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HVDC Systems in Smart Grids

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Abstract— The use of DC power networks, either at high voltage or at medium voltage, is being increasingly seen in modern smart grids. This is due to the flexible control possible with DC and its ability to transmit and distribute power under circumstance where AC networks are either unable to, or less economic. This paper provides an overview of the evolution of High Voltage DC transmission from early Thury systems, to modern ultra-high voltage DC and multi-terminal voltage-source converter systems. The operation of both current-source and voltage source systems is discussed, along with modelling requirements. The paper provides a snapshot of the state-of-the-art of HVDC with copious references to enable in-depth reading. Key developments over the last twenty years are highlighted. Issues surrounding multi-terminal operation and DC protection are explained as are drivers in economics and policy.

Index Terms—Power conversion, power system control, power grids, power transmission, smart grids, HVDC transmission.

I. INTRODUCTION AND HISTORY

WHETHER AC or DC is a better solution for electrical transmission was debated since the first days of electrical power. The famous ‘war of currents’ in the 1880’s and 1890’s between Edison, proposing DC, and Westinghouse, championing AC, was a prime example. Despite lurid initial claims about the dangers of AC, publicity stunts, and even the electrocution of the circus elephant Topsy [2], AC initially ‘won’ the contest [1]. Tesla’s invention of the induction machine and advances in transformers, meant that AC at the time had too many advantages, namely:

- In the 19th century, only transformers allowed efficient conversion between voltages. This permitted generation and end use at low voltage, but transformation to high voltage for efficient long-distance transmission. This situation remained largely unchanged until mercury arc rectifiers became sufficiently advanced in the 1950’s.
- AC currents are easier to interrupt, since they fall to zero twice per electrical cycle. A circuit breaker can therefore

switch off at zero, or nearly zero, current making them cheaper and more compact.

- DC machines require brushes, induction machines do not – an advantage in terms of robustness. Induction machines have gone on to become a, if not the, dominant electrical load.

A. First Applications

Despite the initial advantages of AC, DC was still used in a number of installations in the subsequent decades, particularly when two different unsynchronised, or different frequency, AC systems needed to be connected. In this case the AC:DC:AC HVDC link acted as a buffer to connect the two. Between the 1880’s and 1930’s a number of HVDC installations were employed. These used the Thury system, where voltage conversion was accomplished by back-to-back motor-generator sets [3]. The Moutiers-Lyons line was the most powerful such system: running from 1906 to 1936 in France, over a distance of 200km at ± 75 kV with a current of 150A (or about 22MW).

B. Line Commutated HVDC History

By the 1930’s, the concept of rectification with a mercury arc, demonstrated in 1902 by Peter Hewitt [5], had reached a level of development that allowed mercury arc rectifiers to be used with moderate power AC-DC-AC conversion systems. Examples included: 110kV 2-phase AC-AC converters coupling the 50 Hz network to a 16 2/3 Hz electric railway network in 1932 (Siemens); BBC, a precursor company to ABB, connecting a 3MW supply to the 110kV German network at Pforzheim the same year [6]. Experience with the technology developed, until between 1942 and 1944, Siemens (with AEG) built a 60MW, 115km ± 200 kV transmission line. At the end of World War Two, this was transferred to the Soviet Union, serving as the Moscow-Kashira 30MW, 112km HVDC system [6].

The development of the mercury arc rectifier’s capability by Uno Lamm and his team at ASEA (now part of ABB) in the 1930’s and 1940’s led to the first ‘modern’ commercial HVDC system the 20MW, 98km, 100kV system linking the island of Gotland and the Swedish mainland [7]. This led to the rapid development of the technology reaching ± 250 kV and 600MW in 1965 with the first New Zealand Inter-Island link and ± 400 kV 1440MW in the USA Pacific Intertie in 1970 [8].

From the early 1970’s onwards mercury arc rectifiers started to be replaced with thyristor valves, which had matured as a technology from their introduction in the 1950’s. As solid state devices they did not suffer the material deposition

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problems that mercury arc devices did, which limited mercury arc device voltage, and required considerable maintenance [9]. Thyristors unlike mercury arc rectifiers also do not suffer from operational problems like arc-backs [31]. Thyristor projects have now reached 8000MW \pm 800kV over a 2210km distance (the Hami-Zhengzhou project commissioned in 2014 [31]) with constructions of the Changji-Guquan 1100kV link to push powers to 13GW per line.

Both mercury arc rectifiers and thyristors can delay turn-on of their valves but in effect require the assistance of the AC grid to commute (switch) from one valve to another. As Line Commutated Converters (LCC) this places minimum strength requirements on the AC grid to which they are connected. Their operation can be considered to be a DC current source, switched between AC phases by the combined action of the AC grid and thyristor control, hence also the name Current Source Converters (CSC).

C. Voltage Source HVDC History

The recent development of Insulated Gate Bipolar Transistors (IGBTs), and other self-commutating high-voltage high-current semiconductor switches, has led to the rise of Voltage Source Converter (VSC) HVDC. These devices can control both switch turn-on and turn-off allowing a DC voltage source (hence the name VSC) to be switched between phases. Since the first such installation in Hällsjön, Sweden in 1997, a 3MW, \pm 10kV system, power has risen to 2000MW (INELFE) [10] and a voltage of 500kV (Skagerrak 4) [11].

II. KEY DRIVERS FOR HVDC IN SMARTGRIDS

At the time of writing HVDC has become widely used for transmission systems. These are multiple instances where HVDC provides greater flexibility or functionality, can connect systems that AC cannot, or can transmit more power in a given space than AC can. HVDC is preferred over AC in several cases.

First if two unsynchronized AC networks, or AC networks of differing frequency, need to be connected, HVDC can act as a frequency and phase conversion stage. Examples of this are the HVDC connections between the UK and Europe, where two systems operate at 50Hz nominal frequency but are not synchronized.

Second, for very long distances HVDC may be more economical. This is because HVDC lines are cheaper per km than AC, and unlike AC, HVDC lines do not consume reactive power, and therefore are not limited by length or the requirement for periodic reactive power compensation. Moreover, the losses of a DC line are smaller than the losses of an AC line due to high voltages and thus lower currents. HVDC stations are more expensive than AC stations, so the breakeven point is typically 600-800km for overhead lines or 50-100km for cables (which have higher reactive power exchange per km), depending on location, project power and voltage [31]. Examples of such HVDC connections are many long distance lines in China, Brazil, Canada, and USA.

Third, two AC systems may need to be connected without increasing AC fault level. The ability of the HVDC system to

block AC power flow quickly (in AC timescales) means that power can be fed through the HVDC link into a system, but minimal extra fault current is added to the AC network. Consequently AC switchgear need not be upgraded. Often this HVDC connection is through back-to-back AC:DC:AC stations on one site. This was one of the advantages of VSC HVDC for ABB's Mackinac converter project in Michigan [29].

Fourth, HVDC can transmit more power for a given transmission corridor size than AC. Where space is constrained this may mean in future HV AC lines may be replaced by HVDC. This has been the case in Germany for the Ultranet project [27]. Other examples for this type of HVDC connection are DC links directly into the downtown area of large cities like New York (Hudson Project) and San Francisco (Transbay Cable).

Lastly VSC HVDC can provide a variety of power quality support functions. Thus reactive power support, AC voltage control and black-start functionality can be provided, again a key factor in ABB's Mackinac project in Michigan [29]. However since the total current capability of the VSC converter is current and voltage limited, such additional functionality requires careful coordination with the converter's real power import and export capability. Other functions include: firewalling one AC system so that disturbances do not spread to an adjacent system; providing frequency stabilizing functions, provide artificial fast frequency response (also called artificial inertia, as implemented in the Caprivi Link project); providing power oscillation damping (such as implemented in the Pacific DC Intertie, INELFE, BritNed, ATCO, WATL) [33]; stabilizing the AC system (in New Zealand: Fault Recovery Modulation, Frequency Keeping Control, Frequency Stabilization Control, Spinning Reserve Sharing, Constant Frequency Control, Wellington Over-Frequency Brake, Automatic Governor Control) [61,62]

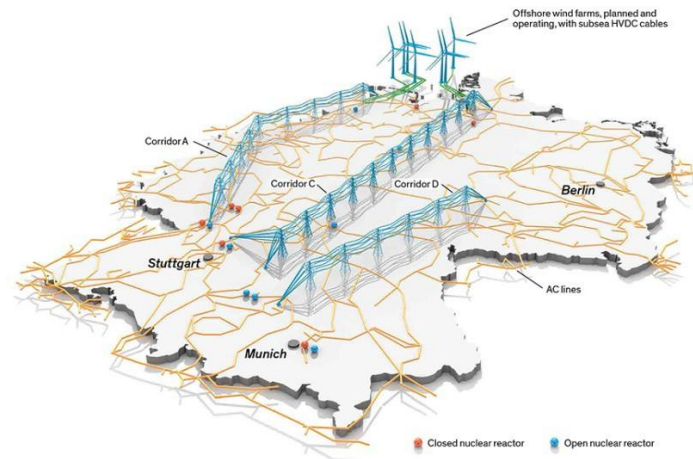


Fig. 1. German Planned North-South Corridors Connections [27]

According to a recent industry report the market is split roughly equally between CSC and VSC technologies [26]. CSC HVDC is presently preferred for very large bulk power transfer. The more compact VSC is used when space is at a premium or additional services are required at the grid

connection point.

Renewables will form an increasing fraction of generation, and transmitting such power to the point of use will be a major driver for long transmission corridors. This can be seen in the VSC HVDC networks linking offshore windfarms to shore in Northern Germany (see also section III.E). HVDC connections in Germany are the first step, Fig. 1, to transmit this offshore wind from Northern Germany to industrial centers in Southern Germany. Similarly LCC HVDC connections like the Three Gorges Project in China transmit hydropower to the country's growing mega-cities [30].

The increase in demand in urban and industrial centers, both as a result of demographic, lifestyle and industrial changes, will require extra power. Since urban space is often constrained and expensive, and utilities do not wish to uprate other utility infrastructure, VSC-HVDC, and its medium voltage variant, MVDC, may become a replacement solution for AC to increase supplied power. They may also be used to connect AC bulk-supply points, reinforcing the network, without increasing fault level.

'Supergrids' – large meshed HVDC networks - have been proposed [27] and radial networks are starting to be constructed, see section III.F. These would potentially allow transcontinental (or even intercontinental) sharing of resources. For example in Europe offshore wind power from the UK could be shared with Norwegian hydropower and storage, Icelandic thermal energy generation and solar power from Spain (as well as from other countries and conventional generation). The different demand profiles in the continent's countries could be smoothed out over time and energy traded optimizing generation investment and utilization. A number of technical problems remain before this vision can be realized though.

III. HVDC DEVELOPMENT OVER THE LAST 20 YEARS

A. Ultra-High Voltage DC Transmission

The principle development of LCC over the last two decades has been in the increase of operational voltage, Fig. 2.

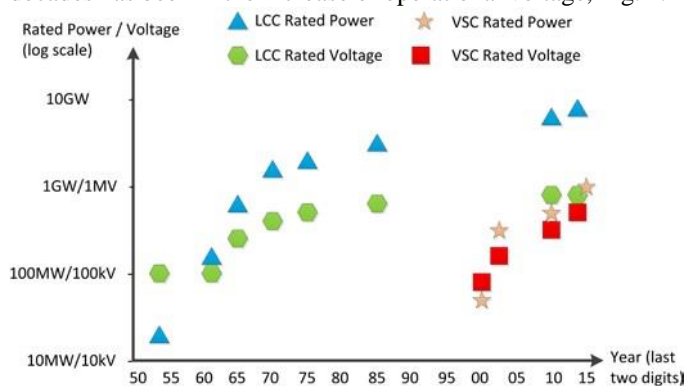


Fig. 2. Progression of Voltage and Power Ratings for LCC and VSC HVDC (Data from [9] and company websites)

Although previous projects have used ± 600 kV (Itaipu 1 and 2, each 3150MW), most projects in previous decades had limited themselves to ± 500 kV (e.g. Three-Gorges and Gui-Guang in China or the East-South Interconnector in India in

the first decade of the 21st century). In 2010 Siemens and ABB set a new upper voltage target of ± 800 kV in the form of the Siemens Yunnan-Guangdong 1418km, 5000MW project and the ABB Xianjiaba-Shanghai SGCC Project, China 1980km, 6400MW project, Fig. 3, [8]. The inauguration of the Hami-Zhengzhou HVDC line raised this to 8000MW at ± 800 kV over 2210km [31]. This step in voltage was economical for the increased power requirement (5000MW or more) and distance covered (more than 1000 to 2500km) [12]. A substantial amount of research was required both to reassess the internal and external electrical field design of the system, as well as to provide type testing at this new voltage, which required the extensive use of demonstrators [12].



Fig. 3. Xianjiaba-Shanghai SGCC Project, China, UHVDC Valve Hall

B. Pioneering VSC-HVDC Stations

Following a technological review of the HVDC sector in the 1990's by ABB [13], it was found that scope existed for a complementary VSC product to established CSC technologies. An initial proof-of-concept installation at Hällsjön in 1997 (3MW, ± 10 kV DC, 10km) [14] was followed the first commercial installation at Gotland in 1999 (50MW, ± 80 kV, 70km) [15], Fig. 4.



Fig. 4. Gotland HVDC Light Link converter station

ABB rapidly developed the technology and three years later in 2002 installations that used ± 150 kV were available, namely Cross Sound (330MW, 40km) [16] in the USA and Murraylink (220MW, 180km) in Australia [17], Fig. 5. Many of these early installations were influenced by the desire to minimize the environmental impact and the need to manage

and minimize potential power quality issues on the AC side. Low profile stations, fed by cables, with self-commutating VSC, producing low amounts of low frequency harmonics were a clear advantage.



Fig. 5. Cable Laying for Murraylink

C. Troll – First Offshore VSC HVDC

VSC HVDC has a significantly smaller footprint than LCC, and so is ideally suited for use offshore. The controllability of the converter also makes it highly suited to weaker grids. This was utilized in the first offshore station in 2005, where a 70km ± 60 kV DC cable fed two 44MW gas compressor drives on the offshore Troll gas mining platform, Fig. 4 [18].

The success of this first Troll system was underlined by a second system powering the Valhall platform in 2011 and another set of drives on the Troll field being powered by a further VSC HVDC project in 2015 [18].



Fig. 6. Troll A HVDC Platform

D. Transbay Cable – First MMC Systems

In 2010 Siemens installed its first VSC HVDC system in San-Francisco, USA. VSC HVDC has previously used two- and three-level converter designs. The Trans-bay Cable project (400MW, ± 200 kV and 85km long) [19], Fig. 7, was the first to use a Modular Multi-level Converter of the type proposed by Marquardt [20]. In this, instead of an AC waveform being synthesized by pulse width modulation, it is

formed by switching multiple modules to form a staircase output (see section V.A). All manufacturers have since moved to some form of a modular converter.



Fig. 7. Transbay Cable HVDC Station (Copyright Hawkeye, "Courtesy of Siemens", [63])

E. German Offshore Windfarms

Following on from the success of the Troll offshore platform, the utility TenneT and the German government have pioneered the development offshore connection of windfarms through VSC HVDC [28], Fig. 8. At the time of writing, over 4GW of VSC-HVDC transmission is available to allow offshore renewable energy to be fed to the mainland. Initial projects experienced some delay to the complex offshore environment. Type testing and prototyping on demonstrators is possible with onshore installations – this is not practical for large offshore installations connected to distributed energy sources like offshore wind - some initial learning in such large industrial projects is not uncommon. The delivery of five offshore HVDC connections in 2015 though has shown that this is now a well-understood solution.



Fig. 8. German HVDC Connected Offshore Windfarm Locations [63]

F. Multi-terminal VSC HVDC

HVDC with LCC has largely been a point-to-point solution. Historically multi-terminal installations have been few and far between though more recently they have attracted considerable attention as VSC HVDC has developed.

The Hydro-Quebec System designed in the 1980's is often cited as the original HVDC multi-terminal system, based on initial studies for a five-terminal system [21]. The initial point-

to-point system was meant to be expanded to this in two stages – in practice a separate three-terminal link was constructed for phase two [22], in part due to the consideration that a different vendor might be used. In practice this three-terminal link has predominantly spent its time operating as a unidirectional system, either transferring hydropower from Radisson to Sandy Pond or Radisson to Nicolet stations.

In 1967 a 200MW, monopolar LCC 200kV DC link between Italy and Sardinia was established. In 1986-7 a 50MW tap was added [21]. This is known as the SACOI (Sardinia-Corsica-Italy) link. However fast-reversing switches were required to allow rectifier/inverter operation of the Corsican station.

The 2016 North-East Agra LCC HVDC Link is a ± 800 kV 6000MW, four terminal, three converter station [32]. This is designed to supply hydropower from the North-East India.

A collaborative, government sponsored project to build a back-to-back multi-terminal VSC-HVDC station at the Shin-Shinano substation in Tokyo was undertaken by Toshiba, Hitachi and Mitsubishi Electric in the 1990s. The 300MW back-to-back station used GTOs [23].

The first VSC HVDC multi-terminal network systems are the Chinese Nan'ao Island (2013) and Zhoushan (2014) VSC-HVDC systems, Fig. 9 [25]. Nan'ao Island is a ± 160 kV three terminal (200MW, 150MW, 50MW) collaboration between Rongxin Power Electronic, NR-Electric and XiDian [24]. Zhoushan is a five-terminal (400MW, 300MW and three times 100MW) ± 200 kV system built by C-EPRI and NR Electric [25]. Both systems are radial networks - as yet no meshed HVDC grids have been constructed.

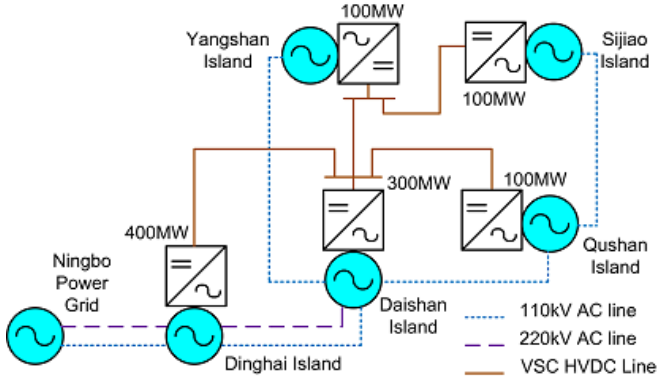


Fig. 9. Zhoushan Five Terminal VSC HVDC Network [25]

IV. MODERN LINE-COMMUTATED CONVERTER HVDC

Line Commutated Converter HVDC, by virtue of its longevity, is well covered in a number of textbooks for example [34-36]. This section provides a brief introduction.

A. Hardware and Control

The fundamental building block of a line-commutated converter is the 12-pulse thyristor bridge, Fig. 10, made up of two 6-pulse bridges. A large inductor on the DC side ensures that the DC side appears as a source of nearly DC current. Mercury arc valves, or now stacks of series connected thyristors, switch this DC current between phases 'unfolding it' in to an AC waveform. This consists of an AC fundamental current phase-shifted with respect to the AC voltage

fundamental at the output of the converter, Fig. 10. This phase-shift is the 'turn on delay angle', α . Commutation between phases causes an additional voltage drop which is proportional to the DC current. The constant of proportionality is modelled as a commutation resistance (R_c).

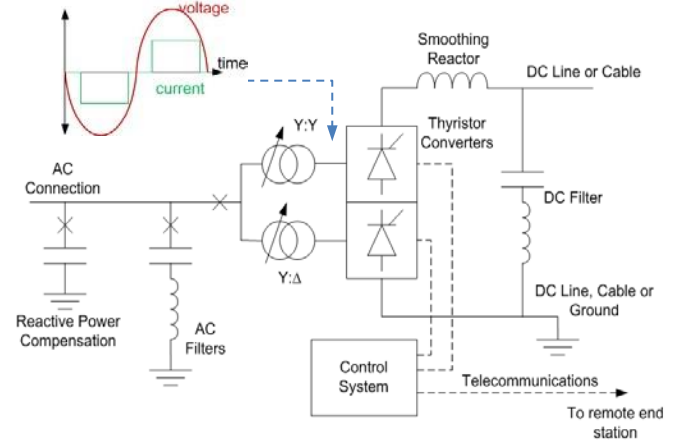


Fig. 10. Simplified single-line diagram of 3-phase LCC HVDC 12-pulse bridge (fundamental voltage and unfolded DC component of current shown at thyristor converter terminals)

The DC output voltage of one 6-pulse bridge is given by:

$$V_{DC} = \frac{3\sqrt{2}E}{\pi} \cos \alpha - R_c I_c \quad (1)$$

where E is the line-to-line RMS AC voltage at the converter terminals [34]. The square wave pattern of the output current is rich in low order harmonics, hence a 12-pulse configuration of two bridges (and sometimes a higher number) is used, with one connection transformer connected star:star and one star:delta, Fig. 10, to cancel 5th and 7th harmonics in steady state. Further harmonic filters are required. Since phase shift between AC voltage and current controls power flow, this results in reactive power consumption. Local reactive power compensation is thus typically required. Tap changing transformers are typically used with a slow outer control loop, to keep the turn-on advance angle within a tolerance band that does not exceed limits which would either consume too much reactive power or cause problems with converter control.

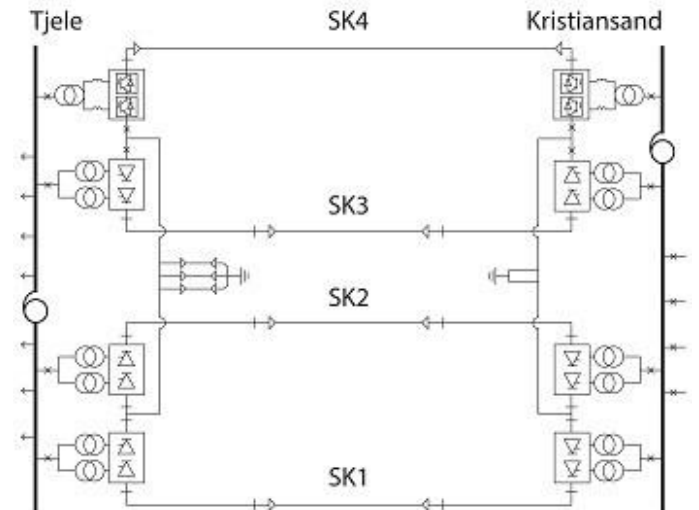


Fig. 11. Skaggerak HVDC system – lower half LCC Bipole, Upper half Hybrid LCC and VSC HVDC system

From (1) it is evident that the converter is operating as a rectifier with $\alpha < 90^\circ$: positive DC voltage and current results in power flow from the AC to the DC side. A turn on delay angle above 90° will cause the DC output voltage to go negative and the converter becomes an inverter: power flows from DC to AC. The terminals of the converter can be mechanically reconnected in the reverse direction to accommodate this, Fig. 11.

The arrangement in Fig. 10 is known as a monopolar arrangement and requires an earth return, typically via a cable or line. More usually a second 12-pulse bridge of the opposite polarity is used in a so-called bipole, Fig. 11. Both sets of twelve pulse converters are then controlled to carry the same current, meaning the ground return path is not used during normal operation. Mixed LCC and VSC systems are also possible, Fig. 11.

Precise choice of the control scheme is based on reactive power consumption (and its availability) at the AC network at either end, and loss reduction/running cost. Typically the rectifier is assigned current control and the inverter is run on so called minimum extinction angle (γ) control to set a DC voltage (where $\gamma = \pi - \alpha - u$, typically 18° at 60Hz and 15° at 50Hz [35] and u is the angle required to commute current from one phase to another). In practice control design of the converter is complex [35] with a number of factors to consider: symmetry of valve turn on in steady-state (to reduce non-characteristic harmonics); robustness to voltage and frequency variation; ability to minimize risk of commutation failure; speed of response to set-point changes or disturbances. Operation at the highest voltage possible to minimize losses is also desirable.

The first step of the control scheme is to trigger the valves. This was initially done on a per phase basis (Individual Phase Control, IPC). This has advantages, including simplicity of control, but can produce non-characteristic harmonics as control between phases is not balanced. More recently a controlled oscillator is used to produce a waveform locked to a composite of all three phases (a so-called Phase Locked Loop, of which many types exist [37]) in so-called Equidistant Pulse Control (EPC). Pulse Frequency Control (PFC) and Pulse Period Control (PPC) are subsets of this control method.

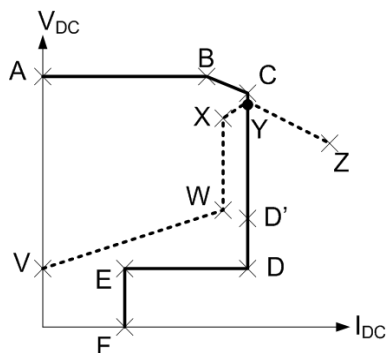


Fig. 12. LCCC HVDC Typically bridge control diagram – rectifier characteristic - solid line, inverter - dotted line, operating point is at Y

The firing angle of the inverter and rectifier are then varied to give a stable operating point based on local station control

variables (i.e. telecommunication between stations is used to enhance operation, but is not critical for normal stable operation). The schemes use (1) in a variety of forms, a theoretical example of which is shown in, Fig. 12. Each line segment utilizes a different control to manipulate equation (1) or (its equivalent for the inverter). In segment AB the DC voltage is limited, in BC α is held constant and hence changing DC current causes DC voltage to change, and in CD the current is held constant. D'F represents a Voltage Dependent Current Limit (VDCL) to manage behavior at low voltages (of the bang-bang type).

The inverter characteristics CZ, again represents an inverter version of equation (1). This slope of this is modified in the region CX to ensure a stable operating point. The remaining part of the characteristic is a ramp-type VDCL to ensure stable operation of the converter down to low voltages [35]. A ramp type VDCL generates fewer harmonics, less over-current and over-voltage, but responds more slowly than the bang-bang type – it tends to be used with weaker AC systems.

The difference in current between XW and YD' is referred to as the current margin. Either converter can adjust its current order by up to this amount and the system will remain stable with the above control scheme. For larger changes, and to ensure coordinated start-up and shut-down, telecommunications are typically used.

It is worth noting at this point that back-to-back schemes have much lower nominal operating voltages, since the distance which DC current is transmitted is minimal. Also since both converter stations are co-located, a single joint controller may be used.

B. Modelling Methods

For smartgrids employing DC components, multiple design studies are required prior to construction. For AC system studies the dominant low-frequency dynamics are in a time-frame determined by synchronous generator rotor inertias [35]. Thus detailed models of the converters are not needed in these studies and a Thevenin or Norton equivalent circuit may be used with phasor (and load-flow) studies. However the inherent 'firewall' that a DC system provides, means that it presents a problem for conventional modelling. The behavior of the DC circuit is not inherently driven by the physics based behavior of the AC system (its angles and voltage magnitudes) but by the control of the converter. Thus solution of the AC circuit and DC circuit typically have to be split in many simulation packages solvers, complicating and potentially slowing solution. Where multiple AC systems exist, multiple solutions are required.

Harmonic analysis forms a major piece of any design. Appropriate filters must be appropriately selected and tuned for the AC and DC sides. Factors include the amount of current to be filtered, reactive power requirements, the filter response characteristics, the peak voltages under transients, fault recovery and the size of the filter (much of the extra size of LCC compared to VSC is the reactive compensation and filtering requirement) [35]. The interaction between filters and the station, and filters and the AC network need carefully

consideration and are undertaken by simulation of the detailed system or by in effect undertaking a harmonic load-flow – modelling all elements as Thevenin or Norton circuits for each harmonic frequency of interest. Obtaining real data, particularly of the AC network, can be challenging and typically a ‘worst case’ locus of network impedances is considered.

DC side harmonics must also be considered since they can couple to metallic telephone lines (giving rise to a Telephone Interference Factor or TIF limit). They can even couple to metallic structures near to overhead lines through stray capacitances, leading to ‘touch voltages’, unless careful design is undertaken [35].

For detailed studies, time-stepping models are required. A Cigré benchmark model exists [36, 38] of a 12-pulse monopole with standard filters, line models and control.

In addition finite element modelling is required for both earthing structures of the HVDC system and the electric field surrounding the structures themselves, Fig. 13. Particularly for the latest generation of UHVDC systems, the extremely high voltage means the design of system components to avoid local breakdown discharge resulting from inadvertently high fields, requires extensive study.

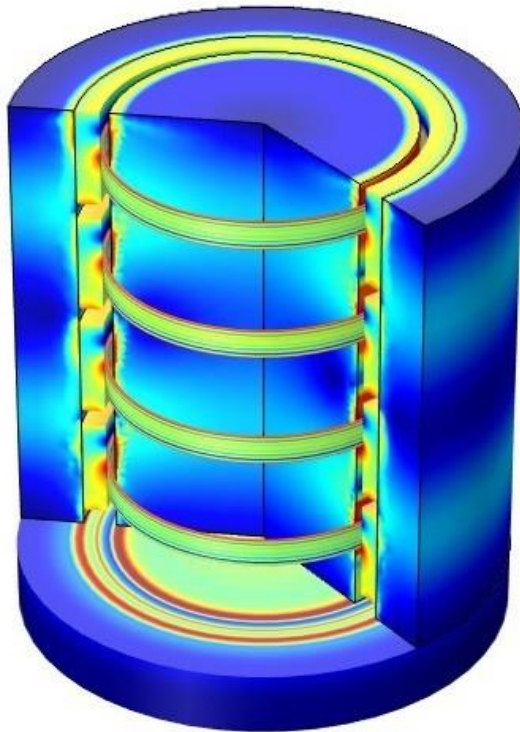


Fig. 13. Finite Element Analysis Model of an Experimental Moving Coil Actuator in an HVDC Breaker System

C. Technical Challenges

A problem for LCC HVDC is operation with weak networks, (those with a Short-Circuit Ratio, SCR, i.e. ratio of AC rated power to DC link power, of less than 3). The weak AC system may not be able to provide sufficient reactive power to the HVDC station and will be vulnerable to voltage disturbances caused by the HVDC system current (such as

voltage instability, small-signal control instability, harmonic responses, over-voltages) which may lead to commutation failure in the HVDC scheme [36]. AC series capacitors have been proposed to help LCC HVDC operate with weak AC systems (so called Capacitor Commutated Converters) and have been used in two back-to-back projects (Garabi in Brazil-Argentina, 2002, 2000MW ± 70 kV and Rapid City, 2003, 200MW, ± 13 kV).

Technical developments in recent years for the converter have been the replacement of electrically triggered thyristors by those using laser light to trigger conduction (Light Triggered Thyristors, LTTs). This gives advantages in terms of circuit isolation for the multiple thyristors used in series in each valve. Current rating of converters is still constrained by that of individual devices: while putting devices in series is readily possible, though overvoltage and voltage grading components are needed, getting semiconductor devices to reliably share current is problematic.

The main development in LCC HVDC has been the gradual increase in voltage in order to raise power levels. This required considerable research and development across all elements of the system: transformers, lines/ cables, switchgear and the converter, all from a current, fault current and insulation coordination perspective. Much of this has been enabled by modern computer simulation and study tools, particularly for insulation coordination. The impact of computers is also felt within control – where digital control is now standard and hot-swap redundancy is typically enabled.

V. VOLTAGE SOURCE CONVERTER HVDC

Voltage source converters emerged from the advent of suitably powerful self-commutating semiconductor switches in the late 1990s. Since then they have undergone rapid development in terms of power and voltage, a factor enabled by their ability to use much of the hardware (transformers, DC cables, switchgear) used previously for LCC HVDC.

A. VSC HVDC Hardware

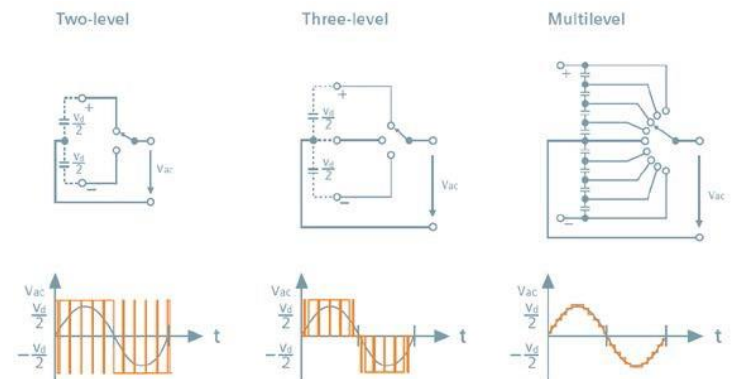


Fig. 14. VSC HVDC converter operating principles

VSC HVDC synthesizes an AC voltage at its terminals from the DC voltage supplied to it. Initially this used Pulse Width Modulation (PWM): a two-level converter switches rapidly between the voltages at the upper and lower DC supply, Fig. 14. The output is the local time average of this,

which can be varied sinusoidally. Only higher order switching harmonics need to be filtered, leaving a sinusoidal fundamental voltage at the point of connection, and drastically reducing the AC filter compared with LCC HVDC.

Losses at this point were still relatively high (Table I), compared with LCC converter losses of less than 1% per converter. In order to reduce this, ABB moved to a three-level technology, Fig. 14, Table I, using the Neutral Point Clamped (NPC) topology. Subsequent improvement of two level converter design and the use of Optimum PWM (careful switching selection to reduce harmonics and third harmonic injection to boost DC voltage utilization) allowed a further reduction in switching frequency and losses.

TABLE I
DEVELOPMENT OF VSC HVDC TECHNOLOGY [42,43]

Technology	Year	Converter Type	Losses per converter (%)	Switching frequency (Hz)	Example Project
HVDC Light 1st Gen	1997	Two-Level	3	1950	Gotland
HVDC Light 2nd Gen	2000	Three-level Diode NPC	2.2	1500	Eagle Pass
		Three-level Active NPC	1.8	1350	Murraylink
HVDC Light 3rd Gen	2006	Two-Level with OPWM	1.4	1150	Estlink
HVDC Plus	2010	MMC	1	<150*	Trans Bay Cable
HVDC MaxSine	2016	MMC	1	<150*	S West Link
HVDC Light 4th Gen	2016	CTL	1	=>150*	Dolwin 2

In two and three-level designs each ‘switch’ or valve is made of many series connected IGBTs, which requires careful control to ensure voltage sharing. In 2010 Siemens proposed a Modular Multi-level Converter (MMC) design based on the work of Marquardt [20], and other manufacturers also now offer similar multilevel products. In the MMC HVDC, IGBTs are connected in sub-modules which insert or bypass a capacitor. The inserted capacitors in the upper valve (or arm) subtract from the upper DC rail voltage ($+V_{dc}/2$), Fig. 15, to (ideally) produce a voltage at the output (point V_a). The inserted capacitors in the lower arm add to the lower DC rail to also produce V_a . Since the total capacitor voltage inserted must balance the DC link voltage, at each switching instant one or more upper and lower sub-module(s) are switched and a staircase waveform is produced, Fig. 14.

To balance transient voltages and limit potential fault currents, arm inductors as also inserted. In case of a fault, a fast protection thyristor can bypass the IGBTs and diodes, and a mechanical bypass switch then shorts out the sub-module. For a DC side fault, an AC breaker then disconnects the

converter, Fig. 15. More advanced topologies such as the alternate arm converter and full bridge sub-module converter have also been proposed, since they offer fault blocking capability [44].

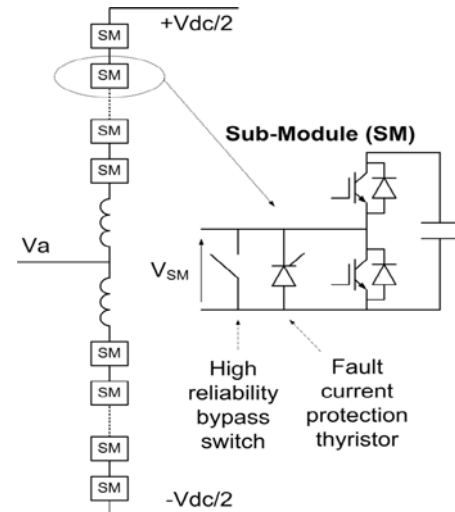


Fig. 15. One Arm of a VSC HVDC converter showing a limited number of sub-modules.

Since each phase output voltage is controlled by means of ‘subtracting’ voltage from the DC rail voltages, instead of switching between the rail voltages, transient voltage differences can occur between the three-phases which are only partly suppressed by the arm inductors. These ‘circulating currents’ can be controlled by a supplementary controller, additional hardware filtering and other methods [45].

Most installed VSC HVDC stations use a ‘symmetrical monopole’ arrangement where a single converter feeds two overhead lines or cables, rated at $\pm V_{dc}/2$, Fig. 16. This minimizes the insulation requirement with respect to ground and also means the transformer does not need to be designed to have an appreciable DC offset. Other designs with a DC offset have been implemented (e.g. Skagerrak 4 [11]), Fig. 11.

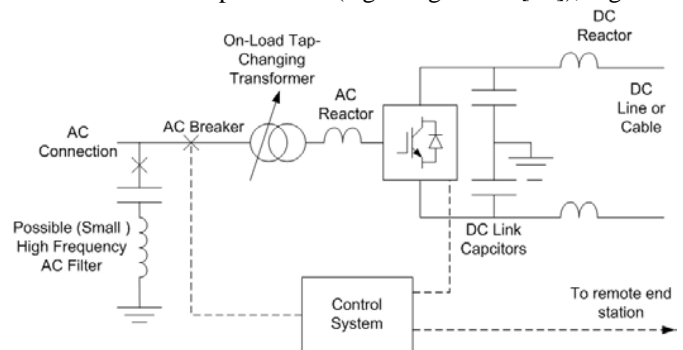


Fig. 16. Typical VSC HVDC converter station layout (AC filter may be omitted for MMC, and offshore the tap charger is typically omitted on the transformer to reduce space and maintenance requirements)

B. VSC HVDC Control

The VSC HVDC system typically controls the current of each phase using the voltage at the converter terminals. Since the semiconductor switches are self-commutated, providing a sufficient DC voltage exists, this can continue to operate down to very low AC voltage levels. However the IGBTs have in

essence no overload capability – the output is limited to rated current, so fast acting control and current protection is needed.

In most publications a dq control structure of the converter current is used. A Phase Locked Loop (PLL) is used to convert three-phase AC voltages and currents to a two-phase (d and q) DC representation ‘locked’ to the AC network voltage. This is then used to control real and reactive power either in a feedforward structure, Fig. 16(a) or using a power feedback loop, Fig. 16(b). In practice, except when very fast control is needed, power control based only on Fig. 16(a) has drawbacks. As with other feed-forward only schemes it is substantially more affected by voltage disturbance than feedback schemes (and except for very strong AC systems, any change in converter power produces a change in AC voltage [39]).

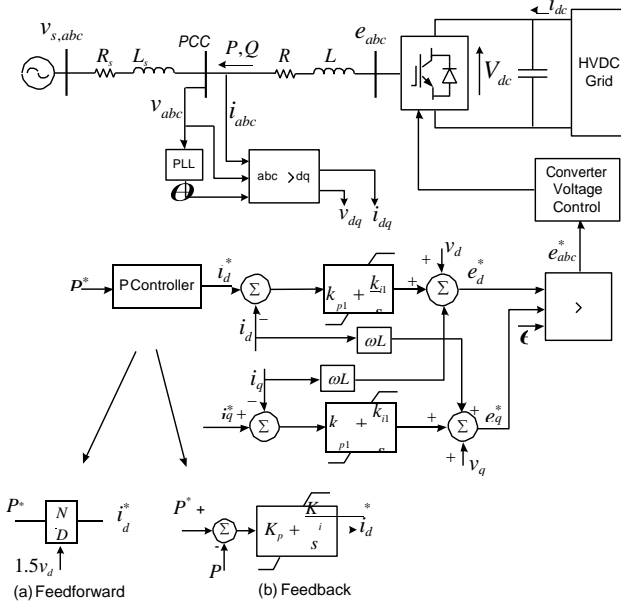


Fig. 16. DQ Control structure of VSC HVDC [39]

C. VSC HVDC Modelling

Modeling of VSC-HVDC has been the focus of a recent Cigré working group [40]. The hierarchy proposed, Fig. 17, is a useful delineator for modelling: the IGBT switching level is only required if detailed investigation at the level of sub-module voltage and current waveforms are required. Lower level controls (circulating current and capacitor voltage controls for example) are only required if the internal dynamics of the converter are required. If transient performance of the converter is required then upper level controls need to be defined (PLL performance and transient voltage and power control). Dispatch and station controls only need to be defined for load flows.

This then links into the level of modelling fidelity proposed, Table II. For valve group switching, a type 2 or 3 model is required. For lower level controls, at least a type 4 model is used, in which each submodule is converted to an equivalent circuit and these are manipulated algebraically to speed numerically solution. This is the level used in some real-time hardware-in-the-loop simulators. Upper level controls can typically be sufficiently modelled with a level 5 control, where AC and DC sides of the converter are modelled by

controlled voltage or current sources, and power balance is typically used to link the two. Phasor domain models are sufficient for slower systems studies. Most economical of all in terms of run-time are pure load flow models.

As with LCC a variety of other studies are needed, though in format these are common with LCC, section IV.B.

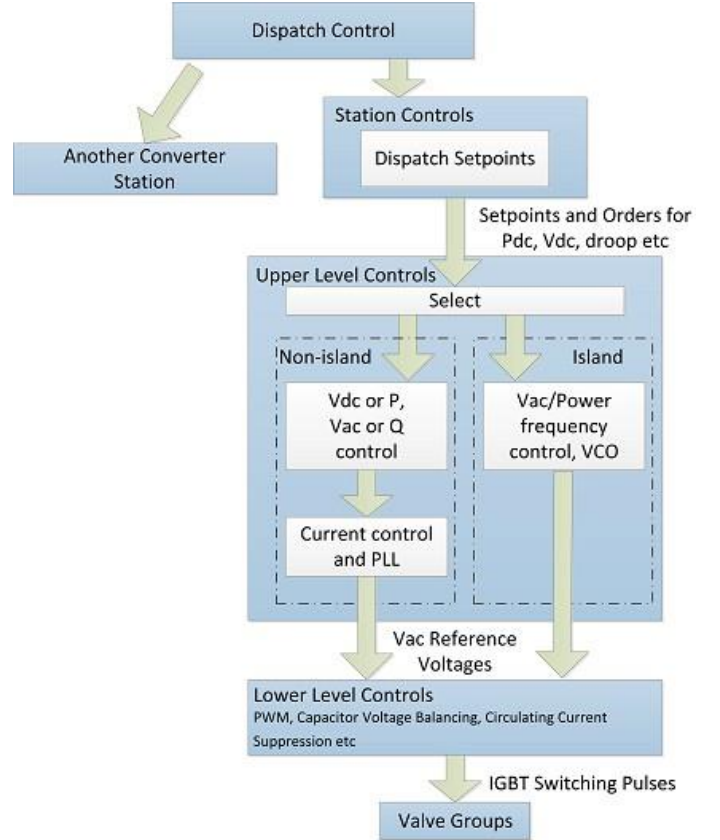


Fig. 17 – VSC HVDC Control and modelling hierarchy [40]

TABLE II
SIMULATION FIDELITY FOR VSC HVDC [40]

Model 'level'	Relative run time	Type of simulation	Type of study
1	n/a	Full physics based model	Sub-module design - Not suitable for circuit studies.
2	1000	Full detailed models: semiconductors shown by nonlinear characteristics	Detailed studies of faults in submodules; validation of simplified models
3	900	Semiconductors modelled as switched resistances	As level 2
4	30	Detailed Equivalent Model(DEM)- Norton circuit reduction	Detailed studies of AC and DC faults close to converter
5	2	Average Value Model – equivalent voltage or current source model	Studies of AC and DC transients – high level control system design / harmonics
6A	1.5	Phasor domain models	Studies of remote AC and DC transients
6B	0.1	Simplified phasor domain	As level 6A
7	0.01	Load-flow	Power Flow

In practice Average Value Models (level 5) are used in most transient system simulations, with simplified representation of the connection transformers (neglecting saturation), and DC cables (lumped parameter pi-section models). However where hardware and software limits of the

converter control are required, the Detailed Equivalent Model (level 4) of the converter gives accurate and fast performance for most applications [46]. If fast transients ($<10\text{ms}$) need to be accurately represented, a more detailed cable model such as the Frequency Dependent Phase Model [47] may be appropriate, or an equivalent circuit model that more accurately represents the frequency range of study than the cascaded, lumped equivalent pi circuit models [48]. For transient studies, transformer saturation can play a role and may need to be included [49].

D. Recent Developments in VSC HVDC

Most recent developments for VSC HVDC have focused on increasing power levels and also on tackling new applications for which VSC HVDC is particularly better suited than LCC HVDC: offshore windfarm connection and formation of multi-terminal systems.

Offshore engineering of the converter requires ensuring that environmental controls are suited to operation offshore and engineering the solution for low maintenance and the limited space available in the offshore platform, Fig. 18. This is because the dominant cost is that of the platform rather than the converter, and operation and maintenance costs are strongly influence by the cost of transporting crews and parts to site.

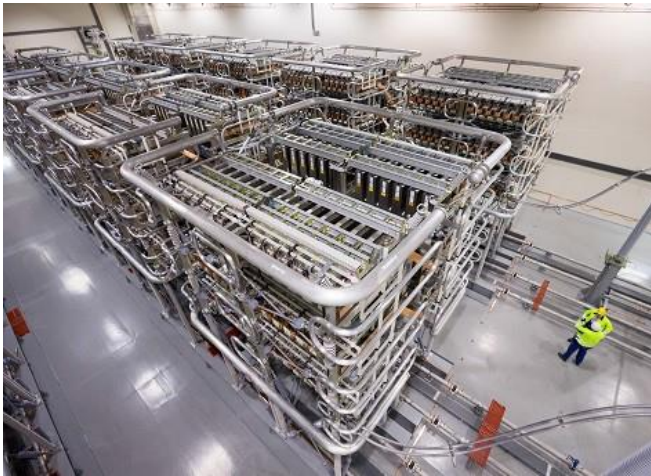


Fig. 18 – Offshore VSC HVDC valve hall [63]

Multi-terminal solutions are better served by VSC HVDC since a converter station can transition from rectifier to inverter model by varying the direction of current. For LCC this would require a reversal of voltage and a (mechanical) reconnection of the converter station to the DC grid. Solutions like Nan'ao [24], Zhoushan [25] and the German Ultrahigh [27] systems are initial examples of the technology needed.

VI. MULTI-TERMINAL OPERATION

Since VSC HVDC is well suited to multi-terminal operation, suitable control schemes need to be developed.

In a multi-terminal grid, each converter will be some distance from the others, typically 100km or more, Fig. 19, otherwise AC would have been used. A central telecommunication system is not fast enough to control all stations from a central point for primary or current control

(section VI.B), given the very fast time constants of this. Local control needs to be used. For onshore converters at present some form of droop control is typically used, i.e. real power is adjusted in response to DC voltage, and reactive power is adjust in response to AC voltage variation. Offshore the VSC HVDC converter typically sets the AC voltage and frequency and absorbs the real power generated by the wind farm.

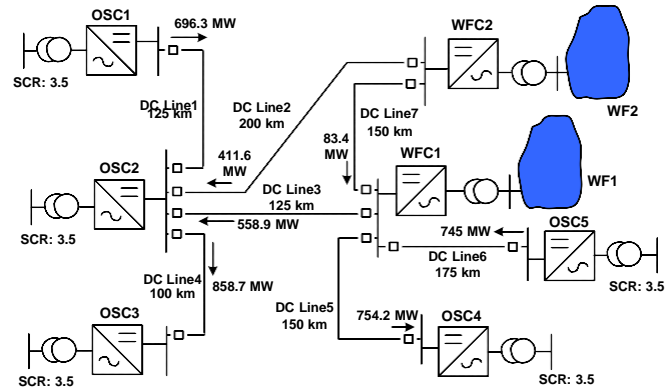


Fig. 19. – Seven terminal example VSC HVDC test system with Onshore Converters (OSC) and Wind Farm (WF) Converters (WFC) Offshore [51]

A. Droop Control Algorithms

Typical droop characteristics for DC voltage are shown in Fig. 20. AC voltage against reactive power characteristics may be similarly drawn. Power or current limits indicate the maximum that each converter can import and export. The flatter the 'droop', the less the converter allows the DC voltage to vary. A converter in DC voltage control mode (or 'DC slack bus' mode) can be considered the special case of a 'flat' droop, Fig. 16(a). The steeper the droop line, Fig. 16(c), the less aggressively the converter responds to a change in DC voltage to try and stabilize the DC voltage.

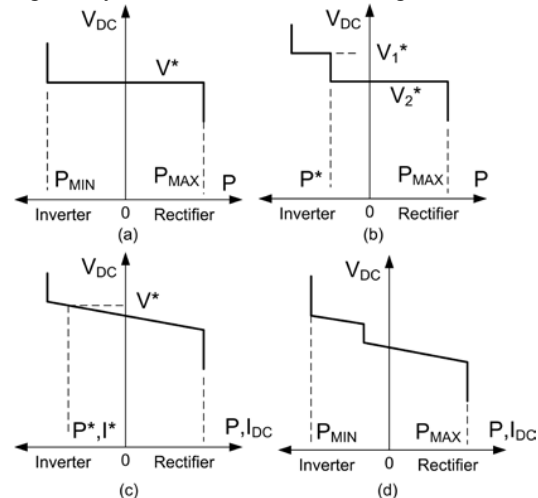


Fig. 20. Basic voltage characteristics for MTDC control [50], (a) slack bus, (b) voltage margin, (c) voltage droop, (d) voltage droop with dead-band

A constant power control can be thought of as the special case of a vertical droop line [50]. Droop control can be used to share DC voltage control simultaneously between converters. Alternatively margin control, Fig. 16(b) may be selected to determine a range of voltage values over which a converter

undertakes voltage regulation. The overall goal is to minimize the risk of interaction after a large power disturbance and keep DC voltage at a maximum to minimize losses. A dead-band may be introduced into voltage droop to help achieve this in some converters, Fig. 16(d) [60]. An important point to note is the impact of electrical quantity measurement accuracy. 0.1% DC voltage accuracy in measurement at high voltage is considered very accurate [52]. Particularly for shallow DC droop lines, realistic errors in DC voltage measurement can lead to substantial power excursions unless appropriate actions are taken [52].

B. Multi-terminal control hierarchy

The segmentation of control levels proposed in [40], Fig. 17, maps well to the levels proposed in [41] for control hierarchy: in an AC system an innermost governor exciter control is acted upon by primary frequency droop control with typically a proportional controller type behavior. A slower secondary power control (PI) in turn acts on this, and tertiary (optimal power flow, OPF, dispatch control) affects the secondary control. In HVDC the corresponding control levels are: an inner current loop, primary DC voltage droop control, a secondary power (often PI) loop, and again a tertiary OPF dispatch control. Significantly though, the primary and inner loop controls in HVDC, particularly VSC HVDC, are order(s) of magnitude faster than for AC and this needs to be reflected in the simulation tools and studies used.

VII. HVDC PROTECTION

At present much work is being undertaken to develop adequate protection of DC grids. The transients after a DC short circuit are one order of magnitude faster than those at the AC side. Furthermore, the DC current itself is harder to interrupt as there are no zero crossings.

A. DC fault clearing strategies

At the time of writing VSC HVDC systems are still protected by breakers on the AC side. The size of such systems is consequently limited in power so that their complete or temporary outage can be tolerated by the connected AC system(s). As large links grow, for example as DC grids arise, this may not be the case. In theory DC breakers could be used on each line, Fig. 19. However this would be prohibitively expensive at present, due to the cost associated with currently proposed DC breakers.

Different philosophies have been approached to manage the fault clearing process in DC grids [64]. One alternative [53] would be to use a DC breaker to segment the DC grid into two sections, the loss of any one of which could be tolerated. Another option which has been proposed is to clear the DC through the use of fault-tolerant converters. Such converters allow containment of the DC short circuit by actively controlling (reducing) the DC voltage. The short circuit could be cleared using much simpler DC switches or disconnectors, after which the DC voltage can be restored quickly.

B. Fault detection in DC grids

As the transients in DC systems are much faster, the fault detection and clearing process needs to be fast enough to identify

faults and take appropriate actions depending on whether the fault lies within its protection zone or not. In recent years, many different fault detection strategies have been developed. These strategies distinguish themselves in the use of voltage, current or combined measurements (such as derivative or wavelet methods). They also differ in terms of signal processing requirements, the need for communication within the substation or between terminals, and the dependence on knowledge of cable, line and substation parameters. These different detection algorithms also differ in the types of fault (including backup) that can be detected and the time it takes to do the analysis. At this moment, while there are several academic proposals which can identify the fault sufficiently quickly, there is still the need to develop an industrial solution.

C. Grounding topology

Historically, HVDC systems were built either as an asymmetrical monopole or a bipolar configuration, with a solid grounding point. These systems are characterized by high short circuit currents, without high voltage transients. With the development of VSC HVDC, the symmetrical monopole configuration became the new standard. Such a system is grounded using a high impedance ground, which significantly reduces the DC short circuit current in case of a pole to ground fault, but causes doubling of the voltage on the healthy pole. For future DC grids, the decision on which system will be developed is not clear. Nevertheless, it is clear that both systems might employ different approaches to protecting the grid. Furthermore, the protection system should retain its efficiency in case of asymmetric operation of a bipolar grid [64].

VIII. HVDC PROTECTION EQUIPMENT

DC breakers exist for lower voltage applications. However the DC current breaking problem is challenging since simultaneous large currents and voltages must be dealt with, without the periodic current zero and voltage present in AC.

A. DC Breakers and LCC

LCC HVDC has the advantage of a large DC side reactance (except in back-to-back stations, which tend to be at much lower voltages) which limits rate of rise of fault current. Such HVDC breakers which are used in LCC HVDC are for reconnecting a pole, and such systems (such as the Metallic Return Transfer Breaker) do not need to break full voltage and current simultaneously [36]. The principle challenge is thus for VSC HVDC which is also the presently preferred technology for future multi-terminal grids.

Investigation of a fully-rated DC breaker for LCC HVDC was undertaken on the Pacific Intertie in the 1980's. The 400kV, 2kA device used the negative impedance characteristics of the electric arc to set up a resonant circuit with passive components, providing a current zero to allow mechanical circuit breakers to extinguish the fault current [54].

B. DC Breakers and Multi-terminal VSC HVDC

The use of mechanical breakers is however too slow for VSC HVDC. While fault-blocking converters, such as those

with full bridge sub-modules, could help, they would still require that the entire DC network be de-energised. This may not be permissible for large DC grids.

The DC breaker must be fast. Even with a large current limiting reactor, the rate of rise of current in such a situation is such that at present DC breakers would need to operate in around 2-5ms [55, 56] based on a peak current that DC breakers could handle of 10-20kA. In order to obtain such fast operation, solid state switches would need to be used. A purely solid state breaker (with all semiconductor switches in the main path), would require many series devices to provide enough over-voltage capability, which would result in unacceptable conduction losses.

C. The Pro-Active Hybrid DC Breaker Concept

A solution is the proactive hybrid circuit breaker concept developed by ABB, Fig. 21. Current normally flows through a large current limiting reactor, an ultra-fast disconnector (UFD), mechanical switch and a load commutation switch (LCS). The LCS is made of a relatively few semiconductor devices in series and parallel. If a fault onset is suspected, the parallel branch made up of a stack of semiconductor devices (the Main Breaker) can be closed, and the LCS opened. Current now transfers to the Main Breaker. The UFD can then open under zero current conditions. The Main Breaker can quickly extinguish fault current, or transfer current back to the normal conduction path if the breaker is not required to trip. This and other circuit breaker concepts are presently under investigation by manufacturers and academia for HV and MV applications [57].

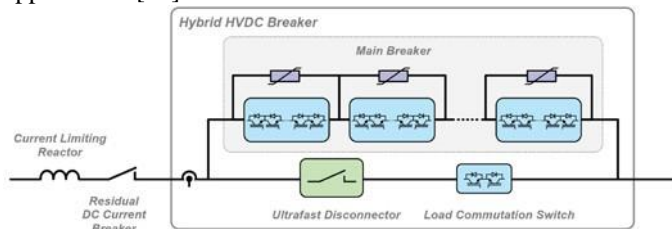


Fig. 21 – ABB Pro-Active Hybrid Circuit Breaker [55]

D. Peculiarities of HVDC Breakers

A key factor of HVDC circuit breakers is the impact of the DC current limiting reactor. This is a large component which must withstand full DC fault current. The addition of this to a multi-terminal DC network will also change the effective cable or line impedance and may negatively impact on stability [58]. Also since the travelling wave caused by the DC fault will be reflected by the fault limiting inductor, this will cause a transient increase of the voltage at the DC breaker [56, 59] at the onset of the fault appearance. This causes an initial faster rate of rise of current than had a terminal fault occurred. After several milliseconds, in a terminal fault, current eventually rises to a higher level than a non-terminal fault, as a result of the lower series impedance, but for those initial few milliseconds, a non-terminal fault can give higher fault currents. Since the DC breaker must act within the first few milliseconds, this means a non-terminal fault can be the worst case fault condition for such breakers.

IX. ECONOMICS AND POLICY

A. Drivers for HVDC

HVDC has received much attention in recent years, not only because of its technical merits, but because of the advantages from an economic point of view. HVDC offers specific advantages over AC systems. DC systems are specifically advantageous when transferring high power over long distances, connection of systems using cables and the connection of asynchronous networks. Different drivers have created new opportunities for HVDC. In industrialized countries, a liberalization of the energy system increase international trade and a change towards alternative energy sources require fundamental upgrades of the already ageing power system. Furthermore, a strong drive for more cable connections (also on land) arose, since such systems experience much less opposition and shorter lead times. The need for additional transmission is driven by the general policy objectives of having a more reliably, sustainable and cost effective energy supply. ENTSO-E has announced in 2014 that over 50000 km of new transmission assets are needed in Europe by 2030, of which 25% would be realized using HVDC [66]. In developing nations, high growth rates resulted in high increases in electric power consumption and generation. These new investments require substantial upgrades in the transmission infrastructure. This has led to new record breaking installations in terms of voltage, power and transmission line length for DC systems in China and India.

B. Framework for HVDC

The development of HVDC systems needs to be economically viable, as with any other transmission investment, and a positive outcome of the cost benefit analysis is required from the investor point of view. The development of such systems is therefore strongly linked to the manner in which the remuneration of such systems is organized (particularly for links between different countries). This remuneration either comes tariffs (regulated), comes from market revenues (merchant) for selling capacity, transmitting power or from offering ancillary services, or from a mix. The regulatory framework in place has a strong influence on the risks associated with such investments: appropriate ratings, connection points, timing, possibilities to interlink with existing projects etc. At the current stage, a patchwork of different regulations exist, often focused on the local, national level. This patchwork complicates the development of a cost-optimal transmission system.

C. Grid Codes

HVDC connections are currently predominantly built by a single vendor. Such systems will in the future, especially when DC grids are concerned, consist of different components from different manufacturers and with different properties. These systems also should allow the connection of new components to the system. In order to assure a neutral, multi-vendor system which operates reliably, a number of technical requirements need to be agreed. This agreement or requirement is described in grid codes. Factors which need to be set in such a grid code are described in [65]. These include

the steady state operating ranges of the DC grid, allowed transient over- and undervoltages, the voltage-power balancing requirements, the connection requirements of new components, data exchange requirements, amongst many others. Considerable work is presently being undertaken to develop a consensus on such grid code requirements

X. CONCLUSION

HVDC technology is a well-proven and economic solution to a number of problems in power network transmission. Many years of successful operational experience are now held with both LCC and VSC HVDC. Both technologies are still developing rapidly, and higher power solutions are being developed by a number of manufacturers. Point-to-point solutions are well understood. Future innovative solutions will arise to further develop markets for HVDC grids in HVDC grids, including common grid codes and HVDC DC protection.

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