Review of Worldwide Experience of Voltage Source Convertor (VSC) High Voltage Direct Current Technology (HVDC) Installations

REPORT

- Final Rev 0
- 25 March 2013

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Sinclair Knight Merz
13th Floor, Cale Cross House
156 Pilgrim Street
Newcastle upon Tyne
NE1 6SU
United Kingdom
Tel: +44 191 211 2400
Fax: +44 191 211 2401
Web: www.globalskm.com

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1. Executive Summary

The Office of the Gas and Electricity Markets (Ofgem) engaged Sinclair Knight Merz (SKM) to undertake an independent review of the current state of site installation progress for the new family of multi-level Voltage Source Converter (VSC) High Voltage Direct Current (HVDC) convertors which is likely to be the most common technology used in interconnectors and connecting large scale offshore wind farms (OWF).

The main object of the study was to gauge the success and number of VSC installations that have been implemented so far worldwide as well as those that are likely to be developed over the next 5-8 years. Additionally this study has also assessed the technology challenges relating to VSC installations that have already been overcome and has identified those that are likely to require addressing on future projects.

This study has been developed based upon information which is available in the public domain plus a survey using a questionnaire which was prepared to capture information from existing project owners and developers together with discussions with VSC technology vendors, on the future technology challenges to be addressed.

The summary of the report is as follows:

A large number of VSC HVDC projects are either under construction, or are in the stages of design, planning and consenting. Some information on many of these projects is already in the public domain, typically through project owner or developer websites. Through the first part of the survey undertaken as part of this project this knowledge base has been extended in terms of the number of projects identified as well as specific project detail. The cooperation of project owners and developers has been invaluable in this process.

The resulting project summary therefore provides a useful reference document for all those stakeholders interested in VSC HVDC technology and current project status; however it is recognised that this area is dynamic and to remain useful the project summary needs to be updated on a regular basis to obtain ongoing benefit from the additional projects completed.

A high level presentation of the project summary is shown below in Table 1.

Table 1 High Level Summary of VSC Projects Identified

		Europe			North America			Asia			Australasia	Africa	Sub total by Application	Subtotal by Architecture
		In Service	Under Construction	Under Consideration Planning or Consent	In Service	Under Construction	Under Consideration Planning or Consent	In Service	Under Construction	Under Consideration Planning or Consent	In Service	In Service		
Point to Point DC	**Offshore Wind**	0	5	5	0	0	0	0	0	0	0	0	**10**	**36**
	Onshore Wind	0	0	0	0	0	0	1	0	0	0	0	**1**	
	Demonstration Project	2	0	0	0	0	0	0	0	0	0	0	**2**	
	National Interconnector	1	0	1	2	0	1	0	1	0	2	0	**8**	
	International Interconnector	1	3	3	1	1	0	0	0	0	0	1	**10**	
	Offshore Platform Supply	2	0	2	0	0	0	0	0	0	0	0	**4**	
	Offshore Wind / AC International Interconnector	0	0	1	0	0	0	0	0	0	0	0	**1**	
Multi terminal DC	**National Interconnector**	0	0	1	0	0	0	0	0	1	0	0	**2**	**4**
	Offshore Wind / National Interconnector	0	0	0	0	0	2	0	0	0	0	0	**2**	
	Regional Subtotal	**6**	**8**	**13**	**3**	**1**	**3**	**1**	**1**	**1**	**2**	**1**	**Total**	
	Regional Total	**27**			**7**			**3**					**40**	

The second part of the survey questionnaire focused on project specific issues. The responses to the questionnaire were recognised as being commercially sensitive and therefore the responses received have not been attributed to specific projects and have not been published. The issues raised are discussed in Section 5 of the report and were also used to inform SKM's view on the challenges associated with VSC projects as detailed in Section 6.

Questions were targeted to ensure they were relevant to each project and recipient, but in general the following areas were covered:

- Utility network integration issues
- Integration with offshore wind projects
- Consenting and planning issues
- Project programme adherence
- In service performance and vendor guarantees
- Multi-terminal schemes

SKM also engaged with the main VSC technology providers; to elicit further technology information and provide a balanced assessment of expected future VSC technology challenges. The engagement with prospective technology providers provided validation of SKM's own views and opinions regarding VSC technologies and also enabled the most up to date view on technology developments to be included in the report.

The high level summary of existing and future technology challenges and the likely timescales for these challenges to be overcome is provided in Table 2 and a summary of the other issues associated with VSC projects, potential solutions and general outlook is provided Table 3.

Table 2 High Level Summary of Technology Challenges for VSC Project Implementation

Technology Challenge	Potential Solution	Timescales to Overcome Challenge
Multi-terminal VSC schemes with single vendors	Are being delivered today based on three terminal schemes with single zones of protection (with a view to being operational by 2014). Further developments required for multiple protection zone arrangements including the establishment of regulatory standards, potential across several jurisdictions. Technology is unlikely to be the main obstacle in the delivery of HVDC grids.	First three-ended VSC multi-terminal scheme with a single protection zone expected to be operational by 2014 No schemes have plans for multi-zone protection at the moment. Whilst enabling technologies are likely to be two to three years away, this timescale fits within the wider project timeline, therefore technology availability is unlikely to be a timescale obstacle.

Technology Challenge	Potential Solution	Timescales to Overcome Challenge
Multi-terminal schemes with multiple vendors	For a single protection zone scheme main need would be a common voltage. However significant commercial discussions would be required to establish responsibility interfaces.	Technically could be delivered, commercial interfaces and therefore commercial justification may be difficult to establish. Likely that multiple vendor projects will follow on from multi-terminal schemes with single vendors.
DC circuit breakers for multiple protection zone schemes	Prototypes and designs exist however ratings, application and even need for devices is not agreed and until there is a clear market need it is likely that the final stages of development will be held.	First devices could be delivered within two to three years, possibly before but final stages of development dependent on market pull.
Compact HVDC switchgear for use on offshore platforms and HVDC hubs	Adapted versions of existing HVAC Gas Insulated Switchgear (GIS) Switchgear	Proven designs with a rated voltage of 300 kV to 400kV could be available by 2014, dependent on market demand
Increased ratings of VSC IGBT modules than the currently available 1400 to 1600 A, thus allowing higher power transfers.	2000 A modules likely to be developed.	Expected to be available for adoption in projects by 2016.
Delivery of bipole VSC systems	Bipole converter configurations similar to the symmetric monopole systems supplied to date.	Designs available such that systems could be delivered.
2000 MW converter on a single offshore platform	Feasibility looked at but not believed to be a credible market need as yet.	Unlikely to be realised in foreseeable future but designs could be realised in 2014/2015 if needed.
Equipment susceptibility to harsh offshore environments. Airborne molecular sodium chloride (salt) contamination is associated with temperature cycling and high relative humidity which causes concerns regarding condensation and subsequent corrosion	HVDC VSC vendors are developing environmental protection for the different equipment rooms on the offshore platforms associated with enclosures provided for the power electronic modules. Experience gained with HVAC substations as well the early HVDC offshore converters will be significant in minimising future issues as well as the lessons continually being learnt from the oil and gas sector.	Lessons are being learnt from the First HVDC projects which are now in-service.

Table 3 Summary of Other Issues Associated with VSC Projects

Issue	Potential Solution	General Outlook
Utility network integration	Range of solutions include: • Dynamic Braking • Control Strategy • Protection • DC Load Flow • Reliable operation of power electronic driven wind generators in weak AC networks.	• Dynamic braking has been delivered. • Control strategy and application is complex and yet unproven for multi-terminal above three ended schemes. Cigre and other work is progressing on issues associated with HVDC grids • Multi-zone protection schemes not yet implemented where HVDC circuit breakers are needed (see above). • To overcome concerns with weak HVAC networks wind farm developers are looking for either classical (e.g. synchronous condenser) or Flexible Alternating Current transmission Systems (FACTS) based solutions for addressing expected operational issues. Cigre is also setting up a Working Group B4-62, to look at the specific issue of connection of wind farms to weak AC networks.
Expected levels for system and converter availability	• Vendor guarantees • Industry reliability surveys • Consideration could be given to the design of specific reporting formats for Offshore Transmission Owners (OFTOs) and interconnector operators to facilitate the collection of such data.	Vendors are reaching agreements with developers on a contractual basis so guarantee levels are being established on a project by project basis. Cigre and other bodies will develop surveys as the number of installations increases. It is suggested that there will be a need in the UK for specific collection and analysis of reliability data so that in the future there is clear information for project developers, OFTOs and lenders of what levels of availability can be expected.

Issue	Potential Solution	General Outlook
Regulation and Standards	• Agreed standard voltage levels would be needed to facilitate multi-terminal scheme. • A DC Grid Code for multi-terminal schemes would be needed,	Pre-work by organisations such as Cigre and the European Committee for Electrotechnical Standardization CENELEC is ongoing and the outlook is positive that standards will emerge as required. Potential impacts on the supply chain and technology developments such as cable voltage levels are difficult to assess. Experience suggests that standards and codes take a minimum of one to two years to be finalised although agreements on principles are generally reached in shorter timescales allowing projects to proceed in parallel.
Need for higher cable voltages and thus higher power transfers	Higher voltage 600 kV MIND cables and potential for up to 500 kV XLPE cables.	600 kV MIND cables will be delivered for commissioning in 2015. 400 kV or even 500 kV XLPE could be available by 2016. So whilst 2000 MW connections could be proposed there would be issues with size of single load loss.
Project programme delays	• Lessons learnt • Better understanding of the planning and consenting stages of a project • More realistic upfront project planning.	Experience is bringing improvements, but many projects are still hitting delays on consenting or installation. Technology is not as significant a problem as weather windows and vessel availability.
Delays in consenting and planning	• Enhanced stakeholder engagement • More realistic expectations of process timing. • Changes to process	Consenting and planning remains a major concern for major infrastructure projects. Changes have been introduced in the UK consenting and planning process but it is too early to assess the improvement that these changes will deliver.
Ensuring transmission equipment lifetimes are consistent with generation assets.	Mid-life upgrades on control, cooling and converter modules will enable lifetimes of up to 40 years to be reached in well controlled environments.	Can be realised now if requirement exists.
Offshore installation problems	• Learn lessons from HVAC experience • Self Installing technology • New logistic arrangements such as hotel platforms • New approaches to O&M	Whilst there is now 10 years operational experience with offshore assets in the UK, the challenges with VSC projects are changing due to their location (further from shore) and larger size. Hence new installation arrangements will be needed which will need to draw on experience, including from the Oil and Gas industries.

Issue	Potential Solution	General Outlook
Achieving cost reduction	Projects involving VSC interconnectors as well as connections to offshore renewables are justified on the basis of present costs. As competition increases and enhancements are made to VSC technology it is likely that the cost and price of VSC technology will reduce. In the case of offshore renewables this may assist in achieving the necessary overall cost reduction targets (of £100/MWh by 2020)[1], however it must be recognised that the cost of the export connection is a relatively small proportion of the overall project cost.	Likely to occur in three to five year timescale as significant competition develops. Another factor in cost reduction is the ability of vendors to provide standard solutions, allowing savings in terms of reduced design and engineering as well as manufacturing efficiencies.

It is much appreciated that all of the main VSC vendors provided support to this review by responding to particular technical questions. This response is significant given that the technology vendors are actively responding to the market requirements of the large number of projects which are being developed at present. It is intended that this report will assist in the process of introducing VSC technology to a range of potential stakeholders and alleviate some of the potential concerns that accompany the deployment of any new technology, particularly where the established alternative technologies have seen relatively little change over previous decades.

Tables 2 and 3 show that many technology challenges still remain to be addressed, in relation to the implementation of VSC technology on a wide scale. However these challenges are currently being addressed by VSC technology vendors and users (where there is a market need). Consequently, it is concluded that no fundamental technology issues or barriers exist which are likely to significantly delay the wider adoption of the technology. The large number of HVDC VSC projects currently under development (Table 1) provides evidence to support this view. Comfort can also be taken from the fact that challenges have already been overcome to allow VSC technology to be applied at its current level. The relatively few problems experienced to date, in relation to HVDC VSC technology should give confidence that in future a similar record will be achieved.

In order to realise HVDC grids there are additional specific challenges that will need to be overcome as detailed in Tables 2 and 3. However, such a network and the associated standardisation and regulatory measures that would be necessary in order deliver such a concept would first need to be justified in terms of costs and benefits. Standardisation is especially needed if VSC technology deployed to deliver an integrated HVDC grid across regions or between

[1] Target proposed by the Offshore Wind Cost Reduction Task Force.

countries. It is concluded that considerable further work is required to justify and define the concept of such a network and the regulatory framework to allow such a system to be developed.

Whilst the report has focused on VSC technology it is clear that, even as VSC technology becomes more mature and the remaining technology challenges are addressed, as projects become larger so the associated installation risks will increase. This applies to both offshore platforms and submarine cables in particular. Submarine cable installation remains one of the most significant risk areas associated with the application of many VSC HVDC projects despite the relative maturity of the submarine cable industry.

Based on the review of VSC installations and associated technology challenges the recommendations of SKM for further work are:

a) In order to deliver ongoing benefit from the summary of existing and planned VSC projects it will be necessary for the database to become a “live” document which is updated with new project information as this becomes available, Ofgem should consider a mechanism to achieve this.

b) Given the importance of system availability and the need to understand the performance of each element of the system there will be a need in the UK for the collection and analysis of reliability data so that there is clear information for future project developers, OFTOs and lenders of what levels of availability can be expected. Also what choices exist to undertake cost benefit analysis as to options that might be selected in design, maintenance provision and spares. Ofgem could consider the design of specific reporting formats for OFTOs and interconnector operators to facilitate the collection of such data.

c) Further work is required to justify and define the concept of an integrated HVDC network and the associated regulatory framework to allow such a system to be developed. It is recommended that this work is progressed such that the actual technology issues which need to be addressed can be identified with more confidence that currently exists. Consideration of this requires a broader perspective than can be applied by any single project developer or TSO.

2. Introduction

The UK Government has set an ambitious target for the deployment of renewable energy over the next decade. By 2020, the Government expects that 15 percent of the UK's energy needs will be met from renewable sources and suggests around 30 percent of electricity may come from renewables. Offshore wind will play an important part in meeting these renewable energy targets.

While offshore wind is important in reducing the carbon intensity of electricity generated in the UK, one of the most fundamental issues affecting the adoption of offshore wind generation is the cost of OWFs and associated offshore transmission assets.

OWF sites are leased by The Crown Estate (TCE). They have run four tendering rounds to date to appoint generators for offshore sites (Rounds 1, 2 & 3 and a Scottish Territorial Waters round). In total, there is almost 50,000MW of capacity of offshore wind generation that is either subject to an agreement to lease (including Scottish Territorial Waters) or has already been leased, including 32,000 MW under Round 3 alone. To facilitate the expansion of offshore wind, the UK Government has introduced a regulatory regime for offshore electricity transmission which effectively separates the offshore generation from the offshore transmission. Offshore transmission is a licensed activity, regulated by Ofgem, with the OFTO licence awarded through a competitive tender process run by Ofgem to encourage new participants and funding into the regime.

The OFTO regime is being delivered in two parts: a Transitional Regime and an Enduring Regime. The Transitional Regime commenced in June 2009 and applies to assets constructed, or currently under construction by generation developers. The Transitional Regime allows developers to transfer ownership of completed offshore transmission assets to a licensed OFTO, appointed through a competitive tender process. Transitional Regime projects must have met the qualifying project requirements set out in the Tender Regulations by 31 March 2012. Projects that did not meet these requirements by this date will be subject to the qualifying project requirements in the Enduring Regime.

Unlike the Transitional Regime, projects for the Enduring Regime will also include those requiring the use of HVDC technologies due to the greater distances offshore on many of the large Round 3 projects. Additionally there will be scope for interconnections between projects and indeed between offshore wind projects and the significant number of submarine interconnectors being considered between countries or between regions within the UK.

Ofgem, on behalf of The Gas and Electricity Markets Authority (the Authority) required that an independent review be undertaken of the current state of site installation progress for the new family of VSC HVDC convertors which is likely to be the most common technology used in interconnectors and connecting large scale offshore wind farms.

The main object of the study was to gauge the success and number of installations that have occurred so far worldwide and those that are likely to occur in the next 5-8 years and to assess the technology challenges already overcome and those that will need to be addressed in the future.

This report is structured as set out below:

- **Section 3 – HVDC Technology and Applications**

  A brief technology review is provided identifying the history of VSC developments and the differences in approach between the main vendors of VSC equipment, the linkage with HVDC cable technology and the types of converter configurations.

- **Section 4 - Methodology**

  The methodology adopted by SKM was to collate publically available information and in-house experience into a project specific database which was then verified with project developers, owners and vendors wherever possible.

  To assist this process two questionnaires were developed:

  a) The first focussed on project installations and was sent to project developers, owners and vendors.
  b) The second focussed on technology challenges and was discussed directly with VSC vendors

  All information was then verified, wherever possible, and reviewed by SKM before being included within the main body of this report as a high level summary supported by an Excel spreadsheet with project specific information. Details of project installation issues and specific vendor responses to questions were kept anonymous and have not been included in the report or the spreadsheet.

- **Section 5- VSC Installation Data and Technology Challenges and Achievements**

  Data compiled has been collated into a project spreadsheet which contains high level details of each VSC HVDC project which has been installed, under construction or those planned projects where details exist in the public domain.

  A summary of this project data is presented in this section of the report together with a commentary on the technology challenges which have already been overcome, those issues which have arisen and the technology challenges which will need to be overcome for future projects.

- **Section 6 - SKM View on VSC Technology Challenges**

  An SKM view is provided on the risks associated with technology challenges for the future and the claims made by vendors concerning technology readiness.

- **Section 7 - Conclusions**
- **Section 8 - Recommendations**

  Recommendations for further areas for study are given.

3. VSC HVDC Technology

A brief technology review is provided here identifying the history of VSC developments and the differences in approach between the main vendors of VSC equipment, the types of converter configurations and the linkage with HVDC cable technology.

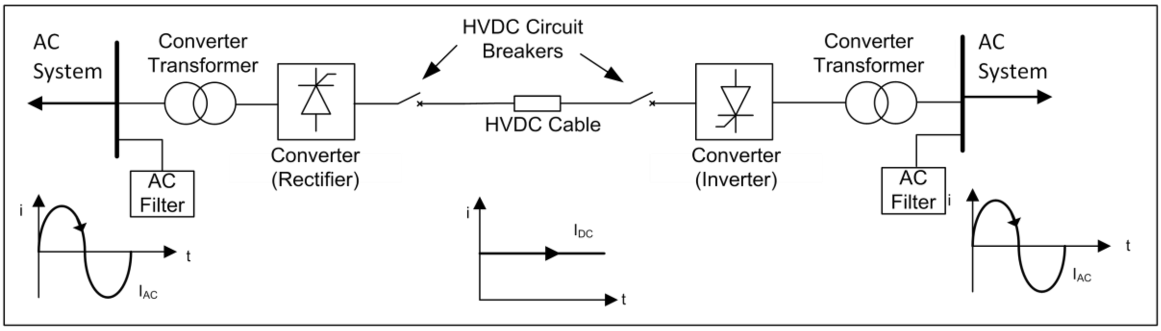
It is well known that significant reactive power (MVAr) compensation is required for HVAC cable connected systems due to the capacitive charging current of the cable. For long HVAC cables the reactive charging current requirements can be of the same magnitude as the cable active power rating. Given that connection of large scale offshore wind farms and interconnector projects require submarine cables it follows that for given cable electrical characteristics there becomes a distance beyond which the operation of an HVAC cable becomes impractical due to the dominance of the cable charging current.

A general "rule of thumb" used within the industry is that for HVAC, distances up to 60-70 km and for transmission capacities up to 1000 MW can be realised. For longer distances and/or higher capacities HVDC becomes the normally accepted solution. In practise a detailed technical/economic study is required to determine the least cost technically acceptable (LCTA) arrangement taking into account ongoing technology developments, including:

- 3-core HVAC cables are now available up to 220 kV and potentially 275kV which could extend the crossover or tipping point between HVAC and HVDC to at least 90 km
- The concept of intermediate reactive compensation offshore platforms which could be used to potentially extend the range of HVAC systems
- Wider application of VSC HVDC and availability of extruded HVDC cables at higher voltages suggest that HVDC could be the LCTA solution for relatively short distances.

The use of HVDC technology for international interconnectors also facilitates the independent operation of the two connected networks.

Figure 1 shows the fundamental principle of an HVDC scheme. In general, offshore HVDC transmission systems (as used for the connection of large offshore wind farms) require an offshore HVDC converter platform, an onshore HVDC converter station and various cables, both subsea and onshore. International interconnectors require the same arrangement but with both converter stations constructed onshore.



■ **Figure 1 HVDC Scheme**

The system is generally comprised of the following electrical equipment:

Converter: This is required for the conversion of the AC voltage to DC via a rectifier and the DC voltage back to AC via an inverter, using either Line Commutated Converters (LCC) or VSC technology.

Converter transformer: This is the connection point between the AC system and the AC side of the DC system at the offshore AC collector platform (for an offshore wind farm) and at the onshore grid connection point substation.

HVDC cable: Offshore applications rely on cables as a transmission medium, rather than overhead lines (OHLs). Some onshore applications use overhead lines as the transmission medium.

HVAC switchgear: This refers to all circuit breakers, disconnectors and all associated equipment to protect, isolate and monitor electrical equipment and systems. Standard HVAC switchgear technology can be employed both onshore and offshore.

HVDC switchgear: HVDC switchgear exists today to a certain extent, but relies on the capability of the converters or AC circuit breakers to extinguish fault currents. The availability of a DC circuit breaker with DC fault current breaking capability is required to fully realise multi-terminal schemes.

AC Filters: These may be required on the AC side in order to remove any harmonics and to ensure that the resulting AC waveform is acceptable before it is fed in to the grid.

DC Filters On OHL schemes DC filters may be required to limit the harmonic content flowing in the DC line. Such filters are normally not needed with a cable connected system.

Reactive compensation: LCC converters require supporting reactive compensation to produce capacitive reactive power for power factor correction for AC voltage control.

HVAC cables and overhead lines Standard HVAC cables, Gas Insulated Line (GIL) and overhead lines can be used to make connections between the HVDC system and the grid connection point.

There are two basic types of HVDC convertor technology, Line Commutated Converters (LCCs) which have been used commercially since the 1950s and Voltage Source Converters (VSCs) which emerged more recently in the late 1990s.

The principal concept of both technologies relies on the use of power electronic switching devices to convert AC power into DC power, transferring the power over long cables or overhead lines and converting the DC back to AC at the other end. LCC converter technology utilises Silicon Controlled Rectifiers (SCRs or thyristors) as the switching device, without gate turn-off capability and require an AC current zero to turn off. VSC technology is self-commutating employing insulated-gate bipolar transistors (IGBTs) as the switching device with both gate turn-on as well as turn-off capabilities that can turn-off at any AC Point on Wave (PoW).

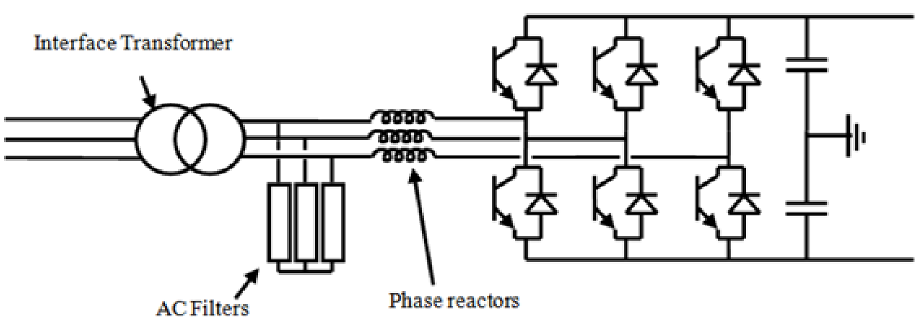
There are advantages and disadvantages associated with both LCC and VSC, and the preferred choice of technology for any project will be determined from a detailed analysis which considers project specific factors such as:

- Land availability for converter stations
- Required MW capacity of the project
- Strength of network(s) at which the converters are connected
- Losses
- Capex cost
- Technology maturity
- Filtering requirement

A detailed comparison between these technologies is outside of the scope of this project which is focussed on VSC technology only.

3.1. VSC Technology

The basic concept of VSC is depicted in Figure 2.

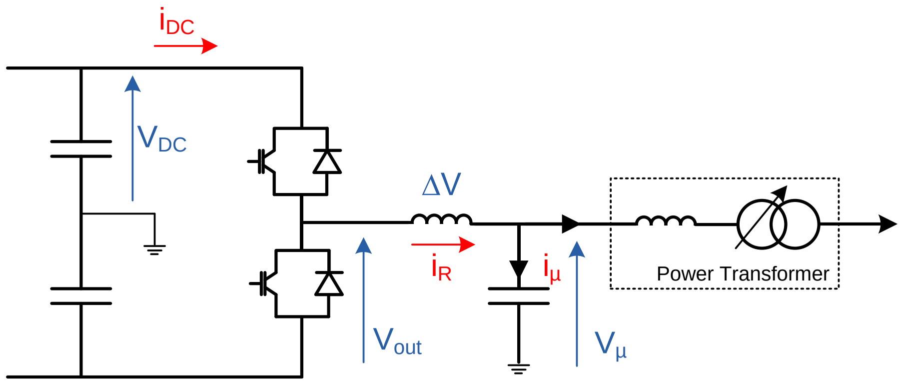


- **Figure 2 - Basic concept of voltage source converter**

The main switching device used in VSC technology is the IGBT as used in traction or industrial drives or with specially developed IGBT modules for HVDC applications. For high voltage applications, it is essential to connect switching devices in series in a reliable manner. Each VSC module is built from a large number of parallel elements connected with bond wires; therefore unlike thyristors that fail into a short circuit, IGBTs fail into an open circuit when bond wires fail. This building block approach solution which is used to mitigate the issue of IGBT failure, in practice creates a number of other challenges related to voltage sharing for a stack of IGBTs, where any differences in the gate drives of individual units can represent a large voltage spread. Therefore the gate drives for a modular building block approach need to run an active voltage sharing method, and snubber[2] circuits are provided to resolve this, with consequential power losses.

The half-bridge arrangement, presented in Figure 3 is the simplest form of a VSC. This converter works with two DC voltages for conversion to AC, which are $\pm V_{DC}$. The midpoint of the DC bridge is the reference for the voltage and the peak AC voltage amplitude is half of the total DC voltage between the two poles. The phase, magnitude and frequency of the output AC voltage are all controlled by the switching pattern of the half-bridge converter with current and voltage being independently controlled. The VSC converter is a voltage source with the capability to consume or generate both active and reactive power, provided the DC capacitor is large enough and kept at constant voltage. A reactor is placed in series to serve as a filter and sustain the voltage difference between the two sources.

[2] Power semiconductor devices need protection systems to overcome the electrical stresses which are placed on the device during the switching process (turn-off and turn-on) to ensure safe levels within the electrical range of the device. These protection systems are called snubber circuits.



V_{DC} = The DC voltage of the link with respect to ground (e.g. For a +/-320 kV link V_{DC} = 320 kV

ΔV = Voltage phase difference caused by reactor element to provide flow of power

V_{μ} = Harmonic filter voltage

V_{out} = Voltage across whole IGBT stack (voltage across IBBT module = V_{out}/number of modules)

i_{DC} = Current through DC circuit

i_R = Phase Reactor current

i_{μ} = Harmonic filter current

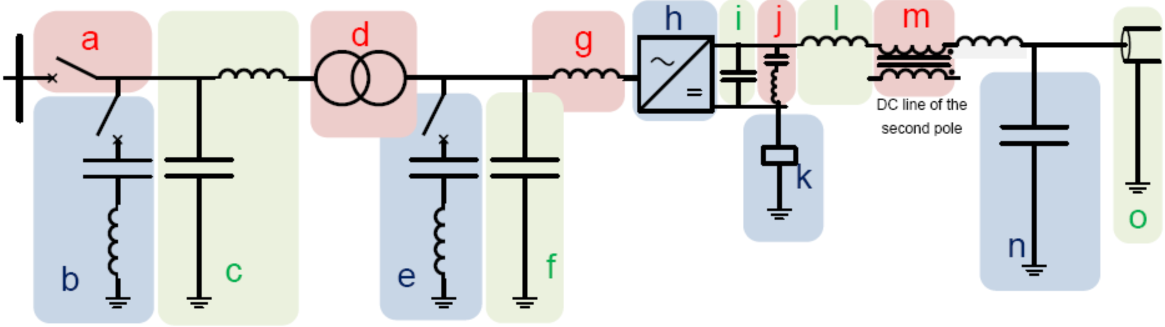
- **Figure 3 - Power flows from a two-level converter**

The basic principle of VSC converter operation in steady state is to measure the AC system voltage, estimate the required frequency, amplitude and phase angle of the currents to be injected in the point of connection, and synthesize a DC voltage capable to produce such a current. This must be achieved with the highest degree of reliability and with the lowest possible losses.

There are a number of control strategies to provide an adequate switching pattern which fulfils the above requirements at any point in time, particularly if the AC voltage suffers variations due to switching operations or constant variation of the VSC working point balancing load and generation.

Control strategies which would take advantage of soft switching (at zero current and zero voltage), would be preferred by the industry as they would generate lower power losses. This is why multi-level VSC converter systems are now superseding earlier Pulse Width Modulation (PWM) VSC converter designs.

An example of a basic arrangement for a VSC-HDVC transmission system is presented in Figure 4, though this can vary depending on the project requirements and the chosen converter technology.



a) VSC substation circuit breaker
b) system side harmonic filter
c) AC side power line carrier harmonics filter
d) interface transformer
e) valve side harmonic filter
f) AC side RFI filter
g) phase reactor
h) VSC unit
i) VSC DC capacitor
j) DC harmonic filter
k) neutral point grounding branch (1)
l) DC reactor (2)
m) common mode blocking reactor (2)
n) DC side RFI filter (2) (3)
o) DC cable or overhead transmission line

1) The location of the neutral point grounding branch may be different depending on the design of the VSC unit
2) Optional for DC side filtering
3) Only required if power line carrier communications is used on the connected AC lines

- **Figure 4 Basic diagram of a VSC System**[3]

3.2. State of the Art VSC Technology

HVDC technologies vary between the manufacturers and the principles currently employed are as follows:

Two level or three level PWM VSC converters were first introduced by ABB in the 1990s. This technology is known under the brand "HVDC Light"

Modular Multilevel Converters (MMC) which were introduced around 2006 by SIEMENS and are known under the brand "Plus-Technology"

Cascaded two level converters were introduced by ABB in 2010. This approach is a development of the two-level and three-level PWM-VSC technology which will be marketed under the brand "Light-Technology".

A hybrid alternate convertor arm multilevel approach was introduced by Alstom Grid in 2010 and first projects are now being supplied. Technology wise this approach is a combination of the other technologies mentioned above. This technology is known under the brand "HVDC MaxSine".

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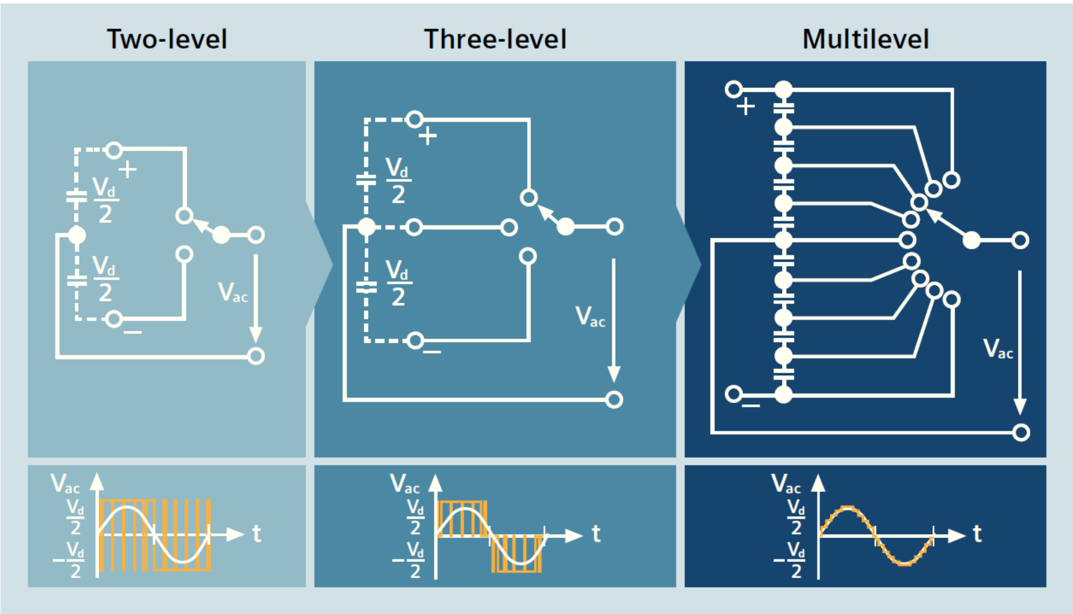
[3] CIGRE Working Group B4.48, Components Testing of VSC System for HVDC Applications

Finally, VSC technology has also been developed by C-EPRI which is understood to utilise a MMC approach and is being utilised in China. This technology is marketed under the brand "HVDC Flexible"[4].

In addition the Japanese supplier Toshiba is expected to enter the market within the next one to two years.

Whilst the fundamental approaches of the main suppliers are different, the functions performed are the same and the capabilities of the systems can be considered equivalent. The purpose of this report is not to compare and contrast the benefits of each system, however it is relevant to understand the different approaches.

Multi-level converter designs have been developed to reduce the large voltage steps associated with PWM operation and thereby reduce power losses and all three main suppliers have today adopted this approach. The multi-level converter aims to generate the AC voltage from a large number of smaller voltage steps, which more closely matches the ideal sine wave and reduces the proportion of harmonics generated by the switching process hence reducing the need for filters. The output voltage from various levels of VSC-HVDC topologies are presented in Figure 5. Therefore each of the three main VSC vendors offers a version of the multi-level converter.



- **Figure 5 Resulting AC waveform from various levels of VSC-HVDC converters[5]**

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[4]http://www.epri.sgcc.com.cn/prgc/english/Product_Solution/HVDC_Flexible/201203/t20120307_1038875.html

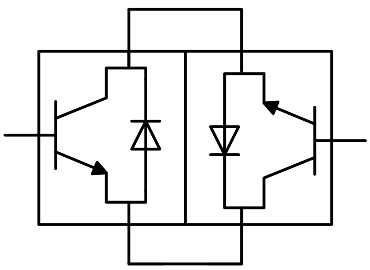
[5] Siemens Debuts HVDC PLUS with San Francisco's Trans Bay Cable, Justin Gerdes

Whilst the basic concept of the multi-level converter and the characteristics and performance of the converters are the same, the approach taken and the arrangement of components within the converter designs are unique to each vendor. This is due to historical development of HVDC technology within each company, considerations of technology protection through patents and of course differences of opinion as to which approach provides overall benefits. Direct comparisons between the technology can only be made on the consideration of application specific requirements given the influence of factors such as:

- Capital cost
- Losses
- Operating costs
- Availability
- Converter configuration
- Application (e.g. point to point or multi-terminal)

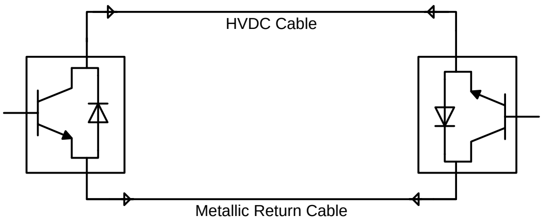
3.3. Converter Configurations

Both LCC and VSC converters can be assembled into various configurations as shown in Figure 6, Figure 7 and Figure 8 below. For long distance transmission, the bipolar arrangements shown in Figure 8 are generally considered to be more suitable; the poles are designed to be independent of each other. During an outage of a transmission line or station for one pole, the second pole should still be capable of monopolar operation, with the metallic return providing the return current path for the DC current.

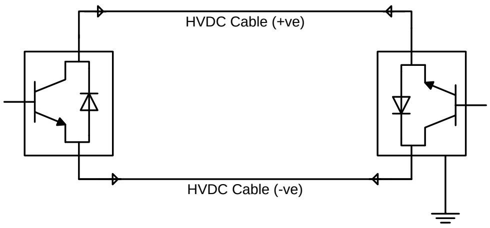


Back to Back
This arrangement is used to link two asynchronous networks. By converting from AC/DC/AC, power can be transferred between the two networks whilst still operating the networks independently, at different frequencies if required.

- **Figure 6 - Back to Back Converter Arrangements**

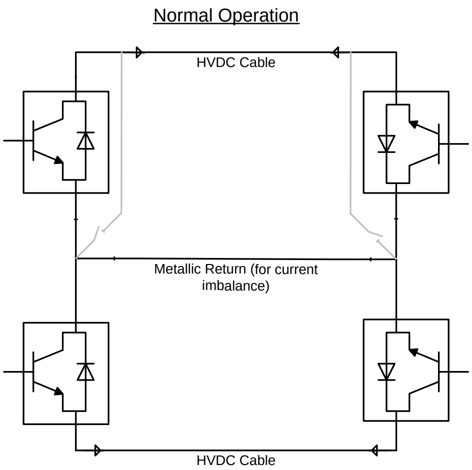


Monopole, metallic return
If there are constraints against using earth electrodes (there are issues with corrosion of pipelines, production of chlorine and ship navigation) then such a metallic cable can be installed instead



Symmetrical Monopole
If a fully rated HVDC cable is installed instead of a return conductor, then two converters per pole can be utilised to double the power transferred using opposing voltage polarities. However, if a cable or converter is faulted then the whole transfer capability is lost.

- **Figure 7 - Monopole Converter Arrangements**



Bipole, metallic return
The bipole arrangement utilises a single return path for two poles. An equal and opposing voltage from each pole means that the return path will carry only minor current due to any imbalance between the two poles. The return path can be provided by either a metallic conductor or sea/earth electrodes if consent can be gained for their use.

- **Figure 8 - Bipole Converter Arrangements**

Table 4 provides a summary of the main converter arrangements and a high level indication of availability during a cable or pole outage.

- **Table 4 - Summary of Converter Arrangements**

Arrangement	Converter Requirements	Cable Requirements	Availability
Back to Back	1 x Rectifier, 1 x Inverter (Both at same site)	N/A	Zero during Pole Outages
Monopole Metallic Return	1 x Rectifier, 1 x Inverter	1 x HVDC 1 x LVDC	Zero output during cable or pole outages. Increased losses.
Monopole Earth/Sea Return	1 x Rectifier, 1 x Inverter	1 x HVDC (plus earth electrode systems)	Zero output during cable or pole outages.
Symmetric Monopole	2 x Rectifier, 2 x Inverter	2 x HVDC	Zero output during cable or pole outages
Bipole Metallic Return (or fully rated earth/sea return)	2 x Rectifier 2 x Inverter	2 x HVDC 1 x LVDC	Half capacity during cable or pole outages.
Bipole without Metallic return (assuming no earth/sea Return is available)	2 x Rectifier 2 x Inverter	2 x HVDC	Half capacity during pole outages. Zero output during cable outages

In some cases environmental restrictions do not allow the use of earth/sea returns, however such LCC HVDC projects have been installed in Scandinavia[6] and New Zealand[7].

The configurations in Figure 7 and Figure 8 are based on the most common arrangement of HVDC system which is a point to point arrangement between two converters which are directly connected by overhead line or cable.

Multi-terminal HVDC links with configurations of series, parallel, or hybrid (a mixture of series and parallel) which connect more than two points, are relatively rare. Parallel configurations tend to be used for large capacity stations, and series for lower capacity stations. Examples include the 2,000 MW Quebec - New England Transmission system opened in 1992, which is currently the largest multi-terminal HVDC system currently in operation.

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[6]The Baltic Cable HVDC Connection Sweden to Germany http://www05.abb.com/global/scot/scot245.nsf/veritydisplay/a74338323cd88e19c1256e36003ffd7a/$file/project%20baltic%20cable%20450%20kv%20mind%20subm-.pdf

[7] Cigre Paper B4-206 2010 New Zealand Bipolar HVDC Earth/Sea return operation-Environmental Experience

Multi-terminal systems are more difficult to realise using line commutated converters because reversals of power are effected by reversing the polarity of DC voltage, which affects all converters connected to the system. With VSCs, power reversal is achieved instead by reversing the direction of current, making parallel-connected multi-terminals systems much easier to control.

A simple arrangement of a three terminal (sometimes referred to as three ended) symmetrical monopole arrangement is shown in Figure 9.

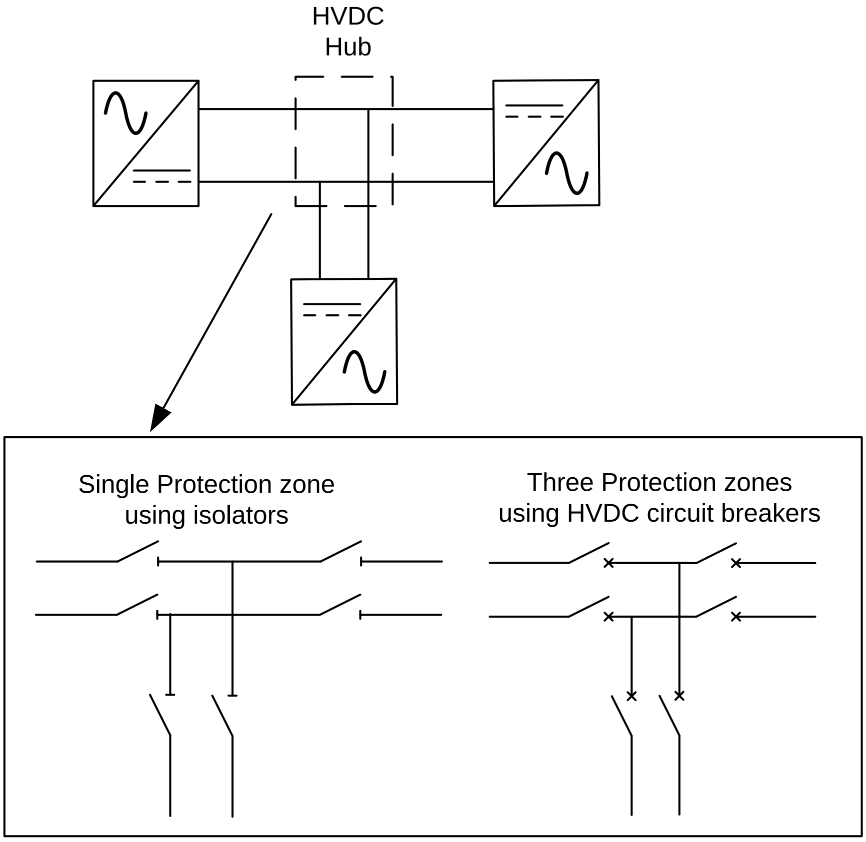

Figure 9 Three Terminal Symmetrical Monopole Scheme

Additional terminals can of course be added, with additional layers of complexity and requirements for added functionality to increase flexibility and improve reliability. For example with a single "protection zone" a multi-terminal scheme would likely result in the loss of all converter connections in the event of a single DC fault to ground. A scheme which employs multiple protection zones, would allow only the section with the fault to be isolated and allow the remaining converters and cables to continue in operation. In order to achieve this however, HVDC circuit breakers (see Section 3.4.2) would need to be utilised at the HVDC hub.

An example of a single protection zone scheme and a multiple protection zone scheme are shown below in Figure 10 for a three-terminal HVDC project during a fault on one of the cables.

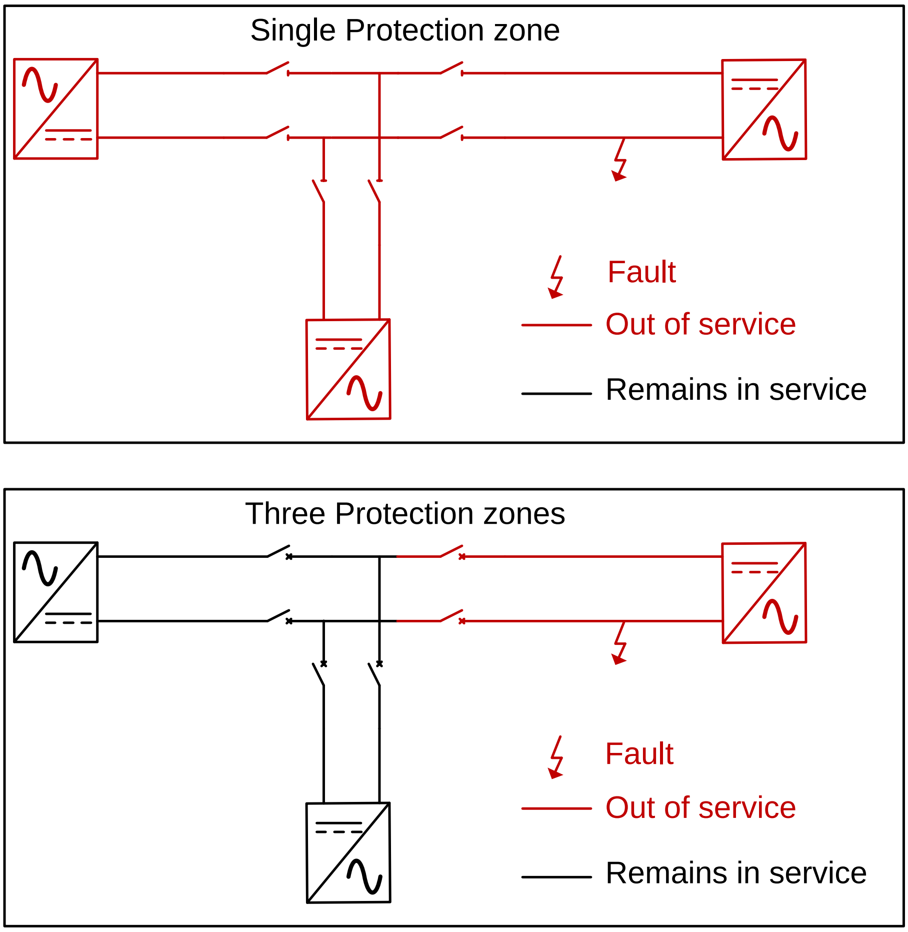

Figure 10 - Single Protection Zone and Three Protection Zone Arrangements During Fault Conditions

It can be seen in Figure 10 that the multi-zone (three) protection scheme reduces to the total capacity lost when clearing the fault which increases the overall availability of the project. For a three terminal scheme a single protection zone may be sufficient providing the total loss of capacity does not exceed the limits outlined in the Security and Quality of Supply Standards (SQSS). However for a scheme with four or more terminals, the total capacity lost when clearing a fault may exceed the SQSS limit, and therefore a multiple zone protection scheme would be required. The increased availability obtained from a multiple zone protection scheme would also be a significant advantage for a scheme with four or more terminals.

3.4. Introduction of Other VSC Converter Related Technology Issues

A brief introduction is provided here of some of the issues which face the application of VSC technology across a range of system and project requirements. This discussion is not intended to be a complete consideration of the issues.

3.4.1. Network Integration

A number of issues need to be considered when applying a VSC system and there are some particular issues associated with successful integration with the associated HVAC networks. Some particular issues are highlighted here, but this is not intended as an exhaustive list.

3.4.1.1. System Dynamic Performance

During faults in the onshore HVAC receiving system leading to loss of power transfer capability by the HVDC link associated with an offshore wind farm connection, there could be a risk of build up of DC voltage levels beyond what the equipment can withstand. Switching off the converters, causing a full load rejection on all Wind Turbine Generator (WTG) population in service at that point in time would take several seconds to be controlled by the WTG control scheme.

Switching off of all WTG converters should also only be used as a last resort in the case where the power transmission system would not need to recover for example in the case of a major cable fault.

There are cases when the converter is isolated from the last power line feeding the converter station, and thereby preventing power to be evacuated to the power grid. If a fault occurs within the receiving substation bus differential protection zone, for example, or if an outgoing line is tripped at the receiving station and a circuit breaker gets stuck clearing the busbar through all the “next in line” circuit breakers, a forced isolation of the converters may occur.

There is very little to be done in such a case to avoid full load rejection.

For most of the cases when remote faults occur, the converter station should not trip, and should allow the WTG to remain on line to attempt a full system recovery when the fault is cleared by protective action in the grid. The HVDC system must therefore be capable of dealing with such scenarios

Detailed engineering studies must be conducted to identify the detailed operating conditions during steady state, as well as all the dynamic performance expected from the transmission system.

Therefore in spite of the fault, the VSC converters must continue operation and be provided with fault ride through capability, hence in a controlled fashion continue to transfer energy from the OWF to the Grid. For the cases when an excess of energy causes the DC voltage to increase above a prescribed level, dynamic braking resistors can be employed to dissipate a pre-calculated amount of energy within certain time duration. The value of the resistor, the energy to be dissipated, the time in which this has to occur and the duty cycle the process might follow, are all determined in the detailed engineering studies made by the HVDC system vendors.

Such resistors can be integrated into a special converter valve design or it can be a separate device activated by power electronics. Alternatively the braking resistor functionality could be provided by the capability integrated within each individual wind turbine power conversion system.

The final design choice as to whether to have integrated or standalone dynamic braking resistors would be made by each of the HVDC manufacturers.

Options also exist for converter designs with inherent fault blocking capability which may be applied in the future.

3.4.1.2. Protection

In addition to the protection requirements associated with the VSC system itself there is a need to consider the impact of the HVDC system on the existing network protection system.

Compared with traditional HVAC transmission systems, HVDC transmission systems exhibit different electrical characteristics, and HVDC systems do affect adjacent HVAC systems.

In steady state, the DC system can be regarded as a constant power source or constant current source. Whilst filters can successfully limit harmonics during steady state conditions, under transient conditions additional input hardware and software filtering and additional signal processing methods may be required to ensure correct operation of the AC protection system.

Fault current in-feed to the HVAC system by the HVDC system is limited by the HVDC control system, while fast response of control & protection system and converter makes the fault phenomena different from the HVAC system and brings about challenges to AC protection.

In some cases, the HVDC system may bring about different fault characteristics in the HVAC systems, influence the operation of HVAC protection or even cause mal-operation.

Hence when an HVDC scheme is installed, it is necessary that a careful review of protection philosophies and settings in the nearby connected AC networks be made to determine possible adverse affects/risks of mal-operation due to the influence of the DC scheme during steady state and transient conditions.

Coordination of AC breaker trip signals is likely to be required and inter-tripping schemes may need to be implemented in order to ensure that where necessary AC trip signals are delayed or tripping times are faster, where required. Further information of the issues arising can be found in the literature[8]

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[8] Cigre Brochure 484, Impact of HVDC Stations on Protection of AC Systems. JWG B5/B4.25

3.4.1.3. Harmonics

One of the advantages of a VSC HVDC system compared to an LCC system is that the switching process generates less harmonic content, particularly for multi-level converters. However the level of harmonics still needs consideration.

Earlier 2 level and 3 level converters may certainly have needed harmonic filters whilst the more recently introduced multilevel converters produce a voltage waveform much more closely matched with the desired sine wave with vendors claiming that AC filters are not normally necessary for such schemes.

Any HVAC harmonic component of the HVDC voltage will result in HVAC harmonic current flow in the DC circuit and the field generated by this HVAC harmonic current flow can link with adjacent conductors and induce harmonic current flow in these other circuits. For cable connected systems these harmonics tend to be minimal but on OHL systems it is more likely to be necessary to provide HVDC filters to limit the amount of harmonic current.

HVDC capacitors also provide an energy buffer during transient conditions.

The more significant the harmonic content or the need for minimisation of harmonic ripple then the larger the HVDC capacitor required. However a larger capacitor will generate larger currents and also have potential impacts on HVDC system control. Hence the choice of DC filter capacitors is a balance of a number of project specific factors.

Harmonics can also be generated on the HVAC system therefore HVAC filters may be required on the HVAC side in order to remove any harmonics and to ensure that the resulting HVAC waveform is acceptable before it is fed in to the grid.

A number of harmonic and resonance problems have been experienced with some LCC HVDC systems[9], although other systems[10] have been successfully demonstrated to not contribute appreciable levels of harmonics following detailed studies and subsequent measurement.

Additionally harmonics can cause issues with Power Line Carrier systems or telephone circuits if the converter can generate harmonics and adequate filtering systems are not fully implemented.

3.4.2. HVDC Circuit Breakers

As offshore wind developments increase, and with the associated increase in HVDC circuits, the development of interconnected and meshed HVDC networks will become more viable.

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[9] Cigre Brochure 184 Cross-modulation of Harmonics in HVDC Schemes
[10] CIGRÉ 1996 : 36-302 Penetration of Harmonics from the Baltic Cable HVDC Station into the Feeding AC System

For Round 1 and Round 2 wind farms the capacities, distances to shore and distances between adjacent existing OWF meant that HVAC radial connections were the only economically viable option with each individual wind farm connecting to a specific onshore HVAC substation. As wind farm capacities and distances to shore increase, it is expected that HVDC connections will provide the majority of new connections. Development zones with capacities of up to 9 GW will require multiple HVDC converter stations. The complete loss of a converter or HVDC circuit will have a significant effect on the output of the wind farm and the option of interconnecting converters within a zone using HVDC technology could become cost effective.

Multi-terminal operation requires sophisticated control systems to balance converter current. In offshore wind applications this is further complicated by the intermittent nature of the generation output. To implement any multi-terminal HVDC scheme it will be necessary to install sufficient HVDC switchgear and current breaking capability at each converter position to allow the various configurations to be achieved and to protect healthy equipment during fault conditions. The interrupting requirements of HVDC switchgear or converters are much more onerous than conventional HVAC switchgear. This is due to the lack of a current zero and the very rapid overcurrent build up (due to the intrinsic nature of the HVDC side power circuit), therefore fast operating times are required. Considering the large capacities of future offshore wind farms, the safe and reliable operation of these power connections would be essential and therefore it is important to add the considerations of multi-terminal configurations to the reliability analysis.

Whilst DC switchgear is available, DC circuit breakers at the voltages required for large OWF with enough breaking capability are not available. Hence DC circuit breakers or alternative schemes will be required to allow the application of HVDC multi-terminal arrangements.

3.4.3. LCC-VSC Integration

LCC and VSC technologies have their advantages and disadvantages in the application of HVDC conversion. Hence there is a need to consider the potential arrangement of the LCC-VSC HVDC link, which essentially employs LCC technology on one end of the transmission system and VSC technology on the other end.

Fundamentally the limiting problem with such a link is in the LCC inverter when there are VSC converters also connected, for example in a multi-terminal configuration. Potential issues arise 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 firstly requires the valves be rated to pass this higher current. 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 consequences arise from having LCC inverters operating with VSC converters on the same DC circuit. However, if the LCC converters are only rectifiers, then this could operate satisfactorily with appropriate engineering design. 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.

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 a potential LCC wind farm connection that can provide electricity to the WTG under no wind conditions must have its thyristor valves designed to operate at a low HVDC voltage and with sufficient continuous HVDC current to provide the necessary no-wind reverse power. This results in increased conduction losses because the HVDC 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.

As described in the previous sections there are fundamental problems that would need to be addressed for VSC and LCC technology to be used in a hybrid arrangement. A functional hybrid scheme requires the following conditions to be satisfied:

1) An AC supply derived from the main onshore system needs to be available to any LCC converters for black-start purposes. This supply can be via VSC converters if required (e.g. Onshore AC supply → VSC rectifier → VSC inverter → AC connection → LCC converter is an acceptable black-start arrangement)
2) An LCC cannot be used as an inverter if a VSC is used as a rectifier

Further details of the possible integration of VSC and LCC systems are shown in Appendix C.

3.5. Cable Technology

Cables are a vital part of any offshore power network. As HVDC converter capabilities are also closely linked to developments in cable technologies it is necessary to provide details of cable technologies within any review of VSC HVDC systems.

3.5.1. Application and Description of HVDC Cables

Whilst the fundamental technology utilised on onshore and submarine applications is the same, offshore HVDC cables have different physical and installation constraints compared to onshore cables. The mechanical protection and water blocking requirements for onshore cables are less onerous meaning that the overall diameter of the cable for a given conductor size can be reduced. Onshore cables can be installed in single core groups with greater ease than in offshore environments and can be constructed for use at higher voltages and with greater conductor cross sections. The greater choice in conductor size means that aluminium conductors can sometimes become the more economical choice than copper. As well as different mechanical properties of the conductor material the choice also depends on the relative prices of copper and aluminium at the time of purchasing which would be compared with the capitalised value of losses, which are increased in aluminium cable designs due to increased resistivity.

The main issues associated with onshore cables are those concerning installation and the limitation of the longest length of section of cable that can be transported compared to an offshore environment. Typically 7000 Tonnes of cable, representing up to 80 km, can be produced in the factory and laid as a single length offshore, limited by the size of vessel available. For onshore the maximum length of cable will typically be (due to onshore transport limitations) 1 km, therefore many more joints will be required onshore compared to offshore.

For both onshore and offshore applications the careful selection of the cable route is required and crossing of obstacles such as pipelines and other utilities is necessary both onshore and offshore, albeit with different techniques and approaches.

Consideration of magnetic fields produced from HVDC cables is required when determining the laying of cables both onshore and offshore. HVDC cables are often bundled to reduce resultant magnetic fields, the cable configuration can however have a significant impact on the consequences of external cable damage due to ships anchors, diggers etc. where multiple cables could be damaged if laid in close proximity. Cable protection measures are important factors to consider.

The magnetic fields produced by HVDC cables are dependent on the physical arrangement of the cables but are normally less than the strength of the earth's magnetic field and generally less than a HVAC cable with an equivalent rating. These levels are accepted by the ICNIRP (International Commission on Non-Ionizing Radiation Protection) as safe for humans and animals[11]. The magnetic field produced by the cables does however add to the earth's magnetic field, thereby potentially interfering with compasses. By laying cables close together, the magnetic field can be reduced further but will also de-rate the cable due to mutual heating and increase the risk of simultaneous damage. The magnetic field of DC cables has little effect on third-party structures such as pipelines unless an earth return system utilising ground electrodes is applied. In this case additional protection measures are required.

3.5.2. State of the Art Cable Technology

The two main submarine cable insulation types are Mass Impregnated Non-Draining (MIND) and Cross Linked Polyethylene (XLPE) also referred to as extruded. MIND refers to cable insulation based on layers of paper impregnated with non-draining impregnating fluid as the dielectric. XLPE refers to cable insulation based on extruded polyethylene as the dielectric. XLPE is increasingly becoming the insulation technology of choice given its lower cost compared to that of the same rated MIND cable. Present limitations of XLPE are a reduced maximum operating voltage

[11] http://www.icnirp.de/documents/emfgdl.pdf

compared to MIND cable which results in a lower potential power transfer; however technology advancements are ongoing to increase the operating voltage of XLPE cables.

The choice of cable and technology for an offshore wind farm or interconnector project will depend, in addition to economic aspects, largely on the total connection distance (offshore plus onshore) of the project and the capacity of the wind farm connection. In DC cables there is no reactive current component and therefore cables are not theoretically limited by length. Also only the two high voltage poles need to be provided, as opposed to the three phases for an AC system with full voltage insulation. Moreover for a symmetric monopole there is no need for a current return path. It follows that as cable length and capacity increases there will be a tipping point where HVDC is more economical to install than HVAC as the additional cable costs for AC cables matches the additional cost for the power electronics in the terminal converters also taking into account losses and system availability. In subsea installations this is usually at shorter distances than for onshore applications as the maximum practical voltage that can be installed for offshore AC cables is lower than for onshore AC cables (primarily restricted by the requirement for 3-core cables offshore and the limitation on conductor size this represents). Submarine cables can also be laid more easily in continuous lengths offshore without laying joints as transport weight is less of a limiting factor.

Extensive use has been made of 132kV 3-core submarine cables using XLPE technology, including on many offshore wind farms in the UK, Submarine 3-core cables at 220kV are also now being applied and designs exist for 275kV. The issue for the higher voltage ratings becomes in the handling and laying of such a large cable. As HVAC cable rating increase the capability to provide longer HVAC connection distances has become more feasible. The longest 220kV HVAC connection presently under construction[12] being that between Malta and Sicily at approximately 120 km of which some 95 km being submarine cable.

As technologies, particularly HVAC and HVDC subsea cabling and VSC-HVDC converters continue to develop over the next decade, increased capacities and voltages may become available which may further change the preferred architecture selection.

Table 5 below shows the maximum cable ratings presently available, also noting the maximum operating current. Suppliers offer a range of cables and intermediate values are available.

[12]http://www.nexans.co.uk/eservice/UK-en_GB/navigatepub_0_-28532/Nexans_wins_contract_for_the_Malta_to_Sicily_power.html

▪ **Table 5 - Maximum cable ratings for HVAC and HVDC technology**

Cable Type	Operating Voltage	Maximum Submarine Cross-Sectional Area (mm^2)	Distance (km)	Rating (A)	Capacity (MVA)	Project Experience
HVDC MIND	±600kV DC	2500	420	1667	2200 (bipole)	Being supplied on the Western Interconnector project. Currently employed (Max. ±500kV – SAPEI Italy to Sardinia, Neptune and Feno-Skan 2)
HVDC XLPE	±320kV DC	2400	400	1407	900 (bipole)	Currently employed (Max. ±200kV – East West Interconnector)
HVAC XLPE	132kV AC	1000		825	188 (3-phase)	Employed in a number of existing offshore wind farm connections
HVAC XLPE	220kV AC	1000	120	825	314 (3-phase)	Malta-Sicily Interconnector (2013)
			81		400 (3-phase)	Arnholt Windfarm in Denmark in 2012
HVAC PPLP	275kV	1000	11	825	550 (1-phase)	Hong Kong – Lamma Island

Present state of the art mass impregnated (MIND) DC cables operate at up to ±500 kV with the capacity to deliver approximately 1000 MW per pole[13] and with developments focused 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. A typical example of MIND cable is shown in Figure 12. New developments in laminates that sandwich a polymer film between paper layers, termed Polypropylene Laminate Paper (PPLP)[14]. PPLP cable applications are well-known among South East Asian countries and have become a de facto standard in the field of underground transmission cables. A ±500 kV DC submarine cable utilising PPLP technology was installed in Japan in 1999 with 800 kV AC cable demonstrated in Canada in 1990 as part of trials[15]. In conjunction with new, more viscous impregnates it is possible for PPLP to achieve some significant advantages over conventional MIND cable constructions in terms of:

- 25% increase in cable manufacturing batch length due to impregnation improvements

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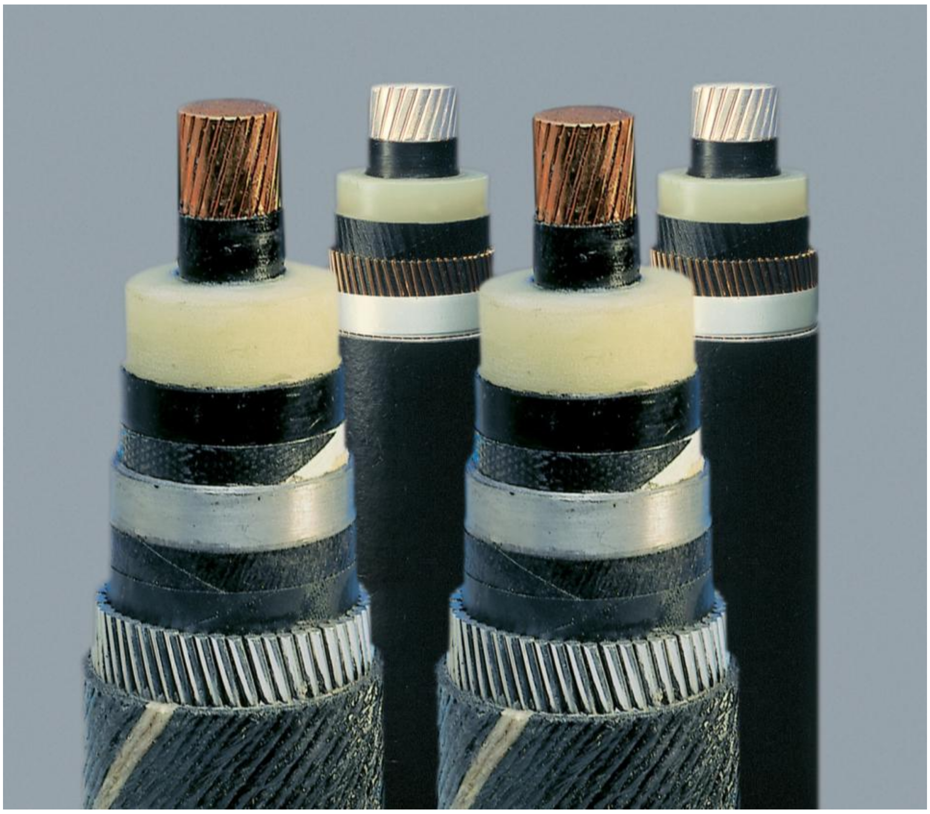
[13] ABB High Voltage Cable Systems
[14] "Solid DC Submarine Cable Insulated with Polypropylene Laminated Paper (PPLP)" http://www.globalsei.com/tr/pdf/energy/62-01.pdf
[15] R.Hata, "Solid DC Submarine Cable Insulated with Polypropylene Laminated Paper", SEI Technical Review, June 2006

- 25-50% increase in power transmission
- 70% conductor size and 90% of overall diameter for the same power rating as an Mass impregnated (MI) paper cable

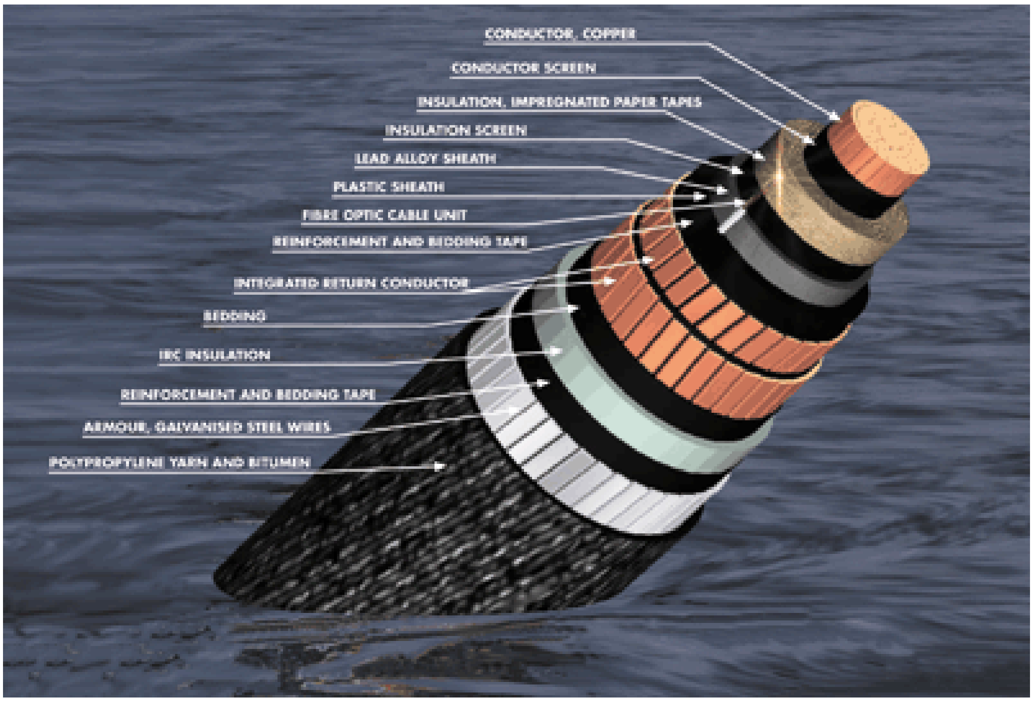
These improvements are seen as the PPLP cable can operate at a higher temperature, typically 80ºC as opposed to 50ºC of MIND cable, allowing higher power transfer for the equivalent size MIND cable, or reduced physical size for equivalent power rating. One example of this cable is the Western Interconnector link being supplied by Prysmian with a ±600 kV and 2200 MW rating, due for commissioning in late 2015.

Further work is also being done with discrete polyethylene tapes and polymer films to see if further reductions in insulation thicknesses are possible alongside research into new dielectric fluids which have improved viscosity and flow characteristics for HVDC systems to increase power transfers and or reduce physical sizes.



- **Figure 11 - ±320kV XLPE HVDC submarine and land cable courtesy: ABB**

The XLPE construction of HVDC cables is comparable to that of HVAC cables. The cable construction constitutes a number of elements; the conductor transports the electrical energy and is of copper or aluminium material to allow efficient power transfer; whilst the insulation is utilised to retain the electrical energy to the conductor only. The extruded plastic insulation is highly reliable and cost effective. Integrated or bundled optical fibre will generally be provided with the cable to provide a telecommunications link required for Supervisory Control and Data Acquisition (SCADA) functions. The inner packaging material is a soft polymer material such as polypropylene string or polyethylene. Armour is provided on subsea cables for mechanical protection and is generally constructed of galvanised steel wires helically wrapped. The outer sheath encloses the entire cable and is normally constructed of helically applied polypropylene yarn or a continuous polymer sheath such as polyethylene.



- **Figure 12 - ±500kV MIND HVDC Cable Courtesy: Nexans**

The construction of MIND cable is comparable to that of XLPE cable described above, with the main difference being the insulation medium. In XLPE cable the insulation is of an extruded plastic polymer, while MIND cable utilises paper tapes mass impregnated with a non draining impregnating compound as the insulation medium.

Installation and testing of MIND and XLPE cables has the same constraints and requirements although jointing of XLPE cables is more straightforward and requires less time, for onshore cable installation this can be a factor where significant numbers of joints may be required on some projects.

A high level comparison of cable technologies is provided in Table 6.

▪ **Table 6 - High Level Comparison of HVDC Cable Technologies**

MIND	XLPE
Can be applied to both VSC and LCC technologies	Not suitable for LCC schemes with polarity reversals
Service experience at up to 500kV, 600kV now being supplied	Service experience up to 200kV, 320kV now being supplied (excluding projects in Japan where 400kV is in service)
Suitable for onshore and submarine applications	Suitable for onshore and submarine applications
Cost depends on rating and situation in market supply	Cost depends on rating and situation in market supply but generally -20% compared to MIND

4. Methodology

The methodology adopted by SKM was to collate publically available information and in-house experience into a project specific database which was then verified with project developers, owners and vendors wherever possible.

To assist this process, questionnaires were developed and sent to project developers, owners and VSC vendors:

a) The first focussed on project installations and was sent to project developers, owners and vendors.
b) The second focussed on technology challenges and discussed directly with VSC vendors

All information was then verified, wherever possible, and reviewed by SKM before being included within the main body of this report as a high level summary supported by an Excel spreadsheet with project specific information. Details of project installation issues and specific vendor responses to questions were kept anonymous and have not been included in the report or the spreadsheet.

4.1. Project Survey

Each project developer, owner and VSC vendor was sent a version of the project database and questionnaire with the publically available data included for their own projects and questions relevant to their projects. The database is split into two sections. The first section includes basic project data and specific challenges associated with a project (e.g. a project being the first offshore VSC installed) will be made publically available.

Information included in the first section of the database includes:

- Converter ratings (MW)
- Voltages
- Cable/Overhead line parameters
- Converter topology (Bipole, symmetrical monopole etc)
- Cable and converter OEMs
- Project timescales (consenting, design, manufacturing, installation, commissioning, time in service)
- Achievements and challenges associated with the project

As much of the above data is available in the public domain, it was intended that such information will be published and this was made clear to the project developers.

The second part of the survey was the questionnaire which focused on project specific issues. The responses to the questionnaire were recognised as being commercially sensitive and therefore the responses received have not attributed to specific projects and have not been published. These have instead been used to inform SKM's view on the challenges associated with VSC projects as detailed in Section 6.

Questions were targeted to ensure they were relevant to each project and recipient, but in general the following areas were covered:

- Utility network integration issues
- Integration with offshore wind projects
- Consenting and planning issues
- Project programme adherence
- In service performance and vendor guarantees
- Multi-terminal schemes

The project questionnaire was sent to a total of 23 project developers/owners covering 36 projects.

4.2. Vendor Discussions

To enhance Section 6 of the report on specific technology challenges for VSC projects, SKM engaged with the major VSC vendors to validate SKM views and where appropriate ensure that the most up to date view on technology developments were included in the report to ensure a balanced assessment of VSC technology challenges.

5. Results - VSC Installation Data and Technology Challenges and Achievements

Data compiled has been collated into a project spreadsheet which contains high level details of each VSC HVDC project which has been installed, is under construction or those planned projects where details exist in the public domain together with specific project information provided by project owners and developers.

The information is contained in a separate Excel spreadsheet. A high level presentation of the spreadsheet information is shown in Table 7.

As can be seen a large number of VSC HVDC projects are either under construction, or in a stage of design, planning or consenting. Whilst some details of many of these projects are available in the public domain through project owner or developer websites, through the survey this knowledge base has been extended in terms of the number of projects as well as specific project detail. The cooperation of project owners and developers has been invaluable in this process.

The project questionnaire was sent to a total of 23 project developers/owners covering 36 projects. Responses were received from 11 project developers/owners encompassing 14 discrete projects, some of which involve multiple phases of VSC connections over significant project timescales. Questionnaire responses also led to the addition of 4 potential future projects which had not been previously identified. Hence a total of 40 projects have been included in the Project Database. Of these:

- 13 are in-service
- 10 under construction
- 17 in planning or consenting

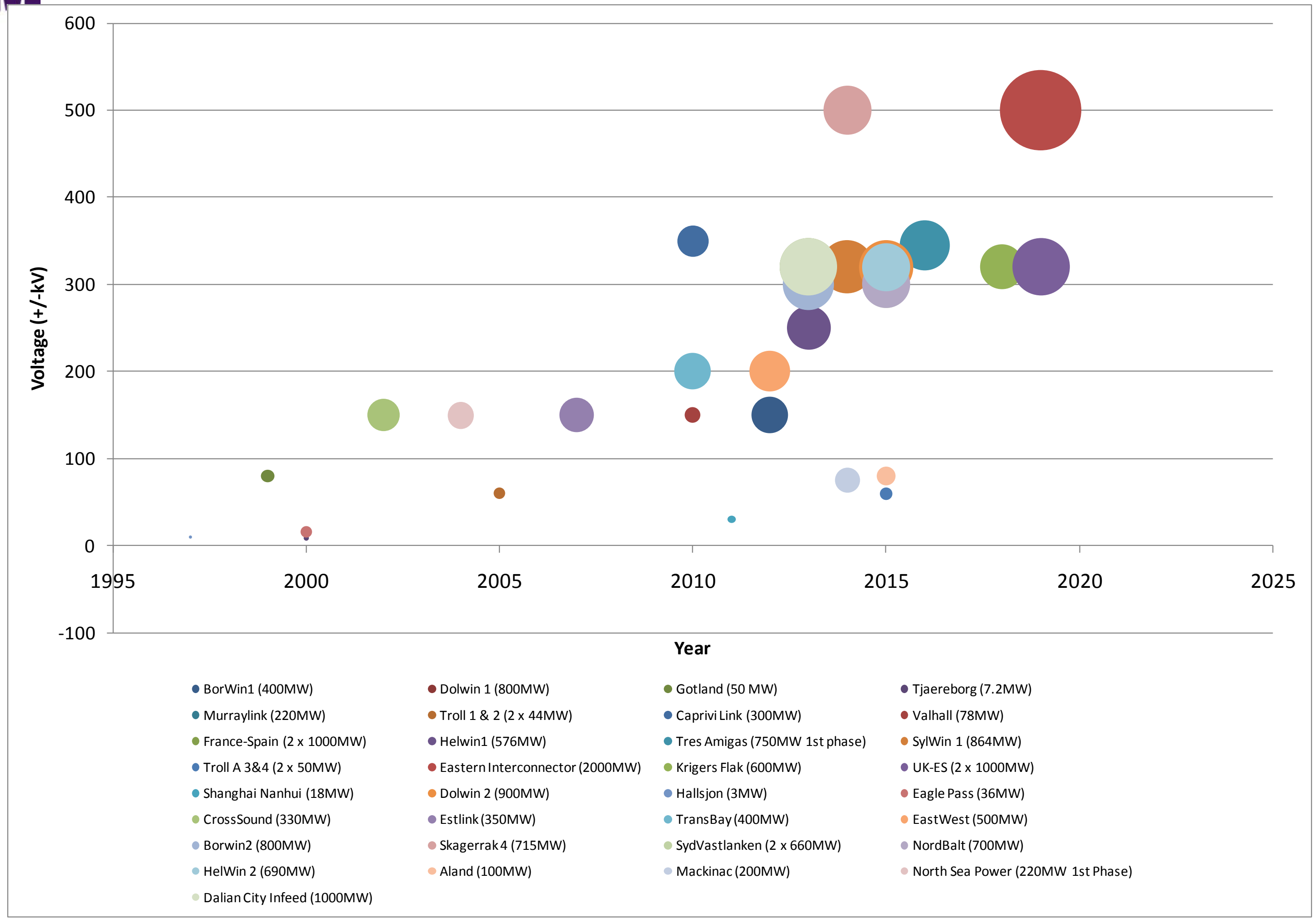
Figure 13 shows the projects identified but plotted on a Voltage Rating v Time scale, with the size of project in MW represented by the area of the circle.

This representation highlights some interesting features of the projects implemented and those planned.

- As would be expected, there is a progression in terms of project voltage and size
- A clustering of projects around converter size and rated voltage directly linked to the associated cable technology limit which currently is around 320 kV for XLPE systems.
- The responses highlight those projects which present a specific technology challenge e.g. Eastern Interconnector which might be up to 600 kV, the 2 GW, Skaggerak 4 with 500 kV and Caprivi being the first project above 300 kV

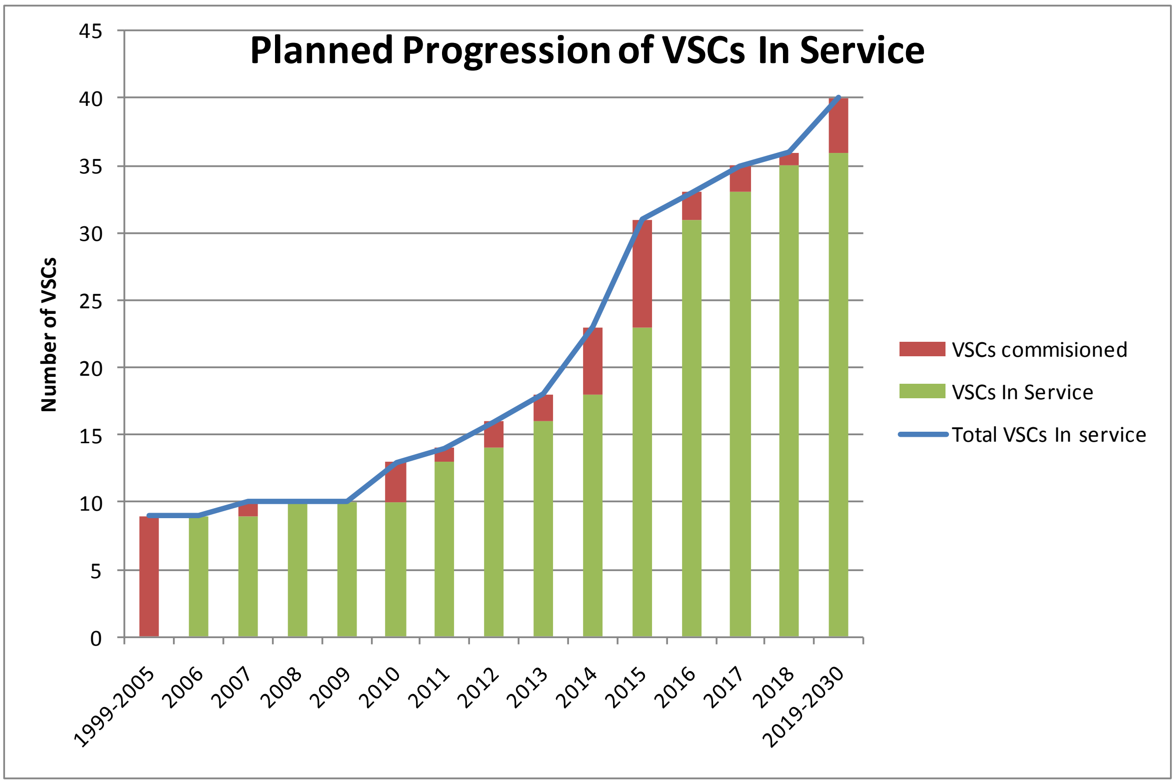
Table 7 High Level Summary of Project Spreadsheet

		Europe			North America			Asia			Australasia	Africa		
		In Service	Under Construction	Under Consideration Planning or Consent	In Service	Under Construction	Under Consideration Planning or Consent	In Service	Under Construction	Under Consideration Planning or Consent	In Service	In Service	Sub total by Application	Subtotal by Architecture
Point to Point DC	Offshore Wind	0	5	5	0	0	0	0	0	0	0	0	**10**	**36**
	Onshore Wind	0	0	0	0	0	0	1	0	0	0	0	**1**	
	Demonstration Project	2	0	0	0	0	0	0	0	0	0	0	**2**	
	National Interconnector	1	0	1	2	0	1	0	1	0	2	0	**8**	
	International Interconnector	1	3	3	1	1	0	0	0	0	0	1	**10**	
	Offshore Platform Supply	2	0	2	0	0	0	0	0	0	0	0	**4**	
	Offshore Wind / AC International Interconnector	0	0	1	0	0	0	0	0	0	0	0	**1**	
Multi terminal DC	National Interconnector	0	0	1	0	0	0	0	0	1	0	0	**2**	**4**
	Offshore Wind / National Interconnector	0	0	0	0	0	2	0	0	0	0	0	**2**	
	Regional Subtotal	**6**	**8**	**13**	**3**	**1**	**3**	**1**	**1**	**1**	**2**	**1**	**Total**	
	Regional Total	**27**			**7**			**3**					**40**	



- **Figure 13 Representation of Projects by Voltage/Capacity and Commissioning Year**

Figure 14 illustrates the planned progression of VSC projects based on the results from the survey with planned commissioning dates (the red bars indicate the number of projects commissioned in any given year). As might be expected beyond a 10 year timescale the progression of projects "flattens" as uncertainties increase on project specific detail. Nevertheless an impressive increase in the anticipated number of projects is shown.



- **Figure 14 Planned Progression of VSC Systems In Service**

The remainder of this section focuses on the technology challenges which have already been overcome, those issues which have arisen and the technology challenges which will need to be overcome for future projects. This commentary is based on responses received from project owners and developers as well as discussions with the main VSC technology suppliers.

5.1. Utility Network Integration Issues

The breadth of projects identified provides a wide range of network integration issues that have generally been addressed during the planning and design phases of projects. Examples of experience during planning, commissioning and operation can be found[16,17,18].

The complexity of network integration issues depends on the type of project and significantly the existing network conditions that prevail. For some projects the characteristics that VSC technology can bring are seen as solutions to system problems.

Issues associated with AC faults and dynamic performance seem to have been addressed as would be expected for any new system which is connected to the grid, whether AC or DC. Comprehensive design studies and subsequent review of aspects such as protection coordination and protection settings are undertaken as part of the application engineering process to ensure that problems are not encountered on site. Utilities seem to be relying on vendors as well as in-house expertise and consultants to assist in such studies.

Issues with harmonics have been encountered, even after studies, although the determination of reliable input data for such studies is an issue for both HVAC as well as HVDC schemes. In the event that issues arise with harmonics, technical solutions can be found relatively easily although the commercial and project timescale implications are much more problematic.

Interference with telephone communication systems due to harmonics has also been encountered[19]. Whilst such issues would be expected to be addressed during the design stage of a project, technically they are relatively easy to address after commissioning albeit with potential problems with project stakeholders and project delays.

Overall for straightforward point to point projects the network integration issues encountered on more recent projects do not seem to be significant.

Where more complex projects are being contemplated, involving multi-terminal arrangements then additional technical and regulatory issues arise.

Some projects will require the development of an energy management system that will be able to control power transfers between asynchronous grids. Defining the control system may be

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[16] Cigre Paper B4-102 2004. Cross Sound Cable Project Second Generation VSC Technology for HVDC
[17] Cigre Paper 14-108 2002. The Directlink VSC-Based HVDC Project and its Commissioning
[18] Cigre Paper B4-203 2010. HVDC VSC (HVDC light) transmission – operating experiences
[19] http://www.eirgrid.com/media/Media%20Statement%20-%20East%20West%20Interconnector.pdf (East West Interconnector)

complicated by the evolution occurring within energy markets and the need to adapt to changing situations[20].

In many areas there will be a need to not only integrate the VSC system with the AC network but also into areas of the network where existing LCC HVDC systems exist. Here coordination will be required during the design, commissioning and operating phases, which adds complexity if the neighbouring systems are operated by different grid operators[21]. Solutions are available and indeed ramp rates of the VSCs can be set to prevent abnormal interactions with the existing LCC systems for those projects where this condition exists.

5.2. Integration with Offshore Wind Projects

For cases where there are WTG (Wind Turbine Generators) connected nearby to the same AC system where a VSC HVDC system is to be installed, the issues associated with potential interaction seem to be well recognised and are being addressed through design studies[22].

Simulation also typically includes a frequency dependent representation of the AC system in the design of the interconnected system, to predict and mitigate mechanical oscillations within the WTG excited from the grid connection.

Perhaps the most significant issue being addressed when considering the implementation of VSC HVDC projects with the connection of offshore wind is the need to provide the VSC converters with the capability to continue operation and be provided with fault ride through capability in the event of AC system faults.

For most of the cases when remote faults occur, the converter station should not trip, and allow the WTGs to remain on line to attempt a full system recovery when the fault is cleared by protective action in the grid, the HVDC system must therefore be capable of dealing with such scenarios

Detailed engineering studies must be conducted to identify the detailed operating conditions during steady state, as well as all the dynamic performance expected from the transmission system.

Therefore in spite of the fault, the VSC converters must continue operation and be provided with fault ride through capability, hence in a controlled fashion continue to transfer energy from the OWF to the Grid. For the cases when an excess of energy causes the DC voltage to increase above a prescribed level a means of dissipating the energy from the WTG needs to be found and on projects where connections to offshore WTGs have been implemented such schemes have

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[20] "The Tres Amigas Superstation - Uniting The Nation's Electric Power Grid" – D. Stidham - EPRI HVDC & FACTS Conference, Palo Alto - August 2011
[21] Cigre Paper B4-309 2012 "Tres Amigas : A flexible gateway for renewable energy exchange between the three asynchronous AC networks in the USA"
[22] Cigre Paper B4-306 2012 "Projects BorWin2 and HelWin1 – Large Scale Multilevel Voltage-Sourced Converter Technology for Bundling of Offshore Windpower"

already been applied and are being applied on current projects where a straightforward point to point connection is made.

On some projects the dissipation “braking” or “chopper” resistors are realised[19] in a modular design for which each power module is combined with an individual braking resistor.

In another arrangement[23,24] the braking resistor is a lumped component, located onshore, but outside of the converter building to assist in the thermal rating of the device.

For projects with parallel combinations of HVDC and HVAC connections offshore then further challenges may arise due to potential cascade failures of the HVDC connections in the event of the loss of one connection.

There are also specific concerns regarding reliable operation of power electronic driven wind generators in weak AC networks. These concerns include fast dynamic response of wind generator converter systems following system disturbances, and interactions between wind generator converter systems and any other power electronic driven network assets (e.g. HVDC links and FACTS devices) in the vicinity. The wind farms connected through or in the vicinity of series compensated transmission lines or HVDC lines may also be vulnerable to sub synchronous oscillations. Hence wind farm developers are looking for either classical (e.g. synchronous condenser) or FACTS based solutions for addressing expected operational issues.

Cigre is setting up a Working Group B4-62, to look at the specific issue of connection of wind farms to weak AC networks.

In terms of actual projects VSC connections to wind farms Borwin 1[25] has been operational since autumn 2012 and several other projects are currently under construction.

5.3. Consenting and Planning Issues

There are three issues that arise when considering the issues surrounding the consenting and planning process.

The first is the general level of uncertainty across all projects in virtually all countries associated with planning and consenting. Project developers find it difficult to have confidence that a project which is approached using best practice will still achieve a timely and predictable outcome. Of course some risk is inherent in the nature of a fully engaged consultation process, nevertheless the level of uncertainty is a significant issue.

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23 http://www02.abb.com/global/seabb/seabb364.nsf/0/564e6d7557570255c12575e70040fbac/$file/ABB+Review+03_2008_72dpi.pdf

24 http://www.taplondon.co.uk/bwea31/files/peterjones.pdf

25 http://www.abb.co.uk/industries/ap/db0003db004333/a8e328849ac67b66c125774a00243367.aspx

The second issue, which is discussed more in the UK than in some other countries, is that of uncertainty surrounding project viability given uncertainties with the market framework for the justification of projects linked to connection of renewables or international interconnections. Such uncertainties cover not only the direct financial implications of subsidies and incentives but also the structure of the regulatory regime and the impact this has on the market need, not only the projects themselves, but also the technologies that these projects need to encompass.

The third aspect is where planning and consenting delays cause significant disruption to project delivery. This can be during the early stages of a project, prior to construction, but can also arise during construction, perhaps due to the need to change cable installation technique or an unforeseen situation. Such delays can have severe financial implications due to onshore grid congestion costs as well as project specific cost implications.

5.4. Project Programme Adherence

Determination of the specific reasons for project delays and the absolute extent to which projects have been delayed is extremely difficult.

Invariably commercial considerations colour any such discussion and given that several different contract models have been used on VSC projects, this makes analysis of the issues and reasons even more difficult. However, what can be determined is that some VSC projects have and are continuing to suffer from project delays. Typical reasons seem to include:

- Delays in planning and consenting. Such delays can be significant, months and even years.
- Regulatory delays.
- Supply chain availability. Cable supply being a particular concern, although here the type of cable and timing of the contract is critical in determining project lead times which may be outside those anticipated.
- Lack of standards e.g. system voltage.
- Health and Safety when operating in harsh environments has led to fatalities which inevitably have a knock on delay on project timescales.
- Manufacturing delays are always possible. For very long HVDC cables these can perhaps be the most problematic although any activity involving offshore platforms is also a sensitive area.
- Right of Way negotiations
- Labour disputes, manpower
- Resource availability
- Environmental impact studies and assessment, political/social acceptance,
- Non Governmental Organisation opposition

- Installation delays. Experience with some recent cable installation projects has not been good; delays due to errors and insufficient weather contingencies can be significant.

It is noted that the first offshore wind connections being delivered in Germany suffered significant delays; more recent projects appear to have an improved level of project programme adherence. Specific delays have been reported associated with a multi-stage approvals process and absence of standards for HVDC converter platforms[26].

In the UK the first and, to date, only HVDC VSC project completed is the East West Interconnector. Delays have been well reported including the late deferral of the commercial go-live date due to telephone noise interference discovered during acceptance testing.

5.5. In-service Performance and Vendor Guarantees

Feedback received suggests that on contracts placed to date vendors have been able to provide demonstration/commitment of acceptable levels of module performance and VSC availability such that these can be used as the basis for contractual arrangements with the project developer. Whilst the adherence to guaranteed levels of scheduled outages and connection availability has yet to be determined it seems that there is a recognition that guaranteed levels of availability need to be provided and a commitment from vendors to take steps during the system design to enable these levels to be achieved.

The practical aspects of providing appropriate response teams for repair and maintenance will depend on the project details as will the provision of spare parts.

The experience of vendors and utilities on LCC HVDC connections will of course be used as a starting point on many projects.

Whilst some developers refer to Cigre and other published reliability data it appears that many developers rely on their own assessments of reliability supplemented by industry wide surveys. This is not unsurprising given the significance of availability analysis in determining project viability.

5.6. Multi-terminal Schemes

There are currently no full scale VSC multi-terminal schemes in service, although there are a small number of schemes under construction and planning including the South West project in Sweden[27] and Tres Amigas in the USA[28].

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[26] Modern Power Systems - December 2012
[27] http://www.svk.se/Start/English/Projects/Project/The-South-West-Link/
[28] http://www.tresamigasllc.com/

Multi-terminal operation requires sophisticated control systems to balance converter current. In offshore wind applications this is further complicated by the intermittent nature of the generation output.

Multi-terminal schemes with a single protection zone such as for the three terminal schemes under construction can be delivered with available technologies, whilst for those that require multiple protection zones it will be necessary to install sufficient DC switchgear and current breaking capability at each converter position to allow the various configurations to be achieved and to protect healthy equipment during fault conditions.

The interrupting requirements of DC circuit breakers or converters are much more onerous than conventional AC switchgear. This is due to the lack of a current zero and the very rapid overcurrent build up in the DC side power circuit. Therefore fast operating times required. Considering the large capacities of offshore wind farms, the safe and reliable operation of these power connections would be essential and therefore it is important to add the considerations of multi-terminal configurations in the reliability analysis.

At the moment the multi-terminal schemes being constructed or with specific plans are single protection zone schemes and so do not require HVDC circuit breakers and therefore vendors are proving prototypes and technologies in anticipation of a future market requirement rather than satisfying a definite market need.

Furthermore there are suggestions to use autonomous converter control based on droop-control relying on its capability of removing its contribution to DC fault currents to integrate into multi-terminal schemes without the need of DC breakers.

Whilst there are possibilities that some of the potential multi-terminal schemes planned could be considered for multiple vendor schemes (different vendors supplying converters) this approach has not been implemented on any of the VSC projects currently planned. However the approach has been applied previously on LCC schemes and could be applied on VSC schemes if the potential benefits were considered by a project developer to offer overall advantages.

Of course at the moment there are no specific plans identified to establish an international HVDC grid, if such a plan existed then the need for incorporation of multiple vendors would be a definite requirement.

6. SKM View on VSC Technology Challenges and Future Project Risks

The SKM view is provided here on the risks associated with technology challenges for the future and the claims made by vendors concerning technology readiness.

To enhance this section of the report on specific technology challenges for VSC projects, SKM engaged with the major VSC vendors to validate SKM views and where appropriate ensure that the most up to date view on technology developments were included in the report to ensure a balanced assessment of VSC technology challenges. All of the main VSC vendors assisted the review by responding to particular technical questions. Their response is appreciated given that the technology vendors are responding to the market requirements on the large number of projects which are being considered at the moment. Hopefully this report will assist in the process of introduction of the technology by addressing some of the concerns which are inevitable when introducing technologies which are less familiar than that which has seen relatively little change over several decades.

6.1. Utility Network Integration Issues

The application of VSC technology will, in some cases, be made on the basis of a decision between LCC and VSC technology (where HVDC is definitely required) and sometimes as an alternative to HVAC (where either HVDC or HVAC could be used).

The features and benefits of LCC and VSC technology are summarised in Table 8.

- **Table 8 Summary Comparison of Features for VSC and LCC for Typical Offshore Wind Application**

Feature	LCC-HVDC	VSC-HVDC
Type of network connection (active or passive)	LCCs require active network connection	VSCs can operate in passive networks with an independent clock to control firing pulses to the VSC valves, which also defines the AC frequency
Network strength	LCCs require a typical AC network with a short circuit ratio (SCR) of >3	VSCs 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
Provision of voltage control	LCCs cannot provide AC voltage control	VSCs can provide substantial AC voltage control at the AC interconnection busbars, even black start capability
Power flow reversal	LCC achieves reverse power flow though polarity reversal therefore	VSCs achieve reverse power flow by changing current direction

Feature	LCC-HVDC	VSC-HVDC
	cables must be capable of withstanding increased dielectric stresses.	therefore can use lighter, solid insulated extruded DC cables which enables the effective use of undersea and underground cable transmission as polarity reversal not required.
Ability for multi-terminal schemes	Multi-terminal schemes require more complicated control schemes as power flow reversal is achieved through change of polarity, thus impacting on all connected converters.	VSCs are considered more appropriate for multi-terminal schemes as power flow reversal is achieved by changing current direction.
Susceptibility to commutation failures	AC system faults lead to commutation failures	VSC valves are self-commutating and commutation failures due to AC system fault or AC voltage disturbances do not occur
Minimum DC current levels	LCC transmission has minimum DC current limits which would be a problem during periods of minimal wind generation.	VSCs Transmission has no minimum DC current limits
Capability to provide reactive power support	LCC schemes require separate reactive power control	VSCs can control reactive power, either capacitive or inductive, independently of the active power within the rating of the equipment
Harmonic interference	Extensive harmonic filters required leading to a larger converter station footprint.	Only minimal harmonic filters are needed
Design of converter transformers	Converter transformers need to be able to withstand DC stresses.	Transformers do not have to be specially-designed HVDC converter transformers, but conventional ac transformers may be used
Level of converter power losses	Converter losses typically 0.7%.	Converter losses higher, typically 1.2 to 1.4% although expected to reduce to 1% over the next 5 to 10 years.
Cost of technology	Lower cost per installed MW.	As a guide, currently onshore VSC converters might be approximately 25% more expensive than LCC of an equivalent rating

There is a view that as VSC technology develops, and the size of converters increase and the losses decrease, that VSC will dominate the market, given the significant benefits that VSC can deliver to the AC network. The capability to deliver reactive power can be an extremely attractive feature on many networks and the “STATCOM for free” can more than offset some of the potential issues that have to be overcome or even justify a premium compared to the price of an LCC system.

Of course the assessment of options on any specific project leading to the selection of LCTA needs to not only consider technology but also commercial models which might include the provision of guaranteed connection availability with an associated service payment compared to a more conventional Capex + Opex model.

It is the view of SKM that the number of projects where there will be a direct choice between HVAC or HVDC technology will be extremely limited. The tipping point between HVAC and HVDC technology is well understood and when the considerations are applied to potential projects, such as those identified in the survey, then the number that could be achieved using HVAC in the UK is very small. Of course this is based on the present regulatory framework which favours point to point connections, where the tipping point concept is valid. In a framework where projects are linked together, then a series of shorter interconnected AC connections might be advantageous.

Therefore under the present circumstances the choice becomes not one of HVAC or HVDC but which type of HVDC. Hence comparison of the differences in integration between HVAC and HVDC is useful, but does not become a determining factor.

Integration of any HVDC system onto an existing AC network requires significant studies to be undertaken with consideration given to factors such as

- Levels of harmonics
- Dynamic stability
- Protection grading
- Sub Synchronous Resonance
- Energy management
- System recovery (after an extended blackout)

Whilst some of these will add complexity and cost to the implementation of the scheme, or indeed modifications to the HVAC network, these appear to be well understood with no significant technology challenges remaining, for straightforward point to point systems.

6.2. Integration with Offshore Wind Projects

Solutions to provide VSC converters the capability to continue operation and be provided with fault ride through capability in the event of AC system faults have already been delivered on projects where a point to point connection is provided such as Borwin 1[29] in Germany.

Existing solutions consist of a separate resistor device which is activated by a power electronic switch. Other solutions could be integrated into a special converter valve design or alternatively the braking resistor functionality could be provided by the capability integrated within each individual wind turbine power conversion system. In future projects the final design choice as to whether to

[29] http://www.tennettso.de/site/binaries/content/assets/press/information/en/100341_ten_husum_borwin_1_en.pdf

have integrated or standalone dynamic braking resistors would be made by each of the HVDC manufacturers in consultation with the wind turbine suppliers.

For projects with potential parallel combinations of HVDC and HVAC connections offshore then further challenges arise.

The need for parallel connections is likely on some of the large Round 3 wind farm projects in the UK where interconnection between projects within a zone are likely to be made with HVAC, whilst the connections to the onshore network will be made with HVDC.

If such HVAC links are operating closed, to fully utilise the transmission capacity of the HVDC links then the loss of a single HVDC link could result in an overload condition for the remaining HVDC links leading to a potential rapid cascade failure. This overload could be too rapid to be reduced by tripping generation, hence alternative approaches may be necessary.

The scope of the potential solutions will depend on the particular network configurations and of course the level of loading on the HVDC connections. A similar n-1 approach, as applied to HVAC networks onshore could alleviate the problems, but would have implications on the economics of the generation.

Installing additional DC braking resistors, but installed offshore rather than onshore, would provide a solution but this would require additional transformers, power electronic components as well as the resistor, which would significantly add to the space and weight requirements on the offshore platform.

Hence this technical challenge can be overcome, but presently not without commercial implications for either how the offshore grid connections are operated to provide the benefits of parallel connections or the cost of connecting the offshore wind projects themselves.

Therefore it is concluded that whilst the control strategies require significant further development, the basic technologies are available to enable all aspects of offshore wind projects to be integrated.

6.3. Consenting and Planning Issues

Whilst not a technology challenge as such, it is apparent that consenting and planning remains a major concern for large infrastructure projects, including VSC technology, in most countries, irrespective of the specific procedures and processes followed. Concerns are due not only to delays which have occurred on projects to date, but to some lack of confidence that lessons have indeed been learnt and that future projects will potentially suffer from similar delays.

Of course experiences vary, not only between countries but also between similar projects in the same country. Specific and diverse project experiences are easily understood when consideration of variables such as:

- Project specific design details
- Area or region where the project is to be constructed and operated
- Approach taken with stakeholder engagement
- Details of connection route and location of converter stations
- Type and number of utilities, roads and infrastructure to be crossed
- Presence of protected species and fauna
- Similar projects in area
- Familiarity of technology amongst stakeholders

Within the UK a number of initiatives have been undertaken to streamline the consenting process and to give greater confidence to project developers. Significantly in England and Wales the National Infrastructure Directorate within the Planning Inspectorate (PINS) has been formed together with the designation of a National Policy Statement for Energy.

In Scotland the Scottish government is responsible for the consenting of projects and has established a “one-stop-shop” for offshore renewables projects.

At the moment there are no VSC projects which have been identified for Northern Ireland although this may change if projects are developed in Northern Irish waters.

It remains to be seen as to whether the changes made in the UK will result in increased confidence in the consenting process.

Whilst project developers have to address the particular requirements of their own project it is encouraging to see that there is a growing discussion on the exchange of best practice and in particular the adoption of stakeholder consultation with an emphasis on engagement rather than communication. The sharing of best practice in the area of stakeholder engagement is being promoted by Cigre[30] and other organisations such as the Renewables Grid Initiative[31].

6.4. Project Programme Adherence

Given the potential risks associated with large offshore grid expansion, particularly those involving offshore platform elements which are very dependent on weather conditions to undertake construction, it would be unwise to suggest that all future projects will follow more closely the scheduled delivery programme.

However SKM is confident that lessons learnt will allow some of the delays experienced on projects to be avoided as well as a better appreciation of the planning and consenting stages of a project to be made. The level of pre-work done onshore and appropriate facilities for testing and take-over

[30] Cigre WG C3-04 Stakeholder Engagement Strategies in Sustainable Development
[31] RGI Presentation “The Way towards Support Engaging with the Public” Paris C3 Session Proceedings 2012.

process, will be further adapted for these installations. These will allow project programme adherence to improve in the future, albeit that an element of this will be more realistic programming in the first instance.

Technology risk does not appear to have been a significant factor in projects delivered to date and whilst this gives confidence for the future, given the challenges ahead, the same rigour as applied to the development of technology needs to be applied to all aspects of a project.

6.5. In Service performance and Vendor Guarantees

In service performance data for VSC projects is limited to determination of likely VSC availability based on direct reference to reliability surveys as is generally the case for other transmission system components. This is particularly the case where offshore VSC installations are required.

A number of Cigre Working Groups have been set up in this area and in particular B4-60: “Designing HVDC Grids for Optimal Reliability and Availability Performance” will provide information in the future, however the current information collected and published is limited. The derivation of VSC availability requires assessments including the comparison of;

- VSC HVDC with LCC HVDC onshore, where experience exists.
- HVDC with HVAC offshore on an equivalent basis.
- Bottom up assumptions as to what will be achieved with VSC technology based on vendor FMEA (Failure Mode and Effects Analysis) studies.

As with LCC schemes there is scope to determine overall converter availability through the selection of redundancy in components or systems, based on the specified level of availability required. This approach has been well proven in LCC HVDC projects and will continue on VSC schemes; hence consideration of failure rates of sub-components within the HVDC converter module is not necessary and will be addressed by the VSC vendors depending on the detail of their respective design approaches.

Similar engineering design approaches will be made for LCC and VSC technologies and of course lessons learnt in some of the earlier LCC schemes will be applied in VSC schemes. It is also recognised that whilst VSC has a higher number of individual components the more extensive application of self-diagnostics will assist when realising reliability.

In part the assumption of similar failure rates for LCC and VSC technologies takes into account that due to increased Mean Time to Repair (MTTR) for offshore applications there will be a need to “enhance” the reliability of VSC converters through additional redundancy; however we assume here that this may be offset by the likely increase in failure rates due to the offshore environment.

Project owners and developers are therefore assessing project viabilities based on commitments and guarantees being provided by vendors. Vendors then design their converter configurations and systems to deliver the required connection availability.

Of course on many VSC projects involving long cable connections one of the most significant elements of unreliability can be the HVDC cables. For projects involving HVDC submarine cables unavailability can be exacerbated by long MTTR times due to difficulties in accessing submarine cables to implement repairs due to weather constraints. This is recognising of course that most cable failures are caused by third party damage incidents.

Availability of spares as well as repair staff and equipment mobilisation will also be a key factor in determining MTTR as well as the design and delivery of the maintenance schedule which needs to be specifically matched to the level of redundancy included in the HVDC system design.

Given the high level of importance of system availability and the need to understand the performance of each element of the system it is suggested that there will be a need in the UK for collection and analysis of reliability data so that in the future there is clear information for project developers, OFTOs and lenders of what levels of availability can be expected. Also what choices exist to undertake cost benefit analysis as to options that might be selected in design, maintenance provision and spares. Ofgem could consider the design of specific reporting formats for OFTOs and interconnector operators to facilitate the collection of such data.

6.6. Multi-terminal Schemes

HVDC grids, and particularly offshore grids, based on multi-terminal HVDC converter arrangement are considered by many[32] as a means of reducing overall costs and losses of connecting large scale renewables to onshore networks compared to a number of separate point to point or radial arrangements. Additional benefits such as overcoming onshore network constraints will also be a consideration.

There are fundamental differences in principle between VSC and previous LCC technology. Thus control principles are significantly different. Specifically the power flow control during reversal of the power flow in LCC is made by reversing the polarity and the reactive power must be supplied externally. In VSC the active power flow is changed by changing the direction of the HVDC current. The reactive power is controlled independent of the active power as in an HVAC system; VSC does not need communication between stations during normal operation. This makes control and communication issues for multi-terminal arrangements much easier for VSC compared to the previous LCC technologies.

Although multi-terminal schemes for LCC converters have been in operation for a number of years there are still a number of challenges that need to be addressed so that multi-terminal and HVDC grid schemes can be realised for VSC technology.

As discussed in Section 5.6 there are a small number of VSC multi-terminal schemes which are planned, these will not however need all of the technology challenges identified to be addressed as they are three terminal schemes with a single protection zone at a common voltage. Hence there is

[32] http://www.friendsofthesupergrid.eu/about-us.aspx

a clear two way relationship between the timing of the provision of the solution for the technology challenge and the project/market need. Each of these challenges and the respective trigger point for the technology are now considered.

6.6.1. HVDC Breakers

In the event of a DC system fault the converter IGBT devices will be blocked at the current maximum Imax and the AC network will start feeding in current through the freewheeling diodes. In a DC grid the resistance and reactance are such that a rapid rise in fault current will appear and widespread voltage dip across the system. A DC breaker is one solution to protect the DC grid in combination with a series reactor to limit the rate of rise of the fault current. A hybrid DC Breaker of the type proposed[33] would combine the advantages of high speed operation of a semiconductor based DC breaker, together with the negligible conduction losses of a mechanical DC switch with an inbuilt DC fault current limiting function.

The main HVDC VSC vendors suggest that HVDC breakers with HVDC grid capabilities will be commercially available within the next few years. However vendors also suggest that the use of HVDC breakers is only one possible solution to provide fast selective fault clearing in HVDC networks and suggest that a more open view is taken at this stage for the need for such devices.

One approach may be the use of full bridge converters which have fault blocking capability, which depending on the AC system requirements may eliminate the need for a DC breaker in some schemes.

Hence despite the progress made with the technology solution it seems the final stages of the development process for HVDC circuit breakers may be "held" until there is a specific market requirement. Thus the present two to three year lead time for the availability of a HVDC circuit breaker device that could be applied on a system, may remain for the foreseeable future.

The market requirement will of course not only cover the basic need, but also the ratings and performance of these devices which is also being reviewed by projects looking at the feasibility of international grids such as the EU Twenties[34] study focused on integration of offshore wind.

It is also noted that CIGRE is very active in the area of DC Grids. Specifically Working Group B4/B5-59: is addressing Control and Protection of HVDC Grids.

So whilst there is significant work ongoing to verify what technology could achieve, there is significant uncertainty as to the detail of the technology challenges actually required to be addressed. The challenges will also vary depending on the detail of the project, such as the size and scope of any HVDC grid and whether overhead line connections are included.

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[33] Proactive Hybrid HVDC Breakers – A key innovation for reliable HVDC Grids Cigré, International Symposium in Bologna, Italy13-15 September, 2011
[34] http://www.twenties-project.eu/node/3

At present there is no standardisation of DC voltage levels and this may be required before manufacturers can commit to substantial development and in order for multi-terminal HVDC systems to be fully realised,

The SKM view is that whilst HVDC breakers may not be the only solution to enable HVDC grids, the development of the technology and the availability of prototype devices is such that the requirements of HVDC grids during fault conditions will not be an issue that prevents the application of the HVDC multi-terminal or grid concept.

The trigger point for the final development work on the HVDC technology will be the project requirement for a three (or likely more) ended multi-terminal scheme where there is a need for more than one protection zone to cover a potential HVDC fault to ground condition.

Whilst the technologies which will be incorporated into a HVDC breaker are proven separately there will of course be a potential risk with the first application, therefore the vendors would be expected to take a fairly prudent approach on the first project application.

6.6.2. DC Load Flow

Depending on the transmission task, some converter stations import power into the DC circuit whilst others export power. Power import tends to increase the DC voltage level of the network; power export tends to decrease the DC voltage. Control of power requires the DC voltage to be maintained within certain limits by individual converter station controllers.

An HVDC Grid Controller serves the purpose of providing the individual Converter Station Controllers with their control characteristics and reference values. It needs to use the system status and measurement signals to optimize the power flow within the network according to pre-defined rules, such as pre-calculated load flows in the DC circuit.

Any power surplus either needs to be stored in energy stores or turned into heat using discharging devices, like so-called DC choppers. Energy stores would also have to compensate any power deficit. If a DC network does not contain energy stores or DC choppers, power export and import have to be balanced at all times by the converter stations, requiring proper controls. Of course in a comparable AC connected system then measures will be required during load rejection, so any comparison of issues needs to be done on an equivalent basis.

The Converter Station Controller handles the operating point of its converter controlling the voltages and currents at the converter DC and AC terminals with response times typically in the range of microseconds to some milliseconds. Control targets may be:

- a certain active power on the AC or DC terminals of the converter
- a certain AC system frequency
- a certain DC voltage
- a certain AC voltage

- a certain reactive power exchange

The Converter Station Controller obtains measuring signals from its own converter station or receives status signals from external controllers that may influence the control strategy. The Converter Station Controller does not need to rely on external communication. Coordination with the DC and AC networks can be achieved by pre-determined characteristics.

Different concepts to achieve the desired DC load flow have been discussed including:

- Voltage-power droop together with dead band
- Voltage-current droop
- Voltage-power droop

It is likely that three concepts represent viable technical solutions and furthermore appear interoperable, provided that there is an appropriate information interface between the HVDC Grid Controller and the Converter Station Controller.

Cigre WG B4-58 is engaged on studying “Devices for load flow control and methodologies for direct voltage control in a meshed HVDC Grid” and SKM conclude that there is significant work required to develop fully operational DC load flow control schemes and controllers for HVDC grids and complex multi-terminal arrangements, this is not an area that poses significant risk to the delivery of HVDC grids.

6.6.3. Capability to operate multi-terminal system with multiple vendors?

The soon to be published Cigre Working Group B4-52 HVDC Grid Feasibility Study will conclude that HVDC Grids are feasible and a key element of this is the ability of multiple vendors to connect converters together on the same system. There are perhaps three areas where the most significant issues can be identified.

Voltage standardisation – Although it would be possible to connect regional networks or converters of different operating voltages onto a common voltage it is clear that agreed standard voltage levels would facilitate multi-terminal scheme. DC/DC converters could be important if HVDC grids with different voltages should be interconnected or if existing point to point HVDC schemes should be connected to an HVDC grid and the voltages do not match.

Voltage levels are likely to be dictated by available cable voltage levels and it is expected that voltage levels will not prevent multiple vendors from providing a multi-terminal scheme.

***Protection Requirements* –** It is clear that the HVDC Grid imposes new requirements which are not necessarily met by existing protection systems. For instance distance relays cannot be used for the HVDC Grid. Differential protection can be an option in short lines or to protect the busbar in the substation, but travelling wave speeds make them unsuitable for long lines. The challenge will be to develop a protection that is stable for disturbances, such as energization of lines, connection of lines and converters etc. The requirement will be for a very fast protection but to ensure that it does not trip when there are disturbances. The agreement on, and development of protection schemes for HVDC multi-terminal schemes involving different vendors is recognised as one of the most significant challenges to be addressed and this will be facilitated by the ongoing work on the development of Grid Codes.

Grid Code – HVDC Grids will require rules in the same way that AC grids operate within "AC Grid Codes. Given that an HVDC grid will likely include several Transmission System Operators (TSOs) and converter stations from different suppliers there will need to be early establishment of such a "Grid Code" to enable HVDC grids to be achieved. Where a multi-terminal scheme does not involve multiple TSOs an easier process should result.

Nevertheless progress is already being made with Cigre WG B4- B4-56 Guidelines for the preparation of "connection agreements" or "Grid Codes" for HVDC grids having been established. Additionally CENELEC[35] has established TC8X. Unofficial Study Group Technical Guidelines on HVDC Grids

It is anticipated that the outputs of these studies will be necessary to establish the HVDC grid protection requirements including those HVDC breakers will have to fulfil as set by a grid code.

ENTSO-E[36] is in the process of launching a HVDC user group to develop a network code on HVDC which will follow ACERs[37] framework guidelines on grid connections.

6.7. Commissioning

The commissioning and takeover process for an HVDC installation is in many respects similar to that of a conventional AC substation. The system and all of its components have to fulfil technical requirements emanating from various sources, such as:

- System overall requirements;
- General technical requirements related to standards, mainly International Electrotechnical Commission (IEC);
- The electrical point of connection,
- Industry practice;
- Environmental conditions;
- General design criteria in terms of mitigation of risks and life cycle expectancy, reliability and how critical an asset maybe for the grid, etc.

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[35] European Committee for Electrotechnical Standardization
[36] European Network of Transmission System Operators for Electricity
[37] Agency for the Cooperation of Energy Regulators

Therefore in general the type and routine testing prescribed in the IEC standards are followed for most of the components, in certain cases accompanied by additional guidelines which have not yet become standard or are under the process of discussion within IEC or CIGRE working groups, which generally follow each other in a very coordinated fashion.

The type testing of main components such as of the converter transformers or converter valves are normally important milestones in a project and they will form part of the quality assurance plan or specific contractual hold points, which should be formally witnessed and signed off as completed.

There are a number of components which are bespoke and manufactured as one-off items for a specific HVDC project. Their specifications follow a “system design rule set”, as opposed to a component application standard. The three main components which obviously are comprised within this category are the converter transformer, converter valves and the control equipment. Then by consequence of the above other obvious parts follow the same principle, such as cooling, ventilation, auxiliary power, etc. However most of the main-circuit, high voltage equipment also follow the same principle because electrical parameters are no longer standard when the volts and amps have been chosen specifically for the valves and transformers, including a specific insulation coordination set of parameters.

Therefore the main difference between HVDC and conventional HVAC installations is that HVDC is a “system” project and therefore one should accept the parts, if-and-only-if the system will work as a whole. This is different to what is practiced in an HVAC system, where the focus is much more focused on component application followed by a complete system functional verification. Hence the initial focus is on the system design activities and their reports, then on the component specifications and what safety margins have been applied to ensure what has been determined in system simulations is translated into standard IEC design and test requirements in a conservative enough fashion for the equipment to perform throughout its envisaged life cycle.

Most of the components are coordinated in terms of current, voltage and thermal stresses in such a way. Then the system is tested for the performance required, not only to transfer power from point A to point B, but also to do it at the specified kW losses, and with the least disturbance to the existing grid, such as harmonic or electromagnetic interference.

The next stage in the system verification is to test the system’s capability to perform under transient, temporary and dynamic conditions, for the worst credible scenarios found in the operation of the scheme or envisaged as a credible case of the future.

The last and most important step is to make sure the control system absorbs all of the system requirements and runs the power electronics to conduct what has been studied and prescribed in a safe and reliable manner. Therefore a comprehensive Factory Acceptance Test (FAT) is made for the control system in a RTDS (Real Time Dynamic Simulation) environment that may take several months depending on the complexity of the system, to have it completely exhausted in terms of simulated tests.

Only then it can be said the system is ready for transfer to site to be installed because it will be actually a proven and tested “plug-and-play” unit and would have gone through in the time in the RTDS Lab what it will not be possible to occur in the whole of its life time, in terms of disturbing events. It is industry practice that even the cables between panels and main control devices should be pre-fabricated and the same as used in the FAT. Therefore the FAT also covers the cabling to be used on site.

The above process can therefore be considered as well understood and implementable, as has been proven on many schemes. However a concern would be the number of potential projects anticipated and this may cause difficulties with resources being stretched too thinly across multiple projects. Hence each developer/utility/OFTO considering the implementation of a VSC project, as well as the vendor, should give careful consideration to the commissioning stage of the project. Preparation in terms of testing facilities and engaging Operation and Maintenance personnel as early as possible, as well as onshore pre-assembly sites might be important aspects in the future to secure human resources or to mitigate the weather downtime, by preparing the onshore facilities required to the highest standard to conduct long term testing and assembly of most of the components prior to sailing offshore.

From a project developer/OFTO/lender/insurer perspective the difference between a HVAC and HVDC project is that the risk profile on a HVDC project is more significant during the commissioning process, whilst for a HVAC project by the time commissioning is undertaken the project risks will already be minimal. This aspect is one that may require more review during any consideration of the OFTO transfer process for HVDC projects associated with connection of large offshore wind farms.

6.8. Post-Commissioning

In the same way that commissioning resources may be an issue for VSC projects, the resources during in-service operation may also become a constraint, however it is likely that this constraint will be easier for utilities and service organisations to address. Vendors will no doubt supply operation and maintenance services on their products which may be a very cost effective solution for the system operator, however the early determination of a long term strategy of the system operators likely to be advantageous.

Warranties will also be dependent on precisely following the vendor’s recommendations and if availability guarantees are provided it may be a requirement that the vendor actually provides the maintenance themselves.

Warranty duration periods will continue to be a point for negotiation between the purchaser and the vendor, although it is noted that for HVAC onshore and offshore projects there has been a general trend for longer warranty period, with 5 years not being uncommon.

6.9. Offshore Installations

There is now approaching 10 years operational experience with offshore wind farms in the UK involving an offshore substation platform of some type.

The focus of this study has been the future requirements for connecting large scale offshore wind farms in the next 5 to 8 years which have some significant differences to the AC projects which have previously been completed. The impact on some of these factors is highlighted below:

- ***Harsh offshore environment*** – Existing substation platforms have been designed and constructed to cope with harsh offshore environments however for HVDC equipment the potential impact of the conditions imposes additional considerations.
- HVDC VSC vendors are developing environmental protection for the different equipment rooms on the offshore platforms based on enclosures provided for the power electronic modules. For HVDC VSC, airborne molecular sodium chloride (salt) contamination associated with temperature cycling and high relative humidity causes concerns regarding condensation and thereby corrosion. The combination of environmental considerations with a chosen level of active redundancy is a significant factor in determining reliability performance.

  Experience gained with HVAC substations as well the early HVDC offshore converters will be significant in minimising future issues as well as the lessons continually being learnt from the oil and gas sector.
- ***Platforms size and type*** **–** The first HVDC offshore converter platforms installed were based on conventional jacket and topside arrangements with a topside size of typically 3,300 Tonnes for a 400MW capacity. For the large offshore wind farm projects of up to 1000 MW now being constructed and considered the size of the platforms increases to perhaps 9,000 Tonnes. Such a size is well within the capabilities of designs applied in oil and gas, where topside weights of 20,000 Tones have been delivered. Therefore size and type is not a restriction by itself. Other factors such as installation do become more significant as platform size increases.
- ***Self Installing Platforms*** **–** One of the constraints with the installation of large offshore platform topsides is the need for a large capacity crane (or cranes used in tandem) to install the topside onto the jacket structure. Such vessels are very costly to hire with limited availability, such that any delay in the readiness of the topside fabrication and commissioning process onshore could lead to significant and costly project delays. The concept of self-installing platform is being applied on a limited number of projects to alleviate some of these issues, particularly when large topsides are required for HVDC converters. However such platforms are themselves expensive, complicated and can be fabricated by a more select group of suppliers. Therefore it is likely that the more conventional topside/support structure combination will prevail although there will be continued efforts to minimise costs of offshore platforms through all elements of design, manufacture, installation and commissioning.

- ***Location –*** The locations for existing projects have all been relatively close to shore whereas for Round 3 projects the distance to shore may be up to 150km. This has a significant impact on a number of factors
    - Primary access and egress systems – given the potential distance offshore it is not feasible to consider access/egress using boats and facilities for helicopters and accommodation of maintenance staff needs careful consideration. This is not new for oil and gas installations, but is different to the approach on existing AC projects.
    - Health and Safety - becomes even more important when the platform is a significant distance from shore, with platforms needing to be much more equipped to cover for emergency scenarios than those already delivered.
    - Material handling and storage – given the transport times from shore to the platform additional materials such as spare parts are likely to be needed to be held on the platform, thus requiring a different approach to material handling and storage.
    - Remote monitoring – an even higher reliance on remote monitoring to allow specialists access to information rather than rely on physically being on the platform
- ***Hotel Vessels/Offshore logistics*** – The combination of distance offshore, connection size and maintenance required is such that the offshore logistics required for a VSC HVDC converter located offshore becomes an even more significant element compared to HVAC connections. Hence consideration needs to be given to the location offshore of permanent operation and maintenance staff to be associated with the VSC connection. When this is combined with the requirements of the HVAC collector platforms and of course the offshore WTGs themselves, it is clear that consideration of some kind of accommodation platform offshore needs to be evaluated.
- ***Transport and installation –*** Existing jacket and topside design rely on barges to deliver the jacket and topside structures for installation using a large mobile crane or multiple cranes. Barge and crane solutions do exist for platforms beyond what is required for HVDC offshore platforms but as the size increases so the availability of suitable vessels reduces and the cost of hire increases as do the potential penalties of programme overruns. An alternative approach being applied on some projects is to use gravity ballasted floating platforms which are largely commissioned in the construction yard and towed to the final installation location and ballasted into position on the seabed. Such designs are likely to become more prevalent on HVDC projects but there may be a limited number of suitably equipped and qualified construction yards to undertake such projects. However any such limitation is likely to be temporary depending on the level of activity within the oil and gas sector which could be a competitor for resources.
- ***Insurance*** – Whilst the larger nature of HVDC projects with larger single assets and a lack of experience compared to HVAC projects will generate some uncertainties within project insurers the project risk elements such as cable installation will remain similar (fewer cable circuits but longer distances) and familiarity with HVDC interconnector projects should

ensure that concerns of the insurance community are minimised. As HVDC converter platforms increase in size, and novel designs are considered the implications on insurance as well as design/safety standards needs to be considered.

- **Ongoing operation and maintenance -** in addition to installation and commissioning the location of significant transmission resources long distances offshore will generate new challenges for the operation and maintenance of the assets. Existing assets relatively close to shore can be reached using vessels to transfer staff. Further offshore consideration will be required to use not only helicopter transfer but also potentially offshore hotels for long term accommodation of staff. Recognising that the maintenance requirements for WTG are more significant than for the transmission assets it is likely that the provision of accommodation for operation and maintenance staff will be considered along with that for the generation assets. Whilst provision of accommodation for transmission maintenance personnel could be provided on the platforms provided for such assets as HVDC converters, it is the opinion that whilst this is unlikely to be the most cost effective solution it may still be favoured when commercial factors are considered between the OFTO and generators, which may allow multi project opportunities for vendors or other service providers.

6.10. VSC and IGBT Ratings

Ratings for VSCs can reach up to 1800 A, limited by IGBT capabilities, at voltages up to 600 kV using MIND cables. Although no projects have been delivered at this voltage level yet, this technology has potential to deliver a symmetric monopole or bipole achieving 2 GW rating (2x (600 kV x 1800A) = 2160 MW. There is a trend to use the more cost effective extruded XLPE cables that are limited to about 300 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 3.5

A single VSC connection at present could be rated up to approximately 1000 MW using currently available XLPE cable technology and, though there is no operating example of this yet, both ABB and Siemens have concept designs for comparable offshore HVDC platforms. First orders for such systems are being supplied for the 900 MW, ±320 kV, 1400 A DolWin 2 project in Germany, which is expected to be commissioned in 2015[38] and the 1000MW, ±320 kV Dalian project in China, which is expected to be operational 2014[39].

It is anticipated that further incremental developments will occur with Silicon based IGBT devices as thermal capabilities and device size increase.

Whilst some vendors have access to in-house IGBT manufactured devices it has to be remembered that the main driver for the development of power electronic devices is not

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[38] http://www.abb.com/industries/ap/db0003db004333/E1E1631CA0D32A92C12578DB0034CDBF.aspx

[39] Prepared contribution Tang B4 session Cigre2012

transmission and distribution applications. Developments of these devices are most likely to be driven by other sectors including transportation and defence, hence HVDC vendors will tend to adopt the technology as it appears. Thus the potential significance of in-house capability is more limited than might otherwise be expected.

As previously discussed, IGBT devices are extensively used in VSC-HVDC and these silicon based devices have been developed to an upper limit rate of 6.5 kV. Potential significant developments for VSC in the next decade are developments associated with the basic IGBT building blocks. IGBT devices from silicon carbide are currently in development and this could achieve device ratings up to 15 kV. There are also developments using diamond based materials which could potentially reach voltage ratings of 50 kV, but this technology is not as proven and it is not guaranteed to be taken up by manufacturers.

6.11. HVDC Cable ratings

As discussed in Section 3.5 MIND cables have reached a rated voltage of 600kV which allows up to 2 GW converter sizes to be realised.

Manufacturers are also actively developing extruded HVDC cable systems due to the reduced cost, and other advantages such as comparative ease of jointing and improved reliability[40] that this technology can bring. Current state of the art restricts HVDC extruded cables using XLPE to around ±320kV allowing 1000MW per symmetric monopole. Manufacturers are now introducing extruded dielectric technology up to ±320kV for Voltage Source Converter (VSC) HVDC applications and have noted that the incorporation of larger conductor sizes into the cables will allow higher power magnitudes to be transferred. Further development of dielectric materials with screening and insulation materials is expected to continue to increase the levels of electrical stress that the cable can withstand and therefore capacity levels will continue to increase.

Developments in Japan suggest that HVDC XLPE cables have been produced with a capability up to 400kV, although these do not comply with the CIGRE[41] guidelines, European manufacturers are also developing higher voltage cables and 500kV XLPE cables are now being promoted and can confidently be expected to be delivered in the next two or three years. It has also been suggested that a similar development that allows the production of higher voltage HVDC XLPE cables through doping of the XLPE dielectric (through the use of nano-particle fillers[42]) could enable the development of XLPE cable suitable for use on LCC converter systems.

It is interesting to note that whilst it is generally believed that XLPE cables are cheaper to manufacture than equivalent MIND cables it is also known that the price of comparable MIND and XLPE cables depends on rating and the actual market situation, hence the general rule of XLPE being of the order of 20% lower price compared to MIND does not always apply. Consideration is

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[40] Cigre Brochure 379 – Service Experience for HV Underground and Subsea Cable
[41] CIGRE Electra 171 and 189
[42] CIGRE B1 Session Paris 2012, prepared contribution by Katakai (Japan)

also required when considering cable joints. Whilst the need for subsea joints is limited based on the ability to ship and install very long lengths of cable there will be a need for frequent joints (approximately every km of route length) onshore, hence the fact that MIND cable joints tend to be more expensive than XLPE joints and take additional time to prepare and complete. This can have an impact on the choice between the technologies depending on the project requirement. Testing requirements the two technologies are equivalent.

The choice between XLPE and MIND technologies will be made on a project basis, although XLPE is expected to dominate in the future as the available ratings increase and allow the potential for a 2 GW VSC system based on XLPE cable technology to be realised.

Thermal rating of onshore and offshore cables is a significant factor in the design of any VSC system with the thermal limitations of the offshore sections of the cable typically being determined by the J Tube where the cable enters the offshore platform or at the point at which the cables cross any sea defences at the cable landfall point. Distributed Temperature Sensing (DTS) technology has recently been applied to some HVAC offshore transmission schemes and it is anticipated that the application and utilisation of such technology will increase significantly over the next 5 years.

6.12. HVDC Switchgear and Hub Connections

Switching devices are provided on the DC side of an HVDC converter in order to perform a number of functions related to re-configuring the HVDC system following a fault and also to facilitate maintenance. HVDC switching devices can be classified into current commutating switches, disconnectors and earthing switches.

DC circuit breakers would be required should full multi-terminal HVDC systems with multiple protection zones be realised but are not needed for the schemes currently planned.

A DC hub could simply be a point or node where a connection is made between two HVDC systems. In the context of large scale offshore wind generation such hubs would most likely be located offshore on suitably designed separate platforms or integrated into the design of HVDC converter platforms. Such a hub would not require DC circuit breakers.

Some existing DC switchgear (current commutating switches, disconnectors, earthing switches) do widely exist as air insulated substation (AIS) equipment which is used on existing LCC and VSC schemes. A challenge for the application of DC switchgear for offshore installation is for the introduction of gas insulated substation (GIS) equipment which is commonly used for AC applications where compactness is required, GIS equipment being very much more compact than AIS equipment and therefore much more suitable for offshore application.

GIS HVDC equipment has been developed in Japan[43,44] and therefore if required for application on offshore hub connections could be provided without appreciable technology risk. Existing VSC vendors also supply conventional HVAC GIS switchgear and some have indicated that HVDC GIS switchgear could be available by as early as 2014.

Given the relatively low level of technology challenges associated with providing HVDC GIS switchgear for rated voltages of the range of 300 kV to 400 kV, SKM also believes that there is no significant technology risk in this area. However, should HVDC GIS switchgear be required for ratings above 500 kV then a much more significant technology challenges would have to be overcome.

Two of the main issues to overcome for HVDC GIS are the different requirements on solid insulation systems due to the influence of space charge and the susceptibility of the insulation system to particulate contamination.[45]

6.13. Equipment Lifetimes

For conventional HVAC assets with an anticipated lifetime of 40 or 50 years it is normally anticipated that a mid-life upgrade of control and protection equipment will be necessary and justified to ensure the ongoing operation of the assets.

Experience with VSC HVDC technology is much more limited but for existing LCC HVDC systems mid-life upgrades have been more extensive than for HVAC technologies where not only have control and protection schemes been upgraded but also cooling systems and valves where significant technology changes have occurred to justify the more significant upgrades based on improved reliability, reduced losses and reduced maintenance costs. For VSC projects with a potential for a 40 year project lifetime, it is anticipated that a similar approach to that seen on existing LCC HVDC schemes will apply. In order to ensure a 40 year optimum operational performance it is anticipated that significant "replanting" of the VSC system will take place. This is likely to encompass:

- Converter control system
- Converter cooling systems
- Converter IGBT valve modules

It would be expected that such replanting would be justifiable for both onshore and offshore installation, however for offshore installations it may be that the justification of these upgrades will

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[43] http://www.toshiba.co.jp/sis/en/tands/switch/gis7.htm
[44] IEEE Power Engineering Review Issue 1 January 1997 “Development of Insulation Structure and Enhancement of Insulation Reliability of 500 KV dc GIS”

[45] Cigre Paper 15-103 1994, “the use of Novel Monitoring Techniques to Investigate the Distribution, Behaviour and Effect of Trapped Charges in GIS”

require even closer analysis and will inevitably be linked to a possible programme for the replanting of the offshore generations assets themselves.

Basic primary equipment such as switchgear (HVAC and HVDC) transformers and other items would not be expected to be replanted during the lifetime of the assets.

The technology challenge will be to ensure that such upgrades of the VSC HVDC technologies are done as cost effectively as possible and with minimum possible connection down times, although again the link with potential replanting of the generation assets will be critical.

For VSC HVDC assets located on offshore platforms the degree of impact of the environment on equipment lifetimes is not yet understood and SKM consider that it is likely that some bad as well as good experience will be encountered on projects despite the hazards being well appreciated. Hopefully good practice will be quickly adopted and limitations of in-service lifetime and reliability will be minimised.

6.14. Costs

The study has not specifically reviewed how the price of VSC technology has developed since its first introduction, nor in comparison with the alternative LCC or indeed HVAC technology.

There have however been a number of significant improvements in VSC technology which will contribute to the technology becoming more cost effective, for example:

- The introduction of multi-level converters which have reduced the need for separate harmonic filters which require not only extra cost but additional space requirements.
- Converter losses have reduced from over 1.5% to approaching 1% which reduces the cost of operation of a VSC connection.
- XLPE cable technology has developed such that voltages of up to 320 kV are now available and 400 kV and potentially 500 kV available soon. This enables larger single connections to be achieved with significantly reduced overall project costs.

As well as further technology developments it is also recognised that increased market competition should help reduce price levels.

6.15. Summary of VSC Technology Challenges

A summary of the technology challenges, potential solutions and anticipated timescales to overcome the challenges discussed in Sections 6.1 to 6.14 is provided below:

Table 9 - High Level Summary of Technology Challenges for VSC Project Implementation

Chapter Reference	Technology Challenge	Potential Solution	Timescales to Overcome Challenge
5.6 and 6.6	Multi-terminal VSC schemes with single vendors	Are being delivered today based on three terminal schemes with single zones of protection (with a view to being operational by 2014). Further developments required for multiple protection zone arrangements including the establishment of regulatory standards, potential across several jurisdictions. Technology is unlikely to be the main obstacle in the delivery of HVDC grids.	First three-ended VSC multi-terminal scheme with a single protection zone expected to be operational by 2014 No schemes have plans for multi-zone protection at the moment. Whilst enabling technologies are likely to be two to three years away, this timescale fits within the wider project timeline, therefore technology availability is unlikely to be a timescale obstacle.
6.6.3	Multi-terminal schemes with multiple vendors	For a single protection zone scheme main need would be a common voltage. However significant commercial discussions would be required to establish responsibility interfaces.	Technically could be delivered, commercial interfaces and therefore commercial justification may be difficult to establish. Likely that multiple vendor projects will follow on from multi-terminal schemes with single vendors.
6.6.1	DC circuit breakers for multiple protection zone schemes	Prototypes and designs exist however ratings, application and even need for devices is not agreed and until there is a clear market need it is likely that the final stages of development will be held.	First devices could be delivered within two to three years, possibly before but final stages of development dependent on market pull.
6.12	Compact HVDC switchgear for use on offshore platforms and HVDC hubs	Adapted versions of existing HVAC Gas Insulated Switchgear (GIS) Switchgear	Proven designs with a rated voltage of 300 kV to 400kV could be available by 2014. dependent on market demand
6.10	Increased ratings of VSC IGBT modules than the currently available 1400 to 1600 A, thus allowing higher power transfers.	2000 A modules likely to be developed.	Expected to be available for adoption in projects by 2016.
6.10	Delivery of bipole VSC systems	Bipole converter configurations similar to the symmetric monopole systems supplied to date.	Designs available such that systems could be delivered.
6.10	2000 MW converter on a single offshore platform	Feasibility looked at but not believed to be a credible market need as yet.	Unlikely to be realised in foreseeable future but designs could be realised in 2014/2015 if needed.

Chapter Reference	Technology Challenge	Potential Solution	Timescales to Overcome Challenge
6.9	Equipment susceptibility to harsh offshore environments. Airborne molecular sodium chloride (salt) contamination is associated with temperature cycling and high relative humidity which causes concerns regarding condensation and subsequent corrosion	HVDC VSC vendors are developing environmental protection for the different equipment rooms on the offshore platforms associated with enclosures provided for the power electronic modules. Experience gained with HVAC substations as well the early HVDC offshore converters will be significant in minimising future issues as well as the lessons continually being learnt from the oil and gas sector.	Lessons are being learnt from the first HVDC projects which are now in-service.

6.16. Summary of Other Issues Associated with VSC Technology

A summary of the other issues associated with VSC technology, potential solutions and general outlook as discussed in Sections 6.1 to 6.14 is provided below.

■ **Table 10 - Summary of Other Issues Associated with VSC Projects**

Chapter Reference	Issue	Potential Solution	General Outlook
5.1 and 6.1	Utility network integration	Range of solutions include: • Dynamic Braking • Control Strategy • Protection • DC Load Flow • Reliable operation of power electronic driven wind generators in weak AC networks.	• Dynamic braking has been delivered. • Control strategy and application is complex and yet unproven for multi-terminal above three ended schemes. Cigre and other work is progressing on issues associated with HVDC grids • Multi-zone protection schemes not yet implemented where HVDC circuit breakers are needed (see above). • To overcome concerns with weak HVAC networks wind farm developers are looking for either classical (e.g. synchronous condenser) or Flexible Alternating Current transmission Systems (FACTS) based solutions for addressing expected operational issues. Cigre is also setting up a Working Group B4-62, to look at the specific issue of connection of wind farms to weak AC networks.
5.5 and 6.5	Expected levels for system and converter availability	• Vendor guarantees • Industry reliability surveys • Consideration could be given to the design of specific reporting formats for Offshore Transmission Owners (OFTOs) and interconnector operators to facilitate the collection of such data.	Vendors are reaching agreements with developers on a contractual basis so guarantee levels are being established on a project by project basis. Cigre and other bodies will develop surveys as the number of installations increases. It is suggested that there will be a need in the UK for specific collection and analysis of reliability data so that in the future there is clear information for project developers, OFTOs and lenders of what levels of availability can be expected.

Chapter Reference	Issue	Potential Solution	General Outlook
5.6 and 6.6	Regulation and Standards	• Agreed standard voltage levels would be needed to facilitate multi-terminal scheme. • A DC Grid Code for multi-terminal schemes would be needed,	Pre-work by organisations such as Cigre and the European Committee for Electrotechnical Standardization CENELEC is ongoing and the outlook is positive that standards will emerge as required. Potential impacts on the supply chain and technology developments such as cable voltage levels are difficult to assess. Experience suggests that standards and codes take a minimum of one to two years to be finalised although agreements on principles are generally reached in shorter timescales allowing projects to proceed in parallel.
6.11	Need for higher cable voltages and thus higher power transfers	• Higher voltage 600 kV MIND cables and potential for up to 500 kV XLPE cables.	600 kV MIND cables will be delivered for commissioning in 2015. 400 kV or even 500 kV XLPE could be available by 2016. So whilst 2000 MW connections could be proposed there would be issues with size of single load loss.
5.4 and 6.4	Project programme delays	• Lessons learnt • Better understanding of the planning and consenting stages of a project • More realistic upfront project planning.	Experience is bringing improvements, but many projects are still hitting delays on consenting or installation. Technology is not as significant a problem as weather windows and vessel availability.
5.3 and 6.3	Delays in consenting and planning	• Enhanced stakeholder engagement • More realistic expectations of process timing. • Changes to process	Consenting and planning remains a major concern for major infrastructure projects. Changes have been introduced in the UK consenting and planning process but it is too early to assess the improvement that these changes will deliver.

Chapter Reference	Issue	Potential Solution	General Outlook
6.13	Ensuring transmission equipment lifetimes are consistent with generation assets.	Mid-life upgrades on control, cooling and converter modules will enable lifetimes of up to 40 years to be reached in well controlled environments.	Can be realised now if requirement exists.
6.9	Offshore installation problems	• Learn lessons from HVAC experience • Self Installing technology • New logistic arrangements such as hotel platforms • New approaches to O&M	Whilst there is now 10 years operational experience with offshore assets in the UK, the challenges with VSC projects are changing due to their location (further from shore) and larger size. Hence new installation arrangements will be needed which will need to draw on experience, including from the Oil and Gas industries.
6.14	Achieving cost reduction	Projects involving VSC interconnectors as well as connections to offshore renewables are justified on the basis of present costs. As competition increases and enhancements are made to VSC technology it is likely that the cost and price of VSC technology will reduce. In the case of offshore renewables this may assist in achieving the necessary overall cost reduction targets (of £100/MWh by 2020)[46], however it must be recognised that the cost of the export connection is a relatively small proportion of the overall project cost.	Likely to occur in three to five year timescale as significant competition develops. Another factor in cost reduction is the ability of vendors to provide standard solutions, allowing savings in terms of reduced design and engineering as well as manufacturing efficiencies.

[46] Target proposed by the Offshore Wind Cost Reduction Task Force.

7. Conclusions

A large number of VSC HVDC projects are either under construction, or are in the stages of design, planning and consenting. Some information on many of these projects is already in the public domain, typically through project owner or developer websites. Through the first part of the survey undertaken as part of this project this knowledge base has been extended in terms of the number of projects identified as well as specific project detail. The cooperation of project owners and developers has been invaluable in this process.

The resulting project summary therefore provides a useful reference document for all those stakeholders interested in VSC HVDC technology and current project status; however it is recognised that this area is dynamic and to remain useful the project summary needs to be updated on a regular basis to obtain ongoing benefit from the additional projects completed.

The second part of the survey was a questionnaire which focused on project specific issues. The responses to the questionnaire were recognised as being commercially sensitive and therefore the responses received have not attributed to specific projects and have not been published. These were discussed in Section 5 and also used to inform SKM's view on the challenges associated with VSC projects as detailed in Section 6.

Questions were targeted to ensure they were relevant to each project and recipient, but in general the following areas were covered:

- Utility network integration issues
- Integration with offshore wind projects
- Consenting and planning issues
- Project programme adherence
- In service performance and vendor guarantees
- Multi-terminal schemes

SKM also engaged with the main VSC technology providers; to elicit further technology information and provide a balanced assessment of expected future VSC technology challenges. The engagement with prospective technology providers provided validation of SKM's own views and opinions regarding VSC technologies and also enabled the most up to date view on technology developments to be included in the report.

It is much appreciated that all of the main VSC vendors provided support to this review by responding to particular technical questions. This response is significant given that the technology vendors are actively responding to the market requirements of the large number of projects which are being developed at present. It is intended that this report will assist in the process of introducing VSC technology to a range of potential stakeholders and alleviate some of the potential concerns that accompany the deployment of any new technology, particularly where the established alternative technologies have seen relatively little change over previous decades.

Tables 2 and 3 show that whilst many technology challenges still remain to be addressed, in relation to the implementation of VSC technology on a wide scale. However these challenges are currently being addressed by VSC technology vendors and users (where there is a market need). Consequently, it is concluded that no fundamental technology issues or barriers exist which are likely to significantly delay the wider adoption of the technology. The large number of HVDC VSC projects currently under development (Table 1) provides evidence to support this view. Comfort can also be taken from the fact that challenges have already been overcome to allow VSC technology to be applied at its current level. The relatively few problems experienced to date, in relation to HVDC VSC technology should give confidence that in future a similar record will be achieved.

In order to realise HVDC grids there are additional specific challenges that will need to be overcome as detailed in Tables 2 and 3. However, such a network and the associated standardisation and regulatory measures that would be necessary in order deliver such a concept would first need to be justified in terms of costs and benefits. Standardisation is especially needed if VSC technology deployed to deliver an integrated HVDC grid across regions or between countries. This would require considerable further work.

Whilst the report has focused on VSC technology it is clear that, even as VSC technology becomes more mature and the remaining technology challenges are addressed, as projects become larger so the associated installation risks will increase. This applies to both offshore platforms and submarine cables in particular. Submarine cable installation remains one of the most significant risk areas associated with the application of many VSC HVDC projects despite the relative maturity of the submarine cable industry.

8. Recommendations

Based on the review of VSC installations and associated technology challenges the recommendations of SKM for further work are:

a) In order to deliver ongoing benefit from the summary of existing and planned VSC projects it will be necessary for the database to become a “live” document which is updated with new project information as this becomes available, Ofgem should consider a mechanism to achieve this.

b) Given the importance of system availability and the need to understand the performance of each element of the system there will be a need in the UK for the collection and analysis of reliability data so that there is clear information for future project developers, OFTOs and lenders of what levels of availability can be expected. Also what choices exist to undertake cost benefit analysis as to options that might be selected in design, maintenance provision and spares. Ofgem could consider the design of specific reporting formats for OFTOs and interconnector operators to facilitate the collection of such data.

c) Further work is required to justify and define the concept of an integrated HVDC network and the associated regulatory framework to allow such a system to be developed. It is recommended that this work is progressed such that the actual technology issues which need to be addressed can be identified with more confidence that currently exists. Consideration of this requires a broader perspective than can be applied by any single project developer or TSO.

Appendix A List of Abbreviations

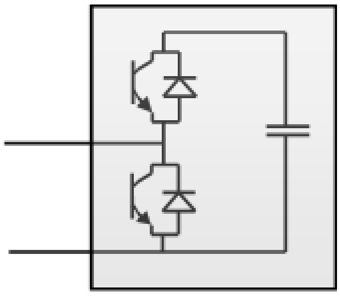
AC	Alternating Current
ACER	Agency for the Cooperation of Energy Regulators
AIS	Air Insulated Switchgear
Authority	The Gas and Electricity Markets Authority
CAPEX	Capital Expenditure
CENELEC	European Committee for Electrotechnical Standardization
CIGRE	International Council on Large Electric Systems
CSC	Current Source Converter (alternative name for LCC)
CT	Current Transformer
DC	Direct Current
DECC	Department of Energy and Climate Change
DTS	Distributed Temperature Sensing
EIA	Environmental Impact Assessment
ENTSOE	European Network of Transmission System Operators for Electricity
FAT	Factory Acceptance Test
FACTS	Flexible Alternating Current transmission Systems
FEPA	Food and Environmental Protection Act
FMEA	Failure Mode and Effects Analysis
GIL	Gas Insulated Line
GIS	Gas Insulated Switchgear
GIT	Gas Insulated Transformer
GTO	Gate Turn-Off
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
ICNIRP	International Commission on Non-Ionizing Radiation Protection
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronic Engineers
IGBT	Insulated Gate Bipolar Transistor
ICNIRP	International Commission on Non-Ionizing Radiation Protection.
LCC	Line Commutated Converter
LCTA	Lowest Cost Technically Acceptable
MIND	Mass Impregnated Non-Draining
MMC	Modular Multi-level Converter
MTBF	Mean Time Between Failures
MTTR	Mean Time To Repair
MTS	Mixed Technology Switchgear
NGET	National Grid Electricity Transmission
Ofgem	The Office of Gas and Electricity Markets

OFTO	Offshore Transmission Owner
OHL	Overhead Line
OSP	Offshore Platform
OWF	Offshore Wind Farm
PoW	Point on Wave
PPLP	Polypropylene Laminate Paper
PWM	Pulse Width Modulation
RAML	Rectifier Alpha Minimum Dynamic Limit
RMS	Root Mean Squared
RTDS	Real Time Dynamic Simulation
SF_6	Sulphur Hexafluoride
STATCOM	Static Compensator
SCADA	Supervisory Control and Data Acquisition
SCR	Silicon Controlled Rectifiers
SQSS	Security and Quality of Supply Standard
SVC	Static VAr Compensator
TCE	The Crown Estate
TSO	Transmission System Operator
VDCOL/VDCL	Voltage Dependent Current Order Limitation
VSC	Voltage Source Converter
VT	Voltage Transformer
WTG	Wind Turbine Generator
XLPE	Cross-Linked Polyethylene

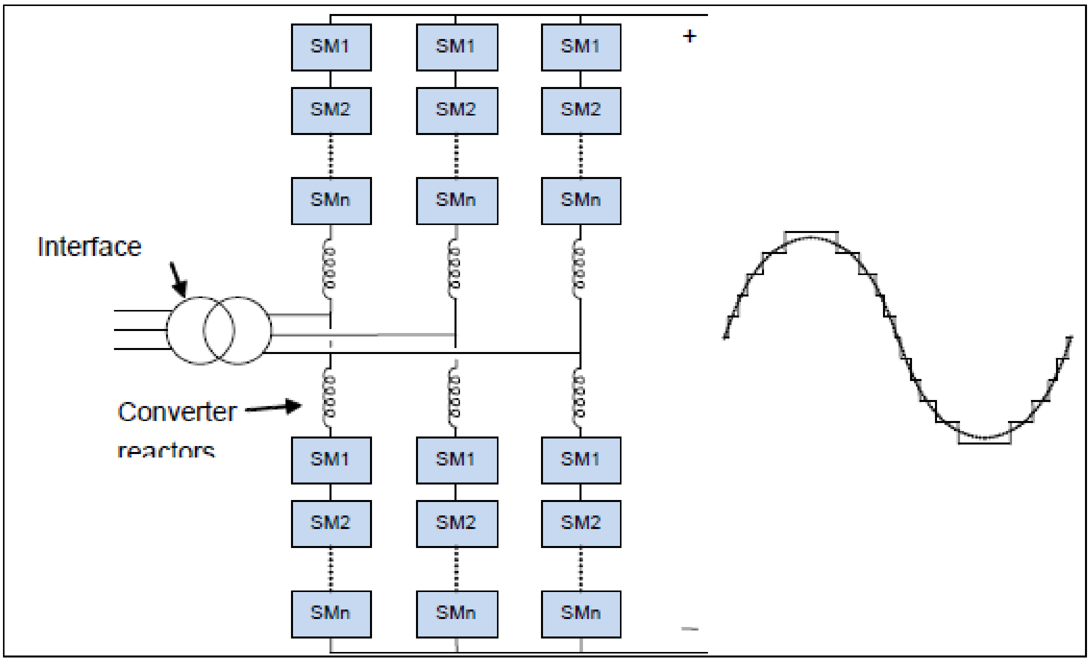
Appendix B Multi-Level Converters

B.1 Modular Multilevel Converters

The modular multilevel converter (MMC) is a principle that has been used since the 1990's using Gate Turn-Off GTO Thyristors and full bridges in STATCOM applications. In this arrangement the valves comprise a series connection of sub-modules which are each configured as shown in Figure 15 (half bridge). The sub-modules are assembled into a modular multilevel converter as shown in Figure 16.

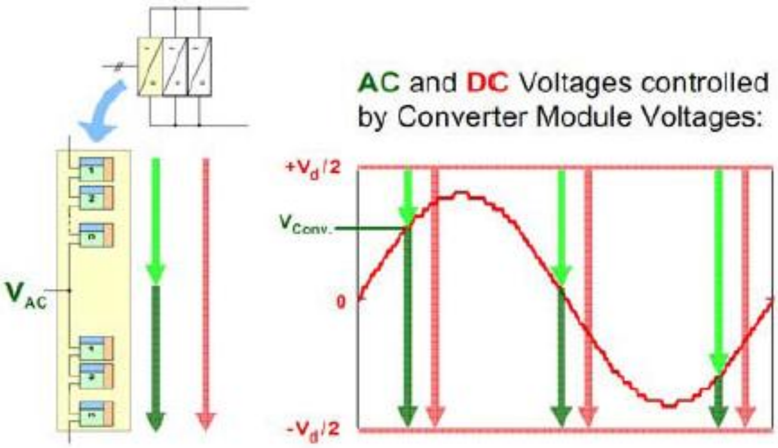


- **Figure 15 Sub-module of the MMC consisting of 2 IGBTs, 2 diodes and a capacitor**



- **Figure 16 - An MMC converter made up of sub-modules and the resulting ac wave shape generated by selective switching of the sub-modules**

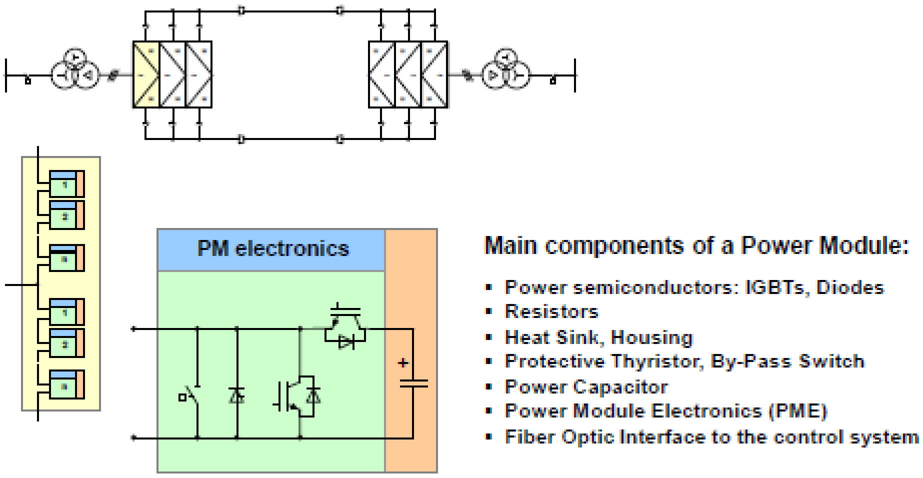
Each of the six legs of an MMC valve group consists of sub-modules in series along with a converter reactor as indicated in Figure 16. The sub-module produces a voltage step and with a large number of sub-modules in series in each valve location it is possible to build AC side voltage up one step at 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 sine wave as also indicated in Figure 16. In each cycle, the ac bus voltage is controlled by the ratio of the converter modules which are bypassed, as seen in Figure 17.



- **Figure 17 Voltage control of multi-level VSC-HVDC**[47]

One of the main advantages to MMC technology is the reduced switching losses, compared to the conventional VSC with PWM. This is because the switching frequency experienced by each sub-module is significantly lower, with each sub-modules only switching on and off once per cycle of the fundamental frequency, unlike the initial concepts of VSC where all sub-modules are switched simultaneously. The main components of the MMC-VSC-HVDC power module are presented in Figure 18.

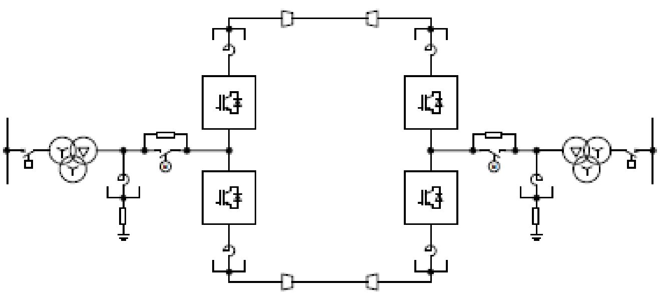
[47] CIGRE Working Group B4.46 - Voltage Source Converter (VSC) HVDC for Power Transmission – Economic Aspects and Comparison with other AC and DC Technologies, April 2012



- **Figure 18 Main components of MMC-VSC-HVDC[47]**

Figure 19 presents an example of a MMC-HVDC configured as a symmetric monopole (see section 3.3). The converter systems are designed and rated to meet the performance requirements of the HVDC transmission system and is protected to withstand over-current and over-voltage stresses due to fault occurring in the various parts of the station.

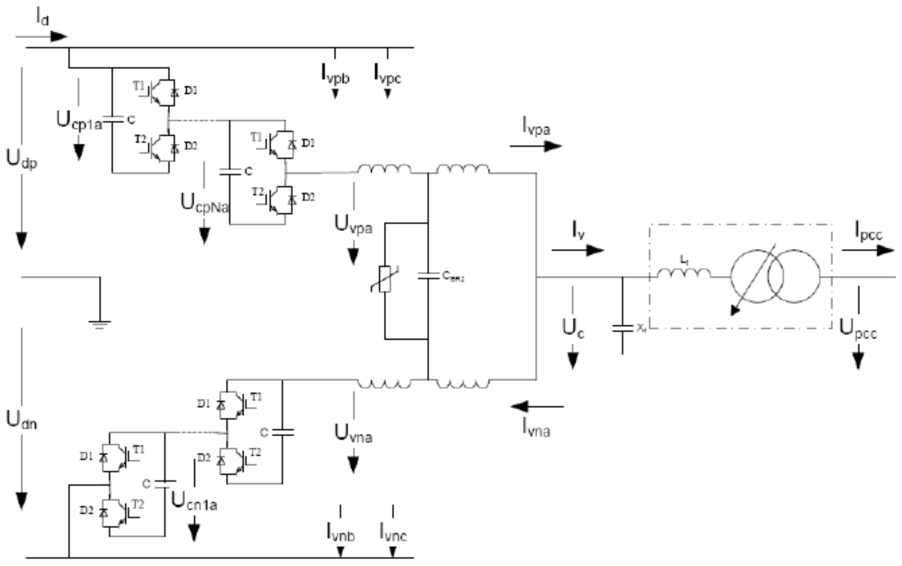
During normal operation, the series resistors shown in Figure 19 are bypassed. The DC-side voltage to ground is floating, and in this symmetrical configuration, if the DC voltage to ground is symmetrical, a DC offset on the transformer secondary side is avoided. Standard AC power transformers can therefore be used with this technology. Special grounding devices are installed between the secondary winding of the AC transformer and the converter, which provides a reference to ground for one station. The converter of this substation can then control the DC circuit voltage to ground. If independent reactive power exchange is required in both stations, for example in the case on an open circuit, an optional connection to ground can also be made at the other converter station.



- **Figure 19 MMC-HVDC in a symmetric monopole configuration**

B.2 Cascaded Two Level Converters

Cascaded Two Level Converters are the equivalent of MMC technology being offered by ABB. The principle is similar to the MMC with multiple two level PWM converters connected in series in positive and negative voltage arms as shown in Figure 20 below. The main difference between this technology and the MMC-VSC is the use of series-connected press-pack IGBT, which allows the conventional two-level converter VSC technology to be extended to multi-level VSCs through a cascade connection.



- **Figure 20 Cascaded Two Level Converter Principle**[48]

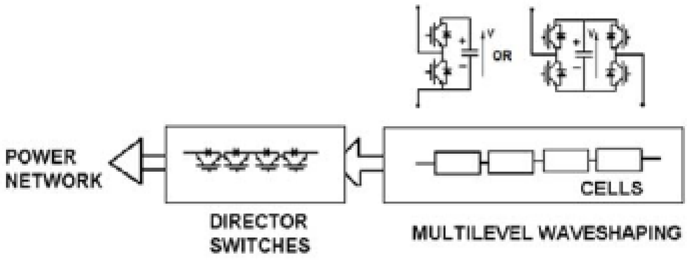
Figure 17 above illustrates how the cascade two-level converter comprises of a series of half bridges, each containing two switching elements, T1 and T2. Each arm connects the positive and negative poles of the DC bus to the converter bus, which can be controlled to produce the fundamental frequency output voltage through the individual switching of the converter cells. The switching frequency is low, with about three pulses for a fundamental frequency of 50 Hz. As with MMC technology, this technology therefore has the advantage of lower switching and harmonic losses compared to the conventional VSC-HVDC, with PWM. The total converter station losses are in the range of 1% of rated power transfer at operation with rated power[49].

[48] VSC-HVDC Transmission with Cascaded Two-Level Converters
Bjorn Jacobson, Patrik Karlsson, Gunnar Asplund, Lennart Harnefors, Tomas Jonsson
[49] CIGRE Working Group B4.46 - Voltage Source Converter (VSC) HVDC for Power Transmission – Economic Aspects and Comparison with other AC and DC Technologies, April 2012

B.3 Alternate Arm Multi-Level Converter

Alstom has developed a multi-level converter technology is based on the Alternate Arm Multi-Level Technology[50].

This technology is based on a hybrid design of both LCC and VSC technology whereby, multi-level converter elements comprising of full and half bridge cells are used to synthesize the AC waveform, which is then directed to the network using semiconductor switches. The basic concept of this technology is presented in Figure 21.



- **Figure 21 Alternate Arm Multi-Level switch cell concept[51]**

The technology allows various practical converter configurations to be derived. A simple example of the single-phase AC to DC conversion is shown in Figure 22. The figure indicates the flexibility of the multi-level cells which can be arranged in either a parallel or a series connection. Under this design, the semiconductors are switched in the H-Bridge configuration at the frequency of the AC supply and near zero voltage, which enables the soft switching of the IGBTs thus minimising switching losses.

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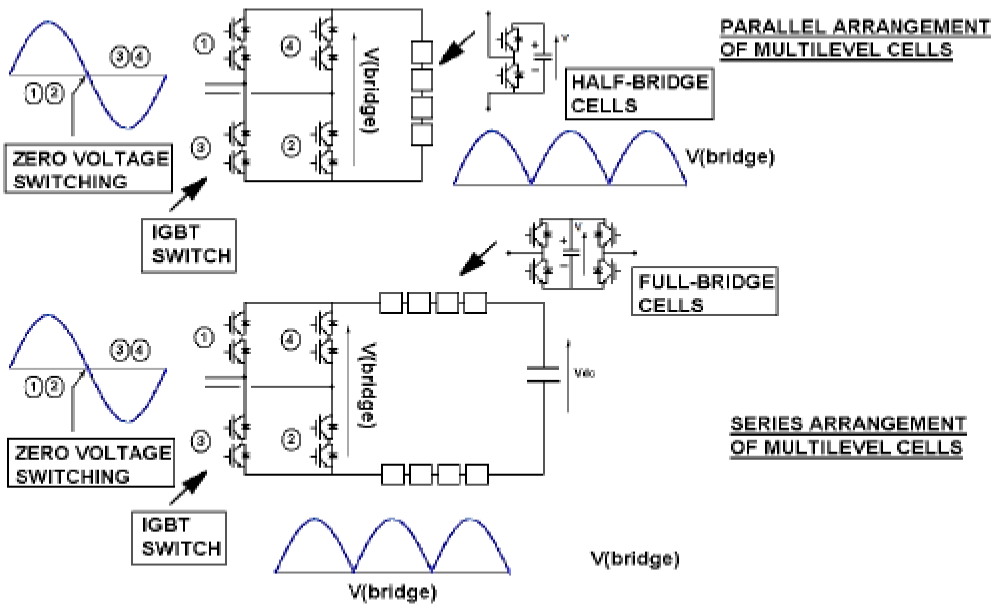
[50] A New Hybrid Multi-Level Voltage-Source Converter with DC Fault Blocking Capability M.M.C. Merlin*, T.C. Green*, P.D. Mitcheson*, D.R. Trainer†, D.R. Critchley†, R.W. Crookes

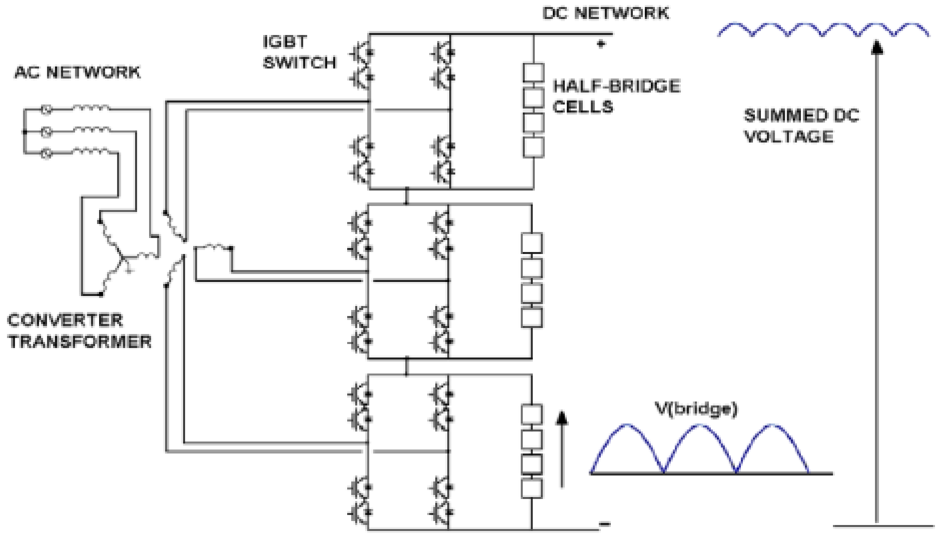
[51] CIGRE Working Group B4.46 - Voltage Source Converter (VSC) HVDC for Power Transmission – Economic Aspects and Comparison with other AC and DC Technologies, April 2012



- **Figure 22 Alternate Arm Multi-Level single phase AC to DC conversion**[52]

A three phase converter can be produced by connecting three singe phase AC to DC converter units in series via a three winding transformer, Figure 23. The units can be operated with a phase angle of 120° apart, so that many of the DC harmonics that appear across the H-bridge cancel in the final summation of the DC output. The voltage at each H-bridge in this three phase arrangement will also pass through a zero condition, spaced at 120° apart, allowing soft switching of the series IGBT string to be maintained. This approach allows the VSC to ride through AC-side faults and can provide reactive power to the network.

[52] CIGRE Working Group B4.46 - Voltage Source Converter (VSC) HVDC for Power Transmission – Economic Aspects and Comparison with other AC and DC Technologies, April 2012



- **Figure 23 Alternate Arm Multi-Level three phase AC to DC conversion**[53]

The operation of this converter is similar to that of a conventional three phase converter with each upper and lower limb nominally conducting for 180° per cycle. During the cycle, the multi-level converters add or subtract voltage steps, to or from the voltage from the DC network, to create half an AC waveform that is directed to the AC network. The cells within the inactive limb provide the added benefit of generating an opposing voltage which reduces the voltage applied to the off-state IGBT switch. This decreases the required rating of the device and therefore reduces the number of series-connected devices required, thus providing a positive impact on equipment cost and converter losses.

[53] CIGRE Working Group B4.46 - Voltage Source Converter (VSC) HVDC for Power Transmission – Economic Aspects and Comparison with other AC and DC Technologies, April 2012

Appendix C Hybrid VSC LCC Systems

Both LCC and VSC technologies have their advantages and disadvantages in the application of HVDC conversion and whilst the focus of this study is VSC technology there is a need to consider the arrangement of hybrid LCC-VSC HVDC links, where LCC technology is applied on one end of the transmission system and VSC technology on the other end.

The fundamental issue and main limitation to employ this arrangement is that LCC converters, unlike VSC, cannot control power and voltage independently. The AC power in an LCC converter is not vector controlled, i.e. it is not controlled by displacing the phase angle of the converter voltage with respect to that of the AC system voltage. Basically LCC converters will control the power absorbed or delivered to the AC system by controlling the DC power value and its direction. Also there is very little room to control reactive power by the LCC converter control. The AC power in the LCC converters is determined by the DC power being transmitted as a current source, for which at any moment, the DC current should ideally be constant.

For clarity and simplicity, in the following text in this discussion, the term rectifier will be used to name the converter at the power sending end of the DC transmission, whereas the converter at the power receiving end will be referred to as inverter.

Assuming firstly a VSC rectifier offshore and a LCC inverter onshore, the need for a black-start sequence of the OWF might be challenging as the LCC inverter would have to operate initially as a rectifier, hence reversing the polarity of its voltage, as the DC current direction cannot be reversed.

A number of solutions for this could be envisaged with different degrees of added cost, perhaps an auxiliary VSC converter starter, not rated at full voltage or an uncontrolled rectifier operated at lower power, or perhaps a fast cross-paralleling switching scheme of the poles could be made. Assuming some means can be found in order to start the system without having to reverse the voltage, which would otherwise have many impacts, including the type of sub-sea cable to be selected. In the remaining discussion it will be assumed it should be possible to make the initial start and the VSC rectifier attains rated voltage with minimum current in the order of 3 – 10% of the rated value giving the corresponding power transfer from the OWF to the onshore grid.

A LCC converter would not typically work well as inverter having a VSC converter as rectifier on the same DC cable because the inverter would need coordination of is operating characteristic with the feeding rectifier. This would imply that at any AC voltage abrupt fluctuation, the DC current fed by the rectifier, would also fluctuate in the opposite direction, i.e. a sudden voltage decrease on the inverter side would be followed by a DC current increase, as the VSC rectifier would tend to keep its constant voltage. This would not be a stable combination, as a relatively minor sudden loss of sinusoidal wave voltage over any time duration in one of the AC phases, as consequence of a grid switching operation particularly at the commutation margin interval, could result in a spurious random commutation failure of one of the valves at the 6-pulse level due to the resulting overcurrent.

In the classical LCC arrangement the voltage decrease is naturally detected by a LCC rectifier strictly running in current control mode and the detection of the commutation failure is made instantaneously at the inverter as the DC current becomes greater than the Root Mean Squared (RMS) AC currents fed to the grid. This signal is also immediately transferred over to the rectifier through a high speed telecommunication channel. The inverter would upon this situation stop symmetrisation of its commutation and would go on an individual control of each phase. A number of control actions would be started, such as the dynamic increase in commutation margin for the next commutations current compounding to enable the rectifier see a “positive resistance” at the inverter end, etc. At the dip of the DC voltage, the LCC rectifier would proportionally decrease its voltage and current to allow the LCC inverter quickly to recover already at the next commutation, hence trying to prevent a 12-pulse commutation failure, which would further provoke a full DC voltage collapse. In summary the LCC rectifier would allow the inverter to recover in a smooth manner and increase its voltage back to normal only when the inverter is ready. Upon recovery the inverter would resume its normal symmetrised minimum commutation margin (Gamma).

The described coordination is possible between two LCC converters operating respectively as rectifier and inverter. There are two main functions which are very well-known which impose static and dynamic characteristics in the rectifier to coordinate its operation with those of the inverter, namely the Voltage Dependent Current Order Limitation (VDCOL or VDCL) and the Rectifier Alpha Minimum Dynamic Limit (RAML) amongst other algorithms mentioned above. These functions establish a smooth transition between voltage and current control at the inverter, as well as push the exact amount of current the inverter can handle to avoid persistent commutation failures during AC voltage transient recovery following AC or DC fault inception and clearance, or to manage and minimise spurious random commutation failures. This is made to achieve optimum dynamic performance and resume power transmission to pre-fault levels within 100 – 200 ms after the fault has been removed. These mechanisms would also provide fault ride through capability, and for most unsymmetrical AC faults with volts being available at the converter AC bus, allowing power to be transmitted even during the fault.

With VSC rectifier, the single 6-pulse commutation failure due to a minor AC voltage disturbance could potentially evolve into a much large disturbance with multiple 12-pulse commutation failures and even with complete de-energisation and re-energisation of the entire scheme by tripping AC breakers or DC breakers when they become available. This situation might lead in the worst case to a permanent trip of the link, because full reliance would have to be made on fast telecommunication protective channels, and these should be considered to be out of service as the first contingency excluding the fault itself.

Furthermore a much worse scenario would develop for actual faults in the AC system. The HVDC link which would normally be capable of providing fault ride through performance and deliver as much power as possible during grid faults to avoid dynamic instability would not in this case. Thus the recovery would be slow after faults and no damping control would be provided. The conclusion is that in this arrangement all the functionality would have its capability impaired.

Another potential disadvantage of having the VSC rectifier in DC voltage control with the LCC inverter trying to control its current is simply the higher rating this would imply for the LCC inverter with consequential costs.

The reason is that in classic LCC transmission inverters normally control their DC voltage, operating with negative current order margin and at its voltage ceiling, allowing the On Load Tap Changer OLTC and the reactive power control function to adjust AC and DC voltages. This results into operation at the minimum specified commutation margin at the inverter side, which then generate savings in MVA ratings for valves and transformers, reduction of harmonics and thereby AC and DC filters sizes, as well as reduction of the ohmic losses by running at minimum control angles near softer switching.

One potential solution to accomplish a VSC rectifier working with a LCC inverter is if the VSC rectifier could operate as an LCC rectifier. The only case this can be realised is if the VSC rectifier is provided with full-bridge configuration, hence being able to reduce and mirror the voltage drop on the inverter side, using a function that emulates the VDCOL function mentioned above.

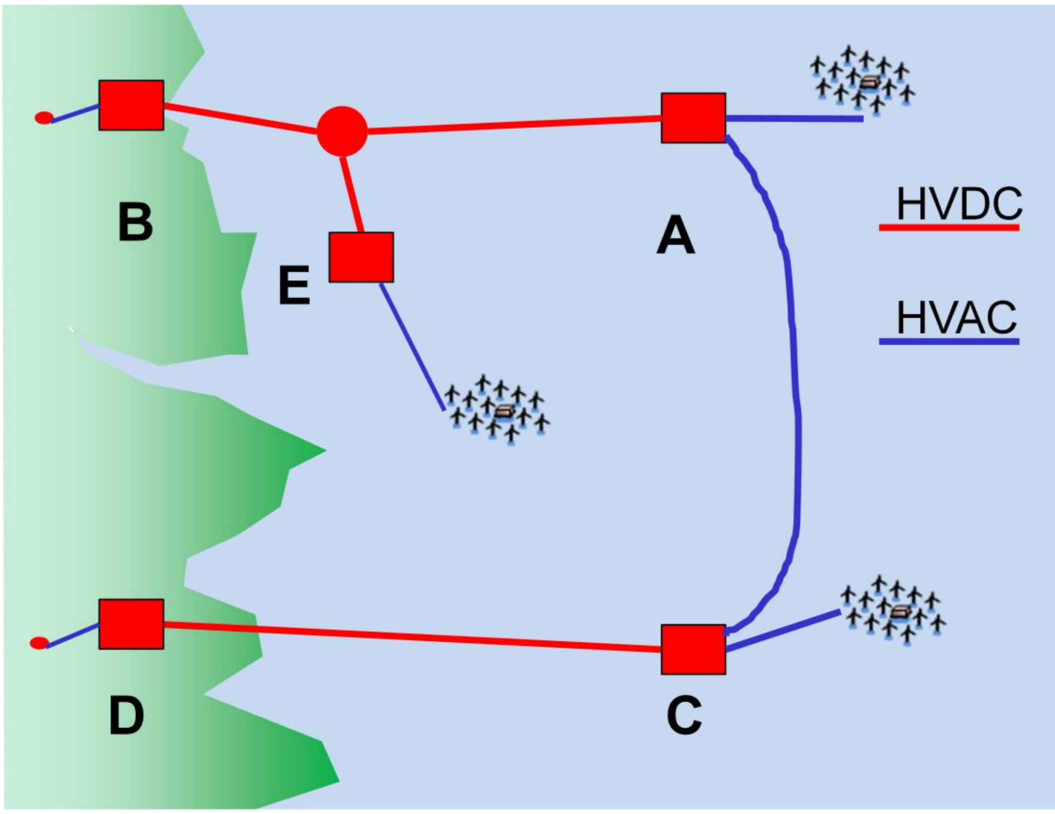
On the other hand a LCC rectifier potentially could feed power to an inverter VSC. In this scenario the LCC rectifier would be offshore and have a VSC inverter onshore. The main issues with this case would be again the lack of black start up capability at the OWF AC platform, the reactive power requirements would have to be met by the OWF WTGs and corresponding array cables, which would have to suffer an increase in ratings, or shunt compensation could be provided at the HVDC platform making its sheer size much larger in footprint.

Assuming an acceptable solution is found for the black start of the OWF AC platform, different start up sequences could be tried for the HVDC transmission, involving LCC rectifiers normally starting at lower voltages, to build it up smoothly to establish a minimum current, say 3 – 10% of the rated current, normally at control angles around 90 degrees. This would result in the least stress for equipment including cables and converters, which otherwise would have to operate with discontinuous current leading to voltage transients and protective firing of thyristor levels.

In this case the VSC inverters would not manage if configured with half bridges, as they would lose their control capability as the DC voltage would be at a level below the minimum converter AC voltage leading to uncontrolled rectification of the 6-pulse Graetz-bridge formed by the anti-parallel diodes.

Therefore it is anticipated that in this case only full bridge VSC converters would handle to operate as an inverter having a LCC rectifier.

Potential combinations of LCC and VSC can be envisaged and these are illustrated in Figure 24 and Table 11.



▪ **Figure 24 Scheme 3 Hybrid VSC-LCC Configuration**

The high level assessment of the viability of each of these options is provided in Table 11.

▪ **Table 11 Summary of VSC-LCC Hybrid Arrangements**

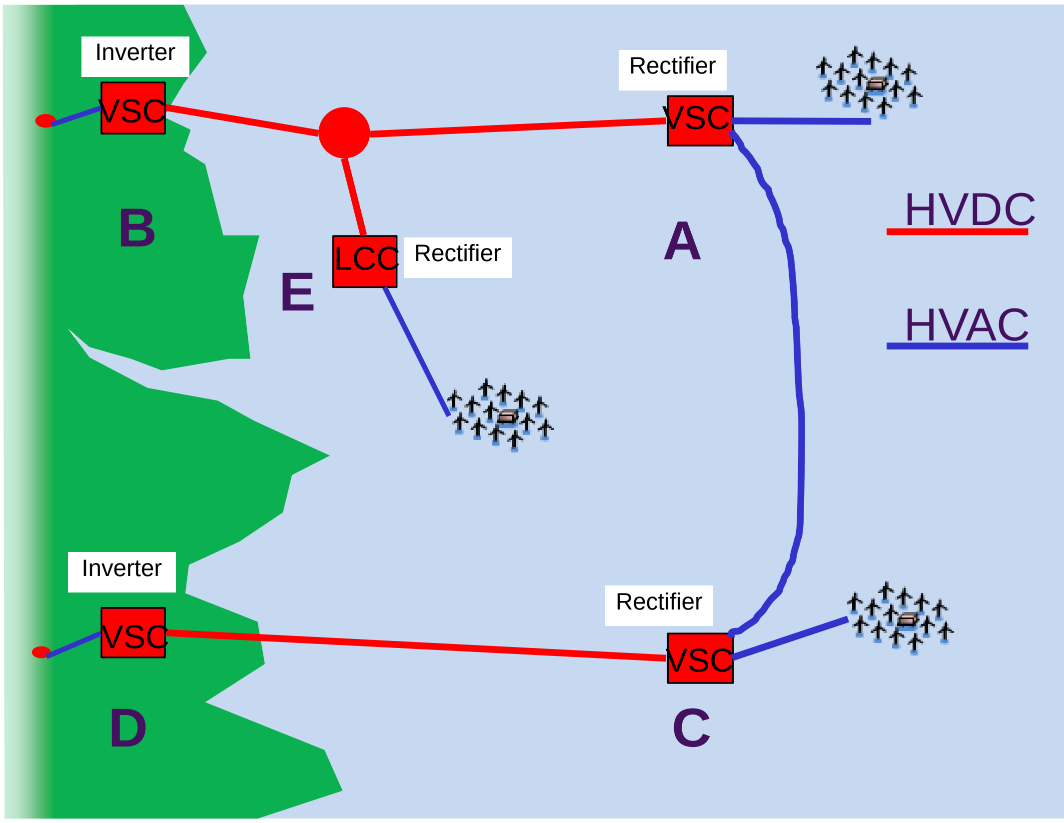
	9. Node Converter Type						
Scheme	**A**	**B**	**C**	**D**	**E**	**Status**	**Explanation**
1	VSC	VSC	VSC	VSC	VSC	OK	Fully functional VSC multi-terminal scheme
2	VSC	VSC	VSC	VSC	LCC	Not OK	No black start capability for LCC at E
3	VSC	VSC	VSC	LCC	VSC	Not OK	LCC inverter with VSC rectifier[54]
4	VSC	VSC	LCC	LCC	VSC	OK	If AC interconnection is available
5	VSC	LCC	LCC	LCC	VSC	Not OK	LCC inverter with VSC rectifier
6	LCC	LCC	LCC	LCC	LCC	Not OK	No Black start capability for LCC at A, C E
7	LCC	LCC	LCC	LCC	VSC	Not OK	No Black start capability for LCC at A, C
8	LCC	LCC	LCC	VSC	VSC	Not OK	No Black start capability for LCC at A, C
9	LCC	LCC	VSC	VSC	VSC	OK	Functional scheme
10	LCC	VSC	VSC	VSC	VSC	OK	Can be made functional

[54] Could be feasible with a VSC full-bridge converter

To illustrate how the Table has been constructed and the rules that are applied the examples below demonstrate the normal running arrangements and black-start arrangements for schemes 2, 3 and 4.

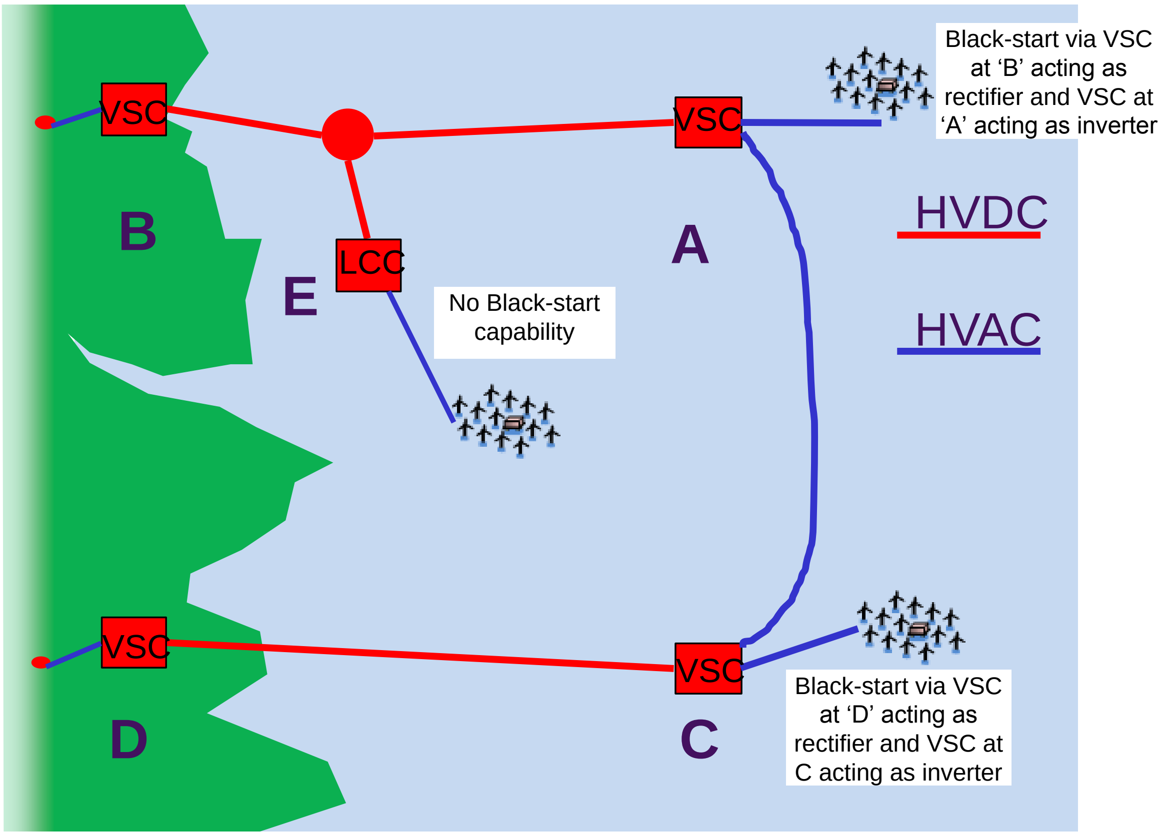
Scheme 2 – Under normal operation this scheme would have the following arrangement:

- **Figure 25 - Hybrid Scheme 2 Normal Running Arrangement**



In this arrangement, the DC to AC inversion is achieved using VSCs at B and D therefore the scheme is potentially viable from a normal running arrangement point of view as there is no LCC acting as an inverter with an associated VSC rectifier. However the black-start arrangements would only cover converter A and C as demonstrated in Figure 26.

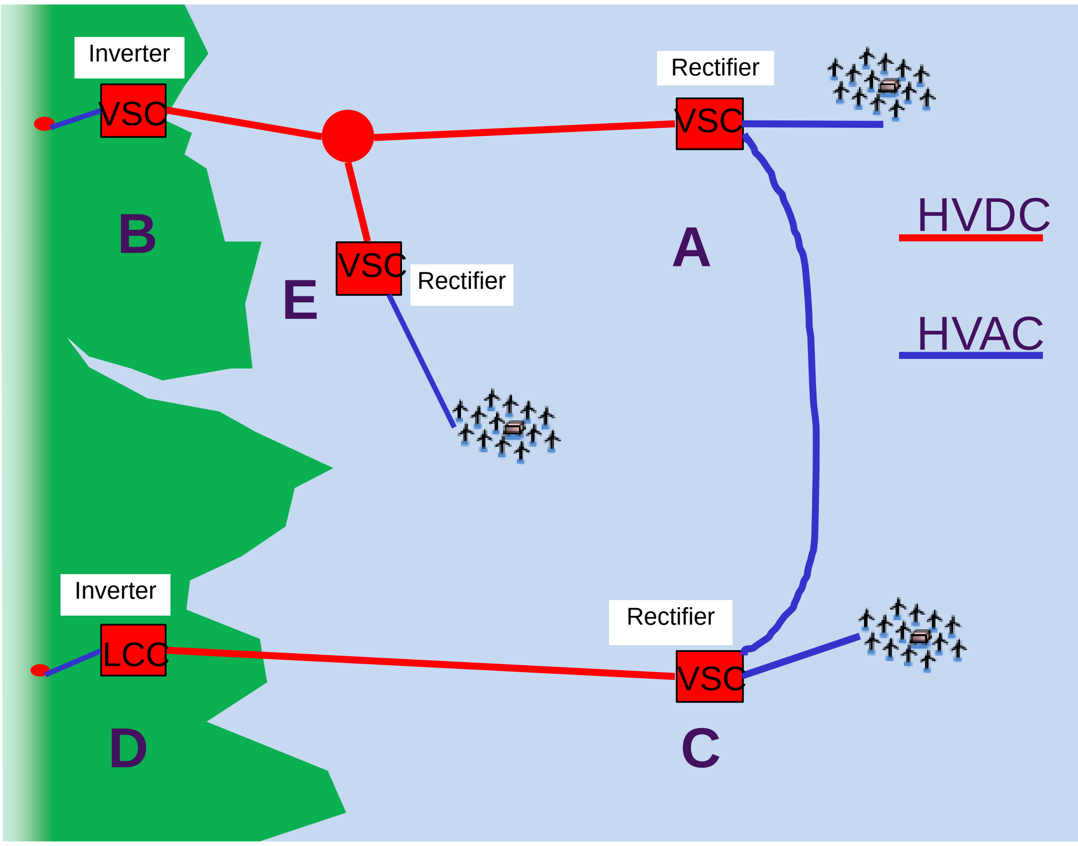
- **Figure 26 - Hybrid Scheme 2 Black-start Arrangements**



Scheme 2 is therefore not viable (without some additional black-start equipment) as no black-start arrangement is available for converter E.

Scheme 3 - Under normal operation would have the following arrangement:

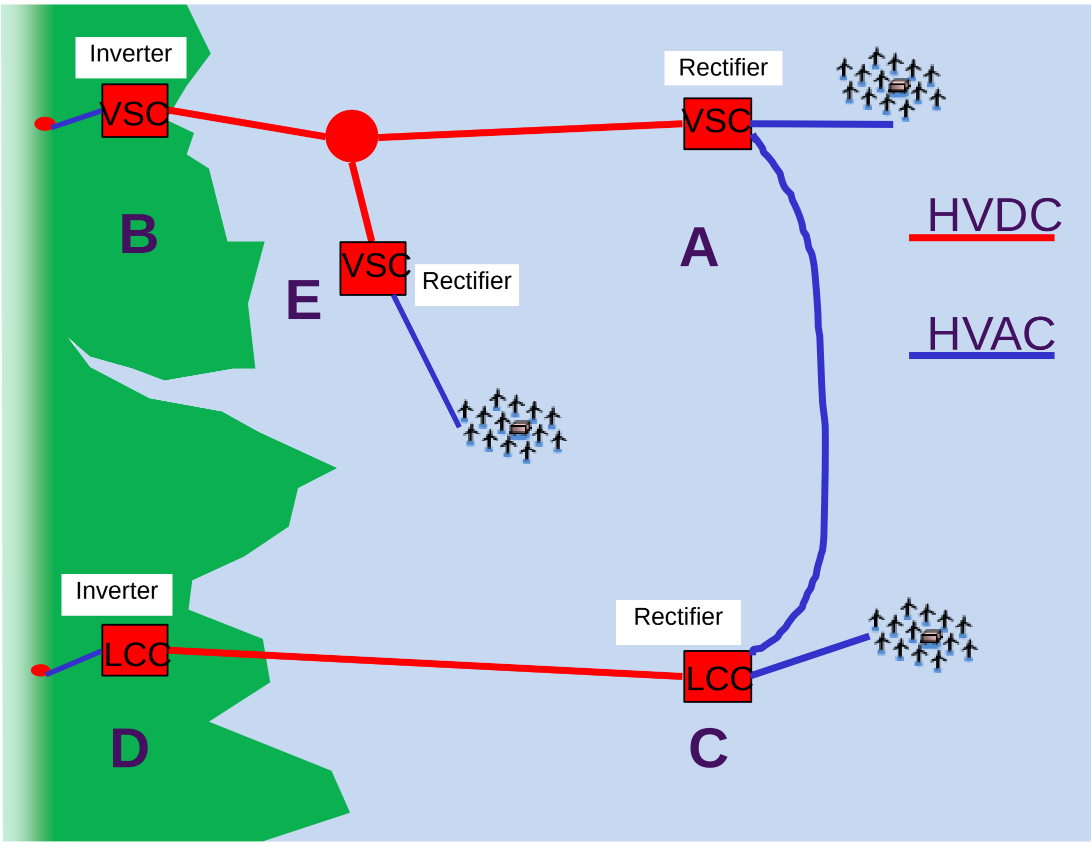
- **Figure 27 Hybrid Scheme 3 Normal Running Arrangements**



Scheme 3 is therefore not viable as it requires an LCC at D to act as an inverter with the DC power supplied by a VSC rectifier at C.

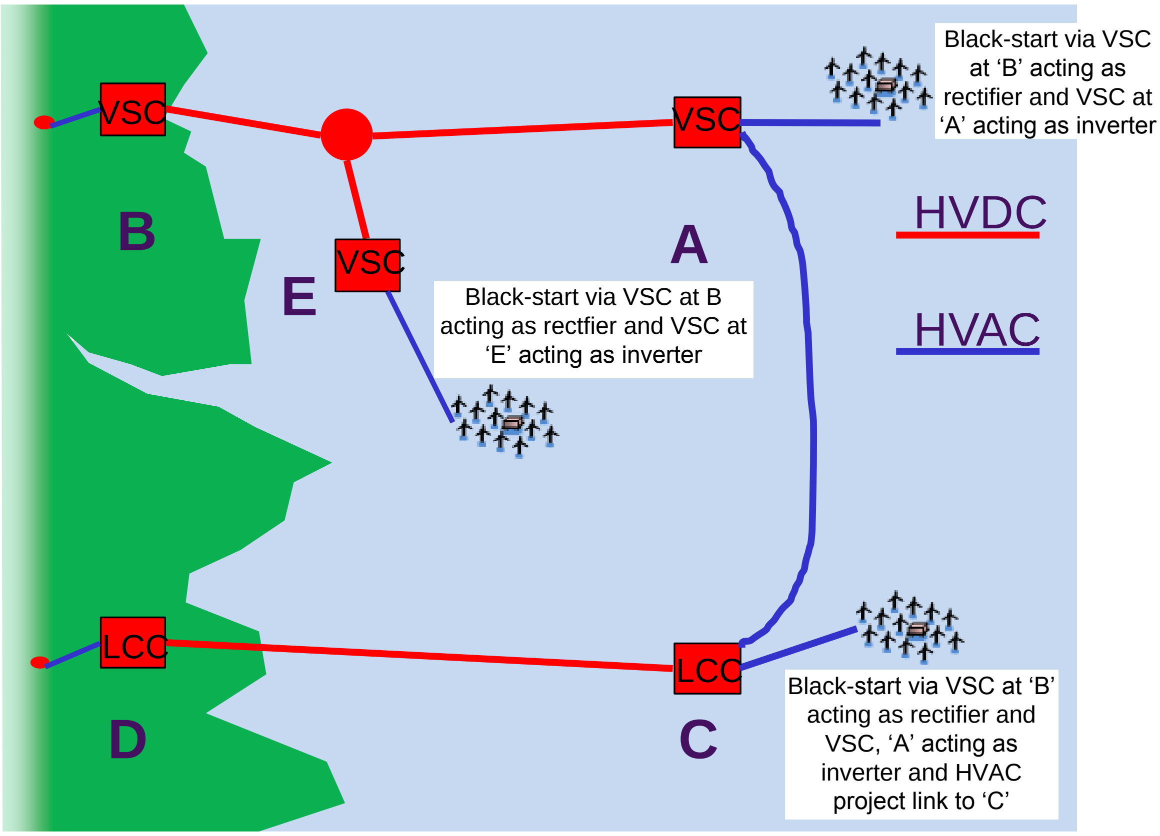
Scheme 4 - Under normal operation would have the following arrangement:

▪ **Figure 28 - Hybrid Scheme 4 Normal Running Arrangements**



In normal running arrangements, the inversion at B is achieved via a VSC converter with two associated VSC rectifiers. The inversion at D is achieved with an LCC converter with a single associated LCC converter. This satisfies the requirements under normal running arrangement and therefore is viable from this point of view. The black-start arrangements are shown below:

- **Figure 29 - Hybrid Scheme 4 Black-start Arrangements**



All of the converters have a black-start supply available and this scheme is therefore potentially viable.

In summary it can be said that in hybrid configurations including LCC and VSC, the capability to provide black start is the main limiting factor. When this difficulty is overcome, for example by being able to black start by an AC project link between OWFs, the stiff voltage of the VSC transmission would become the limitation, which could be overcome by the use of full bridge VSC converters which would then be required if these hybrid solutions proved to be economic.

To determine the potential functionality of such hybrid schemes would require significant further study and system simulations studies using appropriate software/hardware configurations and representations of the control systems in order to provide a more definitive answer of which combinations would work best from a dynamic performance point of view. The review here is provided for guidance only.