# Appendix E
# **Technology**

# E.1
# HVDC: Voltage Source Converters

## Description

Figure E.1
BorWin1 HVDC platform, North Sea
Image courtesy of ABB

Converters form the terminals of an HVDC transmission system and are used to convert AC power to DC (rectifier) and DC power to AC (inverter). Voltage Source Converters (VSC) have been used in HVDC transmission systems since the late 1990s [1]. VSC technology is distinguished from the more conventional Current Source Converter (CSC) technology by the use of self commutated semiconductor devices such as Insulated Gate Bipolar Transistors (IGBTs), which have the ability to be turned on and off by a gate signal and endow VSC HVDC systems with a number of advantages for power system applications.

Most of the VSC HVDC systems installed to date use the two- or three-level converter principle with Pulse Width Modulation (PWM) switching. More recently, a multi-level HVDC converter principle has been introduced by most manufacturers and it is likely that all future VSC installations could be of a multi-level or hybrid configuration.

VSC is a practical solution where an offshore wind farm requires an HVDC connection.

## Capabilities

The VSC HVDC systems installed so far have been limited to lower voltage and power ratings than CSC systems. Notwithstanding this significant development has occurred and while the highest transmission capacity for a VSC HVDC transmission system in operation to date is 400 MW [2], there are two projects with a transmission capacity of 800 MW due to be commissioned in 2013 [3, 4] along with a 2 x 1000 MW system due for the same year [5]. Further to this is a 700 MW monopole system due for commissioning in 2014 [6] that implies that a 1400 MW bi-pole VSC HVDC system is technically feasible.

VSCs are capable of generating or absorbing reactive power and allow real and reactive power to be controlled independently. The direction of power flow may be reversed without changing the polarity of the DC voltage. VSCs do not depend on the presence of a synchronous AC voltage for their operation and may be used to feed weak or passive networks.

VSC technology possesses the ability to restart a dead AC network in the event of a Blackout scenario. The fault ride through capability of VSC technology can useful to help satisfy Grid code requirements, whilst maintaining system stability.

VSC technology can also provide voltage support (STATCOM operation) to a local AC network during fault conditions or during occurrences of system instability.

A VSC has a smaller footprint and less weight than a CSC with equivalent ratings. Indicative typical dimensions for a 1000 MW VSC located onshore are 90 m x 54 m x 24 m [7].

Converter losses are approximately 1% of transmitted power (per end) for a multi-level converter [8].

VSCs are able to meet the requirements of the System Operator – Transmission Owner Code at the Interface Point including reactive power capability, voltage control, fault ride through capability, operation over a range of frequencies and can provide power oscillation damping.

Since the power flow is reversed without changing the polarity of the DC voltage and since the IGBT valves do not suffer commutation failures, VSC technology is, in principle, well suited to multi-terminal applications.

## Availability

Suppliers include ABB, Siemens and Alstom Grid, with other potential Eastern World Suppliers also able to deliver VSC solutions. Lead times are dependent on the requirements of a given project and are typically 2 to 3 years. The lead time for a project may be dominated by any associated cable manufacturing time.

## Dependencies and Impacts

The ability to reverse power flow without changing the voltage polarity allows VSC HVDC transmission systems to use extruded cables which are lower in cost than the alternative mass impregnated cables. However, where extruded cables are used, the achievable transmission capacity may be limited by the ratings of the cable rather than the converter.

Experience with VSC technology in HVDC systems dates from the late 1990s and although increasing, consequently, there is little information on the reliability and performance of VSC HVDC systems.

## Project Examples

- **Borwin1:** The project connects the Borkum 2 wind farm to the German transmission system by means of a 125 km HVDC circuit comprising submarine and land cables [3]. The connection has a transmission capacity of 400 MW at a DC voltage of +/- 150 kV and is due to be commissioned in 2012. The converter stations and cables were supplied by ABB. The project is the first application of HVDC technology to an offshore wind farm connection.
- **France Spain Interconnector:** This project is an interconnector project that will interconnect the French and Spanish Transmission systems. It consists of two 1 GW HVDC bi-poles 60 km apart on either side of the Pyrenees. The total transmission capacity will be 2 GW and both bipoles will operate a DC voltage of ±320 kV. The link is due to be commissioned in 2013.

Figure E.2
Borwin1 offshore 400 MW converter

- **Borwin2:** The project will connect the Veja Mate and Global Tech 1 offshore wind farms to the German transmission system by means of a HVDC submarine cable [4]. The connection will have a transmission capacity of 800 MW at a DC voltage of +/- 300 kV and is due to begin operation in 2013. The converters will be supplied by Siemens and will be the first application of multi-level VSC technology to an offshore wind farm connection.

## Information and Additional Information


[1] CIGRE Working Group B4.37, 'VSC Transmission', Ref. 269, April 2005 http://www.e-cigre.org/

[2] Transbay HVDC Plus Link http://www.energy.siemens.com/hq/pool/hq/power-transmission/HVDC/HVDC-PLUS/pm-pdf/Press_TransBay_2007_10_10_e.pdf

[3] DolWin 1HVDC Light http://www.abb.co.uk/industries/ap/db0003db004333/8b74a5fe4cc03e44c125777c003f3203.aspx

[4] BorWin2 HVDC Plus http://www.energy.siemens.com/hq/en/power-transmission/grid-access-solutions/references.htm#content=2013%3A%20800%20MW%20offshore%20HVDC%20PLUS%20link%20BorWin2%2C%20Germany

[5] France Spain interconnector http://www.energy.siemens.com/hq/pool/hq/power-transmission/HVDC/HVDC-PLUS/pm-pdf/INELFE_en.pdf

[6] Skagerrak 4 http://www.abb.co.uk/industries/ap/db0003db004333/448a5eca0d6e15d3c12578310031e3a7.aspx

[7] ABB, 'It's time to connect – Technical description of HVDC Light® technology', [Online] http://library.abb.com/global/scot/scot221.nsf/veritydisplay/bcd2f0a98218a66bc1257472004b83a8/$File/Pow0038%20rev5.pdf

[8] Jacobson, B. et al, "VSC-HVDC Transmission with Cascaded Two-Level Converters", 2010, Cigre B4-110

# E.2
# HV Cables Systems and Overhead Lines: HVDC Extruded Cables

## Description

Figure E.3
Image courtesy of Prysmian

Extruded HVDC cables use cross-linked polyethylene (XLPE) for their insulation. The insulation is extruded over a copper or aluminium conductor (copper has a lower resistance and thus a higher power density, although it is heavier and more expensive than aluminium) and covered with a water tight sheath, usually of extruded seamless lead for submarine cables or welded aluminium laminate for land cables, and a further protective polyethylene plastic coating.

Extruded XLPE insulation is a relatively new entry to the HVDC cable market, previously dominated by Mass Impregnated cables. XLPE insulated cables are generally mechanically robust and they may operate at higher temperatures (70 $^{o}$C) than Mass Impregnated (MI) cable designs (aside from Polypropylene Laminated MI) allowing them to carry more current for a given conductor cross section.

Cables intended for submarine use have an additional layer of galvanised steel wire armour to increase the cable's tensile strength so it can better withstand the stresses of submarine installation. This is usually a single layer of wires helically wound around the cable (although in deeper waters or over rocky sea beds a double layer may be used) covered in a serving of bitumen impregnated polypropylene yarn to inhibit corrosion. Submarine cables usually utilise copper as the conductor while Aluminium is often used for land cables.

## Capabilities

Extruded HVDC cables are presently available in voltages up to 320 kV. The table below gives an example of cable systems for the stated power transfers and are for indicative purposes only, actual cable system designs will vary from project to project.

**Table E.1**

| | | Typical Submarine Cable Cu Conductor | | | Typical Land Cable Al Conductor | | |
|---|---|---|---|---|---|---|---|
| **Bipole Capacity (MW)** | **Voltage (+/- kV)** | **Cross Section ($mm^2$)** | **Weight (kg/m)** | **Diameter (mm)** | **Cross Section ($mm^2$)** | **Weight (kg/m)** | **Diameter (mm)** |
| **200** | 150 | 400 | 17 | 79 | 500 | 5 | 62 |
| | 200 | 185 | 15 | 78 | 300 | 5 | 62 |
| **300** | 150 | 630 | 21 | 85 | 1000 | 7 | 73 |
| | 200 | 400 | 19 | 85 | 630 | 6 | 71 |
| | 320 | 185 | 17 | 84 | 300 | 5 | 68 |
| **400** | 150 | 1200 | 29 | 96 | 1600 | 9 | 82 |
| | 200 | 630 | 22 | 91 | 1000 | 8 | 79 |
| | 320 | 300 | 19 | 88 | 500 | 6 | 71 |
| **500** | 150 | 1800 | 39 | 105 | 2400 | 12 | 93 |
| | 200 | 1000 | 29 | 99 | 1600 | 10 | 88 |
| | 320 | 500 | 22 | 94 | 630 | 9 | 93 |
| **600** | 150 | 2200 | 44 | 112 | X | X | X |
| | 200 | 1400 | 36 | 108 | 2000 | 12 | 94 |
| | 320 | 630 | 24 | 97 | 1000 | 9 | 85 |
| **800** | 200 | 2200 | 46 | 120 | X | X | X |
| | 320 | 1000 | 33 | 107 | 1600 | 11 | 94 |
| **1000** | 320 | 1600 | 41 | 116 | 2400 | 14 | 105 |

The following assumptions were made for the above table:

Ground/sea bed temperature 15ºC, burial 1.0m, thermal resistivity 1 kW/m, 4 mm steel round wire armour, bipole laid as bundle. Physical characteristics are given for a single cable; bundle weight is twice that of a single cable. Ratings calculated from IEC 60287 [1].

Subsea XLPE cables have been successfully deployed at a depth of 200m.

Ratings calculated from IEC 60287 [1]. Laying cables separately so that they are thermally independent would result in a reduced conductor cross section for a given power transfer.

### Availability

Suppliers: The ABB cable factory in Karlskrona, Sweden is undergoing expansion to accommodate the manufacture of submarine cables. The Prysmian cable factory in Naples, Italy is also being expanded to supply the 600kV dc cable for the Western HVDC link project.

In America, Nexans, Prysmian and ABB are all building new factories with completion dates between 2012-2014. While Nexans and Prysmian facilities are located in South Carolina and focused towards the production of extruded underground & submarine cables, ABB on the other hand is located in North Carolina and focused on EHV AC & DC underground cables.

Supply and installation times are highly dependent upon the length of cable required, the design and testing necessary (using an already proven cable design removes the development lead time) but are generally in the region of two to three years.

### Dependancies and Impacts

With all plastic insulation, there is minimal environmental impact in the case of external damage. XLPE cable joints are pre-fabricated and thus require less time per joint than those required for mass impregnated cables and are therefore less expensive. This has benefits for land applications where individual drum lengths are shorter and there are a correspondingly higher number of joints. For long submarine cable connections the manufacturing extrusion lengths of the XLPE cable is shorter than that of similar MI cable and a higher number of factory joints are therefore necessary.

Presently XLPE extruded cables are only used with Voltage Source Converter (VSC) HVDC systems due to the risk represented by voltage polarity reversal and space charge effects [2]. Some suppliers are testing extruded cables to meet CIGRE LCC type test requirements.

### Project Examples

- **NordE.ON1 Offshore 1 Windfarm:** ±150 kV 400 MW DC bipole, two 128 km parallel 1600 mm² cables [3].
- **Trans Bay Cable:** 400MW, ±200kV DC, 1100mm² CU, bipole with fibre optic laid as single bundle (254 mm diameter), 88 km in length [4].
- **Sydvastlanken, Sweden:** ±300KV,2x660MW, 200km [6].
- **Inelfe, France-Spain:** 2x1000MW, 320KV, 64km land route, 252km of cable, 2 x bipole [6].

### References and Additional Information


[1] International Electrotechnical Committee, *IEC 60287: Electric Cables - Calculation of the Current Rating*, 1995

[2] Electric Power Research Institute, *DC Cable Systems with Extruded Dielectric*, Dec 2004. Compiled by Cable Consulting International.

[3] ABB, NordE.ON 1 – the world's largest offshore wind farm HVDC Light® Offshore Wind Farm Link. [Accessed: Sept. 26, 2012]. Available: http://www05.abb.com/global/scot/scot221.nsf/veritydisplay/48f35510b32f309dc1257459006e45e1/$File/DEABB%201396%2008%20E%20ABB%20goes%20offshore%20080408.pdf

[4] M. Marelli, A. Orini, G. Miramonti, G. Pozzati, Challenges and Achievements For New HVDC Cable Connections, Prysmian.
Cigre B4 Norway 2010 Session 205 paper 2

[5] ABB, Murraylink – the worlds longest underground power link. [Online]. [Accessed: Sept. 27, 2012]. Available: http://www.abb.co.uk/industries/ap/db0003db004333/840b1dc566685f86c125774b003f8f37.aspx

# E.3
# HV Cables Systems and Overhead Lines: HVDC Mass Impregnated Insulated Subsea Cables

## Description

**Figure E.4**
**Neptune 500kV bundle [8]**
**Image courtesy of Prysmian**
***(lightly insulated XLPE return cable is shown on the right, smaller fibre optic communications cable in the centre.)***

HVDC Mass Impregnated (MI) insulated cable systems are a mature technology (in use since the 1950s) with an excellent tradition of high reliability and performance. They permit very high power transfers per cable and are suitable for use with both CSC and VSC converter station technologies. Voltage levels are now approaching 600 kV.

The conductor is usually copper due to the lower temperature these cables are permitted to operate at (55$^{o}$C) but may also be aluminium. The insulation is made from layers of high density oil impregnated papers. Polypropylene laminated paper designs (PPLP) with the potential to increase operating temperatures to 85$^{o}$C for very high power applications exist (but these are as yet untested).

The insulation is surrounded by a lead sheath (for both land and sea cables – both to add mechanical strength and to protect the insulation from water ingress) which is then covered with a plastic corrosion inhibiting coating.

Cables intended for submarine use have an additional layer of galvanised steel wire armour to increase the cable's tensile strength so it can better withstand the stresses of submarine installation. This is usually a single layer of wires helically wound around the cable (although in deeper waters or over rocky sea beds this may be a double layer) covered in a serving of bitumen impregnated polypropylene yarn to inhibit corrosion. Submarine cables usually utilise copper as the conductor.

Conventionally HVDC cable system designs tend to use single concentric conductor designs in a range of configurations depending on the return current arrangements. A dual concentric conductor design exists which allows some power transmission capability following a single cable fault (monopolar operation on a single cable with a return conductor), albeit at a reduced rating [1]

## Capabilities

MI HVDC cables are usually designed and manufactured according to specific project requirements. They are available up to voltages of 600 kV and ratings of 2500 MW/bipole; although the maximum contracted rating is 500 kV and 800 MW on a single cable (Fenno-Skan 2 [4]). The following are some cable specifications for particular projects:

**Table E.2**

| Project | NorNed [3] & [6] | BritNed [5] | Neptune [2] | Sapei [2] | Bass Link [2] |
|---|---|---|---|---|---|
| **Type** | Bipole | Bipole | Monopole + ret | Bipole + emergency return | Monopole + ret |
| **Capacity** | 700 MW | 1000 MW | 600 MW cont 750 MW peak | 2x500 MW | 500 MW |
| **Voltage** | ±450 kV | 450 kV | 500 kV | 500 kV | 400 kV |
| **Core Type** | Two Core + Single Core in Deep Water | Single Core | Single Core | Single Core | Single Core |
| **Core Area** | 790 mm$^2$ | 1430 mm$^2$ | 2100 mm$^2$ | 1000 mm$^2$ Cu (shallow waters) and 1150 mm$^2$ Al (deep waters) | 1500 mm$^2$ |
| **Weight** | 84 kg/m | 44 kg/m | 53.5 kg/m | 37 kg/m | 43 kg/m |

Cable lengths of several hundred kilometres can be manufactured, the limitation being the weight of cable the transportation vessel or cable drum can carry. MI cable has been installed at water depths of up to 1650m [2]. Typical weights for a single core cable are 30 to 60 kg/m with diameters of 110 to 140 mm [2].

### Availability

Suppliers: ABB (cable factory in Karlskrona, Sweden), Prysmian (cable factory in Naples, Italy) and Nexans (cable factory in Halden, Norway). Mass impregnated cable is more complex, time consuming and expensive to manufacture than extruded XLPE cables.

Supply and installation times are highly dependent upon the length of cable required and design and testing necessary (using an already proven cable design removes the development lead time), but are generally in the range of two to four years.

### Dependancies and Impacts

Where required, cable joints are time consuming to prepare and make (three to five days each) and hence expensive, which makes this cable less competitive for onshore application in the range of HVDC voltages up to 320 kV, although projects with up to 90 km of MI land conductors have been let.

MI cables weigh more than XLPE cables but XLPE cables of equivalent rating tend to be physically larger than MI cables, so that transportable lengths will not differ by much.

There are only three European suppliers with factories capable of manufacturing HVDC mass impregnated cables.

There are not thought to be significant differences in the robustness of XLPE or MI insulation, both of which need similar levels of care during installation.

Due to the high viscosity of the oil, mass impregnated cables do not leak oil into the environment if damaged [7].

### Project Examples

- **NorNed:** ±450 kV DC bipole, 700 MW, 580 km cable supplied by ABB, links Norway and The Netherlands. The cable was produced in six continuous lengths of up to 154 km of single-core and 75 km of twin-core. Five cable joints were required offshore [3].
- **Basslink:** 400 kV DC monopole, 500 MW, 290 km cable supplied by Prysmian, linking Tasmania to Australian mainland. The cable is a 1500 $mm^2$ conductor plus metallic return and fibre optic, has a diameter of 150 mm and weighs 60 kg/m. The water depth is 80m. In service from 2006 [2].
- **Fenno-Skan 2:** 500 kV DC, 200 km, 2000 $mm^2$ cable to be supplied and installed by Nexans in 2011 will link Finland and Sweden. The cable is supplied in two continuous lengths of 100 km so only one joint is required offshore. The cable will add 800 MW transfer capability to the existing monopole link. The contract value is 150 million euro [4].
- **SAPEI:** 500 kV, two DC monopoles, 2x500 MW, 420 km cable route supplied by Prysmian links Sardinia to the Italy mainland. The cable is a 1000 $mm^2$ copper conductor for the low-medium water depth portion (max 400 m) and 1150 $mm^2$ aluminium conductor for the high water depth part (up to 1650 m). Pole 1 was completed in 2008 and was operated as a monopole with sea return for a temporary period. In 2010 Pole 2 was completed and the system is now operating as a full bipole [2].

### References and Additional Information


[1] Harvey, C. Stenseth, K. Wohlmuth, M., *The Moyle HVDC Interconnector: project considerations, design and implementation*, AC-DC Power Transmission, 2001. Seventh International Conference on (Conf. Publ. No. 485)

[2] M. Marelli, A. Orini, G. Miramonti, G. Pozzati, *Challenges and Achievements For New HVDC Cable Connections*, Prysmian, Cigre B4 Norway 2010 Session 205 paper 2

[3] ABB, *The NorNed HVDC Connection, Norway – Netherlands*. [Online]. [Accessed: Sept. 1, 2012]. Available: http://library.abb.com/global/scot/scot245.nsf/veritydisplay/2402665447f2d054c12571fb00333968/$File/Project%20NorNed%20450%20kV%20DC%20MI%20sub.pdf

[4] Nexans, *Nexans wins 150 million Euro submarine power cable contract to interconnect Finland and Sweden*, Press Release, Mar. 19 2008. [Online]. Accessed: Jul. 15, 2010]. Available: http://www.nexans.com/Corporate/2008/Nexans_Fenno_Skan%202_GB_1.pdf

[5] ABB, *BritNed – interconnecting the Netherlands and U.K. power grids*. [Online]. [Accessed: Sept. 1, 2012]. Available: http://www05.abb.com/global/scot/scot245.nsf/veritydisplay/1efa2a0680f6b39ec125777c003276c9/$file/project%20britned%20450%20kv%20mi%20subm-land%20rev%204.pdf

[6] J. E. Skog, Statnett SF, *NorNed – Innovative Use of Proven Technology*, [Online], [Accessed July. 15, 2010]. http://www.cigrescb4norway.com/Documents/Presentations/Session%203/Presentation%20302%20NorNed.pdf

[7] Thomas Worzyk, *Submarine Power Cables: Design, Installation, Repair, Environmental Aspects,* Published 2009 ISBN 978-3-642-01270-9

E.4

# HV Cables Systems and Overhead Lines: HVDC Overhead Lines

### Description

Figure E.5
Bipolar Tower 300kV Link
Photo courtesy of Siemens

HVDC overhead lines can be used to transmit large quantities of power at the highest DC voltages over long distances onshore. HVDC overhead lines are an alternative to AC overhead lines and cables and HVDC cables for land applications.

The main differences between AC and DC lines are: conductor configuration, electric field requirements and insulation design. A DC tower carries two conductors for a bipole compared to three conductors for a single AC circuit or six conductors for a double AC circuit. The land use requirements (area for towers and lines) for HVDC for a given transfer capacity and reliability are about two thirds that for AC. Overhead lines rely on air for insulation and heat dissipation. The thermal time constants for OHL are therefore generally much shorter than for cables.

Insulators separate the conductors from the steel tower body. One of the main requirements of insulator design is to have a long creepage path as pollution, such as salt deposits, on the surface of the insulator can cause the insulation to flash over. DC insulators are subject to increased contamination due to the electrostatic attraction caused by the constant DC electric field. Therefore they need to be designed with longer creepage paths (43.3 kV/mm for AC insulators under heavy pollution levels [3] relative to 53-59 kV/mm for DC insulators [2]) [1] and polymeric insulators, which have improved performance in highly polluted environments, may be favoured. Pollution levels in the UK outside of coastal areas have been falling with the recent demise of heavy industry.

### Capabilities

Construction of an overhead line comprises the foundations, footings, towers, conductors, lightning protection earthing conductor(s) (shield wires) and fittings such as insulators, spacers, dampers and surge arresters. There are similar planning, easement, access and land compensation considerations to cables, in addition to the differences in impact on visual amenity.

Due to the high potential voltage and current ratings of HVDC lines, power transfer capabilities are usually dictated by the converter station equipment at either end of the route. At 500 kV transfers of 4 GW are possible on a single bipole, and 800 kV permits transfers of 6.4 GW.

HVDC overhead lines may operate as a monopole in the event of a single pole line fault provided an earth return path is present (e.g. the earth wire must be lightly insulated). In this case the availability of HVDC lines is expected to be similar to double circuit AC lines.

### Availability

There are several distinct components to overhead line construction such as civil works, tower steel fabrication, insulators, and conductor and specialist suppliers for these individual elements. No HVDC overhead lines have been built in the UK to date.

### Dependancies and Impacts

Overhead lines have an enduring impact on visual amenity compared with underground cables and generate some audible noise (particularly in fair weather [1]).

The installation of overhead lines circuits is potentially less disruptive than the installation of cables where the continuous linear nature of the construction at ground level can require road closures and diversions for significant periods. However, achieving planning consent for overhead line routes can be more challenging as the recent Beauly Denny public inquiry has demonstrated (consultation documents available [6]).

Overhead lines are less costly than underground cables and may be able to follow shorter, more direct routes. As HVDC bipolar overhead lines only require two conductors the transmission towers are simpler in design and shorter in height than the three phase HVAC towers of equal capacity and comparable voltage levels, which may prove more acceptable from a planning perspective.

## Project Examples

- **Pacific DC Intertie:** 500 kV HVDC, 3.1 GW, 1362 km overhead bipole [3]
- **Caprivi Link:** 300 kV VSC HVDC, 300 MW, 970 km overhead monopole (potential to upgrade to 2 x 300 MW bipole) [4]
- **Xiangjiaba, Shanghai:** 800 kV HVDC 6400 MW 2071 km overhead bipole using 6 × ACSR-720/50 steel core conductors. [5]
- **North East (India) - Agra:** 800 kV HVDC 8,000 MW 1,728 km multi-terminal bipole. [7]
- **Rio Madiera Brazil:** 600 kV HVDC 3,150 MW 2,500 km it will be the world's longest transmission link. Scheduled for completion in 2012. [8]

## References and Additional Information

[1] Electric Power Research Institute, *EPRI HVDC Reference Book: Overhead Lines for HVDC Transmission, Electrical Performance of HVDC Transmission Lines*, June 2008

[2] International Electrotechnical Committee, *IEC 60815 – Guide for the Selection of Insulators in Respect of Polluted Conditions*, 2008

[3] ABB, *Pacific HVDC Intertie* [Online]. [Accessed: Sept. 1, 2011]. Available: http://www.abb.co.uk/industries/ap/db0003db004333/95f257d2f5497e66c125774b0028f167.aspx

[4] ABB, *Caprivi Link Interconnector* [Online], [Accessed: Sept. 1, 2011]. Available: http://www.abb.co.uk/industries/ap/db0003db004333/86144ba5ad4bd540c12577490030e833.aspx

[5] PacRim Engineering, *800KV HIGH VOLTAGE DC (HVDC) TRANSMISSION LINE PROJECT FROM XIANGJIABA TO SHANGHAI*. [Accessed: Sept. 1, 2011]. Available: http://www.pacrimpowergroup.com/take%20all%20the%20files%20here%20and%20move%20it%20up%20a%20level/projects/projects%203.pdf

[6] Beauly Denny Public Inquiry [Online]. [Accessed: Sept. 1, 2011]. Available: http://www.beaulydenny.co.uk/

[7] ABB, North East - Agra (HVDC Reference Projects in Asia) [Online]. [Accessed Sept. 1, 2011] Available: http://www.abb.co.uk/industries/ap/db0003db004333/9716a8ac9879236bc125785200694f18.aspx

[8] ABB, Rio Madeira, Brazil (HVDC Reference Projects in South America) [Online]. [Accessed Sept. 1, 2011] Available: http://www.abb.co.uk/industries/ap/db0003db004333/137155e51dd72f1ec125774b004608ca.aspx

# E.5
# HVAC Cables Systems and Overhead Lines: HVAC Three Core AC Subsea Cables

### Description


Figure E.6
Image courtesy of Prysmian

AC three core cables have been the preferred technology for connecting offshore wind farms located close to shore having relatively low power transfer requirements.

Three core AC cables comprise three individually insulated single core cables (usually with XLPE insulation) laid up into a single cable with common over sheath and armouring with the option of incorporating a fibre optic cable for communications. Each cable has its own lead sheath to prevent water ingress. Copper is generally used as the conductor for subsea cables as it has a lower resistance than aluminium. Aluminium on the other hand is used mainly for land cables to reduce the cost and weight of the cable at the price of a reduction in rating (of approximately 20% for a given cross section).

A three core cable (1 x 3c) is somewhat larger and heavier than the equivalent three single core cables (3 x 1c). Laying a complete circuit in one trench however reduces installation costs and largely leads to the cancellation of magnetic fields and thus reduction of losses in the steel wire armour and reduction of the induced circulating currents which de-rate the cable system.

Three core AC cables are not generally used for onshore applications where their size and weight would render them impractical due to the number of joints required and difficulties in transport. Three single core AC cables are usually used instead.

### Capabilities

Three core AC cables are presently available in voltages up to 245 kV (220 kV nominal) and 400 MW transfers. The table below gives an example of cable systems for the stated power transfers and are for indicative purposes only, actual cable system designs will vary from project to project.

**Table E.3**

| Capacity (MW) | Voltage (kV) | Number of Cables Required | Cross Section ($mm^2$) | Weight (kg/m) | Diameter (mm) |
|---|---|---|---|---|---|
| **100** | 132 | 1 | 300 | 48 | 167 |
| **150** | 132 | 1 | 500 | 58 | 176 |
| **200** | 132 | 1 | 1000 | 85 | 206 |
| | 220 | 1 | 300 | 67 | 204 |
| **300** | 132 | 2 | 500 | 2x58 | 2x176 |
| | 220 | 1 | 800 | 95 | 234 |
| **400** | 132 | 2 | 1000 | 2x85 | 2x206 |
| | 220 | 2 | 300 | 2x67 | 2x204 |
| **500** | 132 | 3 | 630 | 3x65 | 3x185 |
| | 220 | 2 | 500 | 2x81 | 2x219 |
| **600** | 132 | 3 | 1000 | 3x85 | 3x206 |
| | 220 | 2 | 800 | 2x95 | 2x234 |
| **800** | 132 | 4 | 1000 | 4x85 | 4x206 |
| | 220 | 3 | 630 | 3x87 | 3x224 |
| **1000** | 132 | 5 | 1000 | 5x85 | 5x206 |
| | 220 | 3 | 1000 | 3x104 | 3x241 |

The following assumptions were made for the above table:-

Sea soil temperature 15ºC, burial 1.0m, thermal resistivity 1 kW/m, copper conductor, steel wire armour. The capacities data has been taken from references 1 and 2. 132 kV and 220 kV are the nominal voltage ratings. These cables can operate up to 145 kV and 245 kV respectively allowing slightly increased capacities on the same cables.

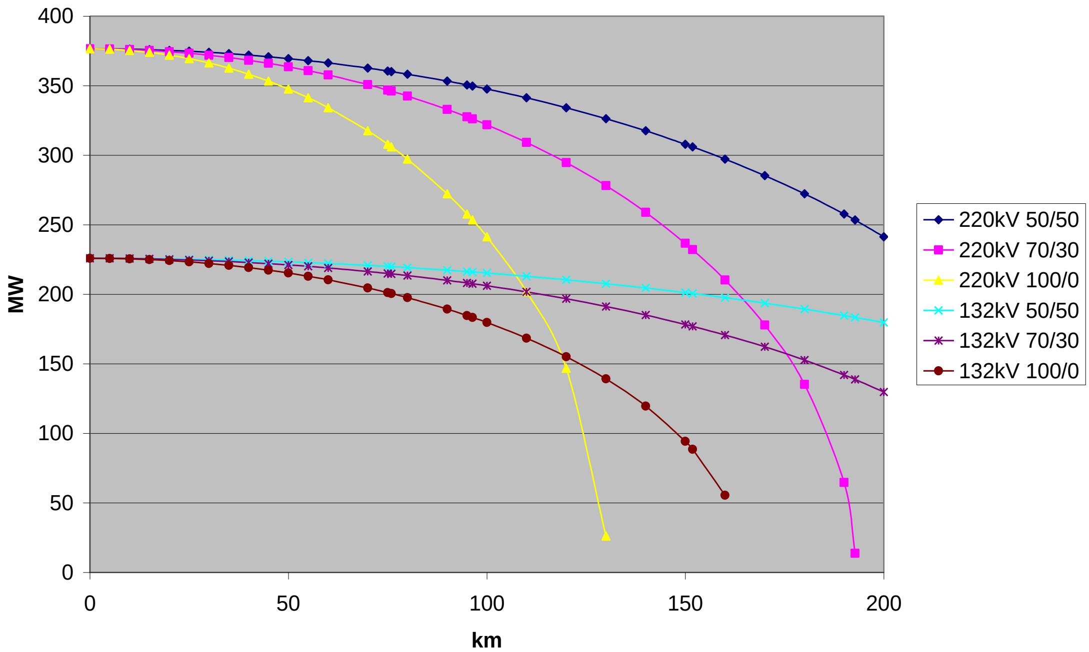
### Availability

Supply and installation times are in the region of one to two years. Suppliers include: ABB, Prysmian, Nexans and NKT.

### Dependancies and Impacts

Three core cables are intended for AC use and due to their inherent capacitive nature require reactive compensation equipment in the form of shunt reactors to be installed at one or both ends of the cable. As the cable length increases, so the amount of capacitive charging current increases and the amount of active power that can be transmitted decreases. Beyond a certain threshold distance, HVDC links should be considered. The following graph shows how for AC cable transmission the maximum real power transferred reduces dramatically for longer cable lengths:

Graph E.1
**Maximum real power transfer in 132 kV and 220 kV cables with 100/0, 50/50 and 70/30 reactive compensation split between onshore and offshore. (1000mm$^2$ copper cross section).**




The 100/0 scenario is the least expensive but also the least effective - as all the reactive compensation is placed onshore, the weight requirements on the offshore platform are reduced substantially.

Another limitation on three core AC cable capacities are the circulating currents generated in the metal sheath. For land cable routes, this is largely mitigated against by the application of special sheath bonding arrangements. It is not possible to apply these to submarine cable systems. Close bundling of the three phases in three core cables removes this to an extent for smaller cable currents; however as current increases the de-rating effect becomes significant. A cross sectional area of 1,000 mm$^2$ (copper) probably corresponds to the largest practically permissible current rating for this type of cable which would be capable of 400 MW transfers per cable at 245 kV. Beyond this multiple cables will have to be considered and this should be weighed up against the cost for a HVDC system or single core AC cables.

## Project Examples

- **Thornton Bank 2 offshore substation:** 38km, 150kv, 3-core subsea cable at a depth of 12-27m [3].
- **Greater Gabbard offshore windfarm:** 175 km of 132 kV 3-core subsea cable [5].
- **Little Belt Strait power cable project, Denmark:** 15km, 420kv, 2x3-core subsea cable. [4].
- **Anholt wind farm in Denmark:** 25 km of 245 kV 3 core 3 x 1600 $mm^2$ aluminium core cable capable of transporting 400 MW [6].

## References and Additional Information


[1] ABB, *XLPE Land Cable Systems User's guide (rev. 1)* [Online]. [Accessed: 24 Sept. 2013]. Available: http://www05.abb.com/global/scot/scot245.nsf/veritydisplay/ab02245fb5b5ec41c12575c4004a76d0/$file/xlpe%20land%20cable%20systems%202gm5007gb%20rev%205.pdf

[2] ABB, *XLPE Submarine Cable Systems, Attachment to XLPE Cable Systems – User's guide*.

[3] http://www.lorc.dk/offshore-wind-farms-map/thornton-bank-1 [Accessed: Sept.24,2013].

[4] 420kv subsea and underground power cable system will replace overhead power lines across the Little Belt strait in Denmark. (Accessed: Sept. 7, 2012) http://www04.abb.com/global/seitp/seitp202.nsf/c71c66c1f02e6575c125711f004660e6/f43cd6d00061b0783c12579a3002b0d06/$FILE/ABB+wins+$30+million+order+for+world's+highest+voltage+three-core+AC+subsea+cable.pdf

[5] T&D World, *Prysmian to Supply Cables for the Offshore Greater Gabbard Wind Farm in UK*, Jun. 26 2008. [Online]. [Accessed: Sept.24,2013]. Available: http://tdworld.com/projects_in_progress/business_in_tech/prysmian-cables-gabbard-0806

[6] NKT, *nkt cables receives order for one of the world's largest submarine cables*. [Online]. [Accessed: 24 Sept. ,2013]. http://www.nktcables.com/news/2012/6/anholt/

# E.6
# HV Cables Systems and Overhead Lines: HVAC Single Core AC Cables

### Description

Figure E.7
Image courtesy of ABB

Single core HVAC cables are widely used in onshore networks. They consist of a conductor (usually copper); insulation (now mainly XLPE) and a lead or aluminium sheath to prevent moisture ingress (so far similar to other cable designs). For larger area conductors, above 1000 $mm^2$ or so a segmental stranded conductor is used to reduce the skin effect resulting from higher AC currents. Land cable sheaths are usually cross bonded to mitigate the impact of circulating currents.

To date, Single core HVAC cables have rarely been used for subsea applications and have so far only been used for very short distances (of the order of 50 km maximum) and have mostly used low pressure oil filled technology, such as the Spain-Morocco interconnection [5]); however there is no technical barrier to extending their use to longer routes.

The inability to effectively bond the metallic sheaths to reduce circulating currents (which adds an additional heat source to the cable) would lead to significantly reduced ratings relative to their land equivalent cables and high magnetic losses in steel armour. As such, alternative designs of armouring have been used such as non-magnetic copper (or less usually aluminium alloy) which provides a low resistance return path as well as removing magnetic losses in the armour [1]. This has a significant cost implication in cable manufacture as effectively twice as much copper is consumed per unit length in their manufacture. Lead is favoured over aluminium as a sheath material for submarine cables.

Submarine HVAC single core cables are often installed in groups of 4 consisting of three active conductors and a redundant cable in case of failure.

### Capabilities

Single core, XLPE insulated cables are available up to 500 kV voltage levels. 500 kV, however, is a non-standard voltage level on the electricity transmission system in GB; 400/275 kV cables are commonly used onshore and the use of a standard system voltage would remove the need for onshore transformers. For submarine transfers of less than 300 MW 3 core AC cables should be considered over single core.

### Table E.4

| | | Submarine | | | Land | | |
|---|---|---|---|---|---|---|---|
| Capacity (MW) | Voltage (kV) | Cross Section ($mm^2$) | Weight (kg/m) | Diameter (mm) | Cross Section ($mm^2$) | Weight (kg/m) | Diameter (mm) |
| **100** | 132 | X | X | X | 185 | 5 | 64 |
| **200** | 132 | X | X | X | 630 | 10 | 74 |
| | 220 | X | X | X | 240 | 8 | 88 |
| **300** | 132 | 1000 | 36 | 120 | 1200 | 16 | 89 |
| | 220 | 400 | 27 | 109 | 500 | 11 | 80 |
| | 275 | 240 | 26 | 106 | 300 | 10 | 90 |
| **400** | 220 | 630 | 31 | 113 | 800 | 15 | 97 |
| | 275 | 400 | 30 | 112 | 500 | 12 | 91 |
| **500** | 220 | 1000 | 38 | 122 | 1200 | 19 | 109 |
| | 275 | 630 | 32 | 115 | 800 | 15 | 99 |
| | 400 | 300 | 33 | 131 | 400 | 14 | 109 |
| **1000** | 400 | 1400 | 47 | 138 | 1400 | 24 | 123 |

The following assumptions were made for the table above:

Soil / seabed temperature 15 ºC, burial 1.0 m, thermal resistivity 1 kW/m, copper conductor. Transfers are based upon a single AC circuit (3 cables). On land cables are laid 200 mm apart in a flat formation. Submarine cables are laid at least 10 m apart using copper wire armour. Ratings calculated from [2]. Physical characteristics are derived from [3] and [4].

Because of their construction and spaced laying single core AC cables have a higher thermal rating than three core cables of a comparable cross section.

Land cable failure rates are well understood (see 'Land Installation' appendix). Submarine single core cables are often installed with one redundant cable which can be used in the event of a single cable fault, all but eliminating circuit unavailability.

### Availability

Suppliers include: ABB, Prysmian, Nexans, NKT and Sudkable.

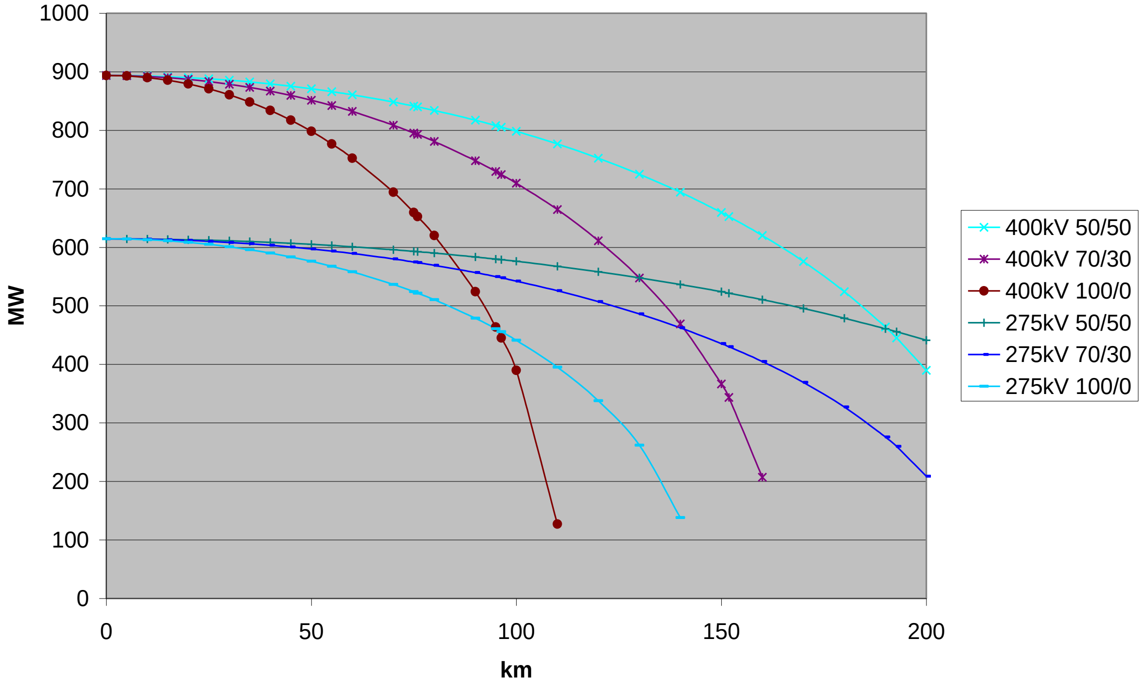
### Dependancies and Impacts

Single core AC cables may also require reactive compensation equipment to be installed to mitigate against capacitive effects (as for three core cables). The amount of compensation required is dependant upon the cable route length and operating voltage. Beyond a certain threshold distance HVDC links should be considered.

The following graph shows how for AC cable transmission the maximum real power transferred reduces dramatically as cable length increases. The charging current also increases as the cable operating voltage is increased. As single core cables generally operate at higher voltages than three core cables this effect is therefore generally more pronounced.

Grpah E.2

**Maximum real power transfer in 275 kV and 400 kV cables with 100/0, 50/50 and 70/30 reactive compensation split between onshore and offshore (1000mm$^2$ copper cross section)**



The 100/0 scenario is the least expensive but also the least effective - as all the reactive compensation is placed onshore, the weight requirements on the offshore platform are reduced substantially. For land cables it is possible to install compensation mid-route if necessary.

For the lower rated submarine connections, it would be more economic to use 3 core cabling.

### Project Examples

- **New York-New Jersey power cable project:** 10km, 345kV, 3x1-core subsea cable, 20m depth, 4-6m burial depth (no factory joints) [6]
- **Gwint-Y-Mor off shore wind farm:** 4 circuits of 11 km length each of 132 kV -1000 $mm^2$ aluminium conductor single-core XLPE land cable.
- **Lillgrund Offshore Windfarm in Sweden:** 6 km long 145 kV 630 $mm^2$ aluminium conductor single-core XLPE land cable [8]
- **Orman Lange grid connection:** 2.4 km of 400 kV 1200 $mm^2$ copper submarine single core AC cable. [7]
- **Hainan, China:** 600MW, 525kV, 3x31km, 800$mm^2$ [7]

### References and Additional Information

[1] Thomas Worzyk, *Submarine Power Cables: Design, Installation, Repair, Environmental Aspects*, Published 2009 ISBN 978-3-642-01270-9

[2] International Electrotechnical Committee, *IEC 60287: Electric Cables - Calculation of the Current Rating*.

[3] ABB, *XLPE Land Cable Systems User's guide (rev. 1)* [Online]. [Accessed: 24 September 2013]. Available: http://www05.abb.com/global/scot/scot245.nsf/veritydisplay/ab02245fb5b5ec41c12575c4004a76d0/$file/xlpe%20land%20cable%20systems%202gm5007gb%20rev%205.pdf

[4] ABB, *XLPE Submarine Cable Systems, Attachment to XLPE Cable Systems – User's guide*.

[5] R. Granandino, J. Prieto, G. Dence, F. Mansouri, K. Stenseth, R. Comellini, CHALLENGES OF THE SECOND SUBMARINE INTERCONNECTION BETWEEN SPAIN AND MOROCCO, Presented at Jicable 2007 [Online]. [Accessed: Sept. 1, 2011]. Available: http://www.see.asso.fr/jicable/2007/Actes/Session_A9/JIC07_A91.pdf

[6] ABB sets new power cable record in New York Harbor.[Online] [Accessed: Sept.24,2013]. Available: http://www.abb.com/cawp/seitp202/f905a3905c832a63c12579800038f8e4.aspx

[7] Nexans, Olivier Angoulevant, *Offshore Wind China 2010 Bergen, 15th March 2010, Olivier Angoulevant*, [Online]. [Accessed: 26 September 2013]. Available: http://www.norway.cn/PageFiles/391359/Nexans%20-%20Olivier%20Angoulevant.pdf

[8] ABB, *Lillgrund - the largest offshore wind farm in Sweden* [Online]. [Accessed: 26 September 2013]. Available: http://www05.abb.com/global/scot/scot245.nsf/veritydisplay/59af86e7d42ac9e9c125777c0032a69f/$File/Project%20Lillgrund%20145%20kV%2036%20kV%20XLPE%20subm-land%20rev%202.pdf

E.7

# HVAC Cables

## Description

Underground cables are used by electricity transmission and distribution companies across the world. Along with Overhead Lines (OHL) they provide the connections between power stations and bulk electricity power users and at lower voltages in some countries provide connections between distribution centres and the end consumer.

Figure E.8
Transmission cables installed in a 4m tunnel

Unlike overhead lines, underground cables cannot use air as an insulating medium and therefore need to provide their own insulation materials along the entire length, adding significantly to the cost. Air is also better at transferring heat away from conductors than the cable insulation and soil, so larger conductors are usually required to transmit the same power levels as OHLs.

HVAC underground cables are used in built up and densely populated urban areas where space for above ground infrastructure is extremely limited and where, for landscape or visual mitigation measures, their additional cost may on balance be considered appropriate, for example, National Parks and Areas of Outstanding Natural Beauty (AONB).

HVAC cables are inherently capacitive and may require the installation of additional reactive compensation to help control network voltage. The likelihood that additional reactive compensation will be required for a particular transmission route increases with cable operating voltage, conductor size and circuit length. Additional land space will be required to build compounds for the reactive compensation plant.

AC Cables are operated at voltages ranging from 230 V to 400 kV. For a particular cable increasing the voltage allows more power to be transmitted but also increases the level of insulation required. At 275 kV and 400 kV most circuits have one or two conductors per circuit. In order to match the ratings of high capacity OHL circuits very large cables will be required.

## Capabilities

At 400 and 275 kV HVAC Cables consist of a copper conductor, an insulation layer, a lead sheath, and a protective plastic coating.

HVAC transmission cable insulation has developed from Self Contained Fluid Filled (SCFF) construction with a hollow conductor and paper insulation using pressurised low viscosity oils to extruded plastic insulations. SCFF cables have also used Polypropylene Paper Layers (PPL) now being introduced into HVDC cable systems.

For direct buried underground cables Utilities must obtain easements from the land owners of all the sections of land it crosses.

The power carrying capability or rating of a HVAC cable system is dependent upon the number and size of conductors and also on the installation method and soil resistivity. Larger conductors and higher voltages mean increased ratings. Cables are usually buried at a depth of around 1m in flat agricultural land. As the number of cables per circuit increases so the width of the land required to install them (the swathe) increases. Cable swathes as wide as 50 m may be required for high capacity 400 kV routes. A 3 m allowance for maintenance needs to be added to most corridor widths quoted in supplier information sheets. At 275 kV and 400 kV the rating for each circuit can range from 240 MVA to 3500 MVA based on size and number of conductors in each trench.

Ratings are calculated on ambient conditions and the maximum safe operating temperature of the conductor, this means that ratings are higher in winter than they are in summer, spring and autumn.

## Availability

HVAC cable technology is mature with many manufacturers offering reliable products up to 132 kV. The Higher Transmission voltages are more specialised with proportionally fewer suppliers.

Since the mid nineties, far fewer SCFF cables have been manufactured, while sales of extruded (XLPE) cable systems have increased significantly.

### Dependancies and Impacts

Whilst HVAC cable systems have a lower impact on visual amenity there are still considerable portions of the cable system above ground, especially at the terminal ends between sections of OHL. Cable systems are generally less prone to environmental issues than OHL as they generate less audible noise.

The installation of underground cable systems is potentially more disruptive than the installation of OHL circuits as the continuous linear nature of the construction at ground level can require road closures and diversions for significant periods. Cable systems do still encounter some environmental issues around the disturbance of land.

# E.8
# Construction:
# Subsea Cables Installation AC & DC

## Description

Figure E.9
Cable carousel on Nexans Skagerrak
Image courtesy Nexans

The installation of submarine cables is a very challenging operation and careful consideration should be given to this aspect before commencing any project. A detailed survey and the selection of an appropriate route are particularly important.

Figure E.10
Sea Stallion 4 power cable plough
Image courtesy IHC Engineering Business

Submarine cables are installed from dedicated cable laying vessels with turntable capacities of up to 7000 T or from modified barges for use in shallower waters which have considerably reduced cable capacities. The length of cable that can be installed in a single pass is dependant upon the capacity of the laying vessel. Where vessel capacity is insufficient to lay in a single pass offshore cable jointing will be necessary. This is a complex and potentially time consuming operation requiring the laying vessel to return to port to re-stock (or the use of a separate vessel to allow re-stocking to be accomplished offshore) and the number of jointing operations should be minimised where possible.

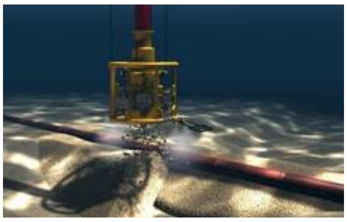


Figure E.11
Rock Placement courtesy of Tideway

To protect them from fishing gear or anchor strikes, cables are buried at an appropriate depth (usually 1m or more) beneath the seabed using jetting which fluidises the soil; or a cable plough or rock ripping. The depth and burial method chosen depends on seabed conditions e.g. soft sand and clay, chalk but in some circumstances burial may prove too challenging e.g. solid rock. In such cases cable protection by rock placement/dumping or concrete mattressing may be required. The appropriate depth is based on risks such as dragging anchors, disturbance from fishing activities and seabed sediment mobility. Cigré propose a method for determining acceptable protection levels for submarine power cables [2].

## Capabilities

Cable laying rates of up to 500 m/hr are possible but 200m/hr is average when laying and burying simultaneously. Ploughing is generally a faster operation but may not be suitable for all seabed conditions. Cables may be buried by the main installation vessel or by a smaller vessel at a later stage in installation (this approach can prove to be more economical as the large, expensive laying vessel is required for less time at sea [1]). If this approach is taken vessels can be employed to guard the un-protected cable until it is buried. The maximum length of cable is determined by the carousel capacity in terms of weight and volume (e.g. 7000 T equates to approximately 70 km 3 core HVAC cabling but this length maybe limited by the volume of the coil). Vessels can operate twenty four hours a day, seven days a week given suitable sea conditions. Water depth is not a significant factor but changing seabed structure may have a greater influence on the burial technologies used (jetting, rock ripping, ploughing). Downtime during cable jointing operations, mobilisation and demobilisation costs and poor sea conditions (approx 40% of time in the winter months) are significant factors to consider in calculating cable installation costs.

The use of bundled bipole cables in the case of HVDC links, or three core HVAC cables, rather than single core cables may be preferred as it reduces the time a cable laying vessel is required at sea, although the installation and subsequent recovery of the cable in the event of a fault is made more challenging. If jointing is necessary separate burial in multiple passes may be cost effective so as to reduce the number of offshore jointing operations. It is also possible to perform jointing operations on a separate vessel to the main laying vessel and this may positively impact project costs and timetables [1].

Bundling cables also engenders a reduction in the overall rating of the cable system due to mutual heating effects. Laying the cables separately can result in an increase in rating of up to 25% over that stated in these appendices. The most economic laying arrangement, weighing installation costs against increases in the cost of the cable given the increase in conductor cross section necessary for bundled cables, would have to be the subject of a detailed cost-benefit analysis for a given project. On the other end each HVDC or HVAC project is unique and requires ad hoc engineering study in order to identify the most appropriate solution.

Typical failure rates for subsea cables are 0.1 failures per 100 km per year [2], with a mean time to repair of 2 months [3] but this could obviously vary with local conditions. Submarine cable systems have an expected lifetime of 30-40 years [1].

### Availability

Subocean Group, Global Marine Systems Limited and Visser & Smit Marine Contracting have been the main installers of subsea cables on UK offshore wind farms to date. Manufacturers Prysmian and Nexans also own and operate vessels i.e. Giulio Verne [4] and Skagerrak [5] respectively. The majority of current cable laying vessels have a carousel capacity from 1,000 up to 4,000 tons but those owned by the cable manufacturers have a carousel capacity up to 7,000 tons (op.cit). Other companies with experience in telecoms cables and oil & gas who are now involved in offshore wind include CTC Marine, L D Travocean, Tideway and 5 Oceans Services.

Manufacturers of mattresses/blankets include: SLP (Submat Flexiform), Pipeshield and FoundOcean (MassivMesh). Mattressing is readily available in stock or can be manufactured to order in a relatively short time period subject to demand. Tubular products are widely used in the global telecommunications industry and oil and gas sectors with manufacturers including, Trelleborg Offshore (Uraduct®), Protectorsheel from MSD Services and Uraprotect from Dongwon En-Tec. There will be additional effort required to manufacture larger diameter sections for use with undersea HVAC cabling. There are a range of companies providing diving services e.g., Hughes, REDS, Red7Marine and ROVs e.g. Subsea Vision, Osiris, Fugro or a combination of both. Companies providing vessels and services include, Briggs Marine, Trico Marine, TS Marine.etc and all have considerable experience of pipeline crossings in the oil & gas sectors

### Dependancies and Impacts

There are a number of companies with capabilities for laying short cables near shore and in shallower waters. Larger vessels with the capability of long cable runs offshore e.g. 70 km -100 km are limited and the investment in such vessels will to some degree be dictated by the certainty of offshore wind projects going ahead. Investment in new vessels requires a pipeline of commitments to justify the investment.

The forces involved in offshore cable installation are large, and the risk of damage to the cables is always present. Key parameters to consider included cable tension and Side Wall Pressure (SWP) over the laying wheel. Both of these depend upon cable weight, depth of installation and the impact of vessel motion in swells. CIGRE type testing may not fully account for the dynamic forces [1] and detailed computer modelling of these is recommended. Care must be taken if separate parties are used for separate cable supply and installation, as it may be difficult to identify where liability lies should problems occur [6].

Thermal bottlenecks which effectively de-rate the entire cable system may occur in the J tubes connecting the cables to offshore platforms and consideration should be given to sitting these on the north side of a platform to minimise solar heating.

Wherever possible the crossing of subsea obstacles (e.g. other cables/pipelines) should be avoided through route selection. Where it is necessary it can be accomplished through the use of concrete mattresses, tubular protective products or rock dumping. It should be noted that other subsea assets, particularly power cables, may introduce a heat source and could result in a thermal bottleneck unless the crossing is appropriately designed.

The number of obstacles will depend on the geographic location of the offshore substation, cable routes, landfall and desired onshore connection point as well as the particular sea area. Oil & gas pipelines are predominant in the North Sea but towards the English Channel telecommunications cables are more frequent. The rights to cross an obstacle, and the method used to do so may need to be negotiated with the obstacle owner. Up to half of obstacles encountered may be disused pipes/cables left in situ. Tubular products are designed to be fitted during subsea cable laying operations but obstacle crossing using mattresses would typically be done in advance, so minimising down time on the cable laying vessel. Putting several crossings together in an installation programme would be more cost effective, with mattresses supplied to site by barge.

Detailed cable route surveys are essential and will of course consider obstacle crossing as well as other restrictions that impact on cable laying e.g. subsea conditions (seabed temperature, makeup, thermal resistivity etc), munitions dumps, fishing areas.

### Project Examples

- Nysted, Thanet, Greater Gabbard, Westermost Rough, Beatrice, Horns Rev2, Sheringham Shoal, Walney 2 and Ormonde, Anholt, Gwynt y mor.
- NorNed HVDC cable.

### References and Additional Information


[1] Thomas Worzyk, *Submarine Power Cables: Design, Installation, Repair, Environmental Aspects*, Published 2009 ISBN 978-3-642-01270-9

[2] Cigré Working Group B1.21, Technical Brochure TB 398, *Third-Party Damage to Underground and Submarine Cables,* December 2009

[3] Cigré Working Group B1.10, Technical Brochure TB 379: *UPDATE OF SERVICE EXPERIENCE OF HV UNDERGROUND AND SUBMARINE CABLE SYSTEMS*, April 2009

[4] Prysmian website: http://ita.prysmian.com/attach/pdf/Group_Brochure_2008.pdf

[5] Nexans website: http://www.nexans.com/eservice/Corporate-en/navigate_224932/Skagerrak_cable_laying_vessel.html

[6] J.E. Skog, *NorNed-Innovative Use of Proven Technology,* Paper 302, Cigre SC B4 2009 Bergen Colloqium. [Online]. [Accessed: July 15, 2010]. http://www.cigrescb4norway.com/Documents/Papers/Session%203/302%20NorNed,%20Innovative%20Use%20of%20Proven%20Technology.pdf

# E.9
# Construction: Onshore Cable Installation and Landfall

## Description

Figure E.12
HDD rig
Image courtesy of Land & Marine

Onshore HVDC and HVAC cables can be direct buried in trenches, installed in pipes or ducts or in dedicated cable tunnels (the last option is very expensive and normally reserved only for urban areas where space to excavate trenches is unavailable).

Figure E.13
A typical open trench cable swathe [1]

Direct buried cables are buried with approximately 1 m cover [1] but detailed site survey and system design is essential. Cables will be buried in Cement Bound Sands (CBS) to improve thermal resistivity and then covered in engineered materials or in the case of agricultural land indigenous material. Pipes or ducts can be installed in advance of cable delivery, and the cable can then be pulled through in lengths. Ducts may be filled with bentonite and sealed to improve heat transfer from the cables. Jointing pits are required for cable jointing activities and access is required for inspections.

AC cables can be laid either in flat or the more compact trefoil formation (although due to the close proximity of the cables in trefoil mutual heating causes a slight reduction in rating relative to flat cable groups). DC cables are generally installed in bipole pairs in the same trench.

Obstacles such as roads, railways, rivers and other sensitive areas can be crossed using Horizontal Directional Drilling (HDD), directional boring using a steerable boring rig, but there are other methods including auger boring, cased auger boring etc. [6]

Shoreline transition or landfall is typically carried out through HDD, directional boring using a steerable boring rig from the onshore side. Trenching and ploughing through a beach area may also be viable, but HDD is seen as less intrusive, offers better protection to cable systems and when correctly executed causes minimum environmental damage. HDD can pass under sea defences and out to sea, typically horizontal distances up to 500 m and depths of 15 m below the seabed. The pilot hole is reamed out to the required size and protector pipes or ducts used to provide a conduit for the offshore cable. A transition joint pit is constructed onshore, with the offshore cable pulled through the duct by means of a winch. For the marine works a barge and/or typically Multi Purpose Marine Vessel (MPMV) is required along with diving team for various support tasks. Landfall either through a duct prepared by HDD or via a trench is a complex operation and requires specialist knowledge.

Figure E.14
Cable plough on shore
Image courtesy of IHC Engineering Business

## Capabilities

Onshore jointing times vary depending upon cable type however they are usually in the range of 1 day per joint for XLPE and 3-5 days for mass impregnated paper insulated cables.

Cable trenches are usually 1-1.5 m deep, 1 m wide, with increased width required for jointing bays and construction access leading to a total swathe of at least 5 m for a single cable trench [1]. AC cables also require the provision of link boxes for the purposes of sheath bonding and earthing.

Land cables are transported on steel drums. The following table shows the maximum continuous length of cable that can be transported on a particular drum size:

**Table E.5**

| Drum Type (Steel) | Drum Width mm | Drum Diameter mm | Drum Weight kg | Length of cable, for a specified cable diameter, that can be carried on one drum | | | |
|---|---|---|---|---|---|---|---|
| | | | | *66 mm* | *76 mm* | *92 mm* | *116 mm* |
| St 30 | 2400 | 3130 | 1700 | 1680 m | 1210 m | 860 m | - |
| St 36 | 2400 | 3730 | 2800 | 3120 m | 2130 m | 1330 m | 890 m |
| St 40 | 2400 | 4100 | 3500 | 3280 m | 2180 m | 1570 m | 850 m |

Data extracted from reference [2]

Transport to the site on a low loading lorry is possible for the larger drums (carrying capacity up to 100 tonnes). The limitation on cable length is the amount that can be fitted onto a steel drum. Transport height/weight restrictions will have to be considered on a project basis; although the maximum weight permissible on British roads is 44 tonnes (vehicle and load) before qualifying as an abnormal load [3].

Directional drills are available for distances greater than 500 m. Typical minimum timescales for drilling would be one week site preparation, two weeks drilling and one week reinstatement.

HVDC underground cables are expected to have a similar availability to AC cables. 3rd party damage accounts for about 70% of all underground cable failures [4]. Onshore cables have an expected lifetime of 40 years.

### Availability

Neary Construction,Durkin & Sons, are prime installers of underground HV cable but companies including Carillion, United Utilities and the ,National Grid's Overhead Line and Cable Alliance Partners (AMEC, Babcock and Balfour Beatty) all have extensive experience and capability.

Major Directional Drilling providers with the experience and capability to manage projects of this nature include AMS No-Dig, Land & Marine, Allen Watson Ltd, DEME , Stockton Drilling (HDD 500 m +) and VolkerInfra (parent company Visser & Smit Hanab).

Belgian based DEME has group companies including Tideway and GeoSea with experience of landfall operations.

### Dependancies and Impacts

Cable route surveys will be required to determine feasible options with geotechnical surveys required to determine ground conditions. System design is an essential element and may have a considerable impact on the final costs. Trenching and drilling through rock is considerably more expensive and time consuming. Cabling can potentially be routed along public highways, avoiding the need for potentially costly wayleaves and access agreements. If cable routes go cross country (including access for HDD) additional costs to consider include wayleaves, access agreements, trackway costs, farm drain repair, soil reconditioning and crop damage charges. Generation and offshore transmission licensees may have compulsory acquisition powers and there are legal and compensation costs associated with these powers. There may be additional licence and project management costs e.g. Network Rail.

Due to the bulk and weight of cabling there are limitations as to the total length between joints and allowance must be made for the additional cost (and time) for civil engineering works, land access issues and the actual completion of cable jointing activities. Additional costs to consider include mobilisation costs as well as the per km cost.

Landfall operations are largely dictated by environmental considerations as many areas of shoreline have designations such as SSSIs, Ramsar sites, RSPB Reserves etc. Conditions are imposed that may strictly limit when drilling can take place. Tidal conditions and weather can also effect operation of MPMVs and diving teams. There is competition for resources with oil and gas and other construction projects as well as significant market activity overseas.

Landfall and land cable routing often present the thermal limiting case for cable rating. As such it may be economic to utilise a larger cable cross section for the landfall and land route than for a submarine section to ensure that thermal bottlenecks do not de-rate the entire cable system.

### Project Examples

- Vale of York 2 x 400 kV circuits over 6.5 km, Lower Lea Valley Power Line Undergrounding
- West Byfleet Undertrack Crossing
- Gunfleet Sands landfall to Clacton substation
- NorNed HVDC project, [5]

### References and Additional Information

[1] National Grid, *Undergrounding high voltage electricity transmission - The technical issues*, [Online].[Accessed: Sept. 26, 2012], Available: http://www.nationalgrid.com/NR/rdonlyres/28B3AD3F-7821-42C2-AAC9-ED4C2A799929/36546/UndergroundingTheTechnicalIssues3.pdf

[2] ABB, *XLPE Land Cable Systems User's guide (rev. 1)* [Online]. [Accessed: Sept. 26, 2012]. Available: http://www05.abb.com/global/scot/scot245.nsf/veritydisplay/ab02245fb5b5ec41c12575c4004a76d0/$file/xlpe%20land%20cable%20systems%202gm5007gb%20rev%205.pdf

[3] Department of Transport: *The Road Vehicles (Construction and Use) Regulations*

[4] Cigré Working Group B1.21, Technical Brochure TB 398, *Third-Party Damage to Underground and Submarine Cables,* December 2009

[5] Thomas Worzyk, *Submarine Power Cables: Design, Installation, Repair, Environmental Aspects*, Published 2009 ISBN 978-3-642-01270-9

[6] Cigré TB 194 “Construction, laying and installation techniques for extruded and Self contained fluid filled cable systems

# E.10
# Structure:
# Offshore Electrical Platforms

## Description

Figure E.15
Thanet substation under construction Image courtesy SLP Engineering

AC collection platforms are widely used to collect wind generation and the voltage is stepped up for transmission to shore via AC or DC technology.

Figure E.16
BorWin Alpha HVDC topsides and jacket. Courtesy of ABB

Offshore platforms house the electrical equipment for generation collection and transmission to shore. Multiple platforms may be required depending on the capacity of the project and the functionality of the platform. Where the offshore transmission is via HVDC, a separate platform would be required. Common requirements for all platform types include cooling radiators, pumps, fans, switchgear, protection, control and possibly living quarters.

Figure E.17
DolWin Alpha HVDC topside

HVDC equipment to be installed on the platform typically weighs from 2000 tonnes to over 4,000 tonnes. HVDC Platform topside weights are difficult to predict as they depend on a number of factors, as such their weight range can vary by as much as 20%.

The supporting substructure for smaller rated HVDC platform consists of four piles with tubular bracings in between. This method is known as 'Jackets' and can range from anything from 4 to 8 legs piled into the seabed. The number of legs required is determined by the seabed conditions as well as the platform weight. Jackets used in North sea waters are usually about 30 – 50 m in depth. The platforms are usually about 25 – 40 m above sea level depending on wave height at particular locations.

In an effort to cut costs, AC technology can be pushed further by using compensation platforms. The primary function of these types of platforms is providing reactive compensation as AC cables reaches it economical transmission distance. Mechanical Vibration issues with a lighter platform design would need to be overcome to allow utilisation of cheaper AC technology.

Some of the additional equipment necessary for an offshore platform will include emergency accommodation, life-saving equipment, cranes for maintenance, winch to hoist the subsea cables, backup diesel generator, fuel, helipad, and the J-tube supports which house the subsea cables as they rise from the seabed to the platform topside where they are terminated.

All platforms are constructed and fully fitted out on shore, then transported out to the offshore site/ wind farm.

As the need for larger platforms increases alternative designs are being considered, such as semi-submersible platforms. These designs are floated out to location and then sunk onto the seabed using ballast materials. Self installing jack up platforms are used where the platform is floated out on a barge and then jack up legs lifts itself off the barge and onto the sea bed.

## Capabilities

The size of the platform is dependent on the equipment it needs to house. For every additional tonne or square meter of space on the topside, additional support steel work and jacket reinforcement is required.

The depth of the water is another key factor in the design of the platform; hence most wind farms are located in shallow seas where possible.

AC platforms tend to use GIS equipment and therefore be more compact and densely populated than DC platforms (where AIS equipment is used).

HVDC platform sizes are usually based on the assumption that the HVDC scheme is a balanced monopole (a bipolar system would require more room hence a larger platform). The table below gives platform dimensions for different substation power ratings.

Table E.6
**Topside Dimensions (W X D X H (m))**

| Platform facility | Water depth (m) | Size (m) W H L | Total Weight (tonnes) Including plant |
|---|---|---|---|
| **300 MW AC** | 20 -40 | 20, 18, 25 | 1800 |
| **500 MW AC** | 30 -40 | 31, 18, 39 | 2100 |
| **400 MW VSC** | 30- 40 | 35, 21, 52 | 3200 |
| **1000 MW VSC** | 40+ | 50, 21,50 | 10000 – 14000 |
| **Accommodation** | 40+ | 35, 21, 35 | 3000 – 5000 |

### Availability

AC and HVDC offshore platforms construction timescales are dependent on the primary equipment lead-time, therefore they influence the delivery schedule for both AC and DC platforms. The installation timescale for a HVDC platform of between 1000 MW -1500 MW would take about 5 years while a platform of rating 1800 MW or above would take about 7 years due to time required to carry out feasibility studies and design development of the platform. This time may also include possible extensions to the fabrication facilities to enable the build of larger platforms.

The main UK capabilities are from SLP, Heerema and McNulty (fabrication yards in Lowestoft, Tyneside and Fife) and potential facilities in Northern Ireland e.g. Harland & Wolff.

### Dependancies and Impacts

Platform delivery lead times and capacity is dependant on two factors, fabrication yard capability and vessel restrictions such as availability and capability. Currently the maximum lift capacity for the largest vessels is 14000 tonnes, for platforms above 2100 tonnes, the number of available vessels significantly reduces and further increases the installation cost. Due to competition from other industries, the booking of these vessels may be required up to 2 years in advance. Individual vessels have differing crane lengths that would complicate off shore installation. The installation process requires combination of favourable weather and sea conditions.

Suppliers having previously serviced the oil and gas sector have the capability to construct and install topsides and jackets. Electrical equipment would be provided by the major equipment manufacturers. As the fabrication facilities are limited, the offshore wind industry will have to compete with the oil and gas sector.

Platforms used as landing or dropping points will need to adhere to Civil Aviation Authority (CAA) regulations which may impact on the level of emergency equipment and safety procedures required.

An asset life of over 20 years would significantly increase the capital and operational cost due to increased weight, anti-corrosion specifications and operation / maintenance regimes.

### Project Examples

- **Thanet Platform AC Collector:** 300 MW, 30 x 18 x 16, 1,460 t Jacket
- **Greater Gabbard AC Collector:** 500 MW, 39 x 31 x 18m, 2,100 t, Jacket
- **Sheringham Shoal:** 315 MW, 30.5 x 17.7 x 16 m, 30.5 x 17.7 x 16 m Monopole
- **Borwin Alpha HVDC Platform:** 400 MW, 4,800 t, 54 x 25 x 30 m, Jacket
- **HelWin2 HVDC Platform:** 690 MW, 98 x 42 x 28 m, 12,000 t, Self Install
- **DolWin Alpha HVDC Platform:** 800 MW, 62 x 42 x 36, 15,000 t, Jacket

## References and Additional Information

DNV – OS-J201, Offshore Substations, Oct 2009

Designing substations for offshore connections, J. Finn, M Knight, C Prior, CIGRE Paris session B3-201, Aug 2008.

Cigre brochure B3.26: guidelines for the design and construction of AC offshore Substations for wind power plants.

http://www.4coffshore.com/windfarms/converters.aspx

http://www.4coffshore.com/windfarms/substations.aspx

# E.11
# Series Compensation

## Description

Series Compensation (SC) is widely used in many transmission systems around the world, typically in long transmission lines where increased power flow, increased system stability or Power Oscillation Damping (POD) is required.

This technology can be employed in some scenarios as an alternative to building new or additional transmission lines.

As SC operates at system voltage, in series with the pre-existing transmission lines, the equipment is installed on insulated platforms above ground.

There are two main types of series compensation:

- Fixed series Capacitors (FSC)
- Thyristor Controlled Series Capacitors (TCSC)

There is also a third design that has been developed by Siemens called Thyristor Protected Series Capacitors (TPSC).

The FSC is the simplest and most widely used design as it has a fixed capacitance that is switched in and out using a bypass switch. The load current through the transmission line directly "drives" the Mvar output from the capacitor and makes the compensation "self regulating".

The TCSC installation offers a more adaptable option. It has the ability to vary the percentage of compensation by use of a Thyristor Controlled Reactor (TCR) and has potential to manage or control power systems conditions such as POD and Sub-Synchronous Resonance (SSR). In some designs it may also allow the capacitors to be returned to service faster than FSCs after fault recovery. One drawback of the TCSC may be that the valves must be continuously cooled by a fluid filled cooling system as they are always operational.

The TPSC is similar to a FSC in that it only has a fixed value of capacitance, however by the use of thyristor valves and a damping circuit, it may allow the capacitors to be returned to service faster than FSCs after fault recovery. As the valves are only operational during fault conditions (compared to those of a TSCS which are in continuous operation) there is no need for a fluid cooling system.

## Capabilities

In a transmission system, the maximum active power that can be transferred over a power line is inversely proportional to the series reactance of the line. Thus, by compensating the series reactance using a series capacitor, the circuit appears to be electrically shorter (than it really is) and a higher active power transfer is achieved. Since the series capacitor is self-regulated, i.e. its output is directly (without control) proportional to the line current itself, it will also partly balance the voltage drop caused by the transfer reactance. Consequently, the voltage stability of the transmission system is raised.

$$P = \frac{|U_A| \cdot |U_B| \cdot \sin(\delta)}{X_{Line} - X_C}$$

Power Transfer Equation

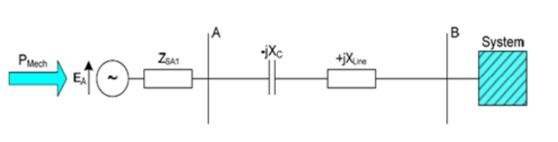



Figure E.18
Simplified Model of Transmission system with series compensation

Installing the series capacitors on the network provides following advantages:

- Boosting transmission capacity
- Increased dynamic stability of power transmission systems
- Improved voltage regulation and reactive power balance
- Improved load sharing between parallel lines

With the advent of thyristor control, the concept of series compensation has been widened and its usefulness has been increased further which include:

- Smooth control of power flow
- Improved capacitor bank protection
- Mitigation of SSR
- Electromechanical Power Oscillation Damping

### Availability

Suppliers for FSC and/or TCSC include: ABB, Alstom Grid, GE and Siemens

Suppliers for TPSC: Siemens

### Dependancies and Impacts

The first installations of SC are due on the NGET and SPT transmission networks in 2014/15. Several challenges have been identified with the installation of the SC on the GB power network;

Concerns due to SSR are being carefully considered to ensure the advantages of SC are gained. Complex network analysis is being performed to understand the effects of introducing series capacitors in the network and to avoid potential hazards to generators.

It's use will also have an impact on Protection equipment of adjacent circuits under fault conditions and will require changes to existing P&C policies to accommodate the SC.

New procedures will need to be developed to provide safe access/egress to platform, including safe working practices on the platform.

### Project Examples

- **2008 North South Interconnection III, BRAZIL (FSC)**

Figure E.19

The major part of Brazil's energy is generated by hydroelectric power plants in the North to cover the energy demand in the South.

In 2006, after the first two North-South Interconnection lines had proved successfully, the Brazilian Electricity Regulatory Agency (ANEEL) awarded a third parallel line, North South Interconnection III. In the middle section of the transmission line from Colinas (Tocantis) down to Serra da Mesa II (Goiás) power had to be transmitted over a distance of 696 km. This was awarded to INTESA, a consortium of Eletronorte, Chesf, Engevix and a private investor. To avoid losses and voltage stability problems, Siemens supplied in a consortium with Areva, five Fixed Series Capacitors (FSCs), Line Protection and substation HV equipment. Siemens as the consortium leader installed four FSCs at Eletronorte´s substations Colinas, Miracema and Gurupi and one at Furnas´ substation Peixe II within a delivery time of 14 months.

Capacitor Rating:

- 200 MVAr FSC at Colinas
- 2 x 194 MVAr FSCs at Miracema and Gurupi
- 130 MVAr FSC at Gurupi
- 343 MVAr FSC at Peixe II

Compensation Degree:

- 51 % Colinas
- 70 % Miracema and Gurupi
- 70 % Gurupi
- 68 % Peixe II

- **The Isovaara 400 kV SC: increased power transmission capacity between Sweden and Finland (TCSC)**

ABB supplied and installed a 515 Mvar series capacitor in the 400 kV Swedish National Grid at Isovaara in northern Sweden. This installation was designed to increase the power transmission capacity of an existing power corridor between Sweden and Finland by means of increased voltage stability at steady state as well as transient grid conditions. Series compensation allows the existing power corridor to operate closer to its thermal limit without jeopardizing its power transmission stability in conjunction with possible system faults.

- **FURNAS, Serra da Mesa North South Interconnection (TCSC)**

Figure E.20

The network in the south, south-east, central and mid west regions of Brazil supplies energy to the areas of the country south of the capital, Brasilia, and the network in the north and north east provides energy to the areas north-east of Bahia to Belém on the Amazon delta.

Most of the electric power of both networks is generated by hydroelectric power plants, for example from the power plant Xingó at the Sao Francisco river. The backbone of the interconnection line is the 500 kV transmission line from Imperatriz to Serra da Mesa. The North-South Interconnection, with its capacity of 1300 MW, enables a more flexible expansion of the hydroelectric power plants along the Tocantins river. To increase the energy transmission capacity and to stabilize the system, Electrobrás decided to use Flexible AC Transmission Systems. In 1997, Siemens received the order from FURNAS to supply one TCSC.

Capacitor Rating:

- 13.27 Ohm (blocked valve) and 15.92 Ohm (TCSC)/107.46 MVAr at 1.5 kA

Compensation Degree:

- 5-6 % (continuous)
- 7-15% (temporary)

- **Series Capacitors in Nevada / USA (TPSC)**

Figure E.21

In September 2004 Siemens succeeded in winning the contract for the refurbishment of two series capacitor installations at Edisons Eldorado Substation southwest of Boulder City, Nevada. As a result of new power generation installed in the Las Vegas area the fault duty on the 500 kV transmission network is above the design ratings of the existing equipment and therefore the two series capacitors "Lugo" and "Moenkopi" at the Eldorado Substation were to be replaced.

The Lugo series capacitor installation consists of two segments, one FSC segment and the other a TPSC segment. The Moenkopi series capacitor installation consists of three segments, two FSC segments and the other a TPSC segment. The Lugo FSC has been in service since March 2006 and the Moenkopi FSC since June 2006.

Capacitor Rating:

- 199 Mvar / segment[1)]
- 162 Mvar / segment[2)]

Compensation Degree:

- 17,5 % / segment[1)]
- 11,7 % / segment[2)]

### References and Additional Inforamtion

[1] Series Compensation (SC) (Siemens) http://www.energy.siemens.com/hq/en/power-transmission/facts/series-compensation/

[2] Fixed Series Compensation (ABB) http://www.abb.com/industries/db0003db004333/c12573e7003305cbc125700b0022edf0.aspx?productLanguage=us&country=GB

Cigre TB123 – Thyristor Controlled Series Compensation, WG 14.18, Dec 1997.

Cigre TB411 – Protection, Control and Monitoring of Series Compensated Networks, WG B510, Apr 2010.

# E.12
# HVDC:
# Current Source Converters

## Description

Figure E.22
Ballycronan More converter station
(Moyle Interconnector)
Image courtesy of Siemens

The majority of the HVDC transmission systems in service are of the Current Source Converter (CSC) type. The technology has been in use since the 1950s and is well established. Since the 1970s, current source converters have used Thyristor valves.

The thyristor can be switched on by a gate signal and continues to conduct until the current through it reaches zero. A CSC is therefore dependent on the voltage of the AC network to which it is connected for commutation of current in its valves. A CSC HVDC system is larger and heavier than a VSC and hence will be more difficult to implement in an offshore location.

## Capabilities

CSC HVDC is well suited to transmission of large quantities of power over large distances. An installation rated at 6400 MW at a voltage of +/- 800 kV using overhead lines is in operation today and a 7200 MW installation is planned for commissioning in 2013. As further development of this technology is a continual process, a new UHVDC +/- 1100 kV / 5000 Amp project (Zhundong-Chongqi) is currently being considered by CEPRI China.

As a consequence of the commutation process, the converter current lags the phase voltage and the CSC absorbs reactive power. The CSC also generates non-sinusoidal currents and requires AC filtering to prevent harmonic limits in the AC network being exceeded. Reactive compensation and AC harmonic filters are therefore provided which account for around 40 to 60% of the converter station footprint [1]. Indicative typical dimensions for a 1000 MW CSC located onshore are about 200 m x 175 m x 22 m, but the footprint is highly dependent on the AC harmonic filtering requirements at the particular location.

Transmission losses are typically 0.85 % of transmitted power (per end) [2].

## Availability

Suppliers include ABB, Alstom Grid and Siemens, although several Eastern Suppliers such as CEPRI can also offer such products. Lead times are dependent on the requirements of a given project and are typically 2.5 to 3 years. The lead time may be dominated by any associated cable manufacturing time.

## Dependancies and Impacts

CSCs require a relatively strong AC network for valve commutation. In general, the Short Circuit Ratio (SCR), defined as the short circuit power or fault level divided by the rated HVDC power, should be at least 2.5. Recent developments such as capacitor commutated converters have reduced the SCR requirement to around 1.0, but in either case to use a CSC offshore would require a voltage source such as a STATCOM or rotating machine to provide sufficient voltage for successful valve commutation.

CSC technology may be used with mass impregnated cable or overhead line to form the HVDC connection between the converter stations. A reversal of the power flow direction requires a change in the polarity of the DC voltage. This may impose a waiting time before re-start of power transfer in the opposite direction when using mass impregnated cables. Extruded cables may be used in case no reversal of power flow is foreseen.

Although having higher ratings than extruded cable where mass impregnated cables are used, the achievable transmission capacity may still be limited by the ratings of the cable rather than the converter.

CIGRE Advisory Group B4.04 conducts an annual survey of the reliability of HVDC systems and publishes the results at the CIGRE Session held in Paris every two years [3]. The reports contain data on energy availability, energy utilization, forced and scheduled outages and provide a continuous record of reliability performance for the majority of HVDC systems in the world since they first went into operation.

## Project Examples

- **HVDC Cross-Channel Link:** the link connects the French and British transmission systems [4]. The link consists of two separate bi-poles each with a transmission capacity of 1000 MW at a DC voltage of +/- 270 kV. Each bi-pole can operate as a monopole to transfer 500 MW allowing operational flexibility. The Cross-Channel Link went into operation in 1986. The Converter Stations were supplied by Alstom Grid.
- **BritNed:** The link connects the British and Dutch transmission systems. The link is a 1000 MW bi-pole that operates at ± 450kV over a 260km subsea cable. The link was commissioned in early 2011. The converter stations were supplied by Siemens and the cables by ABB.
- **Basslink:** the link connects Victoria, on the Australian mainland to George Town, Tasmania, by means of a circuit comprising 72 km overhead line, 8 km underground cable and 290 km submarine cable [5]. The connection is monopolar with a metallic return. It has a nominal rating of 500 MW, operates at a DC voltage of 400 kV and went into operation in 2006. The converter stations were supplied by Siemens and the cables by Prysmian.
- **NorNed HVDC:** the link connects the transmission systems in Norway and the Netherlands by means of a 580 km submarine cable [6]. The connection has a transmission capacity of 700 MW at a DC voltage of +/- 450 kV and went into operation in 2008. The converter stations were supplied by ABB and the cables by ABB and Nexans.
- **North-East Agra:** this link will have a world record 8,000 MW Convertor capacity, including a 2000 MW redundancy, to transmit clean hydroelectric power from the North-Eastern and Eastern region of India to the City of Agra across a distance of 1,728 km. The project has a ± 800 kV voltage rating and will form a Multi-terminal solution and will be one of the first of its kind anywhere in the world (the others being the New England–Quebec scheme and the HVDC Italy–Corsica–Sardinia (SACOI) link respectively). The project is scheduled to be commissioned in 2014. The project is being executed by ABB.

## References and Additional Information

[1] Carlsson, L, '"Classical" HVDC: Still continuing to evolve', available on www.abb.com

[2] Andersen, B R and Zavahir, M, 'Overview of HVDC and FACTS', CIGRE B4 Colloquium, Bergen, 2009

[3] Vancers, I, Christofersen, D J, Leirbukt, A and Bennet, M G, 'A survey of the reliability of HVDC systems throughout the world during 2005 – 2006', Paper B4-119, CIGRE 2008

[4] Dumas, S, Bourgeat, X, Monkhouse, D R and Swanson, D W, 'Experience feedback on the Cross-Channel 2000 MW link after 20 years of operation', Paper B4-203, CIGRE 2006

[5] Bex, S, Carter, M, Falla, L, Field, T, Green, M, Koelz, A, Nesbitt, P, Piekutowski, M and Westerweller, T, 'Basslink HVDC design provisions supporting AC system performance', Paper B4-301, CIGRE 2006

[6] Skog, J-E, Koreman, K, Pääjärvi, B, Worzyk, T and Andersröd, T, 'The NorNed HVDC cable link A power transmission highway between Norway and the Netherlands', available on www.abb.com

# E.13
# HVDC: Switchgear

## Description

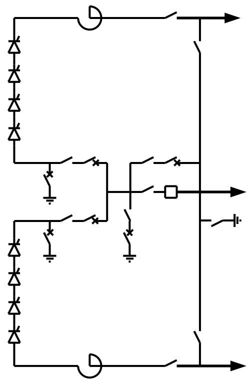


Figure E.23 Example of HVDC Switchgear configuration

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. The various functions are described in [1, 2, 3], although not all will be present in all schemes.

HVDC switching devices can be classified into current commutating switches, disconnectors and earthing switches. Standard AC switching devices with appropriate ratings may be used.

HVDC line circuit-breakers are not commercially available at present, however it has been demonstrated at laboratory level [4]

## Capabilities

The function, mode of operation and duties of current-commutation switches is described in [1] and those of disconnectors and earthing switches in [2]. Operation of the metallic return transfer breaker is described in [3]. Capabilities of prototype HVDC line Circuit-breakers are described in [4, 5]

## Availability

The HVDC switchgear is supplied as part of the converter station. Suppliers include ABB, Alstom Grid and Siemens. Based on manufacturers responses, the availability of HVDC Line Circuit breakers are described in [5]

## Dependancies and Impacts

The future availability of HVDC line circuit-breakers will be a benefit in multi-terminal HVDC systems in allowing a fault on the DC side to be cleared without tripping the entire HVDC system.

## Project Examples

Many bipolar HVDC schemes use DC switchgear to switch between bipolar and monopolar operation.

## References and Additional Information


[1] CIGRE WG 13.03, ‘The metallic return transfer breaker in high voltage direct current transmission’, Electra No. 68, Jan. 1980, pp 21-30

[2] CIGRE WG 13/14.08, ‘Switching devices other than circuit-breakers for HVDC systems, part 1: Current commutation switches’, Electra No. 125, July 1989, pp 41-55

[3] CIGRE WG 13/14.08, ‘Switching devices other than circuit-breakers for HVDC systems, part 2: Disconnectors and earthing switches’, Electra No. 135, April 1991, pp 32-53

[4] “The Hybrid HVDC Breaker, An innovation breakthrough enabling reliable HVDC grids” ABB Grid Systems, Technical Paper Nov’2012

[5] CIGRE WG B4.52 “HVDC Grid Feasibility Study” April 2013, pp 38 – 44, 77 – 83, Appendix H

# E.14
# HVAC: Switchgear

## Description

Figure E.25
GIS (up to 300kV)
Image courtesy of Siemens

Figure E.24
Typical 132kV AIS bay

Switchgear is equipment which allows switching to be performed to control power flows on the network. Switchgear comes in 2 predominant forms, Air Insulated Switchgear (AIS) and Gas Insulated Switchgear (GIS).

The term switchgear encapsulates a variety of equipment including circuit-breakers, disconnectors, earthing switches and instrument transformers. In the case of AIS equipment this is typically stand alone whereas in GIS this is fully encapsulated within its earthed metallic enclosure.

GIS is defined as 'metal-enclosed switchgear in which the insulation is obtained, at least in part, by an insulating gas other than air at atmospheric pressure' [1]. The insulating gas in GIS is sulphur hexafluoride ($SF_6$) at a pressure of a few bars, which has excellent insulating properties and allows a more compact solution to be achieved compared to AIS.

One of the main benefits of having equipment enclosed is to protect it against harsh environments. The insulating gas also allows the switchgear to be more compact and it is for these reasons GIS is typically installed in city locations and offshore where space is a premium. AIS equipment is typically installed in more rural and spacious areas, such as Brownfield sites.

## Capabilities

Switchgear is available in rated voltages up to 1200 kV with rated normal currents of up to 8000 A.

Typical switchgear technical data relevant for UK use is given in the table below:

**Table E.7**

| Rated voltage, kV | 36 | 145 | 300 | 420 |
|---|---|---|---|---|
| Rated lightning impulse withstand | 170 | 650 | 1050 | 1425 |
| Rated normal current, A | 2500 | 2000 | 3150 | Up to 5000 |
| Rated short-circuit breaking current, kA | 25 | 40 | 40 | 63 |

## Availability

Suppliers include: ABB, Alstom Grid, Crompton Greaves, Ormazabal, Hapam, Hyosung, Hyundai, Mitsubishi and Siemens.

## Dependancies and Impacts

In addition to the switching of load currents and fault currents, circuit-breakers should be specified to be capable of breaking the capacitive charging currents associated with cables and over head lines. For certain applications such as capacitor banks and shunt reactors, additional duty specific testing may also be required.

The present generation of GIS requires little maintenance. Remote condition monitoring systems such as electronic gas density monitoring may be used to reduce the need for attendance at site for checks and inspections. The remaining maintenance requirements mainly concern the switching devices and their operating mechanisms with inspection and lubrication intervals of many years.

Modern AIS requires more frequent maintenance due to the fact that the conducting components are exposed to their local environment. This is even more predominant in disconnector and earth switches with maintenance intervals of a few years. Modern AIS circuit breakers typically use SF6 as an arc quenching medium and are very similar to their GIS counterparts. Older switchgear typically requires more frequent maintenance, mainly due to them having more complex operating mechanisms and showing signs of wear due to their age.

New AIS switchgear which combines the functions of several separate devices, and other Hybrid switchgear is starting to become available at transmission levels. The aim of these more compact devices is to reduce the physical footprint of AIS substations, thus reducing the need to install costly GIS where space is a premium.

When working with equipment filled with SF6 it can become necessary to evacuate the gas to allow it to be maintained. Personnel who perform SF6 gas handling must be suitably trained and qualified. The gas has a high Global Warming Potential and should not be released deliberately to the atmosphere. In addition, following exposure to high temperatures such as arcing during circuit-breaker operation or as a result of an internal fault, decomposed gas can react to yield decomposition products that are highly reactive and toxic. Guidance on SF6 gas handling is given in [2].

Data on GIS service experience has been published by CIGRE [3] [4].

### References and Additional Information


[1] IEC 62271-203 'High-voltage switchgear and controlgear – Part 203: Gas-insulated metal enclosed switchgear for rated voltages above 52 kV'

[2] IEC/TR 62271-303 'High-voltage switchgear and controlgear – Part 303: Use and handling of sulphur hexafluoride'

[3] CIGRE WG 23.02, 'Report on the second international survey on high voltage gas insulated substations service experience', Ref. 150, February 2000

[4] CIGRE WG A3.06 'Final Report of the 2004 – 2007 International Enquiry on Reliability of High Voltage Equipment', Ref . 509, 513 and 514, 21 October 2012.

# E.15
# HVAC:
# Transformers

## Description

Transformers are employed where different operating voltages need to interface. In addition to transforming the voltage, they also introduce an impedance between the systems controlling fault currents to safe levels.


Figure E.26

Step up transformers are used to connect generation to the network; offshore this is used to step up the wind turbine array collection voltage to the high voltages required for efficient long distance power transmission. Increasing the voltage reduces the current required to give the same power flow, which reduces the size and hence cost of the conductor required and also reduces power losses in the conductors. Grid supply transformers are used to step down the voltage from transmission to more manageable levels for distribution.

Transformers are typically comprised of copper windings wrapped around a laminated iron core immersed in oil for cooling. There are many different construction options depending on design constraints (size, noise, cooling, transport or losses). HV Transformers can be equipped with On Load Tap Changers (OLTC) to regulate the voltage within design limits.

Power transformers used offshore are largely the same as onshore units with the exception of painting and hardware fixture requirements.

## Capabilities

Offshore transformers should be considered to some degree as generation units since they are used to step up the offshore wind farm array voltage to offshore network transmission voltage. Typical designs use a star connected primary high voltage winding and double secondary delta windings. The double secondary windings allow the switchgear to be segregated and to not exceed available current ratings and manage fault levels within the wind farm array. A neutral point must be provided for earthing on the low voltage side of the transformer. This is commonly done with a zig-zag earthing transformer which is equipped with 400V windings to provide the auxiliary supply to the offshore platform.

**Table E.8**

| Rated voltage kV | 400/132/13 | 245/33/33 | 145/33/33 |
|---|---|---|---|
| Power (MVA) | 180-240 | 180 | 120-180 |
| Impedance (% on rating) | 15 | 15-20 | 15-20 |
| Losses (load/no load) % | 0.39/0.03 | 0.5/0.05 | 0.5/0.05 |
| Windings | Auto | Ydd | Ydd |
| Insulation withstand (LIWL kV) | 1425/650 | 1050/170 | 650/170 |
| Cooling | ONAF | ONAF | ONAF |
| Weight - without oil (tonnes) | 200 | 150 | 90 |
| Volume of oil (litres) | 90000 | 50000 | 20000 |

Transformers may be two winding, three winding or autotransformers. Autotransformers are usually smaller in weight and size than an equivalent two winding power transformer, but do not provide electrical isolation between the primary and secondary voltages or lower short circuit levels. Both autotransformers and two winding transformers may have an additional tertiary winding with a delta configuration, which reduces triplen harmonics (multiples of 3rd harmonic) passing through the transformer and also helps reduce any voltage unbalance between the phases. The voltage of the tertiary winding may be chosen to allow connection of reactive compensation equipment at a lower voltage than the primary or secondary windings.

The life expectancy of onshore and offshore transformers is determined by the loading, since the insulation is generally paper and oil. Generator transformers are likely to have a shorter lifetime than supply transformers due to the loading seen over the asset lifetime, typically 25 years, while many supply units have been in service for 40 years or more.

## Availability

Transformers are reliable if appropriately specified and looked after. Failure rates of 0.25% are not unreasonable for supply transformers however generation units will exhibit higher rates due to heavier usage (80-90% loading). This is discussed in the CIGRE Technical brochure TB 248 [1]. Offshore units should be no less reliable than onshore, however the offshore circuit topology includes long cables which may induce stress and resonance in the transformer during energisation. The compact nature of the substation will result in close up very fast voltages to the transformer winding generated by vacuum circuit breaker transients on the LV windings and disconnector switching. These could in time cause overvoltage damage due to part winding resonances.

A transformer is made up of a number of elements, in addition to the core and winding. There is the OLTC, the cooling and bushings, all of which require more maintenance than the core itself, therefore it is important to monitor all parts of the transformer.

Suppliers include: ABB, Areva, Crompton Greaves, Hyosung, Hyundai, Mitsubishi, Prolec GE, Siemens and SMIT/SGB. The procurement lead time for a large power transformer is approximately 18 – 24 months.

### Dependancies and Impacts

Weight and space are critical design parameters for offshore platforms. Transformers will be one of the heaviest items of plant on the platform and would normally be situated close to the centre of gravity above the pile or jacket for stability. Associated radiators and cooling fans are placed on the outside of the platform. Sea water based cooling may also be preferred to the conventional oil/air based cooling. As with all the equipment on the platform, it is important that the paint specification is to a marine grade and applied carefully with regular inspections carried out to promptly take care of any defects. Stainless steel hardware should be used where possible.

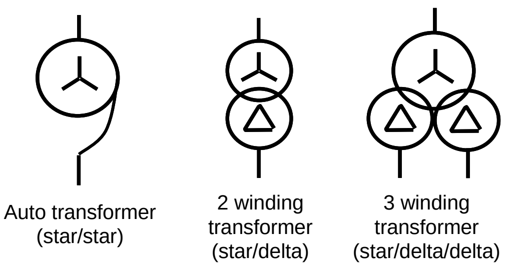



Figure E.27

Transformer ratings will need to be specified for the apparent power (MVA), which comprises both the real power (MW) and reactive power (MVAr) provided by wind turbines and reactive compensation as well as reactive power requirements of cables. Standardisation of ratings, configurations and voltages across offshore wind farms would minimize the number of spares required.

Transformer HV terminals can be connected directly to the HV gas insulated switchgear. This allows efficient use of space on the offshore platform. Platforms with more than one transformer can have the wind farm switchgear configured with normally open bus section breakers. This allows one of the transformers to be switched out for maintenance or following a fault and still allow all of the wind farm to be connected to the grid within the ratings of the transformers still in service. Transformers may be temporarily overloaded although this decreases their lifetime expectancy.

Transformers pose the two greatest environmental risks on the platform in the event of a major failure; namely oil spillage and transformer fire. Oil bunds, separation and dump tanks will be required. Fire suppression or control should be investigated. Synthetic oils are available with much lower likelihood of combustion. Synthetic oils are more expensive than mineral oils and require a bigger transformer due to lower dielectric strength. Research is ongoing into the use of synthetic esters for 400kV applications.

The logistics around a transformer failure and replacement must be considered, in particular the removal from the platform. An incident offshore will be very costly depending on the availability of a spare, repair vessel availability and weather windows. Long lead times could lead to extended outages while a replacement is sourced therefore a cost benefit analysis of redundancy or overload options are recommended.

### Project Examples

- **Lillgrund Windfarm:** Supply and installation of 33/138 kV 120 MVA transformer by Siemens
- **Princess Amalia Windfarm:** Supply and installation of 22/150 kV 140 MVA transformer by ABB

- **Gunfleet Sands Windfarm:** Supply and installation of two 132/33 kV transformers by ABB/Areva
- **Greater Gabbard Windfarm:** Supply and installation of three 132/33/33 kV 180/90/90 MVA transformers by Siemens

### References and Additional Information

Guide on economics of transformer management: CIGRE Technical brochure 248

IEC 60076 – Power Transformers

IEC 60214 – On load tap changers

International Survey on failure in service of large power transformers. CIGRE ELECTRA 88_1, 1978

Transformer reliability surveys, CIGRE Session paper A2-114, 2006

N. Andersen, J. Marcussen, E.Jacobsen, S. B. Nielsen, *Experience gained by a major transformer failure at the offshore platform of the Nysted Offshore Wind Farm*, Presented at 2008 Wind Integration Conference in Madrid, Spain.

# E.16
# HVAC:
# Shunt Reactors

### Description

Figure E.28
Air Core Reactors (blue), image courtesy of Enspec Power

Shunt Reactors are used to compensate for the capacitive reactive power present in AC transmission networks and provide a means to regulate the network voltage. HVAC cables have a high capacitance and shunt reactors are utilised at the onshore interface point and possibly at the offshore substation platform, and potentially at intermediate points along the cable length (e.g. at the shore landing point).

Reactors are constructed either with an air-core or gapped iron core design. Iron core reactors are commonly immersed in a tank of oil with a similar construction to power transformers, except the gapped iron core provides a higher reluctance to allow a higher magnetising current to flow. Air Core Reactors (ACR) are physically larger than iron core reactors, but are simpler, and require less maintenance. Since they do not have non-linear iron cores, they are not subject to core saturation effects. Shunt Reactors may be connected to tertiary windings on power transformers or connected to the HV busbar via switchgear for operational switching and protection.

### Capabilities

Generally ACRs are lower in cost, but are larger in size, so where space is limited and high ratings are required oil immersed units dominate. ACRs are commonly available up to 72 kV and 100 Mvar. Larger voltages and ratings are possible but generally regarded as special designs. Oil immersed iron core reactors are available up to 800 kV and 250 Mvar.

### Availability

There is little data available on reactor reliability, however oil immersed units can be comparable to transformers (without tap changers). Air cored units will have a lower availability due to the large surface area, fauna impact (birds and nests) and exposure to the environment. There is little maintenance necessary with air cored units other than visual inspection, oil immersed units will be similar to that of transformers.

Suppliers Include: ABB, Alstom Grid, Crompton Greaves, GE Energy Hyosung, Hyundai, Enspec Power, Mitsubishi, Nokian Siemens and Trench. Lead times of Shunt Reactors range from 12 to 24 months.

### Dependancies and Impacts

A drawback with ACRs is that the magnetic field extends beyond the reactor and the installation requires special consideration. Metallic loops in adjacent constructions must be avoided where circulating currents could flow, this could be problematic offshore. Iron core oil immersed reactors in a tank do not have significant magnetic fields extending beyond the tank and the reactor is well protected from the environment making them better suited for the offshore environment. Reactors can be used with AC offshore transmission networks to supply the reactive demands of the offshore power park cables and the 3 core offshore transmission cables. Attention should be paid to the contribution that harmonics play in the temperature rise of the ACR, excessive temperature can cause overheating, ageing and possibly fire.

Circuit breakers need to be suitably rated and tested to switch reactors, in particular the Transient Recovery Voltage (TRV) established during opening.

### Project Examples

- **Majorca / Minorca Subsea Cable:** 5 x 30 Mvar, 132 kV shunt reactors supplied by ABB, operating for 26 years.
- **Alpha Ventus Offshore Substation:** 10 Mvar, 110 kV shunt reactor supplied by Areva
- **Alpha Ventus Onshore Substation:** 11.7 – 29.3 Mvar, 127 kV adjustable shunt reactor supplied by Trench

### References and Additional Information

IEC 60076-6 Power transformers – Part 6: Reactors - Edition 1.0 (2007)

# E.17
# HVAC:
# Shunt Capacitor Banks

## Description

Figure E.29
Open rack capacitors
Image courtesy of Areva

Shunt Capacitor Banks may be considered as an option at the on-shore substation to provide capacitive reactive power (other options include Static Var Compensators (SVC's) or Static synchronous Compensators (STATCOM's)). This capacitive reactive power is part of the requirement to supply active power between a 0.95 leading power factor and a 0.95 lagging power factor at the (onshore) interface point as required under Section K of the System Operator / Transmission Owner (STC) Code [1].

Racks of capacitor cans are also found in Flexible AC Transmission System (FACTS) devices such as SVC's, STATCOM's or Series Compensation, HVDC converter stations and harmonic filters.

Within the 'bank' capacitors are connected in series and parallel to achieve the desired voltage and reactive power rating. They can be open rack mounted or for lower voltage installations, fully enclosed.

## Capabilities

Shunt capacitor banks can take several forms;

- Fixed Capacitors that are permanently connected to the power network (usually at LV, i.e. 11 kV)
- Mechanically Switched Capacitors (MSC) that use dedicated circuit breakers to connect them to the power network
- Thyristor Switch Capacitors (TSC) that use thyristor valves to connect them to the power network (i.e. SVC)

The decision to employ one type of reactive compensation over another is a combination of power system requirements (ie to meet the Grid Code, licence obligations, SO/TO etc.) and the most economic method in which to provide the required levels of compensation at any given connection point, including the size of land available for the on-shore installation. This will vary from site to site (on-shore) and will also be dependant on generation capacity and the method of connecting the generation in to the on-shore network, i.e. AC or DC).

Technical preference tends towards SVC's or STATCOM's as these are capable of providing dynamic response (rather than switching lumps of capacitance in and out of service, as is the case with shunt capacitor banks), however, these technologies are more costly to purchase and manage over their planed life.

To allow controllability of the capacitor banks, for varying power network conditions, an MSC is likely to be the most economic chosen design so long as it is able to meet the performance requirements.

MSC's for connection at 132 kV and below may have a number of individual banks (say 3 X 45 Mvar) each capable of being switched in and out of service by their own circuit breaker and may also be ganged in parallel via a common circuit breaker that is capable of switching all of the banks in and out of service together.

It should be noted, the switching of MSC's introduces voltage step changes and power quality issues on the connected power network [2] and these effects need to be taken in to consideration when locating and designing a MSC installation.

The circuit breakers for the MSC may have a Point-On-Wave (POW) control facility to ensure the each pole of the circuit breaker closes as close to the zero voltage crossing as possible to reduce the amplitude of any switching transients generated. Alternative methods are to introduce a Damping Network (DN) in to the MSC circuit (MSC-DN) which acts to reduce the amplitude of the switching transients, or to have a combination of POW and DN.

MSC's for connection on to the transmission system at 275 kV or above typically comprise single banks of capacitance that are switched in and out of service by individual circuit breakers (i.e. the individual banks are not ganged together). However, they also have a DN may or may not have POW facilities depending on the transmission system requirements.

MSC's may have an automated control scheme that monitors network parameters at the substation and is able to switch capacitor banks in and out of service for a pre-defined target. This target is selected by a network operator either locally or remotely. It may also be possible to over-ride the automated control scheme and allow an operator to manually switch capacitors in and out of service as required.

### Availability

Suppliers of capacitor cans/racks and complete shunt capacitor installations include: ABB, Alpes Technologies, Alstom Grid, Cooper Power Systems, Crompton Greaves, Enspec Power, GE Power, NEPSI, Phaseco, SDC industries and Siemens.

### Dependancies and Impacts

Capacitor banks are available in metal enclosed or open rack outdoor designs.

Metal enclosed capacitor banks are typically available up to a rating of 38 kV and 40 Mvar [3]. Beyond this, open rack outdoor designs are the norm.

By comparison a large open rack installation may have ratings up to 765 kV and 600 Mvar [4], however, it is technically possible to increase this rating by adding additional capacitors in series and parallel until the desired rating is achieved.

The relative advantages and disadvantages of metal enclosed and outdoor racks would be considered during the specification and design of any such system.

As mentioned, capacitor banks are switched in/out as lumped units with a circuit breaker. If finer gradation is required then multiple smaller banks, with more circuit breakers are required. The overall size of the capacitor banks is limited by the circuit breakers ability to interrupt reactive power flow, and is determined by the power network's requirement for reactive power at a given location and its ability to accept reactive power.

### Project Examples

- **Grendon Substation:** 3 x 225 Mvar, 400 kV MSCs supplied by Siemens for National Grid [5]
- **RTE:** Purchase of 4 x 80 Mvar and 1 x 8 Mvar MSC-DN's [6]

### References and Additional Information


[1] System Operator – Transmission Owner (STC) Code, Section K:- Technical Design & Operational Criteria & Performance Requirements for Offshore Transmission Systems v1. [Accessed: 23 Sept 2013]. Available: http://www.nationalgrid.com/uk/Electricity/Codes/sotocode/

[2] Electra No. 195, April 2001, Cigre WG 36.05 / Cired 2 CC02, Thomas E. Grebe, Capacitor Switching and its impact on power quality. [Accessed 23 Sept 2013] Available: http://www.e-cigre.org/

[3] NEPSI, *Medium Voltage Metal-Enclosed Capacitor Banks*. [Accessed: 23 Sept 2013]. Available: http://www.nepsi.com/files/catalog/100-00-Metal%20Enclosed%20Capacitor%20Bank%20Main.pdf

[4] ABB, *Open Rack Shunt Bank*. [Accessed: 23 Sept 2013]. Available: http://www.abb.co.uk/product/db0003db002618/c12573e7003302adc12568100046a069.aspx?productLanguage=us&country=GB&tabKey=2

[5] Siemens, *Mechanical Switched Capacitors Reference List*. [Accessed: 23 Sept 2013]. Available: http://www.energy.siemens.com/hq/pool/hq/power-transmission/FACTS/MSC/Siemens_Reference_List_MSC.pdf

[6] Siemens Capacitors, RTE purchase of 5 MSC-DN's. [Accessed: 23 Sept 2013]. Available: http://www.energy.siemens.com/hq/en/power-transmission/facts/mechanical-switched-capacitor/references.htm

# E.18
# HVAC:
# Static VAR Compensators

## Description


Figure E.30
Sidmed SVC, Spain, image courtesy of Alstom Grid

A Static VAR Compensator (SVC) is a fast acting power electronic device used to dynamically control the voltage in a local area or at an interface point. It is regarded as part of the Flexible AC Transmission System (FACTS) genre of equipment. Essentially SVCs and STATCOMs deliver a similar function using different power electronic technologies and methods.

The SVC provides variable inductive and capacitive reactive power using a combination of Thyristor Controlled Reactors (TCR), Thyristor Switched Reactor (TSR), and Thyristor Switched Capacitors (TSC). These are connected to the AC network using a compensator transformer or via a transformer tertiary winding.

## Capabilities

An SVC can provide a continuously variable reactive power range using the TCRs, with the coarser reactive control provided by the TSRs and TSCs. The reactive power (Mvar) output of the SVC may be controlled directly or be configured to automatically control the voltage by changing its Mvar output accordingly. Since the SVC uses AC components to provide reactive power, the Mvar production reduces in proportion to the square of the voltage.

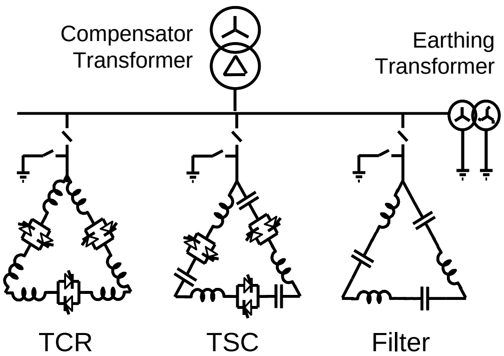


Figure E.31
Typicla SVC Configuration

A suitably rated SVC will provide fault ride through capability at the interface point of the offshore transmission network and the onshore transmission system, as required by the System Operator/Transmission Owner Code (STC).

SVCs can be used with AC or Current Source Converter (CSC) HVDC based offshore transmission networks, but are not required for Voltage Source Converter (VSC) HVDC, which can inherently control Mvar output.

SVCs have been manufactured up to 500 kV and 720 Mvar and have been in operation for many years and at higher ratings and voltages than STATCOMs. SVCs tend to be cheaper than STATCOMs on a like for like basis, however they have a larger footprint.

## Availability

Suppliers Include: ABB, AMSC, Alstom Grid, Mitsubishi and Siemens.

Supply and install lead times are typically 12 to 24 months.

## Dependancies and Impacts

The TCRs produce harmonics which normally require 5th and 7th harmonic filters, and star-delta transformers to block 3rd and 9th harmonics. Six pulse SVCs are typical, but where the space is available and harmonic performance is a concern, twelve pulse SVCs can be considered.

A step-up transformer is usually required to couple the SVC to the required bus voltage. These are specialised transformers with low voltage secondary windings (e.g. 10 kV) and the capability to handle the reactive power flow and block triplen harmonics. In the event of a transformer failure the SVC will be out of service until the transformer is repaired or replaced.

The fast dynamic aspect of the SVC is provided by thyristor valves which are water cooled, air insulated and designed for indoor use. The reactors and capacitors are usually housed outdoors unless noise considerations prevail.

SVC reliability is heavily dependent on the auxiliary systems (cooling, LVAC power supply) and availability of spare components. 1–2 days per year for auxiliary systems such as converter cooling and building systems will be a minimum. Duplication of these systems may help to improve overall availability.

SVC design lifetime is 20-30 years (20 years for the cooling system and control and protection).

### Project Examples

- **Nysted Offshore Windfarm:** -65/+80 Mvar, 132 kV SVC supplied and installed on-shore (at Radsted) by Siemens to comply with Grid Code requirements.
- **Alleghny Power, Black Oak:** 500 Mvar, 500 kV SVC supplied and installed by ABB to improve transmission line reliability by controlling line voltage.
- **National Grid, UK:** 60 MVA re-locatable SVCs supplied by ABB and Alstom Grid
- **Brown Switching Station near Brownwood, Texas:** 2 x -265/+300 Mvar, 345 kV supplied by Mitsubishi Electric to support the transmission of renewable energy from generation sites in West Texas, due to be placed into commercial operation in January of 2014.

### References and Additional Information

B4_201 Operational experiences of SVCs in Australia, A. Janke, J. Mouatt, CIGRE, Paris 2008

CIGRE Technical Brochure TB025 – Static Var Compensators, TF 38.01.02, 1986

CIGRE Technical Brochure TB093 - Guidelines for testing of thyristor valves for static var compensators. WG14.01.02, 1995

# E.19
# HVAC:
# Static Compensator (STATCOM)

## Description

Figure E.32
32 Mvar STATCOM (building required)
Image courtesy of ABB

A Static Compensator (STATCOM) is a fast acting device which can generate or absorb reactive power more quickly than AC capacitor banks, reactors or SVCs.

It is a Flexible AC Transmission (FACTS) technology, which may be used at the onshore interface point to achieve System Operator/Transmission Owner Code (STC) dynamic compliance between 0.95 power factor lag and 0.95 power factor lead.

The design and faster response enables it to be used to control flicker to improve power quality. STATCOMs are voltage source converters (VSC) using typically Insulated Gate Bipolar Transistor (IGBTs) or Insulated Gate Commutated Thyristor (IGCTs). They can also incorporate static capacitors and reactors into their design.

## Capabilities

Ratings up to ±100 Mvar continuous at 138 kV (via a step-up transformer) are in service with pilot projects up to 200 Mvar under development. The STATCOM may control the Mvar output or local network voltage by controlling the Mvar output in response to voltage rises or depressions.

STATCOMs may be more suitable on weak networks as the reactive compensation capability of SVCs reduces more significantly than STATCOMs below nominal voltage ratings. STATCOMs with reduced ratings can be integrated with fixed reactors and capacitor banks to provide a lower cost solution than a fully rated STATCOM alone.

The ABB STATCOM at Holly has a VSC section with a rating of ±95 Mvar continuous. The majority of STATCOMs produced to date have been low or medium voltage devices requiring a transformer to connect to the local grid voltage. Recent developments in HVDC VSC technology has lead to the introduction of high voltage STATCOM devices that can connect directly to the grid without a transformer at medium voltages (e.g. 33kV), higher voltages will require a transformer.

## Availability

Suppliers Include: ABB, Alstom Grid, AMSC, Hyosung, Mitsubishi, Siemens, S&C Electric Company and Toshiba. Suppliers of high voltage STATCOMs are ABB (SVC Light®), Alstom Grid (SVC MaxSine®) and Siemens (SVC PLUS®).

## Dependancies and Impacts

STATCOM's are not designed to be installed outside and require a building or enclosure. A step-up transformer is usually required to couple the STATCOM to the required bus voltage.

STATCOM can be combined with Mechanically Switched Capacitor (MSC) banks, Mechanically Switched Reactors (MSR) and Thyristor Switched Capacitor (TSC) banks into a cost effective scheme to achieve technical compliance requirements. However, the equipment needs to be adequately rated and designed for continuous capacitor bank and reactor switching for the solution to meet STC and Grid Code dynamic and harmonic requirements.

The STATCOM design lifetime is 20-30 years (20 years for the cooling system and control and protection). STATCOMS are stated to have an availability rate of above 98%. This can often be increased by adding redundant modules within the STATCOM and keeping replacement components on site.

## Project Examples

- **Greater Gabbard Windfarm:** +/- 50 Mvar SVC PLUS with MSC and MSR, supplied by Siemens.
- **Basin Electric, Wyoming:** 34 Mvar D-VAR with short term rating of 91 Mvar supplied by AMSC.
- **Holly STATCOM:** Comprises a +110/-80 Mvar VSC, together with capacitor banks and filters to give a total range of 80 Mvar inductive to 200 Mvar capacitive. Supplied and installed by ABB.
- **SDG&E Talegat:** ±100 Mvar 138 kV STATCOM, supplied and installed by Mitsubishi Electric.

## References and Additional Information


Guillaume de Préville, Wind farm integration in large power systems; Dimensioning parameters of D-Statcom type solutions to meet grid code requirements. CIGRE 2008 Session paper B4_305

Grid compliant AC connection of large offshore wind farms using a Statcom, S. Chondrogiannis et al. EWEC 2007.

CIGRE Technical Brochure – TB144 Static Synchronous compensator (STATCOM), CIGRE WG14.19, 1999.

Operational experiences of STATCOMs for wind parks, Ronner, B. Maibach, P. Thurnherr, T.

Adv. Power Electron. (ATPF), ABB Switzerland Ltd., Turgi, Switzerland, Renewable Power Generation, IET, Sept 2009.

# E.20
# Technology Availability for Strategic Optioneering

### Purpose and Scope

Many of the technologies required for strategic wider works are new and developing rapidly. Voltage Sourced Converter (VSC) HVDC technology was introduced in 1997 and since then has been characterised by continuously increasing power transfer capabilities. Significant developments have taken place in the area of dc cables including the introduction of extruded and mass impregnated polypropylene paper laminate (MI PPL) insulation technologies. New devices are emerging, such as the HVDC circuit-breaker. The present document aims to anticipate how the capability of the key technology areas for strategic wider works might develop in coming years and provide an indication of technology availability by year in order to inform planning decisions.

### Introduction

Matrices are presented for each of the key technology areas, in which technology capability is tabulated against year. The availability of technology with a given capability in a given year is indicated by means of a colour-coded cell. The key is shown below. Red indicates that the technology is not expected to be available in that year. It is important to distinguish between the time at which a technology becomes commercially available and the time by which it might be in service; amber indicates that the technology is expected to have been developed and to be commercially available but not yet in service. It has been assumed that project timescales for HVDC schemes are such that a period of typically four years would elapse between technology becoming available and being in service. It is clear that for technology to be in service, a contract will have to have been placed at the appropriate time. Consequently, yellow is used to indicate that it would be possible in principle for the technology to be in service in a given year provided a contract has been placed. Green indicates that the technology is in service or scheduled to be in service on the basis of contracts which are known to have been placed.

| | |
|---|---|
| R | **Technology not available** |
| A | **Technology available but not in service** |
| G | **Technology potentially in service subject to contract** |
| G | **Technology in service or scheduled to be in service** |

Where the availability of a technology is indicated by an amber cell, its introduction will require an appropriate risk-managed approach that takes account of the lack of service experience. Where the availability is indicated by a green cell, a greater level of experience will be available but appropriate risk management will still be required particularly in the earlier years.

The information represents National Grid's best estimates and has not been endorsed or confirmed by manufacturers.

## E.20.1
## Technology Availability (Individual)

### HVDC Converters

Voltage sourced converters

| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2030 | 2035 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1563 A | G | G | G | G | G | G | G | G | G | G | G | G | G |
| 1800 A | A | A | A | G | G | G | G | G | G | G | G | G | G |
| 2000 A | R | R | A | A | A | A | G | G | G | G | G | G | G |

Key

| | |
|---|---|
| R | **Technology not available** |
| A | **Technology available but not in service** |
| G | **Technology potentially in service subject to contract** |
| G | **Technology in service or scheduled to be in service** |

**Figure E.33**

## HVDC Cables

Extruded dc cables at 70 to 90 ºC

| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2030 | 2035 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 320 kV | G | G | G | G | G | G | G | G | G | G | G | G | G |
| 350 kV | A | A | A | G | G | G | G | G | G | G | G | G | G |
| 400 kV | A | A | A | A | G | G | G | G | G | G | G | G | G |
| 500 kV | R | A | A | A | A | G | G | G | G | G | G | G | G |
| 600 kV | R | R | R | R | R | A | A | A | A | G | G | G | G |
| 650 kV | R | R | R | R | R | R | R | R | R | R | A | A | A |
| 700 kV | R | R | R | R | R | R | R | R | R | R | R | R | A |

Key

| | |
|---|---|
| R | Technology not available |
| A | Technology available but not in service |
| G | Technology potentially in service subject to contract |
| G | Technology in service or scheduled to be in service |

Figure E.34

Mass impregnated dc cables at 55 ºC and mass impregnated polypropylene paper laminate cables at 80 ºC – voltage.

| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2030 | 2035 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 500 kV | G | G | G | G | G | G | G | G | G | G | G | G | G |
| 600 kV | A | A | G | G | G | G | G | G | G | G | G | G | G |
| 650 kV | R | R | A | A | A | A | G | G | G | G | G | G | G |
| 700 kV | R | R | R | R | R | R | A | A | A | A | G | G | G |
| 750 kV | R | R | R | R | R | R | R | R | R | R | A | G | G |

Key

| | |
|---|---|
| R | Technology not available |
| A | Technology available but not in service |
| G | Technology potentially in service subject to contract |
| G | Technology in service or scheduled to be in service |

Figure E.35

Mass impregnated cables at 55 ºC and mass impregnated polypropylene paper laminate cables at 80 ºC – current.

| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2030 | 2035 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1876A | A | A | G | G | G | G | G | G | G | G | G | G | G |
| 2000 A | R | R | A | A | A | A | G | G | G | G | G | G | G |

Key

| | |
|---|---|
| R | Technology not available |
| A | Technology available but not in service |
| G | Technology potentially in service subject to contract |
| G | Technology in service or scheduled to be in service |

Figure E.36

## Offshore HVDC Platforms

Offshore platforms for HVDC converters

| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2030 | 2035 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 320 kV | G | G | G | G | G | G | G | G | G | G | G | G | G |
| 400 kV | G | G | G | G | G | G | G | G | G | G | G | G | G |
| 500 kV | A | A | A | A | A | A | G | G | G | G | G | G | G |
| 600 kV | R | R | R | R | R | R | R | R | R | R | R | A | G |

Key

| | |
|---|---|
| R | Technology not available |
| A | Technology available but not in service |
| G | Technology potentially in service subject to contract |
| G | Technology in service or scheduled to be in service |

Figure E.37

# E.20.2
# Technology Availability (Combinations)

## HVDC systems with converters located onshore

### HVDC systems comprising voltage sourced converters and extruded cables

| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2030 | 2035 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1000 MVA | G | G | G | G | G | G | G | G | G | G | G | G | G | 320 kV 1563 A |
| 1260 MVA | A | A | A | G | G | G | G | G | G | G | G | G | G | 350 kV 1800 A |
| 1440 MVA | A | A | A | A | G | G | G | G | G | G | G | G | G | 400 kV 1800 A |
| 1800 MVA | R | A | A | A | A | G | G | G | G | G | G | G | G | 500 kV 1800 A |
| 2000 MVA | R | R | A | A | A | A | G | G | G | G | G | G | G | 500 kV 2000 A |
| 2400 MVA | R | R | R | R | R | A | A | A | A | G | G | G | G | 600 kV 2000 A |
| 2600 MVA | R | R | R | R | R | R | R | R | R | R | A | A | A | 650 kV 2000 A |
| 2800 MVA | R | R | R | R | R | R | R | R | R | R | R | R | A | 700 kV 2000 A |

Key

| | |
|---|---|
| R | Technology not available |
| A | Technology available but not in service |
| G | Technology potentially in service subject to contract |
| G | Technology in service or scheduled to be in service |

Figure E.38

### HVDC systems comprising voltage sourced converters and mass impregnated cables

| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2030 | 2035 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1400 MVA | G | G | G | G | G | G | G | G | G | G | G | G | G | 500 kV 1400 A |
| 1563 MVA | G | G | G | G | G | G | G | G | G | G | G | G | G | 500 kV 1563 A |
| 1876 MVA | A | A | G | G | G | G | G | G | G | G | G | G | G | 600 kV 1563 A |
| 2160 MVA | A | A | A | G | G | G | G | G | G | G | G | G | G | 600 kV 1800 A |
| 2600 MVA | R | R | A | A | A | A | G | G | G | G | G | G | G | 650 kV 2000 A |
| 2800 MVA | R | R | R | R | R | R | A | A | A | A | G | G | G | 700 kV 2000 A |
| 3000 MVA | R | R | R | R | R | R | R | R | R | R | A | A | A | 750 kV 2000 A |

Key

| | |
|---|---|
| R | Technology not available |
| A | Technology available but not in service |
| G | Technology potentially in service subject to contract |
| G | Technology in service or scheduled to be in service |

Figure E.39

### HVDC systems comprising line commutated converters and mass impregnated cables

| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2030 | 2035 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2250 MVA | A | A | G | G | G | G | G | G | G | G | G | G | G | 600 kV, 1875 A |
| 2600 MVA | R | R | A | A | A | A | G | G | G | G | G | G | G | 650 kV, 2000 A |
| 2800 MVA | R | R | R | R | R | R | A | A | A | A | G | G | G | 700 kV, 2000 A |
| 3000 MVA | R | R | R | R | R | R | R | R | R | R | A | A | A | 750 kV, 2000 A |

Key

| | |
|---|---|
| R | Technology not available |
| A | Technology available but not in service |
| G | Technology potentially in service subject to contract |
| G | Technology in service or scheduled to be in service |

Figure E.40

## HVDC systems with converters located offshore

### HVDC systems comprising voltage sourced converters and extruded cables (offshore)

| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2030 | 2035 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 800 MVA | G | G | G | G | G | G | G | G | G | G | G | G | G | 320 kV 1250 A |
| 1000 MVA | G | G | G | G | G | G | G | G | G | G | G | G | G | 320 kV 1563 A |
| 1440 MVA | A | A | A | A | G | G | G | G | G | G | G | G | G | 400 kV 1800 A |
| 1800 MVA | R | A | A | A | A | A | G | G | G | G | G | G | G | 500 kV 1800 A |
| 2000 MVA | R | R | A | A | A | A | G | G | G | G | G | G | G | 500 kV 2000 A |
| 2400 MVA | R | R | R | R | R | R | R | R | R | R | R | A | G | 600 kV 2000 A |

Key

| | |
|---|---|
| R | Technology not available |
| A | Technology available but not in service |
| G | Technology potentially in service subject to contract |
| G | Technology in service or scheduled to be in service |

Figure E.41

HVDC systems comprising voltage sourced converters and mass impregnated cables (offshore)

| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2030 | 2035 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1280 MVA | G | G | G | G | G | G | G | G | G | G | G | G | G | 400 kV 1600 A |
| 1440 MVA | A | A | A | G | G | G | G | G | G | G | G | G | G | 400 kV 1800 A |
| 1800 MVA | A | A | A | A | A | A | G | G | G | G | G | G | G | 500 kV 1800 A |
| 2000 MVA | R | R | A | A | A | A | G | G | G | G | G | G | G | 500 kV 2000 A |
| 2400 MVA | R | R | R | R | R | R | R | R | R | R | R | A | G | 600 kV 2000 A |

Key

| | |
|---|---|
| R | Technology not available |
| A | Technology available but not in service |
| G | Technology potentially in service subject to contract |
| G | Technology in service or scheduled to be in service |

Figure E.42

## HVDC protection and control

HVDC protection and control

| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2030 | 2035 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Control (two-terminal) | G | G | G | G | G | G | G | G | G | G | G | G | G |
| Protection (two-terminal) | G | G | G | G | G | G | G | G | G | G | G | G | G |
| Control (multi-terminal, single vendor) | A | A | G | G | G | G | G | G | G | G | G | G | G |
| Protection (multi-terminal, single vendor) | A | A | G | G | G | G | G | G | G | G | G | G | G |
| Control (multi-terminal, multi-vendor) | A | A | A | A | G | G | G | G | G | G | G | G | G |
| Protection (multi-terminal, multi-vendor) | A | A | A | A | G | G | G | G | G | G | G | G | G |

Key

| | |
|---|---|
| R | Technology not available |
| A | Technology available but not in service |
| G | Technology potentially in service subject to contract |
| G | Technology in service or scheduled to be in service |

Figure E.43

## HVDC circuit-breaker

HVDC circuit-breaker

| 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2030 | 2035 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A | A | A | G | G | G | G | G | G | G | G | G | G | 320 kV, 2000 A |
| R | R | A | A | A | A | G | G | G | G | G | G | G | 550 kV, 2000 A |

Key

| | |
|---|---|
| R | Technology not available |
| A | Technology available but not in service |
| G | Technology potentially in service subject to contract |
| G | Technology in service or scheduled to be in service |

Figure E.44

## AC cables

Three core ac submarine cables

| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2030 | 2035 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 500 MW | G | G | G | G | G | G | G | G | G | G | G | G | G |
| 600 MW | A | A | A | A | G | G | G | G | G | G | G | G | G |
| 700 MW | R | R | R | R | A | A | A | A | G | G | G | G | G |

Key

| | |
|---|---|
| R | Technology not available |
| A | Technology available but not in service |
| G | Technology potentially in service subject to contract |
| G | Technology in service or scheduled to be in service |

Figure E.45

Single core ac submarine cables

| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2030 | 2035 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1000 MW | G | G | G | G | G | G | G | G | G | G | G | G | G |
| 1200 MW | A | A | A | A | G | G | G | G | G | G | G | G | G |
| 1300 MW | A | A | A | A | A | A | A | A | G | G | G | G | G |

Key

| | |
|---|---|
| R | Technology not available |
| A | Technology available but not in service |
| G | Technology potentially in service subject to contract |
| G | Technology in service or scheduled to be in service |

Figure E.46

## HVDC gas-insulated switchgear (GIS)

Gas-insulated switchgear (GIS) is a compact alternative to conventional air-insulated switchgear. It has been widely used in ac systems for a number of years in applications where space is limited, such as substations located in urban areas. At present, however, GIS has not been widely applied to HVDC systems. Under the influence of a dc electric field, charge tends to accumulate on solid insulation. The accumulated charge distorts the electric field and may reduce the performance of the insulation system. The need for compact HVDC switchgear for offshore application might drive the development of HVDC GIS. At present, however, no HVDC GIS is known to be commercially available.

## Offshore platforms for ac substations

Offshore ac substations are of significantly smaller size and weight than those required for HVDC converter stations and the required power transfer capacity can usually be achieved without great difficulty.

# E.21
# Unit Costs

### Voltage Source Converters (per unit)

**Table E.9**

| Specifications | Cost (£M) |
|---|---|
| 500 MW 300 kV | 68 - 84 |
| 850 MW 320 kV | 89 - 110 |
| 1250 MW 500 kV | 108 - 136 |
| 2000 MW 500 kV | 131 - 178 |

### Current Source Converters

**Table E.10**

| Specifications | Cost (£M) |
|---|---|
| 1000 MW 400 kV | 73 - 94 |
| 2000 MW 500 kV | 136 - 168 |
| 3000 MW 600 kV | 178 - 209 |

### Transformers

**Table E.11**

| Specification | Cost (£M) |
|---|---|
| 90 MVA 132/11/11 kV | 0.73 - 1.4 |
| 180 MVA 132/33/33 or 132/11/11 kV | 1.05 - 1.9 |
| 240 MVA 132/33/33 kV | 1.26 - 2.09 |
| 120 MVA 275/33 kV | 1.26 - 1.68 |
| 240 MVA 275/132 kV | 1.57 - 2.09 |
| 240 MVA 400/132 kV | 1.88 - 2.30 |

### HVAC GIS Switchgear

**Table E.12**

| Specifications | Cost (£k) |
|---|---|
| 132 kV | 1.15 - 1.47 |
| 275 kV | 3.04 - 3.46 |
| 400 kV | 3.98 - 4.29 |

### Shunt Reactors - supplied cost

**Table E.13**

| Specifications | Cost (£K) |
|---|---|
| 60 Mvar/13 kV | 0.52 - 0.84 |
| 100 Mvar/275 kV | 2.30 - 2.51 |
| 200 Mvar/400 kV | 2.51 - 2.72 |

### HVAC Shunt Capacitor Banks - installed cost

**Table E.14**

| Mvar of capacitive reactive compensation | Cost (£M) |
|---|---|
| 100 | 3.14 - 5.24 |
| 200 | 4.19 - 7.33 |

### Static VAR Compensators -Installed costs

**Table E.15**

| Mvar of reactive compensation | Cost (£M) |
|---|---|
| 100 | 3.14 - 5.24 |
| 200 | 10.47 -15.71 |

### STATCOMs - installed cost

**Table E.16**

| Mvar of reactive compensation | Cost (£M) |
|---|---|
| 50 | 3.14 - 5.24 |
| 100 | 10.47 - 15.71 |
| 200 | 15.71 - 20.94 |

### HVDC Extruded Subsea Cable

**Table E.17**

| | Cost (£/m) |
|---|---|
| Cross Sectional Area ($mm^2$) | 320 kV |
| 1200 | 314 - 471 |
| 1500 | 346 - 471 |
| 1800 | 314 - 524 |
| 2000 | 366 - 576 |

### HVDC Mass Impregnated Cable

**Table E.18**

| Cross Sectional Area ($mm^2$) | Cost (£/m) 400 kV | Cost (£/m) 500 kV |
|---|---|---|
| 1500 | 366 - 576 | 418 - 576 |
| 1800 | 418 - 576 | 428 - 628 |
| 2000 | 418 - 628 | 418 - 681 |
| 2500 | 627 - 733 | 524 - 785 |

### HVAC Overhead Lines

**Table E.20**

| Description | Cost (£M/km) |
|---|---|
| Cost per route km 400 kV, double circuit | 1.57 - 1.99 |
| Cost per route km 132 kV, double circuit | 0.73 - 0.94 |
| Cost per route km 132 kV, single circuit | 0.52 - 0.63 |

### HVAC 3 Core Subsea Cable

**Table E.19**

| MVA Rating | Voltage | Cost (£/m) |
|---|---|---|
| 200 | 132 kV | 471 - 733 |
| 300 | 220 kV | 524 - 785 |
| 400 | 245 kV | 681 - 1047 |

### Subsea Cable Installation

**Table E.21**

| Installation Type | Cost (£M/km) |
|---|---|
| Single cable, single trench | 0.31 - 0.73 |
| Twin cable, single trench | 0.52 - 0.94 |
| 2 single cables; 2 trenches, 10m apart | 0.63 - 1.26 |

Uplifted costs have been calculated by using HICP Inflation rate for the European Union using 3.1% for 2011 & 2.6% for 2012.

**Table E.22**

| DC Platforms | | |
|---|---|---|
| **Ratings** | **Weight (Tonnes)** | **Cost (£M)** |
| 1000 MW @ 320-400 kV | 8000-10250 | 260 - 329 |
| 1250 MW @ 320-400 kV | 9500-14000 | 281 - 385 |
| 1500 MW @ 450-500 kV | 17000-27500 | 352 - 496 |
| 1750 MW @ 450 550 kV | 20000-30000 | 414 - 530 |
| 2000 MW @ 500-600 kV | 24500-33000 | 419 - 534 |
| 2250 MW @ 600-700 kV | 29500-39250 | 480 - 588 |
| 2500 MW @ 650-750 kV | 32000-43000 | 506 - 638 |

**Table E.23**

| AC Platforms | |
|---|---|
| **Ratings** | **Cost (£M)** |
| 200-400 MW @ 132-150 kV | 30 – 55 |
| 500-700 MW @ 132-150 kV | 45 - 130 |

Platform costs have been derived from studies prepared by Petrofac in 2011 and TSC research from January 2013 and have allowed for HICP inflation as above.

The market were given the opportunity to support this initiative, but on the whole declined, therefore all prices should be treated as indicative only.