost attributes for the current state of the art. We then use the same attributes to map the development of the equipment over time periods which are consistent with the identified technology developments. The spreadsheets have been included in Appendix C.

b) We then use the information in the individual attribute spreadsheets to visualise technology road maps based on the expected development of major components. The main drivers in offshore systems and with significant developments expected are HVDC and subsea cable technologies. For such equipment, technology maps have been drawn up to visualise the time to service as well as the expected advantages the development can bring. Other equipment types such as switchgear and transformers are expected to have little or few significant developments and technology maps are not given for these, however data is provided in the attribute spreadsheets. The maps have been included in Appendix C.

Using the aforementioned technology maps a similar map has been produced representing the architecture development of Case 1 as identified in the scenarios report (Figure 32). This map visualises the expected development of the connection architecture of Case 1 over time. This map and others like it representing the remaining Cases will be one of the outcomes of the studies and optimisation in subsequent tasks; as such the cost axis is without scale.

- **Figure 32 Case 1 – Expected Significant Developments to Impact Development Case 1 - Distributed Smaller Wind farms**



7. Conclusions

The main purpose of the State of the Art Technology review was to establish the current state of the art of offshore network technology and prospective development paths as indicated by manufacturers. Specific equipment types were selected on the basis that these would define the network technologies that required further investigation.

Definition of the current state of offshore network technologies was relatively straightforward and could be established as envisaged by interviews and discussions with the current suppliers of such technologies. What also became quickly apparent is that even for current technologies there exist alternatives which are already proven in non offshore applications, which could potentially deliver benefits in offshore applications. However the drivers for offshore technology are not always clear and general uncertainty in the industry means that the adoption of these alternative technologies is also uncertain.

An example of this uncertainty is with power transformers where current state of the art is to use conventional mineral oil insulated technology which has been well proven in onshore applications. There are already alternative technologies which have been applied onshore which could bring benefits in offshore applications e.g. synthetic ester insulating fluids or even SF_6 insulated transformers. The uncertainty as to whether such technologies are applied is not due to technical uncertainty but with the fundamental drivers for the offshore industry and in this case the relative importance of environmental assessments.

Hence, in describing the current state of the art there is an element which also describes technologies which could be applied if the fundamental drivers for offshore technology demand certain characteristics.

The environmental challenge posed by the use of SF_6 onshore and offshore of course provide a substational prize for an alternative environmentally friendly technology, which may become more relevant if GIT and GIL were to be considered for offshore applications. However due to the uncertainty of whether widespread application of SF_6 offshore will be needed and the difficulty in identifying an alternative gas, no specific alternative insulating gas projects are recommended at this time.

The task of identifying prospective technology development paths is more difficult as most individuals have some degree of vested interest based on the technology that they are promoting based on their organisations capabilities, their own research projects or indeed even their role within their organisation. For large global manufacturers it is likely that several competing technologies will exist within a single organisation and this is one reason why the initial discussions were focused at a system level so that bias towards individual technology solutions could be minimised. The identification that some independent views should be taken from those involved in competing technologies to those promoted by the main manufacturers was extremely useful so that a more balanced view could be obtained, a task that is difficult within a constrained timescale.

Whilst it is concluded overall that the requirements for offshore networks are not driving fundamental technology development, with the possible exception of submarine cables, it is clear that technological developments can be adapted and optimised for offshore applications and it is this area that most of the focus of this report has concentrated. Inevitably it is in these areas of adaption and application that the most significant opportunities arise for support of individual technologies.

Added to, and directly linked to, the issues of technology there is the general issue of system architectures that exist which leads to a complex interaction of technologies and architectures which becomes the key element of the entire project. It is for this reason that the method of trying to map specific technology developments was utilised so that as the project progresses the equipment technology and architecture opportunities can be mapped together.

General Technology Focus Areas

During Stage 1 of the Manufacturers Interview process it quickly became apparent that there were two main primary areas of focus for offshore network technologies, these being Submarine cable systems and HVDC technologies.

Submarine cable systems being critical to the development of networks because they contribute such a significant element in terms of project cost, risk and technology developments and also impact on the optimisation of system architectures.

HVDC systems utilising technology which currently exists are able to be applied to support the development of offshore renewables for projects which are growing in size,complexity and connection distance.

Hence, a significant part of the focus of the State of the Art review has been in these two areas of technology together with the general area of equipment marinisation.

Most of the equipment currently being deployed for offshore networks applications is basically onshore equipment that has been adapted for offshore applications. There are of course specific examples of where equipment exists for specific offshore applications such as submarine transformers but these are the exception rather than the general case.

All suppliers recognise the need to adapt standard equipment for harsh marine environments but it also has to be recognised that experience with some equipment is very limited and it is not yet known whether general experience will be good or bad. Reliability and maintenance assumptions made are generally based on onshore data and the relevance of this data to offshore applications should be treated with some caution. In terms of potential risk to the rapid implementation of offshore renewables the issue of marinisation of equipment remains a very significant factor. Whilst considerable experience has been acquired in the Oil and Gas industries, the equipment now being deployed contains new elements (large power transformers, EHV switchgear, HVDC equipment) where experience is limited and an opportunity exists to mitigate some of these risks by undertaking appropriate studies / testing now rather than after a potentially negative incident or experience occurs.

Interoperability and Control Issues

Interoperability and control issues and barriers to integration of technologies from different suppliers were not seen as significant based on the input from those consulted, apart from the issues that were raised by several individuals concerning the application of multi-terminal HVDC systems. Here two specific areas were raised.

- Firstly, the need to standardise on voltage levels such that timely progress could be made in the development of the DC circuit breakers required for multi-terminal DC solutions.
- Secondly, the need to agree standards for exchange of control information between suppliers of different HVDC systems when operating multi-terminal HVDC systems.

In both of these areas, investment and thinking at an early stage was seen as being beneficial to the overall deployment of HVDC technologies in a potential HVDC offshore grid.

Supply Issues

Major bottlenecks in the supply chain over the next 30 years are well documented in the report 'Quantification of Constraints on the Growth of UK Renewable Generating Capacity'[30] carried out by SKM on behalf of BERR. Excluding those linked to wind turbines, the major constraint identified was that of subsea cables, where there is no UK subsea cable manufacturing capability. There are three European suppliers, ABB, Nexans and Prysmian who are fully booked for the next 5 years. Further, manufacturing time from order is around a year for HVAC cabling and over 2 years for HVDC mass impregnated cabling.

In order to justify manufacturers ramping up production to meet demand, a substantial amount of orders will need to be placed and novel designs may be put aside in favour of standard designs that can be produced quickly.

[30] Available at http://www.berr.gov.uk/files/file46779.pdf

Technology Opportunities

Summarising the detailed information in the report it is concluded that there are a number of areas where ETI could focus future research in order to achieve its objectives to reach innovative solutions for the collection of electrical energy from offshore renewable projects more efficiently and more effectively. At this stage these opportunities have only been highlighted and assessments have not yet been made which prioritise the opportunities against key ETI evaluation criteria. This is seen as being one step in a process involving much more detailed review of individual technologies and the potential benefits that could be delivered. The list of opportunities is listed here with further details being provided in Table 18.

- HVDC voltage standardisation
- HVDC circuit breakers
- HVDC multi-terminal control standardisation
- HVAC collector voltage optimisation studies
- Offshore cable reliability and repair improvements
- Pilot projects to connect small generation sized units using direct DC connections
- Alternative technologies for production of higher voltage power electronic devices
- Alternatives to replace HVAC export cables
- Offshore platform design including standardisation on approach for fire protection.
- Marinisation of offshore connection equipment

Next Steps

The identification and evaluation of technologies that has been completed at this stage of the project provides the necessary input into the direction to be taken, and the assumptions to be made, in terms of technology that will potentially impact on the implementation of offshore renewables.

The optimisation studies which are to be performed next will of course clarify which developments, and the benefits they can deliver, will have the most significant impact in the future. A particular technology is only useful if it can deliver a benefit that can be utilised based on the system requirements at that time or based on a very clear implementation route.

For example 550kV Gas Insulated Line shows a potential opportunity to enable AC to be used as an export voltage with very large transfer capabilities. By itself this is not useful if point to point schemes are to be employed with a maximum size around 1000MW will be adequate until 2025 or later. Equally if HVDC is already the leading technology for export technologies, then GIL for AC may not be beneficial at all.

Hence, the conclusions in this report are valid as the current state of the art and give an indication of where the technologies may lead to. How useful these technologies might ultimately be in expediting the development of future offshore renewable generationwill become clearer as the optimisation work is completed in the later stages of the project.

- **Table 18 Summary of Initial Thoughts on Specific Technology Opportunities for ETI**

Technology Area	Potential Benefit of Technology	Development Need	Potential ETI Input
HVDC circuit breakers and switchgear	DC circuit breakers and switchgear required for multi-terminal DC systems.	DC circuit breaker and switchgear devices	Specific projects to support development of DC circuit breakers and switchgear
HVDC voltage standardisation	DC circuit breakers and other switchgear items required for multi-terminal DC systems. Voltage standardisation would allow more rapid development of these devices.	International cooperation between HVDC suppliers. Ensure clarity of offshore renewable requirements	1 - Promote international bodies such as CIGRE to initiate such work 2 - Fund studies to ensure that the needs of offshore renewable are clearly identified and can be fed into the standards process
HVDC multi-terminal control standardisation	To allow interoperability between different suppliers HVDC systems in multi-terminal configurations without IPR concerns	International standard activity to develop requirements	1 - Promote international bodies to initiate such work 2 - Investigate whether specific requirements of likely offshore multi-terminal systems will contain any unique elements (task 7.5)
HVAC collector voltage optimisation studies	In the short term benefits in terms of system efficiency and cost optimisation likely if collector voltages are optimised	Fundamental studies to investigate benefits of voltage optimisation and select optimised voltages	Task 7.2 optimal design of electrical infrastructure addresses this point

Technology Area	Potential Benefit of Technology	Development Need	Potential ETI Input
Offshore cable reliability and repair improvements	Reduce the significant costs involved in repair/loss of offshore cabling	1 - Opportunity to use fibre optics to measure/monitor mechanical strain during cable laying and when in service 2 – Cable system physical protection systems 3 – Development of techniques to condition assess extruded cable cores during manufacture and in service	Identify whether there are cost effective mechanisms to support these developments or whether to leave to market forces
Pilot projects to connect small generation sized units using direct DC connections	DC collection and DC export schemes potentially offer benefits of simpler overall architectures and reduced losses	Project to highlight what can be achieved and to ensure that all issues are understood and have been addressed	Support to identify, scope and deliver a suitable project
Alternative technologies for production of higher voltage power electronic devices	System losses and converter footprints/weights can be reduced through use of alternative power electronic based materials technologies	Integration of new devices into offshore applications	Identify whether there are cost effective mechanisms to support the deployment of new devices or whether to leave to market forces
Alternatives to replace HVAC export cables	May provide the ability to utilise AC export systems for large offshore projects and potential offshore grid	Application development of specific technologies. A) GIL B) Superconducting cables	1 - Participation/support of existing projects 2 - Set up new specific projects
Equipment marinisation	Ensure that potential risks to operation and reliability of offshore connections are not compromised through equipment marinisation issues.	Up front studies and environmental tests on current marinisation methods to determine accelerated long term performance.	Support for a specific project with objective focused on offshore connection equipment and system.
Platform design	Reduced costs for offshore collector and converter platforms	Up front design work to further implement standardisation and modularisation concepts.	Support specific projects including standardisation of fire protection
Condition Monitoring	Optimise connection availability	More widespread application of condition monitoring systems	Promotion of neefits of application of condition monitoring philosophy

Finally it is worth noting that since the initial drafts of this report were prepared in late December 2009, the National Grid Offshore Development Information Statement[31] has been published. This document also provides a review of offshore transmission technologies. In terms of current state of the art the document provides a similar view of technologies but is not intended to consider a longer term view as to what new technologies might emerge or how existing technologies might develop.

31 http://www.nationalgrid.com/uk/Electricity/ODIS/

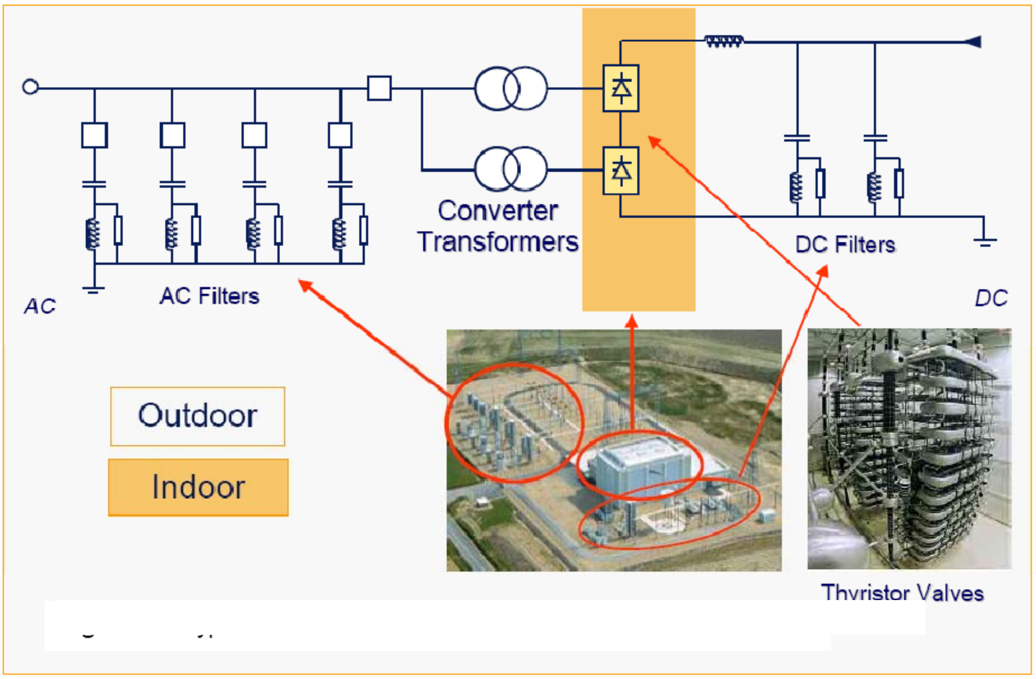
Appendix A Overview of Offshore Equipment

A.1 HVDC Converter Technology

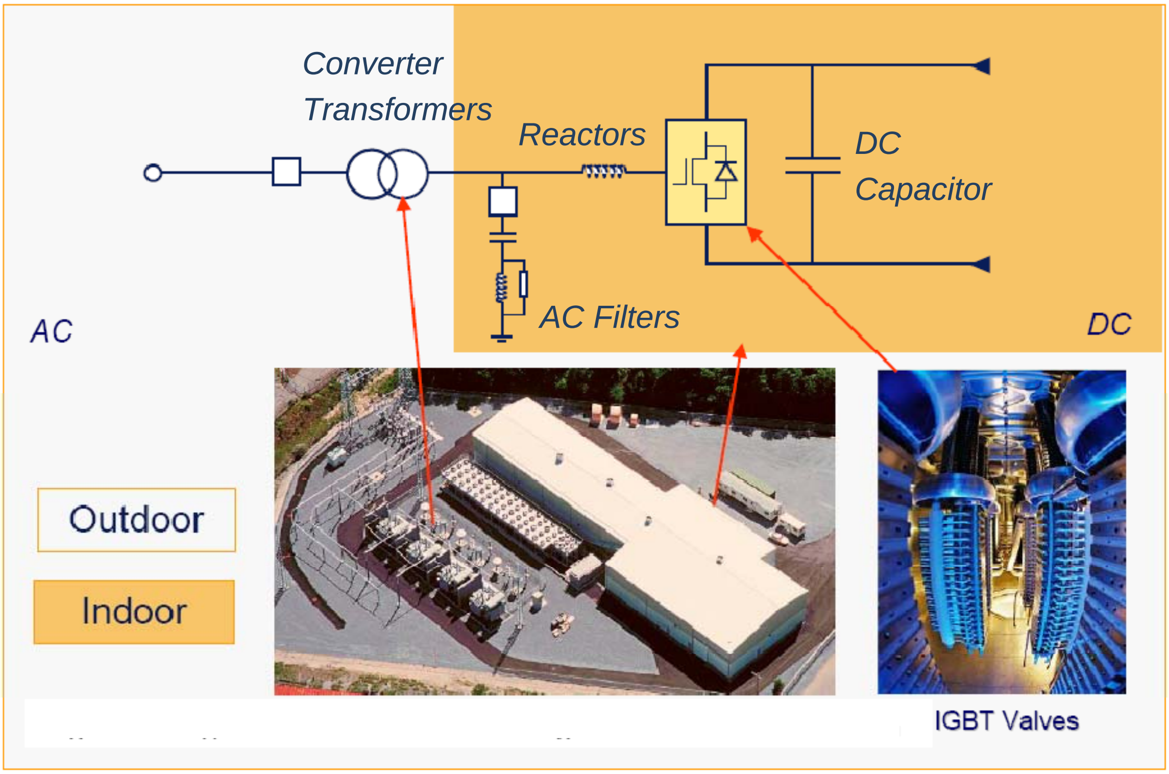
HVDC is very much an evolving technology with the emergence of Voltage Source Converters (VSC's) and offshore applications. Line Commutated Converters (LCC's) have been used commercially since the 1950s however VSC's only emerged commercially in the 1990s with ABB pioneering the technology. HVDC is generally recognised as the solution to long distance bulk power transmission and as such will play a major role in the development of large scale offshore renewable generation. For offshore applications VSC based HVDC is generally considered vastly superior to LCC given its smaller footprint and weight, greater degree of control over the output, and resilience to weak and unpredictable local networks. Disadvantages are that cost, both in terms of losses and capital, are greater with VSC-HVDC technology over LCC. It is expected that for the foreseeable future HVDC applications offshore will use VSC exclusively.

HVDC is much less familiar to most than AC equipment which has been the dominant power network technology for the majority of the 20th century, for this reason we have included a detailed description of HVDC technology and its application offshore in Appendix D. A brief summary of LCC and VSC station equipment is provided below.

- Figure 33 Line-Commutated Current Source Converter Station (Courtesy: ABB)



■ **Figure 34 Voltage Source Converter Station HVDC Light (Courtesy ABB)**



For offshore platforms there are two major competing technologies to be considered, HVDC Light (ABB) and HVDC Plus (Siemens). Both are based upon voltage source converters (VSC) and both offer more control, greater compactness and reduced weight compared to traditional current source converters (CSC). AREVA are expected to enter the market in 2010 with a similar voltage source technology.

HVDC Light potentially offers the greatest control of the two VSC technologies, with conversion being based upon PWM (Pulse Width Modulation). However, this is at the expense of greater size and weight due to equipment required to filter out harmonics produced by the PWM process.

HVDC Plus is based upon a MMC (Multilevel Modular Converter) which uses voltage stacking; this can lead to a reduction in control compared to PWM, the control being limited by the voltage step between levels. However, the technique obviates the need for major AC filtering.

From a high level review, both technologies would present an adequate solution from a functionality and performance perspective, with the final distinction likely to be based on commercial issues resulting from competitive tendering.

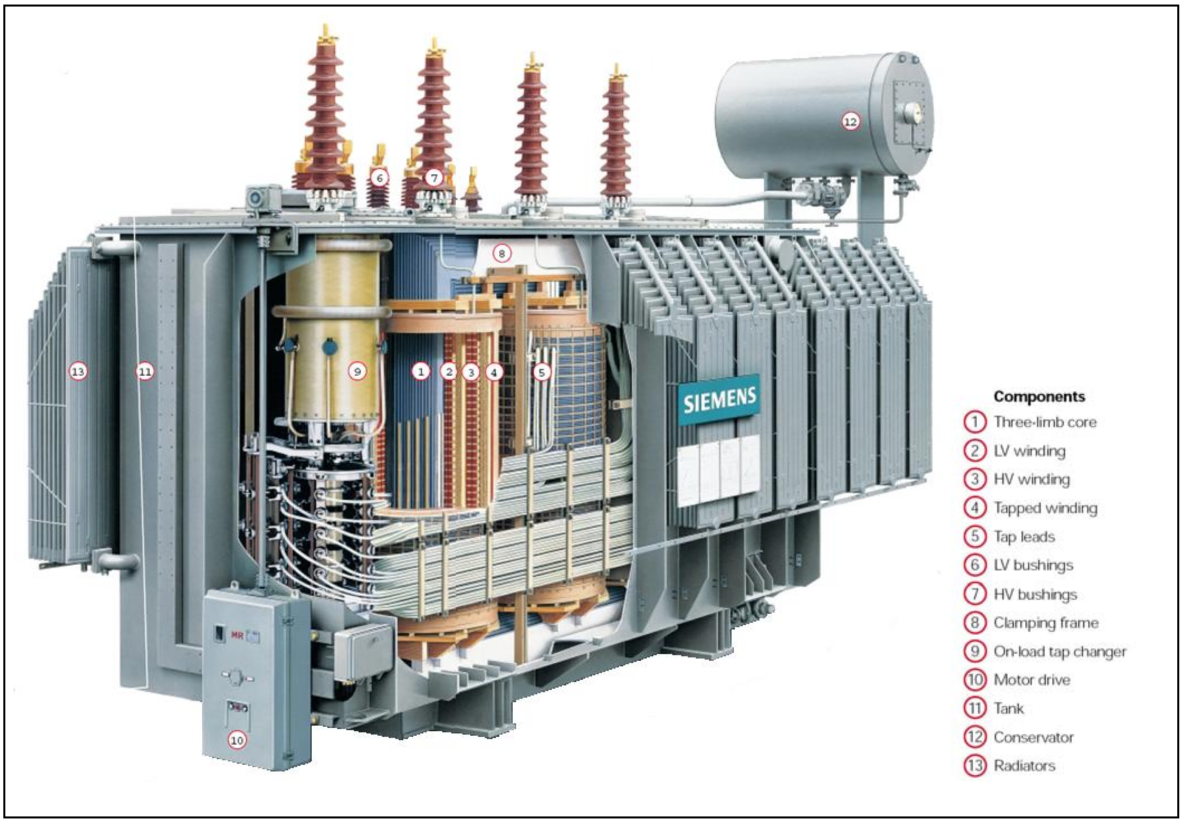
Development of all HVDC offerings is ongoing and expected to evolve dramatically over the next 20 years with an ever increasing number of applications.

A.2 Transformers

Transformers are used extensively in a range of applications in a power network; the primary transformer type concentrated on in this report is the power transformer. The purpose of the power transformer is to step the voltage of the network up or down to suit the operation of the local network. In the case of an offshore renewable farm the inter-array voltage at which power is collected from the generators (typically 33kV) must be stepped up to transmission voltage to facilitate export to shore (to date typically 132kV).

The construction of a modern power transformer is demonstrated in Figure 35 below.

- **Figure 35 Power Transformer Construction (Courtesy of Siemens[32])**



The windings and core are central to the transformer with the voltage ratio between the primary and secondary windings equal to the ratio between the number of turns in the primary and secondary coils.

A transformer tap is a point of connection on the winding and is a vital piece of equipment as it facilitates an adjustment to the winding ratio by switching taps without a major reconstruction of

[32] "Power Transformers 10 to 100 MVA" Product Brochure, Siemens, 2006

the transformer. In general tap changers are on load, where the tap can be adjusted without de-energising the transformer, or off load, where the transformer must be de-energised for the tap to be adjusted. Off load tap changers are generally set at transformer installation and then unchanged, or at least changed infrequently, on load tap changers however can be altered during operation to compensate for a shift in network condition.

The transformer tank could be considered the third main component of the transformer alongside the core and the windings. The tank accommodates the core and coil assembly along with the oil filling and as such must be oil tight and extremely durable. Oil filling refers to the insulation medium used in the transformer, in the vast majority of cases this will be a mineral oil filling but alternatives such as natural and synthetic esters or silicone oils also exist. The oil constitutes a part of the electrical insulation between internal live parts however also doubles as a part of the transformer cooling system. In an oil natural (ON) arrangement oil will circulate through the radiators by natural convection where as in an oil forced (OF) arrangement oil will be pumped through the radiators for extra cooling performance. Similarly in an air natural (AN) arrangement air moves past the radiator fins naturally or in an air forced (AF) arrangements air is blown over the fins by fans. By enhancing cooling transformer load can be increased however complex cooling systems increases operation and maintenance requirements and raise the likelihood of failure.

Finally, the conservator is an oil storage tank, as the oil in the tank expands and contracts with temperature oil flows in and out of the conservator ensuring that the tank is always full.

The construction shown in Figure 35 is typical but there is a large degree of variation across suppliers and applications, a typical example would be to separate the radiators into a freestanding radiator bank.

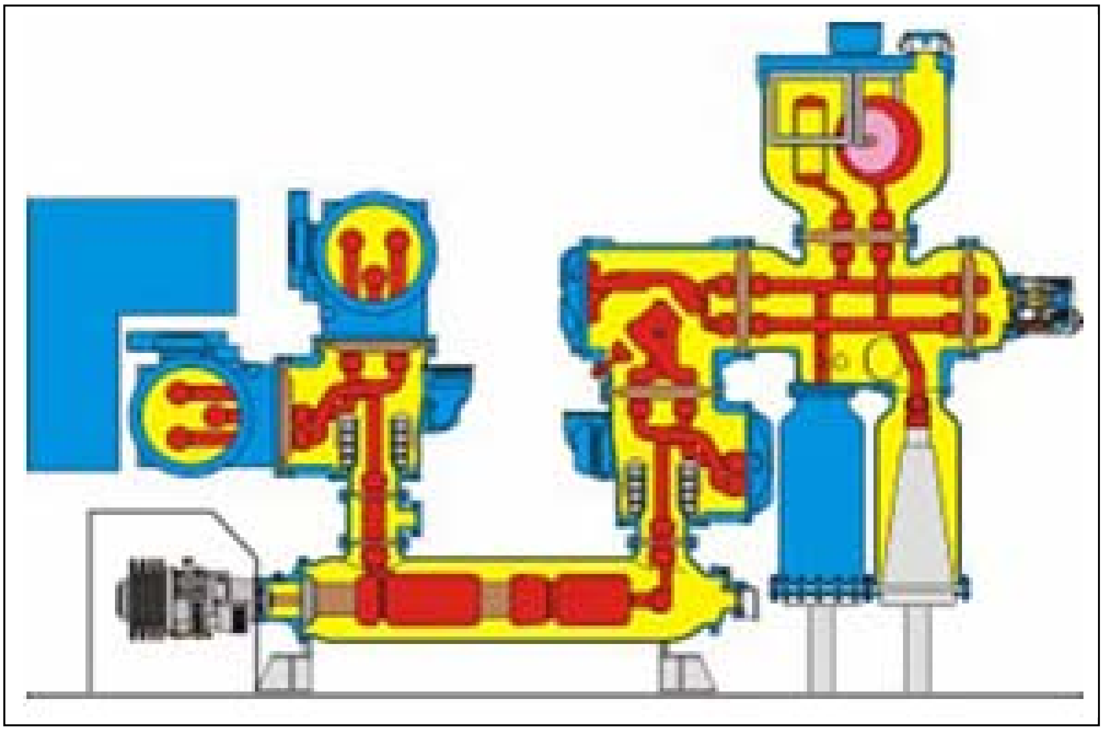
A.3 Switchgear

The term switchgear refers to electrical disconnectors, fuses and circuit breakers used to break electrical circuits and isolate electrical equipment. In this report we generally refer to circuit breakers as the primary switchgear.

Circuit breakers are switches whose primary purpose is to interrupt electrical flow. This can be as an automated response to fault conditions or remotely controlled for network management purposes. Unlike fuses circuit breakers can be reset and used repeatedly.

The components of switchgear are defined as interrupter, mechanism, insulation, busbar/cable connection and low voltage control panel. Switchgear designs vary but the main differentiators are insulation type (gas or air) and interrupter type (vacuum, oil, SF_6, etc). The purpose of the interrupting medium is to quench the arc that is formed when the circuit breaker switch contacts separate. Figure 36 below shows a typical construction for modern gas insulated switchgear.

- **Figure 36 132kV Gas Insulated Switchgear Construction Type ELK 14 (Courtesy: ABB)**



A.4 Protection, Control, and Communications

Within the scope of protection, control and communications are all secondary systems necessary for the actuation, protection and optimum operation of the electrical system and interfaces with generating systems and network control and management systems. Protection control and communications are thus integral to the operation of any power network.

Operationally protection is required to remove faulty parts of the network from the power system as quickly as possible in order to prevent damage to otherwise healthy parts of the network. Network conditions are monitored through voltage transformer or current transformer and relay configurations which identify fault conditions and then trigger an appropriate response which is usually the operation of switchgear to isolate the faulty network or plant from the larger system.

Fundamentally the purpose of control is to change the actual state of a piece of equipment to a desired state. The operating sequences of controlling, interlocking and signalling can be performed by electromechanical and electromagnetic devices but now are almost universally performed by contactless electronic devices as part of fully integrated and high levels of automation microprocessor based control schemes.

Communications protocols and networks are required to enable the secure transmission of signals for the protection and control of the system taking into account different requirements for system security and operating times.

The technologies and systems applied in offshore technology are the same as applied in onshore transmission and distribution networks and other than the environmental requirements the offshore application imposes no additional factors onto the technologies applied, however as will be discussed later some specific new requirements of how technologies are applied for control of HVDC technologies will be necessary.

A.5 Reactive Compensation

Reactive power is a term used to describe energy movement in an AC system relating to the storage of energy in electric and magnetic fields. Devices that store energy by virtue of a magnetic field produced by a flow of current are said to absorb reactive power; those which store energy by virtue of electric fields are said to generate reactive power.

In order to maintain a stable system within defined voltage limits power flows must be controlled. Reactive power flows can cause significant voltage changes across the system. It is necessary to maintain a balance between generation sources and demand points on a 'zonal basis'. Balance is maintained through network design, transformers, and reactive compensation.

Reactive compensation consists of devices that can be connected to the system to adjust voltage levels. A capacitive compensator as the name suggests consists of capacitor banks and produces an electric field, generating reactive power. An inductive compensator consists of inductors (effectively coils) and produces a magnetic field which absorbs reactive power. Reactive compensation can be either capacitive, inductive, or a combination to provide a range of operations. [33]

Shunt Reactors

In this instance with offshore renewables being the focus reactive compensation will be focussed around inductive compensation also referred to as shunt reactors which compensate for capacitive generation on the export cable. Construction will be fully enclosed type similar to a transformer albeit with no secondary winding as demonstrated in Figure 37 below which shows a representative 60 MVAr 420kV shunt reactor construction. Insulation and cooling is the same as with transformers and taps can be utilised to vary the MVAr output of the reactor, with offshore renewables however this is not an important feature as the reactive compensation requirement is not expected to vary.

[33] "An Introduction to Reactive Compensation", The National Grid Company, 2001

SINCLAIR KNIGHT MERZ

SKM

- **Figure 37 Shunt Reactor Construction (Courtesy of Siemens [34])**

1, Five-Limb Core

2, Winding

3, Tank

4, Radiators

5, Bushings

6, Conservator

Static VAR Compensators

State of the art reactive compensation would refer to Static VAR Compensators (SVC) which has the flexibility to produce variable inductive and capacitive reactive power required at the interface point of the offshore transmission network and the onshore transmission system. The reactive power output may be configured automatically responding to measured system conditions to maintain the desired voltage. SVC's may be used with AC or Current Source Converter (CSC) HVDC based offshore transmission networks but are not needed for Voltage Source Converter (VSC) technology.

SVCs use thyristor based technology and have a longer track record with devices in operation at much higher ratings and voltages than the alternative STATCOMs. SVC's are considerably cheaper than STATCOMs though are less suitable on weak networks as the reactive compensation capability of SVCs reduces below nominal voltage ratings. STATCOMS are able to control the

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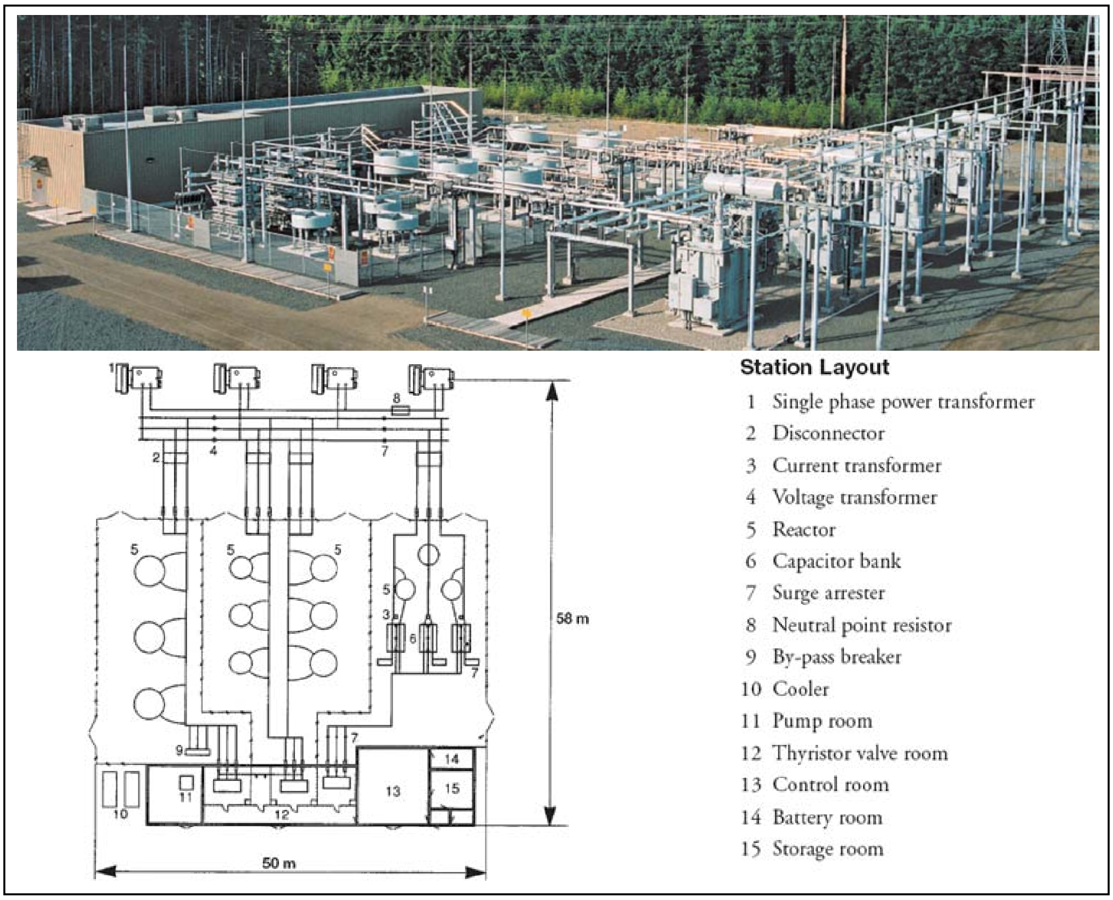
[34] "Shunt Reactors, for Medium and High-Voltage Networks", Brochure, Siemens,

MVAr output in proportion to the system voltage but SVC MVAr production reduces in proportion to the square of the voltage.

SVCs are built from a combination of thyristor controlled reactors (TCR), thyristor switched reactor (TSR), and thyristor switched capacitors (TSC). This provides the benefits of the continuous reactive power range provided by the TCRs, with the coarser reactive control provided by the TSRs and TSCs. The harmonic content produced by the TCR's can be reduced by the use of filters. The dynamic aspect of the SVC is controlled by thyristors, often referred to as 'valves' and are the only equipment usually located indoors as shown in Figure 38 below

- **Figure 38 135 MVAr Inductive to 165 MVAr Capacitive SVC (Courtesy: ABB[35])**



[35] "SVC for dynamic voltage stabilization of 132 kV system in western Canada", ABB Application note A02-0144 E

STATCOM's

Static Compensators (STATCOM) are fast acting devices which produce or consume reactive power, the level of which can be changed more quickly than with capacitor banks, reactors or SVCs.

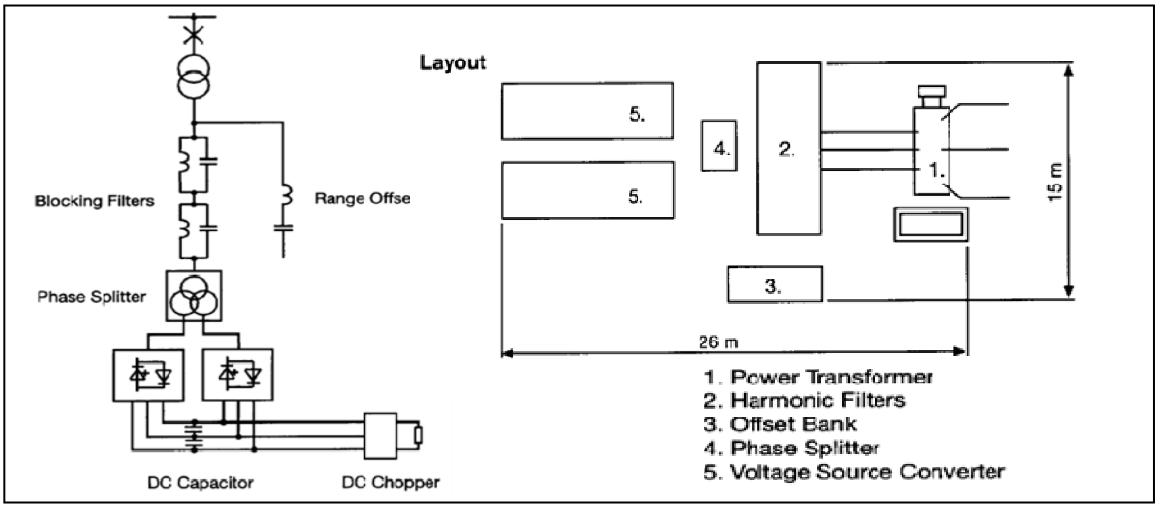
They are based on voltage source converters (VSC) using IGBT (Insulated Gate Bipolar Transistor) or IGCT (Insulated Gate Commutated Thyristor) devices. They can also incorporate fixed reactors and capacitors in their design but these are usually smaller in comparison with those required by Static VAR Compensators (SVC), which means that the STATCOM has a smaller space requirement.

Ratings up to ±100MVAr continuous at 145kV are in service with designs up to 200MVAr available. STATCOMs with reduced ratings can be integrated with fixed reactors and capacitor banks to provide a lower cost solution than a standalone fully rated STATCOM. Such systems currently in operation are relatively small in size and require circuit breakers suitable for repeated switching of the static elements. .

Most STATCOMs produced to date have been low or medium voltage devices requiring a transformer to connect to the local grid voltage. Recent developments in HVDC VSC technology has lead to the introduction of high voltage STATCOM devices that can connect directly to the grid without a transformer at medium voltages (e.g. 33kV), higher voltages still require a transformer at present.

Figure 39 below shows the comprising equipment and indicative layout of a compact STATCOM.

- **Figure 39 STATCOM Equipment and Layout (Courtesy: ABB[36])**



[36] "ABB STATCOM For flexibility in power systems", ABB Pamphlet A02-0165E

A.6 Power Cables

Cables are a vital part of any submarine power network as bare conductor overhead connections which are utilised onshore are impossible for obvious reasons. Figure 40 below shows a typical submarine cable construction. Cables are constructed from a number of layers and materials however the primary components are the core, and the insulation. The core will be copper or aluminium and represents the conducting medium, the conductivity and cross sectional area of the core sets the current rating of the cable, the insulation dictates the rated voltage of the cable.

The two main submarine cable insulations are mass impregnated and XLPE (Cross Linked Polythylene, also referred to as extruded). XLPE is gradually becoming the insulation of choice given the cheaper price and environmentally neutral credentials. A fibre optic communications cable is routinely included in the cable makeup for control purposes.

AC submarine cables are generally constructed in a three core format to reduce the installation costs and difficulty however there have been examples of single core applications where the phases are installed in a spaced arrangement. There are a number of reasons for using spaced single core cable:

- Minimizing the risk of multiple cable damage from external interventions such as ships anchors
- The minimum cable spacing would typically be two water depths to enable subsequent repair should it be needed
- Single core cables are generally used when the required circuit rating can't be achieved using three core cable therefore spacing the circuits improves the thermal conditions of an installation

Conversely separating the cable phases apart increases the circulating currents within the sheath and armour of the cable. These losses are dependent on a number of factors such as:

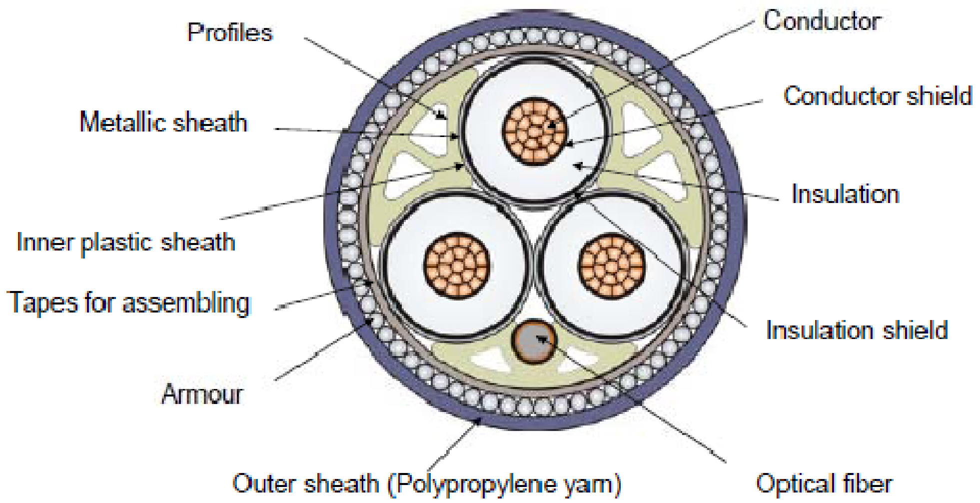
- Current flowing through the main cable conductor
- Resistance of the main cable conductor
- Resistance of the sheath or armour wires
- Mutual impedance between cables i.e. the cable spacing

These losses can be minimized by utilising copper armour wires, an example being the Ormen Lange XLPE cable where the main conductor cross section is 1200mm^2 and the outer copper armour wires have a cross section of 1930mm^2.

In terms of environmental impact each possible application has to be assessed on a case by case basis taking into account magnetic field implications of the circuits. This can include marine life and ships compasses.

Some examples where single core submarine AC cables have been employed are:

- Vancouver Island, installed 1984, 525kV, 1600mm², 4 single core oil filled cables x 39km length, 400m deep
- South Padre Island, installed 1991, 138kV, 380mm², 3 XLPE insulated single core cables x 14km length, 1.5m deep
- Spain – Morocco, installed 1997, 400kV, 800mm², 4 single core oil filled cables x 26km length, 630m deep
- Ormen Lange, installed 2006, 420kV, 1200mm², 4 single core XLPE cables x 2.2km, 210m depth
- **Figure 40 Submarine 3 Core XLPE Cable Construction (Courtesy ABB)**



Subsea installation of cables provides a number of difficulties both in terms of the vessels required and the seabed geography on which the cable is laid. Significant seabed surveying is required prior to the installation to assess the conditions. Foreign objects such as wrecks and pipelines need to be avoided as by traversing these obstacles there is an increased chance of cable failures. In addition as the seabed is not even, the undulating geography must be navigated carefully to avoid large sand banks or ditches as the added stress in traversing these obstacles can further impact on cable reliability.

A.7 Offshore Platforms

Offshore platforms are required to house the substations which gather cable connections from the array of wind turbines on larger developments where export to shore needs to be done at a higher voltage than the 11kV or 33kV which has been used for the collection system. Hence the platform provides the necessary step up power transformers, MV switchgear (typically 33kV), HV switchgear (132kV) and associated cable interfaces, control, protection and ancillary systems.

Current projects with capacities of under 500MW utilise a single platform but in the future multiple platforms may be required depending on the capacity of the project, and also the specific user requirements. Projects involving DC transmission have been completed in Europe and a specific HVDC platform is provided.

Platforms consist of a topside which will typically weigh 1000 to 2000 Tonnes for projects currently being delivered. Larger projects will require topsides up to 4000 or 5000 Tonnes. Compared to offshore oil and gas structures where topsides of up to 16000 or 20000 Tonnes are produced the structures for substation platforms are considered small by the offshore platform industry.

Topsides are supported on rigid structures fixed to the sea bed. Structures with three or more legs are termed as being Jackets whilst on small structures Monopiles can be used. Sea bed conditions, sea depth as well as platform weight determine the construction and number of legs required.

In addition to housing the electrical equipment consisting of transformers, transformer cooling system, switchgear, control and protection equipment, emergency power supplies (and fuel) the platform will also have to make provision for operation and maintenance of the equipment. Typically this may include permanent or emergency accommodation, evacuation and life-saving equipment and cranes/winches for maintenance. The installation requirements of the cables must also be accommodated for which includes the 'J' tubes which are supported by the platform.

Additional features such as a helipad may also be included dependent on the size of the platform, distance from shore and accommodation provisions. Design and production techniques for offshore platforms are well established for the Oil and Gas industries. The offshore structures are built onshore in fabrication yards with all electrical equipment and systems being installed. This minimises the work required offshore which attracts a very high price premium as well as environmental difficulties.

Once the topside is completed onshore it undergoes a loadout process by bogey or skid (Figure 41) onto a vessel to allow transportation to the site where the subsea structure will already have been installed. Onshore lifts up to 2000T are typical whilst offshore cranes are available for a 10000 Tonne single lift. Where platforms exceed the weight then multiple cranes can be used before a floating structure is needed.

Once the topside is positioned then cable installation and final commissioning of the electrical systems can be completed.

- **Figure 41 Image of Load out bogey as Used for Greater Gabbard Offshore Platform[37]**

[37] SKM Source

Appendix B Manufacturers Interviews Response

High Level Questionnaire for Suppliers
Pertaining to Off-shore Renewable Generation Connections

The ETI is aiming, through its funding and research initiatives, to encourage the development and deployment of offshore renewable generation in UK territorial waters. The information collected through this questionnaire will contribute to a number of recommendations to the ETI with regard to the most effective use of their resources to have maximum positive impact on offshore renewable development.

SKM has been engaged by the ETI to investigate opportunities to accelerate offshore renewable development through investment in offshore connection technology or design. SKM has carried out a preliminary analysis of offshore renewable generation connections identifying areas in which we feel improvements might be made either from a system or a product point of view. The next stage of our investigation is to seek the ideas, advice, and experience of the manufacturing and installation industry. Through this questionnaire and subsequent interviews we intend to build a robust view of the current state of offshore technology as well as a view of the industries potential and likely development path. Further we will aim to measure opinion on a number of opportunities and issues that we have identified in our preliminary reviews.

The information received by SKM through this request will be included in reports that may enter the public domain. Corporate names associated with this information will not be disclosed by SKM. However, respondents must identify any information that is confidential and not to be disclosed to anyone beyond the immediate study team.

Spreadsheet Colour Code Key:
Suppliers
Consultant
Academics

AC Transmission and Distribution Equipment

	Question
1	The majority of equipment being used at present in offshore applications was initially designed for onshore conditions. • Do you think that sufficient work has been carried out to research and investigate the effect of the change in operational conditions to the application of the equipment with reference to manufacturing / component issues, equipment lifetimes, operation and maintenance requirements, equipment reliability, proven technology track record? Are there specific areas of work that you would suggest are looked at where perhaps risks are unknown? • What limitations and issues have been highlighted to date that should/could be improved with research and development? • With the possibility of funding for investigation into these issues, what types of projects would you put forward for consideration and what would be your priority?
	Answer
1	1 Marinisation - "I think that the move to HV offshore substations has come upon us quite fast and so there has not been sufficient work done to research what changes are required to onshore equipment to make it suitable for this new offshore environment. The obvious areas are "marinisation" to suit the atmospheric environment and this will apply not only to the primary plant but probably also some work may be needed on secondary equipment." - "Equipment for offshore demands higher requirements related to corrosion due to the marine atmosphere. Many T&D equipments already satisfy these requirements, alternatively such equipments are installed in containers with a controlled atmosphere (air with overpressure)." - "Improved surface treatment/protection of areas directly exposed to the marine atmosphere (requires investigation)." - Paint systems for transformers based on marine C5M system, believed to give 10 - 15 years life....so will not last lifetime of equipment but actual experience yet to be learnt. - " many items of equipment currently being used for offshore applications is standard equipment adapted for offshore application. So yes there is certainly scope to do more to adapt equipment for offshore applications. This however is not R&D type activity but application refinement.....learning from lessons.....some of which has already been done, but there is more to do." - "Issue on suitability of secondary equipment and suitability to offshore environment....yes in rooms etc. but do printed circuit boards need special coatings etc? Could well be lessons to learn from Oil and Gas and apply these to T&D specific equipment." - - Transformers were never intended for application offshore so there is scope to do some work here but application is key.....for example there are already designs of underwater transformers that exist but not at the sizes now being applied on offshore platforms for example. 1.1 Further Issues Resulting from Environment Requirement for; "More accurate network parameters and operating duties as seen by the switchgear. More accurate life cycle costs. Better use of integrated condition monitoring. Requirements for Point on Wave switching" 2 Less Flammable Transformers and Related Precautions - "Areas needing research and development include the need for transformers at high power ratings using synthetic esters which will assist with fire protection and environmental issues. These are readily available and proven for small transformers but experience is limited on larger units. A corollary to this is a better understanding of transformer explosions, their statistical probability and the mechanism of the explosion to decide what if any blast protection is actually required on offshore platforms. Another aspect is condition monitoring and modularity of plant to enable timely change out of components before they impact on the output of the wind farm. " - " I think that research into transformer fires and explosions would be the most important ion removing a major area of risk." - "A primary area for consideration is transformers and in particular the approach to transformer fires.......One option is to go for an alternative to mineral oil insulation such as Midel which has widespread application on distribution transformers but on EHV limited to around 220kV." - "the issue of fire protection is not fully thought through...Apply salt water system?... or fresh water but then need 60T storage... Also different types of system...deluge, mist?" - "Could be an opportunity here to do studies/simulations on transformer events and fire/explosion protection given use of different technologies. Unlikely that at this stage there can be standardisation but there is a basic lack of experience at this point in the application of the technologies." - Bottom line is that explosion / fire risk on platform has not been fully thought through and also impact of oil leakage into sea. 3 Further Comments - View is that any R&D has to be application base as there are too many issues with IPR to make fundamental funding realistic. We are looking at the application of superconductors for fault current limiters and for fault current limiting transformers. We expect to be in the market for FCLs with the next 18 months and for FCL in a transformer within about 3 - 5 years. We have also looked at superconducting DC cables with low to medium voltage converters...very interesting, except for the cryogenics.

	Using GIT provides several advantages for wind farms - non flammability - non explosive - no risk of oil contamination - less maintenance - more compact - no need for fire extinguishing system - no oil conservator no need for separation between GIT and GIS - Potential for water cooling Typically the capital cost of a GIT can be 2 to 2.5 times that of a conventional oil transformer. However this is before the benefits of Life Cycle Cost and auxilary systems are evaluated. GIT have a near perfect reliability record and are basically maintenance free except for cooling plants. Midel 7131 is a transformer insulating liquid on a synthetic ester base. It is environmentally benign and has a higher firepoint in comparison to mineral oil. It can be used for Power, Distribution and Traction transformers. Midel has a higher viscosity in comparison with mineral oil requiring a more complex filling and impregnating process and is more expensive.

	Question
2	Equipment manufacturers offer similar types / models of equipment used in UK in other applications, markets and countries with differing technical parameters (i.e. operating frequency, voltage, technical standards, etc). • Have you already considered the possibility utilising a particular switchgear model at its proven upper limits (rather than rated values) to maximise space / weight utilisation a) where the AC collection system is electrically not directly coupled to the onshore T&D system and b) where the AC collection system is electrically connected the onshore T&D system. • If yes, what conclusions were reached regarding the benefits that this may bring to equipment (i.e. thermal capacity, reliability, cost, O&M, lifetime, etc) • If no, would you consider doing so if their were demonstrable benefits associated with such applications?
	Answer
2	a) We, together with our clients always look to obtaining the optimum equipment for the function. A simple example is on London Array the use of 150kV rather than 132kV in order to get better value out of the submarine cables. We would not consider using equipment beyond its rated values as the impact of failure or extended maintenance requirements would almost certainly outweigh any perceived benefits. b) and c) refer to answer above a): Yes, for example MV GIS up to 60kV b): Benefit could be lower currents in the cables with higher voltage at constant power Any requirement to operate switchgear at levels above its assigned rating should involve the switchgear manufacturers, in particular in terms of any erosion of switchgear life and maintaining correct operation. Operating HV Switchgear outside of its Type Tested values, is a risk that operators would need to consider - There are already options to use a multitude of equipment with different ratings if the work is done to actually determine what the optimised voltages might be. - All of the major manufacturers have standard pieces of equipment which are capable of such intermediate AC voltages. Not an issue for DC although there is much scope for work to demonstrate the optimum solution AC or DC. There is scope for the standardisation of modules rather than the standardisation of systems as there must be some scope for novelty Not really considered as initial feeling is that standard IEC ratings give the options........i.e. Move from 33kV to 66kV on collection voltages ....don't need an intermediate voltage.......but perhaps there is scope for this to be investigated by studies. Certainly too early to standardise on systems for offshore as the practical experience is so limited.........can only really standardise after lessons have been learnt. Are areas on O&M which need to be reviewed after experience including access for O&M, basic working offshore, how to transport equipment offshore for repairs/replacement/maintenance. How can offshore costs be reduced.......have some sort of offshore base where staff are located for 4 weeks or so moving to jobs without returning to shore........(how are existing oil and gas platforms positioned to be used for this? or some kind of ship?)

	Question
3	How do you feel the next generation of electrical equipment for offshore renewable connection will be developed? For example do you feel that the next generation of wind and marine farms will use equipment that has been adapted from onshore designs to meet the change in operating environmental conditions? • Taking into account the difficulties of access and space constraints, what do you see as the most important areas for improvements e.g. primary circuits, secondary equipment, environmental protection? • In what ways have you adapted equipment with reference to the aspects listed above in the past for either bespoke or general use on offshore projects? • What do you see as the most likely near term / imminent widespread equipment adaption? What range of equipment within your current market offerings will this be applied to? • With the possibility of funding for the proving of adaption's to existing equipment, what types of projects would you put forward for consideration?
	Answer
3	a) Maybe the next step to significantly increase the power capability would be to move up to a higher voltage for the inter array connections. Also, if the cost effectiveness and reliability of transformers with synthetic esters instead of mineral oil can be proven this would have a significant impact. On the secondary side better integration of the SCADA systems would be a benefit but this may be hampered by political developments such as the unnecessary introduction of an OFTO. b) Transformers are painted with a marine paint specification. Special versions of switchgear have been designed for the WTG collection points at the transition pieces. The protection features in modern multi functional relays have been used more extensively than onshore e.g. use of negative sequence protection and voltage controlled over current in addition to directional features. c) Transformer insulating fluid and cooling method. On AC platforms the transformers are the largest and heaviest items of plant and trying to optimise how these are installed would help. d) Transformer cooling and insulating fluids. a): Primary circuits with smaller footprint and environmental protection b): Compact switchgear products available with SF6 insulation 36/40.5/50/52kV c): New GIS switchgear (not yet formally released therefore is still CONFIDENTIAL d): Power Transformer for compact design of radiators to dissipate heat. Important to ensure technical interface between all parties to wind farm projects. E.g. for off shore wind farms any design issues with the platforms which might affect the integrity of the switchgear should be considered. We feel that adaption of onshore designs will occur. '- There are already options to use a multitude of equipment with different ratings if the work is done to actually determine what the optimised voltages might be. - All of the major manufacturers have standard pieces of equipment which are capable of such intermediate AC voltages. Not an issue for DC although there is much scope for work to demonstrate the optimum solution AC or DC. There is scope for the standardisation of modules rather than the standardisation of systems as must be some scope for novelty '- Application work is required not development, yes there is work to do on marinisation etc. but in terms of priorities would suggest: - Work required is not to introduce novelty but application to optimise solutions and how do we best apply what we have already - Selection of architectures DC or AC - Optimisation of voltages - Marinisation - Plans for round 3, could be DC transport and collection - Issues are not to do with introducing novelty, about how do we best apply what we already have. IPR is an issue hence focus needs to be on application

	Question
4	Looking further into the future it is assumed that equipment for offshore developments will be largely bespoke equipment designed exclusively for offshore use. • Would you consider developing, from existing product lines or as new products, a range specifically designed for offshore applications. This could be on the basis that offshore AC collection systems would be electrically segregated from the onshore AC systems by the HVDC link? • What products do you feel would benefit most from this approach? • Do you have a feel for the volume of business in each product line that would be required to stimulate interest in such development? If so please elaborate. • Do you see other markets for products developed as part of this strategy or do you feel offshore renewable generation is particularly UK focussed? • If there is interest how would you see the cost of development being funded? The options appear to be to: - manufacturers fund the development internally recovering cost from product sales, - apply for external funding to cover some or all of the development cost, - a mixture of the two • Power equipment for railways are a subset of the main product lines (switchgear) or custom designed for the application. Do you see a similar approach being taken with offshore collection systems where they are electrically isolated from the onshore T&D system?
	Answer
4	a) I doubt that totally new products will be developed unless the market increases significantly, development of adapted models is more likely. b) Transformers and more modularisation on other plant. c) For 33kV a big change would be needed as these products are commodities and sold in very large quantities. Transformers are basically custom designed and HV switchgear is somewhere in between. d) There are already extensive plans for offshore wind farms off the coasts of Denmark Holland and Germany. Interest is also growing from Spain and Italy. e) Maybe generic research and development could be funded. Manufacturers will do their own developments to make them more competitive. f) Railways are big market. If offshore grows to a similar size (which I think is unlikely) it may be possible. a): Yes depending on the market b): Wind turbine tower (Distribution Transformer & MV switchgear) Offshore substation (MV Primary switchgear; Transmission/distribution transformers; HV GIS switchgear) c): Depends mainly on the quantities to be sold and the cost of the associated development d): Other markets - Oil and Gas probably and wind. Not UK focussed, includes other countries such as: Germany, Holland, Norway, Denmark.. e): Depends on the value of the cost: probably a mixture of the two. High cost: external funding for at least part of the cost; Low cost: internal funding f): Possibly Any development of switchgear products for offshore use would almost certainly be from existing product lines, with the exception of DC application. Product standardisation would assist in any development process '- View is that products used will be standard ones that have been adapted for the offshore requirements, in switchgear, transformer, HVDC terms the size of the offshore market does not warrant special developments. - Also have to recognise that there is a lack of commitment to justify specific developments. Globally and outside of UK renewable sectors there is more certainty about plans. - Confident that equipment will be sold into UK market but not confident that it will be optimised for system needs. - Have to recognise that UK, despite probably being the single biggest market opportunity, maybe following the market e.g. application of HVDC offshore.....Germany ahead. Therefore new applications may well happen elsewhere first. DNV standard for platforms now exists but unlikely that at this stage can be considered to be definitive. DNV have decided now to cooperate with CIGRE WG and will re-write the electrical sections of the standard in two years to align with work of CIGRE WG. - At this stage options have to be kept open until more lessons are learnt. - Opportunity to use sea water cooling for transformers? In terms of investment there is a need to better understand the relationship between; '- Benefit (for user) '- Investment needed '- What the market is (which will in turn derive the benefit for the supplier) With regard to having a sub line of equipment as with railways it will come down to volume of supply, railways are a massive global market. He does not feel that offshore renewable are in that league however this is not something that has been properly investigated and could use some research. An offshore super grid is a compelling idea and something that is of great interest to many however a credible technical proposal is yet to be put forward which would make the wish a potential reality. Such a proposal could be a major step forward.

	Question
5	To what extent do you feel that the supply chain or equipment installation issues (both in the UK and across Europe) could become a constraining factor in the large scale development of offshore renewable over the next 15 years? • Will there be sufficient manufacturing capacity available for specialist products required considering: - high volume, moderate value items such as MV switchgear - low volume, high value items such as step-up or converter transformers • Are other major production demands e.g. renewal or extension of onshore assets likely to impact on available production capacity for offshore equipment assuming that demand reaches peak levels in the period 2018 to 2028. • What equipment do you feel is most likely to be affected by such constraints, and in your opinion how can these constraints be overcome?
	Answer
5	a) I would doubt that high volume low value equipment would become the constraint. However, any kind of transformer is already a constraint on timescales and specialist units like those for HVDC will make this worse. The other obvious constraints are WTGs and submarine cable. b) Yes, not only in terms of materials, factory capability but also human resources. c) See a) above. Needs the Government to actually be constructive in creating the right infrastructure to attract manufacturers to establish new factories. This is in terms of some guarantee of continued business and the actual facilities on suitable sites to attract them in. a): MV switchgear - sufficient capacity Transformers - most probably not sufficient capacity b): Difficult to make a statement c): Power transformers Any constraints in the manufacture of HV circuit breakers can be overcome by involving manufacturers in the early stages of project planning and forecasting. Call off ordering process with estimated requirements over a time period say 5 years would be an advantage. Adopting standardised solutions would also assist manufacturers in their planning. We feel that supply will adapt to meet the demand. '- There are concerns about the supply chain and the company has made repeated comments to OFGEM etc. to highlight concerns as part of corporate obligations. Feeling is that points made have not been taken on board. e.g. capacity for supply of sub sea cable....but a dialogue with customers is required. - Yes the UK may suffer due to lack of coordinated thinking and forward certainty, leaving those markets with clearer plans to be served first. - Current market situation is "mush" ....who will be the developer, who will be the OFTO, role of OFGEM...........cannot consult with everybody and as their is no coordination there is no certainty. In other markets the situation is much simpler and predictable.....e.g. in Germany only 2 TSO's to consult with. - Also should be recognised that projects can also be delivered much faster if everybody is aligned and can pull together.......allowing issues to be overcome. Are obvious areas of limitation (specialist equipment such as lifts and cable laying vessels but also with the supply of some equipment as well e.g. HVDC converter transformers..........but not explored fully

	Question
6	To what extent do you feel that regulatory (grid code requirements, GB SQSS, etc) and operating regimes are or could become a constraining factor in the large scale development of offshore renewable over the next 15 years? a) Do you think that an examination of the impact of system performance requirements demanded by regulatory authorities at the various interfaces between elements of the offshore system would offer benefits to the offshore installation, perhaps at the expense of the onshore installations? b) Do you think that close cooperation between the wind turbine manufacturers and the collection system designers would provide better ways of meeting regulatory requirements.
	Answer
6	a) It would be useful for the technical people to get together between the utilities, the WTG manufacturers and the transmission people to work out the optimum compromise on what the code should be and how it can be best achieved rather than allowing the accountants to screw up the whole system before we a start. b) Yes, if they are allowed to and not constrained by inappropriate legislation. a): Do not know, but am sure that not all aspects relating to the connection of distant offshore wind energy to the onshore network have yet been examined. So more work is still to be done. b): Yes, for sure! Current regulatory regime is causing uncertainties from a technical perspective which do not help the choices that need to be made by suppliers of equipment. '- What should have happened is definition of the basic system design and then add the regulatory model.....not the other way around. - Reliability could be improved at a stroke by cooperative design offshore.....a little joined up thinking would go a long way.....but the regulatory regime would have to take second place and do what's more efficient from a system and technical perspective. - The regulatory regime does not promote such fundamental issues as cross connections and the opportunity to apply standard network planning methods.......such a technical first issue would enable reliability and availability issues to be addressed. OFTO approach is fundamentally not the right one ....only makes sense if the interface points are on shore. Some fundamental issues are unclear e.g. How do you assess and value availability ? There is much scope to develop fundamental models here.....Availability of connection might suggest more importance here but N-1 is surely not the right approach.

	Question
7	To what extent do you feel that legislative requirements (e.g. health & safety, environment, etc) are or could be a constraining factor in the large scale development of offshore renewable over the next 15 years? a) Do you believe that particular equipment modifications / adaptations may be necessary to overcome such restrictions that are not required purely from a technical perspective (i.e. making equipment easier to commission and decommission, smaller or lower weight and simpler to commission, etc) b) Do you believe that the use of redundant systems and hardware diversity in those systems would improve availability e.g. two protection systems normally operating in 1 of 2 mode and operation allowed with one system out of service? c) Do you believe that increased use of condition monitoring and the provision of more detailed diagnostic information to the user's or manufacturer's specialist engineering teams would improve availability and / or reduce the need for offshore travel and time spent offshore? d) Would manufacturer's provide specialist maintenance and repair teams trained and available for product support for equipment installed offshore?.. If specialist products are developed is this more likely to be a requirement? Is staffing such teams feasible.
	Answer
7	a) The best way to work safely offshore is to reduce the amount of time needed offshore. This may be achieved by condition monitoring and modularity which allows a quick and easy exchange of components. b) I do not think that this is necessarily the best approach from the point of view of cost space and weight. c) Yes see a) above d) Specialist teams will definitely be required, but the specialism is being trained to work safely offshore. However if the level of modularity is right then people will be able to change out all kinds of modules and leave the technically specialist repairs to be done onshore. a): Yes, due to environmental issues (smaller, lower weight, easier commissioning/decommissioning…) b): Redundancy…Yes Hardware diversity…..? Due to: Different handling Increased quantities of spare parts Different skills and trainings required for personnel Probability to be calculated c): YES d1): Most probably Yes d2): Could be d3): see answer to d1 Condition monitoring should be an advantage in respect of HV switchgear from a monitoring process and form a maintenance regime. This is particularly relevant in remote wind farm locations '- If the system is designed correctly then existing equipment reliability can deliver excellent system availability but the isolated thinking does not encourage such an approach.

	Question
8	Superconducting • Have you considered the implementation of superconductors in the near future? What timescale do you feel it will become viable? • In your experience is their a demand for such technology? • What will its effects be on transformer characteristics, cost, operation and maintenance, and availability? • What effect do you feel superconducting materials for transformers and cables, or indeed any other fundamental technological development (please detail) could have on the technology evolution that we have so far identified?
	Answer
8	We are looking at the application of superconductors for fault current limiters and for fault current limiting transformers. We expect to be in the market for FCLs with the next 18 months and for FCL in a transformer within about 3 - 5 years. We have also looked at superconducting DC cables with low to medium voltage converters...very interesting, except for the cryogenics. It may be that in the short term that conventional subsea cables make most sense for collector systems, especially considering the lower power levels. Once on land superconductors open the option for underground, low loss, longer distance, high power, multi-point transmission. To the question of submarine applications the length of cable is not an issue. The main complicating factor with superconducting cables is the need for periodic refrigeration stations. This would require the development of subsea coolers or floating substations. However the lower power of these offshore feeder cables may make the economics of superconductors questionnable, at least in the present time. Also in the 20 to 30 year time horizon, superconducting DC cables could be available for integrating offshore power sources. Regardding superconductivity it is simply not practical for subsea application i.e. my prediction would be "never". The maintenance and reliability of superconducting cables have to be considered very major challenges when compared to standard cables. A rise in temperature due to loss of vacuum or refrigerant flow would take the cable out of superconductivity. Should the cable suffer a third party damage or internal failure it is likely to be out of service for "years" due to contamination. It is thus concluded that the technology is not suitable for subsea applications now or in the foreseeable future.
	Question
9	Submarine Transformers • Do you currently offer submarine transformers? What currently are their limits in terms of capacity and voltage, what is the cause of these limitations? What development would be required to overcome these limitations, for example if current transformers are limited to small capacities and relatively low voltages what development would be required to develop power transformers and would they ever be likely or practice? • Would you envision their application for offshore renewable developments, please elaborate on your answer? • What is the level of requirement for operation and maintenance of submarine transformers compared to oil immersed standard transformers and what if the comparative availability? • What is the cost of a submarine transformer in comparison to a similar standard oil immersed transformer?
	Answer
9	My only thought is to consider submarine substations.These are needed for any floating device as dynamic cable must be connected and the voltage increased. GEC proposed one 30 years ago when the wave power programme was strong. We are working on multi terminal HVDC and the lack of a circuit breaker is a problem. Even when we have one, having to build a platform for it is a problem. I do think we need to consider what can be done on the sea bed. Underwater designs of transformers exist but not at the sizes now being applied on offshore platforms.

HVDC Transmission Equipment

	Question
1	What systems are you able to offer for the connection of offshore generation groups to connection points within the Main Interconnected Transmission System (MITS)?
	Answer
1	Line commutated HVDC and Voltage Sourced HVDC are available now, these can be multi ended if necessary. In the near future complete DC systems are possible and the technology is well understood by companies like Siemens. We can develop any necessary new products from our own resources once the market need is there. ETI support for a fast track process to set standards for fully HVDC grids would be most valuable. We need to agree at what voltage the 1st generation EU super grid will operate, then all manufacturers can develop DC breakers, protection and control systems to suit. Turnkey AC offshore systems with the appropriate switchgear at all voltage levels, plus transformers, protection systems, etc. With partners could also provide the platforms and all associated cabling. Depending on the distances involved between the generation groups and the connection points: turnkey VSC based HVDC systems including, with partners, the platforms and associated power cables Offshore renewable provides the opportunity for HVDC to really come into it's own from a technology perspective. More and more systems are becoming DC based e.g. electric vehicles and this provides opportunities for new system architectures to be considered, VSC technology will become a key enabler. We have a full range of HVDC technologies available. For true multi terminal HVDC then breakers and protection systems will have to be developed but the first stage will be to agree standardised voltages. - Issue will be the sharing of control information as this will require exchanging of potentially sensitive information between competitors. - Current architectures with AC/DC/AC conversion are not elegant and completely DC systems are possible using novel architectures. We have LCC and VSC technologies choice depends on application and overall architecture. Choice between AC and DC determined by size and distance....rule of thumb 1000MW up to 70km at AC is right choice. At moment still sees collection being done at AC.

	Question
2	What are the maximum ratings available for the different HVDC technologies available: - in service and proven? - in production? - in development?
	Answer
2	HVDC Classic (LCC) in service 800kV in China rated at 5000 MW Yunnan-Guangdong, but contracts under negotiation for >7,000MW. Future development is possible, but highest power requires EHV overhead lines as no cable designs for this voltage. HVDC Plus (VSC) 400MW Transbay project in San Francisco was energised in 2009. Designs for up to 1,000MW are under discussion with customers and will be available for Round 2 and Round 3 projects. Line Commutated Converter (LCC) technology for cable schemes: In service and proven: Monopole: 450kV/600MW. Bipole: +/- 500kV/1000MW. Double Bipole: +/-270kV/2000MW In production: Monopole: 500kV/800MW Note the limits for LCC cable schemes is the cables, not the converters. Maximum cable ratings available are 500kV, 800MW per cable Converters with ratings of +/- 500kV/3000MW are in service as a bipole Converters with ratings of +/- 800kV/6400MW as a bipole are close to being put into service NOTE: LCC is not at all the ideal solution for offshore applications Voltage Source Converter (VSC) technology for cable schemes In service and proven: Monopole: +/-150kV/350MWMW (Note: this is a 'bipolar' topology and exhibits the characteristics of a monopole) In production: Monopole: +/-200kV/500MW Note the limits for VSC cable schemes will be the cables, not the converters. 200kV cables exist, 300kV cables are being worked on. 600kV converters are announced by one supplier in power point presentations, but nothing on order yet NOTE: VSC is the ideal solution for offshore applications '- Current constraints in terms of HVDC technology relate to submarine cables where a 320kV DC cable is now available and 400kV on drawing board. - Designs exist for 1000MW platform. - Ideas exist for potential DC collection using novel arrangements, however these are sensitive and cannot be shared. May be that platforms can be avoided altogether! - scope to do work on optimisation of footprints for converter platforms. Capacities will increase as new semiconductors come on stream along with new topologies. The big need is for a greater range of economic IGBTs mounted in pressure contacted packages from multiple suppliers. I do not believe that VSC converters will become available for scheme ratings much greater than +/-600kV and 4000MW. Within 5 years we should see ratings at +/-500kV and 2000MW, in 10 years we should see +/-600kV and 4000MW.

	Question
3	What developments or evolution do you anticipate which will result in improved performance or service in the following timescales: - within 5 years? - 6 -10 years? - 11 - 15 years? - beyond 15 years? • Gas Insulated Converter Stations (GIS). If HVDC off-shore converter stations are required for accommodating off-shore wind farms, can GIS equipment be used to minimize weight and space? This could no doubt be applied for the AC bus and circuit breakers, but can it be successfully applied for the dc side bus and equipment? Has there been any experience with use of GIS for the dc side bus and equipment? Would you expect development along these lines and if so within what timeframe? • AC Filters. AC filters are essential for LCC converters and have been applied for most VSC converters. Will VSC converters evolve to where AC filters will be not required at all while power quality is preserved for the AC busbar? What timeframe would you perceive such a development and what indicative effect on cost and footprint would it have?
	Answer
3	We are confident of having all necessary HVDC products available when they are required by the market. We don't see a role for ETI in funding new core technology - manufacturers will invest when they see a need. Beyond 15 years there is the potential for chemically vaporised diamond based devices which could make a big difference to devices. Currently all Silicon Carbide efforts are focused on low power devices rather than High Power.....diamond could move into the research space. Nothing significant for LCC solutions For VSC the availability of higher voltage extruded cables, expect to reach 400V For VSC the availability of converters up to 400kV and 1500MW Three suppliers as a minimum able to offer similar ratings and performances Greater levels of VSC Standardisation, including interoperability Prototypes of HV DC breakers Multi-terminal VSC based HVDC schemes being proposed Cost reductions of VSC schemes Losses of VSC schemes ~1% 6-10 years For LCC +/-1000kV, 10,000MW bipole systems....but only for very long overhead line applications For VSC the availability of higher voltage extruded cables, expect to reach 500V For VSC the availability of converters up to 500kV and 2000MW VSC Standardisation complete HV DC breakers available Multi-terminal VSC based HVDC schemes in build with some terminals operating, using the new HV DC breakers Significant cost reductions for VSC schemes Losses for VSC converters equal to LCC Automated condition monitoring systems 11-15 years Multi-terminal VSC based HVDC fully operating VSC converter ratings rise to 600kV/3000MW Beyond 15 years DC networks replacing many AC networks, particularly at the distribution levels Potential availability of devices based on chemically vaporised diamond devices which could have big impact on high power devices. Currently research efforts into Silicon Carbide devices are focused on low power applications.

Potentially we have the opportunity for a complete DC solution. 440V devices exist and EHVDC technologies exist.......perhaps there is a need for devices in 33-132kV range as well as DC breakers needed for meshed systems.
DC breaker is really an enabler and could be an area for collaborative development.
Stage 1 - standardise on Voltage
Stage 2 Agree functional specification
Stage 3 Device development
Individual suppliers might decide to do their own development at any stage but collaborative development could be done for stage 1 and 2 and then choose on approach for stage 3.
'- Some conceptual information is available in the public domain but detailed plans and novel thinking is not something that can be shared whilst there is no standards existing for voltage levels etc.
- Specific systems can de designed when constraints are identified.
'A Big questions around multi terminal DC?
Is there a credible technical proposal for a Super Grid offshore? Could be an opportunity here to do some basic work on models to support the way in which the technology needs to develop.
Can we determine what the break points are in terms of technology based on size......distance and other parameters?
Potential application for DC breakers
Can we get B17 on a single platform?

I do not believe that Silicon Carbide devices will enable larger ratings, we may get SiC diodes which may help reduce losses.

The most promising device could be CVD Diamond. This has the potential of >10kV and several 1000 Amps per device with very low losses...should be available in 15 to 15+ years...depending on funding. There is some good UK based work going on that deserves a lot of EPSRC funding.
CVD diamond has the potential to offer "switches" rather than semiconductors...this would need new circuit topologies to be fully exploited, but could give very low loss, high power converters

GIS is already used both onshore and offshore to minimise weight and footprint.
I do not know if GIS has been used yet for DC, also I do not know what the problems would be to use it on DC, if any...I would need to refer to my GIS colleagues.

We hope that Diamond based 15kV devices rated to several hundred amps should be commercially available by 2015.

The main reason for an AC filter with the 'newer, soon to be announced ' VSC topologies is to clean up the connected AC network - not to enable the VSC system to be connected. Another supplier has just also announced a new topology which it also expected to be filterless. No comment on cost benefits of going filterless. The footprint saving is small, but not insignificant, say 7% of station area.

VSC converter losses will eventually become close to those of LCC within 2-3 years. The enablers are new semiconductor deveices, their topologies and their control systems.

	Question
4	How do you see the development of control and management systems for offshore installation developing: - separate WTG, collection system and HVDC control systems loosely co-ordinated with each system having specified operating parameters? - integrated control for all aspects of the offshore installations designed to optimise the overall performance of the offshore system?
	Answer
4	We see strong engineering and commercial logic in optimising wind farms and grid connections together. E.g. size of wind farm to match available grid capability. Wind turbine technology can be simplified where it is connected to the MITS via HVDC as there is no technical requirement for tight limits on frequency or voltage etc. The AC/DC conversion process will clean up the power. Only political factors like regulation would drive projects in a less efficient direction. Again a role for ETI in supporting the rapid development of standards and making the case for a common EU system operator or at least harmonised standards. Integrated system controlling the whole generations and transmission cycle This will require a lot of standardisation and interoperability Certainly scope for standardisation on Voltage levels, Power levels and on control. One approach would be to use "IEC" type software stacks with agreements on top level information that has to be exchanged whilst device control information is kept separate.....what is needed is plug and play. Such standardisation work could overcome the barriers on when information does and doesn't need to be exchanged. '- Control of multi terminal HVDC will be difficult to achieve without standards
	Question
5	Looking further into the future it is assumed that equipment for the connection of offshore generation will be largely bespoke equipment designed specifically for offshore use. • If there is interest how would you see the cost of development being funded? The options appear to be to: - manufacturers fund the development internally recovering cost from product sales - apply for external funding to cover some or all of the development cost - a mixture of the two
	Answer
5	Strong bias towards the first. If the market is there we are used to investing. A mixture of the two. Currently each DC project tends to be considered as being bespoke, need some degree of standardisation in the way that ac systems do....then technology will move forward faster. The market for offshore wind could be sufficient for bespoke products to be developed but this is not sure given the uncertainties of what systems will be used and in what volumes e.g. AC or DC? Have to consider players in the market. Currently 3 and no new players in next 5 years. Within 10 years there might be two new Chinese players and then their is the question of what the Japanese do? ' - Manufacturers are unlikely wishing to compromise IPR for applications which are uncertain and relatively small in global terms. Hence opportunities for funding are in areas of - Identifying optimum voltage levels for short term projects using AC collection and system refinement - Identification of architectures for round 3 and work to establish opportunities for cross linking and cooperative thinking - There is a need for new definitive works on future architectures and interconnection issues .....next step from original Crown estates report

	Question
6	DC Standardisation • How vital do you feel DC standardisation in the sense of voltage and control architecture will be to offshore renewable development? • How do you feel standardisation should be approached, for example could it initially be handled by CIGRE? Do you feel that their would be significant benefit in up front studies being carried out up front by the ETI? If so what studies do you feel would be the most useful and remove some of the biggest question marks? • In what timescale do you feel standardisation must be achieved in order to avoid slowing the development of DC as a large scale solution to offshore network collection and connection? How likely is it that this timescale will be met? • Are there specific research projects where funding could accelerate developments?
	Answer
6	Standardisation is absolutely vital to allow large DC grids to be built embodying DC equipment from multiple suppliers. Standardisation will be needed in at least the following areas: DC voltage(s) Fast fault detection and Fault handling/protection systems DC circuit breakers Disconnectors System behaviour particularly during abnormal conditions and faults Protection: structures, timings, transducers, etc System topology(ies): e.g. with transformers, without transformers (without transformers, if only at the offshore end would be of significant advantage to remove the big heavy item from the offshore platform) Control functions such as: Operation with a master controller! Balancing the current orders between the various converters Balancing the total power flows DC bus voltage profile control to maintain efficiency and be within the constraints of all of the connected equipment DC power ramping between two stations Control of overloads between converters Reactive power at wind parks Fault ride through: DC grid control during AC faults Recovery of power balance per converter after a forced outage System stability All without telecoms? How to prevent cascading faults Cables Additionally there will need to be some form of a DC Grid Code for connectivity into the DC grid Some standardisation has already (just) started in IEC (TC115) and in Cigre B4-52. This activity needs to be significantly accelerated...the results of any ETI up front studies would be welcomed particularly by Cigre B4. ETI could make a valuable contribution to the System behaviour, Protection, Control and Grid Code aspects. Standardisation has to be coming on stream during the next 5 - 7 years to avoid de-facto standards (from manufacturers own solutions) being "implemented". Funding is always welcome to accelerate developments. The EC is expected to provide some funding starting in 2010 for DC breakers, but more would be appreciated for DC Grid Codes, Fault detection/handling and the whole offshore implementation experience. Transformer less systems topologies?

	Question
7	DC Collection Systems • Potentially how could the architecture of a fully DC collection system look? • Within what timescale do you feel full DC collection systems for offshore renewables could be realised? • How likely is this sort of development, what things need to happen for it to become a reality? • How will the application of full DC systems effect the cost of offshore renewable connection?
	Answer
7	Not sure to all of these questions. It would require the wind generators to all be DC, then there is the issue of "transforming" the DC from a relatively low voltage to a high voltage - which adds extra cost and sensitive equipment.. In the longer term, a fully DC connection system will most probably happen, but after the basic HVDC multiterminal offshore grid is reasonable well established Integrated Power Link technology could be a very promising alternative to tradditional LCC HVDC technology and to modern VSC technology. IPL concept aims to functionally integrate the components of an HVDC substation providing: - Substantial cost reduction - Considerable size reduction - Improvement to overall reliability - Lower operating losses than VSC technology
	Question
8	DC to DC converters • What limits are their currently on Dc to DC converters with regard to power, ratio, and voltage? • Given the limitations listed for the previous question what likely developments could be expected over the next 5, 10, 15, and 15+ years? • Could interest in full DC systems for offshore renewable stimulate development, if yes to what extent, if no what would? • Please provide indicative costs for DC to DC converters along with electrical and availability characteristics both now and in the future? • Are there specific research projects where funding could accelerate developments?
	Answer
8	Not sure about the DC/DC converter limits today. I am sure that there arev not any DC/DC converters available that would be useful for DC grids. Some manufacturers are starting to mention them: driven by the requirements of DC "networks" in the future SmartGrids and offshore DC networks Expect to see DC/DC converters becoming available during the next 7 to 7 years. These would be in two classes: SmartGrid related: Voltages from 5kV to 25kV, powers from 1MW to 25MW Transmission grid related: Voltages from 50kV to 300kV, powers from 40MW to 600MW All of the HVDC suppliers are already considering DC/DC converters, so funding is perhaps not appropriate

	Question
9	DC Switchgear Development • HVDC Circuit Breakers. Multi-terminal HVDC transmission and HVDC grids may be enhanced with the use of HVDC circuit breakers. What is the current status of HVDC circuit breaker development, and what is the most likely technological solution? What ratings of HVDC circuit breakers are anticipated and what developments can we expect to see over the next 5, 10, 15, and 15+ years? How quickly will they clear a DC line fault? Are solid state HVDC circuit breakers a possibility or would their operating losses detract from their practical use? • There has been significant interest in not only HVDC but also medium voltage DC for renewable collection, what is the current status of DC circuit breaker development and what are the limitations? What level of development can we expect over the next 5, 10, 15, and 15+ years? • In your opinion how important is voltage standardisation to the development of HVDC and DC circuit breakers? To what extent could a delay in the standardisation of Voltages delay the development of breakers? • What do you feel will be the comparative cost of DC and HVDC circuit breakers compared to similarly rated AC circuit breakers? • Over what timeframe do you expect to see DC circuit breakers developed to an "off the shelf" level of standardisation?
	Answer
9	Some static DC breakers are just coming available: up to about 50kV and a few hundred amps. On losses, cost and size grounds, such static breakers most probably will never be used in HVDC networks. The likely technology will be a hybrid of semiconductors and modified AC switchgear connected together in some form of topology, maybe with some of high frequency assistance. Ratings of such devices in 5 years should be up to 500kV and 1000A, ring to 600KV and 2000A in 10 years. The current thinking is that DC breakers will have to emulate their AC counterparts and open/reclose within the usual 300ms or so. Note that the phase leg converters of a the VSC HVDC converters could be used as DC switchgear....a bit expensive, high losses.... but the could operate in a microsecond or two! Note that not all faults will need to be isolated by DC switches, there will be converters in the system that can handle most of the faults even if only momentarily. Some faults will require the DC switchgear and the AC side switchgear to work together, this may help take some of the high-speed current interruption duty away from the DC switches. Best guess for DC breakers to be "off the shelf" is 7 to 10 years. Note DC breakers are already fully available for voltages up to about 22kV for traction applications, these could be considered for Mv DC applications Regarding HVDC breakers, we've started some practical work in this area as I had identified it as an issue especially with the longer dc links required for off shore generation. I'm aware of the resonant principle but it does have its problems. I have a number of research ideas which will need developing to explore which are the practical options to take forward into development. There is scope for research but EPSRC may not be the right funders, ETI is a good option. There is research ongoing regarding wind generators and the use of power electronics. Discussions include the use of long dc links connecting off shore generation to a dc backbone which is connected at suitable locations to the ac network. Overall may result in lower transmission losses (i.e. lower CO2 emissions etc) and would overcome the connection problem of renewable energy to the ac system. There would be a need to look more closely at this.

Cables

	Question
1	What technical / equipment challenges do you see existing with respect to the current cable / technology offerings that you provide for the offshore renewable market, that would need to be overcome to speed up the development or deployment of offshore renewable across the UK with reference to the following aspects; manufacturing / component issues, equipment lifetimes, equipment reliability, proven technology track-record, O&M issues?
	Answer
1	Our experience so far is mainly in the supply of cables and accessories for the offshore wind farm market, including both export and array. We are not aware of any insurmountable technical/equipment issues for ourselves, but we are conscious of the increasing demands towards ever larger conductor sizes, lengths and voltages. These are now pushing the boundaries of what has been achieved so far and do require further development, investment and type testing.
	Question
2	A major factor in the future development of offshore renewable will be the limit of capacity per single circuit connection as it is likely to dictate the capacity of "farm" that will be collected together at any one point. • What are the likely limits of submarine AC single circuit capacity over the next 5 - 15 years? What are the main limiting factors? What are the opportunities to mitigate these limiting factors. • What opportunities does your company see for the development of AC submarine cables and given adequate funding what goals would you set? • With the possibility of funding for investigation into these issues or proving of a new technology / technique via a pilot project, what types of projects would you put forward for consideration.
	Answer
2	• The present power limits are dictated mainly by conductor size and voltage which, under typical conditions, give a maximum of around 200MW per single 132kV export cable. In the next few years we foresee the voltage level increasing to the 220-275kV range for a 3 core construction, which will increase the power level per circuit to around 350MW. The main limiting factors are the equipment capability in the factory, particularly layup, armouring and test facilities. The transportation and installation of of such large cables is also something that will present much higher difficulty and risk. • We foresee the possibility of AC submarine cables being established up to 400kV level for the extruded type. At the moment the development is not yet completed and it is expected that a commercial product will be available in the next two-three years. With suitable funding we could speed up the development, including very large conductor cross sections, thus capable of transmitting a power in the range of 1000 MW and above, with single core construction. • See above answer
	Question
3	The apparent trend is for larger renewable developments further from shore, would you agree that this will necessitate a step change in the application of HVDC connections and result in a major reduction in the use of AC of offshore connections? • Are the major limitations of higher capacity HVDC cable (either through greater current carrying capacity or higher voltage) due to technical or material limitations or the limitations of the installation process restricting the diameter of the cable? And which aspect do you feel would benefit more from research, development and investment? • What are your companies major goals in the development of HVDC cables? • With the possibility of funding for investigation into these issues or proving of a new technology / technique via a pilot project, what types of projects would you put forward for consideration.
	Answer
3	• Very high limits for HVDC are already available considering mass impregnated type that is established for ~500kV and tested up to 600 kV. This type of cable can deliver up to 2GW per bipole if considering the largest conductor size, highest voltage and specialised insulation. Extruded type HVDC is developed to a lesser degree, but can still offer ~800-1000MW per bipole. The limits are generally determined by the maximum available conductor size and voltage level. • We intend to continue the development of HVDC extruded type in terms of voltage level. • We would consider a pilot project with HVDC extruded in the range of 300-350kV • GIL technology could be applied to offshore developments, particularly for very large transfer of power. They have advantages compared to cables with lower losses and higher capacities.

	Question
4	What manufacturing and supply challenges do you foresee that could limit offshore development over the next 5 - 15 years? • Do you feel manufacturing and supply issues could outweigh the technical / equipment challenges that have been identified? • Do you feel that the volume of offshore development that is required to meet UK CO_2 emission targets will be sufficient to justify development and investment in this area by yourself and other suppliers?
	Answer
4	• Yes, we believe that supply chain issues will become the challenge, rather than the technical issues. • Based upon current projections there appears to a future demand that would justify investments from our company. The timing of such investment depends on the rate and sustainability of such demand.
	Question
5	Further to the technical considerations of connection capacity and length a major issue with offshore connections is the crossing of gas pipes which has major issues with gaining permission due to the risk of damage to the pipe through current crossing methods. • Are you currently researching or developing less risky crossing methods that could make pipe crossings significantly less onerous for developers? • If not do you feel their would be significant enough benefit and potential business to justify such development? Would the potential of funding to develop / prove such a technique be appealing to you?
	Answer
5	• No, we are not developing alternative methods of crossing pipelines or other services; so far we did not have any perception or experience of risks involved in pipe crossings. • Difficult to say; in general terms, no.
	Question
6	To what extent do you feel that regulatory (grid code requirements, GB SQSS, etc) and legislative requirements (e.g. health & safety, environment, etc) are or could become a constraining factor in the large scale development of offshore renewables over the next 15 years? • Do you believe that particular equipment modifications / adaption's may be necessary to overcome such restrictions that are not required purely from a technical perspective (i.e. making equipment easier to decommission, greater equipment automation and diagnostics to minimise man-hours offshore, etc)
	Answer
6	These questions are better answered by the Utilities/Developers
	Question
7	What installation and application issues would benefit through further research or investment? • Do you believe that there are likely to be opportunities to fundamentally change techniques for installing, routing and terminating cables that could be accelerated with additional research?
	Answer
7	In our opinion the increasing size and length of cables is driving a need for newer and larger installation vessels than are already on the market. However, we do not see any significant change in the current techniques for installing subsea power cables

Offshore Platforms

	Question
1	What do you see as being the technical / equipment or practical challenges for the application of offshore platforms for the purposed of offshore renewable farm connection (substations or HVDC converter stations)? • What challenges are faced by windfarm / marinefarm developers that have not been solved previously for the Oil industry? • Do you foresee any limitations on development caused by availability of platform supply or installation given a step increase in offshore renewable developments? • Do you have a feel for the volume of offshore renewable development that would be required to justify investment in new construction facilities and installation vessels. • With the possibility of funding for investigation into these issues or proving of a new technology / installation techniques via a pilot project, what types of projects would you put forward for consideration?
	Answer
1	- Don't really see any technical issues that haven't already been overcome for the Oil and Gas industry. Irrespective of the requirement then solutions can be provided.............up to 16kT or even 20kT............60m fixed structures or floating if necessary. - For the 2kT platforms done/being done at the moment these can be considered as "tiddlers" and each yard can employ their own preferences in terms of lift onshore (bogey v skid) - Relatively few fabricators left in the market (SLP, McNulty's, Fabricon, Burnitsland) - Surface area of yards could be a problem but more likely are skills to actually keep yards busy. Manpower market is very volatile and there has been a shortage of training done such that labour could easily become unavailable if other projects (e.g. Nuclear Programme) soak up labour. Currently the average age of workforce is 54.......... - Anticipated that renewables could provide up to 50% of offshore platform business in the future and a yard needs £50m per annum.
	Question
2	Are there specific areas of risk based on schemes designed and installed to date which would benefit from research now that could either reduce risk on existing schemes or enable potential changes for future schemes?
	Answer
2	Technical risks are not such an issue. Major issue is coordination across the industry. Too much uncertainty.
	Question
3	Are there opportunities to modify future schemes based on lessons learnt where further work is needed before final improvements can be verified?
	Answer
3	Lessons are being learnt very quickly by the renewables connections business, however the lessons could have been learnt much more quickly from the existing Oil and Gas knowledge. E.g. Fire protection philosophy. There are many new people involved in the industry and some are having to learn from scratch. In terms of design approach the oil and gas industry has built up databases of experience upon which choices can be made, hence there is a need to accumulate operating cost and maintenance procedure models so that experience can be learnt from and the appropriate choices made in the future. The cost of doing things offshore is typically 6 times the cost of doing it onshore.........some people are still to learn this lesson. An area where lessons have not yet been learnt is in logistics....recent "hook ups" show that the expertise of oil and gas was not taken on board.
	Question
4	To what extent do you feel that legislative requirements (e.g. health & safety, environment, etc) are or could be a constraining factor in the large scale development of offshore renewables over the next 15 years?
	Answer
4	Lessons learnt from oil and gas provide the necessary basis from which to start however there are aspects of T&D activity which have not yet been adapted for offshore.

	Question
5	Based on your experience are there items of transmission and distribution equipment which have not been adequately taken into account in existing schemes? E.g. • Is transmission and distribution equipment suitable for long term operation offshore? • Has adequate provision been made for operation and maintenance of platform equipment? • Are proven standards for Oil and gas been adopted in an appropriate manner for Offshore substation applications? • If there are issues associated with these and other related points, with the possibility of funding for investigation could you envisage worthwhile projects?
	Answer
5	As the detail of T&Dc equipment is not known it is difficult to comment on whether or not will have problems in an offshore environment but there are examples where equipment may well have problems in an offshore environment because onshore practices have been applied.
	Question
6	Availability of suitable cranes to install offshore substation platforms appears to be a limitation for future implementation of projects. Do you see opportunities for novel ways of designing and installing platforms which could mitigate this problem?
	Answer
6	Not thought to be necessary. Cranes up to 14kT are available and combinations can be used if necessary. There are solutions from oil and gas available for problems that haven't even been thought of yet.
	Question
7	Is there scope for a more standardised approach to platform design which could bring benefits of reducing project lead times? Is up front investment in such standardisation design studies preventing such standardisation?
	Answer
7	There is certainly scope for standardisation (jackets and platforms) in the same way that oil and gas standards have developed. Aware of DNV standard and this is a step in right direction. Also scope for modularisation which is approach adopted on accommodation platforms. There are supply chain issues here though e.g. 75mm thick steel which is not available in the UK nor are there facilities to bend for certain monopile designs. This could impact on designs that could be delivered from the UK. Globally the business looks to India and China, Germany and Holland as customers and also suppliers/competitors. Fabrication of flat pack kits for assembly in India etc. being one option, but more likely that complete structures will end up coming from India.........unlikely to happen the other way around. The platform business has always been very cyclical, overall capacity is not so much of a problem but timing is critical. Opportunity for overall/sustainable programme to be established to optimise yard utilisation but that would require coordination. Experience with use of Chinese suppliers has not been good.

Appendix C Technology Attribute Spreadsheets and Roadmaps

HVDC	Current Voltage Source Cable Connected	Date / Approx 2010	Date / Approx 2012	Date / Approx 2015	Date / Approx 2020	Date / Approx 2020	Date / Approx 2025 MW	Date / Approx 2025
Single Converter Capacity	Up to 1000 MW	-	-	1500 MW	2000 MW	-	3000	-
Converter Voltage	±250 - 320 kV	-	-	±400 kV	±500 kV	-	±600 kV	-
Offshore platform size (m)	90L/40W/35H	-	7% reduction	-	-	Small reduction	-	Small reduction
Converter Weight - Equipment and Platform Tonnes	2000 Tonnes Equipment 5000 Tonnes Platform	-	Very small reduction depending on technology and amount of filter equipment obviated.	-	-	-	-	-
Capital Converter Cost - €/kW	£225	Potential drop	Removal of filters will present an obviouse equipment saving however it is as yet unclear if this will translate into an overall saving.	Small relative decrease	Small relative decrease	Reduced number of devices will likely be offset by a greater device cost resulting in comparable converter cost.	Small relative decrease	Reduced number of devices will likely be offset by a greater device cost resulting in comparable converter cost.
Installation Cost - €/kW	Included in capital cost	-	Reduction in footprint and weight could result in small reduction in installation cost.	-	-	Reduction in footprint and weight could result in small reduction in installation cost.	-	Reduction in footprint and weight could result in small reduction in installation cost.
Converter Losses - % of rating	1.2	-	-	1	Match LLC	Significant Reduction	-	Significant reduction from whats possible with current IGBT technology.
Converter Transformer Losses - Fixed / Variable	Included in converter losses Normal transformer losses	-	-	-	-	-	-	-
Reactive Power Control	Reactive Power can be controlled freely within the given operating	-	-	-	-	-	-	-
Interoperability	A lack of any standardisation limits interoperability.	-	-	Beginnings of standardisation driving the development of standard DC cables and switchgear.	Standardisation complete and established with early multiterminal applications in build.	-	Multiterminal HVDC operational and established.	-
Performance During Onshore and Offshore AC Grid Fault	Faults at either end of the link can be accommodated very effectively with the HVDC converters acting as a buffer and severely attenuating the impact on the other end of the link. The most significant impact is when the HVDC converter at the receiving onshore end becomes disconnected from the AC system so that the transmission line is open ended. Power from the sending end wind farm continues to pump power into the HVDC transmission, causing the DC cable voltage to increase rapidly. The remedy for sudden isolation at the receiving end is to transfer trip at the sending end and open the AC circuit breaker from the offshore wind farm collecting system that feeds the sending end rectifier.	-	-	-	-	-	-	-
Run Up Run Down - Performance / Sequence / Time	The operational requirement for the converters to follow the intermittent generation pattern from the wind is accommodated through the VSC converter and feeder automatically. The receiving end must be able to deal with the changing power schedule and compensate accordingly. The power can be made to vary as quickly as needed.	-	-	-	-	-	-	-
Bi-Directional Performance	No Technical Barrier In calm wind conditions power will need to be fed back from onshore to supply essential standby power.	-	-	-	-	-	-	-
Low Power Performance	Operates down to 0 MW power flow	-	-	-	-	-	-	-
DC Smoothing Requirement	None	-	-	-	-	-	-	-
AC Filter Requirement	Required for PWM type VSC	-	-	-	-	-	-	-
Typical AC and DC Protection Requirement	Protections for the converter and cables are not extraordinary for voltage sourced converters. However, the HVDC equipment suppliers ensure that limited or no power overload is imposed on the converters by virtue of their controls. Such overloads can occur on recovery from an AC side fault if the wind turbines are prone to overshoot their generated power under such conditions. For the protection and control needs of a feeder from an offshore wind farm will be best served with a fibre optic cable between the sending end and the onshore receiving end.	-	-	-	-	-	-	-
AC Auxiliary Power Requirement - No Load / Full Load	A station service transformer would be applied at each converter station and its source of power would be derived from the main AC busbar. Redundant service could be applied with a back-up station service transformer. An emergency generator and associated fuel tank may be installed on the offshore platform and be capable of providing emergency operation and continuous load for a safe shutdown of converters.	-	-	-	-	-	-	-

Fire Prevention Requirement	The converter valves and transformers must all be equipped with fire protection. The converter unit valves are designed to minimize the risk of fire. Non-metallic materials used in the converter stations are constructed of low flammability. Fire detection and alarm systems are in place in the converter stations.	-	-	-	-	-	-	-
Converter Cooling Requirement	The cooling systems in the onshore and offshore converter stations provides adequate cooling for all expected range of atmospheric conditions, and not freeze up.	-	-	-	-	-	-	-
Reliability / Availability	>99%	-	-	-	-	-	-	-
O&M Requirement - Periodicy / Duration / Outage Times	Once in 2 years for 1-2 Weeks	-	-	-	-	-	-	-
Lifetime - Primary and Secondary Equipment	Their has not been enough time to evaluate VSC component lifetimes however they are expected to have similar life expectancy as LCC quoted below, note that these values do not take into account an offshore environment. Component — Life Years Capacitors — 25 Air core reactors — 25 AC power circuit breakers — 35 Circuit switches — 25 Surge arresters — 35 Bus insulators, structures — 50 AC controls and protection — 15 Instrument transformers — 30 Valve hall cooling and fire protection — 20 Valve cooling (dry systems) — 20 Transformers — 40 Auxiliary power (batteries) — 15 Auxiliary power equipment (battery chargers) — 20 Auxiliary power equipment (station service transformers) — 40 Valves — 30 HVDC controls and protection — 15 Communication systems — 10 SCADA/RTU — 10 DC buswork, insulators, structures — 50	-	-	-	-	-	-	-
Lead Times - Design / Manufacture / Installation / Commissioning	2.5 years order to in-service	-	-	-	-	-	-	-
Narrative Description - What is the What is the effect What the resulting opportunity		Areva will be in the market in 2010 with an MMC configuration for the VSC converter. This opens up competition, keeping prices competitive.	Introduction of filterless converter station topologies	High interest in HVDC development will result in general improvements in maximum ratings and efficiency.	High interest in HVDC development will result in general improvements in maximum ratings and efficiency.	Introduction of Silicon Carbide devices could significantly reduce converter size, weight and losses.	High interest in HVDC development will result in general improvements in maximum ratings and efficiency.	Introduction of diamond type devices could significantly reduce converter size, weight and losses. More than those possible with Silicon Carbide.

Transformer Data		Mineral Oil	Use of Midel (Synthetic Ester)	Use of Silicon Oil	Use of SF^6
Voltage	**V**	33/132	No Change	No Change	No Change
Capacity	**MVA**	120	No Change	No Change	No Change
		YNd11	No Change	No Change	No Change
Losses	**No Load kW**	48	No Change		
	Load kW	468	10% decrease		
Impedance	**Uk %**	18	No Change		No Change
	Ur %				
Tapping	**Type**	Primary On Load	No Change	No Change	No Change
	Range	+12/18% 18 steps	No Change	No Change	No Change
Weight	**Tx With Oil kg**	106900	Comparable to mineral oil 2% more	Comparable to mineral oil 2% more	% that of oil
	Tx Without Oil kg	72850			
	Cooler With Oil	27600			
	Cooler Without Oil	20750			
	Maximum Transport kg	72850			
Dimensions	**Transformer mm L/W/H**	7280/2630/5350	Comparable to mineral oil 5% more volume	Comparable to mineral oil 5% more volume	50% volume of mineral oil immersed
	Cooler if Separate mm L/W/H	7460/3070/7000			
Cooling	**Medium**	Mineral Oil	Midel	Silicone Fluid	SF^6
	Type	ON, OF, AN, AF	No Change	No Change	Similar to liquid filled, Gas Natural GN, Air Natural AN, Gas Forced GF, Air Forced AF, GN <30 MW and 33kV, GF >30 MW
Lifetime	**Years**	40	40+ Midel claims to extend life	40+ years (longer than mineral oil)	20 years service to date, lifetime predicted to be well over 30 years
O&M	**Periodic Per Annum**	0.5	Comparable	Comparable	Minimal. Almost maintenance free with the exception of cooling system, gas samples required to be taken following energisation, 1 week, 6 months, 1 year, 2 year, 4 year cycle. Further gas pressure must be monitored though the transformer will operate safely for extended periods at atmospheric pressure.
	Duration Days	5	Comparable	Comparable	
Availability per annum	**In Situ Repair MTBF**	0.05	No Change	Comparable	The lack of examples and service time mean there is no solid figures for MTBF and MTTR, however a 2002 report (20 Years Operating Experience of Gas Insulated Transformer by L. Chan of Hongkong Electric Co. Ltd states that "in over 50,000 transformer-year operations of GTx there was only ONE electrical failure". which highlighted a requirement for partial discharge testing which is now carried out routinely and avoids the fault.
	In Situ Repair MTTR	10 days	No Change	Comparable	
	Factory Repair MTBF	0.003	Midel claims to reduce degradation of solid insulation	Comparable	
	Factory Repair MTTR	107 days	No Change	Comparable	
Cost	**Transformer**	£1,204,350	10% more	Much more expensive	200-300% Mineral Oil Immersed
	Installation	35% Tx	Same	Same	Cheaper
Flammability characteristics of insulation	**Flash Point °C**	160	275	> 300	Non Flammable
	Fire Point °C	170	322	> 350	Non Flammable
	Auto ignition Temp °C	280	438	435	Non Flammable
	IEC61100 Classification	0	K3	K3	Non Flammable
Fire Requirements		**Fire suppression requirements as per "FM Global Property Loss Prevention Data Sheets" (for comparison with Less Flammable Requirements)** Significant Fire Suppression System - For more than 100 gal (0.38 m3), one of the following methods should be used: a) Room with a fire resistance rating of 3 hours. b) Room of one-hour fire resistance and automatic sprinkler protection or an FM Approved gaseous agent suppression system, or a water mist system FM Approved for machinery spaces. If automatic sprinklers are used, a discharge density of 0.30 gpm/ft2 (15 mm/min) should be provided over the area of the room.	**Fire suppression requirements as per "FM Global Property Loss Prevention Data Sheets" (for comparison with mineral oil Requirements)** Reduced spacing and bunding requirements, reduced fire resistance requirements - Transformers should be FM Approved or equivalent or the following should be done: • Location within a room with a fire resistance rating of one hour; or • Automatic sprinklers should be provided over the transformer and for 20 ft (6.1 m) beyond. The design discharge density should be 0.20 gpm/ft2 (10 mm/min).	Less flammable liquid (better than midel by a little), similar reduction in fire and blast precautions as with Midel.	No Fire Suppression required in Tx room given non flammable nature of SF^6.
Blast Requirements		Blast Walls in all Tx Rooms	Less flammable liquid	Less flammable liquid	SF6 Tx is considered non explosive
Environmental Requirements		Containment Required	Biodegradable, Containment Not Required	Non Biodegradable - Containment Required	SF6 must be occasional checked for leakage
Additional notes				Non compatibility with some materials, very high cost, high cost of disposal.	Used in combination with GIS can provide a significant space saving
Development **Effect description** **Pros / Cons**			Use of Midel as insulating medium. Results in reduced fire and blast risk due to high flash point of 275degC (twice that of mineral oil) and fire point of 322degC (low net calorific value <32 MJ/kg, K3 class liquid IEC 61100) coupled with a slow heating rate and thermal conductivity, and hence reduces cost and weight of fire suppression system and the extent of blast precautions. Further midel is less environmentally onerous being biodegradable and classified as "non hazardous to water" (UBA Germany) reducing spill collection requirement. However Midel use results in an increased capital cost of approximately 10%. Further Midel claims to reduce the incidence of insulation failure due to moisture as it absorbs water.	Use of Silicon oil as insulating medium. Results in reduced fire and blast risk compared to mineral oil with Ignition time similar to ester based fluids and a heat release characteristic lower than synthetic esters. Silicon oil also has the lowest smoke production rate. Further silicone oil is very stable and results in increased security. High thermal stability and oxidation requirements result in a long transformer life and low maintenance.	Use of SF6 as insulating medium which is non flammable and has a lower specific gravity than mineral oil (1/60 that of mineral oil). Results in reduced fire and blast risk as well as reduced transformer weight, hence reduces cost and weight of fire suppression system (which could be almost entirely removed from the transformer rooms) and the blast precautions. SF6 poses no local environmental risk however SF6 is a potent green house gas and must be monitored to ensure escape is within limits. SF6 has a lower heat constant and thermal capacity than mineral oil resulting in a lower overload capacity than mineral oil transformers. The lower cooling capability and issues with ensuring seals increase manufacture costs making SF6 transformers significantly more expensive than mineral oil immersed. (Transformer engineering design and practice, by Shrikrishna V. Kulkarni, S. A. Khaparde

Current Cabling Technologies and Future Developments

		Factors to be addressed	State of the Art Development	Future Developments
Inter-Array Cabling	11kV AC (3 Core)	Rated Voltage	11kV	
		Capacity	5.445MVA	
		Rated Current (kA)	0.495	
		Construction type (Conductor and Insulation) and dimensions	Cu 18mm, XLPE 3.4mm	
		Maximum Submarine Cable Cross-sectional Area	630mm2	
		Short Circuit Withstand	37.6kA	
		Typical DC Resistance(Ω/km)/Inductance(mH/km)/Capacitance(uF/km)	0.125/0.28/0.44	
		Capital Cable cost (£/m)	130-610 (95mm2-630mm2)	
		Expected Life	25 Years	
		Reliability (failures/100km/annum)	0.0705	
		Cable Procurement Lead time	6-12 Months	
		Losses (% of generated energy/km)	96.4W/m (185mm2)	
		Installation :		
		- Capital installation Cost (£/m)	10	
		- Maximum length of Cable possible on Laying Drum	N/A	
		- Minimum bending radius	1.8m	
		- Cable Laying Vessel Availability	Available	
		Year of development	**Ongoing**	
		Comments on development:	The development requirements for 11kV inter-array subsea cabling is market driven. Generation transfer between turbines is tending towards 33kV rather than 11kV - developments are therefore mainly to drive down the manufacturing costs of the product e.g. value engineering exercises. Large conductor size cables although feasible are not generally necessary as the cables are feeding only moderate loads from a chain of turbines into the power generation scheme. Cable accessories such as J-tube hang off arrangements and armour clamps are being developed to reduce the time taken to assemble components offshore.	
		- Barriers or issues to overcome		
		- Explain Technological Advancement and Reason		
		- Summarise Impact on Performance/Cost		
	33kV AC (3 Core)	Rated Voltage	36kV	40.5kV
		Capacity	20MVA	25MVA
		Rated Current (kA)	0.627kA	0.627kA
		Construction type (Conductor and Sheath) and dimensions	Cu 20.5mm, XLPE 7.5mm	Cu 20.5mm, XLPE 7.5mm
		Maximum Submarine Cable Cross-sectional Area	630mm2	630mm2
		Short Circuit Withstand (Conductor and Sheath)	47kA	47kA
		Typical DC Resistance(Ω/km)/Inductance(mH/km)/Capacitance(uF/km)	0.06/0.31/0.24	0.06/0.31/0.24
		Capital Cable cost (£/m)	130-610 (95mm2-630mm2)	130-610 (95mm2-630mm2)
		Expected Life	25 Years	
		Reliability (failures/100km/annum)	0.0705	0.0705
		Cable Procurement Lead time	6-12 Months	
		Losses (% of generated energy/km)	86.4W/m (300m2)	
		Installation :		
		- Capital installation Cost (£/m)	10	10
		- Maximum length of Cable possible on Laying Drum	N/A	N/A
		- Minimum bending radius	2m	
		- Cable Laying Vessel Availability	Available	
		Year of development	**Present**	**2012**

	Comments on development:	The development requirements for 33kV inter-array subsea cabling is market driven. Developments are therefore mainly to drive down the manufacturing costs of the product e.g. value engineering exercises. Large conductor size cables (say greater than 800mm²) although feasible are not generally necessary as the cables linking small chains of turbines into the power generation scheme. Cable accessories are being developed with the aim to reducing offshore installation times.	
	- Barriers or issues to overcome		
	- Explain Technological Advancement and Reason		Movement towards non-standard voltage levels to optimise AC Collector technology. Could be achieved using already available cabling
	- Summarise Impact on Performance/Cost		Performance improved and cost reduced with less losses and string requirements
66kV AC (3 Core)	Rated Voltage	72.5kV	
	Capacity	38.5MVA	
	Rated Current (kA)	0.883kA	
	Construction type (Conductor and Sheath) and dimensions	Cu/XLPE	
	Maximum Submarine Cable Cross-sectional Area	630mm2	
	Short Circuit Withstand (Conductor and Sheath)	90kA	
	Typical DC Resistance(Ω/km)/Inductance(mH/km)/Capacitance(uF/km)	0.04/0.11	
	Capital Cable cost (£/m)	130-610 (95mm2-630mm2)	
	Expected Life	25 Years	
	Reliability (failures/100km/annum)	0.0705	
	Cable Procurement Lead time	6-12 Months	
	Losses (% of generated energy/km)	49.4W/m (630mm2)	
	Installation :		
	- Capital installation Cost (£/m)	10	
	- Maximum length of Cable possible on Laying Drum	N/A	
	- Minimum bending radius	2.5m	
	- Cable Laying Vessel Availability	Available	
	Year of development	**Present**	
	Comments on development:		
	- Barriers or issues to overcome		
	- Explain Technological Advancement and Reason		
	- Summarise Impact on Performance/Cost		
	Rated Voltage	±500kV	±600kV
	Capacity	1000MW (Per Pole)	1200MW
	Rated Current (kA)	2000A	2000A
	Construction type (Conductor and Sheath) and dimensions	MIND	MIND
	Maximum Submarine Cable Cross-sectional Area	3300mm²	3300mm²
	Short Circuit Withstand (Conductor and Sheath)	100kA/20kA	
	Typical DC Resistance(Ω/km)/Inductance(mH/km)/Capacitance(uF/km)	0.0093	
	Capital Cable cost (£/m)	300-360 (3300mm2)	
	Expected Life	40 Years	40 Years
	Reliability (failures/100km/annum)	0.0998	
	Cable Procurement Lead time	> 2 Years	
	Losses (% of generated energy/km)	44.6W/m (3300mm2 at 2000A)	
	Installation :		
	- Capital installation Cost (£/m)		
	- Maximum length of Cable possible on Laying Drum	100km on a large cable Vessel	

- Minimum bending radius	3m	
- Cable Laying Vessel Availability	Available	
Year of development	**Present**	**Ongoing**
Comments on development:	Recent developments have been the use of HVDC Monopole systems installed with separate, extruded dielectric, metallic return conductor (e.g. Bass link, New Jersey - Long Island, Swepol Link)	Manufacturers are looking to develop new insulation materials and impregnating fluids to enable the conductor temperature and voltage level to be furthered.

HVDC Classic	- Barriers or issues to overcome	Conductor temperature limitations - conductor temperatures are limited to 60°C; compound migration / draining on vertical risers, the formation of contraction voids during cooling. Physical size and weight of the product for installation handling. Prequalification / proving tests to demonstrate the performance of new products	
	- Explain Technological Advancement and Reason		**Cable Insulation materials: Kraft** paper has been historically used providing a very reliable product. Laminates that sandwich a polymer film between paper layers, termed "polypropylene laminate paper (PPLP)" have been successfully trialled however the advantages of PPLP on a DC system are not as great as for an AC system. Thinner paper tapes have also been used to improve the electrical performance. The use of alternative materials - polymer films in combination with paper tapes is being explored to see if a reduction in insulation thickness can be achieved. **Insulation Impregnates**: New dielectric fluids are being developed that have improved rheological characteristics to fit the manufacturing and operational requirements for HVDC cable systems e.g. highly viscous when at cable conductor operating temperatures, low viscosity at moderate impregnation temperatures. These advancements will enable an increase in power transfer across an HVDC link without a further increase in cable size. The developments will also aid a reduction in physical size of the cables enabling longer lengths to be manufactured. A 10 degree increase in allowable conductor temperature can lead to a 15% increase in power transfer capability.
	- Summarise Impact on Performance/Cost		
	Rated Voltage	±250kV	±300kV
	Capacity	300MW per pole	600MW per pole
	Rated Current (kA)	1200A	
	Construction type (Conductor and Sheath) and dimensions	Cu/extruded dielectric/lead/PE	Cu/extruded dielectric/lead/PE
	Maximum Submarine Cable Cross-sectional Area	$870mm^2$	
	Short Circuit Withstand (Conductor and Sheath)	100kA/16kA	
	Typical DC Resistance(Ω/km)/Inductance(Ω/km)/Capacitance(uF/km)	0.0203	
	Capital Cable cost (£/m)	400 (870mm2)	
	Expected Life	40 Years	
	Reliability (failures/100km/annum)	0.067	
	Cable Procurement Lead time	1-2 Years	
	Losses (% of generated energy/km)	35W/m (870mm2 at 1200A)	
	Installation :		
	- Capital installation Cost (£/m)		
	- Maximum length of Cable possible on Laying Drum	7000T	
	- Minimum bending radius	2.4m	
	- Cable Laying Vessel Availability		
	Year of development	**Present**	**Ongoing**

Export Cabling	HVDC Extruded Dielectric	Comments on development:		Manufacturers have tested extruded dielectric technology up to 300kV for VSC HVDC applications and up to 250kV for LCC HVDC applications. The incorporation of large conductor sizes into the cables would enable higher power magnitudes to be transferred (VSC technology limited).
		- Barriers or issues to overcome	Conductor temperature limitations; reliability - particularly under polarity reversal and superimposed impulse conditions, prequalification testing.	Continued development of dielectric materials and combinations of screening and insulation materials that can withstand increased levels of electrical stress. The thermal resistivity characteristics of the dielectrics are key in determining the extent of stress inversion that can occur when a cable is operating at maximum temperature. The development of insulation packages, along with cable accessories that can withstand high electrical screen stresses, will enable the technology to increase in reliability.
		- Explain Technological Advancement and Reason - Summarise Impact on Performance/Cost		
	132kV AC	Rated Voltage	132kV-150kV	110kV-150kV
		Capacity	210MVA	
		Rated Current (kA)	0.92	
		Rated BIL	650	
		AC withstand level	145kV	
		Construction type (Conductor and Sheath) and dimensions	Cu/XLPE/Pb/Pe	
		Maximum Submarine Cable Cross-sectional Area	1200mm^2	up to 2000mm²
		Short Circuit Withstand (Conductor and Sheath)	170kA / 3x19.8kA	
		Typical DC Resistance(Ω/km)/Inductance(mH/km)/Capacitance(uF/km)	0.0192/0.25	
		Capital Cable cost (£/m)	530-700 (800mm2-1200mm2)	
		Expected Life	20/40yrs	
		Reliability (failures/100km/annum)	0.0705	
		Cable Procurement Lead time	~1 Year	
		Losses (% of generated energy/km)	61W/m (1200mm2)	
		Installation :		
		- Capital installation Cost (£/m)		
		- Maximum length of Cable possible on Laying Drum	Vessel Carousel Req (50km)	
		- Minimum bending radius	3.5m	
		- Cable Laying Vessel Availability	DP Vessels and Barges Available	

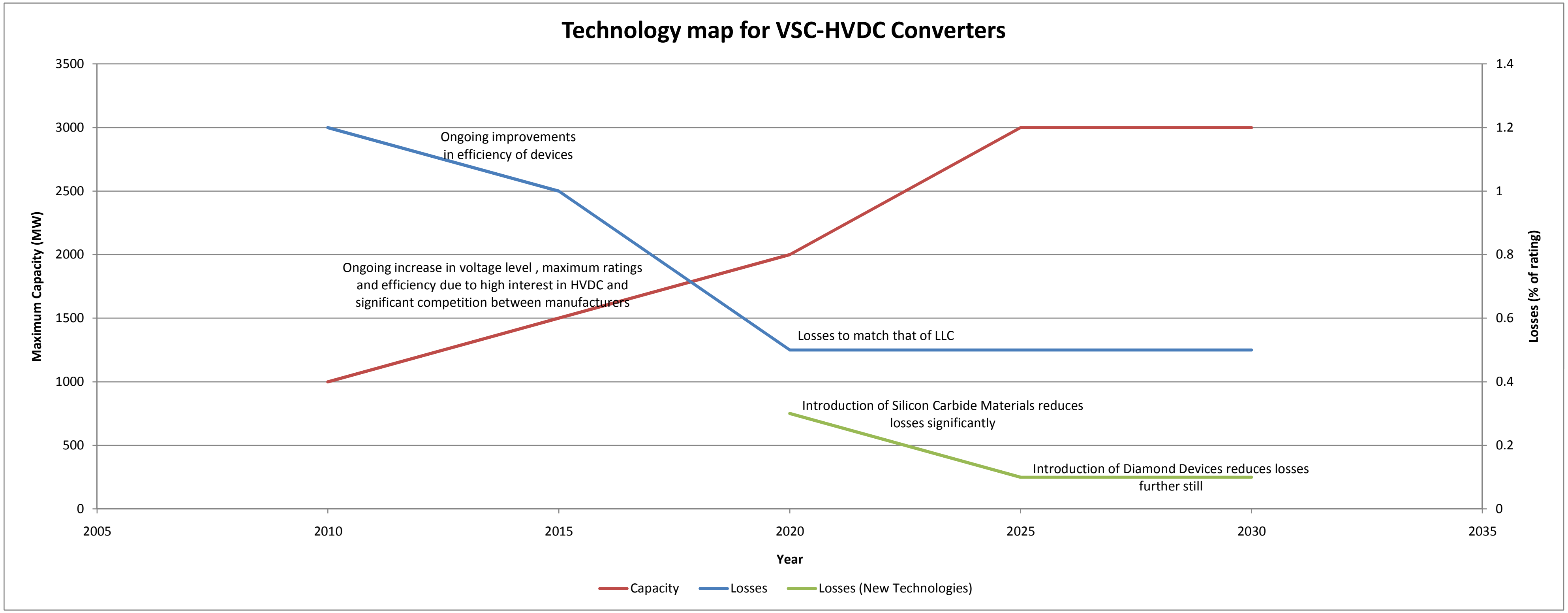
	Year of development	**Present**	**Ongoing**
	Comments on development:		High stress extruded dielectrics
	- Barriers or issues to overcome	Physical size and weight of the product elements (conductors/power cores/laid up power cores) limits manufacture. Some manufacturers are power core extruder size limited, some are armouring machine limited, some are storage turntable limited.	
	- Explain Technological Advancement and Reason		Continued development of dielectric materials and combinations of screening and insulation materials that can withstand increased levels of electrical stress. The development of suitable insulation packages, along with cable accessories, will enable the size of the power cores to reduce relieving some of the existing manufacturing constraints.
	- Summarise Impact on Performance/Cost		
220kV AC	Rated Voltage	220kV	
	Capacity	339MVA	
	Rated Current (kA)	0.89	
	Rated BIL	1050kVp	
	AC withstand level	245kV (Um)	
	Construction type (Conductor and Sheath) and dimensions	Cu/XLPE	
	Maximum Submarine Cable Cross-sectional Area	1000	
	Short Circuit Withstand (Conductor and Sheath)	141kA / 3x21kA	
	Typical DC Resistance(Ω/km)/Inductance(mH/km)/Capacitance(uF/km)	0.027/0.19	
	Capital Cable cost (£/m)	950 (1000mm2)	
	Expected Life	40yrs	
	Reliability (failures/100km/annum)	0.067	
	Cable Procurement Lead time	~1 Year	
	Losses (% of generated energy/km)	104W/m (1000mm2)	
	Installation :		
	- Capital installation Cost (£/m)	£100k per day	
	- Maximum length of Cable possible on Laying Drum	Vessel Carousel Req (50km estimated)	
	- Minimum bending radius	3.9m	
	- Cable Laying Vessel Availability	DP Vessels and Barges Available	
	Year of development	**Present - to be more prevalent circa 2011**	
	Comments on development:	Cable designs are available in the market place.	
	- Barriers or issues to overcome	Although proposed by cable manufacturers and wind farm developers - I don't believe to date that there have been any export cables installed at this voltage level. Increasing the voltage level from HV to EHV places a greater performance emphasis on cable accessories (flexible factory assembled joints, offshore cable terminations, rigid subsea repair joints, shore landing transition joints).	
	- Explain Technological Advancement and Reason		
	- Summarise Impact on Performance/Cost		
	Rated Voltage	420kV	
	Year of development	**Present**	**2013-2014**
	Comments on development:	400kV extruded single core submarine cables are available in the market place. Schemes have tended to be short and involve the installation of 3 phases plus a spare phase (spare can be used in the event of a fault).	

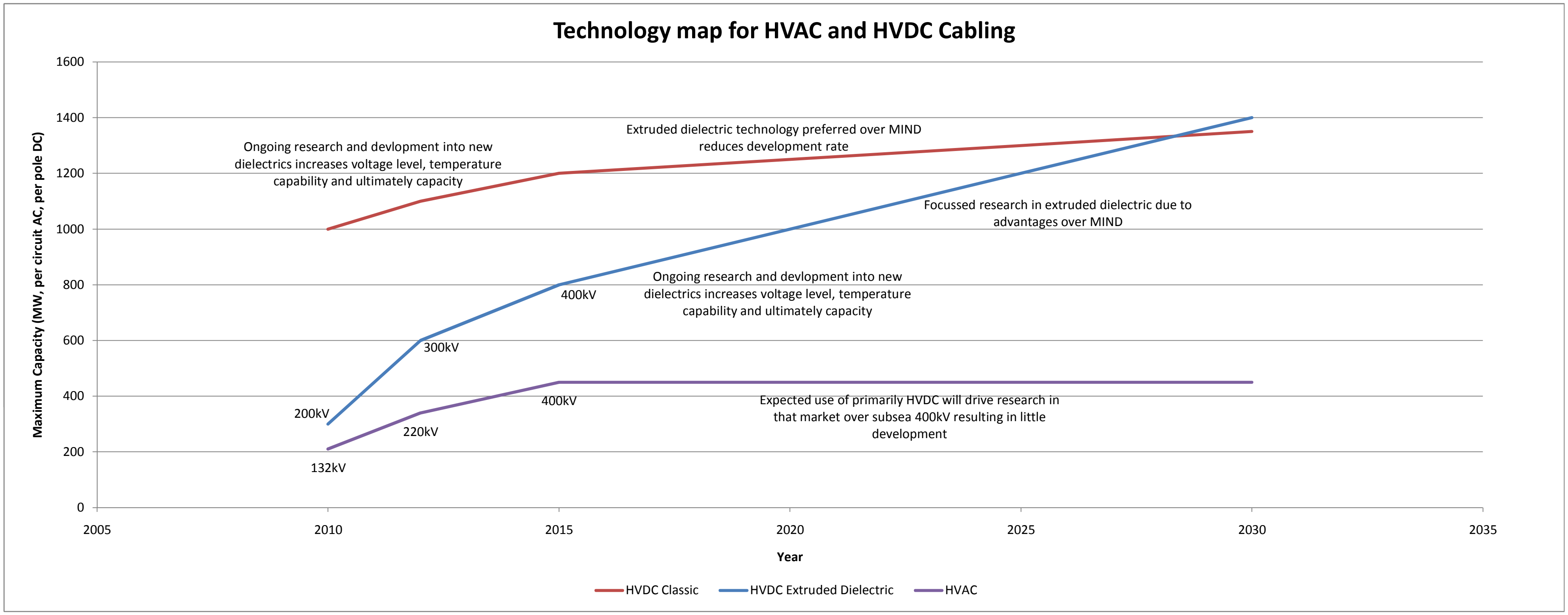
400kV AC	- Barriers or issues to overcome		We understand that the use of 400kV has not been carried out as an offshore export cable. Mainly due to the inability to provide 3-core cable. If an advancement in this or the ability to tie single core cables together became apparent this may be a viable option.
	- Explain Technological Advancement and Reason		Development of extruded cabling would allow 1000MW transfer with single core construction. With funding this research could be accelerated
	- Summarise Impact on Performance/Cost		

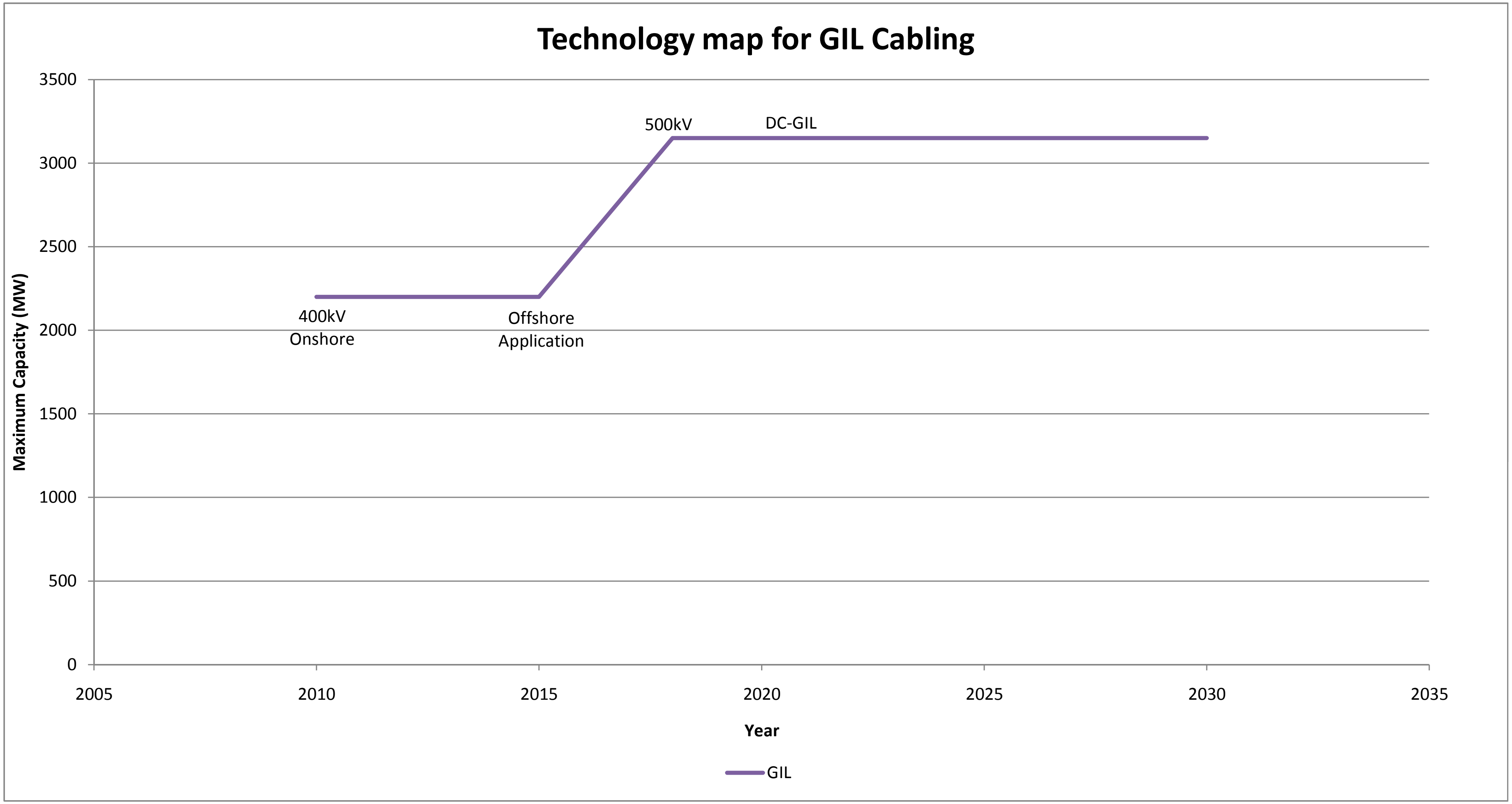
Current Switchgear Technologies and Future Developments

	Factors to be addressed	Present Day State of the Art	2011
33kV AC	Type	Areva Flusarc 36 (36kV)	
	Rated Current (A)	1250A	
	Construction type	SF6 GIS	
	Peak Withstand Current	25kA	
	Short Circuit Break	20kA	
	Capital cost (£)	£36,000 (Triton Knoll)	
	Expected Life	40yr	
	Reliability	3000 year MTBF	
	Operation and Maintenance requirements and costs	20-25yrs maintenance free	
	Procurement Lead time	6 months	
	Installation :		
	- Capital installation Cost (£)	25% of capital cost	
	- Dimensions	0.92L/1.226W/1.72H	
	- Weight	1.2T	
	Comments on development:		
	- Barriers or issues to overcome	Probably not better multiatomic gas than SF6 but perhaps better liquid than oil is feasible (Power System Protection and Switchgear pp.392 written 1977)	
	- Explain Technological Advancement and Reason	Possible liquid SF6	
	- Summarise Impact on Performance/Cost	Higher Speed of operation	
66kV AC	Type	FujiElectric (72.5kV Compact)	
	Rated Current (A)	2000A	
	Construction type	SF6 GIS	
	Peak Withstand Current	31.5kA	
	Short Circuit Break	20kA	
	Capital cost (£)	£300,000	
	Expected Life	40yr	
	Reliability	1000 MTBF	
	Operation and Maintenance requirements and costs	20-25 years maintenance free	
	Procurement Lead time	9 months	
	Installation :		
	- Capital installation Cost (£)	25% of capital cost	
	- Dimensions	2.7L/1.1W/2.3H	
	- Weight	2.3T	
	Comments on development:		
	- Barriers or issues to overcome		
	- Explain Technological Advancement and Reason		
	- Summarise Impact on Performance/Cost		
132kV AC	Type	Siemens 8dn8 (145kV)	
	Rated Current (A)	3150A	
	Construction type	SF6 GIS	
	Peak Withstand Current	108kA	
	Short Circuit Break	40kA	
	Capital cost (£)	£450,000	Basic costs higher
	Expected Life	40yrs	
	Reliability	750 years MTBF	
	Operation and Maintenance requirements and costs	20-25yrs maintenance free	Reduction in maintenance requirements
	Procurement Lead time		
	Installation :		Faster erection and commissioning
	- Capital installation Cost (£)	25% of capital cost	ownership costs reduced
	- Dimensions (m)	0.8L/0.65W/1.2H	
	- Weight	3.2T	
	Comments on development:		Found in CIGRE document (WG B3-20 Brochure Evaluation of different switchgear technologies)
	- Barriers or issues to overcome		
	- Explain Technological Advancement and Reason		Highly Compact Mixed Technologies Switchgear (MTS) - Uses AIS and GIS with significant advantages over 52kV
	- Summarise Impact on Performance/Cost		Performance improved but with marginally greater footprint. Higher flexibility in layout
220kV AC	Type	Siemens 8DN9 (245kV)	
	Rated Current (A)	4000A	
	Construction type	SF6 GIS	
	Peak Withstand Current	135kA	
	Short Circuit Break	50kA	
	Capital cost (£)	£850,000.00	
	Expected Life	>50 years	
	Reliability	500 years MTBF	
	Operation and Maintenance requirements and costs	25yrs maintenance free	
	Procurement Lead time	12 months	`
	Installation :		
	- Capital installation Cost (£)	25% of capital cost	
	- Dimensions (m)	3.7L/1.55W/4.1H	
	- Weight	4.5T	
	Comments on development:		
	- Barriers or issues to overcome		
	- Explain Technological Advancement and Reason		
	- Summarise Impact on Performance/Cost		

DC (Traction Operations)	Type	Hawker Siddeley Lightning (1500V DC)	
	Rated Current (A)	4000A	
	Construction type	Magnetic Actuator	
	Peak Withstand Current	71kA	
	Short Circuit Break	125kA	
	Capital cost (£)		
	Expected Life	>30yrs	
	Reliability	20,000 Operations	
	Operation and Maintenance requirements and costs	20 year major maintenance free	
	Procurement Lead time		
	Installation :		
	- Capital installation Cost (£)	25% of capital cost	
	- Dimensions (m)	1.7L/0.5W/2.3H	
	- Weight	0.37T	
	Comments on development:		
	- Barriers or issues to overcome		
	- Explain Technological Advancement and Reason		
	- Summarise Impact on Performance/Cost		
33kV RMU	Type	ABB SafeRing 36kV (Released 2005)	
	Rated Current (A)	630A	
	Construction type	SF6 GIS	
	Peak Withstand Current	50kA	
	Short Circuit Break	16kA	
	Capital cost (£)	£108,000	
	Expected Life	>30yrs	
	Reliability		
	Operation and Maintenance requirements and costs	Maintenance Free	
	Procurement Lead time	5 months	
	Installation :		
	- Capital installation Cost (£)	25% of capital cost	
	- Dimensions (m)	0.885L/1.33W/1.92H	
	- Weight		
	Comments on development:	http://www.abb.com/cawp/seitp202/6721FB311CF6EC5 6482575380030E349.aspx	
	- Barriers or issues to overcome		
	- Explain Technological Advancement and Reason	40.5kV 34x3MW Windfarm using SF6 RMU Chinese Being constructed (Press Release Jan 09)	
	- Summarise Impact on Performance/Cost	Alternative to 3 CB format if only 1 CB and 2 Disconnectors can be used	


Technology map for VSC-HVDC Converters
Maximum Capacity (MW)
Losses (% of rating)
Year
3500
3000
2500
2000
1500
1000
500
0
1.4
1.2
1
0.8
0.6
0.4
0.2
0
2005
2010
2015
2020
2025
2030
2035
Ongoing improvements in efficiency of devices
Ongoing increase in voltage level , maximum ratings and efficiency due to high interest in HVDC and significant competition between manufacturers
Losses to match that of LLC
Introduction of Silicon Carbide Materials reduces losses significantly
Introduction of Diamond Devices reduces losses further still
Capacity
Losses
Losses (New Technologies)


Technology map for HVAC and HVDC Cabling
Maximum Capacity (MW, per circuit AC, per pole DC)
Year
Ongoing research and devlopment into new dielectrics increases voltage level, temperature capability and ultimately capacity
Extruded dielectric technology preferred over MIND reduces development rate
Focussed research in extruded dielectric due to advantages over MIND
Ongoing research and devlopment into new dielectrics increases voltage level, temperature capability and ultimately capacity
Expected use of primarily HVDC will drive research in that market over subsea 400kV resulting in little development
200kV
300kV
400kV
132kV
220kV
400kV
0
200
400
600
800
1000
1200
1400
1600
2005
2010
2015
2020
2025
2030
2035
HVDC Classic
HVDC Extruded Dielectric
HVAC

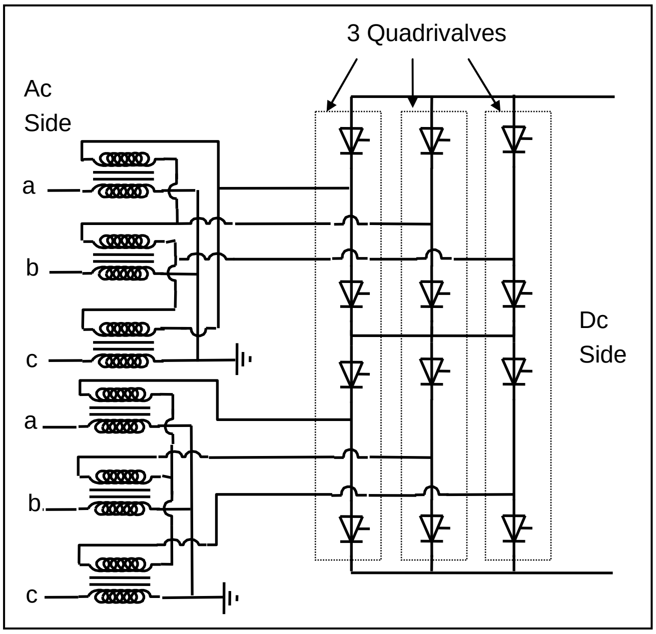

Technology map for GIL Cabling
Maximum Capacity (MW)
3500
3000
2500
2000
1500
1000
500
0
2005
2010
2015
2020
2025
2030
2035
Year
500kV
DC-GIL
400kV
Onshore
Offshore
Application
GIL

Appendix D HVDC Technology

D.1 Line Commutated Converters

The thyristor based conventional converter is designated line commutated converter (LCC) and is usually configured in a pole with quadrivalves as shown in Figure 42.

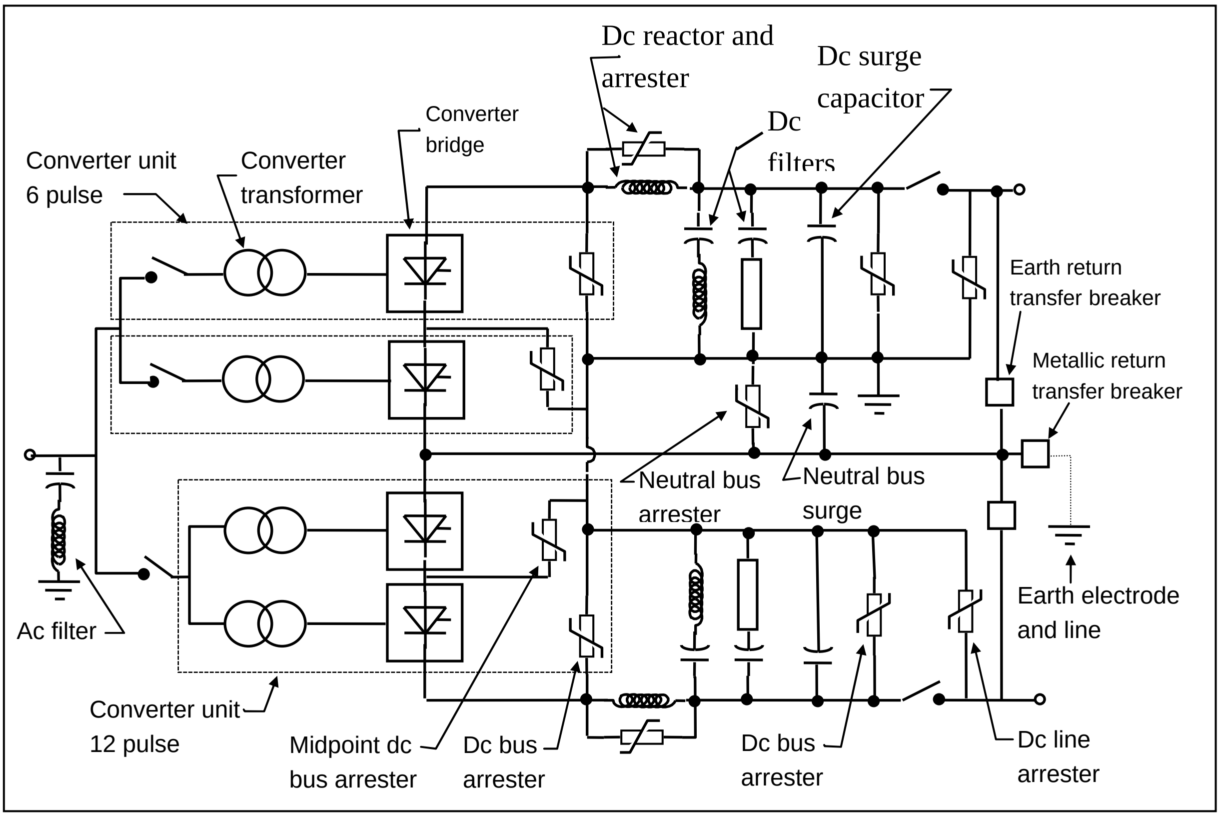
- **Figure 42 The twelve pulse LCC valve group configuration with two converter transformers. One in star-star connection and the other in star-delta connection**



Nearly all HVDC power converters with thyristor valves are assembled in a converter bridge of twelve pulse configuration. Consequently the AC voltages applied to each six pulse valve group which make up the twelve pulse valve group have a phase difference of 30 degrees which is utilized to cancel the AC side 5th and 7th harmonic currents and DC side 6th harmonic voltage, thus resulting in a significant saving in harmonic filters. Figure 42 also shows the outline around each of the three groups of four valves in a single vertical stack. These are known as "quadrivalves" and are assembled as one valve structure by stacking four valves in series. Since the voltage rating of thyristors is several kV, a 500 kV quadrivalve may have hundreds of individual thyristors connected in series groups of valve or thyristor modules. A quadrivalve for a high voltage converter is mechanically quite tall and may be suspended from the ceiling of the valve hall, especially in locations susceptible to earthquakes.

Figure 43 shows an example of the electrical equipment required for an LCC substation. In this example, two poles are represented which is the usual case and is known as the "bipole" configuration. Some DC cable systems only have one pole or "monopole" configuration and may either use the earth or sea as a return path when permitted or use an additional cable to avoid earth currents.

- **Figure 43 Example single line outline of an LCC HVDC substation**



Reversal of power flow in an LCC converter is not possible by reversing the direction of the direct current. The valves will allow conduction in one direction only. Power flow can only be reversed in LCC converter bridges by changing the polarity of the direct voltage. The dual operation of the converter bridges as either a rectifier or inverter is achieved through firing control of the grid pulses to change polarity of the direct voltage.

Due to the pulsating currents existing within the AC circuits of the LCC converters significant reactive power (approximately at a level of 55% of real power) is required to be supplied from the connecting AC network. This reactive power is usually supplied from AC filters, AC switched shunt capacitor banks and from the AC grid. When the AC short circuit capacity at the point of interconnection is very low relative to the DC power being transmitted through the converter, reactive power may be supplemented by synchronous condensers although the use of this rotating machinery increases operation and maintenance costs and also power losses.

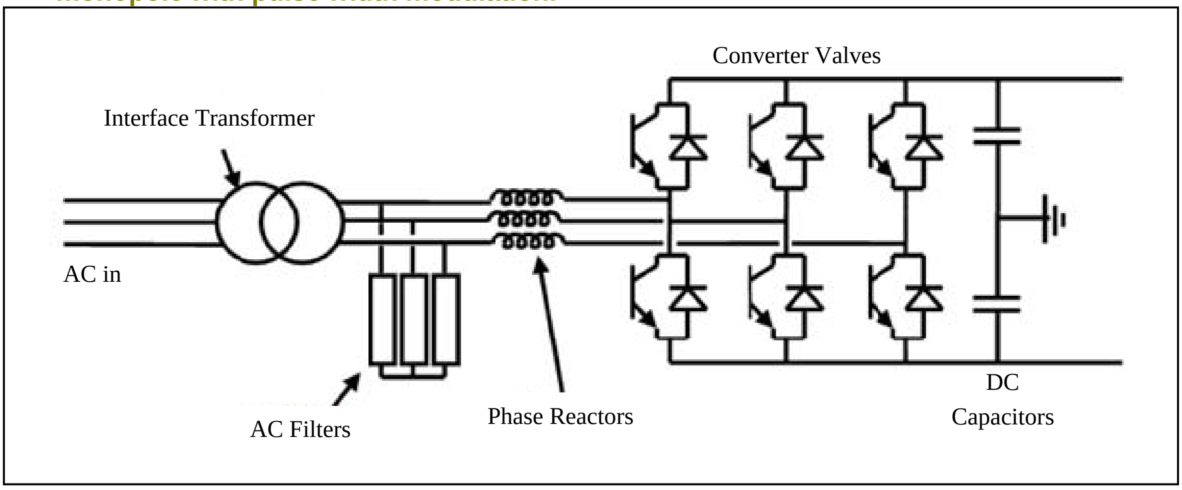
LCC converters when operating as inverters (converting from DC back into AC) are prone to commutation failure[38]. This is a complete but usually temporary loss of transmitted power. It usually occurs when there is an AC disturbance or fault in the grid near the inverter. In general, the more rigid the AC voltage to which the inverter feeds into and with an absence of AC system disturbances, the less likelihood there will be commutation failures.

D.2 Voltage Sourced Converters

Insulated gate bipole transistors (IGBTs) and diodes are required for VSC converter bridge configurations. It is the VSC converter bridge that is being applied in new developments[39][40]. Its special properties include the ability to independently control real and reactive power at the connection bus to the AC system. Reactive power can be either capacitive or inductive and can be controlled to quickly change from one to the other.

In contrast to LCC converters, a voltage source converter as in inverter does not require an active AC voltage source to commutate into as does the conventional line commutated converter. The VSC inverter can generate an AC three phase voltage and supply electricity to a load as the only source of power. It does require harmonic filtering, harmonic cancellation or pulse width modulation (PWM) to provide an acceptable AC voltage wave shape.

- **Figure 44 Voltage sourced converter configured as a six pulse, two level symmetrical monopole with pulse width modulation.**



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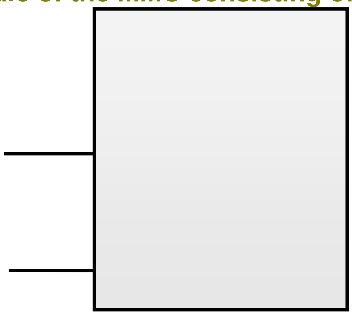
[38] CIGRE Working Group 14-05, Commutation failures – causes and consequences, ELECTRA, No. 165, April 1996.
[39] “VSC Transmission”, CIGRE Brochure 269, Working Group B4.37, April 2005.
[40] S.Hirano, J.Haraguchi, T. Mizuno, H. Niinobe, Y. Nagoya, “Development of ±250 kV Coaxially-Integrated Return Conductor Extruded Insulation Cable,”

Many applications are now available for the voltage source converter. The first application of VSC transmission was in 1997 where it was developed in Sweden by ABB and known today as "HVDC Light." Today, other equipment manufacturers can provide VSC Transmission. Siemens have designated their offering as "HVDC^{PLUS}." Areva will have their offering on the market in 2010. There are many applications for VSC transmission, but two of interest is:

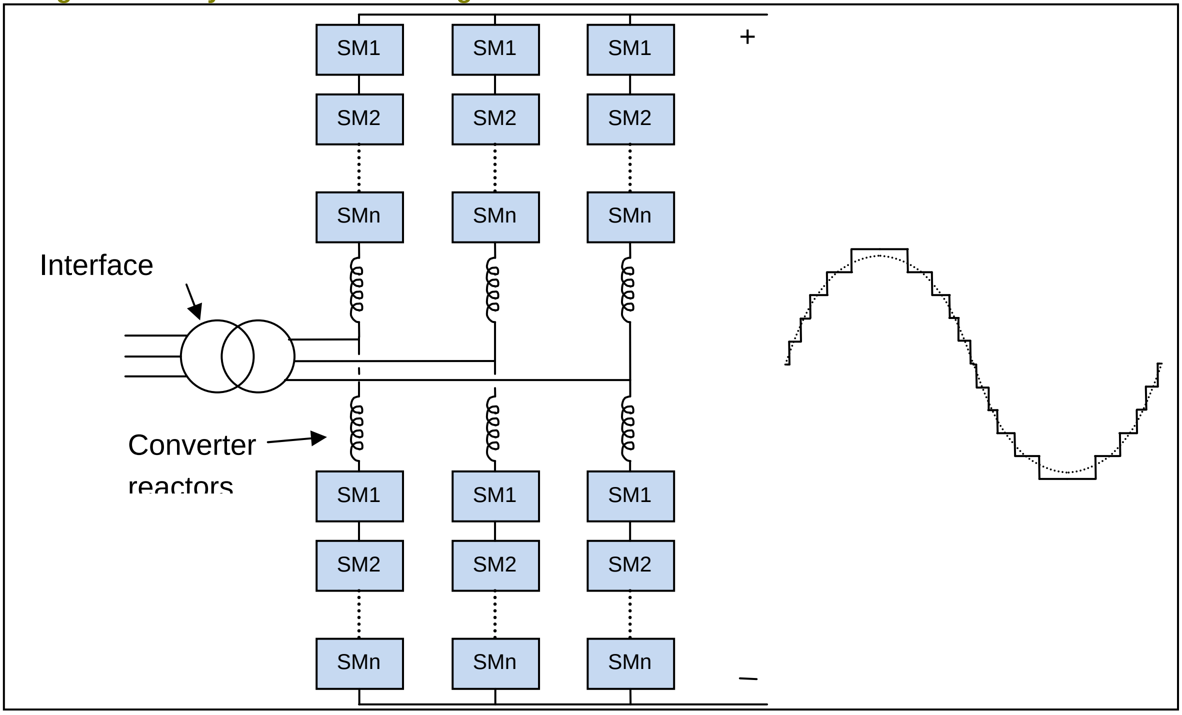
- As a DC feeder to remote or isolated loads, particularly if underwater or underground cable is necessary
- A collector system of a wind farm where cable delivery and optimum speed control of the wind turbines is desired for peak efficiency.

The Siemens modular multilevel converter (MMC) is recent innovation for a voltage sourced converter arrangement whose valves are comprised of a series connection of sub-modules which are each configured as shown in Figure 45. The sub-modules are assembled into a modular multilevel converter as shown in Figure 46.

- **Figure 45 sub-module of the MMC consisting of 2 IGBTs, 2 diodes and a capacitor**



- **Figure 46 An MMC converter made up of sub-modules and the resulting ac wave shape generated by selective switching of the sub-modules**

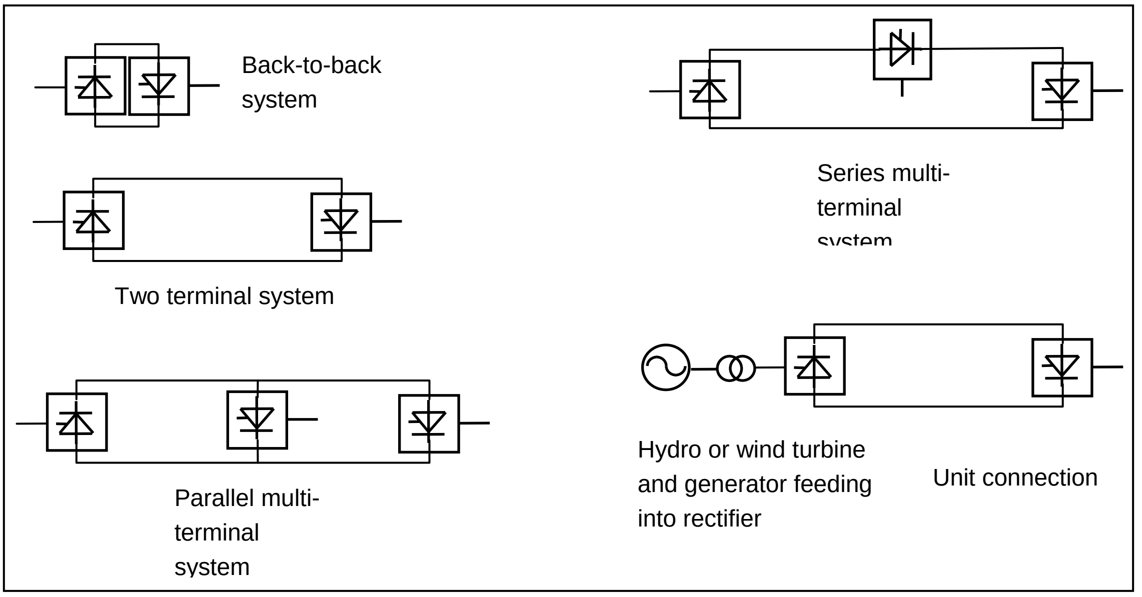


Each of the six legs of an MMC valve group consists of sub-modules (SM) in series along with a converter reactor as indicated in Figure 46. With a large number of sub-modules in series in each valve location it is possible to build ac side voltage up one step at a time to create a rising portion of a sine wave. As the expected ac voltage falls, the sub-modules are turned off to create the falling portion of a sign wave as also indicated in Figure 46. Each sub-module switches on and off once per cycle of fundamental frequency resulting in significantly less IGBT switching's compared to a conventional VSC with PWM. The MMC has the advantage of lower converter losses compared with a VSC with PWM.

D.3 Converter Configurations

Both LCC and VSC converters can be assembled into various configurations as shown in Figure 47.

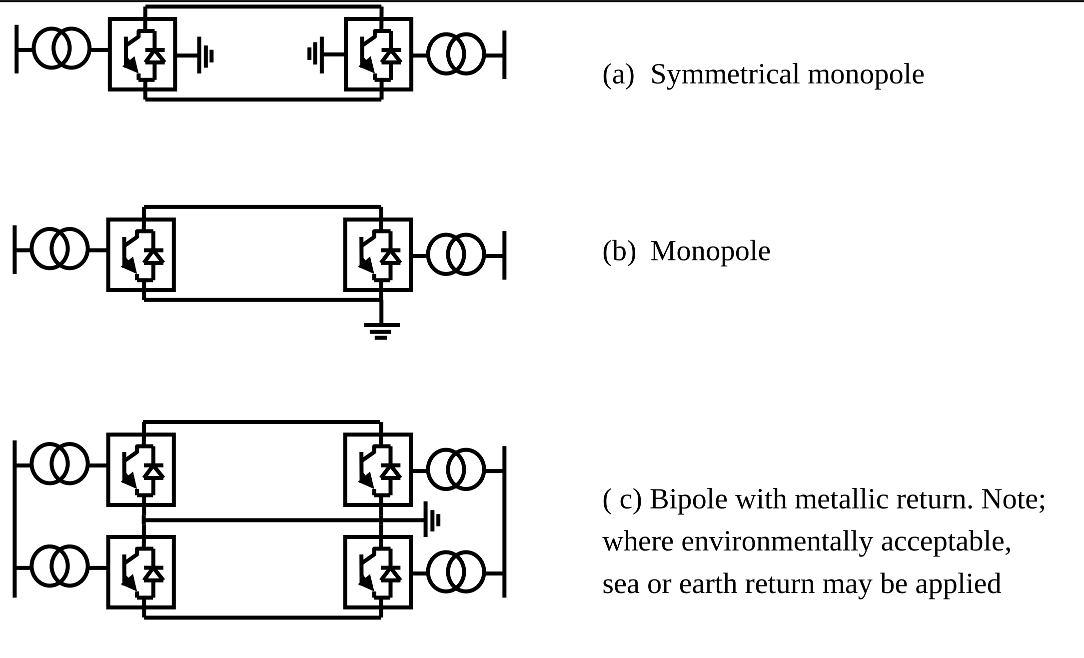
Figure 47 HVDC converter bridge arrangements



For undersea or underground VSC transmission, the voltage rating limits are restrained by the cable DC voltage rating. For overhead transmission, higher DC voltage ratings are possible, either to 500 kV or higher with appropriately designed transmission lines. Since the IGBT is the semiconductor switching device most commonly applied for VSCs, practical current and voltage limits for the converter is achieved by their parallel and series connections within the valve.

The HVDC transmission valve group configurations that can be applied with VSC transmission and back-to-back converters are presented in Figure 48.

- **Figure 48 Converter configurations for VSC transmission**



D.4 VSC Compared with LCC Converters

VSC transmission has a number of technical features that are superior to LCC transmission as follows:

- It can operate into passive networks with an independent clock to control firing pulses to the VSC valves, which also defines the ac frequency. If the ac system(s) can switch from an active synchronous system to a passive network, then a special control is required in the VSC converter to switch from firing pulses generated from a phase locked oscillator tied to the ac voltage to firing pulses generated from the independent clock
- It can feed into or out of weak ac systems. However, the ac system must be capable of delivering or receiving the transmitted power which will set a minimum limit to how comparatively weak the ac system can be in practice
- It can provide substantial ac voltage control at the ac interconnection busbars, even black start capability
- The use of lighter, solid insulated dc cables enables the effective use of undersea and underground cable transmission
- It is better able to provide dc feeder operation for remote wind farms
- Improved control of multi-terminal dc transmission converters.

D.5 Hybrid Converter Connections

The question arises as to whether both VSC and LCC converters could be connected to the same transmission system. The limiting problem is seen to be in the LCC inverter when there are VSC converters also connected, such as in a multi-terminal configuration. When the LCC inverter fails commutation due to an ac side disturbance, this causes the dc side LCC inverter valves to momentarily suffer a DC short circuit and the DC line discharges current through the thyristor valves. This short circuit current is substantially increased if there are VSC converters connected since the DC capacitors needed for the VSCs also discharge into the LCC inverter that is suffering the commutation failure.

The extra discharge current through the thyristor valves requires the valves be rated to pass this higher current, which may not be possible. Secondly, the recovery from the commutation failure, which is normally a cycle or two of fundamental frequency (50 Hz), is significantly prolonged to in excess of 250 msec. Therefore it is not a good idea to have LCC inverters operating with VSC converters on the same DC circuit. However, if the LCC converters are only rectifiers, then with appropriate design could operate satisfactorily. The LCC converters so connected would need to accommodate the consistent polarity of the VSC converters, which should not be a problem if they are confined only to rectifier operation.

D.6 HVDC Application for Off-shore Wind Farms

There are applications requiring DC transmission feeders for wind farms which may be located on islands or off-shore. DC transmission for such feeders will be economically attractive if long, undersea cables are needed.

Conventional LCC dc transmission suffers the disadvantage that it normally cannot operate at current levels less than about 10% rated current or at a level where the current through the thyristor valves become discontinuous. So an LCC wind farm feeder that can provide electricity supply under no wind conditions must have its thyristor valves designed to operate at low dc voltage and with sufficient continuous dc current to provide the needed no-wind reverse power. This results in increased conduction losses because the dc current is relatively high when power flow in the feeder is relatively low. In addition, synchronous condensers may be needed at or near the wind farm to supply short circuit capacity for the LCC converters and wind turbines to operate.

VSC transmission is better suited as a dc feeder for wind farms. This is because in part VSC transmission can operate to zero power or to low reverse power levels by reducing dc current to zero or in reverse while dc line voltage stays at or near rated levels. Furthermore, operation of the sending end VSC converter is possible regardless of how many wind turbine generators are operating or at what level the wind is blowing.

Wind turbine generators normally require short circuit capacity and an ac connection at rated frequency to operate. This is particularly true for induction generators and doubly fed induction generators (DFIG). The sending end VSC converter has the advantage that it creates virtual short circuit capacity when operating at ac voltages at or close to normal levels. This is because the voltage sourced converter generates a fundamental frequency voltage source at its ac terminals whose effective short circuit capacity under normal operation is defined by the impedance of the interface transformer and phase reactor. With the phase angle of the voltage source generated by the VSC rigidly fixed by the independent clock, its virtual short circuit capacity is very effective in supporting the operation of wind turbine generators.

Some of the limitations identified above with respect to LCC convertors within a predominantly wind environment may be managed out of the link, or at least the onshore grid connection point converters if the grid is intended to operate in a multi use mode.